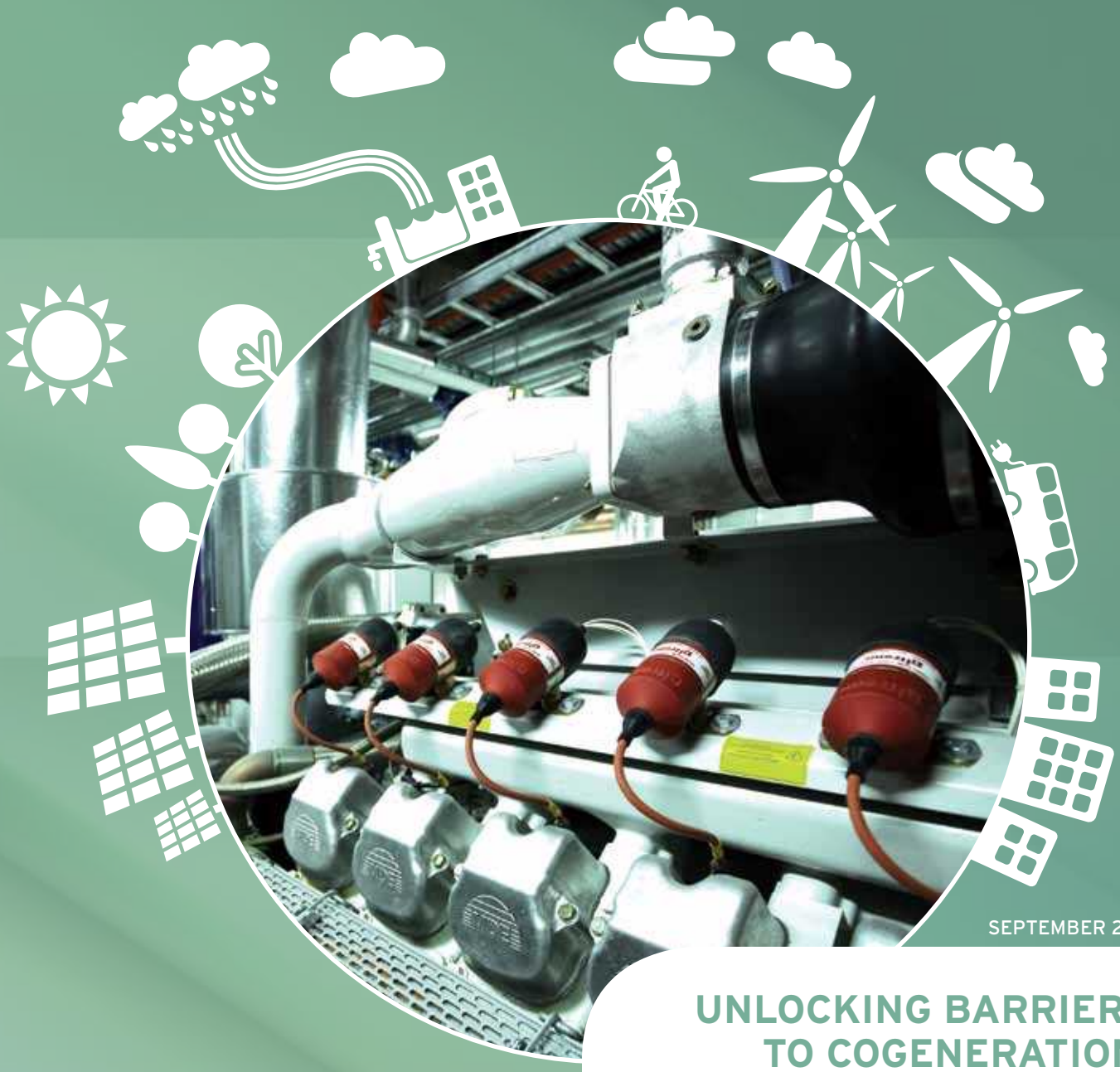
ClimateWorks AUSTRALIA

seed advisory



SEPTEMBER 2011

UNLOCKING BARRIERS TO COGENERATION:

Project Outcomes Report

A project by ClimateWorks Australia with Seed Advisory

PROPERTY COUNCIL of Australia

Publication of this report was sponsored by the Property Council of Australia

Disclaimer

The Unlocking Barriers to Cogeneration Project participants operated on a consensus basis, with input from government representatives. However, this report does not necessarily reflect the formal position of each participating organisation. While the purpose of the participants was to facilitate cogeneration and trigeneration and to encourage further connections, the participants recognise the obligations facing electricity market participants when dealing with embedded generation.

Copyright

Published by ClimateWorks Australia
Melbourne, Victoria, September 2011

© Copyright ClimateWorks Australia 2011

This work is copyright. Apart from any use permitted under the Copyright Act 1968, no part may be reproduced by any process without written permission from the publisher. Requests and inquiries should be directed to the publisher.

ISBN 978-0-9871341-1-0

Contact

ClimateWorks Australia
Monash University

Building 74, Wellington Road, Clayton VIC 3800
T +61 3 9902 0741
F +61 3 9905 9348
E anna.skarbek@climateworksaustralia.org

This document may also be downloaded from the ClimateWorks Australia website at: **www.climateworksaustralia.org**

Seed Advisory Pty Ltd
Level 6, 52 Collins Street, Melbourne VIC 3000
T +61 3 9658 2352
F +61 3 9658 2355
E pboyce@seedadvisory.com.au
www.seedadvisory.com.au

Property Council of Australia Limited
Victorian Division

ABN 13 008 474 422

Level 7, 136 Exhibition Street, Melbourne VIC 3000

T +61 3 9650 8300
F +61 3 9650 8692
E mkundevski@propertyoz.com.au
www.propertyoz.com.au/vic

© Copyright 2011

Printed on 100% recycled paper.

ecoStar is an environmentally responsible paper, made carbon neutral and manufactured from 100% post consumer recycled paper in a process chlorine free environment under the ISO 14001 environmental management system.

Contents

Purpose and scope	3
Acknowledgements	4
Foreword by the Federal Energy Minister, the Hon. Martin Ferguson AM MP	5
Message from the CEO of the Property Council of Australia	6
Glossary	8
1. Executive summary	10
2. Benefits of and opportunities for cogeneration	14
3. Barriers to deployment	22
4. A new approach to energy market management	33
5. Solutions for greater deployment	34
Appendix A: Previous reports	44
Appendix B: The rule change process	44
Appendix C: About the Reliability Panel	45
Appendix D: Explanation of Chapter 5A of the National Electricity Rules	46

Purpose and scope

ClimateWorks Australia (ClimateWorks) was founded in 2009 through a partnership between The Myer Foundation and Monash University, with a mission to substantially reduce Australia's greenhouse gas emissions over the next five years.

The Unlocking Barriers to Cogeneration (UBC) Project set out to design solutions to the barriers facing the deployment of cogeneration (including trigeneration)[1]. These solutions have been designed to be implemented in the short term; with longer-term actions considered and noted for further work.

Cogeneration offers significant low-cost carbon reduction opportunities, particularly relative to other currently available emissions reduction measures. It also offers a potential long-term electricity and heat generation alternative to traditional energy sources. Making it easier to install and operate cogeneration will see wider economic benefits, promoting the more efficient operation of the National Electricity Market (NEM).

This project identified barriers in the connection and development process for small and larger urban cogeneration projects and identified ways to resolve these barriers and ensure greater deployment of cogeneration in the short term.

The UBC Project, facilitated by ClimateWorks Australia and Seed Advisory, introduced a unique consultative approach to the management of new generation in the electricity distribution network. The Project:

- Used 'live' Victorian-based commercial projects as case studies: commercial scale cogeneration plants that would otherwise be ready to commence within one year, but for regulatory/market barriers
- Established a core working group, including customers, market participants, regulators, operators and policymakers
- Jointly developed short- and long-term solutions in a series of small, facilitated workshops from April to June 2011, facilitated by ClimateWorks and Seed Advisory.

The workshops successfully aimed to:

- Envision a commercial and regulatory solution that is relevant to all in the portfolio, thereby moving beyond one-off approaches to a more systemic approach that can then guide subsequent market-wide evolution.

To achieve practical and implementable solutions, the Project focused specifically on cogeneration. However, the UBC Project recognises that many of the issues are common to other forms of embedded generation. The recommended solutions for cogeneration will contribute towards addressing barriers to the implementation of these technologies in the future.

[1] In this report references to 'cogeneration' include trigeneration.

Acknowledgements

The Unlocking Barriers to Cogeneration Project has been made possible by the assistance and financial support of numerous property, energy and government sector stakeholders and advisors. ClimateWorks Australia would like to thank those who participated in the UBC Project and contributed their valuable time and expertise. ClimateWorks extends further thanks to those participants who provided financial support, without which this project would not have commenced.

Particular thanks goes to the case study hosts: Colonial First State Management Services, Crown Melbourne, Leighton Properties and the APN Property Group, Monash University, Moreland Energy Foundation and VicUrban. These participants gave this project its unique value by agreeing to allow their experiences on their current commercial projects to be used as case studies. We are grateful for the extra time they spent in providing and explaining their information, in addition to attending all workshops with the other participants.

ClimateWorks Australia thanks the following participants (in alphabetical order)

Australian Energy Market Operator

Australian Energy Regulator

CitiPower

Cogent Energy

Colonial First State Management Services

Crown Melbourne

Leighton Properties and the APN Property Group with Aurecon

Monash University

Moreland Energy Foundation

Origin Energy

Property Council of Australia – Victorian Division

Sustainability Victoria

United Energy

VicUrban

Victorian Department of Business and Innovation

Victorian Department of Primary Industries

In addition to the participants' financial support, this project was funded by the Consumer Advocacy Panel (www.advocacypanel.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

About the Project facilitators

ClimateWorks is an independent non-profit organisation established to enable practical projects to reduce emissions, focused on implementation where barriers to action remain.

Seed Advisory is a commercial advisory firm specialising in the energy sector, with expertise in strategy, risk management, policy development and commercial management.

About the sponsor of the published report

The UBC Project participants gratefully acknowledge the support of the Property Council in producing the published report and hosting its launch. The Property Council of Australia is the largest advocacy organisation for the property sector with 2200 member companies throughout Australia that represent property assets of over $400 billion. Members of the Property Council are involved in the entire property investment cycle; the financing, design, development and maintenance of property, as well as the services that underpin the industry.

Property Council members are responsible for Australia's most environmentally sustainable buildings. The members aspire to further transform buildings, precincts and cities to higher levels of environmental sustainability.

Foreword by the Federal Energy Minister, the Hon. Martin Ferguson AM MP

In the decades ahead Australia will see significant changes in the way we produce, transport and use energy.

Already we are seeing growth in gas, and in the years ahead we expect to see greater commercial deployment of renewable energy technologies, and new technologies to manage electricity grids and consumer interactions with energy markets.

Cogeneration and trigeneration have a role to play in this changing energy mix.

Importantly, in the current environment where electricity prices are driven significantly by electricity network infrastructure requirements, cogeneration and trigeneration offer new ways to reduce some of the demand on our electricity networks.

On 10 July 2011, the Government announced its carbon pricing package. This will support the deployment of low emission and clean energy technologies. It will provide incentives to increase the uptake of cogeneration and trigeneration, and other technologies to reduce greenhouse gas emissions.

It is important in this context to ensure that there are no unnecessary barriers to these technologies, and that they are efficiently considered in the frameworks that govern market operation and regulation – existing processes provide opportunities to test these outcomes.

These are complex issues. This report is a welcome contribution to the policy debate, and will provide valuable input into new partnerships described in the report, and the rule making and market development work of the Australian Energy Market Commission.

The Hon Martin Ferguson AM MP
Minister for Resources and Energy
Minister for Tourism

Cogeneration and trigeneration have a role to play in this changing energy mix.

It is important in this context to ensure that there are no unnecessary barriers to these technologies, and that they are efficiently considered in the frameworks that govern market operation and regulation – existing processes provide opportunities to test these outcomes.

Message from the CEO of the Property Council of Australia

Imagine green grids of buildings and precincts that power themselves…renewably.

At first, these green grids will complement the traditional, centralised coal-fired brown grid. In time, they will evolve into localised, self-sufficient clean energy power stations.

Co and trigeneration technologies offer a critical step toward this goal.

Unlocking the Barriers to Cogeneration identifies the benefits of tested cogeneration technology.

The report also explores barriers to wider take-up, based on the hard evidence of multiple case studies.

Finally, the report offers an action plan for realising green grid dividends.

Unlocking the Barriers to Cogeneration shows this readily available technology is 80 per cent more energy efficient than conventional energy sources – it also produces 60 per cent less carbon emissions.

The CSIRO has previously reported that green grid technologies can abate up to 18 megatons of carbon emissions by 2020 and 40 megatons by 2030.

They found the value cost savings of these technologies could be $130 billion by 2050.

In addition, the Prime Minister's Task Group on Energy Efficiency identifies these technologies as critical complements to a carbon price.

However, there is an urgent need to move away from a business as usual reliance on the brown grid.

At present, the main barriers to mainstream adoption of cogeneration are:

- an inefficient connection process that is costly and time-consuming, due to outmoded case-by-case assessment processes characterised by unclear rules and standards;
- the absence of clear guidelines about the roles and responsibilities of distribution network service providers; and,
- a bias against multi-site, precinct-level cogeneration plant and systems.

This report proposes a suite of practical solutions to these problems, including:

- a national, standardised connection process;
- automatic connection rights; and,
- practical district level licencing frameworks.

At first, these green grids will complement the traditional, centralised coal-fired brown grid. In time, they will evolve into localised, self-sufficient clean energy power stations.

The Property Council congratulates the authors of *Unlocking Barriers to Cogeneration* – ClimateWorks and Seed Advisory – for their innovative thinking and collaborative approach to this exciting project.

Our next step is to advocate the massive benefits of moving to a green grid approach and fostering the widespread adoption of cogeneration technologies, in particular.

We are:

- working with stakeholders to **advocate sensible reforms to Australia's energy markets,** especially changes to the national electricity rules;
- submitting our views on **connection charge guidelines** to the Australian Energy Regulator;
- developing a **toolkit for developers and property owners** that will guide them through current and emerging regulatory processes;
- drafting a **standard connection manual and cogeneration technical guide**, in close cooperation with industry participants; and
- preparing a **submission to the Victorian Government's October 2011 inquiry** into the barriers for embedded energy.

Unlocking Barriers to Cogeneration speeds us on the journey to green grid dividends.

Peter Verwer
Chief Executive Officer
Property Council of Australia

Next Steps

- Work with stakeholders to **advocate sensible reforms to Australia's energy markets**, especially changes to the national electricity rules.
- Submit our views on **connection charge guidelines** to the Australian Energy Regulator.
- Develop a **toolkit for developers and property owners** that will guide them through current and emerging regulatory processes.
- Draft a **standard connection manual and cogeneration technical guide**, in close cooperation with industry participants.
- Prepare a **submission to the Victorian Government's October 2011 inquiry** into the barriers for embedded energy.

