Submission
No 8

COGENERATION AND TRIGENERATION IN NEW SOUTH WALES

Organisation: City of Sydney

Name: Ms Clover Moore

Position: Lord Mayor of Sydney

Date Received: 3/09/2013

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3 September 2013

Jonathan O'Dea MP
Chair, Public Accounts Committee
Parliament House
Macquarie Street
Sydney NSW 2000
By email pac@parliament.nsw.gov.au

Dear Jonathan

Cogeneration and Tri-generation in New South Wales Inquiry

I am pleased to forward the City's submission to the *Cogeneration and Trigeneration in New South Wales Inquiry* currently being conducted by the Public Accounts Committee on behalf of the Legislative Assembly of NSW.

Precinct trigeneration is one of the main decentralised energy technologies that should be supported and promoted in major urban areas like the City of Sydney. It is essential that the State now prepare for the large-scale, roll-out of precinct trigeneration. There must be a much greater role for decentralised energy across our City, State and nation to avoid a repeat of recent dramatic electricity price increases.

Precinct trigeneration benefits are that it:

- helps stabilise electricity prices in the long term by reducing or avoiding future network augmentation cost;
- makes a significant contribution to reducing peak demand for electricity by displacing heating/cooling fuelled by electricity with heating/cooling fuelled by waste heat from local electricity generation;
- makes a significant contribution to decarbonising electricity supply in major urban areas;
- substantially improves overall energy efficiency;
- contributes to improved certainty and reliability of energy supply in major urban areas like the City of Sydney; and
- provides a pathway to an economic non-intermittent renewable-energy future.

Regulatory and institutional change is essential to achieve the widespread roll-out of precinct trigeneration. This change deserves support from across the political spectrum for sound economic, energy efficiency and environmental reasons.

In the City's submission, we identify key actions to expedite the move to affordable, clean, efficient decentralised energy. I commend these actions to the Committee.

I also enclose the following documents with our submission:

- *Game Change: Decentralised Energy and Electricity Networks in the Low Carbon Era*. University of Technology, Institute for Sustainable Futures for the City of Sydney. August 2013.
- *Close To Home: Potential Benefits of Decentralised Energy for NSW Electricity Consumers*. Prepared by Institute for Sustainable Futures for the City of Sydney. November 2010.

City staff would be pleased to appear before the Committee to provide additional information and answer questions in support of this submission.

If you would like to speak to a Council officer about the City's submission, you can contact Allan Jones (Chief Development Officer, Energy and Climate Change) on [redacted] or at [redacted] or Peter Coombes (Senior Program Manager, Green Infrastructure) on the same number or at [redacted]

Y[redacted]

Clover Moore
Lord Mayor of Sydney

Encl.

Submission by the City of Sydney to the Inquiry by the Public Accounts Committee into Cogeneration/Trigeneration in NSW

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TRIM 2013/317324

Key terms and measures

ACCC
Australian Consumer and Competition Comission

AER
Australian Energy Regulator - Australia's national energy market regulator

AEMO
Australian Energy Market Operator - operates and plans the National Energy Market

AEMC
Australian Energy Market Commission - rule maker/developer for energy markets

ISF
Institute for Sustainable Studies, University of Technology Sydney

MW
megawatt – standard measure of the rate at which electricity or energy is generated
1 MW = 1000 kW = 1000 kilowatt (kW), 1000 MW = 1GW = 1 gigawatt

MWh
megawatt hour – standard measure of amount (not rate) of electricity or energy generated
1 MWh = 1000 kWh = 1000 kilowatt hours, 1000 MW = 1 GW = 1 gigawatt hour

NABERS
National Australian Built Environment Rating System - voluntary national rating system

NEM
National Electricity Market

NER
National Electricity Rules

Executive Summary

Terms of reference

This submission has been prepared by the City of Sydney in response to the establishment of a parliamentary inquiry into the installation and use of cogeneration/trigeneration technology in NSW.

The inquiry is being conducted by the Public Accounts Committee. Its terms of reference are to inquire into and report on the installation and use of cogeneration/trigeneration technology in NSW.

The City welcomes the opportunity to make a submission to the inquiry on this important topic, and would be pleased to appear before the Committee to provide further information in support of this submission and answer questions.

Precinct trigeneration - essential to a sustainable energy future

In the City of Sydney's view, it is essential that this State prepare now for large-scale roll-out of precinct trigeneration for economic, energy efficiency and environmental reasons.

With more than 330GWe of worldwide electricity generating capacity using mainly precinct or city-wide cogeneration/trigeneration, and with significant growth in such systems in advanced economies, the world is moving towards decentralised energy for economic and energy efficiency as well as environmental reasons.

Electricity bills have risen dramatically in recent years. Regulated prices for NSW households and small businesses rose over 70 per cent in the five years to 2012-13.

Most of this was due to rapidly increasing network charges that pay for the poles and wires that distribute electricity to homes and businesses.

Recent actions by policy makers at all levels may contain increases in electricity bills in the short term e.g. by slashing forward network capital expenditure plans and by instigating the first of many much-needed reforms of electricity regulation. Other factors may also help to contain costs in the short term – demand has slowed, new technologies are emerging.

However, unless there is fundamental change to the way that supply of electricity is managed to customers in NSW and across Australia, a renewed bout of increases in electricity bills is inevitable.

To avoid a repeat of recent dramatic price increases, there must be a much greater role for decentralised energy across our City, our State and our nation.

Chief amongst the decentralised energy technologies that should be supported and promoted in major urban areas like the City of Sydney is precinct trigeneration.

High electricity prices impact most heavily on members of the community who are least able to pay.

The Independent Pricing and Regulatory Tribunal found that households in the lowest quartile can pay up to 10 per cent of their income in electricity costs, while households in the top quartile pay less than 4 per cent.

High network charges also impact on business competitiveness.

Precinct trigeneration:

- helps stabilise electricity prices in the long term by reducing or avoiding future network augmentation cost
- makes a significant contribution to reducing peak demand for electricity by displacing heating/cooling fuelled by electricity with heating/cooling fuelled by waste heat from local electricity generation
- makes a significant contribution to decarbonising electricity supply in major urban areas
- contributes to improved certainty and reliability of energy supply in major urban areas like the City of Sydney
- substantially improves overall energy efficiency
- provides a pathway to an economic non-intermittent renewable-energy future.

To achieve the most widespread roll-out of precinct trigeneration, regulatory and institutional change is essential. Such change deserves support from across the political spectrum for sound economic, energy efficiency and environmental reasons.

Actions required to support precinct trigeneration

It is to be applauded that some reform of the National Electricity Market is beginning to occur, thanks to recent reviews like 'Power of Choice' (Australian Energy Market Commission) and 'Electricity Network Regulatory Frameworks Inquiry Report' (Productivity Commission).

However, no governmental review to date in Australia has fully embraced decentralised energy regulatory reform. Such reform would incentivise precinct-based decentralised energy systems (both cogeneration/trigeneration and renewables) and make them more economic.

To realise the full benefits of precinct trigeneration, it must be possible to effectively share energy (both electricity and thermal energy) between buildings. The current regulatory environment does not adequately support sharing of energy from precinct trigeneration between buildings.

Reforms must be made to facilitate decentralised energy providers to connect to and supply energy over electricity distribution networks. Clearly such change is possible, as demonstrated in Europe, the UK and many parts of North America and Asia.

The City of Sydney commends 15 key actions to regulators at state and national level to hasten the move to affordable, efficient, clean, reliable decentralised energy:

Electricity regulatory framework

Action 1: Introduce a benefit-reflective network tariff for decentralised electricity generators to reflect their role in avoiding/deferring future capital investment by electricity networks

Action 2: Ensure the regulatory framework established under the National Electricity Rules facilitates connection of decentralised generators and sale of decentralised electricity

Action 3:, Introduce a feed-in tariff for precinct cogeneration/trigeneration (as a precursor to implementation of Actions 1 and 2) to promote the transition to decentralised energy

Action 4: Provide similar powers for thermal network operators to carry out their core business activiites as are provided to electricity network operators under Part 5 of the Electricity Supply Act 1995 (NSW)

Building energy efficiency standards

Action 5: As a matter of urgency, reverse the October 2012 NABERS ruling that disadvantages uptake of decentralised electricity from precinct trigeneration

Action 6: Reform the Building Energy Efficiency Disclosure Act 2010 so that it recognises both electricity and thermal energy outputs of precinct cogeneration/trigeneration

Action 7: Fully recognise the benefits of thermal energy from cogeneration/trigeneration under the NSW Energy Savings Scheme

Action 8: Fully recognise the energy efficiency benefits of decentralised energy in the Building Code of Australia

New development

Action 9: Remove regulatory impediments under competition law to supply of thermal energy from precinct cogeneration/trigeneration

Action 10: Amend the Strata Schemes Management Act to exclude supply of thermal energy as part of sustainable new development from the provisions of section 113 of the Act

Action 11: To promote sustainable development, provide new building development with access to similar provisions as now apply under Environmental Upgrade Agreements to existing buildings

Action 12: Increase the dollar value applicable to precinct trigeneration developments to be state significant development for the purpose of SEPP (State and regional development) 2011 and streamline the application of this SEPP to precinct trigeneration

Gas distribution and renewable gas

Action 13: Remove barriers to roll-out of precinct cogeneration/trigeneration from gas distribution charges

Action 14: Reform the Gas Act and Regulations to enable renewable gas to be supplied to customers via the gas network

Action 15: Amend the draft NSW Energy from Waste Policy Statement to facilitate production of renewable gases.

Additional actions that could be implemented by the NSW Government to initiate or incentivise decentralised energy are identified under "Reference 7: Other relevant matters"

Overview: Decentralised energy matters

Cogeneration/trigeneration

Cogeneration and trigeneration are well-established technologies and make up a substantial component of the energy supply infrastructure in many overseas countries as diverse as the US, the UK, Europe and Asia.

Cogeneration (or combined heat and power - CHP) recovers the waste heat from localised electricity generation to provide electricity and thermal energy for space heating/hot water.

Trigeneration (or combined cooling, heat and power - CCHP) adds an extra service. Thermal energy is converted to chilled water for air conditioning and/or refrigeration, which further displaces electricity used for air conditioning and/or refrigeration. Cooling energy can be delivered to customers via central thermal chiller stations combined with district cooling pipes, or it can be delivered via hot water pipes to decentralised thermal chillers in individual buildings.

Different models suit the specific circumstances of individual cities and individual climates.

Compared with the traditional model of centralised generation based on large remote coal-based power stations, precinct cogeneration/trigeneration has three key advantages:

- Precinct-scale cogeneration/trigeneration is economically attractive. It can provide much needed relief from electricity network augmentation (both to meet peak demand growth and to meet requirements for better security of supply). As well, it can offset future investment in centralised generation (e.g. new power stations in the Hunter Valley). Thermal energy can be economically stored, as opposed to electricity which must be consumed as soon as it is produced or else stored in expensive batteries. This provides a useful buffer against extreme electricity peak demand events.

- Precinct cogeneration/trigeneration is a much cleaner source of energy, because natural gas has much lower carbon intensity than coal. Additionally, renewable gas can substitute for natural gas when suitable renewable resources are developed, as already happens in many other countries. Natural gas is seen as a transitional low-carbon fuel; eventually, with the use of renewable gases injected into the gas grid, trigeneration can achieve non-intermittent renewable base load generation.

- Precinct cogeneration/trigeneration is a more efficient form of energy production and use, because the electricity generation process is more efficient (typically 40 per cent or more of the energy resource is converted to electricity) and because waste heat that would otherwise be lost is captured and used in a variety of applications, including hot water, space heating and space cooling. Typically, the waste energy that can be captured is 35 per cent or more of the energy resource, which almost doubles the energy efficiency of the process. The most energy-efficient decentralised energy system in the world delivers an overall energy efficiency of 94 per cent.

  Additionally, because electricity is generated locally or on-site, transmission losses are non-existent and distribution losses are negligible. This contrasts with the substantial losses associated with remote power stations, which can amount to 10 per cent or more.

- Finally, precinct cogeneration/trigeneration networks are installed underground and are able to operate in island generation mode in the event of a failure of the electricity grid. Hence, they are more resilient in the face of natural disasters and extreme climate change events than electricity grids reliant on remote generation and overhead poles and wires. This has been evidenced with disasters and extreme events around the world, particularly the USA.

The value of precinct cogeneration/trigeneration is recognised around the world on both energy efficiency and carbon abatement grounds. More than 330 GWe of electricity generating capacity worldwide comes from cogeneration/trigeneration

It is the benefits that precinct trigeneration provides that makes its widespread deployment so desirable. Despite this, current regulatory barriers in the National Electricity Market prevent widespread deployment of precinct trigeneration.

Accordingly, a large part of this submission focuses on removing regulatory barriers in the National Electricity Market so as to enable precinct cogeneration/trigeneration and other forms of decentralised energy on a large scale in a timely and economic manner.

Decentralised energy

Decentralised energy is the term used to describe precinct-scale cogeneration or trigeneration and includes a thermal reticulation or district heating network and sometimes a district cooling network or sub network. Decentralised energy can also include renewable electricity generation connected to the electricity distribution network, renewable heat generation connected to the district heating network and renewable gases fuelling the cogeneration or trigeneration energy generators.

Decentralised energy systems are a stark contrast to traditional centralised energy systems. Typically, centralised energy systems depend on massive power plants that burn fossil fuels through the use of steam turbines to generate electricity. Centralised power stations are often located hundreds of kilometres (or potentially thousands of kilometres in the NEM) from where energy is consumed. This makes them inefficient and a major source of pollution. As well as being inefficient energy-wise, coal-fired power stations emit high levels of carbon dioxide, nitrous oxides, sulfur dioxide, particulates and other noxious emissions and consume significant quantities of water.

The flexibility of decentralised energy networks has enabled progressive cities (and even countries) to move away from reliance on fossil fuels for energy. For example, the Greater Copenhagen decentralised energy network supplying 98 per cent of buildings is now fuelled by 33 per cent renewable energy sources and Paris is fuelled by 36 geothermal district heating networks. Germany, since 2009, is injecting 8.5 billion kWh of renewable gas a year into its gas grid to supply decentralised energy networks in its cities.

Game change: Decentralised energy in the low carbon era

The City of Sydney made a submission to the Australian Energy Regulator (AER) on its proposed determination of NSW electricity network expenditure for the five year period from July 2010 to June 2015. In that submission, the City forecast huge increases in electricity network charges and electricity bills unless major changes to the electricity supply system occurred.

In its 2010 report, *Close to Home: Potential benefits of decentralised energy for NSW electricity consumers,* the Institute for Sustainable Futures estimated that the City's plans to supply 70 per cent of electricity from a network of trigeneration plants could potentially avoid well over $1 billion in electricity generation and network investment by 2030.

Little notice was taken of the City's submission and the ISF report at the time, but history has shown that the City's forecast of increased electricity network charges and electricity bills to be correct.

Following the huge increases that have occurred, there have been several high profile reviews of the electricity supply system, which have started to lead to some reform of the National Electricity Market.

However, in a new report titled *Game Change: Decentralised energy and electricity networks in the low carbon era,* the Institute for Sustainable Futures states that further policy and regulatory changes are needed to take full advantage of the opportunities that decentralised energy provides.

Removal of barriers for connecting distributed energy is important, especially for precinct trigeneration. This technology can help reduce network peaks by replacing electrical air conditioning with thermal air conditioning.

Reference 1: Adequacy of regulatory frameworks

Whether the current regulatory framework can adequately support the utilisation of cogeneration/trigeneration precinct developments

Precinct-based approach versus building-based approach

Precinct cogeneration/trigeneration (which shares energy between buildings) is intrinsically more efficient and more environmentally beneficial than building-based cogeneration/ trigeneration:

- Precinct-scale generating plant is typically larger, more energy-efficient and lower-cost per unit of generation (typically 1 MW to 4 MW per engine) than building-scale generators (typically 100 kW to 500 kW per engine).

- Precinct operators can balance electrical loads between a number of buildings/consumers which have different patterns of electrical consumption (this is known as "load diversity"), increasing their economies of utilisation.

- Precinct operators can balance thermal energy loads between numbers of buildings/consumers which have different patterns of thermal energy consumption (for example, residential demand is typically morning/evening while office demand is typically daytime).

- Precinct thermal energy networks provide a valuable form of energy storage, meaning both short-duration and long-duration demand peaks can be accommodated without the need for extra generating capacity.

Precinct trigeneration therefore, through increased utilisation provides significantly greater reductions in greenhouse gas emissions than building-based trigeneration.

Despite this, precinct trigeneration is currently heavily disadvantaged against much less efficient building-based cogeneration/trigeneration in NSW and across Australia. Fundamentally, this is because the current regulatory environment at both state and national level is not supportive of sharing of energy (both electrical and thermal) between buildings, or between local energy producers and local energy consumers.

Barriers to precinct trigeneration

Barriers that prevent sharing of energy between buildings in precincts and discourage uptake of precinct trigeneration must be removed.

These barriers are in four main categories:

Barrier 1: Barriers to decentralised electricity in the electricity regulatory framework

Barrier 2: Barriers to recognition of shared energy benefits in building energy efficiency standards and associated energy rating tools and disclosure requirements

Barrier 3: Barriers to precinct trigeneration in new sustainable building development

Barrier 4: Barriers in the gas production and distribution system.

Barrier 1: Electricity regulatory framework

Barriers to provision of decentralised energy under the National Electricity Rules (NER) take three forms:

- First, the cost for decentralised generators to send electricity over local public wires to local customers is too high, because current network tariffs do not reflect the very short distance travelled by the electricity or the substantial financial benefits for all electricity consumers that accrue to electricity networks from decentralised electricity. Customers for decentralised electricity end up paying more than they should, making decentralised electricity less competitive.

- Second, apart from the very limited provisions in the AER Exempt Selling Guidelines, decentralised energy generators cannot sell electricity to customers in the National Electricity Market (NEM) without authorisation. The costs of being an authorised retailer in the NEM are substantial when compared to the small scale of typical decentralised energy generators.

- Third, the cost of connecting to an electricity network can be very expensive for many decentralised generators; the time taken to have connections approved is too long; and there is lack of certainty as to whether an application to connect or to export will be approved.

The combined effect of these regulatory barriers is particularly evident in the case of precinct cogeneration/trigeneration (despite this form of decentralised generation being particularly beneficial to electricity networks) and leads to sub-optimally sized investments and diminished energy efficiency and environmental outcomes.

Barriers under the National Electricity Rules are as much about institutional mind-set as they are about regulatory detail. The rules were drawn up with the need for effective competition between large-scale remotely-located coal-fired power stations in mind. Out-of-date thinking is evidenced by the increasing number of decentralised generators seeking to self-generate, despite the current regulatory barriers to decentralised energy.

Continuing to prop up the current institutional mind set is not rational on economic, energy efficiency or environmental grounds. A higher portion of decentralised energy, especially precinct trigeneration, provides a path to more efficient use of energy, lower carbon emissions and more effective use of existing electricity transmission and distribution assets.

As the ranks of decentralised generators include many renewable energy generators, ensuring the NER operates to support decentralised generation is a key strategy to increase the amount of renewable energy in our electricity generation, thereby decreasing the carbon intensity of our electricity consumption. By contrast, decentralised energy is actively encouraged in advanced economies in Europe, North America and Asia.

Electricity markets in other countries support decentralised energy

In 2001, regulatory barriers to private wire networks in the UK were removed with some surplus exports over public wires. In 2009, the regulatory barriers to decentralised energy export over public wires distribution networks were also removed.

Market failure was addressed by the introduction of an electricity supply licence modification order to make it easier for decentralised energy schemes and small suppliers to operate as a licenced supplier on the public network by exempting them from the requirement to be a direct party to the industry codes (otherwise known as a 'decentralised energy supply licence').

This enabled local decentralised energy generators to export surplus electricity over the local public wires distribution network to local customers on the 'virtual private wire' principle outside of the national electricity market. This avoids the high costs of participating in the market which is out-of-scale with the size of decentralised energy providers.

The UK has also introduced a common pricing methodology for electricity networks, which reflects the positive benefits of decentralised electricity generation. Specifically, decentralised electricity generators are offered a positive (credit) network tariff for feeding electricity into local networks.

The scale of this credit (which takes the form of a negative decentralised generation use of system charge) is calculated on the level of benefit that each network receives from local generation.

Non-intermittent technologies such as precinct trigeneration are generally recognised as providing the highest level of benefit to networks.

Barrier 2: Building energy efficiency standards

NABERS ruling: The National Australian Built Environment Rating System (NABERS) is a voluntary national rating system that measures the energy efficiency, water usage, waste management and indoor air quality of a building or a tenancy and its impact on the environment. The rating takes into account the energy sources that the building uses, and encourages reduced energy and water consumption and greenhouse gas emissions.

NABERS was originally introduced in 1998 as the Australian Building Greenhouse Rating Scheme. It is managed on behalf of Commonwealth, state and territory governments by the NSW Office of Environment and Heritage. Buildings with high NABERS ratings are valued in the marketplace, attracting higher valuations and higher market rentals and enjoying lower operating costs.

Commercial Building Disclosure is a national program designed to improve the energy efficiency of Australia's large office buildings. Under the Building Energy Efficiency Disclosure Act 2010 owners selling or leasing commercial office space of 2,000 sq m or more, are required to obtain and publicly disclose a current Building Energy Efficiency Certificate which must include a NABERS Energy star rating for the building.

In July 2010, NABERS introduced a ruling on the proportioning of energy used by precinct cogeneration/trigeneration. The purpose of the ruling was to define the methodology by which energy inputs to cogeneration or trigeneration systems are apportioned to the parties using the outputs of these generation systems. This includes the export of electricity or thermal energy to tenants within the building or third parties outside the building and the import of electricity or thermal energy from district heating/cooling/generation systems.

The NABERS 2010 ruling addressed the emerging precinct-scale decentralised energy market in Australia and incentivised more energy efficient precinct-scale decentralised energy systems over less efficient stand-alone building-based systems.

In 2012, NABERS published a consultation position paper seeking to overturn its previous ruling. Although 20 out of the 25 respondents did not support this, NABERS implemented a new ruling in October 2012 that overturned its previous ruling in July 2010.

The October 2012 NABERS ruling effectively removed low carbon electricity from precinct scale trigeneration from the headline NABERS rating.

This ruling also treats precinct-scale renewable electricity in the same manner as remote coal-based electricity and completely ignores how emissions from electricity generation are allocated. Decentralised energy generators are not accounted for in the National Greenhouse Accounts Factors for the NEM. Their emissions can only be accounted for locally as they connect to distribution networks, not to transmission grids.

Thus, this ruling encourages a sub-optimal scale of investment and performance and lead to needless duplication. This makes no sense – a series of buildings served by a shared cogeneration/trigeneration plant ought to be able to access the same level of benefits (or better, due to greater efficiency) as would be available to a single building.

The October 2012 NABERS ruling effectively ignores this key issue. It is illogical and must be reversed as a matter of urgency.

NSW Energy Savings Scheme: The City recognises the benefits of the NSW Government's Energy Savings Scheme for reducing building electricity consumption. The Energy Savings Scheme reduces electricity consumption in NSW by creating financial incentives for organisations to invest in energy savings projects. Buildings which reduce electricity consumption by installing, improving or replacing equipment may be eligible to receive energy savings certificates which may be sold to liable entities, electricity retailers.

It is anticipated that some of the efficiency benefits offered by thermal energy produced from trigeneration may be eligible for energy savings certificates under the scheme, such as where thermal energy used to displace electricity through replacement of an electric air conditioning chiller with a thermal air conditioning chiller. Currently the ESS applies to savings delivered from reduced electricity use. The eligibility of energy efficiency projects which reduce gas consumption is currently unclear.

It is recommended that projects which reduce gas consumption be explicitly recognised under the scheme. Doing so would allow building owners to claim energy savings certificates where they connect to a thermal energy network supplied by trigeneration to displace gas, for example for water heating. Maximum energy efficiency benefits from precinct trigeneration are gained when thermal energy can be shared between buildings. It is essential that the scheme recognise the eligibility of thermal energy delivered over a thermal energy network, as well as thermal energy generated on the premises.

Building Code of Australia: There is lack of recognition at the current time of the benefits of decentralised energy benefits in the Building Code of Australia. This is discussed further in "Reference 6: Actions required".

Barrier 3: New sustainable building development challenges

Additional barriers to precinct trigeneration apply to new development.

Pre-commitments on behalf of incoming owners corporations: During the initial development of precinct trigeneration, especially in redevelopment and greenfield areas, it is essential that prospective thermal energy suppliers be able to have a level of confidence about future customer demand.

Unlike electricity networks, there is not a longstanding customer base spread across the state that can subsidise forward infrastructure provision in new development areas.

To provide for future demand, thermal energy providers ought to be able to enter into binding agreements in advance, typically with building developers. The terms of such arrangements would of course be subject to suitable checks and balances.

An exemption from section 113 of the Strata Schemes Management Act1996 (NSW) is required to ensure that the supply of thermal energy is not covered by the provisions of this section.

Regulatory impediments in competition law to thermal energy: Under section 47 of the Competition and Consumer Act 2010, it is prohibited to require as a condition of supply that a party enter into a separate commitment with a third party for goods or services. This is known as third-line forcing (a type of exclusive dealing). Third-line forcing is a contravention of the Competition and Consumer Act 2010 even if it does not have any adverse effect on competition. There is a process for notifying third-line forcing conduct to the ACCC where there are public benefits which flow from it.

Further, arrangements between the owner of cogeneration/trigeneration infrastructure and a single services provider that provide for the service provider to be the sole user of the cogeenration/trigeneration infrastructure may also fall foul of the exclusive dealing prohibition under section 47 of the Consumer and Competition Act 2010, if such arrangements have the purpose or effect of substantially lessening competition in a market.

For example, at Green Square Town Centre, it was expected that all new developments would make use of thermal energy (e.g. for residential apartment hot water and space heating, for commercial tenancy hot water and space heating/cooling) from precinct cogeneration/ trigeneration plant. This arrangement was established in the interest of a lower carbon footprint and better sustainability. To obtain space heating and cooling services and domestic hot water services, occupants would need to enter into a thermal energy services agreement with the single local provider.

To ensure that no third-line forcing concerns arise, it would be necessary to lodge notifications for any conduct which might involve third-line forcing under subsection 93 of the Competition and Consumer Act 2010.

In the City's view, the need to enter into a thermal energy service agreement with a single local supplier should not give rise to any prospect of being regarded as anti-competitive. The need to lodge a notification under section 93 creates unnecessary delay and risk and imposes additional costs on projects. Given the obvious and substantial sustainability benefits of what is proposed, and the fact that such arrangements have been agreed to with a public authority, it would be productive for some statutory or regulatory exemption to be available.

A proposed remedy is set out in further on in this submission under "Reference 6: Actions required".

Non-availability of environmental upgrade agreements: The NSW Environmental Upgrade Agreement (EUA) legislation has been successful in incentivising environmental improvement works in buildings. The largest EUA implemented so far in Australia is the $26.5 million trigeneration precinct at Central Park. However, the Local Government (Environmental Upgrade Agreement) Act 2010 and Regulations 2011 apply to existing development only and exclude new development. An EUA was only possible at Central Park because the trigeneration energy centre was located in the old Carlton United Brewery building.

New development becomes existing development once it is built. It is illogical and counter-productive to deny developers access to EUA low cost finance to implement environmental improvement works in new development, including precinct trigeneration. The EUA legislation must be extended to provide comparable provisions for new development to achieve a step change in the sustainability of new residential apartments and commercial buildings.

A recommendation to this effect is included as part of "Reference 6: Actions required".

Requirements for state approval for larger precinct trigeneration projects: Medium and large-scale precinct cogeneration/trigeneration projects are likely to be covered under the provisions of State Environmental Planning Policy (State and regional development) 2011.

Specifically, this SEPP covers development for the purpose of electricity generating works or heat or their co-generation (using any energy source, including gas, coal, biofuel, distillate, waste, hydro, wave, solar or wind power) that (a) has a capital investment value of more than $30 million, or (b) has a capital investment value of more than $10 million and is located in an environmentally sensitive area of State significance.

The dollar value limits set in the SEPP for such projects to be treated as state significant development are too low. The threshold value should be increased, preferably to $50 million or a higher figure.

Also, guidelines should be prepared to assist assessors for any precinct trigeneration project that (irrespective of the actual dollar threshold at the time) is deemed to be state significant development.

Barrier 4: Gas production and distribution

Gas distribution network charges

There is room for doubt about how gas distribution network access arrangements currently apply to trigeneration projects that (inter alia) supply residential buildings with thermal energy for bulk hot water. It is arguable whether the gas has been supplied to a single customer or to each of the ultimate domestic hot water customers, by virtue of the gas having been used to heat the water that the domestic hot water customers then consume.

In particular, current access arrangements have been interpreted by the gas distributor so as to impose a cost of gas delivery for trigeneration projects that supply thermal energy for domestic hot water heating that is higher than would otherwise apply for the trigeneration plant operator. This is even though the supply of domestic hot water may be a minor part of the overall range of services of the plant operator.

Current gas distribution access arrangements have been approved by the AER. The interpretation of these arrangements by the gas distributor may need to be reviewed by the AER. If necessary, the wording of the access arrangements should change from the start of the next regulatory period (i.e. from 1 July 2015) to make it explicit clear that cogeneration/ trigeneration providers are to be treated in the same ways as other large gas consumers.

Distributing renewable gas via the gas network

As renewable gas souces are developed and made available to the market, a primary attraction for customers will be their renewable or zero-carbon status. As with GreenPower, renewable gas requires official recognition.

The Gas Act and Regulations must be updated to enable renewable gas injected into the gas grid to be separately identified/accredited and directly purchased by consumers via a renewable gas purchase agreement in a similar way to renewable electricity being able to be purchased by a consumer via a renewable power purchase agreement.

The City's Renewable Energy Master Plan[1] shows that sufficient renewable gas can be generated from waste feedstocks within 250km of Sydney to replace 100 per cent of the natural gas needed for the full capacity of trigeneration and cogeneration set out in the City's Decentralised Energy Master Plan - Trigeneration. The Decentralised Energy Master Plan - Renewable Energy also shows that the delivered cost of renewable gas could be cheaper than fossil-fuel natural gas by 2014-15 and becoming progressively cheaper with a build-up of the renewable gas market by 2030.

Both syngas and biogas generated by gasification and anaerobice digestion, respectively, can be converted into substitute natural gas for injection into the gas grid to supply the trigeneration networks in the City of Sydney local government area. However, the gas regulatory gas regime is not currently set up for matching renewable gas generation and supply in the same way as the regulatory regime for renewable electricity and supply. Therefore, regulatory reform is needed to overcome the regulatory barriers.

[1] City of Sydney 'Decentralised Energy Master Plan – Renewable Energy'
http://www.cityofsydney.nsw.gov.au/__data/assets/pdf_file/0019/146116/Renewable-Energy-Master-Plan.pdf

The German Government through the German Energy Agency legislated for renewable gas grid injection under the Renewable Energy Resources Act 2009. Germany now has the largest renewable gas grid injection program in the world. A public/private market-led mechanism called 'biogaspartners[2]' has been established to faciltate the renewable gas grid injection market which injected 8500 GWh of renewable gas into the gas grid in 2012. Germany's target is to inject 60,000 GWh a year into the gas grid by 2020, and 100,000 GWh by 2030.

Collectively, the entire value chain, market development and political framework for renewable gas grid injection now exists in Germany. The new value chain now comprises around 60 companies and market players and employs around 11,000 people, mainly in rural areas.

Renewable gas grid injection could provide NSW with a significant economic and job creation opportunity, particularly in rural areas. This state could take the lead in establishing a renewable gas grid injection market in Australia. This would not only address waste and landfill issues. It could also develop into a much bigger renewable energy mining and exports opportunity using 'power to gas' technologies making use of the existing gas export liqufaction infrastructure.

To support this opportunity, it is essential that the draft NSW Energy from Waste Policy Statement be amended to avoid the Policy Statement from becoming unnecessarily prescriptive and counter-productive in generating renewable gases from waste for injection into the gas grid and avoid waste going to landfill.

Conclusion

Some progress is occurring on regulatory reform, as the boxed text below shows. However, the response to recommendations by bodies like the Productivity Commission has been mixed, and there is still far to go. Discussion on specific proposals is set out further on in this submission under "Reference 6: Actions required".

The City has taken every opportunity to advocate and lobby for regulatory change to create a more level playing field for decentralised energy and centralised energy, and will continue to do so. A list of representations by the City is provided in Appendix One.

Regulatory change: current state of play

Some reforms have been proposed for the National Electricity Market:

- The National Electricity Amendment (Small Generation Aggregator Framework) Rule came into effect in 2013. This creates a new category of Small Generation Aggregator which will be able to sell the output of small generating units (up to 30MW) without the expense of individually registering every generating unit.

- A rule change to facilitate connection by embedded generators was proposed by Climate Works Australia, the Property Council of Australia and SEED Advisory). If fully

[2] DENA (German Energy Agency) Biogaspartner – A Joint Initiative. Biogas Grid Injection in Germany and Europe – Market, Technology and Players http://www.dena.de/fileadmin/user_upload/Publikationen/Erneuerbare/Dokumente/biogaspartner-a_joint_initiative_2012.pdf

implemented, this will improve access for embedded generators.

- AEMC undertook a review of network charging including demand management called 'Power of Choice'. Reforms proposed by AEMC would facilitate efficient demand side participation in two ways. First, proposed reforms would enable customers to see and be rewarded by taking up demand side options (changes on the demand side). Second, proposed reforms would enable the market to support consumer choice through better incentives to capture the value of demand side participation options (changes on the supply side).

- The Productivity Commission was recently commissioned to report on electricity network regulatory frameworks. It found there are information and financial barriers around the ability to, and costs of, connection to the electricity network for distributed generators, and also the subsidies provided for generation that have little impact on peak times or in network constrained areas, and therefore offer no opportunity to avoid network investment. The Australian Government has now responded to the commission's report.

Reference 2: Use of cogeneration and trigeneration

The operation of cogeneration/trigeneration technology in other jurisdictions and the applicability of the technology to NSW

International applications

There is more than 330GWe of worldwide electricity generating capacity using cogeneration/trigeneration. The US has the largest generation capacity from cogeneration/ trigeneration, followed by Russia, China, Germany, India and Japan. China is not a member of the International Energy Agency but its estimated potential for cogeneration/trigeneration potential by 2030 is 200GWe.

North America

The first public electricity supply in the world was the cogeneration system implemented by Edison in 1882 to supply electricity and steam to Manhattan, New York, later converted to a trigeneration system which is now the 8th largest decentralised energy network in the world. The New York decentralised energy network serves 1,800 buildings.

New York State generates 6GW of electricity from decentralised energy which includes the largest residential trigeneration network in the US at Riverbay (Co-op City), Bronx which supplies electricity, heating and cooling to 60,000 residents in 15,372 high-rise apartments, seven clusters of townhouses, three shopping centres, schools, churches and other public buildings. Other major decentralised energy networks exist in Indianapolis, Philadelphia, Baltimore, Chicago, Detroit, Houston, Las Vegas, Miami, San Francisco, St Paul and Seattle. Today, there are more than 5,000 decentralised energy networks in the US generating 85 GWe.

The US Government is also fuelled by trigeneration. The Capitol Hill plant supplies heating, cooling and electricity to the US Capitol (House and Senate), Supreme Court, Library of Congress and 19 other buildings in the complex. The district heating network was built in 1910 and cooling was added in 1930.

Canada's first decentralised network was built in London, Ontario in the 1880s to serve its university, hospital and government complexes. Toronto launched its first decentralised energy network in 1911, while Canada's first commercial decentralised energy network was established in 1924 to serve Winnipeg's CBD. Today, there are over 150 decentralised energy networks operating in Canada.

Europe

Most European cities are supplied by decentralised energy networks, including Berlin, Copenhagen, Stockholm, Helsinki, Vienna, Hamburg, Gothenburg, Paris, Moscow, St Petersburg, Turin and Barcelona. The European Union generates 11 per cent of its electricity from cogeneration/trigeneration. At 60 per cent, Denmark has the highest proportion of electricity generated from cogeneration/trigeneration followed by the Netherlands and Finland.

Germany, the most populous industrialised country in the EU, has a cogeneration/ trigeneration capacity of 21GWe, the highest in the EU. Germany has set a legislated target to double electricity generated from cogeneration/trigeneration to 25 per cent by 2020.

The expansion of cogeneration/trigeneration networks in France, Germany, Italy and the UK alone would double the existing primary fuel savings in the whole of the EU by 2030. This would increase Europe's annual energy savings from cogeneration/trigeneration networks from 156,000 GWh to 465,000 GWh.

The decentralised energy network in Greater Copenhagen began in the 1920s and today supplies 98 per cent of the thermal energy demand in the City of Copenhagen, some 30,000 customers and 500,000 residents across a 1,500km network extending 40km across metropolitan Copenhagen. Natural gas originally replaced coal; now natural gas is being replaced by renewable gases and fuels so that today the decentralised energy network is supplied by 33 per cent renewable energy sources with a target to replace 100 per cent of fossil fuels with renewable energy sources by 2025.

United Kingdom

The iconic Battersea Power Station built in 1933 was not a power station but one of the largest cogeneration stations in Europe. Heat was piped underneath the River Thames to Westminster supplying 10,000 homes and other buildings. When Battersea Power Station closed in 1983, Westminster City Council took over the decentralised energy network and continued to supply customers with thermal energy and later added cogeneration plant.

The heritage-listed Battersea Power Station site is now being redeveloped as a major residential/commercial/leisure hub with a renewable-fuelled trigeneration network which forms part of the Vauxhall, Nine Elms and Battersea decentralised energy network[3].

The UK Government is also fuelled by cogeneration. The Whitehall District Heating Scheme began operating in 1966 and today supplies electricity and heat to 23 government buildings, including Downing Street, Ministry of Defence, Foreign and Commonwealth Office, Department for Environment, Food and Rural Affairs, Horse Guards and the Treasury. Plans are under way to connect the Westminster and Whitehall decentralised energy networks together.

Decentralised energy (cogeneration/trigeneration and renewable energy) is a key part of the London Plan and the Mayor's Climate Change Action Plan. Under the revised London Plan 2008, all major new development must provide or connect to precinct scale decentralised energy. As well there is a 20 per cent renewable energy requirement to gain development approval. This saw 106 cogeneration/trigeneration, including six fuel cell CHP and six biomass CHP systems as well as 196 renewable energy installations, form part of the development applications in the first year of operation of the new planning instrument.

Major trigeneration networks driven by the London Plan include the precinct-scale systems at the London Olympics 2012, Stratford City, Kings Cross, Greenwich Peninsula and Elephant and Castle.

Asia

[3] GLA Victoria Nine Elms Battersea Opportunity Area – Technical Appendix TA5 LDA Energy Master Plan http://www.london.gov.uk/sites/default/files/VNEB_OAPF_2012_0.pdf

Trigeneration networks were first introduced in Japan in 1970 where it quickly gained government recognition as an essential infrastructure for modern urban environments. This came with the passing of the Heating Industry Act 1972, which recognises trigeneration district heating/cooling networks as a third type of utility along with electricity and gas utilities. Today there are 87 decentralised energy companies operating in Japan, serving 148 districts, the largest of which is Greater Tokyo.

Under the Singapore Green Plan around 1,600MWe of trigeneration has been installed to date. As an equatorial city island state, trigeneration-based cooling is a key requirement in reducing Singapore's emissions and energy imports. Some of this is renewably fuelled.

Seoul has the 3rd largest decentralised energy network in the world. The Korea District Heating Corporation supplies electricity, heating and cooling to more than 1 million households and 2,000 customers of commercial and public buildings over a 1,433km distribution network in the Greater Seoul Metropolitan Area. However, this is likely to be overtaken by Beijing's decentralised energy networks, which are currently being renovated and expanded.

