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MANAGEMENT PLAN 2011

DEMAND MANAGEMENT

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			Reviewed by	BD
			Approved by	MJIG

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1. PURPOSE

The purpose of this document is to describe, for demand management:

- Aurora's approach to demand management, as reflected through its legislative and regulatory obligations and Network Management Strategy;
- The key demand management projects and programs underpinning its activities for the period 2012/2013 – 2016/2017; and
- Forecast CAPEX and OPEX, including the basis upon which these forecasts are derived.

2. STRATEGY

The objective of the Network Management Strategy is:

> *To minimise cost of supply to the customer whilst:*
>
> 1. *Maintaining network performance;*
> 2. *Managing business operating risks; and*
> 3. *Complying with regulatory, contractual and legal responsibilities.*

3. SCOPE

This document covers the framework of plans to manage expected demand on the network by implementing cost effective non-network initiatives that are balanced against efficient supply side/network solutions.

4. DEMAND MANAGEMENT

As stated by the Australian Energy Regulator (AER):

> *Demand management refers to implementation of any strategy to address growth in demand or peak demand.*[1]

The following non-network alternatives to supply side augmentation may provide effective strategies to manage the demand on the network:

- Embracing demand side management, i.e. managing the customer's peak demand on the system;
- Utilising embedded generation in the network (both on the customer side and on the network side, and includes storage solutions);
- Supporting energy efficiency initiatives to reduce demand;
- Installing automated load transfer systems to optimise the configuration of the network during peak demand; and
- Adopting system optimisation methodologies, such as dynamic ratings based on real-time thermal measurements.

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[1] ACCC/AER, *Final Framework and approach paper Aurora Energy*, November 2010

4.1 Objective

The objective of the implementation of demand management to address growth in demand or peak demand is to:

- Curtail peak demand on the distribution and transmission networks;
- Improve utilisation of distribution and transmission network assets;
- Reduce system augmentation capital expenditure;
- Address specific network limitations by reducing localised demand;
- Provide time to develop additional options to address network limitations; and
- Deliver an understanding of changing customer energy need and usage behaviour.

4.2 Background

Managing the network demand rather than continual investment in network capacity is increasingly becoming a viable means of delivering the goal of minimising the cost of supply to customers.

A network is expected to convey energy to its customers all year round. Network investment must be based on the event where the cumulative requirements of multiple customers combine to create the highest point demand the network must supply, known as the coincident maximum demand (CMD). Where this CMD is significantly higher than the average demand, assets tend to be poorly utilised, and therefore the cost of supply to the customer can potentially be higher than optimal.

Opportunity exists to work with a customer (or group of customers) to smooth their demand, thereby reducing asset size (and cost) and deferring augmentation investment. While there are a number of approaches possible, the general principle remains the same. If the demand profile can be made as smooth as practical, then the asset utilisation can be maximised, and the deployed capital can be minimised to service the customer.

4.3 Peak Demand

Peak demand on Aurora's network has historically occurred in the winter quarter with a strong correlation to the maximum daily temperature at the time of peak demand. That is, demand increases as temperature decreases.
The underlying drivers of peak demand on the distribution network drive the need for network infrastructure investment.

Peak demand of 1,022 MW on the distribution network occurred on Thursday 8th July 2010 at 8:30 am. This occurred on a day where the maximum daily temperature was higher (milder) than the long-term average. Using the temperature sensitivity coefficient for each connection point to adjust to the long-run average temperature, the temperature corrected peak demand was 1,095 MW.

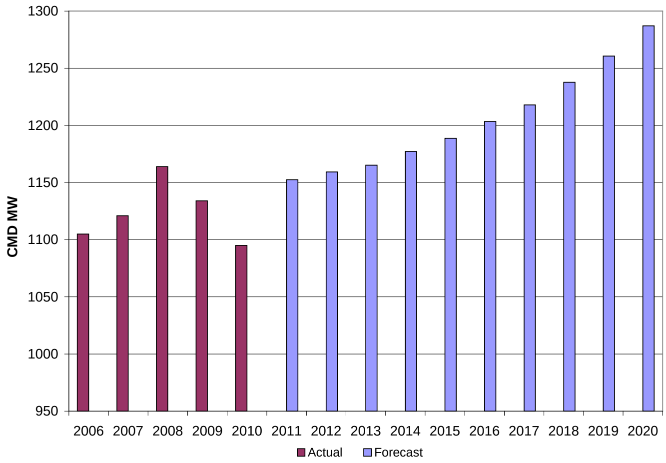

Figure 1: Temperature corrected System Coincident Maximum Demand

Continuation in demand growth based on historical trends and state econometric forecasts is presented in Figure 1.