Glossary

Access standards	The technical terms and conditions and standards of performance required of market participants connecting to the National Electricity Market. The National Electricity Rules currently contain both automatic access standards – rarely used and applicable to large generators - and minimum access standards, applicable to all connections to the National Electricity Market.
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System, which technically means both the terms and conditions on which a user connects to the distribution network and, as used in this report, the charges by a distributor for connection and access to its network.
Embedded generation	Generation – conventional or other – connected to a distribution network, not to the transmission network.
Embedded network	A connection to a licenced distribution network that, for a range of possible reasons, serves more than one customer.
ENA	Energy Networks Association
Fault level headroom	Certain types of connection – particularly generation - to the transmission and distribution networks can contribute fault currents to the network in the event of plant failure, resulting in network instability and, in certain failure cases, risks to the safe operation of the network. Distribution networks are required to meet three phase and single phase design fault levels – the potential contribution from plant failures – where the acceptable fault level depends on the nominal voltage of the network. Fault level headroom is the difference between the required and existing fault levels in a relevant section of the network.
MCE	Ministerial Council on Energy
MWh	Megawatt hour, meaning one million watt hours of electricity.
NEM	National Electricity Market
NER	National Electricity Rules
Deep augmentation	Any augmentation of the distribution system other than shallow augmentation generation services (Victoria). Generally intended to refer to infrastructure not specifically attributable to any single customer.
Shallow augmentation	The installation of connection assets and any augmentation of the distribution system up to and including the first transformation in the distribution system in respect of the embedded generator (Victoria), for example, up to a zone sub-station. Generally the cost is incurred by the customer seeking the connection.
NSP	Network Service Provider
R&DG	Renewable and Distributed Generation
Registrable exempt network	Category proposed by the AER for future distribution networks not subject to distribution licencing requirements. Certain embedded network operators in defined circumstances are and will be entitled to exemptions from the requirement to hold a Distribution Licence providing that, in this case, they meet the defined requirements and register with the AER.
Subtractive metering	Subtractive metering occurs where a customer network contains a small market generator that is not metered at the connection point between the local network service provider's network and the customer site. A parent metering point is placed at that connection point while a child metering point is situated at the small generator within the site. A subtractive metering calculation is used to determine the net energy generation or consumption for the generation and load components of the site. In this report, the term is used in a wider sense to include "virtual" embedded networks combining small generators and related sites.
TUOS	Typically, charges for the use of the transmission network.
UBC Project	Unlocking Barriers to Cogeneration Project

Table 1. Unlocking Barriers to Cogeneration Project Case Studies

Description of site	Size of generation unit	Directional Flows	Relationship to load serviced	DNSP
CBD office tower, single title, new build	2 by 1.15MW cogeneration units and possibility of further diesel back-up generation. Trigeneration under consideration	Grid synchronised. Overflow and synchronising flows into the distribution network planned	Servicing own needs, base power, heating and possibly chilling	CitiPower
CBD office tower, single title, retrofit	2MW trigeneration	Inflows at the meter for tenants' requirements; no planned flows into the distribution network, (including in the event of failure)	Servicing own needs, base power, heating and chilling. Desirably, sale of power to third party tenants	CitiPower
New build within large brownfields development, single land owner	1MW cogeneration	Grid synchronised, in line with requirements of private network; capable of running in island mode	Own use, with potential for a small number of unrelated tenants to take power off the network assuming metering capability existed	UED (Jemena)
Multi-use, single site, existing build	Existing 6 x 1MWe cogeneration units also connected to absorption chillers. Proposed project is to expand to 12MWe trigeneration	Grid synchronised. Overflow into the distribution network for export to other related contiguous buildings	Servicing own needs with base power, standby power, heating and cooling	CitiPower
Brownfields development, consolidated site, single land owner	200kW cogeneration	Grid synchronised. Inflows at the meter for balance of development's requirements; no planned flows into the broader distribution network (including in event of failure)	Small number of tenants (land owner sponsored/ funded enterprises) on consolidated site to take power from cogeneration unit	UED (Jemena)
Greenfields urban development, currently single site and title. Subsequent subdivision and sale of land parcels	1MW trigeneration, with increments to 3MWs and 6MWs as development proceeds, linked by hub-and-spoke network	Planned export from cogen unit within development. Will require net inflows from grid for backup and for balance of development's requirements. Consideration of alternative network configurations to address 'export'	District scale heating and cooling network provided to future owners/tenants; power provided to a range of future businesses/ activities connected to local network	SP AusNet

1. Executive summary

Cogeneration (combined heat and power) and trigeneration (combined cooling, heat and power) offer Australia significant environmental and economic benefits in the short and long term. Cogeneration (including trigeneration) technology lends itself to deployment in Australian buildings to supply local electricity, heat and/or cooling.

Increasingly, Australian property developers and owners are seeking to incorporate cogeneration into their existing buildings and new developments. However, they face a complex and burdensome connection process and regulatory barriers that inhibit them from deploying the technology. The Unlocking Barriers to Cogeneration Project ("UBC Project") has identified implementable solutions to these short-term barriers that will provide system-wide efficiencies to the NEM.

These solutions are a result of the work conducted for the UBC Project, with participation of representatives from the cogeneration demand and supply chains. From the demand side there were representatives of cogeneration project owners (with a demand for connection to the electricity distribution network, the 'grid'). From the supply side there were representatives of the owners of the electricity grid: the distribution network service providers (DNSPs, or distributors), who own and operate the grid and are responsible for new connections. Government agencies also participated in recognition of the important policy and regulatory oversight of the electricity market.

The solutions identified build on a significant body of work in the past decade analysing the issues and presenting solutions. In addition to the work undertaken for the Ministerial Council on Energy, regulators and market operators, individual participants have put forward proposals, most recently CitiPower in its 2011-2015 regulatory proposal. What is novel here is the involvement of a wide group of stakeholders and the commitment to pursuing an implementable solution.

Solutions for greater deployment

The following solutions are proposed.

Proposal 1

Change the National Electricity Rules (NER) in the short term to streamline the process for cogeneration project owners seeking connections to the distribution network and substantially improve system-wide process and workload efficiencies.

Specifically:

What should change in the rules?

- Introduce a standardised connection process to replace the case-by-case approach that is currently the status quo.
- Extend the NER's existing concept of automatic access standards to incorporate cogeneration facilities of up to 5 megawatts (MW) in size– as provided for in Chapter 5 for all generation projects meeting the automatic standards and in Chapter 5A of the National Electricity Rules for micro generation meeting Australian Standard 4777. This would give embedded generators that meet the required technical standards a right of connection to the distribution grid.
- Streamline the connection process for non-standard projects by implementing agreed timeframes, common information requirements and contract terms under the NER.

Why?

- Small to medium sized cogeneration projects would be treated similarly to micro generators such as household solar panels. Household solar panels and other micro generators have a dedicated standardised connection procedure which has been agreed as part of a new Chapter 5A of the NER which will take effect from July 2012. The UBC Project recommends applying this to cogeneration projects, recognising that for small to medium sized projects it is more efficient to use a similar standardised process as opposed to the connection process in the current rules that is based on a process developed for much larger generators.
- The standard right to connection would be similar to that to be introduced for micro generators, and already existing for conventional generators.

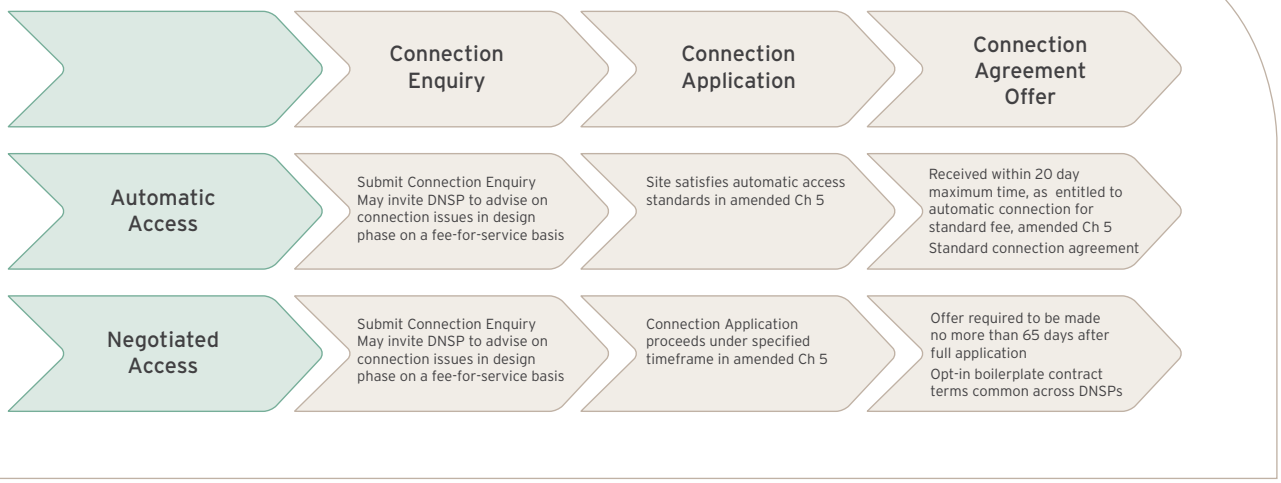
What else can be improved in the process?

- In addition to the rule changes above, the participants have identified an opportunity before the formal connection process begins to encourage greater engagement and information exchange between DNSPs and cogeneration project owners. It is proposed that:
  a. Project owners pay DNSPs a fee-for-service to work in a collaborative fashion during the connection enquiry stage of a proposal to shape and improve the potential project, and
  b. DNSPs are required to publish an annual 'exceptions' report showing areas where constraints (such as no fault level headroom) exist in the network that may prevent connections within a defined near term period such 12 months.

These solutions respond to the numerous challenges cogeneration project owners in the property sector currently face in deploying the technology.

The new connection process

The diagram below outlines the steps, timeframes and responsibilities involved in the new process.



Proposal 2

Encourage economies of scale through the development of larger multi-site and district level cogeneration projects by:

- Extending the use of metering arrangements that support the aggregation of separate sites, similar to that currently proposed for demand side participation. This would enable larger cogeneration systems to service multiple contiguous sites.
- Making larger district level cogeneration projects eligible for consideration as a 'registrable exempt network' in lieu of existing licencing requirements, to enable cogeneration project owners to charge for the use of their services and recover the capital costs of their investment.

To progress this latter solution, project participants are engaging in the Australian Energy Regulator's (AER's) consultation process on this issue. Other cogeneration stakeholders who support the solution proposed above are encouraged to also engage in the AER consultation.

Barriers to deployment

These solutions respond to the numerous challenges cogeneration project owners in the property sector currently face in deploying the technology. Fundamentally, these challenges are the result of the costs and uncertainties that arise from the process owners must go through to connect their projects to the electricity distribution grid.

The UBC Project identified two main barriers to cogeneration project delivery:

1. An inefficient connection process that is costly and time-consuming:

This stems from asymmetries between DNSPs and cogeneration project owners, including uncertainty surrounding timelines, the lack of standard and readily available DNSP technical application requirements, poor information exchange, the case-by-case manner in which connection applications are considered, and uncertain, often high, costs of connection. The connection process is inconsistent across DNSPs and lacks transparency.

From a DNSP's perspective, connection applications require consideration of the interaction between the operation of the proposed embedded generator and the safe operation of the network.

In the absence of accepted national technical standards for embedded generation, DNSPs analyse connection applications for the potential to give rise to fundamental issues relating to the safe operation of the network. The DNSP considers both the proposed installation and the characteristics of the location of the connection for each application.

Barriers to developing medium-large projects across multiple sites:

Two development types were identified as facing this barrier, each with different challenges.

a. Installing a larger cogeneration system or upgrading an existing system to service more than one building where those buildings are next to each other.

b. Developing medium – large cogeneration systems to service multiple sites across a district.

The UBC Project was established to work through these short-term barriers to the deployment of cogeneration and deliver solutions that can be implemented today. Representatives from all parts of the cogeneration supply chain contributed funding and participated in the Project - reflecting their view that solutions need to be found and implemented.

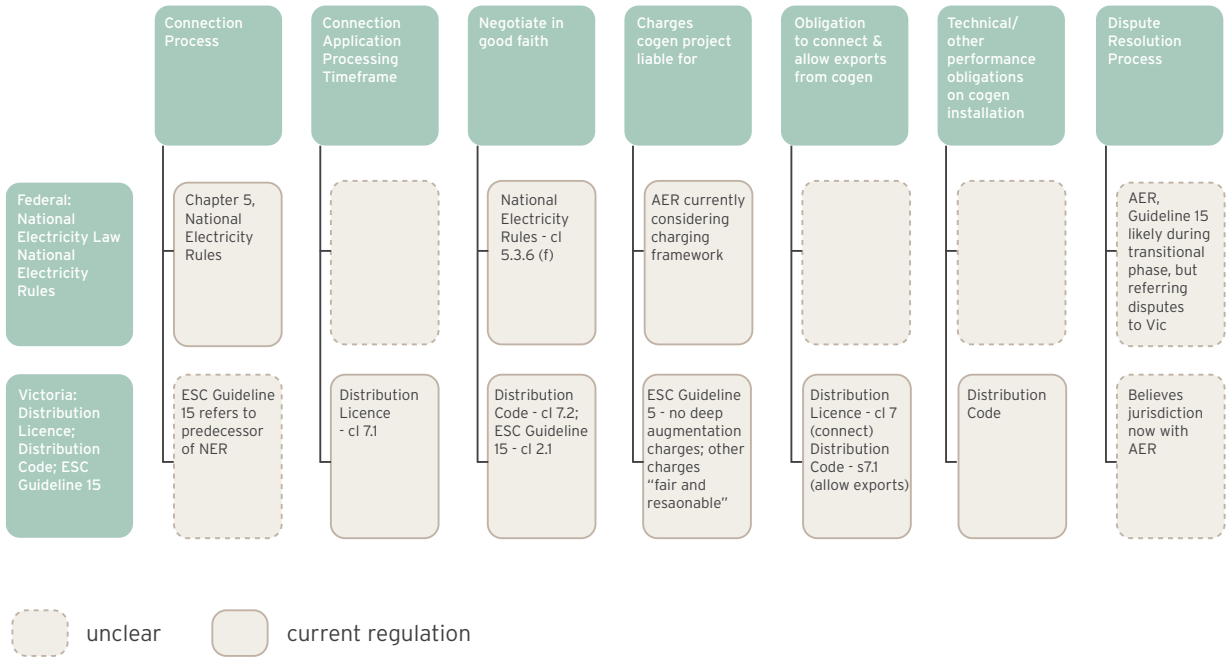
Benefits of reducing the barriers to cogeneration

Improving the connection process for mini, small and medium cogeneration systems up to 5MW would translate to several hundreds of thousands of dollars in savings for the six project proponents involved in the UBC Project alone, with much greater system-wide savings achieved for cogeneration project owners in Australia over the coming years[2].

Barriers to multi-site cogeneration developments in particular discourage cogeneration project owners from pursuing larger systems. These barriers discourage economies of scale and the most efficient use of cogeneration technology being achieved. As a result, private sector experimentation and innovation in delivering lower emission energy solutions is, while often initially pursued, ultimately deferred to the too-hard basket.

In the longer term, cogeneration has a key role to play in the wide benefits embedded generation systems offer to the community. Experimentation and innovation are important now so that the potential benefits from changes in the way future energy is delivered are understood and realised.