China currently generates more than 28 GWe of cogeneration/trigeneration and more than 60 per cent of urban central heating comes from decentralised energy networks servicing more than 330 cities. China has recently announced plans to deliver 50 GWe by 2020, including 30 GWe of gas-fired trigeneration to replace coal.

Most Chinese cities have some form of district heating source primarily fuelled by coal and a handful of cities have district cooling. Under its 'Transit Synergised Development' program the Chinese Government is seeking to modernise its energy infrastructure through the deployment of gas fired and/or where available, renewable fuelled decentralised energy.

Australian applications

Cogeneration and trigeneration in Australia is less developed than in many countries. In 2006, Australia ranked 34th out of 40 countries surveyed for decentralised energy generation by the World Association of Decentralised Energy[4], with around 5 per cent of total generation coming from decentralised sources, primarily in large industrial applications, compared with 40 per cent in the Netherlands and 60 per cent in Denmark.

Up to 2009, there were a small number of non-precinct trigeneration plants operating in Australian cities, typically small scale plants in commercial and other properties. The installation of these plants was primarily driven by the desire to achieve a high NABERS or GreenStar rating to attract or retain high profile anchor tenants wanting to occupy the greenest buildings available.

All these plants had one thing in common – they were much smaller than they potentially could be, in order to avoid exporting electricity into the public distribution network and because there was no mechanism to export surplus waste heat to other premises.

[4] World Association of Decentralised Energy 'World Survey of Decentralised Energy 2006' http://www.stuffit.org/carbon/pdf-research/statistics/WADE_-_World_Survey_of_Decentralized_Energy06.pdf

A number of precinct-scale trigeneration plants and networks have been developed in recent years, including Dandenong (Victoria), Canberra Airport (ACT), Sydney Airport (Qantas operations) , Charlestown Square (NSW), Crown Casino (Victoria), Symex (Victoria), Coopers Brewery (SA), Qenos (SA), Condong and Broadwater Sugar Mills (NSW).

Only the Dandenong trigeneration system currently supplies a mixture of buildings and ownership as a full-scale precinct. Dandenong will soon be joined by the Central Park precinct trigeneration network in Sydney. The obligation to install precinct scale trigeneration at Central Park was part of the development approval conditions and the project was financed via a NSW Environmental Upgrade Agreement.

Applicability to NSW

As the international survey above shows, cogeneration/trigeneration is not limited to colder climates. Singapore has built a substantial level of trigeneration capacity, some of which is renewably fuelled. There are also many applications in the Middle East and other warm climate areas such as the US cities of Houston, Las Vegas and Miami.

In principle, there is no reason why cogeneration/trigeneration should not be as successful in NSW as elsewhere. However, as pointed out extensively in this submission, there are numerous regulatory and institutional barriers which must be overcome. This submission also sets out key actions that together will bring about more effective use of precinct trigeneration in NSW.

Precinct trigeneration in the City of Sydney

The City of Sydney has developed an ambitious plan for its local government area - *Sustainable Sydney 2030.* The City spent more than a year consulting its community and a consensus emerged on the way to make Sydney a greener, more global and connected city. Throughout the consultation, 90 per cent of people wanted the City to take urgent action to tackle climate change and become more sustainable. To achieve this, the City has committed to reducing greenhouse gas emissions by 70 per cent (on 2006 levels), and developing the capacity of the City to meet up to 100 per cent of electricity demand by local electricity generation (70 per cent trigeneration, 30 per cent renewable electricity) by 2030.

In 2012, the City resolved that by 2030 renewable gases from waste and other renewable energy resources should replace fossil fuel natural gas in the trigeneration systems, effectively providing 100 per cent of the electricity, heating and cooling needs across the City of Sydney local government area from renewable energy sources.

About 80 per cent of the City's emissions are from electricity consumption, as electricity supply is dominated by coal-based generation. To reduce carbon emissions by 70 per cent, the City's electricity supply will need to fundamentally change. A series of Green Infrastructure Plans have been developed, including the *Decentralised Energy Master Plan - Trigeneration* and the *Decentralised Energy Master Plan – Renewable Energy.*

Decentralised Energy Master Plan - Trigeneration

The Trigeneration Master Plan identifies that trigeneration/cogeneration could produce up to 477 MW of local power and displace a further 542 MW of peak electricity demand by using waste energy for heating and cooling (particularly air-conditioning). The Trigeneration Master Plan if fully implemented would reduce electricity consumption by 30 per cent and peak demand by 60 per cent.

This generation and associated offsets could reduce greenhouse gas emissions in the City of Sydney local government area by 1.381 to 2.027 million tons a year; representing a 24-32 per cent reduction in greenhouse gas emissions per year. Based on 477 MWe of trigeneration plants to be installed by 2030 achieving annual energy savings of 300 GWh, this could defer electricity network costs of $224 million by 2020 and $1.28 billion by 2030 (medium uptake scenario).

The City has resolved to implement the trigeneration master plan, as follows:

<u>Town Hall Trigeneration Precinct</u> – Commence design of a trigeneration precinct that includes Sydney Town Hall, Town Hall House, the Queen Victoria Building and other nearby buildings.

<u>Prince Alfred Park</u> – Commence design of a demonstration fuel cell project to serve Prince Alfred Park Pool.

<u>Green Square Town Centre</u> – Install trigeneration when a more favourable regulatory environment is in place and customers are available to connect to the thermal energy network.

<u>Connect Existing Decentralised Energy Networks</u> – Construct and operate thermal energy networks in public streets connecting existing private sector trigeneration operators to a broader customer base.

<u>Renewable Gases</u> – Investigate the design, planning, construction and regulation of initiatives that support incorporation and uptake of waste to energy and production of renewable gases derived from waste, including the production of renewable gases converted into substitute natural gas for injection into the gas grid (based on the European model) for use by the City for trigeneration and for customers across the local government area to reduce greenhouse gas emissions.

<u>Regulatory Reform</u> – Promote regulatory reform that incentivises the market for precinct scale trigeneration and renewable energy through recognition of low and zero carbon electricity and zero carbon thermal energy generated and the associated benefits to electricity networks that it provides. Continue to seek reform of the Building Code of Australia, Commercial Building Disclosure and associated rating tools such as NABERS to include precinct scale trigeneration and renewable energy. Promote suitable feed-in tariffs and escalate the City's engagement with energy regulators and electricity distribution network providers to remove the regulatory barriers to decentralised energy.

Decentralised Energy Master Plan - Renewable Energy

The City began work on a Renewable Energy Master Plan in 2010. The Renewable Energy Master Plan identifies the renewable electricity and renewable gases resources both inside and outside the local government area. The Master Plan shows annual renewable electricity generation potential of 703 GWh inside the City of Sydney local government area and 468 GWh within 250 km of the local government area.

Of critical importance, sufficient renewable gases can be sourced from renewable feedstock within 250 km of the local government area to displace 100 per cent of natural gas supplying trigeneration. The Renewable Energy Master Plan will deliver 48.96 petajoules (PJ) a year of syngas and biogas, of which 37.06 PJ/year is renewable gas and 11.9 PJ/year is non-fossil fuel gas. The Renewable Energy Master Plan would reduce GHG emissions by 2,384,000 tonnes of CO2-e a year by 2030 which equates to a 37.5 per cent reduction against 2030 business as usual emissions.

The combination of renewable electricity, renewable thermal energy, and trigeneration using renewable gas would reduce greenhouse gas emissions by a total of 69.5 per cent. Together, the Trigeneration and Renewable Energy Master Plans come close to achieving the overall target to reduce 2006 greenhouse gas emissions by 70 per cent by 2030.

Energy Efficiency Master Plan

Sustainable Sydney 2030 shows that energy efficiency has the potential to reduce the City's GHG emissions by 14 per cent by 2030. However, the Energy Efficiency Master Plan foundation report currently in contract may show a greater potential for energy efficiency across the City's local government area than that identified in Sustainable Sydney 2030, although the potential for this may be prevented by regulatory barriers to energy efficiency. The Master Plan will be put on public exhibition in 2014.

Energy efficiency and decentralised energy in the City's operations

Energy efficiency is an essential element in reducing energy consumption and the carbon footprint of the city as well as improving electricity productivity. The City's 'showing by doing' (by implementing energy efficiency and distributed generation in its own buildings and operations) acts as a catalyst for activity in the wider local government area.

The City has reduced energy consumption in its own buildings by 23 per cent from 2006 to 2012. This represents a 19 per cent reduction in greenhouse gas emissions across all of the City's buildings and operations. This will increase to a 29 per cent reduction in greenhouse gas emissions by 2016 with the completion of its three major energy efficiency and renewable energy projects. This includes the City replacing all City-owned 6,500 street lights with LEDs which will reduce electricity consumption and emissions across all the City-owned public lighting by 40 per cent by 2015 and the City installing 1.25MWp of solar PVs on more than 30 buildings by 2016.

Reference 3: Economic viability

The economic viability of cogeneration/trigeneration technology in NSW including the impact of future gas prices on the running costs of cogeneration/trigeneration systems

Economic benefits of precinct trigeneration

There are significant tangible economic benefits to NSW on a state-wide basis from the development and utilisation of an extensive network of trigeneration precincts. These benefits include but are not limited to future avoided electricity network capital investment.

In its reports 'Combined Heat and Power' and 'Cogeneration and District Energy' the International Energy Agency modelled 43 countries and, in particular, the G8+5 under the IEA's Accelerated CHP Scenario which showed that there would be a $US795 billion saving in overall costs by 2030, primarily in avoided transmission and distribution network investment, the main cause of rising electricity prices to consumers. There would also be a reduction in centralised power generation that is displaced as well as a reduction in the overall amount of generating capacity required to meet the reduced grid demand.

Overall, there would be a small reduction in delivered costs to consumers and a reduction in fossil fuels used in the G8+5 countries delivering a reduction in CO_2 emissions of 950 million tonnes a year.

In NSW, the regulatory barriers to decentralised energy represent an unnecessary drag on the economy. However, certain features of the NSW environment make cogeneration/ trigeneration inherently attractive (for example, generating electricity behind the meter to avoid network charges and decarbonising the emissions intensive electricity grid).
With regulatory reform there is no reason why cogeneration/trigeneration should not be as successful in NSW as elsewhere in the world.

Close to Home

Three years ago the Institute for Sustainable Futures (ISF) produced a report for the City of Sydney on the benefits of decentralised energy systems. *Close to Home: Potential Benefits of Decentralised Energy for NSW Electricity Consumers* highlighted the very high level of investment ($17.4 billion over five years to 2013-14) that was to occur in electricity networks in NSW, and the impact that the associated rising electricity network charges would have on customer bills.

Close to Home also reviewed the City's plans for a decentralised energy system utilising trigeneration plants in the City's local government area. The report showed that decentralised energy had the potential to defer or avoid substantial capital investment planned for the Ausgrid network, which includes the City of Sydney local government area.

Close to Home estimated that the City's Interim Trigeneration Master Plan could generate a financial benefit in the form of deferred network costs of more than $200m by 2020 and more than $1billion by 2030, and that it could reduce carbon emissions from electricity supply by around 18-26 per cent (compared to 2006 levels) across the City area.

The City has now commissioned a further report from ISF, called *Game Change: Decentralised Energy and Electricity Networks in the Low Carbon Era.*

Gas price uncertainty

While medium-term gas price forecasts have become more uncertain than previously indicated due to international demand for LNG exports, there are many ways in which future gas costs can be mitigated, including ensuring its efficient use and also developing the very sizeable renewable gas resources in this state. Based on the City's Renewable Energy Master Plan, this can be done at very reasonable cost.

Sooner or later, short term reliance on high-emission coal fired power stations will end. By commencing the transition to cleaner energy sources sooner, the pain of transition can be dramatically eased.

Many countries with much higher gas costs than Australia have been able to successfully introduce large scale cogeneration/trigeneration. It is salutary that in the US large-scale trigeneration was already occurring when gas prices were two to three times their current low level.

City's own experience

At Green Square, the climate for investment in large-scale precinct trigeneration is considered to be less favourable than when the City commenced its procurement process for trigeneration services in 2009.

At its June 2013 meeting, Council resolved not to proceed with a trigeneration precinct at Green Square Town Centre for the time being.

Factors that contribute to reduced commerciality of the Green Square precinct include:

- the October 2012 NABERS ruling, which reduced the commercial attractiveness of precinct trigeneration electricity for NABERS-rated buildings. The impact of this factor has been referred to elsewhere in this submission

- the less certain outlook for both electricity prices and gas prices in the short term, on outcome of changes to the carbon pricing scheme and a higher-than-expected spike in gas commodity prices on account of delays in export gas projects

- the slow pace of the reform process for the National Electricity Market. Faster reform is essential to facilitate comprehensive roll-out of decentralised energy in Green Square. The issue is dealt with extensively elsewhere in this submission.

Council resolved to revisit precinct trigeneration at Green Square when the regulatory environment becomes more conducive.

Despite the challenges of the current regulatory environment, there are specific, but limited situations where trigeneration can deliver carbon abatement at a cost which is competitive to other low-carbon solutions.

Typically, this is in situations where there is an existing market for waste heat and where a significant proportion of the electricity that is locally generated can be used within a host building ("behind the meter") This allows electricity customers to make significant savings on electricity network charges. While this is not the case at Green Square as a new redevelopment area, it is the case for the proposed Town Hall trigeneration precinct and for other limited opportunities across the City of Sydney local government area.

However, for the large scale development of precinct trigeneration required to deliver the economic, energy efficiency and environmental benefits already described in this submission, effective regulatory reform remains essential.

Reference 4: Financial, public safety and other risks

Any financial, public safety and/or other risks to prospective cogeneration/ trigeneration customers

The risks for prospective customers associated with cogeneration/trigeneration precinct developments are low. Europe is a world leader in standards for cogeneration/trigeneration precinct developments; its standards are used in North America, Asia and elsewhere. Accordingly, there is no need to develop new standards from scratch in NSW.

The two main components of a cogeneration/trigeneration precinct are the energy centre and the thermal energy network.

Energy centres

Cogeneration/trigeneration energy centres produce combustion emissions. The NSW Interim Nitrogen Oxide (NOx) Policy for Cogeneration in Sydney and the Illawarra requires NOx emissions for reciprocating engines not to exceed 250mg/m^3 of air (500mg/m^3 of air elsewhere in NSW).

Large-scale precinct scale cogeneration/trigeneration engines can be fitted with selective catalytic reduction (SCR) which reduces the NOx emissions to 50mg/m^3 of air (one fifth of the NSW NOx emissions limit and half the NOx emissions of a modern gas fired boiler). It is economic to fit SCR to large-scale cogeneration/trigeneration engines supplying precincts whereas it is not possible or economic to fit SCR to small scale (normally packaged) stand-alone cogeneration/trigeneration engines supplying individual buildings. SCR with CO catalysts for large scale gas engines can reduce NOx, formaldehyde, CO and other aldehydes emissions by 97-99 per cent, substantially better than the emissions emanating from uncontrolled small-scale gas engines.

Also, cogeneration/trigeneration plant supplying precincts (rather than single buildings) have the advantage that they are able to select the best sites and locations in a precinct for the dispersal of emissions. By comparison, cogeneration/trigeneration plant for individual buildings are fixed in their location.

The precinct scale trigeneration networks for the four low carbon zones as set out in the City of Sydney's Trigeneration Master Plan[5] would reduce absolute NOx emissions from power stations in the Hunter Valley and elsewhere in and around Sydney by 5,000 tonnes a year in exchange for an additional 180 tonnes of NOx emissions in the City's local government area. This represents less than 0.2 per cent of the NOx emissions in the Sydney Metropolitan Area compared to the 78 per cent of NOx emissions generated by motor vehicles.

Thermal energy networks

[5] City of Sydney (2013) Decentralised Energy Master Plan – Trigeneration, CoS: Sydney
http://sydneyyoursay.com.au/document/show/267

The risks and benefits for customers connected to a thermal energy or district heating and cooling or district energy network are set out in detail in the Euroheat and Power District Heating in Buildings – Task Force Customer Installations[6]

The main disadvantage of thermal energy or district heating and cooling or district energy networks supplying existing buildings is the cost of conversion from individual heating and cooling. Depending on the type of system that was previously used, this can be rather complicated and can need careful planning. However, over the lifetime of such a system, this investment can be depreciated very reasonably.

On the other hand there are considerable advantages, like the ease of use, the unlimited amount of domestic warm water available constantly, the desired temperature at all times, and reduction in space required by the heating and hot water services systems. Thermal air conditioning chillers are a different shape and size to existing electric chillers but in most cases can be accommodated in existing spaces.

For customers, thermal energy will generally be a worry-free experience characterised by:

- Minimal noice
- Good air air quality
- Improved sustainability
- Significant reduction in GHG emissions
- Price predictability
- Avoidance of fuel handling issues
- Limited requirements for equipment servicing, particularly for residential customers (no flues, boilers or split system air conditioning issues)
- Remote heat metering and trouble shooting by utility companies.

Thermal energy networks are also very safe due to:

- No local risk of fires or explosions
- No dangerous medias inside the system
- Less risk of failure in energy delivery

Steam based thermal energy is typically found in older thermal energy networks around the world, particularly in the US and Eastern Europe. This is due to industrial thermal energy loads being the original customers for city thermal energy loads such as New York.

From the mid 20th century new systems have been installed using hot water. Many existing steam-based systems are being replaced with hot water systems, such as in Munich[7]. The reason for this is that industrial steam loads do not exist in most cities anymore.

Steam systems have typical losses of 20 per cent, whereas hot water systems have losses of only 5 per cent. Also, hot water systems are relatively low temperature and much safer than steam systems in public safety terms.

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[6] Euroheat and Power District Heating in Buildings – Task Force Customer Installations 2011 http://www.euroheat.org/Files/Filer/documents/Publications/District%20Heating%20in%20buildings_final.pdf
[7] BINE Converting Steam-Based District Heating Systems to Hot Water 2007 http://www.bine.info/fileadmin/content/Publikationen/Englische_Infos/projekt_0107_engl_internetx.pdf

Steam systems are normally supplied by turbines and hot water systems are normally supplied by reciprocating engines which develop higher electrical efficiencies than steam turbines.

Hot water systems are also fitted with electronic leak detection embedded in the pipework so that any water leaks or ingress of moisture from other piped water systems can be pin pointed.

The City's Trigeneration Master Plan modelled 24 possible combinations of engine type, engine size, distribution method and type of operation, including low temperature (hot water) reciprocating engines and high temperature (steam) turbines. Nine preferred configurations were selected for detailed analysis of greenhouse gas emissions savings, fuel efficiency and capital and operational costs.

The best configuration for the City was found to be a low temperature hot water thermal energy network (95^{o}C) driven by reciprocating gas engines and with decentralised heat fired absorption chillers to provide the greatest reduction in greenhouse gase emissions, highest fuel efficiency and the lowest capital and operating costs.

Reference 5: Residential customer issues

Any supply security and reliability issues associated with cogeneration/trigeneration, especially for residential customers of these systems

Cogeneration/trigeneration for precinct developments provides a high degree of security of supply and reliability. Many district energy systems are configured to operate in island generation mode when the electricity grid fails. Systems are normally connected to the local electricity grid but self-disconnect when a grid failure is detected and switch over to island generation mode and operate in a similar way to standby generation. Thermal energy networks can also continue to supply heating and cooling to customers.

Most precinct scale cogeneration/trigeneration networks or district energy systems provide availability of service for 99.99 per cent of the time on an annual basis[8]. For example, the Minneapolis decentralised energy centre has reported only 3 hours of unscheduled outage in 25 years of operation.

Precinct cogeneration/trigeneration networks or district energy with their networks installed underground are also more resilient to natural disasters than electricity grids reliant on overhead poles and wires, an increasing issue with more frequent and extreme climate change events. For example, in the 1989 San Francisco earthquake, the 1998 great Ottawa/Montreal ice storm and the 1998 Seattle earthquake, the only utilities that reported continuous and uninterrupted service were the respective district energy systems.

When Hurricane Sandy hit the Mid-Atlantic and North Eastern US in 2012, it caused major damage to 24 states with damages of nearly $66 billion, excluding losses due to business interruption. The failure of the electricity grids caused major interruptions to the power supply, causing problems with the water supply, sewers, electric grids and telecommunications. With a loss of electricity supply the public transport system also collapsed, including roads, tunnels, bridges, trains, subways and even air travel. The power outage continued not only for several hours, but for days and weeks.

In contrast, those customers connected to a decentralised energy network, including residential, commercial and industrial customers, universities and hospitals, continued to receive their electricity, heating and cooling. When Hurricane Sandy hit New York City the 40MWe trigeneration precinct supplying Co-op City, in the Bronx, provided electricity, heating and cooling to 60,000 residents in 35 high-rise buildings, six schools, three shopping centres and the police precinct in island generation mode[9]. Similar stories emerged right across the Eastern US seaboard where cogeneration/trigeneration was able to keep the lights on for those customers connected to these systems, outperforming diesel standby generators which failed after a few hours when the diesel ran out.

With increasing natural disasters and extreme climate change events, precinct cogeneration/ trigeneration is emerging as a real practical climate change adaptation as well a climate change mitigation measure affording connected customers with reliable security of supply.

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[8] International District Energy Association 'The District Energy Industry' http://www.districtenergy.org/assets/pdfs/IDEAIndustryWhitePaper.pdf

[9] National Association of State Energy Officials 'Combined Heat and Power: A Resource Guide for State Energy Officials, USA, 2013' http://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf

Reference 6: Actions required

The ability of existing regulatory arrangements at the NSW and national level to address issues which may be identified

ELECTRICITY REGULATORY FRAMEWORK

Action 1: Introduce a benefit-reflective network tariff for decentralised electricity generators to reflect their role in avoiding/deferring future capital investment by electricity networks

It is essential to introduce a more equitable charge for use of electricity networks by decentralised generators. This must recognise the much lower level of network infrastructure that such decentralised generators require, especially non-intermittent decentralised technologies like precinct trigeneration.

For example, non-intermittent decentralised generators make no use of the extra-high-voltage transmission infrastructure and much less use of the distribution network when sending out electricity to local customers.

Despite this, customers of non-intermittent decentralised generators are charged for this unused infrastructure at the same rate as customers of remote coal-fired power stations.

It is time that this hidden subsidy to remote generation was exposed for what it is, and that decentralised generators (which do not use such expensive infrastructure) were rewarded for avoided upstream network investment.

The City proposes that a credit tariff be introduced for decentralised generators that supply customers within the distribution network. The scale of this credit tariff should be calculated on the basis of the positive benefits that particular classes of decentralised generators make in terms of deferred network investment.

For example, non-intermittent generators (e.g. precinct trigeneration) that feed directly into the 400V or 11 kV networks and make no call on higher voltage systems would be expected to receive a higher credit tariff. Large-scale intermittent generators (e.g. wind farms) would receive less, because they make feed in at higher voltage (33 kV, 66 kV or even 132 kV) and make more use of the network.

This is the approach adopted in the United Kingdom by the Office of Gas and Electricity Markets (Ofgem). It is transparent and equitable. Each distribution network publishes the applicable credit tarrif to be paid to decentralised generators as part of their annual schedule of distribution tariffs.

Decentralsied generator tariffs are calculated annually based on a standard methodology provided by the national energy regulator. They vary for different classes of generator depending on the size of the generator, the level of intermitency and the time of operation.

The benefits of local electricity are evident in the credit tariffs offered to decentralised generators in the UK.

The value of the credit for each class of decentralised generator in each of the UK network is on the public record and is disclosed at the following Energy Networks Association Common Distribution Charging Methodology website:

http://www.energynetworks.org/electricity/regulation/duos-charges/common-distribution-charging-methodology.html

In Australia, the electricity market is governed by the National Electricity Rules (NER). These rules allow for distribution networks to reimburse decentralised generators for the value of defered investment.

The process involves negotiation between the decentralised generator and the distribution network. It is a complex and time-consuming process and contains significant uncertainty and time delays. The value of the benefit is often not available before the deadline for a project investment decision is reached.

By contrast, the approach used in the UK provides a decentralised generation proponent with certainty up-front as to the tariff it will receive. As the tariff is a recognition of deferred network investment, it is equitable for existing users of the distribution system.

Benefit-reflective network tariffs: the economic argument

- Benefit-reflective network tariffs slow growth of the transmission and sub-transmission networks, with their associated energy losses and extremely high capital costs.
- This in turn slows increases in network tariffs and provides benefits that are felt by all customers of the National Electricity Market.
- Benefit-reflective network tariffs provide more consistent rewards to decentralised electricity generators for the benefit they provide in keeping capital-intensive upstream network investments that would otherwise occur, to a minimum.

As part of its recent *Electricity Network Regulatory Frameworks Review,* the Productivity Commission made the following recommendation:

"11.5: When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced, the Rules should be amended to:

- *ensure that any time-based tariff is determined by (rather than 'take into account') a reasonable estimate of the long-run marginal cost for the service concerned*
- *ensure that the grouping of customers for the purposes of setting time-based tariffs is based on economic efficiency (rather than 'having regard to' it)*
- *make it explicit that significant differences in the long-run marginal cost of meeting peak demand between locations and across customer groups should be reflected in network pricing structures with any deviation from this principle arising from any state or*

territory government decisions about community service obligations transparently funded by the relevant jurisdiction."

Such an approach is in the interest of networks as well as decentralised generators. If the lower costs are not recognised, more and more customers that are able to do so will simply bypass the public networks completely (for example, going off-grid or installing private wires), creating unnecessary and wasteful duplication along the way.

Benefit-reflective network tariffs: calculating the numbers

- Detailed calculations are required to inform the precise level of reduction in charges available for localised generation, either by location or by time of day.
- This submission has referred to the method that applies in the UK. Such a system could be adapted to apply in the National Electricity Market in Australia.
- Information about the UK methodology used to calculate benefit-reflective tariffs can be found at: http://www.dcusa.co.uk/Public/DCUSADocuments.aspx?s=c

  (Alternatively, use your search engine to find UK DISTRIBUTION CONNECTION AND USE OF SYSTEM AGREEMENT – Common Distribution Charging Methodology Schedule 16)

This reform can be pursued by the NSW Government via a submission to the Australian Energy Regulator.

Action 2: Ensure the regulatory framework established under the National Electricity Rules facilitates connection of decentralised generators and sale of decentralised electricity.

As outlined earlier in this submission ("Reference 1: Adequacy of regulatory frameworks"), there are three main barriers to decentralised generators being able to operate in the National Electricity Market on an equitable and competitive basis.

These barriers have to do with connection of decentralised generators, retailing of electricity from decentralised generators and the lack of recognition of network benefits provided by decentralised generators.

The need to introduce a benefit-reflective network tariff for decentralised generators has been set out under Action 1 above.

This section covers generator connection and energy retailing issues.

Reforming the decentralised generator connection process

Decentralised generator connection issues are of particular interest at the current time.

AEMC has made a draft determination in response to a rule change proposed by Climate Works, the Property Council of Australia and SEED Advisory that would go some way towards facilitating decentralised connections.

However, some key issues have yet to be addressed:

- The definition of 'fast track' or 'agreed' projects has yet to be clearly defined and must be based on performance criteria, not specific equipment criteria or left to the discretion of the distribution network operator.
- The proposed rule change sets out a maximum of 95 days for 'fast track' or 'agreed' projects but does not set out any maximum timescale for 'non fast track' projects.
- Technical requirements for connecting embedded generation are not standardised. Other countries have had such standards in place for some time. The G59 standard, which applies in the UK, could be used as a model for an Australian standard.
- There should be a right to export subject to the network being able to safely handle the export from an embedded generator.
- Processes to ensure recovery of shared network augmentation costs must be resolved.

Reforming the process for retailing decentralised electricity

There are specific requirements under the National Electricity Rules that impose disproportionate transaction costs on small-scale generators for participating in the National Electricity Market, especially for small-scale generators that wish to retail electricity directly to other customers, rather than wholesale it to other retailers. Transaction costs that may seem minimal to giant coal-fired power stations are in fact unreasonably high for small-scale precinct trigeneration operators and other decentralised electricity generators.

Overall, the regulatory obstacles to selling surplus power to local customers over private wires and across the public wires distribution network are too great to promote the comprehensive roll-out of decentralised electricity generation that is needed. An innovative solution must be found based on examples that are known to work and have been successfully implemented by other countries to remove the regulatory barriers to decentralised energy such as the UK

The proposed regulatory reform comprises two regulatory reform mechanisms which can be used in isolation or in combination with each other, depending on the nature of the decentralised energy scheme:

- The retail and network exempt licencing regime must be broadened and made more flexible to support for generation, distribution and retail of decentralised energy generation up to 30MWe per generation site. Where retail or network exceptions have been granted the delivery of electricity will generally be over private wire networks. However, some export over local public wire distribution networks should be permitted similar to the exempt licensing regime set out in the UK Department of Trade Industry 'Electricity (Class Exemptions from the requirement for a Licence) Order 2001[10].

[10] DTI The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001 http://www.legislation.gov.uk/uksi/2001/3270/pdfs/uksi_20013270_en.pdf

- Decentralised energy schemes that intend to retail electricity to customers over the local public wires distribution network would be enabled to do so under a 'stripped down' retail authorisation which would operate under an umbrella agreement with a standard authorised retailer. The National Electricity Rules need to be modified to make it easier for decentralised energy schemes and small retailers to operate as retailers on the public network by exempting them from the requirement to be a direct party to the industry codes.

  This new 'stripped down' authorisation will include the relevant protections for domestic customers and will enable local decentralised energy generators to export surplus electricity over the local public wires distribution network to local customers on the 'virtual private wire' principle. This approach would be on a basis similar to the Ofgem Supply Licence Modification Order 2009[11] in the UK.

  See 'Electricity markets in other countries support decentralised energy' on page 12 of this submission.

Both of the above regulatory reform mechanisms to be used in conjunction with the introduction of a benefit-reflective network tariff for decentralised electricity generators to reflect their role in avoiding/deferring future capital investment by electricity networks as detailed under Action 1.

This reform can be supported by the NSW Government. For example, the NSW Government could proposed a rule change to be considered by the AEMC.

<u>Action 3:</u> Introduce a feed-in tariff for cogeneration/trigeneration (as a precursor to implementation of Actions 1 and 2) to promote the transition to decentralised energy

This submission argues that the way forward for precinct trigeneration is to break down the barriers for decentralised electricity in the National Electicity Rules.

Both Action 1 and Action 2 above are designed to achieve this outcome in the medium term.

However, comprehensive change will take time to implement, and there is a need for action in the short term to grow precinct cogeneration/trigeneration capacity.

Short-term incentives are needed for precinct trigeneration providers. These incentives can be phased out as changes to the National electricty Rules occur.

The most straightforward and transparent form of incentive is the introduction of an feed-in tarrif for precinct trigeneration electricity during network peak and shoulder periods (working week days, 7 am to 10 pm).

This feed-in tarrif would comprise two elements:

- a market-aligned payment for the value of the energy being sent out by precinct generators; and

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11 Ofgem Distributed Energy – Final Proposals and Statutory Notice for Electricity Supply Licence Modification 2009 http://www.ofgem.gov.uk/Sustainability/Environment/Policy/SmallrGens/DistEng/Documents1/DE_Final_Proposals.pdf

- a provisional network-benefit payment. This would be a precursor to a benefit-reflective natwork tariff, as described under Action 1.

The value of the energy payment would be comparable to the value of the feed-in tariff for solar PV that is determined by the Independent Pricing and Regulatory Tribunal as part of its annual regulated customer determination. This payment does not currently recognise network benefits, because of the intermittent and diverse character of household PV installations.

The value of the network benefit for precinct trigeneration would for the time being be a fixed proportion of the applicable network use of system charge at the relevant time of day. Based on evidence from the UK, the benefit would be at least 50 per cent of the applicable network charge.

Such an arrangement could be implemented via an amendment to section 15 of the Electricity Supply Act (NSW).

This reform can be implemented by the NSW Government.

Action 4: Provide similar powers for thermal network operator to carry out their core business activities as are provided to electricity network operators under Part 5 of the Electricity Supply Act 1995 (NSW)

A number of challenges experienced by the City in seeking to develop a large scale trigeneration network lead to the conclusion that thermal energy network providers ought to be afforded all or many of the statutory protections now afforded to electricity network operators under the Energy Supply Act 1995 (NSW).

Without such protections, the ability to deliver cost effective infrastructure and to establish ongoing investor confidence (for example, in terms of the right of thermal network providers to place pipes in streets) is much diminished.

This reform can be implemented by the NSW Government.

BUILDING ENERGY EFFICIENCY STANDARDS

Action 5: As a matter of urgency, reverse the October 2012 NABERS ruling that disadvantages decentralised electricity produced via precinct trigeneration

The National Australian Built Environment Rating System (NABERS) is a voluntary national rating system that measures the energy efficiency, water usage, waste management and indoor air quality of a building or a tenancy and its impact on the environment. The rating takes into account the energy sources that the building uses, and helps to reduce energy and water consumption and greenhouse gas emissions.

NABERS was originally introduced in 1998 as the Australian Building Greenhouse Rating Scheme. It is managed on behalf of Commonwealth, state and territory governments by the NSW Office of Environment and Heritage. Buildings with high NABERS ratings are valued in the marketplace, attracting higher valuations and higher market rentals and enjoying lower operating costs.

Commercial Building Disclosure is a national program designed to improve the energy efficiency of Australia's large office buildings. Under the Building Energy Efficiency Disclosure Act 2010 owners selling or leasing commercial office space of 2,000 sq m or more, are required to obtain and publicly disclose a current Building Energy Efficiency Certificate which must include a NABERS Energy star rating for the building.

In 2010, NABERS introduced a ruling on the proportioning of energy used by cogeneration/ trigeneration. The purpose of the ruling was to define the methodology by which energy inputs to cogeneration/trigeneration systems are apportioned to the parties using the outputs of these generation systems. This includes the export of electricity or thermal energy to tenants within the building or third parties outside the building and the import of electricity or thermal energy from district heating/cooling/generation systems.

The NABERS 2010 ruling addressed the emerging precinct-scale decentralised energy market in Australia and incentivised more energy efficient precinct-scale decentralised energy systems over less efficient stand-alone building-based systems.

In 2012, NABERS published a consultation position paper seeking to overturn its previous ruling. Although 20 out of the 25 respondents did not support this, NABERS implemented a new ruling later that year.

The October 2012 NABERS ruling effectively removed low carbon electricity from precinct scale trigeneration from the headline NABERS rating. This ruling would also treat precinct-scale renewable electricity in the same manner as remote coal-based electricity and completely ignore how electricity emissions are allocated.

Decentralised energy generators are not accounted for in the National Greenhouse Accounts Factors for the NEM. Their emissions can only be accounted for locally as they connect to distribution networks, not to transmission grids.

This ruling encourages a sub-optimal scale of investment and performance and lead to needless duplication. This makes no sense – a series of buildings served by a shared cogeneration/trigeneration plant ought ot be able to access the same level of benefits (or better, due to greater efficiency) as would be available to a single building.

The October 2012 NABERS ruling effectively undermines precinct trigeneration, particularly for new development such as Green Square Town Centre, where infrastructure has to be built in advance of connected load and the ability to export the generated electricity to other consumers that have a need for low carbon electricity such as the owners of existing buildings seeking to reduce their emissions to gain a higher NABERS rating is key to economics of such projects.

The Octobers 2012 NABERS ruling effectively ignores this key issue. It is illogical and must be reversed as a matter of urgency.

This reform can be implemented by the NSW Government.

Action 6: Reform the Building Energy Efficiency Disclosure Act 2010 so that it recognises both electricity and thermal energy outputs of precinct cogeneration/trigeneration

To coordinate with Action 5 the Building Energy Efficiency Disclosure Act 2010 should be reformed so that it recognises both the electricity and thermal energy outputs of precinct cogeneration/trigeneration.

This reform can be supported by the NSW Government.

Action 7: Fully recognise the benefits of thermal energy from cogeneration/ trigeneration under the NSW Energy Savings Scheme

The NSW Government plans to undertake a review of the Energy Savings Scheme as part of its Energy Efficiency Action Plan to encourage a broader range of energy efficiency actions. The City of Sydney recognises the benefits of the NSW Government's Energy Savings Scheme (ESS) for reducing building electricity consumption.

There are a number of actions that could be considered as part of the Government's review of the scheme which would clarify the eligibility of use of thermal energy from cogeneration/ trigeneration to improve building efficiency:

- Recognise reductions in building gas consumption as an eligible efficiency improvement activity under the scheme
- Recognise the eligibility of thermal energy delivered over a thermal energy network
- Explicitly recognise replacement of an electric air conditioning chiller with a thermal air conditioning chiller driven with thermal energy from trigeneration as an eligible activity.

Currently ESS applies to savings delivered from reduced electricity use. The eligibility of energy efficiency projects which reduce gas consumption is currently unclear. It is recommended that projects which reduce gas consumption be explicitly recognised under the scheme. Doing so would allow building owners to claim energy savings certificates where they connect to a thermal energy network supplied by cogeneration/trigeneration to displace gas, for example for water heating.

Maximum energy efficiency benefits from precinct cogeneration/trigeneration are gained when thermal energy can be shared between buildings. It is essential that the scheme recognise the eligibility of thermal energy delivered over a thermal energy network, as well as thermal energy generated on the premises.

Some of the efficiency benefits offered by thermal energy produced from cogeneration/ trigeneration may be currently eligible for energy savings certificates under the scheme, such as where thermal energy used to displace electricity by through replacement of an electric air conditioning chiller with a thermal air conditioning chiller. Explicit recognition of the use of this activity under ESS would promote its application.

This reform can be implemented by the NSW Government.

Action 8: Fully recognise the benefits of decentralised energy in the Building Code of Australia

In May 2012, the Australian Department of Climate Change and Energy Efficiency published a report on Inclusion *of Energy Generation in Building Energy Efficiency Standards*. The study covered Zero and Low Emission Energy Generation (ZLEG), comprising both renewable energy and low-carbon cogeneration/trigeneration. Low carbon is defined as a 50 per cent reduction in greenhouse gas emissions, which is consistent with the Intergovernmental Panel on Climate Change target for emissions

Based on International Energy Agency studies, the report advises that precinct-scale ZLEG systems such as district heating/cooling must be included in building energy efficiency standards, as their value for reducing national emissions is clear. Short-term products or contracts such as Green Power are excluded.

The report sets out the technical potential of ZLEG for new and existing buildings if the Building Code of Australia was used to foster ZLEG. This breaks down into two major technologies and customer loads - solar PV primarily for the residential sector and precinct trigeneration for the commercial sector. For solar PV the technical potential is 8,126 GWh per year and for precinct scale trigeneration the technical potential is 9,300 GWh per year. This compares with the 8,465 GWh per year growth in forecast electricity consumption for the residential sector and the 6,300 GWh per year growth in forecast electricity consumption for the commercial sector, both by 2020. Stand-alone building-based cogeneration/trigeneration and building wind energy would have limited impact on generation or addressing growth in electricity demand.

The report makes two key recommendations:

(a) A ZLEG system (cogeneration/trigeneration or renewable energy) needs to be connected to buildings by way of a private wire network, a 'virtual private wire' network over public wires (similar to the UK) or pipes carrying hot or chilled thermal fluid.

(b) The Building Code of Australia should be modified to incorporate a method to calculate the impact of ZLEG and that the same method should be used in all related rating tools such as NatHERS and NABERS.

The Australian Government's 'Inclusion of Energy Generation in Building Energy Efficiency Standards in the Building Code of Australia' must be implemented as soon as possible.

This reform can be supported by the NSW Government. It may be able to be implemented in part by the NSW Government.

