UNIVERSITY OF TECHNOLOGY SYDNEY

INSTITUTE FOR SUSTAINABLE FUTURES

Institute for Sustainable Futures

BREAKING THE SOLAR GRIDLOCK: POTENTIAL BENEFITS OF INSTALLING CONCENTRATING SOLAR THERMAL POWER AT CONSTRAINED LOCATIONS IN THE NEM

AUSTELA
Australian Solar Thermal Energy Association

Centre for Energy and Environmental Markets

UNSW
THE UNIVERSITY OF NEW SOUTH WALES
SYDNEY • AUSTRALIA

ERGON ENERGY

Breaking the solar gridlock. Potential benefits of installing concentrating solar thermal power at constrained locations in the NEM

AUTHORS

Jay Rutovitz[1], Juergen Peterseim[1], Ben Elliston[2], Stephen Harris[1], Steve Mohr[1], Keith Lovegrove[3], Andrew Want[4], Edward Langham[1], Iain MacGill[2]

A collaborative research project of:
Institute for Sustainable Futures, UTS[1],
The Centre for Energy and Environmental Markets, UNSW[2] and
The Australian Solar Thermal Energy Association (AUSTELA)[4]

The project was funded by the Australian Renewable Energy Agency (ARENA), Ergon Energy, and AUSTELA

Left photo: 20MWe Gemasolar tower plant with 15hr storage in Seville, Spain.
Source: http://www.torresolenergy.com/EPORTAL_IMGS/GENERAL/SENERV2/IMG2-cw4e41253840d81/gemasolar-plant-june2011-2b.jpg

Right photo: 280MWe Solana CSP plant with 6hr storage in Arizona, USA.
Source: http://guntherportfolio.com/2013/01/abengoa-solar-solana-generating-station-sortie/

THE CONSORTIUM

The consortium brings together ISF's expertise in decentralised energy, intelligent network solutions, and renewable energy analysis, CEEM's expertise in energy market dynamics and solar capabilities, and AUSTELA's firsthand knowledge of solar thermal technologies, project development and markets. IT Power (Australia)[3] provided expert advice on CSP.

The Institute for Sustainable Futures (ISF) is part of the University of Technology, Sydney, and was formed in 1997 to work with industry, government and the community on applied research projects that aim to create change towards a sustainable future. ISF has a research focus on the market benefits of large scale decentralised energy deployment in the Australian National Electricity Market. **www.isf.uts.edu.au**

The Centre for Energy and Environmental Markets (CEEM) is an interdisciplinary research Centre housed in the Faculty of Engineering and Australian School of Business within the University of NSW that focusses on market-driven transition of the energy sector. **www.ceem.unsw.edu.au**

AUSTELA is the industry body solely dedicated to concentrating solar thermal power (CSP) generation in Australia. Composed of some of the leading national and international solar thermal industry participants, AUSTELA's membership is open to organisations involved in the development of solar thermal power systems on a large scale to supplement or replace existing power requirements in Australia, whether in the electricity sector or in other industry sectors. **www.austela.com.au**

ACKNOWLEDGEMENTS

The authors of the report would like to thank the Australian Renewable Energy Agency (ARENA), the Australian Solar Thermal Energy Association (AUSTELA), and Ergon Energy for their support throughout the project. This measure received funding from the Australian Government as part of the Emerging Renewables Program.

The report could not have been completed without the assistance of the network operators; Ergon Energy, in particular, has been a major collaborator on the project. We received assistance from Essential Energy, Transgrid, ElectraNet, SP Ausnet, SA Power Net and Powercor who provided data, answered our questions and contributed to workshop discussions. The authors would like to thank, in particular:

- Andrew Nelson (Ergon Energy) who provided invaluable feedback and advice,
- David Bellew and Ian Thompson (Essential Energy),
- Gordon Burbidge and Samantha Christie (Transgrid),
- Rainer Korte and Hugo Klingenberg (ElectraNet),
- Tom Langstaff (SP Ausnet),
- Neil Gascoigne (Powercor),
- David Pritchard (SA Power Networks), and
- Tim Couchman and David Beins (ARENA)

We would also like to thank UTS and UNSW colleagues who have assisted with ideas, data analysis, mapping, review and comments throughout the project: Stuart White, Nicky Ison, Nicole Thornton, Jonathan Bruck, and Julian Fyfe (ISF, UTS).

CITATION

Please cite this report as: Rutovitz, J., Peterseim, J., Elliston, B., Harris, S., Mohr, S., Lovegrove, K., Want, A., Langham, E., and MacGill, I. 2013. Breaking the solar gridlock. Potential benefits of installing concentrating solar thermal power at constrained locations in the NEM. Prepared for the Australian Solar Thermal Energy Association (AUSTELA) by the Institute for Sustainable Futures, UTS.

DISCLAIMER

UTS and the authors make no representations or warranties as to the accuracy or currency of the content of the report and disclaim liability for any error or omission in this report and in any associated material, and they specifically disclaim any liability for any costs, losses, claims, demands or liabilities of any kind suffered or incurred by any person acting in reliance on information contained in the report or associated materials. While due care and attention has been taken in the analysis of available data and to verify the accuracy of the material published, this report and all associated materials are not intended to be used as the basis for any investment decision. Users should make their own detailed investigations and determinations before considering any investment relating to the subject-matter of this report.

Data supplied by the network operators and other parties and used in the formulation of this report has been compiled and assessed in good faith, but may be incomplete and is subject to errors and to change over time as the network situation changes, load projections are amended and operational and technical matters affect network performance and investment. Such changes are likely to have occurred through the period of this research and prior to publication of this report. The network operators and other parties are not responsible for any analysis and conclusions drawn from data they have provided, nor for any network information presented, which is the responsibility of the authors alone.

REVIEW

Version	Author	Reviewed by	Date
Final draft	J.Rutovitz	JR	29 July 2013
Final reportv1	J.Rutovitz	JR	14 August 2013
Final reportv2	J.Rutovitz	JR	4 February 2014

INSTITUTE FOR SUSTAINABLE FUTURES
University of Technology, Sydney
PO Box 123, Broadway, NSW, 2007
www.isf.edu.au

© UTS 2013

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

Abbreviations

ACAP	Available Capacity
ADV	Annual Deferral Value
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AS	Australian Standard
AUSTELA	Australian Solar Thermal Association
AVGR	Average Growth Rate
BOM	Bureau of Meteorology
BSP	Bulk Supply Points
CEEM	Centre for Energy and Environmental Markets
CSP	Concentrating Solar Power
CY	Current Year
DANCE	Dynamic Avoidable Network Costs Evaluation
DECY	Demand Exceeds Capacity
DEPR	Depreciation Rate
DISR	Discount Rate
DNI	Direct Normal Irradiance
DNSP	Distribution Network Service Provider
ELCC	Effective Load Carrying Capability
GIS	Geographic Information System
GW	Gigawatt
IFC	Indicative Firm Capacity
INVA	Investment Amount
INVY	Commissioning Year
ISF	Institute for Sustainable Futures
ITP	Investment Trigger Point
kWh	Kilowatt hour
kVA	Kilovolt Ampere
LCOE	Levelised Cost of Electricity

LGC	Large Generation Certificate
MAXP	Maximum Potential
MDEM	Maximum Demand
MJ	Megajoule
MPa	Mega Pascal
MVA	Megavolt Ampere
MW	Megawatt
MW_e	Megawatt electrical
MWh	Megawatt hour
MW_{th}	Megawatt thermal
NAN	Not A Number
NEM	National Electricity Market
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PoE	Probability of Exceedence
PPA	Power Purchase Agreement
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SAM	System Advisor Model
SNAP	Sub-transmission Network Augmentation Planning
Stli	Sub Transmission Lines
SUP	Support
TES	Thermal Energy Storage
TNSP	Transmission Network Service Provider
TS	Terminal Station
WACC	Weighted Average Cost of Capital
ZS	Zone Substation

EXECUTIVE SUMMARY

This study was undertaken to quantify the potential benefits of installing concentrating solar thermal power (CSP) generation at constrained network locations in the Australian national electricity market (NEM). The primary objectives were to identify and map locations where CSP could provide cost-effective network support services, quantify the potential effect of network support payments on the business case for CSP, and engage network service providers regarding the potential for utilisation of CSP as an alternative to network augmentation.

Concentrating solar thermal power electricity generation has been in commercial operation at utility scale for over 20 years. By the third quarter of 2013, there was 3GW of installed CSP capacity worldwide and close to another 2.5GW under construction (SolarPACES 2013). However, despite excellent solar resources and considerable research and development expertise in CSP, Australia, to date, has only deployed one demonstration plant. The Australian market is very challenging, with a gap between current estimates of the levelised cost of electricity (LCOE) from CSP and likely revenue for grid-connected systems, of between $100/MWh for large systems, to more than $200/MWh for smaller systems (Lovegrove et al. 2012).

Little attention has been paid to the potential for CSP systems to alleviate grid-constraints in electricity networks. Australia’s electricity network experienced a dramatic increase in capital investment over the last six years, with over $45 billion in electricity network infrastructure planned for the period 2010 to 2015 alone.

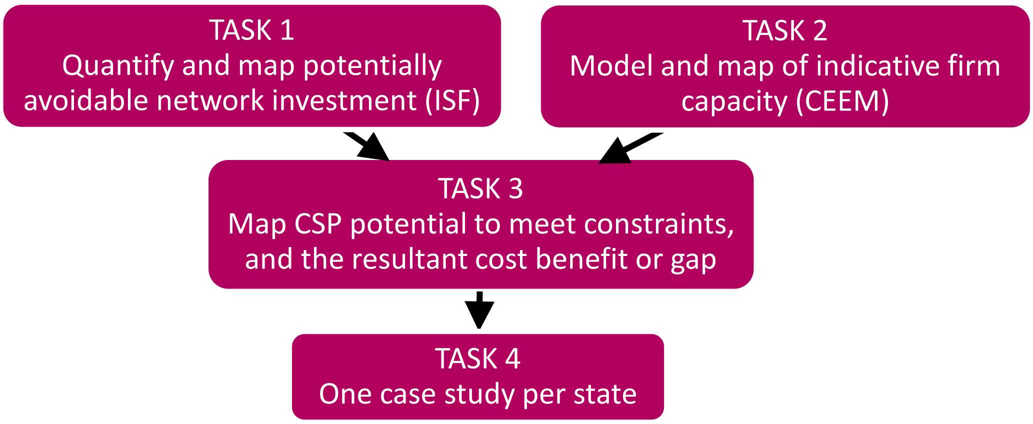
The fact that CSP may be developed with or without storage, at a variety of scales, and may be hybridized – for example with biomass or natural gas – means grid integration is relatively straightforward, in comparison with some other renewable energy options. Further, the potential network services offered by CSP are both reliable and flexible.

The central premise of this study is that rather than continuing to invest, by default, in increasing the capacity of a transmission and distribution network system designed for centralised power generation to meet growing peak demand, facilitating distributed generation or demand reduction options may provide cost effective alternatives. Increasing the deployment of these decentralised energy options, and CSP in particular, could concurrently enable greater deployment of renewable energy in the electricity system, and reduce total system greenhouse gas emissions.

Methodology

The project had four main components, as shown in Figure 1. Task 1 was to quantify and map potentially avoidable network investment, using the Dynamic Avoidable Network Costs Evaluation model (DANCE) developed by the Institute for Sustainable Futures (ISF) at the University of Technology, Sydney, according to location and expected constraint year. The main inputs are data about proposed network investment, forecast electricity demand, peak day demand profiles, and firm capacity at constrained assets in the electricity network. These are mapped for the distribution areas or connection points where distributed energy could potentially alleviate the constraint.

Figure 1: Methodology overview



Task 2 was to quantify the likelihood of CSP being able to generate during peak load periods at different locations in the NEM. The model, developed by the Centre for Energy and Environmental Markets (CEEM) at the University of New South Wales, assigns an indicative firm capacity (IFC) to each location, essentially an estimate of the probability that CSP would be generating during the most acute summer and winter peak network constraint periods. The IFC is calculated by selecting twenty-one of the highest peak demand events for each state in each of the defined peak time periods during 2009, 2010, and 2011. The model examined whether CSP with different amounts of storage, from 0 to 15 hours, would have been generating during the peak event. The IFC assigned at each location is the average value of modelled output for the specific plant configuration for the defined period (for example, summer afternoon).

Task 3 integrates the output from Tasks 1 and 2 to identify locations where CSP may provide cost effective network support, and identifies appropriate plant capacities and configurations. For modelling purposes, CSP is defined as being able to meet a network constraint when the IFC at the location for the time and season is above 80%, and a CSP plant of capacity equal to the maximum projected network constraint could be physically connected at the appropriate connection point. The cost effectiveness of CSP replacing network augmentation is assessed by comparing the CSP plant's LCOE to potential revenue, including a calculated network support payment. Different CSP plant configurations are assessed, ranging from the minimum size plant to alleviate the constraint, to the maximum size able to be connected without requiring network augmentation to export energy. The configurations include the assessment of varying amounts of thermal energy storage (TES). A reduction of 4% per year was included in the modelling of CSP capital costs to allow for the projected learning curve for CSP, a mid-range amongst estimates for likely cost reduction.

The proposed network investment is reduced by 20% prior to calculating the network support payment, reflecting the fact that electricity generation (of any type) cannot replicate the certainty offered by wires and poles. This also means the total societal cost of meeting network constraints is reduced by 20%. Note, however, that the comparison of CSP installation to other non-network solutions is not considered in this study.

Task 4 involved undertaking five case studies at constrained locations in Queensland, New South Wales, Victoria and South Australia, in consultation with the relevant network service provider.

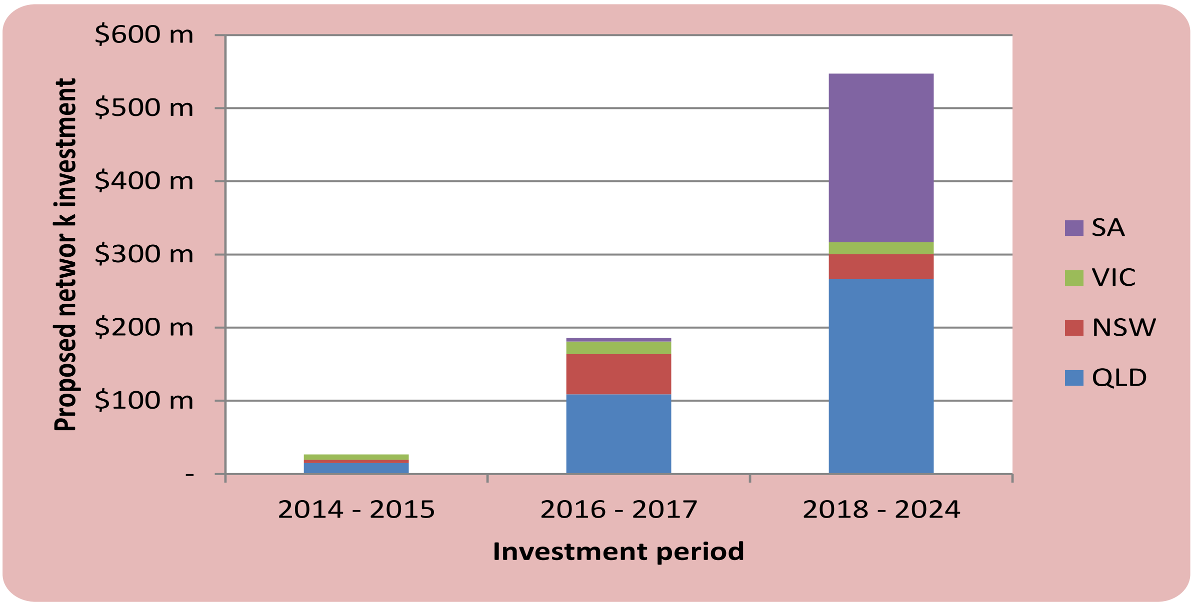
Results – potentially avoidable network investment

A total of 92 constraints, or constrained areas, were identified in non-metropolitan areas in the NEM during this research, either from public network planning documents or information supplied directly by the network operators. In two states, Queensland and South Australia, constraints were only examined in areas with direct normal insolation (DNI) likely to be sufficient for CSP to operate economically, while in Victoria and New South Wales all non-metropolitan constraints were mapped where possible. The high number of constraints in Victoria reflects the fact that use of data from public information allowed easy inclusion of all the identified non-metropolitan constraints, so low DNI areas were included, and is not because the network is more constrained.

Approximately $0.8 billion of potentially avoidable network augmentation has been identified across the NEM in areas with suitable solar irradiance for installation of CSP (defined here as average DNI which is more than 21 MJ/m^2/day). This is broken down by time period and state in Figure 2. There is a further $0.5 billion of potentially avoidable network expenditure which has been identified in areas with DNI below 21 MJ/m^2/day.

Most of the investment occurs in the period from 2016 onwards. This reflects the fact that maximum demand forecasts were reduced significantly during 2012, with the result that proposed growth-related augmentation has in many cases been deferred. It is important to stress that proposed investment changes as demand forecasts change, as different non-network solutions come into play, and as reliability criteria are adjusted. Thus the investment identified here is a snapshot of expectations at the present time.

Figure 2: Potentially avoidable network investment in areas with average daily DNI > 21 MJ/m^2



Results – indicative firm capacity

The modelling showed that IFCs in excess of 80% can be achieved in all seasons and most locations. Very little storage is required to reliably meet summer afternoon and evening peaks in most areas of the NEM. In winter, IFC is less due to the lower solar resource, but high IFCs can still be reached by increasing storage levels.

Figure 3: Indicative firm capacity summer afternoon (5 and 10 hours storage)

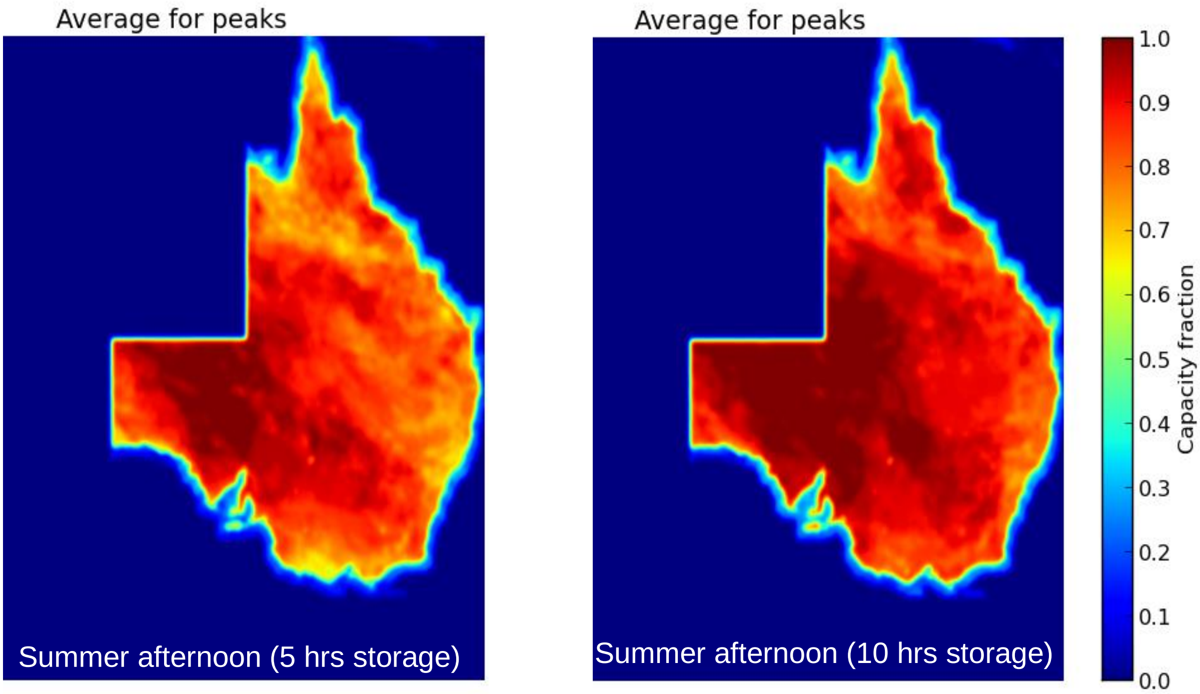


Figure 4: Indicative firm capacity winter evening (0 and 10 hours storage)

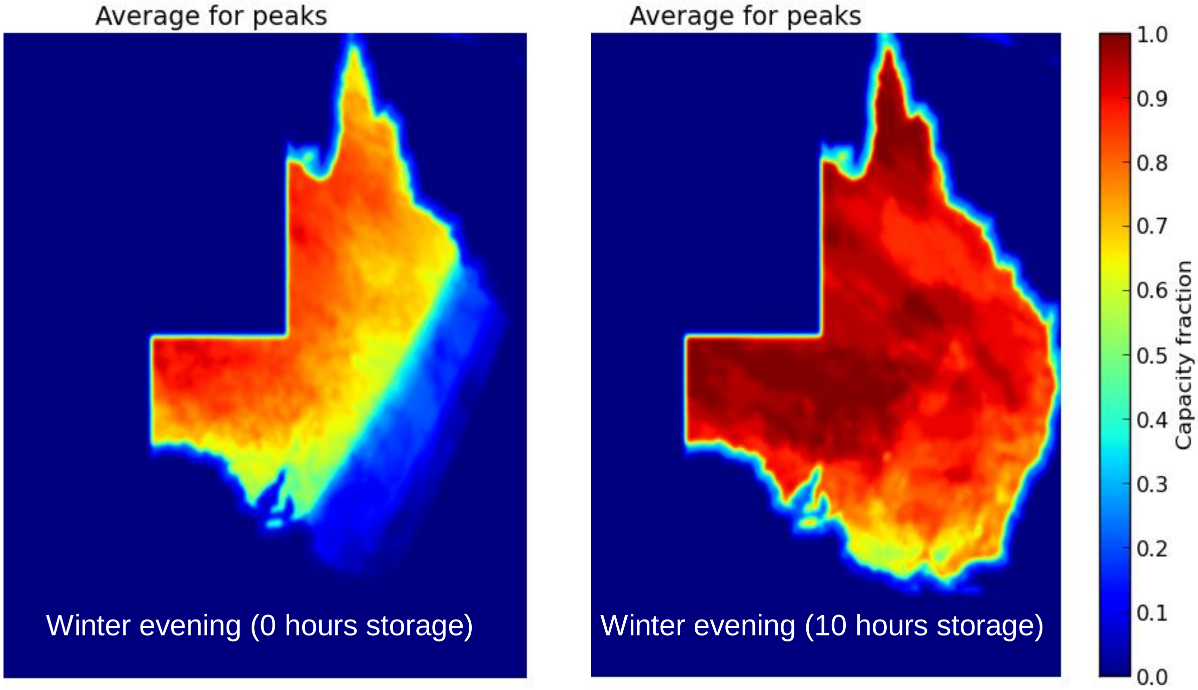


Figure 3 shows two plots of IFC across the NEM during the summer afternoon peak, with 5 and 10 hours of storage. The plots have a number of common features. First, coastal areas have lower values due to the weather systems that generally prevail on the coast. This is also true for tropical northern Queensland, where summers include monsoonal impacts and periods of high rainfall. In winter, Queensland sees higher IFCs because of the absence of monsoonal weather patterns. Second, we find that IFCs are somewhat higher the further west the plant is located (e.g. northern South Australia).

Results for winter evening (the 'worst case' for CSP) are shown in Figure 4. The plot on the left is an extreme case: winter evening results for a plant with no TES. The band across the map shows locations where IFCs are approaching zero simultaneously, as sunset falls within the period of interest (5 to 8pm on winter evenings). Further north on the plot, IFC increases because sunset occurs later. The plot on the right shows the effect of increasing storage to 10 hours, which results in IFCs of 80% and above in most areas.

The CSP model simulated plant output using a simple dispatch strategy, with generation starting at 12pm and continuing as long as possible. In practice, a more sophisticated dispatch strategy would be employed to meet any obligations under a network support contract, as well as considering solar forecasts, demand forecasts, and prevailing market prices. This could achieve much better availability than indicated by the IFC.

Results – cost effects of CSP replacing network augmentation

The results indicate that CSP could avoid the need for network augmentation in 72% of the constrained areas examined, i.e. in 48 locations. Altogether, 93 constraints, or constrained areas, were considered, of which 67 had sufficient information to make a determination. If constraints were limited to only those with solar resources better than 21 MJ/m^2/day DNI, CSP could avoid the need for augmentation at 94% of locations.

Victoria has the lowest percentage of locations where CSP can avoid the requirement for augmentation, essentially because sites with average DNI as low as 13.5 MJ/m^2/day have been included in the overall analysis. The lowest DNI for the sites examined in other states respectively is 20 (QLD), 19.8 (NSW) and 18.9 (SA).

For each location where CSP could indicatively meet the constraint, cost benefit calculations were undertaken. The results for each state are shown in Table 1. Overall, CSP installation was found to have a positive cost benefit in 25% of the constrained locations examined (where DNI > 21 MJ/m^2/day), meaning that a CSP plant operating under a network support contract would have a commercially viable business case, while the cost to energy consumers of meeting constraints is reduced by 20% relative to traditional network augmentation. An additional 36% of constrained locations come close to cost-effectiveness, with a cost gap of less than $20 (that is, overall cost benefit was between -$20 and $0 per MWh), as shown in Table 2.

Altogether, installation of 533MW of CSP at grid constrained locations was found to be cost effective during the next 10 years, and an additional 125MW had a cost benefit between -$20 and $0 per MWh. Across all states, the average plant was 40MW, with 10 hours storage, and the average and lowest LCOE were $202/MWh and $111/MWh respectively.

Table 1: Proportion of grid constrained locations where CSP could indicatively avoid the need for network augmentation

	QLD	NSW	VIC	SA	All states
Number of locations where CSP could indicatively avoid the need for network augmentation	20	7	17	4	**48**
Proportion of all locations	87%	88%	53%	100%	**72%**
Proportion of locations with DNI > 21 MJ/m^2/day	90%	100%	100%	100%	**94%**

Note: Excludes locations with insufficient information

Table 2: Cost benefit of CSP installed at grid constrained locations

	QLD	NSW	VIC	SA	All states
Proportion of cost effective sites	30%	0%	14%	67%	**25%**
Proportion of sites cost benefit > -$20/MWh	45%	17%	14%	67%	**39%**

Note: Only sites with DNI >21 MJ/m^2/day are included

The network support payment was not found to be a crucial factor to CSP plant viability in most locations, although it certainly contributed to the overall cost effectiveness, and made a major contribution in some locations. As the optimisation process generally increased the plant size to the maximum able to be connected, this had the effect of diluting the contribution from the network payment when measured as a value per MWh of plant output. The largest network support payment contribution calculated was $134/MWh (83% of the LCOE at that site), and the average $15/MWh (8% of LCOE). The average value of the network support payment at cost effective sites was somewhat higher, at $31/MWh., contributing an average of 20% of the LCOE.

Results – case studies

Five case studies were undertaken, at locations in each NEM state other than Tasmania, in consultation with Network Service Providers. The results are summarised in Table 3.

Overall, the study found that CSP installed at the case study locations would be able to delay, or avoid entirely, the planned network augmentation in all cases, and provide similar reliability to a traditional network solution in four of the five cases.

Strategies to achieve sufficient reliability varied according to the network requirements at each location. In four locations (two in Queensland, one in New South Wales and one in South Australia), the gas boiler normally installed as part of a CSP plant was modelled as oversized in order to provide emergency backup. Network requirements were to provide on–demand operation at these locations, and there were periods in each year where CSP would not provide sufficient certainty. It is expected that total gas use would be minimal, as the purpose is to provide emergency backup in the event that required network support falls outside of a period when the CSP is generating.

Table 3: Case study overview

	Network operator	Optimum plant MW / TES	Proposed augmentation year and cost	Network payment $/MWh	Net benefit $/MWh
The Riverland, SA (line replacement)	ElectraNet	40MW, 5hrs	2022, $226m	$110	$144
The Riverland SA (line upgrade)	ElectraNet	130MW, 5hrs	2022, $10m	$1	$60
Charleville, Qld	Ergon	20MW, 5hrs	2022, $70m	$6	$16
Wemen, Vic	Powercor	77MW, 5hrs	2021, $12m	$3	$23
Gunnedah supply, NSW (CSP at Moree)	Transgrid	50 MW, 5hrs	2019, $24	**$9**	**-$13**
Millchester, Qld	Ergon	40MW, 15hrs	2017, $46m	**$16**	**-$29**
Gunnedah supply, NSW (CSP at Gunnedah)	Transgrid	50 MW, 5hrs	2019, $30m	**$13**	**-$39**

In the fifth location (Wemen in Victoria), CSP could not provide certainty of generation by the end of the forecast period, as there could be a capacity shortfall for up to 100% of the time during the summer months, and CSP is not suitable for such constant generation. The CSP could reduce the likelihood of a capacity shortfall by 72%, which may be sufficient to defer the investment indefinitely. However, the CSP plant was found to have a positive cost benefit at this location without a network support payment.

The network support payment was not generally found to be a decisive factor in the case study economic outcomes, other than in the Riverland, where the network payment could provide $110/MWh if the investment from the higher cost augmentation was transferred to the CSP. In other cases, the value varied from $1/MWh to $16/MWh.

Conclusions and recommendations

This study confirms that CSP can provide a viable alternative to traditional network augmentation solutions in addressing electricity grid constraints. It supports the hypothesis that CSP has potential to play a significant role in optimising costs in electricity networks with high levels of renewable energy generation capacity. The study did not extend to other types of distributed energy as an alternative to network augmentation, and further research and an options analysis would be useful.

This study identified $0.8 billion of potentially avoidable network investment, and 533MW of cost effective CSP which could be installed at grid constrained locations in the next 10 years. Based on the current emissions intensity of electricity generation in each state, this would reduce greenhouse emissions by an estimated 1.9 million tonnes per year.

Network support payments can play a role in increasing the cost effectiveness of CSP, and such installations can avoid or defer the requirement for network augmentation. The potential for such cost effective installations will change as network forecasts are modified. If CSP and other distributed energy are to compete with traditional network solutions, the availability and accessibility of network information is likely to require improvement. The mapping outputs of this project provide an example of how information could be produced and disseminated to increase industry engagement and drive innovation and investment in developing non-network opportunities to defer augmentation. These outputs can be found at: www.breakingthesolargridlock.net.

A key requirement is for network data to be harmonised, and rules established to enable project proponents easier access to timely data, in formats that support scenario modelling. The Australian Energy Market Commission (AEMC) noted the value of more transparent network planning processes, including data access, in their 2012 review (Australian Energy Market Commission 2012).

While Regulatory Investment tests have provided consistency and rigour in economic analysis of network investments, adjustments may be required in order for the benefits of CSP (and other forms of distributed generation) to be considered appropriately and to enable greater scope for private investment and innovation.