Current Victorian connection process/applicable Federal and Victorian regulation



[2] This classification of small and medium systems up to 5MW is in ENA's 2008 'Embedded Generation ENA Policy Framework Discussion Paper'. The report uses terminology "small to medium" interchangeably with these classifications.

Leighton Properties and the APN Group
567 Collins Street, Melbourne Victoria 3000

CASE STUDY 1

567 Collins Street will deliver what business wants – an invigorating, efficient and sustainable workplace that is designed to enhance business performance, support growth and help attract and retain staff. It will offer tenants the workplace of the future, targeting a 6 Star Green Star rating and a 5 Star NABERS rating with a focus on providing the occupant a high quality environment.

2. Benefits of and opportunities for cogeneration in Australia

Cogeneration (the generation of electricity and heat) and trigeneration (electricity, heat and cooling) offer Australia significant environmental and economic benefits in the short and long term.

As the nation's peak electricity demand continues to challenge current energy market infrastructure and as we move to a less carbon intensive economy, cogeneration (including trigeneration)[3] is a proven technology solution that is available today, and that can meet the challenges posed by a changing energy landscape.

Despite its significant potential to meet these challenges, however, cogeneration remains underutilised. Australia currently has approximately 3338 MW of cogeneration installed, 592 MW of which is fuelled by renewable sources[4].

The UBC Project has identified that cogeneration project owners ready to bring their projects online face significant short-term barriers to achieving this goal.

Cogeneration and trigeneration explained

Cogeneration (also known as combined heat and power) is the simultaneous production of electricity and heat from the same fuel source where both the electric energy and heat energy are used. Trigeneration (also known as combined cooling, heat and power) is the simultaneous production of heat, cooling and electricity.

In both cogeneration and trigeneration systems, a fuel is burnt in an engine which drives a generator to produce electricity. In cogeneration systems the waste heat from the engine is used for space, water or process heating and in trigeneration systems it can also be converted to cold water for cooling through an absorption chiller[5].

Cogeneration and trigeneration systems are typically fuelled by gas, although they can be fuelled by renewable or fossil fuels.

Cogeneration systems can be small-scale, servicing one building, or larger-scale servicing multiple buildings next to each other or across a whole district.

Cogeneration has significant environmental benefits over conventional fossil-fuelled power generation. Through the use of natural or waste gas as opposed to coal it reduces CO_2e emissions. More importantly, by using a single fuel source to produce multiple useful forms of energy (e.g. heat and electricity), cogeneration systems significantly reduce fuel requirements, CO_2e emissions, and increase thermal efficiencies. While conventional power plants reach thermal efficiencies of approximately 30 to 40 per cent, the overall efficiency of cogeneration plants can reach in excess of 80 per cent at the point of use[6]. Thermal efficiency is the rate at which the energy input from raw materials is converted into energy that is used by the customer.

As embedded generation (ie, electricity generation located in buildings and precincts), cogeneration systems also avoid the need to transport electricity long distances to the load. Not only does this reduce electricity transmission losses, but with billions of dollars of investment forecast in upgrading and maintaining Australia's national electricity grid to meet rising demand over the next decade, the potential for embedded generation to assist in the management of overall system costs is significant.

With the additional benefit of heating and/or cooling, cogeneration and trigeneration are ideal for residential and commercial properties where there is adequate demand, particularly for the system's heat energy. And with heating and cooling requirements representing a significant proportion of Australia's energy use, the potential for cogeneration is economically and environmentally material.

[3] In this report references to 'cogeneration' include trigeneration but not other forms of embedded generation.
[4] Clean Energy Council cogeneration project data, July 2011.
[5] Trigeneration Fact Sheet, Moreland Energy Foundation, November 2010. Available online: http://www.mefl.com.au/key-areas/sustainable-energy-supply/item/379-trigeneration.html
[6] UK Combined Heat and Power Association, http://www.chpa.co.uk/what-is-chp_15.html

Opportunities for embedded cogeneration in the building sector

Environmental benefits

The property sector accounts for approximately 19 per cent of total energy consumption in Australia, or 24 per cent of Australia's total greenhouse gas emissions[7]. Yet the property sector offers significant opportunities for low cost or cost-neutral abatement. One such opportunity is greater deployment of cogeneration.

ClimateWorks Australia's 'Low Carbon Growth Plan' has identified at least 13.5 million tonnes of cost effective abatement potential from the deployment of cogeneration systems per annum by 2020[8].

Many within the property sector recognise the financial and long-term economic benefits of investing in low carbon solutions and have been leaders in deploying the technology.

Environmental building rating systems, particularly the National Australian Built Environment Rating System (NABERS) and the Green Building Council of Australia's Green Star program, have been instrumental in driving greener investment decisions within the industry. Property owners are also encouraged in this investment by increasing tenant demand in urban environments – particularly from government and large corporations – for environmentally responsible buildings.

With these green building programs in place, property owners are highly aware of the financial and economic benefits to be gained in the future by investing in greener alternatives today. Given its high efficiencies and low CO_2e emissions, cogeneration is an attractive energy generation technology for property owners compared to renewable alternatives, such as solar PV and wind.

Demand for green building developments is clustered in dense urban areas where tenants are willing to pay the higher rents associated with these buildings. However, these areas are also often characterised by network infrastructure with limited capacity to incorporate more connections into the network. This factor makes the connection process for cogeneration project owners difficult and calls for solutions to reflect green building characteristics and accommodate more cogeneration connections in the existing network.

The fact that cogeneration technology lends itself to dense urban areas is one example of the dilemmas cogeneration proponents in the property sector face.

Sustainability Victoria, on its Resource Smart webpage for businesses, 'Cogeneration – Frequently Asked Questions' states that gas-fired cogeneration "demonstrates an attractive case to businesses that are seeking an energy solution that is both *secure* and has the *potential to protect from rising energy costs*". However, Sustainability Victoria also advises businesses that *"connection costs can have a major impact on the financial viability of embedded generation projects"*[9].

A greenfields urban development, with a low planned carbon footprint, to be achieved through a combination of energy efficient design, onsite co and trigeneration and district level heating and cooling.

As well as advising that costs are project-specific and that the "location of the scheme, connection voltage and export capacity will all impact on the connection cost", it notes a fundamental inefficiency in the connection process identified by the UBC Project – time.

"Connection to the electricity grid is not simple; the solution is complex... Developers should recognise that it can take a significant time to get a connection built"[10].

On a larger, yet more challenging scale in the current regulatory environment, cogeneration offers significant benefits for property owners and managers developing district level electricity, heating and cooling systems. For example, in New South Wales, the City of Sydney plans to use cogeneration to take most, if not all, of city buildings off the coal-fired grid as part of its 2030 goal to cut carbon emissions by 70 per cent. In Victoria there are plans to implement district level heating and cooling in a new housing estate development.

However, as is illustrated in the next section, significant connection and regulatory barriers hinder the development of medium to large cogeneration projects.

The vision:

A greenfields urban development, with a low planned carbon footprint, to be achieved through a combination of energy efficient design, onsite co and trigeneration and district level heating and cooling. An initial 1MW trigeneration unit is proposed, with later increments to 3MW and then 6MW as development proceeds, linked by hub-and-spoke network. The development is expected to need to supplement the energy supplied from its trigeneration plant with net electricity inflows from grid for backup and to balance the development's electricity requirements.

---

[7] The Second Plank Update: A review of the contribution that energy efficiency in the buildings sector can make to greenhouse gas emissions abatement', The Allen Consulting Group, Commissioned by the ASBEC Climate Change Taskgroup (CCTG), June 2010.

[8] ClimateWorks Australia *Low Carbon Growth Plan for Australia - Impact of the carbon price package*, August 2011.

[9] Sustainability Victoria 'Cogeneration – Frequently Asked Questions' webpage, accessed July 2011, Available at http://www.resourcesmart.vic.gov.au/for_businesses/energy_4513.html. Emphasis added.

[10] Sustainability Victoria 'Cogeneration – Frequently Asked Questions' webpage, accessed July 2011, Available at http://www.resourcesmart.vic.gov.au/for_businesses/energy_4513.html

The benefits:

Compared to the conventional provision of energy services on a building-by-building basis, this precinct level development offers:

Capital cost savings:

- Buildings connected to the system have lower capital costs because they don't need conventional chillers and boilers
- The total installed capacity of the central plant can be reduced compared to the capacity that would need to be installed on a building-by-building basis. This is achieved by taking advantage of the diversity in energy loads – particularly in mixed use developments where operating times vary. This diversity arises from the fact that not all energy users need energy at the same time.

Operational savings:

- Building owners will have reduced operating and maintenance costs
- Gains in operating efficiency can be achieved through highly efficient plant that is centrally operated and managed by specialist expertise
- A central plant is likely to have a more constant base load resulting in a better operational performance than individual building systems.

Environmental savings:

- District systems can use a variety of fuel sources, and can more readily incorporate renewable or low emission technologies
- Transmission losses (that is, electricity lost while it travels along the transmission network from source to use) are reduced as electricity is generated at the point of use
- The waste heat produced through electricity generation can be utilised locally to provide heating and cooling.

Other:

- Building owners will save building space that can be used for other purposes
- The reliability of a central plant would also typically be higher than in individual buildings as greater redundancy can be built in, meaning greater buffer against outages.

A key component of the potential revenue and ultimate viability of any district scale cogeneration scheme is the operator's ability to capture the retail value of the electricity generated.

The barriers the Project is experiencing[11]:

Due to issues of third line forcing, which prevent sellers of one product forcing customers to also buy a third product, it is not possible to mandate that customers purchase services such as heating and cooling from a centralised plant. This uncertainty adds a level of risk that operators are unwilling to accept, unless underwritten by another party. In addition, sales of electricity are subject to their own regulatory requirements, in this case requiring either a retail license or an on-selling exemption to the licence requirements.

A key component of the potential revenue and ultimate viability of any district scale cogeneration scheme is the operator's ability to capture the retail value of the electricity generated. The intent is to be able to on-sell this to precinct customers rather than export the electricity to the grid. The current regulatory framework does not enable the transport of electricity across title boundaries without an electricity distribution licence, unless an exemption is received to operate a private network.

[11] There is currently no regulation that covers the provision of district heating and cooling networks, including access rights for infrastructure on public and private land, as well the retail tariffs for the sale of heating and cooling to customers.

Colonial First State Asset Management Group
385 Bourke Street Melbourne Victoria 3000

CASE STUDY 2

Colonial First State Asset Management Group

Colonial has a strong focus on environmental performance resulting in real savings and improved efficiencies across their portfolio. At 385 Bourke Street, the introduction of a trigeneration plant will assist Colonial in achieving its goal of reducing carbon emissions by 30% and achieving a NABERS 5+ star rating at the property. Achieving and maintaining energy efficiency and low carbon emissions at 385 Bourke Street will ensure the property remains competitive in attracting and retaining tenants and property values are maintained.

Economic benefits – today and in the longer term

Numerous property owners and developers, particularly those involved in the UBC Project, are already committed to incorporating cogeneration into their developments.

The Productivity Commission's most recent report lists the estimates for the levelised costs of energy (LCOE) of various sources of electricity in Australia. The LCOE is a method of comparing many different energy technologies using a common cost measure in units of electricity produced. The results included:

- Coal-fired electricity (without carbon capture and storage) – A$78–91/MWh
- Combined-cycle gas turbines (without carbon capture and storage) – A$97/MWh
- Wind – A$150–214/MWh
- Medium-sized (5MW) solar PV systems – A$400–473/MWh[12].

For individual projects, cogeneration is a viable alternative to conventional power, particularly when considered along with other energy efficiency measures. The introduction of a price on carbon from July 1, 2012 will improve the economic viability of cogeneration systems as they become more price competitive with conventional fossil fuel energy generation alternatives. Considered from an economy wide perspective, the benefits of cogeneration may be even higher – including, for example, the reduction in the system-wide costs of providing for peak load and, as cogeneration penetration increases, a reduction in system-wide transmission losses.

For many in the electricity supply chain, cogeneration is often a preferred alternative to conventional electricity and heating/cooling due to:

- The high efficiencies it achieves in the production of energy and its supply of reliable power during peak hours
- The low investment and running costs involved relative to wind and solar alternatives
- The costs being substantially borne by private participants, not the community as a whole.

The long-term benefits of embedded generation to an electricity system that requires significant ongoing investment to keep up with demand (particularly peak demand) have been well explored and documented.

Embedded generation, as a form of demand side management, avoids transmission charges (TUOS) and can avoid distribution charges (DUOS). TUOS and DUOS make up approximately half our electricity costs. Increasing the use of embedded generation in the NEM (and thereby reducing demand on the national electricity grid during peak periods) will help reduce future investment on upgrading grid infrastructure.

The benefits of embedded generation

Parsons Brinckerhoff's 2006 report prepared for the Utility Regulators Forum, 'A National Code of Practice for Embedded Generation - Consultation Paper' outlines the advantages of embedded generation.

"The connection and operation of [embedded generation] can offer a number of benefits when compared to large, centrally operated, conventional (thermal) generation stations. These benefits can include the following:

- *Lower capital cost of generation;*
- *Smaller incremental increases in generation capacity to more closely match demand;*
- *Reduction in environmental emissions; and*
- *Potential for enhanced security of supplies and improved power quality"*[13].

[12] The Productivity Commission quotes the Electric Power Research Institute, 2010. Sustainability Victoria's Resource Smart website advises businesses that typical capital costs of cogeneration systems are in the range of $1.8 million to $2 million/MW when all infrastructure and connection costs are included. Source: http://www.resourcesmart.vic.gov.au/for_businesses/energy_4513.html

[13] 'A National Code of Practice for Embedded Generation - Consultation Paper', Parsons Brinckerhoff prepared for the Utility Regulators Forum (Embedded Generation Working Group), February 2006, pp4-5.

In many cases cogeneration is financially and economically viable today. Indeed, the substantial investment already committed by property owner participants in the UBC Project and by those in other states who are currently incorporating cogeneration into their building designs reflects the economic benefits of reducing these short-term barriers.

Cogeneration is also often looked to as a preferred energy generation technology because of its capacity to meet base load demand for heat and electrical energy very efficiently.

McLennan Magasanik Associates estimates that, subject to the introduction of a carbon price and changes to transmission pricing arrangements, embedded generation could ultimately supply at least one-third of Victoria's total load growth and that its uptake could result in an economy wide benefit of between $210 million and $2.4 billion[14].

In many cases cogeneration is financially and economically viable today. Indeed, the substantial investment already committed by property owner participants in the UBC Project and by those in other states who are currently incorporating cogeneration into their building designs reflects the economic benefits of reducing these short-term barriers.

This is the case despite the fact that many owners take account of only the expected return on their building, and not on any additional return from the DUOS and TUOS costs they are helping to avoid by installing onsite energy generation[15]. The property owners involved in the UBC Project have cogeneration systems that would be commissioned in the next 12 months 'but for' the immediate barriers they face. This in itself suggests that there would be more cogeneration installed if proposed installation did not face such significant barriers to connection.

There are significant advantages and real cost savings to be made by reducing the short-term barriers to the deployment of cogeneration. Given the time and money already being invested in cogeneration, the UBC Project has identified that reducing the short-term barriers could result in several hundreds of thousands of dollars in system-wide savings for these projects alone.