4.4 Load Profiles

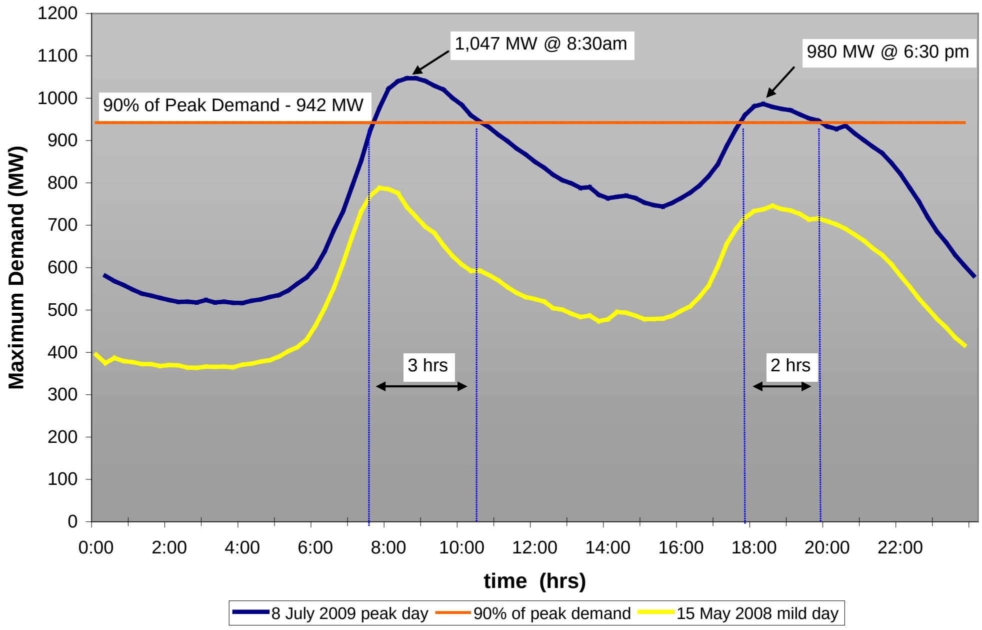

Figure 2: Aurora total system day load profile

Figure 2 compares the load profile of the 2009 total Aurora distribution network system peak day with a mild autumn weekday (15 May 2008). It shows that at the time of maximum system peak demand, the load on the system was some 250 MW higher than the load of a typical non-heating day. Most of this increase is attributed to temperature- sensitive space heating load in the residential and business sectors.

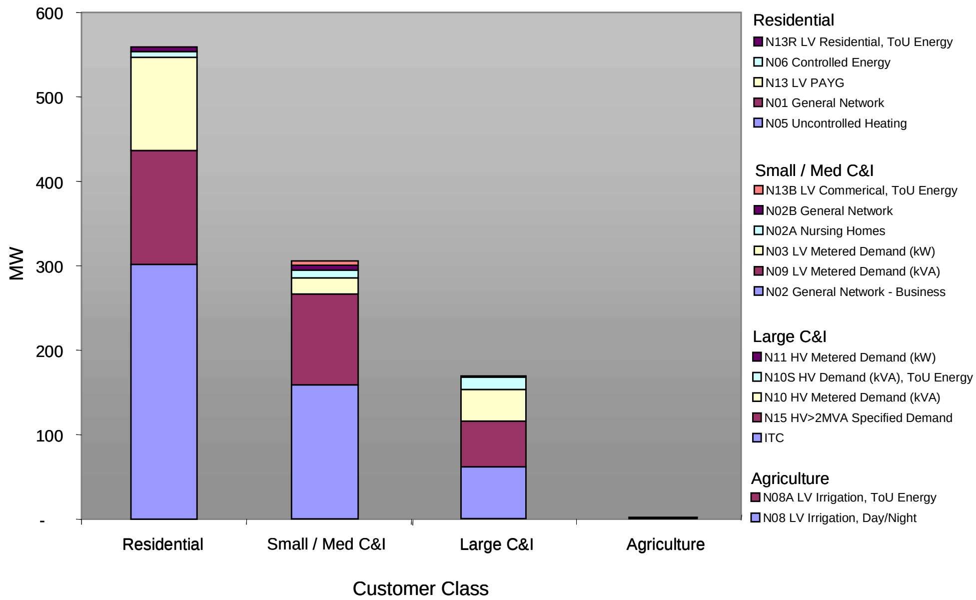

Figure 3: Customer & tariff class contribution to winter MD (8:30am 8 July 2009)

Figure 3 disaggregates the 2009 winter morning system maximum demand of 1,042 MW into the customer and tariff classes that contribute to the peak. The residential sector is estimated to have accounted for 560 MW (or 54%) of the winter system maximum demand. Of this, space heating and water heating loads supplied on the Uncontrolled Energy N05 tariff are estimated to account for 300MW (or 29%) of total system peak.