The study supports the contention that CSP can play an important and economically efficient role in Australia’s electricity system.

1 INTRODUCTION

This project was undertaken to quantify the potential benefits from installing concentrating solar thermal power (CSP) generation at constrained network locations in the Australian National Electricity Market (NEM). The four primary objectives were to:

- Quantify the potential economic benefits;
- Identify and map locations where CSP could provide cost-effective network support services;
- Undertake four case studies, one per state, to further explore the economic and network benefits of CSP in promising locations; and
- Engage network service providers regarding the potential for utilisation of CSP as an alternative to network augmentation, its potential costs and benefits, how CSP plant configuration could address issues of network reliability, and the implications for reform of network reliability standards.

The project was undertaken with funding from the Australian Renewable Energy Agency (ARENA), electricity network services provider Ergon Energy Ltd (Ergon Energy) and the Australian Solar Thermal Energy Association (AUSTELA). The project was led by the Institute for Sustainable Futures (ISF) at the University of Technology, Sydney with the Centre for Energy and Environmental Markets (CEEM) at the University of New South Wales and AUSTELA. Assistance and advice was provided by IT Power (Australia) Pty Limited. Ergon Energy is a major project partner and has collaborated extensively on the project, as well as providing funding support. Essential Energy and Transgrid (New South Wales), ElectraNet and SA Power Networks (South Australia), and SP AusNet and Powercor (Victoria) have all collaborated on the project and assisted with data provision.

The study is intended to provide analysis and perspectives on the potential value of CSP generation in electricity network development to both accelerate the implementation of CSP systems, where the economics prove to be favourable, and to assist network service providers to evaluate strategies utilising distributed renewable energy generation to meet current and future constraints in Australia's electricity networks.

The original focus of this project was network constraints in the distribution system, indicated by the Australian Government's Energy White Paper in 2012 as the largest proportion of network investment required in Australia in the period to 2020 and a major driver of electricity cost increases in recent years. However, following analysis of network constraint data, revised demand forecasts from the Australian Energy Market Operation (AEMO), and advice from distribution network operators in New South Wales and South Australia, the examination was extended to include transmission constraints in New South Wales and South Australia.

The study did not consider other types of renewable or non-renewable distributed generation as an alternative to network augmentation, as this was outside the scope of the project. However, further research and a options analysis of distributed energy as an alternative to network augmentation would be very useful.

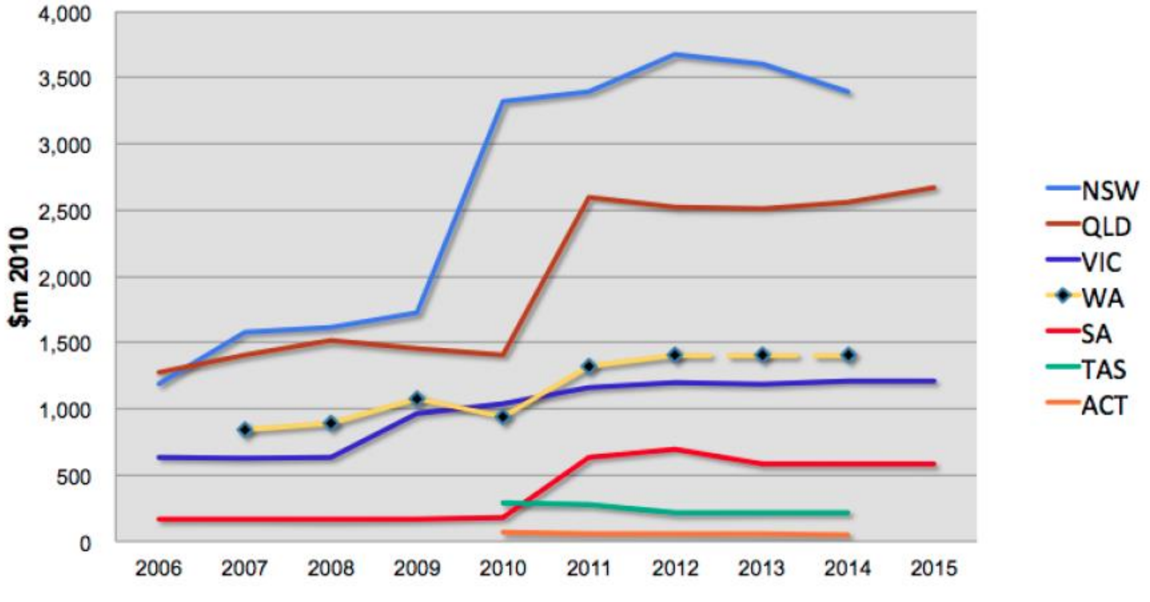
1.1 BACKGROUND

CSP electricity generation has been in commercial operation at utility scale for over 20 years. Installed capacity of CSP has accelerated in recent years, with Spain and the USA being the leading markets. Major developments are now underway in India, South Africa, the Middle East and Northern Africa, Israel and China. By the third quarter of 2013, there was 3GW of installed CSP capacity worldwide and close to another 2.5GW under construction (SolarPACES 2013). Analysis suggests sustained rates of growth in CSP development between 20% and 40% per annum are likely between 2012 and 2030 (Lovegrove et al. 2012).

Despite excellent solar resources and considerable research and development expertise in CSP, Australia, to date, has only deployed one demonstration plant. The Australian market is very challenging, with a gap between current estimates of the levelised costs of electricity (LCOE) from CSP and current average wholesale electricity and renewable energy certificate prices. Estimates of this cost gap vary from $100/MWh for large systems on the NEM to more than $200/MWh for smaller systems (Lovegrove et al. 2012). Although CSP systems, due to their ability to store and dispatch power at times of high demand, have potential to achieve higher revenues than non-dispatchable renewable energy types, market structures and regulation limit the ability of CSP projects to monetise this potential revenue increment (Lovegrove et al, 2012).

Little attention has been paid to the potential for CSP systems to alleviate grid-constraints in electricity networks. Australia's electricity network experienced a dramatic increase in capital investment over the last six years, with over $45 billion in electricity network infrastructure planned for the period 2010 to 2015 alone, as shown in Figure 5. Almost one third of this investment is motivated by the need to meet expected growth in peak electrical demand (Dunstan et al. 2011).

Figure 5: Electricity network capital expenditure (transmission & distribution) by state, 2006-2015



Source: Langham, Dunstan, & Mohr, 2011b

The central premise of this study is that rather than continuing to invest, by default, in increasing the capacity of a transmission and distribution network system designed for centralised power generation to meet growing peak demand, distributed generation, or demand reduction options, may provide cost effective alternatives. CSP in particular, providing dispatchable generation and thermal energy storage, offers potential to provide network support in addition to the broader benefits of carbon emissions reduction available with other renewable energy generation types. Network expenditure currently accounts for around half of the average electricity bill, and the use of cost effective distributed energy options could reduce network expenditure significantly.

Increasing the consideration of distributed energy, and CSP in particular, as an alternative to network augmentation may also enable greater total deployment of renewable energy in the electricity system, reducing total system greenhouse gas emissions.

CSP plants are highly scalable, with commercial plants ranging from 5 to 390MW in operation or under construction. CSP output, by its nature, aligns well with Australia's dominant summer peak demand. CSP systems have inherent thermal inertia from the mass of receivers and the volume of high temperature heat transfer fluid that is in circulation during operation as well as other high temperature components, such as heat exchangers. Even without the construction of dedicated thermal energy stores, the energy stored in these elements is sufficient to allow the system to keep generating for 15 to 30 minutes after loss of sun. Adding purpose-built thermal energy storage (TES), a relatively mature technology now deployed in the majority of new CSP developments (Lovegrove et al, 2012), increases a CSP plant's capacity factor and dispatchability, and allows CSP plants to deliver power when it is needed outside of daylight hours, and in peak network or wholesale market periods that do not directly correspond to peak solar radiation, such as winter evening peak times. In addition, CSP systems, as a rule, employ turbines coupled to synchronous generators of the same type as coal-fired power stations. Thus, they are able to provide ancillary services such as voltage and frequency support, usually associated with fossil-fired stations.

The fact that CSP may be developed with or without storage, at a variety of scales, and may be hybridized – for example with biomass or natural gas – means that grid integration is relatively straightforward, by comparison, with some other renewable energy options, and the potential network services offered by CSP systems are both reliable and flexible. In Australia, CSP hybrid plants already exist with coal-fired power stations with Figure 6 showing the first reference plant at Liddel power station in the Hunter Valley, New South Wales.

Understanding this potential value is important to assist evidence-based analysis of the need and justification for policy support for local CSP demonstration, scale-up, and further research and development.

The Institute for Sustainable Futures has previously developed a model (called Dynamic Avoidable Network Costs Evaluation, or DANCE) to estimate the potential avoidable network expenditure as part of the Intelligent Grid Research Program (Langham, Dunstan & Mohr 2011), and subsequently applied the model in urban Victoria (Langham et al. 2011). The model quantifies the planned network expenditure that is related to peak demand growth, maps it to geographic locations in the network, and calculates the expenditure in terms of $/kVA/year. The purpose is to inform consideration of whether distributed energy can provide a more cost effective means to achieve adequate performance in Australia’s electricity network.

Figure 6: CSP hybrid plant at Liddel power station, Hunter Valley, Australia.

Source: Juergen Peterseim

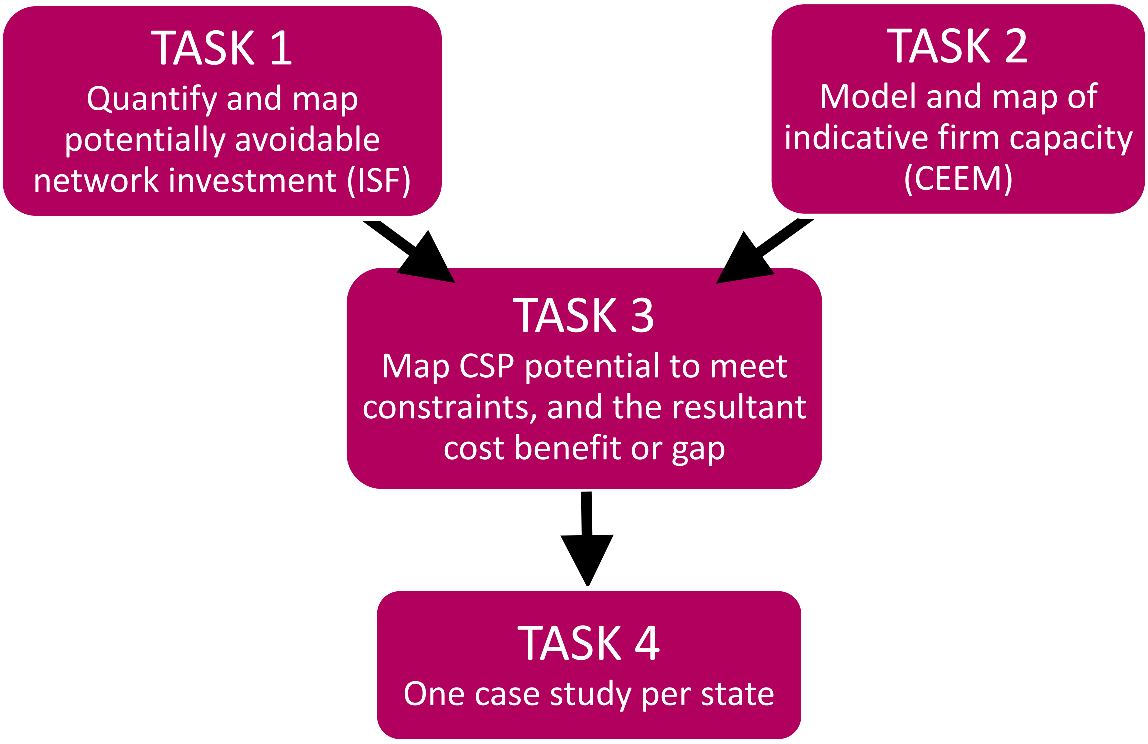
This project extends the quantification of network constraints using the DANCE model to areas of the NEM suitable for CSP generation, and integrates this with modelling of indicative firm capacity (IFC) from CSP generation in different seasons under real world weather conditions. This enables assessment of the potential for CSP to provide reliable network support, and quantify the potential value of network support to the CSP business case.

2 METHODOLOGY

2.1 OVERVIEW

The project had four main components, as shown in Figure 7.

Figure 7: Methodology overview



Task 1, conducted by the Institute for Sustainable Futures (ISF), quantified and mapped potentially avoidable network investment, using the DANCE model, according to location and expected constraint year. The main inputs are data on proposed network investment, forecast electricity demand, peak day demand profiles, and firm capacity at constrained assets in the electricity network. These are mapped for the distribution areas or connection points where distributed energy could potentially alleviate the constraint. The primary DANCE model outputs are maps displaying the characteristics of the constraint and the value of distribution zone and upstream transmission investment where load reduction or embedded generation has the potential to alleviate the need for augmentation. The DANCE model outputs are provided in Geographic Information System (GIS) map and spreadsheet form.

Task 2, conducted by the Centre for Energy and Environmental Markets (CEEM), quantifies the likelihood of CSP being able to generate during peak load periods at different locations in the NEM. The model, developed by CEEM, assigns an IFC to each location, essentially an estimate of the probability that CSP would be generating during the key summer and winter peak network constraint periods. The IFC is calculated by selecting a number of the highest peak demand events for each state in each of the defined peak time periods during 2009, 2010 and 2011. The model examined whether CSP with different amounts of storage (from 0 to 15 hours) at each location would have been generating during the peak event. The IFC assigned at each location is the average value of modelled output for that plant configuration for the defined period (for example, summer afternoon). The IFC at a constrained network location is the average value of the CSP plant's output at that location for the 21 highest demand events that occurred during the peak period associated with the network constraint.

Task 3 integrates the output from Task 1 and Task 2 to identify areas where CSP may provide cost effective network support, and appropriate capacities and plant configurations to achieve this. For modelling purposes, CSP is defined as being able to meet a network constraint when:

1. The IFC at the location, calculated in Task 2, is above 80%; and
2. A CSP plant of installed capacity equal to the 10 year projected magnitude of the network constraint could be physically connected at that connection point.

The cost effectiveness of CSP replacing network augmentation is assessed by calculating an overall cost benefit for the CSP, by comparing the CSP plant's LCOE to potential revenue, including a calculated network support payment. Different CSP plant configurations are assessed, ranging from the minimum size (MW_e) plant to alleviate the constraint to the maximum size able to be connected without requiring network augmentation to export energy. Varying amounts of storage are considered. The modelling outputs from Task 3 are the cost benefit or cost gap for the optimum, smallest and largest CSP plants that may be connected to meet the constraint.

The methodology builds in cost effectiveness compared to traditional network augmentation, as the proposed investment is reduced by 20% prior to calculating any potential network support payments. However, the comparison of CSP installation to other non-network solutions is not considered here, although this is likely to be an aspect of regulatory testing prior to approval of network support payments.

Task 4 includes one case study per mainland NEM state (that is, excluding Tasmania), with locations selected on the basis of the cost benefit identified in Task 3, and in consultation with the relevant network service provider. Each case study examines whether CSP could have met the network constraint in previous years by comparing the electricity demand profile to weather and solar resource records and modelling CSP plant dispatch to meet the constraint. The case study then examines the business case by doing a detailed comparison of dispatch strategy and historical prices. As part of the development of the research, the outputs and assumptions have been workshopped with the relevant network service provider.

Further details of the methodology are given in Sections 2.2 to 2.4.5, and details of the models are given in Appendix 1 and Appendix 2.

2.2 QUANTIFYING AVOIDABLE NETWORK INVESTMENT

Not all investment in network capital expenditure is avoidable. Approximately two thirds of network capital expenditure from 2010 to 2015 is associated with replacing ageing infrastructure, connecting new customers, and other non-system expenses (Dunstan et al. 2011). However, the remaining third that is driven by augmentation of constrained network assets, primarily due to growth in peak demand, is considered ‘potentially avoidable’ through the utilisation of ‘distributed’ generation or demand reduction options.

While past versions of the DANCE model have quantified and mapped the ‘growth-related’ investment only, the definition of potentially avoidable constraints (and associated investment) for this work is widened to include meeting reliability standards, which frequently lead to the installation of new network infrastructure, and the provision of voltage support.

For CSP in particular, the study examines whether potential network support payments (capped at 80% of the value of supplying additional network capacity through conventional network expenditure) can bridge the cost gap to make appropriate CSP projects in those locations financially viable. It is assumed that CSP would provide a long-term alternative to augmentation, so that augmentation is effectively avoided rather than deferred. This could allow a high proportion of the proposed investment to be considered for the network support payment.

An overview of the DANCE model is given below, with a detailed description in Appendix 1.

2.2.1 DANCE model inputs and outputs

The DANCE model uses data on constrained assets in the electricity network to map potentially avoidable investment by location. However, as only incomplete datasets were available for many constrained assets, much of the modelling task is to extrapolate from a minimum data set. DANCE thus uses the simplest inputs possible to reconstruct, with reasonable accuracy, complex variations in electrical demand throughout the year, to enable calculation of potentially avoidable electricity network investment over time and space.

The outputs from the model are:

- Proposed network investment related to growth, voltage support, or Security of Supply requirements, by asset, location and year;
- Potentially avoidable investment presented in terms of the ADV ($/kVA/year);[1]
- The avoided cost and net present value (NPV) of the investment for the asset itself, and of upstream linked assets;
- Available capacity by year;
- Description of the constraint, including type (for example, growth), season, maximum and minimum MW required (commissioning year and 10 years on), and asset owner;

[1] Requires hourly data (or synthesised hourly data) to calculate

- The estimated maximum generator size (MW) that could be connected; and
- The support required where the constraint is due to a requirement to change to n-1 Security of Supply conditions.

These outputs are mapped (where locations are available) using Google Earth. The following are calculated, and are available in the spreadsheet output:

- Number of hours above the network constraint value by the peak day, number of days per month, the year in which network investment would have occurred, and 10 years after the investment would have occurred (called 'worst year' or 'year 10');[2]
- A daily profile for the winter and summer peak day;[2] and
- The average annual growth rate of electricity demand at the asset.

The model inputs are listed below, with an indication of whether they are required:

- Constrained distribution zone substations (ZS), terminal stations (TS) or bulk supply points (BSP):
    - Name and GIS co-ordinates (required);
    - Proposed investment for a network solution, and proposed commissioning year (required);
    - Nameplate capacity, n-1 capacity (if applicable), and secure capacity (or support needed);
    - Summer and winter peak demand forecast in MVA;
    - Historic hourly load data for a recent year, where available. This can be estimated with monthly values and two daily demand curves, for a summer and a winter peak day. See Appendix 1 for details; and
    - Where the constraint is due to a requirement to change to n-1 Security of Supply conditions, the support required.
- Constrained sub-transmission lines:
    - Proposed investment for a network solution, and proposed commissioning year (required);
    - Details and GIS co-ordinates of ZS, TS or BSP supplied by the line (required); and
    - Secure capacity of the asset, or the network support needed.

If components of the listed data are unavailable, omission will generally restrict the outputs from the model. For example, any outputs related to daily profiles or hours above the constraint load requires hourly demand data for the year (or sufficient proxy data that the model may estimate the yearly load profile).

In addition to the network data inputs listed, there are economic variables used to undertake the calculations. These are:

- Weighted average cost of capital (WACC) – a figure of 6.4% per annum 'real vanilla WACC' is used for all states, as discussed in Section 2.2.3;

[2] Requires hourly data (or synthesised hourly data) to calculate

- Depreciation value of network assets – a default of 2.5% is used, assuming a linear depreciation over a 40 year economic lifetime; and
- Discount rate – a default value is of 7% is used.

2.2.2 Key calculations in DANCE

2.2.2.1 Annual deferral value

If a non-network investment (e.g. a CSP plant) can effectively defer investment in upgrading a network asset, then there is a financial benefit to the network associated with that deferral. By assuming the asset is unconstrained in the year prior to commissioning the proposed augmentation, the value of support required each year (in $/kVA) can be calculated from the annual peak demand forecast and investment information. In all situations other than the requirement to change to n-1 Security of Supply conditions, the annual deferral value (ADV) in year Y in $/kVA/year is:

$$ADV(Y) = \frac{INVA\ x\ (WACC + DEPR)\ x\ 1000/AVGR}{(1 + DISR)^{INVY-Y}}$$

Where:

INVA is the Investment Amount that is occurring for the asset,

WACC is the Weighted Average Cost of Capital,

DEPR is the Depreciation Rate,

AVGR is the Average Growth Rate in demand in year Y,

DISR is the Discount Rate and

INVY is the Commissioning Year.

In the real world, there are instances where the asset is already constrained for several years prior to commissioning the network augmentation, and the network operator has advised what support is required in year 1, year 2, etc. In this case, the data is adjusted so the model will output the specified support value, by making the demand in the year prior to commissioning equal to the demand in the commissioning year, less the required support.

Note the ADV is zero if either the average growth rate is not positive, or the year under consideration is after the commissioning year of the network augmentation, as it is assumed that by then the investment has occurred.

In locations where the constraint is not due to growth, but due to the requirement to change to n-1 Security of Supply criteria, the ADV is calculated with reference to the support required rather than to the average growth rate.

In general, the requirement to move to an n-1 Security of Supply criteria results from demand exceeding 15MVA. When the support required is more than 15MVA above the forecast demand in the investment year, the ADV in year Y in $/kVA/year is:

$$ADV(Y) = \frac{INVA\ x\ (WACC + DEPR)\ x\ 1000/SUP}{(1 + DISR)^{INVY-Y}}$$

When the demand in the investment year is less than 15MVA greater than the support required, the ADV is:

$$ADV(Y) = \frac{INVA\ x\ (WACC + DEPR)\ x\ 1000/(demand\ in\ invest\ year - 15)}{(1 + DISR)^{INVY-Y}}$$

Where:

INVA is the Investment Amount that is occurring for the asset,

WACC is the Weighted Average Cost of Capital,

SUP is the Support required,

DEPR is the Depreciation Rate,

DISR is the Discount Rate and

INVY is the Commissioning Year.

2.2.2.2 Net Present Value of a constraint

Net present value (NPV) of proposed investment is calculated for a chosen year by summing the NPV values of potential network payments from the invest year to 10 years after the investment year, that is:

$$NPV(Y) = \frac{(WACC + DEPR)INVA}{(1 + DISR)^{Y-CY}}$$

Where:

WACC is the Weighted Average Cost of Capital,

DEPR is the Depreciation Rate,

INVA is the Investment Amount (in $ millions) that is planned by the network at that location,

DISR is the Discount Rate and

CY is the Current Year (as specified in the global inputs to the model).

2.2.2.3 Minimum / maximum constraint & maximum generator size

In all cases other than the requirement to provide n-1 Security of Supply, the minimum constraint is the amount by which the electricity network asset is forecast to exceed the investment trigger point (ITP) in the commissioning year, which is effectively the amount of network support which is required. The ITP is defined as the secure capacity of the network asset (if that is available), or the forecast demand in the commissioning year minus the average growth rate in that year. The maximum constraint is the forecast electricity demand in year 10, minus the ITP.

Where the constraint results from the requirement to provide n-1 Security of Supply, the minimum constraint is set as the support required, as advised by the network operator.

The maximum constraint is set as the support required, plus positive growth forecast between the investment year and the end of the period. Where growth is zero of negative, the maximum constraint is set at the support required, and so equals the minimum constraint.

The maximum generator which can be connected to the electricity network asset is taken as the nameplate capacity, unless otherwise advised by the network operator.

2.2.3 Weighted average cost of capital

The WACC values for network operator investment used in this analysis were taken from the Australian Energy Regulator (AER) 2009 determination (Australian Energy Regulator 2009).

A different WACC may be applied to each NEM state distribution network service provider (DNSP) and transmission network service provider (TNSP) over each five year (minimum) regulatory period. Owing to the staggered periodicity of NEM state regulatory periods, a representative WACC for each NEM state DNSP and TNSP was calculated using a time weighted average of the appropriate AER published nominal 'vanilla' WACC, over the study period 2014/15 to 2022/23. Note that owing to the alignment of the regulatory periods in 2014/15, all DNSPs and TNSPs will effectively have the same WACC for this study if a time weighted average approach is used. A start year of 2014/15 was selected, as this is the earliest year that a CSP plant is likely to be commissioned with the purpose of alleviating a network constraint.

The nominal network service provider WACC figures were then adjusted to real 'vanilla' WACC figures by subtracting the average of the mid-year 2013 to mid-year 2015, Reserve Bank of Australia inflation projection (Reserve Bank of Australia 2013), shown in Table 4. It was assumed the AER held the 2009 WACC determination constant for the study period, and post-tax WACC figures were used in the analysis.

Table 4: Underlying inflation 2013 - 2015

	2013		2014		2015
	Jun-13	Dec-13	Jun-14	Dec-14	Jun-15
6 monthly (%)	2.25	2.25	2.5	2.5	2.5
Annual (%)	2.25		2.5		2.5
Av. all years (%)	2.42				

Source: Reserve Bank of Australia, 2013, Table 6.1

The resulting WACC for use for the network operators for this analysis is 6.4%, derived using the following formula:

$$Real\ vanilla\ WACC\ =\ Nominal\ vanilla\ WACC\ -\ Average\ annual\ forward\ inflation$$

$$Real\ vanilla\ WACC\ =\ 8.82\%\ -\ 2.42\%\ =\ 6.4\%$$

2.2.4 Data collection

The original intention in the project was to obtain all data electronically, in partnership with the network operators, in order to facilitate updating on an annual basis. This would have allowed mapping the entire regional NEM, with a view to the constraint mapping being available for all decentralised technology proponents, and as an aid to network planners and policy makers. This was attempted with the two network operators who partnered in the project, namely Ergon Energy and Essential Energy.

It became apparent relatively quickly that acquiring data for the entire network was not feasible within the project timeframe, as current data management systems used by the DNSPs did not easily allow data extraction in a suitable format, and nor were consistent systems, data schema or nomenclatures applied. Ergon Energy, in particular, made considerable effort to supply comprehensive data, but it transpired that it was extremely difficult to automate the process to any significant degree. This rendered it impossible to process data for the entire network. In particular, the lack of a common identifier for the same asset between different data sets of a DNSP (such as the hourly data and the load forecasting), made it almost impossible to achieve any degree of automation. Essential Energy found that even extracting data from their systems on a network-wide basis was too difficult and time consuming.

This inconsistency, inaccessibility, and apparent inefficiencies of the data management, has been an important observation emerging from the study. Improving consistency and accessibility, and harmonising systems across the different DNSPs, would be beneficial for future network constraint analysis and assessment of market and policy response alternatives.

For this reason, the project changed emphasis to map constrained assets where investment is proposed only, and in all states other than Victoria, to restrict mapping to areas where the solar resource was likely to be sufficient for CSP to be economic. This decision was taken because of the considerable time and resources needed to process network data manually.

Initially, South Australian and Victorian network operators were not able to assist with data provision, so constraint mapping was undertaken using publicly available reports only. Once this was undertaken, the relevant DNSPs and TNSPs were asked to review data and fill in missing information, which all have done.

Electricity demand forecasts in the NEM were revised downwards significantly during 2012, with forecast annual growth rates in maximum demand reduced by 0.5% in Victoria, 0.7% in South Australia and New South Wales, and 1.7% in Queensland (AEMO 2012). This has a significant effect on the proposed network investment throughout the NEM, both by reducing the absolute amount as some constraints are no longer relevant, and by pushing investment proposals further away in time. This revision, which occurred to a significant extent during the project, meant that network data entered had to be then considerably revised and updated.

Once the likely effect of the revised demand forecasts became clear, and on the advice of the relevant DNSPs, the project team decided to include transmission constraints in those states where distribution constraints were less likely to prove suitable for CSP, namely New South Wales and South Australia.

The data issues encountered may be broadly summarised as:

- Data format;
- Currency of data;
- Accessibility of data; and
- Clarity.

Data format

Electricity network planning documents are available publically in report format only (i.e. PDF). This makes extracting data much more difficult than if data were available in spreadsheet format (such as Excel). Further, the report format varies considerable across the NEM, so it is very time consuming to extract the required data.

Not all electricity network planning reports contained the same level of information, and none provide all the information required. For example, key information such as proposed investment amounts and years, or demand forecasts for sub-transmission feeders were not included in some reports. The co-ordinates of electricity assets are never included, and while this was assumed to be a relatively easy item for network operators to provide, this proved not to be the case – matching of constraint data with asset location proved to be a highly labour-intensive process. Hourly demand profiles are also not publicly available, even for districts. Reports from Victorian DNSPs are considerably more informative than public network planning reports from other states and could provide a useful template for harmonisation.

Currency of data

Publicly available NEM electricity network planning documents, including electricity demand forecasts, are updated annually. However, these are updated internally a number of times per year. This means publically available network data can be up to 12 months old, and if there are significant changes in the demand forecast between the release of public reports, this may significantly change the timing and size of any proposed network investment.

Accessibility of data

Negotiation with DNSPs and TNSPs for access to the network data was very time consuming, owing to concerns about confidentiality and because of the timing of DNSP network review processes. This has meant, in some instances, that by the time the requested data had been negotiated, supplied and entered, more up-to-date information was available, requiring data to be re-entered. Different DNSPs have different levels of concern as to accessibility of data, with commercial sensitivities dominating in some cases and security concerns (e.g. terrorism) in others. Harmonisation across the NEM of rules for data access for research and planning purposes would enable more timely analysis of options on a NEM-wide basis.

Clarity of data

Descriptions of proposed investment in public electricity planning documents are very brief and are difficult to interpret without prior knowledge of the local electricity network. This means that attributing proposed investment to particular nodes of the network can be difficult. Where DNSPs and TNSPs were engaged with the project, much guidance was required to ensure the network planning data was interpreted correctly.

Most public electricity planning documents do not contain sufficient spatial information regarding how assets, e.g. ZS are linked to other ZSs, TS and ultimately, feeders. This makes it difficult to calculate the deferral value, as augmentations upstream from the ZS may be missed. Only Ergon Energy and Essential Energy were able to supply Google Earth and schematic maps of their networks, which greatly illuminated this process.

Proposed network investments that are not yet committed, and thus potentially avoidable, are commonly represented as ‘locked in’. Forecast network demand is then presented as if the proposed investments are approved and constructed, for example when it is assumed the new electricity assets will off-load currently constrained assets. This affects neighbouring connected network components, as load may be shifted onto or away from sites. This makes it difficult to assess the alternatives to augmentation.

Network investment will often go out for regulatory testing as discrete ‘packets’, while the investment is frequently made on the basis of strengthening a network region, rather than a single point. Considering a regional non-network solution may be more appropriate than disaggregated point investments, but this is difficult when investment goes to regulatory test on a point-by-point basis.

