REALISING THE POTENTIAL OF CONCENTRATING SOLAR POWER IN AUSTRALIA

PREPARED BY IT POWER (AUSTRALIA) PTY LTD
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Realising the Potential for Concentrating Solar Power in Australia

The Australian Solar Institute (ASI) has commissioned this study to facilitate discussion on the potential for Concentrating Solar Power (CSP) in Australia.

Study undertaken and report prepared by IT Power (Australia) Pty Ltd, part of the IT Power group, a specialist engineering consultancy focussing on renewable energy, energy efficiency and climate change. IT Power has offices in Australia, China, India, Kenya, Morocco, Portugal, UK and USA.

Authors; Keith Lovegrove, Muriel Watt, Robert Passey, Graeme Pollock, Joe Wyder, Josh Dowse.

The views expressed in this report are views held by IT Power, formed on the basis of the conclusions reached in the course of its analysis. The report does not seek to present the views of ASI, or any employee or Director of ASI, nor that of the Australian Government.

This document, whether in hard copy or electronic form, is made up of three parts: Report at a Glance; Executive Summary and Main Report. The Report at a Glance together with the Executive Summary are also separately available in a combined document "**Realising the Potential for Concentrating Solar Power in Australia - Summary for Stakeholders**" with different formatting but containing the same material.

For further information contact IT Power (Australia) Pty Ltd
ph: 61-2 6257 3511
email: itpau@itpau.com.au
web: www.itpau.com.au

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CSIRO Solar Thermal Research Hub, CSIRO National Energy Centre, Newcastle, NSW, Australia.

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Report at a Glance

Major changes in the world's established energy supply systems are being driven by growing energy demand, energy security concerns, rising greenhouse gas emissions, local environmental issues, increasing oil prices, and international competition to lead in the emerging clean energy technologies. Australia shares these global concerns. To address them all at least cost and risk, while providing energy for intra-day peaks and longer-term demands, a portfolio of energy options is needed. Concentrating Solar Power (CSP) is one of those options. However, a significant cost-revenue gap for CSP projects is deterring private investment. Concerted action is needed to close that gap and retain CSP as a strong energy option for Australia's future.

CSP is proven and available

Global installed capacity of CSP is growing rapidly and is predicted to reach 2GW in 2013, led by Spain and the US. Concentrating solar thermal (CST) plants dominate, typically using standard steam turbines and often integrating thermal energy storage.

CSP can contribute significantly to Australia's energy needs

Australia has just over 50GW in electricity generation capacity from all sources. This study finds that, it would be technically feasible to add up to 15 GW of CSP capacity, with only modest grid extensions. Hybrid systems within existing fossil-fuel plants, and smaller plants for off-grid mines and towns, are important near term applications for CSP systems. Future 'nation-building' grid extensions would unlock more of Australia's world-leading solar resource, which vastly exceeds all predictable energy demand.

CSP offers particular benefits

As part of a future energy portfolio, CSP systems would deliver:

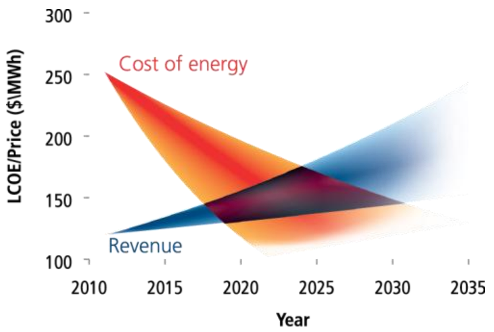
- **Dispatchable energy supply:** Systems that can dispatch electricity in the range of baseload to peaking power are an essential complement to variable renewable sources. CSP with storage has that capability.
- **Lower emission conventional power plants**: CSP can be efficiently integrated into existing and new coal and gas power plants to reduce emissions and extend plant life for a least-cost transition to a low-emission energy future.
- **Emission reduction**: 10GW of capacity would reduce Australia's emissions by roughly 30Mt CO_2 per year, about 15% of current electricity sector emissions.
- **Clean energy sector growth:** Only a few countries are currently investing in CSP. With CSP exploiting its world-leading solar resources, Australia can claim a significant place in the global clean energy supply chain. Delaying action will see that opportunity missed.
- **Community-supported generation:** CSP need not compete for valuable land or water and is low-impact. Every 100MW system would create around 500 job years during construction and 20 jobs during operation, mostly in regional areas.
- **Potential for future solar fuels**: Emerging technology will convert solar energy to liquid fuels, supplied at scale to both domestic and export markets.

However, the cost-revenue gap is currently too great

The CSP cost-revenue equation varies enormously with system configuration and location. Instantaneous CSP generation correlates well with peak electricity prices. With thermal storage, the energy value of CSP systems is even higher, up to double the wholesale market average. Even so, CSP projects are not yet commercially attractive in Australia. For utility-scale systems, the baseline 'levelised cost of energy' (LCOE) is around $250 per MWh, while maximum revenue streams in main grid-connected markets currently total around $120 per

MWh (including renewable certificates). The gap is smaller for the relatively small off-grid mining and remote towns sector.

The gap will close, with the help of Australian action



Consistent with overseas research, this study finds that the cost-revenue gap for CSP in Australia is likely to close over the next 6 to 18 years as plant costs fall through global deployment and technology improvement and available revenue rises. However, these projections depend on continued global investment in CSP. At this early stage of the global industry, Australia has the opportunity to contribute significantly to momentum in reducing costs and risk. Completing 250MW of Solar Flagships and other deployments and maintaining a sector annual growth in line with recent global rates would lead to an Australian CSP capacity of around 2GW by 2020.

Concerted Australian action needed

1: Bridge the reducing cost-revenue gap

Whilst continuing to focus on lowering cost, the CSP sector should work with governments and regulators to increase the reward for clean energy systems that better correlate generation to real-time demand.

Rather than subsidising CSP specifically, technology-neutral measures should target the dispatchable characteristics that Australia needs. Early deployment where the cost-revenue gap and other challenges are smaller will help maximise CSP opportunities and bridge the gap. The CSP industry must continue to focus on demonstrating lowering costs from deployment learning and technology improvement.

2: Build confidence in CSP's offer

The CSP sector should better communicate CSP's value proposition to key stakeholders including AEMO, AEMC, electricity retailers and financiers.

Government, consumer, energy industry and investor support for CSP will remain ephemeral until there is a base of understanding and confidence. The CSP sector must explain CSP's potential benefits, demonstrate them in practice, and respond to concerns.

3: Establish CSP-solar precincts

The CSP sector should work with governments, regulators and service providers to pre-approve and provide connections for CSP systems in selected areas of high solar resource.

CSP precincts would reduce planning, approvals and grid connection costs, helping to reduce early-stage project risk. They would also spread the costs of solar data collection, environmental impact assessments and community consultation across projects.

4: Foster CSP research, development and demonstration

The CSP sector should leverage continued public and industry investment in research, development and demonstration, with more emphasis on meeting Australian needs.

Building CSP in Australia requires growth in skills and capabilities that are lacking; targeting deployment of systems below 50MW (overlooked by the global industry); incorporating energy storage; improving efficiency; hybridisation with fossil fuel plants; and using advanced cooling technologies (reflecting our water constraints).

If these actions are pursued successfully, the CSP sector would be large enough to deliver economies of scale within immediate investment and policy horizons.

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Executive Summary

Outlining CSP's future in Australia

Major change in the world's established energy supply systems is being driven by growing energy demand, energy security concerns, rising greenhouse gas emissions, local environmental issues, increasing oil prices, and international competition to lead in the emerging clean energy technologies.

Australia shares these global concerns. We have local pollution issues associated with energy generation. Although gas production is rising, Australia's domestic oil production is declining just as demand is growing and international prices continue to rise. Electricity demand, while slowing due to energy-efficiency and demand-side measures, is predicted to grow at 0.9 to 1.5% annually.[1]

There is also a continuing lack of diversity in an energy mix dominated by fossil fuels. Although these have given Australia comparatively low energy costs, that advantage is being eroded. As fossil-fuel prices rise, countries that offer the best clean technologies may gain a new competitive advantage.

Nonetheless, Australia's most explicit driver is the aim to reduce net greenhouse gas emissions to 80% below 2000 levels by 2050. Given the high proportion of emissions from the power sector, and the challenges of reducing greenhouse emissions in the transport sector, meeting this target will require extensive clean electricity generation to be in place by 2050.

Concentrating Solar Power (CSP[2]) technologies are one of the future options being deployed with rising confidence and rapidity around the globe, led by Spain and the US.

Meeting Australia's energy needs

Decisions about Australia's energy future taken through to 2020 will lock in significant parts of our energy mix for decades. Most electricity used in Australia in 2050 will be generated from plants that do not yet exist. Over $200 billion in new generation investment is projected, over half being in renewables. Australia's transmission and distribution networks also require significant investment.

A portfolio approach is likely to offer the least cost and lowest risk pathway to meeting Australia's energy needs and emission targets. Wind and solar photovoltaic (PV) generation are the international success stories to date. However, they convert wind and solar energy only when they are available, and so require spinning reserve and fast-start power plants to manage their variability.

A significant part of our future clean electricity mix must be dispatchable on demand. Apart from concentrating solar power (CSP)[3] , clean energy technologies that are often suggested to provide that dispatchable power include geothermal and fossil-fuel generation with carbon capture and storage. All have risks that match their potential. CSP should be kept as an available option.

CSP's role in meeting those needs

CSP systems offer large-scale clean energy generation that can be configured to provide energy for intra-day peaks and longer-term demands. Australia has previously invested in a handful of small demonstration projects (see Table 3) and at the time of writing, is working to

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[1] Australian Government, *Draft Energy White Paper 2011*, p 38.

[2] The term Concentrating Solar Power is often used synonymously around the world with Concentrating Solar Thermal Power (CST). In this study, the term is used in a more general sense to include both CST and Concentrating Photovoltaic (CPV) systems. The scope of the study was limited to systems designed for utility scale power generation and did not specifically include solar fuels or industrial heat.

[3] CSP systems can also be variable but CST variants with built in thermal storage offer dispatchable characteristics.

finalise a major “Flagship” CSP project. Together with the overseas experience, they point to the potential for CSP making a significant contribution to Australia’s future energy needs.

However, private investment in commercial projects remains limited. Though it is closing, the cost-benefit gap is still significant. Benefits to both the energy sector and the broader community are not recognised in the limited equations of project finance. Two of the most important benefits – preparing to meet Australia’s long term greenhouse gas emissions reduction challenge, and securing for Australia a valued part of the global renewable energy supply chain – have greatest value if early action is taken. Targeted effort is needed to ensure the commercial case becomes positive as quickly as possible. Part of that effort must be to raise awareness of CSP technologies among Australian policymakers, energy consumers and financiers, and to build confidence in their potential.

As a step towards that awareness, the Australian Solar Institute has commissioned a detailed study on the current realities, potential and challenges for a CSP industry. This summary report for stakeholders presents the core findings of the study, and its views on constructive actions ahead. It offers a snapshot of:

a. CSP technology and its international adoption and growth,
b. Its potential applications and markets in Australia,
c. At the project level in those markets, the available revenues and the costs of attaining them,
d. The resulting commercial equation for CSP projects,
e. Available public and sector benefits that aren’t being captured at project level, and
f. Options to accelerate CSP’s development in Australia and so capture those benefits.

Table 1; CSP technologies currently in use

	**TROUGH** > The most widely deployed CSP technology, with 1,400 MW_e (CST) installed as at 2011. > Parabolic mirror tracks sun east to west, and focuses energy onto a linear ‘evacuated tube’ receiver. > Mature technology with systems operating for over 25 years.
	**LINEAR FRESNEL** > Long rows of flat or slightly curved mirrors, moving independently on one axis. > Energy reflected up to fixed linear receivers mounted on towers well above the mirrors. > Medium maturity, 38 MW_e (CST) installed as at 2011.
	**DISH** > Paraboloidal shape with two-axis tracking focuses sunlight to a point receiver. > The highest optical efficiency of all CSP types, because full aperture directed toward the sun avoids the ‘cosine loss effect’. > Low maturity, 6 MW_e (CPV & CST) installed as at 2011.
	**TOWER** > An array of heliostats (large mirrors with two-axis tracking) concentrate sunlight onto a fixed receiver at the top of a tower. > Large single receiver facilitates complex conversion processes such as direct heating of molten salt. > Medium maturity, 60 MW_e (CST) installed as at 2011.
	**FRESNEL LENS** > Flat plastic lenses made as a series of concentric steps. > Point focus used with high efficiency PV cells. > Mounted in arrays to track the sun in two axes. > Medium maturity, 15 MW_e (CPV) installed as at 2011.

Available CSP technologies

CSP has proven itself as a technically sound electricity generation option. Since the sector was reinvigorated in 2005, global installed capacity has grown by c.40% annually and will reach 2GW in 2013.

Concentrating solar power systems

The defining characteristic of CSP systems is that solar radiation is concentrated by mirrors or lenses onto a single point or linear receiver. The receiver can convert the concentrated sunlight directly into electricity (with photovoltaics or receiver-mounted engines) or use a heat transfer fluid to transfer the energy to a central power system. The more common concentrated solar thermal (CST) plants typically use standard steam turbines, and often integrate thermal energy storage.

The five CSP technologies that are being used globally are set out in Table 1 on the previous page: trough, linear Fresnel, dish, tower and Fresnel lens. Systems that use two-axis tracking to concentrate sunlight onto a single point receiver – the tower and dish – are more efficient than the linear focus systems. When constructed as CST plants, they can operate at higher temperatures, and so generate power more efficiently.[4] However they are also more complex to construct.

Conversion and storage systems

Thermal storage works to make CST a more flexible and valuable electricity generation technology than variable renewable energy options. CSP systems can use a range of approaches to convert solar energy to electrical energy, though most rely on steam turbines. Manufacturers now offer customised CSP steam turbines that convert around 40% of steam thermal energy to AC electricity, at full load. Other conversion systems include photovoltaics (for CPV), Stirling engines, Brayton cycles and Organic Rankine Cycles. All need cooling. Water-cooled plants require similar water quantities to fossil fuel plants: 2 to 3 kilolitres per MWh. Air-cooling cuts water use by around 95%, but with a decrease in electricity production.

Opportunities for hybridisation with fossil fuel arise from CST systems, since both CST and fossil-fuelled plants convert heat to electricity. Options include feeding CST-generated steam to existing power stations, or adding gas-fired backup to CST plants.

CST’s main advantage though comes from its use of thermal storage to provide ‘dispatchable’ clean energy. Storing heat energy is cheaper than storing electrical energy. CST plants add a thermal storage unit between the heat receivers and the turbines. This means that heat energy beyond or below the turbine’s operating range can be stored and not wasted, and also allows the turbines to run at optimal loads for longer periods. Most importantly, thermal energy can also be converted into electricity and dispatched when the demand or price for that electricity is highest.

The thermal storage technology that is most advanced is the two-tank molten salt system: see Figure 1. For a trough based system, these cycle molten Nitrate salt[5] between a ‘cold’ (energy depleted) tank at 300°C and a ‘hot’ (energy charged) tank at nearly 400°C. At the end of 2011, 62% of installed CST systems in Spain used molten salt energy storage.

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[4] The efficiency of heat engines is measured in part by the relative loss of heat in the heat transfer fluid as it passes through the steam turbine or other heat engine: Carnot’s theorem.

[5] The salt composition is 60% $NaNO_3$ + 40% KNO_3

Figure 1: Two tank molten salt, thermal energy storage at Andasol 3, Spain (background image Ferrostaal).

International growth in CSP capacity

Though CSP technology is being adopted internationally, the rate of its continued expansion depends on policy decisions in key countries. With supportive policies in place since 2005, global installed CSP capacity[6] will reach at least 2 GWe by 2013. Countries believing it will be a major contributor to a future clean energy mix have offered CSP-specific feed-in tariffs, renewable portfolio obligations and direct project support. This support comes after a decade-long hiatus: after tax incentives that stimulated growth in the US in the 1980s and '90s ended, the deployment of utility-scale CSP plant stalled. The recent CSP adoption has been led by Spain, and increasingly by the south-western states of the US.

Though continued expansion of CSP is expected, it is not yet secure. Spain is winding back its industry support due to fiscal constraints. Future US federal programs, designed to complement state-based initiatives, are by no means certain. On the positive side, several Middle Eastern and North African countries have just begun low-level CSP activity. India is taking the first steps on its Jawaharlal Nehru National Solar Mission, which aims to install 20 GWe of CSP and PV capacity by 2022. China could play a major role but has yet to demonstrate its intentions in a concrete way.

Installed capacity has grown at approximately 19% per year since 1984, and at about 40% per year since 2005. For the next decade, a range of industry studies estimate growth at between 25% and 40% annually. There are three scenarios that can be considered:

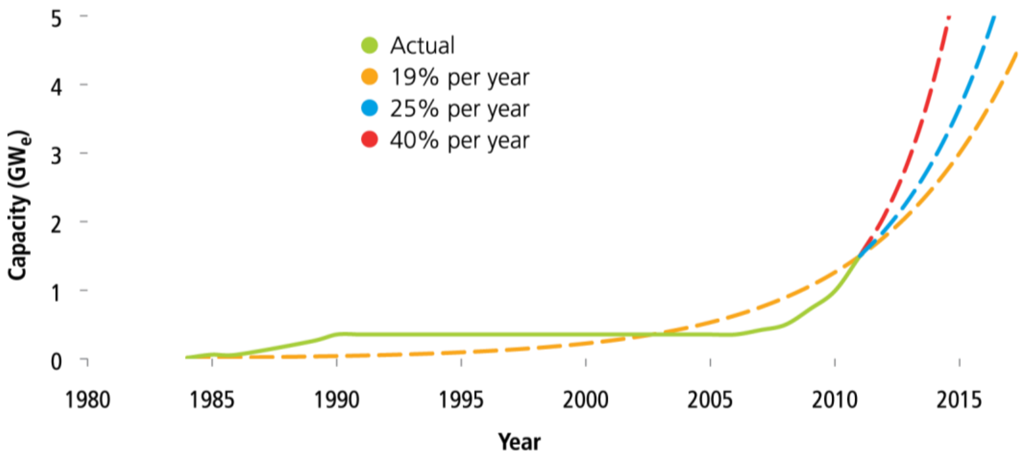
- Complete stagnation of the global CSP industry as competing technologies win on cost.
- Piecemeal growth spurts in various countries that allow the industry to maintain its existing 19% p.a. long term average growth rate.

6 Installed capacity (in GW_e) is a somewhat misleading metric, since systems with storage and a higher capacity factor produce more energy per year and have a larger system area per GW_e of installed capacity. Capacity referred to here is an equivalent capacity normalised to have the same average capacity factor as plants existing at end 2011.

- 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 recent years.

While complete stagnation of the CSP industry is possible, the need and demand for dispatchable clean energy makes this unlikely. If there is a concerted global effort to address greenhouse gas emissions and improve future energy security, the strong growth scenario is clearly possible. However, the current global situation suggests growth of 25% per year is more likely, at the low end of industry studies yet still substantial: see Figure 2. See the section 'Cost of delivering CSP energy' below for the likely implications of this growth.

Figure 2: Global installed capacity and possible future trajectories of CSP plants to end of 2011.



Australian markets for CSP

Despite being limited to areas of both high solar resource and grid connectivity, CSP could provide up to 15 GW in the near-to-mid-term, about 30% of Australia's total current electricity generation capacity, with significant benefits to the energy sector.

Market segments and location

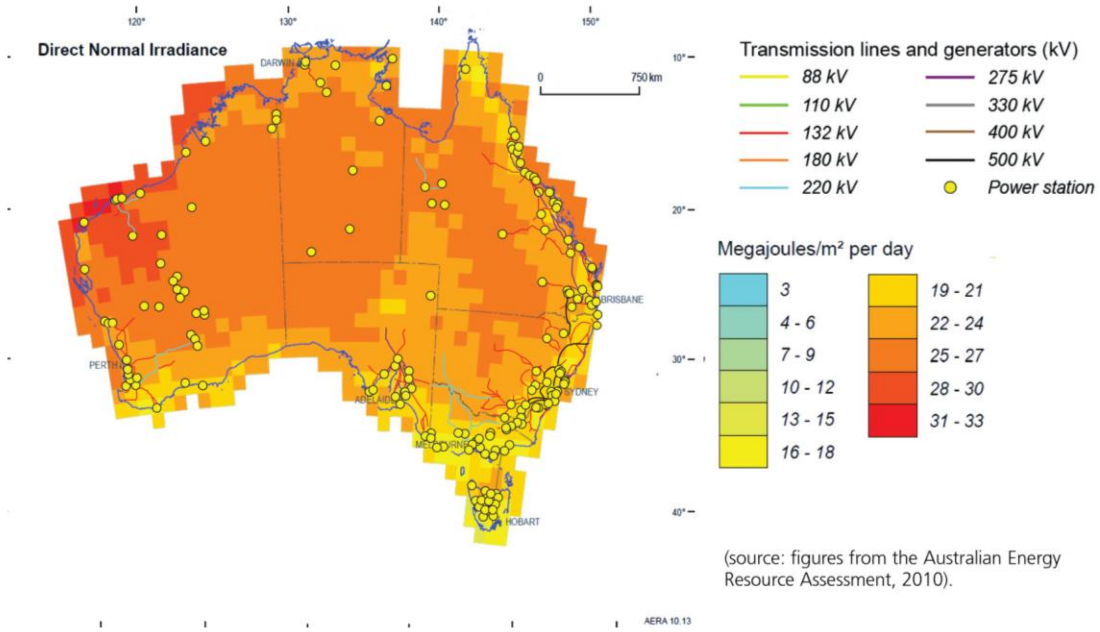
Both off-grid and grid-connected market segments can be considered for CSP. Demand for off-grid CSP applications comes from remote towns, mines or other industrial plants. Australia's growing electricity demand and mandatory renewable energy targets mean that there is a use for any electricity produced as long as the output profile is suitable to the customer. Whether that delivery is commercially viable is discussed below.

Australia's existing transmission and distribution networks are not ideally configured for CSP. Where the solar resource is best, there is either no grid to access, or the suitable grid capacity is limited: see Figure 3. It is not just a question of location. Australia's networks have been designed to transmit electricity one way: from large central generators, located near coal, gas or hydro resources, to their customers. In many potential locations, CSP-generated electricity would need to flow the other way, over relatively long distances. The local capacity of the network will also constrain the potential size of the CSP system seeking to connect to it.

Nonetheless, sufficient areas of high standard solar resource are accessible for CSP to make a significant contribution to Australia's energy needs. Three location-based market segments should be considered:

- large-scale plants connected to the high-capacity transmission network[7];
- medium-scale plants connected to lower-capacity distribution network; and
- off-grid systems.

Figure 3: **Map of Australian transmission networks overlaid with the distribution of Direct Normal Insolation (source figures from the Australian Energy Resource Assessment, 2010).**



The technical potential for these market segments in Australia has been assessed, based on network limitations in areas of sufficient annual solar radiation and is summarised in Table 2 below. In total, there is about 14 to 15GW of technical potential for CSP in Australia that could in principle be installed in a straightforward manner with modest grid extension. For CSP to meet more of Australia's future electricity demand than this, grid extensions of a 'nation-building' nature would be required.

In each of these location-based segments, CSP plants could be configured with or without thermal storage. This means that the energy potential ranges, between 25,000 and 60,000 GWh per year (equivalent to 8 to 20% of current annual electricity demand). Systems could be configured to offer combinations of:

- Immediate generation when solar is available (no thermal storage).
- Energy on-demand using storage or co-firing.
- Continuous generation at lower power level using storage or co-firing.

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[7] The electricity network (grid) is made up of a backbone of high capacity, very high voltage, "Transmission" lines of > 66kV from which radiates a network of lower capacity sub 66kV distribution lines.

Table 2 **Technical potential of different market segments**

Market segment	Technical potential	Notes
Large-Scale grid-connected		
Hybridisation with existing fossil fuel plants or industry (CST only)	2 GW_e	Assumes 25% of appropriate coal-fired power station's steam needs are delivered by CSP.
Stand-alone 50–150 MW systems (grid-connected)	3 to 4 GW_e	Requires grid connection point capable of receiving significant new energy injections.
Stand-alone< 1 GW clusters (modest grid extensions)	8 GW_e	Likely requires high-capacity plants with thermal storage whose economics cover cost of grid extension
Stand-alone > 1GW clusters (nation-building grid extensions)	Limited by market demand	Available high solar resource land area vastly exceeds all conceivable demand if accessed with dedicated major grid extensions
Medium Scale grid-connected		
Grid-connected (1–20 MW systems)	0.6 GW_e	Particular systems (large solar field, large storage, smaller capacity, high capacity factor) suited to distribution networks with capacity constraints.
Mini-grid-connected (1–10 MW systems)	0.12 GW_e	Would need thermal storage and dispatchability to have an advantage.
Off-grid		
Mining (systems < 10 MW)	0.1 GW_e	> 50 remote mine sites may be suitable for small-scale CSP, but short mine life and risk avoidance by mine owners/operators limit uptake.
Remote Towns (1–10 MW systems)	< 0.005 GW_e	Relatively small-scale demonstration systems.
Remote Towns (CPV systems < 1 MW)	< 0.005 GW_e	Could be suitable to test equipment and integration strategies.
Total	**~ 14 to 15 GW_e**	

CSP's potential advantages

If CSP systems proved themselves viable to meet the needs of these market segments, they would deliver strong advantages to Australia's energy sector:

- **Dispatchable energy supply.** Systems that can dispatch electricity in the range of baseload to peaking power are an essential complement to variable renewable sources. CSP with storage has that capability.
- **Lower emission conventional power plants**: CSP can be efficiently integrated into existing and new coal and gas power plants to reduce emissions and extend plant life for a least-cost transition to a low-emission energy future.
- **Emission reduction**: 10GW of capacity would reduce Australia's emissions by roughly 30Mt CO_2 per year, or about 15% of current electricity sector emissions.
- **Clean energy sector growth:** Only a few countries are currently investing in CSP. With CSP exploiting its world-leading solar resources, Australia can claim a significant place in the global clean energy supply chain. Delaying action will see that opportunity missed.
- **Community-supported generation.** CSP need not compete for productive land or valuable water, is low-pollution and low-impact. Every 100MW system would create

around 500 job years during construction and 20 jobs during operation, mostly in regional areas.

- **Potential for future solar fuels**. Emerging technology will convert solar energy to liquid fuels, supplied at scale to both domestic and export markets.

However, as with all technologies, CSP's place in the generation mix will be determined by project economics. These are explored over the following three sections.

To date Australia has only deployed some small CSP systems, largely of a demonstration or experimental nature. Some examples of these are listed in Table 3.

Table 3: Early demonstration and experimental CSP installations in Australia

LIDDELL POWER STATION (CST)

Liddell Power Station in the Hunter Valley, NSW, hosts a 1,300m² array of Linear Fresnel reflectors installed by Ausra (now Areva) Solar. Work is nearing completion on an additional 18,490m², 9.3 MW_{th} Linear Fresnel array provided by Novatec Solar. The arrays pre-heat feedwater for the coal-fired station.

ALICE SPRINGS AIRPORT (CPV)

As part of the Alice Springs Solar City project, a 235 kW CPV plant has been constructed at Alice Springs Airport. The system uses SolFocus SF-11100 tracking arrays which are based on panels of 'micro dishes' assembled behind a glass cover. The system was commissioned in early 2011.

SOLAR SYSTEMS INSTALLATIONS (CPV)

Solar Systems Pty Ltd first added a CPV power station to a diesel mini-grid in 2001. Four more CPV stations (total 1.25 MW), now fitted with Spectrolab III-V PV cells, were installed in Hermannsburg (2005), Yuendumu (2006), Lajamanu (2007) and Windorah (2008), with support funds from the Australian Government's remote power program.

AUSTRALIAN NATIONAL UNIVERSITY DISHES (CST)

Following on from a 14-(small)-dish system at White Cliffs, a 400m² SG3 dish was completed in 1994, then the world's largest. A 500m² aperture design, optimised for mass production for large-scale plants, was built in 2009.

CSIRO NATIONAL SOLAR ENERGY CENTRE (CST)

CSIRO has a major presence in CST R&D. The Newcastle site houses two Tower systems, a 500 kW_{th} system and a recently commissioned system with a 30m high tower and a 4000m² field of 450 heliostats. Key areas of ongoing investigation include solar reforming of natural gas, steam generating systems and solar-driven Brayton cycle systems.

GRAPHITE ENERGY STORAGE (CST)

The Australian Government's Advanced Electricity Storage Technologies program included a demonstration of graphite-based thermal energy storage by Lloyd Energy / Graphite Energy. The tower systems with their receiver-mounted thermal energy stores are visible from the town of Lake Cargelligo. The systems a drive a steam turbine of approximately 3 MW.

KOGAN CREEK FLAGSHIP AND SOLAR BOOST (CST)

The successful Solar Flagship Round 1 CST proposal is the 250 MW_e Solar Dawn system at Kogan Creek, yet to be finalised. It is sited next to the 44 MW_{th} Solar Boost CST project funded by the Australian Government's Renewable Energy Demonstration Program, which is under construction. Both use Areva Linear Fresnel technology. When complete, these systems will together account for most of Australia's CSP capacity.

Available revenue for a CSP asset

The major source of revenue for CSP assets is the sale of electricity into Australia's wholesale electricity markets. Renewable generation that offers dispatchability could secure revenue well beyond average wholesale market prices – perhaps double the per-unit- revenues of base-load fossil-fuel plants. Additional network income may contribute a little extra under current settings, with renewable energy certificates (RECs / LGCs) adding a further $30-40 per MWh.

The income available to a CSP system, whether under a negotiated power purchase agreement (PPA) or not, reflects the following income streams that represent the system's underlying value:

- Income set by pool prices in wholesale electricity markets, and
- Additional income for network benefits such as:
  - avoided line losses/marginal loss factors
  - ancillary services such as the ability to compensate for supply variations from other sources, and
  - avoided grid augmentation expenses.
- Renewable Large-scale Generation Certificates (LGCs)
- Capacity Credits in the Western Australia South West Interconnected System (SWIS), and
- Direct sale via contract to off-grid and mini-grid customers.

Pool prices in wholesale electricity markets

Extensive modelling using the NREL System Advisor Model (SAM) has been used together with historical price data to test the hypothetical revenue that CSP plants could produce in Australian wholesale electricity markets. The results confirm the additional value that dispatchability offers a CSP plant. Table 4 sets out the results from two relevant scenarios:

a) generation of electricity and sale whenever solar is available; and
b) storage of the energy and subsequent sale at a time of day that maximises the revenue value accrued[8].

Table 4 Sale price of energy from a CSP system, averaged over 2005– 2010, with and without storage.[9]

State	Market average price $ / MWh	Immediate dispatch average sale price	Ratio immediate / market average sale price	Dispatch from storage average sale price $ / MWh	Ratio Storage / market average
VIC	$39.2	$58.9	1.50	$74.6	1.90
SA	$49.5	$89.7	1.81	$136.9	2.77
QLD	$36.9	$50.0	1.35	$77.2	2.09
NSW	$41.3	$54.7	1.32	$80.7	1.95
WA	$50.1	$58.1	1.16	$65.8	1.31
AVERAGE	$43.4	$62.3	1.43	$87.0	2.01

All regions show that immediate dispatch solar has a higher value than the pool average, and that store and dispatch produces a higher value still. This analysis was repeated for different

8 Dispatch start times were varied separately for summer and winter to seek a simplified approach to maximising value. Plant power block size was increased relative to the solar field size and an optimum storage size of approximately 6 hours was indicated by the model.

9 All NEM regions except Tasmania are compared in Table 4 along with results for the Western Australian South West Interconnected System (SWIS), which also operates a competitive energy market, the Short Term Energy Market (STEM).

technologies and different sites within a state and found to be virtually independent of both issues. However, there is quite a large variation (+/- 30%) from year to year. While the average wholesale price of energy in the NEM for 2005 –2010 was $43.4 per MWh, modelling suggests dispatchable energy from CSP storage would have averaged $87.0 per MWh.

This analysis neglects the potential effect that a large amount of solar capacity could have on the pool prices if it were installed. The addition of very large amounts of CSP generation would tend to reduce the premium for immediate-dispatch and storage; conversely, a large proportion of other variable renewable generation in the network may actually increase the price premium available to a CSP plant with dispatchable capability.

Additional network value and income

While there is clarity on the wholesale energy prices available through the NEM, an operating CSP system offers the network further values, some of which are only partly recognised by expected plant revenues at present.

Avoided line losses

The positioning of CSP systems in areas of high line losses may lead to their generated energy securing higher prices. As electricity moves through the transmission and distribution networks, some energy is lost as heat. Marginal Loss Factors (MLFs) measure the energy loss in the transmission network, and Distribution Loss Factors (DLFs) do so for the distribution network. Where energy is fed into the network at a location with a high loss factor (>1), it has a higher value. Electricity prices vary in direct proportion to the MLFs and DLFs. In 2010-11, MLFs ranged from 0.8 to 1.16, though usually within 5% of unity. DLFs also range generally within 5% of unity, but in 2010-11 ranged up to 1.251 (in Ergon Energy's network).

CSP systems are likely to be in rural or reasonably remote locations, where the loss factors are greater than 1, implying a higher value for their generated energy. However, as the loss factors are recalculated annually, the new CSP plant will itself reduce the local loss factor, and so the price paid to it. Some policy or contractual price adjustment may be needed to recognise the underlying benefit to the network.

Avoided network costs

To meet peak demand across the network, lines must have the capacity to carry electricity from generation to supply points, allowing for line losses throughout. Reliable generation at the end of near-capacity lines potentially reduces the network capacity needs throughout. Though this network benefit is recognised in the Code of Practice Demand Management for Electricity Distributors, anecdotal evidence suggests that there has been little financial recognition. There is no matching requirement for the transmission system.

Again, a policy or contractual price adjustment may be needed to recognise the underlying network benefit. The implied value would vary, depending on the CSP plant's capacity characteristics and the costs of network infrastructure. The benefit may fall between 1 and 5% of total energy value, with the likely onus on the CSP plant to demonstrate that benefit.

Capacity Value

The capacity value relates to the extent that the CSP plant can offset the need for investment in other dispatchable systems on the grid. To some extent, this capacity value is recognised in the NEM by the high wholesale prices for peaking power. In the WA SWIS, capacity value is recognised explicitly, with payments of around $180,000 per MW per year for available capacity. If a high-capacity CSP system could earn 90% of that rate it would equate to an extra

$20 per MWh income. A CSP system that could retain a few hours of energy in storage would qualify for such payments[10]. A hybrid system with fuel-fired back up could also qualify.

Ancillary services

'Ancillary services' are those provided by generators and others connected to the electricity network, that are needed to keep the network operating reliably within its specifications of voltage and frequency. The more variable the energy supply to the grid, the more that these services are needed. CSP systems, particularly those with appropriate energy storage, may offer the NEM a range of ancillary services. The services are recognised independently of the sale and purchase of energy, though their combined value amounts to only $1 per MWh at present. This may rise to significant levels if very large amounts of variable renewable generation are connected to the grid.

Income beyond the wholesale markets

Large-scale Renewable Energy Certificates

The Renewable Energy Target was expanded in 2009 to an additional 41,000 GWh per year of 'new renewable generation' by 2020. Large-scale generation certificates (LGCs) are earned for every MWh generated by accredited renewable energy power stations, and were trading at around $40 per MWh at the end of 2011. While there has been volatility in the REC/LGC spot prices and uncertainty in projected prices remains, LGC income is likely to remain material to project finance considerations.

Off-grid systems

For CSP systems with off-grid or mini-grid customers, there is no open market; Power Purchase Agreements (PPAs) are negotiated with each customer. The main fuel has been diesel, with natural gas used where available. The per-MWh cost of these fuels is highly variable, and depends on the size of the system and fuel transport costs as well as the base commodity price. A recent study[11] of the cost of large (30 MW_e) diesel and gas systems in the Pilbara and mid-west of Western Australia estimated generating costs of $285–$300 per MWh from diesel (priced at about 85c per litre) and $180–$190 per MWh for gas. CSP systems with acceptable output characteristics could negotiate PPAs of similar value.

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[10] Note that molten salt storage can retain energy for one to two weeks if it is not used. Molten salt tanks also have resistive electrical heaters fitted so they can be kept molten in the event of several weeks of zero input. These could provide a last resort way of meeting capacity obligations.

[11] Assessment of the potential for renewable energy projects and systems in the Pilbara, Evans and Peck 2011.

Cost of delivering CSP energy

Identifying the cost of delivering energy to grid or off-grid customers is a complex process. Capital costs depend on the configuration, size and location of a plant. In addition, given the relatively early stage of the CSP industry in Australia, reliable data is difficult to establish. The best comparative metric is the Levelised Cost of Energy (LCOE), which amortises the construction, operation and other costs across the plant's lifetime. A baseline LCOE of $252 per MWh represents the most conservative, least technical-risk CSP technology built at a 'most favourable' site in Australia. However, that baseline is strongly sensitive to capital cost variables (notably system size, storage, and relative power block size), the cost of capital, and the amount of energy generated annually.

A baseline cost and sensitivities

Capital cost estimates for Australia have been established from published data and confidential briefings from key technology providers. These have been converted to cost estimating coefficients[12] that allowed a range of configurations and system sizes to be examined. Table 5 gives three possible examples of system costs established in this way, for the particular case of 100MW$_e$ systems with differing capacity factors.

Table 5 Examples of specific CSP system costs for 100MW$_e$ central power block systems

	No storage (lowest capital cost)	2 hours storage (approx min LCOE)	5 hours storage (earns higher value)
Configuration	100 MW$_e$ block, 350 MW$_{th}$ field, 21% capacity factor at 2,400 kWh/m^2/year	100 MW$_e$ block, 395 MW$_{th}$ field, 30% capacity factor at 2,400 kWh/m^2/year	100 MW$_e$ block, 526 MW$_{th}$ field, 40% capacity factor at 2,400 kWh/m^2/year
Specific installed cost (AUD 2012)	$4653 / kW$_e$	$5534 / kW$_e$	$7350 / kW$_e$

These costs include grid connection, but not grid extension costs nor the cost of construction finance. While adding two hours' storage increases the system's installation cost, it reduces its LCOE. This and other variables and sensitivities need further analysis and are discussed below.

Capital cost estimates have been used, together with modelled annual generation for a 64 MW$_e$ trough plant[13] with no storage, using solar data equivalent to a typical year in Longreach Queensland. With a capital cost of $308 million (or $4,817 per kWe) and annual generation of 128,800 MWh, the LCOE is $252 per MWh. This baseline represents the most conservative, least technical risk technology built at a representative 'most favourable' site in Australia.

Around this baseline, the strong sensitivity to key parameters is shown in Figure 4. Annual energy generation, capital cost and weighted average cost of capital (WACC) all influence LCOE materially. Indices that track construction costs in regional Australia imply that initial capital costs could be 10 to 20% higher for remote regions. Early Australian 'first of a kind' projects may also cost 10–15% more again due to inexperience along the supply chain.

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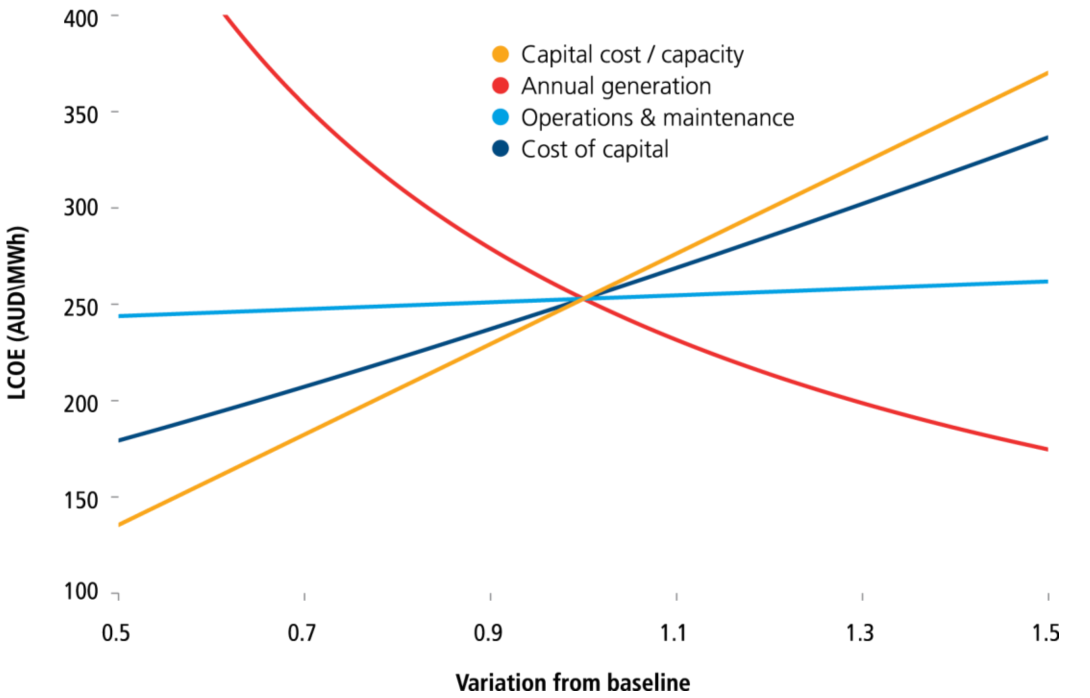
[12] The costing calculations used are wherever possible based on the status and potential of CSP as a general combined technology class.

[13] The characteristics of the actual Nevada Solar 1 plant in Las Vegas were used, with a known solar field capacity of 241 MW$_{th}$. 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%.

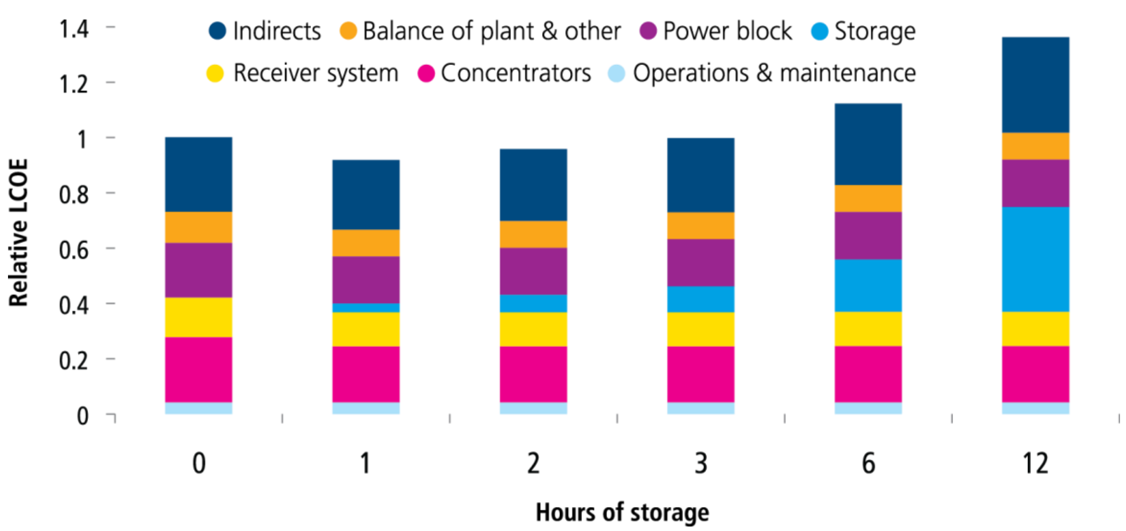
Figure 4: Variation of costs and performance against an LCOE baseline for a 64 MW trough system at Longreach.



Effect of energy storage

CST with storage is now the most common CSP configuration installed globally. A small amount of storage (1 to 2 hours) improves plant performance and reduces the LCOE compared to the no-storage case. However, increasing storage beyond around 3 hours adds significant further capital cost without generating more energy, and so increases LCOE.[14] Figure 5 shows the modelled results for a CSP trough system. These have been normalised to a value of 1 for the no-storage case, so that the impact of storage on LCOE can be seen independent from the assumed site, size, technology and financial parameters.

Figure 5: Impact of storage on LCOE for a 64 MW_e trough system, relative to a base case of no storage

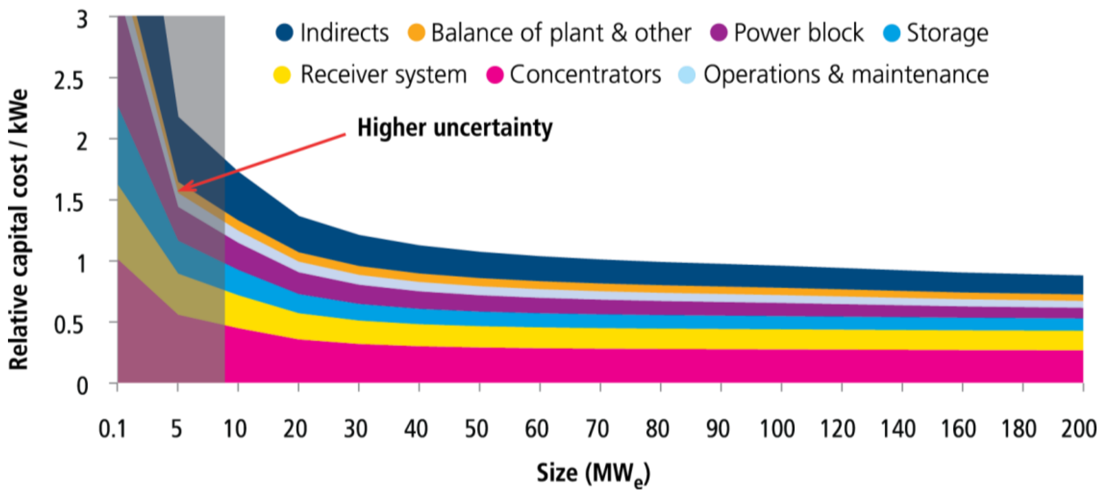


[14] This finding is consistent with overseas studies: www1.eere.energy.gov/solar/thermal_storage_rnd.html.

Effect of system size

Whatever the ratios between solar field, storage and power block size, the overall system size has a significant impact on the LCOE. Calculating the optimal size and its benefits is a global challenge. The current consensus is that the minimum LCOE for stand-alone systems is reached at around 250 MW_e. Beyond that, greater energy losses[15] reduce the system's relative output and the LCOE starts to increase. Over about 60MW_e the cost curve flattens considerably, as shown in Figure 6, with LCOE within ±15% relative to systems with a 100MW_e central power block. The results follow the installed cost of the systems very closely[16]. The relative cost curves for systems without storage reveal a very similar size dependence.

Figure 6: Estimated LCOE dependence on system size (normalised to a 100 MW_e system with 5 hours' storage).



Two key factors drive these economies of scale:

a) many components are more cost effective at large size; and

b) CST turbine efficiency falls with reductions in turbine size, so that all subsystems on the thermal side of the power block must be increased to compensate.

Where a CST system is added to an existing fossil-fuel plant, its LCOE would be virtually independent of size, since the power block would be set and have a fixed efficiency. Without the need for storage and power block costs, the LCOE would be about 30% lower than for a large stand-alone plant.

By comparison with central power block systems, CPV or Dish Stirling systems appear to be more cost effective below approximately 10 MW_e, but do not offer storage.

Effect of power block size relative to field and store

The ratio of power block size to input energy and thermal storage determines a system's best application. To supply baseload power, the system will have a relatively small power block: more thermal energy is being stored to be released uniformly. Increasing the relative size of the power block gears the plant to meet intermediate and peaking demand, and earn higher prices. However, this increases the plant's LCOE: see

Figure 7.

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15 Eg thermal losses from pipe networks or optical losses from distant heliostats.

16 Financial parameters such as cost of capital were assumed independent of size.

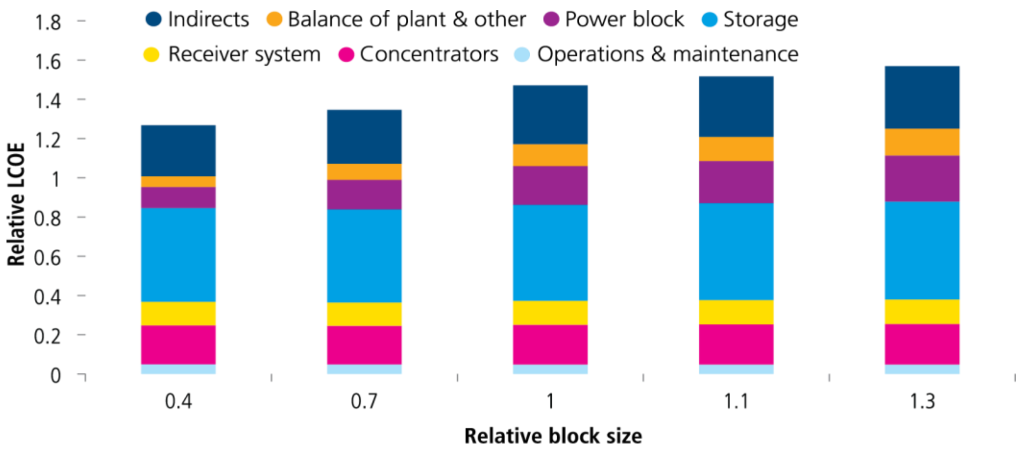


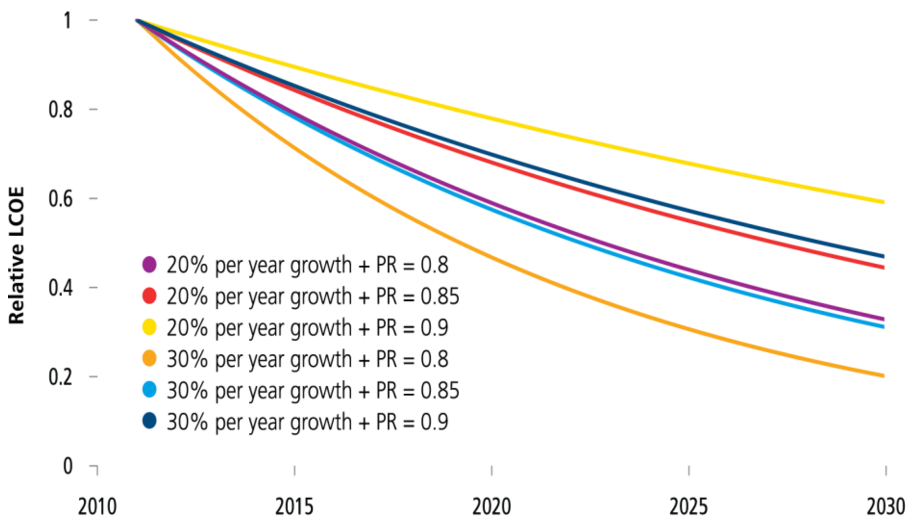
Figure 7: Impact on LCOE of relative power block size[17] for a trough plant (fixed thermal store and collector area).

Projected cost reductions

Significant reductions in the CSP system costs could be occurring within just a few years, as long as deployment levels are maintained. Consistent with other technologies at a similar stage of development, the LCOE of a CSP system is expected to fall by at least 20% by 2020, with a 50% reduction being quite feasible.

Cost projections are made while acknowledging that the global CSP industry has not stabilised sufficiently since its 2005 restart to show clear data points. Available evidence from CSP and similar industries points to a cost reduction of 10–15% for every doubling in global capacity (a progress ratio of 0.9–0.85). Compound growth in capacity appears likely to continue at at least 19% per year (the historical rate since 1984, including the sector hiatus), and more likely somewhat higher. Figure 8 plots the progression over time of relative costs (either LCOE or capital costs[18]) under either 20% pa or 30% pa growth rates, and for cost progress ratios of 0.8, 0.85 and 0.9.

Figure 8: Relative cost reductions over time under different deployment growth rates and progress ratios



A system's cost of energy does not, however, correspond directly to its commercial viability. For example, smaller systems built for remote or end-of-grid markets may have a higher LCOE, but can earn higher revenues. These value analyses are pursued below.

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[17] The block size of 1 corresponds to the 12 hour storage data point in Figure 5

[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.

The commercial equation for a CSP asset

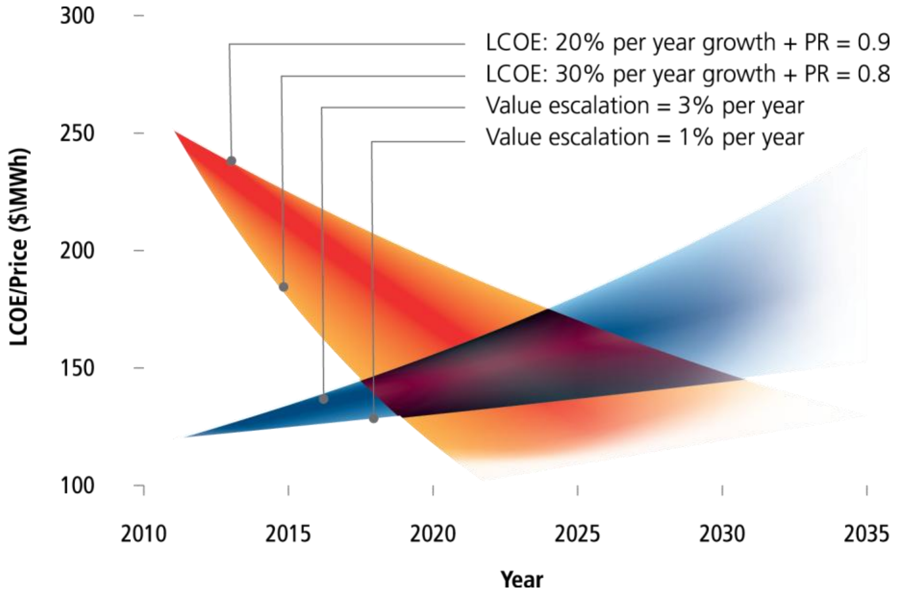
Under current market and policy conditions in Australia, CSP projects are not commercially attractive without subsidy. Private investors cannot monetise the broader public and sector-wide benefits that CSP generation may offer, so that project Net Present Value (NPV) does not meet their risk-reward benchmarks. There are other sector and project-specific challenges that hinder investor interest. But the cost-revenue gap, though closing, is the main issue.

The financial gap

The revenues available to a potential Australian CSP plant in 2011 fall far short of the cost of building and running it. The indicative baseline LCOE of $252 per MWh for a typical $64MW_e$ trough CSP plant, compares to potential earnings of around $120 per MWh in today's grid-connected markets.

However, rising energy prices and falling CSP capital costs should close this gap between 2018 and 2030. On the revenue side, real energy values are likely to rise at between 1% and 3% per year through to 2030. Meanwhile, capital costs are expected to fall by 20% to 50% by 2020, depending on the eventual growth rate and progress ratio: see Figure 9. These projections are supported by international investigations[19], and suggest that private investment in CSP will increase significantly as the cost and revenue lines converge. They are however at odds with the very small projected cost reductions in the Draft Australian Energy Whitepaper[20,] which in turn led to projected solar contributions of just 3% by 2050.

Figure 9: Possible progression of indicative CSP LCOE and market value in Australia (2011 real AUD) for 2 combinations of growth rate and progress ratio.



While Figure 9 considers an indicative, medium-size CSP plant without thermal storage, the investment case for actual CSP projects varies enormously according to its configuration and market. The most significant variable for both revenues and cost is whether the proposed system includes thermal storage. Table 6 compares the LCOE with potential revenues in the key market segments, with and without storage.

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[19] SunShot vision study US Department of Energy 2012.

[20] Draft Energy White Paper - strengthening the foundations for Australia's energy future. Commonwealth of Australia 2011.

Table 6: Estimated 2012 Australian LCOE[21] and market value of CSP systems for various market segments

	CSP with no storage			CSP with significant (5+ hours) storage		
	LCOE ($ / MWh)	Value ($ / MWh)	Gap ($ / MWh)	LCOE ($ / MWh)	Value ($ / MWh)	Gap ($ / MWh)
Large Systems on NEM	220 to 300	100 to 106	115+	250 to 360	125 to 138	110+
Small Systems on NEM	350 to 550	102 to 110	240+	370 to 500	132 to 148	220+
Large Systems on SWIS	250 to 300	98 to 102	150+	260 to 360	154 to 162	100+
Off-grid / mini grid	400 to 550	290 to 390	10+	500 to 650	340 to 450	50+

While LCOE significantly exceeds income in every case, the gap varies considerably. For example:

- A CSP plant in a remote, high solar resource area that targets off-grid or mini-grid customers has a smaller value gap to close. However, it is also the segment with the greatest uncertainty in both the cost and value estimates. There is also a high level of technical risk avoidance, and payback times less than a CSP plant lifetime are expected.

- The NPV implications of storage are not linear. A system with one or two hours of storage may be more attractive than the two extremes of no storage and high storage.

- CSP systems connected to large gas or coal power stations to become hybrid systems should also be considered. While LCOE drops to $150–170 per MWh, value falls to around $70 per MWh if the system essentially becomes a fuel saver for the existing plant, or could be up to $100 per MWh if the system offered extra output when solar was available.

Comparison with other renewable sectors

This study does not judge the relative merit of CSP investment against investment in other forms of renewable energy. It is suggested that all forms will be required to meet the twin challenges of energy security and emissions reduction. However, because the current cost gap for CSP is large and undermines confidence in the sector, it is reasonable to compare Figure 9 with the cost curves of other available technologies. The starting point is that wind and solar PV are more mature technologies than CSP, so that their cost curves are expected to slow and level out in coming decades. A recent key study[22] suggests that the LCOE of CSP with storage will match that of wind by 2025, and be half that of solar PV with batteries. Available CSP revenue would be more than wind, and similar to a PV system with batteries. Accordingly, though CSP is starting further behind, its commercial case will be as strong as any other form of renewable energy within the strategic horizon of this review.

[21] Estimates reflect expected system size and configuration together with likely range of annual solar radiation for the market segment location.

[22] AT Kearney 2010, *Solar Thermal Electricity 2025*, Report for ESTELA.

Challenges, confidence and risk

In addition to the pure financial equation detailed above, there are other considerations that influence the project developer and financiers' investment decision. Many of these are specific issues facing CSP market segments, as set out in Table 7 below.

Table 7: Specific issues facing CSP market segments

Market	CSP Value Proposition	Specific issues
Off-grid / mini grid	• Reliable power at price competitive with diesel. • Hedge against future fuel price fluctuations and supply chain risks.	• Customer expectations of very high overall system availability and capacity factor. • Short time horizons on investment decisions. • Split/perverse incentives around diesel fuel excise rebates. • Requires demonstration at 1 to 10 MW scale in grid connected areas to build confidence.
Stand-alone, grid-connected plants	• Grid-stabilising, load-firming, zero-carbon generation. • Enables penetration of renewable energy sources to > 20%. • High correlation with daytime peak loads. • Load-following using thermal energy storage. • Co-fire with gas, biomass etc to maximise reliability of supply.	• Very large capital costs of individual projects. • Lack of transmission infrastructure to optimal solar locations. • Benefits of avoided line loss and grid extension not adequately rewarded. • Building confidence with network service providers. • Hard to get long term PPAs.
CSP add ons to fossil-fired systems	• Lower emissions intensity for existing power plants. • Leverage existing infrastructure. • Prolong existing fleet lifetime. • High performance systems with lower project risk and capital cost.	• Building confidence of existing generators re CSP integration with core (traditional/fossil) operations. • Split/perverse incentives, e.g. free carbon permits reducing pressure to lower emissions.

The CSP sector must build confidence in its capability among key stakeholders, including government, network service providers, electricity retailers and financiers, for the projects are perceived to be high risk.

For any significant CSP system, the initial capital cost is large. Investors do not underwrite large capital projects unless they are familiar with the technology and confident in its financial returns. For an Australian investment community unfamiliar with CSP, these factors weigh against investment.

This higher risk profile has four consequences. Most obviously, CSP investments must offer higher rates of return than investments in more familiar energy systems. The time horizons for those returns are shortened to further minimise risk. Third, CSP projects can draw only from the smaller pools of funding that are available to riskier investments. Finally, those smaller pools manage their own portfolio risk, making a relatively large single investment from that smaller pool unlikely.

Public and sector benefits

The investment case for individual CSP projects currently does not take into account the national and sectoral benefits that CSP investment offers. Yet these benefits are significant, and the means to capture them should be explored. For the energy sector and its customers, they include network performance (explored above), energy security, and price security. For the broader public, the benefits include reduced emissions and related pollution, and regional employment and infrastructure. Many of these benefits are to an extent time-sensitive: the window for securing them will close if, for example, emission reduction action is delayed, or other countries secure the lead positions available in CSP development. Accordingly, the option value of CSP's potential in Australia will be eroded unless that option is retained.

Looking at Figure 9 above, the need for supportive market intervention becomes clearer. Purely commercial deployment will only occur when the cost and revenue lines are close to converging. However when public and sector benefits are added to the existing market returns on CSP investment, the net returns from the project look far more attractive. If these benefits can be captured, some of the corresponding value could be invested to accelerate CSP development, and so bring forward the point at which private investment will sustain the industry.

Potential benefits

The major capital investments associated with CSP plants are challenging but there are also flow-on economic benefits. The fraction of the expenditure that is likely to remain in the country is considerably higher than for many other electricity generation technologies. There are considerable levels of employment both direct and indirect, and much of this can be in the regional areas where plants are built.

Reducing emissions

Australia aims to reduce its greenhouse gas emissions by 80% (from 2000 levels) by 2050. To do so will logically require electricity-generation to be near emissions-free. Every available option needs to remain in play until the exact composition of a long-term least-cost portfolio is established.

The operational range of CSP systems with storage is from base-load to peak generation, making them complementary to other variable renewable electricity sources.

Clean energy sector development and R&D

Clean energy has become a major global economic driver, with more than US$246 billion invested in 2011, more than half the total spend on new power generation[23]. In some countries, notably including the US and Germany, clean energy jobs already dominate the energy sector. Although the renewable energy target, carbon pricing and the Solar Flagships Program provide some support, more initiatives are needed for Australia to claim a place in the global supply chain for clean energy. CSP provides a clear opportunity for it to do so, as its level of development is at an earlier stage than other clean energy sectors, and Australia has the solar resources and R&D capabilities to be a sector leader. The construction and operation of CSP plants in Australia would provide a focus for applied R&D, with the essential links between commercial players and research institutions.

Energy security

Energy security is the adequate, reliable and competitive supply of energy for Australia's industrial and domestic needs. The recent Australian energy security assessment rates the

[23] *Clean Energy Trends 2010*, www.cleanedge.com

level of security in the electricity sector to be moderate over the short, medium and the longer term to 2035. This assessment reflects Australia's multiple energy options and resources. CSP is one of those options. Once a CSP system is installed, it offers a long-term energy source with very low supply, price, environmental, trade and sovereign risk. While security issues around future transport fuels are less certain for Australia, and although out of scope of this study, it is noted that CSP has significant long-term potential to contribute in this area also, both as a clean energy source for the electric vehicles becoming available now, and through the creation of CSP-generated liquid fuels.

Regional employment and education

Employment created by CSP plants varies significantly depending on project location, system size and technology type. About 10 construction and manufacturing job-years are created per MW for plant in the 100 MW range. Continuing operation and maintenance jobs range from 0.2 jobs to 0.7 jobs per MW, with smaller plant having much higher employment.

It is likely that a CSP plant will be constructed in regional areas, giving those regions a greater share of employment, with the potential to gain from both local projects and exports. Local employment can be increased by leveraging the local project to increase the local manufacturing proportion of the project, and to integrate local parts of the CSP value chain into the international supply chain. This in turn provides opportunities for existing or new training institutions.

Option value of CSP

Public economics recognises the concept of 'option value', and it applies well to the nascent CSP sector in Australia. Option value can be thought of as a form of insurance value: how much should one spend now to retain access to a future asset, given uncertain future developments. Option value rises with the likely future value of the asset, and rises with the cost of its replacement if lost. Though it was not in the scope of this study to attempt to quantify the option value of CSP in monetary terms, a qualitative analysis suggests that it is substantial.

Australia's emerging CSP sector is an asset that has two quite distinct future values. The first is its potential to deliver the clean dispatchable energy that Australia needs. The other likely technologies– such as geothermal, and fossil-fuel generation with carbon capture and storage – carry significant technical risks and may prove more costly than proponents suggest. If they fail to deliver on expectations, it will take many years to build the CSP capacity that will be needed. CSP would be kept as an available option via some early deployment and establishment and maintenance of capability.

Doing so will also retain CSP's second option value as a significant place for Australia in the future clean energy supply chain. At the moment, Australia has the option of having a significant stake in a highly valuable global clean energy supply chain – a stake we do not hold for other technically-sound clean energy alternatives (such as wind or PV). As other countries invest more in the CSP sector, the value of Australia's potential share in that asset falls. Conversely, if insufficient countries invest, the value of the CSP sector relative to other options is eroded. Accordingly, the option value of our CSP asset cannot long be preserved.

Actions needed for CSP investment

With falling capital costs and rising energy prices, commercial viability for CSP projects will be attained between 2018 and 2030, as shown in Figure 9. Many of the significant benefits from including CSP in Australia's energy mix are maximised through early deployment. It is therefore in the interests of investors, the sector and the nation that CSP projects reach commercial viability as soon as practicable within that time range.

For this, the CSP industry must work with the energy sector and its regulating governments to systematically identify and address the barriers to investment delineated above. This will support the smooth, rational development of the sector, and help avoid the *'boom-bust'* cycles that both renewable and fossil-fuel industries have experienced.

These barriers are real yet surmountable. Specific actions to increase investment, demand and product development are needed. These actions are discussed in turn below. If they are successful, the sector could track international growth rates to provide at least 2000MW of clean energy by 2020. This figure presents itself as a realistic medium-term target for overall CSP installations, toward which the sector could set clear milestones in meeting its challenges.

1: Bridge the reducing cost-revenue gap

Whilst continuing to focus on lowering cost the CSP sector should work with governments and regulators to increase the reward for clean energy systems that better correlate generation to real-time demand.

The benefits identified in this study would be maximised by early deployment.

Rather than simply subsidising CSP, technology-neutral market-based measures should target the dispatchable clean energy characteristics and strong correlation of generation to real time demand that CSP provides and Australia needs. Rewards linked to competitive market time of day pricing or equivalent firm capacity contributions should be considered. Towards this, energy sector agencies should build on this study and model future prices of both energy and ancillary services in the NEM, to calculate future CSP value under scenarios that include high penetration intermittent renewables.

The CSP industry must continue to focus on lowering cost through deployment learnings and technology improvement, particularly efficiency. Those cost reductions must also be clearly demonstrated to stakeholders. Major cost reductions will be achieved through capturing the lessons of early deployment. The CSP Industry should work pro-actively to leverage the lessons gained from publically funded early deployment to ensure they flow to the widest possible base within the constraints of competitive markets.

Public sector loan guarantees to mitigate construction risk have been used successfully in other countries, in parallel with other risk-mitigation measures. Facilitated finance, such as through the Clean Energy Finance Corporation, will only be defensible if revenue and capital depreciation settings are in place for both public or private loans to be repaid on their respective terms. Financial products such as infrastructure bonds, developed for large capital assets in the energy and infrastructure sectors to offer long-term low-risk returns, may be adapted to CSP projects to meet their large upfront capital cost.

Unless the gap is bridged, there will be no significant CSP deployment in Australia in the near term. Early deployment in market sectors where the cost revenue gap is smaller has the potential to optimise public sector investment. This includes off grid applications (where the competing cost is diesel generation) and hybrid applications with existing fossil fuel technologies. However these sectors do not offer a "silver bullet" and do not replace the need to address the main grid connected segment that ultimately offers greatest potential.

2: Build confidence in CSP's offer

The CSP sector should better communicate CSP's value proposition to key stakeholders including AEMO, AEMC, electricity retailers and financiers.

For those stakeholders who are unfamiliar with CSP's advantages and international progress, CSP's potential role in Australia may appear fanciful. Any actions taken to develop CSP in Australia can only be laid on a base of understanding and confidence. Without that base, the risk premiums that the sector currently faces will remain in place, and government, consumer, energy industry and investor support will remain ephemeral. The CSP sector must take every opportunity to explain CSP's potential benefits, demonstrate them in practice through successful ventures, and respond to the reasonable concerns of their stakeholders.

Specific actions could include:

- Working with AEMO and the transmission industry on the National Transmission Network Development Plan, factoring CSP availability into plans for grid extensions and upgrades (or the avoidance of them).
- Working with electricity distributors to raise awareness of CSP availability and benefits, and on plans for developing the distribution network to take advantage of those benefits.
- Ensuring that CSP's offer is fully represented in every government review of any part of energy generation, transmission, distribution and use in Australia, and in every public investment in the energy sector.
- Engaging more closely with financial sector asset owners and managers who have a demonstrated interest and understanding of long-term alternative asset classes.
- Better targeting information dissemination and education, leveraging Australia's membership in the IEA SolarPACES and PVPS programs for real international collaboration.
- Working with key customers and networks to establish best practice guidelines and standards for CSP system development, finance and operations.

Inviting stakeholders to visit operational CSP plants will add intensity to all of these engagement strategies.

3: Establish CSP-solar precincts

The CSP sector should work with governments, regulators and network service providers to pre-approve and provide connections for CSP systems in selected areas of high solar resource.

A precinct or solar park plan, developed with tri-level governments and energy sector partners, would have several benefits. For example:

- CSP projects would proceed to completion with a much reduced overhead in approvals and planning, helping to reduce early stage project risk.
- Planned and facilitated grid connection would reduce costs, which may then also be shared over multiple projects.
- The cost of solar data gathering, environmental impact assessments and community consultation would also be shared across projects, improving their value and levels of certainty for project development and financing.

4: Foster CSP research, development and demonstration

The CSP sector should leverage continued public and industry investment in research, development and demonstration, with more emphasis on meeting Australian needs.

Given that the benefits of early technology and market development will flow to future participants, there is a strong case for continued public sector support. Funding should be targeted at areas that offer the most traction for Australia's market conditions. These include:

- Systems optimised for below 50 MW_e (overlooked by the global industry, but with off grid / end of grid application in Australia)
- Hybridisation and enhancement of fossil fuel systems and exports
- Improved energy storage
- Advanced cooling systems to minimise or avoid groundwater and river water use, (reflecting our water constraints) and
- Improved efficiency of advanced energy conversion systems and receivers.

Other global R&D priorities should be considered for public co-investment where there is strong commercial involvement. In addition to these research and development priorities, program design and project selection should foster the skills and capabilities that the Australian CSP sector needs.