General light and power loads account for 135 MW (13%) while customers on the PAYG tariff are estimated to contribute 110 MW (11%) to the system peak. The tariff conditions of the PAYG tariff do not place restrictions on the types of end uses that can be supplied under the tariff and there will be space heating and water heating loads that are contributing to the system peak in addition to that under N05.

Small to medium commercial and industrial customers are estimated to contribute about 300 MW (or 29%) to the system peak. The large commercial and industrial customer sector, comprising mainly Individual Tariff Customers and customers on high voltage tariffs (contestable customers), is estimated to account for 170 MW (or 16%) of the system peak.

The agriculture sector, characterised as customers on the low voltage Irrigation tariffs, is estimated to account for less than 1% of the system peak. This is on the basis that irrigation loads will predominantly operate during the warmer months, and in off-peak periods.

A load profile for day of peak demand for the distribution network load on Transend's Kingston Substation is presented in Figure 4. The composition of load connected to this substation is typical of many of the Aurora distribution network connection sites to the transmission network.

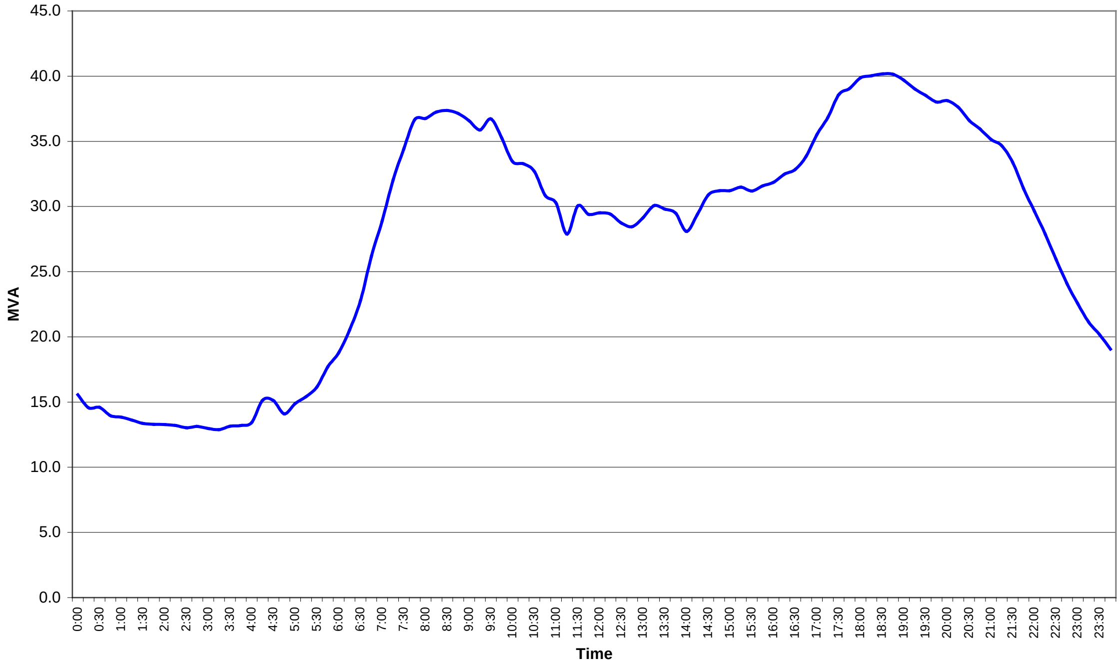

Figure 4: Load profile for Kingston Substation on 21 July 2008

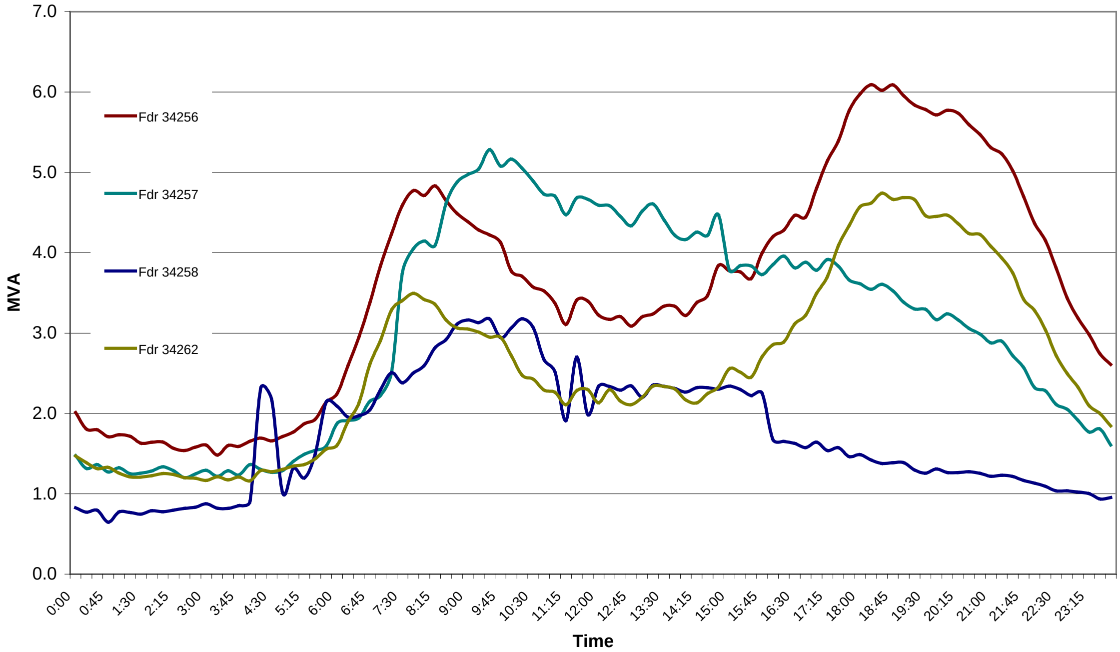

Figure 5: Load profile for four of the Kingston 11 kV feeders on 21 July 2008

Figure 5 presents load profiles for a sample of distribution high voltage feeders serving the Kingston general area. Feeders 34256 and 34262 serve residential loads in the Kingston Beach and Blackmans Bay areas, while feeders 34257 and 34258 serve commercial and retail loads in the Kingston business centre.

4.5 Load Duration

Figure 6 presents the results of a load duration analysis of the distribution network winter load for the winter period (1 June – 31 August) of the 2009 calendar year. The analysis indicates that the top 100 MW (or 10%) of the distribution network capacity was utilised for 66 hours (or less than 1% of the time).