The research team found that this represented a significant impediment to the assessment of options for CSP plant configuration and economics; the same impediment would apply to other (non-network) alternatives. Ideally, data should be made available in forms enabling scenario analysis on both aggregated and point-by-point bases, to determine how different distributed energy options could compete commercially with network alternatives.

Improved data (timeliness, accessibility, consistency and structure) could facilitate a breadth of scenario analysis facilitating far more flexible assessment of alternatives, including CSP generation alternatives.

2.2.4.1 Data collection – Queensland

The primary sources of data for the DANCE modelling in Queensland are reports and databases provided by Ergon Energy, including Ergon Energy Corporation Limited, 2013, 2012a, 2012b, 2012c, 2012f, 2012d, 2012e, with considerable additional information provided by Ergon Energy staff.

Ergon Energy has been an invaluable partner in the project, and has not only supplied network and investment data for the modelling undertaken in this project, but has tirelessly provided assistance in interpretation.

Ergon Energy attempted to supply network-wide data electronically, in order to test the ability to automate the processes. Unfortunately, the lack of a unique identifier for each asset in different data sets meant the various electronic data streams (for example, asset location, nameplate capacity, demand forecast and historical hourly demand) could not be linked to each asset in a systematic way. All data, therefore, had to be processed and interpreted manually.

The timing of Ergon Energy's internal network planning review meant that a complete data revision occurred part way through the project, when network augmentation plans were completed.[3] The initial plan had been to automate systems using the previous data set, and update automatically once the revision was complete. Unfortunately, the failure to achieve data automation meant that both sets of data had to be processed and interpreted manually. There is a further complication as the Sub-transmission Network Augmentation Planning (SNAP) documents are not public, and the original data set did not reference the previous SNAP documents. It was decided that the data should be updated nevertheless.

However, mapping was limited to areas likely to be suitable for CSP in order to reduce the time and resources required. This was defined as areas with a minimum direct normal irradiance (DNI) of 21 MJ/m^2/day which did not fall in areas mapped as 'least suitable' for non-engineering reasons (Beninga 2009, reference in Lovegrove, Watt, Passey, *et al.*, 2012).

2.2.4.2 Data collection – New South Wales

The primary sources of data for the DANCE modelling in New South Wales are information from public documents (Country Energy & Transgrid 2011; Transgrid 2012), with considerable additional information provided by Transgrid and Essential Energy staff.

2.2.4.3 Data collection – Victoria

The primary sources of data for the DANCE modelling in Victoria are information from public documents (Jemena et al. 2012; SP AusNet 2011; Powercor 2012; SP AusNet 2012), with additional information provided by SP AusNet and Powercor staff.

[3] 10-Year Sub-transmission Network Augmentation Plans (SNAP) for Ergon Regions – November (2012) Report IDs: ND 350, ND 351, ND 352, ND 354, ND 355, ND 356; and Ergon Demand Forecast Post Summer 2012 SNAP publication, 50% and 10% Probability of Exceedence (PoE) published October and November (2012) respectively.

2.2.4.4 Data collection – South Australia

The primary sources of data for the DANCE modelling in South Australia are information from public documents (ElectraNet 2012; ETSA 2012), with additional information provided by ElectraNet and SA Power Networks staff.

2.3 MAPPING INDICATIVE FIRM CAPACITY FOR CSP

The issue of capacity is critical within the electricity industry which requires that supply precisely meet demand (and losses) at all times and at all locations within the network. Variability and unpredictability in both locational demand and generation adds to this challenge. So do the time ranges that need to be considered – from operational supply-demand balance within periods of less than a second, to forward-looking planning processes considering periods of a decade or more ahead.

Capacity estimation plays a key role in planning for scales ranging from overall system generation, to particular regions of the network, down to network elements and individual plants. However, the range of relevant scales and timeframes, and the inherent future uncertainties in planning, makes defining capacity challenging. As noted earlier, improved data arrangements could facilitate enhanced scenario analysis to overcome the impediments caused by this inherent level of complexity.

The concept of equivalent firm capacity, which is sometimes called capacity value or capacity credit, has been examined in detail for CSP systems by the USA's National Renewable Energy Laboratory (NREL). This parameter can be expressed as either a number of MW or as a percentage of the nameplate capacity of the plant. NREL identify the effective load carrying capability (ELCC) as one of the most robust techniques. The ELCC is defined as 'the power capacity of the conventional generator that yields the same loss of load expectation as the system with the renewable resource' (Madaeni, Sioshansi & Denholm 2011). Evaluation of the loss of load expectation is a complex statistical process that requires comprehensive load and generation data for a whole system. There are however, some approximate methods that can be used, all of which are shown to underestimate the more accurate ELCC calculations. The easiest of these is the highest load hours approximation method. In this method, the capacity value is approximated by the capacity factor of the system during the highest load hours.

A particular challenge for this project is that all electricity generators are prone to occasional failure – fossil fuel and renewable alike – whilst network elements generally have far greater reliability, although they are also subject to unexpected failures, such as line outages.

Given the lack of a well-established measure of CSP capacity for network augmentation deferral in utility practice around the world, a modified version of highest load hours method has been used in this project. Note that there has not been comparison to the more accurate equivalent firm capacity method, and even that method does not fully account for some of the specific network-related issues noted above. The capacity fraction numbers determined are therefore considered indicative. The term, indicative firm capacity (IFC), is used here to distinguish from the more precise definitions, such as the capacity value which is mentioned above.

This section describes the method by which the IFC was determined. Sections 2.3.1 to 2.3.3 describe each component of this modelling work, while Section 2.3.4 explains how each of these were integrated to perform the analysis.

2.3.1 Identifying peak demand events

Half-hourly electricity demand data for the years 2008 to 2010 in each market region of the NEM were obtained from AEMO. At present, the NEM has five market regions, each of which falls within a single state. For this work, only New South Wales, Queensland, South Australia and Victoria were considered.

Peak demand events were defined to occur in one of four peak period classifications:

- Summer afternoons (December to February, 2pm to 4pm);
- Summer evenings (December to February, 5pm to 8pm);
- Winter afternoons (June to August, 2pm to 4pm); and
- Winter evenings (June to August, 5pm to 8pm).

For each peak demand classification and each state, we identified the top seven half-hourly peak demand events in each of the years 2008, 2009 and 2010. In order to ensure that weather conditions and peak events were examined on the full number of different days, half hourly peak events occurring on the same day were treated as one event, centred around the highest value. The seven peak demand events for each region in each of the three years formed 21 peak demand events, which were used for further analysis.

2.3.2 Solar radiation data

DNI is the measure of solar resource relevant for CSP generation systems. DNI data was obtained from the Bureau of Meteorology’s (BOM) gridded solar data product (Bureau of Meteorology 2013). BOM provides satellite-derived solar data across the Australian continent at 5km x 5km resolution and hourly intervals for the years 1998 to 2011.

2.3.3 Concentrating solar thermal model and plant configurations

CSP plants essentially consist of three basic sub-systems:

- A solar field of mirrored concentrators of some type;
- A thermal energy storage (TES) system; and
- A power block with condensing system.

Each of these sub-systems can be sized independently, relative to the others. Solar fields are typically larger than needed to run the power block at nameplate output under design point maximum DNI level. This enables the power bock to operate at full capacity at times of less than maximum DNI resource availability. Precise configurations are dictated by commercial factors, with the rule of thumb that plants will be configured to optimise revenue generation in a given market location for the lowest possible capital cost.

The actual field size, divided by the nominal requirement to run the power block at the nameplate output, is referred to as 'solar multiple', while the levels of storage are usually expressed as the number of hours of nameplate capacity operation that can be sustained from the TES. Therefore, three hours of TES is sufficient storage to run the power block at rated output for three hours. Where TES is included in plant configuration, solar field size will typically be greater, enabling a proportion of solar energy captured to be stored while the generator continues to operate at full capacity.

Part of a system design for a particular project is to estimate the optimum combination that maximises economic return. This optimum configuration depends both on the level of solar radiation resource available, and the nature of the different possible sources of revenue from plant operation. A lower level of solar resource will suggest a bigger solar field relative to the other components.

Depending on the relative costs of storage to other components, some level of TES will generally deliver the lowest LCOE due to a combination of operation of the power block at higher output levels for longer periods, and the avoidance of energy dumping at times of highest solar input. In effect, TES enables more capital efficient usage of major capital components such as the turbine, generator and grid connection assets. However, the key issue is maximising the net benefit (income minus costs) so different plant configurations might be optimal under different circumstances. For example, electricity markets which have highly variable electricity prices, might see plants with a larger power block relative to the other components, in order to permit higher dispatch during high price events. Additional network support revenue might change the optimal plant configuration by requiring the ability to supply electricity across a wide range of time intervals. Hence, a range of possible configurations is considered in the study.

Table 5: CSP plant configurations

Thermal energy storage	Solar multiple
0 hours	1.4
1 hour	1.5
3 hours	1.7
5 hours	1.9
10 hours	2.5
15 hours	2.8

For this study, a specific solar multiple was used for each level of storage, as shown in Table 5, rather than varying the solar multiple independently. These solar multiple values are typical for a good solar location with a plant configured for lowest LCOE rather than peaking performance. This is a reasonable assumption given current typical patterns of wholesale market pricing in the NEM, the common power purchase agreements being offered for renewable generation, and the Renewable Energy Target income available, which is entirely based on overall MWh output of the plant.

Each plant configuration required a full set of model runs for each location and year. Options of 0, 1, 3, 5, 10 and 15 hours were considered for evaluation of IFC, to provide a view across a reasonable variety of configurations. In reality, CSP plants can be built with any amount of TES, from hours, to days, and even weeks, and have been built with capacities ranging from 0 to 15 hours of nameplate capacity output.

This project used an existing model for analysis of a CSP plant - a Python implementation of a simple energy-balance model published by Stine and Geyer (2001). The model incorporates storage, varied collector sizes, heat losses in the collector field, heat losses in storage, and the requirement for a certain amount of energy each day to heat the working fluid before any steam is produced. It does not include additional detail included in some other CSP models, such as NREL's highly regarded System Advisor Model (SAM) (National Renewable Energy Laboratory 2013). SAM considers additional weather factors that affect the performance of a CSP plant, such as ambient air temperature, wind speed and relative humidity, as well as incorporating detailed dynamic modelling of heat flows within the plant.

The hourly time series of power output from the model used in the project demonstrated good agreement with the more detailed SAM physical model, and also with models used in a major recent Australian study by IT Power (Australia) (Lovegrove et al. 2012). In a series of validation trials, the project model underestimated the annual energy production by about 1%. Comparing the two-time series of hourly power output, the cross-correlation coefficient was approximately 0.81. The advantage of this simplified project model is that it permits rapid simulation of the performance of different plant configurations and potential control strategies. By comparison, SAM can only be used in stand-alone mode.

2.3.4 Simulating CSP output during peak demand events

The timing of peak demand events and the CSP model performance are integrated to gain IFC figures for the CSP plant configurations given in Table 5 (on page 26).

For each peak demand event (21 events x 4 NEM states x 4 classifications x 5 configurations), we simulated CSP plant generation in the lead-up to the peak demand event in every 5km x 5km cell located in each state. Operational simulations commence at midnight the day before the peak demand event. This ensured that at the end of the day prior, TES levels were approximately representative for the following day. We then simulated all of the hours of the day of the event leading up to the peak demand event. At the hour of the peak demand event, we then noted the CSP plant output. Once each of the 21 events was simulated, we took the average plant output to be the IFC for that state and peak period classification.

2.4 MODELLING THE COST BENEFIT OR GAP FOR CSP AT GRID CONSTRAINED LOCATIONS

An overview of the methodology used to determine the cost benefit or gap of installing CSP at network constrained locations is shown in Figure 8.

Initially, the model determines if CSP is likely to be suitable to meet the constraint, and the minimum size (MW) of plant required to do so.

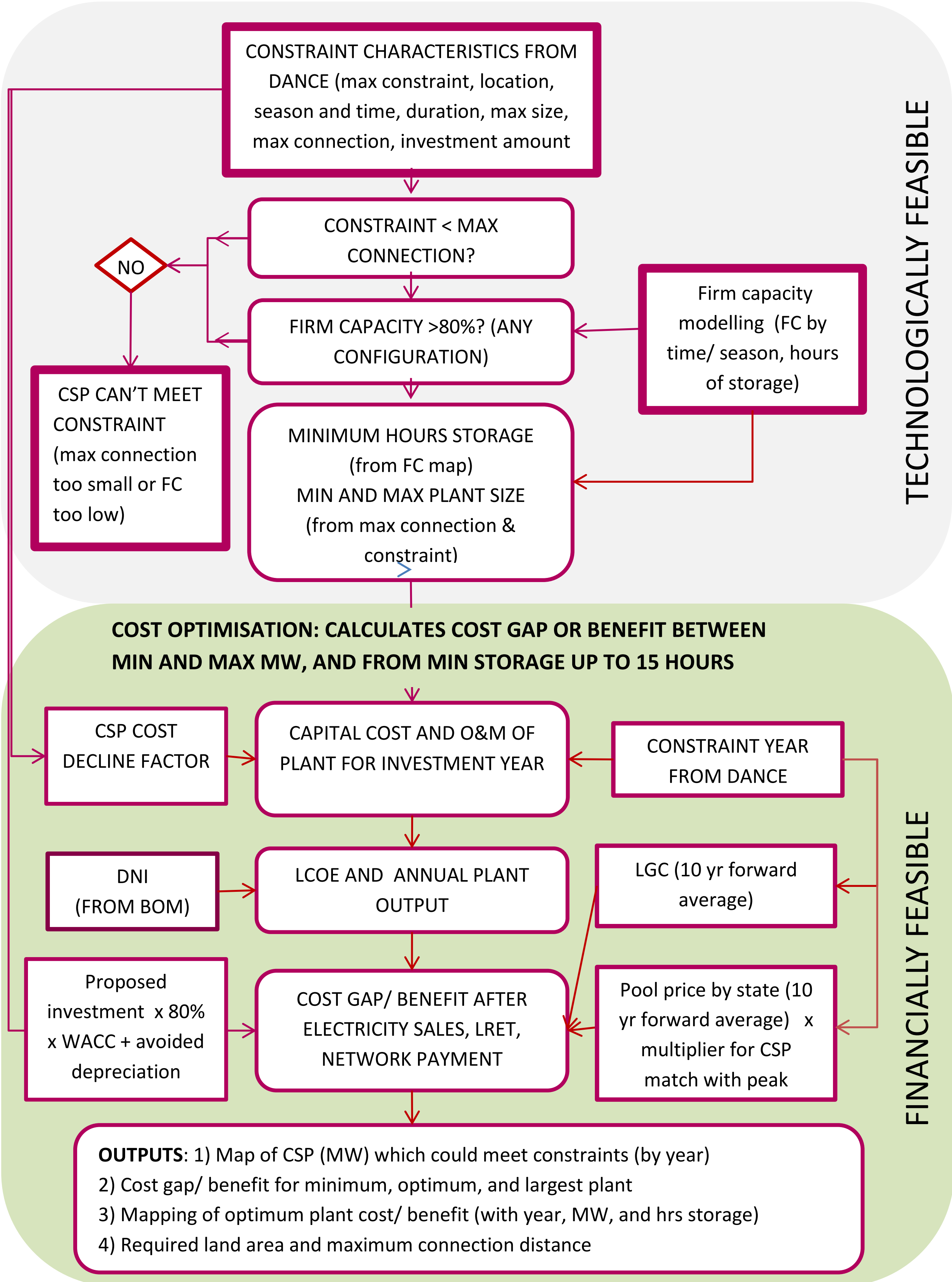
The suitability of CSP to alleviate a network constraint is determined by comparison of the network constraint location, time of day, and season with a CSP plant's IFC for that location for the relevant period. If, under the network constraint conditions, no configuration of CSP plant is able to provide an IFC of 80% or higher, then the CSP is deemed unsuitable to alleviate the network constraint. It should be noted that the 80% IFC threshold has been chosen as indicative of what would, in practice, be a much higher probability of meeting a real constraint.

Firstly, in situations with a financial reward or contractual obligation to meet a constraint, dispatch strategies can and would be tailored to give a high level of priority to meeting the particular constraint. This is not reflected in the simple dispatch strategy adopted by our model to determine the IFC, in which the plant essentially commences generation at 12pm and continues generation until the storage is empty.

Secondly, we assume that CSP plant operators with a network support contract could use on-site gas supply to provide additional emergency generation (possibly at part load) for limited periods. Most CSP plants currently operating worldwide have on-site gas-fired heaters for pre-heating on start-up. Typically, the heaters are designed to start the plant and continue operation at minimum load, circa 25%, depending on steam turbine and plant design. While it is highly unlikely that a CSP plant operator would choose to run on gas for any significant period, configuring the gas boiler to allow the capability to provide emergency generation at whatever level of support is required can give additional certainty to the provision of network services.

An alternative to running the plant directly is to integrate the existing gas boiler into the TES system, to allow the heater to charge the storage over a longer period. Even if gas was used as emergency backup as described, it is likely to be for a very much lower proportion of generation.

Figure 8: Determining the cost benefit or gap



The minimum hours of storage capacity for the plant is determined by the IFC mapping, and is taken as the least hours of storage required for the plant to achieve 80% IFC at the relevant network constraint location, time of day, and season.

The minimum size (MW) of CSP plant is matched to the projected constraint size (MVA) at year 10, as it is assumed that it would only be cost effective to alleviate network constraints in situations where the investment could be avoided rather than deferred.

The maximum size (MW) of CSP plant is the maximum generator size which could be connected to the constrained node of the network, be it ZS, TS or BSP. This is the nameplate capacity of the connection point, unless we were advised otherwise by the network operator.

The cost benefit per unit energy of the CSP plant is calculated by comparing the LCOE to the plant's estimated revenue, including a network support payment:

$$\begin{matrix}\textit{Cost} \\ \textit{benefit}\end{matrix} = LCOE - \begin{matrix}\textit{Average electricity sales} \\ \textit{energy income}\end{matrix} - LGC - \begin{matrix}\textit{network support payment} \\ \textit{per unit energy}\end{matrix}$$

Where:

LCOE is the Levelised Cost of Electricity and
LGC is the Large Generation Certificate.

The model iterates through the cost benefit calculation for all plant sizes and storage configurations to determine the optimum economic configuration. Plant size is considered in increments of 2MW between the minimum and maximum, and each storage configuration (0, 1, 3, 5, 10 and 15 hours) above the minimum storage is determined by the IFC modelling. Note that the discrete steps are reflective only of what was modelled in the IFC and cost calculations, and that CSP plants may have any amount of TES.

The inputs to the calculations were:

- Constraint characteristics from the DANCE modelling (location, size, season, potentially avoided network investment, maximum generator size which may be connected, and the year a generator would have to be commissioned to provide network support);
- Firm capacity from the IFC modelling;
- DNI from BOM mapping (Bureau of Meteorology 2012);
- A projection of average pool prices by state (SKM MMA 2012a), adjusted to allow for the fact that the time of day CSP plants generate electricity which corresponds to higher than average prices for electricity;
- Capital cost by plant size (MW) and storage hours, adjusted for installation year by use of learning curve cost reductions for CSP; and
- Operations and maintenance (O&M) costs by plant size, adjusted for installation year by use of learning curve cost reductions for CSP.

More details of the LCOE calculation is given in Section 2.4.1, and of the cost benefit or gap calculation and its components in Section 2.4.3.

2.4.1 Capital cost and LCOE

The capital investment required for different plant sizes and TES configurations was modelled using Thermoflex (version 23.0)[4] and subsequently used to determine the LCOE for each plant configuration.

Thermoflex software is widely used in academia and industry to model detailed physical and financial performance of parabolic trough, Fresnel and solar tower plants. The model has financial adjustment factors to meet specific country conditions, such as higher Australian labour costs. Comparisons of capital costs for a number of examples (Lovegrove et al. 2012) showed good agreement, with values within 5%.

At present, the development stage of CSP technology tower plants with storage have lower costs than other types of collectors. Tower plants have a higher temperature difference between hot and cold tanks, and are currently able to deliver the most cost effective overall storage solution using twin-tank molten salt (which is the commercially established storage solution). Consequently, a tower plant with twin-tank molten salt has been used as the proxy technology for this comparison. Figure 9 and Figure 10 show an example of molten salt thermal storage and the associated auxiliary equipment. Trough or Fresnel plants could deliver similar technical performance, if the cost of their storage systems could be reduced to compete with the higher temperature tower storage solution.

Figure 9: Molten salt storage tanks (7.5hrs) at Andasol III plant in Andalusia, southern Spain.

Source: Juergen Peterseim

[4] www.thermoflow.com

Figure 10: Auxiliary equipment at Andasol III plant in Andalusia, southern Spain.

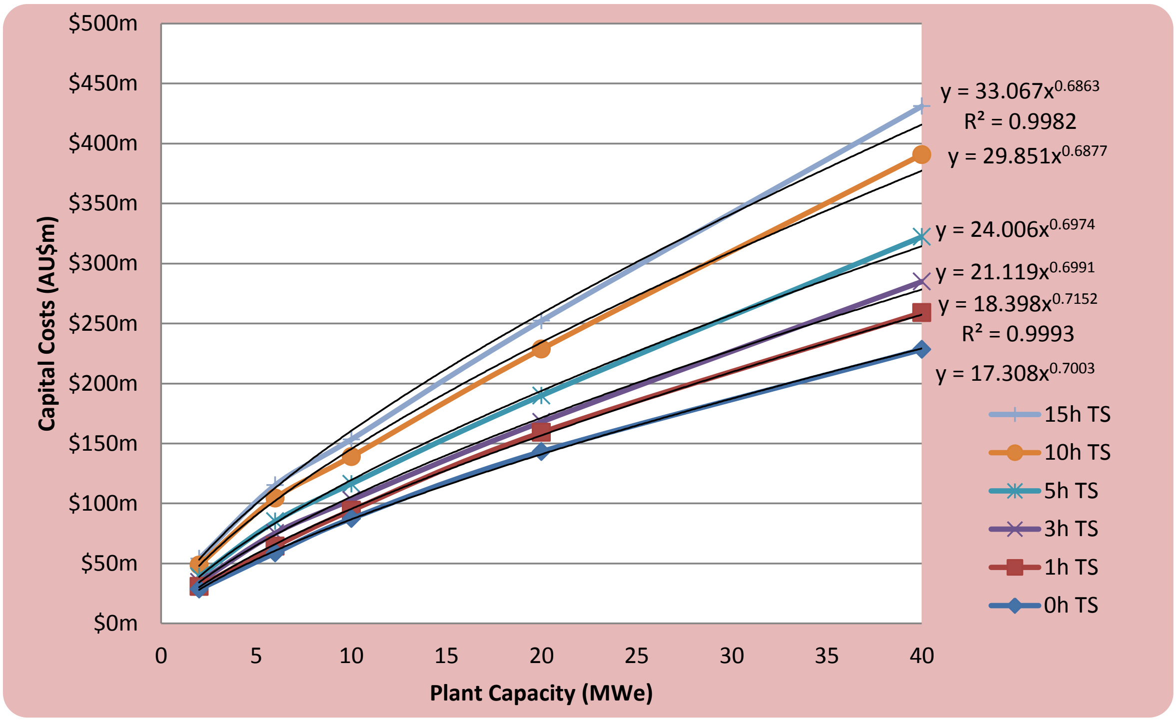
Source: Juergen Peterseim

Table 6 shows selected investments for $2MW_e$ to $100MW_e$ plants with 0 to 15 hour TES. These costs were used to derive a capital costs formula for any given plant capacity and TES configuration, shown in Figure 11 and Figure 12 (shown on page 34). This is the plant investment only and does not include grid connection costs.

Table 6: CSP capital cost by plant capacity and thermal energy storage (AU$m)

	Thermal energy storage					
Plant capacity (MW_e)	0 hr	1 hr	3 hr	5 hr	10 hr	15 hr
2	$29m	$31m	$34m	$39m	$49m	$54m
6	$59m	$64m	$75m	$85m	$104m	$115m
10	$87m	$94m	$103m	$116m	$139m	$153m
20	$143m	$159m	$168m	$190m	$229m	$252m
40	$228m	$259m	$285m	$322m	$391m	$431m
70	$355m	$411m	$452m	$512m	$634m	$699m
100	$487m	$562m	$623m	$705m	$903m	$996m

Figure 11: CSP investment for 2-40MW$_e$ with 0-15hr thermal energy storage



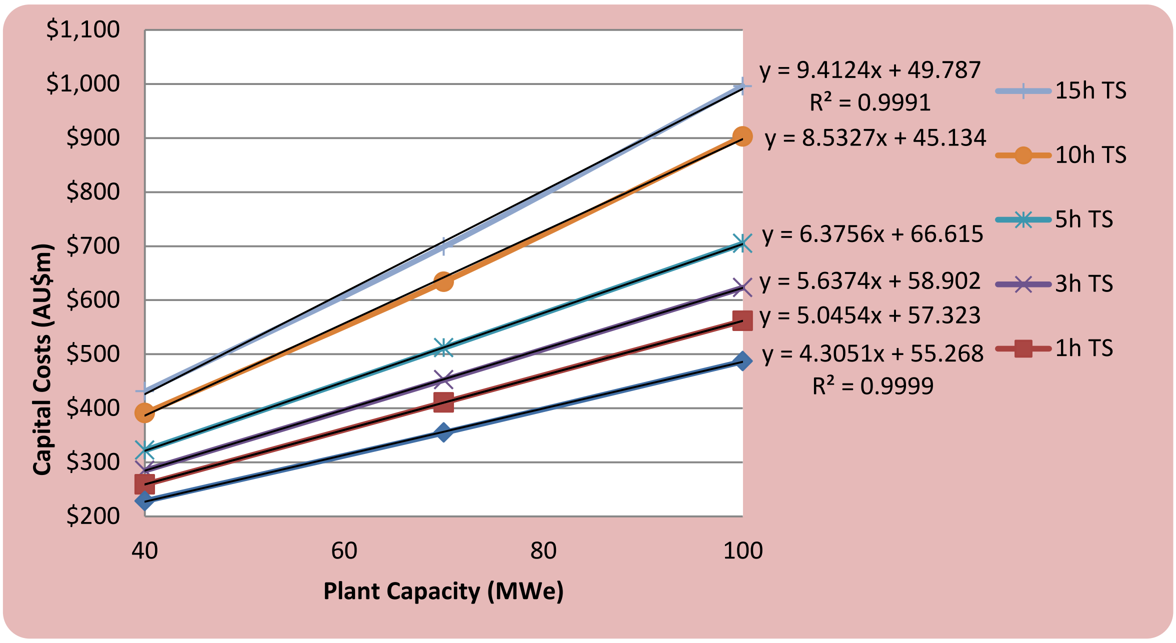
The costs include a backup boiler with 25% full-load capacity in all cases, giving quick start-up capabilities to allow the compensation of DNI fluctuations when TES is empty (Peterseim et al. 2012). Plants smaller than 20MW$_e$ are modelled without steam reheating, while larger units include single steam reheating.[5]

Cycle efficiencies are lower with smaller plant capacities, up to 50% lower for 2MW$_e$ compared to 100MW$_e$, and are considered in the cost modelling as they affect total plant investment significantly. However, it should be mentioned that the investment accuracy in this assessment decreases with decreasing plant sizes, as site- and technology-specific criteria such as plant efficiency, connection costs and local labour cost are more complicated to determine than for larger plants.

Figure 11 and Figure 12 show the capital cost for 2 to 100MW$_e$ CSP plants with different TES capacities. The data is derived from modelling using Thermoflex for specific plant capacities of 2, 6, 10, 20, 40, 70 and 100MW$_e$. These points were used to derive equations to determine the capital expenditure for all capacities between 2 to 100MW$_e$. R^2 are greater than 0.99.

[5] Steam reheat is a mechanism employed in large steam power blocks whereby intermediate pressure steam exiting a high pressure turbine is reheated before entry to a lower pressure turbine. It increases efficiency but is too complex to implement in a small system.

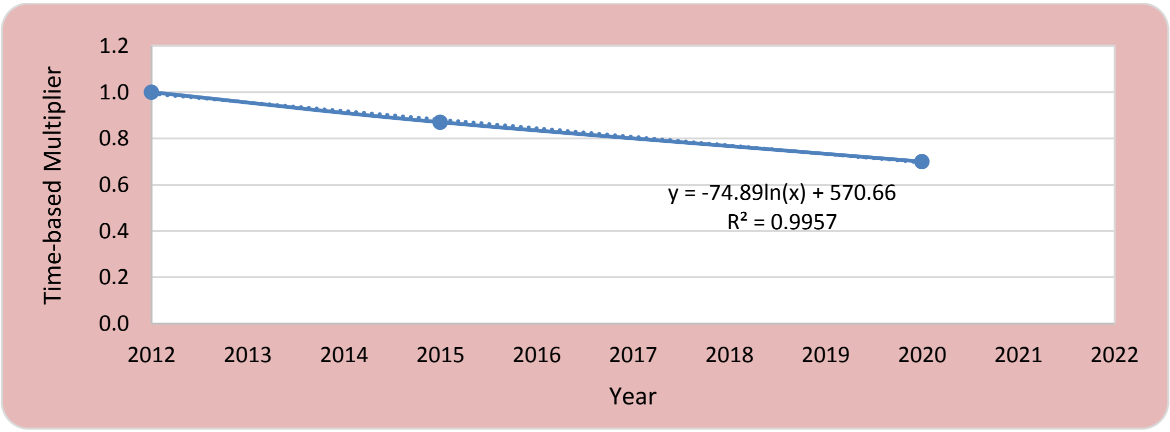
Figure 12: CSP investment for 40-100MW$_e$ with 0-15hr thermal energy storage



Refer to Table 5 in Section 2.3.3 (on page 26) for the solar multiples used for the different TES configurations.

Future CSP investment reductions could vary significantly from 25% to 60% by 2022, depending on the plant deployment, learning curve advancements, and technology improvements (Lovegrove et al. 2012; IRENA 2012). This study assumed an annual CSP growth rate of 20% with a 0.85 progress ratio, which was the mid-point of the estimates, leading to a 39% investment reduction in 2022 (Lovegrove et al. 2012). Higher investment reductions might be too optimistic in the current CSP environment, with considerable uncertainties in CSP markets, such as Spain; and lower rates may be too pessimistic as new countries, such as India, South Africa or the MENA region, become important market players.

Figure 13: Time based cost reduction multiplier



The future investment reduction path, and the corresponding logarithmic curve that has been used for interpolation, are shown in Figure 13. The reductions were applied to the operational as well as the capital costs.

The LCOE is determined using the following simple LCOE equation based on a plant lifetime of at least 25 years, a WACC of 7.9%, the O&M (shown in Figure 14 on page 38), and the capacity factors provided in Table 8 (on page 37):

$$LCOE = \frac{(F_R + \mathrm{O\,\&\,M}_{fixed})C_0}{PF_c} + O\,\&\,M_{\mathrm{var}iable}$$

Where:

LCOE is the Levelised Cost of Electricity,

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.