Supporting actions

The key pathway actions would be further supported by activities that include:

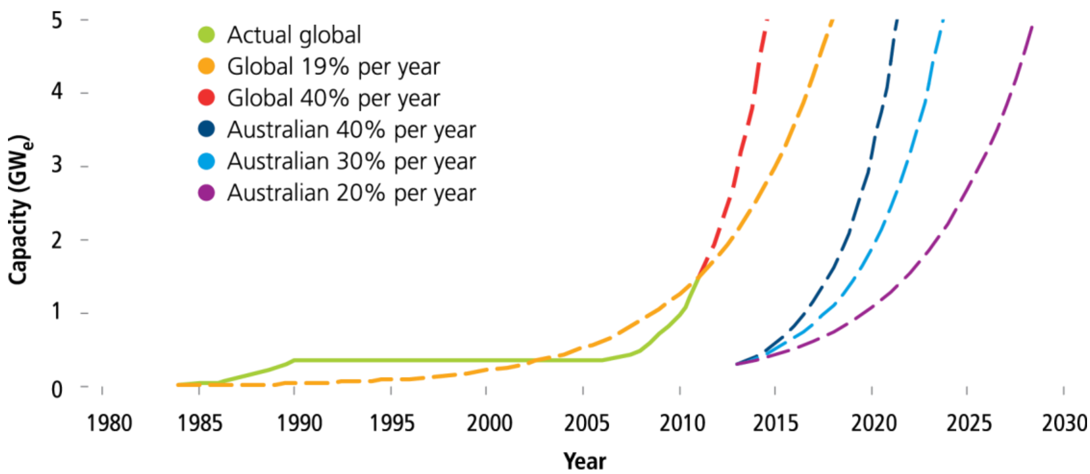
- Further extending Bureau of Meteorology direct beam solar radiation data collection, both to extra sites and to higher frequencies, to better support plant output prediction.
- Synthesising an improved set of data files for use with NREL Solar Advisor Model, both Typical Metrological Year and real historical years, to allow this excellent publically available tool to be used to best effect by researchers and commercial organisations.
- Modelling the likely effects of climate change over the coming two decades on solar radiation levels and CSP system performance, to help reduce risk in project planning.
- Studying the potential for concentrating-solar-driven fuels production as a possible major future driver for CST in Australia.
- More detailed study of the relative economics and potential for new combined gas / CSP systems.

CSP's future contribution

If these actions are pursued successfully, the CSP sector would be large enough to deliver economies of scale within immediate investment and policy horizons. A contribution of 2,000 MW by 2020 is readily achievable, which would see CSP play a significant role in Australia's low emission solution, and Australia be a significant part of the global CSP industry.

The growth of CSP technology globally has started to form the familiar S-curve that traces the early stages, fast development and eventual maturity of technology adoption. The medium-case growth projection for Australia, the 30% per year line in Figure 10, reaches 2 GW of capacity by 2020. Looking at CSP's market segments in Australia, this figure is quite reasonable. It could realistically be structured as c.100MW in off-grid or mini-grid systems, c.500MW in solar add-ons to fossil-fuel systems, c.300MW in 10-50MW systems connected to energy distribution networks, and c.1000MW in larger units connected to transmission networks: see Table 2 above. Investment in Australia would reach approximately $5.5 billion by 2020, assuming the retention of $1.4 billion in project commitments made to the end of 2011.

Figure 10: Global and Australian CSP development trajectories and projections



These projections form the basis for a series of development goals for the Australian CSP industry: see Figure 11 below. The 2013 goal will be reached assuming present-committed demonstration projects are successfully deployed. If the 2020 target is reached, Australia would be well on its 30% growth track to 10GW of capacity by 2030. Beyond that is the aspiration for CSP to be a significant contributor to the essential decarbonisation of Australia's energy supply by 2050, and make up 30-50% of Australia's electricity mix.

Figure 11: Aspirations for an Australian CSP Industry[24]

Cumulative capacity	Timing	Fraction of national demand	Notes
100s GW	2050 +		Significant source of export income via solar derived fuels and or HVDC links to Asia
100 GW	2050	30–50%	CSP provides between 30–50% of Australia's electricity in a mature 100% clean energy scenario
10 GW	2030	5–10%	CSP provides significant contributions in all market segments. Established Australian supply chain
2 GW	2020	1%	First fully commercial projects in the most prospective market segments
0.3 GW	2013	0.2%	First assisted demonstration systems at various scales

In the foreseeable future, CST-driven chemical processes already under development could deliver clean transport fuels and may allow the export of CSP-generated fuel. Alternatively, high-voltage DC transmission lines have been forecast to connect North Africa to Europe and Mexico to the US, and have also been proposed to connect Australia to Indonesia and beyond. This is a vision of very large commercial potential for the industry that, while remaining in the background of more immediate goals, will continue to offer inspiration for our young and future scientists, investors and policy makers.

* * *

As with all developed economies, Australia is gearing itself to meet the joint challenges of rising energy demand and greenhouse gas emissions. To meet these diverse needs at least cost and risk, a portfolio of energy options is needed. On its current development projections, concentrating solar power should be one of those options. However, that development is not assured. The current cost-revenue gap for Australian CSP projects is deterring private investment, while overseas support cannot be guaranteed. This is a powerful opportunity for Australia. If it takes responsible, collaborative action, Australia could grasp a substantial role in the global clean energy supply chain, and solve a critical piece of its long-term energy puzzle.

* * *

[24] Adapted from LEK Consulting's *Advanced Biofuels Study – Strategic Directions for Australia*, Summary Report, 14 October 2011 prepared for the Department of Resources, Energy and Tourism.

* * *

1 Introduction

Concentrating Solar Power (CSP) generators use combinations of mirrors or lenses to concentrate direct beam solar radiation to produce electricity by various methods. This report examines the potential of Concentrating Solar Power in Australia and has been prepared by IT Power Australia for the Australian Solar Institute.

The term 'Concentrating Solar Power' is often used synonymously around the world with 'Concentrating Solar Thermal Power'. In this study the term is used in a more general sense to include both solar thermal and photovoltaic (PV) energy conversion. Where a distinction is needed, reference is made separately to Concentrating Solar Thermal (CST) systems and Concentrating Photovoltaic (CPV) systems.

This study seeks to:

- Provide a summary of the global status of CSP.
- Review previous investigations of the potential for CSP in Australia.
- Establish a best estimate of current installed costs of large-scale systems, if they were to be built in Australia, and analyse the resulting Levelised Cost of Energy.
- Analyse the value of CSP electricity in the market place, with particular examination of the value of dispatchability and ancillary services.
- Analyse the various potential market segments for CSP electricity in Australia, considering cost and value.
- Examine the challenges that currently impede the development of a CSP industry in Australia.
- Identify pathways for CSP industry development and supporting R&D activities.

1.1 Background

Major changes in the world's established energy supply systems are being driven by growing energy demand, energy security concerns, rising greenhouse gas emissions, local environmental issues, increasing oil prices, and international competition to lead in the emerging clean energy technologies. Global investments in clean energy generation are continuing to increase and arguably the world is undergoing a clean energy revolution. For example, over the last three decades the world wind industry has grown at an average rate of approximately 30% per year to reach a total installed capacity of 239GW by the end of 2011 . This represents nearly 3% of total world electricity annual generation (WWEA 2012) and wind capacity is now being installed at a faster annual rate than nuclear.

Over a shorter period, the solar PV industry has grown with comparable or higher rates of growth but from a lower base in 2011 had a worldwide installed capacity of approximately 69GW (EPIA 2012). Concentrating solar thermal power technology developments were stagnant for a long period following an initial period of growth in the 1980's. Since 2005, CSP developments have recommenced and gained considerable momentum. Total installed capacity is an order of magnitude smaller than PV and the industry lags a decade or more behind in its level of development.

The 1980's CSP initiative saw a series of parabolic trough plants with steam turbine based power generation established in California. These plants continue to operate after more than 20 years and establish the technology as commercially proven.

The CSP industry is widely forecast to continue to grow at very high rates. So far this growth has predominantly been in Spain and now increasingly in south-west USA and is linked to policy interventions in those jurisdictions. In 2010, India took a major initiative with the establishment of the Jawaharlal Nehru National Solar Mission, with a target of 22 GW_e of combined PV and CSP capacity to be installed by 2020.

For a long time, conventional wisdom held that large scale (>50 MW) CSP plants were more cost effective than flat-plate PV systems. However in recent years there has been significant progress on cost reduction in PV, whilst CSP is still seen to be at the beginning of its cost reduction path. Under these circumstances, greater attention has turned to CST's potential benefits of built in thermal energy storage and dispatchability.

A recurring theme in the analysis is differentiating the *Cost of Energy* from the *Value of Energy*. This concept is key to providing focus for future development of the CSP Industry in Australia.

1.2 Scope

The terms of reference for this report are provided in Appendix A.

Stakeholder consultation was a critical element for developing this report and was used to help form a common and unifying view across stakeholder groups and industry representative bodies. The scope required a '*Technology Agnostic*' approach with no technology, research group or developers to be promoted as providing the optimal path to large-scale deployment.

Discussion of Government policy in terms of industry support during the coming years, with the formation of Australian Renewable Energy Agency (ARENA) and its subsequent incorporation of ASI, and the Solar Flagships program is included.

The investigation also focussed on how the CSP Industry can further develop itself by overcoming technical and non-technology barriers, and how it can integrate and provide value to the energy industry in the medium to long term.

It is acknowledged that some long term, strategic Government assistance is required for CSP to develop to it's full potential. However the Industry needs to also work on areas where it can increase its value to the energy industry, thereby increasing its income and moving closer to commercialisation.

It is clear, once an understanding of CSP's place in the energy industry is developed, that cost is not the sole determinant of market success. A strong emphasis has been placed on identifying the various sources of value that CSP offers. This includes both values currently rewarded by market mechanisms and those that may be inherent but possibly not currently rewarded financially.

1.2.1 Definition of technologies covered

Noting that a definition of CSP that includes both thermal and PV energy conversion has been adopted, the technical scope was limited to systems designed for utility scale power generation, which was interpreted as:

- Constructed in a scale suited to a power station, therefore in deployments of greater than approximately 200 kW.

- For application in Australia's main-grid systems or in significantly sized, remote mini-grid systems.
- Must be a part of the electricity generation process.
- Has a concentration of greater than 50 suns.
- Not including process heat or water heating applications.
- Not including building integrated systems or semi-domestic power production;

The production of solar fuels using solar concentrator systems is also outside of the scope of this investigation. It is apparent, after stakeholder consultation, that the field of solar fuel and other thermal processing is a potentially large market for CSP and is worth further investigation.

1.2.2 Technology agnostic approach

This report does not seek to '*pick winners*' within the CSP category nor to contribute to debates that may divide the CSP industry. A key intent of this investigation was to help unite the sector in its view of the future.

Any analysis of costs or development potential of individual technologies always has the potential to be divisive as there are a wide variety of views, methodologies and potential assumptions. For this report, the Levelised Cost of Energy (LCOE) calculations are based on the status and potential of CSP as a general combined technology class, with established existing costs of construction as a starting point.

1.2.3 Stakeholder input

A high level of relevant stakeholder input was sought. This was achieved through:

- the project being coordinated by a Review Reference Group;
- a series of three stakeholder workshops; and
- key discussions and briefings with a range of individual stakeholders.

1.3 Needs and Drivers

Commercialisation of a new technology will only progress if there are some underlying societal needs and drivers that create a market for it.

The Australian Government's Clean Energy Initiative indicates that Australia has a 2050 emissions reduction goal to reduce Australia's net greenhouse gas emissions to 80% below 2000 levels by 2050. Given the challenges of reducing greenhouse emissions in the transport sector along with the high proportion of emissions from the power sector, this target could be interpreted to indicate that almost 100% clean electricity generation is required by 2050.

A portfolio approach across location and technology is likely to offer the least cost final solution for achieving clean electricity generation. A significant fraction of the total generation will need to be dispatchable – potentially a major driver for CSP. Recent studies have shown that such future scenarios are technically possible in terms of meeting demand reliably at all times (eg Elliston et al 2012 and Wright and Hearps (2010)).

These future drivers also coincide at the present time with a pragmatic need for some major catch up investment in electric power infrastructure in Australia. Figure 1-1 illustrates predictions that suggest that even under a Business-as-Usual Scenario, only of the order of 12% of electricity generated in 2050 would come from generating plant that is in place today. Major investment decisions will be made in the coming years and it is these decisions that will lock in consequences for generation in later years.

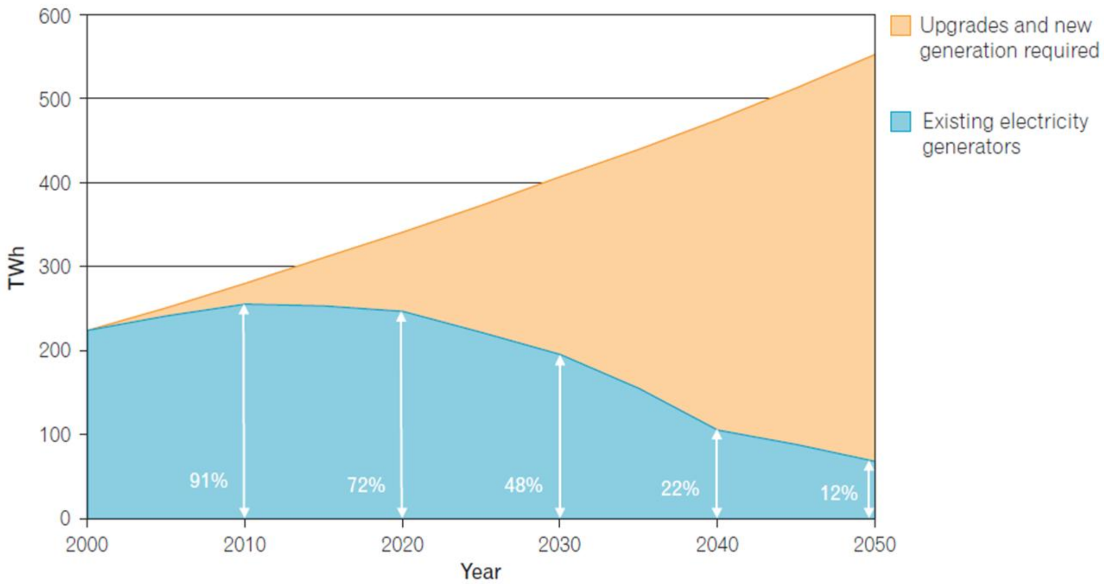


Figure 1-1: Projected Australian annual electricity consumption, (Commonwealth of Australia 2006).

In addition to annual load growth, peak demand is increasing significantly faster than average demand. Peak demands also require new generation investment to ensure reliability of power supply.

Significant investments are also required to maintain existing transmission and distribution infrastructure which covers a wide geographic area. This network infrastructure also requires significant expansion and upgrades to cope with growing annual loads and the rapidly increasing peak power demands.

This current investigation follows in the footsteps of the High Temperature Solar Thermal (HTST) Roadmap, (Wyld Group 2008) that was produced for the Council of Australian Governments. The HTST Roadmap introduced four categories of prime drivers for change toward clean / renewable energy technologies as shown in Figure 1-2.

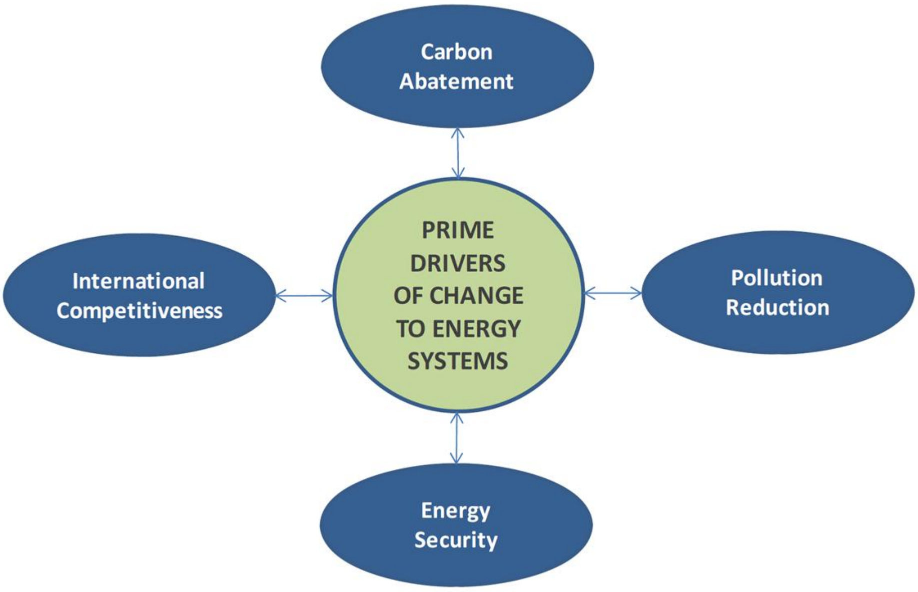


Figure 1-2: Four categories of prime drivers for renewable energy, reproduced from Wyld Group (2008)

Considering these categories from an Australian CSP perspective:

Carbon abatement

Despite the rather uncertain nature of progress on international agreements, the predictions of climate science continue to increase in certainty and the negative consequences of lack of action are virtually universally acknowledged. The issue has reached a point where it could be argued that every major business initiative around the world now considers the risks to its bottom line or opportunities for advantage available from moving business into low carbon areas.

Australia has legislated to introduce a carbon price into the economy from 1 July 2012 and this will begin to provide a signal for future investment in the energy sector. Nevertheless, significant assistance will be provided to incumbent fossil fuel generators, so the transition to lower carbon sources will occur over a long time period.

Local pollution reduction

Pollution that is national rather than global, continues as an immediate problem, although in developed countries greenhouse issues have been the focus. Pollution could be particulate, noxious emissions, toxic spills, oil spills. It is a very big driver in India and China, both of whom are emerging as major players in clean energy overall and have already position themselves for CSP.

Australia has its share of pollution issues, even if they appear less critical. Air quality in Australia's major cities is still less than ideal. This concern could serve as a multiplier, if for example the apparent move to electric vehicles gains pace. This would in turn drive increased demand for electricity and so multiply the other drivers for clean energy.

Other local pollution issues can and do emerge. Current concern over the effects of expanded coal seam gas exploitation are an example. If Hot Dry Rock geothermal gains momentum, it could face the similar concerns. The visual amenity issue for wind farm developments is also a driver for expanding the portfolio of clean energy technologies.

Energy security

For countries dependant on energy imports, security of supply in the face of global political change is an ever present concern. Even countries self sufficient in conventional (fossil) energy sources need to consider the finite nature of their reserves.

In Australia's electricity system, supply security is more concerned with reliable delivery than in resource availability. Hence, for new technologies entering the electricity market, reliability of supply and the characteristics of power station output are of prime concern. CSP has time of generation and potential dispatchability benefits, suggesting there is a major driver to have CSP in the future portfolio of clean energies globally and in Australia.

As a major fossil fuel exporter, Australia's energy security issues are less than for other countries. However on oil reserves, domestic production is declining, demand is growing and international prices continue to rise. This could grow into a major driver for change in Australia. It will definitely reinforce any trend to electrification of transport for example. It may also bring coal to liquids processing proposals to the forefront in the near future. If done in a conventional manner, such approaches could massively increase GHG emissions.

International competitiveness

Whilst much attention on the future of clean energy is focussed on the competition from 'cheaper' fossil fuel alternatives, it should be noted that if a clean technology is actually the more profitable option, that becomes a massive driver for change. In a sense this is a positive feedback mechanism that comes into play as soon as a technology is competitive in even a few market segments.

There is also a driver associated with the desire to participate in value chains when other factors are driving deployment. Businesses and countries, will work to compete with others when major cash-flows are generated by deployment anywhere in the world.

International competitiveness issues for Australia are two-fold. Given the major drivers to a clean energy future, the portfolio that provides the Australian economy with the greatest benefits relative to cost is not simply the use of least cost technology. Feedback effects such as expected greater fractions of local manufacturing with CSP solutions provide a driver to encourage its growth. The other issue is the future of our conventional fossil energy exports. If the world does move to a reduced emissions scenario, then Australia should consider how it will adapt to changing demands. This may be a powerful driver to seek value adds and alternative energy export mixes such as solar / hybrid fuel export and/or international grid connections.

1.4 Report Structure

This report is the detailed presentation of the results of the investigation resulting from ASI's brief. The Executive Summary of this report is also available separately. It has been written for a wide readership with policy makers identified as a key target audience.

This report is structured as follows:

Chapter 2 describes the various CSP technologies and their current stage of development.

Chapter 3 reviews the status of the CSP industry globally, its past and projected growth paths and the previous activity in Australia.

Chapter 4 examines the various potential markets in Australia for CSP and describes the operation of the National Electricity Market in the Eastern States and the South West Integrated Market in WA.

Chapter 5 analyses the different market values which CSP might exploit to establish income streams. It examines both values which are already rewarded by current market structures, as well as others which could be rewarded in future as the electricity system moves towards higher renewable contributions.

Chapter 6 examines cost structures and methodologies for arriving at standard values for the Levelised Cost of Electricity for various CSP technologies. It looks at the various contributors to LCOE and models the possible costs for different CSP systems and configurations.

Chapter 7 discusses the challenges facing the CSP industry, incorporating learnings from stakeholder input, and identifies different possible ways to overcome these challenges in general and in Australia.

Chapter 8 explores pathways for developing a sustainable CSP industry in Australia, including possible policy options, roadmap activities and key R&D issues which Australia could focus on, both for exploitation of CSP in Australia, as well as to assist in the global effort to bring the various technologies to market.

Chapter 9 provides the conclusions.

* * *

2 Technologies

CSP technologies use systems of mirror or lens-based concentrators to focus direct beam solar radiation to receivers that use the energy for power generation. CSP systems capture the direct beam component of solar radiation. Unlike flat plate photovoltaics (PV), 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.

2.1 CSP Approaches

The configurations that are currently available can be categorised (in order of deployment volume)as:

- Parabolic Trough,
- Central Receiver Tower,
- Linear Fresnel,
- Fresnel lenses, and
- Dishes.

There is no consensus on which approach inherently produces power at the lowest overall cost. Companies and developers are actively pursuing all types of CSP technologies.

The International Energy Agency's '*Technology Roadmap Concentrating Solar Power'*, (IEA, 2010A) is a key reference that provides a good overview of the status of CST today and its potential for future deployment.

In addition, there are many worthwhile CST 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[25]. Similarly, the European PV Technology Platform provides up-to-date information on the status and development requirements for CPV in its Strategic Research Agendas, the latest of which was published in 2011[26].

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25 Solar Power and Chemical Energy Systems program , see www.solarpaces.org.

26 EU PV Technology Platform, 2011, A Strategic Research Agenda for Photovoltaic Solar Energy Technology, Edition 2, www.eupvplatform.org

2.1.1 Parabolic Trough

Parabolic trough-shaped mirrors also 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. 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.

Figure 2-1: Parabolic Trough Collector (Nevada Solar 1, picture R Dunn).

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 is usually used.in CPV systems with trough concentrators, cells are arranged at the linear focus as with the Fresnel approach and again either a cooling fluid or passive heat dissipation is needed.

2.1.2 Central Receiver Tower

Figure 2-2: Central Receiver system, Spain.(Gemasolar plant, owned by Torresol Energy (c) Torresol 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. Application of the Tower approach to CPV is also under development, the high concentration levels, mean that the cell cooling task is more challenging.

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.

CPV systems using this approach have a row of PV cells at the focal line, whereas CST systems have a heat transfer fluid. For PV systems, cooling fins or a flow of cooling fluid are needed to remove energy not converted by the cells. For CST systems, the fixed receiver not only avoids the need for rotary joints for the heat transfer fluid, but also works to minimise convection losses from a thermal receiver because it has a permanently down-facing cavity.

Figure 2-3: Kimberlina LFR plant, California, (picture AREVA Solar).

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 (for CST) thermal efficiency. To increase optical efficiency and, Compact Linear Fresnel Reflectors (CLFRs) use multiple receivers for each set of mirrors so that adjacent mirrors have different inclinations in order to target different receivers. This allows higher packing density of mirrors which increases optical efficiency and minimises land use.

2.1.4 Fresnel Lens

A conventional lens is expensive and impractical to manufacture on a large scale, the Fresnel lens overcomes these difficulties and has been employed extensively for CPV systems.

Figure 2-4: Fresnel Lens based CPV, River Mountains, USA.(picture Ammonix)

A Fresnel lens is made as a series of concentric small steps, with each having a surface shape matching that which would be found on a standard lens but with all the steps kept within a small thickness. A plastic material is usually used. This is also a point focus approach requiring accurate sun tracking in two axes.

2.1.5 Parabolic Dishes

Dish systems, like troughs, exploit the geometric properties of a parabola, but as a three dimensional paraboloid. The reflected direct beam radiation is concentrated to a point focus receiver and in CST systems can heat this to operating temperatures between 500 and more than 1000^{o}C, the same temperature as tower systems.

Figure 2-5: CPV dishes at Windorah Queensland (Picture K Lovegrove).

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. They are however the least commercially mature. Dishes up to 24m diameter have been demonstrated. CPV conversion on dishes is well established, it is also applied with “Micro dishes” with diameters of just several centimetres.

2.1.6 Summary of key features and status

Key features and status of the five CSP technology categories are summarised in Table 2-1.

Technology	Annual solar to electricity efficiency	Focus type	Practical Operating Temperature for thermal conversion	Power cycles considered	Commercial maturity	Installed Generating Capacity as at end 2011
Parabolic Trough	12 to 15%	Linear	150 to 400°C	Steam Rankine Organic Rankine PV	High	1,500 MW_e
Central Receiver Tower	20 to 30% (concepts)	Point	300 to 1,200°C	Steam Rankine Brayton (gas turbine) PV	Medium	60 MW_e
Linear Fresnel	8 to 10%	Linear	150 to 400°C	Steam Rankine Organic Rankine PV	Medium	38 MW_e
Fresnel lens	12 to 15%	Point		PV	Medium	15 MW_e
Parabolic Dish	20 to 30%	Point	300 to 1,500°C	Stirling Engine Steam Rankine Brayton (gas turbine) PV	Low	2 MW_e 4 MW_e

Table 2-1: Summary of CSP technologies

2.2 Electricity Generation

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

2.2.1 Concentrating Solar Thermal

With CST systems, the concentrated solar radiation is collected on a receiver that for most thermal systems is fabricated from tubes. A heat transfer fluid 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 use a thermal oil as the heat transfer fluid, however the use of molten salt or direct steam generation has been demonstrated.

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.[27] 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. 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 to directly operate gas turbine cycles. Ultimately, combined cycle operation, where the exhaust heat from a high temperature gas turbine is used to produce steam for a steam turbine cycle, offers the possibility of 50% or more cycle efficiency.

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 absorbtivity in solar wavelengths and low emissivity for infrared wavelengths. Process heat applications may use simpler, non-evacuated receivers.

Steam turbines

The bulk of the world's electricity is generated with steam turbines. All the concentrator types with the possible exception of Fresnel lenses, have been applied to steam production for use in steam turbine energy conversion. One of the advantages of CST is the ease with which a 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 CST plant with 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 using a heat exchanger with another heat transfer fluid;
- expanding the steam to low pressure via a series of turbines that drive a generator; and

[27] 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).

- at the end of the expansion process, condensing the low pressure steam with the aid of a cooling tower and then re-using in the cycle.

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 water quality.

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 CST application, a larger turbine requires a large field, which results in increased energy losses of various kinds[28], 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. To the end of 2011, no CSP systems have been built to this size although there are several in planning stages, (the SEGs plant’s 354 MW_e consists of 9 separate generation units).

The most efficient 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) 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 CST 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 are now producing steam turbines customised for CST application, with these issues in mind. Such steam turbines are be able to reach full power within 30 minutes from a cold start and less for a warm start. Typical steam turbine heat to AC electricity conversion efficiencies for existing CST plants are around 40% gross at full load.

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). However, the capital and O&M costs are higher per

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

installed MW than for a water/steam system. ORC technology is 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 CST systems.

Another potential application for ORC systems in CST is as a 'bottoming cycle', whereby a high temperature cycle (see discussion of Brayton cycle below), produces exhaust heat (that would otherwise be wasted) that is at sufficiently high temperature to drive an ORC system for additional power generation.

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 CST 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.

Stirling engines have long been applied to Dish concentrators and continue as the main generator used in commercial application of dishes. This long history and predominance leads many in the CST field, to refer to dishes in general as 'Dish Stirling', even though steam, CPV and other generation technologies are also applied. Stirling engines have not been applied in any serious way to other collector types.

Engines with crankshaft driven pistons are used, however so called 'free piston' systems are also applied. In these systems, free pistons oscillate linearly on gas bearings and have built in linear generators.

Dish Stirling systems continue to hold the record for the highest solar to electric conversion efficiency of any technology, with total solar to AC electric efficiencies of around 30% at design point solar iradiance, reliably reproduced. Stirling systems can be used for much smaller systems than Rankine cycles.

However overall cost, not efficiency is the key investment criteria. The biggest challenge for Stirling engine technology is reducing O&M and capital costs.

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 (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 CST systems using a Brayton cycle have been operated.

In fossil 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. Potentially the combined conversion efficiency is in excess of 50% and represents the highest thermal to electric conversion efficiency solution currently available commercially. A major attraction with applying the Brayton cycle to CST applications is to also implement combined cycle operation with either steam or ORC bottoming cycles in a similar high efficiency manner.

For dish applications, the Brayton cycle offers the potential of reduced O&M costs compared to Stirling engine systems.

2.2.2 Concentrating PV

For the purpose of this study, only CPV systems categorised as '*power station*' type systems have been considered. These include large dishes, power tower/heliostat systems and large array Fresnel lense with >100 sun concentration. Smaller systems, designed for installations on buildings, typically for combined heat and power supply, while potentially beneficial are beyond the scope of this report.

Cell type and concentration

CPV systems typically use expensive, high efficiency cells. High quality, single crystal silicon cells with efficiencies of around 20% have been utilised. Going beyond this, cells, such as the triple junction III-V cells developed for space applications, achieve a system solar to AC conversion efficiency of some 25 to 30% under 500-sun concentration.

Triple junction cells have had a rapid efficiency increase over the last decade (from 30% efficient to 43% efficient) and potential to reach 48 to 52% efficiency in production cells by 2020.

Given the infrastructure for concentration is expensive, using high efficiency cells within the receiver ensures the highest output capacity. The actual cost of the PV cells is less important than in a flat-plate PV system, as it is no longer a high proportion of total system costs.

With a CPV system, there are parasitic losses relating to tracking system operation, controls, wiring losses, inverter efficiencies and operation of the cooling system. These parasitic losses reduce the useful AC output of the entire system. Currently, a typical system efficiency of a large scale CPV plant is in the order of 27 to 33%. There is, with PV cell efficiency gains and optimisation of systems, the potential to raise this system efficiency to around 45% over time.

Given that a typical system efficiency for current CST or flat plate PV plant is in the order of 18 to 20%, there is significant attraction to a CPV based system.

Heat dissipation

A key issue with any high concentration PV system is the heat that results from the photons that are not converted directly to electricity. At 500 suns, a triple junction cell would be destroyed within a few seconds without a highly efficient cooling system to extract the heat.

Opportunities exist with CPV systems to employ light spectrum splitters – removing the infrared (IR) light before conversion of the shorter wavelengths to electric power, and then harnessing the infrared for thermal energy conversion. Several companies worldwide, including some in Australia, continue research into spectrum splitters and hydrogen production in conjunction with CPV electrical generation.

Heat removal has been a key challenge for the >100 sun concentrators, especially those employing dishes and heliostats rather than lenses, with any cooling system failure potentially leading to rapid damage of generation equipment. The intricate nature of the cooling system means that any minor blockages will rapidly lead to hot-spotting and damage. As the systems generally require high flow of cooling fluids through an intricate heat sink, small blockages in the heat sink will rapidly gather further debris, potentially turning a small problem into a large problem in a short period.

As the cooling system requires very clean fluids, it must be a closed loop system with a further source of heat transfer remote from the cells to dump the heat into. Several dump systems have been used in remote CPV systems in Australia, including ground loops using buried plastic pipe and sewerage ponds co-located with the power station. Wet or dry cooling tower systems have also been trialled, however their parasitic energy requirements are large.

The heat from PV cell cooling can be applied for other processes to produce a combined heat and power system and this is being pursued commercially. PV cell efficiencies drop proportional to the temperature above 25°C, so that operation as a combined heat and power system is typically limited to temperatures below 80°C, which restricts the useful applications.

Fresnel lens CPV systems tend to use passive finned heat sinks using air rather than a cooling liquid. While this results in higher cell temperatures, this method removes much of the complication and risk of operation. Rather than attempting to focus a large array of mirrors onto a large array of cells, Fresnel lens systems tend to use a single lens for a single cell, reducing the risk of poor optics leading to over-concentration on small areas of an array. Thus large numbers of these are mounted on a shared heliostat structure to establish a module of significant capacity. Fresnel systems for CPV require large numbers of very small generation systems to be co-located, while Dish systems at 35 to 40 kW per unit require fewer '*systems*', and a multiple megawatt heliostat/tower system significantly less again.

Optics

The optical characteristics of a CPV system are very important. An uneven distribution of concentrated solar radiation across cells within a receiver array, results in over exposure of some cells and under exposure of others. This reduces the overall receiver's output, and increases the risk of hot spotting damaging or destroying cells.

To reach optimum performance, the array of cells within a receiver, needs an even spread of sunlight. Concentrator focal regions have natural bell-shaped radiation profiles that must be addressed by tailoring the mirror alignment or other mechanisms.

For example, receivers on dish systems have employed a device referred to as a flux modifier. The aim of the flux modifier is to reflect light across the PV array as evenly as possible. This may be done in conjunction with alignment of the mirrors on the dish during construction to spread light evenly across the receiver.

Flux modifiers tend to use expensive materials given their important role, nickel plating is common, and as such they can be sensitive to hot spotting. A potential hot spot cause is the common bush fly, attracted to the light, the fly is burnt onto the flux modifier, creating a hot spot. If not removed within a few days, this can lead to cracking of the nickel plating.

2.2.3 Hybridisation

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

- solar input augmentation to existing fossil fuelled steam power plants;
- 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*'.

For CPV, there is not the same opportunities for sharing technical system components. However, design of integrated systems with CPV as a fuel saver operating in parallel with diesel power stations has been demonstrated.

2.3 Energy Storage

One of the identified key competitive advantages of CST compared to CPV or flat-plate PV, is the inherent thermal inertia and the ability to build in thermal storage for dispatchable operation.

2.3.1 Thermal storage

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

Configurations can be optimised for peaking, shoulder or baseload power generation via the relative sizing of collectors, thermal storage and generation unit (power block). The thermal storage system is typically located between the concentrator and the power block. This allows the power block to be sized in an optimal manner as opposed to a system without storage. The addition of storage systems can increase overall annual generation levels from a given solar field as they:

- avoid the need for energy dumping at times when solar input exceeds the power block's capacity;
- allow the capture of intermittent solar energy bursts, that are too small to operate a turbine and;
- allow turbines to be operated at closer to full load for longer periods.

As the percentage of intermittent / variable, renewable energy capacity in a grid increases above certain thresholds, some level of short-term storage makes management of power quality less onerous. The inherent thermal inertia of CST systems enables some smoothing of power outputs. For example, for a proposed 15 MW_e 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, (DLR & Evonic 2009).

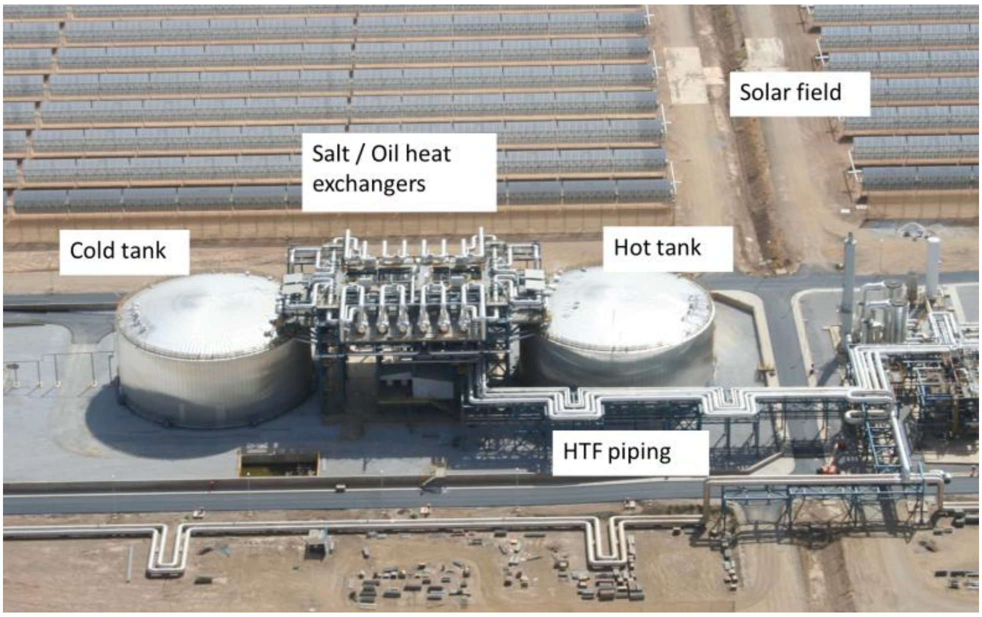

Figure 2-6: Two tank molten salt, thermal energy storage at Andasol 3, Spain. (background image Ferrostaal)

The technology for thermal storage that is most advanced commercially is two tank molten salt, illustrated in Figure 2-6. 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 salt[29]. The 28,500 tonnes of salt always remains molten (liquid) and cycles 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, as listed in Table 3-1. Recently, the Gemasolar 19 MW_e Tower plant with 15 hours storage was commissioned near Seville. At the end of 2011, 62% of installed CST systems in Spain used energy storage as a key component. A significant cost saving development for molten salt storage which is progressing well is the use of a single tank, with a thermocline[30].

Direct storage of high temperature 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) spectrum include; solids such as graphite or concrete, reversible chemical reactions and high temperature phase change materials.

2.3.2 Chemical conversion and solar fuels

Chemical conversion and solar fuels are not part of the scope of this report. However, their potential is worth further investigations.

Point focus Tower or Dish systems can operate with good efficiency at temperatures in excess of 1000°C. This is the temperature range needed to drive many industrially important thermochemical reaction processes. Closed loop, energy storage systems have been investigated using reversible chemical reactions. However, as of the end of 2011, none are yet commercialised.

Possibly of greater significance is the potential to use CST processes to produce solar fuels. Solar fuels are defined as chemical products that can be burnt / oxidised to produce energy as needed at a different time or place. Examples include solar reforming of natural gas, solar gasification of biomass and other hydrocarbons, and ultimately, multi-step water splitting for solar hydrogen.

A common theme with many investigations is to use the solar input to produce a mixture of hydrogen and carbon monoxide - so called '*Syngas*'. Syngas is the basic input to the Fischer-Tropsch process for the artificial synthesis of liquid hydrocarbons. It is a well established process that has been used in Gas-to-Liquids and Coal-to-Liquids plants for many decades.

The solar fuel could be applied to produce dispatchable power generation at high efficiency via gas turbine combined cycle plants. However, it is feasible that increasing oil prices and the need for alternative transport fuels will be the main driver for CST solar fuel developments. While less commercially developed than power generation, solar fuels could be a large market for solar concentrator technology. In the long term, solar fuels also offer the potential to increase the sustainability of Australia's energy exports.

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29 The salt composition is 60% $NaNO_3$ + 40% KNO_3

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

However, solar fuels are a large and diverse field which is not covered in this report. An investigation of the long term potential of solar fuels for Australia, may provide synergies and significant benefits.

2.3.3 Electrical storage

Electrical storage is the only storage option for CPV systems, in principle it could be applied to CST also. Indeed, electrical storage systems can be applied to any electrical generation technology.

A key challenge of CPV systems is the current difficulty in storing electrical energy at low cost. Thus CPV systems typically operate as immediate dispatch units. Some attempts have been made to use battery technologies to manage dispatchability from CPV stations but this adds significantly to overall costs.

There are a range of technologies for storing electrical energy on a medium to large scale at various levels of development, these include:

- lead-acid batteries,
- flow batteries – such as zinc-bromine and vanadium redox,
- other battery types – such as lithium, nickel-cadmium, sodium etc,
- flywheels,
- pumped hydro,
- compressed-air storage, and
- hydrogen.

These energy storage systems can be applied to any electricity generating technology including CPV or CST power systems. They are separate self-contained technologies that do not need to be in the same geographical location as the original generator of electricity. They are not analysed in this report.

2.4 Typical Power Station Requirements

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

2.4.1 Water use

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

Similarly, water is required for CST 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 wet cooling towers are employed, is by far the largest water consumer.

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 2010A).

It is feasible to use dry-cooling to reduce water consumption in arid regions. However, this results in a decrease in electricity production from a trough plant by an estimated 7% and increase the cost of the electricity by about 10%.

Table 2-2 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.

Table 2-2: Water Requirements for Power Generation (reproduced from NREL (2010B) with original figures converted to litres per MWh of Plant Output).

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 720)	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 75 to 200 gal / MWh (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 (60 gal / MWh = 227 l / MWh) and solar field mirror wash (20 gal / MWh = 227 l / MWh) data from KJCOC.

Like CST, CPV requires some water for general purposes such staff use, fire fighting, and other services. CPV systems also require water for collector cleaning and for cooling PV receivers where air-cooling is not used. In each case the usage rates would be comparable.

2.4.2 Land area

The amount of land required has been reported, (Australian Cleantech, 2010) as approximately:

- 2 ha / MW for trough systems without storage, and
- 4 ha / MW for Fresnel systems with no storage.

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 factor[31] for existing trough plants is typical (DLR, 2005) as the spacing of rows needs to ensure that shading is minimised.

For example, the Solnova 50 MW_e trough plant consists of 300,000m^2 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 510,000m^2 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) will consist of 3 towers with heliostat fields for a total of 392 MW_e on 1,457 hectares, (3.7 ha / MW).

Typically, CPV area requirements are similar to CST plants Theoretically, as conversion efficiency of CPV is higher than that of CST, less land would be required for a large scale plant. However, as a large CPV plant is yet to be built, this remains a theoretical assumption.

2.4.3 Staffing levels

There is a wide range of forecasts for staffing levels for CSP plants. There will be significant variations with; project location; system size and technology type. The following observations give indicative levels.

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[31] Meaning that the collector area is 30% of the land area.

Brightsource's Ivanpah 392 MW_e solar tower project is forecast to create around 1,000 jobs at peak of construction and have 86 ongoing operations and maintenance jobs (0.2 ongoing jobs / MW).

AT Kearney (2010) indicates that a 100 MW_e plant would require between 40 and 45 full time equivalent employees for operation and maintenance, ie .4 to .45 per MW_e. Other references report lower numbers, on the other hand. DLR & Evonik, (2009), forecast that the operations and maintenance team needed for a 15 MW_e trough project will be 21 staff to operate and maintain the 147,150m^2 collector field and 19 staff to operate and maintain the power block on a two shift operation. This is 2.6 ongoing jobs per MW which, compared to the previous examples, illustrates the benefits of economies of scale.

CPV projects in Australia have been limited in scale. In most cases the sites have been un manned sites due to their remote nature. As a result no data exists for what a large scale CPV plant would need in terms of O&M staff. However, given the high performance equipment, it would be fair to assume that staffing levels would be of a similar order to similarly sized CST plants.

Employment is discussed further in section 5.6.2

2.4.4 Construction time

Typical construction times from ground breaking to end of commissioning for large commercial plants are of the order of 18 months. In addition to this, proponents need to factor in the time required for approvals and to reach financial closure, which can be extensive.

Figure 2-7: Indicative timeline for 15 MW_e trough plant (DLR & Evonik, 2009). gives an indicative timetable of 39 months for the construction time for a proposed 15 MW_e trough plant.

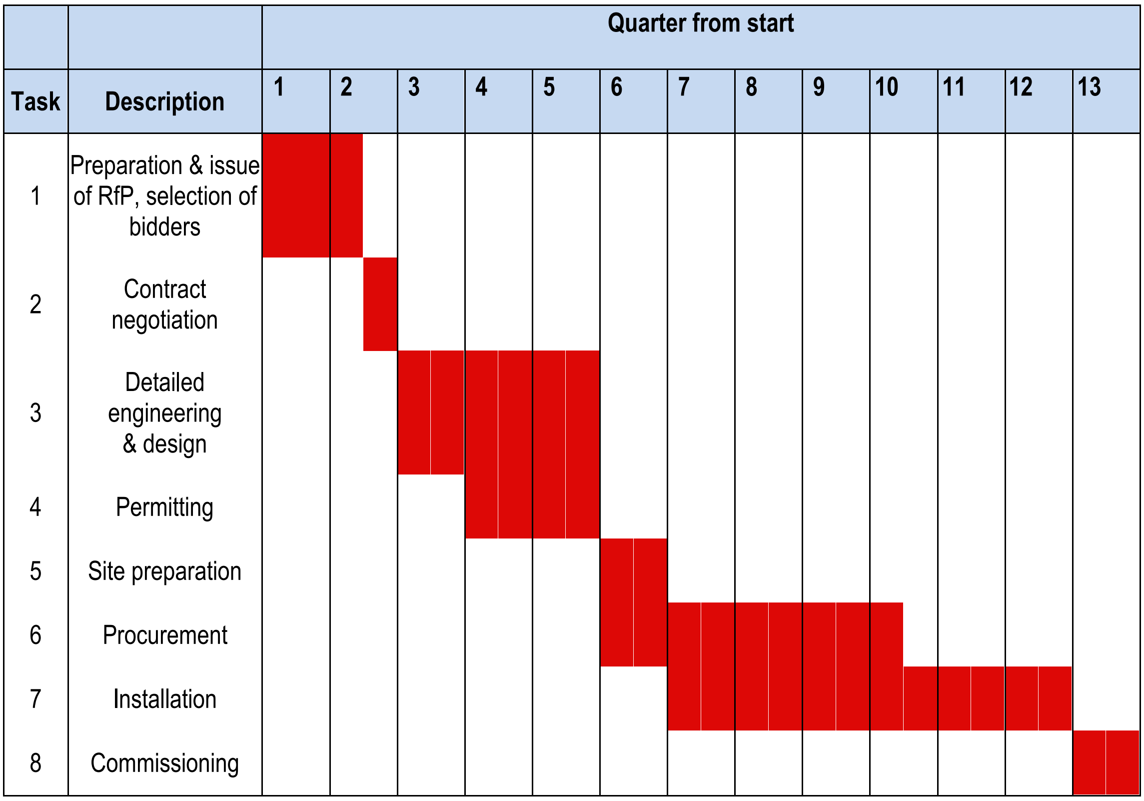

Figure 2-7: Indicative timeline for 15 MW_e trough plant (DLR & Evonik, 2009).

2.5 International R&D facilities

Research activity in Concentrating Solar Thermal has always been strong in Germany, Spain, and the USA. France, Switzerland, Israel and Japan have been consistent significant players over many years also. In addition, China, Korea and India are now accelerating their R&D efforts. Various other countries have a minor presence. In the USA a steady decline has now been replaced by a significantly boosted R&D budget since 2005.

Figure 2-8 indicates the geographical location of the most significant CSP R&D facilities around the world. In addition there are many more research group's and activities based in universities and companies. It is instructive to examine the high profile centres in some detail.

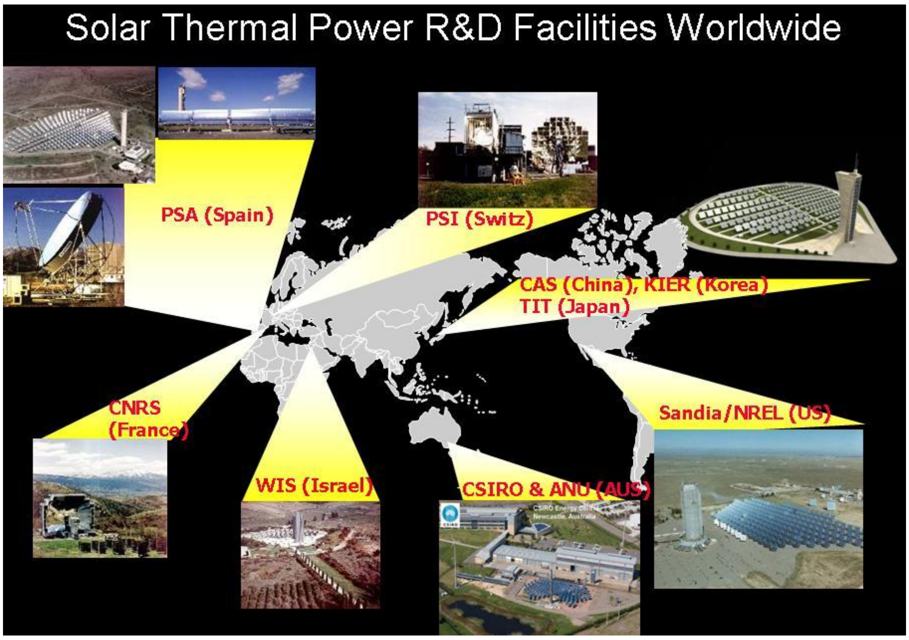

Figure 2-8: Worldwide R&D Facilities, (from SolarPACES).

An outline of the relevant key features of the key overseas R&D Facilities is provided on the following pages.

Switzerland;Paul Scherrer Institute (www.sollab.eu/psi.html)

The Paul Scherrer Institute in Switzerland is a major recearch centre that hosts a solar technology laboratory in conjunction with ETH Zurich. Facilities include:

- a 40 kW 5,000-suns solar furnace;
- a 50 kW 11,000-suns high-flux solar simulator;
- two 75 kW 5,000-suns high-flux solar simulators; and
- physical chemistry laboratories.

This is much predominantly a fundamental research facility.

US; Sandia (www.sandia.gov/Renewable_Energy/solarthermal/nsttf.html)

The Sandia National Laboratories based in Albuquerque, New Mexico, hosts the National Solar Thermal Test facility. As well as being a platform for fundamental R&D, this centre has a strong track record of collaboration with commercial players for testing and demonstrating commercial prototypes. Dish Stirling activities have been a major part of this.

It includes a solar furnace and experimental solar tower facility for fundamental research. In addition, it hosts tests and demonstrations of commercial CSP systems. In 2010, this included an array of dish systems being trialled by Stirling Energy Systems and an array being trialled by Infinia. A multi-purpose platform also is used for performance testing of prototype commercial trough modules.

Figure 2-9: Sandia site (picture www.sandia.gov/Renewable_Energy/solarthermal/nsttf.html.)

US; National Renewable Energy Laboratory (www.nrel/gov/solar/)

The National Renewable Energy Laboratory (NREL) Solar Thermal facility in Colorado is similar but smaller in extent to Sandia. It has extensive material laboratories, a small solar furnace, a trough test platform and other outdoor test facilities. The NREL group has played a lead role in linear / trough system R&D in complement to Sandia's greater emphasis on Towers and Dishes. NREL also has a major effort in a range of PV technology R&D in addition to CSP.

Israel Weizman Institute of Science www.weizmann.ac.il/ESER/People/Karni/research.html

In Israel, the Weizmann Institute of Science hosts the solar research facilities unit. The website states, 'A major feature of the unit is a Solar Power Tower containing a field of 64 large, multi-faceted mirrors (heliostats), each measuring 7 x 8 meters.'Once again, the work is very much R&D focussed.

US; SolarTAC, Colorado (www.solartac.org)

Work is underway to establish the Solar Technology Acceleration Centre, (SolarTAC). This new centre will occupy a 74 acre (30 ha) site near Denver International Airport. .It is a public-private partnership that aims to be an integrated, world-class test facility where the solar industry can research, test, validate, and demonstrate solar technologies. Both CSP and PV technologies are included in its scope. Abengoa are one of the foundation partners and are planning a significantly sized test system of commercial trough units. SunEdison is also a founding partner.

Spain, Plataforma Solar de Almeria (PSA) (www.psa.es/webeng/index.php)

The Plataforma Solar de Almeria (PSA) in south-east Spain, is the largest, existing global solar thermal test facility.The PSA site is more than 100 ha (250 acre) and is utilised for testing and optimisation of a variety of high-temperature solar technologies. PSA is owned and operated by CIEMAT. It was established through a Spanish-German collaboration and also closely collaborates with several large companies.

'At present, the main test facilities available at the PSA are:

- CESA-1 and SSPS-CRS central receiver systems, 7 and 2.7 MW_{th} respectively;
- SSPS-OCS 1.2 MW_{th} parabolic -trough collector system, with associated thermal storage system and water desalination plant;
- DISS 1.8 MW_{th} test loop, an excellent experimental system for two-phase flow research and direct steam generation for electricity production;
- HTF test loop for new parabolic trough collector components;
- DISTAL dish/Stirling facility, 6 units;
- A 60 kW_{th} solar furnace for thermal materials treatments;
- DETOX Loop: A solar chemistry facility;
- Laboratory for Energy Testing of Building Components (LECE); and
- Meteorological station.' [32]

Figure 2-10: Plataforma Solar de Almeria site (picture www.psa.es/webeng/index.php).

In addition to the key features listed on the website, there is an extensive administration, reception, visitors centre complex. While much of the activity is R&D based, there are also major commercial demonstrations of technologies.

Spain, Solucar

The Spanish company Abengoa are the developers of the PS10 and PS20 tower based CSP plants demonstrated at Solucar. The towers are co-located with three Solnova 50 MW trough power plants, plus a range of private R&D facilities. This is a major overall concentration of effort across all technology types and spanning the full spectrum of RD&D activity. It is unique in the world for its major scale combined with exclusively commercial ownership and operation.

Germany, German Aerospace Centre (DLR)

Germany is one of the lead countries for CSP research. The German Aerospace Centre (Deutsche Forschungsanstalt für Luft-Und Raumfahrt - DLR) is the focal point for this activity. DLR does not have a single main facility, it has major laboratories in Stuttgart, a solar furnace in Cologne and a tower system in Julich. In addition DLR researchers are heavily involved in activities carried out at PSA in Spain.

France, Odeillo Centre National de la Recherche Scientifique (CNRS)

This iconic large solar furnace facility also manages the nearby Themis 2 MW Tower system.

[32] www.sollab.eu/psa.html

3 Global CSP Status

Following an initial period of growth in the 1980s that was stimulated by tax incentives in the USA, there was a hiatus in deployment of utility scale CSP plant. Since 2005, developments have recommenced and gained considerable momentum with continued expansion expected.

This growth has predominantly been in Spain and now increasingly in the south-western states of the US. The growth since 2005 has been supported by Feed-in Tariffs and Renewable Portfolio Obligations in those jurisdictions.

Though continued expansion of CSP is expected, it is not yet secure. Spain is winding back its industry support due to fiscal constraints. Future US federal programs, designed to complement state-based initiatives, are by no means certain. On the positive side, several Middle Eastern and North African countries have just begun low-level CSP activity. India is taking the first steps on its Jawaharlal Nehru National Solar Mission, which aims to install 20 GW_e of CSP and PV capacity by 2022. China could play a major role, it has a target of 1GW of CSP by 2015, but has yet to demonstrate its intentions in a concrete way.

3.1 Installed Capacity

The history of installed, global CSP capacity is illustrated in Figure 3-1.

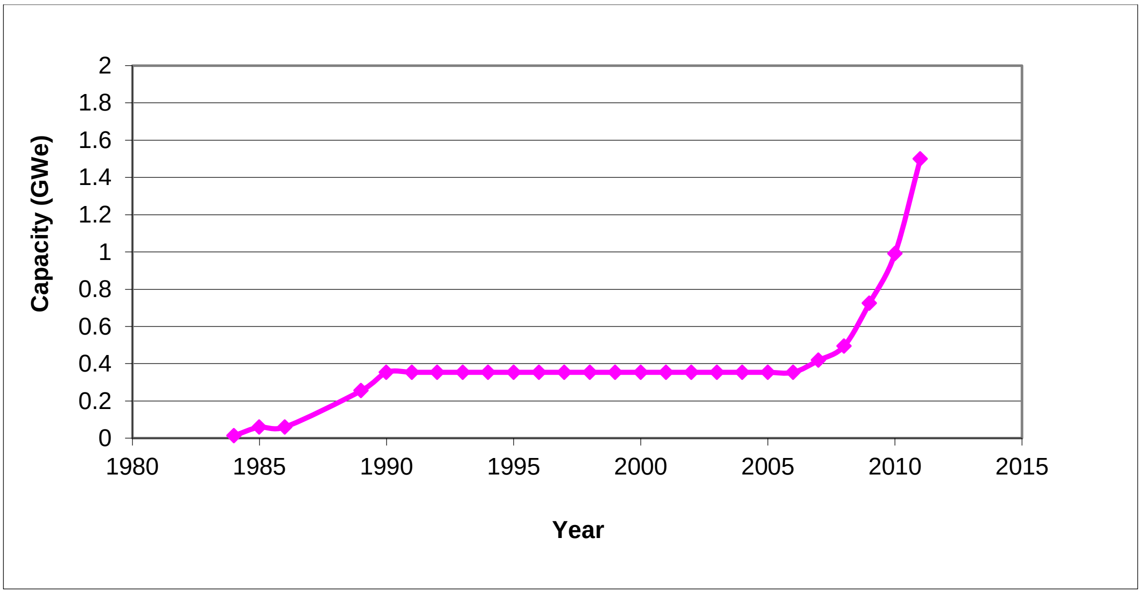

Figure 3-1: Global installed capacity of CSP plants to end of 2011.

With the industry evolving rapidly, listing projects proposed or under development is likely to be out-of-date before a report is published. Also the number of proposals has reached a point that such a listing would be cumbersomely large.

There are many sources of information that can be monitored to track construction progress. 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.

3.1.1 Concentrating Solar Thermal

The IEA Solar Power and Chemical Energy Systems (SolarPACES) program is the umbrella under which the CST community has worked together and shared information for many years. The SolarPACES website[33] has good overview information and a link to a project listing hosted by NREL. This is a reliable source for project information. However, the status of projects can date quickly, so that a project noted as under construction could actually have commenced generation.

Wikipedia also has comprehensive listing[34], however given the open source nature of the site, data must be treated with some caution. It would appear that some projects listed as under construction are really only announced, although some listed as announced may have started construction. The Spanish Solar Thermal industry association website[35] also publishes a list of projects and their status in Spain. As with other sites, care needs to be taken in interpreting the relevant date of the information. For the USA, the Solar Energy Industries Association website[36] has a similar listing.

Table 3-1 lists operating CST power plants over 1 MW_e in capacity, as at November 2011 (largely based on the NREL listing). The list may not be exhaustive as there may be some demonstration systems that have been commissioned without extensive publicity. The 1 MW_e limit is chosen somewhat arbitrarily, to capture only those systems that are routinely run for extended hours for power generation, thus capturing first of a kind demonstrations but excluding initial experimental prototypes and research systems.

Table 3-1: Operating CST power plants over 1 MW_e capacity as at end 2011, sorted by approximate completion date

System	Capacity (MW_e) and power gen type	Location	Storage or hybrisation	Technology Provider	Remarks
Solar Energy Generating Systems (Trough)	354 Steam turbine	Mojave Desert California, USA	Gas back up	Luz	Collection of 9 units ranging from 20 to 80MW and operating since the 1980s
Saguaro Solar Power Station (Trough)	1 ORC	Red Rock Arizona, USA		Starnet	2006, Organic Rankine Cycle system
Nevada Solar One (Trough)	64 Steam turbine	Boulder City, Nevada, USA		Acciona Solar Power	Completed June 2007
Keahole Solar Power (Trough)	2 ORC	Hawaii, US A		Sopogy	Organic Rankine cycle

33 http://solarpaces.org/

34 http://en.wikipedia.org/wiki/List_of_solar_thermal_power_stations

35 http://www.protermosolar.com/boletines/29/mapa.html

36 http://www.seia.org/galleries/pdf/Major%20Solar%20Projects.pdf

Operating CST power plants over 1 MW_e capacity as at end 2011, continued

System	Capacity (MW_e) and power gen type	Location	Storage or hybrisation	Technology Provider	Remarks
PS10 Solar Power Tower (Tower)	11 Steam turbine	Seville, Spa in	Steam accumulators for half hour storage	Abengoa	Operational 2007
Solar Energy Development Centre (Tower)	2	Har Hotzvim Technology Park, Jerusalem, Israel.	na	Brightsource	Commenced June 2008
Liddell Power Station Solar Steam (LFR)	2 Steam turbine	New South Wales, Australia	Hybrid to existing coal plant	Ausra	Electrical equivalent steam boost for coal station
Kimberlina (Linear Fresnel)	5 Steam turbine	Bakersfield, California, USA		Ausra	Ausra demonstration plant (2008)
Jülich Solar Tower (Tower)	1.5 Steam turbine	Jülich, Germany	Ceramic bed, experimental storage system	DLR/Jülich Solar Institute (SIJ)	Completed December 2008
Andasol solar power station (Trough)	150 (3x50) Steam turbine	Granada, S pain	Two tank Molten salt for 7.5 hours full load operation	Solar Millennium AG	Andasol 1 (2008) Andasol 2(2009) Andasol 3 (2010)
PS20 Solar Power Tower (Tower)	20 Steam turbine	Seville, Spa in	Steam accumulators for half hour storage	Abengoa	Completed April 2009
Puerto Errado 1 (Linear Fresnel)	1.4 Steam turbine	Murcia, Spa in	no	Novatec Solar España S.L.	Completed April 2009
Ibersol Ciudad Real (Trough)	50 Steam turbine	Puertollan, Ciudad Real, Spain	Gas fired HTF heater	Iberdrola / Schott	Completed May 2009
Alvarado I (Trough)	50 Steam turbine	Badajoz, Spain		Acciona Solar Power	Completed July 2009
Sierra SunTower (Tower)	5 Steam turbine	Lancaster, California, USA		e-Solar	eSolar commercial power plant, , completed August 2009
Maricopa Solar (Dish)	1.5 Stirling engine	Peoria, Arizona, US A		Stirling Energy Systems, Tessera Solar	Stirling Energy Systems / Tessera Solar's first commercial-scale Dish Stirling power plant. Completed January 2010
Solnova (Trough)	150 (3x50) Steam turbine	Seville, Spain		Abengoa	Solnova 1 (May 2010) Solnova 3 (May 2010) Solnova 4 (August 2010)

Operating CST power plants over 1 MW_e capacity as at end 2011, continued					
System	**Capacity & gen type**	**Location**	**Storage or hybrisation**	**Technology Provider**	**Remarks**
Extresol 2 (Trough)	50 Steam turbine	Torre de Miguel Sesmero, Spain	Two tank Molten salt for 7.5 hours full load operation	Sener Group / Schott	Completed March 2010
Archimede solar power plant (Trough)	5 Steam turbine	Near Siracusa, Sicily, Italy	Molten salt is also HTF	ENEA	ISCC with heat storage Completed July 2010
La Florida (Trough)	50 Steam turbine	Alvarado (Badajoz), Spain	Two tank Molten salt for 7.5 hours full load operation	SAMCA / Schott	Completed July 2010
Colarado Integrated Solar Project (Trough)	2 Steam turbine	Pailisade, Colarado USA	Solar input to an existing coal plant	Xcel Energy, Abengoa	Start production 2010
Majadas 1	50	Majadas de Tieter, Spain		Acciona Energia	October 2010
Palma Del Rio II	50	Spain		Acciona Energia	December 2010
Martin MNGSEC (Trough)	75 Steam turbine	Indian town Florida USA	Part of a combined cycle plant	Florida Power and Light	Attached to a large gas fired combined cycle power plant. Start production December 2010
Manchasol 1	50	Ciudad Real, Spain	Two tank Molten salt for 7.5 hours full load operation	ACS Cobra group	January 2011
La Dehesa	50	La Garrovilla, Spain	Two tank Molten salt for 7.5 hours	Renovables SAMCA	Feb 2011
Yazd ISCC (Trough)	17 Steam turbine	Yazd, Iran	Combined with gas turbine plant	NA	First CSP in Iran, one of first ISCC systems anywhere.
Bikaner (Tower)	3.5 Steam turbine	Rajasthan, India	no	eSolar	First working CSP system in India 2011
Gemasolar (Tower)	19 Steam turbine	Seville, Spain	Molten salt for 7.5 hours full load operation	Sener / Torresol	Highest capacity factor Solar plant in existence October 2011
Argelia (Trough)	25 Steam turbine	Hassi R'mel, Algeria	Part of a combined cycle plant	Sonatrach, Abener	ISCC system, production from July 2011
ISCC Morocco (Trough)		Ain Beni Mathar, Morocco	Part of a combined cycle plant	ONE, Abener	ISCC system, Production from May 2011
Valle 1	50 Steam turbine	Cadiz, Spain	Molten salt for 7.5 hours full load operation	Torresol Energy	Commenced commissioning January 2012
Valle 2	50 Steam turbine	Cadiz, Spain	Molten salt for 7.5 hours full load operation	Torresol Energy	Commenced commissioning January 2012

The first entry in Table 3-1 refers to the Solar Energy Generating Systems (SEGS) plants in Southern California. 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.

The SEGS plants have continued to generate effectively for over 20 years with an increasing availability over that time. 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 projects are also variations on the SEGS technology approach.

The case study of the Californian SEGS plants (Lotker, 1991), notes that the total of 354 MW_e of installed CSP capacity and associated gas-boosting infrastructure required US $1.2 billion to construct and incorporates more than two million square metres of glass mirror. Between their completion and 2009, they were responsible for more than half of the solar electricity generated in the world. More importantly, they continue to operate with over 99% availability and have shown reductions in O&M costs over their operating life (Richter et al, 2009).

Whilst attempting to list projects under development or under construction is even more prone to error, it is worth noting a number of major examples that appear to be 'beyond the point of no return' at end 2011:

- Brightsource's Ivanpah system in California consists of 3 modules of Tower direct steam systems to make a total 390MW_e. The first module is well progressed and the other 2 have started construction.
- Abengoa's Solana project near Phoenix Arizona, will be a 280MW_e system, using troughs and with 6 hours of molten salt based storage.
- There are at least 20 further 50MW_e systems, most with storage, that are reported as well under construction in Spain.
- Novatec's 30MW_e PEII linear Fresnel system in Spain is close to completion and will be the biggest Fresnel system in operation at that point.

3.1.2 Concentrating PV

Table 3-2 lists working CPV power plants over 150 kW_e capacity. A lower limit of 150 kW_e is chosen for CPV in reflection of the fact that smaller systems can be considered as commercial arrays with CPV technology. Once again the limit is arbitrary and chosen to exclude small experiments and early demonstrations.

Table 3-2: Operational CPV Plants of greater than 150 kW_e capacity at end 2011.

Capacity (MW) and power gen type	Location	Technology Provider	System type
0.50 MW	Durango, Mexico,	Skyline Solar	Low concentration
0.35 MW	Umuwa, SA	Solar Systems / Silex	Dishes with III-V Triple junction 500 sun. Power station on diesel fired mini grid
0.19 MW	Hermannsburg, NT	Solar Systems / Silex	Dishes with III-V Triple junction 500 sun. Power station on diesel fired mini grid
0.24 MW	Yuendumu, NT	Solar Systems / Silex	Dishes with III-V Triple junction 500 sun.

			Power station on diesel fired mini grid
0.29 MW	Lajamanu, NT	Solar Systems / Silex	Dishes with III-V Triple junction 500 sun. Power station on diesel fired mini grid
0.175 MW	Windorah, Queensland	Solar Systems / Silex	Dishes with III-V Triple junction 500 sun. Power station on diesel fired mini grid
0.225 MW	Alice Springs, NT	Solfocus	Triple junction PV at 650 suns
0.218 MW	Liuzu, Kaohsiung, Taiwan	Everphoton	Fresnel lens
0.24 MW	Liuzu, Kaohsiung, Taiwan	Browave	
0.546 MW	Liuzu, Kaohsiung, Taiwan	Delta Electronics	
0.27 MW	Tempe Arizona, USA	Amonix	Fresnel lens and multijunction cells
0.175 MW	Prescott, Arizona, USA	Amonix	Fresnel lens and multijunction cells
0.24 MW	Henderson, Nevada, USA	Amonix	Fresnel lens and multijunction cells
1.0 MW	Victorville, California, USA	Solfocus	Primary and secondary mirrors and non-imaging optical system with with III-V triple junction cells
1.0 MW	Hanford, California, USA	Solfocus	Primary and secondary mirrors and non-imaging optical system with with III-V triple junction cells
0.42 MW	Coachella, California, USA	Solfocus	Primary and secondary mirrors and non-imaging optical system with with III-V triple junction cells
0.30 MW	Austin, Texas, USA	Entech Solar	Stretched lens array with monocrystalline cells
0.95 MW	Talayuela, Spain	Amonix/Guascor Fotón	Fresnel lens and multijunction cells
7.8 MW	Parques Solares de Navarra, Spain	Amonix/Guascor Fotón	Fresnel lens and multijunction cells
1.5 MW	Ecija, Seville, Spain	Amonix/Guascor Fotón	Fresnel lens and multijunction cells
0.20 MW	Puertollano, Spain	Solfocus	Primary and secondary mirrors and non-imaging optical system with with III-V triple junction cells
0.50 MW	Puertollano, Spain	Soitec/Concentrix	Fresnel lens and multijunction cells
0.30 MW	Almoguera, Spain	Solfocus	Primary and secondary mirrors and non-imaging optical system with with III-V triple junction cells
0.80 MW	Flix, Tarragona, Spain	Sol3G	Fresnel lenses and secondary non imaging elements with triple-junction cells
0.375 MW	Ibahernando, Extremadura, Spain	Emcore	Optical lens and mirrors with triple junction cells
0.20 MW	Santa Pola, Alicante, Spain	Sol3G	Fresnel lenses and secondary non imaging elements with triple-junction cells
0.30 MW	Puertollano, Spain	Emcore	Optical lens and mirrors with triple junction cells
0.33 MW	Tarragona, Spain	OPEL Solar	Dual element refractive concentrator and triple junction Boeing-Spectrolab solar cells

3.2 CSP Global Growth Forecast

There are a variety of forecasts for the global growth of installed CSP generation.

3.2.1 Previous forecasts

A major study (DLR, 2005) of the potential for CSP in the countries surrounding the Mediterranean concluded that CSP could grow to provide over 50% of the electricity generation in those countries. In doing so, employment in the sector could grow to close to two million persons while the cost of generation was forecast to decrease to around EU 0.05 / kWh by 2030.

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'.

Three future scenarios are analysed by Richter et al (2009):

- a reference scenario based on 2007 IEA World Energy outlook assuming only measures in place at that time,
- a moderate scenario that assumes all proposed policy measures and targets around the world are implemented and met, and
- an advanced scenario that represents a best case CSP vision, that could be achieved if optimal policies were adopted around the globe.