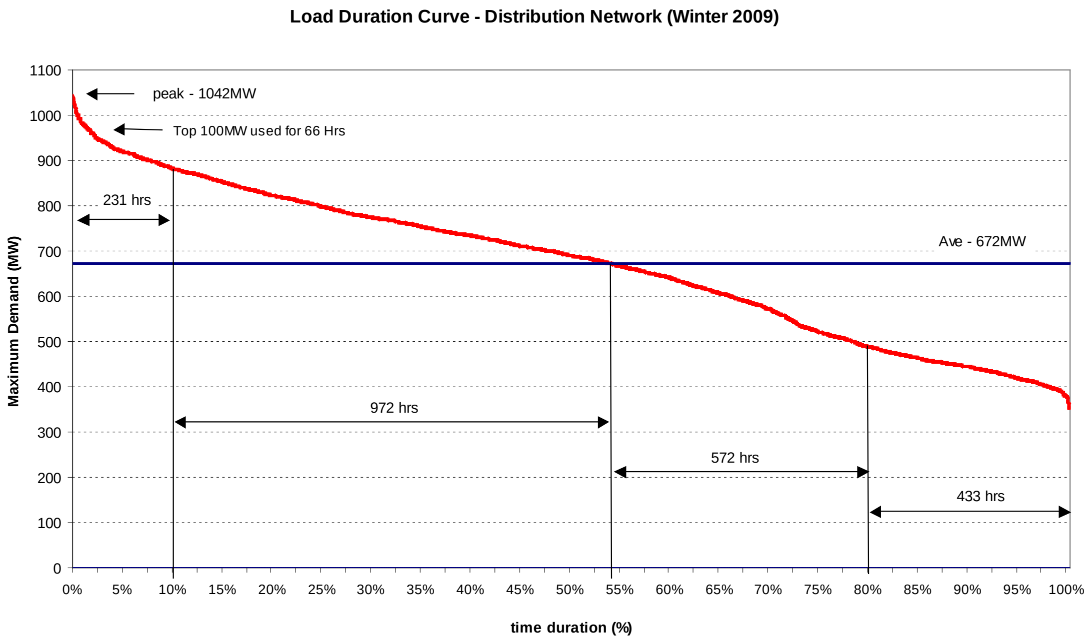

Figure 6: Load duration for Winter 2009

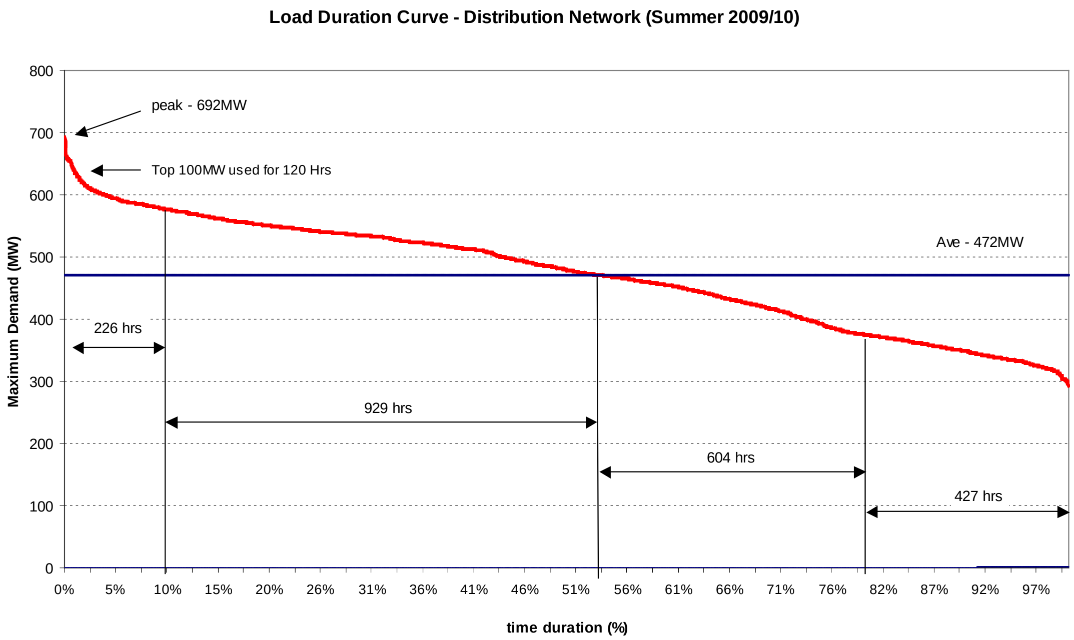

Figure 7: Load duration for Summer 2010

Figure 7 presents a similar picture to the winter load duration curve.

For the full year period of 1 September 2009 to 31 August 2010 the Load Factor (average demand divided by the maximum demand) was 48.9%, and the asset utilisation (maximum demand divided by installed capacity) was 34.3%.

4.6 Conclusion

The network infrastructure required, and its associated value, to serve 10% of the system peak demand for less than 1% of the time clearly indicates that the continued sole use of traditional network augmentation to deal with the short duration peaks is an expensive and sub-optimal strategy.

The level of asset utilisation clearly indicates that the capacity of the network exceeds requirements for a considerable period of time as is typical for electricity networks, while the load factor indicates that there is considerable opportunity to moderate the demand profile.

Non-network approaches, such as demand side management and distributed generation options, integrated as part of Aurora’s overall planning process, offer a far more cost effective strategy than continuing to allocate scarce capital to serve short duration peak loads.

Space heating and water heating loads are estimated to account for nearly 30% of the total system peak demand. Adopting non-network solutions to address the water heating and space heating contribution to peak demand will be a significant factor in delivering the Network Management Strategy objective of minimising cost of supply to the customer.

5. FACTORS INFLUENCING DEMAND MANAGEMENT STRATEGIES

Managing the network demand may be a viable alternative to investment in network augmentation, in turn, minimising the cost of supply to the customer. Strategies to reduce the demand (or growth in demand) need to be evaluated against network augmentation to determine the least cost way of addressing network limitations.