In addition to smaller units having inherently lower cycle efficiencies, their operational costs are higher, particularly for personnel. A $50MW_e$ plant, such as Andasol 1, requires forty O&M employees (Madaeni, Sioshansi & Denholm 2011) while a $2MW_e$ plant would require three to five operators (depending on the degree of plant automation). This higher ratio of personnel-to-MW_e increases the operational costs significantly.

As can be seen in Figure 14, estimate O&M costs vary from $40/MWh for a 2MW plant to $22/MWh for a 40MW plant. Despite high automation and the possibility for unattended or limited attendance, the Australian Standard (AS) 2593-2004 (Boilers – Safety management and supervision systems) requires a boiler check with unattended operation (maximum $10MW_{th}$ and 6MPa) every 24 hours, and of a boiler with limited attendance operation (maximum $20MW_{th}$ and 6MPa) every four hours to ensure safe operation and minimise risk. The procedure has to be performed by trained personnel (i.e. an accredited boiler attendant). Additional requirements are specified in AS 2593-2004 for boilers with gas and oil firing, which are the predominant fuels used in CSP backup systems. Boilers larger than $20MW_{th}$ require attended operation as per AS/NZS 3788 and AS 3873. These codes have been considered when determining the O&M costs for the different plant capacities provided in Figure 14.

Figure 14: Operations and maintenance costs by plant size ($/MWH)

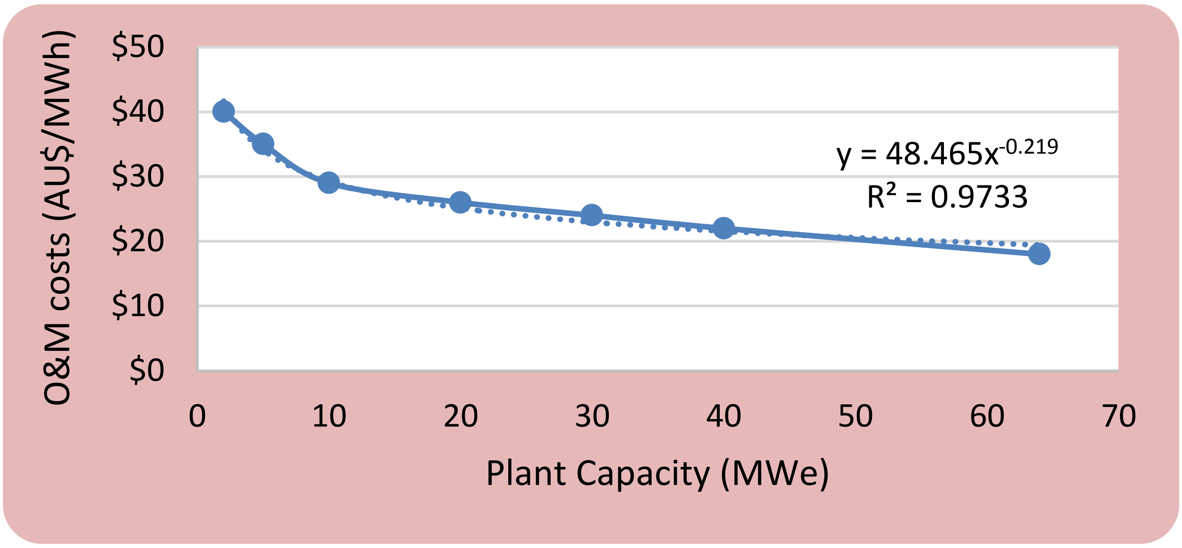


Table 7 gives LCOE examples for a $2MW_e$ and $100MW_e$ CSP plant with different TES configurations for the years 2013 and 2022.

Table 7: LCOE for CSP in 2013 and 2022 (DNI 21.7MJ/m²/day) AU$/MWh

Thermal energy storage	2013 LCOE ($/MWh)		2022 LCOE ($/MWh)	
	$2MW_e$	$100MW_e$	$2MW_e$	$100MW_e$
0 hours	$805	$281	$520	$182
1 hours	$693	$260	$448	$168
3 hours	$619	$230	$400	$148
5 hours	$593	$217	$383	$140
10 hours	$571	$216	$369	$139
15 hours	$559	$210	$361	$136

2.4.2 Annual plant output

The capacity factor for the individual plant configurations was modelled in Thermoflex considering different DNI levels and TES configurations (as shown in Table 8). Thermoflex contains a DNI database which was used for this purpose.[6] As expected, the capacity factor increases with higher DNI and thermal storage levels and the results are in line with

[6] The Thermoflex model was based on a solar tower technology, and a plant at Mildura was used as a base-case scenario. For the purpose of this assessment, the results were interpreted as a proxy for overall performance of CSP plants.

other studies (Lovegrove et al. 2012; IRENA 2012). It should be stressed that the capacity factors provided are based on modelled DNI data and are generic for the purpose of an Australia-wide assessment. Using measured DNI data, and a specific CSP technology in a more detailed project investigation, is likely to result in slightly different results.

Table 8: Capacity factor for different storage levels, based on average DNI

Thermal energy storage	Solar multiple	Capacity factor by average daily DNI					
		15.8 MJ/m^2	17.8 MJ/m^2	19.7 MJ/m^2	21.7 MJ/m^2	23.7 MJ/m^2	24.7 MJ/m^2
0 hours	1.4	10.7%	13.2%	15.7%	18.3%	23.0%	26.3%
1 hours	1.5	13.4%	16.6%	19.7%	23.0%	28.9%	33.1%
3 hours	1.7	17.0%	21.0%	25.0%	29.1%	36.6%	41.8%
5 hours	1.9	20.5%	25.2%	30.0%	35.0%	44.0%	50.3%
10 hours	2.5	26.3%	32.5%	38.6%	45.0%	56.5%	64.7%
15 hours	2.8	29.8%	36.8%	43.8%	51.0%	64.1%	73.3%

2.4.3 Calculating the cost benefit

Once the LCOE and annual plant outputs are known, the remaining elements to calculate the cost gap or benefit are the estimated annual network support payment, the electricity sales income, and the income from the large-scale Renewable Energy Target received in the form of large generation certificate (LGC) sales.

There is considerable uncertainty over future wholesale electricity prices, the carbon price and LGC, as all three will be considerably affected by future policy directions. For this reason, the cost gap modelling uses average revenue over the first 10 years, while the LCOE is calculated over the full project life of 25 years. It is assumed that the LGC and the network payment will be replaced by similar policy initiatives and instruments providing compensation for network support and support for low carbon energy generation at the end of the first 10 year period.

The cost benefit, or gap, is calculated both with, and without, a carbon price. However, the effect of removing the carbon price is negligible, as the projected price of LGCs rise when no carbon price is in effect, as can be seen in Table 13 on page 40.

2.4.3.1 Network support payment

The network support payment calculation assumes that construction of the CSP system will avoid the proposed network investment for the duration of its economic life. The potential network support payment available at a constrained location is based on the investment proposed to address the constraint. The calculation assumes that the payment is discounted from the total value of the network based comparator, acknowledging that the nature of network support provided by any form of non-network (distributed generation) solution, fossil-fuelled or renewable, differs from that provided by additional poles and wires, and that, in the absence of regulatory or market incentives, network operators' decision to adopt non-network solutions would likely be driven by lower cost. A factor of 0.8 has been applied to the proposed investment to reflect this discounting impact. This appeared to be a reasonable first assessment on discussion with network operators (note also that CSP options would need to be compared with other non-network solutions).

The network support payment is calculated as:

$$\textit{Network payment} = (\textit{Proposed investment} \ x \ 0.8 \ x \ \textit{WACC}) + \textit{Average avoided depreciation}$$

The WACC is the same value as used in the DANCE modelling (see Section 2.2.3 for details). The average avoided depreciation is calculated over 10 years at a rate of 2.5% per year, assuming that network assets would be depreciated over 40 years.

2.4.3.2 Electricity sales

Ten year forward averages of wholesale electricity and LGC prices were calculated from modelling undertaken for the Climate Change Authority (SKM MMA 2012b), which projected pool prices for each state, and LGC prices with and without a carbon price, after 2015 (both cases include a carbon price until 2015 on the assumption that the legislated carbon price would remain in effect until then). Forward averages of the pool price and the effect of the carbon price on pool prices,[7] are shown in Table 9 and Table 10 by state.

Table 9: Ten year forward average: wholesale electricity pool price (no carbon price) ($/MWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Qld	$38.9	$39.2	$39.8	$42.6	$46.0	$49.3	$52.2	$55.1	$58.3	$60.7	$62.9
NSW	$36.0	$36.0	$36.6	$39.4	$42.9	$46.0	$49.2	$52.0	$55.2	$57.3	$58.9
Vic	$37.9	$37.9	$38.5	$41.3	$44.9	$48.5	$52.2	$55.9	$60.3	$62.7	$64.4
SA	$40.4	$39.6	$39.7	$41.4	$44.4	$47.6	$50.9	$54.4	$58.4	$60.7	$62.2

Source: SKM MMA, 2012

[7] In the case with the carbon price, the 10 year forward average wholesale electricity price = 10 year rolling average price without carbon price + the 10 year rolling average of the carbon price effect on a state by state basis.

Table 10: Ten year forward average: carbon price effect on average pool price

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Qld	$14.1	$18.8	$24.4	$29.1	$33.1	$37.4	$41.2	$45.3	$49.0	$51.9	$52.7
NSW	$15.9	$20.3	$25.1	$28.5	$31.0	$34.5	$37.7	$41.2	$44.2	$47.0	$47.7
Vic	$14.5	$18.6	$23.2	$26.7	$29.8	$33.5	$37.3	$41.1	$44.0	$47.1	$48.0
SA	$14.4	$18.6	$23.2	$27.1	$30.3	$34.1	$37.9	$41.7	$44.7	$47.8	$48.7

Source: SKM MMA, 2012

A multiplier is applied to the 10 year forward average pool prices to account for the fact that CSP generation, by its nature, tends to align relatively well with peak demands and pricing. The multipliers derived in this project, and used in the cost calculations across the NEM, are shown in Table 11.

Table 11: Multipliers used to adjust average pool price for CSP dispatch time

	0 hrs	1 hrs	3 hrs	5 hrs	10 hrs	15 hrs
Qld	1.29	1.48	1.66	1.25	1.13	1.09
NSW	1.48	1.64	1.80	1.35	1.19	1.13
Vic	1.38	1.48	1.58	1.30	1.25	1.20
SA	1.97	2.21	2.45	1.61	1.36	1.26

During the first iteration of the modelling, we used multipliers taken from Lovegrove *et al*. (2012), shown in Table 12, which were calculated by comparing the estimated revenue from CSP with a reasonable dispatch strategy, and average pool prices for 2005 to 2010. However, in the course of this research, we undertook revenue optimisation for case studies in each state, using three years of weather data at each location and optimising the plant output for revenue (see Section 2.5.1 for details). The multipliers were found to be considerably lower than those reported in the IT Power (Australia) work (Lovegrove et al. 2012), particularly for high levels of storage (above five hours). The difference arises from the underlying assumption in this project that solar multiple and storage hour combinations are chosen to increase capacity factor, in contrast to the IT Power (Australia) analysis that looked at configurations suitable for 'peaking' dispatch to maximise energy sales revenue.

Table 12: Multipliers from "Realising the potential of concentrating solar power in Australia" report

	0 hrs	High levels of storage
Qld	1.35	2.09
NSW	1.32	1.95
Vic	1.50	1.90
SA	1.81	2.77

Source: Lovegrove, Watt, Passey, et al., 2012, page 126

We tested the effect of reducing the solar multiple significantly, relative to TES, and found that the ratio of optimised revenue compared to average pool prices did increase, to be somewhat higher than the multipliers shown in Table 12. However, the modelled economic benefit from improved electricity sales revenue was far outweighed by the increase in LCOE which resulted. We therefore, used the more conservative multipliers derived during this study, shown in Table 11, to adjust the projected average pool price to calculate revenue. The multipliers shown are the average values for the three years examined from three locations in Queensland, and two locations in each of the other states.

2.4.3.3 Large generation certificates

Rolling 10 year averages were calculated for LGC prices, both with and without a carbon price, using the SKM MMA modelling for the Climate Change Authority (SKM MMA 2012b). The annual forward rolling 10 year averages are shown in Table 13.

Table 13: Ten year forward average: Large generation certificate price

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
With carbon price	$57.2	$54.5	$50.6	$45.9	$40.5	$34.6	$28.2	$21.8	$15.6	$11.6	$8.7
No carbon price	$72.6	$73.3	$73.4	$72.4	$70.9	$69.0	$67.0	$64.8	$59.8	$58.5	$57.0

Source: SKM MMA, 2012

2.4.4 Land requirements and connection distance

The land demand in this assessment is modelled with Thermoflex considering different TES levels. Some examples for the plant footprint are provided in Table 14 and the graphs and equations to calculate the specific plant footprint are shown in Figure 15.

Table 14: CSP plant footprint as a function of plant capacity and thermal energy storage (hectares)

Thermal energy storage	Plant capacity in MW_e											
	2	4	6	8	10	12	14	16	18	20	50	100
15 hours	27	47	66	83	101	117	133	149	165	180	390	729
10 hours	23	40	55	70	84	98	112	125	138	151	327	612
5 hours	17	30	42	53	64	75	85	95	105	115	249	466
3 hours	16	27	38	48	58	68	77	87	96	105	226	423
1 hours	14	24	33	42	51	59	67	75	83	91	197	368
0 hours	13	23	32	40	48	56	64	72	80	87	188	352

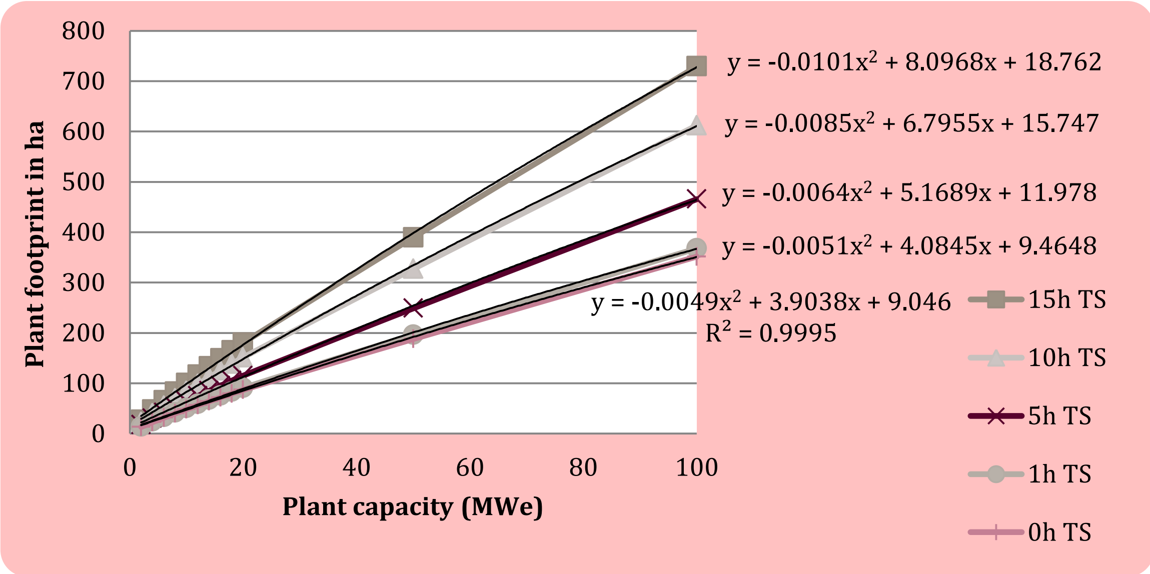
Note: See Table 5 for the assumed solar multiple for each storage level

Typically, large power tower systems require more land than parabolic trough and Fresnel systems plants of the same capacity. However, smaller modular configurations (such as that being developed by eSolar)[8] have higher land use efficiency. The land area use requirement difference can be significant (Müller-Steinhagen & Trieb 2004). The results in Table 14 use the total plant area for large central tower plants, with the results in line with actual installations. However, land cost typically makes up a small proportion of the capital cost of CSP plants.

For example, the $20MW_e$ 15 hour TES Gemasolar plant in Spain has a footprint of 185 hectares (Burgaleta, Arias & Ramirez 2011); the land area is large compared with the MW capacity due to the additional solar energy collection required to charge the large amount of TES. The Thermoflex modelling results in 177 hectares for the same plant capacity and TES configuration. This marginal difference is acceptable as it can be accounted for by factors such as differences in heliostat spacing and field layout, which will be optimised based on latitude and longitude of the plant location and heliostat size and dimensions. A constant DNI average value was also used for all locations rather than site-specific DNI value, as required for a real project.

[8] http://www.esolar.com/

Figure 15: Plant footprint depending on plant capacity and thermal energy storage



2.4.5 Connection costs

Total cost calculated with Thermoflex for no TES plants were within ±5% of the costs given in the IT Power (Australia) report (Lovegrove et al. 2012), which included generic connection costs. However, the Thermoflex software does not include connection costs because these are site specific and vary from country to country. In this study, a conservative approach was adopted with connection costs added to the modelled CSP system cost from Thermoflex. This increased the assumed cost of the CSP system by 8% to 11% for a CSP plant without TES, relative to costs given in Lovegrove *et. al.*(2012).

We have used the following generic connection costs (Nelson 2013), although it must be stressed that these are site specific and could vary considerably:

- 5MW (assumes 11kV connection): $6m,
- 10MW (assumes 33kV connection): $9m,
- 20MW (assumes 66kV connection: $12m, and
- 30MW to 100MW (assumes 132kV scheduled connection): $25m to $40m.

These costs were used to derive two formulas (for plant sizes 25MW and below, and for plant sizes greater than 25MW) on the assumption that plants above 20MW would be connected to the 132kV system. The equations used are shown in Figure 16 and Figure 17. These calculations assume the plant is close to the connection point.

Figure 16: Connection costs by plant size, 5MW – 25MW (AU$m)

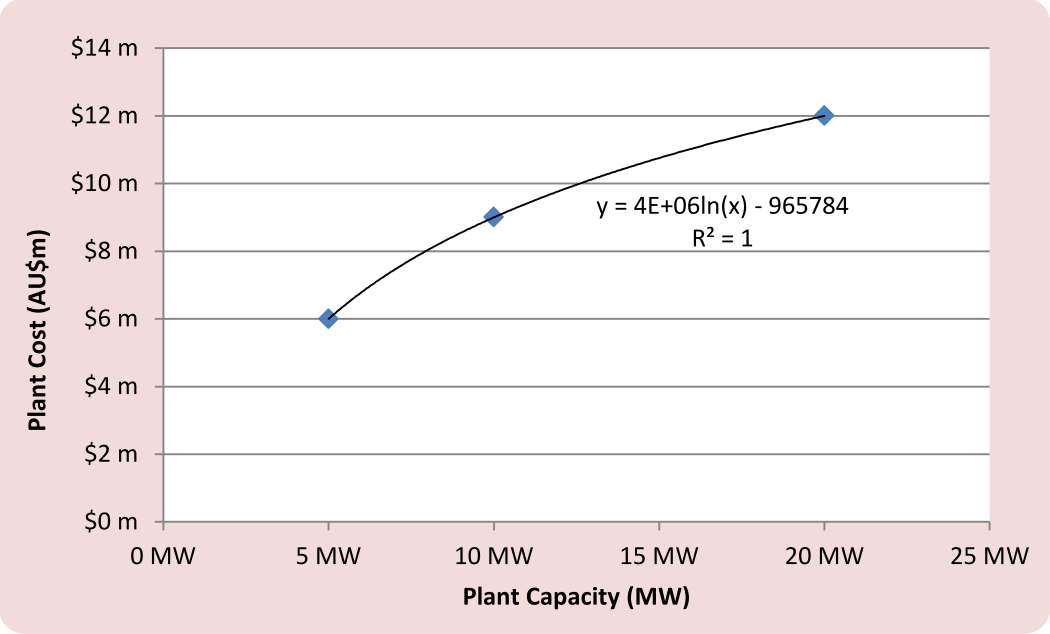
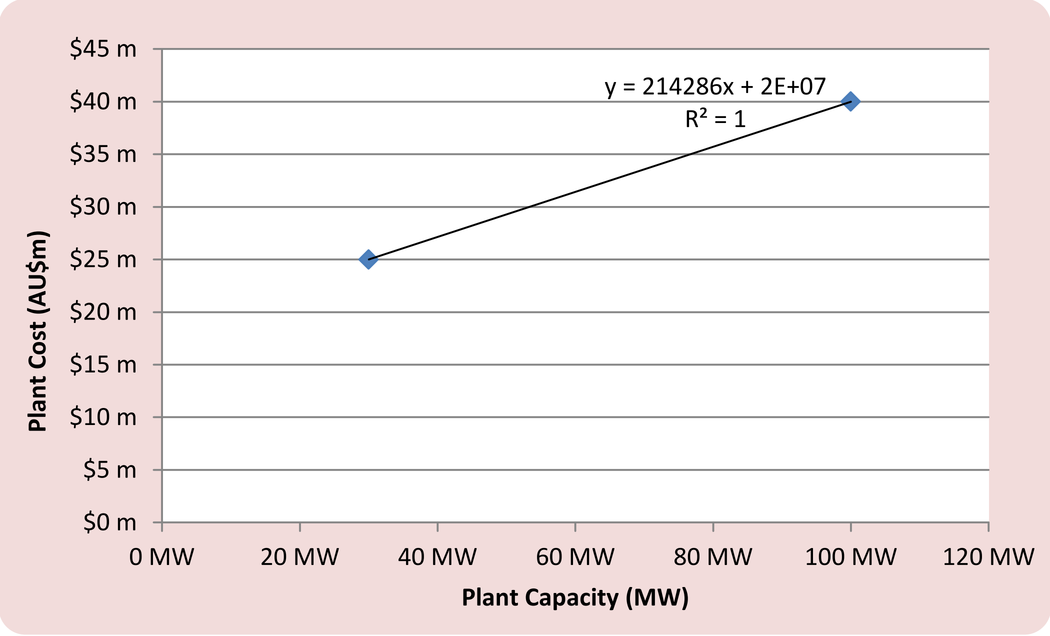


Figure 17: Connection costs by plant size, 25MW – 100MW (AU$m)



When undertaking case study analysis, we obtained location specific connection costs where possible, which in some cases were considerably lower than the costs outlined above.

2.5 CASE STUDY METHODOLOGY

Case study locations were chosen in each state in consultation with the relevant DNSP or TNSP. Selection was based on the cost benefit found in the NEM-wide mapping, but also on inclusion of a range of years and constraint types.

The specific constraint and draft results were discussed in a workshop with the relevant DNSP or TNSP, in order to define minimum requirements for plant operation that could avoid the need for augmentation. The workshops were also used to explore appropriate plant sizes, connection costs and the potential for network support payments.

Information from the workshops was subsequently used to revise the case studies, and to set parameters on plant type and operation.

In each case study location, weather records for 2009/10, 2010/11 and 2011/12 were used to obtain a generation profile modelled on 0, 5, 10 and 15 hours of energy storage for each of the three years.

This was used to derive both economic and performance data, specifically:

- The potential for revenue optimisation, relative to average pool prices, to derive a specific multiplier for the location;
- The number of days generation below relevant thresholds, as determined in discussion with the network operator; and
- The performance of the CSP plant at peak times, by comparison of the modelled CSP generation for the relevant year to the hourly demand data for the same year.

Simple cost benefit analyses were undertaken for a potential CSP plant at the location, using data derived from modelling, and information from the case study workshops.

2.5.1 Potential for revenue optimisation

The total hours of generation for each day of the year, including operations from TES, was modelled as described in Section 2.3.3. The output was the proportion of nameplate generation capacity occurring at each hour of the year. As noted earlier, the dispatch strategy assumed was unsophisticated - simply that the plant started generation as soon as possible and continued until all storage was empty, as the purpose was only to obtain the total number of generation hours, including hours of operation needed to meet the constraint.

The hours of generation for each day were matched to the average pool prices for that year, choosing the optimum revenue with several conditions:

- There could be no more than two blocks of generation per day;
- No block could be less than two hours; and
- When generation hours exceeded storage hours, those hours above the storage levels had to be dispatched at times when a plant with no storage would have been generating.

The results from this optimisation were used both for the case studies, and also to derive state by state revenue multipliers to use for the NEM-wide cost benefit analysis, as described in 2.4.3.2.

2.5.2 Number of days generation

The three years of modelled hourly generation data were used to determine the number of days below various levels of generation that had occurred in each of the three analysis years, and the length of continuous days of low generation days. This data informed the requirements of the CSP to provide sufficient reliability.

2.5.3 Performance of the CSP plant at peak times

Hourly output data was compared to demand data for the constrained network asset to determine whether CSP, with varying levels of storage, could have been operating at the required times.

2.5.4 Cost benefit and ‘what if’ analysis

Cost benefit was calculated by comparing the calculated LCOE for the indicated plant configuration to projected revenue streams available from a plant with that configuration.

The cost of oversizing the gas boiler for backup generation purposes was included if required to meet the minimum performance standard, as determined in the case study workshop.

Revenue was considered in two models. The first assumes the generator sells into the wholesale pool, using the revenue multiplier applied to the average pool price, derived for that location, as described in Section 2.4.3.2 (‘pool sales model’). The second model assumes a power purchase agreement (PPA), using a base price adjusted by an annual increment. The LGC value is included in the PPA price. A 10 year forward average of projected prices for electricity and LGC sales was used (SKM MMA 2012a), with and without the effect of the carbon price. This is described in more detail in Sections 2.4.3.2 and 2.4.3.3.

A ‘what if’ analysis was carried out to identify:

- The effects of a capital grant or cost reduction on cost benefit per MWh, in order to identify the cost reduction needed to attain a ‘break even’ cost benefit in any particular year. This was undertaken for both the PPA and the pool sales model; and
- The effect of storage hours on LCOE.

3 RESULTS

3.1 NETWORK CONSTRAINTS AND POTENTIALLY AVOIDABLE INVESTMENT

A total of 93 constraints, or constrained areas, were identified in non-metropolitan areas in the NEM during this research, either from public network planning documents or information supplied directly by the network operators. As noted previously, network service provider's analyses of network constraints usually assume traditional network responses, and are informed by the Regulatory Investment tests for Distribution and Transmission (RIT-D and RIT-T).

In two states, Queensland and South Australia, constraints were only examined in areas with DNI likely to be sufficient for CSP to operate economically, while in Victoria and New South Wales all non-metropolitan constraints were mapped where possible. The high number of constraints in Victoria reflects the fact that use of data from public information allowed easy inclusion of all the identified non-metropolitan constraints, so low DNI areas were included, and is not because the network is more constrained.

Approximately \$0.8 billion of potentially avoidable network augmentation has been identified across the NEM in areas with suitable solar irradiance for installation of CSP (defined here as average DNI more than 21 MJ/m^2/day), as shown in Table 15. Figure 18 shows all the proposed investment identified in Queensland, New South Wales and South Australia, while Figure 19 shows proposed investment in Victoria. There is a further \$0.5 billion of potentially avoidable network expenditure which has been identified in areas with DNI below 21 MJ/m^2/day.

Table 15: NEM wide - potentially avoidable investment

	QLD	NSW	VIC	SA	Total
2014 - 2015	\$15m	\$5m	\$7m	-	**\$26m**
2016 - 2017	\$109m	\$55m	\$17m	\$5m	**\$186m**
2018 - 2024	\$267m	\$34m	\$17m	\$231m	**\$547m**
TOTAL (DNI>21 MJ/m2/day)	**\$390m**	**\$93m**	**\$40m**	**\$236m**	**\$759m**
Number of constraints	24	10	40	4	78
Total investment 2013 to 2024	\$477m	\$122m	\$430m	\$247m	**\$1,276m**

Most of the investment occurs in the period from 2016 onwards. This reflects the fact that maximum demand forecasts were reduced significantly during 2012 (AEMO 2012), with the result that proposed growth-related augmentation has, in many cases, been deferred. It is important to stress that proposed investment changes as demand forecasts change, as different non-network solutions come into play, and as reliability criteria are adjusted. Thus, the investment identified here is a snapshot of expectations at the present time, and will be different as time moves forward.