The results predicted for global installed capacity till 2050 and the shares predicted for India China and the 'OECD Pacific category are given in Table 3-3.

Australia is considered to be the major part of an 'OECD Pacific' category. In the regional breakdown of these figures, the predictions for India under the advanced scenario, are less in 2020 than the Solar Mission target. Both China and OECD Pacific are predicted to outperform India under the advanced scenario. Given that the report pre-dates India's Solar Mission announcement, it illustrates the sensitivity of outcomes to government policy settings. It also illustrates that the advanced scenario, is probably not the most extreme optimistic projection that could be contemplated.

Forecast cumulative installed capacity (MW_e)				
Scenario	**2015**	**2020**	**2030**	**2050**
Reference	4,065	7,271	12,765	18,018
Moderate	24,468	68,584	231,332	830,707
Advanced	29,419	84,336	342,301	1,524,172

Forecast cumulative installed capacity in 2020 in key regions (MWe)				
Scenario	**Global**	**India**	**China**	**OECD Pacific (incl Australia)**
Reference	7,271	30	30	475
Moderate	68,584	2,760	8,334	2,848
Advanced	84,336	3,179	8,650	9,000

Table 3-3: Forecast CSP installed capacities (Data from Richter et al, 2009).

A recent roadmap published by the IEA for CSP technology presents a highly credible summary of the global situation and way forward, (IEA 2010A). The roadmap notes the view that PV costs are now lower than CSP. The benefits of thermal energy storage, potential for easy hybridisation with existing fossil fuelled technologies and solar fuels production, are discussed in detail. Regarding growth projections, the IEA roadmap chooses to suggest a likely path that lies between the moderate and advanced scenarios from the Richter et al (2009) outlook as shown in Figure 3-2.

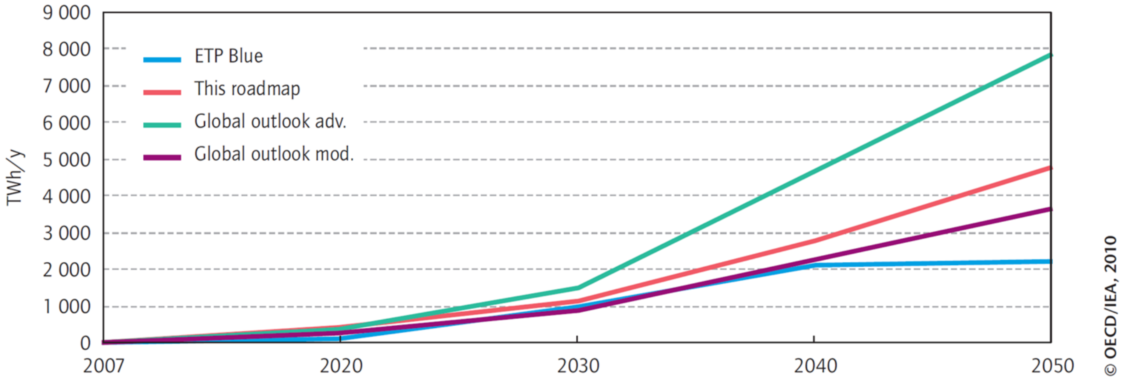

Figure 3-2: CSP generation growth projections from a range of scenario's from the CSP Roadmap (IEA, 2010A).

Figure 3-3 provides predicted shares of the generation by country / region. India is projected to have the third largest share of production through the later stages of this growth phase. Interestingly, Australia is not assessed separately.

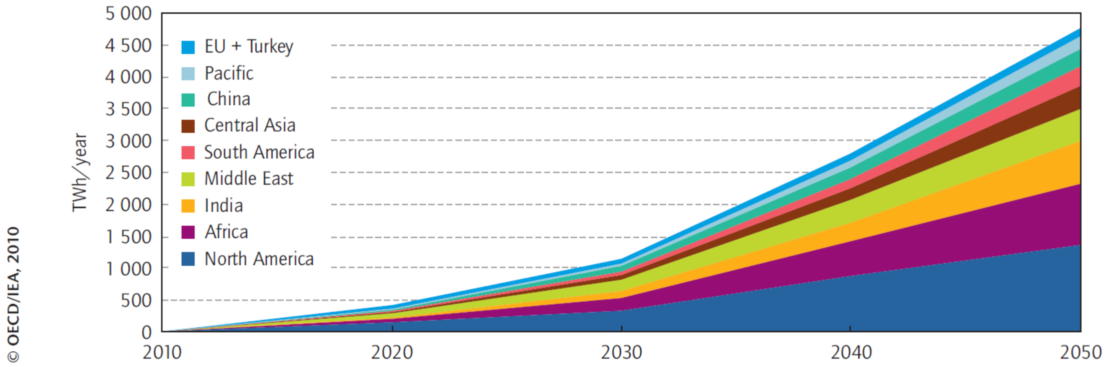

Figure 3-3: Predicted regional shares of CSP generation from the CSP Roadmap (IEA, 2010A).

In the recently published "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.

3.2.2 Growth forecasts

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 usually be modelled with a compounding per cent rate of growth curve.

The last few years clearly show the beginnings of compound growth in CSP generation around the world. The key question is, will this continue or will the recent falls in PV prices mean CSP developments stall? The key characteristic of dispatchability may drive 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.

There are some good historical pointers to the growth trajectory that might be expected for CSP globally. Some relevant data is tabulated in Table 3-4. Where an actual or projected capacity in a particular year has been quoted, this has been fitted to a compound growth curve to arrive at the implied growth rate figure. If a growth rate has been quoted, this is listed in the Quoted growth rate column. The wind and PV industries are very relevant indicators since they represent technologies that target subsections of the overall clean energy space that CSP targets. Solid consistent growth in the range of 28% to 52% pa has been mapped over several decades.

For CSP, the progress to date can be fitted to compound growth curves. If the entire effort from the first SEGS plant in 1984 to the completed 1.5 GW at the end of 2011, is fitted, the result is a historic growth rate over nearly three decades of about 19%. However, there was a long period of zero activity between 1990 and 2006, the early phase from 1984 to 1990 averaged growth of 71% for a short while and the latest phase from 2006 to 2011 has averaged 33.5% pa growth.

The various recent published studies projecting future growth can be converted to Implied growth rates as shown and values between 10% and 60% are indicated. The various scenario's from Richter et al 2009, have projected installed capacities that indicate the idea of a phase of very high growth rate followed by a slowing.

Table 3-4: Installed CSP Capacity Growth Rates.

Reference	Capacity projection (GW)	Year	Quoted growth rate	Implied growth rate
HISTORICAL				
GEF (2005) quotes IEA wind 71 -2000			52.0%	
GEF (2005) quotes PV			32.0%	
Hearps and McConnell (2011) PV last decade			40.0%	
Hearps and McConnell (2011) wind last decade			28.0%	
CSP actual 2006 -2011	1.5	2011		33.5%
CSP actual 1984 -1990	0.354	1990		71.3%
CSP actual 1984 - 2011	1.5	2011		18.9%
PROJECTIONS				

Richter (2009) moderate scenario	24.5	2015		60.0%
Richter (2009) moderate scenario	68.6	2020		45.8%
Richter (2009) moderate scenario	231.3	2030		31.0%
Richter (2009) moderate scenario	830.7	2050		19.3%
Richter (2009) reference scenario	4.1	2015		31.0%
Richter (2009) reference scenario	7.3	2020		24.2%
Richter (2009) reference scenario	12.8	2030		16.2%
Richter (2009) reference scenario	18.0	2050		9.4%
Richter (2009) advanced scenario	29.4	2015		63.6%
Richter (2009) advanced scenario	84.3	2020		48.0%
Richter (2009) advanced scenario	342.3	2030		33.2%
Richter (2009) advanced scenario	1,524.2	2050		21.0%
GEF(2005) quotes Athene from 2004			23.0%	
IEA (2010A	128	2020		62.0%
AT Kearney (2010) low	60	2025		31.0%
AT Kearney (2010) high	100	2025		34.6%

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. Capacity referred to here is an equivalent capacity normalised to have the same average capacity factor as today's plants. 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.

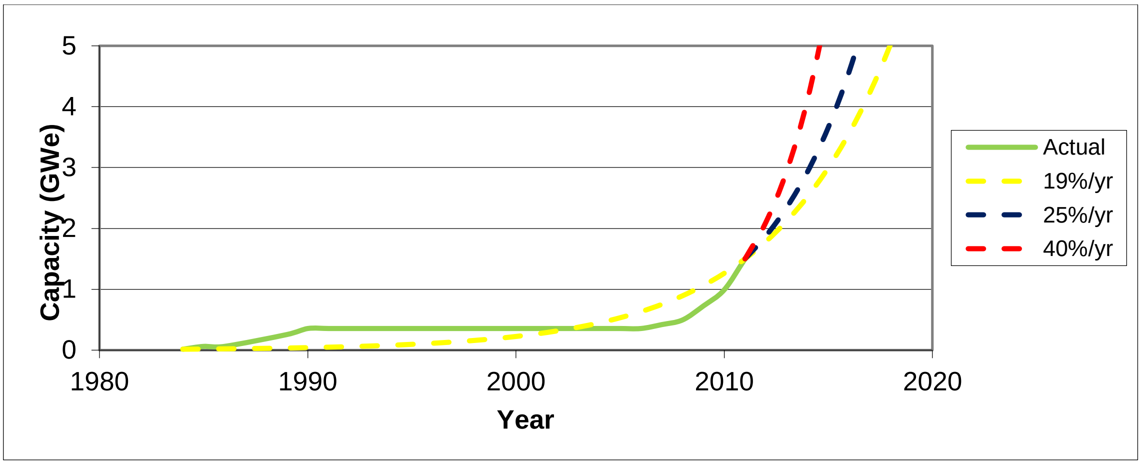

Figure 3-4: Potential Global CSP Generation Growth Scenarios

The history of the industry is that first the USA and then Spain took the lead. Now we are seeing a slowing in Spain with the beginnings of an upswing in the USA. At the same time, India's programs promise the potential for major growth in that country. Other countries such as Australia, have support programs but are yet to see significant generation. 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 decade, 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.

Figure 3-5 shows the three possible scenarios on a larger vertical axis.

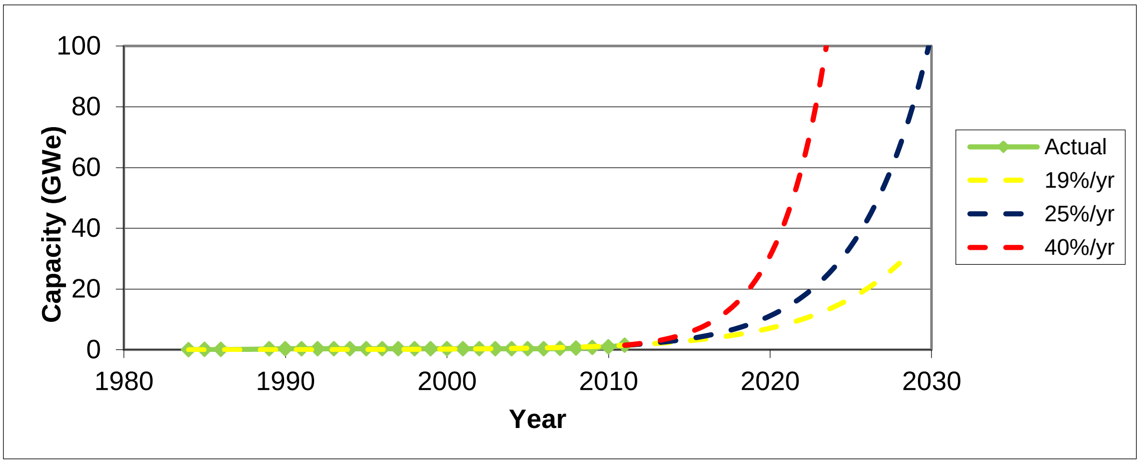

Figure 3-5: Potential CSP Global Growth Scenarios to 2030

An important observation is that there is a significant positive feedback effect on growing capacity and cost reductions, (the progress ratio). Installing capacity assists with progress in cost reductions, while industry momentum is assisted with further cost reductions.

3.3 CSP Activity in Australia

Despite its world leading solar resources, Australia is yet to be a major player in the CSP industry. This report and initiatives such as the Australian Government's Solar Flagships program plus the existence of the Australian Solar Institute and other programs, all point to the possibility of a major engagement in the coming years. However Australia has 'punched above its weight' in many of its contributions from an RD&D point of view. This section reviews some of the most high profile and historically significant activities. It is in no way intended to be exhaustive.

3.3.1 Installed CSP systems

Meekathara Step 100

Figure 3-6: Meekatharra Collectors, (WA World of Energy).

In 1981-82, a CSP system called Step 100 was built at Meekathara in Western Australia and it was the first CSP generation system in Australia. 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
- providing de-bugging, commissioning and O&M services where costs are high and appropriately trained staff may not be available.

White Cliffs

The early work of the CST group at the Australian National University (ANU) lead to the construction of a 14 dish system in the remote town of White Cliffs in New South Wales. Each dish is $20m^2$ 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. After more than 25 years, the dishes remain in good operating condition. However, Solar Systems removed their equipment and this plant has been mothballed since 2008.

Figure 3-7: White Cliffs Dish Systems (picture ANU)

Liddell Power Station

Figure 3-8: Liddell CST Collectors (picture CS Energy and Areva solar)

Liddell Power Station in the Hunter valley, NSW, hosts a 1,300m^2, array of Linear Fresnel reflectors installed by Ausra (Now Areva solar). In addition to this, work is nearing completion on an additional 18,490 m^2, 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.

Solar Systems' installations

Solar Systems first installed a CPV power station at in a diesel mini-grid in 2001. This project was for the Pitjantjatjara Council and the SA Government. This project was supported by Australian Government funding from the Renewable Energy Commercialisation Program. The power station consisted of ten, 500-sun concentrating dishes, (130m^2 each) with 22% efficient PV cells and pumped water cooling, operating in hybrid with the existing, diesel power station.

Solar Systems commissioned four more CPV stations in diesel mini-grid towns, with all sites now fitted with Spectrolab multi-junction PV cells. The projects were Hermannsburg (2005), Yuendumu (2006), Lajamanu (2007) and Windorah (2008) under the Australian Government's remote power program[37].

Subsequently, Solar Systems constructed the Bridgewater Test Facility, comprising a 140 kW Heliostat / Tower system and a number of new-design, dish-based systems.

Solar Systems has undertaken to build a 154 MW solar concentrator power station in North-Western Victoria. The company assets was acquired by Silex Systems Ltd in 2010. Solar Systems Pty Ltd (Solar Systems) is the new project proponent and is a wholly owned subsidiary of Silex Systems Ltd.

Figure 3-9: Solar Systems CPV at Windorah, Queensland (picture K Lovegrove)

The Mildura 154 MW project cost was originally estimated to be $420 million. The Australian Government offered grant support of up to $75 million from the Low Emissions Technology Demonstration Fund (LETDF), and the Victorian State Government offered another $50 million. The LETDF funding was announced in October 2006 (Government of Australia 2006) with construction, at that time, due to commence in 2008.

Alice Springs Airport

As part of the Alice Springs Solar City project, RRPGP funding was made available to the town. Several Major Projects were supported including a 235 kW CPV plant to support the airport's electricity consumption.

The CPV system uses SolFocus tracking arrays which are based on panels of micro-dishes assembled behind a glass cover. The annual output is forecast to be 600 MWh. The Australian Government contributed $1.13m, (50% of total project costs). Construction took place during 2010, with associated grid-integration issues and commissioning progressed in early 2011.

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

Figure 3-10: Alice Springs Airport CPV System (picture K Lovegrove)

Australian National University

The ANU has a track record in CST 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.

Figure 3-11: The SG4 500 m^2 '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. Main-grid connected, large-scale systems using ground-mounted, steam turbine generation were targeted.

In 2009, a dish design with 500m² aperture area was designed and built by ANU in collaboration with Wizard Power, a startup company established to commercialise the technology. 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).

In addition, the ANU's Centre for Sustainable Energy Systems compliments a large effort on Silicon PV R&D with investigation of linear PV concentrator approaches.A 130m^2 Combined Heat And Power system has been demonstrated on one of the campus residential halls. More recently micro-concentrators were investigated in collaboration with Chromosun.

CSIRO

Figure 3-12: National Solar Energy Centre, Newcastle (Picture from CSIRO)

The National Solar Energy Centre (NSEC) at Newcastle is supported with funding under CSIRO's Energy Transformed Flagship. The NSEC 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 recently commissioned 450 heliostat, 4,000m^2 collector field with a 30m tower.

The NSEC is capable of concentrating solar energy to achieve temperatures beyond 1000ºC. 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.

Sydney University and UNSW

The development of Linear Fresnel Reflector technology was pioneered by Dr David Mills at the University of Sydney, latter in Collaboration with Graham Morrison of UNSW. The work was demonstrated and further commercialised by Solar Heat and Power Pty Ltd.

Solar Heat and Power moved its operations to California and eventually, the technology was further developed by Ausra. The company is now owned by Areva, a large French energy company with diverse investments. The technology is being demonstrated in Chinchilla as part of the Renewable Energy Demonstration Program and the Solar Flagship program.

3.3.2 ASI funded projects

The list of ASI funded CSP projects in Table 3-5 is a snap shot of some of the Australian R&D activity underway.

Table 3-5: ASI Funded CSP R&D Projects, (as at April 2012).

	ASI contribution	Total value
CSIRO MHI (Japan) Solar Tower Field	$5,000,000	$5,000,000
CSIRO Abengoa Solar (Spain) Advanced steam-generating receivers for high-concentration solar collectors	$2,821,978	$5,682,432
University of Newcastle, Fabrication of Thermionic Devices Using Directional Solidificaiton/Sintering	$515,359	$705,926
CSIRO Abengoa Solar (Spain) Development of Advanced Solar Thermal Energy Storage Technologies	$3,538,846	$7,184,161
UNSW Spectrolab/Boeing, Solar Systems Pty Ltd 40% Efficient Photovoltaic “Power Cube” Power Tower Receiver	$550,000	$1,370,000
CSIRO Mitsubishi Heavy Industries (Japan) Solar Powered Air Turbine Systems	$3,055,000	$10,554,073
ANU CSIRO, UNSW, Chromosun Pty Ltd, New Energy Partners, Roof mounted hybrid CST system for distributed generation of heating, cooling and electricity	$3,235,710	$9,458,065
Graphite Energy, Graphite Energy Solar Storage	$1,835,000	$3,835,000
CSIRO Thermax Ltd (India), UNSW A Novel Thermoelectric Topping Cycle Receiver for CST Applications	$2,200,912	$4,728,824
Vast Solar Pty Ltd: Validation of performance modelling for 1.2MWth solar array with high temperature receiver and integrated thermal storage	$437,243	$1,261,160
RayGen Resources Pty Ltd: Central Receiver CPV Pilot Project – Stage 2	$1,750,000	$3,636,952
CSIRO : Evaluation and demonstration of hybridisation of CST with carbon capture and storage	$667,500	$1,855,000
Solar Systems Pty Ltd: High-efficiency multi-junction solar cells on low-cost, large-area silicon substrates	$2,000,000	$5,167,370
Chromasun Pty Ltd: Lowest LCOE: Australian pilot of rooftop CST and CPV-T micro-concentrator systems	$3,461,677	$9,263,370
Granite Power Ltd: Solar Supercritical Organic Rankine Cycle for power and industrial heat	$770,000	$1,707,250
CSIRO : Solar hybrid fuels	$1,585,853	$6,845,570
Barbara Hardy Institute, University of South Australia: Development of high temperature phase change storage systems and a test facility	$689,500	$2,380,629
CSIRO Sandia National Laboratories, National Renewable Energy Laboratory, Queensland University of Technology, The University of Sydney, Barber Nicholls Inc. Solar-driven super-critical CO2 Brayton cycle	$2,496,835	$6,244,091
Australian National University, Sandia National Laboratory, CSIRO. Improved high-temperature receivers for dish concentrators	$1,436210	$3,337,604

3.3.3 Solar Flagships

The Solar Flagships program was announced by the Federal Government in May 2009 and officially launched in Dec 2009. The program aims to facilitate 1 GW of solar power generation by 2015.

The Solar Flagships program has been 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 CST and PV power stations. Round 1 of the program targeted 400 MW_e via one CST and one PV project.

The overall Round 1 process attracted 52 proposals of which at least half are believed to be CST. None of the shortlisted PV proposals were CPV. The four shortlisted CST consortia announced were (Ferguson, 2010).

- 'ACCIONA Energy Oceania proposes to generate 200 MW using solar thermal parabolic trough technology at a single site in either Queensland or South Australia;
- Parsons Brinckerhoff proposes to construct a 150 MW solar thermal parabolic trough power station at Kogan Creek in Queensland;
- Wind Prospect CWP proposes to use linear fresnel technology at Kogan Creek in Queensland to construct a 250 MW power plant; and
- Transfield proposes 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. At the time of finalisation of this report, the future of this project was uncertain, with now power purchase agreement in place and suggestions that the new Queensland state government may withdraw its financial contribution. The study has however proceeded on the premise that Australia will add its initial 200 – 300MW_e of CSP capacity under this or similar programs by around 2014.

Areva solar represents an interesting case study in the progression of Australian initiatives and globalisation. As noted above, the original ideas began with Dr David Mills at the university of Sydney, they were spun off into Solar Heat and Power Pty Ltd, this company ultimately found investment in the USA and became Ausra Inc, which was then later bought by the large French Energy company Areva.

The proposed plant is bigger that any CSP plant currently in operation in the world, although there are other projects underway that are equal or bigger. It will be located on a 470 hectare site close to the Kogan Creek power station but not connected to it. The power block will comprise 2 x 125 MW_e steam turbine units. 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'.

3.3.4 Advanced Electricity Storage Technologies Program

Figure 3-13: Multi tower, graphite energy storage demonstration at Lake Cargelligo, NSW (picture K Lovegrove).

The five successful proposals to the Australian Government's 'Advanced Electricity Storage Technologies' program were announced in May 2007. Two of these were CSP projects, a demonstration of ANU's ammonia based energy storage system using dishes by Wizard Power and a demonstration of graphite based thermal energy storage by Lloyd Energy / Graphite Energy.

There is little publicly available information on both these projects. However, the Graphite Energy project has progressed with the tower heliostat systems with their receiver-mounted, graphite-based thermal energy stores in operation and visible from the town of Lake Cargelligo.

3.3.5 ACRE Funded Solar Demonstrations

In May 2010, funding was announced for two major CSP projects. $31.8m towards a CS Energy lead project to demonstrate the Linear Fresnel Reflector technology of the Areva Group. The project will be attached to the existing Kogan Creek A Power Station to provide a 44 MW electrical equivalent superheated steam solar boost to the coal-fired turbines. This is very close to the Solar Flagships site, although it is a separate project. Financial closure has been reached and construction has begun.

The second project offers $60m to the Solar Oasis consortium to build a 300 dish, 40 MW_e power plant based on the big dish technology developed by ANU.

3.4 Previous studies of CSP potential in Australia

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

3.4.1 COAG High Temperature Solar Thermal Roadmap, 2008

The context and priorities for CST 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 HTST represented a major opportunity in Australia, with an ultimate potential for grid-connected systems in the order of 20,000 MW_e.

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

The HTST Roadmap also identified that a carbon price would need to reach AU $50 per tonne to make a major contribution to CST investments. The performance and economics of CST 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.

3.4.2 Beyond Zero Emmissions' Stationary Energy Plan, 2010

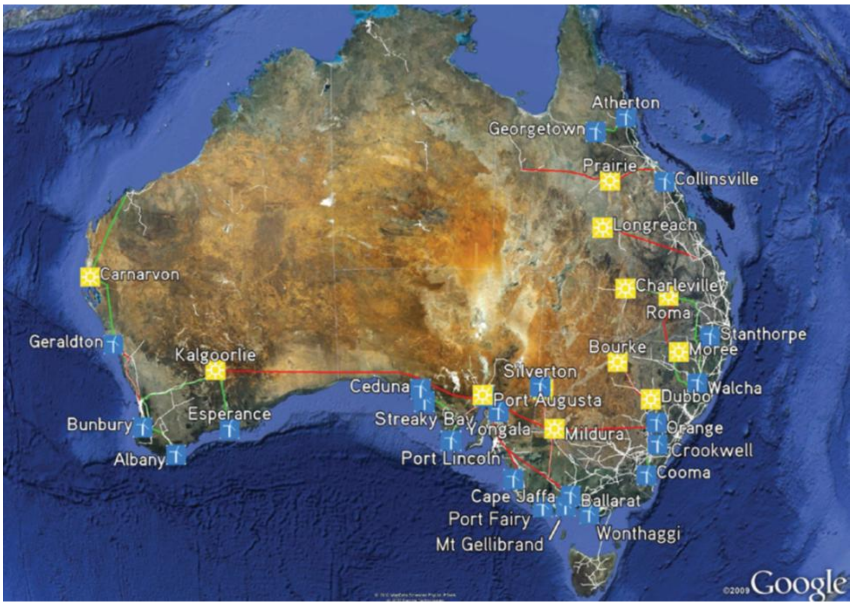

Figure 3-14: Solar and wind farm sites plus major grid extension suggested by Wright and Hearps (2010).

Wright and Hearps (2010) have produced a 'Zero Carbon Stationary Energy Plan'. This is a detailed case study of a scenario based on large wind turbines and CST 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 shows 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 3-14.

3.4.3 NSW Solar Precinct Study 2010

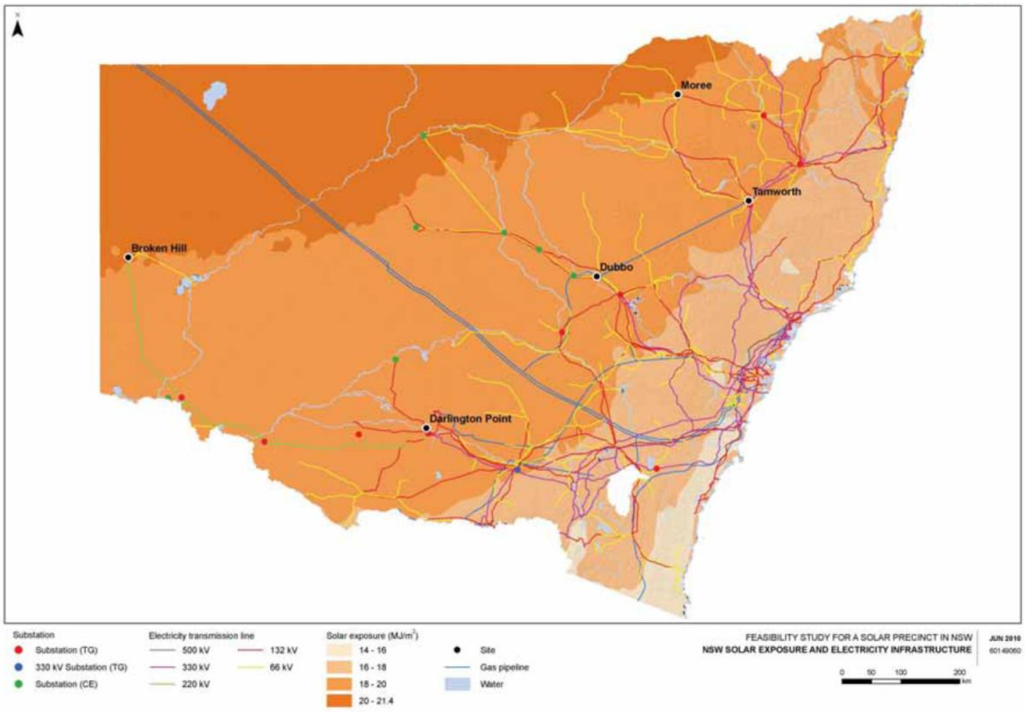

Figure 3-15: Sites examined for solar precincts in NSW compared to solar resource (AECOM 2010).

As a pre-cursor to Solar Flagships, AECOM (2010) have 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.

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.

3.4.4 Queensland CSP Pre-feasibility Study 2010

Also as a precursor to the federal governments Solar Flagships program, 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).

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 offered the least negative NPV.

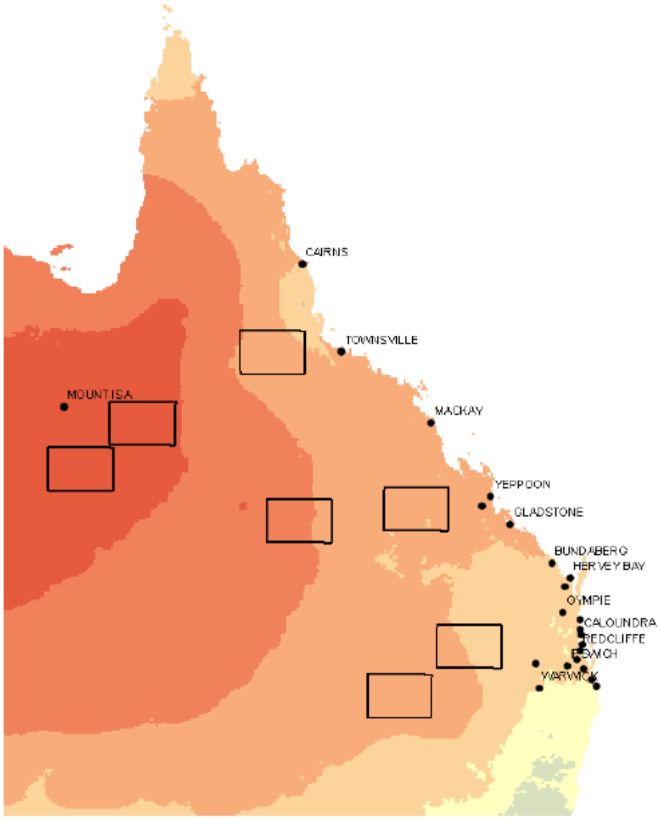

Figure 3-16: Investigation zones for CSP deployment in Queensland, compared to solar resources (Parsons Brinkerhoff 2010).

3.4.5 Site Options for CSP Generation in the Wheatbelt 2010

'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 3-17.

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.

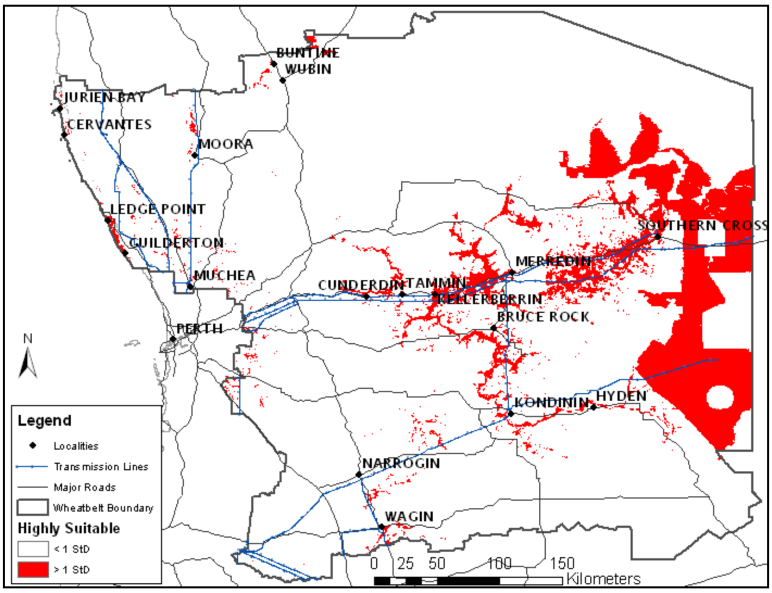

Figure 3-17: Evaluation of site suitability for CSP in the Western Australian Wheat Belt (Clifton and Boruf 2010).

3.4.6 WA Renewable Energy Assessment 2011

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 and Evans and Peck 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. Generation is large capacity diesel engines and gas turbines.

Large growth in demand is expected over the coming decades. The Pilbara demand is 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 CST. The CST 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 CST options indicated a value of $400/MWh or more, however a range of measures were identified that could potentially make the CST option more cost-effective.

3.4.7 Commercial Investigations

There are known to be a body of other investigations carried out by commercial organisations which are not in the public domain. The most obvious and recent of these are the work done by all of the initial applicants to the Solar Flagships program followed by the very detailed studies done by the three short listed projects.

Another major study whose existence is well known and some conclusions of which have been shared (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 3-18. 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.

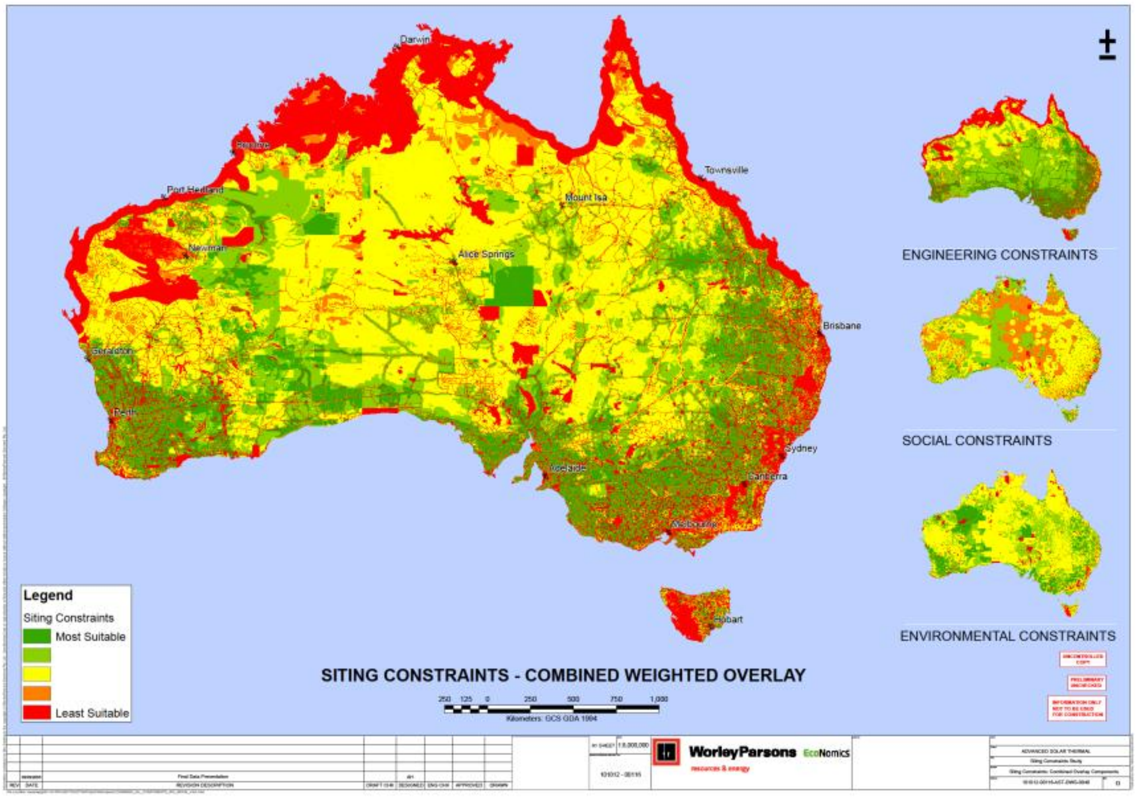

Figure 3-18: GIS mapping of CSP site constraints (Beninga 2009).

The preferred CSP system configuration identified was a parabolic trough plant with:

- Solar Field Mirror Area - 1.5 million m^2;
- Two tank molten salt storage for 1¼ hour storage at full plant output; and
- Export Power 250 MW_e.

The annual generation potential of such a plant at locations around the country is illustrated in Figure 3-19.

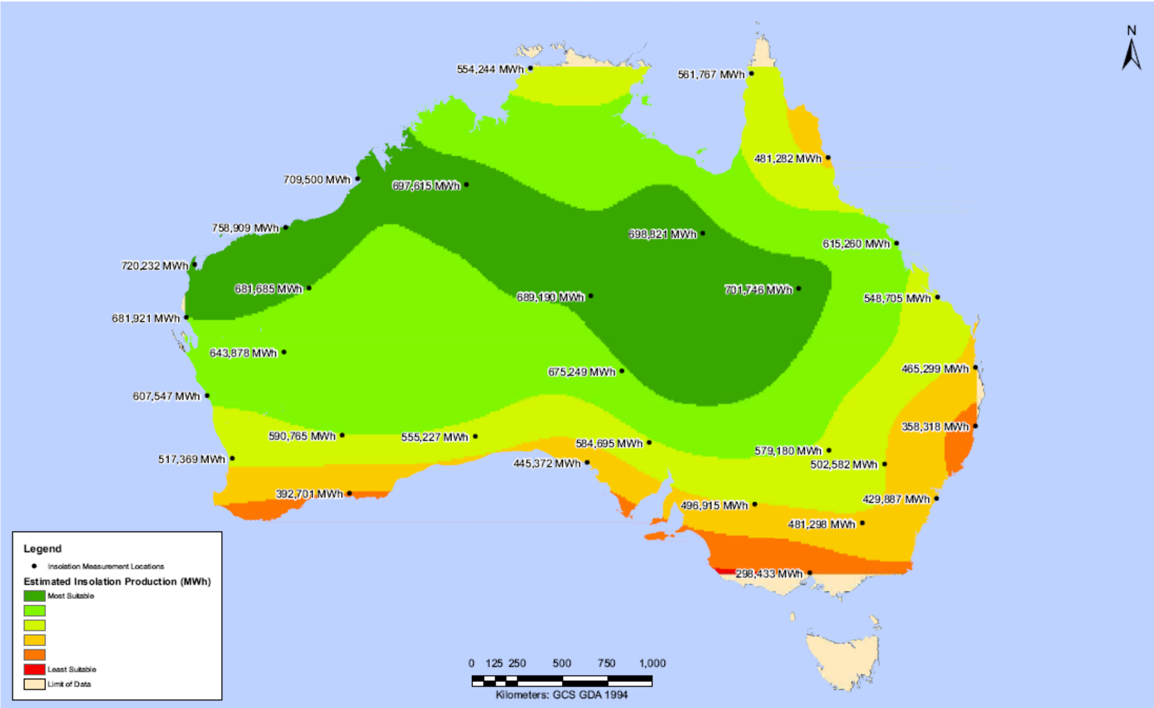

Figure 3-19: Generating potential of a 250 MW_e trough plant at sites across Australia (Beninga 2009).

* * *

4 Review of Market Segments

There are two broad approaches to defining market segments for CSP: by location on the electricity network and/or by mode of operation.

The HTST Technology Roadmap (Wyld Group 2008) defined market segments according to a mixture of location and operation modes: peak lopping, high load duty (baseload and intermediate), solar assist, end-of grid support and remote area power supply.

Definition by location

Here we define market segments according to the location on the electricity network, which can to some extent also dictate the size:

Large-scale grid-connected

- Hybridisation with existing fossil fuel plants or industry (CST only).
- Stand-alone up to 1 GW supported by grid extensions.
- Stand-alone 50-150 MW connected to existing grid.

Medium scale grid-connected

- Grid-connected via the distribution system.
- Mini-grid > 10 MW.

Off main-grid

- Remote Towns < 1 MW (CPV only).
- Remote Towns 1 MW to 10 MW.
- Mining < 10 MW.

Off main-grid is essentially the same as the HTST roadmap's remote area category, medium scale is very similar in concept to their "end of grid support" category and their other categories are essentially a system configuration split of the large grid-connected category.

Section 4.1 provides an overview of the network and the subsequent Sections analyse the various market segments as above.

Definition by mode of operation

Definition of conventional generation market segments according to their mode of operation generally occurs according to the following three sub-categories (although the electricity network will not distinguish between them in terms of transmission access):

- Instantaneous (semi-scheduled) generation;
- Baseload with storage or co-firing element; and
- Load-following using mass storage or gas co-firing to deliver energy on-demand.

The instantaneous mode of operation can occur in any of the large-scale, medium-scale and off-grid market segments. Such plant with a nameplate rating of greater than or equal to 30

MW[38] would operate as a semi-scheduled generator, which means that they would have to submit forecasts of their output, which could be curtailed below their forecast at times when their output would otherwise violate secure network limits – resulting in loss of revenue. They would also have to participate in other processes such as FCAS (Frequency Control Ancillary Service).

Baseload with storage or co-firing can also occur in each of the locational market segments: except for hybridisation with existing plant and/or industry as this implies a subordinate role for the CSP plant. Such plant could possibly operate as scheduled generators in the NEM and so would have to submit forecasts of their output and would be penalised if they did not reach that forecast.

Load following plant could also operate in any of the above locational market segments, again except for hybridisation with existing plant and/or industry. They would operate as scheduled generators and would be the most flexible and could, for example, provide buffering support to other intermittent renewable technologies such as wind or PV, and could also provide peak lopping capability.

[38] Or a collection of generators connected to a common connection point with a combined output of greater than or equal to 30 MW.

4.1 The Australian Electricity Network

The electricity network in Australia is designed to take energy from large central generators, located near coal, gas or hydro resources, and disseminate it to customers. The transmission and distribution network is generally designed and operated as a one-way street. Herein lies a major challenge for new large-scale renewable energy generation, solar in particular, is best suited to remote areas at the extremities of the network that radiates out from the conventional generators.

In the sites of best solar resource, there is either no electricity grid to access, or the grid capacity available to new renewable generation is far lower than the power line's actual total capacity. The amount of intermittent renewable generation capacity that can be connected to fringe-of-the-grid locations is restricted by the frequency and voltage control limitations of the network.

4.1.1 History

The Australia electricity transmission grid was not originally constructed as a national grid. It commenced life as a piecemeal State-based construction effort that, until the mid 1980's, was linked only through the NSW-Victorian and Snowy Mountains Scheme interconnectors and from NSW to SE Queensland. These interconnectors were only really used at that time as a backup against system stability issues caused if a state-owned generation unit failed.

In the late 1980's, following the construction of a major 500 kV transmission line from Geelong to Portland to supply the Alcoa Smelter, there commenced a 10 year program linking the various grids, enabling the formation of the 'national' grid[39]. This was a precursor to the dismembering of the vertically integrated state-based electricity companies into corporatised (and in some states privatised) separate generation, transmission, distribution and retail businesses across the country.

First South Australia and Victoria were linked via the 275 kV Heywood-Mt Gambier line, then stronger links were established between NSW and Queensland, Murraylink joined NSW and SA and Victoria, and Basslink joined Tasmania to Victoria.

Following the reforms of the electricity sector, there are various owners of transmission lines in each State operating commercially, and energy trading between jurisdictions now occurs. The key players are listed in Table 4-1.

Table 4-1: Major Transmission Operators in Australia

State	Company	Ownership
Queensland	Powerlink	Qld Govt - Corporatised
Queensland	Transenergie (QNI Link)	Private Investor
NSW	Transgrid	NSW Govt - Corporatised
Victoria	SPI Ausnet	Privatised
Tasmania	Transend Networks	Tas Govt - Corporatised

[39] National grid and National Energy Market are potentially misleading terms since they do not include Western Australia, the Northern Territory and some regional areas in other States..

Tasmania	National Grid (Basslink)	Private Investor
South Australia	ElectraNet	Privatised
South Australia	Aust Pipeline Trust (Murraylink)	Private Investor
Western Australia	Western Power (SWIS)	WA Govt - Corporatised
Western Australia	Horizon Power (NWIS)	WA Govt - Corporatised
Northern Territory	Power & Water Corporation	NT Govt - Corporatised

4.1.2 The transmission network

The National Electricity Code defines the transmission network as a network operating at nominal voltages of 220 kV and above plus:

(a) any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network;

(b) any part of a network operating at nominal voltages between 66 kV and 220 kV that does not operate in parallel to and provide support to the higher voltage transmission network but is deemed by the Regulator to be part of the transmission network.

Thus it is generally held, within the electricity industry in Australia, that 66 kV is the upper limit of a sub-transmission (distribution) voltage. Typically, powerlines operating at more than 66 kV are classified as a transmission lines. In Australia, this first transmission voltage is the highly unusual 88 kV. Generally, more commonly the starting voltage for transmission in Australia is 110 kV. Other transmission voltages in use include 132 kV, 220 kV, 275 kV, 330 kV and 500 kV.

As with rail gauges, transmission voltages were not standardised across the country. Recent lines constructed have contributed further to a diversity of voltage levels, with a number of DC transmission lines also being built.

Similar to Australia's roads, the further you get from the highly populated areas, the smaller the capacity of the transmission assets. High capacity, multi GW ring systems operate between the generators and the cities but in regional high sunlight areas, transmission capacity is less than 500 MW, and is sometimes only radial. Key exceptions being Gladstone, Kalgoorlie, Chinchilla and Olympic Dam.

In areas with limited transmission capacity, large-scale solar power stations may have an unsettling effect on the system stability of the local transmission network. This restricts the number of major generation sites readily available to large-scale solar in the absence of major transmission system upgrades.

Australia's electricity grid (illustrated in Figure 4-1), has the single longest integrated AC transmission grid in the world. However, larger DC grids do exist in the US and Europe. The East coast's electricity network stretches from Cairns in the Far North of Queensland, South to Hobart, and West to Port Lincoln.

Australia is a sparsely populated country, and is geographically very large in world terms. The main-grid transmission networks cover less than half of the country, while delivering energy to 99% of the population. The furthest inland the main-grid network stretches are to the mining outposts of Olympic Dam and Broken Hill, and in WA, Kalgoorlie and Newman.

Western Australia remains unconnected to the national grid. WA has two separate major Networks – the South West Interconnected System (SWIS) around Perth, and the North West Interconnected System around Port Hedland and the Pilbara mining zone. The Ord River system operates in the Kimberley mining and agriculture region but is of limited supply capacity in an extremely remote location.

The Northern Territory is also not connected to the national grid, and operates two transmission networks – the Darwin-Katherine, and the Alice Springs Grid. Mt Isa in Queensland is also not connected to the NEM and has a moderate scale, island transmission grid.

Australians live and work predominantly by the coast, and the transmission network reflects this, with very few inland lines being present at transmission voltages. A major transmission line proposed to be built is 'CopperString', which is proposed to run from Townsville in North Queensland, 800 kilometres inland to join the Mt Isa island mini-grid to the National Grid. It would also allow a number of large renewable energy projects, including CST, to connect to the national grid. However, Xstrata, which was to have been a major source of load, has announced that it will instead source electricity from the Diamantina Power Station consortium. As a result, the project's viability is now being reviewed, with one option to significantly reduce the capacity of the line.

It is worth noting that even if it is built as originally planned, 'CopperString' has a planned capacity of only 400 MW, the majority of which is projected to be used at the end of the line at Mt Isa and at mines around Cloncurry. Thus there is a risk that there will be very limited capability for major renewable generation to tap into this 'inland' line in an extremely high solar resource location.

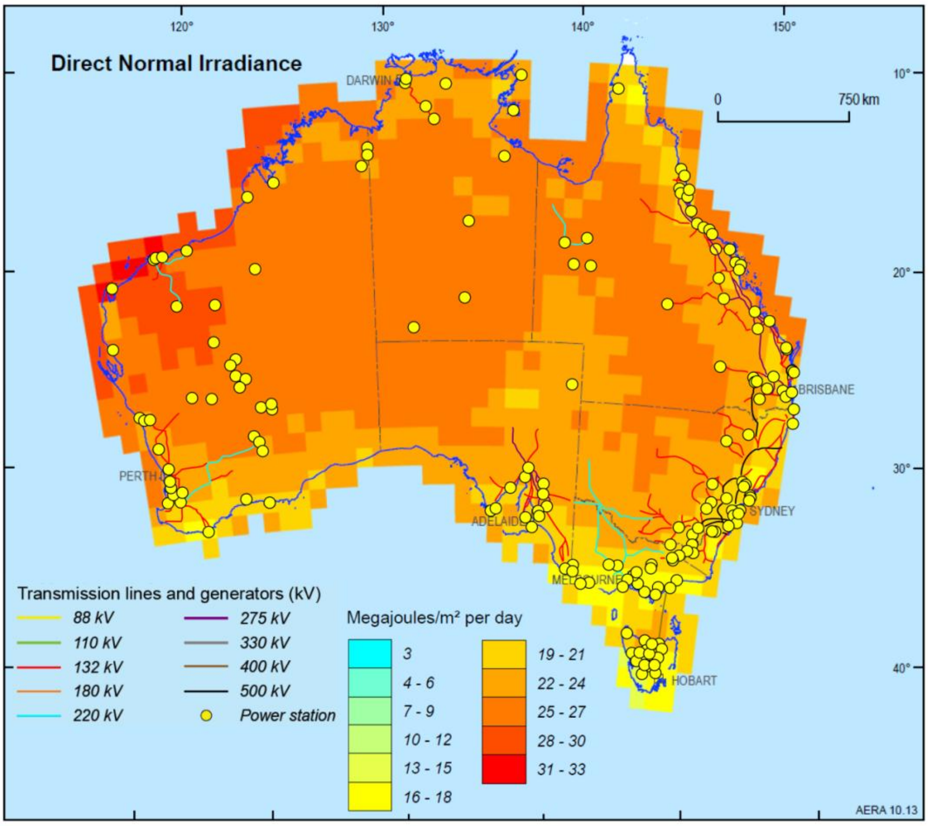

Figure 4-1: Transmission Network in Australia compared to average Direct Beam irradiation (based on two graphics from Commonwealth of Australia 2010)

4.1.3 Generation infrastructure

The major Australian electricity generators are typically located close to the coal/gas/hydro resource deposits. Major power stations connected to the NEM have very high output capacity – generally between 500 MW and 3,000 MW at one site, with major transmission links to them.

In Victoria, the key generation source is in the LaTrobe Valley – where there is a huge source of moist, brown coal[40]. In NSW, the Hunter Valley has enormous black coal reserves and a number of large generators. In Queensland there are vast black coal reserves north west of Brisbane in the Chinchilla Region and inland from Gladstone, where generators are co-located.

South Australia accesses gas reserves in the Moomba fields, and coal from Leigh Creek. As cooling water is required, and much of SA is arid, the key fossil fuel-fired generators are located on the Spencer Gulf and utilise sea water cooling. Tasmania's hydro facilities are mainly in the centre-west of the state.

WA's coal generators are South of Perth, with gas-fired units near Perth, Kalgoorlie and Port Hedland. The NT operates large gas-fired power stations at Darwin and Alice Springs, accessing resources from the Timor Sea (previously supplies came from the Mereenie Gas Fields west of Alice Springs).

An increasing trend over the last decade – springing from the openly competitive retail and wholesale electricity markets – has been the construction of numerous gas-fired 'peaking plants' in urban and non-urban areas. Typically these plants are 40 to 150 MW – very small in comparison to traditional base load power stations.

Additionally, since the opening of the National Electricity Market (NEM), Government has encouraged and legislated for the introduction of renewable generation. Again, generators need to locate near or in the resource. A key issue for large-scale renewable generation is that the coastal electricity grid rarely cross-matches to the resource availability, except for some wind projects which can use onshore coastal winds.

Presumably, in future, the offshore wind, wave and tidal energy sectors will benefit from a correlation of network and resource. Inland solar and geothermal generators face an enormous barrier in accessing electricity grids, especially as transmission lines are expensive to build. For example, 'CopperString', at 800 kilometres, is estimated to cost in excess of $1.5 billion, (approximately $2 million per kilometre).

4.1.4 The distribution networks

There are 13 individual, corporatised (or privatised), electricity distribution networks linked to the NEM:

- Five in Victoria (owned by three companies) – Powercor/CitiPower, TruEnergy, Jemena.
- Three in NSW (corporatised – although there were five in the late 1990's, they were rationalised by the NSW Govt for financial performance reasons) – Ausgrid, Endeavour Energy, Essential Energy.

[40] While brown coal is the least efficient coal in the country for power generation, it is the most bountiful, and the easiest to gasify given it's chemical composition. If gasified using a solar boost, the CO_2 emissions of Victorian Brown Coal could be reduced to lower than that of NSW and Qld black coal. However the LaTrobe Valley is an area of relatively poor solar resources.

- Two in Queensland (corporatised) – Ergon Energy, Energex.
- One in South Australia (leased for 99 years to a private company) – ETSA.
- One in Tasmania (corporatised) – Aurora.
- One in the ACT (a consortium of the ACT Govt and a private company) – ActewAGL.

The NT has a single corporatised government-owned entity (PowerWater Corporation), while WA has two corporatised entities (Western Power and Horizon Power).

Each State operates subtly different standards in terms of construction practices, voltage levels, charging tariffs, and access criteria.

Defined as 66 kV and below, the main role of distribution networks is to deliver energy to end users. As mentioned earlier, the electricity network in Australia is designed to take energy from large central generators and disseminate it to customers. The distribution networks also operate in this fashion, making the establishment of distributed generation systems with a reasonable penetration level a major challenge.

As a single circuit 66 kV line could have a capacity of 20 MW, and given that 66 kV lines are often the main distribution artery to inland provincial cities, there is the opportunity to locate a large number of moderate-scale renewable energy systems across Australia, some 400 to 600 kilometres inland from the coast, where there can be significant solar resources.

4.1.5 The remote grids

Generally, remote mini-grids are located in the outback locations of the larger states.

In Queensland, there are 33 remote mini-grids, as well as the Mt Isa grid, all of which are operated by Ergon Energy. The electricity for Mt Isa's distribution grid is sourced from mining interests in the region. The smaller remote mini-grids – in outback Queensland and throughout the far north and Torres Strait, generally run on diesel-fired power stations.

In the NT, PowerWater operates more than 70 diesel and CNG power stations for communities and resorts. In addition, there are around 50 community-run, power stations and associated mini-grids.

In WA, Horizon Power operates more than 30 remote mini-grids, with a number of Indigenous organisations operating a further 50 mini-grids. The Ord River system also operates in the Kimberley, supplying the mining and agriculture businesses in the area.

One of the larger, remote mini-grids is the one operated by BHP to power the town and mine at Newman. There are plans to connect this mini-grid to the NWIS, but the timing for this investment depends on numerous factors.

In SA, the Government subsidises electricity delivery to 13 mini-grids around the State.

The mining industry across Australia operates many of the larger remote diesel power stations for their operations and camps. Many of these sites operate diesel power stations in excess of 5 MW, some as large as 30 to 40 MW. Larger operations include Ranger, Tanami, MacArthur River and Gove (NT), Embley and Cannington (Qld), Telfer and Granny Smith (WA) and Beverley (SA).

4.2 Potential for Large-scale, Grid-connected Systems

4.2.1 Hybridisation with existing fossil fuel plants or industry

Large-scale, CST power stations have the capacity to produce superheated steam in large quantities. This synergy with the existing coal-fired electricity industry is in the delivery of energy, in the form of steam, to existing coal-fired power stations, allowing co-firing or preheating of the water used to produce steam for the turbines.

The HTST Technology Roadmap found that such hybridisation is potentially economic because there is no need for the CST component to provide a steam generator and any thermal back-up is already provided. In addition, such plant could help extend the life of existing plant where there is limited coal supply or where there are issues in relation to air pollution limits. Additionally, process heat for major industry, such as mining or steel, has potential for co-location.

This is not a new concept – Ausra (now Areva) established a Fresnel array at Liddell Power station in NSW in the early 2000's. Recently, Macquarie generation has contracted Novatec to extend the system and CS Energy and Areva have also been offered REDP funding to build a solar-boost system attached to Kogan Creek Power Station in Queensland[41].

The biggest limitation to the potential of the hybridisation approach is the need for co-location of a good solar resource with an existing fossil-fuelled power station. For example, solar hybridisation is unlikely to be a suitable approach to reduce the emissions intensity of brown coal-fired power stations such as Hazelwood in Victoria.

However, many of the Queensland coal fields and associated power stations are in high solar resource locations. In fact, at Collinsville (inland from Mackay), Transfield had proposed retrofitting the existing coal-fired plant to solar thermal under Solar Flagships round 1. From all accounts, the technology was well suited, the project technically possible, but financial support could not be confirmed.

Power stations inland from Gladstone and at Chinchilla are in locations with a good solar resource. There are also good solar resources around the generators located on the Spencer Gulf at Port Augusta, and Whyalla (the latter is the site of major steel works and the proposed Solar Oasis project that could see Dish Technology built to supply power and process steam to industry).

Similarly, power stations located at Kalgoorlie on the SWIS and near Port Hedland on the NWIS share resource (gas and solar) co-location. Given Port Hedland suffers from regular cyclone activity, it may not be a prime location for CSP.

The Hunter Region in NSW is not a prime solar resource location although not unreasonable in a global comparison. There are certainly co-locational prospects within the region, especially given the massive coal-fired generation present. The Liddel power station system is in this region.

The majority of Victoria does not have optimal solar resources. The best resource is around Mildura-Kerang along the Murray, where there are no other electricity generators located. Similarly, Tasmania does not have any significant CSP prospects.

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41 Not to be confused with the stand alone "Solar Dawn" flagships power station that is to be located close to but not connected to Kogan Creek power station.

While the NT has excellent solar resource, it generates almost entirely using natural gas and the total capacity of generation is not very large, (eg the Darwin-Katherine grid has about 440 MW of centralised generation). Typically, the ratio of minimum noon load to noon solar output determines the amount of intermittent solar generation that can be connected to a grid. It is likely that that there would be challenges in connecting more than 50 MW of intermittent generation to the Darwin-Katherine grid.

The HTST Roadmap examined all steam-based power stations for solar assist potential. The Roadmap assumed that only a 5% solar contribution could be accommodated and land area and other constraints were considered. On this basis a potential market of 460 MW_e equivalent was identified for CST.

Updating this, the current investigation considers that the previous study was optimistic in considering stations with relatively low solar resources. On the other hand, the 5% contribution limit appears overly conservative and reflects the perceived 'comfort zone' of system operators. It is suggested that with appropriate will and motivation, a solar assist system would be able to provide at least 25% of the energy input when solar is available. This would require full super-heated steam generation, not just feedwater pre-heating as implemented at Liddell Power station.

Overall, more than 20 power stations in Australia have both the solar resource and the necessary vacant land for potential CST co-location. If a potential maximum 25% of load was assumed for the CST contribution, then an average CST equivalent capacity of 100 MW_e per power station is feasible.

There is the major issue of private and/or public ownership of the stations and the owner's desire/resistance to co-firing, as well as increases in risk profile as a result of CST injection, investment returns and capital sourcing to overcome.

However, in this section, this review is identifying the *technical potential market*.

These potential sites include:

1. Kogan Creek (Qld, 750 MW)
2. Callide (Qld, 1,700 MW)
3. Stanwell (Qld, 1,400 MW)
4. Swanbank B (Qld, 480 MW) - due for decommissioning 2012
5. Mica Creek (Qld, 325 MW) - Mt Isa grid, future connection to CopperString/National Grid
6. Gladstone (Qld, 1,680 MW) - Cyclone risk apparent
7. Collinsville (Qld, 195 MW) - Cyclone risk apparent
8. Tarong (Qld, 1,400 MW)
9. Millmerran (Qld, 850 MW)
10. Liddell (NSW, 2,000 MW)
11. Eraring (NSW, 2,640 MW)
12. Bayswater (NSW, 2,640 MW)
13. Vales Point (NSW, 1,320 MW)
14. Munmorah (NSW, 600 MW)
15. Mt Piper (NSW, 1,400 MW)

16. Redbank (NSW, 150 MW)
17. Wallerawang (NSW, 1,000 MW)
18. Playford A & B (SA, 330 MW) (Various groups have been promoting this site's potential)
19. Northern (SA, 520 MW)
20. Kwinana (WA, 660 MW)
21. Muja (WA, 854 MW)
22. Collie (WA, 340 MW)

Potentially, this sector of the market, once fully developed, could deliver up to 2,000 MW_e of CST equivalent capacity, assuming 25% of each coal-fired power station's steam needs were delivered by CST. It is recognised that there are a range of other pragmatic issues that may limit the potential in this sector to a smaller number.

4.2.2 Stand-alone up to 1 GW supported by grid extensions

To construct a major 1 GW power station (or cluster of smaller systems totalling 1 GW) in Australia, in any location other than beside the Olympic Dam mine, new large-scale transmission infrastructure would be required.

A 1 GW CSP plant/cluster, with storage and high capacity factor, becomes a possible option at a potential cost in the order of $7 billion. As a result, adding a further $500m onto the cost for a 1 GW capacity 300km transmission line extension is a feasible option.

Should investment of this scale seek to enter the Australian market, there are potentially five to ten of these sites Australia-wide. The NEM could handle significantly more, but the limiting factor is the remoteness of the sites from strong transmission infrastructure in current large-scale generation locations like the Hunter and La Trobe valleys.

The most likely locations would be, given the need for an outstanding solar resource:

- Outback South Australia, with a 300 km transmission line linking back into the Port Augusta Network.
- North of the Riverland in South Australia, with a 300 km line back to Berri (Murraylink).
- Broken Hill, with a major upgrade to the 220 kV line back to Mildura/Murraylink.
- Western NSW with a 100 to 200 km transmission line back to either Dubbo or Griffith.
- Northern NSW in the Moree Region with a 200 to 300 km transmission line back to QNI-Link
- Southern Queensland, with a 200 km transmission line back to Toowoomba, or major investment in upgrading the Roma 132 kV line.
- Inland Queensland in the Barcaldine Region, with a major upgrade to the Barcaldine 132 kV line
- Inland North Queensland with a short link to CopperString at Hughenden, and a major upgrade to CopperString's capacity back to Townsville, (it is only planned for 400 MW).

Thus there is potential for around 8 GW_e of capacity on this basis. Going beyond this, major visionary suggestions have been made to, for example, link through Northern SA to Qld or to link the NEM with the SWIS across the Nullarbor and others (eg. Wright and Hearps, 2010). If such transmission extensions were built, then the market would no longer be limited by the network characteristics, but by competition with other generation sources.

The HTST Roadmap previously estimated the intermediate/base generation in main grids market at 5 GW_e by 2030 and 20 GW_e by 2050. This is highly speculative; there is no new information to hand to allow that estimate to be varied with any certainty. On that basis, it can be said that grid extensions such as outlined above are needed for the medium term and major nation-building scale extensions will be needed for CSP (or other regional renewables) to reach their full potential.

4.2.3 Stand-alone 50 to 150 MW connected to existing grid

The challenge for stand-alone CSP stations in Australia seeking to connect without major grid extension, is finding a grid connection point, in a high sun location, capable of accommodating significant levels of renewable generation.

Due to the high costs of transmission infrastructure, (unless paid for by Government), CSP developers of the project scale of less than 150 MW will have to concentrate efforts in the regions already serviced by transmission infrastructure. Generally those locations are likely to be in Northern and Western NSW, inland Queensland away from the coastal cloud and any cyclone activity, arid areas of South Australia and the Midwest and Goldfields regions of WA.

The assessment of this market segment size is in the order of 3 to 4 GW, made up as follows.

Queensland

Coastal locations from Hervey Bay to Cairns all are within the Category 2 to 5 Cyclone Zone, thus construction of CSP carries significant risk within 200 km of the coast.

Barcaldine, Toowoomba, Emerald and Roma are all serviced by 132 kV transmission lines, and enjoy very good sunlight levels. If CopperString is constructed, locations such as Hughenden and Julia Creek would be class 1 CSP locations for 100 to 150 MW systems.

Regions of Queensland close to existing coal-fired power stations would certainly be first choice, around the Chinchilla and Biloela Region, with very good solar resources.

Potentially six major 150 MW stand-alone CSP stations could be established in Queensland with existing transmission line infrastructure, with potentially another 300 MW post CopperString, totalling 1,200 MW.

New South Wales

The north and west areas of the state seem the most likely locations, with some potential in the Griffith area.

Armidale, Gunnedah and Moree regions have good solar resource and strong transmission infrastructure. However, the Solar Flagships PV project is to be located at Moree. If this project is built, it will effectively fill the renewable input capacity of the network in that region.

Orange, Dubbo and Nyngan also provide strong promise, with reasonable solar resources and strong transmission infrastructure. These could become viable in future.

Broken Hill has a very good solar resource. However, the transmission infrastructure may not support a major CSP station, given there are significant plans and installations of generation from alternative sources such as natural gas, wind and flat-plate PV in the Mildura-Broken Hill region.

As with Queensland, it is feasible that up to six major 150 MW CSP plants could be located in NSW, reaching 900 MW in total.

Victoria

The northern Sunraysia region from Kerang to Mildura has strong transmission infrastructure. However, this region has become a focus of attention since Solar Systems announced plans for a 154 MW CPV plant south of Mildura. While this project has been delayed, the proponents remain committed.

TruEnergy also plan a more than 150 MW solar PV installation, effectively taking most of the injection capacity of the local transmission network. While not successful in Solar Flagships round 1, the proponents continue to be confident of the proposal's eventual construction.

The Wimmera region, in the Vicinity of Horsham, has a reasonable solar resource, but is on the same transmission loop as Mildura. Thus this region may not be able to allow significant renewable capacity to connect to the grid.

Other than the 154 MW Solar Systems CPV project, or a system of equivalent size in its stead, there is a low probability of an additional CSP project of scale in Victoria at this time.

South Australia

Clearly the Leigh Creek, Prominent Hill and Olympic Dam mining zones share a very good solar resource with major electrical loads and high capacity transmission infrastructure. Whyalla also has the Solar Oasis proposal for a 40 MW system.

Olympic Dam's load could feasibly incorporate up to 1 GW of CSP housed in the region.

At that point, the SA transmission grid is likely to become constrained. Already the majority of generation is around the Spencer Gulf, with energy transmitted south to Adelaide. A 1 GW additional source would likely bring the system to its generation acceptance capacity.

There is potential in the Riverland region around Berri for two 150 MW plants to be located, linking into the grid ties provided by Murraylink.

Thus, in the vicinity of 1.3 GW of CSP capacity could be injected into the SA grid.

Western Australia

Much of the Northern WA coast, as with the Queensland Coast, is affected by cyclones each year. This restricts the area available for CSP stations connecting to the NWIS.

The Kalgoorlie region is well serviced with transmission infrastructure and a very good solar resource. The network here is sufficient to connect two 150 MW CSP stations, while Yalgoo, inland from Geraldton, could also connect two 150 MW CSP stations.

The most promising site in WA is co-located with a major mine at Tom Price. It is far enough inland from the coast to not be significantly affected by major cyclones, and has very good solar resources. It is also a site that has extremely large electrical loads for mines and the town. Potentially a 200 MW CSP plant could be located at Tom Price.

WA's CSP market potential is therefore in the vicinity of 800 MW.

4.3 The Potential for Medium Scale Grid Connected Systems

4.3.1 Grid-connected via the distribution network

The opportunity for sites for systems of less than 30MW is far more open – low capacity transmission lines (110kV) could manage 30 MW, while the many 66 kV loops feeding provincial centres throughout Queensland and NSW could manage 15 MW renewable power injections. Such CSP power stations would also be suitable for the type of end-of-grid-support identified in the HTST Roadmap.

Most existing commercial CST systems operate at 50 MW or greater capacity and it is suggested that costs are minimised for CST systems around 250 MW_e. However, systems down to well below 30 MW_e are technically feasible. Chapter 6 examines the cost implications of smaller system capacity. In this market segment, it may be that the network capacity constraints of linking to available distribution (or smaller transmission lines), could motivate the construction of systems with large amounts of energy storage such that large cost-effective fields could be built to drive high capacity factor, smaller capacity systems.

CPV technologies have potential in this sector, using either heliostat or large fields of small tracking devices, and can operate as 1 MW plants, with duplication to achieve larger capacities, similar to the building block approach of flat-plate PV power stations. In this case, CSP is in direct competition with flat-plate PV for the prime sites, and flat-plate PV has a significant price advantage over CPV or CST at present.

For 10 to 15 MW sites, locations of Zone Substations that transform from 66 kV to either 33, 22, 11 or 6.6 kV, are generally on the fringe of 10,000 to 15,000 population centres. With open space generally not far away, there would be a number of prime solar sites available close to Zone Substations.

As the construction cost of a 15 MW CSP station should be in the vicinity of $75m, it is feasible to spend $5m on power infrastructure – and that would be a typical cost of establishing several kilometres of 66 or 22 kV dual circuit line and a dedicated feed into the Zone Substation, including protection and control equipment.

It is estimated that there could be 40 such locations across Queensland, NSW, northern Victoria, the Riverland of South Australia, and southern WA where reasonable solar resource exists. In the HTST Roadmap, the 'end of grid support' segment was examined site by site and it was estimated that there was 200 MW_e of load with good CSP prospects and a further 600 MW_e of medium potential, consistent with the estimate presented here.

In contrast to the HTST Roadmap, it is worth giving attention to the idea of fringe-of-grid systems in the 1 to 5 MW_e size range. This is a size range well suited to CPV and flat plate PV systems. Almost every 3,000-plus person town in inland Queensland, NSW, and the Murray Region will have electrical infrastructure capable of 3 to 5 MW of dispatch. There are literally hundreds of potential locations across the country for this potential market segment.

If the market signals were established (via a modified RET or other policy measure) to make grid connected solar in general a profitable proposition, sites of this nature would be a logical choice for flat-plate PV developers. CSP technologies configured to this size, such as CPV or Dish Stirling systems could target this market segment also, noting that they would face the challenge of competing directly with flat-plate PV on price.

Other than Dish Stirling systems, CST systems have not been seriously proposed commercially on such a small scale. However, they should not be dismissed for this reason. Many new CST technologies are demonstrated at this scale during their development phase, it is simply not the lowest cost unit size. However, it could well be that innovative thinking could develop a system such as that described above for connection to distribution networks with capacity constraints (large solar field, large storage, smaller powerblock capacity, high capacity factor systems).

It is known that many of the sites in this category are facing the need for grid augmentation due to load growth. This could prove to be a driver via the possibility of avoided cost of augmentation. Solar generation of any kind may be of value, particularly if cooling loads correlated with solar availability are part of the issue. A high capacity factor CST system with storage may have further advantage as it is more likely to correlate with the annual peak load.

In summary, the market for 1 to 5 MW grid-connected CSP in Australia in the near term is very challenging but worth continued consideration. There is potential for up to 40 sites in the 15 MW scale (600 MW in total).

4.3.2 Mini-grid

There are some reasonably large mini-grids in regional cities and mining locations in Australia. These sites, by definition, are greater than 10 MW in total peak demand (to delineate from the term off-grid, which is defined as less than 10MW).

Sites include:

- Darwin NT - 275 MW (PWC, mainly gas).
- Mt Isa/Mica Creek PS Qld - 325 MW (soon to be supplemented by Diamantina Generation using Moomba gas).
- Alice Springs NT - 50 MW (PWC, Black Tip gas).
- Derby/Broome WA - 61 MW (Horizon, LNG).
- Ord River WA - 30 MW (Horizon Power, hydro).
- Cannington Mine Qld - 10 MW+ (BHP, diesel).
- Embley Mine Qld - 10 MW+ (Rio Tinto, diesel).
- Ranger Mine NT - 10 MW+ (ERA, diesel).
- Newman WA - 10 MW+ (BHP, gas).
- Gove/Nhulunbuy NT - 10 MW+ (Rio Tinto, Gas)

With the exception of Darwin, Alice Springs and Broome, the sites are all owned by private mining interests. Generally (excepting Ranger, Cannington) these larger mini-grids also service a residential town.