Maintaining network performance standards remains as a primary consideration in the evaluation of prospective non-network solutions.

The following is a brief description of the specific regulatory obligations directly influencing Aurora’s approach to demand management.

A list of the legislation, regulations, standards and codes of practices directly relevant to demand management is provided in section 11.

5.1 National Electricity Rules (Rules)

Clause 5.6.2(a) of the Rules requires Aurora to have regard to future demand side developments when analysisng the future operation of its distribution network.

Clause 5.6.2(b) of the Rules requires Aurora to consider the potential for non-network alternatives such as demand side and generation options when undertaking annual planning reviews in conjunction with Transend.

Clause 5.6.2(g) of the Rules requires that where analysis of the expected future operation of the transmission network or distribution network indicates that any relevant technical limits of the transmission or distribution systems will be exceeded; then Aurora must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test.

It is noted that the Australian Energy Market Commission (AEMC) has concluded its Review of National Framework for Electricity Distribution Network Planning and Expansion, and has prepared a Final Report and draft Rules which provide the following:

- A requirement that DNSPs establish and maintain a Demand Side Engagement Strategy;
- A requirement that DNSPs engage pro-actively with non-network providers in the development of potential solutions to system limitations that can be justified on economic grounds;
- A requirement that DNSPs publish a Distribution Annual Planning Report (DAPR) that includes reporting on non-network initiatives;
- That the current Regulatory Test be replaced with a new RIT-D project assessment process; and
- That the threshold for the RIT-D be set at $5 million, with non-network providers being able to investigate and propose alternative investment options that fall below the threshold through the Demand Side Engagement Strategy.