SUSTAINABLE NEW BUILDING DEVELOPMENT

Action 9: Remove regulatory impediments under competition law to supply of thermal energy from precinct cogeneration/trigeneration

As set out earlier in this submission (see "Reference 1: Adequacy of reference networks"), the City has identified section 47 of the Competition and Consumer Act 2010 as a potential barrier to full-scale roll-out of precinct trigeneration.

There are two key issues stemming from section 47 of the Competition and Consumer Act 2010.

First, section 47 makes it illegal (as a term of an agreement) to require a party to that agreement to enter into a separate commitment with a third party for goods or services, unless the agreement is approved by the ACCC (this is commonly known as "third-line forcing").

For precinct trigeneration, this issue may arise where thermal energy is made available to a new development by a single provider, and the developer imposes a requirement on unit holders or the owners corporation to take and pay for supply from the single provider. This would be to seek to ensure that the single provider would be able to achieve a return on its capital costs of installing the green infrastructure.

Such an arrangement may involve a breach of the Competition and Consumer Act 2010, even though the arrangement is at the request of public authority (the City) and there are clear public benefits to be gained by requiring occupiers of buildings to be more sustainable in their future energy use.

Second, an arrangement whereby the developer/owner of a thermal energy distribution network agrees to restrict the use of the network to a single services provider is also an exclusive dealing arrangement.The purpose of such a provision would be to produce efficiencies, and support the investments which the single supplier is making as part of the supply of services. An exclusive dealing provision of this type is only permissible where it does not have the purpose or effect of substantially lessening competition in any market.

In the City's view, these types of exclusive dealing do not reduce competition in the supply of electricity and gas. Rather, this promotes the use of an innovative product that has clear environmental benefits in residential apartments and commercial tenancies.

It should not be necessary for the City and the relevant developer, on each separate occasion when thermal energy is included in new development, to seek approval from the ACCC.

To this end, the City requests the introduction of a state-level regulatory framework should be considered so that the project can be specifically authorised for the purposes of s.51(1) of the Competition and Consumer Act 2010.

An additional measure to be considered is the price regulation of thermal services by IPART. As limited competition for such services will exist, due to the nature of green infrastructure, this will help to ensure that the price for such services is an efficient representation of the capital and operating costs of this monopoly infrastructure in the premises. This is intended to give consumers confidence that there is a control on the cost of the services and enables them to have regulated prices to compare against the costs of current alternatives for thermal services.

Further, it would be of assistance for standard verification criteria for, or certified design of , thermal meters (to measure the flow and temperature for the supply of hot and cold water) to be recognised nationally. International organsiations like the International Organisation for Legal Metrology, have published standards that apply to thermal meters.

In this regard, there would also be benefits in introducing regulatory standards for thermal meters. This would avoid developers running the risk that regulatory change will require them to replace existing thermal meters. As a corollary to this, it would be beneficial for developers if future regulatory changes grandfathered installed thermal meters, such that they did not need to be replaced. Also, this would avoid commercial risks in relation to billing disputes, to which the developer will have no defence that it acted reasonably by acting in accordance with the regulatory requirements in respect to the calibration and validation of the thermal meter.

This reform can be supported by the NSW Government.

Action 10: Amend the Strata Schemes Management Act to exclude supply of thermal energy as part of sustainable new development from the provisions of section 113 of the Act

During the initial development of a trigeneration precinct, especially in large urban renewal projects and in greenfield areas, prospective thermal energy suppliers need to be able to have a level of confidence about prospective customer demand.

Unlike long-established electricty distribution networks, there is not a large catchment of existing customers who can be relied on to contribute to the forward funding of infrastructure in newly developed (or redeveloped) areas.

To allow thermal energy service providers to be treated on a more equal footing with longer-established electricity and gas distributors, thermal energy service providers ought to be allowed to enter into binding agreeements in advance to cover the fixed costs of supplying thermal energy to buildings for a reasonable period. Such agreements would typically be entered into by residential apartment developers or commercial office block developers on behalf of incoming owners corporations. The conditions of such arrangement must of course be reasonable, reflective of actual costs to be incurred and subject to any normal review mechanisms.

Section 113 of the Strata Scheme Management Act 1996 (NSW) inhibits efficient long term contracting of green infrastructure services such as precinct-based thermal energy. The section prohibits developers (during the initial period of a strata scheme) entering into commitments which may constitute an unfunded debt for the owners corporation, unless particular conditions are met. The initial period is the period from the date of constitution of the owners corporation to the time the original owner's unit entitlement is less than two thirds of the aggregate unit entitlement for the strata scheme. An unfunded debt means the amount of the debt or liability exceeds the amount then available for repyament of the debt/liability from the administrative or sinking fund of the owners corporation.

The consequence is that building developers or thermal energy service providers:

- are obliged to meet the cost of installing such infrastructure up-front or to capitalise the administrative or sinking fund of the owners corporation to cover the potential liability for the commitment period for the services. This makes the units more expensive in comparison to developments where services are provided and funded on a 'pay as you go' (consumption) basis; and

- are unable to agree long-term commitments (for a fixed term, fixed fee, or minimum volume of services, or in respect to break fees) by owners corporations that they will in fact use the service, so developers or service providers have no certainty as to whether the service will be taken up prior to investing in the infrastructure. So, there is a commercial risk of not achieving a return on the capital cost of installing the green infrastructure.

Currently, only the owners corporation can apply to the Consumer, Trader and Tenancy Tribunal to obtain approval of a long-term services contract. As the owners corporation is not formed until after the infrastructure is built, this leaves the developer or services provider with the risk of building the infrastructure and then finding the services contract is not approved by the Tribunal or owners corporation.

Long-term commitments on costs will also benefit prospective customers of thermal energy, as there is no price regulation of thermal services (domestic hot water and hot water for space heating and cooling) or recycled water supply. This would give customers greater certainty on service costs.

Potential amendments to the operation of section 113 would be to:

- exempt any obligations created under contracts for thermal energy services from the provisions of the section; or

- allow the owner of the development land to apply for and obtain, on behalf of the owners corporation to be subsequently formed in relation to that land, pre-approval by the Tribunal of the thermal energy contract, with the intent that such approval would be obtained prior to the design and construction of the project.

Action 11: To promote new sustainable development, provide new development with access to similar provisions as now apply under Environmental Upgrade Agreements

The NSW Environmental Upgrade Agreement (EUA) legislation has been successful in incentivising environmental improvement works in buildings. The largest EUA implemented so far in Australia is the $26.5 million trigeneration precinct at Central Park. However, the Local Government (Environmental Upgrade Agreement) Act 2010 and Regulations 2011 apply to existing development only and exclude new development. An EUA was only possible at Central Park because the trigeneration energy centre was located in the old Carlton United Brewery building.

New development becomes existing development once it is built. It is illogical and counter-productive to deny developers access to EUA low cost finance to implement environmental improvement works in new development, including precinct trigeneration.

The EUA legislation should be reformed to provide comparable provisions for new development to achieve a step change in the sustainability of new residential apartments and commercial buildings.

This reform can be implemented by the NSW Government.

<u>Action 12:</u> Increase the threshold for precinct trigeneration to be state significant development under SEPP (State and regional development) 2011 and streamline application of this SEPP to precinct trigeneration

Medium and large-scale precinct cogeneration/trigeneration projects are likely to be covered under the provisions of SEPP (State and regional development) 2011.

Specifically, the SEPP covers development for the purpose of electricity generating works or heat or their co-generation (using any energy source, including gas, coal, biofuel, distillate, waste, hydro, wave, solar or wind power) that (a) has a capital investment value of more than $30 million, or (b) has a capital investment value of more than $10 million and is located in an environmentally sensitive area of State significance.

In the view of the City, the dollar value limits that are set in the SEPP for such projects to be state significant development are too low and ought to be increased to at least $50 million.

Also, guidelines should be prepared to assist assessors for any precinct trigeneration project that, irrespective of the actual dollar limit at the time, is deemed to be state significant development.

This reform can be implemented by the NSW Government.

GAS PRODUCTION AND DISTRIBUTION

<u>Action 13:</u> Remove barriers roll-out of cogeneration/trigeneration from gas distribution charges

An issue has come to the attention of the City which is of great concern. A gas distribution service provider may seek to charge the operator of cogeneration/trigeneration plant the same (higher) tariff as small residential customers (or alternatively some form of intermediate negotiated tariff) for the gas received by the trigeneration plant. Distributors have acted in this manner where part of the output of such trigeneration plant is thermal energy provided to residential customers for domestic water heating (typically, via centralised plant in residential apartment blocks).

This stems from an ambiguity in the existing scope of reference services (which are described as services for the transportation of gas to a single eligible delivery point for the use on premises to meet the production or energy demands of a single business customer). Disputes have arisen regarding whether the 'use of a single customer' refers to the use of the gas (which is the City's view), or also the subsequent use of the services derived from the combustion of the gas by multiple customers (which is the distributor's view).

In the view of the City and its legal advisors, the distributor's view is a misreading of the existing access arrangements in respect to reference services for gas distrbution networks approved by the AER. In the absence of protracted legal action (by way of an access dispute referred to the AER under the National Gas Law), there does not appear to be a mechanism for a prospective user to prevent the monopoly gas distributor from seeking a higher access charge than would prevail for any other single large-scale (“industrial”) gas consumer.

Whilesoever such provisions endures, trigeneration precincts which include the provision of domestic hot water supply potentially face unreasonably high costs for delivery of gas to generation plant.

This reform can be supported by the NSW Government during the next gas distribution regulatory determination process.

Action 14: Reform the Gas Act and Regulations to enable renewable gas to be supplied to customers via the gas network

As renewable gas souces are developed and made available to the market, a primary attraction for customers will be their renewable or zero-carbon status. As with GreenPower, this requires official recognition.

The Gas Act and Regulations must be updated to enable renewable gas injected into the gas grid to be separately identified/accredited and able to be directly purchased by consumers via a renewable gas purchase agreement in a similar way to renewable electricity being able to be purchased by a consumer via a renewable power purchase agreement.

Renewable gas grid injection could provide NSW with a significant economic and job creation opportunity, particularly in rural areas, and NSW could take the lead in establishing a renewable gas grid injection market in Australia. This would not only address waste and landfill issues it could also develop into a much bigger renewable energy mining and exports opportunity using 'power to gas' technologies making use of the existing gas export liquefaction infrastructure.

This reform can be implemented by the NSW Government.

Action 15: Amend the draft NSW Energy from Waste Policy Statement to facilitate production of renewable gases

The proposed NSW Energy from Waste Policy Statement should be amended to avoid the Policy Statement from becoming unnecessarily prescriptive and counter-productive in generating renewable gases from waste for injection into the gas grid and avoid waste going to landfill.

This reform can be implemented by the NSW Government.

Reference 7:
Other relevant matters

Reform of the planning system to incentivise decentralised energy

Planning reform can be used to initiate or incentivise a decentralised energy market, particularly precinct cogeneration/trigeneration and renewable energy.

In London, the London Plan was given greater emphasis with the Greater London Authority Act 2007 which introduced a new statutory duty on the Mayor to prepare and publish climate change mitigation and adaptation strategies. This includes the specific duty to take action to mitigate the effects of climate change and help London adapt to unavoidable impacts. The Mayor's Climate Change Mitigation and Energy Strategy 2011 confirmed the Mayor's Climate Change Action Plan 2007 key targets to reduce CO_2 emissions by 60 per cent below 1990 levels by 2025 and to supply 25 per cent of London's energy supply from decentralised energy by 2025 and by more than 50 per cent by 2050.

The revised London Plan 2008 changed the energy hierarchy from an energy led policy to an emissions led policy and placed greater emphasis in the planning process of the GLA on connecting new development proposals to decentralised energy or district heating networks and securing site wide networks and on-site CHP where feasible.

Strategic planning applications referable to the Mayor are required to include energy assessments setting out how they will meet the London Plan energy policies. Applicants are required to set out how the CO_2 emissions of the proposed development have been minimised through the application of the energy hierarchy:

1) Be lean: use less energy
2) Be clean: supply energy efficiently
3) Be green: use renewable energy

Each assessment is evaluated by a GLA specialist team to ensure that the key strategic issues are adequately addressed and that the CO_2 reductions have been maximised. The energy hierarchy has the effect of incentivising developers to first reduce emissions through more cost effective energy efficiency measures, then reducing emissions through site-wide or precinct scale cogeneration/trigeneration decentralised energy networks and finally reducing the remaining emissions by 20 per cent from on-site or near-site renewable energy.

The London South Bank University (LSBU) undertook monitoring of the London Plan Energy Policies in the first year of operation of the revised London Plan and analysed 147 applications of about 340 applications referred to the Mayor. Biomass boilers, photovoltaics, ground source heat pumps and solar thermal were the most popular renewable technologies (in that order). The popularity of photovoltaics had significantly increased from the 2007 study due to its compatibility with cogeneration/trigeneration. Similarly, with the sudden growth in biomass boilers due to their compatibility with cogeneration/trigeneration, such as the London 2012 Olympics trigeneration network, as set out below:

More than half of the planning applications analysed achieved CO_2 savings of at least 30 per cent and approximately a quarter met or exceeded 40 per cent CO_2 savings over and above the 2006 UK Building Regulations through the use of a combination of energy efficiency, cogeneration/trigeneration and renewable energy measures (including renewable fuelled cogeneration/trigeneration).

The average CO_2 savings achieved were 33 per cent. This is made up of 14 per cent from energy efficiency measures, 9 per cent related to the use of gas fired cogeneration/trigeneration and a further 10 per cent from renewable energy technologies.

The 2010 monitoring of the London Plan Energy Policies showed that the Policies were continuing to reduce emissions. Overall, in 2010 projected CO_2 savings of 71,813 tonnes of CO_2 were secured compared to 57,911 tonnes of CO_2 in 2009. In addition, installation of on-site heat networks to supply circa 27,000 apartments (96 per cent of the total dwellings approved through planning) were also secured.

Similar planning policies could be implemented in NSW, particularly for Sydney and other major urban developments.

This reform can be implemented by the NSW Government.

Precinct scale or citywide cogeneration/trigeneration incentives

Due to the importance of precinct scale or city-wide cogeneration/trigeneration networks many countries have not only removed the regulatory barriers to decentralised energy they have also inplemented a range of incentive programs. This ranges from legislation such as the Heating Industry Act 1972 in Japan, the Heat Supply Law 1979 in Denmark and the District Heating and Combined Heat and Power Acts 2004 and 2009 (previously the Local Authority Act 1990) in Germany to directives such as the European Union Cogeneration Directive 2004, tax and other incentives for cogeneration and district heating/cooling such as the Public Utilities Regulatory Policies Act 1978 in the USA and the Global Warming Solutions Act 2006 in California and by direct government dictat or direct action mechanisms such as the Guiding Opinions of the Deployment of Gas-Fired Distributed Energy 2011 (which in place the 5,000MWe targets for gas fired trigeneration by 2015 and 50,000MWe by 2020).

As an example of the measures used to incentivise and deploy cogeneration/trigeneration, the suite of energy and climate change policy measures used to incentivise cogeneration/trigeneration in the UK are set out below:

Energy Performance of Buildings Directive[12];
Cogeneration Directive[13];
Building Regulations supporting cogeneration and district heat networks[14];
Planning Law incentivising cogeneration and district heat networks such as the London Plan[15];
New Power Station Consents incentivising cogeneration and district heat networks[16];

[12] Directive 2010/31/EU on Energy Performance of Buildings (Recast) 2010 http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:153:0013:0035:EN:PDF
[13] Directive 2004/8/EC on Promotion of Cogeneration Based on a Useful Heat Demand in the Internal Energy Market 2004 http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2004:052:0050:0060:EN:PDF
[14] DCLG Consultation on Changes to the Building Regulations in England 2012 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/8389/2077485.pdf and DCLG Building Regulations (Amendment) Regulations 2012 http://www.legislation.gov.uk/uksi/2012/3119/pdfs/uksi_20123119_en.pdf
Energy Planning – GLA Guidance on Preparing Energy Assessments 2011 http://www.london.gov.uk/sites/default/files/guidance-energy-assessments-sept-2011.pdf
[15]

Enhanced Capital Allowances (ECAs) incentivising good quality CHP (cogeneration)[17];
Business Rates Exemption[18];
Climate Change Levy (CCL) Exemption incentivising good quality CHP[19];
Renewable Fuelled CHP Renewable Obligation Certificates (ROCs)[20];
Combined Heat and Power Quality Assurance (CHPQA) programme and Standard[21];
Renewable Heat Incentive (RHI) Exemption incentivising cogeneration and district networks[22]; and
Removal of Regulatory Barriers to Decentralised Energy

Similar incentives for precinct cogeneration/trigeneration could be implemented in NSW, particularly for Sydney and other major urban developments.

Similar relevant incentives can be implemented by the NSW Government.

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2 September 2013

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[16] Department of Trade & Industry Guidance on Background Information to Accompany Notifications Under Section 14(1) of the Energy Act 1976 and Applications under Section 36 of the Electricity Act 1989 https://whitehall-admin.production.alphagov.co.uk/government/uploads/system/uploads/attachment_data/file/43594/Power_station_proposals_-_guidance_2006.pdf
[17] DECC Enhanced Capital Allowances http://chp.decc.gov.uk/cms/enhanced-capital-allowances/
[18] DECC Business Rating Exemption http://chp.decc.gov.uk/cms/business-rating-exemption/
[19] HMRC Climate Change Levy - Combined Heat and Power Schemes http://customs.hmrc.gov.uk/channelsPortalWebApp/channelsPortalWebApp.portal?_nfpb=true&_pageLabel=pageLibrary_ShowContent&propertyType=document&id=HMCE_CL_000170#P12_467
DECC CHP and the Renewable Obligation http://chpqa.decc.gov.uk/assets/Presentations/2012/CHPQA2012CHPandtheRenewablesObligation.pdf
[21] The CHPQA Standard Issue 3 http://chpqa.decc.gov.uk/assets/Uploads/CHPQAStandardIssue3.pdf
[22] DECC Renewable Heat Incentive https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/renewable-heat-incentive-rhi and http://www.renewableheatincentives.org.uk/en/renewable-heat-incentive/rhi-overview.aspx

Appendix

Summary of representations by the City of Sydney relating to the regulatory environment for decentralised energy, including cogeneration/trigeneration

Submissions

Electricity Regulation

- Australian Energy Regulator (AER) Electricity Distribution Networks Determination 2009-2014 (2009);
- Prime Minister's Task Force on Energy Efficiency (2010);
- AER Approach to Retail Exemptions (August 2010);
- NSW Special Commission of Inquiry – Electricity Transactions (June 2011);
- Australian Energy Market Commission (AEMC) National Electricity Market (NEM) Rule Change Small Generation Aggregator Framework (April 2012);
- AEMC NEM Rule Change Connecting Embedded Generators (August 2012);
- AER Framework and Approach to NSW Electricity Distribution Networks Determination 2014-2019 (August 2012);
- AEMC Power of Choice (October 2012);
- NSW Renewable Energy Action Plan (October 2012);
- Productivity Commission on Electricity Network Regulatory Frameworks (November 2012);
- Electricity distribution network cost reflective DUOS charging - Trevor Armstrong, Ausgrid (20 November 2012).

NABERS

- City of Sydney Submission - Review of the NABERS Ruling Proportioning of Energy Used by Cogeneration and Trigeneration Systems (August 2012).

Meetings

Electricity Regulation

- May 2011 - Allan Behm, Chief of Staff to Greg Combet, Minister for Climate Change and Energy Efficiency;
- 21 September 2011 - Minister Chris Hartcher, Andrew Humpherson, Chief of Staff and Anthony Englund, Minister's energy advisor;
- 5 December 2011 - Australian Energy Market Operator (AEMO), Bob Bosler, Senior Manager, Electricity Retail Market Development and John Wormald, Senior Manager, Electricity Market Operations and Performance;
- 10 February 2012 - Anthony Albanese, Minister for Infrastructure and Transport;
- 5 April 2012 - Australian Energy Market Commission - Steven Graham, Chief Executive and Dr Rory Campbell, Senior Director.

- 10 November 2011 – Briefing Premier Meeting – City Transformation & Green Square. Long term vision for Sydney night time economy. Barangaroo delivery authority board
- 21 December 2011 - Meeting with Anthony Englund, Office of the Minister for Resources & Energy – Trigen Project
- 2 March 2013 - Meeting with Di Leeson & Kathryn Pearson DPC

Trigeneration at Green Square and need for regulatory change

- 7 April 2011 on - Dew Clarke, Dept Resources, Energy and Tourism
- 7 April 2011 on - Dr Martin Parkinson, Secretary, Treasury
- 7 April 2011 on - Lisa Gooding, Assistant Energy Advisor, Minister Ferguson
- 7 April 2011 on - Loga Chandrakumar, Population Advisor to Minister Burke, Environment
- 7 April 2011 on - Damian Kassabgi – Advisor PM's office
- 7 April 2011 on - Dr Paul Grimes, Dept Sustainability, Environment Water, Population and Communities
- 7 April 2011 on - Mike Mrdak – Secretary Dept Infrastructure & Transport
- 7 April 2011 on - Glenys Beauchamp, Dept Australian Regional Development and Local Govt

NABERS

- 19 June 2012 - Jim Round, Chief of Staff to Minister Dreyfuss;
- 19 June 2012 - Adam Cullen, Director Energy Efficiency Branch, Department of Climate Change & Energy Efficiency;
- 22 June 2012 - Matt Clarke, NSW Office of Environment and Heritage as the COAG administration body for NABERS, and Adam Cullen, Director Energy Efficiency Branch, Department of Climate Change and Energy Efficiency;
- 2 August 2012 - Bernard Carlon, Director, Senior Staff NSW Office of Environment and Heritage;
- 9 October 2012 - Dugald Murray, Senior Advisor at Cabinet Secretary, Parliamentary Secretary for Climate Change and Energy Efficiency and Assistant Director at Department of Climate Change; Gene McGlynn, Assistant Secretary for the Building & Government Energy Efficiency Branch, DCCEE and Stanford Harrison, Director, Commercial Building Disclosure, DCEE;
- 19 November 2012 - Rob Stokes, Parliamentary Secretary for Renewable Energy, NSW Government.

Game change

Decentralised energy and electricity networks in the Low Carbon Era

For the City of Sydney

August 2013

ABOUT THE AUTHORS

The Institute for Sustainable Futures (ISF) was established by the University of Technology, Sydney in 1996 to work with industry, government and the community to develop sustainable futures through research and consultancy. Our mission is to create change toward sustainable futures that protect and enhance the environment, human well-being and social equity. We seek to adopt an inter-disciplinary approach to our work and engage our partner organisations in a collaborative process that emphasises strategic decision-making.

For further information visit: **www.isf.uts.edu.au**

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Please cite this report as:

Dunstan, C., S. Sharpe, S. Harris, L. Wynne, J. Downes and H. Razain (2013) Game change: Decentralised energy and electricity networks in the low carbon era – a report for the City of Sydney, Institute for Sustainable Futures: Sydney.

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Executive Summary

Electricity bills and network costs have been in the headlines recently. Successive annual increases in electricity bills, combined with growing awareness and use of decentralised energy systems, have led to a wider discussion of how our electricity system currently operates and how this might change.

Regulated electricity bills for NSW households and small businesses have more than doubled over the last five years to 2012-13.[1] The main drivers of the increases were electricity network charges; these charges pay for the poles and wires that distribute electricity to our homes and businesses. Network costs now make up more than half the average regulated residential electricity bill.[2]

The Productivity Commission reinforces this point in its report 'Electricity Network Regulatory Frameworks' 2013[3] that the spiralling network costs in most states are the main contributor to the 70% average electricity price increases since 2007, partly driven by inefficiencies in the industry and flaws in the regulatory environment.

Network charges have a disproportionately high impact on members of the community who are least able to pay. The NSW Independent Pricing and Regulatory Tribunal (IPART) found that households in the lowest quartile can pay up to 10% of their income in electricity costs, while households in the top quartile pay less than 4%[4]. Higher network charges also impact on business competitiveness.

In the short term policy makers are taking steps to delay increasing electricity prices however this report makes clear that further price hikes are likely in 5-10 years unless action is taken now to enable decentralised energy by removing regulatory barriers.

This report estimates that City of Sydney trigeneration, renewable energy and energy efficiency plans could defer business as usual electricity network costs of $224 million by 2020 and $1.28 billion by 2030.

Close to Home

Three years ago the Institute for Sustainable Futures produced a report for the City of Sydney on the benefits of decentralised energy systems. *Close to Home: Potential Benefits of Decentralised Energy for NSW Electricity Consumers*[5] highlighted the scale of investment that was to occur in electricity networks in NSW, and the impact that

Household electricity bills have increased by 70% over the last five years. Electricity network charges now make up more than half of the average residential electricity bill

[1] Analysis of IPART Retail Electricity determinations 2008-09 – 2012/13
[2] DRET factsheet (2012) *Electricity Prices* http://www.ret.gov.au/Department/Documents/clean-energy-future/ELECTRICITY-PRICES-FACTSHEET.pdf, accessed 27th November 2012.
[3] Productivity Commission 'Electricity Network Regulatory Frameworks' 2013 http://www.pc.gov.au/projects/inquiry/electricity/report
[4] IPART (2011) Changes in regulated electricity retail prices from 1 July 2011, Sydney: IPART
[5] ISF Close to Home: Potential benefits of Decentralised Energy for NSW Electricity Consumers November 2010 http://www.isf.uts.edu.au/publications/dunstanlangham2010closetohome.pdf

the associated rising electricity network charges would have on customer bills.

Close to Home also reviewed the City's plans for a decentralised energy system utilising trigeneration plants in the City area. The report showed that decentralised energy had the potential to defer or avoid some of the planned investment in the Ausgrid network, which includes the City area.

Decentralised energy optimises the use of local resources, the matching of supply and demand at smaller scales, and transfers some of the consumption and peak load from electric air conditioning to thermal air conditioning. This reduces the need for (and therefore the cost of) large-scale electricity network upgrades.

Decentralised energy systems can increase local reliability and reduce peak demand because they include demand management, energy efficiency, switch heating, hot water and air conditioning loads from electricity to thermal energy supply and renewable energy generation; they also offer the opportunity to significantly reduce carbon emissions from electricity.

The City's plans were estimated to generate a financial benefit in the form of deferred network costs of $200m by 2020 and more than $1billion by 2030.[6] At the same time, the City's plans were predicted to reduce the carbon emissions from electricity supply by around 24-32% (on 2006) levels in the City area[7].

Updating *Close to Home*

When *Close to Home* was prepared, electricity consumption was forecast to grow by 21% over the next decade. These forecasts also showed a gap in generation capacity by 2014-15, for which new base load generation was planned.

Over three years, much has changed. *Game Change* identifies four main reasons:

1. Forecasts of growth did not materialise
2. High electricity bills have attracted political attention
3. The connection between climate change and how we use electricity has been more readily recognised
4. The impact of disruptive technological change such as solar PV has grown.

Forecast growth did not eventuate: Total electricity consumption stopped growing. It peaked in 2008 and has remained stable since. Recent forecasts show no generation gap in NSW before 2022-23.

High electricity bills attracted attention from policy-makers. The operation and regulation of electricity networks has been the focus of several reviews and inquiries

[6] Deferred costs of network investment calculated at $300,000 per MW for each year of deferral, see section 4 for further details on methodology.
[7] City of Sydney (2013) Decentralised Energy Master Plan – Trigeneration, CoS: Sydney http://sydneyyoursay.com.au/document/show/267

in the past three years by the Productivity Commission, the Australian Energy Market Commission, the Australian Parliament and the NSW Parliament.

25% of the average electricity bill pays for the electricity supply system to supply peak power that occurs for only 40 hours per year.

Managing peak demand contributes a lot to electricity bills. The Australian Electricity Market Commission estimates peak load growth accounts for 45% of capital expenditure for electricity networks. The Energy White Paper 2012 estimated system costs (generation, distribution, market operations) to meet maximum peak demand account for 25% of retail electricity bills (see Productivity Commission review[8]).

In the City area, network investment is primarily driven by increased reliability standards and commercial peak demand growth. Augmenting electricity distribution networks is only one of many different solutions to improve reliability and overcome network constraints. Another solution is decentralised energy (DE).

Reducing emissions: The need to develop cleaner energy sources has never been clearer. Energy efficiency and decentralised electricity systems allow for significant reductions in the carbon intensity of energy supply. Many households and businesses have installed their own forms of distributed generation such as rooftop solar. On a larger scale, the City of Sydney is fostering precinct trigeneration.

Incorporating disruptive technology: Decentralised energy systems reduce grid losses and are better than tradition electricity supply systems in accommodating disruptive technological change e.g. widespread up-take of electric vehicles, solar PV, battery storage, 'smart' meters. These technologies will fundamentally alter our electricity network infrastructure.

Energy efficiency, particularly in the built environment, provides some of the lowest cost of carbon abatement available.

[8] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COAG	Council of Australian Governments
DE	Decentralised Energy
DNSP	Distribution Network Service Provider
DSR	Demand Side Response
DSP	Demand Side Participation
DRET	Department of Resources, Energy and Tourism EE Energy Efficiency
IPART	Independent Pricing and Regulatory Tribunal
kW	kilowatt
kWh	kilowatt hour
MW	Megawatt
MWp	Megawatt peak
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
OECD	Organisation for Economic Co-operation and Development
PV	(Solar) Photovoltaic

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1. Overview

1.1 The purpose of this report

This report seeks to update information contained within the report *Close to Home: Potential Benefits of Decentralised Energy for NSW Electricity Consumers,* published by the Institute for Sustainable Futures in 2010.

Section One provides an overview of some of the key issues in the electricity supply arena, reviews the changes that have occurred since *Close to Home* and reinforces the need for further regulatory and policy changes.

Section Two reviews recent trends in electricity supply and demand against previous forecasts. It highlights the drivers of recent price rises and the implications of falling consumption that has occurred at the same time as increased take-up of energy efficiency and distributed generation.

Section Three provides an overview of the benefits that decentralised energy can provide, but also the regulatory hurdles that it faces. It also provides updated information of the cost savings available through the City of Sydney's plans for distributed generation and energy efficiency activities.

The Appendix to this report is a comprehensive overview of recent reports and studies into the electricity system, including the Productivity Commission's inquiry into electricity network regulation, the Senate inquiry into electricity prices and the Australian Energy Market Commission's Demand Side Participation Review ("Power of Choice") and Reliability Standards Review. These recent reviews will set out reforms at the policy and regulator level within the electricity network and will enable and incentivise actions around electricity supply and network investment.

1.2 What a difference three years makes

At the time when *Close to Home* was prepared, electricity consumption was forecast to grow by 21% from 2009-10 to 2019-20. These forecasts also showed a gap in electricity generation capacity at 2014-15 and predicted a need for new base load electricity generation. The intervening years represented a 'game change' for our electricity system. This is due to four inter-related factors:

Forecast growth did not eventuate: Forecasts of continued electricity growth did not materialise. Electricity consumption peaked in 2008 and has remained flat since, even after the economic slowdown associated with the global financial crisis ended. Current electricity demand forecasts no longer show a generation gap for NSW in the next decade.

High electricity bills became an issue for policymakers: Recent electricity price rises have not gone unnoticed. Electricity bills are now a politically charged issue and this political interest is driving reform of electricity regulation. The operation and regulation of electricity networks has been the focus of numerous high profile reviews in recent months, including by the Productivity Commission, and the Australian Energy Market Commission; also Inquiries by the Australian and NSW Parliaments.

Increasing the efficiency of electricity networks has benefits for consumers by limiting future electricity bill increases. The issue of network constraint and reliability is currently only addressed through supply side options. Other solutions must be considered. These include increased demand side participation, decentralising the energy supply and fuel switching (ie, switching electric heating and cooling from remote generation to thermal heating and cooling from the waste heat of local generation) to enable electricity supply and demand to be matched on a smaller scale with reduced peak demand, and therefore minimising the need and cost of large-scale electricity infrastructure. These solutions deserve equal levels of investigation.

Reducing emissions in electricity supply: The need for cleaner energy sources has never been clearer. Energy efficiency and decentralised electricity systems allow for significant reductions in the carbon intensity of our energy supply thereby avoiding carbon costs. Many households and businesses have installed their own forms of distributed generation such as rooftop solar and, on a larger scale, trigeneration such as proposed by the City of Sydney. Energy efficiency, particularly in the built environment, provides some of the lowest cost of carbon abatement available.

Disruptive technological change: Decentralised energy systems also provide the flexibility for early adoption of disruptive technological change including the widespread up-take of electric vehicles, solar photovoltaic systems, battery storage and array of 'smart' meters and appliances in homes and businesses. These technologies will have fundamentally different needs of and uses for our electricity network infrastructure.

Innovative utilisation of smart metering to shift electricity consumption from business days to non-business days such British Gas's free electricity on Saturdays tariff[9] for its smart meter residential customers in the UK and USA will shake up the traditional electricity retail industry.

Emerging new 'power to gas' technologies in Europe such as the Mediterranean and North Sea Power to Gas Platforms[10] and the ability to store excess renewable electricity generation which would otherwise be switched off when generation exceeds demand, typically overnight and at weekends, in the existing gas infrastructure will have profound positive benefits on electricity networks and the

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[9] British Gas to Offer Free Power on Saturdays, Financial Times http://www.ft.com/cms/s/0/01687968-f9ef-11e2-b8ef-00144feabdc0.html#axzz2bQspJT27

[10] European Commission 'The Mediterranean and North Sea Power2Gas Platforms http://www.iphe.net/docs/Events/Seville_11-12/Workshop/Posters/IPHE%20workshop_DNV%20KEMA%20_poster.pdf

avoidance of the need for continuing expensive investment in electricity networks. Similar innovations are also expected in Australia.

At the moment regulation of and investment in the electricity networks is disconnected from demand side management and the actions of energy customers and retailers in an increasingly self-generation and competitive energy market. Ignoring disruptive technological change and the actions of energy customers and retailers could lead to significant stranded assets in the electricity networks.

1.3 Progress on recommendations

Close to Home made six recommendations:

- Recommendation 1: Changing the form of regulation to reward, instead of penalising, electricity network businesses that help customers save energy and peak demand.
- Recommendation 2: Better reporting and assessment of *actual* demand management performance.
- Recommendation 3: Better assessment of the *potential* for demand management to reduce electricity bills.
- Recommendation 4: Putting a significant price on carbon emissions.
- Recommendation 5: Setting targets for demand management and measuring progress towards them.
- Recommendation 6: Establishing a dedicated fund, or scheme, to support demand management. Demand management includes energy efficiency, reduction in peak demand and decentralised energy.

Progress has been made on some of these recommendations; however, overall this has been limited.

Shift focus from supply-side and centralised solutions

The ownership of electricity networks of itself, does not define the efficiency of network operations or investments, although it can lead to perverse outcomes where electricity networks and regulation are 'owned' by the same entity and that entity refuses to implement regulatory reform to protect its income. Regulation provides incentives to act within the context of monopoly ownership. The discussions regarding the efficiency and size of electricity network investment, particularly in NSW, highlight that the incentives in place are not supporting efficient electricity supply. The form of regulation is crucial to providing the incentives for change.

The change from a price cap to a revenue cap (refer to Appendix A.6 for definitions) as the form of regulation for revenue determination of the electricity networks should provide more incentive for non-network solutions rather than network augmentation. Unfortunately evidence of this occurring will only be known well into the next regulatory determination period (commencing July 2014 in NSW); not in time to provide relief from electricity bill increases.

The impacts of remaining unaligned regulatory incentives are best illustrated through the network investment response to peak demand. The response to date has focused almost exclusively on the supply side – building more networks to meet the demand. The demand side response has largely been ignored. Although this too is changing in the light of evidence on the costs savings associated with energy efficiency and demand management and the increasing take-up of distributed generation.

Waiting for the next regulatory reset period is too late

Announcements by the Council of Australian Government (COAG) in December 2012 suggest Australia is on the path to regulatory reform. Regulatory issues raised include amendments to the regulator's powers, and the adoption of a best practice framework for assessing reliability standards. These reforms will be in place for the next regulatory determination period. Customers will see limited impacts after this point, as price increases in other areas will diminish any savings accrued.

Unfortunately the pace of regulatory change is not rapid enough to protect consumers from further price rises, or to allow the quick integration of zero and low carbon sources of energy into the electricity system in timelines that would meaningfully contribute to emissions reductions.

Non-regulatory solutions are needed now

The limited reach of regulation to address other barriers to demand management and decentralised energy such as knowledge gaps and transaction costs further highlights the need for non-regulatory solutions. This is why the second and third recommendations made in *Close to Home* about assessing, reporting and benchmarking of demand management activities are still critical and relevant today.

The systematic assessment of actual innovative demand management practice and the assessment of the potential when compared with network investment need further investigation. This will also allow the establishment of best practice around demand management and decentralised energy.

Evidence to date[11] on the potential of demand management is significant and provides the opportunity to reduce growth-related network investment and halt ongoing bill increases for electricity customers. This benefit justifies the bringing forward of some of this value, and the sharing of it with parties engaging in demand management (such as the City) as a means of avoided additional network expenditure and reducing the carbon emissions from our electricity supply.

Entrench customer focus in the electricity system

The recently proposed COAG reforms need to be strengthened further by increasing engagement between consumers and the electricity networks; this process needs to start immediately and cannot wait for the next regulatory reset process. This

[11] Dunstan, C., Boronyak, L.J., Langham, E., Ison, N.M., Usher, J.S., Cooper, C. & White, S. 2011, *Think small: The Australian decentralised energy roadmap*: Issue 1, December 2011, prepared for CSIRO Intelligent Grid Research Program, Institute for Sustainable Futures, UTS: Sydney.

engagement needs to include discussion on the type of energy system we need as we move into a low carbon economy. Greater inclusion of decentralised energy will offer the flexibility and efficiency required for significantly reducing the carbon intensity of our electricity.

As demonstrated in earlier sections of this report, energy efficiency must be top of the list in terms of priorities. Discussions also need to take place with consumers and electricity networks on how we reduce or manage peak demand, how we support more demand management, and how to better align incentives to encourage these activities.

The opportunities of decentralised energy in terms of avoiding unnecessary network expenditure are only available if they are actually taken-up now, before the further network expenditure occurs. Analysis presented in this report shows that unless changes are made, investments in the centralised electricity network will continue, and the cost of these will continue to be paid by electricity customers, despite the presence of more efficient and cost effective decentralised solutions (such as trigeneration).

Decentralised energy systems facilitate change

Decentralised energy systems also provide the flexibility for early adoption of more disruptive change in our energy system, including the roll out of electric vehicles, further distributed generation and the array of consumer applications and services that can emerge from the diffusion of energy storage and smart metering technology in households.

These technologies at sufficient scale will fundamentally change the operation of our electricity system, and are likely to fully emerge over the next decade. Spending billions of dollars in the interim on additional electricity networks based around a centralised electricity system which may be redundant by 2023 is not economically, financially, socially or environmentally acceptable.

2. Trends in electricity prices and demand

2.1 Rapid electricity price increases

The rapid increase in retail electricity prices has stimulated much of the current discussion on electricity systems in Australia and NSW. Electricity prices across Australia were relatively constant in real terms from 1991 to 2007, but have risen rapidly since then.

The Independent Regulatory and Pricing Tribunal (IPART) provides an annual determination for NSW on the regulated tariff that is provided by electricity retailers for households and small businesses. Around half of all NSW electricity accounts are on regulated tariffs[12] and as such this provides a useful indicator of price trends.

The regulated tariff includes an allowance for network charges associated with the three NSW Distribution Network Service Providers (electricity networks) as a component of the electricity tariff. A national regulator, the Australian Energy Regulator, sets network charges in five-year determination periods. Electricity retailers then pass through these network charges to customers.

Figure 2.1 shows the increases in the regulated electricity tariff for average residential customers in NSW over the past five years.