Darwin is an exception to the rest, given it is a residential/industrial city of 200,000 people. The power supply is mainly by gas turbine, with a transmission grid that runs 400 km south to Katherine. PWC has recently sought Expressions of Interest for the injection of 50 MW of renewables into this grid, and many solar experts proposed a 50 MW CSP or PV plant at Katherine. To connect 50 MW in this grid arrangement, the CSP station would need to be dispatchable with storage.

There is potential in the balance of sites to locate 5 to 15 MW CSP systems to supplement the existing gas, and especially diesel, generation. Integration with the existing generators is crucial, and a huge advantage of CST would be the ability to use storage and so act as 24 hour baseload, or simply a peak lopper, delivering all energy generated over an 8 hour period during the daily afternoon-evening peaks.

As with the medium scale on-grid systems, PV is cheaper, but does not inherently include storage. Investigations over the last decade at major mine sites like Embley and Tanami have identified this as a major issue. Rapid falloff of CPV or PV under a cloud event, with a significant penetration system, would destabilise the fossil fuel generators and risk outages – especially in a mining situation, this would be technically unsuitable.

In Alice Springs – a 30,000 person town with a peak demand of about 50 MW – there is already in excess of 1 MW of PV installed in solar farms, and several hundred kW on rooftops, as a result of the Solar City project. However there remains the potential for a 10 MW CSP project, but only if there is energy storage.

Mt Isa, with a more than 300 MW load, could potentially house a 30 to 40 MW CSP station. The difficulty will be in gaining dispatch contracts. X-Strata, the largest user, has 17 year supply agreements from 2013 with a new power generator (Diamentina) to be located next to the Mica Creek power station. That leaves only the residential town load of Mt Isa (again, 30,000 strong) controlled by Ergon Energy, with some minor mine sites off the Ergon Grid. Thus as with Alice Springs, the likelihood is that 10 MW is the largest possible scale, however storage may be optional.

Newman, a BHP town of about 4,500 people, has about 140 MW of gas generation to power the mine and the town. As a result. it has the potential to incorporate a 20 MW CSP station.

Derby/Broome, Ord River, Ranger, Embley and Gove are all located in category 5 cyclone zones, so CSP would be expensive to build in these locations.

Cannington Mine is currently reviewing its options since Xstrata pulled out of the CopperString project.

As a result the opportunities in this segment are limited to Darwin (50 MW) Alice Springs (10 MW), Mt Isa (10 MW unless X-strata make an entry which could increase it to 50 MW) and Newman (20 MW).

If some of the major new mining initiatives that are proposed progress, this could add to the size of the mini grid segment.

4.4 The Potential for Off-grid Systems

The off grid market sites in Australia have been considered in three categories:

- Remote towns less than 1 MW;
- Remote towns between 1 MW and 10 MW; and
- Mining less than 10 MW.

4.4.1 Remote towns less than 1 MW

This market has been a testing ground for PV, given its large number of remote desert communities across Queensland, SA, WA and the NT, as well as many island communities in the Torres Strait. These sites tend to run multiple diesels on their mini-grids, are operated or funded by Government organisations (Ergon, Horizon, PWC, DTEI) and have high generation costs, making the financial returns for early commercialisation products much more attractive.

Previously five Dish CPV sites of 175 to 350 kW were installed in remote towns by Solar Systems. Umuwa's CPV power station has been mothballed, while Hermannsberg, Lajamanu, Yuendumu and Windorah continue operations. Numerous flat-plate PV projects of 100's kW size have been installed across the country, with varying degrees of success, at Bulman, Kings Canyon, King Island, and more recently Thursday Island, Marble Bar, Nullagine, Ti Tree, Kalkarindji and Lake Nash, among numerous others. The key issue at each site has been integration, or lack thereof, with the diesel gensets.

Given the small scale, this market is well suited to flat-plate PV long term, especially given the price advantage PV has in a diesel mini-grid, where is it now cheaper to produce PV kWh's than diesel kWh's. CSP could use this market as a test bed for their equipment (where applicable) and integration strategies (as Solar Systems and Solfocus have done with their CPV technologies).

4.4.2 Remote towns 1 MW to 10 MW

This market could be harnessed for CSP on a 2 MW scale with storage, however there are very few grids of this size. Tennant Creek, Yulara, Coral Bay, Coober Pedy, Christmas Island, Esperance, Groote Eylandt, Melville Island, Thursday Island and Norfolk Island are some of the sites in this category.

Each of the islands is officially within a Cyclone Zone, except Norfolk, which with a 2.5 MW peak load already has almost 1 MW of rooftop PV. Coral Bay and Esperance already have wind farms contributing a significant proportion of their annual loads.

Tennant Creek operates from piped Black Tip gas at around 6 MW, Yulara is 2 MW, Coober Pedy around 3 MW. It is, as a result, a very small market, reduced further with the potential for wind to be harnessed at Tennant Creek using the Barkly Tablelands breezes.

As a result the only market for a scale demonstration is at Yulara or Coober Pedy, both of which have been the subject of unsuccessful project development proposals in the past 5 years. Coober Pedy has a CPV project in development for a 1 MW station, while PV and wind developers are also interested in the location. The unique arrangements for the supply of energy to Coober Pedy make the site a contractually difficult location to install renewables, despite the high generation cost and the presence of both solar and wind resources.

4.4.3 Mining less than 10 MW

There are more than 50 remote mine sites in Australia with diesel generation of between 1 and 10 MW. These sites are scattered through Queensland, WA, NT and SA, with some in North West Victoria and Northern NSW.

Many attempts have been made to sell PV and CPV fuel-saving solutions at 20 to 30% penetration in this market. The attempts have all failed at this point, mainly due to two factors:

- The mines in this range are generally not owned by the major mining companies and as 'junior mines' they do not have 20 to 30 year mine lives, with the published mine life likely to greatly affect the share price of the resource owner. With 3 to 7 year published mine lives, operators cannot enter into purchase decisions for immovable equipment (or long term PPA's) that have a 20 year lifespan. This then leads to PPA's and financial assessments of returns taking place over 3 to 7 year investment terms, which results in kWh production costs for solar being assessed as significantly higher than low capital cost, high fuel cost diesel gensets.

- The mine operators are focussed on continual production, thus any change in operating procedures that increases shutdown risk is not tolerated. As a result the integration of solar into diesel stations has been a major stumbling block, with expensive energy storage integration tools like flywheels effectively reducing the financial argument for flat-plate PV.

There remains the strong potential that solar, be it PV or CSP – will make inroads into the mining sector by demonstrating viable financial and technical alternatives to diesel and CNG in these remote mines. However given the scale of many of these mines, the largest possible solar sites are likely to be around 2 MW. For CPV to be financially viable, cost-effective electrical storage will be required. For CST, mining sites may be a niche high value market that could be addressed through development of scaled down systems with thermal storage as discussed for the small end-of-grid segment.

4.5 Summary

Table 4-2 summarises the technical potential of the different market segments discussed above. In summary, there is about 14 to15 GW_e of near / mid term technical potential for CSP in Australia. The greatest potential appears to be in the stand-alone, up to 1 GW supported by grid extensions, followed by smaller plant (50 to 150 MW) connected to the existing grid, then hybridisation with existing fossil fuel plants or industry. Going beyond this, major grid extensions of a "nation building nature", such as major SA/NSW/QLD inter-linkages through in land high solar regions, are needed to allow CSP to grow to meet a substantial fraction of all annual demand.

It should be noted that this analysis of potential is expressed in GW_e, and has been based on network limitations. Thus it is an assessment of potential maximum generation levels. These could be combined with whatever capacity factor, technology configurations and system economics dictate. Thus the 14 to 15 GW_e of near to mid term potential would translate to 24,500 GWh pa to 26,300 GWh pa at a 20% average capacity factor, or 55,200 GWh pa to 59,100 GWh pa at an average 45% capacity factor.

It would also be expected that a growing CSP sector targeting these segments would achieve market shares that would be considerably less than the total potential.

Table 4-2: Technical potential of different market segments

Market segment	Technical potential	Notes
Large-Scale grid-connected		
Hybridisation with existing fossil fuel plants or industry (CST only)	2 GW_e	Assumes 25% of appropriate coal-fired power station's steam needs are delivered by CSP.
Stand-alone 50–150 MW systems (grid-connected)	3 to 4 GW_e	Requires grid connection point capable of receiving significant new energy injections.
Stand-alone< 1 GW clusters (modest grid extensions)	8 GW_e	Likely requires high-capacity plants with thermal storage whose economics cover cost of grid extension.
Stand-alone > 1GW clusters (nation-building grid extensions)	Limited by NEM demand	
Medium Scale grid-connected		
Grid-connected (1–20 MW systems)	0.6 GW_e	Particular systems (large solar field, large storage, smaller capacity, high capacity factor) suited to distribution networks with capacity constraints.
Mini-grid-connected (1–10 MW systems)	0.12 GW_e	Would need thermal storage and dispatchability to have an advantage.
Off-grid		
Mining (systems < 10 MW)	0.1 GW_e	> 50 remote mine sites may be suitable for small-scale CSP, but short mine life and risk avoidance by mine owners/operators limit uptake.
Remote Towns (1–10 MW systems)	< 0.005 GW_e	Relatively small-scale demonstration systems.
Remote Towns (CPV systems < 1 MW)	< 0.005 GW_e	Could be suitable to test equipment and integration strategies.
Total	**~ 14 to 15 GW_e**	

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5 The Market Value of CSP Energy

This chapter assesses the market value that is potentially available to form an income stream for CSP systems. This is value strictly in the sense of the income side of the economic equation. The profitability or otherwise of particular configurations and applications are discussed in Chapter 6.

The chapter seeks to identify both values that are realised financially under existing Australian market structures as well as "inherent" values that are not currently rewarded.

The issue of the value that a CSP system can generate is the subject of recent investigation in some key overseas studies. Sioshansi et al (2010) identify that CSP plants with storage have the potential to provide extra value over plants without storage via:

- selling energy at times of higher price rather than time of collection,
- being at least partially dispatchable, they can reduce the amount of conventional plant capacity needed,
- providing ancillary services, particularly "spinning reserve", and

reducing the cost and efficiency penalty associated with dry coolingThe income available to a CSP system, whether under a negotiated power purchase agreement (PPA) or not, reflects the following income streams that represent the system's underlying value. Sources of market value that Australian electricity markets currently quantify include:

- Sale of electricity into the National Electricity Market
  - Income set by pool price (Regional Reference Price, RRP)
  - Alteration to income via Marginal Loss factors depending on location
- Large-scale Technology Certificates (Renewable Energy Certificates)
- Capacity Credits in the South West Interconnected System (SWIS)
- Direct sale via contract to off grid / mini grid customers

Other sources of value considered include:

- Avoided grid augmentation expenses
- Ancillary services

5.1 Predicting system output

Predicting the output of a CSP system with reasonable accuracy is a complex process. Thermal systems include multiple subsystem components with thermal capacity whose behaviour at any point in time depends not only on the instantaneous conditions the whole system experiences, but also the recent history of its operation.

There is a range of approaches to modelling CSP systems and it is an ongoing area of R&D. Many of the available options are proprietary. One of the most respected is the public domain System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL) in the USA (NREL 2012).

The SAM model has been used as the main modelling tool for this study. It is general purpose in nature and can predict hourly, monthly and annual output of CST, CPV, flat plate PV and also a range of other renewable energy systems. There has been an extensive body of work around its application to CST systems in particular.

SAM can be used exclusively for predicting system performance or it can additionally provide financial analysis, such as LCOE calculations, if required. In this study it was used for physical performance predictions only (i.e. average kW for each hour).

SAM uses the well known TRNSYS software developed at the University of Wisconsin as an internal engine. The following relevant key points on SAM are reproduced from selected answers on the FAQ page:

- "Versions 2.5 and later include a dish-Stirling model.
- SAM uses a simple multiple-point efficiency model to represent CPV modules.
- SAM has built in weather files for an extensive range of US sites, for overseas such as Australia: SAM uses weather files in TMY3, TMY2 or EPW format. You can download EPW files for locations around the world from the Energy Plus website - just follow the link on SAM's Climate page. There is more information about weather file formats and sources of data in SAM's help system.
- SAM models thermal energy storage (TES) as a system that can store up to the Maximum Energy Storage shown on the Storage page with maximum charge and discharge rates shown as Maximum Power To Storage and Maximum Power From Storage on the Storage page. These rates are calculated using the Turbine TES Adj. - Efficiency and Turbine TES Adjustment - Gross Output, and Heat Exchanger Duty variables. To account for TES-related losses, SAM applies a "TES correction factor" to the total system output that is calculated using the Turbine TES Adj. - Efficiency variable and the hourly energy quantities delivered by the TES system and to the power block. For systems with TES, SAM also subtracts the Tank Heat Losses amount from the system output for every hour of the year.
- The choice of HTF for the solar field and storage determines whether the storage system is a direct storage system or an indirect system. Direct systems use the solar HTF as the storage fluid. Indirect systems require a heat exchanger and use two fluids, one for the solar field HTF, and another for the storage fluid.
- SAM only models two-tank storage systems."

There is a range of available templates and files of predetermined case studies for use with SAM. One of the most significant of these is the "NREL Reference Trough Plant and Comparisons via Cost Model SAM-2010-04-12 (ZSAM 320 KB)". This has been used to provide an initial baseline for this study. It contains 3 separate case studies, one of which is a verified model of the actual "Nevada Solar 1" 64MW$_e$ system trough system that is located near Las Vegas. This system has been selected as a baseline system for investigation, noting that:

- It provides a tested model of a real operating system.
- The Nevada Solar 1 system represents the largest stand-alone CSP system built in the renewed activity that has taken place since 2005.
- Trough systems dominate the CSP market at present.
- Whilst Tower and Dish systems appear to offer higher performance, for example, general conclusions that can be drawn from a model of an actual trough plant configuration should be robust and conservative.

5.1.1 Solar and weather data

The key inputs for system performance forecasting are the Direct Normal Irradiation (DNI) time series data, together with the associated ambient temperature, humidity and wind speeds. Solar data in general is collected on various frequencies on various timescales from various sources. It could be categorised as:

- Direct site measurements that provide an exact assessment of a particular location at a particular time as reliably as the accuracy of the instruments.
- Satellite-derived data that, depending on the spatial resolution, provides an average assessment by grid cell, with data from a certain period, where its accuracy is dependant on the success of the algorithms used.
- Combined data, whereby a satellite data set is modified and calibrated using a range of ground-based measurements that have been accessed.

Appendix C reviews possible sources of solar data for Australia.

SAM uses weather files in TMY3, TMY2 or EPW format. TMY means "Typical Meteorological Year" meaning an artificial year assembled from real months from real years that match the overall average for those months. Generally the expectation is that the TMY file will include hourly data. TMY3 and TMY2 have slightly different formats, with TMY3 having a format that allows arbitrary time scales to be used and read. EPW refers to the "Energy Plus Weather" file always used by the US Energy Plus Website (Energy Plus 2012).

NREL specifically recommends the US DOE's Energy Plus Website for data for use with SAM. This site has weather data for all countries including Australia. It describes the source of the data for Australia as:

> 'RMY Australia Representative Meteorological Year Climate Files Developed for the Australia Greenhouse Office for use in complying with Building Code of Australia. These data are licensed through ACADS BSG Ltd for use by EnergyPlus users.'

It is understood that these "Australian Climate Data Base" (ACDB) data files were produced for the AGO by the Canberra-based company Energy Partners based on BOM satellite and ground station data and are now employed in Accu-rate and other building energy rating tools.

There is a known but little publicised fault with some of these data files, specifically those for sites for which ground-based data do not exist. In those cases, the daily profile shapes are not physically realistic, even though the integrated annual totals appear correct. Parsons Brinkerhoff (2009), compared the EPS data to a range of other data sources, concluding that all sources were close, with the EPS data slightly underestimating totals compared to the others and so offering a conservative result.

There are no other immediately available Australian site data files in TMY format. In this study, the EPS files have been used with SAM as provided, and where possible, preference is given to using sites which are ground data based and so free of the bug. It is worth noting that modelling other sites does not appear to result in overall generation levels that are in error, only daily profiles that look unrealistic.

The idea of commissioning a revised set of data files specifically for use with SAM deserves consideration.

5.2 CSP System Performance in Australia

By selecting appropriate weather files for particular locations in Australia, the hypothetical output of case study systems in the SAM model can be determined, and compared to the output of actual or hypothetical plants operating in other parts of the world.

In this section, the established SAM model is used to examine the effects of some key system parameters on output, specifically:

- The performance of a trough based system, if it were operated in various Australian locations, showing the effect of latitude in reducing winter output in particular.
- The relative performance of a range of CSP technologies between Longreach Qld and Mildura Vic.
- The effect of adding various amounts of thermal storage to a trough plant, showing that collected energy actually increases with an amount of storage.
- The effect of altering the capacity of the generation block for a trough system of fixed field and thermal storage size.

5.2.1 Interpreting Nevada Solar 1 in the Australian context

The SAM parabolic trough case study contains a detailed model of the Nevada Solar 1 parabolic trough power plant that is located near Las Vegas.

The key parameters of the plant are:

- 64 MW_e name plate output,
- no storage,
- Solar Multiple of 1.264 (i.e. solar field is oversized relative to powerblock system capacity at design conditions),
- Total trough aperture (collector) area: 357,428m^2.

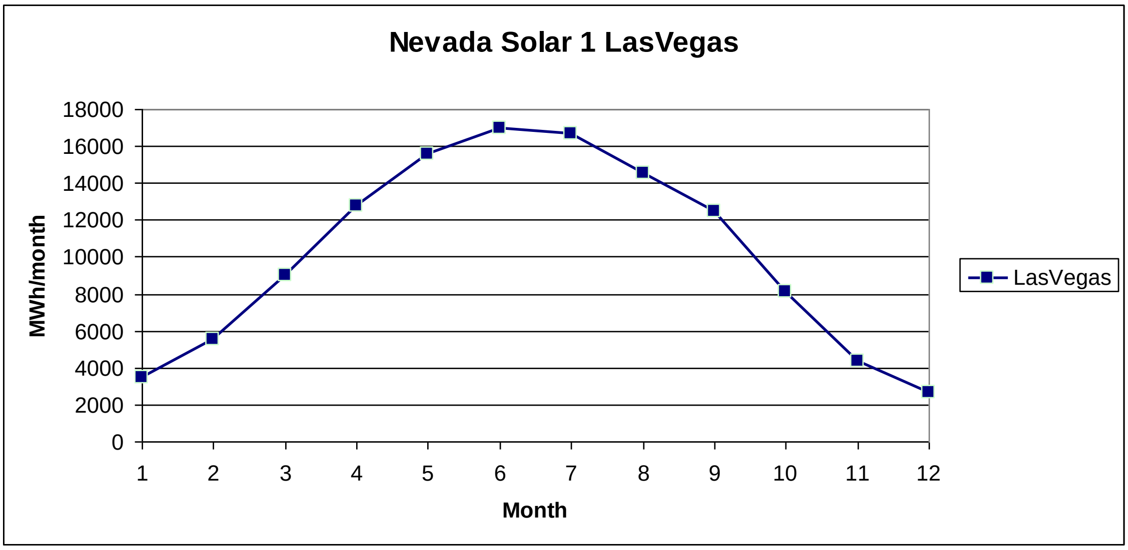

Figure 5-1: Modelled output of the Nevada Solar 1 parabolic trough system at Las Vegas

In Las Vegas, the annual solar to electric conversion efficiency (based on aperture area x annual DNI), is 12.6% and the output profile through the year is shown in Figure 5-1. In the USA, peak output is in June.

For single axis tracking troughs, the output drops off in winter months, essentially because there is less DNI available. However, a significant factor is that the sun is lower in the sky, so trough systems intercept a smaller fraction of the radiation that is available. In addition to this, all thermal systems are less efficient at lower DNI levels, simply because the thermal losses are largely fixed.

The annual output profiles for various sites in Australia are shown in Figure 5-2, where mid year is the period of lowest output. Newman, Mt Isa and Longreach, being closer to the equator, have much more consistent output throughout the year.

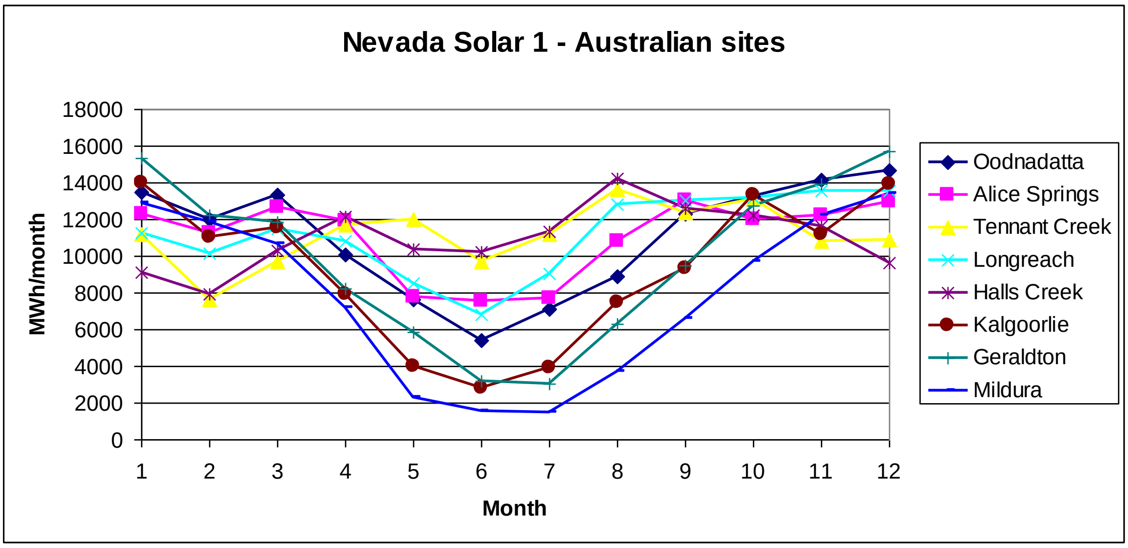

Figure 5-2: Modelled outputs of a parabolic trough system at various Australian sites

The following table compares key site and performance parameters between the Las Vegas site and Australian sites examined.

Table 5-1: Modelled outputs of a 64 MW_e parabolic trough solar thermal system in Las Vegas and at various sites in Australia.

Location [a]	Net Annual Generation (MWh_e)	Annual conversion efficiency	Capacity Factor	DNI [b] (kWh/ m²/yr)	Lat-itude	Long-itude	Ave. ambient Temp °C	Ave. Wind-speed (m/s)
Las Vegas	117,147	12.57%	20.90%	2606.6	36.08	-115.167	19.5	4.1
Oodnadatta	126,998	13.25%	22.60%	2682	-27.5	135.4	21.9	3.7
Alice Springs	126,931	13.47%	22.60%	2636.5	-23.8	133.88	21.2	2.3
Tennant Creek	128,592	13.76%	22.90%	2615.4	-19.63	134.18	26	4.5
Longreach	128,794	14.05%	22.90%	2564.4	-23.43	144.28	23.9	2.4
Mt Isa *	128,401	14.11%	22.90%	2546.4	-20.68	139.48	24.5	2.8
Newman *	128,852	14.40%	23.00%	2502.7	-23.42	119.8	24.1	2.1
Halls Creek	126,400	14.19%	22.50%	2492.2	-18.2	127.6	26.4	2.1
Kalgoorlie	106,070	12.05%	18.90%	2463.7	-30.78	121.45	18.3	3.8
Charleville *	116,018	13.42%	20.70%	2418.8	-26.42	146.27	20.8	3.1
Geraldton	113,048	13.12%	20.10%	2410.5	-28.8	114.7	19.2	4.8
Cobar *	108,034	12.69%	19.20%	2381.1	-31.48	145.83	18.5	2.2
Woomera	108,503	12.81%	19.30%	2368.9	-31.15	136.82	19.2	4.3
Moree *	106,165	13.17%	18.90%	2254.6	-29.48	149.83	18.7	2.3
Mildura	89,714	11.81%	16.00%	2124.6	-34.23	142.08	16.9	3.4
Wagga	85,574	11.75%	15.20%	2038.4	-35.17	147.45	15.1	2.6

Notes

a. Locations marked * have faulty solar data sets that generate physically unrealistic daily profiles.

b. Sorted in order from highest to lowest annual DNI.

It can be seen that Newman, Mt Isa and Longreach outperform the Las Vegas site, even though they have slightly less DNI. Conversely, Mildura, with around 20% less DNI than the best sites, shows output reduced by around 40%. High ambient temperatures and high average windspeeds would work to reduce system output, however the variation in these parameters does not appear significant between the sites. Another differentiator is the extent to which low DNI days are made up of short intervals of broken cloud or whole days of no sun. Broken cloud works against output for CST systems, since the time taken for the system to reach operating temperatures makes operation extremely inefficient in such circumstances.

5.2.2 CSP technologies compared

The results in Section 5.2.1 show that the prevailing solar and geographical characteristics of a site affect the performance of a Trough system to a considerable degree. All CSP technologies are affected to varying degrees. This report does not seek to compare the techno-economic performance of the various technologies on a competitive basis. It can be acknowledged that as a generalisation, Tower, Dish and CPV systems have higher annual efficiencies than Trough systems, but with higher costs of construction per unit area of solar collector. LFR systems offer the prospect of lower per unit area costs of construction for close to the same performance characteristics as Trough systems. In each case, commercial proponents work towards the best cost benefit ratio they can achieve for their chosen technology.

To better inform the present considerations, the relative performance of the different technologies located at a Northern and a Southern Australian site have been examined, specifically Longreach in Queensland and Mildura in Victoria.

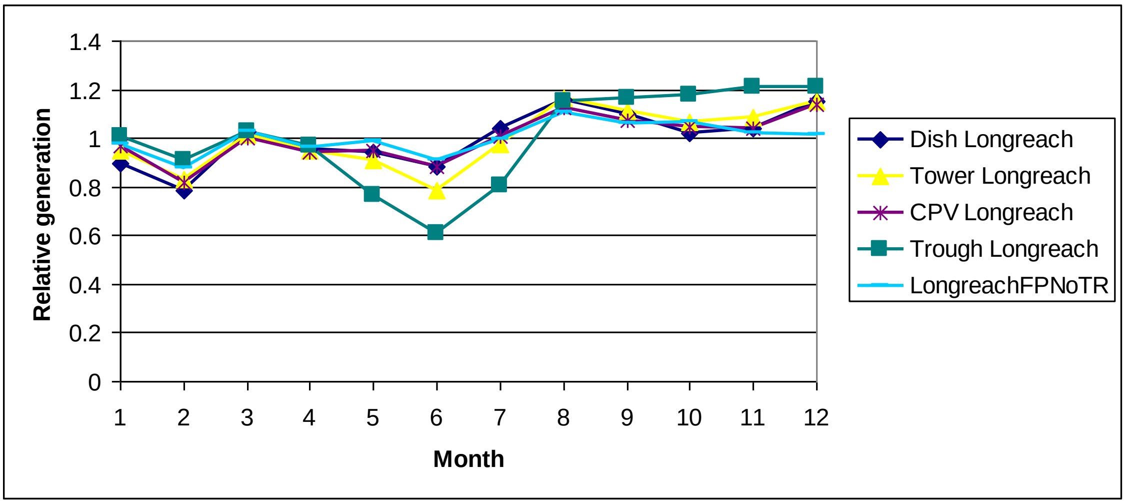

Figure 5-3: Modelled Generation Profiles of various CSP technologies if located at Longreach (normalised)

Figure 5-3 shows the annual profile of generation predicted from Dish, Tower, two axis tracking CPV, Trough and non-tracking Flat Plate PV systems as modelled with SAM, for

Longreach, Queensland. Since normalised relative generation is considered, the results will be essentially independent of the actual system details[42].

All output curves have been normalised to an annual average relative output of one. What is seen is annual profiles that reflect the DNI variation in the RMY data for Longreach. The distinction between the technologies is their degree of month to month variation. The CPV and Dish system profiles are virtually indistinguishable and quite level through the year and reflect the two axis tracking characteristic that maintains constant optical efficiency. The Flat Plate PV profile is also very constant, it assumes a panel mounting angle that helps to favour spring and autumn outputs and is also presumably smoothed somewhat by picking up diffuse radiation in some cloudy periods when DNI is poor.

The Tower and Trough systems both show a mid year drop-off of varying degrees. Longreach, at a Latitude of -23^{o}, is still sufficiently far from the equator that a horizontally mounted trough system captures less radiation when the sun is lower in the sky mid year. A Tower system is also affected, but to a lesser extent as heliostats capture an overhead sun more efficiently than one that it is lower in the sky and reflection angles are larger.

Mildura in Victoria is a Southern potential CSP location with a reasonably good DNI resource. Figure 5-4 shows the output of the same technologies sited in Mildura, but in this case relative to the average generation level of the same system in Longreach.

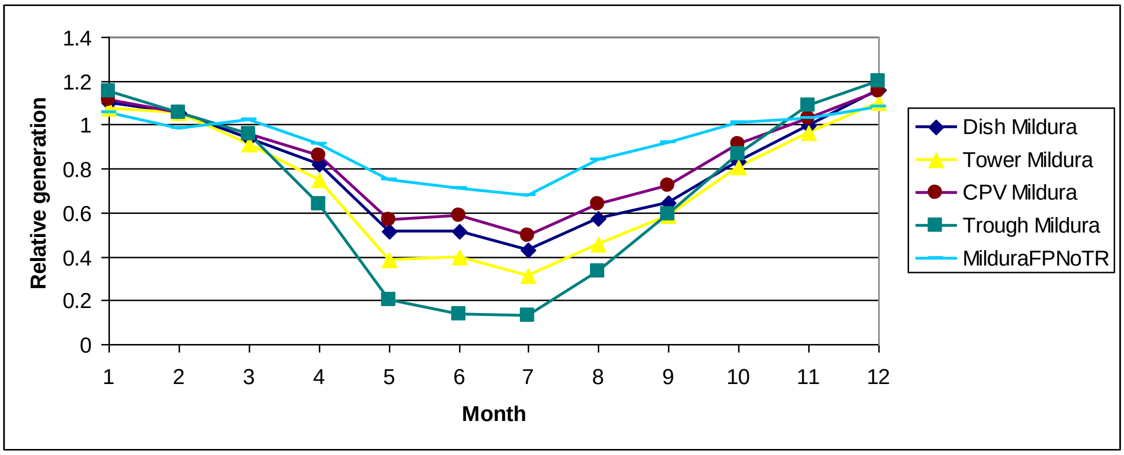

Figure 5-4: Modelled output of various CSP systems at Mildura (normalised to Longreach output)

The annual relative generation is summarised in Table 5-2. It can be seen that all the systems show a mid year drop off in output, with a Trough system being the most affected.

Table 5-2: Annual generation from various technologies at Mildura relative to Longreach

Technology	Annual generation in Mildura relative to Longreach
Dish	0.798
Tower	0.733
Trough	0.697
CPV	0.841
Flat plate PV	0.916

[42]The specific details were; 25kW$_e$ Dish Stirling systems, 100MW$_e$ molten salt based tower, 64MW$_e$ trough with no storage, 2 axis tracking CPV with cSi module, cSi flat plate PV mounted at Latitude angle.

The annual relative numbers can be compared to a ratio of annual DNI between Mildura and Longreach of 0.828. A Flat plate PV system maintains the highest ratio, as it is responding to global radiation levels rather than just DNI and in the South, higher relative diffuse radiation levels are expected, helping to maintain the global total. The modelling assumes that the fixed Altitude angle is optimised for spring and autumn generation in each location. The two axis tracking CPV system actually has a slightly higher relative generation level than the DNI ratio, presumably reflecting slightly improved efficiency with lower ambient temperatures. Of the thermal systems, Dishes come closest to maintaining relative output at the ratio of DNI levels. Both Tower and Trough systems suffer in varying degrees from optical efficiency reduction when the sun is lower in the sky. In this analysis the configuration of the CSP systems is assumed identical for the two locations. Tower systems in particular have scope for optimising their heliostat field layouts for the location and so reducing the performance reduction moving away from the equator. All thermal systems suffer when cloud based intermittency is such that they cannot reach an operating threshold as a consequence of their thermal inertias.

This analysis makes no comment on the actual relative economic performance of the technologies in either location, it does however show that the economic performance picture will shift differently for each technology when moving from North to South.

Whilst thermal inertia brings a small penalty in average annual generation levels, it does have the advantage of providing built-in short-term energy storage which smooths short term generation profiles. The output profile of a typical flat-plate non-tracked PV system on a day with intermittent clouds is shown in Figure 5-5.

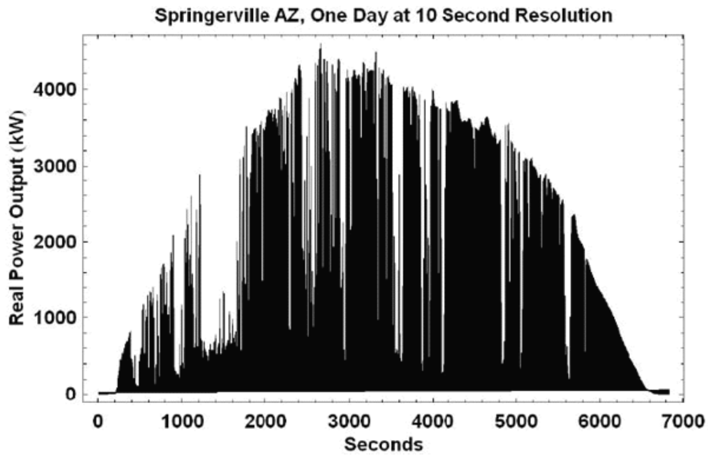

Figure 5-5: Example output from a PV system on a cloudy day[43]

The corresponding output from a CPV system would have an overall flatter output profile compared to a non-tracked PV system, as better relative performance would be achieved in morning and evening as a consequence of tracking. The short term output intermittency could however be more pronounced. A larger flat plate PV array (in the hundreds of megawatts range) would have a slightly smoother output because it would be spread over a larger area. Any of the thermal technologies, even without storage, would show a much smoother output. They would have sufficient thermal inertia to ride through all the disturbances on the day shown in Figure 5-5 with the exception of the approximately 1 hour long mid-morning disturbance. A system with thermal storage would maintain a pre-determined output level irrespective of the variability of solar input.

43 Figure from http://www.megawattsf.com/gridstorage/gridstorage.htm
depicting a day of intermittent generation from a 4.6 MW flat plate PV system in Springerville, Arizona.

5.2.3 The effect of thermal energy storage

To illustrate the effect of thermal storage on output, the Nevada Solar One system has been modelled at Mildura, with the power block left the same and various hours of thermal energy storage added.

Table 5-3: Impact of Storage on the output of a "Nevada Solar 1" Trough System at Mildura.

Storage (hours)	Storage MWh_{th}	Net annual generation MWh_e
0	0	89,714
1	191	104,133
2	382	104,664
3	572	104,461
6	1,145	104,067
12	2,289	104,067

A small amount of storage provides an immediate benefit to the volume of energy generated annually as the amount of energy dumped due to over-sizing of the field relative to the power block at peak solar conditions reduces. However this is not increased significantly as more storage is added – in fact the maximum benefit is achieved with 2 hours of storage.

It is seen that annual energy generation begins to decline slowly if storage capacity is increased beyond 2 hours. This reflects the standing losses from the hot salt tanks, which obviously increase as their size is increased. It is apparent that this is a small effect and not a significant disincentive to adding storage if strategies of dispatching later in the day were shown to be more profitable.

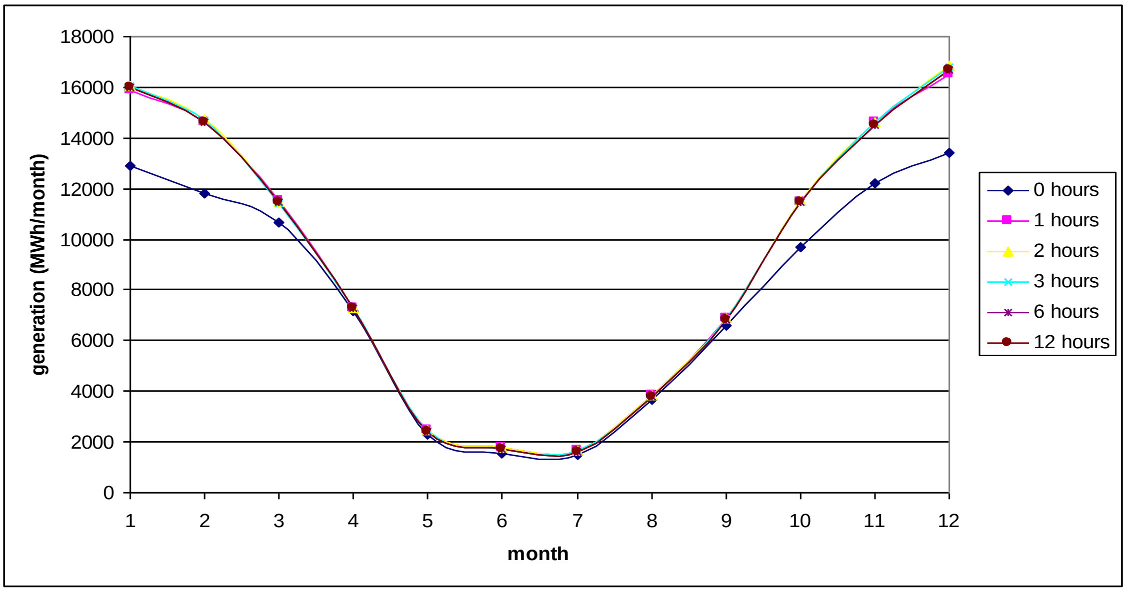

Figure 5-6: Monthly generation versus storage capacity

Comparing the monthly profiles shows that the main effect of storage is to increase generation in the Summer months. The existing Nevada Solar 1 system has a solar multiple of 1.264, this means that at design point insolation of 1,000 W/m^2, there will be 26% excess energy input that will be available but unused in a system without storage. A solar multiple greater than 1 is usually an economically rational choice, in that overall average LCOE will be minimised by a trade-off between the higher capacity factor of the system versus the extra cost of the solar field.

Depending on the capital cost contribution of storage, the minimum LCOE is typically between 1 and 2 hours of thermal storage. There are also some second order benefits to annual generation. On days when the DNI profile is too short or fragmented for the power block to operate, collected energy can be stored for later use. Further, the storage of energy allows the power block to the operated less often at part load and hence closer to its maximum efficiency on average.

5.2.4 Varying the nameplate capacity of the power block for a fixed level of storage

If energy storage is included in the system, there is much greater flexibility in the choice of the ratio of power block size to solar field size. At one extreme, the ratio can be reduced in order to configure the system for a more constant pattern of operation. Alternatively, a larger power block for a given solar field would allow greater generation at times of high demand / price for electricity. In considering this variation, it should be noted that for real projects, it is usually the power block size that is established first and field size and storage hours are then optimised during system design.

Table 5-4: Effect of powerblock size on annual output for a "Nevada Solar 1" system with 2,289 MWh_{th} of storage modelled for Mildura

Powerblock Size (MW_e)	Net Annual Energy (MWh)	Capacity Factor
27	104,818	0.45
45	105,675	0.27
64	104,067	0.19
71	103,212	0.17
80	101,898	0.15

The results in Table 5-4 have been produced using a fixed thermal storage capacity of 2,289 MWh_{th}, the value corresponding to 12 hours of storage for the baseline 64 MW_e power block. It can be seen that annual energy generation peaks for a powerblock size of around 45 MW_e. If the power block is too small, there are times when it cannot process all the energy provided by the field in a 24 hour period and so must waste some. The larger block however, is constrained by the thermal cost of the time taken to start the plant and the parasitic losses that must be covered when it is not generating.

5.3 Revenue Opportunity from Competitive Electricity Markets

5.3.1 Previous studies

In a recent key study, Sioshansi and Denholm (2010) examined the issue of maximising revenue from CST plants in the USA in detail. Their investigation is based on use of the SAM model and, in particular, uses the 'baseline CSP system in SAM'. This system is a 110 MW_e wet cooled trough plant for which they vary the Solar Multiple between 1.5 and 2.7 and the storage between 0 to 12 hours.

They have investigated operations in several high solar resource US states (California, Arizona, New Mexico and Texas). Of most direct relevance to Australia; California and Texas both have hourly varying prices for electricity similar to the Australian NEM.

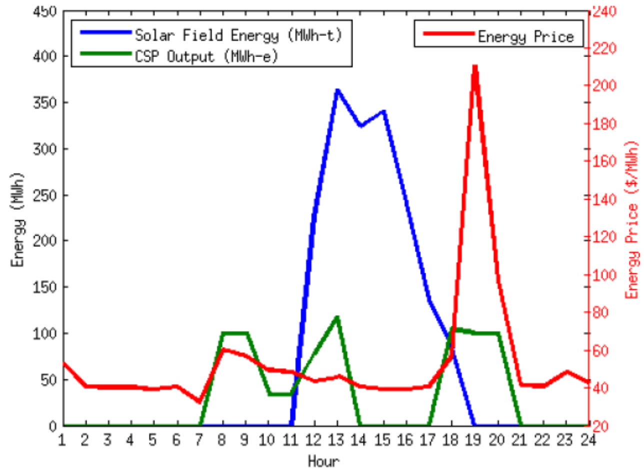

Figure 5-7: Sample dispatch of a CSP plant with 6 hours of storage and a solar multiplier of 2 at a Texas site (reproduced from Sioshansi and Denholm (2010))

Figure 5-7 shows a typical day in Texas, very similar to what would be expected over a summer day on the NEM. Annual operating profit, defined as the difference between earnings and operating costs (ie not including the cost of capital / financing), is examined for the various sites, for the range of solar multiples and storage hours, as shown in Figure 5-8.

For Texas, profits are highest for the highest solar multiples and increased markedly with storage hours out to about 6 hours where they begin to level off. It should be noted though that the capital cost and annual financing cost will also be increasing with both solar multiple and storage hours, so the overall maximum lifetime NPV point cannot be deduced from the annual operating profits.

The average selling price of energy from the basic CST plant without storage is found to be between 7 and 35% more than the average energy price in these US markets and addition of 6 hours storage increases this by a further 7 to 16%. The higher numbers apply to Texas which has higher energy prices overall than the other states considered and also has high peak prices relative to its average.

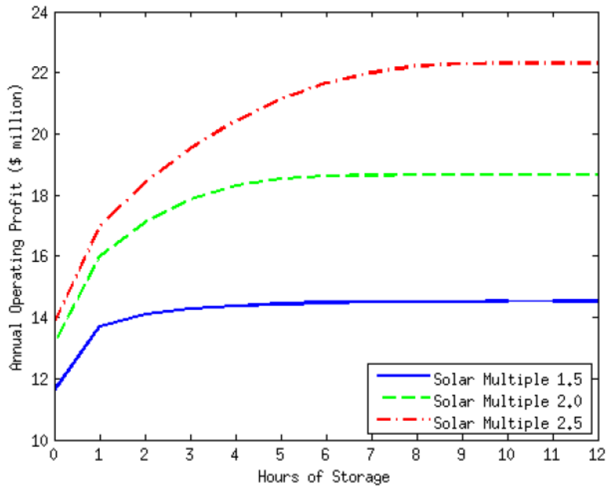

Figure 5-8: Annual operating profits (neglecting capital / financing costs) of a CSP plant at a Texas site (reproduced from Sioshansi and Denholm (2010)).

It is noted that the role of storage when the solar multiple is greater than 1 is two fold; it prevents energy being wasted and it allows energy sales to be shifted to higher price times.

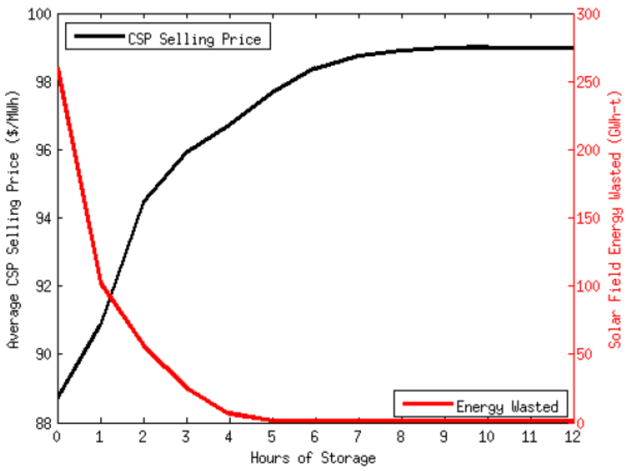

Figure 5-9: Average selling price of energy ($/MWh) and solar field wasted energy (GWh-t) for a CSP plant in Texas with a solar multiplier of 2 (reproduced from Sioshansi and Denholm (2010)).

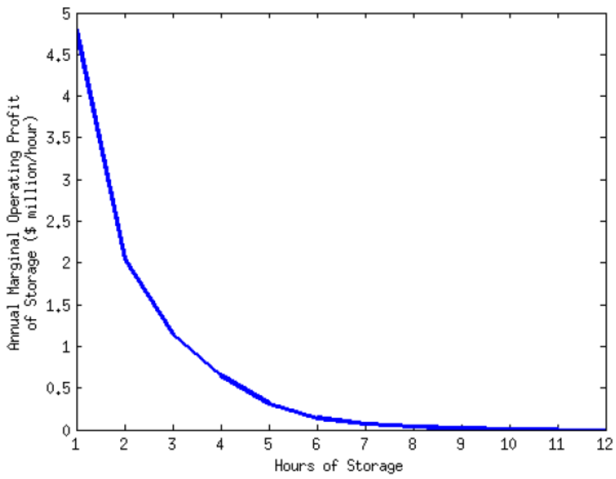

Figure 5-10: Marginal annual value of each incremental hour of storage for a CSP plant in Texas with a solar multiplier of 2 (reproduced from Sioshansi and Denholm (2010)).

Denholm and Sioshansi carry out a sensitivity analysis on dispatch forecasting. Initially, using the historic data to model 'perfect foresight' they show that there is very little to be gained by looking more than one day ahead, since there appears little value in attempting to hold energy over for several days. A much more conservative approach of dispatching, only based on the data from the previous 24 hours, is shown to produce profit levels that are at least 84% of the perfect foresight approach.

5.3.2 The Australian context

The National Electricity Market (NEM) on the Australian east coast and South Australia, and the Short Term Electricity Market in the WA South West Interconnected System, both establish a wholesale price of electricity every half hour based on predicted demand and bids received from generators.

In the NEM, Different Regional Reference Prices (RRPs) are established for each region (corresponding to States). Historical NEM half hour price data dating back to 2005 is available (AEMO 2012).

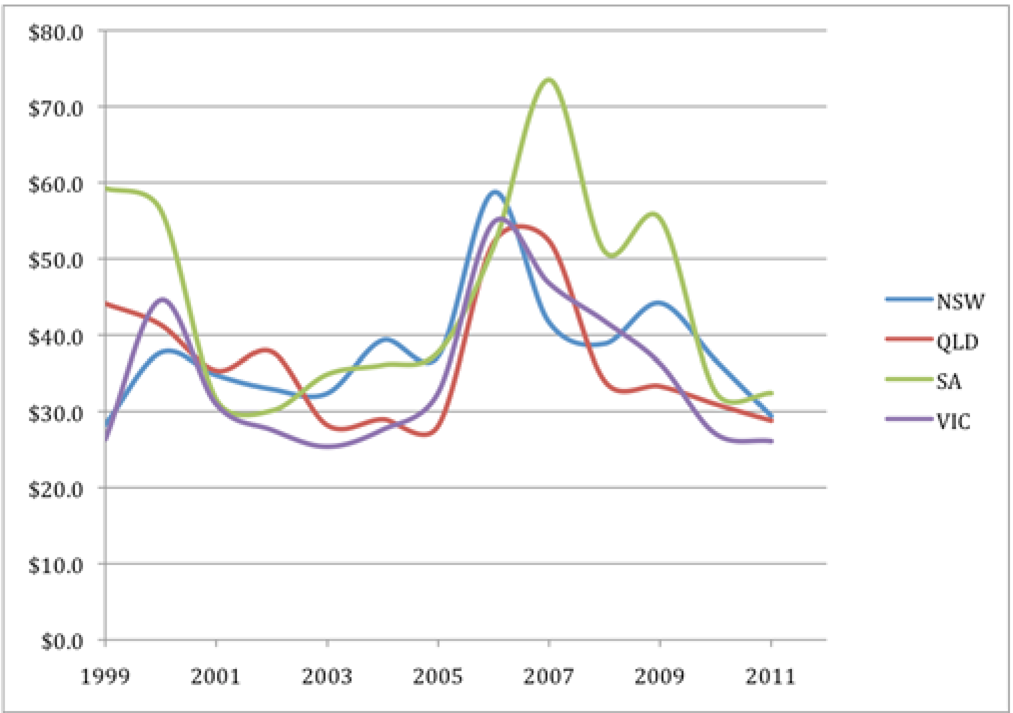

Figure 5-11: Historic NEM Financial Year Average Spot Prices (AEMO 2012)

Figure 5-11 illustrates that the annual average spot price can fluctuate significantly from year to year. Forecasts do not typically show the volatility that climate (eg El Nino or La Nina year (BOM 2012), load, investment timings, outages and government policies have on prices.

Averaging the above historical data from the NEM (together with data from WA South West market) over the period 2005 to 2010 gives the following:

Table 5-5: Average pool prices 2005 to 2010.

State	Average pool price 2005 -2010
Vic	$39.17
SA	$49.51
Qld	$36.93

NSW	$41.32
WA	$50.13
AVERAGE	$43.41

SA's higher prices tend to be due to limited interconnects with other regions, the poor quality of its coal, a higher dependence on long distance pipeline gas and its hot, dry summers with load concentrated in a relatively smaller geographical area (climate zone).

SA also has the highest proportion of wind generation of any state (this has reduced the NEM price) and significant water supply issues, which impact coal use in dry periods and would also impact CST technology choice.

Vic, Qld and NSW have access to large amounts of cheap electricity from local coal. Vic and Qld also benefit from large local natural gas resources. The coal seam methane gas sector is also forecast to grow strongly in Qld and NSW, potentially providing further local supply sources for generation fuels.

The value of CSP energy sold into the pool

If predicted solar energy generation at half hourly intervals is multiplied by historic pool prices that occurred during the same intervals, an average retrospective market value of the energy produced can be estimated and compared to the NEM average. Note that this approach assumes that the hypothetical presence of the CSP system in the market does not change the pool price, which is a reasonable assumption for low levels of penetration only. This is discussed further below.

For CST systems, a key issue to consider is how adding thermal energy storage and adjusting the dispatch profile can improve the market value of the electricity generated.

The SAM model can incorporate storage and it has a simple approach to specifying dispatch. However there are drawbacks: the dispatch profile is very simple and the same for every day of the year and is tedious to change via the user interface. Thus, instead, a simple storage / dispatch algorithm that uses the nominal instantaneous electrical generation produced by SAM was developed for this study. In a literal sense, this is modelling a hypothetical electrical storage system applied after generation. For the purposes of scoping market value, it is a reasonable model of the output of a thermal energy storage system dispatched via a steam turbine as required. It will actually underestimate slightly the amount of energy produced since the benefits of storage to annual generation levels noted above will not be counted.

The dispatch model is simply based on time of day, with the summer dispatch start time and Winter start time varied separately. The capacity of generation was also varied for a system with fixed annual generation potential. The size of energy store required was an output of the process. Further details on the approach taken and the sensitivity of market value to parameters used is given in Appendix D.

The approximate optimum market value determined in this way provides a baseline for further improvements. Clearly a CSP system with storage would be operated day by day, using all the information (eg weather and load / price forecasts) available to the plant operators, to presumably improve upon this simple time of day approach.

The use of a TMY solar data file to predict system output (rather than actual daily data), and then multiplying this by actual year price data, is also expected to slightly underestimate the potential value at low levels of penetration, given the recognised possibility that there is a direct daily correlation between high temperatures / solar resource and pool price.

Technology dependence

It is conceivable that the value benefit to be gained in the market place, either based on immediate dispatch or on storage and dispatch, will depend on the CSP technology used. This has been tested using Mildura solar data and Victorian NEM prices, with the results given in Table 5-6.

It can be seen that both the 'immediate dispatch' and the 'store and dispatch' values are considerably better than the average and are largely technology independent. With immediate dispatch, the trough system appears to have a minor advantage. This may well suggest that its more summer biased output means a better average correlation with summer afternoon price peaks and so pushes its annual average up. No immediate explanation has been established for the +/- 7% variation in value between technologies for storage and dispatch. The overall conclusion is that the extra market value available is essentially technology independent. Consequently, further investigations were carried out using the baseline trough system.

This analysis is of potential revenue only. It should be noted that a CPV / PV system would need to access an electrical storage technology to achieve this. Electrical storage is more costly and less mature on a large scale than thermal energy storage.

Table 5-6: Comparing the average sale price of energy from several solar technologies, modelled at Mildura, averaged over 2005 – 2010 pool price data.

Technology	Vic NEM average price ($/MWh)	Immediate dispatch average sale price	Ratio immediate / NEM av	Dispatch from storage average sale price	Ratio Storage / NEM av
Trough	$39.17	$58.89	1.50	$74.56	1.90
CPV	$39.17	$51.99	1.33	$79.21	2.02
Tower	$39.17	$51.97	1.33	$74.53	1.90
Dish	$39.17	$53.22	1.36	$83.93	2.14
PV Flat Plate	$39.17	$52.82	1.35	$84.63	2.16

Note the same store and dispatch model was applied to the output of a PV flat plate system for this comparison.

Variation between years

Table 5-7 and Table 5-8 examine the value of the modelled annual performance of a Nevada Solar 1 system within the SA and NSW regions. Considerable variation is seen in the annual average prices. For both states, the year with the highest value for dispatch from storage also has the highest value for immediate dispatch and is seen to have the highest average pool price. Interestingly, this occurs for different years for the two states.

Importantly it can be seen that in all years the solar system with immediate dispatch always produces a higher value that the average pool price. In turn, a system with storage and dispatch always produces higher value than one that dispatches immediately.

Table 5-7: Comparing the average sale price of energy from a trough system for specific years, with and without storage for SA (Nevada Solar 1 modelled at Woomera).

Year	SA NEM average price	Immediate dispatch average sale price	Ratio immediate / NEM av	Dispatch from storage average sale price	Ratio Storage / NEM av
2005	$33.60	$46.55	1.39	$57.32	1.71
2006	$38.68	$55.43	1.43	$81.05	2.10
2007	$57.50	$75.62	1.32	$86.63	1.51
2008	$66.50	$156.38	2.35	$278.74	4.19
2009	$60.47	$115.04	1.90	$178.99	2.96
2010	$40.28	$89.19	2.21	$138.58	3.44
AVERAGE	**$49.51**	**$89.70**	**1.81**	**$136.88**	**2.77**

Table 5-8: Comparing the average sale price of energy from a trough system for specific years, with and without storage for NSW (Nevada Solar 1 modelled at Mildura).

Year	NSW NEM average price	Immediate dispatch average sale price	Ratio immediate / NEM av	Dispatch from storage average sale price	Ratio Storage / NEM av
2005	$35.84	$54.82	1.53	$82.64	2.31
2006	$31.01	$45.34	1.46	$76.86	2.48
2007	$67.08	$70.06	1.04	$136.46	2.03
2008	$39.18	$41.25	1.05	$52.15	1.33
2009	$43.92	$73.54	1.67	$83.88	1.91
2010	$30.89	$42.93	1.39	$52.04	1.68
AVERAGE	**$41.32**	**$54.66**	**1.32**	**$80.67**	**1.95**

Effect of sites in a region

To compare the generation at a range of sites within a single NEM region, three NSW sites were modelled as shown in Table 5-9: Comparing the average sale price of energy from a trough system averaged over the years 2005 – 2010, with and without storage, for three sites in NSW.

Table 5-9: Comparing the average sale price of energy from a trough system averaged over the years 2005 – 2010, with and without storage, for three sites in NSW.

Location	NSW NEM average price	Immediate dispatch average sale price	Ratio immediate / NEM av	Dispatch from storage average sale price	Ratio Storage / NEM av
Cobar	$41.32	$55.95	1.35	$80.30	1.94
Moree	$41.32	$54.66	1.32	$80.67	1.95
Mildura	$41.32	$62.83	1.52	$84.96	2.06

It is concluded that there is only variation to within 5% and no significant correlations are apparent.

Variation between States

All NEM regions except Tasmania are compared in Table 5-10, along with results for the Western Australian South West Interconnected System (SWIS), which also operates a competitive energy market (Short Term Energy Market (STEM) (IMO 2011)).

Table 5-10: Comparing the average sale price of energy from a trough system, averaged over the years 2005 to 2010, with and without storage for all relevant states.

State	Market average price	Immediate dispatch average sale price	Ratio immediate / market av	Dispatch from storage average sale price	Ratio Storage / market av
Vic	$39.17	$58.89	1.50	$74.56	1.90
SA	$49.51	$89.70	1.81	$136.88	2.77
Qld	$36.93	$50.03	1.35	$77.24	2.09
NSW	$41.32	$54.66	1.32	$80.67	1.95
WA	$50.13	$58.05	1.16	$65.83	1.31
AVERAGE	**$43.41**	**$62.27**	**1.43**	**$87.04**	**2.01**

All regions show that immediate dispatch solar has a higher value than the pool average and store and dispatch produces a higher value still. Of the regions, SA shows the highest multiples and WA the lowest.

The market value multiple of solar electricity in SA is considerably higher than the other states particularly since 2008 (see Table 5-7). It is hypothesised that this may be due to the higher the constrained grid connection to Victoria and the relative under capacity of fossil-fired peaking plants in South Australia, combined with very strong demand peaks from cooling loads on hot days.

The lower multiples in WA are most likely because the SWIS has a much lower cap on spot prices, with the Reserve Capacity Mechanism used to ensure there should be enough capacity to meet demand. For example, in 2011 the maximum Short Term Energy Market (STEM) price, which is equivalent to the NEM's Value of Lost Load (VOLL) of $12,500/MWh, was only $314/MWh (IMO 2011).

Impact of CSP deployment on pool prices

This analysis using historic data is simplistic in that it assumes that the presence of the CSP plants would have had no impact on the pool prices. This is a reasonable approximation for a scenario of low penetration, however significant penetration of CSP is likely to affect the spot prices and bidding behaviour of market participants.

The most significant impacts are likely to be:

(i) The possible need for more rapidly variable generation (eg. OCGTs) to compensate for the variability of CSP without, or with limited, storage,

(ii) The merit order effect,

(iii) The possibility that large amounts of CSP with storage lowers peak price events relative to the average.

Effect (i) could increase the spot price when CSP plants are not generating, and as such, it is not relevant to the value obtained by CSP plant. If such an effect did occur, it could be construed as a “negative” implicit value contribution for intermittent generation. It is worth noting that it has been reported that the high levels of wind variability in South Australia did not lead to either increased spot prices or increased variation in spot prices in the 2008/09 year (Boerema et al., 2010).

Effect (ii), the ‘merit order effect’ (MOE), is a well documented effect where electricity that is ‘bid in’ at zero, or close to zero (typically from plant which has a low marginal cost of operation), moves the dispatch price down the dispatch order – thereby reducing the average price for each half hour period (Pöyry (2010), McConnell et al (2011), and refs therein). This reduces the spot price received by all generators, including solar. Thus, although renewable electricity reduces the wholesale cost of electricity, which provides a benefit for retailers and electricity users to the extent that this benefit is passed through[44], it does not receive the benefit of this reduction, but instead receives less income.

It is very difficult to calculate the value of the MOE – essentially because such calculations are counterfactual. What would have happened in both the absence of the existing generation and the presence of any proposed generation are unknown. The value of the MOE driven by solar can be estimated either in terms of the reduction in spot prices in any one half hour bidding interval, or in terms of the total value of the reduction in wholesale prices divided by the solar electricity produced.

It would appear that only one attempt has been made to calculate the value of the MOE driven by solar in Australia (McConnell et al 2011). They found that increasing the amount of flat plate PV from 1 GW to 10 GW decreased the spot price from 5.3c/kWh to 3.6c/kWh (averaged over 2009 and 2010). Assigning this value per kWh of solar electricity resulted in values between 17c/kWh (1 GW) and 10c/kWh (10 GW). As noted by the authors, these approximations assumed an historic static dispatch order and so did not account for possible changes in bidding behaviour.

While, from a macroeconomic perspective, the MOE provides value (because the same product is provided at lower cost), it is worth noting that it is a consequence of a particular

44 For example, in NSW, IPART’s Price Determinations use the higher of the Long Run Marginal Cost (for a theoretical least-cost mix of generating plant) or the average spot price. Recently, the average spot price has been the lower of the two, and by reducing this even further, the MOE benefit is retained by the retailers.

market design. Whilst it may deliver savings to wholesale customers at some point, it can only do so by reducing the profitability of some or all of the generators in the market.

Effect (iii) would occur if a large penetration of CSP systems with storage smoothed pool price extremes and so reduced the value multiple. It has been reported that in Germany the geographical distribution of PV systems effectively smoothed out any variation due to, for example, cloud cover (Burger, 2011). A true market equilibrium is however unlikely to result in level prices so long as dispatchable systems have higher LCOE's (which they do, as discussed in Chapter 6). Rather, in an ideal market place, the price swings would settle such that fully despatchable, intermittent and unscheduled plants would operate with similar Internal Rates of Return for investors.

Summary

This preliminary investigation of the hypothetical value of CSP energy in the NEM / STEM shows that, according to the model used here, immediate dispatch increases its value by approximately 40% above the pool average. A basic algorithm for storing and dispatching the energy increases the value of the energy approximately 100% above the pool average.

However this additional value varies considerably by year and by state – apparently because of the variations in the relevant price profiles. Despite the variations, CSP energy is always more valuable than the average, and stored energy more valuable again.

The impact of greater penetration of renewables, and the consequences for CSP value, should be the subject of much more detailed investigation. In particular, it would be of great interest to examine:

- The ability of CSP energy with and without storage to increase the amounts of Wind and PV to the current RET limit and towards 100% renewable electricity.
- The level of penetration of CSP with storage that would work to reduce its apparent higher value in the market place.
- The likely evolution of the non-renewable energy generation mix in coming decades and the effect its characteristics will have on average, maximum and minimum pool prices and hence the value of CSP energy.

5.4 Revenue Opportunity From The LRET

Australia's Mandatory Renewable Energy Target (MRET) was introduced in 2001 and originally aimed for an additional 9,500 GWh per year of 'new renewable generation' by 2010. In 2009, the target was expanded to an additional 45,000 GWh per year by 2020 and renamed the expanded Renewable Energy Target (RET).

The RET was split in two in June 2010 and the enhanced Renewable Energy Target (eRET) consists of the:

- Small-scale Renewable Energy Scheme (SRES); and
- Large-scale Renewable Energy Target (LRET).

The LRET aims to provide an additional 41,000 GWh of 'new renewable generation' by 2020 by creating a market for Large-scale Generation Certificates, (LGCs formerly known as Renewable Energy Certificates or RECs). As liable parties are required to surrender LGCs each year or face a penalty, the LRET allows 'new renewable generation' to earn an additional income above that derived from selling their electricity output. Figure 5-12 illustrates the operation of the LGC market.

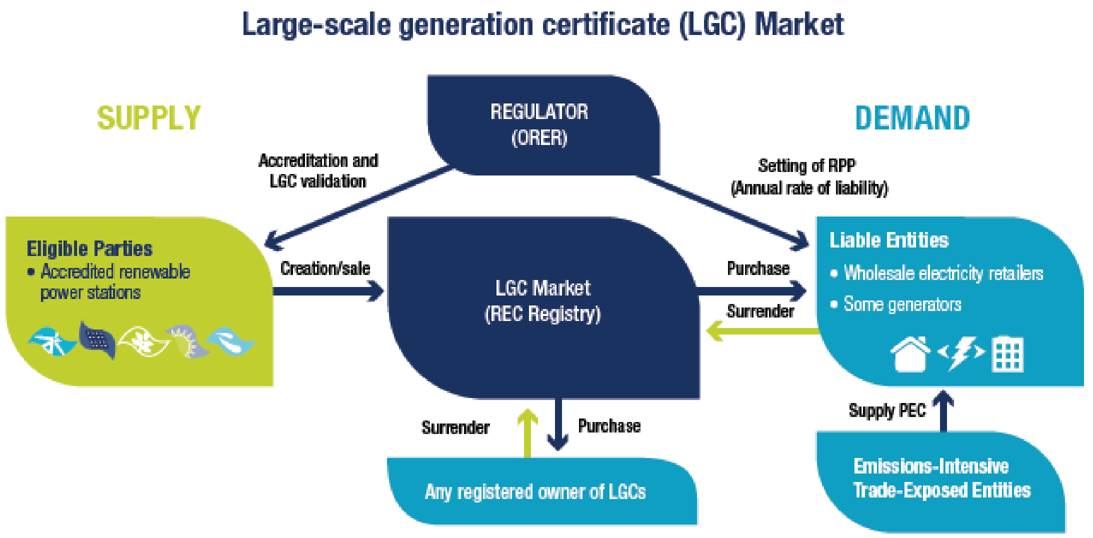

Figure 5-12: LGC market overview
(from the Office of the Renewable Energy Regulator, www.orer.gov.au)

As the LRET is a market mechanism, it is expected that the lowest cost renewable generation will benefit. Many in the electricity sector expect the majority of the 2020 target to be met by new wind farms. However, other renewable technologies, including marine energy, geothermal, hydro, biomass and solar, are eligible and can compete if their costs become competitive.

CSP systems are eligible and methodologies for calculating LGCs for hybrid power stations are available from ORER (2012).

5.4.1 Historic REC / LGC spot prices

While the majority of LGCs are traded through long-term Power Purchase Agreements with costs kept confidential, the historic spot price gives an indication of the value of RECs/LGCs.

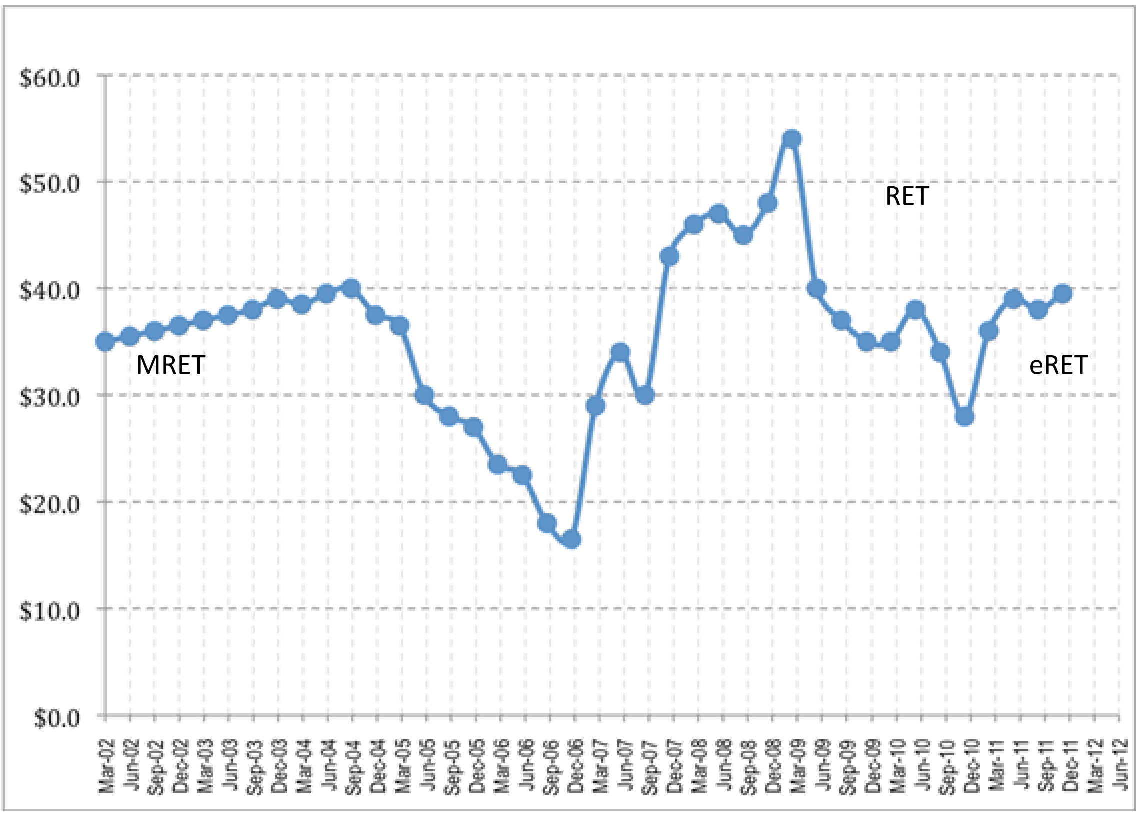

Figure 5-13: Historic REC / LGC Spot prices

While Figure 5-13 gives an indication of when the various legislative mechanisms operated, it is important to note that, for spot prices, the date that changes to the legislation were announced is likely to have more relevance. For example, both the major political parties announced their intention to significantly expand the MRET during 2007 in the lead up to that year's Federal election.

Whilst LGCs are now trading at around $40/MWh, the significant oversupply in 2010 prior to the splitting of the scheme into small scale and large scale components saw the price drop to just below $30.

5.4.2 Forecast LGC prices

Without any price on greenhouse emissions and other market interventions, it could be expected that the LGC spot price would repeat a similar pattern to that shown in the first five years of the MRET. That is, prices remain in the vicinity of $40 to $50 until sufficient renewable generation capacity to meet the additional 41,000 GWh pa is certain to commence construction, after which prices fall.

However, this broad forecast does not take into account the current oversupply of LGCs which means that new renewable generation build is not required until 2014 which will put downward pressure on prices. It also does not factor in the impact of government policies and funding programs, eg State wind farm exclusion zones, Solar Flagships and the Clean Energy Finance Corporation. The impact of these and other government measures and programs on spot prices is difficult to predict.

There is also the complicating factor of Federal elections every three years and State and Territory elections every four years, as well as the review of the eRET which is scheduled for 2012, all of which may have impacts on LGC pricing.