The Ministerial Council on Energy (MCE) supports the new planning arrangements being established in 2011 and commencing operation as soon as practicable thereafter.[2]

5.2 Regulatory Test

Promotion of economic efficient investment in the electricity network through the economic assessment of both network and non-network options to address network limitations is supported by clause 5.6.2(g) of the Rules:

> “Each *Distribution Network Service Provider* must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the *regulatory test*, while meeting the technical requirements of schedule 5.1, and where the *Network Service Provider* is required by clause 5.6.2(f) to consult on the option this analysis and allocation must form part of the consultation on that option”

Clause 5.6.5A (b) states the purpose of the regulatory test is to identify new network investments or non-network alternative options that:

(a) maximise the net economic benefit to all those who produce, consume and transport electricity in the market; or

(b) in the event the option is necessitated to meet the service standards linked to the technical requirements of Schedule 5.1 of the Rules or in applicable regulatory instruments, minimise the present value of the costs of meeting those requirements.

In addition, clause 5.6.2(f) of the Rules states:

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[2] MCE, *National Framework for Electricity Distribution Network Planning and Expansion – Response to Australian Energy Market Commission’s Final Report*, September 2010

> "the relevant *Distribution Network Service Provider* or *Network Service Providers* must consult with affected *Registered Participants*, *AEMO* and *interested parties* on the possible options, including but not limited to demand side options, *generation* options and *market network service* options to address the projected limitations of the relevant *distribution system* except that a *Distribution Network Service Provider* does not need to consult on a *network* option which would be a *new small distribution network asset*"

5.3 Electricity Supply Industry Act 1995 (ESI Act)

Aurora Energy's license, issued under the ESI Act, for the distribution of electricity within Tasmania requires the business to comply with the requirements of the TEC to safeguard the interests of Tasmanian consumers with regard to price, quality and reliability of electricity supply.

5.4 Tasmanian Electricity Code (TEC)

Aurora as a DNSP must submit to OTTER and publish annually, under clause 8.3.2 of the TEC, a Distribution System Planning Report that includes a description of feasible options for meeting forecast demand including opportunities for embedded generation and demand management.

Aurora as a DNSP has an obligation under clause 8.6 of the TEC that the tariff applicable to a customer or an individual contract with a customer connecting to the distribution network provides that the customer must comply with various conditions as set out in the TEC. Those conditions include but are not limited to such things as: access, protection of Aurora owned equipment, safe condition, interference to other customers, protection co-ordination, power factor, load balance and limitation of voltage fluctuation.

Clause 8.7 of the TEC sets out conditions related to the connection of embedded generation units.

Clause 8.8 of the TEC sets out the information to be included in tariff or individual contract conditions that the customer must supply on request for the purpose of planning the distribution system. Details include but are not limited to such things as: existing load profile, forecasts of load growth, and anticipated new loads.

5.5 AER DMIS for Aurora

The AER, in accordance with clause 6.6.3 of the Rules, developed and published a Demand Management Incentive Scheme (DMIS) applicable to Aurora for the regulatory control period commencing 1 July 2012.

The role of the DMIS is to provide incentives for DNSP's to implement efficient non-network alternatives, or to manage the expected demand for standard control services in some other way.[3]

In accordance with the AER's November 2010 framework and approach paper, the DMIS includes a Demand Management Innovation Allowance (DMIA) in the

[3] ACCC/AER, *Demand Management Incentive Scheme Aurora Energy*, October 2010

form of an annual ex-ante allowance of $400,000 provided as additional revenue for each year of the regulatory control period.

6. SELECTION

Non-network initiatives and the process to identify opportunities for non-network initiatives, such as demand side management, can be broadly categorised into broad based non-network initiatives and localised non-network initiatives to address specific network limitations.

Broad based non-network initiatives have been and continue to be identified through:

- Review of the system load characteristics to identify opportunities to modify, reduce or transfer the load at time of system peak demand; and
- Studies of identified non-network opportunities to determine realistic, cost effective broad based options that will provide system wide reductions in peak demand.

Non-network initiatives to address specific network limitations have been, and continue to be, identified through:

- Determination/identification of specific network limitations and risks through the analysis of the load forecast and system capability (principally identified in the Capacity Management Plan);
- Identification of network augmentation options; and
- Review of the network limitation and the identified network augmentation options with a focus on identification of possible non-network options (e.g. peak shaving generation, demand side management, etc).