Network charges have more than doubled in the past five years, and now (2012-13) make up 52% of the average bill for a residential customer on the regulated tariff in NSW, whereas 5-years ago (2008-09) network charges were less than 40%.

Figure 2.1: Regulated domestic electricity price rises in five years to 2012-13

Annual % increases	2008-09	2009-10	2010-11	2011-12	2012-13	Compound total % increase 5-years*
Energy Australia	7.5%	7.3%	21.7%	17.9%	20.6%	99.5%
Integral Energy	8.1%	8.2%	21.1%	15.5%	11.8%	82.9%
Country Energy	6.1%	6%	17.9%	18.1%	19.7%	87.4%

Source: IPART Regulated Electricity Retail Price determinations 2008-09 to 2012-13, * Compound totals are calculated annually.

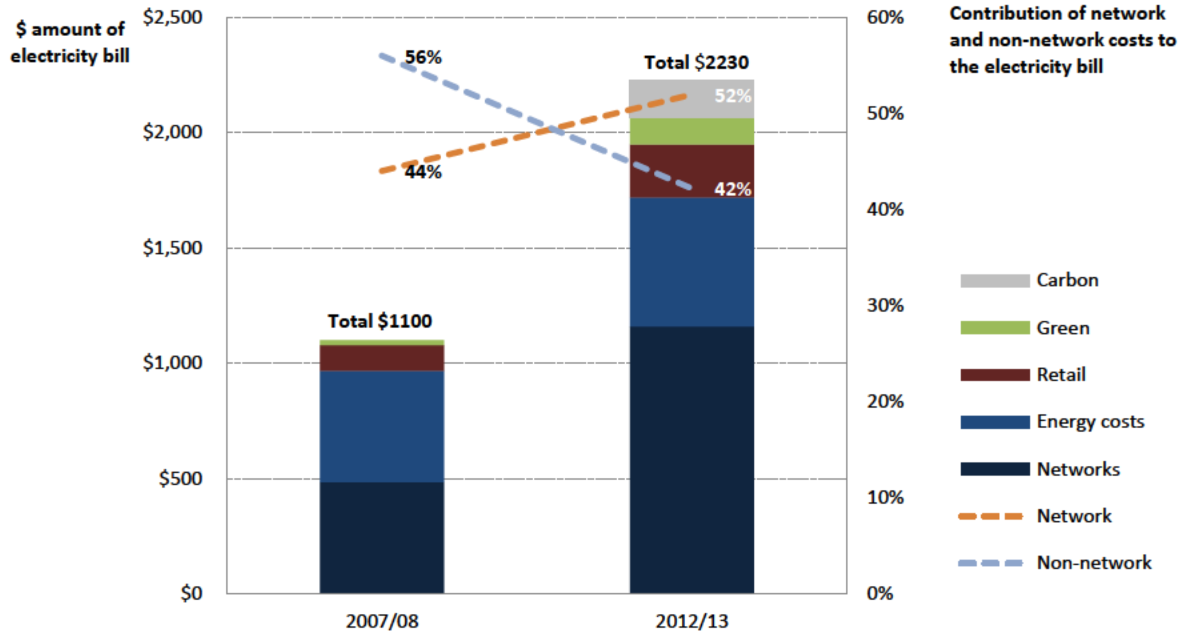
Figure 2.2 shows the composition of an average bill five years ago and now. Energy only costs remained relatively stable until the introduction of the carbon tax. There have been slight increases in retail and other aspects of electricity policy, such as

[12] IPART (2012) *Issues Paper Review of regulated retail prices and charges for electricity 2013 to 2016* Sydney.

Total $1100

increasing support for renewable energy and energy efficiency (labelled 'Green' in the below chart), however, these are small compared with network charges.

Figure 2.2: Domestic electricity price rises and composition



Source: Derived from IPART Retail Electricity Pricing Determinations 2007-08 to 2012-13

Households on lower incomes pay a much higher proportion of their income on electricity than do households with higher incomes. IPART undertakes a regular survey of households in the Greater Sydney Metropolitan area. From analysis of their latest survey, the July 2011 price increases meant that households with high electricity usage and in the lowest income category ($13,000 to $18,000 per year) may spend 10% of their disposable income on electricity. For the majority of households in all other income categories, they were spending less than 4% of their disposable income on electricity costs.[13]

At the same time, NSW Government Budget Papers show a dividend of $884 million from their electricity generation, transmission and distribution assets in 2012/13, which equates to each NSW household contributing $377 to NSW Government dividends.[14]

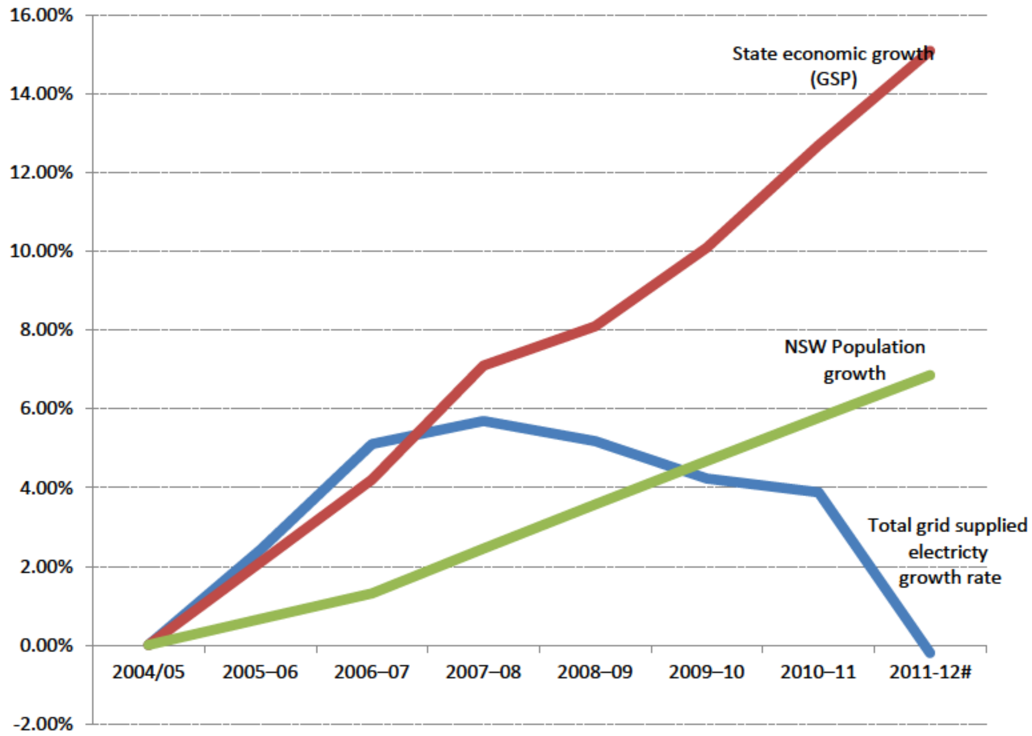
The IPART research also highlighted the factors that strongly influence how much electricity households use: family and household structure, and housing type and structure characteristics. Many of these factors are not within the direct control of the household to manage.

[13] IPART (2011) *Changes in regulated electricity retail process from 1 July 2011* Sydney.
[14] NSW Government (2013) Budget Statement Chapter 9
http://www.budget.nsw.gov.au/__data/assets/pdf_file/0018/25227/Ch_9.pdf

2.2 Recent trends in electricity demand

Grid-based electricity consumption in NSW has not grown in recent years. Total consumption in 2010-11 was 74,512 GWh and in 2011-12 was 71,468 GWh. The 2011-12 estimate is less than the figure for 2004-05 and represents a 6% decline from the high point of total consumption in 2007-08. This is despite NSW growing by 580,000 people and a 15% growth in gross state economic product since 2004. This shows that economic growth is not strictly coupled with electricity consumption.

Figure 2.3: Cumulative Growth in electricity demand, economic and population growth From zero base 2004-05



*Cumulative growth rates from a zero base in 2004/05.
Source: ABS (2012) State Accounts 5220:0 2011-12 Gross State Product (Chain Volume measures); ABS Census 2001-2011 (population growth then calculated on an annual basis); AEMO (2012) ESOO

2.3 Over-estimation of future consumption

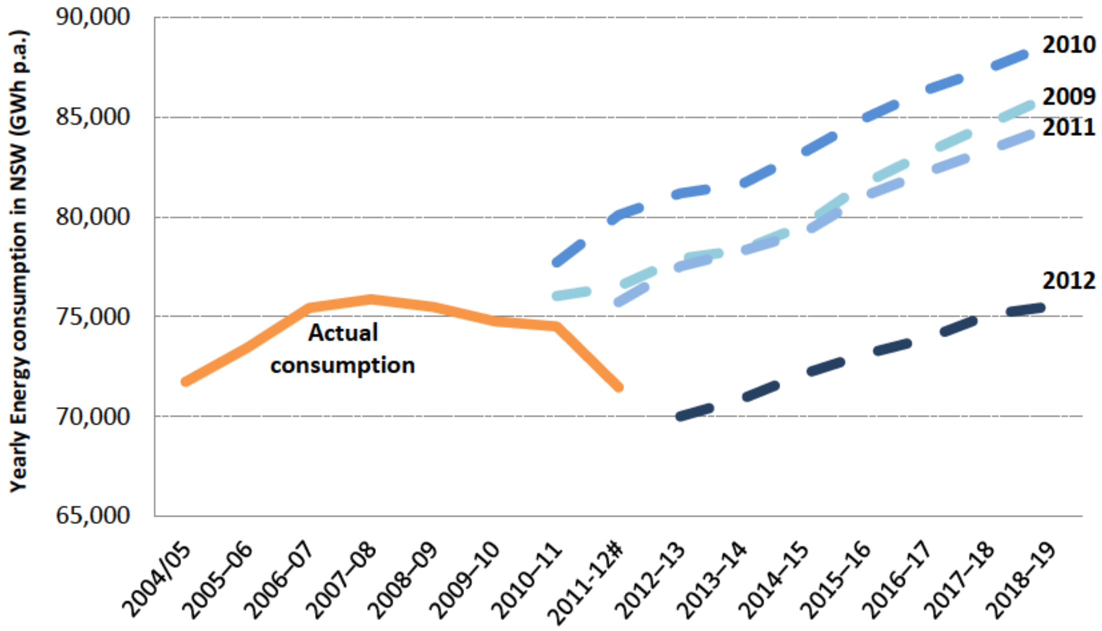
The Australian Energy Market Operator (AEMO)[15] produces annual consumption forecasts for each jurisdiction within the National Energy Market (NEM). These forecasts are published as the annual Electricity Statement of Opportunities (ESOO). This document is used to inform investment decisions for new electricity projects.

Until recently ESOO projections have been based largely on growth estimates provided by the electricity utilities and up to 2012, ESOO projections consistently

[15] AEMO manages the NEM (National Electricity Market) and is responsible for national electricity transmission planning and security of the national electricity grid.

over-estimated actual consumption, as shown in Figure 2.4 below. The trend towards decline has been recognised in AEMO's 2012 figures, however, future projections still differs significantly to the current trend.

Figure 2.4 - Comparison of NSW Medium Growth Electricity Projections 2009 – 2012[16]



Source: AEMO, Electricity Statement of Opportunities, 2009, 2010, 2011, 2012

These figures differ significantly from the findings of *Close to Home.* At this time NSW electricity consumption was forecast to increase by 21%, or 15,500 GWh between 2009-10 and 2019-20. NSW was also forecast to have an electricity generation supply gap by 2014-15.[17]

The decline in total consumption and the downward trend in forward projections mean that NSW does not require further base load electricity generation until at least 2022-23. This conclusion was confirmed in a recommendation from a recent NSW Parliamentary Inquiry on the Economics of Electricity Generation:

"RECOMMENDATION 1: That the NSW Government continue to support the National Electricity Market to operate freely, subject to appropriate regulation. The NSW Government should not seek to invest further in electricity generation."[18]

The rate and pace of the decline in electricity consumption in NSW highlights the radical change facing the electricity system. Electricity consumption has typically

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[16] AEMO, 2009. *Electricity Statement of Opportunities.* Table B.2, p.B.4; AEMO, 2010. *Electricity Statement of Opportunities.* Table 4-10, p.44; AEMO, 2011. *Electricity Statement of Opportunities.* Table 3-10, p.3-18; AEMO, 2012. *Electricity Statement of Opportunities.* Fig 3-7, p.3-9.

[17] AEMO (2010) *Electricity Statement of Opportunities*

[18] Legislative Assembly of NSW (2012) *Public Accounts Committee – The Economics of Energy Generation* Report 6/55, November 2012, Sydney: NSW Parliament.

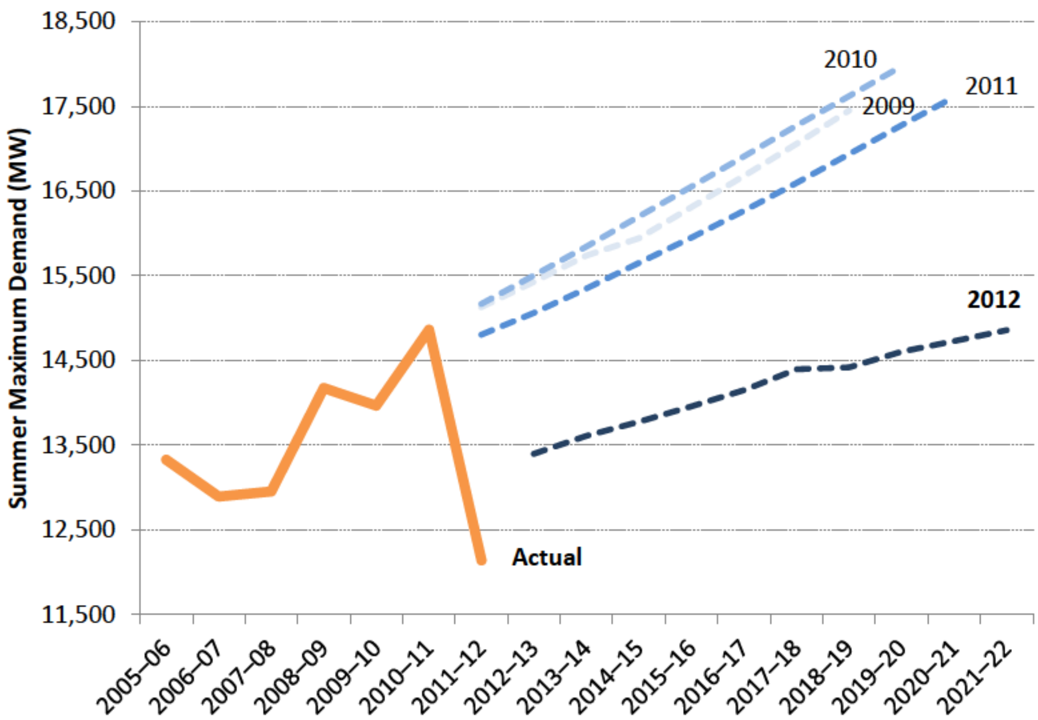
been considered to be inelastic to price increases however recent decreases in consumption disprove this inelasticity.

The dramatic increase of distributed renewables within the electricity system is also having an impact. To date there are more than 1 million homes in Australia with rooftop solar PV and an increasing number of larger scale commercial projects. Installations are still continuing despite the scaling down of most public subsidies for these activities. This is because rooftop solar generation has reached grid parity for some householders.[19] Grid parity means solar generation per KWh is equal or less in price to a KWh obtained from the grid.

2.3 Trends in peak demand

Peak demand refers to the point of highest electricity demand at a single half hour point in time. Peak times fluctuate, and occur on daily and seasonal cycles. In the Sydney CBD, annual peak electricity demand typically occurs during the summer afternoon daily peak (4-7pm).

Figure 2.5 - Comparison of NSW medium growth summer maximum demand projections (50%) 2009 – 2012, [20]



Source: AEMO, Electricity Statement of Opportunities, 2009, 2010, 2011, 2012

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[19] IPART (2012)

[20] AEMO, 2009. *Electricity Statement of Opportunities.* Table B.10, p.B.8; AEMO, 2010. *Electricity Statement of Opportunities.* Table 4-11, p.46; AEMO, 2011. *Electricity Statement of Opportunities.* Table 3-11, p.3-20; AEMO, 2012. *Electricity Statement of Opportunities.* Fig 3-8, p.3-10

Actual aggregate growth in maximum absolute peak demand on a state level has been significantly lower than previous forecasts, as Figure 2.5 shows. At a state level, peak demand grew from 2007-08 to 2010-11. After a steep decline in 2011-12 associated with a mild summer, peak demand recovered in 2012-13. This was associated with heatwave conditions in Sydney in January 2013, when peak demand spiked at excess of 13GW.[21]

The figures in Figure 2.5 highlight the volatility and weather-sensitive nature of peak demand figures and further highlight the inefficiency of centralised electricity networks that are built to service peak loads that occur infrequently and fluctuate from year to year.

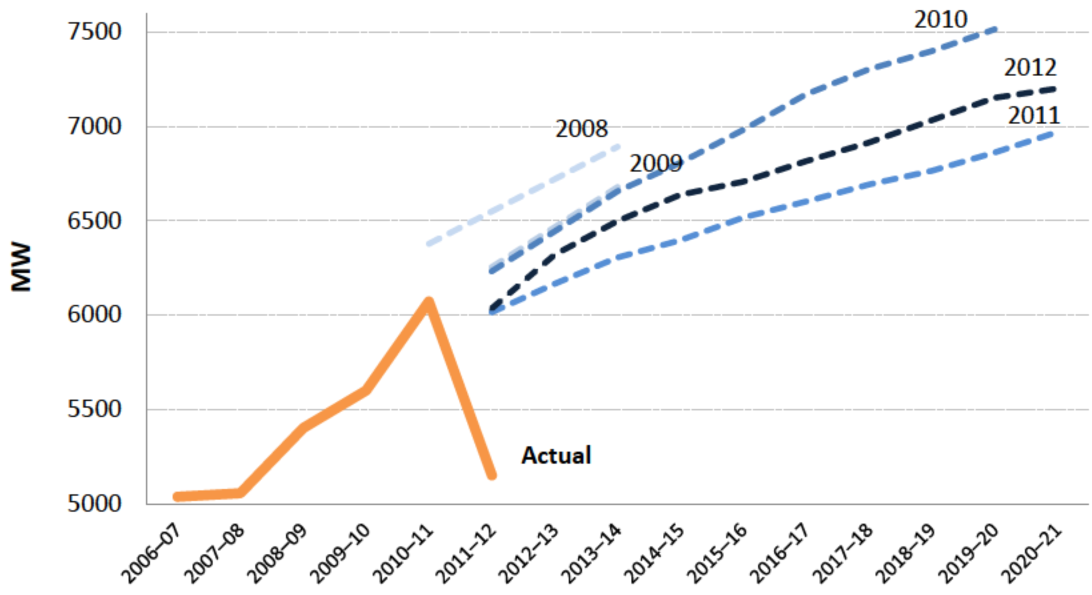
Climate change

One of the impacts of climate change will be an increased frequency of heatwave conditions. Heatwave events are associated with high levels of air conditioner use and higher losses from transmission and distribution networks. If things proceed on a business-as-usual basis, increasing heatwave conditions will likely have the impact of increasing summer peak demands and increasing inefficient network investment to meet these peak events. This will place further upward pressure on electricity prices even if total consumption growth slows or actually declines.

Summer peak demand figures for Ausgrid's distribution area from 2006-07 to 2010-11 show a steady trend upward in peak demand peaking in 2010-11 at just over 6000MW. The 2011-12 year saw a significant decline with peak demand returning to levels of 2006-07. This is in contrast to the Ausgrid 2012 summer projection, which shows peaks levels as similar to 2010-11 and future growth in successive years after this.

[21] AEMO (2013) Aggregate Price and Demand Data Files, 18th January 2013

Figure 2.6 – Comparison of Energy Australia/ Ausgrid forecast peak demand 2008 – 2012[22], MW



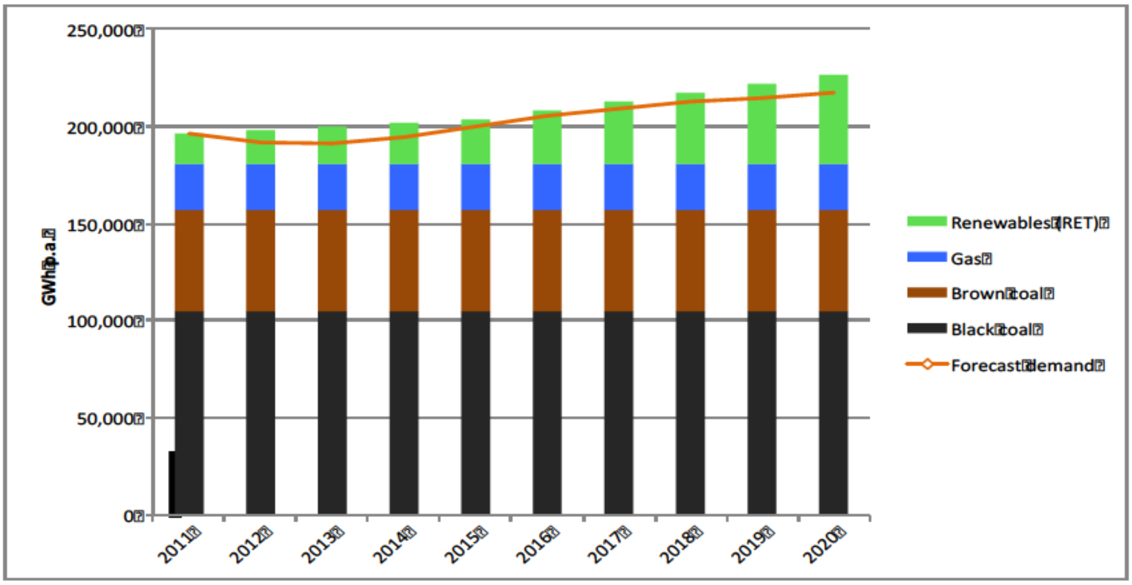
Both peak demand and total consumption impact on the cost of electricity; peak demand impacts on investment in electricity network as the network needs to be built to a level that will support peak demand, this in turn drives the cost of electricity as this investment will need to be recouped. Within the current regulatory framework total or aggregate consumption provides the mechanism for the network costs to be recouped, through network charges.

2.4 Future electricity supply

Figure 2.7 shows the available generation capacity within the NEM by fuel source, plotted with the forecast demand. Renewable energy generation is the only source of energy that is likely to grow over the period to 2020. This is due to the legislated Renewable Energy (Electricity) Act 2000 which under the Large Renewable Energy Target (LRET) and the Small Renewable Energy Scheme (SRES) places obligations on electricity retailers to purchase a proportion of electricity sales from renewable sources. This proportion increases annually and will equal 20% of forecast consumption by 2020.

[22] Ausgrid Transmission Annual Planning Report 2011 Section 4.2, p.13; Ausgrid Transmission Annual Planning Report 2012, Section 5.2, p. 10; AER, Final decision, New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, Table 6.4 p.86.

Figure 2.7 - Energy supply/demand situation in the National Electricity Market, 2010-2020[23], GWh p.a.



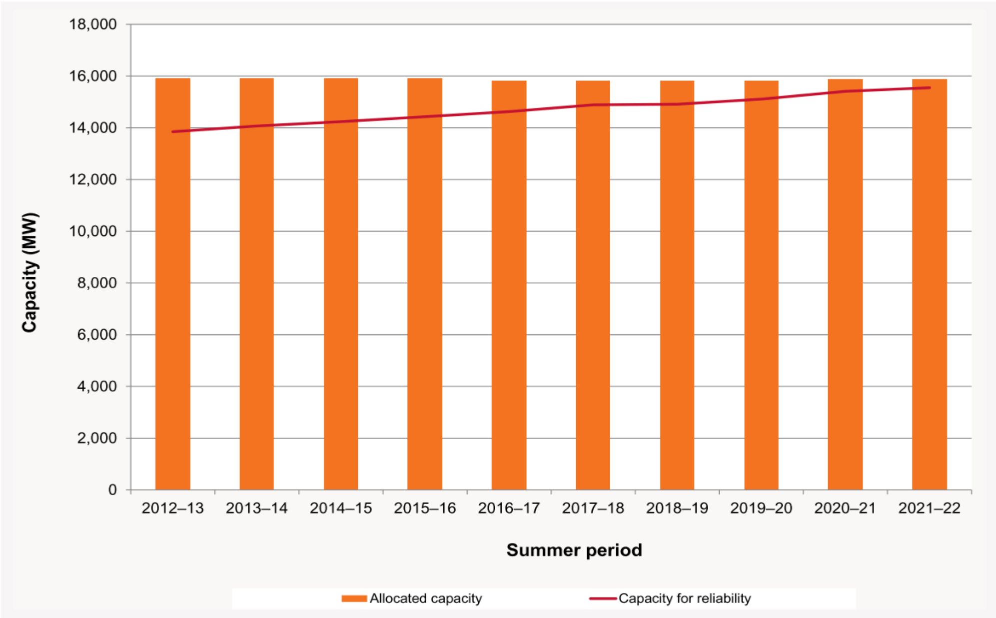
Source:AEMO 2012 ESOO

Increases in renewable energy generation supported through the LRET and the SRES, combined with falling total consumption, will lead to a decrease in the carbon intensity of our electricity supply, as renewable energy displaces fossil fuel electricity generation.

The supply-demand match at the level of total consumption means no new centralised fossil fuel base load generation is required. This also applies to capacity to meet peak demand and reliability standards. Figure 2.8 shows the generation capacity. No short fall in available capacity is forecast before 2021-22.

[23] Data sources: Forecast demand from AEMO, 2012. *Electricity Statement of Opportunities.* Fig 2-4 p.2-12; Breakdown of non-renewable components of existing generation according to AER, 2011. *State of the Energy Market*, Fig 1.3 p.27; Renewable generation from Renewable Energy (Electricity) Act 2000 (Cth), Act No. 174 of 2000 as amended (compilation prepared on 1 February 2010 taking into account amendments up to Act No. 78 of 2009), s.40. Note that this older version of the Act was used to illustrate gross renewable energy additions, as the Act was subsequently amended to create complementary Small (SRES) and Large (LRET) schemes, ultimately intended to lead to the same outcome in terms of total renewable energy provision. However, the new Act does not contain an overall combined target table totaling 45,000GWh by 2020. In fact, it is currently estimated that the SRES will 'overdeliver' and it is expected that the total resulting installed capacity of renewables in 2020 will exceed 45,000 GWh, and thus the numbers used in this report are conservative. See: SKM (Sinclair Knight Merz) MMA (McLennan Magasanik Associates), 2012. *Assumptions And Methodology For Modeling The Emissions From Electricity Generation,* Report to Department of Climate Change and Energy Efficiency. P.11

Figure 2.8 - NSW summer supply-demand outlook for peak capacity (AEMO 2012)[24]



Source: AEMO, 2012. Electricity Statement of Opportunities

2.5 Inefficient network investment

Over the period from 2009-10 to 2014-15, electricity network businesses in Australia planned to spend up to $46 billion[25] on upgrading and extending the electricity network. This network investment needs to be paid for. As identified in the Close to Home report, customers are doing so through the recent sharp increases in the cost of electricity which now represent more than half of the cost for a typical NSW electricity bill. Some electricity distributors have identified some reductions in the need for reduced capital expenditure within the regulatory period (such as the $1.5billion identified by the Darryl Somerville in his 2011 Review of the Queensland Electricity Network's capital investment programs).[26]

Recent reviews of the electricity system[27] have confirmed the role of increasing electricity network charges as the main cause of the sustained and large increases in electricity prices. Increased network charges have dwarfed other increases from the carbon tax and other policy efforts to increase renewable energy and energy efficiency.

[24] Figure source: AEMO, 2012. *Electricity Statement of Opportunities*, Fig. 3-6 p.3-8.
[25] Langham, E., Dunstan, C., Walgenwitz, G., Denvir, P., Lederwasch, A., and Landler, J. (2010), Reduced Infrastructure Costs from Improving Building Energy Efficiency. Prepared for the Department of Climate Change and Energy Efficiency by the Institute for Sustainable Futures, University of Technology Sydney and Energetics.
[26] QLD Government (2011) Review of Queensland Government-owned electricity distributors http://www.business.qld.gov.au/industry/energy/electricity-industry/electricity-queensland/review-electricity-distributors
[27] Including the Productivity Commission, NSW Legislative Assembly, and The Senate Select Committee on Electricity Prices

The causes of increased network charges can be traced back to a number of inter-related factors, including:

- Electricity network regulation
- Network revenue and incentive models
- Increasing peak demand
- Inaccurate forecasting
- Network asset replacement
- Higher reliability standards.

Rising peak demand was a primary driver of network investment, costing an estimated $15 billion[28] in the five years to 2014-15 if implemented. The traditional approach of investing in new power cables and substations to service increasing electricity demand reinforces the reliance on inefficient, large-scale centralised electricity supply. Our predominantly fossil fuel powered centralised electricity system is also responsible for the high and rising levels of greenhouse gases (GHG) pollution from the power sector in Australia. Following this path will make it more difficult to reduce GHG emissions and meet our international climate treaty obligations.

Recent reviews of the electricity system have identified the inefficiency of this current approach to investment in electricity distribution networks.[29]

The Productivity Commission inquired into the efficient delivery of electricity in 2012.[30] This report highlights a number of interlinked barriers to efficiency within the electricity system including:

- A lack of focus on customers
- Inadequate demand management
- Limited resources for the regulator.

A recent Grattan Institute report into electricity prices summarises the issues that have led to over-investment, including:

- risk-profit ratios granted to regulated monopoly electricity networks allowing higher profits than the level that would be associated with the risk profile of electricity assets;
- the wider regulatory environment that incentivises capital investments and does not provide adequate resources to the regulator to assess and scrutinize this spending; and
- increased reliability standards without reference to cost-benefit analysis.

The report estimates that $2.2 billion per year of avoidable costs are being passed on to consumers Australia-wide.[31]

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[28] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC

[29] Including the Productivity Commission, NSW Legislative Assembly, and The Senate Select Committee on Electricity Prices

[30] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC

The conclusions of a number of recent studies and regulatory reviews highlight two issues that are leading to electricity bill increases:

- How we regulate the monopoly components of our electricity system, and;
- How we manage peak demand within the electricity system.

Both of these factors have created perverse incentives for over-investment and inefficient networks,[32] which have caused significant bill increases for electricity customers. The drivers of these two issues are closely linked and discussed in further detail in the Appendix to this report.

[31] Wood, T., Hunter, A., O'Toole, M., Venkataraman, P., and Carter, L. (2012) *Putting the customer back in front: How to make electricity prices cheaper,* Melbourne: Grattan Institute.

[32] The Senate Select Committee on Electricity Prices (2012) *Reducing energy bills and improving efficiency,* Commonwealth of Australia, pp.xi

3. Decentralised energy – the game changer

3.1 Overall benefits of decentralised energy

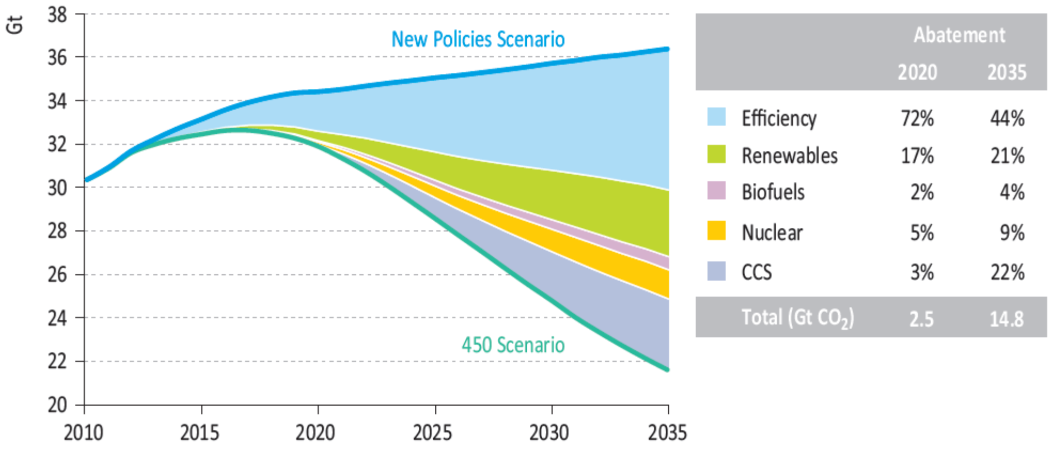
Decentralised energy (DE) refers to energy technologies and practices that optimise the use of local resources and reduce the need for large-scale energy supply infrastructure. The three elements of DE are energy efficiency, peak load reduction/management and distributed generation. Each of these elements has significant potential benefits, but these benefits are maximised when the elements are combined.

Benefits include:

- Deferred or avoided investment in generation and electricity transmission and distribution networks through a flexible alignment between electricity demand and supply;
- Reduced peak demand through more energy efficient systems, and additional offsets achieved via the use of displaced electricity for heating and cooling using cogeneration and trigeneration;
- Avoided energy losses through large transmission and distribution systems and use of more efficient energy generation (such as trigeneration systems) and avoided carbon costs and low cost abatement (with energy efficiency).

Energy efficiency will offer the largest opportunities for decarbonising our energy supply. In the recent IEA World Energy Outlook, energy efficiency activities are forecast to make up 72% of global abatement by 2020. Figure 3.1 shows the contributions of supply and demand side electricity sources to the efforts to meet the 450ppm (parts per million) global carbon scenario.

Figure 3.1 World energy related CO2 emissions abatement in the 450 Scenario relative to the New Policies Scenario



Source: IEA World Energy Outlook

3.2 Barriers to decentralised generation

Decentralised generation faces a number of institutional barriers. The National Electricity Market (NEM) was designed for large-scale centralised electricity generation.[33] The inflexibility of the structure of the NEM is being highlighted by the increasing number of decentralised and smaller distributed generation seeking to participate in the electricity market.[34] As these generators include renewable energy generators, ensuring the NEM operates to support them is a key step in increasing the amount of renewable energy in our electricity supply, and thereby decreasing the carbon intensity of our current supply.

In summary, the barriers to decentralised generation include how generators are registered, technical requirements for connecting to the electricity grid, and the costs of using the network and complying with regulations.

Specifically, regulatory barriers include:

- Disproportionate transaction costs of participating in the NEM for small scale generation.
- Disproportionately onerous requirements for electricity generation and/or retail licenses.
- Inappropriate requirement for an electricity distribution licence.
- Restrictions to export surplus power from local generation to nearby consumers.
- Lack of cost reflective distribution use of system charging for exporting to nearby consumers.

The transaction costs (which per unit are small to large generators) when applied to small-distributed generators, makes decentralised energy generation less commercially viable and in some cases completely unviable. There are a number of regulatory proposals that seek to reduce these barriers to smaller generators.[35]

The Productivity Commission review highlighted information and financial barriers around the ability to, and costs of, connection to the electricity network for distributed generators, and also the subsidies provided for generation that have little impact on peak times or in network constrained areas, and therefore offer no opportunity to avoid network investment.

There are also numerous impediments to electricity network business themselves investing in decentralised energy, particularly demand management. The scale of funds spent on demand management in Australia is relatively small (less than 1% of total annual expenditure on electricity supply in Australia).[36] Australia ranks in the

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[33] Dunstan, C., Boronyak, L.J., Langham, E., Ison, N.M., Usher, J.S., Cooper, C. & White, S. 2011, *Think small: The Australian Decentralised energy roadmap*: Issue 1, December 2011, prepared for CSIRO Intelligent Grid Research Program, Institute for Sustainable Futures, UTS: Sydney.

[34] The City of Sydney have highlighted these barriers in numerous public submissions regarding NEM operation and rules. See http://www.sydney2030.com.au/development-in-2030/city-wide-projects/powering-sydney-allan-jones for further details.

[35] AEMO (2012) National Electricity Amendment (Small Generation Aggregator Framework) Rule 2012.
AEMO (2012) National Electricity Amendment (Connecting Embedded Generators) Rule 2012

[36] Futura Consulting, 2011, Power of choice – giving consumers options in the way they use electricity.

bottom half of international performance on performance in energy efficiency and decentralised energy. [37]

3.3 Recognising decentralised energy in building energy efficiency standards

In May 2012, the Department of Climate Change and Energy Efficiency (DCCEE) published its 'Inclusion of Energy Generation in Building Energy Efficiency Standards report[38]. The study was carried out by Energetics and covered Zero and Low Emission Energy Generation (ZLEG) comprising both renewable energy and low carbon cogeneration and trigeneration. Based on International Energy Agency studies, the report advises that precinct scale ZLEG systems such as district heating and cooling must be included, because of their value for reducing national emissions. Low carbon is defined as a 50% reduction in greenhouse gas emissions which is consistent with the Intergovernmental Panel on Climate Change (IPCC) target for emissions reduction. Short-term products or contracts such as Green Power are excluded from ZLEG systems.

The report sets out the technical potential of ZLEG for new and existing buildings if the Building Code of Australia was used to foster ZLEG. This breaks down into two major technologies and customer loads – solar PV primarily for the residential sector and precinct scale trigeneration for the commercial sector. For solar PV the technical potential is 8,126 GWh/year and for precinct scale trigeneration the technical potential is 9,300 GWh/year. This compares with the 8,465 GWh/year growth in forecast electricity consumption for the residential sector and the 6,300 GWh/year growth in forecast electricity consumption for the commercial sector, both by 2020. Stand-alone building-scale (rather than precinct scale) cogeneration/trigeneration and building-scale wind energy would have limited impact on generation or addressing growth in electricity demand.

If the report's recommendations were implemented, the outcome would not only address and go beyond the growth in forecast electricity consumption. It would also significantly reduce both electricity consumption and peak demands on the electricity networks principally through solar PV and precinct scale trigeneration. In the case of trigeneration, this is not just through generating local electricity at times of peak demand but also by replacing electrically driven air conditioning with thermally driven air conditioning derived from waste heat capture.

Such regulation in conjunction with the consideration of potential investments in the electricity networks must be taken into account with common government policy, as it is in the UK and elsewhere in Europe.

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[37] Dunstan, C., Boronyak, L.J., Langham, E., Ison, N.M., Usher, J.S., Cooper, C. & White, S. 2011, *Think small: The Australian Decentralised energy roadmap*: Issue 1, December 2011, prepared for CSIRO Intelligent Grid Research Program, Institute for Sustainable Futures, UTS: Sydney.

[38] Department of Climate Change and Energy Efficiency (2012) Inclusion of Energy Generation in Building Energy Efficiency Standards http://ee.ret.gov.au/sites/climatechange/files/documents/04_2013/inclusion-of-energy-generation-in-building-energy-efficiency-standards-pdf.pdf

3.4 Decentralised energy in the City of Sydney

Sustainable Sydney 2030

The City of Sydney has developed a plan for the City: *Sustainable Sydney 2030.* The City spent more than a year consulting its community and a consensus emerged on the way to make Sydney a greener, more global and connected city.

Throughout the consultation, some 90% of people wanted the City to take urgent action to tackle climate change and become more sustainable. To achieve this the City has committed to reducing greenhouse gas emissions by 70% (on 2006 levels), and developing the capacity of the City to meet up to 100% of its electricity demand by local electricity generation (70% trigeneration and 30% renewable energy) by 2030.

Approximately 80% of the City's emissions are from electricity consumption, as the electricity supply is dominated by coal-burning electricity generation. To reduce carbon emissions by 70% the City's electricity supply will need to fundamentally change. This change will be delivered through the City's "Green Infrastructure Plan".