A significant impact on LGC prices will be the start of the $23/tonne carbon price on 1 July 2012, which is expected to place upwards pressure on wholesale spot prices. As the LGC price is basically the difference between the lifecycle cost of new renewable generation and the wholesale spot price, this is expected to place downwards pressure on the LGC price. However, as new renewable generation benefits from both wholesale and LGC prices, this does not significantly affect the economics of new renewable generation projects in the period to 2020.

However, the current Australian Federal political situation, with the various interplays between the parties and the independents, and the Opposition's different policy positions, and the next Federal election scheduled for late 2013, gives rise to major uncertainty for projected LGC prices.

While there is, presently, bipartisan support for the size of the LRET, there are differences in the policy approach to supporting emerging technologies and reserving a component of the LRET for them. There are also significant differences on the long-term future of the carbon price legislation, as well as how the carbon price should integrate with RET prices over time.

5.5 Other Network Values

5.5.1 Ancillary services

'Ancillary services' is a term that broadly describes functions and roles of generators and other technology connected to the electricity network that are needed to keep an electrical network operating within desired specifications and reliability, independently of the sale and purchase of energy.

In Australia, currently, the NEM includes market ancillary services, but will also include non-market ancillary services as of the 5th April 2012. Market ancillary services and non-market ancillary services are discussed are discussed separately below.

Market Ancillary Services

The following briefly describes the different types of ancillary services and is paraphrased from *Guide to ancillary services in the National Electricity Market*, (AEMO 2010A and AEMO 2010B, which includes considerably more detail). This is followed by a discussion of CSP's ability to provide ancillary services and the value likely to be obtained.

All NEM Ancillary Services can be grouped under one of the following three major categories: Frequency Control Ancillary Services (FCAS); Network Control Ancillary Services (NCAS); or System Restart Ancillary Services (SRAS).

FCAS are used by AEMO to maintain the frequency on the electrical system close to fifty cycles per second at all times, as required by the NEM frequency standards. Frequency control can be divided into two reasonably distinct subsets: Regulation and Contingency.

Regulation frequency control can be described as the correction of the generation / demand balance in response to minor deviations in load or generation. There are two types of Regulation FCAS requirements: Regulation raise and Regulation lower.

Contingency frequency control refers to the correction of the generation / demand balance following a major contingent event such as the loss of a generating unit or a large transmission element. There are six types of Contingency FCAS requirements:

- *Fast Raise and Fast Lower* (six second response to arrest the immediate frequency deviation)
- *Slow Raise and Slow Lower* (sixty second response to keep the frequency within the single contingency band)
- *Delayed Raise and Delayed Lower* (five minute response to return the frequency to the Normal Operating Band)

Participants must register with AEMO for each of the distinct FCAS markets within which they wish to partake. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service, via AEMO's market management systems.

NCAS are either Voltage Control or Network Loading Control.

- Voltage Control: Control the voltage at different points of the electrical network to within the prescribed standards. The voltage control ancillary services can be further categorised as follows:
  - Synchronous Compensator: a generating unit that can generate or absorb reactive power while not generating energy in the market;
  - Generation Mode: a generating unit that can generate or absorb reactive power while generating energy in the market.
- Network Loading Control: Control the power flow on network elements to within the physical limitations of those elements.

SRAS are reserved for contingency situations in which there has been a whole or partial system blackout and the electrical system must be restarted. This can be provided by two separate technologies:

- General Restart Source: a generator that can start and supply energy to the transmission grid without any external source of supply.
- Trip to House Load: a generator that can, on sensing a system failure, fold back onto its own internal load and continue to generate until AEMO is able to use it to restart the system.

It is worth noting that the value of ancillary services in the NEM to date, is relatively small. Figure 5-14 shows the total value of all market ancillary services from Jan 2010 to Dec 2011, and Figure 5-15 shows the percentage contribution of each type of market ancillary service to the total value. It can be seen that the total value averages a little over 50c/MWh ie approximately 1% of the pool price. About 70% of this is from the provision of reactive power support (41%) and system restart capability (30%) ie. NCAS and SRAS.

Both NCAS and SRAS are provided to the market under long term ancillary service contracts negotiated between AEMO (on behalf of the market) and the participant providing the service. These services are paid for through a mixture of:

- Enabling Payments – made only when the service is specifically enabled
- Availability Payments – made for every trading interval that the service is available.

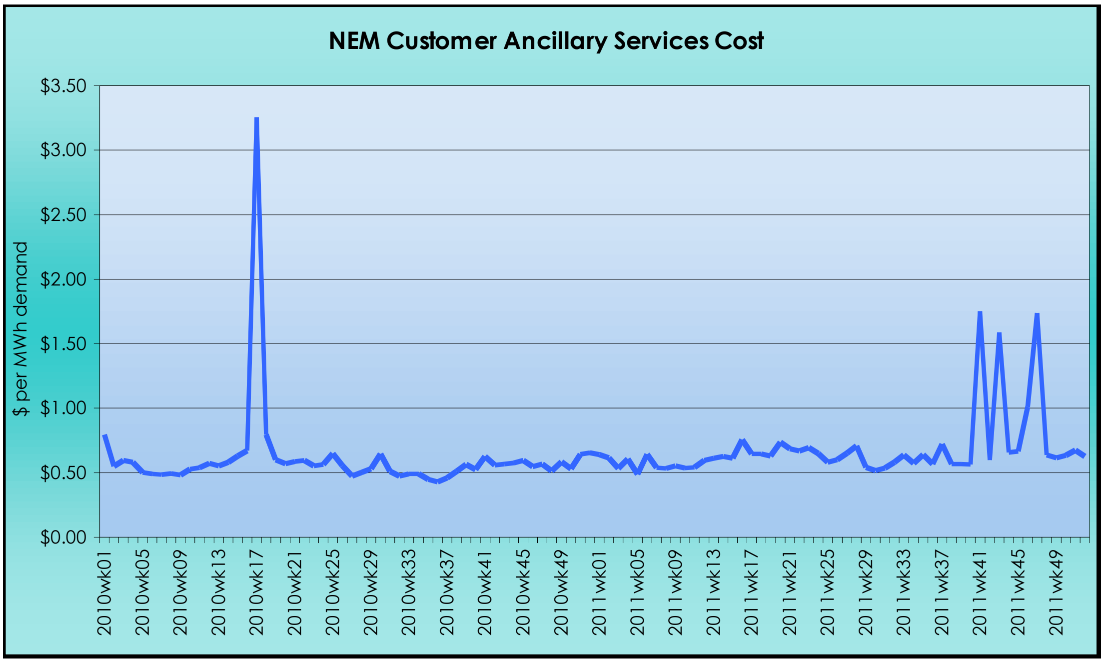

Figure 5-14: Value of all market ancillary services Jan 2010 to Dec 2011 (AEMO)

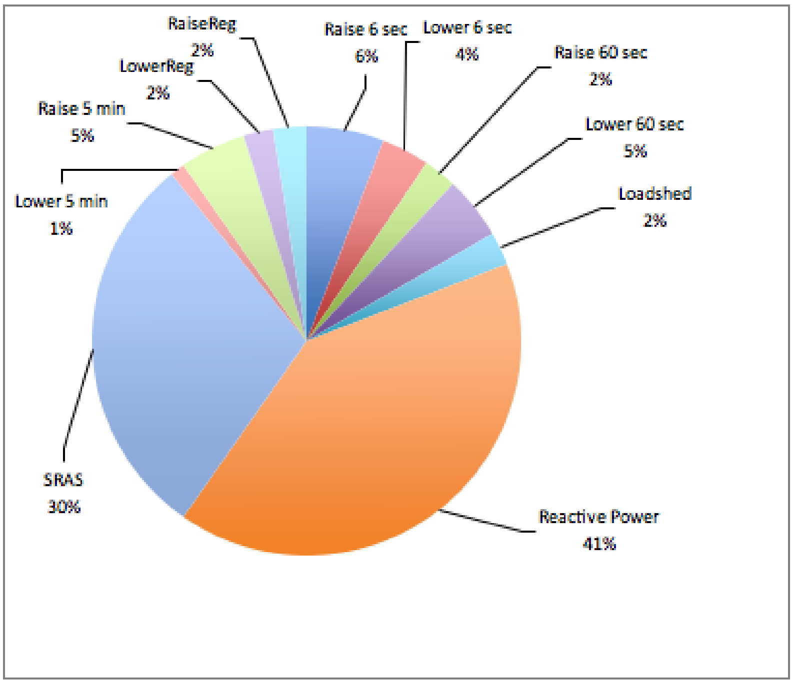

Figure 5-15: Percentage contribution of each market ancillary service to the total value, average Jan 2010 to Dec 2011 (AEMO)

Market ancillary services and CSP

The provision of ancillary services by CSP is at this stage untested. Like all other generators, CSP will be assessed on a case by case basis. AEMO's current approach is outlined in the following text from Wettimuny (2010). Note that MASS is the *Market Ancillary Services Specification* Version 3.01.

"The issue with intermittent generation providing ancillary services is that the generation is 'intermittent' and unpredictable. The ability of intermittent generation providing ancillary services boils down to whether there is certainty that the service can be provided if called upon to do so. Since non-delivery of FCAS would contribute significantly to the [in]security of the power system, AEMO would need substantial evidence to gain confidence that the proposed service would have to capacity to deliver the service when required. The onus is on the market ancillary service provider to ensure that the service they offer is capable of being delivered.

The intent of the MASS is to be technology neutral, and as long as there is certainty that the FCAS service will be provided, and the service delivery can be verified as per the MASS, then a given technology in principle can provide FCAS.

Currently there are storage methods (pumped storage, molten salts, batteries) which, coupled with solar schemes, have demonstrated under some conditions that solar power output can persist for some duration without sunlight. In order for AEMO to approve an FCAS application for an intermittent generation plant, AEMO would require significant evidence to demonstrate that the chosen energy storage solution will provide a high level of certainty of power delivery when called upon to do so."

On this basis and following the analysis of capacity value in 5.5.4, it would appear that a CSP system, particularly one with storage, should be able to provide some or all ancillary services on a case by case basis. Long-term operating experience in jurisdictions such as Spain could be used as significant evidence.

As shown above, 70% of the value of ancillary services is available through NCAS and SRAS, and a CSP plant would need to negotiate long-term contracts with AEMO. However at a value of only 1% of the pool price, this issue would be largely irrelevant. It can be hypothesised however, that with the present mix of generation assets there is actually a surfeit of large generation plant that can provide all the services needed in the normal course of business. Consequently the price is very low. Moving forward to a situation of much larger levels of penetration of intermittent wind and PV without storage, and ultimately towards 100% renewable electricity, it seems highly likely that this would change to some degree. This is another complex area of market prediction that deserves further investigation. The issue should not be neglected simply because prices are currently very low.

While inverters can be configured to provide frequency support, voltage regulation, power factor correction etc, whether they would be is another question entirely.

Non-Market Ancillary Services

Network Support and Control Ancillary Services (NSCAS) are a non-market ancillary service that may be procured by AEMO or Transmission Network Service Providers (TNSPs) to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.

The National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011 No.2 commences on 5 April 2012. It is supported by the Network Support and Control Ancillary Services Description (NSCAS Description) and the Network Support and Control Ancillary Services Quantity Procedure (NSCAS Quantity Procedure). These have recently been developed, with the Final Determination and Report released on the 12th Dec 2011 (AEMO 2012 B) . The following is paraphrased from the Final Determination and Report.

NSCAS are non-market ancillary services acquired to control the active power or reactive power flow into or out of a transmission network in order to:

- maintain power system security and reliability of supply in accordance with the power system security and reliability standards; and
- maintain or increase its power transfer capability to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market.

There are three types of NSCAS service that can be provided, that:

- Increase the secure loading of the network (Network Loading Ancillary Service, NLAS);
- Control the network voltages within acceptable limits including voltage stability (Voltage Control Ancillary Service, VCAS); and
- Improve transient and oscillatory stability limits of the network (Transient and Oscillatory Stability Ancillary Service, TOSAS).

From the NSCAS Description, generators are capable of providing all three types of NCAS. Whether CSP (with or without storage) will be a viable contender to provide such services will become clearer once the Rule commences.

5.5.2 Avoided network costs

A possible benefit to the relevant network service provider (NSP) of a CSP plant is deferral of network augmentation if the output of the CSP plant correlates with the annual peak load and the plant is located at a place immediately downstream of an area of the network which would otherwise need augmentation.[45]

[45] The costs of connecting a CSP plant to the network, including any associated studies on the impact of that connection, are borne by the CSP proponent.

Noting the various market segments identified in Chapter 4, avoided network costs could appear in the transmission system, for a large CSP plant, or in the distribution system for a smaller one. Decision making on network augmentation is a complex process that involves a mix of keeping the probability of loss of load to very low levels, plus societal cost benefit tradeoffs.

This is a contested area and there are two main points of view.

One view is that, for a network service provider to rely on any type of generation to augment its networks, it has to view that capacity as 'firm'. This means that it has to provide capacity at that point in the year when load is at it's highest. Thus, CSP without storage is unlikely to be considered firm as it may be unavailable at critical times – for example, to help meet air conditioning loads on a hot cloudy day or to provide capacity to a transmission network with a winter evening peak. Of course, CSP with storage may well be able to provide capacity at the peak time, especially if the peak on that network is on a summer afternoon.

The other point of view is that, regardless of whether the NSP regards CSP as firm, CSP plant may still be providing capacity at times of high load. It may therefore reduce the peak load forecasts upon which NSPs base their future capacity requirements, and so be of benefit to them. Indeed, renewable generation is already incorporated into AEMO's projections of the non-scheduled generation contribution to meeting summer maximum demand. AEMO's Electricity Statement of Opportunities (ESOO) 2011 indicates that, in the medium capacity scenario, of the 2,605 MW of non-scheduled generation present in the NEM, 730MW of this is assumed to be available during peak demand times in 2011-12 (about 28%) – although it is unclear how much of this is due to renewable plant. This assumed available capacity reduces the required network expenditure in the coming years.

Such network support will be very site-specific because the annual peak load needs to correlate with the output of the CSP plant in question, and augmentation must be required 'upstream' or at the CSP connection point. Implicit value will also only be created by the CSP plant from the time that the load would have reached the level where the NSP would have needed to commence implementing the required augmentation had the CSP plant not been available - which could be in many years' time. This delay would of course provide some time to determine the degree to which the plant's output and the associated network's peak loads correlate. The value of deferral of network augmentation could then be calculated based on the annualised value of the avoided augmentation measure using a discount rate appropriate for the NSP. This could possibly occur ex post – annual payments each year that the augmentation was deferred.

The possibility of avoiding network augmentations in an economically rational way is recognised at least for distribution networks, in the Code of Practice Demand Management for Electricity Distributors. It requires DNSPs to investigate and report on demand management strategies when it "would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion [of a distribution system] by implementing such strategies".

It has resulted in various DNSPs making calls for DSM but anecdotal evidence suggests that there has been little implementation to date and the DNSPs are facing mixed incentives under the current policy settings. There is currently no matching requirement for Transmission system NSPs.

There appears to be a good case that there is a failure in the present policy settings that means that real value that could be produced by appropriately siting generating assets in locations where network augmentation may be avoided, is simply a positive externality for the NSP's and the project developers are not rewarded financially.

The implied value of such a contribution will vary enormously on a case by case basis. Based on approximate costs of network infrastructure vs the value of energy in general, it is suggested that it could fall between 1 and 5% of total market value of energy due to other contributions.

5.5.3 Marginal Loss Factors

As electricity moves through the transmission and distribution networks, some energy is lost as heat. To allow for this the NEM uses Marginal Loss Factors (MLFs, also called Transmission Loss Factors) for the transmission network and Distribution Loss Factors (DLFs) for the distribution network - see Figure 5-16.

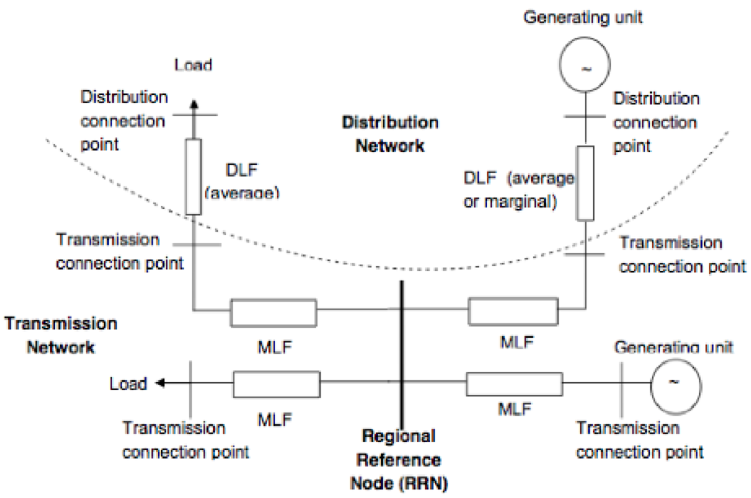

Figure 5-16: Relationship between connection points and loss factors (AEMO, 2009)

DLFs are used to 'increase' the amount of energy that needs to pass through the point where the distribution network connects to the transmission network in order to allow for losses in the distribution system. Thus, the greater the losses, the more energy a retailer needs to buy.

MLFs are used to increase the cost of energy that passes through a transmission connection point to allow for transmission losses. The transmission network connection points can be where the transmission network connects to a large load or conventional generator or to the distribution network, or even a 'virtual node'. Thus, the greater the losses, the more costly the energy is for a retailer to buy.

The Regional Reference Price (RRP) is the price of electricity at the Regional Reference Node (RRN), where there are 5 Regions (Qld, NSW, Vic, Tas and SA). The RRPs in different RRNs differ according to dynamic loss factors – where, in the absence of inter-regional flow constraints, the dynamic loss factor for an interconnector equals the ratio between the spot prices at the respective RRNs.

Thus, for a generator connected to the transmission network, the value of exported electricity is:

Value = RRP x MLF x MWh exported

For a generator connected to the distribution network, the value to the generator of exported electricity is:

Value = RRP x MLF x DLF x MWh exported

Wholesale customers must also pay for energy on the same basis using MLFs and DLFs that apply to their location.

CSP plant are likely to be in reasonably rural or remote locations, and so will be connected to points that are net loads and so have marginal loss factors greater than 1. This increases the value of generation according to the above formulas. Estimating the impact of the MLF on generation income is complicated by the fact that the connection of a generator will reduce the MLF at that point when the MLF is recalculated each year.[46]

It could be argued that this is something of a perverse outcome as the market signals are encouraging a generator to locate at that point, however the benefits of doing so are not captured by the generator, but rather by end users that source electricity through that point. One possible way to capture the value that would otherwise be lost is to co-locate with a large load (new or existing). This will reduce the cost of electricity for that load, and some of that benefit could be paid to the CSP plant via a negotiated payment for the MLF reduction. Where this is not possible, it may be appropriate for some sort of policy intervention that allows the CSP plant to capture some of this benefit. However, care would need to be taken to avoid creating market signals that distort the least-cost outcomes of the NEM, especially since other types of generators would likely seek similar treatment.

MLFs for the 2010/11 year ranged from 0.8436 (Wattle Hill Wind Farm, SA) to 1.1546 (Red Cliffs, Vic), however are generally within 5% of unity. DLFs are also generally within 5% of unity but for the 2010/11 year ranged from 0.921 (an embedded generator on Ergon Energy's network) to 1.251 (generic LV lines in Ergon Energy's network).

5.5.4 Capacity Value

The ability to provide capacity when required, and being credited with the ability to provide capacity, has lead to the general term 'capacity credit', as discussed below. The WA SWIS includes 'Capacity Credits' that have a very particular meaning, as discussed below.

Some key recent references have examined the general concept of the capacity value of a CSP system. Sioshansi et al (2010) offer a simple analysis of potential capacity credit, which assumes that installed CSP capacity can offset an equal capacity of gas turbine. An appropriate installed cost for this plus an 11% per year capital recovery factor results in a 25-40% increase in profit levels for a CSP plant.

Madaeni et al (2011) offer a highly technical in depth look at the capacity value of CSP plants. They quantify the extent to which the presence of a CSP plant can offset conventional generation such as peaking gas turbines. It is suggested that the capacity of the CSP plant should be defined as the equivalent capacity of conventional plant that can reduce the systems "Loss of Load Probability" (LOLP) by the same fraction.

A complex algorithm for evaluating the "Effective Load Carrying Capability" is presented as one of the most reliable methods. Comparative analysis was carried out using the SAM model for parabolic trough plant in high solar locations in 4 US states, Arizona, California, Nevada, New Mexico. Note that the analysis was for a single plant and assumes that the remainder of the generation mix in the system is essentially unchanged. A large penetration of solar could see the marginal capacity value of further additions reduced.

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46 If that point becomes a net generator the MLF will be reduced to be less than 1.

Initial analysis of no storage, solar multiple 1 plants indicated a capacity value of 45-60% of nominal output. This high value is taken as indicating that, as in Australia, many of the highest LOLP times are periods of exceptionally high cooling loads, with good correlation to direct solar insolation levels. Increasing the Solar Multiple to 1.5 increases the capacity value to between 65- 90%. This can be explained by the observation that the peak demands and highest LOLPs come later in the afternoon, and an increasing Solar Multiple allows a plant to achieve its nameplate output for longer into the afternoon. Interestingly, analysis of the same sites for different years gave very large unexplained variations, with some years showing low values. This deserves further investigation.

A key observation is that a simple analysis, based on the capacity of the plant during a mix of the top 10 hours in a year for load and or LOLP, provides a close but conservative estimate of the capacity value of the system. Addition of any more than 4 hours thermal storage took the capacity value close to 90% and close to 100% in many cases.

As a concept, capacity value is not necessarily a direct “value” per se, rather, it is an analysis that may be used to justify values that should be rewarded via ancillary services or avoided network costs for example. In some circumstances however, capacity value is rewarded explicitly, such as within the SWIS market in WA.

SWIS Reserve Capacity Mechanism

The NEM relies on high pool prices to ensure there should be sufficient generation capacity at any particular time, with the Value of Lost Load (VOLL) now capped at $12,500/MWh. In contrast to this, in parallel with the energy market, the WA SWIS uses the Reserve Capacity Mechanism (RCM) to ensure the ongoing operation of the WA electricity market.

The overall SWIS Reserve Capacity Requirement (RCR) is based on the expected maximum demand and includes a contribution to the system-wide reserve margin. Generators and providers of demand side management can commit to providing a certain amount of capacity when required (which is then their Reserve Capacity Obligation, RCO) and so earn Reserve Capacity Credits (RCCs). Market customers (eg. retailers) have an Individual Reserve Capacity Requirement (IRCR) meaning they have to purchase sufficient RCCs to cover their customer’s expected demand and reserve margin.

The Reserve Capacity Price is the price paid by the Independent Market Operator (IMO) for Capacity Credits not traded bilaterally and sets the price ceiling – see Table 5-11.

Table 5-11: Reserve Capacity Prices for the WA SWIS

Period	Price ($/MW/yr)
21/09/06 to 01/10/06	$127,500
01/10/06 to 01/10/07	$127,500
01/10/07 to 01/10/08	$127,500
01/10/08 to 01/10/09	$97,835
01/10/09 to 01/10/10	$142,200
01/10/10 to 01/10/11	$108,459
01/10/11 to 01/10/12	$144,235
01/10/12 to 01/10/13	$131,805
01/10/13 to 01/10/14	$186,001
01/10/14 to 01/10/15	$178,477

CSP systems would apply to the Independent Market Operator (IMO) to have their Reserve Capacity certified, after which they will be issued with a number of RCCs, which can then be sold on the market through a bilateral trade or through an IMO auction, if one is required. No CSP system has been built in WA to date, to test the proposition of elligibility. Note that RCCs are valid for only a particular Reserve Capacity Year, which is for a 12-month period starting from 1 October of the year two years hence.

The number of RCCs earned by a generator is calculated differently depending on whether it is classed as dispatchable or intermittent.

Dispatchable generators are required to offer the capacity (for which they have received Capacity Credits) into the market at all times (unless they are undergoing scheduled maintenance). A hypothetical generator that has all its capacity certified, and has received the associated Capacity Credits with, for example, a value of \$180,000/MW/yr would receive an extra \$20/MWh on top of a STEM pool price of approximately \$50/MWh, a significant increment. However a system can earn this income essentially by being available and reliable, without necessarily generating to a high capacity factor.

For example, a 100MW CSP system that received Capacity Credits for 90% of its nameplate value and had a capacity factor via storage of say 40%, would earn each year 0.9 x 100 x \$180,000 = \$16.2 million via Capacity Credits, and 100 x 0.4 x \$50/MWh = \$17.5 million from electricity sales. For a CSP system with storage, it is possible that it could be operated so as to always retain a few hours of energy in storage to qualify for such payments.[47]

Intermittent generators, such as CPV or CST without storage, now have a recently revised methodology for calculating the number of RCCs that can be earned (IMO 2010). The original methodology, which was based on three year average output, likely overstated the available capacity of wind and understated the capacity of solar. In summary, the new rule states that:

Number of Capacity Credits that are earned = (the average output by the generator during the top 12 Trading Intervals drawn from separate days from the previous five years) - (G X the square of the standard deviation of the generator's output during those peaks)

where G = K + U

K = initially 0.003 per MW

U = initially 0.635 / (average facility output during peaks) per MW

A more detailed discussion can be found in the IMO's Final Rule Change Report: Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO) and Methodology 2 (IMO 2011B) and in (Sapare 2011). The IMO is currently preparing a concise summary of the methodology for intermittent generators.

5.5.5 Off grid sites

For the off-grid or mini-grid market segments, there is no open market in operation; rather, individual PPAs would need to be negotiated on a case by case basis. In these segments, the main approach to generation is diesel, with gas used where it is available. Costs of energy from

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[47] Note that molten salt storage can retain energy for one to two weeks if it is not used. Molten salt tanks also have resistive electrical heaters fitted so they can be kept molten in the event of several weeks of zero input, these could provide a last resort way of meeting capacity obligations.

these sources is highly variable and dependant on the size of the system and fuel transport / delivery costs.

Evans and Peck (2011A & B) have examined the cost of large diesel and gas systems in the Pilbara and Mid West of WA, for relatively large (30 MW_e) systems. They estimate generating costs of approximately $285 to $300/MWh for diesel and 180 to $190/MWh for gas.

Most of this cost is fuel cost, with just a few percent flowing from the (relatively low) capital cost of the systems. Thus, effectively a CSP system with storage, should in principle be able to realise the same value in the market. Systems without storage can expect to realise only the avoided fuel cost component and so may expect slightly less.

In these markets however, the presence of systems with reliable energy storage may prove to be the essential pre-requisite for breaking into the market. The value of this storage is that it allows the CSP plant to operate more like a dispatchable diesel generator or gas turbine and so easier to integrate into the existing generators, or even replace them.

5.6 Broader Societal Benefits

There is a range of broader societal benefits that increased deployment of CSP could bring to Australia. These include industry development and associated capacity building in a globally expanding industry, employment (generally in regional areas), education and training opportunities, contribution of case studies to applied R&D, reduced non-GHG negative impacts, and regional tourism. These are discussed briefly below.

5.6.1 Industry development

Although Australia was one of the early global players in the development, manufacture and export of renewable energy technologies, over the past decade, international developments and market growth have now seen Australia fall well behind. Recent government support through the RET, carbon pricing and Solar Flagships is providing some support for CSP. Should this, and potentially other policies, be successful in driving CSP uptake, Australia will benefit from participating in the global clean energy market.

This global market has become a major economic driver, with more than US$188 billion invested in this sector in 2010, being more than half of the total spent on new power generation capacity worldwide (Clean Edge, 2011). In most countries, clean energy jobs are growing faster than jobs in conventional generation, and in some, including the US and Germany, clean energy jobs already dominate the energy sector.

5.6.2 Employment

Estimating the employment created through the deployment of renewable energy is not straightforward. As a general rule, there is a correlation between the cost of electricity produced by a particular technology and the number of jobs created per MWh ie. the money spent on paying for the electricity is transferred through into wages, so the more wages that must be paid, the more costly the electricity[48].

Thus, at a superficial level, more expensive renewables such as CSP create more employment than cheaper conventional fuels. However, at a macroeconomic level, the more expensive electricity reduces employment elsewhere in the economy – because people have less money to spend on other things. In addition, the employment may be created in Australia or overseas, and possibly in regional areas, which may have greater electoral appeal.

Although all the construction and O&M employment would occur in Australia, only a proportion of the manufacturing employment would, depending on whether manufacturing facilities are developed in Australia, which in turn depends on whether they are justified by the total level of deployment (one-off projects are unlikely to drive significant manufacturing) and export opportunities. However, it is worth noting that CSP frames and assemblies are manufacturing-intensive but hard to transport (for example compared to flat plate PV cells and panels) and so a greater proportion of manufacturing employment should occur in Australia.

A number of reports have been released that model the employment impacts of various policies to reduce greenhouse emissions and drive uptake of renewable energy in Australia. All indicate that at both the macroeconomic level and the energy sector level, employment is expected to significantly increase over the next 10 to 20 years. The caveat is that, all other things being equal, there will be slightly less employment than if emissions had not been

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[48] Correlation with employment levels is of course not the only strong correlation. Fuel costs are another major driver and are the reason for example the diesel fired generation is one of the more expensive options.

decreased (CSIRO, 2008; AMWU, 2008; CFEE, 2008; Access Economics, 2009a; MMA, 2009; CEC, 2009; MMA, 2009a; ACF/ACTU, 2010; AG, 2011).

There is a wide range of forecasts for the employment created by CSP plants. There will be significant variations depending on; project location, system size and technology type. Some indicative employment numbers for CST plant are given in Table 5-12. It appears that for plant in the 100 MW range, about 10 construction and manufacturing jobyears are created per MW. The O&M jobs seem more variable ranging from 0.2 jobs/MW up to 0.7 jobs/MW, with smaller plant having much higher employment.

CPV plant in Australia have been demonstration projects limited in scale and remote, and so there is no employment data for a large scale CPV plant. However, given the high performance equipment, it would be fair to assume that staffing levels would be of a similar order to similarly sized CST plants.

Table 5-12: Indicative employment multipliers for CST plant

Reference	Construction Job years / MW	Manufacturing Job years / MW	O&M Job years / MW	Notes
EREC 2008	6	4	0.3	
Rice 2009	9.33		0.7	This may include some manufacturing jobs
Richter et al 2009	10			Includes construction, manufacture, component supply, solar farm development, installation and indirect employment
AT Kearney, 2010			0.4 to 0.45	
Brightsource 2012	5		0.2	
DLR & Evonik, 2009			2.6	for a 15 MW plant, indicating the benefits of economies of scale

As the cost of CSP plant declines, so will the amount of employment created per MW. However the Australian jobs created per $ invested should remain relatively constant, and would increase if manufacturing occurred in Australia. It is reasonable to assume that, as occurred in Spain, the fraction of investment that remains in the domestic economy would grow with the size of our market.

For example, the Novatec solar assist array being installed at Liddell power station is using much more basic local manufacturing facilities compared to its 30 MW_e system in Spain. It is bringing in the mirror module components as unassembled flat packs from Spain. If they were building a large plant in Australia however, close to full local manufacture would be expected.

It is likely that CSP plant will be constructed in regional areas. Regions that actively support clean energy may get a much greater share of employment, with the potential to gain from both local projects and exports. Local employment can be maximised in a number of ways:

(i) Efforts can be made to capture more of a technology's value chain, for example by increasing Australian manufacturing content, which reduces imports and provides a basis for export industries, and

(ii) A focus on exports – including services such as international education – helps to expand market size which in turn helps local businesses achieve economies of scale that would otherwise not be possible via the relatively small Australian market

(iii) In the context of the proposed carbon tax and emissions trading scheme, targeted support for CSP projects will increase the amount of abatement that occurs in Australia, which reduces the need to buy international credits from overseas projects and so creates employment here,

This presents an opportunity to shift to clean energy and concurrently attract or train a new workforce skilled in new energy technologies. This in turn provides opportunities for existing or new training institutions.

5.6.3 Education and training

Both international and Australian experiences show that renewable energy requires the same types of general skills that are already present in the energy, construction and manufacturing sectors. Renewable energy creates jobs for a wide range of tradespeople and technicians, as well as engineers, IT and computer experts, scientists, architects, accountants, financiers and managers – not only during construction of new plant but also during operation and maintenance. Some additional skills will be required in more optimised jobs, so it is important to provide appropriate training and skills development.

Without a suitably skilled workforce, Australia will not be in a position to capitalise on increased demand for clean energy goods and services. This means training people that are entering the workforce, and also providing additional skills training for sectors likely to be impacted by the transition to a low carbon economy. New skills will be required at many levels, from installation of hardware and provision of 'clean energy' services through to upper management.

5.6.4 Contribution to applied R&D

Australia remains active in renewable energy research, with many universities, research centres and industries undertaking research and development in all aspects of solar, wind, bioenergy, marine and geothermal energy resource assessment and technology development. The construction and operation of CSP plants in Australia would provide valuable opportunities into applied R&D and encourage linkages between commercial players and research institutions. This would contribute to developments that would be very valuable for increased deployment under Australian conditions, but also lead to Australian IP creation that would apply in the global market place.

5.6.5 Reduced non-GHG negative impacts

Conventional generators such as coal and gas-fired turbines have a number of environmental impacts beyond the emission of greenhouse gases. These include acid mine drainage and dust from coal mines, deaths and injury of miners, water use and other airborne pollutants, especially sulphur oxides (SOx), nitrogen oxides (NOx), mercury (Hg), and particulate matter. Extraction of natural gas through fracking can also result in the release of methane and contamination of water aquifers.

5.6.6 Energy security

Energy security is the adequate, reliable and competitive supply of energy for Australia's industrial and domestic needs. The recent Australian energy security assessment rates the level of security in the electricity sector to be moderate over the short, medium and the longer term to 2035. This assessment reflects Australia's multiple energy options and resources. CSP is one of those options. Once a CSP system is installed, it offers a long-term energy source with very low supply, price, environmental, trade and sovereign risk. While security issues around future transport fuels are less certain for Australia, and although out of scope of this study, it is noted that CSP has significant long-term potential to contribute in this area also, both as a clean energy source for the electric vehicles becoming available now, and through the creation of CSP-generated liquid fuels.

5.6.7 Regional tourism

It is possible that large iconic CSP plant would provide tourist attractions in regional areas. This would provide an additional source of income into these areas.

5.6.8 Spain: A Case Study

Spain has been the location of the majority of the deployment activity in CSP in the last few years. The broader economic benefits of the CSP industry in Spain have recently been studied by Caldes et al (2009) and more recently by Deloitte (2011) in a key study of "Macroeconomic impact of the Solar Thermal Electricity Industry in Spain", commissioned by the Spanish Industry association Protermosolar. The following summarises key findings.

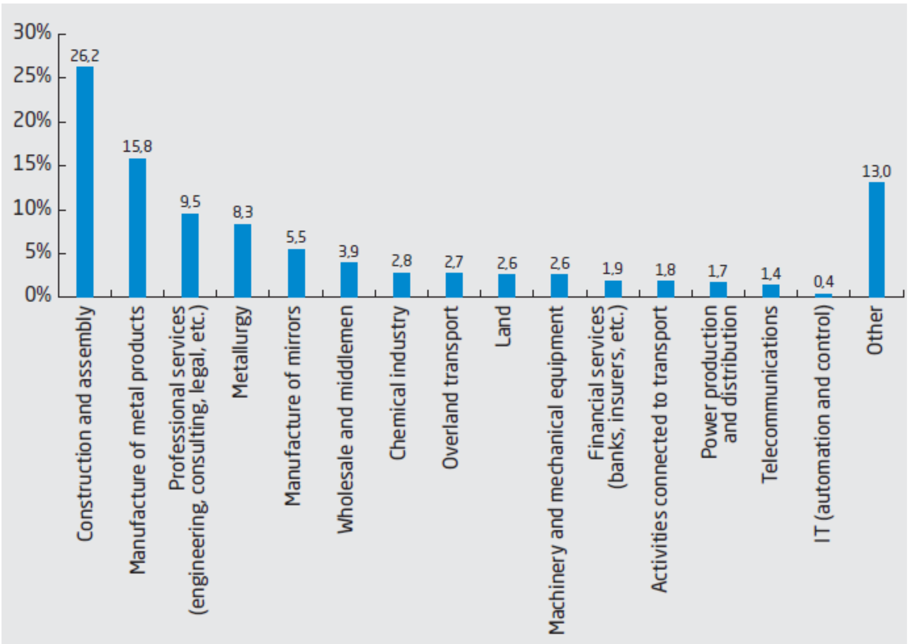

Figure 5-17: Contribution to GDP by different sectors during construction. Figure from Deloitte (2011).

The investment has resulted from generous for CSP plants that commenced in 2007. Since then, investment in the area has grown and contributed Euro 1.65billion to Spain's GDP in 2010 – a period when Spain was significantly affected by the global financial crisis.[49] Of this 1.65 billion Euros, it is reported that 89.3% was in construction and most of the remainder is for ongoing expenditure for operation and maintenance of completed systems, with 2.67% being for R&D.

[49] 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.

This activity was spread over a variety of sectors with about 70% of the investment remaining in Spain (Figure 5-18). 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.

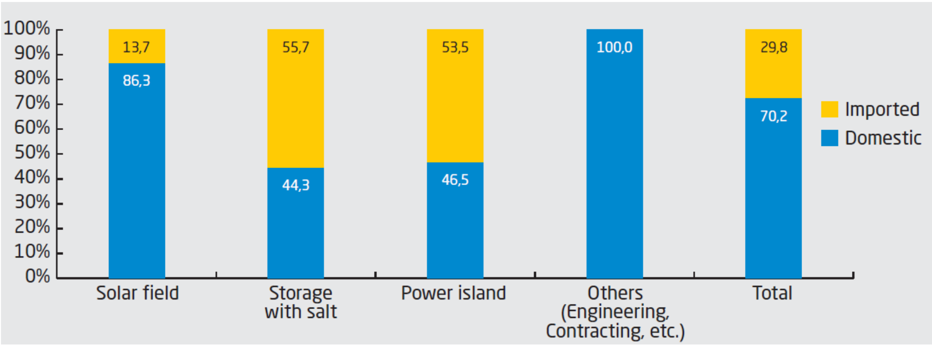

Figure 5-18: Percentage of investment which remains in Spain for CSP with storage. Figure from Deloitte (2011).

A total of 23,844 people were employed in 2010 according to the breakdown in Figure 5-19, and if the growth out to 2020 continues as per the current government targets, this figure is predicted to be maintained at approximately 20,000, with an increasing fraction of those being for ongoing O&M as installed capacity increases.

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**

Figure 5-19: Breakdown by industry activity of jobs created by the CSP Industry in Spain, 2008-2010 (Deloitte 2011)

Much of the employment in construction directly helped a sector most affected by the overall contraction. It is estimated that 176million Euro's in employment subsidies were offset in 2010 as a result.

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 the acknowledged world leaders in the field and in particular are projecting that dominant role into the emerging USA market.

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.

5.6.9 Option value of CSP

Public economics recognises the concept of 'option value', and it applies well to the nascent CSP sector in Australia (see for example Nicodemus 2010). Option value can be thought of as a form of insurance value: how much should one spend now to retain access to a future asset, given uncertain future developments. Option value rises with the likely future value of the asset, and rises with the cost of its replacement if lost. Though it was not in the scope of this study to attempt to quantify the option value of CSP in monetary terms, a qualitative analysis suggests that it is substantial.

Australia's emerging CSP sector is an asset that has two quite distinct future values:

- its potential to deliver the clean dispatchable energy that Australia needs;
- Its potential to offer Australia a significant place in the future clean energy supply chain.

Regarding the first point, the other likely technologies– such as geothermal, and fossil-fuel generation with carbon capture and storage – carry significant technical risks and may prove more costly than proponents suggest. If they fail to deliver on expectations, it will take many years to build the CSP capacity that will be needed. Assuming the global CSP industry continues to progress on its current trajectory, it would be possible for Australia to make a decision to begin deployment at any future time, whilst it will be relatively easy to start that process, it would be unrealistic and probably economically inefficient to establish deployment at faster than around 40% per year, thus at least a decade would be needed before the technology would be making a significant contribution to the countries energy mix. CSP would be kept as a more rapidly available option via some early deployment and establishment and maintenance of capability. There is the further, possibly more significant, issue that it should not be automatically assumed that the global CSP industry progress can be taken for granted. It is currently dependant on policy settings in just a few countries and these are quite uncertain. Spain has already stepped back from its lead role as a consequence of its national financial issues. In this context, early action by Australia would have a material impact on the progress of the global industry and conversely the loss of option with no action could be much more significant than the Net Present Value of the possible extra costs of a decade long delay.

Early action will also retain CSP's second option value as a significant place for Australia in the future clean energy supply chain. At the moment, Australia has the option of having a significant stake in a highly valuable global clean energy supply chain – a stake we do not hold for other technically-sound clean energy alternatives. As other countries invest more in the CSP sector, the value of Australia's potential share in that asset falls. Conversely, if insufficient countries invest, the value of the CSP sector relative to other options is eroded. Accordingly, the option value of our CSP asset cannot long be preserved. This option value also potentially extends into the realm of the solar fuels for export scenario. Australia has a high economic dependance on coal and gas export income and a high exposure to the cost of oil imports. Coming decades are certain to see changes and possibly in unpredictable ways. Developing the CSP option arguably has a value that is at least a small fraction of current annual turnover in these areas.

5.7 Summary of Value by Configuration

The various sources of value (with the exception of option value) are summarised in the tables presented here. Noting that the market segment categories identified in Chapter 4 were for assessing technical potential, the presentation below makes a distinction that differs, particularly given the different market structures in the WA SWIS compared to the NEM. It is also split in each case to consider plants with no storage and plants with significant storage (ie approximately 6 hours or more).

For systems that are hybridisations with fossil fuelled power plants, either the same value as a no storage CSP plant is produced if the fossil plant is designed for intermediate / peak, or for hybridisation to an existing baseload coal plant, the value could be limited to REC plus avoided fuel cost only.

Large systems on NEM

Table 5-13: Value of large CSP generation.

Contributor to value of energy	Value for CSP with no storage	Value for CSP with significant storage	Future Trend / comment
Basic average energy price	$43/MWh	$43/MWh	Depends on state, future trend upward
Increment for CSP	$19	$44	Varies
REC	$40/MWh	$40/MWh	Future trend uncertain
Ancilary services	0	$0 to $0.8	Estimate, future trend depends on generation mix, may grow. Depends on which services plant chooses to participate in
TOTAL recognised in market place	**$102/MWh**	**$128/MWh**	
Avoided line losses	$0 -$2	$1 - $5	Varies depending on generator's impact on MLF and DLF
Avoided grid augmentation	-$2 - +$2	-$5 - +$5	
TOTAL overall Value	**$100 - $106/MWh**	**$125 - $138**	Depends on location

The value of dispatchable solar energy is higher than intermittent renewable energy due to the ability to optimise revenue by considering forecast weather and prices.

Small systems connected to distribution system in NEM

Table 5-14: Value of Small CSP generation.

Contributor to value of energy	Value for CSP with no storage	Value for CSP with significant storage	Future Trend / comment
Basic average energy price	$43/MWh	$43/MWh	Depends on state, future trend upward
Increment for CSP	$19	$44	Varies
REC	$40/MWh	$40/MWh	Future trend uncertain
Ancilliary services	0	$0.8	Estimate, future trend depends on generation mix, may grow
TOTAL recognised in market place	**$102/MWh**	**$128/MWh**	
Avoided line losses	$0 -$4	$2 - $10	Not currently rewarded
Avoided grid augmentation	$0 -$4	$2 - $10	Not currently rewarded
TOTAL overall Value	**$102 - $110/MWh**	**$132 - $148**	Depends on location

Systems in SWIS

Table 5-15: Value of CSP generation in the SWIS

Contributor to value of energy	Value for CSP with no storage	Value for CSP with significant storage	Future Trend / comment
Basic average energy price	$50/MWh	$50/MWh	Depends on state, future trend upward
Increment for CSP	$8	$16	Varies
REC	$40/MWh	$40/MWh	Future trend uncertain
Capacity credit	0	$46	
Ancilliary services	0	0	Estimate, future trend depends on generation mix, may grow
TOTAL recognised in market place	**$98/MWh**	**$152/MWh**	
Avoided line losses	$0 -$2	$1 - $5	Not currently rewarded
Avoided grid augmentation	$0 -$2	$1 - $5	Not currently rewarded
TOTAL overall Value	**$98 - $102/MWh**	**$154 - $162**	Depends on location

Off-grid / mini-grid

Table 5-16: Value of CSP generation in mini-grids

Contributor to value of energy	Value for CSP with no storage	Value for CSP with significant storage	Future Trend / comment
Basic average energy price	$300 to $400 / MWh	$300 to $400 / MWh	Depends on location and load size, future trend upward
Increment for CSP	-$50	$0 to $10	Intermittent systems avoid fuel cost only and are further penalised in market place
REC	$40/MWh	$40/MWh	Future trend uncertain
TOTAL recognised in market place	**$290 to $390 / MWh**	**$340 to $450 / MWh**	
Ancillary services	0	Wide range feasible	
Avoided grid augmentation	0	0	Relevant if a grid extension planned
Increment to REC based on Remote Solar Credits	Varies	Varies	Remote Solar Credits phase out and other REC value mechanisms are feasible.
TOTAL overall Value	**$290 to $390 / MWh**	**$340 to $450 / MWh**	Depends on location and does not include unrecognised values due to wide range feasible.

5.8 Correlation of solar resource and locational value of the electricity

The locational value of CSP electricity is determined by a number of factors:

- the solar insolation (the direct component);
- the availability of suitable land;
- the remoteness of the location;
- the availability of suitable networks to connect to the grid;
- the cost of connecting to the network;
- the capacity of the network to accept the CSP output;
- the relevant Regional Reference Price (RRP) or price of locally provided electricity (on off-grid or mini-grid sites);
- the relevant Marginal Loss Factor (MLF) and the Distribution Loss Factor (DLF) and the impact that construction of the CSP plant will have on them;
- the proximity of any loads, and whether they are open to passing on any MLF or DLF benefits to the CSP plant; and
- the proximity of a section of the network that requires augmentation, how soon that augmentation is required, whether the CSP output correlates with the forecast annual peak load, and whether the NSP will reward the CSP plant.

In addition, larger CSP plants are likely to be more economic than smaller ones. Thus, it is no simple task to correlate these various factors and so identify the best sites. However, some broad conclusions can be drawn.

Australia's best solar resources are inland and in the north-west, while the main grid coverage and population centres are on the east and south-east coasts. Figure 4-1 shows contours of average Direct Normal Irradiance across the continent, with transmission lines and power stations superimposed. It is apparent that the grid, both NEM and SWIS, extends far enough inland that its inner most reaches access areas with very good solar resources by world standards, even if they are not the highest the continent has. Australia's large coal fired power stations are a subset of those power stations shown that are clustered around the coast. The inland power stations shown are incomplete but do indicate some of the more significant large off grid / mini grid locations.

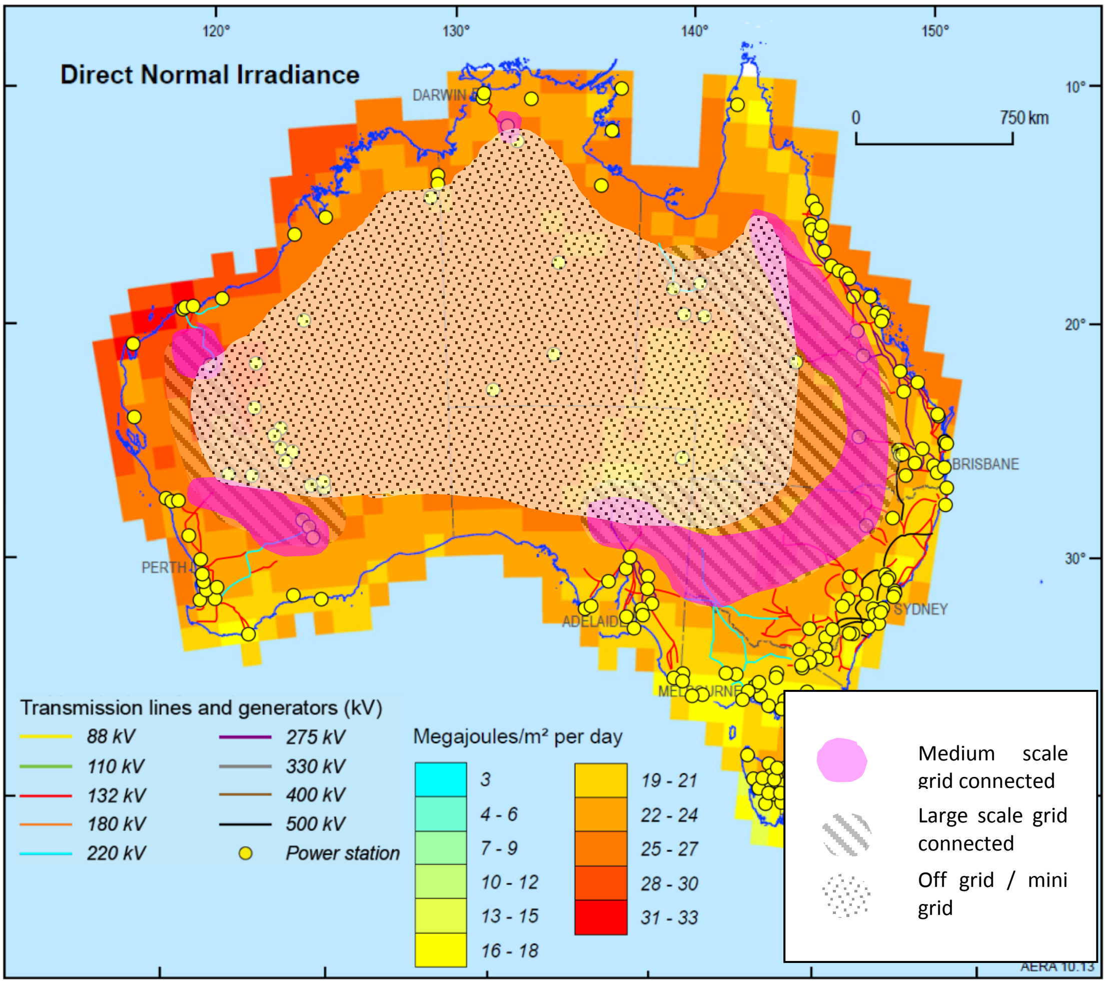

Figure 5-20: Location of market segments relative to Transmission system and DNI resource (Figure produced by combining two figures from Commonwealth of Australia (2010)).

Figure 5-20 adapts Figure 4-1 to illustrate indicative potential locations for CSP systems that might be classified as medium scale grid connected, large scale grid connected and off grid/ mini grid. Whilst it should be emphasised that the regions are purely indicative, the principle applied are:

- No systems are likely to be built below about 32^{o} South
- No systems are likely to be built less that 200km from the coast in cyclone zones
- Medium scale grid connect should be within reasonable proximity to the current limits of the distribution network
- Large scale grid connect can be contemplated further inland on the assumption that plausible strategic transmission extensions are developed.

Ultimately, if the large-scale grid-connected market is the largest segment that must be targeted, it will need to deal with the issues and costs associated with transmission from inland to coastal load centres.

It is possible that CSP plant near the fringes of the grid may benefit from high MLFs and DLFs which would make them more economic. Being rewarded for the deferral of network augmentation would further improve economics.

Although the greatest value of CSP energy is clearly in off grid and mini grid markets and these are indeed in many cases in the highest possible solar resource areas, CSP plant in these locations suffer from lack of scale, and there other key barriers in this segment.

Whilst SA has 10-15% less DNI than Qld, current indications are that the value that can be realised in that state is higher by a similar or higher margin.

6 Cost of Energy Compared to Market Value

6.1 Levelised Cost of Energy

Key metrics in considering the economic performance of any energy technology are the Levelised Cost of Energy (LCOE) generated or the Internal Rate of Return (IRR) for investors. This is forecast from estimated capital costs plus ongoing cost of inputs (O&M, fuels, debt servicing and other variable inputs). 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 smaller generator for a longer time with the same 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, particularly labour and other inputs, are country specific. The best approach for an indicative conversion would be to compare the relative costs of a technology produced at scale in two countries and that has similar inputs and manufacturing intensity to CSP systems.

Going beyond this, it should be noted that, while in Spain and the USA the CSP industry is reasonably established and starting to progress down a cost curve, 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.

6.2 LCOE Methodology

A definitive description of methodologies for the financial analysis of energy systems is available from NREL (Short et al 1995). In the 2012 Australian electricity market, CSP generation technologies are not likely to be profitable, thus evaluating Internal Rates of Return has little value.

More appropriate is to consider the Net Present Value (NPV) over the lifetime of hypothetical projects, subject to variations in configuration and input cost structure and variations in possible sources of income. In doing this, it is of interest to seek out configurations for which the overall NPV is least negative at the present time. Such configurations are the ones that will likely become profitable the soonest as capital costs reduce over time. They are also the configurations which would incur the least immediate economic cost if policy measures were adopted to lift them to profitability in order to establish a CSP industry in Australia.

The basic formula for evaluating 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 rate[50]. Cash flows can be measured in either nominal or real (independant 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 ancilliary 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.

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50 This is the most commonly recognised form or 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).

$$LCOE = \frac{NPV(lifecycle\ \cos ts)}{\sum_1^N \left(\left(annual\_generation \times (1-T)\right) \big/ (1+DR)^j \right)}$$

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. In many cases, the methodology is actually intentionally withheld as it is embodied in proprietary financial models.

This study has adopted a methodology which is somewhat simplified but has sufficient complexity to allow issues of tax, cost of equity and cost of debt to be examined.

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:

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

Where:

P is the nameplate capacity of the system

F_c is the capacity factor

C_o 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.

6.2.1 Financial parameters for baseline

Whilst sensitivity analyses are presented, this study has chosen to adopt a set of baseline financial parameters that aspire to represent realistic numbers for commercial development of systems in the hypothetical situation of a mature industry with similar risk levels to established energy technologies. Real dollar LCOE's are the baseline calculation, although some nominal dollar values are included for comparison.

Specifically:

Cost of equity and cost of debt: The cost of equity and cost of debt are taken from the Australian Energy Regulator's final decision on the NSW Distribution Determination 2009 (AER 2009) and are as follows:

- Nominal pre tax return on equity: 10.29%
- Nominal pre tax return on debt: 7.78%.

Debt share: 60%

Inflation: 2.5%, the middle of the RBA's current target inflation band.

Loan term: 15 years, obtained from discussions with a major bank.

Depreciation period: 20 years. ATO TR 2011/2 (ATO 2011) states that thermal electricity generation is divided into components which have depreciation lives of 15, 25 or 30 years.

System life: 25 years. In the past, CSP systems have been evaluated with 20 year assumed lifetimes. With the Californian SEGS plants now operating continuously for over 20 years and clearly capable of continued cost effective operation, it is not unreasonable to extend this economic lifetime to 30 years, thus 25 years is taken as a conservative assumption.

Residual value: 5% of capital cost. An approximate assumption based on the possibility that systems could still be workable and upgraded after 25 years.

Tax: 30%, applied to energy produced and deductibles at standard corporate rate.

These values can be compared with quoted information from various studies in Table 6-1.

Table 6-1: Financial parameters for LCOE calculations quoted in some past studies.

Reference	Nominal cost of debt	Nominal cost of equity	Debt fraction	Inflation	Tax	Depreciation period (years)	System Life (years)	WACC
Cameron and Crompton 2008		9.50%	0.00%	2.50%	30%		20	9.50% nominal
Sargent and Lundy 2003	8.50%	14.00%		2.50%	40.2%	5	30	
EPRI 2009						15	30	5.90% real
Acil Tasman 2009	8.00%	16.50%	60.00%	2.50%	30%			9.48% post tax nominal
Hinkley et al 2011							20	7.00% real?
AECOM 2010	7.72%	12.32%	60.00%		30%			9.60% post tax
Parsons Brinkerhoff 2010	9.00%	15.00%	65.00%	2.50%	30%	20	30	6.68% real?

In addition to the "commercially mature business perspective" baseline, it is illuminating to highlight the idea of LCOE calculations based on a "tax free societal perspective". This would seek to represent the circumstances of a major government financed initiative, such as is representative of the manner in which much of the country's infrastructure was established in earlier years.

AECOM report that the average Australian Government 10 year bond rate from January 1998 to December 2007 was 5.72% (nominal). This predates the global financial crisis and is suggested by them to be a good "risk free" rate for long term evaluations. This value has been used, together with an assumed 2.5% inflation rate, to give a societal real discount rate of 3.14%.

6.3 Current Capital Cost Structure

The key input to an assessment of the economic performance of CSP systems is establishing the current installed cost and understanding the parameters that affect it, between different possible projects.

Being at an early stage of commercial maturity, reliable cost information for CSP technology is difficult to locate. Every completed system has a cost structure known to the developers, some of this cost information has been shared publically and some has not. Only some of the most recent projects can claim to have moved from demonstration to early commercial classification, so even specific project cost data, where available, must be treated with care.

Clearly, every major project developer and technology supplier has done detailed bottom up studies of a range of projects and scenarios. However, these studies are commercial proprietary information.

There are a range of public domain reference sources that quote values on installed costs, these can be classified as:

1. Definitive bottom up studies
2. Derivative work that borrows and adds from other studies
3. Simple reproduction of results from other studies.

For this study, it is of value to consider category 1 sources, plus category 2 sources that seem most relevant to Australia.

The flat-plate PV sector often quotes a single metric – the cost of installed capacity, $/Watt. For CSP, the convention is also to quote the cost of installed capacity, ($/kW$_e$ or m/MW_e$). However, this is not a good metric for comparing the costs of systems with different capacity factors or different dispatchability capabilities.

The cost of installed peak capacity ($/W) is not a good metric for comparisons. The cost of installed peak capacity is of little use without an associated value for Capacity Factor and / or hours of storage and Solar Multiple. CST systems can be configured with varying amounts of solar field capacity per unit output of the power system. This is quantified by the Solar Multiple, which is the factor by which the field is oversized beyond the minimum needed to run the power block at nominal load at design conditions. Addition of storage allows for the possibility of a large field to provide energy to storage for later operation of a relatively smaller Power block. Such a configuration will have a consequently higher installed Cost per unit of capacity. It will, on the other hand, result in a higher capacity factor and it is the ratio of installed cost / capacity factor that is the key determinant of LCOE.

Table 6-2 brings together quoted installed costs from a range of international sources, largely for US or Spanish locations. Various parameters for the systems to which the cost estimates apply are listed. For an initial assessment, USD and Euro values have been converted to AUD with single approximate exchange rates of 0.9USD/AUD and 0.65Eur/AUD respectively. These are chosen to reflect an indicative long term average rather than the present values with a strong Australian dollar. In choosing these values, it is intended in part to compensate for higher than historical regional labour costs in Australia that would appear to coincide with the current high value of the AUD.

Escalation to 2011 has been calculated using a single average figure of 2.5% pa. There is a clear correlation between installed cost per kW_e and capacity factor. To place the numbers on a standard basis, the final column presents values "normalised" to a capacity factor of 20%[51], this being an approximate capacity factor for a solar technology with no energy storage.

It can be seen that the resulting values still show a very large variation. The variation is so large that year to year effects cannot be deduced. Most data is trough system related, and it is not possible to identify any particular trend with technology type. Nonetheless, the average value provides an indicative value for CST systems in Europe or USA.

Table 6-3 collates in the same way, data that has been published following some level of specific analysis of construction in Australia. It also shows wide variations and ends with an average number that is higher than the Europe / USA context.

Note in both tables, yellow cells denote assumed rather than directly quoted values.

51 The value has been divided by the actual capacity factor and then multiplied by 20%.

Table 6-2: CSP Installed costs quoted for international installations

Year	Reference and Location		Size	Store	Cap. factor	Cost and Currency		2011 AUD	Norm. 2011 AUD
			MW$_e$	Hours	%	Per kW$_e$		\$/kW$_e$	\$/kW$_e$
2003	Sarjent and Lundy (2003), SEGS VI, California	USA	30	0	20%	3,008	USD	4,072	4,072
2003	Sarjent and Lundy (2003), Trough 50 near term	USA	50	3	30%	4,816	USD	6,520	4,347
2003	Sarjent and Lundy (2003), Solar Tres Tower	USA	15	5	40%	9,090	USD	12,306	6,153
2007	Wyld group 2008, Quotes the Andasol 1 project	USA	50	7.5	45%	5,230	AUD	5,773	2,566
2008	EPRI (2009) US,	USA	50	0	20%	4,851	USD	5,804	5,804
2008	EPRI (2009) US,	USA	50	6	40%	6,300	USD	7,538	3,769
2009	Tonopah Solar (2009), estimate based on \$700-800M USD Tower	USA	100	8	60%	7,500	USD	8,755	2,918
2009	Kutscher 2010 , Trough roadmap, based on Turchi 2010	USA	100	6	47%	8,250	USD	9,631	4,098
2009	Turchi 2010, SAM trough ref plant	USA	100	6	47%	8,950	USD	10,448	4,446
2010	Wright and Hearps (2010), Cresecent dunes tower project translated to AUD	USA	100	8	60%	10,500	AUD	10,763	3,588
2010	Hearps and McConnell 2010, Quoting DOE tower roadmap for 2013 .985AUD/USD	USA	100	6	40%	7,540	AUD	7,729	3,864
2010	Kolb 2011, Tower roadmap	USA	100	9	40%	7,400	USD	8,428	4,214
2010	IEA 2010A good site, Good site	USA	50	8	45%	8,400	USD	9,567	4,252
2004	Pitz Paal 2004, trough	Spain	50	3	29%	3,530	Euro	6,455	4,530
2010	Richter et al 2009 , trough Average Spain site	Spain	50	0	20%	3,800	EUR	5,992	5,992
2010	Hinkley et al 2011, Based on Ecostar converted to AUD at original date and escelated to 2010, trough	Spain	50	3	29%	6,600	AUD	6,765	4,747
2010	Hinkley et al 2011, Based on Ecostar converted to AUD at original date and escelated to 2010, tower	Spain	51	3	33%	6,494	AUD	6,656	4,034
2010	IEA 2010 aver site, Average site	Spain	50	0	20%	4,200	USD	4,783	4,783
2011	Gemasolar tower	Spain	17	15	75%	14,000	Euro	21,538	5744
	AVERAGE		**63**	**5.2**	40%			**8,429**	**4,360**

Table 6-3: CSP installed cost estimates for Australia

Year	AUSTRALIAN	Plant size MW$_e$	Store hours Hours	Cap. factor %	Cost $/kW$_e$	2011 AUD $/kW$_e$	Norm. 2011 AUD $/kW$_e$
2007	Wyld group 2008, MMA analysis based on Sargent and Lundy and Simons, trough 0.89USD/AUD assumed	150	7	56%	4,320	4,768	1,703
2008	Cameron and Compton 2008, Study for ACT CPV	30	0	20%	8,525	9,180	9,180
2008	Cameron and Compton 2008, Study for ACT, trough, 0.9AUD/USD used	22	5	42%	4,600	4,954	2,359
2009	Parsons Brinkerhoff 2009, Full costing CCI inputs, trough	250	1	21%	7,688	8,077	7,693
2009	Parsons Brinkerhoff 2009, Less Grid and water connection, trough	250	1	21%	5,988	6,292	5,992
2009	Parsons Brinkerhoff 2009, Full costing CCI inputs, trough	250	1	21%	7,715	8,106	7,720
2010	Hinkley et al 2011, Reporting numbers for a "developer"	50	3	23%	7,501	7,689	6,686
2010	Hinkley et al 2011, Aurecon analysis for Australia nth plant, tower	100	0	20%	4,158	4,262	4,262
2010	Hinkley et al 2011, Aurecon analysis for Australia nth plant, tower	100	6	40%	4,890	5,012	2,506
2010	AECOM 2010, Based on S&L, trough	100	0	20%	4,800	4,920	4,920
2010	AECOM 2010, Based on S&L, trough	100	0	20%	4,900	5,023	5,023
2010	Hearps and McConnell 2010, Quoting AEMO	50	0	20%	6,410	6,570	6,570
2011	Evans and Peck 2011, WA Renewable Energy assessment - Mid West, trough	150	0	21%	6,000	6,000	5,714
2011	Evans and Peck 2011, WA Renewable Energy assessment - Mid West, trough	150	6	34%	9,750	9,750	5,735
2011	Evans and Peck 2011, WA Renewable Energy assessment - Pilbara, trough	150	0	21%	6,200	6,200	5,905
2011	Evans and Peck 2011, WA Renewable Energy assessment - Pilbara, trough	150	6	34%	10,000	10,000	5,882
2011	Solar Dawn, AREVA Fresnell	250	0	20%	4,800	4,800	4,800
	AVERAGE	**135**	**2.1**	27%		**6,565**	**5,450**

Overall installed costs are made up of land, component and construction costs, plus a range of indirect costs, such as project management, approvals, finance and insurance etc.

There have been several detailed definitive studies of the fractional breakdown of direct installed costs for tower and trough systems. This is an area in which there seems to be a reasonable consensus. Table 6-4 summarises the results of four sources for the fractional breakdown of direct installed costs for Tower systems.

Table 6-5 summarises the results from five sources for Trough systems.

Table 6-4: Estimates of fractional installation cost breakdown for Tower systems

Subsystem **(descriptions, with overlapping categories to match different refs)**	**Sarjent and Lundy (2003) Solar Tres**	**Tonopah Solar (2009), Salt Tower 100MWe, 500GWh/a**	**Hinkley (2011), 100MWe plant in Australia 6 hours storage**	**Sandia (Kolb et al 2011), 100MWe plant, 9 hours storage,**
Heliostat field	43.0%	_	40.0%	36.2%
Receiver	_	_	2.7%	_
Receiver system	18.0%	_	_	19.6%
Receiver, Tower, Salt tanks and heliostatst	_	30.0%	_	_
Structural	_	10.0%	_	_
Tower and piping system	4.0%	_	4.0%	_
Piping and instrumentation	_	11.0%	_	_
Thermal storage system	8.0%	_	5.8%	12.7%
Steam generator system	2.0%	_	5.8%	4.5%
Electric power generation system	13.0%	_	13.0%	18.1%
Steam turbine generator and steam generation	_	18.0%	_	_
Structures and improvements / buildings	4.0%	2.0%	_	_
Cooling system	_	6.0%	11.4%	_
Control system	2.0%	_	2.8%	
Miscellaneous process equipment	_	7.0%	_	_
Electrical Instrumentation	_	9.0%	5.0%	_
Civil and site work	_	2.0%	8.4%	_
Mechanical utilities	_	5.0%	_	_
Fire services	_	_	1.1%	_
Balance of Plant	6.0%	_	_	_
Other	_	_	_	8.8%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Table 6-5: Estimates of fractional installed cost breakdown for Trough systems

	Kistner and Price (1999), based on SEGS, no storage	Sarjent and Lundy (2003), 100MWe 12 hours storage, 2.5 solar multiple	Pitz Paal et al; (2004) 1.4 solar fraction 3 hours storage,	IEA (2010A), 50MW with 7 hour storage	Kutscher (2010), 100MWe, 6 hours storage also see Turchi (2010)
Solar Field	**53.3%**	**51.6%**	**61.4%**	**44.8%**	**46.4%**
Mirror		*11.0%*			*7.6%*
Receiver Tubes & Fittings		*11.6%*			*11.1%*
Metal support structure		*16.8%*			*12.5%*
Drive		*3.5%*			
Foundations		*2.3%*			*2.8%*
Inst & Controls & elec		*4.1%*			*2.3%*
Other civil works		*2.3%*			
Field Installation					*9.8%*
Misc. Collector Components					*0.3%*
Heat Transfer Fluid System	**8.7%**	**9.3%**		**7.5%**	**14.4%**
Steam gen of HX system		*3.0%*			
Piping		*4.6%*			*7.9%*
Heat transfer fluid		*1.7%*			*3.5%*
Other					*3.0%*
Thermal Storage System	**0.0%**	**23.0%**	**9.6%**	**13.4%**	**27.0%**
Pumps & Heat Exchangers					*5.6%*
Tanks					*8.2%*
Storage Fluid					*11.8%*
Other					*1.3%*
Power Block & Balance of Plant		**14.0%**	**26.5%**		**12.2%**
Power Block	15.2%			7.5%	
Balance of Plant	8.7%			11.9%	
Site Works and Land	**14.1%**				
Structures and improvements		2.0%		10.4%	
Land			2.4%		
Grid Access				4.5%	
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

In each case it can be seen that, whilst there is a level of variation, a large component of this is associated with variation in the definitions of categories. Underlying this is a general pattern of agreement.

For tower systems, the “solar field” category is essentially the heliostat field, whereas for troughs, the solar field category includes the receiver tubes. If a general definition of “Solar field" as excluding receiver components is adopted along with a "Receiver and Heat Transfer Systems" category that is applied to either troughs or towers and taken to include for troughs; receiver tubes, HTF and piping and for Towers; Receiver, Tower and HTF handling in tower, it appears that the fractional breakdown is virtually the same between the two system types.

Considering all the data presented and the variations in storage hours of the systems studied, it is concluded that, for the purposes of this study, that the overall fractional breakdown of direct costs for a plant with approximately 5 hours of storage[52] is as shown in Table 6-6:

Table 6-6: Synthesised estimate of fractional capital cost breakdown for 2011 CST plants of around 100MW$_e$ capacity with 5 hours of storage .

Subsystem	Fractional cost
Concentrator field (excluding receivers and HTF)	36%
Receiver / Transfer System (including receiver/s HTF, piping, Tower as appropriate)	22%
Thermal Storage System	18%
Power block	15%
BOP and Other	9%
Subtotal	100%

Note that, in doing such a combined categorisation, this makes no comment on the relative costs per unit area of solar field implemented with different technologies. Proponents of Fresnel plants argue that their technology has lower cost per unit area and proponents of dish systems argue they are higher cost but higher efficiency. Both LFR and dish are less commercially mature and slightly higher up their ultimate cost curve. Thus overall it can be argued that the fractional breakdown above is a good rule of thumb representation of the cost structure of any contemporary CST system with a distributed field, central storage plus generation power block.

Indirect costs have recently been quoted as equivalent to 25.8% of total costs by Sandia (Kolb et al 2011) for Tower plants and 20% for trough plants by Kutscher (2010). These are reasonably consistent, so a value of 20% for a 100MW system with storage is assumed in this report. This seems the best reflection of current industry status for proven technology. The assumption is made that indirect costs attribute in proportion to underlying subsystem costs, thus the fractional breakdown above holds either before or after indirect costs.