However, it is not only cogeneration owners who stand to gain from improved process efficiencies. In the broader context, standardised processes present a significant economic efficiency opportunity as more embedded generation comes online.

Broken down, the costs involved for cogeneration project owners to connect to the network include:

- Costs of identifying the required information, providing the information and maintaining information flow with the DNSP
- Project management costs, including the time involved over the length of the connection application
- Costs of consultants to anticipate and then rework the design and technical drawings in line with anticipated and then actual DNSP requirements
- Costs of network studies, particularly where multiple network studies are required by the DNSP to support a connection application
- Costs resulting from having to downsize or redesign a planned system in order to avoid barriers to connection. This could lower the performance and efficiency of the cogeneration system and may result in less efficient approaches to achieving the desired emissions reductions for the building
- Project delay costs
- Incremental internal equipment costs to meet DNSP's preferred requirements
- Where required, costs of network augmentation (eg additional infrastructure to increase capacity or reduce fault levels).

[14] McLennan Magasanik Associates, Report to Sustainability Victoria: Understanding the Business Case for Distributed Energy Generation in Victoria, June 2007, pp4-7.

[15] For most of the project proponents in this study, avoided TUOS and DUOS are relatively unimportant in the business case for their cogeneration project. However, this is not true of all projects and larger projects in particular value the potential contribution but are concerned about the absence of a defined process for negotiating (and collecting) these charges and would value greater clarity on this issue.

ANZ
ANZ

All of these costs add up to higher rents for tenants and/or lower returns to building owners, including a wide range of investors.

By implementing changes to the National Electricity Rules that would enable cogeneration to connect more easily, the market will see more efficient investment in, and efficient operation and use of, Australia's electricity services.

The solutions proposed in this report (see Section 5 below) will help to ease the process and also reduce the barriers to the technology's deployment.

In the short term, these solutions will enable the majority of the UBC projects to come online. In the medium term, the solutions will enable cogeneration proponents to work within the bounds of amended regulations to develop projects that better cater to electricity and heating demand on a larger scale.

Finally, reducing these barriers is expected to pave the way for the real potential of cogeneration to be identified. In the longer term, by enabling cogeneration proponents an unbiased platform from which to deploy new systems and participate in the energy market, the market is given a clear point of view from which to judge how significant a place the technology should have in Australia's future energy mix.

The Australian Government's intention to ask AEMO to expand its planning scenarios to prepare for greater use of renewable energies is encouraging. While this measure is likely to focus on the transmission network rather than connecting embedded generation to the distribution network, the UBC Project notes that there is also scope for AEMO to incorporate the potential for a higher contribution from cogeneration into their planning studies.

By implementing changes to the National Electricity Rules that would enable cogeneration to connect more easily, the market will see more efficient investment in, and efficient operation and use of, Australia's electricity services.

Key benefits

- *Cogeneration and trigeneration offer Australia significant environmental and economic benefits in the short and long term. As a form of embedded generation, cogeneration is a low emission and highly efficient alternative to conventional fossil-fuelled energy sources.*
- *The technology is particularly suited to buildings where there is onsite demand for the heat and electric energy the systems produce. In many cases, cogeneration is financially viable for property owners today.*
- *Property owners are embracing greener energy solutions, driven by environmental building rating programs, including Green Star and NABERS, as well as customer demand for green buildings in urban areas where network capacity is most constrained.*
- *In many cases, cogeneration is viewed as the low emission energy generation technology of choice over alternative renewable energy technologies such as solar PV and urban wind.*
- *Cogeneration systems aid network demand management, avoiding the need to transport electricity long distances to the load and reducing demand, helping to avoid costly network infrastructure upgrades.*

The challenge

Despite these benefits, cogeneration project owners in the property industry face numerous challenges in deploying the technology. The UBC Project has identified the two main barriers to project delivery.

1. *An inefficient connection process that is costly and time-consuming:*
2. *Barriers to developing medium to large projects across multiple sites:*
    a. *Installing a larger cogeneration system or upgrading an existing system to service more than one building where those buildings are next to each other.*
    b. *Developing medium to large cogeneration systems servicing multiple sites across a district.*

3. Barriers to deployment

The introduction of a price on carbon is helpful for the deployment of cogeneration systems. However, despite the realised benefits of cogeneration, proponents of the technology currently face numerous barriers to its integration in buildings. These barriers are largely driven by a regulatory framework that does not reflect the realities of, and is not suited to, small to medium-sized urban cogeneration projects. The result is an inefficient process that impedes the technology's deployment today, hindering its development and innovation in the energy market in the longer term.

The UBC Project has highlighted two main barriers:

- An inefficient connection process
- Developing projects across multiple sites

Barrier 1 – the connection process

The process for connecting to the electricity distribution grid is a major cause of cost and uncertainty for cogeneration project owners.

The application process involves three steps: a connection enquiry by the cogeneration proponent, the submission of a connection application to the DNSP, and finally, a connection agreement offer from the DNSP.

Despite its apparent simplicity, this process is difficult for cogeneration proponents.

The asymmetries between the cogeneration project owner and the DNSP result in the project owner experiencing a range of barriers which have been studied in numerous reports over the past decade. These barriers are summarised below:

- A lack of transparency of information and information exchange, once the information required by the DNSP has been identified
- Misaligned timeframes and milestones between cogeneration proponents and DNSPs. This follows on from the apparent presumption in the National Electricity Rules that generation is the sole purpose of the proposed development and that evaluation of the proposed connection can and should be deferred until the design is substantially complete and the equipment specification agreed
- High costs – particularly network augmentation costs depending on whether shallow or deep augmentation of the network is required, and protection equipment costs – as well as difficulties in evaluating the appropriateness or competitiveness of the cost estimate
- Barriers to connection based on technical network requirements – where the DNSP and the embedded generator are required to meet and maintain specific, often mandated, standards

The introduction of a price on carbon is helpful for the deployment of cogeneration systems. However, despite the realised benefits of cogeneration, proponents of the technology currently face numerous barriers to its integration in buildings.

- Uncertainty due to the project owner's lack of insight into or control over the connection process
- A lack of set timeframes for connection
- A lack of common contract terms.

The UBC Project Victorian case studies illustrate these barriers. They lead to a drawn-out connection process in which the cogeneration project owner must spend an onerous amount of time and money to bring the facility online.

- Each DNSP follows a different connection process. Each DNSP makes different degrees of information about this process available to applicants[16].
- In Victoria, only one DNSP publishes its process. This process only relates to installations larger than 10MW and is tightly based on the 20-step process for large-scale generation facilities seeking connection under the NER. In other states, it is almost standard for DNSPs to provide online information, an information line and a form outlining the connection process. Even so, the problem remains that each DNSP sets its own process. If, in the process envisaged by Chapter 5A, each DNSP was to do this for each of the mini, small, medium and large categories identified by the Energy Networks Association (ENA), this would result in 44 different connection processes in Eastern Australia.
- Once a connection enquiry has been made, DNSPs are not adequately equipped nor given enough incentive to respond to connection enquiries in a manner that reduces the potential for surprises. The NER appear to see this phase as an exchange of basic information, rather than part of an interactive process designed to improve the connection application stage.
- Contrary to the way the NER are currently designed, a connection enquiry is likely to be made at an early stage when a number of potential options for achieving the desired energy efficiency are under active consideration by the owner and a range of specialist advisors with responsibilities for different elements of the concept design. At this stage, the DNSP's advice on the connection point, equipment type and operating mode

[16] One Victorian retrofit project not included among our projects, unable to identify the DNSP's requirements or locate an application form or guide, designed their own application form for the proposed mini cogeneration unit!

most likely to be quickly and easily connected are very valuable in guiding the owner's research by helping them narrow the choices under consideration and limiting the time spent looking into alternatives unlikely to be successful.

- Owners would like to see the DNSP work with the specialist project team at this stage of the project, minimising the possibility of rework or miscommunication with the project team. The DNSPs, on the other hand, appear to see this process as a bureaucratic requirement, rather than one requiring technical skills or engagement. One UBC Project participant, for example, reported difficulties in its ability to effectively engage with its responsible DNSP due to the DNSP's requirement for a single point of contact for both parties through which all information requests and responses would be communicated.
- This barrier is ultimately an issue of engagement. To improve the likelihood of a connection proceeding, DNSPs need to engage with project owners in the early stages of the project design process. However, there is currently no fee, and therefore no incentive, associated with this engagement process. This barrier could be easily resolved, as UBC Project owners have indicated they would be prepared to pay on a fee for service basis to ensure this engagement process occurred.
- Once the cogeneration project owner moves to a connection application, the onus is currently on them to provide the DNSP with technical information about the connection. This information includes details such as usage patterns and market models of proposed equipment that the project owner may not be equipped to provide at an early stage. There are two problems associated with this that are currently embedded in the NER and are largely based on a lack of understanding .
- Firstly, because the information required for a connection application is often not readily available or is unclear to project owners, property project owners are unable to factor these requirements into their project planning.
- Secondly, even if the required information was clearly identified in advance, Chapter 5 of the NER is not designed with small generation in mind. The rules appear to view cogeneration systems as equivalent to a major power station, where detailed designs and a procurement plan identifying all of the major equipment items are ready prior to contacting the DNSP. In a commercial building development, however, the cogeneration facility is only one of multiple building elements that the project owner is progressing in parallel. It is therefore likely that while negotiating with the DNSP, the project owner is also in negotiations with tenants or other stakeholders on the design of the building itself. They may not, therefore, be in a position to provide the DNSP with the required information for the connection application to proceed as the NER and the DNSP's currently require.
- As one of the project owners involved in this study explained, a fully resolved commercial building design only follows the signing of a Heads of Agreement with the key tenant and negotiations with the tenant on the operation of the building. Those negotiations may result in modifications to the earlier concept design. The owner aims to tender the building works around 12 weeks after the Heads of Agreement is signed. During this time, they will be finalising the design of the building and the equipment specification for the building works, and simultaneously negotiating the lease with the key tenant. From the owner's perspective, the least amount of rework is involved if the connection application is made after the Heads of Agreement is signed but before the building works are tendered. Any earlier and the owner risks having to rework the design. One of our participants estimated that the cost of redoing a procurement module as part of reworking the design could be $200,000 in fees, without counting time lost. Any later and the owner bears the costs and risks of altering the design, procuring different equipment to the specification in the building works tender and, depending on the scope of changes, possible additional construction costs.
- Project proponents may not be aware of the process DNSPs must undergo to ensure the embedded generator does not compromise the safe operation of the network or its mandatory performance standards.
- The case study proponents consider that a timeframe of between one and three months for completing the connection application process would be consistent with the wider commercial building development process, with an outer limit of six months in extreme cases. In Victoria, Distribution Licences require cogeneration connection applications to be completed within 65 business days, but this requirement appears not to be widely known or commonly understood. One of the DNSPs indicated that for a large project, the connection application process could take up to two and a half years, while for a small project, six to 12 months, but possibly more, was standard. This may arise because the current process introduces a perpetual loop: without well-defined and accessible information on the technical and information requirements for a connection application, engagement between the project owner and the DNSP can continue for a considerable time. The DNSP may consider that it hasn't received all of the required information for a connection application and, in consequence, not commence the formal assessment of the connection application. The owner in the meantime provides quantities of information in anticipation that the project is moving forward towards a result on its application.

- The costs of delay are significant. Even before considering penalties for later delivery or factoring in higher construction costs to meet a truncated timeline, the holding costs for a large commercial project run to between $50,000 and $100,000 a week. Unsurprisingly, some projects eventually finalise the design, procure equipment and commence construction before the connection application is finalised; the costs of ongoing delay are too high to continue to wait for the DNSP's decision.
- Even after significant time and money has been invested in completing the connection application for the DNSP, including a network study, the outcome of an application is unpredictable and the timeframes unknown. It is particularly problematic that an applicant could still be denied a connection due to fault level headroom or other network constraints which the applicant had no ability to identify before making an application.
- In the case of one of the projects in the UBC Project, the owner received approval of its connection application, only to have it subsequently withdrawn, without explanation for the change of approach.
- If a connection is agreed to, there remains a lack of transparency regarding the costs of connection, including whether a connection requires deep or shallow network augmentation, and who is responsible for that cost.
- A significant body of work in the past decade has analysed these issues and presented solutions. In addition to the work undertaken for the Ministerial Council on Energy, regulators and market operators, individual participants have put forward proposals, most recently CitiPower in its 2011-2015 regulatory proposal.

The high costs of connection

For both cogeneration project owners and distributors, the cost of connecting cogeneration systems often remains unknown until significant time and money has been invested in the application process itself.

The lack of transparency around the responsibility for and the costs of deep augmentation of the network means cogeneration project owners are often surprised at the DNSP's quote to provide the service.

The barriers associated with the costs of connection for embedded generators in Australia are not new. The MCE highlighted the "potentially prohibitive" nature of these barriers in its 2006 'Impediments to the Uptake of Renewable and Distributed Energy' report.

"Incremental connection costs can be potentially prohibitive for new R&DG [Renewable and Distributed Generation] projects, particularly where projects require network augmentations or provision of major new line.

Network connection costs can be a key factor to the viability of R&DG projects…R&DG must negotiate with the NSP [Network Service Provider] what proportion of network connection costs they will be required to pay.

These costs include those incurred in relation to all the connection assets construction for exclusive use of the generation applicant and which connect the generating plant to the network connection point; and network augmentation costs including network augmentation and voltage control equipment…The degree of any required network augmentation will vary for each project and the cost of such augmentation will depend upon the capability of the network to accommodate DG while maintaining secure and reliable supply.

The basis of assessing and assigning costs associated with connecting an embedded generator to the network is generally not transparent to all parties. Augmentation of existing network assets may provide benefits to other network users, creating difficulties in assigning these costs. Furthermore, DG may provide other benefits to network users, for example, through improved system security. Quantifying and assigning these benefits is difficult"[17].

As identified by the UBC Project, the need for, and cost of, network augmentation is a significant barrier for cogeneration project owners. This is particularly the case in dense urban environments where network capacity may be restricted due to historical limitations on the network.

The problem with the current process, in which a cogeneration proponent may be seeking to install a cogeneration project where there is a ceiling on network capacity, and available fault level headroom has been exhausted, are twofold. Firstly, there is little or no relevant information available from the DNSP on the capacity of the local network for new cogeneration connections. As noted by the MCE, cogeneration project owners are not themselves equipped to determine whether there is sufficient network capacity available. Secondly, if it is established that there is not enough network capacity, the

Fault Level Compliance Service Fee proposal

At the Victorian Electricity Distribution Price Review 2011-15, CitiPower proposed capital expenditure of $72M ($2009) to alleviate the fault level constraints in its network, which would have allowed up to 150 MW of embedded generation to be connected and synchronised with the network. This up-front capital expenditure by CitiPower was to be recovered from embedded generation proponents via a Fault Level Compliance Service Fee at the rate of $625 per nameplate kW of connected generation.

If accepted by the Australian Energy Regulator (AER), this would have allowed a more streamlined connection process. The Draft Determination by the AER in June 2010 did not accept this proposal.

[17] MCE 'Impediments to the Uptake of Renewable and Distributed Energy' report, 2006, p28.