The Green Infrastructure Plan includes the following energy-related elements:

Decentralised Energy Master Plan - Trigeneration

The electricity sector is responsible for nearly 40% of Australians greenhouse gas (GHG) emissions. In the City of Sydney this is much higher, with around 80% of GHG emissions due to electricity. This is a result of the City's CBD being a commercial and tourist centre, with high electricity consumption and peak demands, in particular, its very high commercial air conditioning loads.

Coal fired power stations convert less than one third of their total energy to electricity, with the rest of the energy lost through waste heat. As NSW coal fired power stations are far from customers who are using the electricity, a further 10% of the electricity that starts the journey at the power station is lost on its journey to customers through the transmission and distribution system.

Trigeneration is a highly efficient form of electricity generation that uses waste heat from the electricity generation process to provide heating and cooling for buildings. Trigeneration has a higher fuel-to-energy efficiency because waste heat is used to directly produce hot water for heating, and cooling indirectly via heat fired absorption chillers for air conditioning. The energy efficiency of trigeneration is typically two to three times that of centralised energy power stations delivered by a centralised grid.

The City's Trigeneration Master Plan identifies that trigeneration and cogeneration could produce up to 477 MW (megawatts) of local power and displace further 542 MW peak electricity demand by using waste energy for heating and cooling (particularly air-conditioning)[39]. This generation and associated offsets could reduce greenhouse gas emissions within the City of Sydney by between 1.381-2.027 million tonnes a year; representing a 24-32% reduction in greenhouse gas emissions per year.[40]

Trigeneration will initially be fuelled by natural gas but replaced later by renewable gases developed by the Renewable Energy Master Plan. The City has resolved that by 2030 renewable gases from waste and other renewable energy resources such as geothermal will replace fossil fuel natural gas in the trigeneration systems enabling them to provide carbon free electricity as well as carbon free thermal energy for heating and cooling.

The City resolved to implement the decentralised energy master plans[41], as follows:

(a) Town Hall Trigeneration Precinct – Commence design of a trigeneration precinct that includes Sydney Town Hall, Town Hall House, the Queen Victoria Building and other nearby buildings.

(b) Prince Alfred Park – Commence design of a demonstration fuel cell project to serve Prince Alfred Park Pool.

(c) Green Square Town Centre – Install trigeneration when a more favourable regulatory environment is in place and customers are available to connect to the thermal energy network.

(d) Connect Existing Decentralised Energy Networks – Construct and operate thermal energy networks in public streets connecting existing private sector trigeneration operators to a broader customer base.

(e) Renewable Gases – Investigate the design, planning, construction and regulation of initiatives that support incorporation and uptake of waste to energy and production of renewable gases, including the production of renewable gases converted into substitute natural gas for injection into the gas grid (based on the European model) for use by the City for trigeneration and for customers across the City's local government area to reduce greenhouse gas emissions.

(f) Solar PV – Establish contract arrangements with an electricity retailer to capture the economic benefits of surplus electricity export from solar PV arrays on City buildings.

(g) Regulatory Reform – Promote regulatory reform that incentivises the market for precinct scale trigeneration and renewable energy through recognition of low

[39] City of Sydney (2013) Decentralised Energy Master Plan – Trigeneration, CoS: Sydney http://sydneyyoursay.com.au/document/show/267
[40] City of Sydney (2013) Decentralised Energy Master Plan – Trigeneration, CoS: Sydney http://sydneyyoursay.com.au/document/show/267
[41] City of Sydney Corporate, Finance, Properties and Tenders Committee 17 June 2013 – Trigeneration Update http://www.cityofsydney.nsw.gov.au/__data/assets/pdf_file/0004/143572/130617_CFPTC_ITEM16.pdf

and zero carbon electricity and zero carbon thermal energy generated and the associated benefits to electricity networks that it provides. The City will continue to seek reform of the Building Code of Australia, Commercial Building Disclosure and associated rating tools such as NABERS to include precinct scale trigeneration and renewable energy; promote suitable feed-in tariffs and escalate the City's engagement with energy regulators and electricity distribution network providers to remove the regulatory barriers to decentralised energy.

Decentralised Energy Master Plan - Renewable Energy
The City of Sydney has a draft Renewable Energy Master Plan on public exhibition. The Plan identifies the renewable electricity and renewable gases resources both inside and outside the City's local government area (LGA).

The draft Master Plan on public exhibition shows that 18% of the city's total 2030 electricity consumption could be met by renewable electricity generation within the City area and 12% by renewable electricity generation within 250 km of the City area to deliver the 30% renewable electricity target.

In addition, enough renewable gases can be sourced from renewable feedstocks within 250 km of the City to displace 100% of natural gas supplying trigeneration. The draft Renewable Energy Master Plan shows 48.96 PJ (petajoules) a year potential syngas and biogas of which 37.06 PJ/year is renewable gas and 11.9 PJ/year is non-fossil fuel gas.

The renewable gas component of waste is more than the 27 PJ/year of renewable gas needed to replace 100% of the natural gas supplying 372 MWe of trigeneration in the City's four low carbon zones and hotspots or even the 32.7 PJ/year needed to supply 477MWe of trigeneration and cogeneration across the City area as set out in the Decentralised Energy Master Plan – Trigeneration.

The Renewable Energy Master Plan shows that there is potential to reduce greenhouse gas emissions by 2.384 MTCO2-e a year by 2030 which equates to a 37.5% reduction against 2030 business as usual emissions[42].

The combination of renewable electricity, renewable thermal energy, and trigeneration using renewable gas would reduce greenhouse gas emissions by a total of 69.5%. Together, the Trigeneration and Renewable Energy Master Plans come close to achieving the overall target to reduce 2006 greenhouse gas emissions by 70% by 2030.

Energy Efficiency Master Plan
Energy efficiency is an essential element in reducing the carbon footprint of the City and improving electricity productivity. The City has recently let a contract for an Energy Efficiency Foundation Report to inform its forthcoming Energy Efficiency Master Plan.

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[42] City of Sydney (2013) Decentralised Energy Master Plan – Renewable Energy
http://www.cityofsydney.nsw.gov.au/vision/on-exh bition/current-exhibitions/details/renewable-energy-master-plan

In lieu of these results, previous work by ISF has estimated that there is potential for 300 MWh of energy efficiency savings per annum to be achieved throughout the City. This represents around 7% of electricity used in the LGA in 2012 and is the equivalent of 40 MVA of capacity within the electricity network.

The amounts have been modelled for this report however are considered conservative. For example, within its own buildings, the City has reduced energy consumption by 23% from 2006 to 2012. This represents a 19% reduction in greenhouse gas emissions across all of the City's buildings and operations and will increase to a 29% reduction in greenhouse gas emissions by 2016 with the completion of three major energy efficiency and renewable energy projects.

This includes the City, replacing all City owned 6,500 street lights with LEDs (light emitting diodes), which will reduce electricity consumption and emissions across all City owned public lighting by a guaranteed 40% by 2015 and the City installing 1.25MWp of solar photovoltaics on more than 30 of its buildings by 2016. Trigeneration supplying the City's own buildings will increase emission reductions to 40% by 2016.

Decentralised Energy Master Plan – Advanced Waste Treatment

The City of Sydney began work on an Advanced Waste Treatment Master Plan in 2010. The Master Plan is for waste and non-recyclable waste from the City area. Waste that can be converted into renewable gases forms part of the Renewable Energy Master Plan.

The City engaged international consultancy firm Arup to undertake a business case for an advanced waste treatment plant to treat the domestic waste and commercial waste from the City area and determine what renewable energy resources would be needed within and in proximity to the City to deliver the on City's 30% renewable electricity target and the amount of renewable feedstocks from waste that could be converted into renewable gases to displace natural gas supplying the trigeneration network by 2030.

This work has been completed but is being supplemented by a specialist renewable gases and fuels study undertaken by Talent With Energy to review advanced waste treatment technologies and the use of the non-recyclable waste as a renewable gas feedstock and to determine the technologies required to convert renewable gases into synthetic or substitute natural gas for injection into the natural gas grid pipeline or conversion by liquefaction and transportation to replace fossil fuel natural gas supplying the City's trigeneration network.

The combined work will form the draft Master Plan drawn up by the City.

3.5 Impact of Master Plans on deferring and avoiding network investment

Trigeneration energy systems run on natural gas or renewable gas to efficiently produce electricity, heating and cooling.

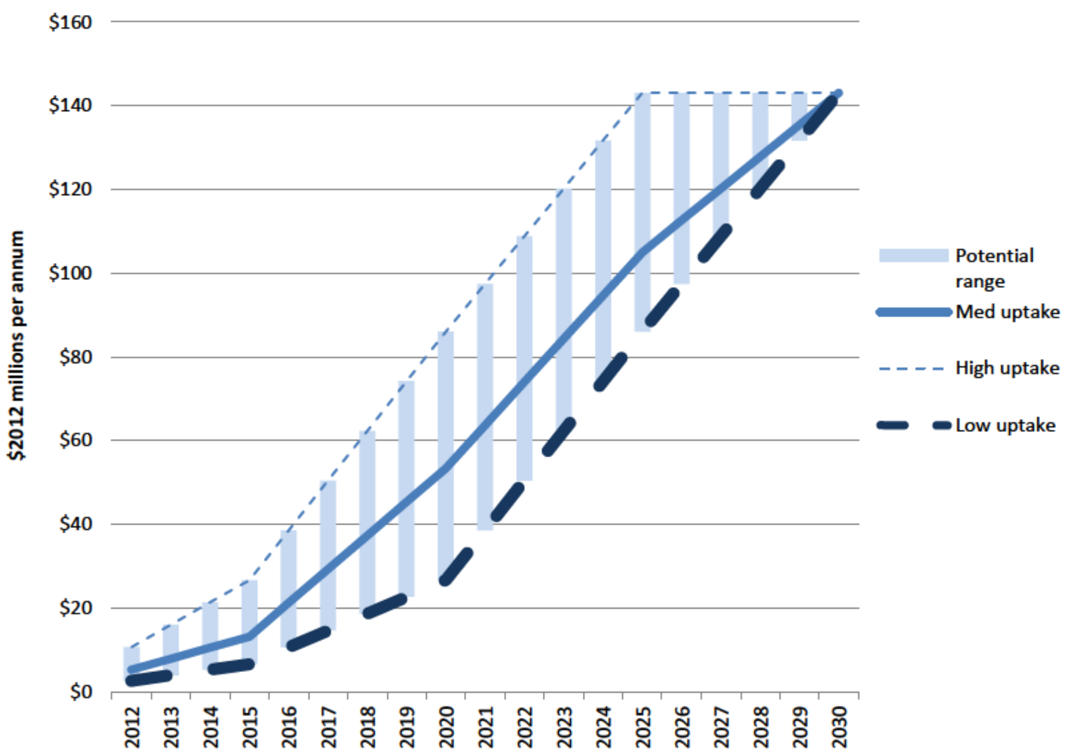
This report estimates deferred electricity network costs of $224 million by 2020 and $1.28 billion by 2030 for a medium uptake of the City of Sydney trigeneration, renewable energy and energy efficiency plans.

These figures are calculated by establishing three (low, medium and high) uptake scenarios. All scenarios achieve the complete rollout of 477 MW of trigeneration installed, with the high scenario reaching this target by 2025 and the low scenario reaching this target in 2030. This estimate also assumes a 3% per annum City area peak summer demand growth rate; details on how growth rates were calculated are explained in the following section. These uptake projections were used to calculate the annual avoided network cost of the rollout, shown in Figure 3.2

The deferred electricity network costs were calculated using the conservative value of $0.3 million per MW (or $300 per kW).

Figure 3.2 – Estimated annual avoided network costs at different trigeneration and energy efficiency uptake rates[43]

Median growth rate 3%



[43] Based on trigeneration uptake and energy efficiency implementation data provided by the City of Sydney.

Methodology for calculations

Given the large variability in peak demand growth rates observed in recent ESOO and Ausgrid summer peak demand projections, avoided network cost projection for the City's trigeneration and energy efficiency plans have been sensitivity tested against various reduced levels of peak demand.

To ensure a realistic representation of the summer peak demand growth rate in the area to be serviced by City of Sydney trigeneration, renewable energy and energy efficiency plans, a number of scenarios of peak demand growth are modelled. The first scenario takes peak summer demand growth between 2010 and 2017 across the relevant zone substations in the City using the latest Ausgrid demand projections for the region covering the City area.[44] This calculated an average annual growth rate of 3.8% pa for the period 2010-2017. This figure was then used to extrapolate the projection to from 2017 to 2030.

The second scenario was developed by taking the growth rates estimated in the first scenario and adjusting it by the proportional drop in the peak demand growth rate observed in the Ausgrid Transmission Annual Planning Report projections from 2008-2009 – 2011-2012.[45] This provided a reduced annual growth rate to 3.0% pa.

The third and final scenario was developed by taking the first scenario and adjusting the growth rate by the proportional drop in the peak growth of the ESOO NSW Medium Growth Summer Maximum Demand Projection 2009-2010 to 2011-12.[46] This reduced the CBD annual peak growth rate to 2.1% pa.

Limits of capturing savings from avoided network costs

When the 3.8% and 3.0% growth rates are applied to the City substation demand projection, in all uptake cases, the growth in forecast peak summer demand exceeds the savings captured by the rollout of the City's trigeneration, renewable energy and energy efficiency plans. This means all of the 477MW of savings generated through the City of Sydney Master Plans could deliver deferred electricity network costs.

When the 2.1% growth rate was applied, growth in forecast peak summer demand *does not exceed* the levels at which the decentralised energy would defer network investment out to 2030. Under the low uptake scenario saturation would occur by 2028, in the medium scenario this occurs at 2023 and all years in the high uptake scenario.

These figures highlight that significant savings can still be made by avoiding additional growth related network investment, but the window for achieving the maximum value from these activities is closing.

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[44] Ausgrid Electricity System Development Review 2011/12. Section 1, Sydney City Region.
[45] Ausgrid Electricity System Development Review 2011/12. Section 1, Sydney City Region.
[46] Ausgrid Electricity System Development Review 2011/12. Section 1, Sydney City Region.

These benefits do not take into account of the costs of installing and operating the trigeneration systems; however they also do not take into account the avoided capital and operating expenditure of centralised power station generation.

Also it is important to note that the benefits available from deferring and avoiding network investment are only available *before* these investments are made.

Appendix: Causes of increased network charges

A.1 The structure of the electricity network in Australia

The electricity market in Australia has four components: Generation, Transmission, Distribution and Retail.

Generation and Retail operate in competitive environments and the organisations involved are mostly privately owned entities, where revenue and market share are determined by competitive forces.

Transmission and Distribution are monopoly businesses. Currently, state governments own the distribution networks in Queensland, New South Wales and Tasmania, while networks in Victoria and South Australia are privately owned. In the ACT, ActewAGL is owned partly by the ACT Government and partly by private interests. The transmission network is owned by Transgrid which is owned by New South Wales Government.

A.2   The Electricity Network Revenue Determination Process

The Australian Energy Regulator (AER) regulates transmission and distribution network service providers. Electricity networks must apply to the AER to determine their total revenue requirements for at least five years (known as the regulatory period). Networks submit a 'building block proposal', which the AER uses in conjunction with other assumptions to make a determination. The proposal specifies the networks annual revenue requirement for each regulatory year, methods for indexation of the asset base, and how any efficiency benefit sharing, performance incentive or demand management schemes will apply.

The AER forecasts the revenue requirements of each network using investment forecasts, operating expenditure, asset depreciation costs, commercial return on capital and taxation liabilities. The return on capital is calculated by applying a rate of return for the network to the value of the asset base at the beginning of that regulatory year. As networks are so capital intensive, the rate of return for the network is one of the major determinants of how much consumers pay. This is discussed further in a following section.

The National Electricity Law allows network businesses to apply to the Australian Competition Tribunal to review the determinations of the AER. Electricity networks are entitled to appeal the return of capital and other variables that may increase their revenue. Between 2008 and 2011, appeals to the Competition Tribunal have increased Electricity Networks' allowable revenue by $2.9 billion.[47]

[47] AER (2012) *State of the Energy Market Report 2011*

In theory this is incentive regulation: the network businesses can profit if they come in under their forecast costs, and in doing so, the regulator gets a better insight into the true costs of service provision to use in the following determination period. In practice the process is much more complex and highlights the information and knowledge imbalances between the regulator and the network businesses, to the disadvantage of the regulator.[48] The regulator is comparatively less resourced to develop forecasts, these forecasts are open to appeal by the businesses and the regulator has little opportunity to learn the true cost of service provision.

A.3 What drives network investment

Network investment is driven by four sources:

- Investment for new network (for example to supply new housing estates)
- Investment to augment the network for increased peak demand
- Investment in replacing old network infrastructure
- Investment to meet more stringent reliability standards.

Network investment programs will involve all of these sources, and in each case of network augmentation a number of sources will be likely. This makes apportioning costs to each of the drivers difficult.

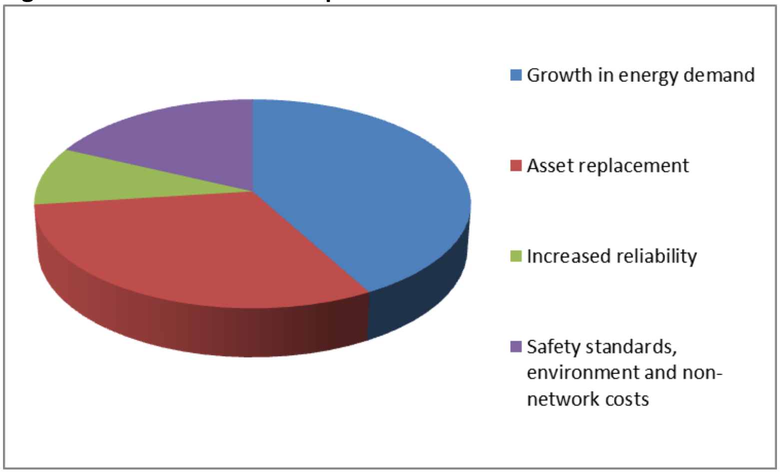
For the current five year period for NSW networks (2009-2014), $14 billion in capital expenditure was approved. Of this, 42% was related to growth in energy demand (including new and peak-related network investments), 31% to asset replacement, 9% to increased reliability and service standards and 18% to safety, statutory obligations, climate change and environment activities and other non-network assets such as IT and business systems.[49] Analysis of capital expenditure has shown that the regulated asset base for the NSW electricity distributors has doubled in the past five years and tripled in the last nine years.[50] This is an unprecedented level of growth.

[48] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC

[49] DRET (2012) Fact Sheet *Electricity Prices*, August 2012, p2.

[50] Leitch, D. (2012) 'The Future Energy Market' presented at the 2012 IPART Conference, http://www.ipart.nsw.gov.au/Home/Quicklinks/IPART_Conference_2012_-_Presentations accessed 10th December 2012.

Figure A.1 – NSW network expenditure 2009-2014



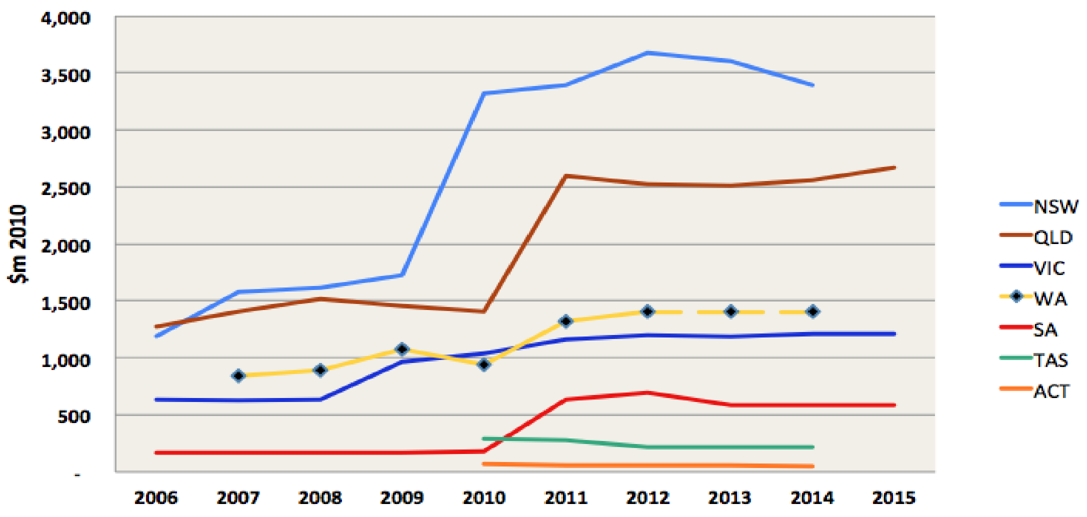
A.4 Differential network investment across the States

The Energy Users Association of Australia (EUAA) claims that capital expenditure per customer in state-owned networks is significantly higher than in privately owned networks.[51] The EUAA notes that expenditure in state-owned networks is four times higher per customer than in privately-owned networks, despite the fact that government-owned networks tend to be newer than privately-owned assets, and that private networks have a higher quality of service. Similar sentiments were expressed in the recent Productivity Commission review into electricity network regulation.[52] Figure A.1 shows the rate and timing of network investment in the jurisdictions across the NEM.

This is not necessarily a story of State Government ownership; previous experience in Victoria showed that, while subject to regulation under the Essential Energy Services Commission, high levels of reliability and declining costs and prices were evident. The experience with other state-owned network providers has not been so successful – capital expenditure has grown at a more rapid rate than has demand for services.[53] In 2013, state-owned providers will use three times as much capital per connection to provide the same services as privately owned electricity networks.[54]

[51] Mountain (2012) Electricity prices in Australia: an international comparisons, for The Energy Users Association of Australia (EUAA)
[52] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC
[53] Mountain, Bruce (2012) Submission to the *Senate Select Committee on Electricity Prices*, Canberra: APH
[54] Mountain, Bruce (2012) Submission to the *Senate Select Committee on Electricity Prices*, Canberra: APH

Figure A.2 - Electricity Network Capital Expenditure (Transmission & Distribution) by Jurisdiction, Financial Years 2006-2015[55]



NSW, Queensland and Victoria have different geographies and population densities and therefore some variation between the network expenditure across the states is to be expected. However, as the regulatory framework stands, there is no way to further investigate what is the result of these geography/population differences and what is the result of different ownership structures of these networks.

NSW particularly experienced a steep increase in network expenditure from $1.7 billion in 2009/09 to $3.3 billion in 2009/10. This level of expenditure has been sustained throughout the current five-year period (2009-10 to 2013-14). NSW has had the highest level of annual network expenditure for much of the last decade.

The ownership of electricity networks of itself, does not define the efficiency of network operations or investments, although it can lead to perverse outcomes where electricity networks and regulation are 'owned' by the same entity and that entity refuses to implement regulatory reform to protect its income. Regulation provides incentives to act within the context of monopoly ownership. The discussions regarding the efficiency and size of electricity network investment, particularly in NSW, highlight that the incentives in place are not supporting efficient electricity supply. Network efficiency must include a broader definition of the supply/demand relationship.

A.5 Issues with the Electricity Network Revenue Determination Process

Three areas of reform for the electricity network determination process were recommended in *Close to Home*:

- *The Form of regulation* – AER decided on the form of regulation. The 2009-2014 determination used a "weighted average price cap" as the form of regulation.

[55] Data sources: AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14,* 28 April 2009, Tables 7.16, 7.17 & 7.18; AER, *Transgrid Final Transmission determination 2009–10 to 2013–14* (28 April 2009), Table 2; Insufficient data available for Northern Territory.

This form of regulation rewarded the distributors if consumers use less electricity and therefore is a significant barrier to the adoption of trigeneration and energy efficiency.

- *Monitoring and reporting demand management (DM) performance* – including consistent and comprehensive reporting of DM performance including outcomes, costs and benefits.
- *Assessment of potential of the relative economic efficiency of DM proposals* – including considering the potential scope for, and relative cost effectiveness of DM in the context of network proposed expenditure.

The next electricity network regulatory period begins in 2014-15, and progress is now underway to assess revenue proposals of the three NSW based networks. Figure A.3 steps through the timetable for this work. As shown, the timetable for the process that will set electricity network costs for the next five years is at an advanced stage and there is limited opportunity for further input.

Engaging with regulatory reform is part of the solution to creating the electricity system that will enable more flexible, decentralised and lower carbon intensity electricity generation and supply. There have been a number of regulatory changes since *Close to Home was prepared.* There are also a number of pending changes and regulatory and non-regulatory options that are currently being investigated.

Figure A.3 – Timetable for the 2014-2019 NSW Electricity Distribution Determination

ACTION	DATE
Consultation on Relevant Issues to Inform Framework and Approach Process (Australian Energy Regulator, 2011)	December 2011
Discussion Paper: Matters Relevant to the Framework and Approach, ACT and NSW DNSPs 2014 – 2019	April 2012
Expert Panel: Submission to the Expert Panel's Interim Stage One Report and Consultation Papers	June 2012
Preliminary Positions: Framework and Approach (F&A) Paper Ausgrid, Endeavor Energy and Essential Energy Regulatory control period commencing 1 July 2014	June 2012
Stakeholder Forum	August 2012
Close of submissions on *Preliminary Positions: Framework and Approach Paper Ausgrid, Endeavor Energy and Essential Energy Regulatory control period commencing 1 July 2014*	August 2012
Expert Panel: Submission to the Expert Panel's Interim Stage Two Report and Consultation Papers	August 2012
Final Positions: Framework and Approach Paper Ausgrid, Endeavor Energy and Essential Energy Regulatory control period commencing 1 July 2014	Pending: 30th November 2012
DNSPs submit regulatory proposal	31 May 2013
Regulatory proposals published (Will be published if found to be compliant with the National Electricity Rules and National Electricity Law. Further consultation will occur near this time.)	Mid June 2013
AER to publish draft distribution determination on the NSW DNSPs	November 2013
NSW DNSPs may submit a revised regulatory proposal to AER	December 2013
AER to publish final distribution determination on NSW DNSPs	30 April 2014
NSW DNSPs to submit initial pricing proposals for AER approval	Mid May 2014
AER to publish approved pricing proposal	Mid June 2014
Distribution determination and approved pricing proposal to commence	1 July 2014

A.6 The next regulatory period

Based on publications released to date, several significant changes to the way that NSW DNSPs have traditionally operated can be expected in the upcoming regulatory period. These will impact distributed generation, energy efficiency, demand side reduction and avoided network investment. This section discusses the form of regulation for the calculation of allowable revenue that electricity networks can collect. Other influencing factors on revenue are also discussed including costs of capital, rates of return, reliability standards and dividends to shareholders.

The AER will apply a *revenue cap*[56] to services classified as standard control services. This means for activities such as network augmentation and incidental services a cap on revenue will be established.[57] A Revenue Cap sets a Maximum Annual Revenue (MAR) for each year of the regulatory control period, which is determined by forecasting sales and price for coming years to meet the maximum, with an over and under accounting system in place for future years.

This is a change from the previous regulatory period where a price cap was used (see Box 1 for expanded definitions of these terms). The benefits of a revenue cap include certainty around DNSP revenue recovery, a reduced reliance on sales forecasts, and incentivising DNSPs to undertake demand side management, which outweigh the potential risks in terms of effective pricing, price stability, and price variability risk.

Box 1. Alternative revenue models

A number of other revenue models have been analysed and discussed in recent reviews. This section provides a brief overview of the different models.

Price caps set a ceiling on distribution tariffs or prices. Networks are free to adjust individual tariffs below the ceiling. Under a price cap model there is no cap on total revenue, and revenues will be dependent on the volume of sales. Under a price cap model, greater volume results in greater revenue, removing any incentive for a network to encourage demand-side management or to minimise peak volumes.

Revenue caps set the maximum revenue that a business can earn within a regulatory period. It is a cap on total earnings, meaning that it is not dependent on volume. Under a revenue cap, Networks have an incentive to reduce the volume of sales so that the tariff per unit is higher. Queensland, Tasmanian and West Australian electricity networks have operated under a fixed revenue cap.

Revenue caps create incentives for demand-side management in the short term, however there is a risk that they can provide incentives to increase the regulated asset base in the long term, instead of providing the assets base that is adequate. However, a preference towards capital expenditure guided by the building-block

[56] A revenue cap sets the maximum revenue that a business can earn within a regulatory period

[57] The PC recommended the use of price caps for standard control services arguing these provided a better incentive for efficient network investment.

model already exists within the NEM, resulting in higher capital expenditure per connection than in other jurisdictions. Additional regulation could remove this preference toward increasing the asset base, improving the efficiency of pricing under a revenue cap or any other model.

A revenue cap was avoided in the previous regulatory period because of a potential for price instability or inefficient pricing. The AER now believes the benefits of a revenue cap in the NSW jurisdiction will outweigh potential for price instability or weak efficient-pricing incentives.[58]

Average revenue caps set a ceiling on average revenues. This model caps total distribution revenues at the average revenue allowance multiplied by the volume of sales. This model means that total revenue is still dependent upon the volume of sales. This mechanism reduces the incentive for demand-side management in both the short and long term.

NSW, South Australia and Victoria have operated under **weighted average price cap** (WAPC). The WAPC allows flexibility in individual tariffs under an overall ceiling, meaning that total revenue is dependent upon the volume of sales. Under this mechanism, if the DNSP exceeds its demand forecast, gains in revenue can be achieved. AER is aware of substantial over-recovery that has taken place under WAPC.[59]

This control allows some prices to rise while others fall from year to year, which may have implications for price stability. There are also incentives for a DNSP to increase the price of services with high sales volume and lower others; meaning price rises for consumers of popular services. WAPC was selected as a control measure largely because it was expected to increase pricing efficiency, however the AER claims that pricing efficiency did not improve under WAPC for the last regulatory period.[60]

South Australia had an added control to reduce volume risk associated with the WAPC, which increased the maximum tariff for services if volumes were lower than forecast and reduced it if they were higher than forecast, intended to reduce over-recovery and remove disincentives for demand-side management. The purpose was to prevent the mechanism undermining efficient demand management practices or creating incentives for the DNSP to under-forecast future demand. The AER argues that the average revenue cap control creates no incentive to set prices efficiently. [61]

Revenue yield control links the amount of revenue that a business may earn to the volume of units sold. Total revenues are not capped and will vary in proportion to the volume of sales. As with price caps and average revenue caps, the total revenue is dependent upon the volume of sales. Revenue yield control has been used in the ACT.

[58] AER (2012) Preliminary Position Paper: Framework and approach, NSW Electricity Distribution Determination 2014-19
[59] AER (2012) Preliminary Position Paper: Framework and approach, NSW Electricity Distribution Determination 2014-19
[60] AER (2012) Preliminary Position Paper: Framework and approach, NSW Electricity Distribution Determination 2014-19
[61] AER (2012) Preliminary Position Paper: Framework and approach, NSW Electricity Distribution Determination 2014-19

A.7 The cost of capital

The cost of capital is established at determination time, which occurs for networks once every five years. The cost of debt can fluctuate significantly in a five-year period; regulatory inflexibility allows these higher debt costs to be passed on to consumers for a longer period of time than necessary. Conversely it can also add to the risk for networks if a financial crisis, such as the GFC of 2008-09 significantly increases the interest rate and availability of finance.

State Government ownership of electricity adds in further complication as these state-owned networks (such those in NSW) can access debt finance at interest rates available to the NSW Treasury. NSW has a triple A credit rating, which attracts a current interest rate of 3-3.75%.[62] However the network determination assumes commercial costs of capital and availability of debt.

The NSW Treasury recently successfully appealed to alter the weighted average cost of capital calculation. Treasury's request for a review of the averaging period for the risk-free rate resulted in a combined revenue increase of $2 billion across its five networks. The AEMC recently rejected a rule change proposal by the AER and Electricity Users Rule Change Committee[63] to calculate return-on-debt for state owned networks differently to non-state owned networks in order to reflect this difference in interest rates.[64]

The AEMC instead introduced a new rate of return framework common across both electricity and gas distributors. The change requires the regulator to make a "best possible" estimate of the rate of return required, taking into account market conditions, financial models, estimation methods and other relevant information. This rate is to be reviewed every three years (rather than at the beginning of the five year regulatory review cycle). The regulatory can also take different approaches to estimate return on debt including making allowances for reduced risk (and therefore cost) of debt financing.[65]

A.8 Rates of return on electricity networks

The value of the electricity networks' assets bases is determined by the AER based on forecast electricity demand and the reliability standards placed on networks by state governments regarding their performance.

Electricity network assets are long-lived and capital intensive. The AER acts to provide both the incentive for capital investment and maintenance of these assets to deliver a certain level of reliability. The rate of return allows networks to attract

[62] Based on current 3-year Waratah Bond rate of 3% and 10 year bond rate of 3.75%, source: NSW Government http://www.waratahbonds.com.au/html/rates.cfm, accessed 27th November 2012.
[63] The Electricity Users Rule Change Committee includes Amcor, Australian Paper, Rio Tinto, Simplot, Westfarmers, Westfields and Woolworths.
[64] AEMC (2012) Rule change final determination
[65] AEMC (2012) Economic regulation of network service providers and the price and revenue regulation of gas services - rule changes Information sheet, http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Economic-Regulation-of-Network-Service-Providers-.html

funds from capital markets to pay for (or service debt for) these intensive and long-lived assets. The capital intensity of electricity networks means that the rate of return on these capital assets is one of the major determinants of their revenue, and hence how much consumers need to pay.

This also highlights the importance of both accurate and adequate forecast of demand, and how sensitivities in fluctuating demand can be managed to the benefit of customers.

The Energy Users Association of Australia attributes rising prices to over-investment and inefficient operation by DNSPs, and comment that it is also partly driven by the way that the structure of determinations incentivises capital expenditure over operational expenditure. Currently, capital expenditure per MWh delivered in the National Electricity Market is seven times higher than in the USA.[66]

State Governments have a number of levels of influence in the cost of networks through reliability standards, borrowing costs and dividend payments they receive from the networks as their only shareholders. Recent evidence highlights that state-owned electricity networks have conflicting objectives and incentives that are leading to inefficient capital investments in networks.[67] State Government and their regulators (such as IPART in NSW) also play a role in regulating retail pricing, and mandating licence conditions.[68]

The political cycle can also influence State Government management of network businesses: reducing dividends to minimise price increases at politically sensitive times, limiting capital expenditure when concerned with debt, and increasing capital expenditure when required to meet reliability standards.[69]

A.9 Reliability standards

Reliability standards for the networks are often set in quite arbitrary ways.[70] It is asserted that consumers value high levels of reliability but the cost-benefit of these reliability standards are rarely evaluated in terms of cost-benefit to the economy or customer capacity to pay.[71]

NSW increased reliability standards for the electricity networks in 2009. The increased stringency in standards forced the electricity networks to increase capital expenditure by an additional $1,342 million and operating expenditure by $172.8 million. This expenditure to meet increased reliability standards contributed 9% to the increase in customers' electricity bills.[72]

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[66] Mountain (2012) Electricity prices in Australia: an international comparisons, for The Energy Users Association of Australia (EUAA)
[67] For example see Productivity Commission (2012) and EUAA (2012).
[68] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC
[69] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC; pp20
[70] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC
[71] Wood, T., Hunter, A., O'Toole, M., Venkataraman, P., and Carter, L. (2012) *Putting the customer back in front: How to make electricity prices cheaper,* Melbourne: Grattan Institute
[72] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC

The Productivity Commission recently estimated that in NSW $1.1 billion worth of distribution network infrastructure could be deferred until the next 5-year determination period by taking into consideration consumers' preferences for reliability.[73]

Following a previous review of transmission reliability in 2010, the Australian Energy Market Commission (AEMC) is currently undertaking a review of distribution reliability. The review has 2 work streams, a NSW work stream and a National Work stream. This may result in COAG's Standing Council on Energy and Resources (SCER) requesting AEMC to draft a best practice framework for delivering nationally consistent reliability outcomes. This framework would then be available for jurisdictions to voluntarily adopt or use as a reference to amend aspects of existing jurisdictional approaches.

The majority of the capital expenditure to meet the existing licence conditions (mentioned above) has already been included in the allowed revenues for the NSW DNSPs for the current regulatory control period. Any changes to the licence conditions arising from the AEMC's current review would therefore not affect capital expenditure or customer bills in the current regulatory period. NSW consumers will therefore still be required to pay for a return and depreciation on new assets until the end of their asset lives, which may be 45 to 50 years. As noted, changes to reliability conditions will not have any impact on the need for NSW consumers to continue to fund the costs of these assets. However, where reliability outcomes are reduced, these assets could instead be used to meet growth in demand, avoiding additional network costs due to growth.

A.10 Dividends to shareholders

NSW Government Budget Papers provide an overview of dividend and corporate tax revenues received from utilities. They show that the NSW Government will receive a dividend of $884 million from their electricity generation, transmission and distribution assets in 2013-14.[74] This equates to each NSW household contributing $377 to NSW Government dividends.[75] The dividends received flow into State Government consolidated revenue and are used on state expenditure for example schools and hospitals. The NSW Government has also recently implemented a Dividend Cap on their electricity assets and made assurances that dividends do not affect prices. However this is a regressive form of taxation, as it takes no consideration of individual householders' ability to pay.

A.11 Peak demand

Peak demand has also contributed to recent price increases. Figure A.2 shows that 10% of the NSW network is only used for 1% of the time (i.e. < 90 hours per year).

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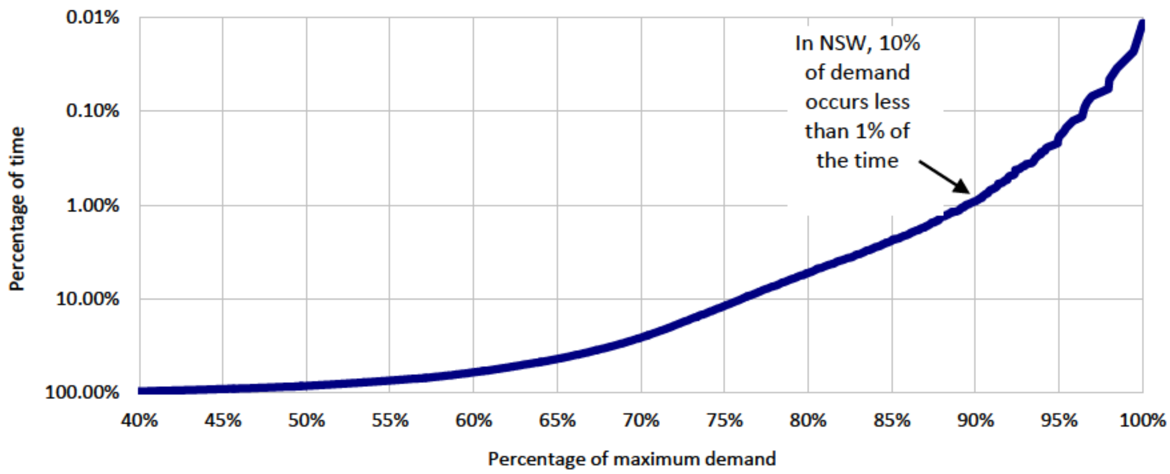
[73] Productivity Commission (2012) *Electricity Network Regulation*, draft report. Melbourne: PC; p3

[74] NSW Government (2013) Budget Statement Chapter 9
http://www.budget.nsw.gov.au/__data/assets/pdf_file/0018/25227/Ch_9.pdf

[75] Calculated using 2,343,677 NSW households (ABS 2011 Census)

Figure A.2 – NSW Electricity Demand Profile[76]



Source: AEMO

As electricity demand becomes 'peakier', the investment that is made to augment the network becomes less and less efficient. In its review of electricity networks, the Productivity Commission cites a claim that peak demand events occurring for less than 40 hours per year account for 25% of average retail electricity bills.[77]

Air-conditioning play a disproportionately large role in peak demand

At the aggregate level, households have played a disproportionately large role in driving peak demand growth, despite being responsible for less than one-third of electricity consumption. Industrial and commercial customers on the other hand have flatter, although large demand profiles and as a result proportionately contribute less to peak demand. Their flatter profiles are mostly due to exposure to peak pricing. For example, some large customers are offered payments to curtail usage at peak times; and the current AEMC Demand Side Participation Review is examining how these measures could be extended to more businesses.[78]

Not all residential electricity customers contribute to rising peak demand, yet all consumers must pay for this through their electricity bills. The recent Productivity Commission review into electricity network regulation highlighted the hidden cross-subsidies that exist, where usually lower income households who do not use power heavily during peak times subsidise those households who do, via network charges.[79] The growth in household air-conditioning use is often cited as an example of this cross subsidy. A household running a 2kW reverse-cycle air-conditioner at its maximum setting at peak times receives an implicit subsidy of about $330 per year from households who don't.