To establish a baseline installed cost estimate for Australia, the study team was informed by the data cited in the tables above, plus confidential briefings from key stakeholders including several major project developers with a track record of CSP system development in Europe and USA. This was used together with the deduced fractional distribution of cost in Table 6-6. Noting the large variations and uncertainty, the assessment reached is that a notional representative CSP system at around 100MW$_e$, could be costed at a good Australian site in 2011 using the costing coefficients as shown in Table 6-7.

[52]Five hours is simply an approximate average value of quoted studies in order to understand the fractional cost contributions, it is not implied as a preferred choice for a plant configuration.

Table 6-7: Estimated costs for a notional approximately $100MW_e$ capacity CST system with storage in Australia (AUD 2012).

Subsystem	Per unit cost	Note / unit
Concentrator field (excluding receivers and HTF)	402	$/kWth capacity, delivered to power island at design point
Receiver/ transfer system (including receivers, HTF, piping, Tower as appropriate)	246	$/kWth capacity, delivered to power island at design point
Thermal Storage System	80	$kWhth of installed thermal energy storage capacity
Power block	882	$/kW$_e$ output capacity
BOP and Other	529	$/kW$_e$ output capacity
Indirect project costs	25%	Of subtotal of others (=20% of total)

These numbers are only accurate to an estimated +/- 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.

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.

Whilst the data that informed this determination are weighted towards proven trough system costs, it is valid within its accuracy limits for any CSP system, trough, tower, Fresnel or dish, which is based around a central steam turbine power block. It may be that, as time progresses, other technologies than trough grow market share and are able to offer kWth to the power island at lower cost. It is also quite likely that, as the industry matures, there will be a greater divergence in conversion efficiency based on temperature at the power block, in which case a single price for kWth of capacity would not be a good model.

A major area of uncertainty is the appropriate ratio of construction price index between Australia and USA or Spain. Opinions vary on this with some holding views that between USA and Australia, an exchange rate conversion is appropriate, with others holding a view that construction in real terms is more expensive in Australia. US costs depend on whether union or non union labour rates are assumed. As noted in the discussion of Table 6.2, use of historical rather than current exchange rates was intended to capture to some degree, higher Australian cost of construction relative to the USA at the present time.

in by Using these established cost factors, examples of specific capital costs of systems are shown in Table 6-8.

Table 6-8: Examples of specific CSP system costs for $100MW_e$ central power block systems

	No storage (lowest capital cost)	2 hours storage (approx min LCOE)	5 hours storage (earns higher value)
Configuration	100 MW_e block, 350 MW_{th} field, 38% block net effic 0 MWh_{th} storage 21% capacity factor at 2,400 kWh/m^2/year	100 MW_e block, 395 MW_{th} field, 38% block net effic 526 MWh_{th} storage 30% capacity factor at 2,400kWh/m^2/year	100 MW_e block, 526 MW_{th} field, 38% block net effic 1316 MWh_{th} storage 40% capacity factor at 2,400kWh/m^2/year
Concentrators	$1,405	$1,588	$2,117
Receiver / transfer	$858	$970	$1,294
Storage	$0	$423	$1,058
Power Block	$882	$882	$882
BOP & Other	$529	$529	$529
Indirects	$979	$1,142	$1,470
Total specific installed cost (AUD 2012)	**$4653 / kW_e**	**$5534 / kW_e**	**$7350 / kW_e**

For Stirling engine and CPV cases, the technologies are at such an early stage of commercial development and so diverse that it is very hard to identify any meaningful cost numbers. Arguably the concentrator component and the indirect cost component should be close to the same as the thermal systems of the same size. Thermal storage does not apply, energy conversion and receiver systems are the largest unknown. Interestingly, what numbers that can be deduced via informal discussions suggest that close to the same current market cost of Power conversion and BOP applies, although at much smaller system sizes.

Thus the rule of thumb costing basis in Table 6-8 is taken as the starting point, for the analyses that follow, as applicable to all CSP technologies for Australian conditions at the start of 2012.

6.3.1 Effect of temperature on storage.

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:

Thermal Storage System $((T_h-T_c)/150) \times 80\$/kWh_{th}$

These rule of thumb sub system cost estimates provide the basic building blocks for an examination of LCOE from a variety of plant configurations. It should be noted that a further caveat is that actual costs have functional dependencies on a range of parameters that are not captured here, so that the further a CSP configuration deviates from the configuration assumed in establishing the rule of thumb numbers, the less it should be trusted.

6.3.2 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 (2011) suggest a typical 50 MW_e Spanish plant has a total of 47 fulltime equivalent jobs per year during operation. Podewils (2008) notes that Andasol 1 has 40 people, with O&M costs of 0.072 Euro/kWh. Suggests a 250MW CSP system could cut O&M costs to 0.02 Euro/kWh. Kolb et al (2011): quote a 2013 O&M contribution to LCOE of 1.8c out of a 15c total, dropping to 1.3 in 2017 and 1.1 in 2020 Kutscher etal (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 the purpose of this study and an Australian context, 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.

6.3.3 Plant size effects.

The size of a system significantly affects the capital cost per installed capacity. There is considerable discussion of this issue within the international community. Much of this stems from the somewhat arbitrary 50 MW_e system size limitation in the Spanish Feed in tariff rules and the suggestion that lowest energy costs would come with a plant size around 250 MW_e.

Morse (2009) offers the Abengoa perspective on size effects in Figure 6-1, without saying if it is LCOE or capital cost although it appears to be LCOE that is discussed. 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.

Figure 6-1 is consistent with AT Kearney (2011), 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.

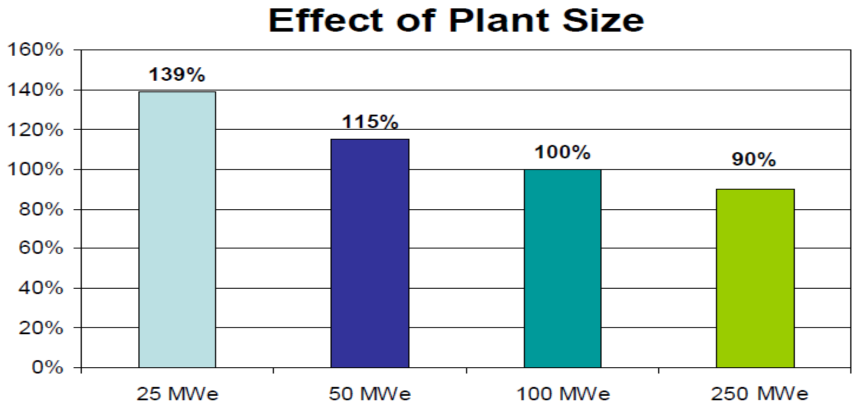

Figure 6-1: Effect of plant size on LCOE (assumed) against a $100MW_e$ base case (from Morse, 2009)

For the Australian CSP context, the issue is important in two ways: Quantifying the benefit of constructing the most cost effective size is a globally shared issue. In Australia, there is also the specific issue of the possible remote and end of grid market segments for relatively smaller systems. Examining the issue from first principles, there are two 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.

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:

BOP Cost/kW_e ~ (System Size)^(-0.1896)

Power Block Cost/kW_e ~ (System Size)^(-0.3145)

This power law scaling has been applied to varied fractions of subsystem cost according to the extent they can be regarded as modular or fixed as shown in Table 6-9:

Table 6-9: Scale factors for subsystem costs depending on size

Cost contributor	Fraction Scaled	Exponent	Note
Concentrator field (excluding receivers and HTF)	0.2	-0.1896	Linked to relative nameplate capacity
Receiver / transfer System (including HTF, piping, Tower as appropriate)	0.2	-0.1896	Linked to relative nameplate capacity
Thermal Storage System	0.55	-0.1896	Linked to relative nameplate capacity
Power block	1	-0.3145	Linked to relative nameplate capacity
BOP and Other	1	-0.1896	Linked to relative nameplate capacity
Indirects	0.7	-0.1896	Linked to relative system cost
O&M	1	-0.1896	Linked to relative system cost

For the thermal storage system, 0.55 of the per unit cost is scaled and the rest is left at the original value. This is based on the estimate of Kutscher (2010), that 0.44 of total cost of a storage subsystem, is attributed to the material (salt) itself and so would be fixed per unit.

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.

Sargent and Lundy also offer estimates of turbine efficiency dependency on size as shown in Table 6-10:

Table 6-10: Turbine efficiency dependency on size, reproduced from based on Sargent & Lundy, (2003)

	Solar One ($10MW_e$)	Solar two ($10MW_e$)	Solar Tres ($20MW_e$)	$50MW_e$	$100MW_e$	$200MW_e$	$220MW_e$
Sun lab data	32%	34%	40.5%	42%	42.5%	43%	46,3%
Sargent and Lundy internal data			38%	40.6%	41.4%	42.8%	45.6%

These have been fitted together with an estimated efficiency of 25% for a 1 MW_e turbine that could be considered to be either a steam turbine or the point of overlap to an ORC system as shown in Figure 6-2

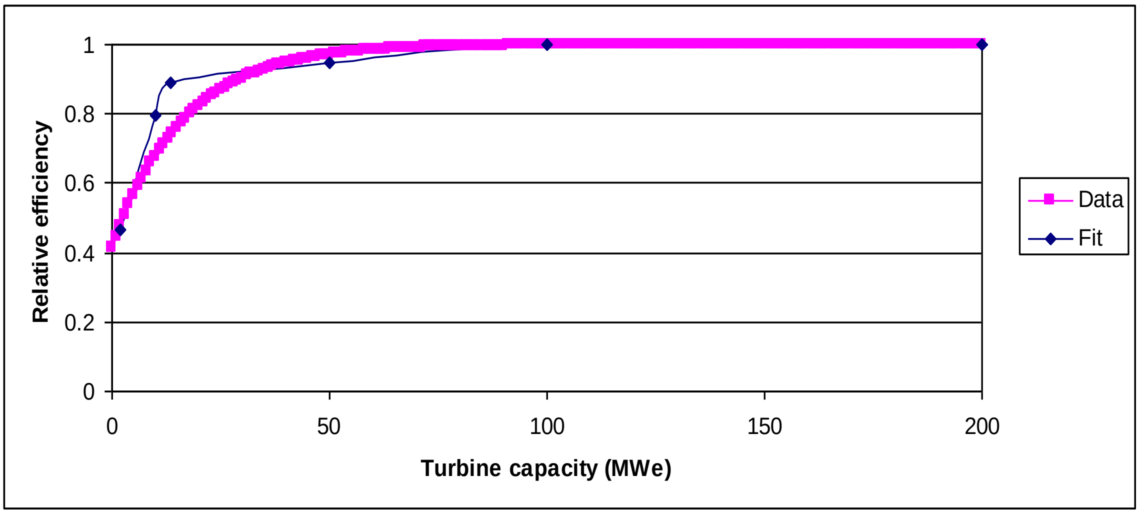

Figure 6-2: Relative efficiency of turbines against a 100 MW_e baseline

The equation of best fit from Figure 6-2 is:

Relative Efficiency = (1-0.59exp(-0.06(Size)/MWe)

The change in Power Block efficiency, effectively changes the contribution of all the other contributors in inverse proportion to efficiency. That is to say, for example, 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 6-3, shows close to but slightly less size dependence than the predictions of Morse and others.

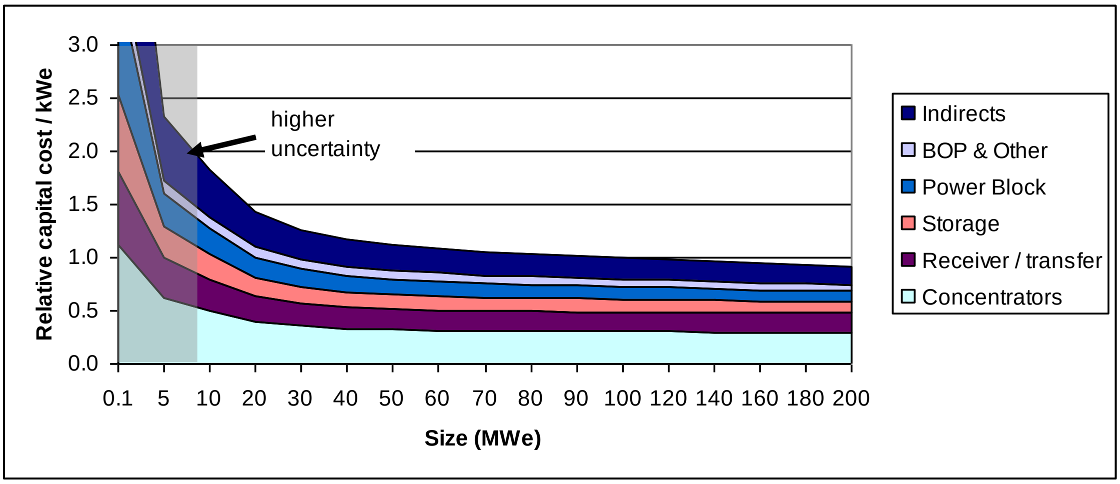

Figure 6-3: CSP capital cost dependency on size, relative to a 100MW$_e$ baseline, for systems with 5 hours storage and assumed 40% capacity factor

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 50 MW. It can be seen that whilst moving to large (>200 MW$_e$) systems brings cost reduction, the penalty for working in the region of 50 MW$_e$ is not great and the reductions in project risk and benefits of modularity may justify that. Going beyond that, systems down to 10 MW or even less may cost 50% more, but this could well be justified if smaller scale systems allowed access to applications of higher value and potentially more installations, especially in the short term. It should be emphasised that this size dependence analysis is based on the steam turbine / central power block model of CSP system. At the small system end, Dish Stirling or CPV approaches are likely to have quite different installed costs. This size dependence on installed cost maps directly to a system size dependence for LCOE as examined later.

6.3.4 Regional effects

Whilst it is challenging to interpret an overseas CSP capital cost estimate for Australian conditions in general, it can be expected that variation may also be expected between regions. This arises because of variations in:

- Cost of labour
- Transport costs
- Other costs of construction (eg plant hire costs)
- Ease of grid connection
- Availability of water

To provide a feel for the magnitude of the issue, Table 6-11 contains general costs of civil construction regional price indices taken from Rawlinsons (2010).

Table 6-11: 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

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 current 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. The 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 that 20% of the overall total. The construction costs quantified by these indices are also typically based on one-off unique projects. If a CSP developer was constructing in the context of a major rollout at various sites around the country, then this would work in favour of the establishment of efficient processes and in-house plant and construction teams able to move from project to project and be less region dependant. A transport component however will be unavoidably higher. A final column has been added to Table 6-11 to quantify a construction index, reduced to 1/3 of the overall variation from the capital city value.

6.4 Examination of LCOE sensitivity

As a starting point, and using the cost estimation basis above, a trough system of the same configuration as Nevada Solar 1, operating at Longreach has the LCOE results shown in Table 6-12:

Table 6-12: Base case assumptions and resulting LCOE for a Nevada Solar 1 type trough system operating at Longreach

	Mature Business		Societal	
Financial parameters				
Loan fraction of total	0.6		0	
Loan period	15	Years	0	Years
Loan interest rate (nominal)	7.78%	/year	0.00%	/year
Discount rate for equity (nominal)	10.29%	/year	5.72%	/year
Tax Rate	30%	/year	0%	/year
Depreciation period	20	year	0	year
Project Life	25	year	25	year
Salvage value	5%		5%	
Inflation	2.50%	/year	2.50%	/year
System parameters				
Variable O&M	0.018	$/kWhe	0.018	$/kWhe
Fixed O&M	0	/year	0	/year
Capital cost after construction	$318,000,000		$318,000,000	
Annual generation	128,800	MWh	128,800	MWh
REAL LCOE 2010AUD	**0.252**	**$/kWhe**	**0.16**	**$/kWhe**

This LCOE baseline represents the most conservative least risk technology configuration constructed at a representative most favourable realistic Australian site.

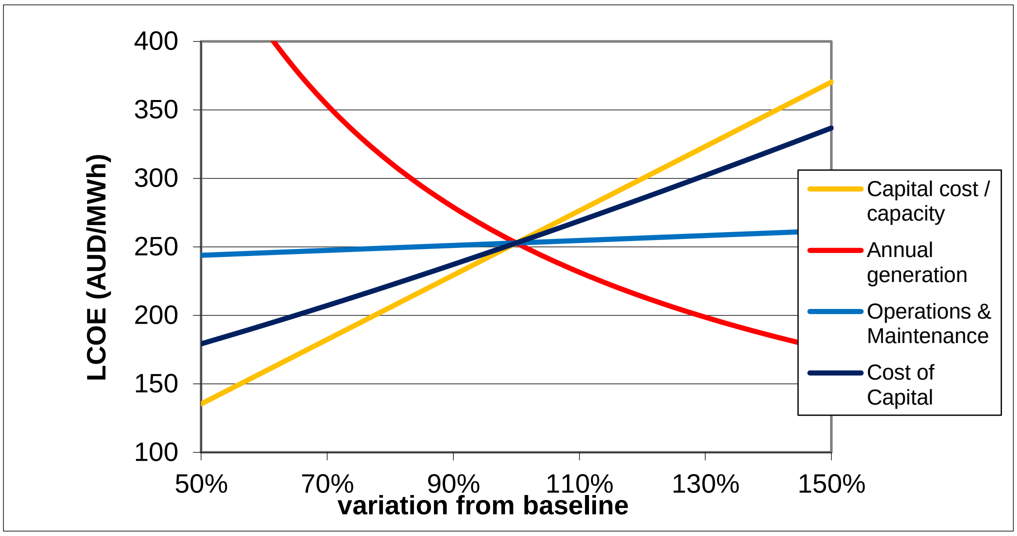

Figure 6-4: Variation of cost against an LCOE baseline of a Nevada Solar 1 type system at Longreach

From this baseline position, the effect of relative variations around the Mature business case LCOE are illustrated in Figure 6-4.

Using the results of SAM modelling quoted in Chapter 5, a Nevada Solar 1 type system in other sites would have a relative generation compared to Longreach and resultant LCOE as shown in Table 6-13.

Table 6-13: System performance and LCOE compared to Longreach for Solar 1 type systems at various sites

Location of a Nevada Solar 1 plant	Net Annual Energy (MWh)	Relative generation (Longreach)	Mature Business LCOE (AUD/kWh)	Societal LCOE (AUD/kWh)
Halls Creek	126,400	98.1%	0.250	0.165
Tennant Creek	128,592	99.8%	0.246	0.162
Longreach	128,794	100.0%	0.246	0.162
Alice Springs	126,931	98.6%	0.249	0.164
Oodnadatta	126,998	98.6%	0.249	0.164
Geraldton	113,048	87.8%	0.278	0.182
Kalgoorlie	106,070	82.4%	0.295	0.193
Woomera	108,503	84.2%	0.289	0.189
Mildura	89,714	69.7%	0.345	0.225
Wagga	85,574	66.4%	0.361	0.235
Mt Isa	128,401	99.7%	0.247	0.162
Newman	128,852	100.0%	0.246	0.162
Charleville	116,018	90.1%	0.271	0.178
Cobar	108,034	83.9%	0.290	0.190
Moree	106,165	82.4%	0.295	0.193

It can also be recalled from Table 5-2 that different CSP technologies had different variations in relative generation from North to South and their LCOEs would move in proportion to those.

6.4.1 Effect of system size

Central power block systems

The size dependence of LCOE follows the size dependence of installed cost very closely, as shown in Figure 6-5.

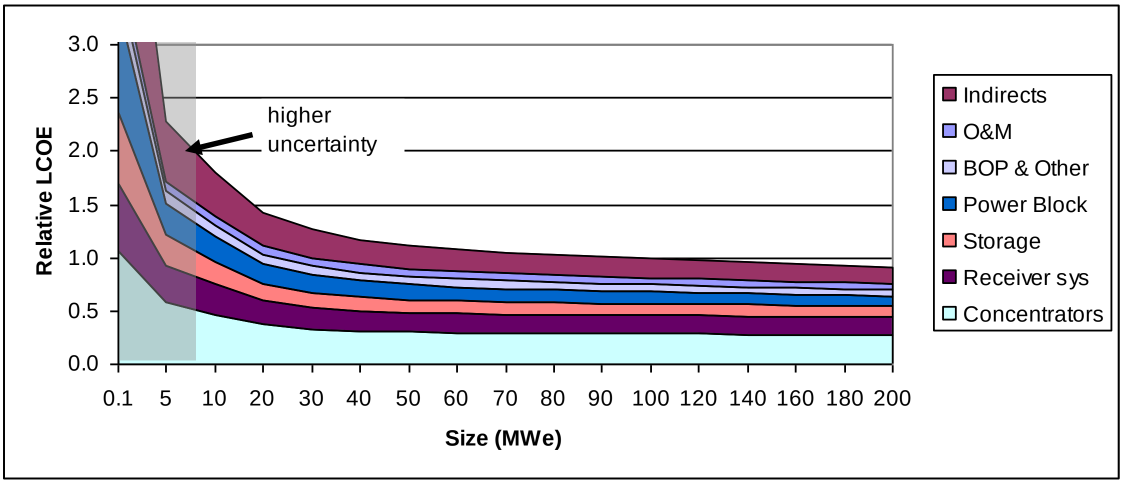

Figure 6-5: Estimated LCOE dependence on system size for a system with 5 hours storage.

Repeating this for a system without storage, we see the results in Figure 6-6.

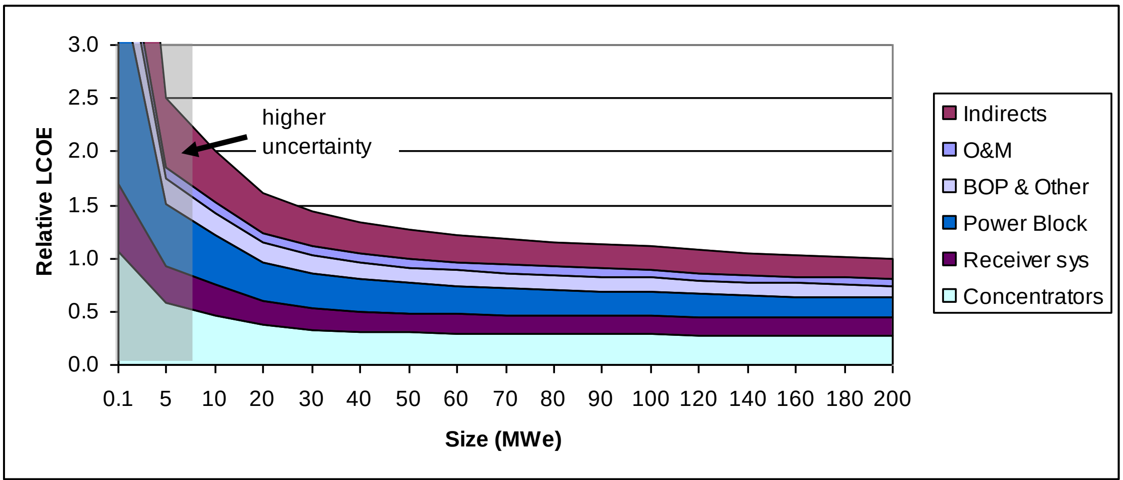

Figure 6-6: Estimated LCOE dependence on system size costs for a system without storage

The model that was adopted for this analysis, projects LCOE continuing to drop for larger systems. There is a general consensus however that 250 MW_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.

CPV / Stirling systems

Whilst there is a lot of uncertainty in the numbers, an attempt has been made to examine the size dependence of a CPV / Dish Stirling system, by changing the assumptions to:

- Net generation efficiency fixed at 30%
- O&M increased to a base of 3c/kWh
- Power block fixed at $1,000/kW$_e$
- All other parameters and size scaling unchanged.

The results are shown in Figure 6-7. Note that after a system size of 90 MW$_e$, the data from the large central power block configuration has been left in to show the transition. It is apparent that, with these assumptions, the modular CPV / Dish Stirling systems have a better LCOE performance below about 10 MW$_e$ but the central power block systems have lower LCOE for sizes above that.

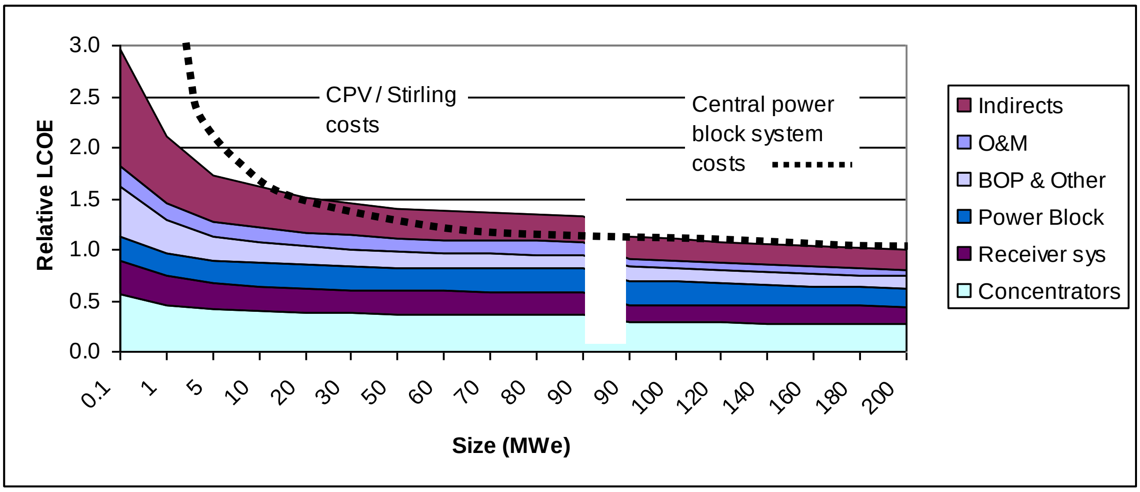

Figure 6-7: Effect of system size on LCOE of CPV / Stirling systems, relative to a 100 MW$_e$ no storage central power block base case

6.4.2 Effect of storage

A Nevada Solar 1 plant at Mildura was modelled, with solar field and power block unchanged, but varying amounts of storage added. The results shown in Figure 6-8 have been normalised to a value of 1 for the no storage case. By presenting the results as Relative LCOE in this way, they become largely independent of; site, technology and financial parameters assumed.

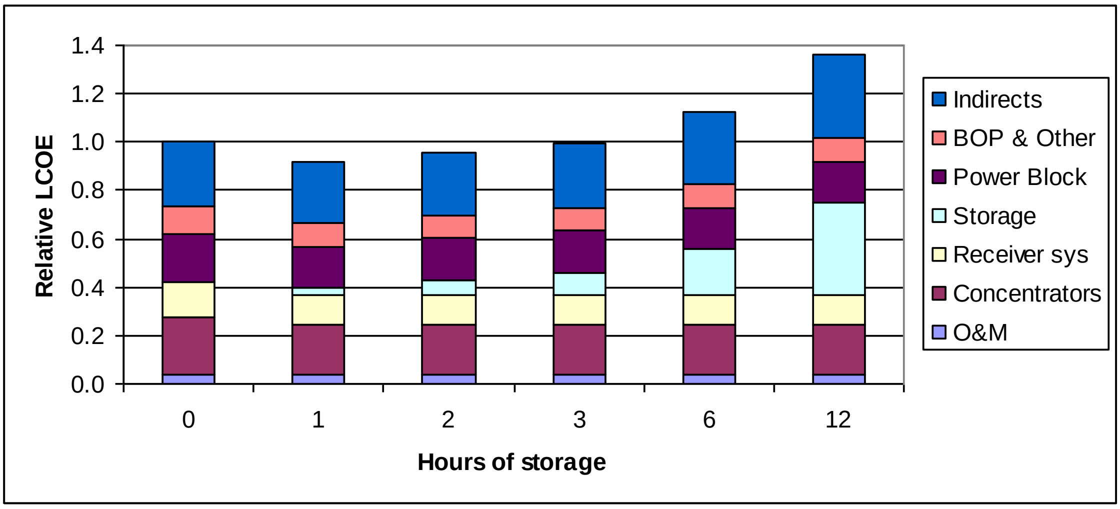

Figure 6-8: Impact of storage on LCOE for a Nevada Solar 1 type trough system at Mildura against a base case of no storage

It can be seen that a small amount of storage (1-2 hours) has the effect of reducing the LCOE over the no storage case. This is in line with similar observations made by others. It is consistent with the effect of storage identified in Chapter 5, which is to increase the overall annual generation by reducing the energy dumping that would occur from a field with a solar multiple greater than 1, plus 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. As more storage is added, the annual generation stops growing and begins to decline slightly due to increased standing losses and LCOE grows with the capital cost increase.

If the unit cost of storage were reduced, the LCOE increase with hours of storage would be reduced and the minimum point would move to a higher level of storage.

Whilst 1 hour of storage may offer the lowest cost of energy, it was seen in Chapter 5 that the maximum value (income) could be generated for around 6 hours of storage. If the value increase with storage is greater than the cost increase, then a higher level of storage will become the economically optimum choice, not simply the lowest LCOE configuration.

6.4.3 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 6-9.

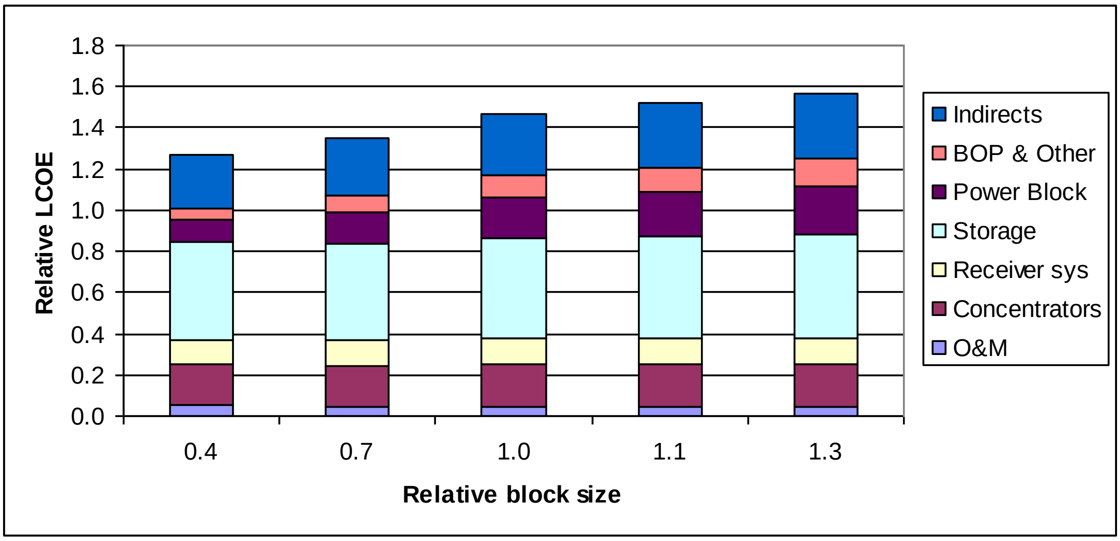

Figure 6-9: Impact on LCOE of power block size modelled for a Nevada Solar 1 configuration with a 2,289 MWh_{th} store and fixed collector area modelled for Mildura. The block size 1 data point coincides with the 12 hour storage data point in Figure 6-9

Dropping further below 27 MW_e, results in lost annual generation because there are times when storage is fully charged and solar resource is available at a higher level than the power block can dispatch. The use of a larger power block and higher resultant LCOE, may be justified in conjunction with larger storage systems, because it allows operation in a more intermediate / peaking manner so as to maximise income value.

6.4.4 Hybrid systems

The idea of hybridisation of CST systems with either existing coal fired generating assets or as new build in conjunction with gas combined cycle plants (the Integrated Solar Combined Cycle ISCC model) has also been examined. For such a system, the storage component of capital cost is removed, the power block and balance of plant contributions should be attributed pro-rata to the CSP and solar contributions to input energy. Further, in examining size dependence, the turbine conversion efficiency can be assumed to be unchanged by the size of the solar field.

Assuming a 30% allocation of Block and BOP plant costs to the CST side and holding the cycle efficiency constant at 38% leads to the results in Figure 6-10. As expected, for large systems an approximately 25% smaller LCOE results. If hybridisation to an existing plant is contemplated, it could be argued that the cost of the block and BOP is close to zero and a reduction to 30% of the stand alone system values would be seen.

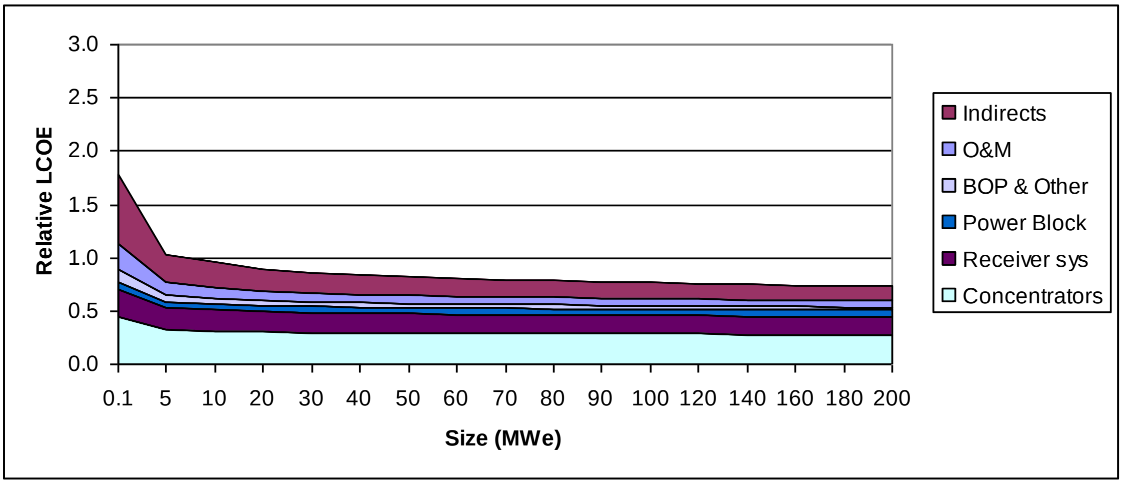

Figure 6-10: Impact on relative LCOE of size for CST / fossil hybrid system. (System size is the effective CST contribution to electrical output).

Possibly of greater significance is the observation that the dependence of LCOE on system size is much reduced. This is a direct consequence of the assumed fixed conversion efficiency. This suggests that smaller demonstration systems could be built as add-ons to fossil fired systems more cost effectively than as stand alone systems.

In contemplating solar fossil hybrids there are some potentially complicating issues around effective conversion efficiency if the CST field does not produce exactly the same steam conditions as the fossil boiler.

6.5 Cost and Value of Energy in Different Market Segments

Noting the large variations in solar resource, system configuration, latitude, grid connection costs and regional construction cost indices, the various market segments have been assessed for energy cost vs value. This has been done by making a qualitative estimate of applicable LCOE that is not the most extreme range obtained from combining all best case and all worst case assumptions, but rather a range that it is estimated “reasonable” systems may fall into if the financial / policy settings needed to enable them were in place. Results for stand alone systems for an abbreviated list of the different market segments are shown in the Tables 6-15 to 6-18 following.

Table 6-14: Estimated LCOE and market value of small CSP systems in the NEM

Parameter	CSP with no storage	CSP with significant storage
System size (MW_e)	2 to 10 MW_e	10 to 20 MW_e
DNI (kWh/m2/yr)	2200 to 2500	2200 to 2500
Value in market	$102 / MWh	$128 / MWh
Currently un rewarded value	$0 - $8	$4 -$20 / MWh
LCOE	$330 to $550	$370 to $500
Current Cost gap	$240+/ MWh	$220+/ MWh

Table 6-15: Estimated LCOE and market value of large CSP systems in the NEM

Parameter	CSP with no storage	CSP with significant storage
System size (MW_e)	50 - 250	50 -250
DNI (kWh/m2/yr)	2100 -2500	2100 -2500
Value in market	$102/MWh	$128/MWh
Currently un rewarded value	$0 - $8/MWh	$2 -$10MWh
LCOE	$220 -$300/MWh	$250 -$360/MWh
Current Cost gap	$115+/MWh	$110+/MWh

Table 6-16: Estimated LCOE and market value of CSP systems in the SWIS

Parameter	CSP with no storage	CSP with significant storage
System size (MW_e)	50 to 250	50 to 250
DNI (kWh/m2/yr)	2100 to 2400	2100 to 2400
Value in market	$98 / MWh	$152 / MWh
Currently un rewarded value	$0 - $4/MWh	$2 -$10 / MWh
LCOE	$250 to $300/MWh	$260 to $360/MWh
Current Cost gap	$150+/MWh	$100+/MWh

Table 6-17: Estimated LCOE and market value of Off grid / mini grid CSP systems

Parameter	CSP with no storage	CSP with significant storage
System size (MW_e)	1 to 10	5 to 10
DNI (kWh/m2/yr)	2400 to 2600	2400 to 2600
Value in market	\$290 to \$390 / MWh	\$340 to \$440 / MWh
Currently un rewarded value	0	0
LCOE	\$400 to \$550	\$500 to \$650
Current Cost gap	\$10+/MWh	\$50+/MWh

While LCOE significantly exceeds income in every case, the gap varies considerably. For example:

- A CSP plant in a remote, high solar resource area that targets off-grid or mini-grid customers has a smaller value gap to close. However, it is also the segment with the greatest uncertainty in both the cost and value estimates. There is also a high level of technical risk avoidance, and payback times less than a CSP plant lifetime are expected.

- The NPV implications of storage are not linear. A system with one or two hours of storage may be more attractive than the two extremes of no storage and high storage.

To consider the option of solar / fossil hybrid systems from this point of view, it can be noted that the dispatchability function is provided by the fossil component thus the revenue value that should be attributed to the CSP system, will fall somewhere between that of a CSP system without storage and a smaller value that arises purely from fuel saving, depending on configuration. Typically ISCC systems have turbines that are oversized relative to the heat input from the gas turbine alone. Thus the solar component will provide extra generation at times where its value is indeed higher than the pool average. For grid connected systems, the 25% LCOE reduction will consequently lead to a significant reduction in cost gap, bringing it to as low as \$50/MWh.

Taken at face value, this cost gap is a high hurdle, however, it must be seen in the context of an industry / technology still in its infancy on the commercial maturity cycle. Clearly the future depends on cost reductions.

6.6 Cost Reduction Drivers and Potential

6.6.1 Previous studies

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

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

- technical improvements, as lessons are learned from installed plants and parallel R&D efforts identify performance improvements,
- scaling to larger installed plant size, that allows for more efficient and more cost effective large turbines and other components to be used, and
- volume production that allows fixed costs of investments in production efficiency to be spread over larger production runs.

The '*Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*' study, (Sargent & Lundy, 2003) analysed the cost reduction potential for Tower and Trough systems utilising a bottom-up process. Their projected cost reduction forecasts for Tower systems identified the above categories contributing in the ratio 23:49:28, with that relativity maintained over a 14 year trajectory of major cost reduction.

The '*European Concentrated Solar Thermal Roadmap*' (Pitz-Paal et al, 2004), establishes recommended priorities for R&D efforts that remain valid today. It reports previous cost reduction studies and also predicts a growth in installed capacity to 40 GW by 2025, with a reduction in the LCOE to EU 0.05 / kWh. This reduction is predicted from a claimed base of between EU 0.15 and 0.20 / kWh in 2004. This compares favourably with the Spanish feed-in tariff of EU 0.21 / kWh introduced at that time. The European roadmap indicates that, based on the information available at the time, there was no clear indicator of a cost winner among the CSP technology options. This is still the case today.

The '*CSP Global Outlook*' study produced jointly by GreenPeace, SolarPaces and ESTELA, (Richter et al, 2009), claims that the costs for CSP electricity are falling and are around US $0.15 / kWh at good US sites. It also indicated that 80% of the lifetime costs are in construction and initial debt, with ongoing O&M accounting for the remaining 20%. They estimate that new parabolic troughs using current technology with proven enhancements can produce electrical power today for about US $0.12 / kWh in solar-only operation mode under the conditions in south-western USA. In Spain, it is reported that the cost currently ranges from approximately EU 0.15 / kWh (US $0.19) at high solar sites to approximately EU 0.23 / kWh (US $0.29) at less favourable sites. These costs were forecast to reduce to between EU 0.10 to 0.14 / kWh (US $0.15 to $0.20) by 2020. These predictions of investment cost reduction over time are shown in Table 6-18.

Table 6-18: Forecast capital cost reduction over time for CSP systems (Richter et al, 2009).

Scenario	Reference		Moderate		Advanced	
Year	Progress ratio	Investment cost	Progress ratio	Investment cost	Progress ratio	Investment cost
	(%)	(Euro/kW)	(%)	(Euro/kW)	(%)	(Euro/kW)
2005	0.90	4,000	0.90	4,000	0.90	4,000
2010	0.90	3,800	0.90	3,800	0.90	3,800
2015	0.90	3,400	0.92	3,230	0.86	3,060
2020	0.94	3,000	0.96	2,850	0.89	2,700
2030	0.96	2,800	0.98	2,660	0.91	2,520
2040	0.96	2,600	0.98	2,470	0.91	2,340
2050	0.98	2,400	1.00	2,280	0.93	2.160

The predicted investment costs, combined with annual installed capacity projections, indicate that expenditure could rise to EU 175,000 billion per year under the advanced scenario in 2050.

A recent roadmap published by the IEA for CSP technology presents a highly credible summary of the global situation and way forward (IEA 2010A). The roadmap notes the commonly held view that PV costs are now lower than CSP. The benefits of thermal energy storage, potential for easy hybridisation with existing fossil fuelled technologies and in the longer term, solar fuels production, are discussed in detail.

The Roadmap's predicted LCOE cost reduction over time is shown in Figure 6-11 for high and low average solar radiation scenarios. Whilst analysts universally predict such asymptotic decay in costs to some ultimate level, it should be emphasised that predictions of the final level are highly dependent on a range of very uncertain assumptions. Despite this, the consensus is that in the long term, CSP should be competitive with alternative large-scale clean energy options.

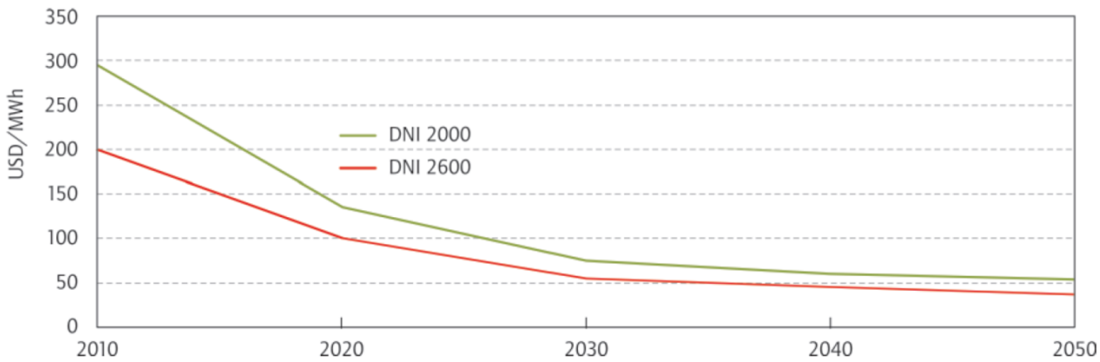

Figure 6-11: Levelised Cost of Electricity forecasts, from the CSP Roadmap (IEA, 2010A).
(Note: DNI is Direct Normal Irradiance, in units kWh / m^2 / yr)

AT Kearney (2010) was commissioned by ESTELA and Protermosolar (European and Spanish CST industry associations respectively) to produce a study of Energy cost reduction projections to 2025. Significantly, virtually every major technology and plant developer active in Europe participated and provided key business information in confidence to the consultants. AT

Kearney has used this to present LCOE's in an indicative manner, in as much as the methodology and key financial inputs are not clearly provided. They have, however, 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 relative to 2012 of 40 to 50%, as shown in Figure 6-13. Over the same time period, they suggest global installed capacity could reach between 60 and 100 GW depending on policy measures in place.

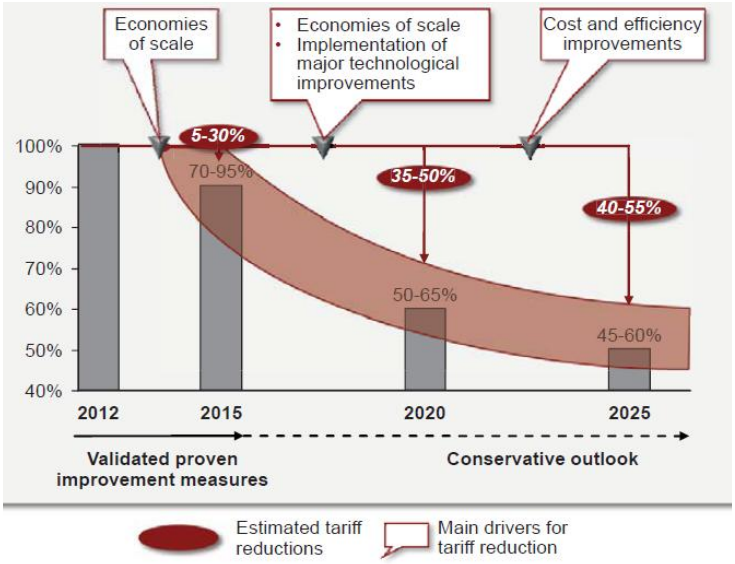

Figure 6-12: Estimated CSP cost / LCOE reductions (Reproduced from AT Kearney, 2010)

AT Kearney compare their predicted ranges of LCOE over time with values for fossil fuels and show a convergence with costs from coal or combined cycle gas in that time frame (presumably under European conditions and carbon price predictions). Comparison with other key renewables of wind and PV is a key aspect.

In a non-dispatchable configuration, present costs favour utility scale PV over CSP, with wind even more competitive. It is noted that the better the solar resource levels the smaller the cost gap currently is between PV and CSP. Cost reduction projections however are greater for CSP as that industry accelerates. PV and wind are suggested to start to level off towards a mature limiting cost of energy.

Overall, AT Kearney's projections result in a convergence of all three technologies by 2025, although CSP still struggles to be competitive on a pure LCOE basis, as shown in Figure 6-13. It is noted however that even a system configured without explicitly included storage offers extra value via its thermal inertia.

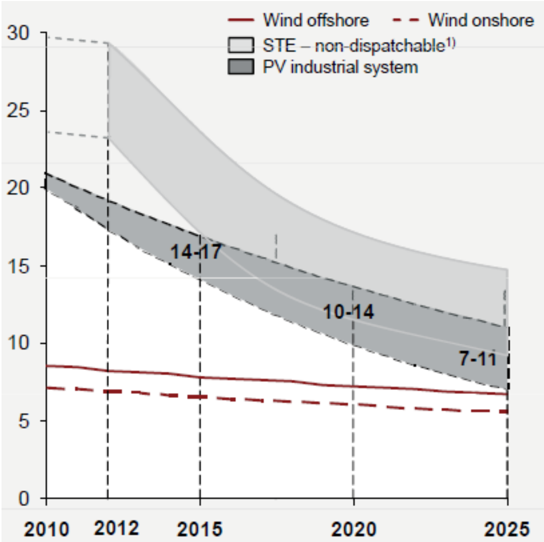

Figure 6-13: Estimated CSP LCOE reductions compared to wind and PV (reproduced from AT Kearney, 2010)

However the comparison of configurations designed for dispatchability is considerably more favourable for CSP. CSP LCOEs fall in the same range with or without dispatchability. If electrical storage is added to wind or PV on the other hand, CSP today is comparable to wind with electrical storage and only half the cost of PV with batteries and this position is maintained out to 2025, as shown in Figure 6-14.

The source of these cost reductions is identified as around 50% for cost and efficiency improvements and 50% from economies of scale. Whilst the big picture view presented by AT Kearney is upbeat, the underlying assumptions and justification as to how these reductions are actually to be achieved is not spelt out in detail.

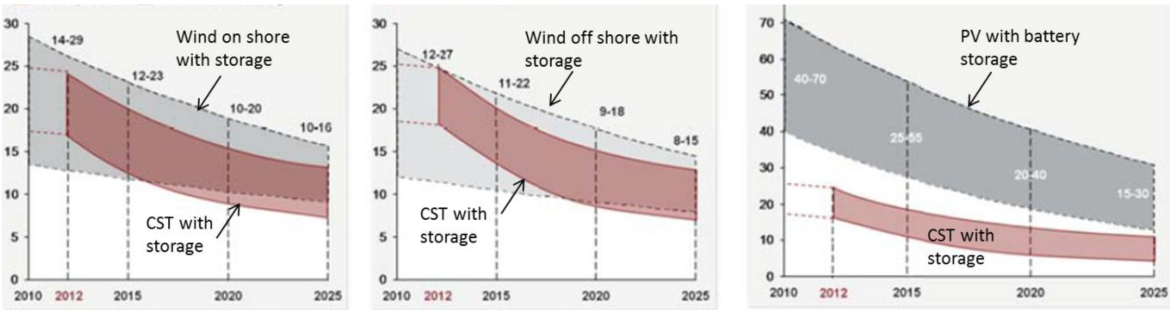

Figure 6-14: Convergence of LCOE (Euro cents / kWh) of CSP compared with wind and PV with storage (reproduced from AT Kearney, 2010)

Other studies support these conclusions on cost reduction potential. NREL's Line focus cost reduction study (Kutscher et al 2010), identifies in detail a range of specific "bottom up" measures that are estimated to deliver a 40% LCOE reduction by 2017. Sandia's Tower cost reduction roadmap, carries out similar analysis for tower systems (Kolb et al 2010) and identifies measures that will deliver 50% cost reductions by 2020. They also discuss the more disruptive / step change improvements needed to achieve the extra 20% reduction for the US government's "Sunshot" program goals.

6.7 Learning Curves for Cost

Bottom up analysis of cost reduction potential clearly establishes that major cost reductions are physically possible. Typically new technologies that are adopted on a large scale show historical development paths that combine a sustained period of compound growth in levels of adoption with a learning curve approach to cost reduction that is correlated with the level of capacity installed. The fact that both wind power and PV have been doing just this for the last three decades and are continuing to do so make the case for this behaviour in CSP all the stronger.

A learning curve is essentially a reduction over time of real installed costs that approaches some limiting value of ultimate cost. In the initial phases of an industry's development, it may take a while for a clear pattern of this reduction to be apparent. In the early phases of cost reduction, it does become possible to extrapolate a cost reduction forward, however, this extrapolation cannot predict the ultimate limiting cost in a meaningful way.

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. A constant Progress Ratio (*PR*) is equivalent to an exponential decay to zero cost (and hence only a good approximation to behaviour in the early stages). 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.

The Progress Ratio that CSP is likely to benefit from in coming years is hard to determine. Precedents from other fields are a reasonable indicator.

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, giving the results in Figure 6-15.

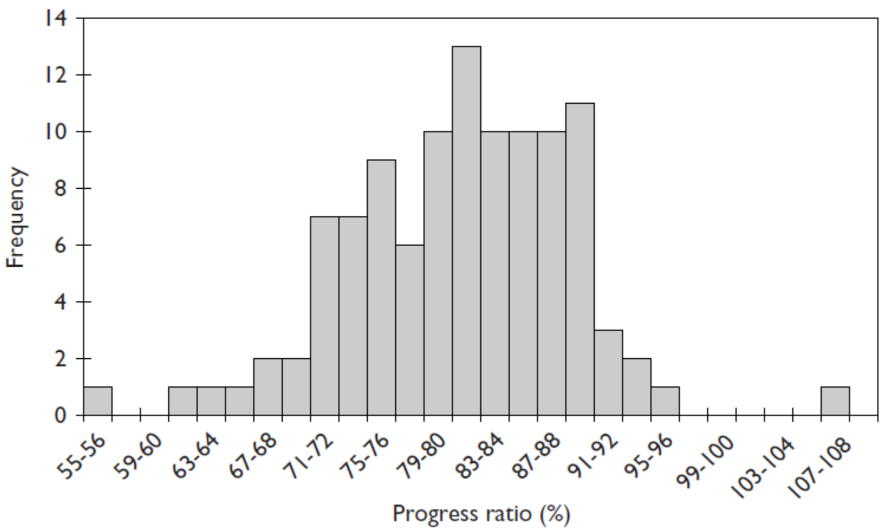

Figure 6-15: Historical Progress Ratios for a variety of technologies including "manufacturing processes in industries such as electronics, machine tools, system components for electronic

data processing, papermaking, aircraft, steel, apparel, and automobiles" (reproduced from IEA 2000)
There is a wide spread with a median value of approximately 0.82 apparent. The message is that if a technology is adopted in a serious way, significant cost reduction is a virtual certainty, with a progress ratio of 0.95 essentially the "worst case" outcome.

Table 6-19 lists a range of quoted Progress ratio's firstly from PV and Wind and general industry experience and then various projections for CSP.

Table 6-19: Progress Ratios quoted for various energy technologies, as well as CSP

Source	Progress ratio	Cost Reduction per doubling
Related industry precedents		
Sargent and Lundy (2003) quoting PV	0.82	18.0%
Sargent and Lundy (2003) quoting wind 1980 - 1995	0.82	18.0%
GEF (2005) quoting PV to 2000	0.8	20.0%
Hinkley et al (2011) quoting Hayward etal on PV	0.8	20.0%
Hinkley et al (2011) quoting Hayward etal on wind	0.85	15.0%
GEF (2005) quoting IEA, median over range of industries	0.82	18.0%
CSP near term projections		
Sargent and Lundy (2003) Low	0.85	15.0%
Sargent and Lundy (2003) High	0.96	4.0%
Richter et al (2009) current estimate for CSP	0.9	10.0%
GEF (2005) quoting 1999Enermodal study for CSP low	0.85	15.0%
GEF (2005) quoting 1999Enermodal study for CSP high	0.92	8.0%
GEF (2005) quoting DLR 2004 Athene study for CSP - solar field 0.9, storage 0.88, power cycle 0.94 gives overall	0.9	10.0%
IEA (2010A) roadmap for CSP	0.9	10.0%
Hinkley et al (2011) analysing CSP to date	0.85	15.0%

In this it appears that the projections for CSP may be erring slightly towards conservatism compared to the historical evidence from other industries.

The Sargent and Lundy numbers have resulted from their detailed bottom up cost reduction study, with cost reduction over time projected from first principles and then fitted to a learning curve. As with the results quoted from the DLR Athene study, the idea that different subsystems may have different progress ratios emerges. The results in Richter at al predict declining Progress Ratios as installed capacity increases, this is physically more realistic than a constant value. It is, however, the value for the short term that is of most interest in informing policy making in the present. Both Richter et al (2009) and the IEA (2010A) suggest that the value for CSP at present is 0.9. Hinkley et al (2011) has attempted to identify real project costs of CSP systems so far and fit them as shown in Figure 6-16.

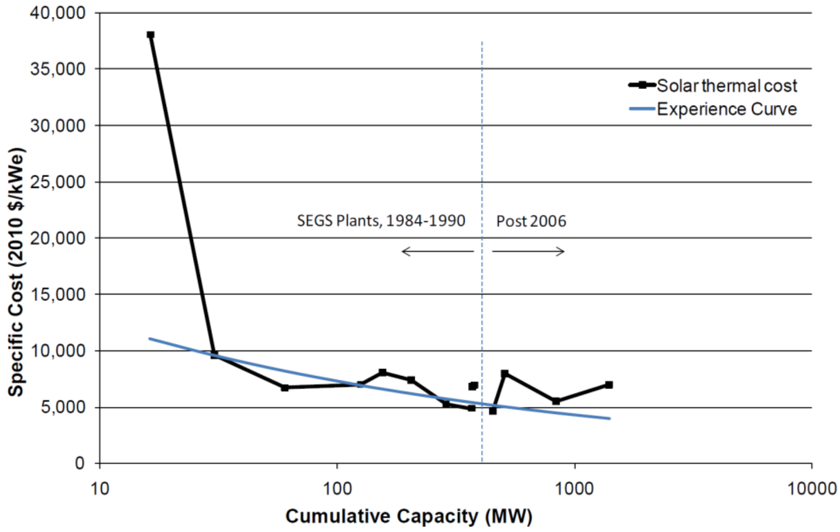

Figure 6-16: CSP Historical cost data vs. cumulative capacity, with a fitted experience curve (reproduced from Hinkley et al, 2011, prepared from data in Hayward et al, 2011)

It is apparent that the CSP industry behaviour since the 2006 restart, has not stabilised well enough to show a clear conclusion. The pre-1990 phase showed a clearer trend, albeit with few data points. The present phase post 2006 has several factors that make it hard to analyse:

- Whereas the 1984 to 1990 phase was a single technology supplier in a single location, the post 2006 phase has multiple developers with a range of technology variations and project assumptions.
- A major escalation in steel and other commodity prices occurred in this period as illustrated in Figure 6-17.

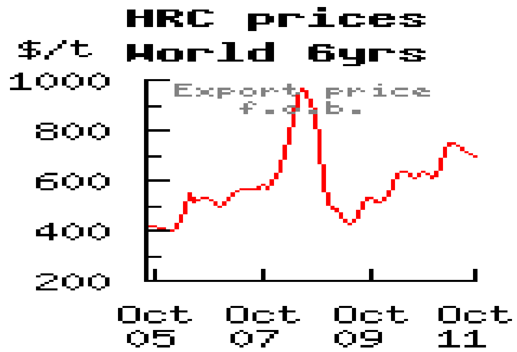

Figure 6-17: Historical steel price 2005 to 2011 (www.steelonthenet.com, 2012)

Aside from the overall trend, it is a common occurrence for technologies to experience "blips" that upset the general trend. The results from PV are a good example of this, as shown in Figure 6-18. A global shortage of Silicon, combined with strong demand resulting from the high German feed-in tariffs, kept prices high until market conditions stabilised.

Note that costs of production nevertheless continued to fall over that time, in line with the historical learning rate. The data is now showing a return to an overall PR less than 0.8.

The overall conclusion that is drawn is that CSP is likely to proceed with a progress ratio of not worse than 0.9, but with a value down to 0.85 or less a strong possibility.

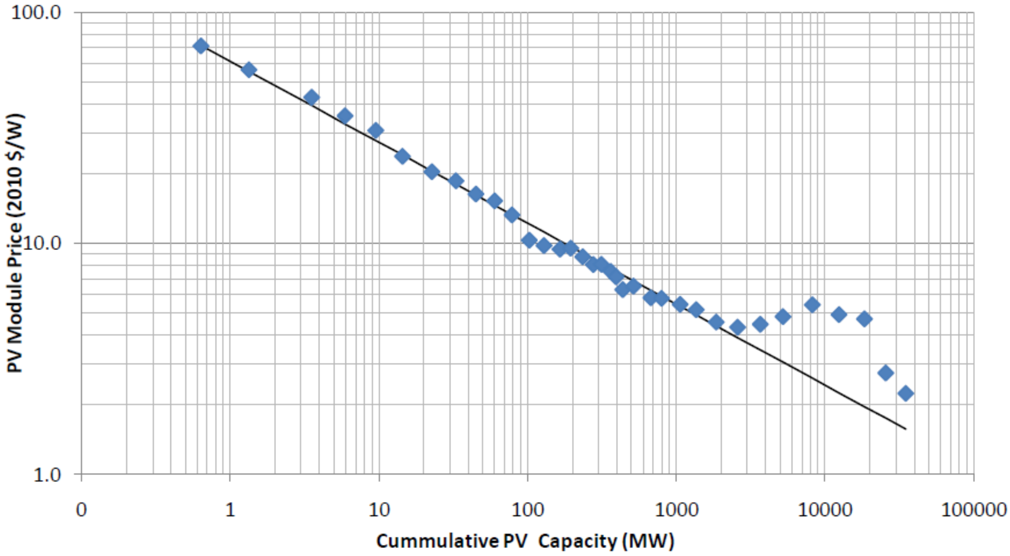

Figure 6-18: Historical experience curve for PV, with a 22% learning rate (reproduced from Hearps and McConnell 2011)

It is instructive to examine what this will mean for costs in the medium term. Figure 6-19 and Figure 6-20 show cost reduction versus normalised installed capacity[53] as a function of a range of possible Progress Ratios. Often historical data is plotted on "Log Log" scales to examine the degree of linearity (as in Figure 6-18 above), however the effect is best understood using a linear scale.

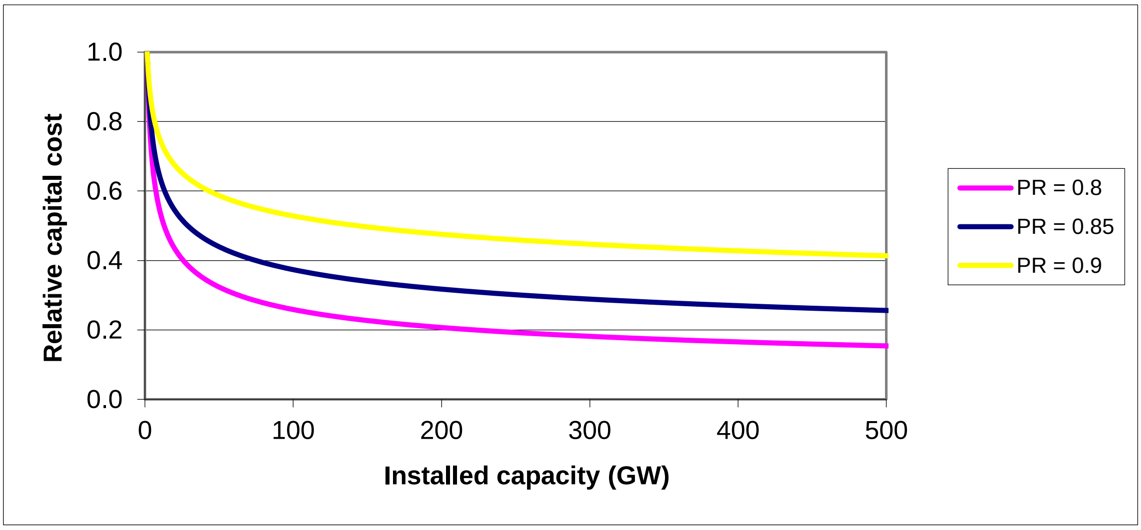

Figure 6-19: Relative capital cost vs. normalised installed capacity under different Progress Ratios

What can be seen from these figures, is that whilst all curves asymptotically approach a cost of zero, even on a scale of installed capacity out to 500 GW, the actual Progress Ratio makes an enormous difference to cost at any given point. This makes forward prediction of costs very difficult. On the other hand, it is also very apparent that under any of the realistic scenarios, major cost reductions would be expected during the course of the installation of the next 10 GW of capacity of any given CSP technology.

53 If capacity factors increase over time, then the actual generating potential of installed plant will increase more than nameplate capacity. Hence in this analysis the progress ratio is assumed linked to equivalent capacity at 2011 average capacity factor.

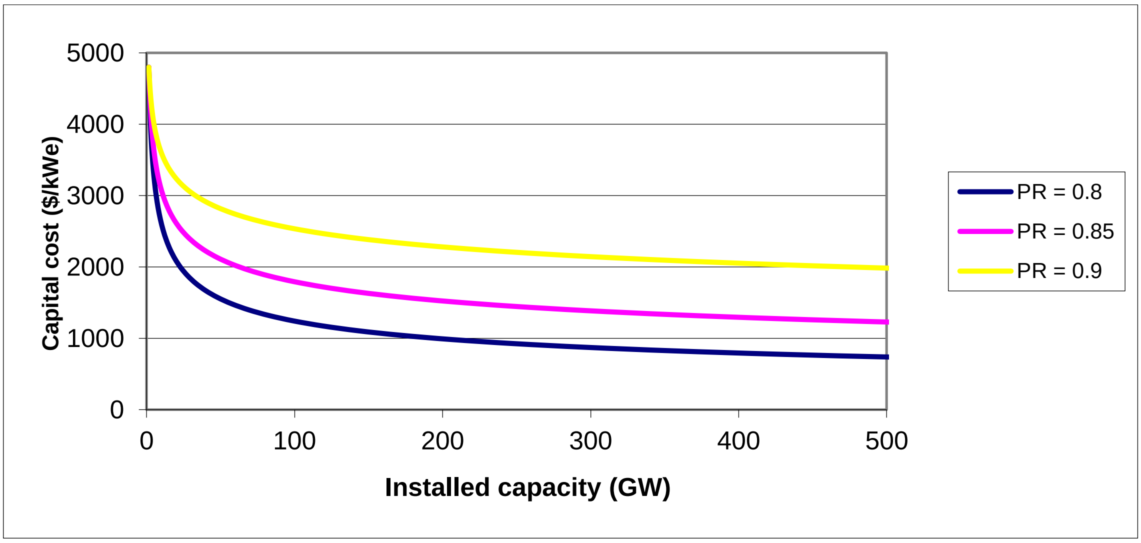

Figure 6-20: Capital cost normalised to 20% capacity factor, (2011 AUD) vs installed capacity under different Progress Ratios.

From a policy perspective, one wishes to know how these cost reductions are likely to track with time. In the discussion in Chapter 3, it was established that compound growth is likely to occur at a rate that will be at least 19%/ annum and most likely somewhat higher.

Figure 6-21 plots the progression over time of relative cost of energy[54] under either 20% pa or 30% pa growth rates (refer to Chapter 3) with the same range of possible progress ratios.

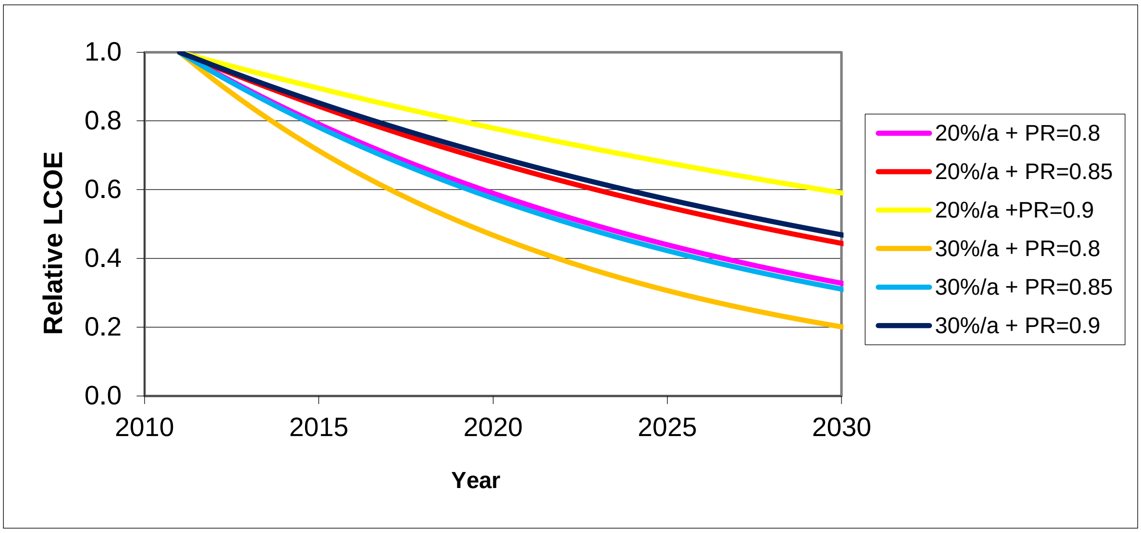

Figure 6-21: Relative energy cost reductions over time under different growth rates and progress ratios

On this basis, a minimum cost reduction of 20% by 2020 would be expected, with a reduction of as much as 50% quite possible. A key observation also is that significant cost reductions should be occurring within just a few years, as long as deployment levels are maintained. An open question is the degree of difficulty that will remain in trying to obtain reliable cost data to test this trend.

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[54] 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.

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 exactly 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?

This introduces a further range of uncertainty in predicting the escalation rates for the various value contributions. Attempting to differentiate this by system configuration and market segment has been judged as largely impossible given all the accumulated uncertainties. Rather, Figure 6-22 offers an indicative projection of starting from an LCOE of $252/ MWh and a market value of $120MWh in 2011 and considering value real dollar escalation rates in the range of 1% pa and 3% pa.

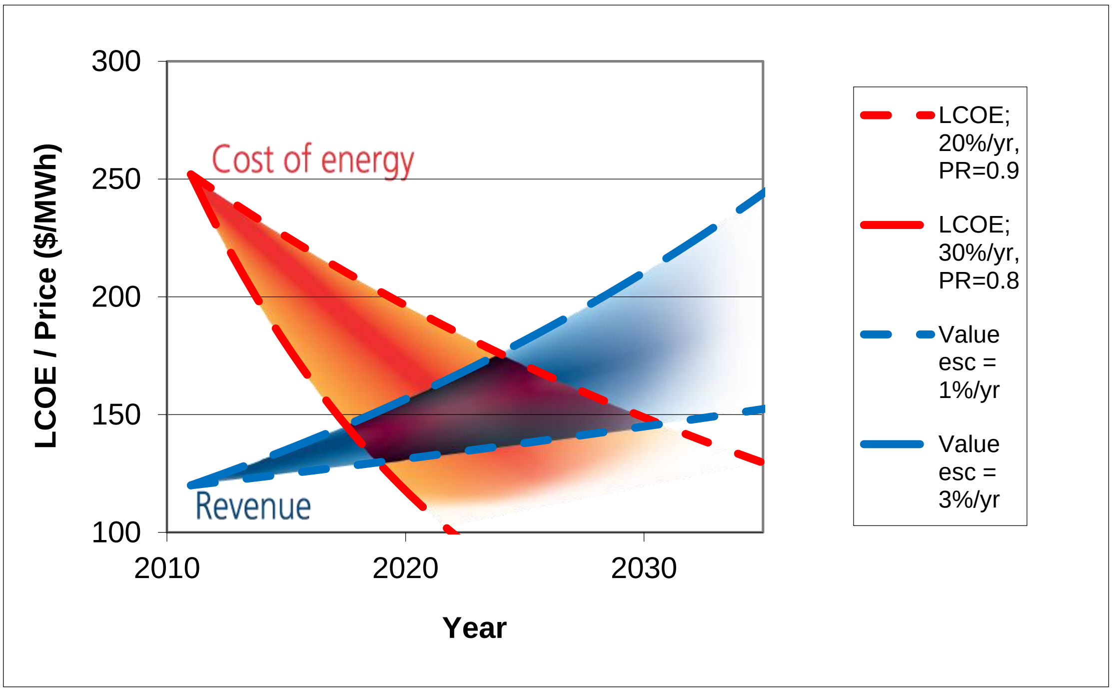

Figure 6-22: Possible progression of indicative CSP LCOE and market value in Australia (2011 real AUD)

This suggests that even without major policy intervention, convergence of LCOE and value could occur as soon as 2018 and by 2030 at the latest. A shift in policy settings to recognise greater value from CSP, would have the effect of raising the value curves bringing the time for convergence forward by a similar fraction.

* * *

7 Challenges and Solutions

7.1 Introduction

Although CSP offers many benefits, there remain many challenges to its widespread deployment. Many of the challenges and possible solutions to the implementation of CSP technology are common globally and have been examined in past reports.