CASE STUDY 3

Monash University, Clayton Campus

Monash University is committed to reducing its carbon footprint and cogeneration can assist this end. The New Horizons project represents the University's first opportunity to implement a cogeneration plant. A significant, practical driver was the requirement for this building to seek a 5 Star Green Star As-Built certification. As an energy-intensive research building, achieving this level of performance is greatly enhanced by implementing a cogeneration plant to reduce the peak load requirements and carbon intensity. Cogeneration also provides a level of energy security in that essential loads within the building can be supported if a major upstream electrical power disruption occurs.

costs of network augmentation are not transparent and are often prohibitively expensive – costing more than the cogeneration system itself.

Explained in more detail, initially a cogeneration project owner is responsible for the cost of determining whether there is enough capacity in the local network for them to connect. Determining this can cost hundreds of thousands of dollars in specialist consultants to conduct network studies, design and redesign proposed installations, identify and procure additional equipment to meet DNSP specifications, and to liaise with the DNSP. If the network study[18] finds insufficient capacity in the local network, the DNSP may seek to recover the costs of deep augmentation of the network from the cogeneration project owner, although depending on the jurisdiction, the DNSP is not entitled to do so[19]. As noted by the MCE in 2006, the cost of this network augmentation is unclear to many participants. The UBC Project has found that it could amount to millions of dollars, making a cogeneration project financially unviable in many cases.

The UBC Project has identified instances in which connection is refused by the DNSP or is subject to conditions that materially restrict the operation of the cogeneration system at all times. For example, by requiring the generator to run in island mode – not synchronised with the network –all export can effectively be prevented. The conditions imposed on the installation can be such that owners are effectively denied a connection for the proposed cogeneration unit despite their significant investment already committed to the cogeneration project's design and in the connection application itself.

The principle that appears to be applied currently in allocating shared network augmentation costs is 'last in, worst dressed'. The project owner - whose connection application coincides with a ceiling being reached on a local network capacity such as available fault level headroom - may be asked to meet the full costs of the required shared network augmentation. No recognition is given to the contribution of other earlier connections to exhausting the available network capacity.

This problematic network capacity situation is compounded by the absence of any relevant information on the capacity of the network for new embedded generation connections or other developments.

A further problem for cogeneration project owners is the extent to which the DNSP's safety and performance requirements can impose excessive costs – either financial or in performance terms – through the extension of the DNSP's concerns past the operation of its network to the operation of the network internal to a building or development.

DNSPs are responsible for the safe operation of their networks and the safety of their employees and the public. In addition, there are significant safety and regulatory requirements imposed on all connections to the network to ensure the safe design, operation, ongoing maintenance and safe operation of the network of electrical installations in private buildings in Victoria and other states. The Victorian Distribution Code, for example, imposes explicit obligations on embedded generators connected to the distribution network to comply with the Code, the Electrical Safety Act and associated regulations, relevant Australian standards and to maintain the installation in a safe condition. These requirements act in concert with the DNSP's responsibilities for their own networks to ensure that the safety of employees, the public and the electricity network as a whole is not prejudiced by the activities of parties connecting to the network.

Fault level headroom, particularly in networks servicing concentrated business districts, can be limited and the maximum fault level contribution that a DNSP can allow is subject to regulation – in Victoria it is regulated under the Distribution Licence and the Distribution Code. As a result, depending on the configuration of the network where the embedded generator proposes to connect, the DNSP needs to consider the implications of the connection for network performance. In considering the safe operation of embedded generator connections, the Distribution Code imposes direct obligations on the embedded generator. The DNSP should take into account the wider safety and regulatory framework in assessing safety requirements for the connection and the upstream network works[20].

---

[18] Or *studies*: a number of developers have been required to undertake multiple network studies relating to the same proposed connection application to satisfy the DNSP about a proposed connection.

[19] In Victoria and a number of other jurisdictions, DNSPs have not been allowed to charge new connections for deep connection costs as part of the connection charge for cogeneration and trigeneration connections. However, a lack of transparency and competitiveness in the DNSP's connection cost estimates, combined with some known instances where deep connection costs have been included in proposed connection costs, result in significant concerns about the nature of the DNSP's charging, estimation and construction practices.

[20] Research recently carried out by the CSIRO for the Energy Networks Association (ENA), for example, in evaluating the fault level contribution modelled in the case studies, makes the point that, for the stylised examples considered the increases in fault levels "did not expose the network to fault levels above those already present during an N-1 contingency condition". These results are based on the Sydney CBD network, and do not apply directly to the Melbourne CBD, which among other differences is typically lower voltage. Elsewhere in the CSIRO study, the findings indicated that, in relation to a number of the findings, the scenarios would be better dealt with under the DNSP's contingency event planning than considered in relation to a single embedded generator or a cluster of embedded generators. This suggests that, considering the network as a whole, a DNSP may be "double counting" in applying protective measures to individual installations. Replicating these tests for the Melbourne CBD network may be desirable. In addition to the areas highlighted in the CSIRO study, there are other areas where a DNSP's methodologies may be imposing additional costs on connection applicants – for example, where a DNSP effectively "reserves" network capacity and fault level headroom for future growth, at the expense of current connection applicants, or where a DNSP chooses to model multiple connections of a similar type for their collective effect on network performance, where only a single connection application has been received for that part of the network.

CASE STUDY 4

Crown Melbourne

Crown's vision is to be the leader in sustainable business practices in the entertainment industry. This project involves the expansion of the existing trigeneration system to allow the connection of multiple buildings across the site. Doubling the size of the trigeneration plant will play a significant part in reducing Crown's environmental footprint.

As discussed above, there are significant system-wide efficiencies to be gained by eliminating the costs imposed by the inefficient connection process and streamlining it to speed up connections to the grid. Moreover, by enabling cogeneration systems to more easily connect to the distribution system, the market is better placed to determine the best scale for the technology as an electricity and heat energy supply solution.

At the regulatory level, embedded cogeneration projects seeking connection to the distribution network are currently treated as if they were similar to new, large customers seeking connection. That is, the projects are seen as new, discrete connections often located at some distance from the existing distribution network[21]. Of the projects involved in the UBC Project, however, only one may fall into this category.

In fact, the UBC Project case studies, and the urban situations the technology lends itself to, suggest that these projects will most likely be situated in existing, high density areas with a high commercial demand for better quality buildings. For these projects therefore, the key issue is and will increasingly be the cost and incidence (who pays) of shared network services.

Network connection barriers – well established, well recognised

The MCE's 2006 report is one of many studies conducted in the last decade on the integration of embedded generation into the transmission and distribution grid[22].

The conclusions from these reports reflect the established and widespread agreement among energy market participants and experts that process efficiencies regarding the connection of embedded generation should be improved with a view to encouraging efficient investment and operational decisions within the NEM.

For example, the ENA has argued that greater standardisation and national harmonisation of these processes are desirable. In 2008, the ENA recommended:

"Increased harmonisation of technical requirements, contractual arrangements, operating protocols and procedures for the connection of the smaller embedded generators across jurisdictions"[23].

NERA Economic Consulting, meanwhile, specifically advised the MCE in 2007 that transparency of information would meet the NEM Objective by "allow[ing] for economically efficient investment and operational decisions to be made"[24].

NERA Economic Consulting's August 2007 report also recognised an ongoing issue identified by the UBC Project.

NERA found that information asymmetries between DNSPs and embedded project owners "may lead to inefficient investment decisions by connecting parties or those offering non network solutions". The report identified that these information asymmetries occur because "the network service provider is likely to possess greater knowledge of the network than third parties, and hence also of the likely costs and benefits of those parties' intended actions"[25].

The solutions proposed by the UBC Project would ensure greater information transparency, thereby improving the efficiency of the process as specified under the NEM objective.

[21] Australian Energy Regulator, *Connection Charging Guidelines*, 2011

[22] MCE 'Impediments to the Uptake of Renewable and Distributed Energy' report, 2006. A list of reports published in the last decade on the subject of connecting embedded generation to the grid appears in Appendix 1.

[23] 'Embedded Generation: ENA Policy Framework Discussion Paper', prepared by ENA, November 2008.

[24] NERA August 2007, p38.

[25] NERA August 2007, p38.

Barrier 2 – deploying cogeneration on multiple sites

Developing cogeneration systems to service the needs of multiple sites poses significant challenges, both network connection and regulatory, for cogeneration project owners. The nature of the challenges associated with deploying cogeneration on multiple sites makes them more complicated to resolve than the problems associated with the current connection process.

Despite the economies of scale achieved through developing larger cogeneration projects, it should be noted that multi-site developments were only being considered by two of the six UBC Project case studies. This suggests that owners are focusing on projects where they will not encounter the issue. However, larger cogeneration facilities that service multiple sites are the most efficient and economically viable way to deploy the technology. As a result, solutions to the problems associated with multi-site developments do need to be worked through and implemented.

The UBC Project identified two development types from the participating projects that currently need to negotiate the barriers posed by multi-site developments.

a. Installing a larger cogeneration system or upgrading an existing system to service more than one building where those buildings are next to each other.

b. Developing medium-large cogeneration systems to service multiple sites across a district.

Each development type faces different barriers in deployment of cogeneration at the district scale level.

Despite the economies of scale achieved through developing larger cogeneration projects, it should be noted that multi-site developments were only being considered by two of the six UBC Project case studies. This suggests that owners are focusing on projects where they will not encounter the issue.

Cogeneration servicing multiple, contiguous sites

Owner A currently has one 6MW cogeneration system in a single building (Building 1) which services the building's own needs with base power, standby power, heating and cooling. However, Owner A also owns a second and third building, one of which is on the same land title as Building 1 and both of which are immediately next-door to Building 1, but separately connected to the distribution system[26]. Owner A wishes to upgrade the existing cogeneration system to one 12MW facility to service the heating, cooling and electricity requirements of all three buildings. As currently implemented, the electricity systems for the three buildings are separate and redesigning the existing facility to directly service all three buildings internally would be a major capital project. Considering the requirements and the expense involved, such a redesign would result in the upgrade being uneconomic.

Currently all three buildings are separately metered by the DNSP. If Owner A was to upgrade the system in Building 1, with the aim of netting off the electricity produced against the consumption of Buildings 2 and 3, it would have to obtain an exemption to the retail licencing requirements or enter into an agreement with a third party, e.g. a retailer[27].

Under these scenarios, Owner A would either:

- Obtain an exemption to the requirement to hold a retail licence; participate in the wholesale electricity market as an exempt market participant to receive the wholesale value from the cogeneration output surplus to Building 1's requirements and/or to purchase the buildings' residual energy requirements from the wholesale market; pay the required prudential deposit to AEMO; negotiate its own transmission and distribution agreements, which may include providing security to both the transmission and distribution businesses; register the meters at Buildings 1, 2 and 3 as customers, effectively netting off the production of Building 1 against the consumption of Buildings 2 and 3; pay AEMO for net wholesale electricity purchases, where Building 1's net output is less than Buildings 2 and 3's requirements; and pay the transmission and distribution business fees.

or

- Enter into an agreement with a retailer: the retailer would manage the wholesale market and the transmission and distribution business requirements, as well as holding the retail licence. The retail agreement is likely to involve the purchase of the cogeneration output surplus to Building 1's requirements at around the wholesale electricity price, but the cost of energy supplied to Buildings 2 and 3 would be a matter of commercial negotiation between the parties.

Alternatively, Owner A could build smaller cogeneration systems on each of the three buildings, netting off production against the consumption requirements of each building individually. However, this is not possible in this case as there is not the space other than at the central building.

These solutions, however, increase the costs to the owner. Upgrading the single cogeneration facility to service all three buildings internally would see Owner A subject to significantly increased capital costs. Becoming a retailer, even where exempt from the requirements of the retail licence, involves significant administrative and working capital costs, while contracting with a retailer may result in unfavourable prices for the power Owner A would have to import, reducing the business case for the larger cogeneration facility. Meanwhile, building two additional smaller cogeneration facilities, if it were possible, would result in Owner A paying for two additional set-up costs and for two additional cogeneration installations, resulting in a higher unit cost of output as a result of the larger number of smaller, less efficient installations required.

These alternatives are likely to make an upgrade to the cogeneration system less attractive in comparison to continuing to purchase power from the grid to service Buildings 2 and 3.

Cogeneration at the district level

Owner B is developing a project on what is currently a single site. Owner B plans to install three large cogeneration systems across the site over time, with the aim of supplying district scale heating, cooling and electricity to future owners and their tenants. In this case, Owner B is looking to recover the costs of its cogeneration investment, as well as the costs of the infrastructure associated with district scale heating and cooling.

While the site remains a single site and title, the current connection process is unlikely to present a significant barrier to developing this cogeneration system, because the site is undeveloped and faces no competition from other participants in the location for network capacity. Depending on the nature of the tenants on such a site, Owner B may be

---

[26] This is a material issue, as the relevant regulation relates sites and connections, so the Developer in this case may not be eligible for any of the deemed or proposed registrable exemptions to the licencing requirements because Buildings 1, 2 and 3, although owned and operated by the same entity, are separate from each other, considered from the perspective of electricity market regulation. If, previously, all three buildings had shared a single connection, then, notwithstanding the fact that there are two separate land titles involved, from the regulatory perspective, only one site would have been identified and the Developer would qualify for the proposed deemed exemption to the retail licencing requirements to allow the on selling of energy to a related company with the limits of a site that they own, occupy or operate and an accompanying exemption to the network licencing requirements for an embedded network relating to sales to a related party. Alternatively, provided that the energy consumption of Buildings 2 and 3 is sufficiently large, the Developer could qualify for a registrable exemption to the requirement to hold a retail licence, as customers consuming more than 160MWhs are year are excluded from customer protections designed to protect small customers.

[27] There is a third possibility currently being contemplated by AEMO which would allow aggregation of the meters for the three sites, as part of its response to the findings of the Project looking at Small Generator Framework Design. The extent to which this would reduce the requirements on the Developer depend on whether the combined energy needs of the buildings are likely to always exceed the production of the cogeneration facility or if, on occasion, the output of the cogeneration unit will exceed the energy requirements of the buildings. However, AEMO does not anticipate its proposals, which are as yet unclear in their precise design, being implemented before the end of 2012.

CASE STUDY 5

Moreland Energy Foundation, Fawkner Leisure Centre

The Moreland Energy Foundation, in conjunction with the Moreland City Council, is developing a blueprint for a pilot carbon neutral project which would see a cogeneration plant installed for the Fawkner Leisure Centre to provide heat and electricity to a group of facilities across the precinct. The project will be implemented as a joint venture between the two organisations. A business model is being developed that aims to capture the savings into a fund to be reinvested into further projects in order to establish the capability to deliver projects to larger precinct redevelopments.

able to obtain a registrable exemption to the retail licencing requirements that allows it to sell the services to tenants[28]. In this scenario, Owner B's material risk is the commerciality of the proposition from a tenant's perspective: how much a tenant is willing to pay for the services provided – heating, cooling and low emission power – by the owner and whether the costs for the services result in a potential tenant preferring an alternative location.

However, Owner B plans to subdivide the land and sell land parcels to future owners and/or tenants. As a result, Owner B's ability to ensure the recovery of its investment in either the cogeneration or the infrastructure investments is considerably lower and the Project, as a result, is considerably more risky.