The situation is also different in areas that have high commercial building land uses, such as major CBDs. In these areas much of the electricity load is for cooling in

[76] Source: AEMO http://www.aemo.com.au/data/price_demand.html
[77] Productivity Commission (2012) *Electricity Network Regulation*, Draft report. Melbourne: PC
[78] AEMC (2012) The Power of Choice: giving consumers options in the way they use electricity, *Final report*, Sydney.
[79] Productivity Commission (2012) *Electricity Network Regulation*, Draft report. Melbourne: PC

buildings and contributes to summer afternoon peak. Trigeneration can greatly assist by displacing electrical air conditioning with thermal energy.

Similarly, street lighting contributes to peak demand during late afternoon/early evening, particularly in winter. Peak demand due to street lighting can be significantly reduced by up to 50% through the use of energy efficient lighting technologies, such as LED lighting currently being installed for City owned lights by the City of Sydney. However, the majority of street lighting in the City of Sydney and elsewhere in New South Wales is owned by the DNSPs who could make a major contribution in reducing electricity consumption and peak demand in assets that they own but charge to local authorities.

A.12 Incentivising demand management

As discussed above, unless there is a revenue cap on networks' income, total revenue is linked to sales volume. This creates incentives for increasing sales volumes but not for demand-side management or minimisation of peak volumes; it is assumed that a range of other market and regulatory controls will guide networks towards demand management. These are set out below.

The first assumption is that the cost of meeting peak volume will result in a profit loss for the network, creating an incentive to reduce peak volumes. Presently, however, the link between peak volumes, higher costs and lower profits is not a straightforward relationship. The costs of peak volumes, for example, only lead to a network loss if the costs are not foreseen at the beginning of the regulatory period. If the network correctly forecasts or over estimates the cost of meeting peak volumes throughout the regulatory period, no loss will be incurred.

The second assumption is that peak pricing can offer an effective method of decoupling profits from volume. However, adjustments are made at the end of the regulatory period to correct any differences between actual and forecast expenditure and investments. The AEMC Demand Side Review 3 "Power of Choice" identified that significant potential revenue recovery is possible through these adjustments if actual volumes are greater than forecast volumes, removing any incentive for networks to manage peak volumes.[80]

Further, networks are entitled to keep the value of any cost saving achieved throughout the period until the end of the regulatory period. This encourages DNSPs to pursue savings that can be immediately realised, rather than creating an incentive to invest in developing products and programs such as demand reduction technologies, which may take longer for the benefits to materialise.

The AER in response to the AEMC Power of Choice review is also investigating further how networks can be encouraged to innovate and explore demand side management solutions. This work involves preparatory work for rule change

[80] AEMC (2012) The Power of Choice: giving consumers options in the way they use electricity, *Final report*, Sydney.

requests. Particularly relevant to this discussion is the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS). The AEMC Review recommended changes to the Scheme to ensure demand side participation projects receive an appropriate return when they deliver net cost savings to consumers; and that current network incentives better align with the further objective placed on networks to achieve efficient demand management.

The AER has set out a process of consultation with the electricity networks and identified a way forward for this work to be included in the forthcoming 2014-2019 Electricity Network Determination period.

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Institute for Sustainable Futures

UNIVERSITY OF TECHNOLOGY SYDNEY

CLOSE TO HOME: Potential Benefits of Decentralised Energy for NSW Electricity Consumers

Prepared by

Institute for Sustainable Futures

for

The City of Sydney

NOVEMBER 2010

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Please cite this report as: Dunstan, C. & Langham, E. 2010, *Close to Home: Potential Benefits of Decentralised Energy for NSW Electricity Consumers*, prepared by the Institute for Sustainable Futures, University of Technology, Sydney for the City of Sydney, November 2010.

Executive Summary

The electricity sector is responsible for 37 per cent of Australia's total greenhouse gas emissions.[1] In the City of Sydney however, around 80 per cent of greenhouse gas emissions are due to coal fired electricity.

The City of Sydney has proposed the installation of 360 megawatts (MW)[2] of "trigeneration" by 2030, in order to reduce greenhouse gas emissions by 18 to 26 per cent from 2006 levels. Trigeneration systems are highly efficient small power plants that can be located in or on buildings. They not only generate electricity but also use waste heat to produce hot water for heating, and cold water (through "absorption chillers") for air-conditioning. The rest of the City's energy needs are proposed to come from renewable energy and energy efficiency measures in order to reduce overall emissions by 70 per cent by 2030 for the local government area, which includes the Central Business District (CBD). This equates to 50 per cent below 1990 levels.

Over the period 2010-2015, electricity network businesses in Australia are proposing to spend over $46 billion – or $9 billion per year – on upgrading and extending the electricity network. This expenditure is more than that proposed for the National Broadband Network, and is the main driver for the current sharp rise in electricity prices.

The traditional approach of investing in new power cables and substations to service increasing electricity demand reinforces the reliance on large-scale, centralised electricity supply which has been responsible for the high and rising levels of greenhouse gas pollution from the power sector. Following this path will make it more difficult for Australia to meet its 2020 greenhouse reduction target of 5 to 25 per cent put forward at international climate treaty negotiations.[3] Alternatively, if electricity regulators provided better support for electricity networks to redirect more of this network expenditure towards energy efficiency, peak load management and decentralised generation, then energy cost pressures and greenhouse gas emissions could be significantly reduced.

In NSW, electricity networks are undertaking capital expenditure of $17.4 billion over the five years to 2013/14. This represents $2,400 per person and an 80 per cent increase on the previous five-year period. **Electricity prices are expected to rise by an average of 83 per cent during this period and the proportion of power bills that goes to pay network charges will rise from 40 per cent to almost 60 per cent[4]**. Network charges reflect the costs of transporting electricity from where it is produced (mostly by coal fired power stations in regional areas like the Hunter Valley) to consumers in cities like Sydney, via the long distance network of wires, poles, cables and electrical substations. Amid the current intense public debate about power price rises, it is important to recognise that increased electricity network

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[1] See Department of Climate Change and Energy Efficiency, 2010. *Quarterly Update of Australia's National Greenhouse Gas Inventor. March Quarter 2010*, p.5.
[2] Megawatts electrical generation capacity, often denoted at MWe.
[3] Note: commitment higher than 5 per cent is conditional upon coordinated international action.
[4] See Section 4. Impact of network expenditure on electricity prices, p. 25

investment is main cause of the price increases (about 86 per cent of the regulated power price rises for Energy Australia customers between 2009/10 and 2012/13).[5]

As much as $7.6 billion of this new capital expenditure on networks in NSW is **'growth-related',** including $3.3 billion to be spent by Energy Australia, whose service territory includes the Sydney CBD. This report suggests that **much of this new investment could potentially be deferred or avoided if peak demand growth was slowed through measures such as energy efficiency, peak load management and decentralised or local energy generation.** This has the potential to moderate future energy costs for all NSW electricity consumers, avoid the need for large new power stations and significantly reduce greenhouse gas emissions.

It is estimated that the City of Sydney's plans to supply 70 per cent of the local government area's electricity needs from a network of trigeneration plants by 2030 could achieve savings in deferred electricity network costs of over $200 million by 2020, or upwards of $1 billion by 2030. When the avoided costs of new fossil fuel power stations of around $0.5 billion of installed capacity are added, the City's proposed 360 MW of trigeneration capacity could potentially avoid in the order of $1.5 billion in electricity generation and networks by 2030.[6] While the City's trigeneration development program would also entail major costs, the above estimated cost savings highlights that the scale of benefits is potentially very large.

In NSW, annual energy consumption is forecast to increase by 21 per cent or about 15,500 gigawatt hours (GWh) of electricity between 2009/10 and 2019/20. There are currently many proposals to meet this additional energy demand, including coal-fired and natural gas-fired power stations, renewable energy generators, energy efficiency and load management. If NSW installed its proportional share of the Federal government's Renewable Energy Target of 20 per cent by 2020, this would equate to 13,200 GWh p.a. of renewable energy production. This means that in 2020 there would remain a notional electricity supply "gap" of 2,300 GWh in NSW, or about three per cent of current energy demand.

The City of Sydney's energy infrastructure plans can play a role in helping to overcome this notional energy 'gap' between forecast demand and supply in NSW to 2020. It is estimated that with 155 MW of the City of Sydney's planned 360 MW of trigeneration capacity in place by 2020, approximately 1,000 to 1,450 GWh per year of grid electricity could be displaced, which represents 44 to 63 per cent of the NSW energy "gap". When combined with energy efficiency and distributed generation, this could contribute significantly to filling this potential energy demand/supply gap.

However, despite this relatively small energy gap in the planning horizon to 2020, two NSW Government owned generators, Macquarie Generation and Delta Electricity, have proposed major expansions of 4,000 MW (combined) of coal or gas baseload power stations at an estimated cost of between $4.6 and $7 billion dollars.[7]

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[5] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity — Final Report*, March 2010, Table 1.2.

[6] This estimate is conservative as it excludes the electrical load avoided due to the heating/cooling load being met by trigeneration using waste heat.

[7] NSW Department of Planning, *Major Project Assessment, Bayswater B Power Station, Director General's Environmental Assessment Report*, December 2009 and NSW Department of Planning,

If coal-fired, these two new large power stations (at Bayswater in the Hunter Valley and Mt Piper near Lithgow) would emit over 23 million tonnes of carbon dioxide per annum.[7] This would be equivalent to over 4 per cent of Australia's greenhouse gas emission in 2015[8] or up to 15 per cent of total NSW emissions.[9]

When combined with the additional network infrastructure required to deliver their power to consumers, these big new centralised power stations are likely to be significantly more expensive and more polluting than a prudent combination of decentralised generation, load management and energy efficiency. A previous report by the Institute for Sustainable Futures[10] found that "Distributed Energy" options including distributed generation, peak load management and energy efficiency measures were, as a response to peak and energy shortfalls, likely to be both cheaper and produce less carbon emissions than either coal or gas fired power stations. These Distributed Energy options were estimated to be able to cut total power bills by as much as $600 million per year by 2020 – equivalent to about $60 per household per year.

Moreover, if the recently recommended target of the Prime Minister's Task Group on Energy Efficiency to improve nationwide energy efficiency by 30 per cent by 2020 is enacted, there would be little if any need for new fossil fuel based electricity generation, as the reduction in energy consumption would be bring 2020 consumption to below that of 2010.

There are, however, numerous impediments to electricity network businesses investing in 'demand management' to support the use of distributed energy to defer generation and network infrastructure). Consequently, the scale of funds spent on demand management in Australia remains relatively small. In total, the aggregated level of annual expenditure on demand management is likely to represent significantly less than 1 per cent of total annual expenditure on electricity supply in Australia. This report outlines six key regulatory and other changes that would help unlock the potential of demand management to deliver greenhouse gas emission reductions and limit price increases for NSW electricity consumers:

1. Changing the form of regulation to reward, instead of penalising, electricity network businesses that help consumers save energy;
2. Better reporting and assessment of *actual* demand management performance;
3. Better assessment of the *potential* for demand management to reduce energy bills;
4. Putting a significant price on carbon emissions;

Major Project Assessment, Mt Piper Power Station Extension, Director General's Environmental Assessment Report, December 2009.

[8] Arup, 2009. *Independent Review of Greenhouse Gas Assessments*; *Bayswater B EA Concept Plan*, Oct 2009, p. 20; Arup, 2009. *Independent Review of Greenhouse Gas Assessments*; Mt Piper Power Station Extension, Oct 2009, p.21.

[9] Aecom, 2009. *Bayswater B Submissions Report*, Report prepared for Macquarie Generation, November 2009, p.32. Uses AeCom citation of NSW Government reported emissions of 158 million tonnes in 2005.

[10] Jay Rutovitz & Chris Dunstan, 2009. *Meeting New South Wales Electricity Needs in a Carbon Constrained World*. Report prepared by the Institute for Sustainable Futures, University of Technology, Sydney.

5. Setting targets for demand management (and measuring progress towards them);
6. Establish a dedicated fund, or scheme, to support demand management by network businesses, and others.

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1. Background

Introduction to Trigeneration and Electricity Networks

Trigeneration energy systems are highly efficient mini-power plants that run on natural gas or renewable gases to produce electricity, heating and cooling. These three distinct outputs are where *tri*generation derives its name. They can be up to three times more efficient than coal fired power stations because they capture the waste heat from producing electricity and use it to heat buildings and, through absorption chillers, to cool them. They are able to do this due to their 'distributed' location within the electricity network, close to the point of building heating and cooling loads. This is distinct from the centralised coal-fired power stations that produce 80 per cent of NSW's electricity, in which two-thirds of the energy content of coal is lost as steam and waste heat through the cooling system. Distributed power generators also reduce transmission and distribution losses, which make up around 7 per cent of electricity produced, by avoiding the need to transport power from distant power plants into the city.

Trigeneration has the potential to reduce electricity demand at peak times because not only is electricity produced, but the waste heat can be used to replace electrical air-conditioning or heating, which are major contributors to peak electricity demand. Trigeneration in the CBD could not only reduce the need for increased capacity in local electricity distribution wires and substations but also in the long-distance electricity transmission and sub-transmission networks servicing the CBD. Thus the City of Sydney's trigeneration plans offer a key opportunity to defer or eliminate a portion of the $7.6 billion being invested in wires, poles and substations over the next five years due to growth in electricity demand in NSW.

Significantly reducing demand on the electricity network in the CBD could also result in the deferral or avoidance of large centralised power stations.

Earlier work by the Institute for Sustainable Futures (ISF)[11] found that "Distributed Energy" options including distributed generation, peak load management and energy efficiency measures were both cheaper and produced less carbon emissions than either coal or gas fired power plants as a response to peak and energy shortfalls. These Distributed Energy options were estimated to be able to cut total power bills by as much as $600 million per year by 2020 - equivalent to about $60 per household per year.

This report builds on the previous analysis specifically in relation to the City of Sydney's decentralised energy plans.

Trigeneration Master Plan and Sustainable Sydney 2030

The City of Sydney ('the City') has set a target to supply 70 per cent of the local government area electricity needs from a network of trigeneration plants by 2030, which is estimated to reduce greenhouse gas emissions by 18 to 26 per cent from

[11] Jay Rutovitz & Chris Dunstan, 2009. *Meeting New South Wales Electricity needs in a Carbon Constrained World*. Report prepared by the Institute for Sustainable Futures, University of Technology, Sydney.

2006 levels.[12] The remainder of the City's energy needs will come from renewable energy and energy efficiency measures to reach an overall emissions reduction target of 70 per cent for the local government area, including the CBD, by 2030 (this equates to 50 per cent below 1990 levels).

To map out this strategy, the City of Sydney commissioned a Trigeneration Master Plan for the CBD to assess a number of technical factors for the establishment of a trigeneration network such as the distribution of electrical and gas loads, the size and location of electrical cables and gas mains, and what capacities could be connected to them and where. This plan, due to be launched in December, outlines the installation of at least 360 MW of trigeneration capacity by 2030.[13]

Last year the City of Sydney also called for expressions of interest to design, install and operate a network of trigeneration plants in the CBD based firstly around council properties but with the potential to expand by connecting to other city buildings. After receiving responses from major national and international energy players, a tender, which closes in January 2011, was sent to a shortlist of companies. The City's tender also seeks expressions of interest in participating in a public/private joint venture with the Sydney Energy Services Company to roll out the 360 megawatts of trigeneration as set out in the Master Plan.

According to a 2009 study prepared for City of Sydney,[14] a broader rollout of the plans similar to Sydney's Sustainable Sydney 2030 in other Australian cities could achieve 50 per cent cuts in greenhouse gas emissions over the next 20 years. This study suggested that a coordinated strategy of this nature could reduce emissions by a cumulative 540 million tonnes between 2010 and 2030, contributing 41 per cent of the national 5 per cent target and almost one quarter towards a 25 per cent national reduction target.

Trigeneration in Australia

Australia employs a relatively small amount of cogeneration (which produces electricity and heating) and trigeneration technologies relative to other parts of the world such as Europe, North Asia and the United States. In 2006, Australia ranked 34th out of 40 countries surveyed for decentralised energy generation, with around 5 per cent of total generation coming from decentralised sources (mostly in large industrial applications) compared to 40 per cent in the Netherlands and 55 per cent in Denmark.[15]

There are a small number of trigeneration plants operating in Australian cities including the Stockland property group building in Sydney, Macquarie University and Canberra Airport. Others are planned for Qantas at Sydney airport and the National Australia Bank's data centre in Melbourne. However, the City of Sydney's plans represent a dramatic change in how the technology is currently used in Australia. It plans to install large-scale plants to supply networks of nearby buildings or "precincts". For example, a trigeneration plant planned for Sydney Town Hall could

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[12] Kinesis, Cogent Energy, Origin. 2010, *City of Sydney Decentralised Energy Master Plan 2010-2030*.
[13] Modelling by City of Sydney consultants, Kinesis, October 2010.
[14] Kinesis, 2009. *Examining the Abatement Potential of Australia's Capital Cities by 2030*, Report prepared http://www.cityofsydney.nsw.gov.au/2030/documents/CCLMKinesisReport.pdf
[15] World Alliance for Decentralised Energy, 2006. *World Survey of Decentralised Energy,* Fig. 9 http://www.localpower.org/documents/report_worldsurvey06.pdf

supply the Queen Victoria Building, St Andrews School, Woolworths and other nearby buildings. The City believes that its plan has the potential to increase significantly the energy efficiency of the system compared to the single building operation, and that greenhouse gas emissions in connected buildings can be reduced by between 39 to 56 per cent depending on how the plants are used.[16]

Background to and structure of this report

In early 2009 the City of Sydney made a submission to the Australian Energy Regulator (AER) outlining the significance of the issue of avoidable electricity network costs to the business case of its planned Trigeneration Master Plan (then called "Green Transformers"). The submission stressed the importance of the AER's regulatory decision in assisting the transition to a regulatory environment in which distributed generators are allowed to capture some of these avoided costs, resulting in an outcome that is both lower in cost and lower in carbon emissions.

This report reviews electricity demand forecasts, generation planning figures and network expenditure information that has changed since the City's submission, to provide an up-to-date assessment of network investment and the potential environmental and consumer benefits achievable through decentralised energy options. It should be stressed that while this report primarily refers to supporting the development of trigeneration, the arguments presented here apply equally to improving outcomes through energy efficiency or other peak load management approaches.

The structure of this report is as follows:

Section 2 reviews the demand forecasts made by Energy Australia and other sources since the 2009 AER network pricing Final Determination (the City's submission was in response to the *Draft* Determination) to determine whether the previous forecasts remain an accurate picture of current trends driving network investment.

Section 3 reviews the network investment approved in the AER's pricing determination, and considers what proportion of this investment may be avoidable through energy efficiency, trigeneration and other decentralised energy options.

Section 4 looks at the consumer implications of this network investment, in terms of the resulting tariff increases.

Section 5 discusses regulatory and other changes that are needed to allow trigeneration and other decentralised energy options to compete on a more level playing field with traditional centralised coal-fired power. It also suggests strategic approaches the City of Sydney can take in pursuing this agenda.

The **Appendix** contains an analysis of the AER's responses to the recommendations contained in the City's submission, as background to the suggested strategy seen in Section 5.

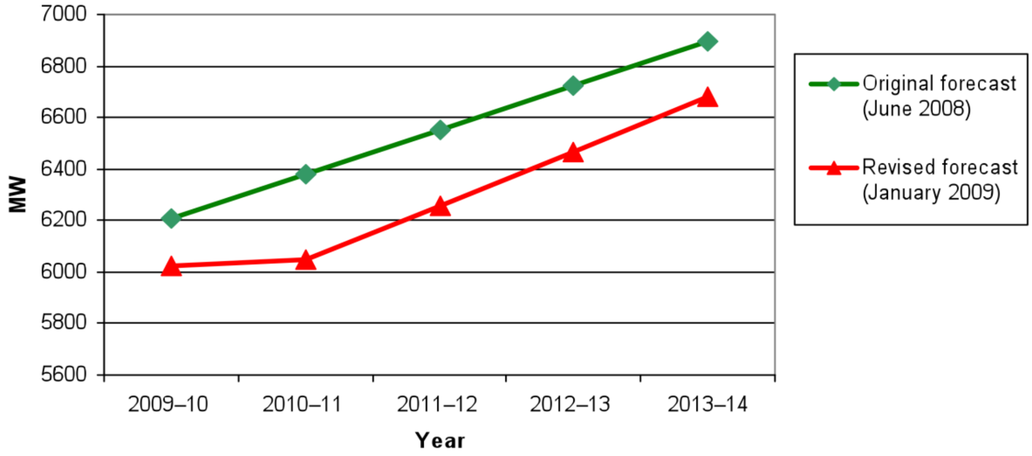
[16] Kinesis et al 2010, above n12.

2. Demand forecasts and generation planning

Demand Forecasts

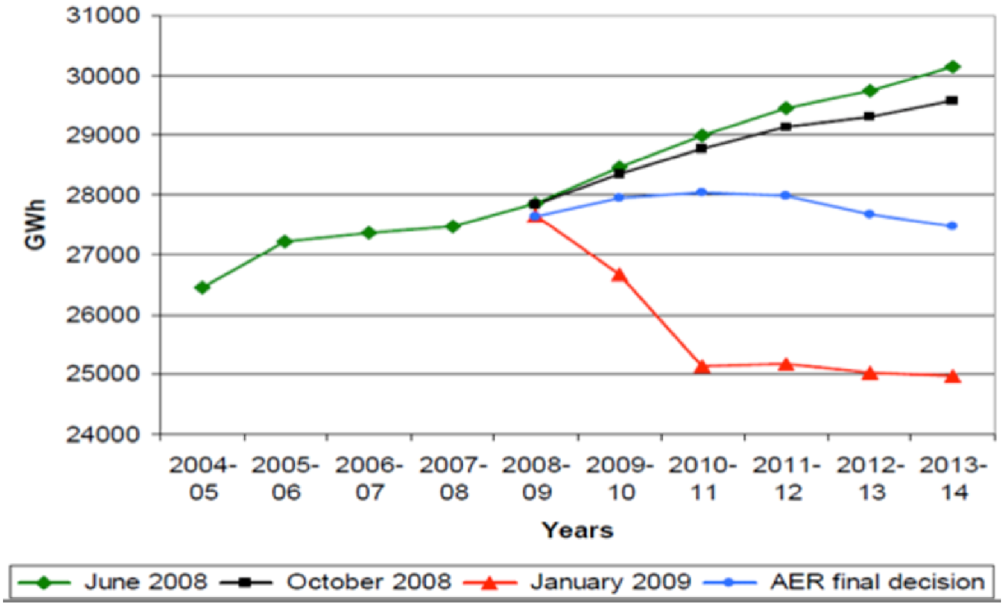
The Australian Energy Regulator's NSW distribution network pricing determination took place during worst impacts of the Global Financial Crisis (GFC) on global financial markets. Energy Australia's (EA) peak demand forecasts at the time reflected the impact of the GFC on economic growth, as illustrated by the January 2009 forecasts shown in Figure 1 and Figure 2 below.

Figure 1 – Energy Australia forecast peak demand as at January 2009[17]



[17] Data source: AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, Table 6.4 p.86.

Figure 2 – Comparison of energy forecasts for Energy Australia's network[18]



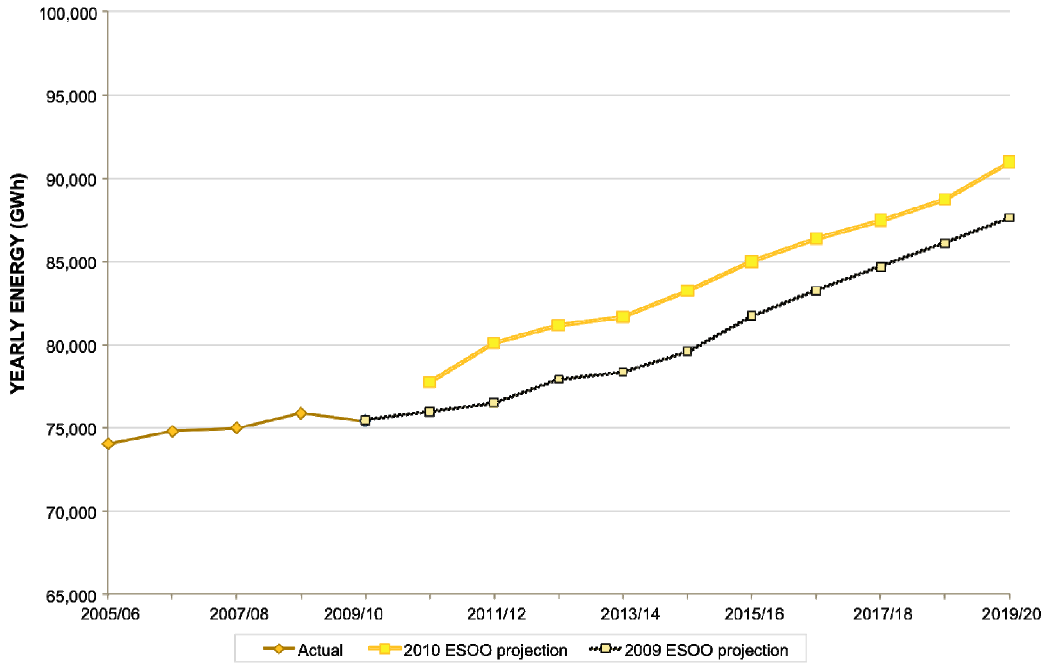
As can be seen from Figure 1 and Figure 2, the reduction between June 2008 and January 2009 in forecast peak demand (which drives network capital expenditure and EA *costs*) was estimated to be much less than the impact on energy consumption (which mainly drives EA *revenue*). This major reduction in EA's forecast of consumption was probably also influenced by the expected impact of rapid increases in customers electricity bills due to increases in electricity network charges. Consequently, EA argued for a higher price increase to compensate for these impacts.

It is pertinent to consider how actual data since compares with these projections. While public data is unavailable for EA's network specifically, the recently released 2010 Australian Energy Market Operator (AEMO) Electricity Statement of Opportunities shows that energy consumption in NSW in 2009/10 did in fact fall slightly compared to 2008/09 (from 75,857 gigawatt hours (GWh) to 75,421 GWh) as shown in Figure 3. If reflective of EA's demand pattern, this would place the actual demand between the forecast of AER and EA. (Note that since the AER's regulation closely ties revenue to sales volume, it is in the financial interest of EA if actual sales exceed the forecast adopted by the AER.)

The 2010 AEMO projections are substantially higher than the 2009 projections due to a quicker than anticipated economic rebound from the GFC. However, it is worth noting the large safety margin applied to the AEMO energy forecast for NSW, in that even in the *lowest* growth scenario of the three considered by AEMO a growth rate of 1.5 per cent is used, which is substantially higher than the observed average annual energy growth from 2004-2009, of just 1 per cent.

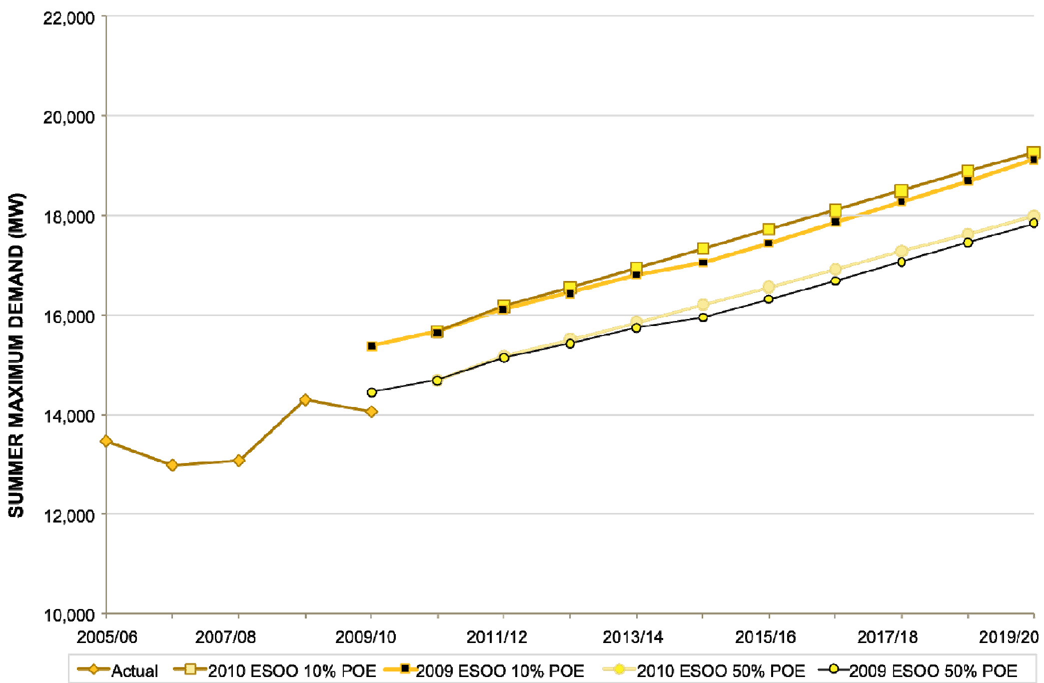
[18] Figure source: AER, above n17, Fig. 6.2, p.114.

Figure 3 - Comparison of NSW medium growth energy projections (AEMO 2010),[19] GWh p.a.



According to AEMO, both summer and winter peak demand for NSW also fell in 2009/10 compared to 2008/09, by around 230MW and 1,300MW respectively. (The AEMO summer actual and forecast demand is shown in Figure 4). It should be noted that peak demand is much more weather dependent than total energy consumption, and is therefore more variable and harder to accurately forecast.

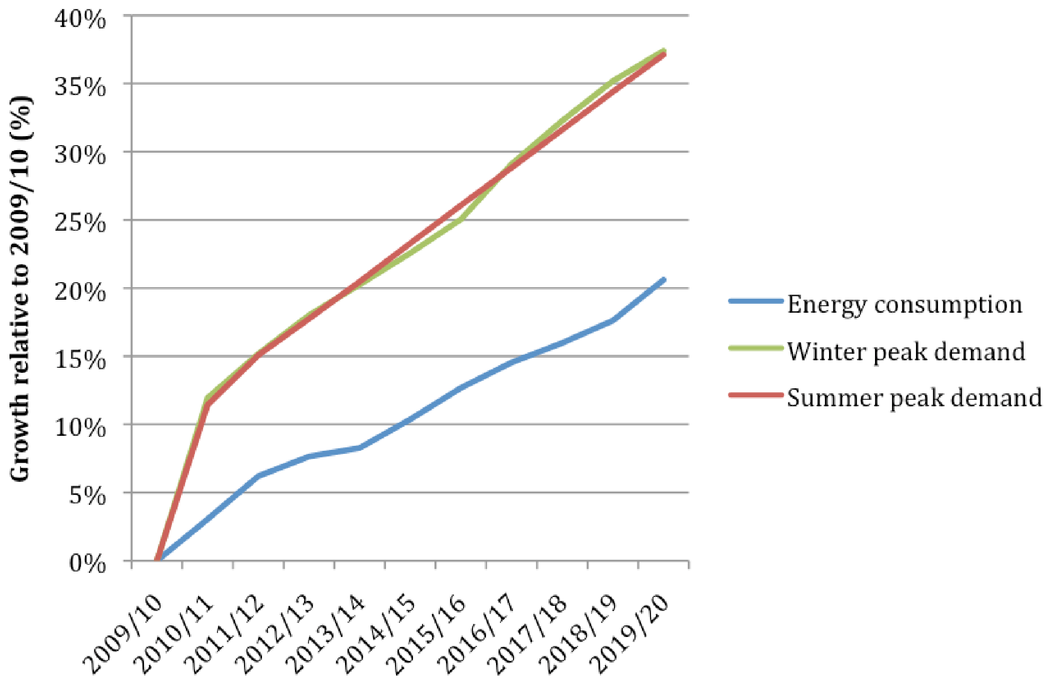
Figure 4 - Comparison of NSW medium growth summer maximum demand projections[20]



[19] AEMO, 2010. *Electricity Statement of Opportunities.* Fig 4-9, p.45.
[20] AEMO, 2010. *Electricity Statement of Opportunities.* Fig 4-10, p.47.

Bringing the above AEMO peak and energy forecasts together as shown in Figure 5, over the 10-year period from 2009/10 to 2019/20 the AEMO medium growth scenario projections suggest that energy consumption is forecast to grow by 21 per cent, while both summer and winter peak demand are forecast to grow by 37 per cent.

Figure 5 – Growth in NSW energy consumption and peak demand relative to 2009/10[21]



In summary, the actual peak and energy data one year into the AER's network pricing determination period are broadly in line with peak and energy forecasts adopted by the AER.

Looking further out to 2014 the forecasts have changed significantly from the 2008 Draft Determination, but are broadly in line with those adopted by AER for the Final Determination. On this basis, it seems reasonable to conclude that changing economic and energy forecasts have neither improved nor diminished the potential for trigeneration and DM or the likely financial impact on Energy Australia of supporting these options compared to when the AER decision was made.

Generation forecasts (energy)

According to the AEMO Electricity Statement of Opportunities (2010), energy consumption in the National Electricity Market (NEM) states is forecast to rise by about 48,000 GWh p.a. between 2009/10 and 2019/20 (medium economic growth scenario). During this period, renewable energy generation is due to increase by at least 33,000 GWh due to the mandatory Renewable Energy Target (RET). This situation is shown in Figure 6 below.

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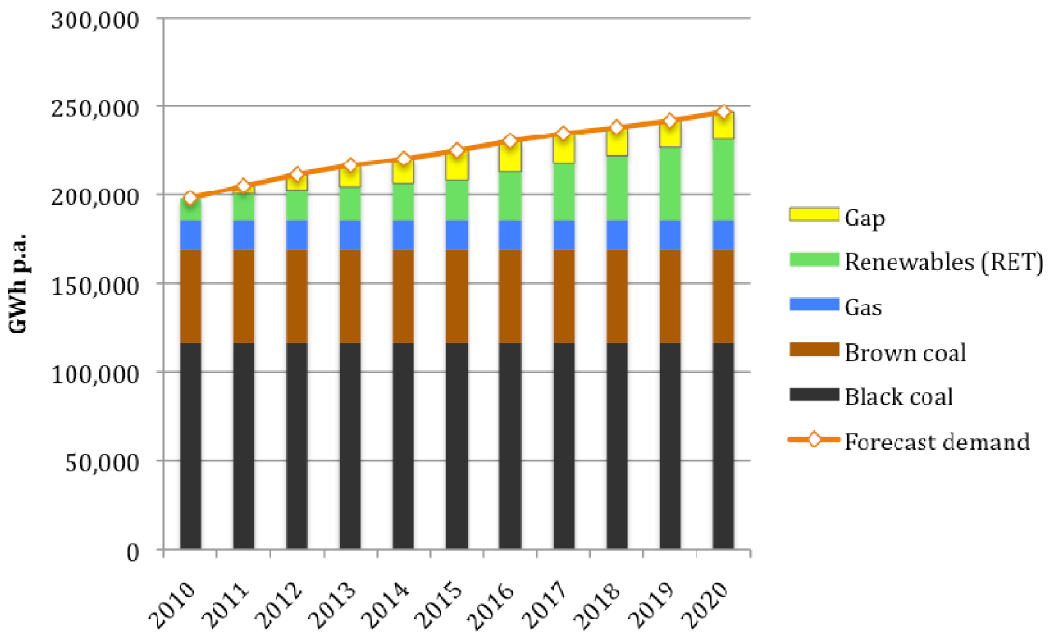
[21] Data Source: AEMO, 2010. *Electricity Statement of Opportunities.* Tables 4-10, 4-11, 4-12. For winter projections the year 2009 was aligned with 2009/10 summer forecasts.

This leaves a gap of about 15,000 GWh to be met by other sources (shown as a notional "gap" in yellow in Figure 6). Note that this is only a notional "gap" as there are a number of existing and proposed options to meet this gap, which are likely to emerge well in advance of any real supply shortfall occurring.

Options to meet the "gap" include:

1. increased output by existing gas- and coal-fired power stations;
2. new gas-fired power stations;
3. new coal-fired power stations;
4. additional renewables beyond that required to meet the national renewable energy target (RET);
5. cogeneration/trigeneration; and
6. improved energy efficiency.

Figure 6 – Energy supply/demand situation in the National Electricity Market, 2010-2020,[22] GWh p.a.



[22] Data Sources: Forecast demand from AEMO, 2010. *Electricity Statement of Opportunities.* Fig 4-3; Breakdown of non-renewable components of existing generation according to AER, 2009. *State of the Energy Market*, Fig 1.5b; Renewables from Renewable Energy (Electricity) Act 2000 (Cth), Act No. 174 of 2000 as amended (compilation prepared on 1 February 2010 taking into account amendments up to Act No. 78 of 2009), s.40. Note that this older version of the Act was used to illustrate gross renewable energy additions, as the Act was subsequently amended to create complementary Small (SRET) and Large (LRET) target schemes, ultimately intended to lead to the same outcome in terms of total renewable energy provision (but the new Act does not contain an overall combined target table totalling 45,000GWh by 2020). In fact, it is currently estimate that the SRET will 'overdeliver' and it is expected that the total resulting installed capacity of renewables in 2020 will be 52,000 GWh, and thus the numbers used in this report are conservative. See: MMA (McLennan Magasanik Associates), 2010. *Impacts of Changes to the Design of the Expanded Renewable Energy Target*, Report to Department of Climate Change and Energy Efficiency.

The approach shown above for the National Electricity Market is now applied to NSW, as shown in Figure 7 below. In NSW energy consumption is forecast by AEMO to increase by about 15,500 GWh or 21 per cent between 2009-10 and 2019/20. This is shown by the black dotted lines in Figure 7. If NSW were to get its proportional share of renewable energy through the RET, or about 40 per cent of total capacity,[23] this would equate to 13,200 GWh of renewable energy supply (the green component of the column in Figure 7). Shown in yellow is the additional energy required to meet the deficit, which is 2,300 GWh, or about 3 per cent of current energy demand. This is equivalent to about 900 MW of wind power (operating at a typical 30 per cent capacity factor).

The two right hand columns of Figure 7 provide a picture of how the City of Sydney and its local government area could contribute to this 2,300 GWh "gap" in 2020. While the City's energy demand only makes up around 5 per cent of total 2020 NSW consumption (shown in orange as the "City's share" in Figure 7),[24] the City has the potential to play a more significant role in addressing an energy deficit. The City is looking at several possible low emission energy options, which could contribute to meeting this forecast energy supply gap, including:

- energy efficiency;
- distributed renewable energy (e.g. solar power, solar hot water); and
- distributed generation, including cogeneration and trigeneration (from renewable and non-renewable fuels).

The relative impact that each of these measures could have is also shown as dotted boxes in Figure 7.