The *'Barriers to Commercialisation of CSP Plants'* report (Lotker, 1991), discusses in depth the lessons that can be learnt from the Luz experience that established the well-known SEGs plants in California. In the 1970's, the US Government established measures such as tax credits and Renewable Portfolio Obligation (RPO) rules that encouraged a plethora of initiatives in renewable energy. In the early 1990's, the government initiatives such as tax credits were progressively dropped and ultimately Luz went out of business. The overall lessons are the desirability of avoiding boom-bust responses to policy and, if a tightening of conditions is planned, to do it in a way that allows companies to plan and survive under a new paradigm.

The '*CSP Global Outlook*' report (Richter et al, 2009) ends with a discussion of recommended policy measures, which emphasise the need to establish a reliable revenue stream through a guaranteed Feed-In Tariff or other mechanism. Importantly, the report also notes the high value of a loan guarantee from government, an approach that has been implemented in the US. This policy option is worth further consideration in the Australian context.

The *Electric Power Research Institute's technical update* (EPRI, 2009), gives a comparison of costs of alternative large-scale centralised electricity generation technologies. EPRI's work has been criticised as being overly pessimistic in its projections for solar technologies. It does however have a useful discussion of the many barriers that can arise from a lack of appreciation of the technical difficulties in building collector fields that are required to cost-effectively track and operate for more than 20 years in a harsh environment.

The '*Technology Roadmap Concentrating Solar Power*' report (IEA, 2010A), presents a range of recommendations that aim to address the financial and technical barriers to expansion of the industry. These are referenced further in subsequent sections of this report.

In Australia, the context and priorities for CSP have been examined with a 2008 '*High Temperature Solar Thermal Roadmap*' commissioned on behalf of the Council of Australian Governments (Wyld Group, 2008). A range of barriers were identified for the Australian context:

- Electricity market arrangements – that were suboptimal or favoured the characteristics of coal-fired plant.
- Lack of resource information – both DNI and also of other renewable resources.
- Limited understanding of business opportunities – investor understanding of claims and potential for the 'new' CSP technologies.
- Rights to the resources – alternatively interpreted as site availability.
- Network pricing and connection issues - rules that are based on the dominant paradigm that unfairly penalise some features of CSP operation and fail to reward some of the benefits.

In a recent Survey of the US CPV industry, PV Insider (2011) found that the biggest challenges were:

- Establishing reliability, especially of trackers, via a pipeline of operating plants
- Developing a supply chain that could deliver consistent, high quality commercial product
- Driving down costs, so as to compete with flat plate PV and other technologies
- Establishing confidence in the finance sector by reducing perceived risk
- Government support for development of the sector.

As part of the research process for this review, stakeholder consultation was undertaken to ensure all challenges being faced by the Australian CSP Industry were identified and discussed. The stakeholder consultation processes and findings are summarised in Appendix B. The remainder of this chapter summarises the key challenges identified internationally and in Australia and then examines possible means of overcoming them.

These different challenges identified fit well into the energy sector technology dissemination model proposed by Haas (2001) and illustrated below:

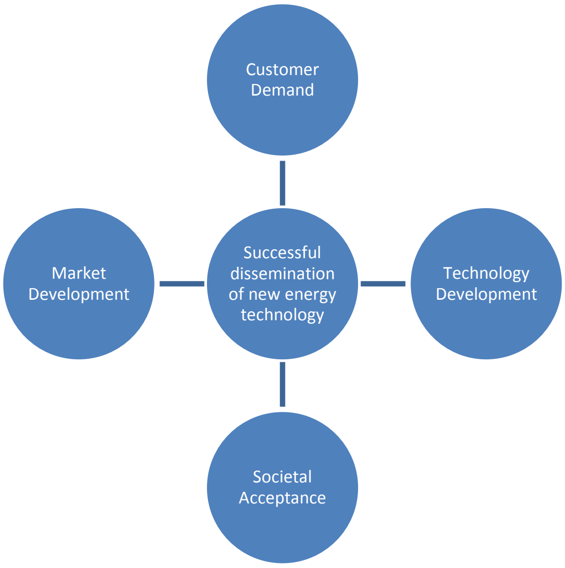

Figure 7-1: Energy technology dissemination model (Haas, 2001)

There are of course many other categorisations and it is also the case that a particular issue could be applicable in more than one category and so the process of allocation is not rigid.

The key challenges that have been identified and categorised and which are discussed in detail in this chapter, along with possible solutions are:

- Technology development
    - The current cost gap
    - Manufacturing scale up
    - Deployment issues
- Societal acceptance
    - Possibility of community push back
    - Consistency of government policy
    - Approvals processes
    - Naysayers and misinformation

- Market development
    - The current cost gap (also identified as a key technology challenge)
    - Financing
    - Operating in a global market
    - Solar and site data
    - Grid and services connections
- Customer demand
    - Value vs cost
    - Understanding of CSP capability
    - Customer needs vs markets

7.2 Technology Development

CSP technologies on offer range from the proven, established Trough technology to what may seem implausible new inventions. The ideal CSP technology is of course; high performance, low capital cost, high reliability and with minimal O&M costs.

The issue for all countries with a serious interest in CSP is how to 'hasten slowly' down the cost curve. A large value project that ultimately fails in a country like Australia that has not established a CSP track record, could be very damaging for the whole industry. Conversely, simply continuing to duplicate the SEGs plants is a recipe for very slow progress.

Key challenges identified in the Technology development category are:

- the current cost gap;
- manufacturing scale up; and
- deployment issues.

7.2.1 The cost challenge

The major challenge for CSP technology is to overcome its higher current energy cost compared not only to fossil fuel generation, but also to flat plate PV and other large-scale renewable technologies such as wind. The high energy cost is caused by the current high initial capital costs of plant, plus installation and finance for CSP generation and, to a large extent, underlies all other challenges.

The cost challenge is a '*chicken and egg*' problem - cost will come down if systems are built and systems will be built if costs come down. The IEA (2010A) roadmap identifies the biggest barrier to CSP as getting systems deployed so the technology can move down the cost curve. In an Australian context, the Clean Energy Council's large solar roadmap (CEC 2011) identifies the need to establish a pipeline of projects as a major imperitive.

The 2009 EPRI report points out that there is an extended period when a new technology is entering the commercial arena where cost estimates are very uncertain and tend to be underestimated by enthusiastic proponents. These estimates are then revised upwards as the realities of early project construction become apparent. Only after these initial developments does the decline in costs start to be seen for future projects. The report notes in regard to new technologies in general:

> 'Large differences between original cost estimates and actual installed costs have been common. Some of these differences have resulted from the type of estimate given, such as a goal type of estimate, without explicit consideration of the likelihood of achievement. Quantifying uncertainty should be an explicit part of developing cost estimates to reduce such misunderstandings.'

Figure 7-2 illustrates the concept of technology implementation costs varying with the maturity of the technology and the experience of local providers.

Australia's recent Energy Resource Assessment (Commonwealth of Australia, 2010), described the process in a similar way and attempted to locate particular renewable energy technologies on this time evolution as shown in Figure 7-3. It can be argued that, whilst the CSP industry is global and the different technology types can learn from each other's experience, every technology developer of every technology type in each country must face a separate version of the same type of experience curve. What this means in practice is that the CSP industry sees a pattern of the most encouraging cost estimates coming from many of the most inexperienced companies with the newest technology options. This is a trend rather than a rule and certainly does not preclude the idea that some of those technologies may be clear cost winners in the long run.

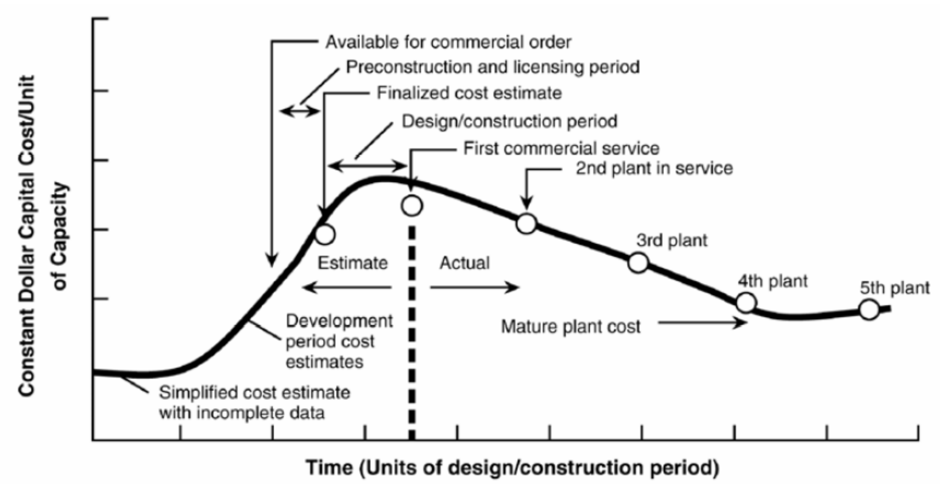

Figure 7-2: Typical cost variations for commercialising new power technologies, (reproduced from EPRI, 2009)

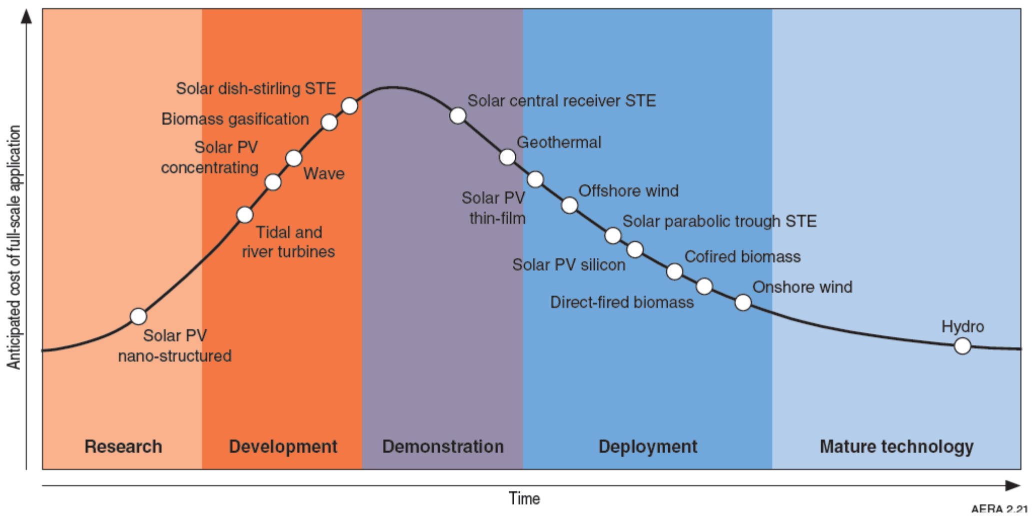

Figure 7-3: Typical cost variations for commercialising new renewable technologies, (reproduced from Commonwealth of Australia, 2010)

7.2.2 Overcoming the cost challenge

The prospects for cost reduction have been discussed in detail in Chapter 6, and are very promising. As discussed in Chapter 6, the path to cost reduction for CSP is three fold; mass production benefits, cost improvements with size, and R&D, with each of these contributing in approximately similar measure to the actual cost reductions that will be reflected in observed cost progress ratio[55] going forward. It should be emphasised though that all three are strongly cross linked in their contributions to cost reduction.

55 As discussed in Chapter 6, progress ratio is the empirical multiple which cost changes by for each doubling of installed capacity.

Major real cost reductions are not going to emerge from R&D carried out in the absence of overall industry growth. Indeed, achieving R&D-linked improvements will require ever increasing investment in proportion to industry scale, something that can only come with ongoing investment by the commercial players involved. R&D programs with limited funding are a well-meaning start, but no substitute for policy settings that result in significant deployment. R&D on its own should not be expected to deliver a 'silver bullet' for cost reduction.

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). Whilst noting that R&D can not be expected to solve the cost problem in isolation, the areas that have been identified for R&D action are summarised here.

R&D occurs at all stages from fundamental research to commerciall application. Different stakeholders have different views of what R&D is. In universities and research institutions it is a definition that favours the fundamental end. In the eyes of industry and government, it extends to include what others may classify as demonstrations. In an extreme view, even the Solar Flagships are R&D projects.

At the more fundamental end of activity it is important to note that 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. This view is very different from Silicon PV device R&D for example, which can be much more tightly defined as a discipline and for which a research laboratory must contain some key and common features wherever it may be.

Globally, the CST component of 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, although at a low level of activity. 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.

The CPV side of the equation is smaller and seems somewhat less coordinated, although it shares significant research efforts with flat plate PV. There is little overlap between the CST and CPV research communities. It is unrealistic to imagine that it would be otherwise as the main point of commonality is in the concentrator structures themselves and this aspect is largely in the commercial domain where deployment drives innovation. Research institutional efforts are largely focused on the various approaches to energy conversion. R&D around high temperature thermal systems has virtually nothing in common with the R&D of a PV receiver and its cells.

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.

Whilst there is a general consensus on CST and CPV R&D priorities globally, these are categorised and presented in many different ways.

For CPV, the European PV Platform (2011) summarised the key R&D issues as:

- Concentrator solar cell manufacturing
- Optical systems
- Module assembly and fabrication methods for modules and systems
- Trackers, inverters and installation.

The 2004 (CST) Ecostar roadmap (Pitz Paal et al, 2004) classifies priorities according to concentrator technology types further subdivided by Heat Transfer type. These remain largely appropriate in 2012.

The IEA (2010) CSP (CST) road map has a list of 10 key R&D actions with suggested timeframes. In addition to recommending increased and sustained funding, these pick out a few key high potential / high priority specific goals. Examples include "three step thermal storage for all DSG plants" 2010 – 2020 and "solar assisted liquid fuel production" 2020 -2030.

AT Kearney (2010) presented a limited number of suggestions categorised in a matrix by concentrator type versus subsystem category (collection, thermal generation, storage and electrical generation), with high medium and low priorities identified.

At a more specific level, Kutscher et al (2010) identify a range of very specific areas for tower systems and rank them by estimated LCOE reduction potential. In a similar vein, Kolb et al (2011) present an assessment for linear focus systems.

For this study, to assist priority setting, the suggestions from the sources reviewed above 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 7-1: 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	Concen-trator 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 / lens cleaning systems	All	Efficiency improve / Reduce O&M	Short	Evolut. / Step ch.	High
Receiver systems (including HTF systems)					
Improvement of evacuated tube receivers (CST)	Trough / Fresnel	Efficiency improve.	Short	Evolut.	Small
Alternative HTF's for below 500oC (CST)	Trough, Fresnel	Efficiency improve.	Short / medium	Evolut. / Step ch.	Med.
Alternative HTF's for above 500oC (CST)	Dish, Tower	Efficiency improve.	Med/ large	Step ch.	Large
Reduce HTF line losses and parasitics (CST)	Trgh, Fresnl, Dish	Efficiency improve.	Short	Evolut.	Med.
Improve receiver assembly processes (CPV and CST)	All	Constr. cost reduct.	Short	Evolut.	Med.
Thermal Energy storage systems (CST)					
Solar Fuels production	Dish, Tower	New market	long	Step ch.	Large
Other thermal storage below 600oC	All	Constr. cost reduct.	Med	Evolut. / Step ch.	Large
Thermal storage above 600oC	Dish, Tower	Efficiency improve	Med / lg	Step ch.	Large
Thermochemical storage	Dish, Tower	Efficiency improve	long	Step ch.	Large
Molten salt system improvements	All CST	Constr. cost reduct.	Short	Evolut.	Large
Electrical generation systems					
CPV cell efficiency improvement	All	Efficienc. improve	Med.	Evolut. / Step ch.	Large
Improved /Advanced steam turbs (CST)	All	Efficienc. improve	Med.	Evolut.	Med.
Advanced thermal power cycles (CST)	All	Efficienc. improve	Med / lg	Step ch.	Large
Systems optimised for 1-10MW$_e$ (CST and CPV)	All	New market	Sh/Med.	Step ch.	Med.
Improved Stirling engines (CST)	Dish	Efficienc. improve, reduce O&M	Sh/Med.	Evolut.	Small
Low / zero water use cooling (CST and CPV)	All	Efficienc. improve, reduce O&M	Sh/Med.	Step ch.	Med.

The assessment of cost reduction potential 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, cost effective, but small existing CSP R&D capability that is close to the forefront of international activity
- A strong concern around water supply and management issues.
- An identified longer term need for dispatchable renewable energy.

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.

Thus this suggests that Australian R&D activities that are largely taxpayer funded should give specific priority to:

- Hybridisation and enhancement of fossil fuel systems and exports, so as to facilitate a smooth transition to future clean energy scenarios with maximum synergies with current operating systems and business activity.
- Systems optimised for below $50MW_{e.}$ targetting Australia's particular off grid / end of grid market segments. Particular effort should be made to support innovation and build on Australian capability and experience in the off-grid and remote area market segment, where system components, and expertise could form the basis for a valuable Australian component and service industry, operating in the large off-grid and fringe of grid markets of the Asia-Pacific region and elsewhere.
- Improved energy storage for systems of all scales since this the key identified area of advantage for CSP globally and also needed in Australia. It is also an area in which realistic Australian investments could make a real difference.
- Advanced cooling systems, given the strong concerns around water availability in locations most suited to CSP in Australia.
- Improving the efficiency of advanced energy conversion systems and receivers, a clear global priority for improving economic performance and another area where realistic Australian investments could make a real difference.

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 can be argued that concentrator improvement and new concentrator design should now be carried out in the commercial arena and that institutional R&D should target fundamental changes, development of new materials and improvements to the basic energy conversion processes.

Noting the small existing CSP R&D capability in Australia and the interdisciplinary nature of the field, taxpayer funded R&D programs could be structured to help nurture and grow capability both in R&D and through flow on capability building, by for example:

- Facilitating technology licencing from the various CSP research groups and companies already operating in Australia
- Open round processes with a high level of negotiation and feedback
- Possible calls for investigation of specific sub tasks taken from the priority areas
- Avoiding direct competition with flat plate PV R&D via undifferentiated 'solar' programs.

7.2.3 Manufacturing scale-up

For CSP to achieve significant penetration in a given market, millions of square meters of solar concentrator collectors of various types along with all the supporting plant will need to be manufactured. The nature of the technology is such that attempting to import all the hardware from another country would be uneconomic, not to mention a lost opportunity to the local economy. It is likely however, that major sections of a plant will be imported and bolted together in Australia, with core items, such as the turbines, almost certain to come from offshore. Mirrors and glass are imported into this country for many locally assembled products, and we import much of our steel (despite exporting the energy and iron ore to the country of manufacture!), thus it is possible that the steel and glasswork of CSP sites would be manufactured elsewhere and imported. The larger the scale of deployment, however, the greater the chance will be that local manufacture will contribute.

To ensure local industry benefits from future CSP plants, the local manufacturing capability must be identified, established and scaled-up. This includes not just the factories but also the skills to design, manufacture, install, operate and maintain. Some components of CSP have the advantage that the manufacturing techniques, infrastructure and skills, are very similar to those encountered universally in major centres with industrial activity. Nonetheless the challenges should not be underestimated.

The IEA Roadmap (IEA, 2010A), discusses the issue of materials and manufacturing capability for CSP globally:

> "The perspectives presented in this roadmap are unlikely to be impaired by a scarcity of raw materials. Large mirror areas will be required, which may exceed current global production by a factor of two to four, so timely investment in production capacity of mirrors will be necessary. This production would only account for a few percentage points of the global production of flat glasses, however. Similarly, accelerated deployment of trough plants would require investment in production of heat collector elements. Receivers for towers are a variety of high-temperature heat exchanger, which industry has largely deployed throughout the world. Only molten salts for thermal storage may raise some production problems. They are used in large quantities as fertilisers for agriculture, but their use as a storage medium requires a high degree of purity."

Cleantech AustralAsia's (2008) report includes in their 10 identified barriers that directly effect manufacturing scale up:

> "8. There is a lack of RE industry information (such as successful case studies and investment grade data) available to investors, financiers, developers and policy makers.

9. There is a general lack of awareness and skills to develop RE technologies and projects amongst financiers, investors, policy makers, developers and consumers.”

It would appear there are no major show stoppers to manufacturing scale up in the event that the industry follows a continued growth trajectory both globally and in Australia. However, supply chains do not appear overnight.

For Australia and other countries moving into CSP, thought should be given to the capabilities that will need to grow. A suggested list for consideration is:

Manufacturing

CSP manufacturing is largely an adaptation of standard manufacturing processes used in other industries. The more established CSP technologies have precisely specified manufacturing processes, with associated skill sets, that must be implemented when new manufacturing facilities are established. In addition to this, there are skills in developing improved manufacturing systems to reduce costs with existing technologies and also to roll out new technology approaches. There are engineering, management and trades disciplines all needed.

Commercialisation

Commercialisation skills are needed for establishing new commercial operations, negotiation of IP licences and Engineering, Procurement and Construction contracts etc. Standard commerce, business, management and legal skills need to be informed by the specific issues of CSP technologies and projects.

Policy

Policy expertise specific to the CSP industry is needed for people working within all levels of government, it is also needed for industry associations, NGO’s and commercial organisations who are involved in dealing with and providing feedback to government policy initiatives

Market management

As energy markets become more sophisticated, particularly with the trend to continuous trading, skills in maximising the benefits of participation in such markets and understanding their dynamics are a valuable skill set for both commercial operators and government organisations. Operation of CSP systems in this context brings its own issues which would need to be understood by all market participants.

Construction

System construction for CSP is largely an adaptation of skills from existing industries, with the whole range of traditional engineering, project management, machine operator and manual construction skills needed. CSP projects have their own unique characteristics, with aspects such as installation accuracy and handling issues. These result in a particular adapted skill set best learnt from experience, assisted by targeted professional training.

Design

Many engineering disciplines are needed for CSP system design. There are CSP-specific aspects to the skills and there is a distinction between system design for projects employing already commercially deployed technology versus design supporting new product development and product improvement. All the CSP-specific aspects are learnt by experience and probably most effectively by newcomers receiving some specific training, then joining teams with already experienced people.

Operation

As with manufacturing, operation of CSP systems based on more established CSP technologies have precisely specified operating procedures with associated skill sets, that must be implemented when new facilities are established. In addition to this, there are skills in developing improved operation practices to reduce costs with existing technologies and also to roll out new technology approaches. There are engineering, management and trades disciplines needed.

Research & Development

Aside from the R&D priorities discussed above, there is the basic issue of R&D capabilities. Scientific and engineering R&D skills are needed if a country wishes to be a technology leader or a fast follower. R&D activities can also work in parallel with training for the other skills areas. The approaches come from a range of engineering and science disciplines. The particular nature of CSP-related R&D skills is associated with the specific instrumentation and experimental methods involved, but more importantly with being up to speed with the international cutting edge position on the particular research area. The latter is facilitated by collaborative research arrangements and secondment to international research groups.

In further considering the expertise needed, possible commercialisation models for CSP need to be taken into account. Examples include:

a) Small to medium company develops a technology from first principles based on technology concepts already in operation and gradually grows the business from demonstration to full commercial operation.

b) Original technology invention taken to start-up company, investment sought to follow the demonstration and then the commercial operation path.

c) Major Australian company starts a new division, possibly builds experience with some home grown technology, ultimately buys an existing overseas technology company and then proceeds to grow the business at home and globally.

d) Major overseas player establishes a division in Australia, possibly with equity partners. This division may ultimately spin off as an international company and develops its own business direction.

7.2.4 Facilitating manufacturing scale up

Cleantech AustralAsia (2008) suggested solutions to overcoming manufacturing scale-up issues include four of relevance to CSP:

"5. Develop tailored capacity building programs for project developers, venture capitalists/investors, project financiers, RE technicians and policy makers.

7. Establish a RE incubator program and more international R&D collaborative models to fast track commercialisation of RE technologies.

8. Undertake targeted RE business missions between APP[56] partner nations.

9. Standardise protocols and procedures for RE monitoring, measurement, verification and technical certification."

To a large extent, manufacturing scale-up is about quality control. The discussion of the value of facilitating small test systems on a scale of 1 MW_e or more indicates the importance of providing a way of qualifying new system and component suppliers. It also provides opportunities for side-by-side performance tests of similar components from multiple suppliers. A reliable supply chain that can deliver consistent, high quality product needs to be established. To do this of course requires a pipeline of orders.

Role of tertiary educational institutions

The natural assumption is that tertiary education and / or research institutions have a major role to play in the development of expertise. Clearly they are responsible for the basic undergraduate and post-graduate degree training of all the qualified professionals who become involved in the CSP industry. Roles that can be identified include:

- cutting edge R&D,
- training engineers for design, manufacturing, operation, and
- training managers, policy specialists, lawyers, economists etc for commercial and related activities.

In addition, vocational training of technicians for construction manufacturing, operation and maintenance is required.

As has been noted above, many of the skills needed to support the CSP industry are generic and obtained through existing courses. For undergraduate degrees, particularly in engineering, it would clearly benefit the industry for CSP issues and technology to become incorporated at least via elective units. At the other extreme, there are now examples in Australia and elsewhere of dedicated degrees in photovoltaic engineering being established. This is not necessarily a precedent that would be of benefit to CSP.

At the engineering level, it could be argued that engineers are best served for CSP purposes with a multi-disciplinary and flexible general training. There is however a very good case for the introduction of specialised post-graduate courses / degrees for the CSP field. Short courses, suitable as professional development for qualified engineers can also be a good option as they would allow existing skilled engineers to move more rapidly into the CSP area.

At the vocational and trades level however, dedicated and specialised training via certificate level courses dedicated to CSP plant operation for example are very valuable. To provide greatest value in this regard, such courses should ideally be conducted with access to a working CSP system, either via a small plant on the institution's campus or else via hands on access to a commercial plant or a mixture of both approaches.

7.2.5 Deployment issues

The Electric Power Research Institute (2009) notes that:

> "Successful R&D efforts resolve many technical uncertainties, but others persist until initial demonstration. Examples of technical uncertainties that can remain include:

[56] Asia Pacific Partnership

- Unanticipated interactions between system elements that previously were independently tested.
- Incompatibilities between materials or incompatibilities between utility operation and the industries from which the new technology was adapted.
- Some unanticipated operating problem that becomes significant.

Demonstration and commercialization reduce technical and estimation uncertainties, but economic and other uncertainties always remain.”

Deployment issues could include any or all of:

- excessive capital cost,
- low system performance,
- lack of long term track record,
- below specification construction,
- failure of key components, and
- failure of after-construction backup.

Lotker (1991) comments on the evolution of the SEGs plants in California. Luz initially established the smaller (15 MW_e) SEGS I and II plants in 1984 and 1985. The report notes:

> ‘Although the performance of SEGS I & II was not up to the level of projections (a classic example of excess optimism regarding performance of a technology yet to be deployed at commercial scale). LUZ quickly learned from the experience so that projections for later plants were more realistic. Thus early problems did not spell the end of the technology so long as the reasons for the difficulties were understood and the market for the technology remained healthy.’

The subsequent five 30 MW_e plants that were built successfully learnt from the technical lessons and outperformed design specifications. The later 80 MW_e plants also performed well. All the SEGS plants continue to operate in 2012.

Many of the best Australian CSP sites are in regional and remote areas, including mining towns and communities in the most remote regions. This raises a key issue for CSP deployment, since little industrial or other infrastructure may be available at the site to provide backup services and the extra costs of providing these will need to be considered. Hard lessons around deploying new technology in remote locations have been learnt from previous small-scale remote region CSP systems in Australia. Hence the additional costs of deployment in remote areas must be included when planning deployment.

New entrants

CSP technology is conceptually simple and appealing. It is also relatively easy to build basic prototypes. Growing interest in the field attracts new players at all levels; who may be naive in their approach and overly optimistic of the actual performance they will achieve. It is at the point of deployment that such players are most likely to, very publicly, come to grief. The level of effort and investment required to make a safe, high performance prototype compared to a basic amateur level one is an order of magnitude higher.

Similar increased orders of magnitude of effort are required to make the subsequent steps of first demonstration, first commercial plant and finally proven technology. The final goal of bankable proven technology usually takes investments in the billions of dollars and effort over decades. This is well known to those players who are operating commercial plants and rarely fully appreciated by new entrants. New entrants can be very vocal in promoting their ideas and lobbying government for support. Risks associated with new entrants need to be considered and carefully managed. This is especially relevant if R, D&D support is restricted to innovation or new technologies.

7.2.6 Overcoming deployment challenges

Demonstration

In addition to maintaining strict tests to minimise technical risk in large plants, the barrier of technology shortcomings in general can be greatly minimised by initiatives that enable multiple demonstration and test systems at a level of 1 MW_e or more to be put in place.

A requirement of 1 MW_e for at least 12 months is an appropriate demonstration criterion, for CST in particular, as it is essentially the minimum size that a viable central power block-based CST plant can actually be built. It is also a plant size at which, once constructed, the electricity revenue should be sufficient to cover O&M costs, such that there is every incentive to continue operation and maximise performance for several years. A 1 MW_e size is also the appropriate first step scale up for a technology that has completed an initial collector prototyping phase. It is also a very good size for a new player in CSP who is licensing an existing technology, to build experience and test locally sourced components.

Australia adopted guidelines for its first Flagship project that sought to minimise deployment challenges via requirements for previous successful demonstrated projects at reasonable scale, as well as key criteria around the financial abilities of the developers. These technical risk minimisation guidelines were sensible for the circumstances, indeed it could be argued that they should be even tighter for future programs.

Support of pilot scale and pre-commercial demonstrations under government programs should target all stages in the commercialisation spectrum. Project size, fraction of taxpayer funding and technical risk minimisation guidelines should all vary in proportion to position on the commercialisation spectrum.

Designated Solar Parks / Precincts

Solar Parks[57] or precincts can be used to facilitate demonstration of a range of different technologies, using shared facilities to reduce cost. The provision of grid-connection, water and other services, such as central energy storage and hybridisation with CCGT generators can be contemplated. Arguably the further the concept is taken, the more benefit there will be to the progress of the CSP industry. A Solar Park can also be used to provide big picture basic requirements such as labour hire, workforce accommodation and transport (rail, road, air) for a number of technology providers in one location. Of particular interest may be hybrid configurations of CSP with other renewable energy technologies, particularly biomass plant. This may allow smaller scale CSP systems to be built as part of the technology development phase, with reduced finance and other requirements. IEA (2010A) sees this also as a road towards solar fuels.

Hybrid systems

CSP has strong technology cross-links with fossil-fired generators. As a concept, both produce high volumes of high temperature steam to drive a turbine to create electricity. They are therefore well matched to form hybrid power stations, which can facilitate deployment.

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57 Solar Parks are discussed in various places in this report, they could be configured purely as precincts for large scale systems or as locations for smaller pilot scale systems or for both.

The first two major CSP stations in Australia are hybrids - The Liddell power station project and the Kogan Creek, 'Solar Boost' project.

A cooperative approach could conceivably see a series of hybrid solar-coal plants with CCS technology producing zero emissions. Nevertheless, this approach would need to take into consideration the fact that CCS is even less tried and tested than CSP, and combining two such immature technologies at the same location would increase project risks significantly and make financing even more difficult.

The other major hybrid option is the Integrated Solar Combined Cycle plant, in which a a gas driven combined cycle power plant has an allowance for injection of extra solar steam into its steam cycle.

Potentially, a solar-coal hybrid could be solar gasified coal as part of a future 'Integrated Gasification Combined Cycle' system (meaning cleaner burning and less CO2 emitted), with subsequently less required of the CCS technology.

As discussed in Chapter 6, the ISCC model does offer a lower cost gap than stand alone plants. However possibly the greatest advantage with the hybrid models, is that the size dependance of LCOE is significantly reduced. Thus experience can be gained with smaller solar arrays for lower capital cost but without unduly worsening the project economics.

Co-location with other industries

Cooling processes potentially provide opportunities for co-location with other industries where heat can be used, including desalination and bioenergy systems, although these are of course site-specific.

7.3 Societal Acceptance

Society in this context has been interpreted as encompassing the general / local community plus all arms of representative government.

The key challenges identified in the Societal acceptance category are:

- Possibility of community push back
- Government policy and support mechanisms
- Approvals processes
- Naysayers and misinformation

It can be argued that, on the whole, solar enjoys a high level of societal acceptance and this is much less of a challenge than it is for other energy technologies. This is not a reason for complacency however, as there are some potential issues.

7.3.1 Possibility of community pushback

Potential issues include:

- Visibility of tower systems and bright receivers
- Water use in water constrained areas
- Land clearing in sensitive habitats

Community consultation

Given the recent political disquiet over land use for wind farms, solar developers should proceed cautiously and ensure community support before large-scale systems are proposed.

Ensuring that other sources of income pass to people in communities that previously used the land should help ensure ongoing community support. Efforts should be made to ensure such income generation is not in itself divisive in communities. People affected by changes to visual amenity, or who may potentially question a project for environmental reasons, should also be able to see / benefit from income to the community. It is also valuable to develop community education and awareness campaigns so as to avoid the sort of backlash that has occurred with wind farms.

Land clearing

So far, most large CST plants around the world have been established under a model of completely clearing and levelling a site with earthmoving equipment and then maintaining the plant in a securely fenced and patrolled precinct. This has obviously increased community concerns about traditional land use, local vegetation and wildlife impacts.

Rather than total land clearing, it may be feasible to allow some re-growth and ongoing grazing within a plant's precinct. This has been done with some large PV systems (e.g. 43MW tracking system in Muoro, Portugal), where grazing continues as before, visual impact is improved, compared to total land clearing, and community support is high. The Brightsource "Ivanpah" project has also paved the way in this regard by developing a good approach to dealing with desert tortoise habitat in its site.

Other services

Gas, water, sewerage, roads and fencing must also be considered to varying degrees and according to the technology type being used. The CSP Technology Roadmap (IEA, 2010A), discusses non-economic barriers and indicates that the slow approvals process for grid-connection plus the difficulty of accessing water and gas are significant barriers.

Water issues are important for CST plants in particular, and to a lesser extent to some styles of CPV plants using active cooling of cells. As detailed in Chapter 2, some level of water use is required for steam-cycle makeup and mirror cleaning. Employment of wet cooling systems markedly increases water consumption, but is not essential since dry cooling solutions are also available.

Wet cooling however offers lower capital costs and higher cycle efficiency and so uses water to good economic benefit. Water issues present a potential barrier at several levels including the:

- potential limited physical availability of clean surface water,
- potential limited access to artesian basin water,
- approvals process for accessing water supplies, and
- cost of supply, storage and recycling infrastructure.

Dry and hybrid cooling options

Where water is unavailable or has competing higher value uses, dry cooling options can be implemented for some technologies. However, the IEA CSP Roadmap (2010A) estimates a 10% cost penalty and a 7% production penalty in moving from wet to dry cooling for trough systems. An alternative hybrid cooling option exists, whereby dry cooling is used in the cooler winter months and wet cooling in summer, or the hotter parts of summer days. The production penalty for trough systems is estimated to be only 1% for a 50% saving on water use (ibid).

Water is clearly an issue of high community concern in Australia. Nevertheless, from an economic perspective, it would be unwise to simplistically insist that all CSP systems use dry cooling, since an analysis of the implied value of water when used for cooling is much higher than most alternative uses (PMSEIC 2010).

Significant research, development and demonstration is recommended to better mould CSP into a palatable solution for Australia from a water use point of view.

Best practice guidelines

To ensure Solar maintains its “clean green” preferred renewable status, the industry must deliver EIS and community consultation processes that are exemplary. To facilitate this, and ensure consistent high standards are met, the development of a “Best Practice Development Guide for Solar Projects” is recommended.

The Government of Western Australia has published a ‘*Renewable Energy Handbook*’ (Government of WA 2010) which provides a good example of a guide for the renewable energy industry, investors and other stakeholders.

7.3.2 Government policy and support mechanisms

Social acceptance is important for governments as it serves to endorse or even drive associated policy support and facilitates change.

Maintaining community support, however, requires that governments manage programs and projects well, minimise poor outcomes, provide transparent processes for participation and communicate outcomes. This in turn requires policies and programs to be well structured, with a long term focus, community involvement and a clear strategy articulated.

7.3.3 Project approval processes

Without suitable sites and approvals, no project can proceed. Generally speaking, land is available through some commercial avenue and every country has some sort of approval process that should not be inherently worse for a CSP project. However both these issues can be extremely onerous in "remote" locations that are more likely, under a material change of use scenario, to be affected by Native Title Claims and general public objection. There is great scope for facilitation and streamlining the process, while maintaining the public and the indigenous owner's rights.

The IEA's CSP roadmap (IEA, 2010A) discusses non-economic barriers. It indicates that the slow approvals process, grid connection issues and the difficulty of accessing water and gas are the most important difficulties. For example, the environmental approval process in California can take up to 2 years.

Designated solar parks

As previously discussed, one method for dealing with land and approvals is possibly the establishment of large-scale Solar Parks, pre-approved for CSP operations. However, even solar parks will require prior processes of community consultation and land allocation.

It is important that there be some eligibility tests that developers must pass to ensure that allocations within parks are not used speculatively. The optimal process may include:

- A rapid in-principle allocation process that gives initial certainty to developers.
- Automatic loss of allocation if financial closure is not achieved in a reasonable timeframe.
- Permission to construct immediately following financial closure but contingent on lodgement of bonds to allow for site clearance if the project is not completed.
- Automatic loss of allocation if the project is not constructed in a reasonable timeframe.

7.3.4 Naysayers and misinformation

CSP and the renewable sector in general does have some vocal opponents, particularly lobby groups working to protect the interests of incumbent industries, that continually misrepresent solar's capability and dismiss its potential. It doesn't help that, like most emerging technologies, solar has the odd setback through a failed project or company that has been hyped beyond realistic delivery capability.

Overcoming misinformation

Credible information, accompanied by a series of successful demonstration projects, via a Solar Park or otherwise, is the best way to overcome current negativity. Because of the range of technology options available, such demonstrations will need to encompass all options and hence would probably best be done via a series of small plants (2-50MW). Even if the small scale cannot capture the lowest LCOE, demonstration would facilitate further uptake, as well as the establishment of suitable support infrastructure and expertise in Australia.

7.4 Market Development

Key challenges identified in the Market Development category are:

- The current cost gap (also identified as a key technology challenge)
- Financing
- Operating in a global market
- Availability of solar and other site data
- Grid services and connection

7.4.1 The Cost Gap

As noted above, high capital cost of CSP technology is a major technology challenge. The analysis in Chapters 5 and 6 has shown that there remains a large gap between realisable market value and energy cost (LCOE) at present in Australia. This is also true in other countries except where policy interventions have been made to bridge the gap.

The cost gap is the most significant challenge to the development of CSP in Australia, all other challenges are of secondary significance.

It is of little value to identify potential market sectors and their hypothetical volumes unless steps are taken to bridge the cost gap.

Global experience in CSP and other technologies offers pointers to the possible measures than can be considered.

7.4.2 Options for developing markets with a cost gap

The options to bridging the cost gap can be divided into those that are relatively generic and those that may be more suited to particular market sectors. For example, small-scale PV has generically been supported through policies such as the Solar Homes and Communities Program (SHCP) then Solar Credits as well as feed-in tariffs, whereas off-grid PV was supported through the Remote Regional Power Generation Program as well as programs such as Bushlight. Such specific programs recognised the special circumstances that may be faced by particular sectors.

The market sectors discussed in Chapter 4 can be broadly divided into grid and off-grid. As discussed, the off-grid market is relatively small and faces significant non-price barriers to deployment including low loads, making them only suitable for some system configurations, and mines which have short lives and high risk avoidance. Thus, measures to bridge the cost gap need to consider the nature of the various sectors.

The grid-connected sector can in turn be divided into medium-scale and large-scale. Medium-scale is connected to the distribution network and minigrids, where 0.1GW-scale flat-plate PV is already being deployed. The attractiveness of CSP would be improved if it included storage and so was dispatchable, and so policy measures to bridge the cost gap could leverage these capabilities. Large-scale flat plate PV would also benefit from similar types of policy measures, although they are also more likely to actively participate in the electricity market as a semi-scheduled rather than scheduled generators (requiring storage), and so policy measures to bridge the cost gap could reflect this. Of the measures discussed below, Policy measures that have been used in various jurisdictions and have been proposed (see for example Richter et al 2009 or AT Kearney 2011) to bridge the cost gap for CSP until technology costs decrease and which could be appropriate for Australia include:[58]

- Feed-in Tariffs
- Contracts for Difference (CfD)
- Renewable Portfolio Obligations
- Put options on LGCs
- Direct subsidies (eg. Solar Flagships)
- Investment tax credits
- Tax flow through

These measures can be divided into those that provide ongoing support and those that help the initial investment. This has important implications for how they are funded, with long term measures generally funded by electricity consumers – which increases electricity costs, and is currently looked on unfavourably by governments, because of the many price pressures already in the market. The exception here is the LGC put options, which only require a government guarantee, and possibly payment at the term of the contract.

It is possible that the optimal policy setting could include a mixture of short and long term approaches that compliment each other, such as put options on LGCs, tax flow through and loan guarantees (discussed in the next section).

Feed-in Tariffs

Fixed Feed-in Tariffs dedicated to particular technology classes have been used in Spain, Germany and elsewhere and have played the major role in successfully bringing the CSP industry to where it is. FITs have been used in several Australian States / Territories to boost the uptake of domestic PV systems but have now largely been wound back.

It is clear from these experiences that, while FiTs can be very effective, if improperly designed they can have undesirable consequences. For example, in Spain, the $50MW_e$ limit on system size resulted in the construction of multiple identical $50MW_e$ systems, despite the recognition that larger systems would be more cost-effective. The NSW FiT for small-scale systems was far too generous and drove much higher levels of deployment than expected, and had no in-built mechanism to limit the scheme costs. Sudden cancellation of the scheme resulted in a boom-bust cycle and damage to the industry.

The design of a FiT is quite complex and so is not addressed in detail here. However, as a general rule, a FiT should be appropriate for the optimal system size and should guarantee payment to the system owner for long enough to ensure payback within a reasonable time. This will create market certainty, attract investment and deliver meaningful economic and environmental dividends.

To allow for changes in installed costs over time, the FiT should be fixed only for the systems installed in any one year and may be changed for the systems installed in successive years. A clear end or exit strategy should be incorporated from the start, preferably through staged reduction of support over time or in line with cost reductions or deployment levels.

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[58] Note that measures to aid financing (such as loan guarantees) or to, for example, enable project development (such as solar parks) are included elsewhere in this report.

One of the shortcomings of fixed FiTs is that, if they are high enough to build profitable projects, it is argued that they do not drive cost reduction and innovation as much as more responsive approaches. To address this, both the “Solar Mission” in India and the ACT Large-Scale Renewable Energy Auction, for example, involve a reverse auction process for establishing what is hoped to be an appropriate level of FiT.[59] In essence, potential project developers make sealed bids for a specified capacity of generation at a specified FiT. The government then chooses sufficient capacity to meet the target.

The ACT auction is yet to take place, however in India this initiative has clearly resulted in some major discounts compared to the baseline capped tariff. The main risk with this approach is that in the competition to secure an allocation, adventurous bids could result in projects that ultimately cannot follow through to either financial closure or construction and successful operation.

A problem with traditional FiTs is that large-scale renewable generators are not exposed to market price signals (because they were just paid a fixed amount per MWh). One solution was to have a FiT on top of the wholesale market price. However, while this meant that generators would be exposed to market price signals, it also meant that they could earn windfall profits if spot prices increased over time, and vice versa, leading to increased risk for both generators and government. Even this approach has a diluting effect on the incentive to generate to match demand, because a substantial share of the revenue is time independent.

It should be noted that there seems little political appetite for FiTs in Australia..

Contracts for Difference

Contracts for Difference (CfDs) are contracts between two parties where one will pay the other the difference between the current value of an asset and its value at a particular time. If the difference is positive then the buyer pays the seller and vice versa. When applied to electricity generation, the strike price (contract price) of a traditional CfD would be set at what is expected to be the average price for the electricity. Thus, as the actual electricity price varies around this value over time, each party pays the other, so that the revenue for the generator is evened out.

However, CfDs can also be used to provide support for particular generators by setting the strike price above the expected average electricity price, where the difference is set according to what is thought necessary to make the generator financially viable. This difference is essentially equal to a FiT. The British government has recently announced that CfD FiTs will be used to support large-scale renewable energy generation, probably from 2014 (DECC, 2011).

In some configurations CfD’s are virtually identical in effect to FiT’s

CfD FiTs have been proposed to expose a generator to market signals, stabilise the income earned through the support mechanism and ensure governments (or the electricity sector) need cover only the minimum amount necessary. A CfD FiT could expose a generator to maximum market signals if it was based on installed capacity using capacity value determinations as discussed in Chapter 5 rather than set per unit of energy.

The UK CfD FiT proposal, and the ACT large-scale FiT, the CfD would apply to actual generation, in which case they would no longer be exposed to market signals.

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[59] Note that the ACT FiT is in fact a type of CfD.

- Note that, as discussed in Rivier Abbad et al. (2012) and DECC (2011), there are many different aspects to be taken into consideration when designing a CfD FiT. How is the strike price set? (eg. by independent experts or reverse auctions)
- Will the CfD FiT be one-way (where, for example, a RE generator would not need to pay back income if the spot price goes above the strike price), or two-way (where it does).
- Will the quantity be based on actual generation or expected?
- Will the daily generation profile be different for different types of generators?
- Will the annual profile be different for fully dispatchable, semi-scheduled or intermittent generators?
- How is the CfD FiT to be funded and the funds collected?

Renewable Portfolio Obligations

The Australian Renewable Energy Target is an example of a class of schemes often called Renewable Portfolio Obligations or Renewable Portfolio Standards in other countries. It is divided into the Large-Scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). Only the LRET is of interest to CSP and so the SRES is not analysed.

The LRET has a mandatory target that is expressed as a specified quantity of renewable energy per year. Renewable energy generators create a certificate (Large-Scale Generation Certificates, LGCs) for each MWh of generation, which they sell to liable parties. The price of LGCs is set through trade in an open market as well as bilateral contracts, and is capped by a penalty for non compliance. In Australia, the LRET has very successfully brought on renewable generation. Despite dire predictions when it was introduced, installed capacity has consistently been ahead of target and tradeable certificates have remained at low prices.

As it stands, the RET has the effect of almost exclusively causing the take up of the cheapest technology on offer, which has been wind until now. While it will improve the economics of CSP, it will not be sufficient to make a CSP plant financially viable. As a result, there has been some debate over dividing the scheme into bands for specific technologies. However, banding is by definition ‘picking winners’ within the renewable energy sector, and as such can be divisive and much debate on the technology descriptions and fractions will be needed.

A general band for ‘solar’ would most likely see the uptake of utility-scale PV in preference to CSP for many years, and although a band for CSP would clearly have the desired effect of driving installed CSP capacity, extreme care would need to be taken in defining what qualifies for the band: Should CPV be part of a CSP band or a PV band? Should the different CSP technologies have their own sub bands? How should hybridisation be treated? How should energy storage be treated?

Another approach is to modify the Renewable Energy Target to reward desired outcome characteristics.

At present a Large Renewable Energy Certificate (LREC) is simply a measure of energy produced. Whilst the projects that are built earn income from both the ‘black energy’ market in which they are connected plus the Renewable Energy market, the LREC that is in proportion to energy only is effectively dampening the signals regarding time of day or other characteristics that exist in the NEM or STEM markets.

Arguably, Australia’s NEM and STEM markets have developed a quite sophisticated approach to obtaining the electricity supply needed to meet demand and expected characteristics with acceptable reliability in a least-cost way. Adding a simple renewable energy only target onto this does not provide a smooth trajectory to an ultimate clean energy electricity sector that keeps the desirable characteristics of the NEM and STEM approaches. Rather, renewables should also need to participate in and be rewarded by the market, albeit via premium payments in the short term.

A policy measure that would amplify the spot price is to modify the RET rules such that tradeable certificates in notional 'MWh' are earnt in proportion to actual generation, scaled to the relative value of the energy in the relevant mainstream market at the time of generation, i.e.:

> *[LREC Certificates earned]= [MWh generated] x (all value earned in the relevant main market place)/(Average value of the main market for previous week)*

This would potentially capture; pool prices, ancillary services and capacity certificate value as appropriate. This would be technology neutral and for example, be expected to help enable biomass and geothermal systems also.

A challenge with this approach, however, is that it raises the 'Phantom RECS' problem that was associated with the multipliers applied to small PV systems when they were included in the combined MRET scheme. These resulted in the spot price of RECs dropping to the point where the scheme needed to be redesigned into the large-scale and small-scale components.

Put options on LGCs

The uncertainty in the price of LGCs into the future increases project risk, making finance more difficult to obtain. The government could back Put Options on a CSP plant's creation of LGCs by funding the purchase of these options on the CSP generators' behalf. The CSP generator would then be able to guarantee sale of future LGCs at a predetermined price. This approach shouldn't require ongoing financial assistance from government, only a guarantee to make up the difference between the strike price and the realised price at the term of the contract. A variation of the put option could act in the same way as a CfD by having a strike price significantly higher than the expected LGC price.

Direct project subsidies

The Australian Solar Flagships scheme, plus many other government schemes, are examples of actions in this category. The rationale for doing this is that the upfront capital cost is a significant barrier and a direct subsidy can help overcome it. However this is not an approach that would efficiently continue into years of sustained industry growth. With the money originally allocated to round 2 of solar flagships now rolled into the new ARENA, it is not clear where the next tranche of direct project subsidy will come from.

Investment tax credits

Investment tax credits are widely used to encourage exploration and development of fossil fuel projects and could be applied to CSP. For government, they reduce tax income, rather than requiring actual expenditure. For industry, however, they do not overcome initial capital raising needs, although they reduce ongoing costs once the project is in operation, at least in the early years. The project would need to be economically viable and thus likely to have a tax liability for this approach to be useful.

Tax flow through

The cost structure of CSP projects is such that most of the costs occur early on, while the revenue occurs over a very long time. Thus, the tax benefits of the initial costs can only be realised over time. Tax flow through allows the tax benefits of the costs to be used to offset the tax currently payable by other entities involved in the project investment – potentially realising an immediate gain, if tax is otherwise payable elsewhere. Such devices have previously been approved for selected agro-forestry and film industry investments. Anecdotally, this approach may be able to improve the LCOE of solar projects by 10% to 15%.

Choosing options

Of the options, FiTs, CfDs and RPOs require ongoing funding from consumers, which increases electricity costs, reducing their political appeal. Put Options on LGCs also provide ongoing support, but only require a government guarantee, and possibly payment at the term of the contract – especially if a 'CfD version' of the Put Option is used. Direct subsidies require an initial payment by government, but are subject to the complications and uncertainties surrounding any government program, and so are unlikely to be successful in driving the establishment of the CSP industry over the long term. Investment tax credits and 'tax flow through' can reduce the upfront costs and are not subject to the whims of a particular program, but instead simply provide technology-neutral support to all entrants – although they still suffer from sovereign risk as governments can remove them at any time.

A combination of measures is likely to be required, that together both reduce the cost gap and enable financing.

- Reducing the cost gap could be achieved using measures that offset the capital cost (such as tax flow through) as well as measures to provide ongoing support (such as LGC Put Options, which could be structured in a similar way to a CfD to provide additional support).
- Neither of these options would increase the cost of electricity to end-users.
- Alternatively, a market-based technology neutral reward mechanism could be established to make income received by renewable energy systems proportional to the price / demand for energy at the time of generation.
- Loan guarantees, as discussed below, could also be used to reduce risk, enable cheaper finance and so reduce the LCOE.
- While CSP's contribution to reduction in line losses is recognised, it's potential reduction in loss factors is not. Mechanisms to recognise this reduction should be developed.
- Procedures to value CSP's ability to defer network augmentation should be developed and integrated into AEMO's network planning processes.
- In the interim, funds of equivalent or greater value to those originally allocated to CSP in round 2 of solar flagships should be made available under a similar program, but that a series of smaller systems be targeted.

7.4.3 Financing

Improvements in CSP technologies are limited without a series of major installations occurring over many years. Each of these projects must be successfully financed. The financial viability of a project is usually the sum of its attempts to mitigate risks and overcome a series of barriers, with a complex mix of investor, grant, equity and debt financing. The key risk categories can be summarised as:

- Technology risk – Is the product mature and can it deliver?
- Deployment or construction risk – can it really be built in Australia?
- Output risk – how long will it operate for and what guarantee of output is there?
- Income risk – what long-term Power Purchase agreements are in place?

To achieve financial closure, the revenue equation must provide the investors and the bankers with an acceptable IRR for the perceived level of risk – this IRR will vary between the investors, the equity providers and the debt providers. All the other barriers contribute to the risk profile of the project and may be showstoppers or may lead to a risk premium on the rate of return expected. Kistner and Price (1999) review the various models for project financing that remain relevant today.

The "construction risk" of a project is a significant barrier for a financier. Most major lenders are extremely conservative, and as such when a new technology, process or format is approaching its first major rollout in Australia, the banks and lending bodies are very nervous about the success and failure prospects.

The result of this is that most early stage technology developments are funded by Venture Capitalists to a point where they are considered ready to construct their first major project. Generally that first major project will need an institutional investor with a willingness to take significant risk, in return for high capital returns or a large stake in the technology provider – but this can only happen once or twice to a particular technology. Then as an "owner", the investor needs to be prepared to continue investing in the technology until it becomes a mature technology that can meet the risk needs of traditional lenders.

An example is the Solar Systems relationship with TruEnergy. Solar Systems acquired LETDF funding for its 154MW plant to be located at Mildura in Northern Victoria. It then went to the Venture Capital market looking for an investor and project sponsor. TruEnergy took a large stake in Solar Systems, providing a cash injection of many $10's of millions in return for a large portion of the company's equity. Not all companies are willing to do this, and investors with such a long term view are few and far between when the investment is >$10M and the returns may be 10 years away.

Operating solely on project funding means an equity investor owns part of the project, but not the technology. Thus there needs to be surety that the technology will deliver on time and over the long term. A first rollout therefore is considered very risky, with equity financing being at much higher IRR's – well into the 25-30% range. Most renewable projects cannot deliver such returns, even on a 30% equity structure and a debt IRR of around 10%.

Anecdotally some financing firms consider this construction risk so large that the statement "you go and build it, and we will finance its operation post construction" is not uncommon. Discussion in the market indicates that this position has been heard in relation to PV, CPV and CST – the financial markets do not yet view any of the solar technologies as "mature". This factor is believed to have cost a Top 8 Flagships bid the chance to secure funding.

This risk averse position by financing institutions means that it is seen as virtually essential for a large project to secure a Power Purchase Agreement in order to access any level of debt finance. This presents another major challenge. The nature and structure of the Australian Electricity market to date means that the long term and large PPAs needed for a major solar project are new territory for the most likely uptakers. With just a few major retailers operating at a time of likely future surplus renewable energy certificates and high uncertainty around future electricity prices, it is not surprising that securing a PPA is challenging. At the time of finalising this report, the Solar Dawn flagship project faces an uncertain outcome as the consortium has required an extension of time to continue to work to secure a PPA as a pre-requisite for financial closure and the incoming Queensland state government have declared an intention to withdraw their support.

In addition, accessing capital requires that CSP project developers provide production guarantees over the system life. Such guarantees can only be provided if the proponents have confidence in their technologies and components. Working with component suppliers which have an established reputation in related sectors can assist, as can lifetime component testing against relevant standards, even if specific standards for CSP are only in their infancy.

For Australia in particular, on top of the risks cited above, is the competition for capital with high return projects, such as in the mining sector.

7.4.4 Assisting project financing

There are large amounts of capital available globally in the Clean Tech sector. Clean Edge (2011) estimates over US$130b per year available for solar alone by 2021, as shown in Figure 7-4.

Cleantech AustralAsia (2008) categorised the possible sources of finance for clean energy as:

- R&D financing - including government grants and researchers personal capital.
- Micro Venture Capital - suitable for small start-ups, Micro Venture Capital often has a strong social agenda.
- Venture Capital - high rate of return expected with clear exit strategy, funds commercial initiatives in the range US $1m - $10m.
- Private Equity - global funds from Institutions and individuals taking equity, typically more than US $10m in commercial operations.
- Project Finance - debt or equity investments from banks or institutions against the projected revenue streams of specific projects.
- Corporate Finance - large corporations acquiring or establishing divisions with investments of more than US $10m.

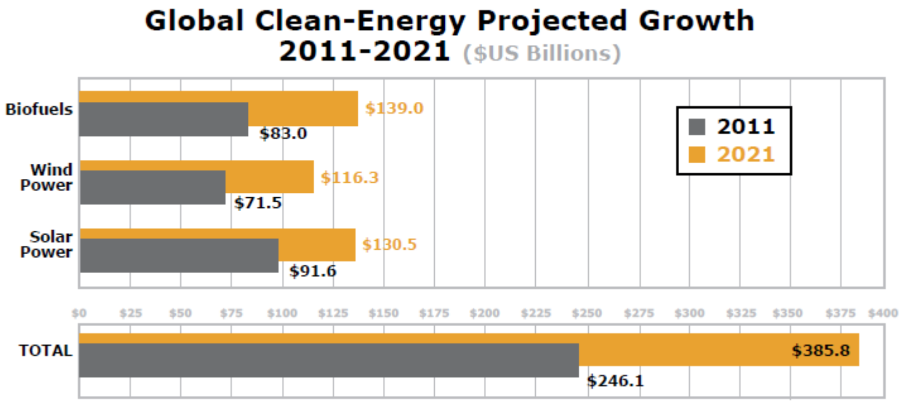

Figure 7-4: Global investments in clean energy 2011 and 2020, (Clean Edge, 2012)

There are a number of paths to accessing this capital The establishment of the Australian government's Clean Energy Finance Corporation clearly recognises the need to address financing challenges. It would desirable if any initiatives by the CEFC were planned in parallel with policy settings around price. Facilitated financing will only help if the settings are in place for adequate cost recovery through income.

Assistance could come in the form of equity investment, facilitation of loans or a direct intervention to offer PPA's for energy that can then be on sold.

Finance could be facilitated by direct provision of loans or alternatively the provision of loan guarantees. In many ways the results are similar. It could be observed that direct provision of loans allows the lowest possible interest rates, whereas a loan guarantee will still need to include some commercial margin in determining its rates. Direct provision of loans does mean that the pool of capital is limited to the amount of public funds made available. The recently released expert review of the CEFC (commonwealth of Australia 2012) favours the direct loan approach.

A government loan guarantee removes the risk of default for the provider of debt finance. This removal of risk allows proponents to negotiate significantly lower interest rates for their debt, which in turn improves the competitiveness of the project. Ideally, loan guarantees should be unconditional, long-term and subordinated.

Putting this in historical context in Australia – Private Equity IRR's can be obtained for 25% for a "risky" project, with Debt IRR's at around 10%. Equity-debt ratio's of 30:70 are common structures, thus an IRR of 14.5% is normally needed to meet the scenario for investment.

If that debt comes from a loan guarantee using Australia's AAA rating, the debt element could be acquired at 3%. A significant proportion of the project's risks are mitigated by having a loan guarantee at a low interest rate, as the need for high risk PPA's and performance guarantees are lower. Thus the equity raising is now less risky, with lower returns, typically around 16%. With an equity:debt ratio of 30:70, the required project IRR would be 6.9%.

The US loan guarantee scheme for solar projects has another benefit: a loan guarantee is not offered unless the project proponents and the proposal successfully pass an onerous assessment process. This minimises the chance of taxpayers actually having to pay out on the guarantee. It has the added benefit of signalling to the financial market that the project is investor ready. Brightsource Energy's 400 MW_e Ivanpah Distributed Power Tower project has been a successful CSP recipient of a US loan guarantee. Unfortunately, the US PV company

Solyndra recently failed, despite receiving a US$500 million loan guarantee and thus causing the US Government to rethink use of this mechanism.

7.4.5 Operating in a Global Market

CSP, like other RE technologies, is a global industry. To date, the major commercial efforts have been initiated by Western European and USA-based companies. These companies are also essential players in new markets. Conversely, upcoming commercial operations for countries such as Australia almost certainly need to consider activities in the Spanish and US markets, plus upcoming activities in India and China. Thus the issue of doing business in a (business) culture other than the place of origin will be encountered by all major players. These can include:

- risk management,
- quality control,
- staffing levels,
- occupational, health and safety,
- lead times on supply,
- Intellectual Property protection,
- contract law, and
- government interactions.

For these reasons, international CSP technology companies typically work with locally experienced power engineering firms, which already have the local knowledge and contacts necessary to deliver large-scale power systems. Nevertheless, since large-scale solar plants have not been built in Australia, a range of new information and skills will need to be gathered.

Additionally, with a global scale-up of manufacturing, there remains a risk that low cost offshore manufacturing will win out over manufacturing in Australia. While the previous section alludes to this being unlikely given the nature of the technology, this would not be the first industry to be surprised by the ability of Asia to produce mass quantities of project elements and ship them to Australia at a price cheaper than local manufacture. Inherent in this 'import everything' approach, within the context of matching business cultures, is the important issue of quality control. While this is an item for each individual project and technology to consider, it is a huge risk to an industry that needs to project reliability in order to achieve credibility.

Facilitating Australian involvement

For Australia, the idea that the CSP industry and market is global should be embraced. Operating in a global market represents a considerable opportunity. Adoption of appropriate standards can help facilitate this. Actions that help facilitate investments by Australian entities in global CSP players could be considered. In this regard some of the educational and awareness raising ideas could be targeted at institutional investors such as superannuation funds managers. Further development of Australian expertise, in the off-grid market area, in specific aspects of component manufacture, in system integration, or other areas, could also allow Australian participation in the global supply chain, independently of the rate of local main grid market development.

Development of templates or checklists for project developers, covering all aspects which need to be addressed for projects in the Australian market, may be a useful way to reduce up-front project development costs and overcome barriers emanating from the global nature of the market. Sample contracts could include specific Australian requirements relating to land use, water use, construction employment, operation employment, power purchase agreements and many more.

7.4.6 Availability of solar and other site data

Reliable long term DNI data collected at high frequency is needed to predict system output accurately. The importance of this is mainly as an input to investment decisions. Where uncertainty remains in the prediction of future DNI levels, project developers need to assume more conservative outcomes and so this affects the probability of successful financing.

The IEA's Technology Roadmap (2010A) specifically recommends:

> "Facilitate the development of ground and satellite measurement/modelling of global solar resources."

However, all efforts at data collection do not address the larger issue of changes to DNI resources due to climate change. There is scope for a thorough investigation of state-of-the-art modelling efforts in this direction also.

The absence of a robust body of solar and weather data means that commercial project developers are installing their own monitoring stations and carrying out their own data correlation. Such activities require a considerable investment and once complete are kept commercial-in-confidence. There is known to be a body of valuable data held by unsuccessful solar flagships bidders and others. These key commercial players should consider the broader benefits that could accrue if this was pooled and shared publicly.

Public data

Publicly funded investigations that place the information in the public domain have a high enabling potential. They remove an area of cost delay and uncertainty for all technology developers and so allow the industry to concentrate its efforts on the technology. They are also very useful to training and research purposes.

In a positive move, more sites are being included in Bureau of Meteorology DNI data collection, however this is really just a reversal of past reductions. Further extension of Bureau of Meteorology DNI data collection, both to extra sites and to higher frequencies should be considered.

Given that this initiative is now progressing on various fronts, it should be noted that 5 to 10 years of good data are needed to make an accurate prediction of plant lifetime output, and so it will be quite a few years before the new monitoring stations deliver the certainty needed.

There is scope to improve data availability in a much shorter time frame. Even a few months of on-ground site data can serve to help calibrate the existing satellite-based data. Going beyond this, there is considerable scope for deriving much greater benefit from the data that currently exists. If all possible sources of data, either DNI or global radiation measurement, plus ambient temperature and humidity together with all the various satellite based predictions are assembled in a single data base, then using state of the art statistical techniques, an optimised model could be built up. Approaches like this can, for example, identify when ground based DNI data from a particular site at a particular time appears to be out of calibration and can then retrospectively re-calibrate it. It should also be possible to link, by appropriate interpolation in time and location, humidity and ambient temperature to DNI results. Geoscience Australia is in the final stages of a project to do this at a high level (Hammond 2011).

A key issue that need to be considered also is that predicted future climate change is likely to change the solar resource in different regions. Modelling such potential effects are as important or more so, than the consolidation of historical data.

7.4.7 Grid and services connection

The best CSP sites are likely to be distant from population centres. However, all medium to large-scale CSP plants need a grid-connection, and generally that grid connection has to be at Extremely High Voltage (EHV), typically 132kV and above. As is discussed in Chapter 4, the Australian electricity grid hugs the east coast, with few exceptions. Thus there are very few areas where high capacity transmission lines at EHV enter the interior of the country, where there are high solar radiation levels. The few locations include Kalgoorlie, Olympic Dam, Broken Hill, Bourke, Moree and Barcaldine.

This is the same issue faced by the Geothermal Industry, although large-scale solar could be argued to have better locational prospects than geothermal, given the resource is much wider spread.

In assessing this problem, it is important to understand several key issues:

- The National Electricity Grid is designed around central dispatch from a small number of key generation points – SE Qld, Hunter Valley and Latrobe Valley being the main sites, with smaller dispatch points at Port Augusta and around Gladstone.
- The electricity network was built, on the whole, over a 60-year period using Australian Government borrowings and Australian Government AAA ratings, to allow the development of the coal-fields (and at Portland, major industry) in each state and to facilitate the construction of an integrated electricity network in each state, and then an integrated East Coast grid.
- Unless Solar can co-locate with existing major generation sites, there is a need to extend the transmission network to accommodate large-scale solar connections.
- The large scale extension of the Transmission network is a major nation-building exercise that cannot, at this stage, be supported by the solar industry alone.

As a result, it is clear that extending the transmission network will require significant Government involvement, and probably co-location of several generating plants.

There are potential benefits to the network operators in avoiding energy losses and avoiding expensive infrastructure upgrades if generation resources can be co-located with large energy load centres. There is also potential for the CSP industry to benefit from current large network expenditure, if lines can be strengthened around suitable solar sites.

High Voltage DC transmission lines

Action on establishing long distance HVDC grid extensions could be a significant enabler for large-scale solar plants, including cross-border connections.

With many billions of dollars currently being spent on networks in Australia, there is scope for transmission connections to be built to facilitate future solar power station construction. It is worth noting that there are serious moves in Europe to interlink the whole of the middle East and North Africa to Central Europe via a network of HVDC links over distances of the order of 1000s of km (AT Kearney 2011). Similar proposals have been made in our region, linking Australia with Indonesia and other sites.

Distribution Networks

As more Distributed Generation (DG) is being connected to the distribution networks, there is increased interest in potential impacts, both positive and negative. This is a very complex area and at this stage most DNSPs are very cautious about allowing significant levels of DG on their networks. The Electricity Networks Association recently released a very detailed discussion paper, *Impacts and Benefits of Embedded Generation in Australian Electricity Distribution Networks* (Senergy 2011*).* Some major findings of the report were:

- There is a wide range of potential impacts of increased penetration of DG on distribution networks: voltage fluctuations, voltage rise and reverse power flow, power fluctuation, impacts on power factor, frequency regulation and harmonics, unintentional islanding, fault currents and grounding issues.
- These impacts generally only occur at relatively high levels, although this level is dependent on the characteristics of the network as well as the associated loads.
- Rules of thumb, such as the "30% rule" used in the US to screen generator connections, are not adequate to assess the impacts.
- Specific studies are required to assess the allowable penetration of DG on a particular distribution feeder, and consequently the additional equipment needed to allow higher penetrations.
- There are existing technological measures to mitigate the issues identified.
- As the majority, if not all, of the issues associated with DG can be overcome through customer expenditure or network investment in known solutions, the primary issue is more economic than technical.
- Planning, design, operation and maintenance approaches and practices will need to change to manage significant penetrations of DG.

It is likely that the various stakeholders need to work together to enable higher penetrations of DG: DG proponents don't fully understand the constraints under which the DNSPs operate; and DNSPs don't fully understand the operational characteristics of different types of DG, as well as the variety of technical options available to enable higher penetrations. There is also a growing recognition that the technical and governance arrangements are inadequate and need updating.

The Australian Energy Market Operator has published reports entitled 'Network Extensions to Remote Areas: Parts 1 and 2', where major enhancements to the 500kV grid are examined, as well as using long-distance HVDC to connect remote renewable generation. As part of their stationary energy plan, Wright and Hearps (2010), with input from Sinclair Knight Merz, have also produced detailed proposals of possible transmission grid augmentations to the generation assets they propose as shown in Table 7-2. These represent an example of a portfolio that make up the nation building type extensions needed to take CSP beyond the first 15GW of technical potential.

The CSP sector should engage with the electricity industry to advance network extension options going forward. Both smaller options for the near term and the larger vision in the long term. Suggestions include:

- engaging with AEMO and the Transmission industry on the National Transmission Network Development Plan, including the potential for major Transmission grid upgrades and builds, strengthening existing inland lines and potentially building major new infrastructure like Copperstring or Olympic Dam-Brisbane loop. There is significant

Transmission Network spending available in the next 5 years, and currently CSP is not being catered for in the planning mechanism.

- engaging with the Electricity Distributors to raise awareness and recognition of CSP's beneficial effect on the 66-11kV grids that abound inland from the coast along the eastern seaboard. This would involve analysis of the non-network solutions to grid stability and constraint issues, and determine the benefit that can be delivered by CSP, and it's value, to network operators. This could create a market for mid-scale CSP.

Table 7-2: Possible transmission line upgrades to facilitate CSP projects (from Wright & Hearps, 2010)

Solar plug in upgrades	Type	Length (km)	Capacity (MW)	Cost (million AUD)
Carnarvon to Geraldton	HVAC	499	6000	$3,610
Kalgoorlie to Perth	HVAC	560	6000	$3,895
Broken Hill to Mildura	HVDC	262	4000	$1,936
Bourke to Mount Piper	HVDC	567	4000	$2,293
Dubbo to Mt Piper Direct	HVAC	249	3000	$1,220
Moree to Armidale	HVAC	364	6000	$2,980
Prairie Plugin	HVAC	296	6000	$2,660
Longreach Plugin (direct)	HVDC	654	4000	$2,395
Charleville to Roma	HVDC	311	4000	$1,993

Grid upgrades	Type	Length (km)	Capacity (MW)	Cost (million AUD)
Roma to Moree	HVDC	417	4000	$2,117
Port Augusta to Mount Piper	HVDC	1169	8000	$5,994
Mildura to Mount Piper	HVDC	708	4000	$2,458
Mildura to Melbourne	HVDC	544	8000	$4,533
Port Augusta to Mildura	HVDC	461	4000	$2,169
Port Augusta to Melbourne	HVDC	886	4000	$2,666
Port Augusta to Naracoorte	HVDC	560	4000	$2,285
Naracoorte to Portland	HVAC	216	6000	$2,286

Inter grid connections	Type	Length (km)	Capacity (MW)	Cost (million AUD)
Roma to Armidale	HVAC	662	6000	$4,372
Mt Isa upgrade	HVDC	847	4000	$2,620
Perth to Port Augusta	HVDC	2146	4000	$4,140

Kalgoorlie to Port Augusta	HVDC	1586	4000	$3,485
SWIS NWIS Connection	HVAC	561	6000	$3,900

Other services

Gas, water, sewerage, roads and fencing must also be considered to varying degrees and according to the technology type being used. The CSP Technology Roadmap (IEA, 2010A), discusses non-economic barriers and indicates that the slow approvals process for grid-connection plus the difficulty of accessing water and gas are significant barriers.