Figure 18: Potentially avoidable network investment in QLD, NSW and SA

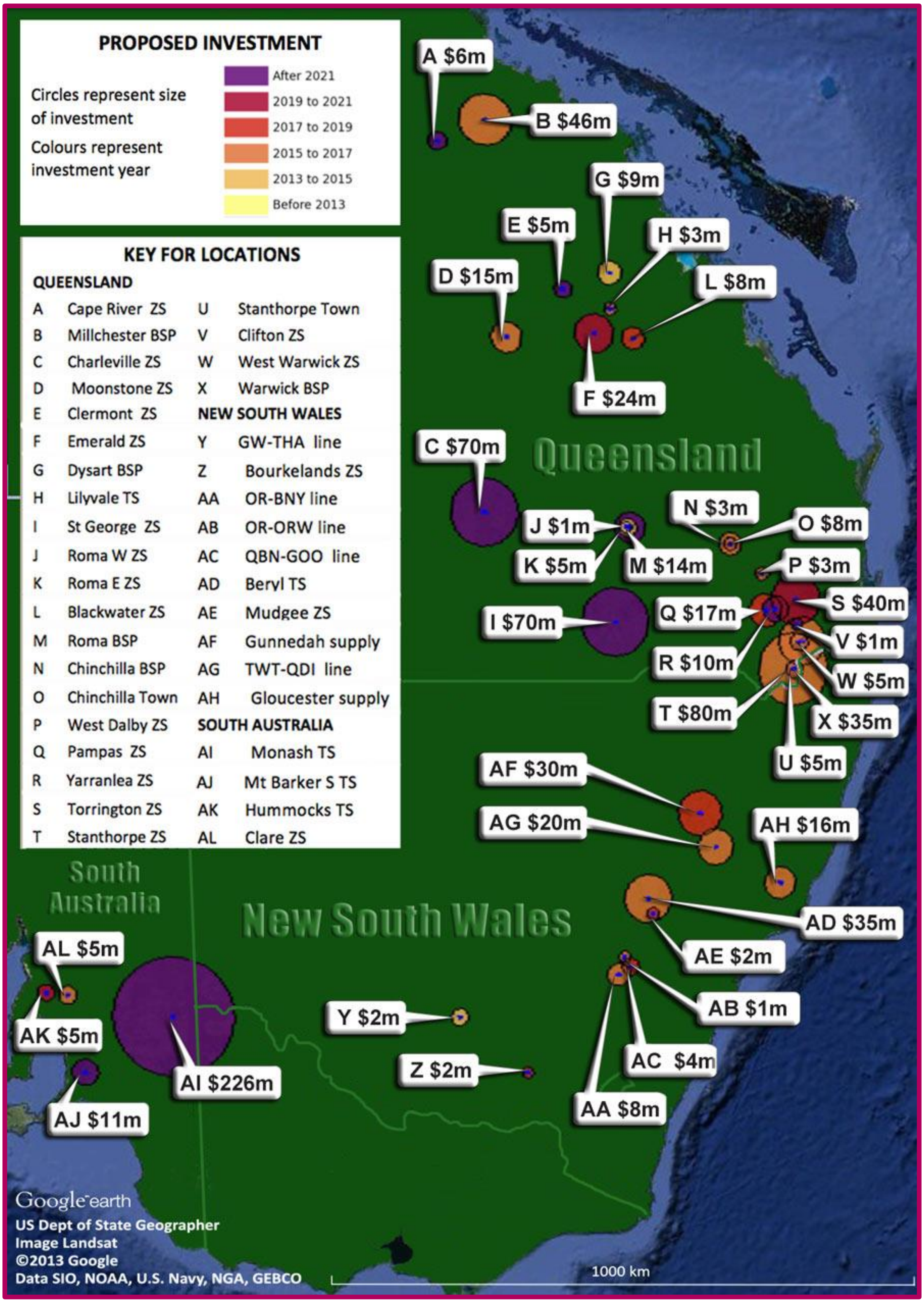
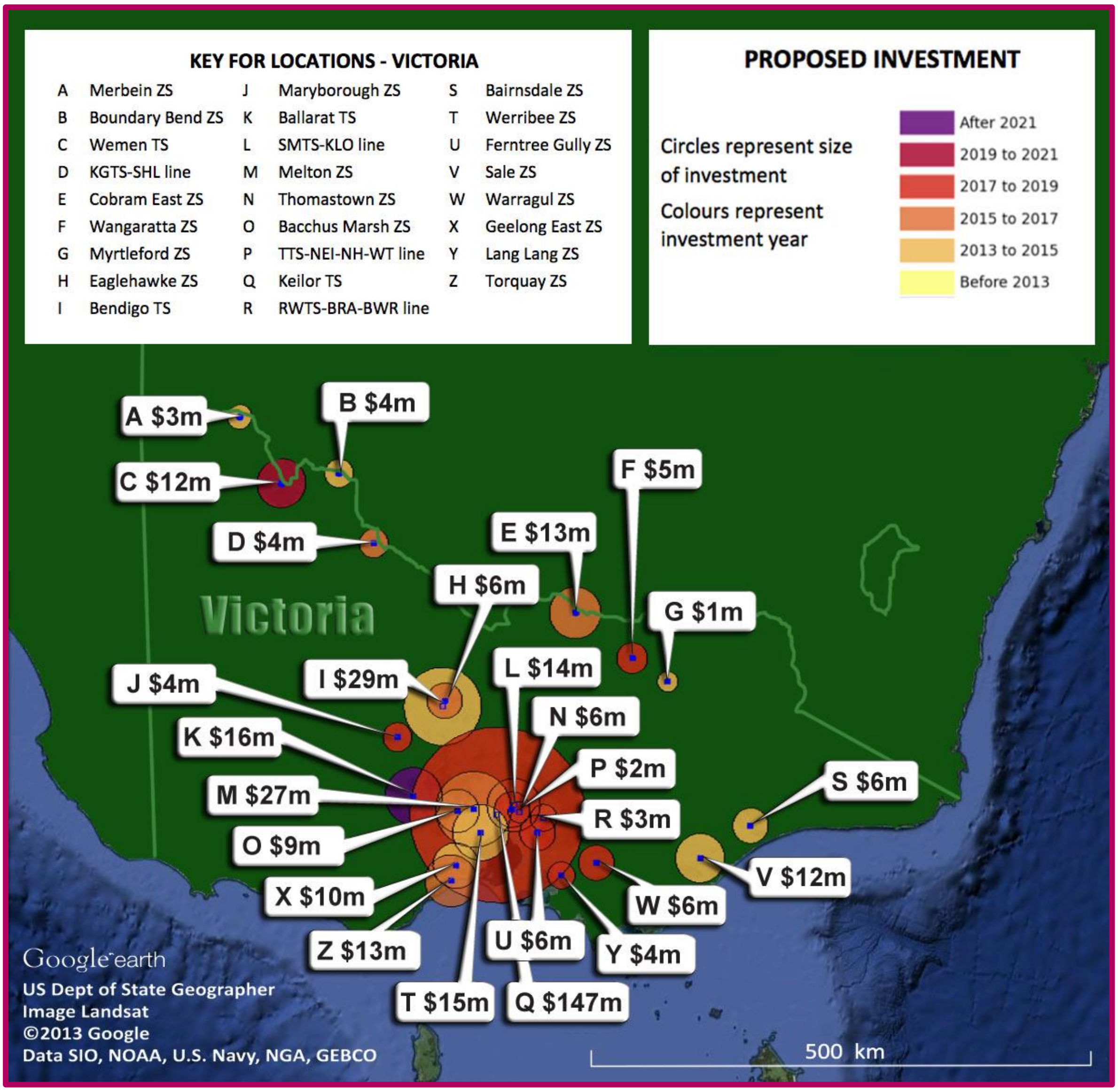


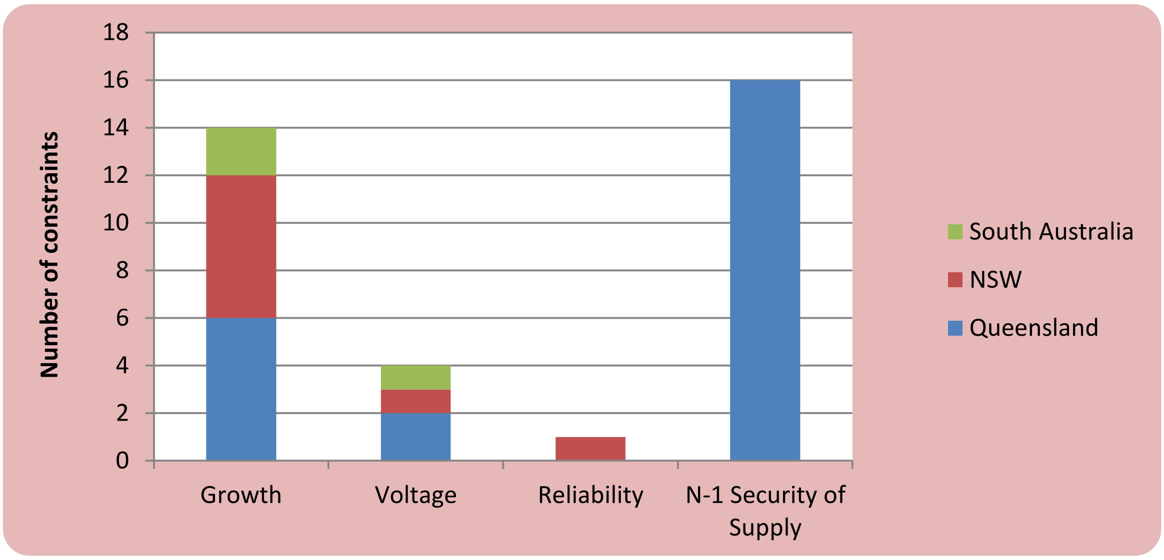
Figure 19: Victoria - potentially avoidable investment



Detailed interactive maps of the proposed network investment and ADV are available at www.breakingthesolargridlock.net. Spreadsheet format is also available.

The type of constraints are shown in Figure 20, by state. The majority of constraints in Queensland were n-1 Security of Supply constraints, resulting from the need to have sufficient network capacity such that supply can be maintained to a region even if a single element of the network is unavailable. The threshold for this criterion is 15MVA, so the applicability of this is also related to growth.

Figure 20: Types of network constraints by state (SA, NSW and QLD)



Note: there was insufficient information to adequately categorise Victorian constraints

3.2 CSP - INDICATIVE FIRM CAPACITY

Three sample maps of IFC are shown in Figure 21 and Figure 22. There are several aspects to consider in these results:

- The characteristics of the IFCs shown in the four different peak demand periods (summer afternoon, summer evening, winter afternoon, and winter evening)[9] around the NEM;
- The effect of controlling the CSP plant dispatch strategy to aid in meeting evening peaks; and
- Most importantly, the effect of different plant configurations on the IFC.

Only three periods are shown here, as once a high level of TES is included, the winter afternoon period is not very different from the winter evening period. The full set of maps of IFC for each peak period (summer afternoon, summer evening, winter afternoon, and winter evening), for 0, 1, 3, 5, 10 and 15 hours of thermal storage are shown in Appendix 3 and downloadable in Google Earth format at www.breakingthesolargridlock.net. A smaller subset of peak periods can be viewed live at the same web resource.

[9] Summer and winter afternoons are 2 to 4pm; summer and winter evenings are 5 to 8pm.

Figure 21: Indicative firm capacity summer afternoon (3 hours storage)

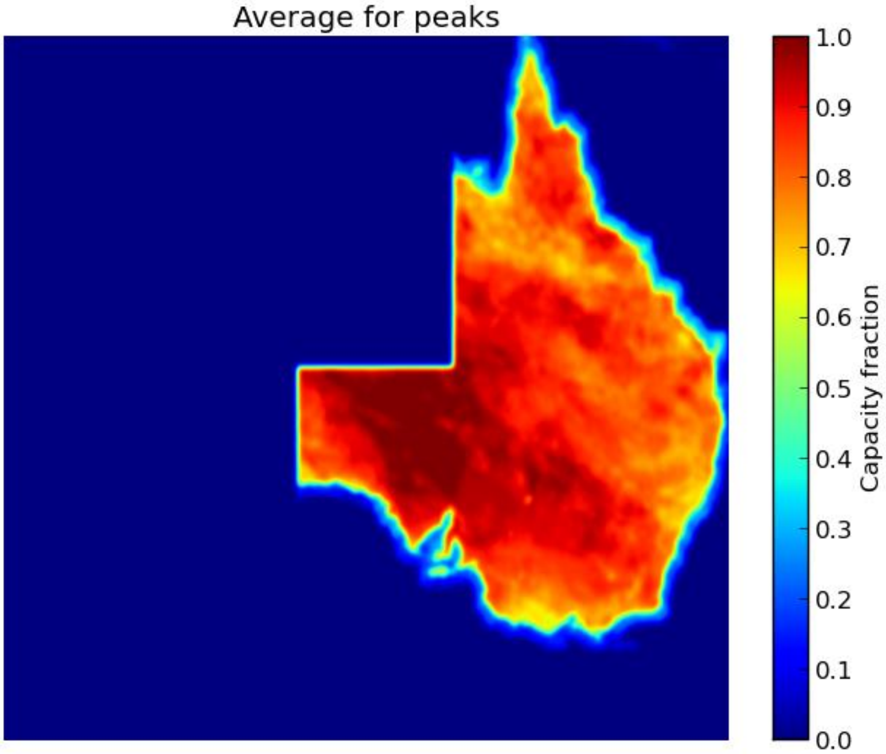
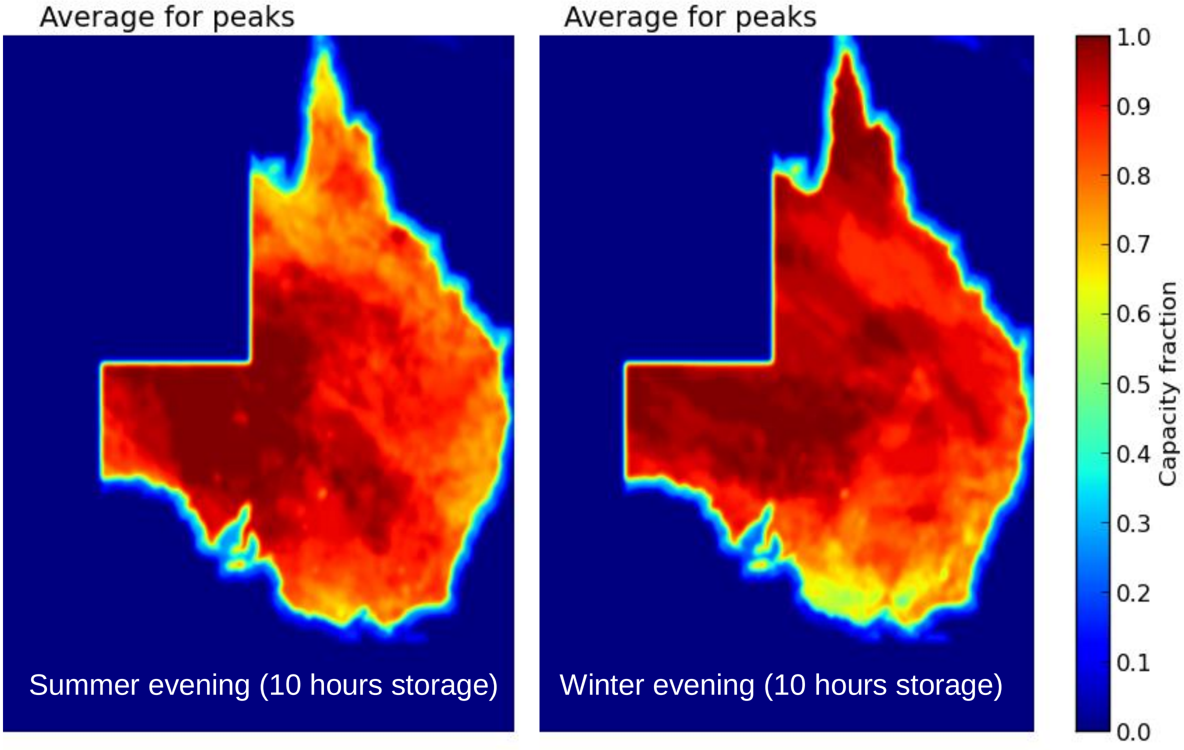


Figure 22: Indicative firm capacity summer and winter evenings (10 hours storage)



3.2.1 Characteristics of IFC in the four peak periods

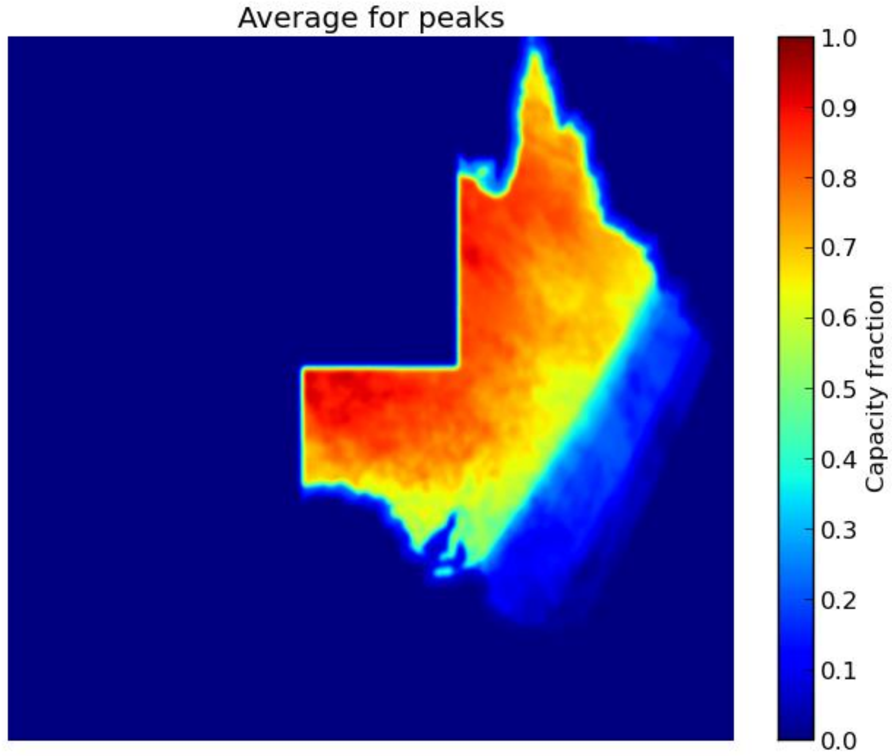
It should be noted that in the maps of the results, a fringe effect can be observed around the coastline, visible as a blue border. This is because the 2011 solar radiation data used in this work was added to an existing data set. The 2011 data came from a newer revision of the BOM solar data, where the BOM started to process grid cells around water bodies differently. Hence, the average of three years, where two of the years produce nil results around the coastline, tends to produce very low values. These should be ignored for the purpose of this study.

In Figure 21, we see a plot for IFC across the NEM during summer afternoon peaks. This plot is quite characteristic and bears out a number of common features found throughout this study. First, coastal areas have lower values due to the weather systems that generally prevail on the coast. This is also true for tropical northern Queensland, where summers include monsoonal impacts and periods of high rainfall. Previous research undertaken by the Centre for Energy and Environmental Markets at University of New South Wales has found that in far northern Australia, CSP plants may often face DNI lulls in excess of seven days where there is insufficient solar radiation to capture any thermal energy; in such extended periods, the ability to operate would depend on energy available in storage or from backup fuels (Elliston et al. 2011). Second, we find that IFCs are somewhat higher the further west the plant is located (e.g. northern South Australia).

In winter, Queensland sees higher IFCs because of the absence of monsoonal weather patterns. This can be seen by comparing the summer and evening plots with identical plant configuration (10 hours of storage) in Figure 22.

Figure 23 shows, as an extreme case, the winter evening results for a plant with no thermal energy storage. The band across the map shows locations where IFCs are approaching zero simultaneously, as sunset falls within the period of interest (5 to 8pm on winter evenings). As the plot extends north, IFC increases because sunset occurs later.

Figure 23: Indicative firm capacity winter evening (no storage)



3.2.2 Effect of controlling the dispatch strategy

As noted earlier, the CSP model simulated plant output using a simple dispatch strategy, namely to generate electricity whenever it was possible to do so. For some configurations of solar multiplier and storage capacity, this leads to sub-optimal IFCs in the summer, and particularly so for the winter evening peak demand periods because thermal energy collected early in the day is consumed before the peak period occurs. In practice, a more sophisticated dispatch strategy would be employed that considers storage levels, solar forecasts, demand forecasts, prevailing market prices, as well as obligations to meet network constraints, in determining when the plant should best operate.

To minimise the total computation required for the full set of peak demand periods, NEM regions and CSP configurations, this study chose a single dispatch strategy designed to improve correspondence of generation output with the peak. The model assumed generation does not begin until noon each day, unless this would lead to thermal energy being dumped, in which case, generation starts earlier. The model assumed that the plant shut down at midnight, and that generation resumed at noon the following day, or earlier if resumption at noon would result in dumping energy. While still rudimentary, this dispatch strategy produced significantly higher IFC results and is a reasonable first approximation of a dispatch strategy designed to meet peak demand in accordance with network support obligations. The IFCs presented are the results from this dispatch strategy.

3.2.3 Effect of technology configurations on IFC

The study found that for summer afternoons, even one hour of storage makes a large difference to the IFC across all modelled NEM regions. IFC in inland areas improves slightly, while one hour of storage improves the IFC markedly closer to the coast, where it is likely to be more affected by transient cloud cover. The IFC improves again at three hours of storage, then reaches a point of diminishing returns. A 2pm peak is harder to meet if the CSP plant has no storage. A small amount of storage to carry thermal energy into the afternoon is sufficient in some locations. With five hours storage in the summer afternoon, most regions of New South Wales are achieving IFCs of over 90%, with the lowest IFC region, the southern Victorian coastline, at about 65%.

These general observations also apply to summer evenings (Figure 22 on page 50). However, the IFCs decline slightly in the evening period due to the longer time between peak solar radiation and the network peak. It should be noted that many of the summer evening peak demands occur at 5pm because they are a continuation of the afternoon peak from 2pm to 4pm. This explains, to some degree, the similarity of results between summer afternoons and summer evenings.

This study confirmed that CSP configurations with greater amounts of storage (and correspondingly higher solar multiples) generally deliver greater IFC, as would be expected. Areas in southern Victoria, northern Queensland and coastal regions tend to have significantly lower IFCs than inland regions, due to their climates and, in the case of Victoria, low latitude.

The storage requirement is seasonal, with much less required for summer peak constraint events than for winter. Very little storage is required to reliably meet summer afternoon peaks. As noted above, IFCs for summer evening peaks are quite similar to summer afternoon peaks. In winter, IFC is less due to the lower solar resource (see Figure 22 on page 50). However, with ample storage and strategic dispatch of the plant, IFCs greater than 80% can be achieved in most locations.

3.3 INSTALLING CSP AT GRID CONSTRAINED LOCATIONS: COST EFFECTS

The network constraint mapping and IFC were integrated to determine whether CSP could remove the need for network augmentation at constrained locations in the NEM. Altogether, 93 constraints or constrained areas were considered, of which 67 had sufficient information to determine whether CSP could potentially alleviate the constraint. Sites are defined as being indicatively able to host a CSP plant sufficient to meet the constraint if:

1) It is possible to connect a CSP plant sufficiently large to meet the constraint for the entire modelled period, including the forecast growth at the site; and
2) The IFC at the site is at least 80% in the constraint season and time (that is, winter afternoon, winter evening, summer afternoon or summer evening) identified for that location.

For each location where CSP can indicatively meet the constraint, the cost benefit was calculated. Cost optimisation was first undertaken to find the most economic plant configuration that would meet the network requirements. This entailed calculating the cost benefit for each size of plant between the minimum that could meet the constraint, and the maximum that could be connected. This was undertaken for each level of storage between the minimum level that would deliver an IFC of 80%, and 15 hours. The outputs from the model are the cost benefit calculations for the optimum economic plant, the smallest plant which could meet the constraint, and the largest plant which could be connected.

The cost benefit was calculated from the LCOE for the particular plant configuration, less the projected revenue including electricity sales, LGC sales and the contribution of a network support payment. The network support payment assumes the entire augmentation is avoided, and is based on 80% of the proposed network investment, reflecting the fact that electricity generation (of any type) cannot replicate the certainty offered by wires and poles. This also means the total societal cost of meeting network constraints is reduced by 20%. The support payment is calculated as an annual payment based on the cost of capital and the avoided depreciation, and is the same irrespective of plant size. The annual network support payment is divided by the annual generation to obtain a contribution per MWh.

An interactive map and accompanying spreadsheet are available online, with details of the cost benefit calculation at each location, at: www.breakingthesolargridlock.net.

3.3.1 Can CSP avoid the need to augment the network?

Sixty-seven constrained locations with sufficient information to make a determination were examined, which indicated that CSP could avoid the need for network augmentation at 48 locations, or in 72% of cases. If only locations where DNI is greater than 21 MJ/m^2/day are included, CSP can avoid the need for augmentation at 94% of locations.

The results for each state are shown in Table 16. When all sites are included, including those with DNI below 21 MJ/m^2/day, Victoria has, unsurprisingly, the lowest percentage of sites where CSP can avoid the requirement for augmentation, essentially because sites with average DNI as low as 13.5 MJ/m^2/day have been included in the overall analysis. The lowest DNI for the sites examined in other states respectively is 20 (QLD), 19.8 (NSW) and 18.9 (SA).

Table 16: Proportion of grid constrained locations where CSP could indicatively avoid the need for network augmentation

	QLD	NSW	VIC	SA	NEM
Number of locations where CSP could indicatively avoid the need for network augmentation	20	7	17	4	**48**
% of locations	87%	88%	53%	100%	**72%**
Proportion of locations with DNI > 21 MJ/m^2/day	90%	100%	100%	100%	**94%**

Note: Excludes locations with insufficient information.

3.3.2 Cost benefit of CSP at grid constrained locations in the NEM

Overall, CSP installation was found to have a positive cost benefit in 25% of the constrained locations examined with DNI greater than 21 MJ/m^2/day, and to have a cost benefit greater than -$20/MWh at 36% of constrained locations, as shown for each state in Table 17.

Table 17: Cost benefit of CSP installed at grid constrained locations with DNI > 21 MJ/m^2/day

	QLD	NSW	VIC	SA	All states
Proportion of cost effective sites	30%	0%	14%	67%	**25%**
Proportion of sites cost benefit > -$20/MWh	45%	17%	14%	67%	**39%**

The optimisation, in most cases, indicated the maximum nameplate capacity possible, which was determined by the limitation imposed by the network connection point, or in some cases, by the limit of 120MW imposed in the model. This limit was imposed both because installation of higher MW of generation at constrained network locations could start to impose its own network augmentation costs, and because the cost formulation was developed for tower plants from 2 to 100MW. The limit of 120MW is close to present international experience, as the largest tower CSP plant with TES is currently 110MW (Solar Reserve 'Crescent Dunes', Tonopah, USA[10] shown in Figure 24).

Figure 24: 110MW tower CSP plant with TES in Tonopah, USA.

Source: SolarReserve [10]

[10] http://www.solarreserve.com/what-we-do/csp-projects/crescent-dunes/

Figure 25 shows where CSP could indicatively avoid the need for network augmentation at constrained locations in Queensland, and the cost benefit for the CSP developer. CSP can indicatively meet the constraint at twenty locations. Figure 26 shows where CSP could indicatively avoid the need for network augmentation at 25 constrained locations in New South Wales, Victoria and South Australia, and the cost benefit for the developer.

Altogether, installation of 533MW of CSP at grid constrained locations was found to be cost effective during the next 10 years, and an additional 125MW had a cost benefit between -$20/MWh and $0/MWh. The plant configuration and LCOE at different locations are shown in Table 18, as determined by the optimisation. Across all states, the average plant size was 40MW, with 10 hours storage, and the average and lowest LCOE were $202/MWh and $111/MWh respectively.

Installation of CSP plants at all of these locations would result in greenhouse gas reduction of 1.9 million tonnes per year, based on current average emissions factors for each state (Commonwealth of Australia 2012) and the capacity factor for the specified CSP plant.

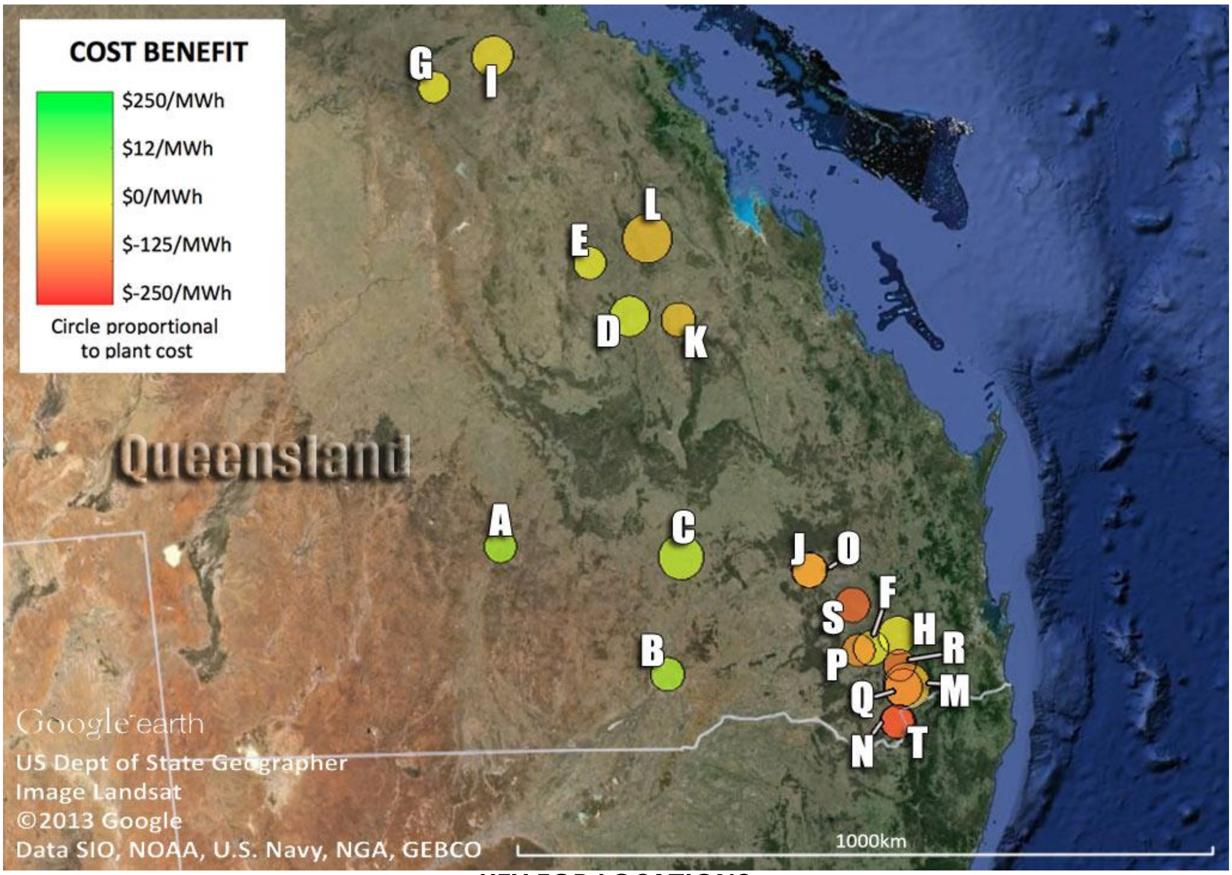
The network support payment was not found to be a crucial factor in most locations, although it certainly contributed to the overall cost effectiveness. As the optimisation process generally increased the plant size to the maximum able to be connected, this had the effect of diluting the contribution from the network payment when measured as a value per MWh of plant output.

The largest network support payment contribution calculated was $134/MWh, and the average $15/MWh. The average at cost effective sites was somewhat higher, at $31/MWh.