Owner B may qualify for an individual exemption to the licencing requirements relating to on-selling under the proposed Australian Energy Regulator (AER) Exempt Selling Guidelines. Conditions attached to these exemptions are likely to include the requirement to individually meter customers and to restrict the price charged to exempt customers at residential premises to the level consistent with that charged by the local area retailer. These requirements are designed to protect customers from price gouging and to ensure that customers maintain the ability to access alternative suppliers.

However, the commercial proposition works best as a bundled service as heating and cooling are effectively by-products of the generation process. If the power is not required, then heating and cooling are not produced. So, the owner needs a critical mass of customers to ensure the commercial proposition is viable.

The requirement for customers to retain the ability to opt out, while potentially acting as a break on the potential for price gouging, also poses the risk of the proposition unravelling if sufficient potential customers opt for alternative supplies. The wholesale market price for energy by itself is insufficient to allow Owner B to recover the costs of the cogeneration system – even for larger scale cogeneration projects – and, depending on the structure of the infrastructure charges to residents and tenants, selling the power to the wholesale market may undermine the economics of the infrastructure installed.

Finally, the potential capping of charges at a level related to local prices, while intended as a customer protection, could reduce customer choice if it prevents developments proceeding that customers, acting rationally and in an informed manner, would otherwise choose because – for example – customers have a preference for cleaner local energy. In providing for a competitive market, it is important that the regulatory environment does not have the effect of reducing service provider innovation and customer choice.

However, the commercial proposition works best as a bundled service as heating and cooling are effectively by-products of the generation process. If the power is not required, then heating and cooling are not produced. So, the owner needs a critical mass of customers to ensure the commercial proposition is viable.

Summary of key barriers

- *The process for connecting to the electricity distribution grid is a major cause of cost and uncertainty for cogeneration project owners.*
- *Cogeneration project owners seeking connection to the grid today face two main short-term barriers:*
  - *An inefficient connection process*
  - *Developing projects across multiple sites to access economies of scale*
- *Improving the connection process for mini, small and medium cogeneration systems up to 5MW would translate to several hundreds of thousands of dollars in savings to UBC Project proponents alone and therefore much greater system-wide savings over the coming decades.*
- *Barriers to multi-site cogeneration developments are complex and discourage cogeneration project owners upgrading their systems or developing district size systems. In doing so, these barriers discourage economies of scale being achieved.*

[28] Large commercial tenants and related parties where the site is *owned, occupied or operated* by the on seller are among the proposed bases for deemed and registrable class exemptions from the retail licencing requirements. Alternatively, the Developer may be able to recover its costs through service fees, for example, for climate control services, provided that costs are not allocated on the basis of energy consumption. The Developer, however, cannot prevent tenants from installing meters and contracting independently for metered electricity supplies, so the issue ultimately becomes a commercial one about the attractiveness of the joint offer in comparison to the alternatives.

4. A new approach to energy market management

Mindful of past work done to identify the long- and short-term barriers to cogeneration deployment, the UBC Project was established to work through these short-term barriers and deliver solutions that can be implemented today.

To deliver these targeted solutions to well-established and well-recognised barriers an innovative project approach was developed by the UBC Project facilitators.

Three workshops brought together owners of cogeneration projects with distribution businesses and government representatives in the same room. Using projects that would be commissioned in the next 12 months 'but for' immediate barriers as 'live' case studies, workshop participants focused on designing solutions to these short-term barriers.

The focused and integrated nature of the workshops enabled frank discussion between participants to understand the immediate barriers for cogeneration proponents and to deliver real solutions that can be implemented today.

Participants were invited to help design an improved system and many were pleased to make the most of their involvement in the process.

"We've never had a forum like this where we've had all or most of the stakeholders in the room."

– UBC Project participant

By engaging and working on solutions in this way, robust solutions were developed.

Project outcome: an innovative approach to energy market problem solving

Participants in the UBC Project worked together in three workshops over a three-month period, with interim technical analysis and additional meetings conducted by ClimateWorks and Seed Advisory. Approximately 300 hours was spent on the workshops and development of solutions, with each workshop attended by 20 to 24 people.

Bringing experienced cogeneration proponents with current 'live' commercial cases underway resulted in constructive dialogue with energy market representatives. This enabled:

- *Learning about counterparties' constraints and motivations with specific, real examples*
- *A portfolio approach involving multiple customers and distributors that avoided any single project defining the outcome*
- *Discussion around barriers and solutions to benefit from regulatory agencies being in the room to explain current approaches*
- *Focused but non-binding negotiation, which allowed open yet detailed debate and testing of consensus.*

In between workshops, Seed Advisory and ClimateWorks Australia undertook detailed analysis, including testing solutions, commercial and regulatory positions in one-on-one meetings, and circulated background information to cover factual explanations ahead of each session

While the barriers identified by this project are not new, the success of this project's approach to energy market management lies in its development of achievable solutions that have been developed collaboratively.

Moreover, that these representatives from different parts of the cogeneration supply chain participated in and were willing to fund the Project reflects their view that solutions need to be identified and, most importantly, implemented.

UBC Project approach outcomes

- The UBC Project was established to work through short-term barriers to the deployment of cogeneration and deliver solutions that can be implemented today.
- Representatives from all parts of the cogeneration supply chain contributed funding and participated in the Project, a reflection of their view that solutions need to be found and implemented.
- The success of this project's approach to energy market management lies in its development of achievable solutions accepted by parties with asymmetrical priorities.

5. Solutions for greater deployment

Mindful of the work undertaken and reports previously written on embedded generation deployment and connection to the NEM, the UBC Project focused only on developing solutions for cogeneration projects that would be developed in the next 12 months 'but for' immediate barriers. The purpose of this focus is that these, and other similar projects, could be delivered in the short term if the incremental rule changes described below are implemented.

Several of the proposed solutions aim to improve connection processes. They recognise that cogeneration projects developed by commercial customers are sufficiently similar and that cogeneration proponents suffer information asymmetry with DNSPs. As a result it is:

a. efficient to provide standardised processes similar to Chapter 5A provisions of the NER that give micro embedded generators an automatic right to connection, and

b. efficient to require consistency across DNSPs in relation to connection application requirements.

These solutions have been incorporated into the design of two pathways for connection – an automatic right to connection for standard cogeneration projects, similar to that granted under Chapters 5 and 5A of the NER; and an improved negotiated access process for those projects ineligible for automatic access.

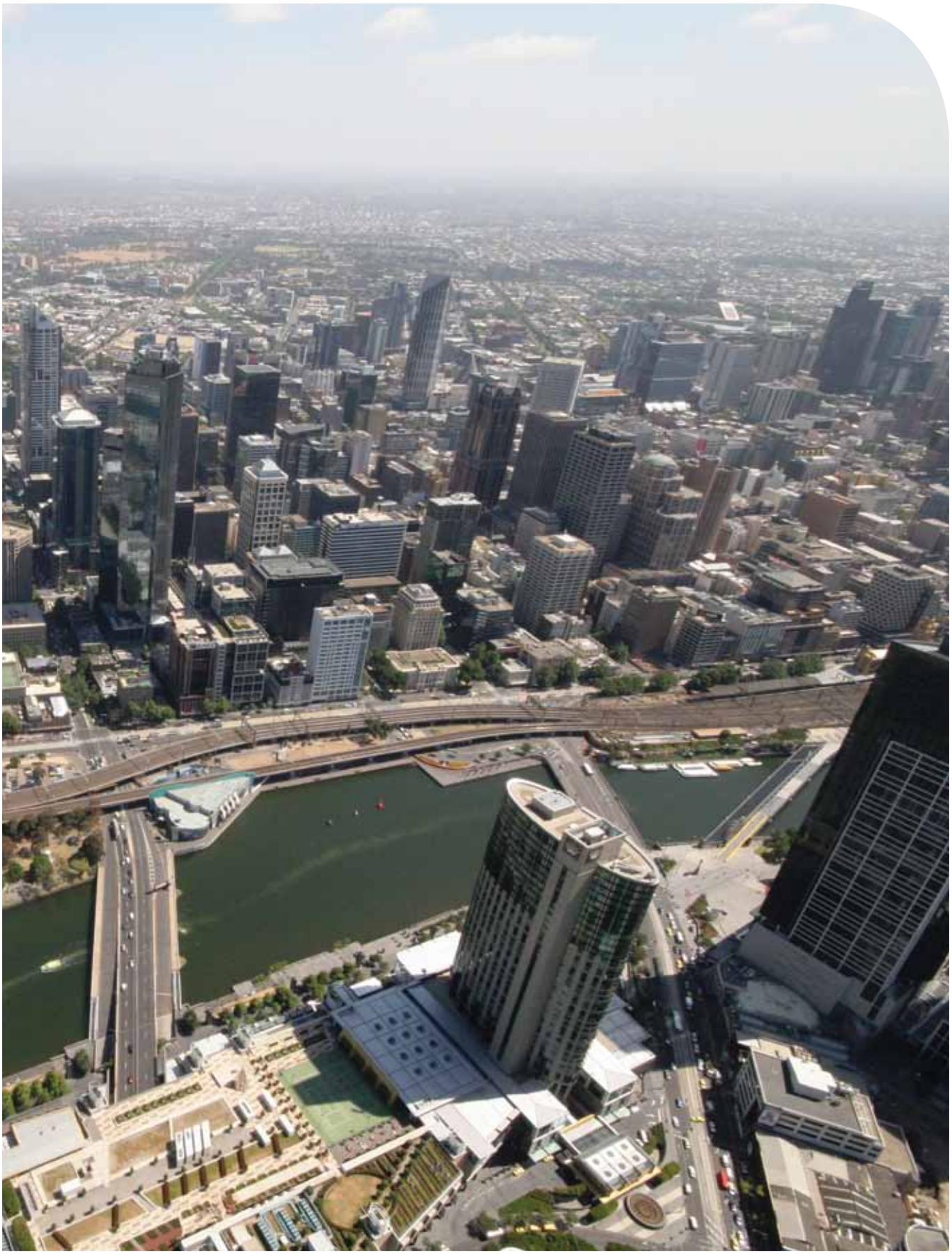
The UBC Project also recommends considering larger cogeneration projects' eligibility as exempt networks under AER regulation to enable cogeneration proponents to achieve economies of scale by developing larger and more efficient projects, developing a specific registrable exemption category for these projects. By allowing the development of these larger scale projects, the amended regulations would in turn be promoting more efficient investment in electricity services.

To progress this latter solution, project participants are engaging in the AER's consultation process on this issue. Other cogeneration stakeholders who support the solution proposed below are encouraged to also engage in the AER consultation.

Key solutions

The UBC Project proposes the following amendments to the NER.

- A standardised connection process should be introduced to replace the case-by-case negotiations that are currently the status quo. This would recognise that small to medium sized cogeneration projects are more efficiently treated similarly to micro generators. Micro generators will have a dedicated standardised connection procedure, as opposed to a negotiated connection process based on a process developed for much larger generators, from the commencement of Chapter 5A of the NER in July 2012.
- The existing concept of automatic access – as outlined in Chapter 5 for all generation projects meeting the automatic standards and in Chapter 5A of the NER for micro generation – should be extended to incorporate cogeneration facilities up to 5MW. This would give the facilities meeting the required technical standards a right of connection to the distribution grid similar to that to be introduced for residential solar PV systems and other micro generators and already existing for conventional generators.
- The negotiated access process for non-standard projects should be streamlined, with agreed timeframes and common information requirements and contract terms implemented under the NER.
- Project owners can choose to pay DNSPs on a fee-for-service basis to work in a collaborative fashion during the connection inquiry stage of a proposal to shape and improve the potential project. It is envisaged that this fee would be additional to any subsequent application fee. However, any subsequent fee would be reduced to account for the improved alignment between the cogeneration system and the DNSP's connection requirements.
- DNSPs should be required to publish an annual 'exceptions' report showing areas where no fault level headroom or other constraints exist in the network that may prevent connections within a defined near-term period such as 12 months.
- The use of subtractive metering – allowing the output of embedded generators to be offset against the usage of a group of other electricity users – in relation to demand side aggregation should be extended to enable larger cogeneration systems to service multiple yet contiguous sites.
- Larger district level cogeneration projects should be considered for a registrable exemption to the network licencing requirements, as opposed to an individual exemption. As an exempt network the cogeneration project owner could charge for use of their services, enabling them to recover the capital costs of their investment.



Proposal 1

Streamline the connection process

This project's proposal for improving the current connection process draws on, extends and improves the existing concept of connection options for generators to connect to the network under the NER – automatic access and negotiated access.

Chapter 5 of the NER outlines automatic access standards for large conventional generators, with negotiated access a common alternative[29]. Moreover, the proposed Chapter 5A of the NER – currently being legislated at state government level – introduces automatic access standards for micro generators, particularly solar PV, meeting the relevant Australian standard.

Given the automatic and negotiated access options already existing under the NER, there is a significant gap for mini-medium generators - those classed by the ENA as having a nameplate capacity greater than 10kW and no more than 5MW.

The UBC Project therefore proposes the (logical) extension of the automatic access concept to explicitly accommodate cogeneration systems. As a priority, enabling automatic access for cogeneration systems up to 5MW should be immediately implemented because, relative to the size of their installation, the costs of connection and the current connection process are very high. Extension of the automatic and negotiated access streams could then be considered for larger systems.

It should be noted that the proposed solution differs to that proposed in Chapter 5A, which envisages the DNSPs defining automatic access standards for micro generators and other classes of customers seeking connection, if they choose to do so. In the case of mini-medium cogeneration systems, this approach by the DNSP's could result in 44 different access standards defining automatic access across eastern Australia. To improve the process the UBC Project proposes that access standards and standard connection agreements are mandated nationally with boilerplate terms and conditions.

Under the proposed amendments to the rules, it is envisaged that the majority of cogeneration connections would be granted automatic access after payment of a standard charge. Other projects would gain connection through an improved negotiation process between the cogeneration proponent and the DNSP.

Table 2 below outlines current and proposed access arrangements under the NER.

Table 2. Proposed access arrangements

Best outcome for cogeneration project owners	Existing allowances under National Electricity Rules – Chapter/Section and scope	UBC Project proposal: (different or similar)
Automatic connection of equipment meeting the standard set in the National Electricity Rules (NER) for embedded generators of the relevant class.	• Chapter 5 of the current NER specifies automatic access standards and minimum access standards for different categories of generator (by type and size) who will be, by requirement (30 MW+) or desire, registered market participants. • The new Chapter 5A proposes that basic connection services for customers who are micro-embedded generators should be provided to all connections below a certain size (not yet determined, but likely to allow for average solar PV or even fuel cell connections) and which meet the relevant Australian standard, AS 4777. A basic connection service specifies, among other things: the safety and technical requirements; commits the DNSP to a timeline for the commencement and completion of the work; details the basis for the connection charge, including requiring a standard connection charge for dedicated (that is, customer specific) assets, excluding special circumstances; and details any special technical or other requirements related to the connection.	• Combines elements of Ch. 5 and Ch. 5A. • Similar to Ch. 5: requires the Reliability Panel to agree to the appropriate standards and publish them. Standards are subject to change from time to time and, furthermore, there can be a plant standard for a particular class of plant, proposed by anyone and approved by the Reliability Panel. • Similar to Ch. 5A: extends the basic connection offer, with boilerplate connection terms, required timelines, common charges, etc.