Where cost effective non-network solutions are identified they are included in the Program of Work (POW) and the network solution either removed or deferred.

7. IMPLEMENTATION OF DEMAND MANAGEMENT

For the purposes of assessing the annual revenue requirement for each year of a regulatory control period, clause 6.5.6(e)(10) and 6.5.7(e)(10) of the Rules require, in addition to operating and capital expenditure, respectively, that the AER have regard to whether Aurora has considered, and made provision for, non-network alternatives.

This section of the management plan focuses on delivery of the initiatives and actions that have been identified to be undertaken in the period up to the end of the next regulatory control period (30 June 2017).

7.1 Demand Side Engagement Strategy

7.1.1 Background

In September 2009, the AEMC published its Final Report on recommendations to establish a national framework for electricity distribution network planning and expansion.

The framework seeks to provide direct requirements for DNSPs to provide planning information to interested parties, and provide sound economic cost-benefit criteria to proposed infrastructure investments.

Schedule 1 of the AEMC's Final Report contains proposed amendments to the Rules to provide for the proposed national framework, including the requirement to publish a Demand Side Engagement Strategy document, establishing and maintaining a public database of proposals and case studies, and maintaining a demand side engagement register.

The MCE supports progressing the proposed national framework through an AEMC Rule change process. With the new planning arrangements being established in 2011 and commencing operation as soon as practicable thereafter.

7.1.2 Implementation Rules requirements

Aurora has produced a draft Demand Side Engagement Strategy document that is to be refined to accurately reflect the Rules requirements following the implementation of the proposed Rule changes to adopt the national framework for electricity distribution network planning and expansion. A copy of the draft document is included in Appendix A.

The final version of the Demand Side Engagement Strategy document and supporting referenced documents is to be published on Aurora's website in accordance with the Rule requirements.

A project to develop a Register of Interested Parties and a Database of Proposals and Case Studies on Non-Network Solutions, based on formats used by ETSA Utilities, Energy Australia and Integral Energy on their respective websites, is to be established mid 2011.

It is currently anticipated that the Demand Side Engagement Strategy document and registers will be published towards the end of 2011.

7.2 Broad Based Programs

The following broad based programs include those that are proposed to be undertaken in the 1 July 2012 to 30 June 2017 regulatory control period:

7.2.1 Implementation of time of use tariffs and incentives to support residential and small business load response

Background:

Network tariffs are a key mechanism for encouraging a voluntary reduction in demand, recognising that there is a general lack of incentive for retailers to develop retail products which actively encourage customers to manage their contribution to peak demand.

Objective:

To facilitate customer voluntary demand reduction at time of peak system demand.

Projects:

Further development of Time of Use (TOU) tariffs over the next regulatory period through:

- Analysis of tariff performance; and
- Optimising price signals.

Implementation of an incentive based scheme in the residential and small business customer classes.

- Scheme to be modelled on the Energex/Ergon's 'Peak Rewards' trial
- Requires installation of type 5 NEM compliant interval meters;
- Small scale trial in 2011 that:
  - determines effective levels of demand threshold;
  - assesses incentive levels;
  - identifies customer issues; and
  - establishes a project framework for a larger scale trial.
- Following evaluation of initial trial, a two-year large-scale trial. The aim of this longer term trial will be to:
  - assess the effectiveness of customer initiated peak demand reduction;
  - optimise incentives; and
  - optimise network tariff pricing signals.

7.2.2 Rationalising tariff conditions and metering to facilitate water heating load control

Background:

Electric water heating is currently allowed under the tariff conditions to be connected to LV Uncontrolled Energy network tariff (N05). While Aurora offers a controlled load tariff (N06) the bulk of electric water heating load is supplied under the N05 and PAYG (N13) tariffs. Under this arrangement, electric water heating is a major contributor to the system peak demand.

Tariff conditions for non-contestable customers are subject to regulatory approval; the current approved retail tariff strategy doesn't expire until 30 June 2013.

Objective:

Reduce the contribution to growth in peak demand of electric water heating through re-alignment of a major contributor to peak demand to more appropriate cost reflective tariffs.

Projects:

Conditions to existing network tariff N05 to be changed to no longer allow new electric hot water heating units to be connected to this tariff from 1 July 2013.

Link to customer education program of alternative connection arrangements for electric hot water heating (off peak tariff) or alternate water-heating solutions.

7.2.3 Residential, small commercial and industrial new construction demand management

Objective:

To facilitate customer voluntary demand reduction at time of peak system demand.

Projects:

Development of a package of educational materials and information on options for demand management for new construction.

Linked to the implementation of an incentive based scheme in section 0, but focused on new construction.