Table 18: Plant configuration and LCOE - variation across states

	QLD	NSW	VIC	SA	All states
Average storage hours	8hrs	13hrs	14hrs	3hrs	10hrs
Average size (MW_e)	$42MW_e$	$43MW_e$	$64MW_e$	$58MW_e$	$49MW_e$
Average LCOE ($/MWh)	$194	$220	$189	$267	$202
Lowest LCOE($/MWh)	$111	$161	$134	$157	$111

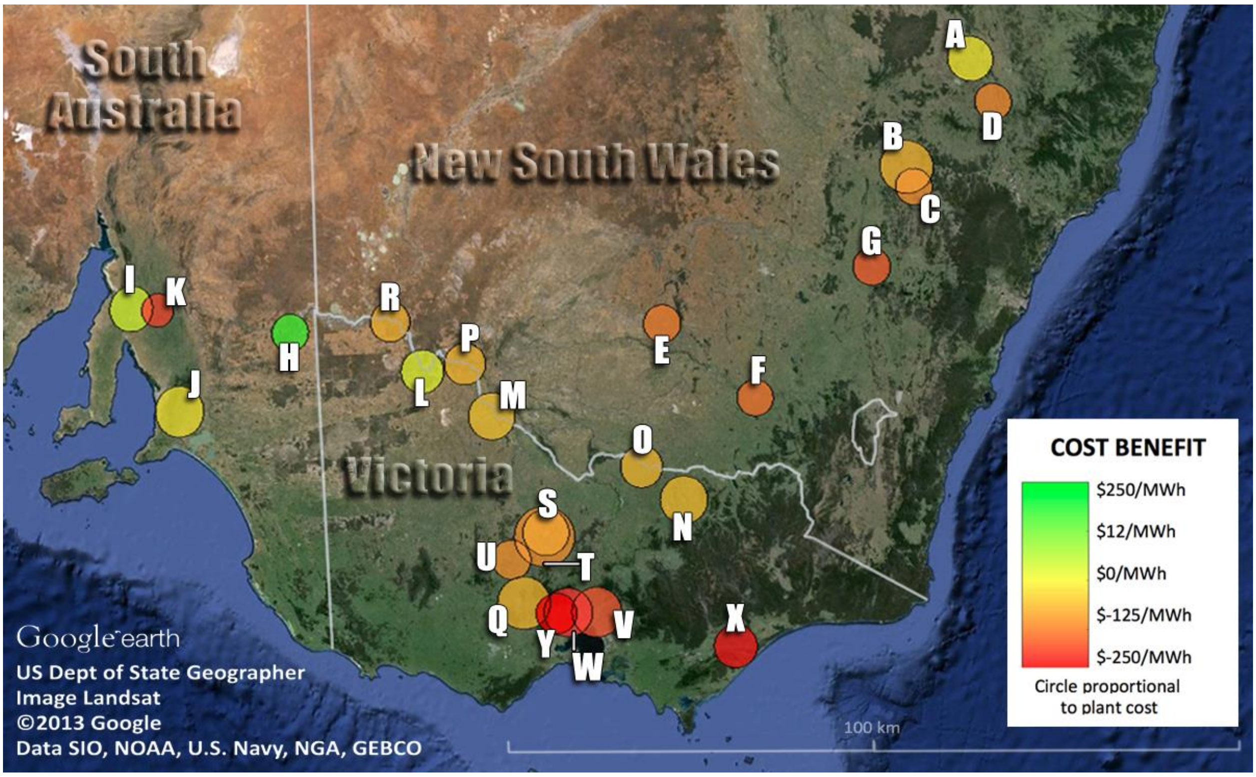
Figure 25: Queensland - potential 'network positive' CSP installations



KEY FOR LOCATIONS

		Cost benefit $/MWh	Size	Year			Cost benefit $/MWh	Size	Year
A	Charleville ZS	$67	20 MW	2022	K	Blackwater ZS	-$45	22 MW	2018
B	St George ZS	$60	27 MW	2022	L	Dysart BSP	-$48	120 MW	2015
C	Roma BSP	$41	120 MW	2022	M	Warwick BSP	-$48	111 MW	2017
D	Emerald ZS	$17	70 MW	2020	N	Stanthorpe ZS	-$49	20 MW	2017
E	Clermont ZS	$2	20 MW	2023	O	Chinchilla Town ZS	-$87	16 MW	2017
F	Yarranlea ZS	$2	30 MW	2024	P	Pampas ZS	-$91	11 MW	2019
G	Cape River ZS	-$4	20 MW	2022	Q	West Warwick ZS	-$107	28 MW	2016
H	Torrington ZS	-$7	55 MW	2021	R	Clifton ZS	-$118	8 MW	2022
I	Millchester BSP	-$18	75 MW	2017	S	West Dalby ZS	-$137	15 MW	2016
J	Chinchilla BSP	-$32	30 MW	2019	T	Stanthorpe Town	-$168	15 MW	2017

Figure 26: NSW, SA and Vic - potential 'network positive' CSP locations



KEY FOR LOCATIONS

		Cost benefit $/MWh	Size	Year			Cost benefit $/MWh	Size	Year
NEW SOUTH WALES					**VICTORIA**				
A	Gunnedah supply	-$11	95 MW	2019	L	Wemen TS	$18	77 MW	2021
B	Beryl TS	-$66	95 MW	2016	M	KGTS-SHL line	-$49	58 MW	2016
C	Mudgee ZS	-$100	19 MW	2019	N	Wangaratta ZS	-$54	66 MW	2018
D	TWT-QDI line	-$108	19 MW	2017	O	Cobram East ZS	-$61	38 MW	2017
E	GW-THA line	-$118	15 MW	2015	P	Boundary Bend ZS	-$61	33 MW	2015
F	Bourkelands ZS	-$129	13 MW	2018	Q	Ballarat TS	-$64	120 MW	2022
G	OR-BNY line	-$153	18 MW	2016	R	Merbein ZS	-$67	26 MW	2015
SOUTH AUSTRALIA					S	Eaglehawke ZS	-$85	54 MW	2016
H	Monash TS	$178	50 MW	2022	T	Bendigo TS	-$96	120 MW	2014
I	Hummocks TS	$32	120 MW	2021	U	Maryborough ZS	-$97	27 MW	2019
J	Mt Barker S TS	-$16	120 MW	2023	V	Thomastown ZS	-$159	84 MW	2019
K	Clare ZS	-$173	10 MW	2016	W	Melton ZS	-$194	66 MW	2016
					X	Sale ZS	-$226	40 MW	2015
					Y	Bacchus Marsh ZS	-$298	27 MW	2014

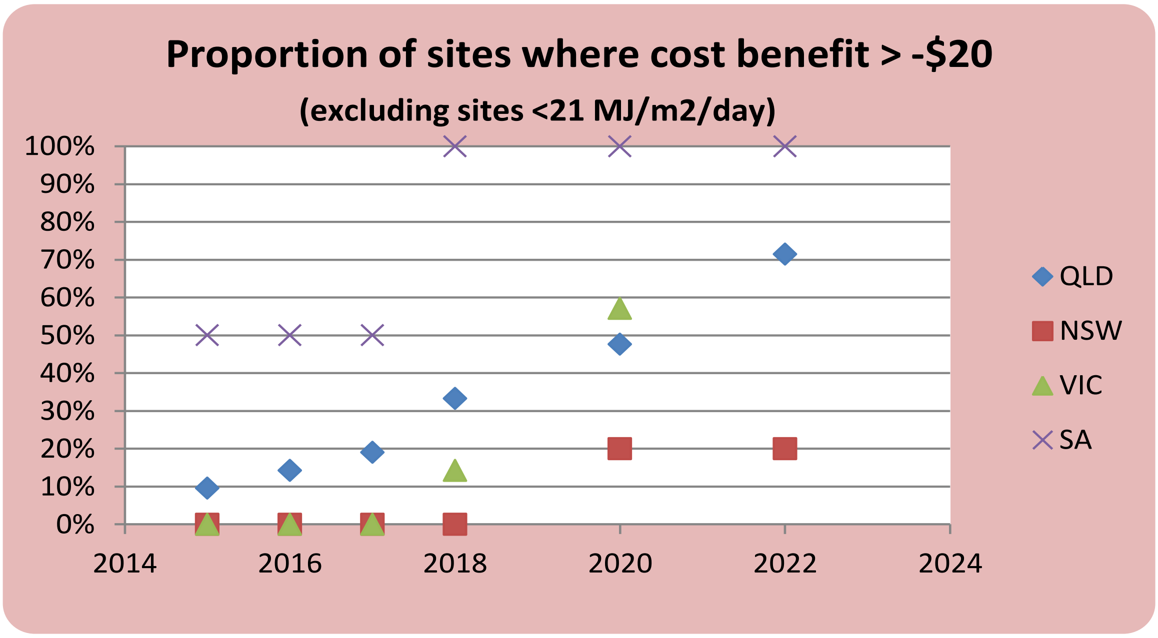
3.3.3 Discussion

Many factors affect the overall cost benefit of CSP at the locations examined, including the plant size, the DNI, and of course, the cost assumptions.

The year of installation was found to be a key determinant of cost effectiveness in the modelling. Installation year has a complex effect on the economics, as it affects not only the projection for the revenue from sales, but the cost of the plant. A cost reduction of 4% per year was included in the modelling to allow for the learning curve projected for CSP, which was the mid-range of estimates for likely cost reduction (see Section 2.4.1 for details). This results in a 39% reduction in costs by 2024.

In order to test the effect of the installation year, the cost optimisation model was rerun with all constraints set to the same year, and the year varied from 2015 to 2022. The results are shown in Figure 27. As can be seen, the installation year has a significant effect. By 2022, 80% of all sites have cost benefit greater than -$20/MWh.

Figure 27: Effect of installation year on cost benefit



The effect of plant size and DNI was then examined with the year set to a single value for all constraints. These effects are shown in Figure 28 and Figure 29. As can be seen, DNI had the most consistent effect.

Figure 28: Effect of plant size on cost benefit (installation year 2018)

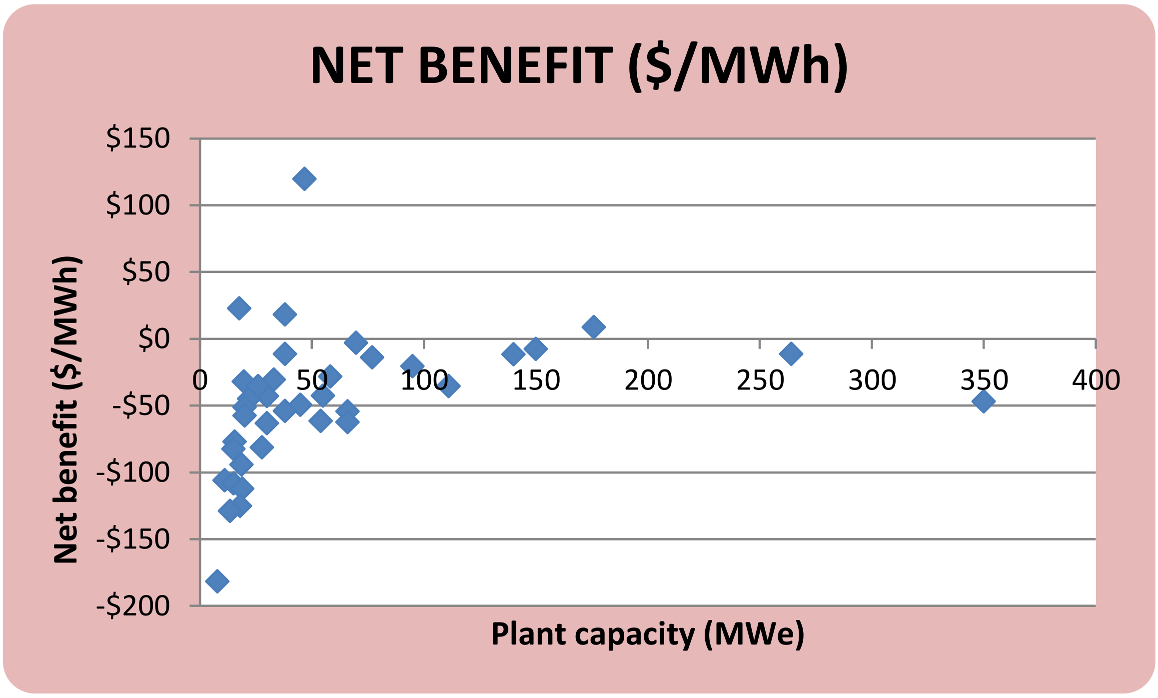
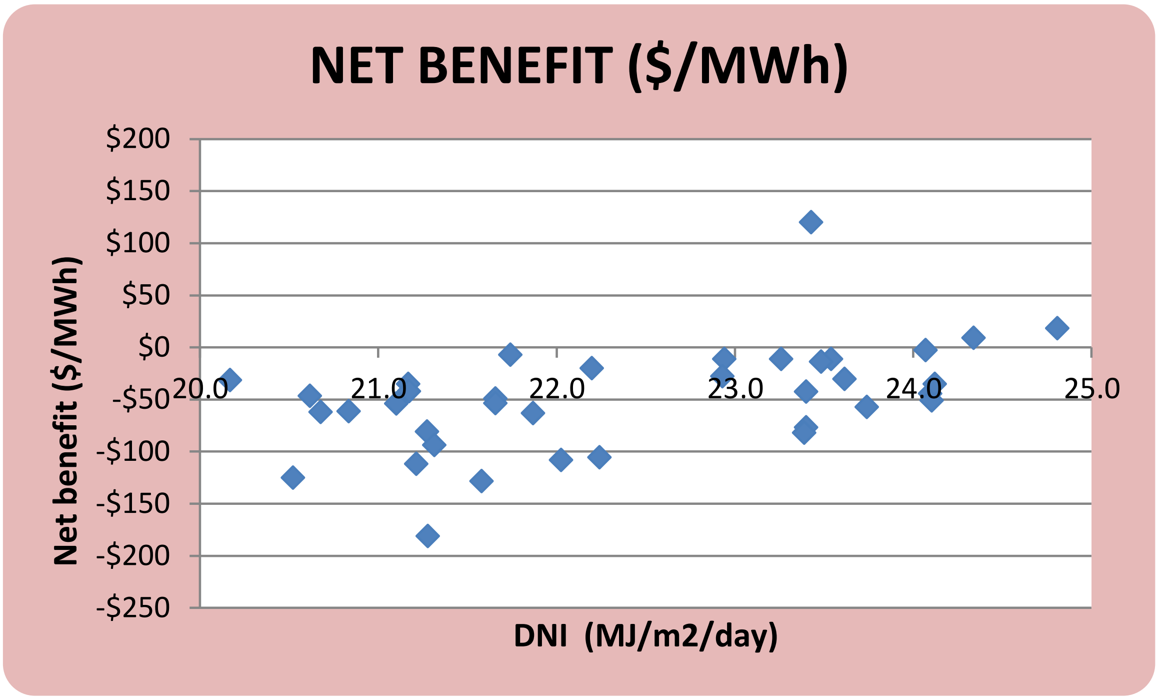


Figure 29: Effect of DNI on cost benefit (installation year 2018)



4 CASE STUDIES

Five case studies were undertaken, at locations in each NEM state, other than Tasmania. These are shown in Table 19, along with the assessed optimum plant size, the proposed augmentation year, the contribution of the network support payment per MWh, and the net benefit. Seven plant and economic summaries are shown in Table 19, as there was a very large spread of proposed network investment at Riverland (SA), and two locations were examined for generation to alleviate the Gunnedah supply constraint.

Table 19: Case study overview

	Network operator	Optimum plant MW/ TES	Proposed network augmentation year and cost	Network payment $/MWh	Net benefit $/MWh
The Riverland (line replacement)	ElectraNet	40MW, 5hrs	2022, $226m	$110	$144
The Riverland (line upgrade)	ElectraNet	130MW, 5hrs	2022, $10m	$1	$60
Wemen	Powercor	77MW, 5hrs	2021, $12m	$3	$23
Charleville	Ergon	20MW, 5hrs	2022, $70m	$6	$16
Millchester	Ergon	40MW, 15hrs	2017, $46m	**$16**	**-$29**
Gunnedah supply (CSP at Moree)	Transgrid	50 MW, 5hrs	2019, $24m	**$9**	**-$13**
Gunnedah supply (CSP at Gunnedah)	Transgrid	50 MW, 5hrs	2019, $30m	**$13**	**-$39**

Overall, the study found that CSP installed at case study locations would be able to delay or avoid entirely the planned network augmentation in all cases, and provide similar reliability to a traditional network solution in four of the five cases.

Strategies to achieve sufficient reliability varied according to the network requirements at each location. In four locations (two in Queensland, one in New South Wales and one in South Australia), the gas boiler normally installed as part of a CSP plant was modelled as oversized in order to provide emergency backup. Network requirements were to provide on–demand operation at these locations, and there were periods in each year where CSP would not provide sufficient certainty. It is expected that total gas use would be minimal, as the purpose is to provide emergency backup in the event that required network support falls outside of a period when the CSP is generating.

In the fifth location (Wemen in Victoria), CSP could not provide certainty of generation by the end of the forecast period, as there could be a capacity shortfall for up to 80% of the time. However, it is likely that CSP could reduce the likelihood of a capacity shortfall by

75% to 80%, which may be sufficient to defer the investment significantly, certainly beyond the study period.

The network support payment was not generally found to be a decisive factor in the economic outcome, other than in the Riverland case study where the network payment could provide $110/MWh if the investment from the higher cost augmentation was transferred to the CSP. In other cases, the value varied from $1/MWh to $16/MWh.

One unexpected observation from the case studies was the modelled effect of storage hours on the average revenue of the CSP plant; specifically the correlation of plant revenues with peak prices. In this work, storage hours and solar multiple were not varied independently, so the capacity factor increased with the storage hours. One effect of this was that the ratio of optimised revenue to average pool price was lower at five hours TES than with zero hours, and fell again as the storage increased to 15 hours. The study did not test this effect for one and three hours storage configurations, however modelling of those effects could be expected to indicate that the ratio would increase somewhat from zero hours storage, and then fall again at five hours storage. Longer storage hours has an averaging effect in this study's modelling of revenue.

There are alternative strategies for designing a plant to follow peak prices, for example, reducing the solar multiple relative to the storage or nameplate capacity of the power block. The project modelled an increase in the power block relative to the solar multiple, to see if this would be positive overall for revenue. While the revenue multiplier for optimised revenue relative to pool price increased significantly, this was more than outweighed by the increase in LCOE as the capacity factor fell. However, more sophisticated scenario modelling of plant configuration options and dispatch strategies could lead to improved cost-benefit outcomes in specific circumstances.

The specific constraint and draft results were discussed in a workshop with the relevant DNSP or TNSP, in order to define minimum requirements for plant operation, set parameters on plant size, and inform the cost benefit analysis.

In each case study location, weather records for three years (2009/10, 2010/11 and 2011/12) were used to obtain a generation profile for 0, 5, 10 and 15 hours of storage for each year. This was used to derive economic and performance data, specifically:

- The potential for revenue optimisation relative to average pool prices, to derive a specific multiplier for the location;
- The number of days per year on which generation hours were below the relevant thresholds, as defined in the workshops; and
- The performance of the CSP plant at peak times, by comparison of the modelled CSP generation for the relevant year to the hourly demand data for the same year.

Simple cost benefit analyses were undertaken for a potential CSP plant at the location, using data derived from modelling and information from the case study workshops. The LCOE was compared to the projected revenue, including an annual network support payment, to obtain an overall projected cost benefit per MWh generated. Details of the case study methodology are given in Section 2.5.

CASE STUDY: MILLCHESTER, QUEENSLAND

Emerging network constraint description

Millchester 132/66kV BSP is supplied by a single 132kV line from Ross, with partial backup via a 66kV line from Clare South and Stuart. Under the relevant Security of Supply criteria, the substation requires full n-1 security, that is, supply should be maintained in the event of one element in the network becoming unavailable. There is a proposal to build a second 132kV line to meet this Security of Supply criteria by 2017, at an estimated cost of $46 million.

Operational requirements to avoid network augmentation

An alternative to line augmentation is to provide local generation that could operate in the event of a line failure. In discussion with Ergon Energy, a minimum requirement was established that such a plant should be able to supply 20MW on demand, for eight hours per day, for a maximum of two consecutive days.

Plant operation was simulated using weather records for 2008/09, 2009/10 and 2010/11 to see whether there were days when a CSP plant would have been unable to dispatch for eight hours on demand. In those years, even a CSP plant with fifteen hours storage had between 60 and 119 days with less than eight dispatch hours at full power.

However, CSP plants usually include gas-fired boilers to pre-heat the storage and for cold starts, with the boiler sized to meet 25% of the plants electrical output. In order to effectively meet the network requirement, the plant could oversize the boiler sufficiently to meet the full 20MW output if needed. The additional cost was found to be relatively low, and this solution would provide equivalent certainty to the provision of a gas generator.

Economics

Two revenue models were considered: a pool price option , in which the plant is assumed to operate to take advantage of peak prices, and a power purchase agreement (PPA) at a fixed price. In the pool price option, three to five hours storage (or a lower solar multiplier) was generally found to be more effective as it allows the operator to follow peak prices, whereas higher storage levels give a lower LCOE, and thus, the best return with a fixed price PPA. Note that the study did not vary solar multiple and storage hours independently. In this case, the 15 hours storage case performed slightly better in both the pool price and the PPA option.

Details of the constraint and the optimum plant configurations are shown in Table 20 and Table 21, along with the LCOE and revenue streams in both the pool price and the PPA cases. The PPA calculations assume a base price of $105/MWh, including electricity and the LGC, with a real increase of 4.5% per year. The annual network payment is calculated by applying a factor of 0.8 to the total proposed investment, and then assuming the payment would be the WACC x the avoided investment + the average avoided depreciation.

Outcome

CSP could avoid the need for network augmentation in this location. Net incomes are negative in 2017, and a 20% to 30% cost reduction would be needed to break even. By 2020, economics are positive, with a 10% cost reduction or capital grant.

Table 20: Millchester 132/66kV BSP – constraint details

Proposed network investment	**$46m**	**Augmentation year**	**2017**
Support required	20MVA	Constraint type	n-1 security of supply
Annual network payment	$3.4m	DNI	23.3 MJ/m^2/yr

Table 21: Economics for optimum plant commissioned 2017 - Millchester

	Pool price calculations		PPA calculations (1)
	Carbon price	No carbon price	
Plant capacity	40MW$_e$		40MW$_e$
Thermal storage	15 hours		15 hours
Solar multiple	2.8		2.8
Gas boiler	60MW$_{th}$		60MW$_{th}$
Capacity factor	62%		62%
Total plant cost (2)	$367m		$367m
Specific investment (AU$m/MW)	$9.2m		$9.2m
Cost benefit calculation			
LCOE ($/MWh)	$174	$174	$174
Electricity sales ($/MWh)	$74	$50	$129 (2)
LGC ($/MWh)	$46	$72	
NSP contribution to LCOE ($/MWh)	$16	$16	$16
NET BENEFIT OR LOSS ($/MWh)	**-$38**	**-$42**	**-$29**
Capital grant to break even	25%	30%	20%

Notes
1) *This is the 10 year average of a base PPA of $105 with an annual real increment of 4.5%. Note that the PPA includes the LGC.*
2) *Includes $1.4m to increase the boiler size, and $20.3m connection costs.*

Table 22: Cost benefit ($/MWh) with varying levels of capital grant or cost reduction by year, assumes $105/MWh PPA (incl. LGC) - Millchester

Plant: 40MW$_e$, 15hrs storage	COST REDUCTION						
Year	**0%**	**5%**	**10%**	**15%**	**20%**	**25%**	**30%**
2015	**-$44**	**-$36**	**-$27**	**-$19**	**-$10**	**-$2**	**$7**
2017	**-$29**	**-$22**	**-$14**	**-$6**	**$2**	**$10**	**$17**
2019	**-$15**	**-$8**	**-$0**	**$7**	**$14**	**$21**	**$28**
2020	**-$7**	**-$1**	**$6**	**$13**	**$20**	**$27**	**$34**

Note: Calculations are based on the 10 year average revenue from a $105 PPA with an annual increment of 4.5%. The PPA includes the LGC.

CASE STUDY: CHARLEVILLE, QUEENSLAND

Emerging network constraint description

Charleville 66/22/11kV zone substation is supplied by a single 66kV line from Roma, with the supply continuing to Cunnamulla and Quilpie. If demand reduction is not sourced to keep load under 15MVA, it is expected that an n-1 Security of Supply criteria will apply soon after 2020. The expected network augmentation cost is $70 million. Ergon Energy may consider installing CSP generation as an alternative to network augmentation.

Operational requirements to avoid network augmentation

An alternative to line augmentation is to provide local generation that could operate in the event of a line failure. In discussion with Ergon Energy, a minimum requirement was established that such a plant should be able to supply 20MW on demand, for eight hours per day, for a maximum of two consecutive days.

Plant operation was simulated using weather records for 2008/09, 2009/10 and 2010/11 to see whether there were days when a CSP plant would have been unable to dispatch for eight hours on demand. In those years, even a CSP plant with fifteen hours storage had between 38 and 74 days with less than eight dispatch hours at full power.

However, CSP plants usually include gas-fired boilers to pre-heat the storage and for cold starts, with the boiler sized to meet 25% of the plants electrical output. In order to effectively meet the network requirement, the plant could oversize the boiler sufficiently to meet the full 20MW output if needed. The additional cost was found to be relatively low, and this solution would provide equivalent certainty to the provision of a gas generator.

Economics

The optimum economic plant configuration was 20MW with three hours storage, but this was increased to a minimum of five because of the nature of the constraint. Two revenue models are considered, a pool price option , in which the plant is assumed to dispatch to take advantage of peak prices, and a power purchase agreement (PPA) at a fixed price. In the pool price option, three to five hours storage (or a lower solar multiplier) is more effective as it allows the operator to follow peak prices, whereas higher storage levels give a lower LCOE, and thus, the best return with a fixed price PPA. Note that the study did not vary solar multiple and storage hours independently.

The details of the constraint and the optimum modelled plant configurations are shown in Table 23 and Table 24 for the pool price and the PPA cases, as well as the LCOE and revenue streams. The PPA calculations assume a base price of $105/MWh (including the LGC), with a real increase of 4.5% per year. A multiplier of 1.2 is used to adjust the projected revenue from average pool prices, with the multiplier calculated by modelling the effect of optimising dispatch for the specific plant configuration at this location using three years weather data. The annual network payment is calculated by applying the WACC to 80% of the total proposed investment, and adding the avoided depreciation.

Outcome

CSP could avoid the need for network augmentation at this location. Economics are positive in two out of three cases modelled, with a net benefit of $8 to $16/MWh. Table 25 shows the effect of capital cost reductions, beyond those modelled, by year. Costs are likely to be positive from 2021, and a 10% cost reduction would bring that forward to 2019.

Table 23: Charleville 66/22/11 ZS – constraint details

Proposed network investment	**$70m**	**Augmentation year**	**2022**
Support required	20MVA	Constraint type	n-1 security of supply
Annual network payment	$5.2m	DNI	25.1 MJ/m^2/yr

Table 24: Economics for optimum plant commissioned 2022, Charleville

	Pool price calculations (1)		**PPA calculations (2)**
	Carbon price	No carbon price	
Plant capacity	40MW$_e$		40MW$_e$
Thermal storage	5 hours		15 hours
Solar multiple	1.9		2.8
Gas boiler	60MW$_{th}$		60MW$_{th}$
Capacity factor	47%		69%
Total plant cost (3)	$225m		$290m
Specific investment (AU$m/MW)	$5.6m		$7.3m
Cost benefit calculation			
LCOE ($/MWh)	$140	$140	$125
Electricity sales ($/MWh)	$134	$73	$129
LGC ($/MWh)	$16	$60	
NSP contribution to LCOE ($/MWh)	$6	$6	$4
NET BENEFIT OR LOSS ($/MWh)	**$16**	**-$1**	**$8**
Capital grant to break even		1%	

Notes
1) *A multiplier of 1.2 is used to increase the average pool price projection.*
2) *This is the 10 year average of a base PPA of $105/MWH with an annual real increment of 4.5%. Note that the PPA includes the LGC.*
3) *Includes $1.4m to increase the boiler size, and $20.3m connection costs.*

Table 25: Cost benefit ($/MWh) with varying levels of capital grant or cost reduction by year – Charleville

Plant: 40MW$_e$, 15hrs storage	**COST REDUCTION**						
Year	**0%**	**5%**	**10%**	**15%**	**20%**	**25%**	**30%**
2015	**-$39**	**-$31**	**-$24**	**-$16**	**-$8**	**-$1**	**$7**
2017	**-$26**	**-$19**	**-$11**	**-$4**	**$3**	**$10**	**$17**
2019	**-$12**	**-$6**	**$1**	**$7**	**$14**	**$20**	**$27**
2021	**$1**	**$7**	**$13**	**$19**	**$25**	**$31**	**$36**

Note: Calculations are based on the 10 year average revenue from a $105 PPA with an annual increment of 4.5%. The PPA includes the LGC.

CASE STUDY: GUNNEDAH-NARRABRI-MOREE SUPPLY, NEW SOUTH WALES

Emerging network constraint description

A new line is proposed to link the Tamworth and Gunnedah TS to provide additional supply capacity to the Gunnedah-Narrabri-Moree area. The need arises because of projected load growth, including new spot loads from mining, and issues with the line between Tamworth and Gunnedah (Country Energy & Transgrid 2011). Up to 40MW of support may be required at peak times. The optimum location for support is Gunnedah, although lower value support could also be provided at Narrabri or Moree.

Operational requirements to avoid network augmentation

An alternative to line augmentation is to provide local generation that could operate at peak time to reduce the load on transmission lines supplying the area. Generators would be required to start up within 15 minutes of overload on the supply line, or alternatively generate pre-emptively at peak periods, as the network is not allowed to shed loads at these supply points. Pre-emptive generation is the preferred option.

Support is likely to be required at peak times during summer afternoons and winter evenings. The winter peak is usually 5.30 to 6.30pm, and could require generation between 4 and 8pm. We therefore defined the minimum requirement for CSP to avoid the need for augmentation as the ability to generate on demand for up to four hours.

Plant operation was simulated using weather records for 2008/09, 2009/10 and 2010/11 to see whether there were days when a CSP plant would have been unable to dispatch for four hours on demand. In those years, even a CSP plant with 15 hours storage had between 15 and 33 days with less than four dispatch hours at full power.

However, CSP plants usually include gas-fired boilers to pre-heat the storage and for cold starts, with the boiler sized to meet 25% of the plants electrical output. In order to effectively meet the network requirement, the plant could oversize the boiler sufficiently to meet the full 40MW output if needed. The additional cost was found to be relatively low, and this solution would provide equivalent certainty to the provision of a gas generator.

Economics

The optimum plant economic plant configuration was 50MW (the largest that could easily be connected), with five hours storage. Two revenue models are considered, a pool price option , in which the plant is assumed to dispatch to take advantage of peak prices, and a power purchase agreement (PPA) at a fixed price. In the pool price option, lower storage (or a lower solar multiplier) is more effective as it allows the operator to follow peak prices, whereas higher storage levels give a lower LCOE, and thus, the best return with a fixed price PPA. Note that the study did not vary solar multiple and storage hours independently.

The details of the constraint and the optimum modelled plant configurations are shown in Table 26 and Table 27 for the pool price and the PPA cases, as well as the LCOE and revenue streams. The PPA calculations assume a base price of $105/MWh (including the LGC), with a real increase of 4.5% per year. A multiplier of 1.2 is used to adjust the projected values for average pool price, calculated by analysing the modelled effect of optimising dispatch for the specific plant configuration at this location using three years weather data. The annual network payment is calculated by applying the WACC to 80% of the total proposed investment, and adding the avoided depreciation.