It is estimated that under the City's medium growth trigeneration scenario, in 2020 with 155 MW of trigeneration in operation, approximately 1,000 to 1,450 GWh per annum[25] of grid electricity would be being displaced by providing low carbon electricity and displacing electrical heating and cooling by utilising waste heat. This equates to about 10 times the City's proportional contribution to a notional NSW energy supply gap, or 44 to 63 per cent of the *total* NSW gap of 2,300 GWh p.a.[26] Using standard industry figures derived from Acil Tasman[27] for proposed new fossil fuel generation costs, deferring investment in coal or gas fired power stations is estimated to result in an avoidable cost of around $1.5 million per MW of installed capacity. Given the City's proposed 360 MW of generating capacity, this translates to over $0.5 billion in avoided fossil fuel generation infrastructure.[28]

In addition, if the City was to improve energy efficiency by 30 per cent in line with the recommendation of the Prime Minister's Task Group on Energy Efficiency this

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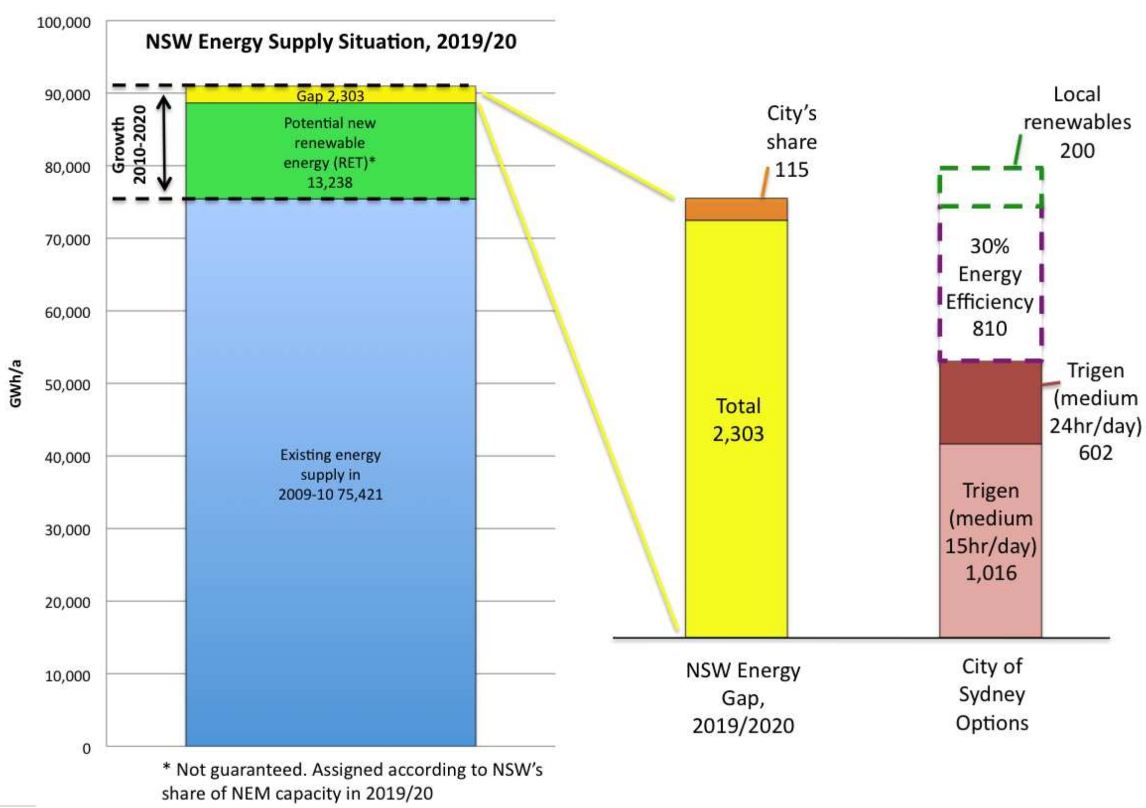
[23] NSW's share of projected peak demand on the National Electricity Market in 2019/20 according to AEMO 2010.
[24] Based on a 2020 demand of 4,874 GWh (Kinesis modelling data from 2009).
[25] Depending on whether the trigeneration is operation for 15 or 24 hours per day.
[26] Furthermore, under the medium growth scenario there is also sufficient potentially dispatchable trigeneration capacity installed prior to a notional *peak demand* 'gap' being observed on the network (69MW of trigeneration is installed by 2016/17 when a 27 MW peak capacity gap is predicted).
[27] ACIL Tasman, 2008, *Impacts of the Carbon Pollution Reduction Scheme and RET: Modelling of impacts on generator profitability*, Department of Climate Change.
[28] Figure is conservative as the heating/cooling load offset from waste heat is not included.

could contribute an estimated additional 810 GWh p.a. (35% of the gap) in savings,[29] while local renewables under the (yet to be finalised) Renewable Energy Master Plan could make up a further 200 GWh p.a. (9%).[30]

Figure 7 – Indicative potential contribution of the City of Sydney to NSW energy supply in 2019/20[31]



Despite this relatively small notional energy gap in the planning horizon to 2020, two NSW Government owned electricity generators, Macquarie Generation and Delta Electricity, have proposed major expansions of 2,000 MW each of coal or gas baseload power stations at an estimated cost of between $4.6 and $7.0 billion dollars.[32] (Note that these costs are reflective of the $1.5 million per MW mentioned above.) These two new power stations (at Bayswater in the Hunter Valley and Mt Piper near Lithgow) would produce in the order of 28,000 GWh per year (if operating at a typical 80 per cent of capacity) and, if coal-fired, would emit over 23 million tonnes of carbon dioxide per annum.[33] This would be equivalent to over 4 per cent of

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[29] This accounts for 10% of the 14% efficiency gains factored into Sustainable Sydney 2030 having already been counted in the 'baseline'.
[30] The City's 2030 target is 1,300 GWh from direct investment in renewables. About half of this would be within the LGA and it is assumed that approximately 30% of this half would be installed locally by 2020. An additional margin has also been subtracted to account for some overlap counted under the national Small Renewable Energy Target (SRET).
[31] NSW forecasts obtained from AEMO *2010*, Table. 4-10, medium growth scenario.
[32] NSW Department of Planning, *Major Project Assessment, Bayswater B Power Station, Director General's Environmental Assessment Report*, December 2009 and NSW Department of Planning, *Major Project Assessment, Mt Piper Power Station Extension, Director General's Environmental Assessment Report*, December 2009.
[33] Ibid.

Australia's greenhouse gas emissions in 2015[34] or up to 15 per cent of total NSW emissions.[35]

To further compound the apparent imprudence of proposing new baseload power stations, the Prime Minster's Task Group on Energy Efficiency recently released a recommendation to adopt a nationwide target of 30 per cent energy efficiency improvement by 2020.[36] Should this recommendation be enacted, there would very likely be no need for new fossil fuel based electricity at all, as the reduction in energy consumption would bring 2020 demand below that of 2010. Such a decision would dramatically shift the goalposts in terms of planning for all energy generation projects.

Generation forecasts (peak capacity)

While thus far this report has focussed on "energy" or "GWh" shortfalls, the availability of electricity generation at peak times (i.e. "peak capacity" in MW) will now be reviewed briefly.

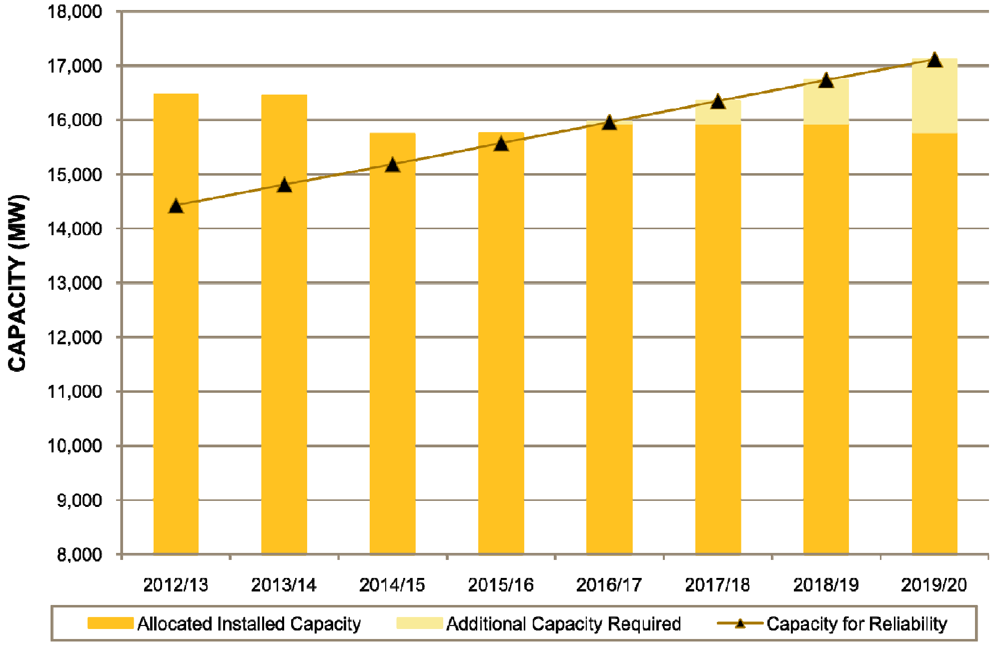
Under the medium growth scenario NSW currently has sufficient generation capacity to meet the State's projected peak electricity demand until 2016/17, at which point the projected deficit is 27 MW (Table 1), or 0.2 per cent of installed capacity in NSW. This projected (notional) "gap" in peak energy capacity occurs one year later than was predicted in last year's (2009) Electricity Statement of Opportunities, which was in turn one year later than the year before. Such a trend of continually pushing out the projected requirement date for new generation infrastructure is to be expected in a well functioning electricity market. Nevertheless, the projected gap in peak capacity quickly increases, to around 1,200-1,300 MW in 2020, as shown in Figure 8.

Table 1 - National supply-demand outlook, 2012/13-2019/20 (AEMO 2010)[37]

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	2015/16	184	**2013/14**	**726**	2012/13	716
New South Wales	2017/18	91	**2016/17**	**27**	2016/17	285
Victoria	2017/18	135	**2015/16**[1]	**249**	2014/15	222
South Australia	2017/18	11	**2015/16**[1]	**50**	2012/13	85
Tasmania (summer)	>2019/20	N/A	**>2019/20**	**N/A**	>2019/20	N/A
Tasmania (winter)	>2020	N/A	**>2020**	**N/A**	>2020	N/A

[34] Arup, 2009, above n8.
[35] AeCom, 2009, above n9.
[36] Full report downloadable from: http://www.climatechange.gov.au/publications/energy-efficiency/report-prime-ministers-taskforce-energy-efficiency.aspx
[37] Table source: AEMO, 2010. *Electricity Statement of Opportunities*, Table 1, p.3.

Figure 8 - NSW summer supply-demand outlook for peak capacity (AEMO 2010)[38]



It is useful to provide a comparison to the scale of the City's Trigeneration Master Plan in relation to meeting peak electrical demand. If 80 per cent of installed trigeneration under the medium uptake scenario was considered to be "firm capacity" – that is, could be called upon when required to meet critical peak loads – this would provide an offset of approximately 170 MW in 2020, or 400 MW in 2030.[39] (Note that this is higher than the 360 MW installed capacity in 2030 as it also accounts for offsetting electrical air conditioning load using waste heat from trigeneration.)

It is apparent therefore that while the City's plans for trigeneration may be sufficient to meet a notional gap in NSW energy supply in tandem with new renewable generation under the RET in 2020, they are highly unlikely to be sufficient to meet the peak demand growth requirements for the entire state. However, if combined with additional energy efficiency and peak load management (or "Demand Side Response"), these resources could make a significant contribution to meeting NSW's current projected peak demand capacity shortfall.

It should be emphasised that these comparisons are for illustrative purposes only, in order to highlight the significant scale of the City's plans. There is, of course, no reason to suggest that the developments in the City of Sydney alone should be expected to meet the entire State's emerging energy needs. Nevertheless, these comparisons highlight the degree to which distributed energy options, even in one small geographic area, could contribute to meeting the community's future energy needs.

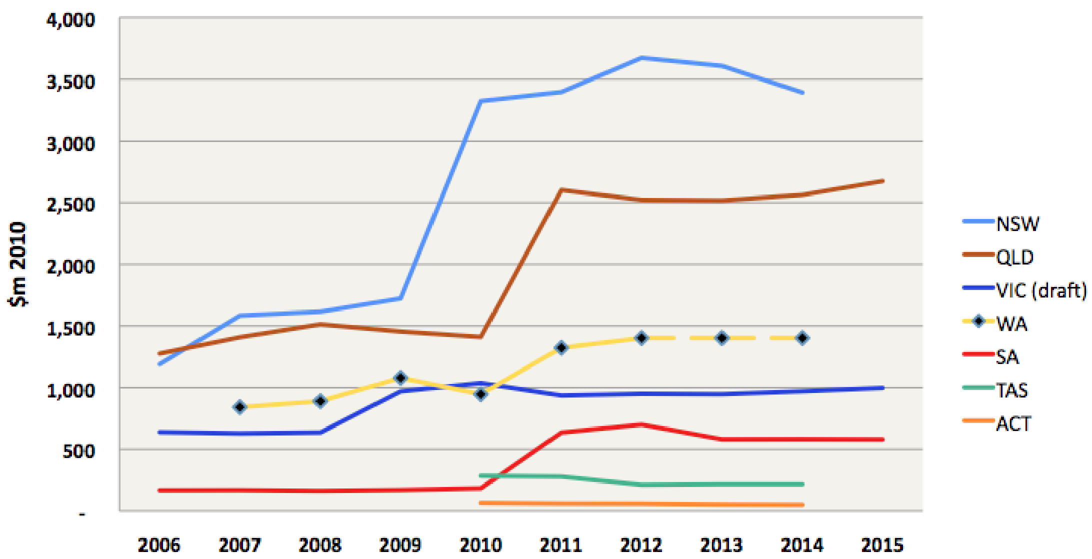
[38] Figure source: AEMO, 2010. *Electricity Statement of Opportunities*, Fig. 7-3 p.150.
[39] Based on modelling data from Kinesis, October 2010.

3. Network expenditure review & potential savings

Capital Expenditure on Electricity Networks

The network expenditure approved for investment in the City of Sydney's LGA is part of a larger and unprecedented nationwide trend of increasing capital expenditure on electricity network infrastructure for both transmission and distribution. This national growth trend is illustrated in Figure 9, which shows the regulator-approved network capital expenditure by jurisdiction. All of the major states shown demonstrate a significant jump in this expenditure from 2009-2010 onwards.[40] Over the period 2009-2015 this dramatic increase in investment totals more than $46 billion (in $2010), or more than $9 billion per annum. This level of expenditure is larger than that of the proposed National Broadband Network and occurs over a shorter period of time.

Figure 9 – Electricity Network Capital Expenditure (Transmission & Distribution) by Jurisdiction, 2006-2015[41]



Of this $46 billion, NSW accounts for $17.4 billion, or approximately 38 per cent of the total national expenditure. To place this value in context, $17.4 billion value represents:

- an 80 per cent increase on the previous five years;
- $2,400 per person in NSW; or
- $9.3 million per day.

Table 2 shows the breakdown of the $17.4 billion of approved spend for NSW by utility (converted to $2010) from 2010-2014.

[40] Where a dashed line is shown, this indicates a basic extrapolation by the authors, to better align the regulatory periods.
[41] Data sources: AER decisions and network business regulatory proposals (see sources for Table 2); Insufficient data available for Northern Territory.

Table 2 - NSW Final Approved Capital Expenditure by Electricity Network Businesses, 2010-14 (converted to $2010 millions)[42]

Utility	Type	2010	2011	2012	2013	2014	TOTAL
Energy Australia	Distribution	1,168	1,322	1,467	1,420	1,468	**6,846**
	Transmission	272	180	253	330	203	**1,238**
	Sub-total	1,440	1,502	1,720	1,751	1,671	**8,084**
Integral Energy	Distribution	589	638	568	517	495	**2,807**
Country Energy	Distribution	738	781	801	803	822	**3,946**
TransGrid	Transmission	557	476	585	537	404	**2,558**
TOTAL	**T&D**	**3,323**	**3,397**	**3,674**	**3,608**	**3,393**	**17,394**

The City's submission to the Australian Energy Regulator (AER), quoted figures from the AER Draft Determination, citing Energy Australia's plans for $7.38 billion capital expenditure for *distribution* infrastructure during the 2009-2014 regulatory period. The figures presented in Table 2 represent a reduction in allowed expenditure between AER's draft and final decisions of 8 per cent for Energy Australia, or 5 per cent for NSW as a whole.

Avoidable "Growth-Related" Investment

The key component of this figure is the proportion that is potentially avoidable through a different approach to electricity system planning. To estimate this sub-component of total network spend, it is necessary to define what is considered "avoidable". The three major drivers of electricity network investment are:

1. Replacing aging network infrastructure;
2. Growth in electricity demand at peak times due in large part to growth in the use of electrical services such as air conditioning; and
3. Increased reliability standards imposed by governments on electricity utilities (refer to box on next page entitled "What is the cost of an hour of power?").

It is the second (and perhaps to a lesser extent the third)[43] point that efforts to reduce electricity demand – particularly at peak times – can avoid investment in network infrastructure. ISF has defined avoidable network capital expenditure firstly as only the component of total approved capital expenditure that relates to the network (as opposed to other capital expenditure items such as vehicles and IT), and secondly only that network expenditure which is related to demand growth. Implicit in this definition is that reducing demand on existing electricity infrastructure will not yield any cost savings unless capacity constraints are observed and *new* infrastructure is avoided.[44]

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[42] Data Sources: AER, above n17, Tables 7.16, 7.17 & 7.18; AER, *Transgrid Final Transmission determination 2009–10 to 2013–14* (28 April 2009), Table 2. An average annual inflation rate of 3.13% has been applied based on 2005-06 to 2008-09 Consumer Price Index Figures for the Weighted Avg of 8 Capital Cities (ABS, *Consumer Price Index*, December Quarter 2009, p.10).

[43] While the *driver* of this investment is not strictly "growth-related", it is considered avoidable in that reducing peak demand could prevent the new lower investment thresholds from being triggered.

[44] Note it is generally considered that the replacement of ageing infrastructure cannot be classed as avoidable. It should be noted that reducing demand on energy infrastructure can be expected to extend the life of assets and therefore reduce the need to replace infrastructure. However, due to the difficulty in quantifying this impact, these cost savings have *not* been considered here.

What is the cost of an hour of power?

How much do electricity consumers value a 0.01 per cent improvement in reliability of electricity supply? The answer is implied by Government regulations and is perhaps in the order of several hundred million dollars. This figure reflects the often unrecognised cost of improving electricity reliability, which demonstrates rapidly increasing cost and rapidly diminishing returns on investment as the electricity system approaches 100 per cent reliability.

For the past 10 years the reliability of the NSW electricity system has remained around 99.97 per cent. To put this reliability level in perspective, in 2009 NSW had the second *best* electricity reliability of all States and Territories, behind only South Australia. This is illustrated in the SAIDI[45] outage figures shown in Figure 10 (noting that a lower figure represents less power outages per customer).

Figure 10 – SAIDI (power outages) by jurisdiction, 2009[46]

While NSW's average reliability level might sound impressive, very high reliability is appropriate, particularly in an area such as Sydney, a global city with a high concentration of high value adding businesses, government, hospitals, transport hubs, and telecommunications. Loss of electrical supply to the Sydney CBD, as occurred for over two hours in March 2009, can be extremely disruptive and expensive.

So while there can be no debate that high reliability is desirable, there can and should be debate about the means of ensuring this reliability and the cost of doing so.

The NSW State Plan contains a target to "achieve average electricity reliability for NSW of 99.98 per cent by 2016",[47] representing an improvement of 0.01 per cent

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45 System Average Interruption Duration Index (SAIDI)
46 Data source: Energy Supply Association of Australia. 2010. *Electricity Gas Australia*. Table 1.4, p.8.
47 NSW State Government, *NSW State Plan: Investing in a Better Future*, pp. 22, 65.

reliability. This translates to 30 per cent shorter total blackout periods during year, or around 53 minutes less blackout time per annum for the average customer. While the cost of achieving such an incremental improvement in *an unreliable electricity system* would be relatively small, the cost of raising reliability criteria by this level in NSW has significant implications for required works and associated energy prices. Amongst other requirements, this commitment requires Energy Australia to raise reliability criteria in the Sydney CBD from '*n-1' to 'n-2'* by 2014.[48] This new *n-2* criteria means that power must remain on even if the largest two power supply lines or transformers to the CBD fail at the same time (as opposed to one for *n-1*). Other areas are also required to upgrade from "*n*" to "*n-1*". Along with peak demand growth and replacement of aging infrastructure, this is one of the major drivers behind Energy Australia's record investment in the Sydney CBD electricity network, which is costing at least $800 million (in the form of the CityGrid project) or up to $2.2 billion when counting other projects in the Sydney east and inner city area.

Without detailed information and analysis, it is impossible to provide a precise estimate of how much meeting the higher reliability standards is costing. However, it is possible to make an indicative estimate based on some reasonable assumptions. Taking an average EA demand of about 3,200 MW and a cost of say $1 billion (13 per cent of EA's approved capital expenditure) to reduce outages by one hour per year, this equates to about $300,000 per MWh. If this investment were to ensure this improvement in reliability for say 10 years, then the cost of this reliability improvement is about $30,000 per MWh or $30/kWh. This is more than 150 times the current average cost of electricity of about $0.18/kWh.

This raises two obvious questions:

1. Are customers willing and able to pay 150 times the average price of power for an extra hour of reliable electricity supply each year?
2. Are there less expensive means of delivering an equivalent improvement in reliability (for example, a combination of local generation, energy efficiency and peak load management)?

While answering these questions is outside the scope of this report, they are crucial questions that need to be examined. In particular, it is crucial to understand better the potential and the costs of trigeneration, energy efficiency and load management in improving reliability of electricity supply and to compare this with network infrastructure solutions.

The AER determination breaks down network expenditure from other capital expenditure for each utility, and then generally reports the growth related component as either 'augmentations' or 'growth-related' expenditure. 'Augmentations' are driven by demand growth and are considered avoidable, by reducing consumption or locating "embedded generators" within the network close to the point of electricity consumption. 'Growth-related' expenditure generally includes 'augmentations' *plus* the cost of new customer connections, which is generally not considered avoidable as

[48] EnergyAustralia, *EnergyAustralia Regulatory Proposal 2008*, p.36.

this relates to providing new access to electricity (e.g. new meters and low voltage lines to premises).

The NSW AER determination primarily presents 'growth-related' capital expenditure and not the sub-category of augmentations, which is shown in Table 3 below.[49] For Energy Australia, new customer connections appear to account for around 16 per cent of growth-related capital expenditure,[50] while reported Integral Energy and TransGrid figures already exclude customer connections. Country Energy's customer metering costs appear to be less than 2 per cent of growth-related capital expenditure,[51] but there is insufficient information available to say conclusively.

Thus while the figures in Table 3 include slightly more than augmentations alone, there is additional planned capital expenditure to meet more stringent service requirements (classed separately as in the determination as 'reliability', 'service enhancement' or 'compliance obligations') that are considered avoidable similar to augmentations. These categories add up to an additional $2.5 billion over five years. Thus even if a small fraction of this category was avoidable this would outweigh the customer connections component discussed above, suggesting the figures shown in Table 3 are reasonably conservative.[52]

Table 3 – NSW growth-related network capital expenditure (converted to $2010), peak demand growth and calculated "Avoidable cost per MW"[53]

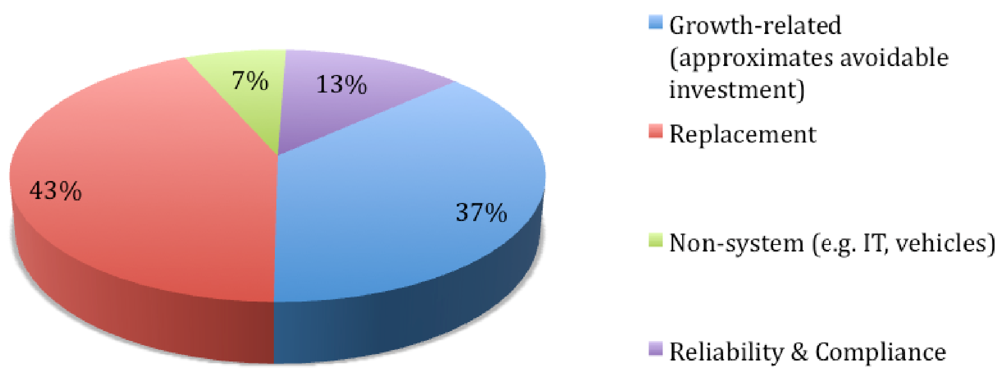
Network business	Avoidable "growth-related" capital expenditure ($m 2009-10)		Peak demand growth (MW)		Avoidable cost per MW	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum	($m/MW)	
Country Energy	$1,461	$292	323	81	$3.62	1
Energy Australia	$3,281	$656	689	172	$3.81	2
Integral Energy	$1,388	$278	643	161	$1.73	3
Distribution Total	$6,130	$1,226	1655	414	$3.05	
TransGrid (transmission)	$2,075	$415	1740	435	$0.95	4
Total	**$7,589**	**$1,518**			**$4.01**	5

1. AER, NSW Draft distribution determination 2009–10 to 2013–14. p.135, p.85
2. AER, NSW Draft distribution determination 2009–10 to 2013–14, p. 136, p.88.
3. AER, NSW Draft distribution determination 2009–10 to 2013–14. p.137, p. 91. This figure does not include customer connections.
4. AER, Transgrid Draft Transmission determination 2009–10 to 2013–14, p. 16, p.34 (10% POE). This figure does not include customer connections.
5. Peak demand cannot be totalled as Transgrid's peak load includes that of the distributors

[49] The draft determination was used for these figures as the breakdown of growth-related expenditure was not presented in the AER Final Determination.
[50] AER, New South Wales Draft distribution determination 2009–10 to 2013–14, p. 136.
[51] Country Energy's Regulatory Proposal 2009-2014, p.91.
[52] These figures also do not account for the potential to reduce planned investment in areas where network infrastructure is being retired and replaced with new equipment, by reducing the future load on the system in that location after replacement (i.e. replacement with smaller capacity equipment).
[53] Table adapted from: Jay Rutovitz & Chris Dunstan. 2009. *Meeting New South Wales Electricity Needs in a Carbon Constrained World,* Institute for Sustainable Futures, University of Technology, Sydney, p.21.

As shown in Table 3, it is estimated that in **NSW there is up to $7.6 billion of approved network capital investment that is 'growth-related',** including $3.3 billion to be spent by Energy Australia. **Much of this new investment could potentially be deferred or avoided if peak demand growth was slowed through measures such as energy efficiency, peak load management and decentralised or local energy generation.** When this $7.6 billion growth-related capital spend is divided by the amount of peak demand growth driving this investment as shown in Table 3, this equates to an incremental avoided network cost of $4 million for each MW of growth in peak capacity avoided (i.e. $4 million per MW).

Figure 11 – Approximate breakdown of Energy Australia $8.1b network capital expenditure, 2010-2014[54]



As a strategically placed network of distributed generation (or energy efficiency) has the ability to reduce or eliminate growth in peak demand, it can thereby be utilised to delay or "defer" planned growth-related network investment. To determine the value of this contribution to the electricity network, we need to calculate the annual value of "deferral" of the construction of network infrastructure by one year. This was done using the following three steps:

- **Step 1:** take the "Avoidable cost per MW" of $4.0 million per MW (Table 3) and multiply this by the real weighted average cost of capital (WACC) of 6.31 per cent per annum.[55] This gives an annualised capital cost of $0.26 million per MW for each year of deferral achieved; then
- **Step 2:** Calculate the avoided cost of depreciation by assuming a uniform depreciation over a 40-year lifespan of network infrastructure (i.e. 2.5% per annum), yielding a figure of $0.10 million per MW per annum.
- **Step 3:** Add these two values together to give a total annualised cost of growth-related network investment of $0.36 million per MW per annum.[56] However, in recognition of the fact that network costs are location dependent, the analysis adopts a lower, more conservative value of **$0.3 million per MW per year** as the annual value of deferring network investment.

[54] Data source: approximated from AER, above n50, Figure 7.4 and pp.135-7. Note that the Final Determination was not used as this did not break down expenditures to an adequate level of detail.
[55] 8.78% nominal WACC less 2.47% inflation from AER, above n17, p. 237.
[56] The WACC represents the opportunity cost of *not* investing capital in infrastructure, and depreciation is included as this is considered as an "avoided loss".

In other words, if distributed generators or energy efficiency service providers were allowed to "capture the value" of this deferred investment, it could be worth up to $0.3 million per MW per annum (or $300 per kW per annum). Where appropriate, there is a strong argument that this value of avoided network cost (or an appropriate portion of) should either be directly invested by network business in their own distributed energy assets, or be passed on to distributed energy service providers, allowing this value to be factored into the business case of these technologies.

Electricity network expenditure in the City's LGA

Of Energy Australia's total $8.1 billion planned capital expenditure (Table 2), a significant proportion is being invested in the Sydney CBD to meet load growth and enhanced reliability of supply requirements. The status and value of these projects, totalling approximately $2.2 billion, are shown in Table 4 below. Based on limited publicly available information it appears that approximately $0.5 billion of these funds have been spent or committed, and over $1.5 billion remains to be spent under the CityGrid project over the next decade.

According to Energy Australia's Managing Director, it is likely that *another* $8 billion of investment in its network will be required from 2014 to 2019,[57] similar to the $8.1 billion being invested from 2010-2014. This would essentially mean that the level of increases in network charges currently being felt by consumers are likely to continue for the remainder of the decade. Yet this assumes that the business-as-usual electricity demand growth continues, and thus reducing this growth through demand management (energy efficiency, distributed generation and load management) remains the only promising way to slow these price increases.

If we were to assume that just 10 per cent of the remaining $1.5 billion investment was deferrable through demand management, and given that Energy Australia assumes a summer peak growth of the CBD of around 15 MW per annum,[58] this equates to an incremental avoidable network work cost of $10 million per MW, or more than double the NSW average of $4 million per MW calculated earlier. Thus, even if a small fraction of this remaining $1.5 billion investment in the City's local government area is deferrable, then using the average NSW deferral value could be considered conservative. The NSW average figure is used later in this report to calculate avoidable network costs attributable to the City's trigeneration plans.

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[57] Australian Financial Review, *EnergyAustralia has its own hefty bill to pay*, 1 September 2010.

[58] EnergyAustralia, 2008. *Sydney CityGrid Project Concept Environmental Assessment Report*, Vol 1, Section 2.4. Avail from http://www.energyaustralia.com.au/Common/Network-Supply-and-Services/Network-projects/Sydney-CBD-and-East/Sydney-CityGrid-Project/~/media/Files/Network/Network%20Projects/Sydney%20CBD/SCGvol1ch2.ashx

Table 4 – Energy Australia and TransGrid Projects Underway or Planned in (or servicing) the City's Local Government Area

Region	Project	Value ($m)	Driver	Timeframe	Deferral possibility	Summer pk growth rate
CBD	City North zone substation	83	Demand; Reliability	Completion end 2009	No (sunk)	11-15 MVA/yr
	City West Cable Tunnel	180	Demand; Reliability	Completion end 2009	No (sunk)	
	Sydney CityGrid	~800	Demand; Reliability; Replacement	2008-2018	Varied	
	- Belmore Park zone substation	180	Demand; Reliability	Completion in 2012	Limited (committed)	
	- City East zone substation	22	Demand; Replacement	Completion mid 2010	Limited (committed)	
	- Surry Hills switching station	499	Demand; Reliability	No information	Some potential	
	- City South and Dalley Street substation upgrades					
	- City South Cable Tunnel extension					
	- 11kV network upgrades					
	- Rozelle to Pyrmont cable project					
	- Other components					
Inner City	Camperdown zone substation Refurbishment	12	Demand; Replacement	2010-2012	Limited (committed)	
	Surry Hills subtransmission substation equipment replacement	5	Replacement	Planned for 2011	No (replacement)	
	Botany Bay Cable Project	110	Demand; Replacement	Completion late 2010	No (sunk)	100 MVA/yr
	Other unaccounted for projects	1012		No information	No information	No information
Trans Grid	Beaconsfield West Substation Upgrade	144	Demand	Commence mid-2010	Some potential	37.5 MVA/yr
	Sydney South Substation Upgrade	15	No information	No information	No information	No information
TOTAL		**2261**				

Notes: Table constructed by ISF based on information on or inferred from http://www.energyaustralia.com.au/Common/Network-Supply-and-Services/Network-projects/Sydney-CBD-and-East.aspx and http://www.transgrid.com.au/projects/projects/Pages/default.aspx . Available information was limited and as such these figures are only intended to provide a broad estimation of the status of network projects in the City's LGA.

Potential network savings through trigeneration

The methodology for costing of network deferral value discussed above can be applied to the City's planned Trigeneration Master Plan, to compute the potential value of avoidable network investment. This does not reflect a cost benefit analysis from the network perspective as only the network *benefits* are represented here, while the *costs* associated with connecting distributed generators to the electricity network are not included.

Using the conservative value of \$0.3 million per MW (or \$300 per kW) developed above, Table 5 calculates the potential avoidable network cost per year of deferral in 50MW increments from 50 to 500MW.

Table 5 – Annual avoidable investment through trigeneration (\$m p.a. for each year of deferral)

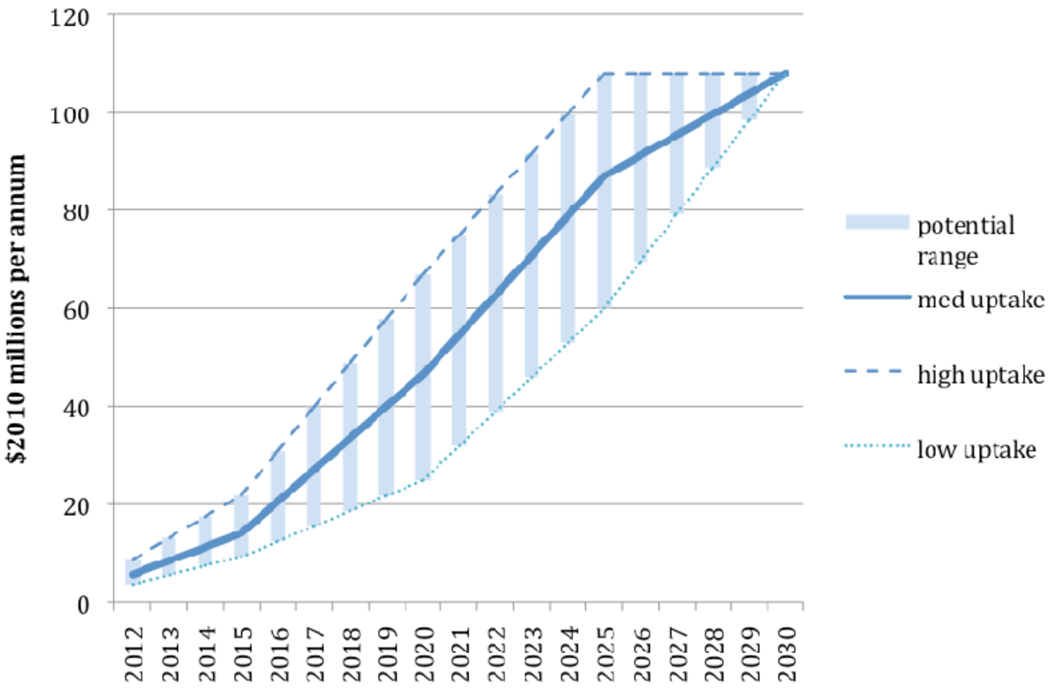
Trigen Capacity (MWe) [59]	Avoidable network investment (\$2010 m p.a.)	Planned timeframe (med uptake)
50	15	2016
100	30	2018
150	45	2020
200	60	2023
250	75	2024
300	90	2026
350	105	2030
360	108	2030
400	120	-
450	135	-
500	150	-

Taking the information from Table 5 and applying it over the planned development timeframe of the City's low, medium and high trigeneration uptake scenarios then allows the visualisation of the annual avoided network cost that would be achieved through the City's trigeneration network, as shown in Figure 12. This is a value that the City (or private trigeneration operators) could argue should be contributed by the network operator for network support services. The dark blue line represents the medium trigeneration uptake scenario, which is bounded by the dashed low and high uptake scenarios.

In the year 2015 – the beginning of the next regulatory period – an installed trigeneration capacity of 47 MW (under the medium uptake scenario) would equate to an allocation for trigeneration-related network support services of \$14 million.

[59] megawatts electrical

Figure 12 – *Annual* avoided network costs at different trigeneration uptake rates [60]



As shown in Table 6, increasing *annual* network deferral payments commensurate with installed trigeneration capacity would result in a *cumulative* total of $39 million in 2015 (medium uptake scenario), $207 million in 2020, or upwards of $1 billion by 2030.

Table 6 – Total potential allocation for trigeneration network support (cumulative $m 2010)

Year	Cumulative trigen capacity (MW)	Total allocation for network support ($m 2010) (medium trigen scenario)
2015	47	39
2020	155	207
2025	290	561
2030	360	1,059

Key peak periods for distributed generation

The peak demand in the Sydney Inner Metropolitan Area typically occurs on hot summer working weekdays between midday and 6pm, which includes the period from mid November to mid March, but excluding the holiday period from 24 December to mid January.[61]

[60] Based on trigen uptake data provided by the City of Sydney.

[61] *EnergyAustralia & TransGrid, Demand Management Investigation Report, Sydney Inner Metropolitan Area, November 2009, p.4;* TransGrid, *Request for Proposal Number: 105 /09, Non-Network Alternatives in the Sydney Inner Metropolitan Area, Technical and Commercial Requirements*, December 2009, p.16.

Energy Australia states that if demand management options such as trigeneration, load management, standby generation or energy efficiency are to be successful in relieving a network constraint and thereby defer network investment, they are required to be available on call on any given day during the aforementioned peak summer period to effectively reduce load on the system:

- for a maximum of *3.5 continuous hours* (this figure is for the first year of constraint – 2012/13 – and increases to a period of 6.5 hours by 2014/15).
- and for a maximum of *21 hours in total,* which would be spread across different days during the full summer period (this figure is also for 2012/13, and increases to a maximum period of 78 hours in 2014/15).[62]

These “maximum” figures above are given due to the unpredictable timing of peak demand and constraints on the electricity network, which generally occur on high temperature days when air conditioning demand is greatest.

In other words, if a trigeneration facility was to be paid for deferring a network investment, it could enter into contract with Energy Australia to supply power according to the conditions described above. From Energy Australia’s perspective the provider would thus only need to guarantee to operate for up to 21 hours in total across the summer of 2012/13. However, from a business perspective, for such a facility to be financially viable it would be more likely to operate for as many hours as possible.

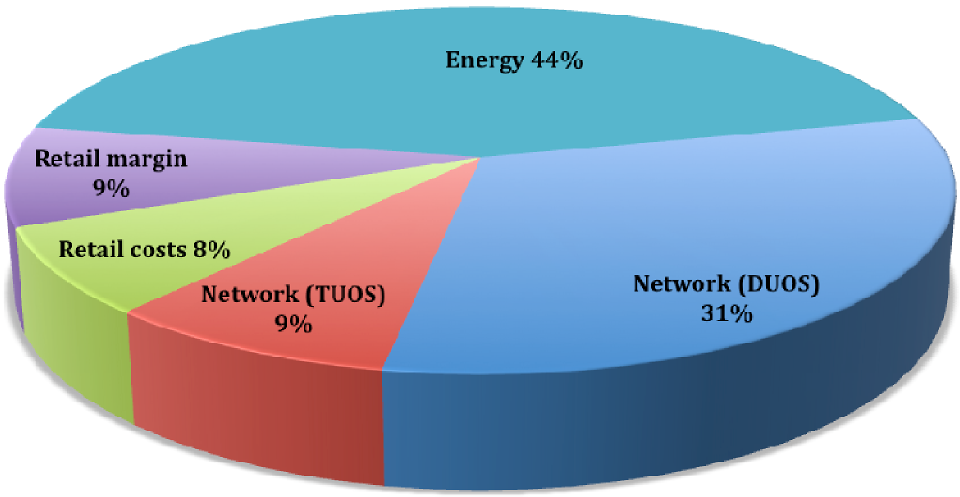
[62] TransGrid, above n61, p.17.