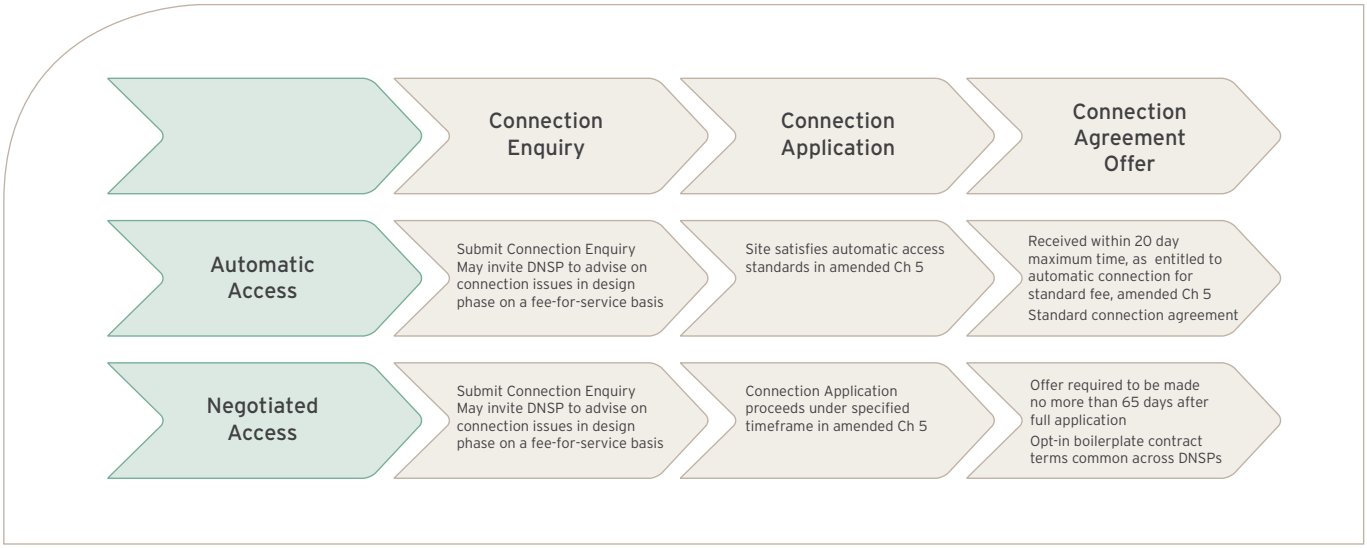
[29] Elsewhere, the NER also effectively guarantees conventional generators a right to connect, a right that Chapter 5A will extend to micro generators.

Table 2. Proposed access arrangements

Best outcome for cogeneration project owners	Existing allowances under National Electricity Rules – Chapter/Section and scope	UBC Project proposal: (different or similar)
Negotiated access for applications where: • the equipment does not meet the automatic standard or has not been considered under the automatic standard. • in other ways (such as where the Project proponent rejects the DNSP's terms and conditions) the application is inconsistent with the automatic access standard.	• Between automatic access standards and minimum access standards, Ch. 5 provides for negotiated access standards to apply to a specific connection, which must be at least as good as the minimum access standard, but, by definition, fall short of the automatic access standard. • Ch. 5A envisages two possibilities: standard connection services for DNSP-defined classes of connections other than those captured in the basic connection service; and negotiated connections, for everyone else.	• Same treatment as Ch. 5 and Ch. 5A, with the difference being that: • Boilerplate connection terms are encouraged in preference to wholly negotiated commercial contracts between two unequally powerful parties – Ch. 5 currently envisages a commercial negotiation between two equally powerful parties. Ch. 5A provides for the AER's approval of proposed terms and conditions for standard connection services.
Timelines are included in the NER	• Ch. 5 provides for explicit timelines relating to the connection inquiry process, but includes no explicit timeline requirement on the connection application process. • In Victoria, the Distribution Licences impose a 13-week (65 working days) timeline on connection offers to the applicant, provided that the connection applicant has provided the DNSP with all the necessary information. • Ch. 5A proposes a 10 day turnaround for applications for basic connection services and a 65 business day turnaround for negotiated connection offers.	• Same treatment as Ch. 5A.
Connection charges	• Due to different state approaches, Ch. 5 does not specify rules in relation to this issue • Ch. 5A proposes that basic connection services pay a unit cost, but that deep connection charges are not part of this. All other connection applicants – standard and negotiated - are required to pay relevant deep connection charges.	• Same treatment as Ch. 5A: • Standardised unit charges, with deep connection costs part of network operations and maintenance expenditures. Consistent with the Victorian Guideline 15 treatment of this issue.
Fault level headroom	• Ch. 5 is silent on cost allocation relating to this. • See above, Connection charges, regarding Ch. 5A.	• Same treatment as Ch. 5A: • Standardised unit charges, with deep connection costs part of network operations and maintenance expenditures.

The new connection process

The diagram below outlines the steps, timeframes and responsibilities involved in the new process.



The solutions proposed to improve the efficiencies of the connection process under the automatic and negotiated access streams are outlined in Table 3 below.

Table 3. Details for each component of the proposed solution

Solution components	Automatic access	Negotiated access
Involving distributor during enquiry phase	Distributor must offer an hourly or negotiated rate for fee-for-service advice if customer requests. This fee would be additional to the connection application fee, which would then be commensurately reduced.	Distributor must offer an hourly or negotiated rate for fee-for-service advice if customer requests. This fee would be additional to the connection application fee, which would then be commensurately reduced.
Agreed timeframes: connection application	10 days between application and offer, based on confirming automatic access standards are met.	65 days between application and offer, based on current Victorian Distribution Licence requirements and Ch. 5.
Boilerplate contract terms	Common standards that, if met, give embedded generators automatic right to connect. Defined for mini, small and medium embedded generators; similar process to current Chapter 5 Access Standards.	Minimum access standards for all mini, small and medium embedded generators; similar process to current Chapter 5 Access Standards, but rather than allowing each distributor to decide its own categories and terms and conditions as proposed in Ch. 5A, standardised for all jurisdictions.
Connection charges	Common connection charge for all customers who meet automatic access standards, varying by embedded generator class (e.g. mini, small and medium). Similar to treatment of micro embedded generation in Chapter 5A.	Only shallow connection costs can be charged to customers (consistent with current Victorian ESC Guideline 15 and treatment in other jurisdictions, but differs from Chapter 5A). Allow customer to choose payment up-front or on an annuity basis subject to satisfactory credit test.
Dealing with fault-level headroom	Managed by distributors under new Ch. 5.	Distributors must publish annual 'exceptions' report: showing areas where no fault-level headroom exists or other constraints would prevent connections in the near term.

Reducing asymmetry

By implementing the solutions proposed above, a standardised process replaces the case-by-case negotiations that are currently the status quo addressing the current significant asymmetry between DNSPs and customers/cogeneration proponents.

The NER Chapter 5A gives an automatic right to connection to micro embedded generators (e.g. household solar PV). This places the onus on the DNSP to manage any network augmentation but enables the DNSP to charge a standard connection fee for the service.

Extending this provision to other embedded generators (e.g. from micro up to 5MW size) would mean that any commercial cogeneration plant could connect for a standard fee, provided their equipment meets common standards.

Dealing with fault-level headroom

The solution outlined above places the onus on DNSPs to manage any network augmentation arising from cogeneration connections. The costs would be recoverable through an upfront connection fee agreed with the DNSP and through the five-year regulatory price determination process, which allows for retrospective recovery in the event of any unforeseen costs.

In addition, to assist customers not using the automatic access process, it is proposed that DNSPs are required to publish an annual 'exceptions' report: showing areas where no fault level headroom exists or where other constraints exist that would/may prevent connections in the near term.

DNSPs are best equipped to undertake a review of their network, and indeed, are already obliged to do so

under the NER. While it is acknowledged that this places additional work on the DNSP, it would result in greater network information transparency and certainty on the part of cogeneration project owners. Informed by such a report and by involving the DNSP at an early stage in the planning process, cogeneration projects would progress more quickly, with significant system-wide savings achieved.

Defining access standards

It is acknowledged that defining the automatic access standards will be more complex than what has already been achieved for micro-generators, which are typically inverter connected and therefore do not contribute to the fault current possible from synchronous generators in failure mode. Defining these standards will be a challenging task and a suitable procedure must be followed allowing input from across the industry including customers as well as distributors and regulators.

Consistent with the MCE's emphasis to the AEMC, the Reliability Panel should be tasked to look at defining such standards.

Support for minimum technical standards and demand-side engagement

In 2009, the AEMC released its Review of Demand-Side Participation in the National Electricity Market[30] *, looking specifically at whether the demand-side of the NEM is participating effectively and efficiently in the market.*

The review recognised the contribution of co-located embedded generators to the NEM and recommended further consideration of minimum technical standards by the Reliability Panel. It highlighted the importance of enabling embedded generators an efficient connection to the grid with "appropriate rewards for any services they provide to the market".

In contrast to the UBC Project's findings, the review did not find the connection process to be a significant barrier. However, it did find that "the flexibility afforded in determining minimum technical standards is causing delays and increasing costs for embedded generators". As such, it recommended that the:

"Reliability Panel consider further the appropriate minimum technical standards for embedded generators as part of its Technical Standards Review."

The review also identified a "lack of [distribution network] planning" in the NER and recommended establishing nationally consistent annual planning requirements. It particularly identified the "requirement for each distribution business to establish and maintain a Demand-Side Engagement Strategy".

The MCE supported the rule changes to provide for these recommendations in late 2010, although the process is yet to be initiated by the AEMC[31].

[30] AEMC 2009, Review of Demand-Side Participation in the National Electricity Market, Final Report, 27 November 2009, Sydney.

[31] MCE, Response to the Australian Energy Market Commission's Stage 2 Final Report, June 2010

Proposal 2

Reduce barriers to multi-site developments

As discussed earlier in this report, the barriers to multi-site cogeneration projects depend on the nature of the site the cogeneration facility is intended to service. In line with the two case studies presented earlier in this report (See Section 3, 'Barrier 2'), the UBC Project proposes two solutions.

Cogeneration servicing contiguous sites

To enable larger cogeneration systems to service multiple yet contiguous sites, it is proposed that the extension of the use of subtractive metering discussed by AEMO in relation to demand side aggregation be introduced.

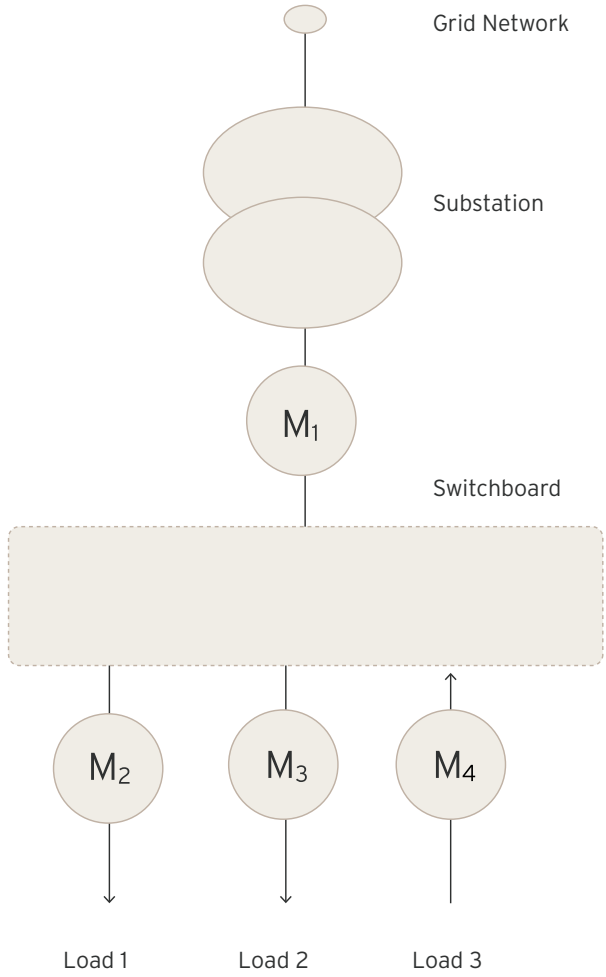
In the case of Owner A, this would allow Buildings 1, 2 and 3 to be aggregated and the cogeneration output from Building 1 effectively to be shared across all three buildings. Subtractive metering places a parent metering point at the DNSP connection point and a child metering point at the on-site generator, with energy produced at the child metering point subtracted from the parent. In the case of Owner A, the parent metering point would be, in effect, a virtual meter which aggregates the meter output from Buildings 1, 2 and 3.

This solution, if implemented, would also allow for aggregation of the meters of dispersed sites – owned by a single property portfolio, for example, or as a result of commercial agreement between individual sites and a load aggregator – improving the commercial prospects for cogeneration, particularly at a more efficient scale.

In the case of Owner A, which has three contiguous buildings (on two different land titles) and wants to upgrade an existing cogeneration system to service all three, this solution is the best commercial outcome. By amalgamating the three meters, the site nets off as a single entity at a single virtual connection point[32].

Enabling the cogeneration project owner to take advantage of scale economies and upgrade the existing system would result in system-wide benefits through lower greenhouse gas emissions and lower power demand on the system as a whole. Owner A also benefits from a system that costs less, leaving it in a better position commercially and, given that this improvement has involved no or minimal public expense, the economy also benefits relative to the alternatives[33].

Subtractive Metering



Subtractive metering is used to net off production and consumption.

In the example, M_4 is an embedded generator exporting its net production. Load at $M_1 = M_2 + M_3 - M_4$

[32] Exemptions to the retail and network licencing frameworks could also address this issues raised in this case, but the case does not fit neatly into the currently defined deemed or registrable categories, assuming that the current configuration is, for the purposes of the exemption frameworks, effectively 3 sites.

[33] The only public expense is the required change in AEMO's procedures, which amortised over a lot of potential projects, is unlikely to be material.

Cogeneration at the district level

To enable larger cogeneration systems to service district level heating, cooling and electricity requirements, it is proposed that such cogeneration project development sites are the subject of a registrable exemption to the licencing requirements. This removes the uncertainty around the proposed individual exemption process, which could see changes in the AER's approach to exemptions being introduced without the benefit of public consultation and could result in changes to or revocation of existing and potential exemptions. The AER is currently consulting on its proposals with relation to retail and network exemption frameworks[34].

As an exempt network, Owner B could charge users for its services and, provided the term of the exemption is set for a sufficient period for recovery of its capital costs, recover the costs of its investment.

The question then arises whether customers should retain the right to opt out during the initial period of the exemption. Alternatively, if customers are informed about the nature and implications of the arrangements at the time they opt into the development, should it be an objective of competition policy to restrict this choice?

To effectively encourage greater deployment of district-scale cogeneration systems, the registrable exemption process should allow for developments of this kind to restrict opting out for a period sufficient to allow the owner to recover some proportion of its costs.