Table 26: Gunnedah supply – constraint details

Proposed network investment	$30m	Augmentation year	2019
Support required	40MVA	Constraint type	Growth
Annual network payment	$2.2m	DNI	22.2 MJ/m^2/yr

Table 27: Economics for optimum plant commissioned 2019 at Gunnedah

	Pool price calculations (1)		PPA calculations (2)
	Carbon price	No carbon price	
Plant capacity	50MW$_e$		50MW$_e$
Thermal storage	5 hours		15 hours
Solar multiple	1.9		2.8
Gas boiler CSP	129MW$_{th}$		129MW$_{th}$
Capacity factor	38%		56%
Total plant cost (3)	$324m		$426m
Specific investment (AU$m/MW)	$6.5m		$8.5m
Cost benefit calculation			
LCOE ($/MWh)	$194	$194	$177
Electricity sales ($/MWh)	$108	$62	$129
LGC ($/MWh)	$35	$69	
NSP contribution to LCOE ($/MWh)	$13	$13	$9
NET BENEFIT OR LOSS ($/MWh)	**-$39**	**-$50**	**-$39**
Capital grant to break even	25%	30%	25%

Notes
1) *A multiplier of 1.3 is used to increase the average pool price projection.*
2) *This is the 10 year average of a base PPA of $105/MWH with an annual real increment of 4.5%. Note that the PPA includes the LGC.*
3) *Includes $2.5m to increase the boiler size, and $29.3m connection costs.*

Outcome

CSP installed at Gunnedah could avoid the need for network augmentation, but the economics are not positive in 2019, with a cost gap of $14 to $25/MWh. A capital cost reduction or grant of 25% to 30% would be needed to achieve a positive cost benefit in 2019. Table 29 shows effects of different levels of cost reduction on the net benefit; at 2021, a 15% to 20% capital cost reduction would result in a positive net cost.

The level of network support per MWh is quite low ($13/MWh), and other areas in the constrained area have better solar resource, so a brief evaluation of the potential effects of relocating the plant to Moree was undertaken. The potential network payment was revised downwards by 20%, to reflect the indicative value Transgrid placed on support at a non-optimum location. The economics of a plant at Moree are shown in Table 28, and appear more favourable as the effect of the higher DNI outweighs the reduced network payment. However, the project scope did not extend to the exploration of whether a CSP plant in Moree could effectively eliminate the need for network augmentation at Gunnedah.

Table 28: Economics for optimum plant commissioned 2019 at Moree

	Pool price calculations (1)		PPA calculations (2)
	Carbon price	No carbon price	
Plant configuration	As in Table 24		As in Table 24
DNI	24.1		24.1
Capacity factor	46%		67%
Annual network payment	$1.5m		$1.5m
Cost benefit calculation			
LCOE ($/MWh)	$164	$164	$149
Electricity sales ($/MWh)	$108	$62	$129
LGC ($/MWh)	$35	$69	
NSP contribution to LCOE ($/MWh)	$9	$9	$6
NET BENEFIT OR LOSS ($/MWh)	**-$13**	**-$24**	**-$14**
Capital grant to break even	10%	20%	$12%

Notes 1) *A revenue multiplier of 1.3 is used to adjust the average pool price projection.*
2) *This is the 10 year average of a base PPA of $105/MWH with an annual real increment of 4.5%. Note that the PPA includes the LGC.*

Table 29: Cost benefit ($/MWh) with varying levels of capital grant or additional cost reduction by year – Gunnedah supply, plant located at Gunnedah

Plant: 50MW$_e$, 15hrs storage	**COST REDUCTION**						
Year	**0%**	**5%**	**10%**	**15%**	**20%**	**25%**	**30%**
2015	**-$71**	**-$61**	**-$52**	**-$42**	**-$33**	**-$23**	**-$14**
2017	**-$55**	**-$46**	**-$37**	**-$28**	**-$20**	**-$11**	**-$2**
2019	**-$39**	**-$31**	**-$23**	**-$14**	**-$6**	**$2**	**$10**
2021	**-$23**	**-$15**	**-$8**	**-$1**	**$7**	**$14**	**$21**

Note: Calculations are based on the 10 year average revenue from a $105 PPA with an annual increment of 4.5%. The PPA includes the LGC.

CASE STUDY: THE RIVERLAND (MONASH), SOUTH AUSTRALIA

Emerging network constraint description

The Riverland area currently relies on the western Victorian network for support at peak load times. This support may be constrained in the future if both South Australian and Victorian networks peak at the same time. It is likely that system augmentation will be required by 2022 to ensure that the network continues to meet its n-1 reliability requirement. This means that the network is not allowed to shed load, even momentarily, following any single contingency. Options range from incremental uprating of 132kV network at a cost of $10m, to construction of a new 275kV supply at a cost of $226m. The preferred option would be determined by the Regulatory Investment Test for Transmission (RIT-T).[11]

Operational requirements to avoid network augmentation

An alternative to network augmentation is to provide local generation that could operate at times when the Victorian network is unable to provide the level of support required. At peak load conditions, the Riverland transmission network currently relies on the Victorian network supplying up to 25MW, and the need is expected to rise to about 40MW over 10 years.

The year 2010/11 hourly demand profile data was used to determine the duration of the required support for current and forecast load. This was compared to modelled hours of operation for a CSP plant using 2010/11 weather data for the location.

Table 30 shows the hours of unmet demand for CSP with different levels of storage, assuming the plant is sized at the nameplate capacity required to supply the maximum support required. At the start of the period, there are no unmet hours for any plant configuration, rising to between 7 and 51 unmet hours by the end of the period. However, there are several alternative strategies to maintain supply. Firstly, a CSP plant can dispatch at part load in order to maintain supply, effectively extending the storage hours. Thus, a 130MW plant can extend five hours TES to 15 hours dispatch at 30MW, if the need arises. An alternate strategy is that CSP plants usually include gas-fired boilers to pre-heat the storage and for cold starts, with the boiler sized to meet 25% of the plant's electrical output. Oversizing the gas boiler allows the plant to continue dispatching at nameplate capacity for a period of hours, with the length of time only limited by the gas storage tank. The additional cost is relatively low compared to the CSP installation cost.

Table 30 Minimum ability of CSP to meet demand, Riverland (5 to 15hrs TES)

Thermal storage	5hr	10hr	15hr	5hr	10hr	15hr
	START OF PERIOD			END OF PERIOD		
Percentage of unmet hours	0%	0%	0%	16%	6%	2%
Number of hours unmet demand	0	0	0	51	19	7
Number of days with unmet demand	0	0	0	11	5	3

[11] http://www.aer.gov.au/node/8865

Two plants were considered, a 130MW plant and a 40MW plant with oversized boilers, as these were the smallest and largest sizes which could potentially avoid the need for augmentation. Both sizes of plant were considered with 5 hours and 15 hours of storage.

Economics

The optimum plant configuration for the $226m network investment case for the pool price and the power purchase agreement (PPA) cases is 40MW, with five hours storage. Details of the constraint are shown in Table 31. The optimum plant configuration is shown in Table 32, along with the LCOE and revenue streams. The lower network investment case is shown in Table 33. In this case, the optimum plant is the largest able to be connected (130MW), and the storage configuration depends on whether the plant will be operated to take advantage of peak prices, described here as pool price option , or whether the revenue is assumed to be via a PPA at a fixed cost. In the first case, three to five hours storage is more effective as it allows the operator to follow peak prices, whereas higher storage levels give the lower LCOE, and thus the best return with a PPA.

The PPA calculations assume a base price of $105/MWh, including the LGC, with a real increase of 4.5% per year. A multiplier of 1.6 is used to adjust the projected values for average pool price, as CSP generation tends to follow peak prices. The multiplier is calculated by analysing the modelled effect of optimising dispatch for the specific plant configuration at this location using three years weather data. The annual network payment is calculated by applying a factor of 0.8 to the total proposed investment, and then assuming the payment would be the WACC multiplied by the avoided investment, plus the average avoided depreciation.

Outcome

CSP has the potential to avoid the need for network augmentation in the Riverland area, providing a similar level of reliability to a network solution by oversizing the plant, or by oversizing the gas boiler. If the full network augmentation ($226m) is planned, the optimum modelled plant configuration is 40MW, with five hours storage and an oversized gas boiler. If the smaller network augmentation ($10m) is planned, a larger plant is more economic, with five hours storage in the pool price option, and 15 hours storage in the PPA option.

Economics are extremely favourable if network investment of $226m is avoided, with an overall net benefit of between $110 and $144/MWh. The plant modelled is to be commissioned in 2022, as that is when the network is expected to require support. However, the plant would be economic in 2014, provided the network support payment was included.

If the potential network investment eventuates to be $10m rather than $226m, the cost benefit is still positive, but reduced. The optimum plant in this case is 130MW, with five hour TES in the pool price revenue case, and 15 hours TES in the PPA case. The net benefit is between $12 and $60/MWh. In this case, the plant would be economic from 2017 to 2020.

Table 31: Riverland area – constraint details

Proposed network investment	$216m OR $10m	Augmentation year	2022
Maximum support required	40MVA	Constraint type	n-1 reliability
Annual network payment	$16.6m OR $0.7m	DNI	23.3MJ/m2/yr

Table 32: Economics for optimum plant at Riverland ($216m investment)

Plant characteristics			
Plant capacity	40MW$_e$	Gas boiler	120MW$_{th}$
Thermal storage	5 hours	Capacity factor	43%
Solar multiple	1.9	Total plant cost (3,5)	$216m
		Specific investment	$5.4m/MW
Cost benefit calculation	**Pool price calculations (1)**		**PPA calculations (2)**
	Carbon price	No carbon price	
LCOE ($/MWh)	$146	$146	$146
Electricity sales ($/MWh)	$93	$93	$129
LGC ($/MWh)	$87	$60	
NSP contribution to LCOE ($/MWh)	$110	$110	
NET BENEFIT OR LOSS ($/MWh)	**$144**	**$117**	$110

Table 33: Economics for optimum plant at Riverland ($10m investment)

	Pool price calculations (1)		**PPA calculations (2)**
	Carbon price	No carbon price	
Plant capacity	130MW$_e$		130MW$_e$
Thermal storage	5 hours		15 hours
Solar multiple	1.9		2.8
Gas boiler	120MW$_{th}$		120MW$_{th}$
Capacity factor	43%		63%
Total plant cost (3,4)	$589m		$833m
Specific investment (AU$m/MW)	$4.5m		$6.4m
Cost benefit calculation			
LCOE ($/MWh)	$122	$122	$118
Electricity sales ($/MWh)	$164	$93	$129
LGC ($/MWh)	$16	$60	
NSP contribution to LCOE ($/MWh)	$1	$1	$1
NET BENEFIT OR LOSS ($/MWh)	**$60**	**$33**	**$12**

Notes
1) *A multiplier of 1.6 is used to increase the average pool price projection.*
2) *A base PPA of $105 is used (including LGC), with an annual real increment of 4.5%.*
3) *Includes $10m connection costs.*
4) *Includes $0.4m to oversize the gas boiler (130 MW CSP.)*
5) *Includes $2.8m to oversize the gas boiler (40 MW CSP).*

CASE STUDY: WEMEN, VICTORIA

Emerging network constraint description

The Wemen TS was commissioned in 2012 with a single transformer. In the event of a transformer failure, some customers may lose supply. Part of the load can be transferred to the Redcliff TS, with a limitation on the supply to Boundary Bend, Wemen, and Robinvale of 51MVA. Powercor estimated the value of customer reliability would equal the cost of a new transformer ($12m) in 2021 (Jemena et al. 2012), although this may be brought forward as load growth has exceeded expectations in this area (Garvey 2013).

Operational requirements to avoid network augmentation

If a generator was connected at Wemen, this could avoid the need to install an additional transformer, if it could deliver the support required. The maximum support in 2021 is estimated at 35MW, potentially rising to 65MW over a 10 year period. The mean replacement time for a transformer is two months, which means avoiding the need for augmentation could require sustained periods of generation.

The available demand data for 2010/11 for the line supplying the three substations from Redcliff TS prior to the Wemen TS being commissioned was adjusted to include the projected growth, in order to obtain an hourly profile of when support would be required over and above what could be transferred to Redcliff in the event of a transformer failure. Winter months were excluded, as Powercor’s modelling indicates that the transfer to Redcliff would not be constrained in the winter period (Garvey 2013). If the projected average annual growth rate from 2014 to 2021 (3.1% per year) is held constant over the 10 years from 2021 to 2031, support would be required for just over 4,300 hours per year by 2031, or nearly 50% of the time.

The projected hours when support is required were compared to modelled hours when a CSP plant would have been generating in 2010/11 to determine whether a CSP plat with various configurations could meet demand in the event of a transformer failure.

At the start of the period, CSP with 15 hours storage could reduce the likelihood of unsupplied energy by 92%. At the end of the period, the likelihood of unsupplied energy would be reduced by 72%. The number and proportion of unmet hours are shown in Table 34, for a CSP plant with five hours and 15 hours storage.

At the start of the period, there are approximately 182 hours where support would not have been available, rising to 1232 hours at the end of the period.

Table 34: Potential unmet hours for CSP in the event of transformer failure

	START	END
5 HOURS STORAGE		
Required hours which are unmet	31%	53%
Number of hours unmet demand	685	2309
15 HOURS STORAGE		
Required hours which are unmet	8%	28%
Number of hours unmet demand	182	1232

It is most cost effective to install the largest CSP plant, which is likely to be 77MW (the nameplate capacity of the TS). There is some potential for the operator to increase the amount of hours where support is delivered by running at part load, but this would not be sufficient to enable CSP to deliver, whenever needed, in the event of a failure.

However, the risk of transformer failure is relatively low at 1% per year (Jemena et al. 2012), so the reduction of risk by 72% at the end of the period may be sufficient to defer the augmentation.

Economics

The optimum plant configuration to increase network reliability is the maximum storage considered, 15 hours. However, as any network support payment will make a relatively small contribution to the plant economics, the low storage case of five hours was also examined. The optimum plant configuration depends on whether the plant will be operated to take advantage of peak prices, described here as pool price option , or whether the revenue is assumed to be via a power purchase agreement (PPA) at a fixed cost. In the first case, three to five hours storage is more effective as it allows the operator to follow peak prices, whereas higher storage levels give the lower LCOE, and thus the best return with a PPA. The optimum economic plant is the largest that could be connected.

Details of the constraint are shown in Table 35. Details of the optimum plant are shown in Table 36, along with the LCOE and revenue streams. The PPA calculations assume a base price of $105/MWh (including the LGC), with a real increase of 4.5% per year. A multiplier of 1.4 is used to adjust the projected values for average pool price, with the multiplier calculated by analysing the effect that the optimising dispatch would have had on revenue for the specific plant configuration over the three years of 2008/09, 2009/10 and 2010/11.The annual network payment is calculated by applying a factor of 0.8 to the total proposed investment, and then assuming the payment would be the WACC x the avoided investment + the average avoided depreciation.

Outcome

CSP has the potential to defer the need for network augmentation at the Wemen TS by reducing the likelihood of unserved hours by 72%, if this degree of reliability is determined as sufficient.

Economics are favourably positive by 2019 in the lower storage case, assuming pool price sales, and are positive by 2021 in all cases. A capital grant, or cost reduction of 30%, is expected to make the plant cost positive by 2015, with the requirement for grant or cost reduction falling to 15% by 2017, as shown in Table 37.

Table 35: Wemen – constraint details

Proposed network investment	**$12 million**	**Augmentation year**	**2021**
Maximum support required	65MVA	Constraint type	n-1 reliability
Annual network payment	$0.9m	DNI	23.4 MJ/m2/yr

Table 36: Economics for optimum plant at Wemen ($12m investment)

	Pool price calculations (1)		**PPA calculations (2)**
	Carbon price	No carbon price	
Plant capacity	$77MW_e$		$77MW_e$
Thermal storage	5 hours		15 hours
Solar multiple	1.9		
Gas boiler CSP			
Capacity factor	43%		63%
Total plant cost (3)	$384m		$533m
Specific investment (AU$m/MW)	$5.0m		$6.9m
Cost benefit calculation			
LCOE ($/MWh)	$135	$135	$129
Electricity sales ($/MWh)	$133	$77	$129
LGC ($/MWh)	$22	$65	
NSP contribution to LCOE ($/MWh)	$3	$3	$2
NET BENEFIT OR LOSS	**$23**	**$9**	**$2**

Notes
1) *A multiplier of 1.4 is used to increase the average pool price projection.*
2) *A base PPA of $105 is used (includes LGC), with an annual real increment of 4.5%.*
3) *Includes $3.4m connection costs.*

Table 37: Cost benefit ($/MWh) with varying levels of capital grant or cost reduction by year – Wemen

Plant: $77MW_e$, 5hrs storage	**COST REDUCTION**						
Year	**0%**	**5%**	**10%**	**15%**	**20%**	**25%**	**30%**
2015	**-$44**	**-$36**	**-$28**	**-$20**	**-$11**	**-$3**	**$5**
2017	**-$22**	**-$15**	**-$7**	**$0**	**$8**	**$15**	**$22**
2019	**$0**	**$7**	**$14**	**$21**	**$27**	**$34**	**$41**
2021	**$23**	**$29**	**$35**	**$41**	**$47**	**$53**	**$59**

Note: Assumes pool price sales a multiplier of 1.4, and includes a carbon price.

5 CONCLUSIONS AND RECOMMENDATIONS

This study confirms that CSP is a technically and commercially viable alternative to traditional network augmentation solutions in addressing electricity grid constraints. Its findings support the hypothesis that CSP can play a significant role in optimising costs in electricity networks with high levels of renewable energy generation capacity.

The study identified $0.8 billion of potentially avoidable network investment, and 533MW of cost effective CSP which could be installed at grid constrained locations in the next 10 years. Based on the current emissions intensity of electricity generation in each state, this would reduce greenhouse emissions by an estimated 1.9 million tonnes per year.

Network support payments can play a role in increasing the cost effectiveness of CSP, and CSP installation can avoid or defer the requirement for network augmentation. The potential for cost effective installations will change as network forecasts are modified, as will the economics of any network augmentation proposal.

A key finding is that, in order for CSP and other distributed energy solutions to compete effectively with traditional network solutions, the availability and accessibility of network information requires improvement. Network data should be harmonised, and rules established to enable project proponents easier access to timely data, in formats that support scenario modelling. The AEMC noted the value of more transparent network planning processes, including data access, in their 2012 review (Australian Energy Market Commission 2012).

Ideally, NEM-wide constraint mapping should become a standardised process, and be available to all interested parties. This would require standardised data supply, perhaps to a central organisation such as AEMO. The authors consider that the output of the DANCE model could become a useful tool for distributed energy providers, network planners and policy makers, and could provide network service providers with a tool, not only for network planning, but to assist in the process of going to market for non-network solutions. This would require an easy system for updating, such as an automated import of the required data from each network service providers' database. This may entail a requirement, like the New South Wales Demand Management code of practice,[12] for network service providers to publish investment and constraint information in a particular format, or to submit such data annually to a database held by an external body.

While Regulatory Investment tests have provided consistency and rigour in economic analysis of network investments, adjustments may be required in order for the benefits of CSP, and other forms of distributed generation, to be considered adequately and the benefits to be appropriately shared between network service providers, project proponents and consumers.

The findings of this report support the conclusions of recent studies that electricity networks may achieve stable operation and appropriate reliability performance with high proportions of renewable energy generation (Denholm et al. 2013; AEMO 2013; Ellison, Iain MacGill & Mark Diesendorf 2013), and that CSP can play an important and economically efficient role in Australia's future electricity system.

[12] http://www.efa.com.au/Library/DMCode3rdEd.pdf

6 REFERENCES

AEMO 2012, *National electricity forecasting report 2012*.

AEMO 2013, *100 per cent renewables study – Draft modelling outcomes [Draft version for stakeholder briefing]* Draft.

Australian Energy Market Commission 2012, *Power of choice review - giving consumers options in the way they use electricity*.

Australian Energy Regulator 2009, *Final decision - Electricity transmission and distribution network service providers Review of the weighted average cost of capital (WACC) parameters*.

Bureau of Meteorology 2012, *Australian Monthly Average Hourly Global and Direct Normal Solar Exposure Gridded Data*, Melbourne.

Bureau of Meteorology 2013, “Australian Hourly Solar Irradiance Gridded Data”.

Burgaleta, JI, Arias, S & Ramirez, D 2011, “Gemasolar, the first tower thermosolar commercial plant with molten salt storage,” in *SolarPACES Conference*, Granada, Spain.

Commonwealth of Australia 2012, *National Greenhouse Accounts Factors*.

Country Energy & Transgrid 2011, *Development of Supply to the Gunnedah / Narrabri / Moree Area: Project Specification Consultation Report*.

Denholm, P, Wan, Y-H, Hummon, M & Mehos, M 2013, *An Analysis of Concentrating Solar Power with Thermal Energy Storage in a California 33% Renewable Scenario*, NREL, Colorado, USA.

Dunstan, C, Boronyak, L, Langham, E, Ison, N, Usher, J, Cooper, C & White, S 2011, *Think Small: The Australian Decentralised Energy Roadmap. CSIRO Intelligent Grid Research Program*, Institute for Sustainable Futures, University of Technology, Sydney.

ElectraNet 2012, *South Australian Annual Transmission Planning Report 2012*.

Ellison, B, MacGill, Iain & Diesendorf, Mark 2013, “Least cost 100% renewable electricity scenarios in the Australian National Electricity Market,” *Energy Policy*, vol. 59, no. August, pp. 270–282.

Elliston, B, Kay, M, MacGill, I. & Diesendorf, M. 2011, “Analysing power system impacts using solar radiation data for Australia,” in *1st International Conference Energy and Meteorology*, Gold Coast, Australia.

Ergon Energy Corporation Limited 2012a, *10 Year Subtransmission Network Augmentation Plan Far North Region*.

Ergon Energy Corporation Limited 2012b, *10 Year Subtransmission Network Augmentation Plan Mackay Region*.

Ergon Energy Corporation Limited 2012c, *10 Year Subtransmission Network Augmentation Plan Northern Region*.

Ergon Energy Corporation Limited 2012d, *10 Year Subtransmission Network Augmentation Plan Wide Bay Region*.

Ergon Energy Corporation Limited 2012e, *10 Year Subtransmission Network Augmentation Plan South West Region*.

Ergon Energy Corporation Limited 2012f, *10 Year Subtransmission Network Augmentation Plan South West Region Capricornia Region*.

Ergon Energy Corporation Limited 2013, *Ergon Post Summer 2012 - 50% POE Demand Forecast*.

ETSA 2012, *Electricity System Development Plan*.

Garvey, J 2013, Personal communication, 19th July 2013.

IRENA 2012, *Renewable Energy Technologies: Cost analysis Series Volume 1 Issue 2/5 Concentrating Solar Power*, Abu Dhabi, UAE.

Jemena, Citipower, Powercor, SP AusNet & United Energy 2012, *Transmission connection planning report*.

Langham, E, Dunstan, C, Cooper, C, Moore, D, Moore, S & Ison, N 2011, *Decentralised Energy Costs and Opportunities for Victoria, prepared for Sustainability Victoria*, Institute for Sustainable Futures, University of Technology, Sydney .

Langham, E, Dunstan, C & Mohr, S 2011, *Mapping Network Opportunities for Decentralised Energy: The Dynamic Avoidable Network Cost Evaluation (DANCE) Model - Working paper 4.4, CSIRO Intelligent Grid Research Program*, Institute for Sustainable Futures, University of Technology, Sydney.

Lovegrove, K, Watt, M, Passey, R, Pollock, G, Wyder, J & Dowse, J 2012, *Realising the Potential of Concentrating Solar Power in Australia (Full Report)*, Australian Solar Institute, Australia.

Madaeni, SH, Sioshansi, R & Denholm, P 2011, *Capacity Value of Concentrating Solar Power Plants*, National Renewable Energy Lab (NREL), Colorado, USA.

Müller-Steinhagen, H & Trieb, F 2004, “Concentrating solar power: A review of the technology,” *Ingenia*, no. 18, pp. 43–50.

National Renewable Energy Laboratory 2013, “System Advisor Model” National Renewable Energy Laboratory.

Nelson, A 2013, Personal communication, 3rd May 2013.

Peterseim, JH, Hellwig, U, Guthikonda, M & Widera, P 2012, “Quick start-up auxiliary boiler/heater – optimizing solar thermal plant performance,” in *SolarPACES Conference*, PSE AG, Marrakech.

Powercor 2012, “Distribution system planning report”.

Reserve Bank of Australia 2013, *Statement on Monetary Policy - May 2013*.

SKM MMA 2012a, *SKM MMA RET Modelling for CCA Excel Output Sheets - Final*.

SKM MMA 2012b, *Modelling the Renewable Energy Target Report for the Climate Change Authority*.

SolarPACES 2013, “International project database, accessed 29th July 2013,” accessed from <http://www.solarpaces.org/News/Projects/projects.htm>.

SP AusNet 2011, *Distribution System Planning Report 2012 - 2016*.

SP AusNet 2012, *Distribution System Planning Report 2013 - 2017*.

Stine, WB & Geyer, M 2001, *Power from the Sun*, USA.

Transgrid 2012, *Annual Planning Report 2012*.

APPENDIX 1: THE DANCE MODEL

The Institute for Sustainable Futures developed the DANCE model progressively during the CSIRO Intelligent Grid Research Program (iGrid) (Langham, Dunstan & Mohr 2011). It was further enhanced during its application to the assessment of decentralised energy opportunities in Greater Melbourne for Sustainability Victoria (Langham et al. 2011). Since these initial applications, the calculation logic has evolved and the GIS display features have been adapted for application to larger scale distributed CSP generators for the purposes of this research.

This Appendix covers the calculations that occur within the latest iteration of the DANCE Model. It is split into two sections:

1. Key calculations; and
2. Method for handling incomplete data.

6.1 KEY CALCULATIONS

All of the following calculations are performed for three hierarchical levels of network assets:

1. Distribution zone substations (ZS),
2. Sub transmission lines or loops (Stli), and
3. Transmission substations (TS) or bulk supply points (BSP).

The calculations are conducted for each asset group separately.

6.1.1 Net present value

DANCE calculates the NPV of avoiding the construction of a network asset, such as through the construction of a strategically located CSP generator. ‘Avoidance’ is defined, for the purposes of this project, as the deferral of the construction of a network asset for 10 years or more. This figure is intended to be useful to CSP or other decentralised energy project developers that are able to provide sufficient, contractually-secured generation or demand reduction to avoid the planned network augmentation for a period of 10 years, by offsetting the projected annual demand growth and / or providing associated voltage or reliability support. It is assumed that 10 years is the maximum period that the network operator would be willing to contract for non-network alternatives to network augmentation.

The NPV in year Y is determined by the following equation:

$$NPV(Y) = \frac{(WACC + DEPR)INVA}{(1 + DISR)^{Y-CY}}$$

Where:

WACC is the Weighted Average Cost of Capital,

DEPR is the Depreciation Rate,

INVA is the Investment Amount (in $ millions) that is planned by the network at that location,

DISR is the Discount Rate and

CY is the Current Year (as specified in the global inputs to the model).

The NPV for the asset is the sum of the yearly NPV amounts, from the current year to nine years after the proposed investment year.

6.1.2 Available capacity

These calculations determine the available supply capacity for each network asset over time. It is used to show which assets are approaching constraints that will need to be addressed in coming years through network or non-network options.

To do this, we need to know the firm capacity of the asset in each season (commonly, network assets have lower capacities in summer when operating temperatures are higher) and the forecast demand in each season. This is used to determine the available capacity, and the year that demand exceeds capacity in each season, which is the basis for determining the critical peak season (whether an asset is winter or summer constrained, or both).

The available capacity (ACAP) in a given season S and year Y, $ACAP_{(S,Y)}$, is determined by:

$$ACAP_{(S,Y)} = ITP_{(S)} - MDEM_{(S,Y)}$$

Where:

$ITP_{(S)}$ is the Investment Trigger Point; that is, the level of demand (MVA) that triggers investment in the asset to occur. The $ITP_{(S)}$ is described in full in Section 6.2.2, and

$MDEM_{(S,Y)}$ is the forecast Maximum Demand in the given season and year.

6.1.2.1 Year demand exceeds capacity

Calculating the year that demand exceeds capacity (DECY) is important from the perspective of determining if there is sufficient time to build a non-network option to address the approaching constraint. The year demand exceeds capacity in a given season S, $DECY_{(S)}$, is the first year forecast demand exceeds the ITP. If forecast demand does not exceed the ITP by two years after the final year of study period, then $DECY_{(S)}$ is defined as ‘not a number’ (NAN). That is, the asset in question is unlikely to be constrained in the relevant time period and hence there is no need for investment.

6.1.2.2 Constraint season

The level of peak demand and the shape of the daily load profile are typically very different in summer and winter. The different load profiles have implications for the type of CSP plant that would be required, and whether CSP could effectively meet the constraint. As a result, it is important to determine which season and time of day the network asset is constrained.

The constraint season (CS) can be one of the following options:

NONE, if $DECY_{(S)}$ is NAN for all seasons. In this case, the season used for analysis is the season with the largest demand in the final year.

SUMMER, if $DECY_{(SUMMER)}$ has a value and $DECY_{(WINTER)}$ is NAN, or $DECY_{(WINTER)} – DECY_{(SUMMER)} > 2$

WINTER, if $DECY_{(WINTER)}$ is not NAN and $DECY_{(SUMMER)}$ is NAN, or $DECY_{(SUMMER)} – DECY_{(WINTER)} >2$

BOTH, if $DECY_{(SUMMER)} = DECY_{(WINTER)}$, the season used for analysis is the season with the smallest available capacity in the demand exceeds capacity year.

BOTH $_{(SUMMER)}$, if $DECY_{(S)}$ is not NAN for all seasons, and $0 < (DECY_{(WINTER)} – DECY_{(SUMMER)}) \leq 2$

BOTH $_{(WINTER)}$, if $DECY_{(S)}$ is not NAN for all seasons, and $0 < (DECY_{(SUMMER)} – DECY_{(WINTER)}) \leq 2$.

The ‘available capacity’ for an asset used in all subsequent calculations is simply the available capacity *in the constraint season*.

6.1.3 Annual deferral value

If a non-network investment, e.g. a CSP plant, can effectively defer investment in upgrading a network asset, then there is a financial benefit to the network associated with that deferral. The ADV is the marginal value per kVA that would accrue to the network each year if construction of the asset were avoided. This is underpinned by the logic that if the demand on the network can be retained at the level in the year prior to commissioning (which assumes that the asset was sufficiently unconstrained to warrant investment action), then the augmentation can be avoided. The ADV in year Y ($ADV_{(Y)}$) in \$/kVA/yr is determined from the annual peak demand forecast and the investment data using the following formula:

$$ADV(Y) = \frac{INVA\ x\ (WACC + DEPR)\ x\ 1000/AVGR}{(1 + DISR)^{INVY-Y}}$$

Where:

AVGR is the Average Growth Rate in demand in year Y,

INVY is the Commissioning Year,

WACC is the Weighted Average Cost of Capital,

DEPR is the Depreciation Rate, and

INVA is the Investment Amount that is occurring for the asset.