4. Impact of network expenditure on electricity prices

The AER determines how much network businesses are able to charge in order to recover the cost of spending on infrastructure and other expenses. In NSW, the Independent Pricing and Regulatory Tribunal (IPART) also currently sets regulated retail tariffs that incorporate these regulated network charges. Although the NSW Government (along with other Australian governments) has committed to phasing out retail electricity price regulation completely where “effective competition exists”, in March 2010 the IPART issued its determination for the (optional) regulated retail electricity tariffs which will be in place for consumer protection until at least 2013.[63] This determination gives an indication of the breakdown of customer tariff components and outlines the price impacts of the AER’s final determination for NSW.

Using IPART and AER data as a starting point, Figure 13 provides an indication of the breakdown of a typical low voltage customer tariff such as a household or small business. It suggests that transmission (TUOS) and distribution (DUOS) network charges make up around 40 per cent of each unit of electricity delivered to the customer, the actual energy component is 44 per cent and the remainder retails costs and profit margin. Note that the “capacity charge” component of network charges (charged per kilovolt ampere [kVA] of demand instead of per kilowatt hour [kWh] of energy used) is not explicitly shown in Figure 13. However, as an indication, these costs are in the order of 20 per cent of the total network charges for large business consumers, while residential customers using under 40 MWh/a are generally not subject to capacity charges.

Figure 13 – Indicative breakdown of typical household customer tariff in 2008-09 before the impact of the AER’s Final Determination[64]

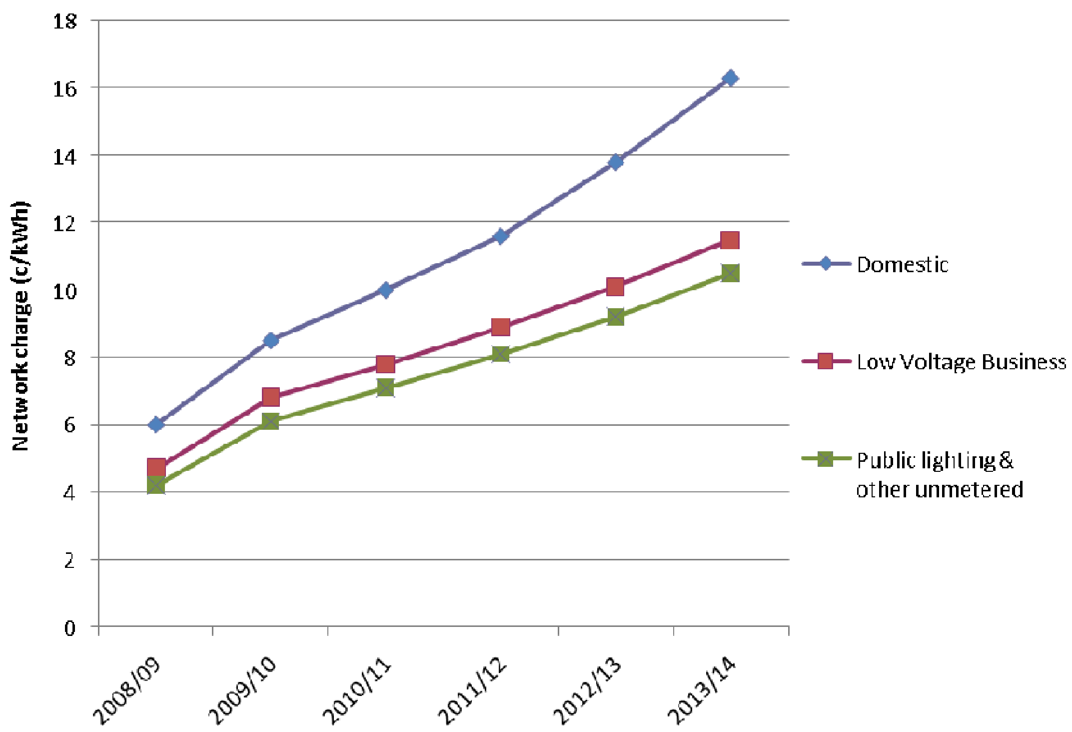


[63] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity — Final Report*, March 2010.
[64] Data source: Modified from IPART, above n63. Effect of carbon price removed; DUOS/TUOS division added based on expected revenues of distribution vs. transmission businesses as found in AER Final Determinations (78/22 split); relative proportion of each component back-calculated to 2010 based on EnergyAustralia price component increases contained in IPART Table 1.1; and 18c/kWh rate assumed to approximate typical regulated low voltage customer tariff.

The AER's Final Determination results in a nominal increase in Energy Australia's average network charges (the navy and red components in Figure 13 above) of almost 100 per cent over the next five years and up to 172 per cent for domestic customers.[65]

Figure 14 provides an indication of the magnitude of increase of network charges. Transgrid's price path for its transmission charges is also following an upward trajectory, with 25 per cent increases over the same period.[66]

Figure 14 – Energy Australia Indicative Network Charges by Customer Type[67]



According to IPART, this increase in network charges (along with much smaller contributions in energy and retail components)[68] will result in average increases in the regulated Energy Australia retail tariffs of 22 per cent in 2009/10 and around 10-11 per cent per annum in subsequent years, as shown in Figure 15. While the IPART determination does not extend beyond 2012/13, the AER's 5-year determination suggests similar price increases of roughly 10-11 per cent would also occur in 2013/14, as indicated by the dashed lines shown in Figure 15. This increase would bring the total nominal rise in average Energy Australia electricity prices to around 83 per cent across the 5-year period of the AER determination, as shown by the red line.

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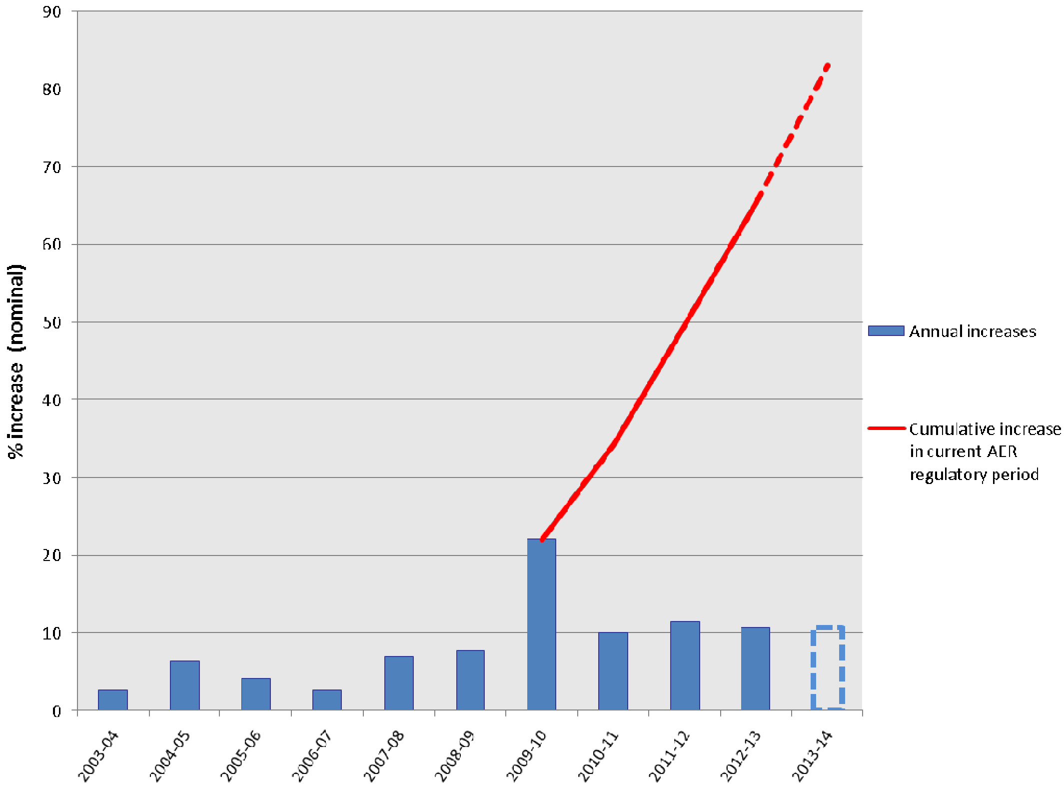
65 AER Final Determination, p. xlviii

66 AER, *TransGrid transmission determination 2009–10 to 2013–14*, 28 April 2009, p.125.

67 Data source: EnergyAustralia, *Revised Regulatory Proposal and Interim Submission*, January 2009, p. 190.

68 Increases in network charges account for 86% of EnergyAustralia price rises in the IPART 2010-13 determination (IPART, above n63, Table 1.2).

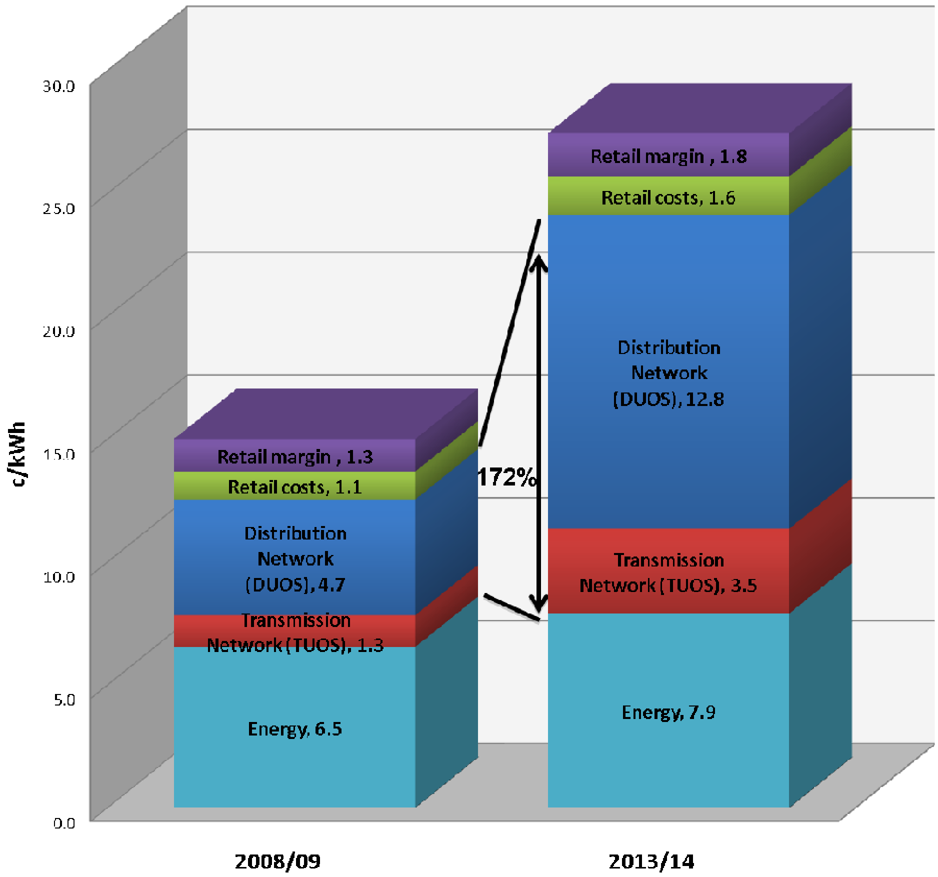
Figure 15 – Nominal increases in Energy Australia average regulated retail tariffs, 2003/04-2013/14[69] (dashed line indicates projection)



As a result of proportionally greater increases in network investment, in 2013/14 the proportion of consumer bills made up by network charges becomes far more significant, surging from 40 per cent to almost 60 per cent of the total average bill.[70] This impact is demonstrated in Figure 16 below, which shows the different components making up a typical residential household tariff in cents per kWh before and after the 5-year period relating to the AER determination. Note the relatively small increase in retail and energy costs, while network charges increase by 172 per cent and make up the vast majority of the 12.5c/kWh increase from 15c/kWh up to around 27.5c/kWh. (The numbers in Figure 16 represent the total 83 per cent cumulative nominal increase over the 5-year period flowing on from the AER's Final Determination shown in Figure 15.)

[69] Data source: IPART, above n**Error! Bookmark not defined.**, p.167. 2013/14 is authors' simple projection of continued investment trend of preceding three years based on data from AER Final Determination, above n17, p.144.
[70] in the absence of a carbon price.

Figure 16 – Indicative breakdown of Energy Australia regulated household tariff in 2008/09 & 2013/14, showing significant increase in network charge components[71]



To show full extent effect of resulting from the AER Final Determination on consumer bills, we need to track prices for the full 5-year period of AER approved capital spending. That is, from 2008/09 before the price increases took effect, to the final year of the determination, 2013/14. To do this we extend the analysis in the IPART 2010 determination forward by one year to 2013/14 (in the same way as Figure 15 and Figure 16) and take account of the 22 per cent price increase from IPART's previous determination. This suggests that the nominal increase in electricity bills for a typical Energy Australia household customer consuming 5.6 MWh p.a. would increase by $760 p.a. by 2013/14, (from $916 to $1,677 p.a). For business customers consuming 20 MWh p.a. this would represent an increase of $3,022 p.a., (from $3,638 to $6,660), or if consuming 80 MWh p.a. would represent an increase of $13,225 p.a. from $15,918 to $29,143 p.a. Figure 17 and Figure 18 below illustrate these price increases by typical customer type.

[71] Data source: Modified based on data from IPART, above n63. Effect of carbon price removed; DUOS/TUOS division added based on expected revenues of distribution vs. transmission businesses as found in AER Final Determinations (78/22 split); relative proportion of each component back-calculated to 2008/09 based on EnergyAustralia price component increases contained in IPART Table 1.2 adjusted for 6c/kWh network charge in 2008/09 (EnergyAustralia, above n67, p. 190); 15c/kWh rate assumed to approximate typical 2008-09 residential tariff.

Figure 17 - Indicative annual bills for typical Energy Australia residential customers in 2008-09 & 2013-14 ($nominal, incl. GST)[72]

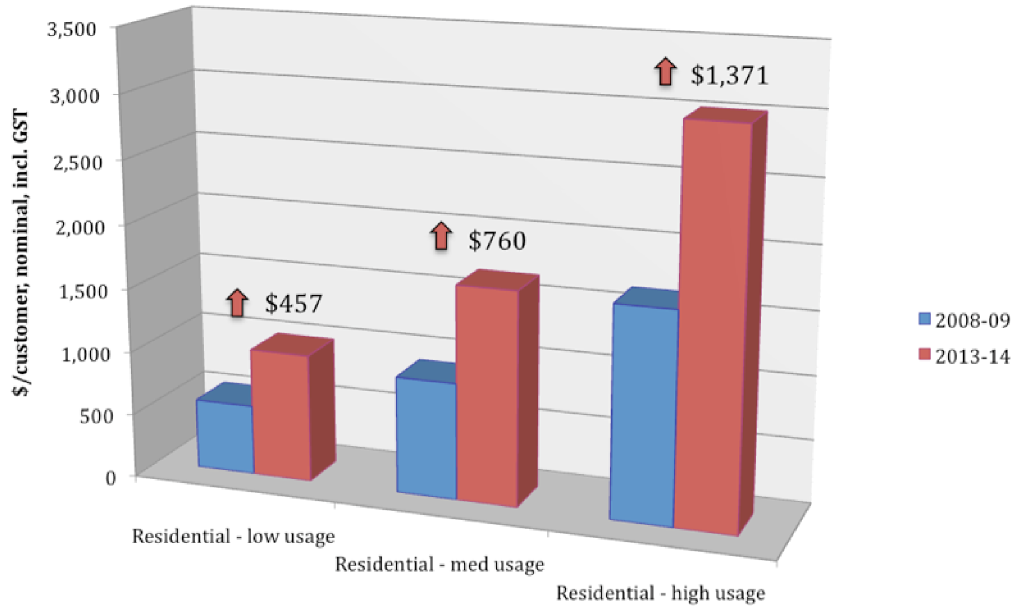
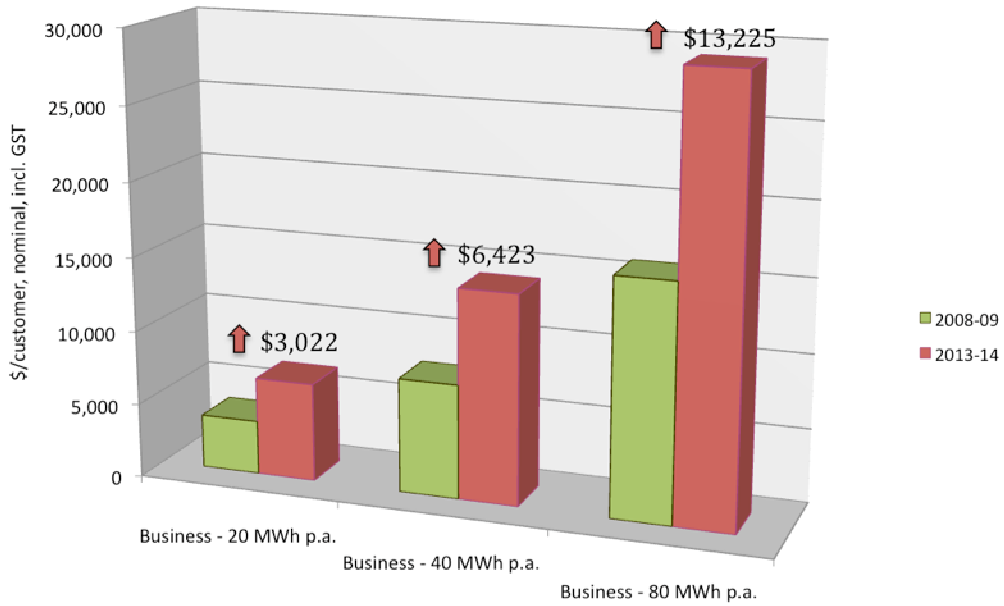


Figure 18 - Indicative annual bills for typical Energy Australia business customers in 2008-09 & 2013-14 ($nominal, incl. GST)[72]



[72] Data source: Modified from IPART, above n63, Table 11.4, p.172 (2008-09 back calculated from 2009-10 using stated 22% increase; 2013-14 projected from 2012-13 applying average annual increase of 10.67%).

5. Required regulatory changes & the role of the City

Engaging with regulatory reform is an essential component in fulfilling the City of Sydney's vision for a greener, more climate-friendly, more resilient and more self-sufficient energy future.

The City has joined other stakeholders in advocating for regulatory reform to encourage networks to support alternatives to network investment, such as decentralised generation, energy efficiency and peak load management (collectively described as "non-network alternatives" or "demand management"- DM). Regulators and policy makers have recognised and responded to this advocacy through measures such as:

The Australian Energy Regulator (AER) has established a Demand Management Incentive Scheme (DMIS) in NSW, albeit it small at $2 million per annum in addition to retaining the Demand Management Factor (D-Factor), which aims to counter regulatory disincentives to DM.

The AER has stated that DM should occur wherever it is economically efficient.

The AER has stated that investment in DM is permitted *in advance of* network capacity constraints occurring.

The AER has acknowledged that the transparency and reporting processes to ensure efficient DM is adopted are currently inadequate and has indicated that it intends to improve them through Regulatory Information Orders.

The AER has recognised that the absence of specific targets or policy objectives for DM has reduced its capacity to encourage investment in DM (particularly in comparison to other policy objectives for which specific standards have been established, such as for improved reliability).

- The Australian Energy Market Commission (AEMC) has made a series of recommendations (through its proposed national framework for electricity distribution network planning) to improve processes for distribution network business to support non-network alternatives such as trigeneration and demand management generally[73]. These recommendations include:
    - Stipulating a national annual reporting process on network planning to improve consistency;
    - Requiring distributors to develop a Demand Side Engagement Strategy; and
    - Developing a Regulatory Investment Test for Distribution (RIT-D) process which aims to facilitate efficient DM.

[73] AEMC, Review of National Framework for Electricity Distribution Network Planning and Expansion Sept 2009

http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-National-Framework-for-Electricity-Distribution-Network-Planning-and-Expansion html

The Ministerial Council on Energy (MCE) has endorsed the AEMC's recommendations and requested that the AEMC proceed to institute them as part of the National Electricity Rules.[74]

However, this regulatory reform has been modest and has yet to achieve a major increase in the adoption of DM in NSW. To achieve this, it is crucial that the City of Sydney, and other advocates for demand management and distributed energy continue to push for faster and wider reform of the electricity sector. Some of these areas of reform are outlined briefly below.

It should also be recognised that where network businesses face strong regulatory, governance and business capacity incentives to continue business as usual, simply removing barriers to DM may not be sufficient to stimulate rapid adoption of cost effective DM.

AER related reform

1. Form of Regulation

The form of price regulation for NSW electricity distribution networks for the period July 2014 to June 2019 is due to be decided by the AER by June 2012. This review process is therefore likely to begin within 12 months. The current "weighted average price cap" form of regulation rewards the distributors if consumers use more electricity from the main grid and penalises distributor if consumers use less electricity. It therefore is a significant barrier to the adoption of trigeneration and energy efficiency.

2. Monitoring and Reporting of DM performance

There is currently no consistent and comprehensive reporting of DM performance including outcomes, cost and benefits. The AER has undertaken to address this through a Regulatory Information Order (which as of October 2010 had yet to be developed). Follow through on this by the AER is important.

3. Assessment of potential for and relative economic efficiency of DM proposals

To date the AER has not effectively considered the potential scope for or relative cost effectiveness of DM in the context on network proposed expenditure. It is crucial that this shortcoming be addressed well in advance of the next regulatory determination (2015-2019).

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[74] Ministerial Council on Energy Standing Committee of Officials - Bulletin No. 184, MCE Response: AEMC Review of a National Framework for Electricity Distribution Network Planning and Expansion 8 Oct 2010 http://www.ret.gov.au/Documents/mce/_documents/2010%20bulletins/Bulletin%20No.%20184%20-%20MCE%20Response%20to%20AEMC%20Review%20Oct%202010.pdf

Other regulatory and policy reform

4. Putting a price on carbon

The uncertainty and inefficiency created by the absence of an effective and adequate national market price on greenhouse gas emissions is now very widely appreciated. The NSW Government has created a modest price on carbon through the innovative Greenhouse Gas Abatement Scheme (GGAS). A higher, more cost reflective carbon price is essential to provide a level playing field for trigeneration, demand management (DM) and other clean energy options. However, the transition to a fully cost reflective carbon price is likely to take many years. Until this occurs other regulatory and policy mechanism will be required to compensate for this distortion.

5. Setting a DM target (and measuring progress against it)

The Prime Minister's Task Group on Energy Efficiency has recognised the importance of targets in driving a national "step change" in energy efficiency.[75] The AER has also noted that the absence of policy or regulatory targets for DM have limited its capacity to encourage DM.

Such targets need not be legislated but must be backed by clear government commitment. DM targets can be mandatory and based on the "stick" of penalties for non-compliance, voluntary and based on the "carrot" of incentives, or some combination of the two. It is crucial to recognise that DM can deliver benefits not just to consumers and for the environment, but also enhance the operational and financial performance of the distributors themselves. Incentives to assist the distributors to identify, capture and highlight these benefits of DM, could be very effective in stimulating greater adoption of DM. In order to accelerate the adoption of DM and to demonstrate clearly its commitment to meeting DM targets, Government could offer additional financial incentives to distributors that perform well in approaching such targets. Such an approach may be described as a "collaborative target" that lies somewhere between the extremes of "voluntary" and "mandatory" targets.

A good example of setting targets in this context is the approach adopted in Ontario, Canada. Through its "Energy Conservation and Demand Management Program" which sets overall targets of peak demand reduction of 1,330 MW and energy savings of 6,000 GWh per annum between 2011 and 2014.[76] The individual targets for each distributor will be developed in consultation with the distributors themselves.
The Queensland "Energy Conservation and Demand Management Program" described below also includes specific DM performance targets[77].

[75] Australian Government, 'Report of the Prime Ministers Task Group on Energy Efficiency, July 2010, www.climatechange.gov.au/~/media/submissions/pm-taskforce/report-prime-minister-task-group-energy-efficiency.ashx

[76] Ontario Executive Council, *Decree No. 437/2010* March 2010, http://www.powerauthority.on.ca/Storage/118/16586_minister_directive_20100423.pdf

[77] Queensland Government, *ClimateQ: toward a greener Queensland Fact Sheet Energy Conservation and Demand Management Program*, 2009. http://www.climatechange.qld.gov.au/pdf/factsheets/1energy-b1.pdf

6. Establish a DM Fund

Until the above reforms are fully implemented, a dedicated fund to support DM and Trigeneration can be an effective tool. Such a fund must be secure, well targeted and managed, extend over a period of at least several years and include transparent performance reporting. Such a fund should be made available to as wide a range of parties as possible, including distribution businesses, and be allocated on the basis of expected and actual performance and cost effectiveness in delivering DM.

There are many precedents for such a fund both in Australia and overseas. For example, the State Electricity Commission of Victoria's $55 million three-year Demand Management Action Plan announced in December 1989 (SECV, 1991), remains one of Australia's biggest DM programs.

The $200 million NSW Energy Savings Fund was established in 2005 with an explicit focus on DM, partly in response the 2002 IPART *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services.* The primary recommendation of this inquiry was the establishment of a "Demand Management Fund" (IPART 2002). However, the DM focus of the Energy Savings Fund has since been blurred with its merging into the Climate Change Fund.

More recently, in its 2009/10 State Budget, the Queensland Government committed to provide $47.7 million to its two distribution network businesses, Ergon Energy and Energex "to initiate a range of energy conservation and demand management measures designed to reduce peak electricity demand in Queensland" (Queensland Government, 2009a). This *Energy Conservation and Demand Management Program* was planned to cease after 2009-10 when it is expected that the measures are to be continued by the distributors as part of their regulated activities (Queensland Government, 2009b). The AER subsequently included proposed DM expenditure of about $221 million by Energex and Ergon Energy as part of its regulatory determination for the period 2010/11 - 2014/15[78],[79]. This represents the largest commitment to DM in Australia to date.

Beyond this, the AER has also made modest provisions for some DM with the continuation of the "D-Factor" scheme in NSW, and the "DM Innovation Allowances" (DMIAs) established in NSW & ACT ($11.5 million over five years),[80] South Australia ($3 million over five years),[81] Queensland ($10 million over five

[78] Australian Energy Regulator, *Queensland distribution determination 2010–11 to 2014–15 Final decision*. May 2010, p. 292 http://www.aer.gov.au/content/item.phtml?itemId=736403&nodeId=371a320444f322cb7b9e3f01d8212690&fn=Queensland%20distribution%20decision.pdf

[79] Energex, *Regulatory Proposal for the period July 2010 – June 2015*, July 2009, http://www.aer.gov.au/content/item.phtml?itemId=729492&nodeId=d389e8d1cfd43fe80a60287c29bc209c&fn=Energex's%20Regulatory%20Proposal%202010-15.pdf

[80] Australian Energy Regulator, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations: Demand management innovation allowance scheme*, November 2008, http://www.aer.gov.au/content/item.phtml?itemId=723848&nodeId=73bf57627acf693dd91c48caa4d70b0a&fn=Guideline%20-%20Replacement%20DMIA%20for%20ACT-NSW%20(28%20November%202008).pdf

[81] Australian Energy Regulator, *South Australia distribution determination 2010–11 to 2014–15 Final decision* May 2010 http://www.aer.gov.au/content/item.phtml?itemId=736345&nodeId=3554008b804b9019e53df0ac3f8b2313&fn=South%20Australian%20decision.pdf

years),[82] and proposed for Victoria ($10 million over five years).[83] Western Australia has also established a D-Factor mechanism.

However, the scale of such funds in Australia remains relatively small. In total, the aggregated level of annual expenditure on DM is likely to represent significantly less than 1 per cent of total annual expenditure on electricity supply in Australia.

[82] Australian Energy Regulator, *Queensland distribution determination 2010–11 to 2014–15 Final decision.* May 2010, p. 292 http://www.aer.gov.au/content/item.phtml?itemId=736403&nodeId=371a320444f322cb7b9e3f01d8212690&fn=Queensland%20distribution%20decision.pdf

[83] Australian Energy Regulator (AER 2010c), *Victorian electricity distribution network service providers Distribution determination 2011 - 2015 Draft Decision*, June 2010 http://www.aer.gov.au/content/item.phtml?itemId=736991&nodeId=1822051ac603ac047389b47cc147e492&fn=Victorian%20distribution%20draft%20decision%202011-2015.pdf

Appendix:

AER's response to City of Sydney's Regulatory Proposals

The Australian Energy Regulator (AER) is responsible for regulating electricity network charges, including reviewing the prudence of networks' proposed capital expenditure. In its submission dated 16 February 2009, based on the Institute for Sustainable Futures' research, the City made some overarching and ten specific recommendations to the AER for consideration in its Final Determination for network price regulation for NSW and ACT for the period 2009/10 to 2013/14.[84] The AER response to each of the City's proposals is summarised in Table 7, followed by a brief summary of each recommendation, the full wording of the AER response and a brief comment.

Table 7 – AER Responses to City of Sydney recommendations in its Final Determination[85]

City's Recommendation		AER Response
General	Facilitate major investment in demand management (DM)	Under current environment, investment in DM should occur wherever it is economically efficient; Demand Management Innovation Allowance (DMIA) in Draft Decision is sufficient DM incentive.
1	Explicitly encourage distributors to invest in cost effective DM	Networks are already required to consider DM & DNSP's have operational independence to best manage their network spending
2	Report on greenhouse emissions implications	Outside AER responsibility
3	Support open, competitive transparent processes	AER is developing Regulatory Information Order (RIO).[86] See also 5 below.
4	Set targets for demand management outcomes	Beyond AER responsibilities (but have advocated to NSW Govt)
5	Require reporting on DM	DMIA and D–factor schemes already require DNSPs to report on the outcomes of DM projects, but may be improved though RIO being developed.
6	Allow early investment in demand management	This is allowed.
7	Assess DM potential	AER will consider more general discussion and engagement; see also AEMC Review.
8	Remove barriers for re-assigning customers to tariff classes, esp. with respect to Time-of-Use tariffs	Current wording does not create barriers.

[84] Recommendation 11 related to other SSROC raise issues regarding public lighting.
[85] AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14,* 28 April 2009.
[86] As of October 2010 this process was not yet complete (AER pers comm., email, 12 October 2010).

City's Recommendation		AER Response
9	Ensure distributed generators receive full benefit of avoided TUOS and distributors are not disadvantaged in this process	Not explicitly addressed.
10	Report on the full network & retail price implications of its determination	AER does not make judgements on the overall 'reasonableness' of prices that result from its decisions.

General recommendation – Facilitate major investment in demand management

AER Responses: "The AER is an economic regulator, limited in its role to applying and enforcing the NER. The NER provides some scope for the AER to develop and apply incentives for DNSPs to consider demand management, however only where demand management is the most economically efficient response to a network constraint" (p.262)

"The AER considers that the allowance provided under the DMIA will provide a sufficient incentive for each DNSP to further develop their demand management initiatives and capabilities over the next regulatory control period." (p.258)

"In determining the appropriate amount of capex and opex for each of the NSW DNSPs over the next regulatory control period, the AER has considered the extent that the NSW DNSPs have considered and made provision for, efficient non-network alternatives, as required by clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the transitional chapter 6 rules." (p.263)

Comment: Essentially the AER suggests that it is only empowered to require utilities to investigate DM where it is economically efficient, which it believes already occurs under the current regulatory environment. Further, it restated that it ruled that the allowable value of direct support published in the draft decision ($1m p.a. for Energy Australia) was sufficient. Hence no further support for DM can be seen in the Final decision relative to the Draft decision. This is a disappointing response, which equates to the suggestion that the current arrangement for DM is performing adequately.

Recommendation 1. Explicitly encourage distributors to invest in cost effective DM

AER Response: "The NER [already] requires that DNSPs consider alternatives to network augmentation, including demand management, when determining potential responses to network constraints…AER's approval of capex and opex does not limit a DNSP's operational independence to best manage their network, including in making decisions to trade network augmentation for efficient demand management." (p.264-5)

Comment: This suggests that the AER sees its role as not to *encourage* demand management *per se*, but to ensure that it occurs where it is economically efficient. The AER considers this objective to be met by Chapter 6 of NER.

Recommendation 2. Report on Greenhouse emissions implications

AER Response: "While it takes into account the policy environment in which its decisions are made, including environmental policies and debates, the NER requires that the AER creates incentives for the DNSPs to make economically efficient business decisions, rather than decisions which preference environmentally efficient outcomes." (p.262)

Comment: The AER sees greenhouse reporting as external to its mandate and a matter for other parts of government. Its role, as stated in the NER, is strictly to deliver economically efficient outcomes. There is thus scope through a Rule Change Proposal to broaden the mandate of the AER.

Recommendation 3. Support open, competitive transparent processes

AER Responses: "the AER is currently developing a [Regulatory Information Order] RIO for DNSPs, which is proposed to include public reporting on demand management programs and expenditures" (p.265)

"The AER is in the process of developing regulatory information notices (RINs) for the NSW DNSPs to report on their incentive schemes (such as demand management) for 2009-10. Following collection of the regulatory information, the AER expects to be in a position to develop a report that publishes relevant regulatory information/performance for the NSW DNSPs. For regulatory reporting arrangements from 2010-11 onwards, the AER expects to issue RINs to the DNSPs to collect the regulatory information (accounts and schemes)."[87]

Comment: There is hope that the RIO being developed by the AER will require better information disclosure and attention to DM issues by utilities.

Recommendation 4. Set targets for demand management outcomes

AER Responses: "The AER has previously considered the differences between its role and the role of the California Public Utilities Commission in relation to demand management.[88] The recommendations made by the City of Sydney in relation to California refer to broader policy decisions which go beyond the AER's responsibilities in respect of applying chapter 6 of the NER to the NSW DNSPs." (p.265)

Comment: This issue is perceived by the AER to be outside its responsibilities, however the AER has advocated to the NSW Government in support of this concept.[89]

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[87] AER, pers comm., email, 12 October 2010.

[88] The AER also stated in relation to the issue of target setting similar to California, that it has previously considered the differences between its role and the role of the California Public Utilities Commission in relation to demand management in the documents AER, *Explanatory statement and proposed demand management incentive scheme to apply to Energex, Ergon Energy and ETSA Utilities over the 2010–15 regulatory control period*, June 2008, pp. 19-20 and AER, *Final decision—demand management incentive scheme—Energex, Ergon Energy and ETSA Utilities, 2010–15,* October 2008, p. 16.

[89] AER, pers. comm. 2009.

Recommendation 5. Require reporting on DM

AER Responses: "The AER's DMIS for NSW DNSPs, consisting of the DMIA and D-factor schemes, requires DNSPs to report on the outcomes of demand management projects in order to be eligible for demand management cost recovery under those schemes." (p.264). See also comment under Recommendation 3 on RIO development above.

Comment: The AER suggests that there is a level of reporting on DM already required, but indicates that this may be improved in future through the RIO.

Recommendation 6. Allow early investment in demand management

AER Response: This was responded to directly in the Final Determination but the implication of the existing arrangements is that there is no restriction on when utilities invest in demand management.

Comment: While in principle there may be no regulatory impediment, there is anecdotal evidence that distribution businesses are reluctant to invest in DM early in advance of network constraints due to concerns that such expenditure may be deemed imprudent by the AER. Further clarification and dialogue between distributors, the AER and DM service providers on this issue would be valuable.

Recommendation 7. Assess DM Potential

AER Response: This was not specifically responded to in the Final Determination. However, during a meeting between ISF and the AER it was noted that the AER would consider more general discussion and engagement on this issue.

Comment: There was some level of acknowledgement that there is a need to a make a high level assessment of where DM could be efficiently adopted for the purposes of cross-referencing the effectiveness of the current regulatory environment around DM.

Recommendation 8. Remove barriers for re-assigning customers to tariff classes, especially with respect to Time-of-Use (TOU) tariffs

AER Response: "Section 5 of the AER's proposed procedures set out in appendix A of the draft decision was not intended to apply a restriction on the circumstances in which a reassignment can take place. The AER considers that it is not necessary to make any changes to the section because the language of the section does not impose any limits, or state that it sets out the only circumstances, in which a reassignment can occur." (p.23)

Comment: The AER reviewed draft wording in response to this comment and considered that it does not impose such restrictions.

Recommendation 9. Ensure distributed generators receive full benefit of avoided TUOS and distributors are not disadvantaged in this process

AER Response: This issue was not addressed.

Recommendation 10. Report on the full network & retail price implications of its determination

AER Response: "Regarding the comments…on the various other issues affecting users' energy costs, the AER does not have any explicit powers to consider or make judgements on the overall 'reasonableness' of prices that result from its decision, nor to make associated adjustments to regulated revenues. The AER has assessed each element of the NSW DNSPs' regulatory proposals and revised regulatory proposals without any preconceived notion of what might be regarded as acceptable price increases." (p.310)

Comment: The AER believes that this issue is beyond the scope of AER's final decision. This represents a flaw in the current system, as once the AER makes this decision, State based regulators such as NSW's Independent Pricing and Regulatory Tribunal (IPART) whose job *does* involve determining reasonableness, have no power to overturn or amend a decision made by the AER. This is an issue (in addition to environmental considerations) on which the City could campaign for amendment to the scope of AER's mandate.

Summary

In summary, the AER Final Determination document contains little in the way of direct support for demand management outside the elements of the Demand Management Incentive Scheme (DMIS).

The biggest concern is that the general position of the AER in response to the City's requests is that the AER believes that the framework for promoting economically efficient DM is *already in place*. This is despite the fact that mandated investigations of DM seldom actually result in DM being undertaken,[90] and there is no systematic mechanism to assess the overall effectiveness of the regulatory framework. If the regulatory framework is assumed to function effectively, then this would suggest that there is in fact very little to no cost-effective DM that can be used to defer or avoid network capital expenditure. This is contrary to international experience such as that of California, and local research findings by ISF and others.[91] This could represent either or both a failure of procedural enforcement of effective undertaking of DM studies by networks, or an issue associated with the design of the assessment process itself, such as inadequate lead time of assessments to deliver DM of sufficient scale to avoid large network investment.

Nonetheless, there are also positive elements that can be drawn from the AER's Final Determination, which include:

1. That network businesses, such as Energy Australia, may choose how to spend its revenue and does not have to spend it all on network expansion. Any savings made through DM are retained by the network businesses, giving some incentive to act;

[90] In only 5 out of 80 cases where DM has been considered to address network constraints has a project been authorised. See http://www.energyaustralia.com.au/Common/Network-Supply-and-Services/Demand-Management/Program-progress-tracking.aspx

[91] See for example, Langham, E., Dunstan, C., Walgenwitz, G., Denvir, P., Lederwasch, A., and Landler, J. 2010, *Reduced Infrastructure Costs from Improving Building Energy Efficiency*. Prepared for the Department of Climate Change and Energy Efficiency by the Institute for Sustainable Futures, University of Technology Sydney and Energetics.

2. That network businesses can recover both DM program costs and forgone revenue through the continuation of the "D Factor" mechanism; and
3. The $1 million per annum Demand Management Innovation Scheme (DMIS) to support less proven DM approaches.