Conclusion

Changing the NER would not only allow cogeneration to compete with other energy generation technologies on a more level playing field but also recognises the similarities between commercial cogeneration projects. It justifies a change from the case-by-case treatment that currently serves as the status quo to the UBC Project's proposed standardised approach that aligns cogeneration connection requirements with the NEM's objectives to

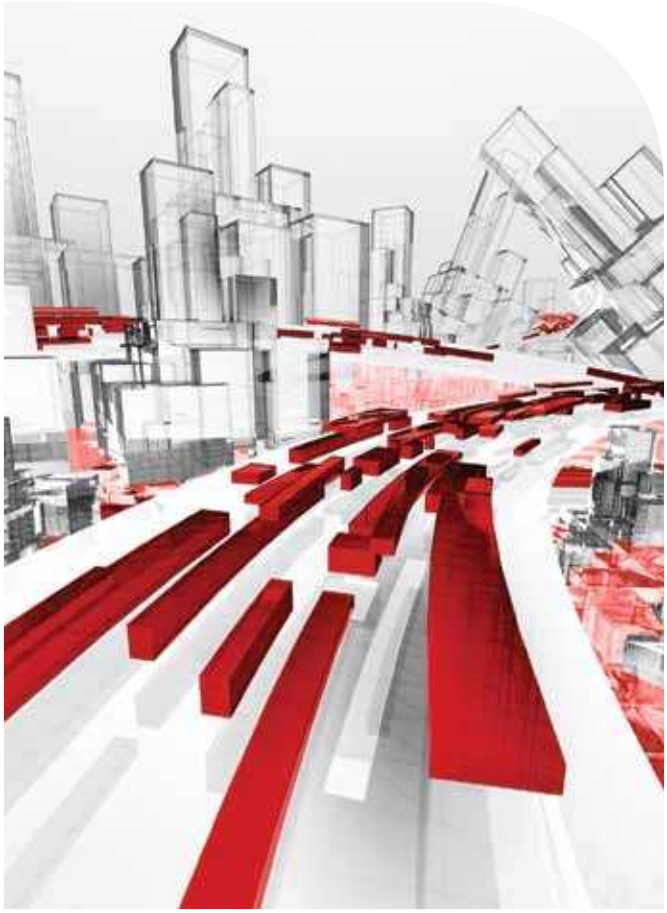
"promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity".

The solutions proposed in this report will help to ease the process and also reduce the barriers to the technology's deployment.

In the short term, these solutions will enable the majority of the UBC projects to come online. In the medium term, the solutions will enable cogeneration proponents to work within the bounds of amended regulations to develop projects that better cater to electricity and heating demand on a larger scale.

Finally, reducing these barriers is expected to pave the way for the real potential of cogeneration to be identified. In the longer term, by enabling cogeneration proponents an unbiased platform from which to deploy new systems and participate in the energy market, the market is given a clear point of view from which to judge how significant a place the technology should have in Australia's future energy mix.

To enable larger cogeneration systems to service district level heating, cooling and electricity requirements, it is proposed that such cogeneration project development sites are the subject of a registrable exemption to the licencing requirements.



[34] AER, *AER Approach to electricity network service provider exemptions*, Consultation Paper, June 2011.

Appendices

Appendix A: Previous reports addressing the barriers to embedded generation deployment

2004

The Australian Government announced that it would work with states and territories to identify specific rule changes required in the National Electricity Market to maximise the benefits of distributed generation.

2006

The MCE SCO Renewable and Distributed Generation Working Group released the 'Discussion Paper on Impediments to the Uptake of Renewable and Distributed Generation'

The Utility Regulators Forum, with assistance from PB Associates, prepared the 'Draft National Code of Practice for Embedded Generation'.

2007

Allen Consulting Group and NERA Economic Consulting prepared two reports for the MCE in 2007 that built on an earlier series of cogeneration case studies they also undertook – 'Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation' and 'Network Planning and Connection Arrangements – National Frameworks for Distribution Networks'.

These reports also mention:

- NERA and Gilbert + Tobin Public Consultation Paper on a National Framework for Energy Distribution and Retail Regulation;
- Expert Panel on Energy Access Pricing;
- COAG Energy Reform Implementation Group (ERIG);
- Ministerial Council on Energy Standing Committee of Officials: Renewable and Distributed Generation Working Group (February 2006), 'Impediments to the Uptake of Renewable and Distributed Energy'; and
- CRA (October 2006) 'Review of NEM Arrangements for Renewable and Distributed Generation'.

2008

The Energy Networks Association (ENA) produced 'Embedded Generation – ENA Policy Framework Discussion Paper' on network considerations of the wider use of embedded generation.

Appendix B: The Rule Change Process (dates taken from most recent private party application)

Step 1
Rule Change Proposal submitted

30 June 2010: Most recent completed Rule Change proposal by a private participant lodged by UED on behalf of all the Victorian electricity distributors received by AEMC.

Step 2
Confirmation letter received by Rule Change proponent

3 business days following lodgement.

Step 3

Notice of Rule Change Proposal received

Submissions in response to proposed changes invited (First Round Consultations). Time for receipt of submissions required to be a minimum of 20 days.

2 September 2010: Notice of Rule Change Proposal published.

Step 4
First round consultation period closes

Note that late submissions can be made.

1 October 2010: First Round Consultations closed.

Step 5
AEMC releases draft Rule Determination and a draft Rule

Notice sets timeframe for requesting a Pre-Determination Hearing and for the close of Second Round Consultations.

2 December 2010: AEMC draft Rule Determination released.

9 December 2010: Requests for a Pre-Determination Hearing required to be received by.

Step 6
Second Round Consultations close

21 January 2011: Second Round Consultations closed.

Step 7
Final Rule Determination

24 March 2011: Notice and Final Determination published, with effect immediately.

Appendix C: About the Reliability Panel

The NEL requires the AEMC to establish the Reliability Panel in accordance with the National Electricity Rules. The role of the Panel is:

- to monitor, review and report on, in accordance with the Rules, the safety, security and reliability of the national electricity system;
- at the request of the AEMC, to provide advice in relation to the safety, security and reliability of the national electricity system; and
- any other functions or powers conferred on it under the Law and the Rules.

Clause 8.8.1 of the Rules sets out the functions of the Panel in more detail.

Under clause 3.9.3A of the Rules the Panel is also responsible for a biennial review of the level of the reliability standard, the level of the Market Price Cap (formerly known as VoLL), the Market Floor Price and the Cumulative Price Threshold (CPT).

The Ministerial Council on Energy proposed that the Reliability Panel be tasked with reviewing minimum technical standards for embedded generation in its response to the AEMC's Stage 2 Demand Side Participation Review Final Report. The MCE said[35] :

The MCE considers the technical aspects of connection to be a significant emerging issue and supports the review of minimum technical standards by the AEMC Reliability Panel as part of the Technical Standards Review.

As part of, or in conjunction with the Technical Standards Review, the MCE supports the AEMC also considering how minimum technical standards may be incorporated into market frameworks to provide greater transparency and certainty for embedded generators regarding the impact of their connection on network performance and fault levels, and hence the allocation of any network augmentation and connection costs that may be required.

The MCE notes the broad industry adoption of technical standard AS4777 in relation to the connection of small inverter-connected generators (such as residential PV) and its intended use in the definition of a small embedded generator as part of the new distribution network connection arrangements being implemented in conjunction with the National Energy Customer Framework.

The MCE considers the adoption of such standards, where appropriate, represents a significant opportunity to address technical connection issues, streamline connection processes and reduce the costs of connection for embedded generators.

The MCE therefore supports the Reliability Panel also considering the development and adoption of similar technical standards for larger embedded generation connections as part of the Technical Standards Review.

However, the MCE notes that an investigation of embedded generation issues may be considered an extension of the Reliability Panel's current expertise. The MCE therefore requests that in undertaking the review, the Reliability Panel incorporates a high level of consultation with embedded generator proponents and industry experts to ensure the technical characteristics of embedded generation and their potential interaction with the grid are comprehensively covered.

The MCE notes the AEMC's finding that the charging frameworks for distribution and transmission connected generators are sufficiently consistent such that they do not present a bias against investment in embedded generation. The MCE also notes that along with network security limitations, these costs present a practical, but legitimate, limitation to the uptake of embedded generation.

The MCE considers, however, that with emerging smart grid technologies and better processes, there may be opportunities to reduce the costs of connecting and managing significantly more embedded generation in the power system, and enhancing its operation to provide grid support. The MCE welcomes the AEMC's intention to investigate this opportunity in Stage 3.

The MCE supports the AEMC's analysis of avoided TUOS and recognises the long term benefits embedded generation can provide in relation to the transmission network, particularly if its operation aligns with network support requirements. The MCE also supports the AEMC's recommended amendments to the Rules to ensure that a generator that is already receiving network support payments from a transmission business does not also receive avoided TUOS, noting that to do so would represent a double payment.

[35] Ministerial Council on Energy, *Demand Side Participation: Response to the Australian Energy Markets Commission's Stage 2 Final Report*, June 2010

Appendix D: Explanation of Chapter 5A of the National Electricity Rules

The new Chapter 5A of the National Electricity Rules contain an improved connection procedure for micro embedded generation, on which the UBC Project has based its proposed solutions for cogeneration and trigeneration.

These rules have been approved by the Ministerial Council on Energy, and Ministers have agreed to a commencement date of 1 July 2012.

Explanatory Memorandum about the new Chapter 5A

From page 16–19 of document available at http://www.ret.gov.au/Documents/mce/_documents/Explanatory%20Material.pdf

Note for reference, full text of Chapter 5A is available here: http://www.ret.gov.au/Documents/mce/_documents/2010%20bulletins/No.185-10-National_Electricity_(Retail_Connection)_Amendment_Rules_2010.pdf

A.2 Framework for electricity connections

A.2.1. Overview

25. The electricity connections framework will form a new Chapter 5A of the NER.
26. The electricity connections framework represents what SCO considers to be an appropriate level of regulation to establish core processes and arrangements which enable the timely and efficient provision of reliable distribution network connections.

A.2.2. Defined connection types

27. The electricity connections framework requires distributors to propose standing offers of two basic connection types: for customers with small loads and for customers with micro embedded generation equipment.
28. The basic connection for small load customers is to capture a substantial class of connections, envisaged to be sought by small, urban retail customers, for which minimal or no augmentation work is required.
29. The basic connection for micro embedded generation is to capture connections that comply with Australian Standard 4777 (Parts 1 – 3).
30. Further standard connection types may be proposed by distributors for other classes of customer or embedded generator. The distributor will be required to publish their standing offer for the basic or standard connections. Retail customers and embedded generators may also apply to negotiate the details of their connection through the negotiation framework (see section A.1.1.4).

A.2.3. Contractual model

31. Contractual arrangements in electricity facilitate a range of different connection scenarios.
32. Retail customers will have the benefit of the terms and conditions approved by the AER as part of their deemed contract with the distributors if they seek a basic or standardised connection.
33. For any standard connections for non-registered embedded generation, distributors will provide a standing offer for approval by the AER which must cover the minimum terms and conditions set out in the NER describing the connection service, including if relevant, requirements for ongoing supply services.
34. In relation to negotiated connections and contracts, stakeholders requested some further guidance on the form and content of the contract. In response, SCO has incorporated into the NER an additional schedule listing the minimum content requirements for retail customers and embedded generation respectively. For National Electricity Market (NEM) registered participants, Schedule 5.6 will continue to operate.
35. Where retail customers exercise the right to connect micro-embedded generation (e.g. solar panels) at their premises, some additional requirements were identified during consultation with stakeholders which are needed to support this right, in relation to the ongoing supply of those premises. These requirements are reflected in the model terms for the deemed standard connection contract under Schedule 2 of the NERR.

A.2.4. Role of third parties

36. There were stakeholder concerns that the original SCO policy response did not satisfactorily recognise or reflect the fact that in many instances, a retailer or other third party may act as an intermediary or interface between the distributor and customer with respect to the processes and through contestability, extending to the actual construction of some of the connection assets.
37. The electricity connections framework has been revised to more fully reflect these circumstances while recognising that, while a retailer or Accredited Service Provider (ASP) may facilitate a retail customer's connection through commercial or contestable arrangements, the distributor retains ultimate responsibility for the provision of accurate network information and technical requirements to customers.

A.2.5. Flexible basic and standard connections

38. In response to stakeholder concerns that the original connection service requirements and scope (particularly relating to the mandatory basic connection service) were too rigid – under the revised electricity connections framework, minor variations to a basic or standard connection service are permitted without requiring the customer and distributor to go through a full and formal negotiation.

39. This is facilitated by the requirement that a distributor include in its connection standing offer a list of additional connection asset component costs, which is subject to approval by the AER. This provides for a basic connection service which is flexible enough to accommodate an individual customer's minor variations and reflects the reality that each connection is individualised to a degree.

A.2.6. Negotiation framework

40. There were significant concerns raised by stakeholders during consultation on the SCO policy response regarding the negotiation framework to apply to the negotiation of a connection. Stakeholders' key concerns centred around confusion about the interaction with NER Chapter 6 negotiations, and the regulatory burden associated with each distributor being required to develop their own framework.

41. Following consideration of stakeholder concerns, the policy was revised to include the establishment of a separate and simpler negotiating framework for retail customers and non-registered embedded generators in the proposed new Chapter 5A of the NER. This is proposed to apply uniformly to all distributors, customers and nonregistered embedded generators seeking to negotiate a connection. For connection services that are also negotiable distribution services as classified by the AER, the negotiation framework contained in Chapter 5A will supersede any negotiation framework developed by a distributor to meet the requirements of Chapter 6 of the NER. This policy may need to be effected by some consequential amendments to the NER.

A.2.7. Charges for connection

42. Chapter 6 of the NER prescribes a range of potential regulatory treatments for services provided by Distribution Network Service Providers (DNSPs), and it is considered that these treatments should apply to the connection services described by the electricity connections framework. The framework also provides that a distributor may require customers in some circumstances to make a capital contribution towards the cost of reinforcing the shared network.

43. Customers will receive a refund of capital contributions paid for previously dedicated assets that have become shared assets within seven years.

44. Some stakeholders argued for various new principles, the continuation of various components of jurisdictional arrangements, and more detail pertaining to methodologies to be placed in the NER to regulate capital contributions. Because of the wide range of historical practices, it was considered appropriate that the NER contain only high level principles. The AER will develop a more detailed set of methodologies in its guideline development process. Stakeholders will have an opportunity to provide further input on the details of the methodologies at that point.

A.2.8. Other matters raised by stakeholders

A.2.8.1. AER'S Role

45. Some stakeholders argued for the role of the AER to be reduced to a more general compliance/oversight role rather than actively approving basic and standard connection services. However in giving regard to the balance between the regulatory burden on distributors and the need to ensure protection of small retail customers, SCO decided that the original policy would remain unchanged – with distributors required to submit basic and standard connection services, including associated connection charges, to the AER for approval.

A.2.8.2. Connection Enquiries

46. Some stakeholders argued against any regulation of information or response timeframes for enquiries. However SCO considers that the requirements for the enquiry phase are minimal in terms of information provision and that some timeframe benchmarks are necessary to ensure that customers are dealt with in a timely fashion, so this minimal regulation of the enquiry phase will remain.

ClimateWorks AUSTRALIA

www.climateworksaustralia.org

seed advisory

www.seedadvisory.com.au

PROPERTY COUNCIL of Australia

www.propertyoz.com.au/vic

© Copyright 2011