Water issues are important for CST plants in particular, and to a lesser extent to some styles of CPV plants using active cooling of cells. As detailed in Chapter 2, some level of water use is required for steam-cycle makeup and mirror cleaning. Employment of wet cooling systems markedly increases water consumption, but is not essential since dry cooling solutions are also available. Wet cooling however offers lower capital costs and higher cycle efficiency and so uses water to good economic benefit. Water issues present a potential barrier at several levels including the:

- potential limited physical availability of clean surface water,
- potential limited access to artesian basin water,
- approvals process for accessing water supplies, and
- cost of supply, storage and recycling infrastructure.

7.4.8 Stable policy support

Given that fossil fuel generators are still cheaper than CSP options, progress with CSP will be dependent on government policy settings and incentive programs for a number of years. At the most basic level, Government support may be needed to allow systems to earn sufficient revenue for energy produced to achieve financial closure on reasonable projects as has been discussed above. Other Government policy settings are also very important; government policy also has a key role to play in addressing all of the other barrier types identified in this Chapter.

Lotker (1991) discusses in depth the lessons that can be learnt from the Luz experience that established the well known CST SEGs plants in California. In the 1970s, the US Government established measures such as tax credits and RPO rules that incentivised renewable energy, motivated mainly by domestic energy security concerns following the 1973 oil price shock. From this, only a few technologies and companies went forward and one of the most notable was Luz. In the early 1990's the government initiatives such as tax credits were progressively dropped and ultimately Luz went out of business. In analysing the final demise of the company, the interesting conclusion is that one of the most damaging things was the arbitrary short-term extension of the credits at the end, that lead to the final power station being constructed in a high-expense accelerated fashion to meet the arbitrary deadline imposed. In hindsight, if that final, expensive plant had not been built in that fashion, the company may have been able to go into a holding mode and save its remaining funds for more attractive future projects. Thus as well as lessons for government there are lessons for commercial organisations as well in their management of changing policy settings.

The overall lessons for governments are the desirability of avoiding boom-bust responses to policy and if a tightening of conditions is planned, to do it in a way that allows companies to plan and survive under a new paradigm.

7.5 Customer Demand

Finally, the challenge for any new technology is to build customer demand. Technology development, societal acceptance and markets are all required, with specific steps then needed to encourage customer uptake.

For CSP, customers are interpreted as entities that may wish to purchase CSP heat or electricity, being a mixture of electricity retailers and large consumers such as mines, as well as conventional generators that may be interested in hybrid systems, and industries that require high temperature steam.

The key opportunities to improve customer understanding and demand are:

- Explaining cost versus value
- Providing dispatch certainty
- Reducing volatility for other renewables
- Incorporating storage
- Standardisation
- Development of guidelines

There is tension between the existing electricity industry players and the solar sector. At the time of writing, the division caused by the Carbon Tax legislation continues to drive wedges where there could, and should, be cooperation. Similarly, there are misunderstandings with regard to generation certainty and dispatch options for solar plants in the NEM and other market segments. This is leading to negative and defensive attitudes, rather than cooperation between the established and the new players.

7.5.1 Increasing customer demand

Cost vs value

A key finding of this review is that, as well as achieving cost reductions, the industry must ensure that the value of CSP electricity is recognised. As the electricity market is the key sales point for solar energy, the value definitions used by the electricity industry need to be adopted by the CSP Industry.

Being able to demonstrate energy value is key to successfully negotiating PPA/offtake agreements. In particular, the realisable market value should be recognised as quite distinct from the LCOE, and better represents the value of CSP derived energy to potential customers.

As the analysis in Chapter 5 has shown, value can be increased by locating plant in areas of the network that either have high loss factors or supply constraints.

Gaining the interest, support and recognition of value from the largest electricity retailers in particular is a critical component of CSP development in Australia.

Dispatch certainty

Under current market conditions in the NEM and SWIS, CSP plants could aim to participate as semi-scheduled generators, although semi-scheduled generators are likely to earn less Capacity Credits in the SWIS than scheduled generators, with storage used only so as to be able to predictably deliver energy during high energy use times of the day, and during high demand seasons. This would deliver predictable peak coverage at the highest $/MWh value. Making this mode of operation clear to the existing electricity industry would assist in future negotiations. Selection of the appropriate level of storage would then be a matter of negotiation, and determined by the level of certainty required by the electricity retailer.

Reducing volatility for other renewables

CST specifically has a higher capacity factor than other renewables, while its inherent heat storage reduces output volatility. Thus it could be used as an intermediary between the networks and other renewables on the same Node, balancing potential negative effects of Wind or PV intermittency. This would allow greater renewables penetration and would also assist electricity network operators. Again, it will be important to demonstrate this capability to the electricity sector, so as to gain greater acceptance and better PPA arrangements.

Incorporating storage

If a major goal of CSP initiatives is to develop large-scale technologies for stand alone application, then incorporation of energy storage should be a high priority. Given that storage adds to overall initial capital costs, it is unlikely to be included if the value it adds is not recognised. The current RET for instance, does not inherently include a time of day component which might provide higher value for power supplied at peak times.

The analysis of Chapter 5 indicates that wholesale electricity prices should provide this, but current uncertainty around CSP system performance is likely to keep any premiums embodied in PPAs quite low. In the short term, other support mechanisms may need to be appropriately structured to allow CSP plants to capture peak prices. This could encourage the addition of storage and thus the creation of more dispatchable solar power stations.

Standardisation

One means of assisting the CSP industry to develop component markets, reduce costs and maintain the quality control necessary to satisfy potential customers is via the establishment of component specifications, installation guidelines and performance standards. For a developing industry with a range of different technologies, this can be a complex process and must be done in such a way as to encourage further innovation and product improvement. Nevertheless, guidelines and standards can be used to indicate a level of technology maturity to an otherwise sceptical market, as well as to provide a means of gauging lifetimes and performance. This is critical to reducing financing risk.

Hybridisation

Hybridisation of CSP with other energy technologies potentially provides a lower risk and faster route to market than stand-alone systems and hence could assist in creating customer demand. It is suggested that the potential for hybrid links be explored with other industries such as:

- Coal generators
- CCGT
- Wind and PV
- Brown Coal for Solar Gasification
- AEMO as a means of balancing intermittent renewables

7.6 Summary

The various solutions identified above are summarised in Table 7-3, with an indication given of where the responsibility for action might lie. The CSP sector needs to be pro-active in pursuing these actions. However, the policy and regulatory environment are clearly important, so that some actions rest with governments and regulators.

Table 7-3: Summary of Australian CSP Actions and Responsibilities.

	Research Institutions	CSP Industry	Australian Government	State and Territory Governments	Regulators and network service providers
Technology Development	Build on existing capabilities to develop and commercialise IP in components and systems Develop research projects in key areas identified	Improve the understanding and perception of CSP technologies Organising visits by key groups to CSP systems overseas and in Australia Share data on real systems	Continue support across all stages of RD&D spectrum	Support RD&D	Develop new technical requirements and systems to facilitate CSP uptake
Societal Acceptance	Extend educational and training activities to cover CSP	Develop best practice guidelines	Support demonstration systems	Establish pre-approved precincts	Develop principles for renewables integration
Market Development	Undertake grid integration modelling specific to CSP	Work to demonstrate cost reduction. Ensure near term projects incorporate energy storage or hybridisation so that high levels of dispatchability become the norm. Encourage institutional investment in overseas companies	Provide a market based signal to bridge the cost gap Continue with Solar Flagships round 2 or equivalent Facilitate CSP project financing Continue to provide improved solar data in public domain	Evaluate possible sites for large scale Solar developments Contribute to provide improved solar data in public domain	Examine Transmission network extensions for CSP
Customer Demand	Undertake background analysis to validate CSP costs and benefits	Demonstrate and document cost reductions on a global basis Facilitate visits to systems by decision makers and community	Adjust settings of various policy instruments to ensure that appropriate financial signals are sent to incentivise CSP	Stream line approvals	Consider predetermined grid connections for Solar precincts recognition of value of avoided network augmentation and line losses

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8 Pathways for Australia

The previous chapters have looked at the status of CSP technologies, potential markets and challenges facing the industry. This chapter now examines some possible pathways for Australia to follow in order to establish markets here and to further develop the technologies for local and international use. It aims to provide a more specific series of actions for Australia, which follow from the generic solutions covered in Chapter 7.

Australia's actions in developing the CSP industry are likely to have a higher impact and visibility in the world scene than the size of our economy and population suggest. Australia is:

- clearly identified as a major coal, gas and nuclear fuel exporting economy;
- clearly identified as a continent with excellent solar resources;
- recognised as a country of lower sovereign risk than many other sunbelt countries;
- recognised for a history of action on GHG reduction, via the RET and now a carbon price.

Thus any action Australia takes to facilitate CSP development is likely to have a significant exemplar effect on other countries' actions, with benefits that then flow back to all countries, including Australia.

If Australia joins other countries in providing support for continued growth of the CSP sector, the sum of these efforts in what is a global industry will provide the best chance of a secure ongoing pathway. Spreading efforts across multiple countries will mitigate against local policy boom / bust cycles and avoid repeats of the 1990 – 2005 hiatus. This will allow a global industry to progress efficiently without loss of momentum. The perception of a secure growing future will feed back to encourage business investment in the sector and speed cost reduction.

8.1 The Australian Roadmap Re-visited

The High Temperature Solar Thermal roadmap (Wyld group 2008) that was released in 2008 was one of four similar technology roadmaps commissioned by the Council of Australian Governments in 2006. Its terms of reference were as indicated by the title, High temperature (above 200^{o}C) solar thermal for power generation or process heat. Ultimately it found little realistic potential for process heat and largely focussed on power generation. Thus, although different to the terms of reference for this study, the effective overlap is very large.

This section seeks to re-evaluate the findings of the previous roadmap in light of developments that have taken place both nationally and internationally since 2008, and incorporating the findings of this review.

It is pertinent to reproduce some key material from the document:

The vision for HTST in Australia that was adopted was:

> *"By 2015, Australia's HTST industry and technologies are strongly positioned in supply chains for local and global energy markets."*

On the market potential for CSP:

"Over the next decade, market opportunities approaching 1,000 MW in total capacity could be available in Australia to HTST systems for large-scale demonstration and early deployment projects."

"This will position Australian industry for the longer term market opportunity, which is for HTST to be an option to supply the major grids in Australia when carbon prices are likely to be above $50/t CO2-e"

"There is a deployment capacity of around 20,000 MW through to 2050 available in Australia in this market" (Note = 500MW/yr)

"This large-scale market should be available to HTST technologies by 2030 (and possibly much earlier) provided that HTST continues to reduce its cost of generation,"

On grasping the opportunity:

"Stakeholders felt strongly that the window of opportunity for Australia to extract significant industry-development value from the R&D legacy and current RD&D capacity and capability in HTST fields is as short as 2015 — particularly given the pace of industry growth and project deployments overseas."

"Achieving this will require:

- Development of a favourable policy framework for clean energy in Australia;
- Knowledge building in consumers, utilities, financiers, industry, regulators and governments about HTST;
- Market development efforts to promote the sector and to remove barriers to deployment;
- Development of Australian supply-chains for viable near-term applications and large-scale demonstration programs; and
- Training and competence building in human resources and technology capability and capacity."

On priorities:

"stakeholders' top five priorities focused primarily on market and supply-chain development activities, as follows:

- Large-scale demonstrations, which stakeholders noted pull and underpin: R&D; technology, industry and policy development; removal of implementation barriers; and overseas interest in Australia as a market.
- Capacity and capability building, particularly in manufacturing and engineering areas relevant to HTST systems and components.
- Establishment of an advocacy group to be a champion for HTST in Australia.
- Establishment now of long-term public policy that both pulls and pushes progress in Australia in HTST, particularly market-support mechanisms and removal of specific or inadvertent barriers to market entry for HTST.
  - For example, as with similar overseas programs, through banding of technologies under the expanded MRET to ensure prescribed levels of deployment are met or implementation of banded feed-in tariff policies.
- Exploit viable near-term markets, which stakeholders noted will enable (in conjunction with large-scale demonstrations) establishment of sustainable supply chains in Australia for HTST system design, implementation and operation."

A key theme was the need for developments within a short time frame of a decade or less. Given that three years has now elapsed, it is useful to assess how things have changed and what progress has been made.

In early 2008 it can be recalled that:

- The Kyoto protocol had just been ratified by Australia and emissions trading was the policy of the new Rudd government and apparent bipartisan support existed for moving that forward.
- An MRET extension to 45000GWh/a by 2020 was announced but details not settled.
- Conventional wisdom held that large CSP systems had a direct LCOE cost advantage over PV
- A global growth of CSP had just begun, but strong trends had not emerged.
- Prospects for carbon capture and storage and enhanced geothermal seemed bullish.
- The Kyoto protocol and its long term extension looked strong
- No global financial crisis was anticipated by the international community
- 82 MW of PV was installed in Australia

In Australia in early 2012, significant factors for the future of CSP include:

- The global CSP Industry is much stronger, with a continued trajectory of growth
- Approximately 2/3 of announced global CSP projects never get built
- Costs of CSP appear higher than thought in 2008 in real dollar terms.
- Cost reduction is not yet unambiguously established via published data
- Spain is winning the deployment race via the use of technology specific feed-in tariffs.
- Major projects have begun in the USA.
- India has entered the field with a major government initiative, but the first projects are not yet completed.
- Two tank molten salt storage has become well proven and standard, with 62% of Spanish systems now incorporating it.
- Flat plate PV costs have fallen dramatically and it is now cheaper than CSP in simple LCOE terms.
- State based domestic FIT's, on top of REC multipliers via the RET, have driven a massive uptake of small PV systems. Installed capacity is now approximately 1.2 GW.
- Issues of grid integration for PV have been raised, which may have follow-on effects for other renewable generators.
- After a lot of political pain, Australia has legislated a carbon price, but there remains a high level of political uncertainty around the mechanism and the future of the Renewable Energy Target.
- Moves to a coordinated World GHG policy are still struggling.
- Australia's domestic oil production declines.
- Coal Seam Gas has emerged as major new force but run into local community opposition.
- Export demand for gas is growing and driving up domestic prices.

- Enthusiasm for CCS technologies has waned in light of upward revision of cost estimates
- HDR geothermal development has proceeded much more slowly than anticipated.
- The Solar Flagships round 1 CSP project has been announced but at time of writing was still in question over reaching financial closure.
- RET has divided into large and small system targets, but the REC price is still low.

Table 8-1 provides a reassessment of the 2008 Roadmap strategies, in light of current market conditions.

Table 8-1: Progress on the 2008 Roadmap Strategies

Key Strategy from 2008 roadmap	Options suggested for activities	Comments on progress to date
Market Development: Market Support Mechanisms	• Ensure timely introduction of Australia's proposed national emissions trading scheme and renewable (clean) energy target for 2020. • Ensure other clean energy market support mechanisms at State and Australian government levels can be applied to HTST systems of appropriate scale. • State and Australian governments continue to cooperate to quickly remove specific or inadvertent barriers to market entry for HTST.	Carbon price legislation has now been passed, with a starting price of $23/t. Current projections suggest that, in the absence of strong coordinated international action, it will not increase significantly in the short to medium term. The RET is projected to be easily met by dominantly wind based projects and large increases in REC value are not predicted under current rules. Even with the carbon and RET prices, there is currently no market support mechanism that is sufficient to allow financing of CSP projects.
Market Development: Strong Industry Advocacy	• Ensure that strong industry advocacy is established to promote HTST in Australia.	A new body, AUSTELA has been established and currently represents a subset of the major potential CST companies. The Clean Energy Council also contributes to discussions as does the Australian Solar Energy Society. A consistent voice may be a little unrealistic given that an industry per se does not yet exist and a wide range of stakeholders have different views of the future.
Supply-Chain Development: Viable Near-Term Applications	• Minimise impediments to market entry and promote uptake in Australia of HTST technologies and systems for applications where they are economically competitive now. • Australian-based companies actively seek opportunities in global supply chains for HTST technology and system design services, components supply and project development to maximise Australian industry and employment growth.	Other than Flagships and specified State based demonstration projects, industry players have yet to identify a viable near term opportunity. The analysis of costs presented in this review confirms that cost gaps remain in all segments. Transfield's investment in Novatec has provided a direct Australian based role. Ausra's move to the US, followed by its purchase by Areva is an example of Australian initiatives going global. Hence, potential exists for Australian innovation, at various points in the supply chain, to contribute to global deployments, even if a local market is slow to develop.

Supply-Chain Development: Large Scale Demonstrations	• Expedite establishment of the Australian government's proposed Renewable Energy Fund for large scale demonstrations. • Develop and promote world-class, large-scale demonstration projects of pre- or early-commercial HTST technologies and, where appropriate, maximise participation by Australian companies in these large-scale demonstrations. • Ensure that such demonstration projects are linked internationally where appropriate and that data is shared internationally as a key input into modelling and analysis of energy system options for Australia.	Government funding schemes including the AEST program, REDP and most recently Solar Flagships have all offered funding to significant CSP projects. So far none of these projects have yet reached final commissioning stage. The funds allocated to ARENA and the Clean Energy Finance Corporation offer an opportunity to learn from experience to date and ensure further valuable projects are established.
Competence Building: World-Scale Collaborative R&D Projects	• Expedite establishment of the Australian government's proposed Energy Innovation Fund in clean energy technology research. • Industry and researchers jointly develop world-class and world-scale R&D projects to submit into Australian and State government R&D funding initiatives.	The major initiative in the R&D space has been the establishment of the Australian Solar Institute. This has successfully maintained overall R&D capability but not grown it significantly. There are some collaborative projects, however the lack of a market in Australia reduces the motivation for overseas companies to engage in a major way. As at April 2012, only 31% of ASI's funding has been for CST projects rather than the 50% as originally designed. A further 12% has been for CPV related projects, but the largest proportion has gone to non -concentrating PV. It is surmised that this has largely been due to the higher number of PV applications bidding into a common competitive process.
Competence Building: Capacity and Capability Building	• Tertiary and secondary educational institutions ensure that relevant technical and business courses incorporate HTST as a key teaching topic and that postgraduate research opportunities in these and allied technical fields are available and promoted.	Arguably the profile has been raised in training institutions. In this regard CSP, together with PV and broader renewables, is seen by many as the way of the future. The level of awareness of clean energy in the community and at all levels of education has risen considerably. The number of postgraduate students in CSP may have grown slightly. However, until an industry exists, students are unlikely to specialise in CSP, other than for research.
Knowledge Building: Education and Outreach	• Develop education and outreach tools (e.g. dedicated website; educational material; up-to-date database of RD&D activities in HTST in Australia) for local use by educators, researchers, government and industry. • Identify key public and private-sector decision makers (e.g. regulators, network planners, project and venture capital financiers) and specifically focus on their information and knowledge	As with training institutions, the profile of CSP has also clearly been raised in the general community and decision maker constituencies. Levels of understanding of CSP status and capability clearly have room for improvement. Energy conferences have at least some exposure of CSP developments almost universally. Industry representative bodies need to continue the education and outreach process.

	needs in HTST. • Ensure that relevant national conferences (e.g. those of the Clean Energy Council, ESAA and ANZSES) incorporate sessions on HTST R&D, demonstration, deployment and market development (as appropriate to each conference).	
Knowledge Building: Active in International Forums	• Continue / enhance involvement in multilateral (e.g. IEA, IPHE, APEC, APP) and bilateral forums.	Australia has continued its involvement in forums such as IEA's SolarPACES and PVPS. However the impact for CSP is diminished relative to those countries with higher levels of industrial activity which can be more involved in the Tasks.

In summary, it can be said that there has been some good progress, however not as much as the 2008 roadmap suggested could be possible. The Roadmap remains a good basis from which to move forward from 2012.

The following sections examine specific activities which could be undertaken in Australia to develop a CSP industry. The strategies discussed follow from the findings of this review and from the more general discussion in Chapter 7 of challenges in the categories of; Technology Development, Societal acceptance, Market development and Customer demand. Where appropriate, the actions proposed in each of these areas are discussed for the market segments identified in Chapter 4.

In addition to the pure financial equation detailed above, there are other considerations that influence the project developer and financiers' investment decision. Many of these are specific issues facing CSP market segments, as set out in Table 8-2: below.

Table 8-2: Specific issues facing CSP market segments

Market	CSP Value Proposition	Specific issues
Off-grid / mini-grid	• Reliable power at price competitive with diesel. • Hedge against future fuel price fluctuations and supply chain risks.	• Customer expectations of very high overall system availability and capacity factor. • Short time horizons on investment decisions. • Split/perverse incentives around diesel fuel excise rebates. • Requires demonstration at 1 to 10 MW scale in grid connected areas to build confidence.
Stand-alone, grid-connected plants	• Grid-stabilising, load-firming, zero-carbon generation. • Enables penetration of renewable energy sources to > 20%. • High correlation with daytime peak loads. • Load-following using thermal energy storage. • Co-fire with gas, biomass etc to maximise reliability of supply.	• Very large capital costs of individual projects. • Lack of transmission infrastructure to optimal solar locations. • Benefits of avoided line loss and grid extension not adequately rewarded. • Building confidence with network service providers. • Hard to get long terms PPAs.
CSP add-ons to fossil-fired systems	• Lower emissions intensity for existing power plants. • Leverage existing infrastructure. • Prolong existing fleet lifetime. • High performance systems with lower project risk and capital cost.	• Building confidence of existing generators re CSP integration with core (traditional/fossil) operations. • Split/perverse incentives, e.g. free carbon permits reducing pressure to lower emissions.

8.2 Strategies for Australia

With falling capital costs and rising energy prices, commercial viability for CSP projects will be attained between 2018 and 2030, as shown in Figure 9. Many of the significant benefits from including CSP in Australia's energy mix are time-sensitive. It is therefore in the interests of investors, the sector and the nation that CSP projects reach commercial viability as soon as practicable within that time range.

For this, the CSP industry must work with the energy sector and its regulating governments to systematically identify and address the barriers to investment delineated above. This will support the smooth, rational development of the sector, and help avoid the *'boom-bust'* cycles that both renewable and fossil-fuel industries have experienced.

These barriers are real yet surmountable. Specific actions to increase investment, demand and product development are needed. These actions are discussed in turn below. If they are successful, the sector would track international growth rates to provide at least 2000MW of clean energy by 2020. This figure presents itself as a realistic medium-term target for overall CSP installations, toward which the sector could set clear milestones in meeting its challenges.

8.2.1 Bridge the reducing cost-revenue gap

Whilst continuing to focus on lowering cost the CSP sector should work with governments and regulators to increase the reward for clean energy systems that better correlate generation to real-time demand.

Unless the cost-revenue gap is bridged, Australia risks losing the option of CSP in Australia's future energy mix, and with it the benefits identified in this study.

Rather than simply subsidising CSP, technology-neutral market-based measures should target the dispatchable clean energy that Australia needs. Towards this, energy sector agencies should build on the research report and model future prices of both energy and ancillary services in the NEM, to calculate future CSP value under scenarios that include high penetration intermittent renewables.

Measures should include incentives for clean energy generation that correlates most strongly to real-time demand. These incentives could include appropriately structured price-support mechanisms, tax and depreciation treatments, loan guarantees, and new long-term financial products.

Public sector loan guarantees to mitigate construction risk have been used successfully in other countries, in parallel with other risk-mitigation measures. Facilitated finance, such as through the Clean Energy Finance Corporation, will only be defensible if revenue and capital depreciation settings are in place for both public or private loans to be repaid on their respective terms. Financial products such as infrastructure bonds, developed for large capital assets in the energy and infrastructure sectors to offer long-term low-risk returns, may be adapted to CSP projects to meet their large upfront capital cost.

Unless the gap is bridged, there will be no significant CSP deployment in Australia in the near term. Early deployment in market sectors where the cost revenue gap is smaller has the potential to optimise public sector investment. This includes off grid applications (where the competing cost is diesel generation) and hybrid applications with existing fossil fuel technologies. However these sectors do not offer a "silver bullet" and do not replace the need to address the main grid connected segment that ultimately offers greatest potential.

8.2.2 Build confidence in CSP's offer

The CSP sector should better communicate CSP's value proposition to key stakeholders including AEMO, AEMC, electricity retailers and financiers.

For those stakeholders who are unfamiliar with CSP's advantages and international progress, CSP's potential role in Australia may appear fanciful. Any actions taken to develop CSP in Australia can only be laid on a base of understanding and confidence. Without that base, the risk premiums that the sector currently faces will remain in place, and government, consumer, energy industry and investor support will remain ephemeral. The CSP sector must take every opportunity to explain CSP's potential benefits, demonstrate them in practice through successful ventures, and respond to the reasonable concerns of their stakeholders.

Specific actions could include:

- Working with AEMO and the transmission industry on the National Transmission Network Development Plan, factoring CSP availability into plans for grid extensions and upgrades (or the avoidance of them).
- Working with electricity distributors to raise awareness of CSP availability and benefits, and on plans for developing the distribution network to take advantage of those benefits.
- Ensuring that CSP's offer is fully represented in every government review of any part of energy generation, transmission, distribution and use in Australia, and in every public investment in the energy sector.
- Engaging more closely with financial sector asset owners and managers who have a demonstrated interest and understanding of long-term alternative asset classes.
- Better targeting information dissemination and education, leveraging Australia's membership in the IEA SolarPACES and PVPS programs for real international collaboration.
- Working with key customers and networks to establish best practice guidelines and standards for CSP system development, finance and operations.

Inviting stakeholders to visit operational CSP plants is judged to be particularly effective. At an early stage, facilitated tours to overseas systems should be considered. As plants come on line in Australia, every effort should be made to establish visitors' centres and easy access site visiting.

Confidence must be built and maintained in the general community also. The as yet embryonic CSP industry in Australia should learn from experiences in the wind and coal seam gas industries and:

- Maximise community consultation
- Consider any long term negative impacts on the industry from community push back, in the cost benefit analysis for siting and design decisions.
- Work to maximise the community support that flows from the nature and distribution of financial contracts associated with projects.

8.2.3 Establish CSP-solar precincts

The CSP sector should work with governments, regulators and network service providers to pre-approve and provide connections for CSP systems in selected areas of high solar resource.

A precinct or solar park plan, developed with tri-level governments and energy sector partners, would have several benefits. For example:

- CSP projects would proceed to completion with a much reduced overhead in approvals and planning, helping to reduce early stage project risk.
- Planned and facilitated grid connection would reduce costs, which may then also be shared over multiple projects.
- The cost of solar data gathering, environmental impact assessments and community consultation would also be shared across projects, improving their value and levels of certainty for project development and financing.

In addition or separately to this it would be desirable to Establish a "one stop shop" for all necessary approvals.

Such precincts could be established under a range of scenarios. In the minimum case, allocation and pre-approval of use would offer a benefit. Going beyond this varying degrees of infrastructure establishment can be considered, begging with grid connection and extending to consideration of water, gas and access roads etc. At least one dedicated solar park tailored for smaller demonstration systems would be a valuable national asset. Such a system could adopt some of the features of the PSA facility in Spain.

8.2.4 Foster CSP research, development and demonstration

The CSP sector should leverage continued public and industry investment in research, development and demonstration, with more emphasis on meeting Australian needs.

Given that the benefits of early technology and market development will flow to future participants, there is a strong case for continued public sector support.

In Chapter 7, global and national CSP R&D priorities were discussed, whilst noting that cost reduction was intimately linked to mass production, scale and R&D. Here, specific priorities for Australia in R&D are summarised.

Given Australia's relatively modest realistic R&D budget, any taxpayer funding should be targeted at areas that offer the most traction for Australia's market conditions. These include:

- **Systems optimised for below 50 MW_e** . An area overlooked by the global industry, but with off grid / end of grid application in Australia.
- **Hybridisation and enhancement of fossil fuel systems and exports.** To allow a broader range of systems to be deployed at lower capital cost to build confidence in the CSP sector in Australia. Also to form alliances with existing large energy industry players to build a transition to a clean energy future.
- **Improved energy storage.** A shared global priority which Australia's R&D activity has a chance of making a substantive contribution to. Energy storage should be explicitly considered in parallel with the targeting of smaller systems.
- **Advanced cooling systems to minimise or avoid groundwater and river water use**. This is clearly an area of particular interest to Australia, reflecting our water

constraints. As well as improved air cooling systems, hybrid cooling and ground loop cooling are options that have been mooted.

- **Improved efficiency of advanced energy conversion systems and receivers.** This is another shared global priority which Australia's R&D activity has a chance of making a substantive contribution to and which offers the greatest chance of a direct energy cost reduction based on R&D

Other global R&D priorities should be considered for public co-investment where there is strong commercial involvement. In addition to these R&D priorities, program design and project selection should foster the skills and capabilities that the Australian CSP sector needs.

8.2.5 Other supporting actions

The key pathway actions would be further supported by activities that include:

- Further extending Bureau of Meteorology direct beam solar radiation data collection, both to extra sites and to higher frequencies, to better support plant output prediction.
- Synthesising an improved set of data files for use with NREL Solar Advisor Model, both Typical Metrological Year and real historical years, to allow this excellent publically available tool to be used to best effect by researchers and commercial organisations.
- Modelling the likely effects of climate change over the coming two decades on solar radiation levels and CSP system performance, to help reduce risk in project planning.
- Studying the potential for concentrating-solar-driven fuels production as a possible major future driver for CST in Australia.
- More detailed study of the relative economics and potential for new combined gas / CSP systems.

8.3 Possible Australian CSP Development Trajectories

If these actions are pursued successfully, the CSP sector would be large enough to deliver economies of scale within immediate investment and policy horizons. A contribution of 2,000 MW by 2020 is readily achievable, which would see CSP play a significant role in Australia's low emission solution, and Australia be a significant part of the global CSP industry.

The growth of CSP technology globally has started to form the familiar S-curve that traces the early stages, fast development and eventual maturity of technology adoption. Past and projected global and Australian growth profiles are shown in Figure 8-1. For Australia, the trajectories start with the combined Solar Dawn, Solar Boost and Liddell power station systems, assumed complete in 2013, and project from that point with growth trajectories matching the global possibilities. The medium-case growth projection for Australia, the dark-blue 30% line in Figure 8-1, reaches 2 GW of capacity by 2020. Looking at CSP's market segments in Australia, this figure is quite reasonable. It could realistically be structured as approximately 100MW in off-grid or mini-grid systems, approximately 500MW in solar add-ons to fossil-fuel systems, approximately 300MW in 10-50MW systems connected to energy distribution networks, and approximately 1000MW in larger units connected to transmission networks. Investment in Australia would reach approximately $5.5 billion by 2020, assuming the retention of $1.4 billion in project commitments made to the end of 2011.

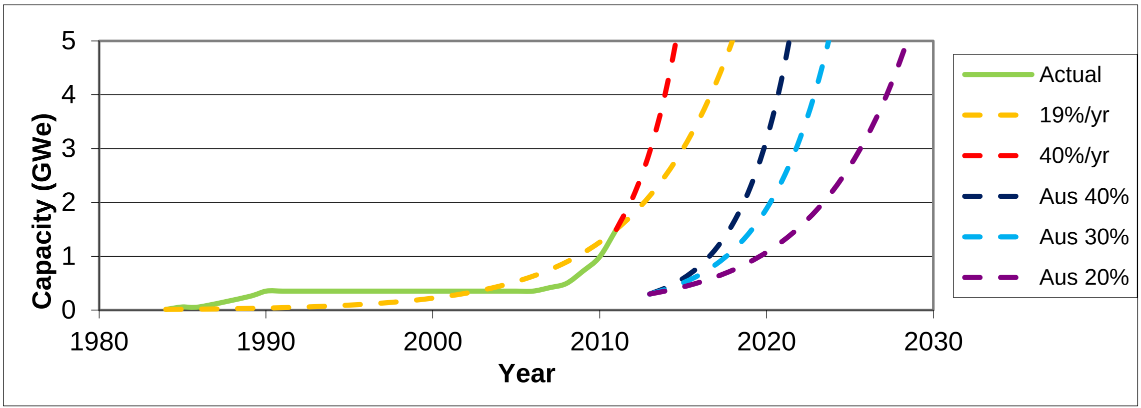

Figure 8-1: Global CSP development trajectories and projections, as well as possible Australian trajectories, if the same percentage growth profiles are followed. (Capacity normalised to a 20 -30% capacity factor)

These projections form the basis for a series of development goals for the Australian CSP industry: see Figure 8-2 below. The 2013 goal will be reached assuming present-committed demonstration projects are successfully deployed. If the 2020 goal of 2 GW is reached, Australia would be well on its 30% growth track to 10GW of capacity by 2030. Beyond that is the aspiration for CSP to be a significant contributor to the essential decarbonisation of Australia's energy supply by 2050, and make up 30-50% of Australia's energy mix.

Cumulative capacity	Timing	Fraction of national demand	Notes
100s GW	2050 +		Significant source of export income via solar derived fuels and or HVDC links to Asia
100 GW	2050	30–50%	CSP provides between 30–50% of Australia's electricity in a mature 100% clean energy scenario
10 GW	2030	5–10%	CSP provides significant contributions in all market segments. Established Australian supply chain
2 GW	2020	1%	First fully commercial projects in the most prospective market segments
0.3 GW	2013	0.2%	First assisted demonstration systems at various scales

Figure 8-2: Aspirations for an Australian CSP Industry[60]

In the foreseeable future, new CST-driven chemical processes already under development may allow the export of CSP-generated fuel. Alternatively, high-voltage DC transmission lines have been forecast to connect North Africa to Europe and Mexico to the US, and have also been proposed to connect Australia to Indonesia and beyond. This is a vision for the industry that, while remaining in the background of more immediate goals, will continue to offer inspiration for our young and future scientists, engineers, investors and policy makers.

[60] Adapted from LEK Consulting's *Advanced Biofuels Study – Strategic Directions for Australia*, Summary Report, 14 October 2011 prepared for the Department of Resources, Energy and Tourism.

9 Conclusions

The world is undergoing a clean energy revolution. It is driven by rising concern over energy security, greenhouse gas emissions, local pollution, increasing oil prices and growing energy demand in key developing economies, among other factors. Wind and PV are the big clean energy success stories of the past decades, with solid compound growth and cost reduction track records.They are, however, variable in nature and cheap electrical energy storage at large scale is not on the immediate horizon. There is a clear need globally and in Australia for a portfolio approach to the clean energy generation mix and a key part of this mix needs to be systems with energy storage / dispatchability characteristics.

CSP systems offer some key technical features that suggest they have an important role to fill in an optimum portfolio of future clean energy technologies:

- **Dispatchable energy supply.** Systems that can dispatch energy for the range of baseload to peaking power are an essential complement to variable renewable sources. CSP with storage has that capability.
- **Extensions for existing plants**: CSP can be used in hybrid coal and gas plants to reduce emissions and extend plant life for least-cost transition to a low-emission energy future.
- **Emission reduction**: 10GW of capacity would reduce Australia's emissions by roughly 30Mt CO_2 equivalent per year, or over 15% of electricity sector emissions.
- **Clean energy sector growth:** Relatively few countries are currently investing in CSP. With CSP exploiting its world-leading solar resources, Australia can claim a significant place in the global clean energy supply chain. Delaying action will see that opportunity missed.
- **Community-supported generation.** CSP need not compete for land or water, is low-pollution and low-impact. Every modest 100MW system would create around 500 job years during construction and 20 jobs during operation, mostly in regional areas.
- **Potential for future solar fuels**. Emerging technology will convert solar energy to liquid fuels, supplied at scale to both domestic and export markets.

CSP began with strong development in California in the 1980s but then had a period of hiatus. There has been a renaissance since 2006, and current installed capacity has reached approximately 1.5 GW_e worldwide. It is still very small compared to wind (approximately 220 GW_e) and PV (approximately 70 GW_e). The recent CSP activity has been largely in Spain, with the USA now re-emerging, and first plants appearing in various other countries. Internationally, recent growth has averaged 40%/yr and the average since 1984 has been 19% per year. Going forward, given the values that CSP can offer, global growth rates of at least 19% should be expected, with around 30% per year most likely.

Australia has a 20% by 2020 renewable energy target, plus an overall policy of 80% GHG reduction by 2050. This is consistent with very high penetration of renewables, with a close to 100% clean stationary energy sector by 2050 a logical possible consequence. If the 20% target is largely met with variable generation sources, this will already present a major management challenge for the networks and markets.

Australia has a reasonable track record of R&D and small demonstrations in CSP. The Solar Flagships program marks the starting point of serious utility-scale deployment. Market segments in Australia can be defined according to the nature and extent of the electricity grid. These have been analysed and their technical potential assessed. The conclusion is that there is technical potential for the installation of 14 to15 GW_e of CSP in the near to mid term if there was an economic case for doing so.

Some transmission extensions to connect high solar resource locations into the grid are needed to exploit this. Depending on the capacity factor of the system configurations built, this would translate to annual generation between 25,000 GWh per year and 60,000 GWh per year. To go beyond this would require major 'nation building' transmission system projects, such as linking Northern SA with Southern Queensland. Included in this Australia has some unique off-grid and end-of-grid market segments that can only be accessed by CSP if systems of less than 10 MW_e in capacity were deployed.

CSP systems generate value in a number of ways, the most important being; sale of energy into the market pool (NEM or SWIS / STEM or by direct sale) and Large-scale Generation Certificates (LGCs) for the Renewable Energy Target. Analysis of historical pool prices finds that CSP systems without storage could earn 40% more than the average pool price, because of their day-time generation profiles. With appropriately configured energy storage systems, this could increase to 100% more than the pool average, since it can be deployed at times of high market prices. The LGC market on the other hand has an energy value independent of demand at its time of generation.

CSP systems could also provide value by reducing loss factors and avoiding network augmentation. These are relatively small additional values, and are location specific. The CSP industry must work with both distribution and transmission sections of the network to ensure best use of CSP. CSP should also be able to generate value from ancillary services. At present this value is less than 1% of the total, however if very large amounts of intermittent generation enter the system, it is possible that this fraction could increase.

Current installed costs of CSP are high compared to wind or PV. A range of information has been reviewed and analysed to establish a rule of thumb for cost estimation of CSP systems in Australia based on system size and thermal storage capacity. Whilst there is a high level of uncertainty with this, it is apparent that at current costs, LCOE's calculated using financial parameters appropriate for mature business-driven development are about 100% higher than the market value of energy for all system configurations and market segments. Specifically, LCOE's in good sites are around \$250/MWh, compared to maximum market value of around \$125/MWh.

However, the potential for cost reduction going forward is very high. Reviewing experience in related industries suggests the most likely result is that cost reduces by around 15% for every doubling of installed capacity globally. On this basis, and assuming a 20 - 30% per year projected global growth rate, convergence between cost and value in the Australian market is likely to occur not later than 2030 and possibly as soon as 2018, with energy market price increases due to carbon prices or otherwise also influencing this.

Cost has a strong system size dependance, however, on analysis, it is concluded that, despite a strong global consensus to move to greater than 100 MW_e systems to reduce cost;

- The penalty for operating at 50 MW_e is only of the order of 15% and there is a considerable reduction in project risk and difficulty of siting.
- The cost penalty for systems below 10 MW_e is less than 100%, and apparently similar to the value increase available to small systems.

Hence, for Australia, deployment of small systems should be seriously considered.

If Australian CSP capacity grows at a rate of 20% per year, following on from completion of the first 250 MW_e flagship project and other current projects, this will:

- Imply construction of an average of 60 MW_e per year in the initial few years.
- Position Australia to end up with a significant CSP contribution to stationary energy by 2050 in an economically efficient and non disruptive way.
- Maximise the chance of Australian IP and commercial activity playing a significant role in the CSP value chain globally.
- Allow acceleration or deceleration of deployment rates in light of international developments, to be made in a non disruptive manner.
- Make both a significant direct and exemplar contribution to the growth and cost reduction progress of the CSP industry globally, with consequent feed back benefits to Australia in the future.

The pathways to growth of a CSP industry in Australia have been reviewed, following on from the 2008 roadmap and a series of recommendations and actions have been suggested across the industry and various arms of government.

The global R&D priorities for CSP have been identified. Australia should focus on those that capitalise on existing research and industry strengths and give the most leverage for a smaller R&D budget. Concentrator system and component R&D should be largely funded by the commercial sector. Government R&D funds would be best used for the energy conversion and energy storage subsystem challenges. Australia's unique market for sub 50 MW_e systems suggests that this should be a particular area of priority.

The single biggest issue in the short term is development of measures to reduce the cost gap. A range of policy options are available and have been reviewed. A government policy that is clearly focussed on outcomes, is linked to value of generation, increasing acceptance and reducing risk is suggested. This could be made up of long term market-based solutions, plus short term demonstration project funding. In parallel with this, the CSP industry should take every step possible to maximise and demonstrate progress in cost reductions. This includes building to reduced margins to help support an overall growth in market volume, plus maximising publicly available cost information.

It may be useful to model future prices of both energy and ancillary services in the NEM and hence calculate future CSP value under a range of scenarios that include; high penetrations of either intermittent renewables or dispatchable CSP systems.

Overall the future for CSP globally and in Australia is very promising. However, the technology is not sufficiently close to cost effectiveness for deployment to occur without policy support in the short term, even with the existing renewable energy target and carbon pricing. R&D can assist, but the cost reductions necessary will not occur without concomitant deployment. Lessons need to be learnt from past mistakes, to avoid boom and bust cycles, perverse outcomes and loss of community support when designing policy positions. CSP is a powerful opportunity for Australia. If it takes responsible, collaborative action, Australia could grasp a substantial role in the global clean energy supply chain, and solve a critical piece of its long-term energy challenge.

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11 Acronyms

AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
ANU	Australian National University
BOM	Bureau of Meteorology
CCS	Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
CEFC	Clean Energy Finance Corporation
CFD	Contract for Difference
CH_4	Methane
COAG	Council of Australian Governments
CO_2	Carbon dioxide
CO_2-e	Carbon dioxide equivalent
CSIRO	Commonwealth Scientific and Industrial research Organisation
CSP	Concentrating Solar Power
CST	Concentrating Solar Thermal
CPV	Concentrating Photovoltaic
°C	Degrees Celsius
DG	Distributed Generation
DKIS	Darwin-Katherine Interconnected System
DLF	Distribution Loss Factor
DLR	Deutsche Forschungsanstalt fur Luft and Raumfaht (German Aerospace Centre, with major CSP activities)
DNI	Direct Normal Insolation
DNSP	Distribution Network Service Provider
DOE	United States Department of Energy
DSG	Direct Steam Generation
DSM	Demand Side Services
DWE	NSW Department of Water and Energy
ESAA	Energy Supply Association of Australia
€	Euro currency unit
EU	European Union
FCAS	Frequency Control Ancillary Services
FIT	Feed In Tariff
GSP	Gross state product
HCG	High-level Coordination Group
HDI	Household disposable income
HTF	Heat Transfer Fluid
HTST	High Temperature Solar Thermal
HVDC	High Voltage Direct Current
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt-hours
IEA	International Energy Agency
ISCCS	Integrated Solar Combined Cycle System
IGCC	Integrated Gasification Combined Cycle Plants
IMO	Independent Market Operator (WA)
K	degrees Kelvin
kWh	Kilowatt-hour
LCOE	Levelised Cost of Energy
LEC	Levelised Energy Cost (same as LCOE)
LETDF	Low Emissions Technology Development Fund
LFR	Linear Fresnel Collector
LGC	Large Scale Generation Certificates, created under the Renewable Energy Target scheme

LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LRET	Large Scale Renewable Energy Target
m^2	Square metres
MCE	Ministerial Council on Energy
MENA	Middle East North Africa
MJ	Megajoule
MLF	Marginal Loss Factor
MOE	Merit Order Effect
MRET	Mandatory Renewable Energy Target
MW	Megawatt
MW_e	Megawatt electrical
MWh	Megawatt-hour
NEM	National Electricity Market
NCAS	Network Control Acillary Services
NGGI	National Greenhouse Gas Inventory
NPV	Net Present Value
NREL	National Renewable Energy Laboratory (USA)
NSEC	National Solar Energy Centre (CSIRO Newcastle)
NSP	Network Service Provider
NSW	New South Wales
O&M	Operation and Maintenance
OECD	Organisation for Economic Co-operation and Development
ORC	Organic Rankine Cycle
ORER	Office of the Renewable Energy Regulator
PCM	Phase Change Materials
PPA	Power Purchase Agreement
PV	Photovoltaic
PVPS	Photovoltaic Power Systems (IEA program)
R&D	Research and Development
RCC	Reserve Capacity Credit
RD&D	Research, Development and Demonstration
RE	Renewable Energy
REC	Renewable Energy Certificates, which were created under the Australian MRET Scheme
RET	Renewable Energy Target
REDI	Renewable Energy Development Initiative
RPO	Renewable Portfolio Obligation
RPS	Renewable Portfolio Standard
SAM	System Advisor Model (NREL)
SEGS	Solar Energy Generating Systems (specifically those built in the Mojave desert in the 1980s)
SRAS	System Restart Ancillary Services
SolarPACES	Solar Power and Chemical Energy Systems
STEM	Short Term Electricity Market (WA)
SWIS	South West Interconnected System (WA)
TNSP	Transmission Network Service Provider
TMY	Typical Meteorological Year
TWh	Terawatt-hours
UCC	Ultra Clean Coal
US or USA	United States of America
VCAS	Voltage Control Ancillary Services
W	Watt
y	Year

12 Appendix A: ASI Terms of Reference

Reproducing the text from ASI's original call for proposals:

A Review of the Potential for CSP in Australia

Purpose of the review:

CSP technologies (PV and Thermal) to date have not been deployed beyond small demonstrations scale in Australia yet various energy models forecast that the technologies have an important role to play in a future low emission economy.

The ASI is seeking a report on the potential for CSP in Australia that can be made publicly available following expert review. It is envisaged the report will form a paper of no more than 20 pages, including an executive summary and key findings, ideally in a graphical and pictorial form to aid dissemination and learning about the challenges and opportunities of the technology.

The ASI recognises the role of support policy in driving industry deployment but does not see value in this being the focus of the report. The report should be a fact based review of the technology's prospects and potential that can lead to a separate discussion on policy options.

Areas to cover:

Areas of interest for this review include but need not be limited to:

- *Review of current state of play*
- *Current barriers to deployment of CSP on a commercial scale in Australia, including technical, economic and financial barriers*
- *Economic model projecting CSP LCOE trends and sensitivities linked to key R&D drivers*
- *Model and discussion of the long run market value including revenue forecasting for CSP generation for the Australian electricity market, for example:*
    - *Historical revenue opportunity in the NEM showing any time of day and location premium CSP deployment could have yielded*
    - *Value of firm capacity*
    - *Delayed dispatch (storage value)*
    - *Correlation of solar resource and locational value of the electricity*
    - *Other network values*
    - *Broader economic benefits*
- *Assessment of market segments and pathway to CSP commercial sustainability*
- *R&D pathways to lower CSP levelised cost of electricity (LCOE) and increase market value*
- *CSP-generated electricity*
- *Cost reduction drivers*
- *Pathway to commercialisation and high level assessment of potential opportunity to Australia*

It was subsequently clarified that:

The 20 pages refers to the main summary report for public distribution. However more detailed supporting information is expected. This is referred to in the CFP document under the heading "Call for Proposals" which asks for an indication of the level of detail to be contained in the "full study" and report itself.

The Actual investigation and report/s that have resulted follow on the ongoing interpretation of these terms of reference in consultation with ASI management and the Report Reference Group

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13 Appendix B: Reference Group and Stakeholder Consultations

During the project, a series of 3 industry workshops took place, along with the formation of a Review Reference Group to provide guidance to the project team during the review.

13.1 Review Reference Group

The Review Reference Group (RRG) included members of key representative bodies for solar in Australia and comprised:

- Dr Bruce Godfrey (ASI – Research Advisory Committee Chair) as Chair of RRG
- Dr Alex Wonhas (Energy Transformed Flagship Director, CSIRO)
- Andrew Want (Chair, AUSTELA, and CEO of Vast Solar)
- Andrew Dyer (Representing AuSES and a Director of BrightSource Energy Australia)
- James Harding (Representing the Clean Energy Council and GM Renewables at IPS Australia)
- Philip Hirschorne, (Boston Consulting Group)
- Mark Twidell (Managing Director ASI)
- Mark Hancock (Project Manager ASI)

Also attending were Graeme Pollock (ITP Project Manager), Dr Keith Lovegrove (ITP Technical Expert) and Gerry Morwell (Workshop Convenor).

The RRG met in September, November and December 2011, January 2012 and March 2012 to monitor progress, provide feedback, and adjust the direction of the project.

13.2 Workshops

Initially three workshops were held to gain an industry perspective of how to realise the potential for CSP in Australia as an input to the ASI commissioned study. The specific objectives set for the workshop were to:

- Confirm or test the barriers/challenges for the Australian CSP industry, technology, finance and market integration
- Seek feedback on the approach to analysis of value and cost
- Identify uniting themes for action that would assist Australian industry given that companies have technologies or market strategies at different stages of development.

The three workshops were held in Brisbane (21 Nov 2011), Sydney (22 Nov 2011) and Melbourne (24 Nov 2011). This maximised the opportunity for interested participants to contribute at the initial stage of this project. For each workshop a range of interested parties were invited representing project proponents, technology providers, regulators and financial investors. Notably few of the invitees from the investment sector attended. The workshops were conducted as an open dialogue to facilitate interaction and elicit views on the key issues.

13.3 Workshop Findings

13.3.1 Value and Cost

Initial results from the ITP team on establishing market value and modelling cost were presented. the concept of realisable market value was broadly discussed, it did gain broad acceptance by workshop participants as a critical metric, along with Levelised Cost of Energy (LCOE), with value better representing the contribution of CSP derived energy compared with that from fossil fuels and other renewable sources. Being able to demonstrate energy value was seen as key to successfully negotiating PPA/offtake agreements..

The workshops, and the discussion on Value, also highlighted the need to identify the best value storage forms and formats for CSP plant to acquire higher revenues within the Australian marketplace.

13.3.2 Image and Perception

It is clear that the Australian Public believes that Solar, despite a few recent failed projects, companies and funding programs, is the cleanest and most sensible of the renewable technologies.

So CSP does not have a positive image outside of political and industry circles – however it's image is as an immature industry that "could" burgeon in the next 15 years.

The PV industry has benefitted significantly in Australia, and worldwide, by public demand being created by government incentives. To meet the demand, PV now has a major supply industry, and market growth in PV worldwide is still incredibly strong. The challenge remains for CSP to create that public demand, and control its own agenda. It faces bigger hurdles, because its market is large users or the electricity industry, rather than individuals, and so must compete with a wider range of alternative and established technologies.

13.3.3 Technology Developer, Taker or Follower

This was a topic generating significant discussion at the workshops. It remains, a contentious issue.

Australia has a significant "research intelligence" that it has used in the past to develop concepts and technologies. It was generally felt that Australia should continue to use this capability in the field of CSP technology development. The linkages between Australian R&D and international efforts – Spain, India, USA - should be continued and encouraged.

Australia is also a high solar resource location, thus is a prime location for Demonstration of technologies. Such Demonstration should be continued, in order to attract international investment interest in home-grown technologies.

The workshop participants considered that Australia was not likely to be the major player in the large scale initial roll-out of CSP technologies, but nevertheless needs to contribute to technology rollout to ensure we have local availability of technology, project development, design, financing, supply chain, manufacturing, construction and project management within the various industries needed to deliver large scale CSP.

While Australia does not have a significant Venture Capital market to speak of (in comparison to that in existence in Europe, Asia and USA), there is enough interest in renewables to support a steady pipeline of projects (if revenue were to provide acceptable ROIs) to meet the needs of the Industry over the coming decade, by which time CSP, under it's current development regime, will have reduced costs and increased performance to be in a position to be a financially viable large scale energy producer.

As a result it seems logical to maintain Australia's RD&D capability, and potentially foster development of the industry further through the ongoing development of new CSP Plants in the locations and circumstances that best suit the output capability of CSP.

Additionally, the concept of developing technological solutions, and then licensing them for export was considered worth pursuing. An example of this is Australia's key expertise in remote community integrated renewables with diesel and renewable stand-alone systems. Australian innovation is now deployed in remote communities across the Pacific, Asia, Africa, India, Antarctica and Canada.

13.3.4 Storage

This was another topic generating significant discussion at the workshops – not necessarily about whether to have or not have storage – but more about how to get the storage levels right, and to maximise energy delivery to meet NEM signals.

13.3.5 Integration into the Electricity Industry

The electricity industry in Australia has been constructed in such a way as to enable the delivery of energy from central plant to outer lying demand areas. This central dispatch mentality comes from a coal-fired history and was a sensible and appropriate development process for the time.

There are significant voltage and frequency control issues in play when remotely located power generators connect in the lower capacity sections of the electricity network, and feed back into the grid.

There are also significant potential benefits to the Transmission and Network operators in avoiding energy losses (energy losses are paid for by retailers) and avoiding expensive infrastructure upgrades if generation resources can be co-located with large energy load centres.

However it is felt that Network Service Providers tend to fight embedded generation in hidden ways because of culture and mixed incentives.

Network Service Providers wish to limit penetration to 20% of any given transformer. They have an obligation to "make an offer" to connect a generator but no real incentive to do so. They can hence make an offer that is costly to the system developer. There is some logical failures with, in that network operators manage to deal with very large intermittent loads (eg motors) if needed, (notably a load equates to revenue and incentive). The concept of motor soft-starters is a precedent for a technical solution to varying differences between demand and supply.

The massive growth in rural Wind Projects and Solar Rooftop PV has created significant concern within the electricity transmission and network providers that CSP (and solar farm PV) will be more of a liability than an asset.

The CSP industry – as well as the PV industry – urgently needs to engage with the Distributors, Transmitters and Grid Operators to better understand the requirements of these organisations and how integration can be beneficial and high value to both the CSP and Electricity industries.

Additionally, there is an enormous quantity of money to be spent on the Australia Electricity Grid over the coming 5-10 years – something in the order of $96B – under the Business As Usual scenarios. There is potential to engage with AEMO and the rest of the industry to ensure portions of this investment, benefit future large scale solar in remote locations. Concepts include the strengthening/duplication of existing inland transmission feeds, the construction of

Copperstring in NW Qld, and the potential for the long-talked about Olympic Dam-SE Queensland link.

AEMO representatives at the workshop indicated an interest to facilitate a dialogue with network managers. The focus of a dialogue would initially be on education for both industries. This could lead to the development of a joint plan of action to examine the potential for CSP on end of grid and fringe of grid for the high voltage networks.

13.3.6 Financing

Financing of CSP (and other "new" renewables) projects in Australia is very difficult given the lack of experience of the policy makers, financiers and project developers.

The key risks discussed at the workshops included:

- Technology risk – Is the product mature and can the product deliver?
- Deployment risk – can it really be built in Australia
- Output risk – how long will it operate for and what guarantee of output is there?
- Income risk – what long term Power Purchase agreements are in place?

Other themes also pervaded the discussions, including: competition for Capital with high return projects such as in the Mining Sector, and the debt-equity mixes available.

The key understanding to come from the discussions was that the Finance Sector does not know or trust the CSP Industry in Australia at this point. As a result, financiers attach high risk profiles to projects, which push financing cost up. This needs to be addressed, through educating Australian Financiers. A concept mooted was bringing European or US financiers to Australia who already have experience with CSP. This could link to any assistance provided by Governments through the CEFC or otherwise.

In part this perception may have arisen because the CSP industry is so closely linked to government grants and other subsidies.

Specific actions including industry level meetings to improve understanding of technology and project needs; and tours of project sites in Europe and the US to enable investors to "kick the tyres" and develop a better understanding of the low risks involved with CSP projects were suggested. Nevertheless it was also accepted that Australian investors are generally risk averse with any new technology and would need to actively pursue finance for projects through offshore banks and other institutions where there is far more demonstrated appetite for investment in higher risk projects.

The proposed Clean Energy Finance Corporation is expected to be an important step in this direction provided that it does not become too risk averse in its approach to investment.

13.3.7 Hybridisation

It was broadly acknowledged at the workshops that Hybridisation with the existing energy industry provided the prospect for developments earlier in the timeline than attempting to stand alone as a power producer.

Delivering steam to coal or CCGT plants has been established with several projects around the world and has been used in the Liddell power station trials and is the subject of the Solar Boost project at Kogan Creek Power Station.

There remains significant potential for solar boosting of coal fired plants, and further for the gasification of coal for domestic and export electricity generation.

Exploring those links further was recommended.

Further, the demonstration that CSP can be complimentary to Wind and PV projects – rather than competitive – is important.

However CST should not become pigeon holed as the “augmentation” technology. We should also address the value in the boost market and the issue of Energy vs Exergy artificially leading to low T system development.

13.3.8 Government Programs

Outside of RD&D programs, the key Government program relating to deployment of CSP is clearly Solar Flagships. Regular concern was voiced at the workshops about the concept of an “all eggs in one basket” approach that was taken by Flagships Round 1.

Generally it was acknowledged that a more beneficial approach in any future Flagships program would be to fund a number of smaller scale projects that were designed to demonstrate the variant CSP platforms.

There was also significant support for a “Demonstration Farm” approach, similar in concept to the PV Demonstration facility at Desert Knowledge Australia Solar Centre in Alice Springs (but on a larger scale). The concept could even involve the provision of central plant such as the power block, and cooling system, while technology providers would construct their various solar collector technologies to feed into the central plant on a commercial basis.

13.3.9 Land Development approvals

The Sydney and Brisbane workshops did not include many of the project developers, thus did not discuss in great detail the land approvals process. In Melbourne however a number of project developers were present, and this was raised as a major issue that will affect the CSP industry in future.

The errors made by the Wind Industry in community consultation and environmental approvals led to the failure of a number of projects across Australia that otherwise would likely have gone ahead. Wind now also has significant challenges in a number of communities that are concerned about the purported health effects from turbine blade pulsing.

CSP has similar challenges, especially in Tower technology, where public perception could be negative.

Solar also may have a less than exemplary record on Environmental Impact Statement delivery, with one major project in Australia being excused from having to perform a full EIS prior to land permitting approval.

The wind industry developed a voluntary code-of-practice several years ago, but it is apparently not usually adhered to.

It was suggested that, to ensure Solar maintains its “clean green” preferred renewable status, the Industry must, in every instance, deliver EIS and community consultation processes that are exemplary.

Developing a Best Practice for Land Development for Solar Projects could ensure that these concerns are addressed.

A far better approach to expedite such things is a careful pre-approval process applied to solar parks in advance of project proposals. The most minimum form of Solar Park, would be simply the pre-approval / EIS process carried out.

Community amenity issues are very important and arguably an area that the wind industry has not handled optimally. CSP would be mistaken to take this area for granted on the grounds that it will be sited in remote areas where people do not care. The potential public opposition to new transmission lines alone should be considered.

13.3.10 Retail Markets

Within the Australian Retail Electricity Markets, there is a range of retailers. However, four major players dominate the majority of the market, and therefore dominate electricity purchasing arrangements through the Wholesale Electricity Market from the existing generators, be they Brown/Black Coal Fired, CCGT, OCGT or Wind.

A number of comments were made that the Big 4 retailers were effectively an Oligopoly that exerted significant power over new CSP and PV Projects, could make it:

- Difficult to obtain a Power Purchase Agreement, and
- Impossible to obtain a PPA that reflected the full energy value of the generation.

Comments were made that this is a major hurdle CSP faces in Australia. The CSP industry can reduce costs through efficiency and technology gains, have broad public support and Government subsidy, and the approval of the electricity networks to connect where it wants to. However if it cannot negotiate sales agreements for energy which reflect the value provided, then efforts in other areas are in vain.

It was also suggested that major Retailers have covered their forward RET liabilities with wind and roof top PV already

Gaining the interest, support and recognition of value from the Big 4 retailers therefore was seen as a critical path item for CSP development in Australia.

13.3.11 Industry Development Vs Requests for Handouts

A discussion item was general concern that the Solar Industry, and CSP in particular, seemed to publish a large number of reports calling for the Government to provide funding and programs to help the Industry develop. Many of these reports did not address what the Industry was doing to help itself develop, and concentrated solely on attracting Government Funding programs.

The workshops made it clear that CSP stakeholders wanted to know how the industry could help itself, first and foremost, so that the Government would only be asked to “bridge the gap”.

A number of potential Government Policy positions were discussed.

The idea that state and federal government is suffering a great deal of “policy fatigue” in the clean energy space was expressed and makes the task challenging. We thus need to look for directions that are win wins, de-risking and making life easier for govt.

There is no stated policy or apparent expressed wish that the government actually wants a Solar Industry specifically although it is clear the public does.

13.3.12 Water Use

In the areas where CSP is likely to be constructed in Australia, there is generally pressure on water resources. The Murray-Darling Basin and the Great Artesian Basin are both sensitive water sources, both physically and politically. There has been little Australian R&D thus far on working to reduce water use, either in the generation cycle or in cleaning.

13.3.13 Other Points

- Solar Data is a very insignificant barrier, just a year or so with a ground station fixes it. This is not to say that a pro-active initiative would not help as an enabler. However perversely, it could well be a displacement activity. It could also mainly help the startups who are actually never going to get a project up anyway, ie big players would not be overly bothered anyway.
- Most barriers just roll into cost issues
- End of grid connection issues are real, but once again its just a cost thing, if there was a profitable business, it would get done.
- Historically, bulk of transmission has been built using government bonds at 3%.
- Manufacturing capability is not a significant barrier – we could go quick
- In California PGE made their own decision to limit wind penetration – note they have a monopoly area still.
- Importance of running a demo of a new technology well; AREVA did not make final payment for Ausra until they had observed a full year of operation.
- Note that much allocated money from past programs is not spent. Government brings it on themselves however industry is also promising things it can not deliver. A mix of naivety and telling govt what it wants to hear to get the money.

***

14 Appendix C: Solar Data for Australia

Australia has a relatively small number of ground based weather stations, operated by the Australian Government's Bureau of Meteorology, that have collected DNI measurements. Sixteen operated prior to 2000, after which it was reduced to six. Eight new stations are however coming online in 2011. There are a larger number of stations collecting diffuse radiation data. There have also been various ad hoc and private short duration data collection efforts. Overall, there is a strong dependence on Satellite based measurement, with calibration based on the limited ground data.

There are various sources of publically available data of varying spatial and temporal resolution. The following summarises them.

14.1.1 Bureau of Meteorology

http://www.bom.gov.au/climate/data-services/#tabs=3

The Australian Government's Bureau of Meteorology has satellite derived data sets of Direct normal Radiation (and other climate data) available. Hourly or Monthly average hourly direct normal solar exposure over the period 1998 to 2007 The resolution of the data is 0.05 degrees (approximately 5km). They also have ground station based DNI measured data for those stations that measure it.

14.1.2 The Australian Solar Radiation Data Handbook

The Australian Solar Radiation Data Handbook (ASRDH) and its companion software AusolRad, is marketed by the Australian Solar Energy Society.

http://auses.org.au/solarpedia/australian-solar-radiation-data-handbook-and-software/

It offers tabulated average data including DNI for a range of specific sites. Quoting from the Handbook:

"All data tabulated in this Handbook are drawn from the Australian Climatic Data Bank (ACDB). … The data bank sets consist of hourly records over numbers of years of climatic variables, including solar radiation. Measurements of global solar radiation are available for 22 locations, and of these, 16 locations have additional simultaneously measured diffuse solar radiation. A further 67 locations contain solar radiation data estimated from cloud cover records."

14.1.3 The Australian Climatic Data Bank (ACDB)

http://members.ozemail.com.au/~acadsbsg/

Quoting from the ACADS website:

"The Australian Climatic Data Bank, for use in air conditioning load estimation and building energy analysis and other HVAC applications, was established in the 1990's by CSIRO in association with AIRAH, ACADS-BSG Pty Ltd, the Australian Federal Government Construction Services, and the Australian Bureau of Meteorology. In 2006 the Australian Greenhouse Office funded the update and extension of the data bank to include data for 1967 to 2004 for most locations and a Reference Meteorological Year for each location being a composite of average months. For some locations only the original data is available."

As noted in Chapter 5, it is the ACDB RMY files that are offered by the US Energy Plus website for use with SAM. The same RMY files are found inside the "Accu-rate" building energy modelling software.

14.1.4 UNSW TMY data

http://solar1.mech.unsw.edu.au/glm/trnaus/CLIMATIC%20DATA.htm

The University of NSW solar thermal group were the first in Australia to develop Typical Meteorological Year (TMY) files for Australian sites.

Quoting from the website:

"The generation of TMY records for Australia from long term measured solar radiation records is described in the STEL report "Condensed Solar Radiation Data Base for Australia" (http://solar1.mech.unsw.edu.au/glm/trnaus/tmy99.pdf) The long term hourly records for Sydney were a combination of measurements at the STEL and two years of measurements by the Bureau of Meteorology. Long term records for other locations were obtained from the Australian Climate Data Bank".

Eight Qld sites, ten NSW sites, three Victorian sites, six Western Australian sites and two NT sites are listed. It is understood that these have not however been updated with post 1999 data.

14.1.5 Australian Solar Energy Information System

Geoscience Australia is in the final stages of a joint Solar Resource Mapping project with BOM, that aims to:

- Improve solar data (including via the 8 new stations)
- Improve Infrastructure and topographic data
- Provide improved access to the data via the "Australian Solar Energy Information System"

http://www.icem2011.org/presentations2011/5_Friday/ASI_Workshop/1000_Graham_Hammond.pdf

Data sets for use with GIS software are now available from

https://www.ga.gov.au/products/servlet/controller?event=GEOCAT_DETAILS&catno=71285

A web based tool is due for later in 2011 and promises to offer a major increase in utility for CSP feasibility study purposes.

14.1.6 NASA

http://eosweb.larc.nasa.gov/sse/

The NASA website service allows DNI data to be downloaded freely for any grid reference across the globe. The data is in the form of monthly averages and is derived from 22 years of satellite data with an effective 30km grid. Hourly data is derived using a calculation procedure based on an average day for each month.

14.1.7 Solemi

www.solemi.de

Solemi is a service run by the DLR (Deutsches Zentrum für Luft- und Raumfahrt), Germany's aerospace research centre. Solemi provides solar radiation data from the Metosat-5 and Meteosat-7 satellites with a nominal spatial resolution of 2.5 km and half-hourly temporal resolution. Solar radiation maps and hourly time series are available for approximately half the earth's surface including part of Western Australia. Approximately 10 years of data collected from the satellites is available. DNI data is derived from satellite data using a method of comparing a reference image (ground only) with the visual spectrum data collected by the satellite.

14.1.8 Meteonorm

www.meteonorm.com

Meteonorm is a commercial weather data and modelling tool that provides approximately 20 years of data for global solar radiation and other climate data including temperature, humidity and wind speed. The data is collected from ground based weather stations and supplemented with satellite data where there is a low density of weather stations. Hourly values are available but are calculated from collected data using a stochastic model.

14.1.9 3Tier

www.3tier.com/en/products/solar/

The company 3Tier have modelled solar datasets available commercially that includes wind and temperature data. 3Tier have modeled hourly values of Global Horizontal Irradiance, Direct Normal Irradiance and Diffuse Horizontal Irradiance at a horizontal resolution of 2 arc-minutes, (approximately 3 kilometers).

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15 Appendix D Approach to maximizing value in NEM

NEM price data is available every half hour. If predicted solar energy generation is multiplied by NEM prices, an average market value of the energy produced can be calculated and compared to the NEM average.

For CST systems, a key issue to consider is what effect adding thermal energy storage and adjusting the dispatch profile can improve the market value of the energy.

The SAM model can incorporate storage and it has a simple approach to specifying dispatch. However there are drawbacks, the dispatch profile is very simple and the same for every day of the year and is tedious to change via the user interface.

For a rapid scoping investigation, The output predicted from the Nevada Solar 1 configuration without storage has been taken into a spreadsheet for further analysis. A simple storage / dispatch algorithm has been constructed using the nominal instantaneous electrical generation from the system. In a literal sense, this is modelling a hypothetical electrical storage system applied after generation. For the purposes of scoping market value, it is a reasonable approximation to the output of a thermal storage system dispatched via a steam turbine as required.

The model is set up to allow specification of the capacity of output generation. Ie increasing the size of the power block relative to the solar field with storage included, is a choice to configure the plant more towards and intermediate / peaking configuration.

The model assumes that any dispatch is done at full load. In reality, turbine efficiency is maximised at full load, so a system with storage is more likely to be run at full load.

Turbine based systems need some time to ramp up and generate at full load, in recognition of this, a “minimum acceptable run time” for the system is specified, a value of an hour and a half has been used.

The dispatch algorithm is based on a first allowed start time for the day. If the store contains enough energy for an hour and a half operation at least, then it starts dispatching until the store is expended. This is irrespective of the instantaneous solar resource level.

The hypothesis that peak loads (and prices) in Winter are later in the day than peak loads in Summer, lead to the inclusion of a sine curve based start delay function through the year. Thus the user specifies the mid summer start time and the mid winter delay over summer (which could be zero).

The capacity of energy storage is not specified, rather it is an output of the calculation.

As an initial investigation, manual searching with the three parameters; capacity level, summer start time and winter delay time was used to establish approximate settings for maximum market value. Starting with the 64MW$_e$ Nevada Solar 1 modelled output, it was found that:

- Parameters for maximising market value were largely but not quite independent of site and year and were:
  - Capacity increased to around 110MW$_e$
  - Mid Summer generation start time between 11.00am and 12.00pm,

- Mid Winter generation start time between 4.00pm and 6.00pm

- The implied energy storage requirement to maximise market value was approximately 6 hours at the 110MW_e capacity level.

- Parameters values for maximising market value were quite sensitive, with poor values providing no significant increase in market value over immediate dispatch.

For further information contact IT Power (Australia) Pty Ltd
ph: 61-2 6257 3511
email: itpau@itpau.com.au
web: www.itpau.com.au

www.australiansolarinstitute.com.au
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