In the real world, there are instances where the asset is already constrained for several years prior to commissioning the network augmentation, and the network operator has advised what support is required in year 1, year 2, etc. In this case, the data is manipulated so that the model will output the specified support value, by making the demand in the year prior to commissioning equal to the demand in the commissioning year, less the required network support.

Note that the ADV in year Y is set to zero if either the average growth rate in demand is not positive, or the year is after the investment year, as it is assumed that by then the investment has occurred.

6.1.4 Maximum potential

In the case of a large embedded generator such as a CSP plant, it is important to consider the maximum generator size that could be connected at that point on the network. This is denoted as the maximum potential (MAXP) for an asset. MAXP is defined as:

$$MAXP = MULT \times PCAP$$

Where:

MULT is the Multiplier defined by the user for the different energy providers, and

PCAP is the Nameplate Capacity.

6.1.4.1 Maximum exceedance

In order to invest in a non-network solution to alleviate a network constraint, it is necessary to determine the maximum amount by which demand exceeds the ITP, which is defined as maximum exceedance ($MAXE_{(SY)}$). $MAXE_{(SY)}$ is the amount by which maximum demand $MDEM_{(SY)}$ exceeds the ITP.

6.1.4.2 Hours exceeding investment trigger point

In order to design a CSP plant, it is necessary to have information on the hours that exceed the ITP. Each hourly demand in the specific year that exceeds the ITP has a (nominally) associated month and day. By keeping track of the times in the year that the demand exceeds the ITP, additional calculations, such as maximum exceedance in a given month or the maximum number of hours exceeded in any given day, can be readily determined.

6.1.4.3 System calculations

In the GIS deferral value outputs, the information presented is for the total upstream set or ‘system’ of assets that are relevant at a given location. That is, each ZS is associated (linked by the user) with a Stli, or loop, and/or a transmission line or terminal station. The ADV in the GIS output displays the NPV and ADV for the system of assets that occur at the location of the ZS. The calculation for the NPV or ADV for a particular location is determined to be the sum of the individual assets in that system (commonly ZS, Stli and TS).

6.2 METHODS FOR HANDLING INCOMPLETE DATA

The model has been designed to be both flexible and robust at handling sparse data. This feature of DANCE is essential as often full information on a particular asset is not available. As a result, the DANCE model performs three tasks before any calculations are made. These tasks are:

1. Check the data to see what has and has not been entered;
2. Estimate missing data wherever possible; and
3. Determine which of the calculations described in Section 6.1 can actually be carried out, based on the input data.

6.2.1.1 Checks to determine what data is available

The model checks what data is available to determine which constraints can be mapped. Frequently, data sets are incomplete, so the model attempts to estimate those inputs which are required for the calculations. This component of the model determines which calculations (if any) can occur for a particular asset.

6.2.1.2 Minimum data to map investment

Valid investment data has been supplied if proposed investment year, an investment amount, and asset co-ordinates have been entered. If any of these three are not entered, the investment will not appear in the mapping

6.2.1.3 Check capacity data supplied

Valid capacity data has been supplied if at least one of the capacity fields (e.g. secure, nameplate or n-1) has been provided; otherwise capacity data is defined as not having been provided.

6.2.1.4 Check average growth data supplied

Valid average growth data has been supplied if at least one of the average growth fields has been supplied; otherwise average growth data is defined as not having been provided.

6.2.1.5 Check demand data supplied

Valid demand data has been supplied if two or more peak load demand values have been entered, or if only one peak load demand value has been supplied and average growth data has been supplied. Otherwise, demand data is defined as not having been provided.

6.2.1.6 Check hourly demand supplied

Valid hourly load curve data has been supplied, if either all hourly load data for one year (that is, 8760 hours) is supplied, or all data needed for the synthetic hourly process has been filled. Otherwise, hourly load curve data is defined as not having been provided.

6.2.2 Estimating missing data

6.2.2.1 Display name of an asset

The display name of the asset is:

- The display name in the input sheet; or if not supplied,
- The short name in the input sheet.

Any asset that does not have a short name is ignored by the model.

6.2.2.2 Average growth of an asset

If neither demand data nor average growth data have been supplied, this section is ignored. Otherwise, the average growth is determined in one of two ways. If demand data has been entered for the start and finish year of the average growth period, then the average growth rate is the gradient determined from these two values. If complete demand data is not available, then either partial average growth data exists, or partial demand data exists.

6.2.2.3 Partial average growth data

If average growth input data has been partially provided, then the average growth rates not supplied are determined by:

- The first average growth supplied, going backwards in time from the missing growth rate time period; or if no previous growth rates have been supplied,
- The first average growth rate supplied, going forwards in time from the missing growth rate time period.

6.2.2.4 Partial demand data

If demand data has been supplied but average growth not supplied, then all the average growth rates are assigned the same growth rate. This growth rate is calculated as the average growth between the first year for which demand data has been provided, and either the demand in the investment year – if investment check is true and the investment year is later than the first valid year – or the last year for which demand data has been provided.

6.2.2.5 Demand for an asset

If demand has been supplied for at least two years, either forecast or estimated average growth data can be determined. Missing demand data is determined by applying the associated growth rates to the first valid year (first year that demand data exists) to determine the demand in the missing year. Mathematically, this is:

$$\text{Demand in missing year} = \text{Demand in first valid year} + \sum_{\text{i=first valid year}}^{\text{missing year}} \text{Growth rate in year i}$$

For example, if the missing year is 2015, then the first valid year is 2012. In 2012, demand is 100MVA/yr, the average growth rate between 2010 and 2013 is 10MVA/yr, and the growth rate from 2013 onwards is 15MVA/yr, then the estimated demand in the missing year, 2015, is:

140MVA/yr = 100MVA/yr (the value in 2012) + 10MVA/yr (the growth rate in 2013) + 15MVA/yr (the growth rate in 2014) + 15MVA/yr (the growth rate in 2015).

6.2.2.6 Capacity for an asset

This is used to determine available capacity and maximum connection. If any capacity data (e.g. nameplate, n-1, secure) has been supplied, this is used to calculate available capacity and maximum connection as follows:

Maximum connection

- If the secure capacity is available, this is used as to determine the maximum connection (after adjusting with the multiplier for that network operator);
- If secure capacity is not available, but the nameplate capacity is available, this is used as above; and
- If only n-1 capacity is available, this is used as above.

Available capacity

- If the secure capacity is available, this is used as to determine available capacity by comparison with demand forecast;
- Otherwise, if n-1 capacity is available, and the reliability criteria is n-1, the n-1 capacity is used to determine available capacity, by comparison with demand forecast;
- If only the nameplate capacity is available, or the reliability criteria is ‘n’, the nameplate capacity is used to determine available capacity; otherwise
- The n-1 capacity must have been entered (since capacity data is supplied) and this capacity is used to fill all other capacity types.

6.2.2.7 Investment trigger point for an asset

The ITP for an asset is the forecast peak load (in MVA) that triggers investment in the network augmentation. Specifically, the model assumes that if the demand is always below the ITP, then the investment is deferred indefinitely, and similarly, if demand reaches or exceeds the ITP, then the investment to upgrade the network asset will commence immediately.

The model estimates the ITP to be the following:

- If n-1 Security of Supply support required is provided, then the ITP is taken to be this value;
- If demand and investment data is available, the assumption is that the forecast demand in the investment year is sufficiently high to warrant investment; hence the ITP is taken as the previous year’s demand. The ITP is calculated as the forecast demand in the investment year minus the average growth rate in that year;
- If neither demand nor investment data is available, but capacity data is available, the ITP is taken as the secure capacity (however, no deferral calculations will take place as no investment data has been entered); and
- If the capacity is not available, and one of demand or investment is also not available, the ITP cannot be calculated.

6.2.2.8 Hourly values for an asset

While the DANCE Model has the capacity to synthetically generate hourly demand values for a given asset from a series of basic inputs, this functionality was not used for this study. Hourly demand values were entered by the user.

6.2.3 Determine what can be calculated

6.2.3.1 Net present value

The NPV is calculated for an asset if the investment data has been provided.

6.2.3.2 Available capacity

The available capacity is calculated for an asset if the demand has been supplied and either investment or capacity has also been provided.

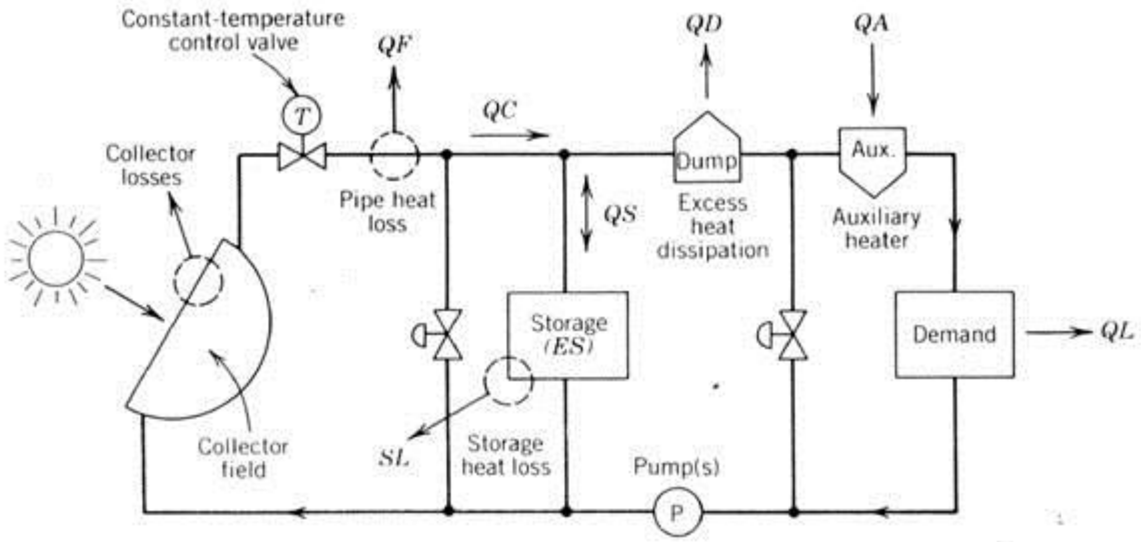
6.2.3.3 Annual deferral value

The ADV is calculated if both the demand and investment has been supplied.

APPENDIX 2: MODELLING INDICATIVE FIRM CAPACITY

This study utilises an existing simple energy-balance model of a CSP plant called SIMPLESYS (Stine & Geyer 2001). The original model was written in JavaScript and was recoded into Python code. A number of simple tests were used to validate that this translation was done correctly. Figure 30 shows a schematic of the SIMPLESYS model and the various parameters.

Figure 30: Schematic of SIMPLESYS model and parameters



Source: Power from the Sun (Stine & Geyer 2001)*, chapter 14.*

The model parameters are:

- Auxilary power — QA (represents unmet load)
- From collector field — QC
- Dumped power — QD
- Field heat loss — QF
- Thermal load — QL
- To/from storage rate — QS
- Storage loss — SL

The model provides for a basic operating strategy for a CSP plant where the unit can be started, then stopped, in any given hour over each 24 hour period. The model does not include any of the additional detail included in some other CSP models, such as NREL's highly regarded System Advisor Model (SAM) (National Renewable Energy Laboratory 2013). The focus, instead, has been on adequate accuracy whilst still achieving fast computation – required given the data intensive spatial processing involved.

The collector input in the original SIMPLESYS model is a simple sinusoidal function representing a clear day, but we have replaced the collector model with actual hourly DNI values estimated by the Australian Bureau of Meteorology in its satellite-derived gridded solar irradiance data at 5km resolution. Metadata for these data can be found at: http://www.bom.gov.au/climate/how/newproducts/IDCJAD0111.shtml

APPENDIX 3: INDICATIVE FIRM CAPACITY RESULTS

Figure 31 Summer afternoon Indicative Firm Capacity – 1, 3, 5, 10 hrs storage

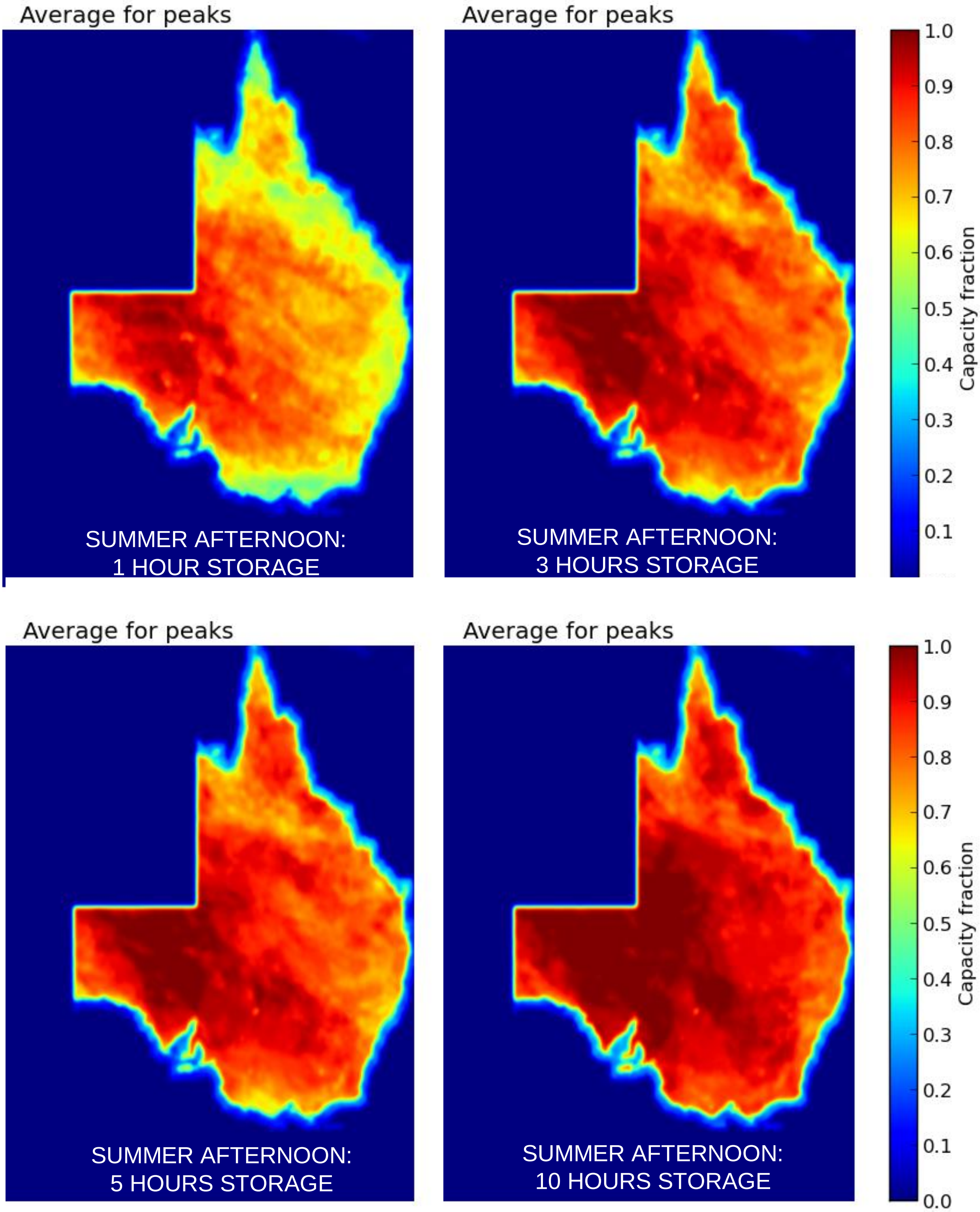


Figure 32 Summer evening Indicative Firm Capacity – 1, 3, 5, 10 hrs storage

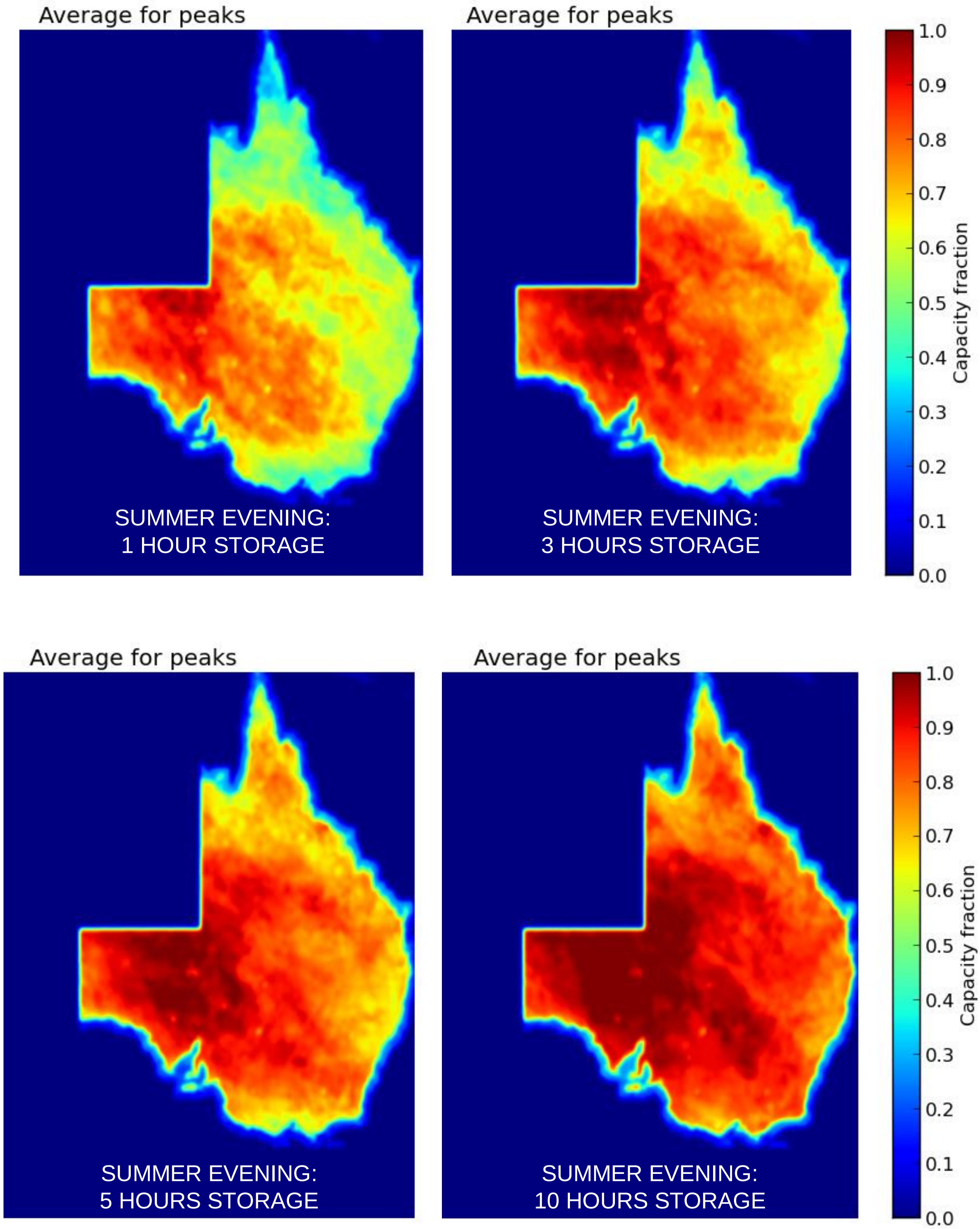


Figure 33 Winter afternoon Indicative Firm Capacity – 1, 3, 5, 10 hrs storage

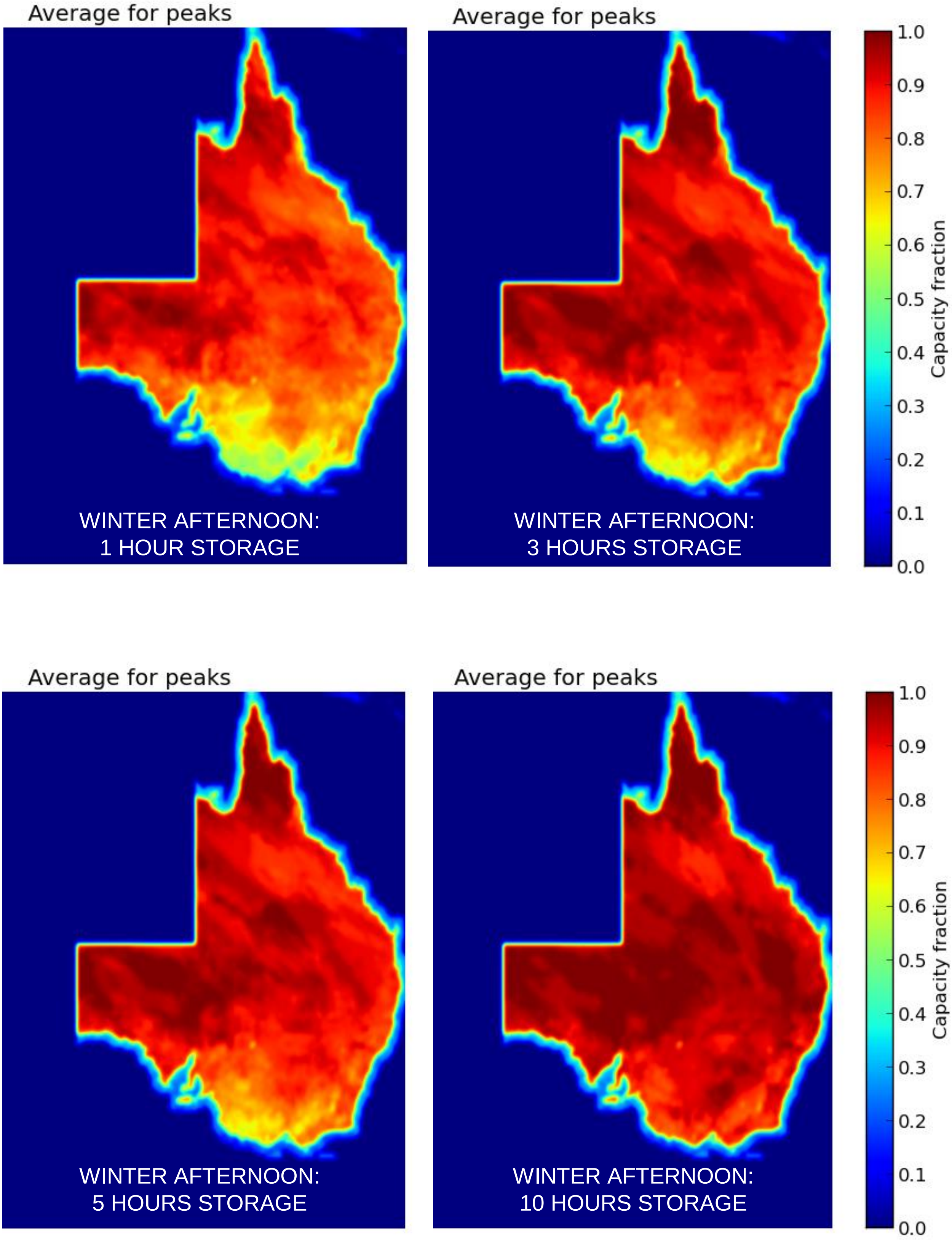


Figure 34 Winter evening Indicative Firm Capacity – 1, 3, 5, 10 hrs storage

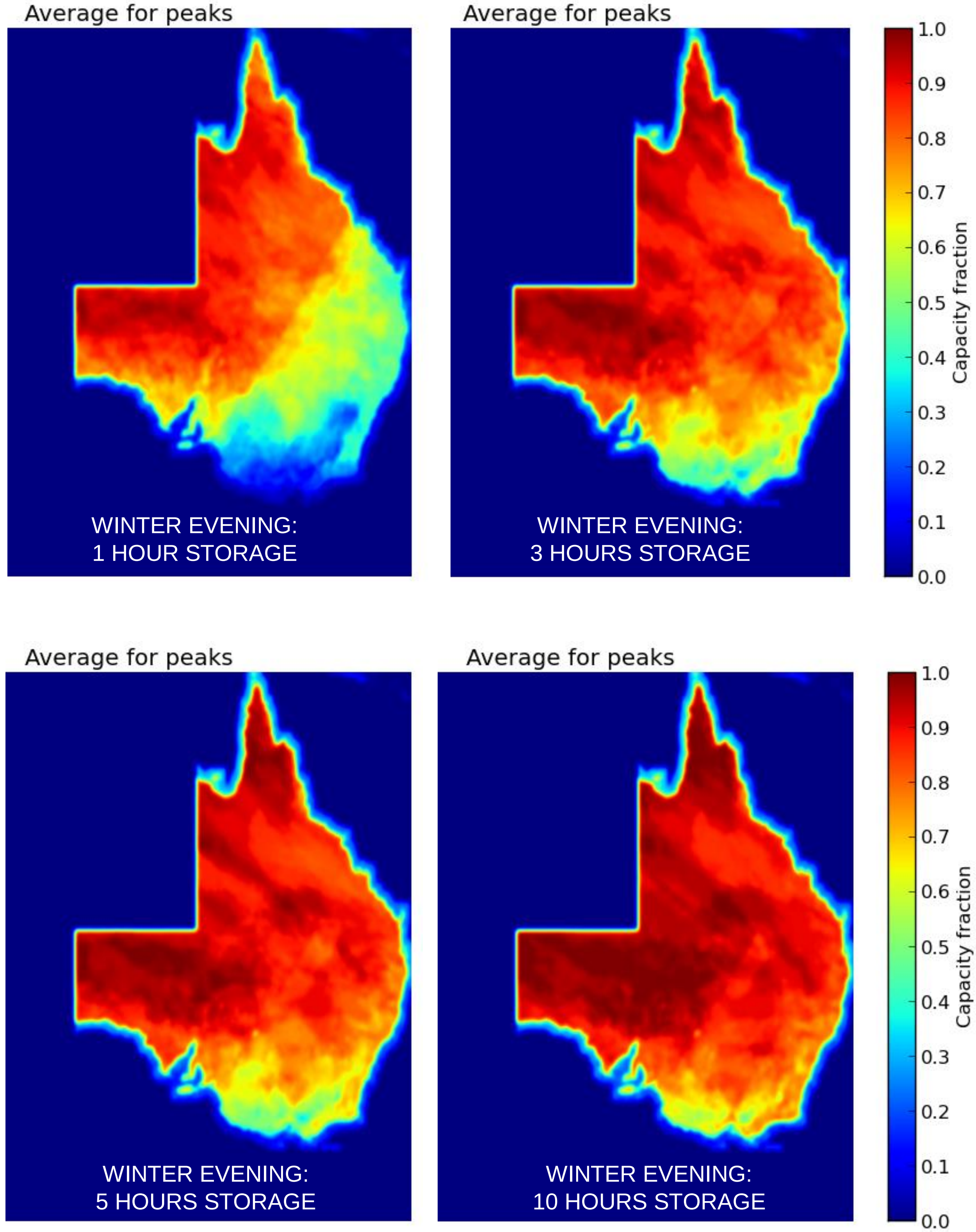


Figure 35 Indicative Firm Capacity all time periods – no storage

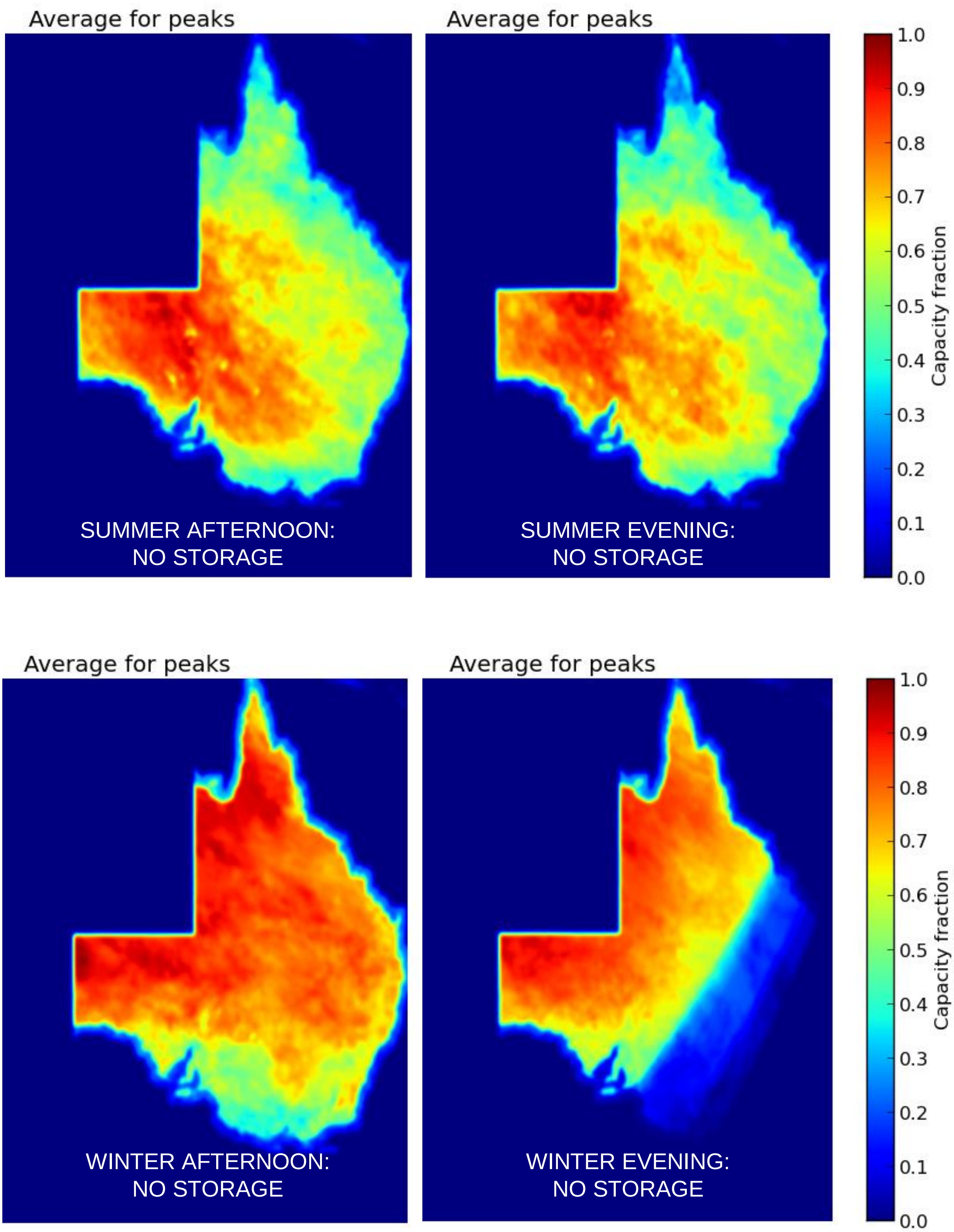


Figure 36 Indicative Firm Capacity all time periods – 15 hours storage