7.2.4 Community and stakeholder engagement

Objective:

To date, Aurora has had only minor involvement in non-network demand management and embedded generation activities. As such customers in Tasmania are unlikely to have substantial knowledge of demand management and embedded generation initiatives, and the benefits these measures can provide in terms of cost efficiencies.

Creating a base level of awareness of these benefits will facilitate the design and implementation of trials and mass market initiatives.

Engagement with the community to gain support for non-network projects is seen as an important element in their success.

Projects:

A range of projects need to be developed to meet the objective of engaging with customers and other stakeholders (such as government agencies and industry service providers) so that they become actively aware of the relationship between the cost of addressing peak system demand and the price reflected in the electricity supply charges.

7.2.5 Trial of incentive based direct load control

Background:

Direct load control (DLC) involves the control of selective customer loads, at times of local or system wide network peak load, directly by the DNSP.

Objective:

To facilitate dynamic direct control of discretionary loads at times of peak demand.

Projects:

A pilot DLC evaluation trial that,

- Starts in 2011;
- Requires at installation of type 5 NEM compliant interval meters;
- Tests marketing approaches;
- Determines the level of customer incentives required to encourage participation in the program;

- Evaluates appropriate control technologies; and
- Used to develop detailed scope requirements, technical parameters and measurement criteria for a large-scale trial.

Following evaluation of the initial trial, undertake a two-year large-scale trial. The aim of this longer-term trial will be to:

- Assess the effectiveness of distributor initiated peak demand reduction;
- Trial technologies such as smart meters, programmable controllable thermostats (PCTs), in home displays (IHDs), and load control devices;
- Optimise control methodologies;
- Optimise incentives;
- Optimise network tariff pricing signals; and
- Provide the basis for the design of a large-scale peak load management program.

7.2.6 Trial to evaluate the impact of utilisation of LED[4] streetlight technology on system demand

Background:

New solid-state technology such as LED and LEP[5] lighting now exists to replace existing traditional street and road lighting methods. The principle advantages of the new Solid State Lighting (SSL) technology are reduced power consumption and extended life.

Projects under this program would be supported through DMIA funding.

Objective:

To assess demand reduction and cost benefit of introducing to Solid State Lighting (SSL) technology to street lighting applications.

Projects:

Develop partnership with local councils and DIER for trials.

A series of evaluation trials across a range of road lighting formats:

- Major road lighting installation;
- Civic lighting installation; and
- Urban street lighting installation.

7.2.7 Development of a curtailable/distributed generation program with large commercial and industrial customers (C&I customers)

Objective:

To develop procedures and capability for contracting load reductions and utilisation of embedded/standby generation from large C&I customers.

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[4] LED - light emitting diode

[5] LEP - light emitting plasma

Projects:

Development of a framework of demand side response contracts & embedded generation network support agreements.

Several curtailable load and embedded generator projects are included in the location specific programs in section 7.3.

7.2.8 Power factor correction program

Background:

Poor power factor at system level leads to under utilisation of distribution assets. Improving the power factor both at customer installations and at the distribution feeder level provides a direct means of optimising the capability of the distribution network and reducing network losses.

Objective:

To improve the utilisation of existing network assets by improving the system power factor.

Projects:

Reinforcement of the requirement that customer installations meet the power factor requirements as defined in the TEC.

Undertake a study with the objective of identifying the potential for installation of power factor correction, within the LV network and customer installations, in areas where system power factor is poor due to aggregated customer loads that on an individual basis potentially meet TEC requirements. It will also gather information on whether there is opportunity to substantiate a case for improving power factor beyond code requirements. This study has been listed in Table 2 as a DMIA funded project.

7.2.9 Institutional partnership trial

Objective:

The institutional segment includes primarily public sector customers such as state and local governments, schools and higher learning institutions, hospitals, and police, and fire departments. The focus of this trial would be to create an ‘energy partnership’ with a public sector customer to generate peak demand reductions, and energy cost savings, through municipal retrofits, and community outreach.

Projects:

Undertake a trial that would seek to develop community specific educational and marketing materials and outreach programs to enhance participation in a suite of measures including load control of water heating, renewable energy technologies, and energy efficiency programs.

This project has been listed in Table 2 as a DMIA funded project.

7.2.10 Fuel substitution

Objective:

To identify whether there is a case to support the further rollout of the natural gas network in areas that have electricity network capacity limitations, to facilitate the transfer of heating load to alternate energy sources, and thereby reduce peak demand on the network.

Projects:

Liaison to be undertaken with interested parties, such as natural gas distributors, with the objective of:

- presenting information in relation to capacity constraints in the network;
- evaluating opportunities to develop the natural gas distribution network; and
- evaluation of opportunities to install embedded generation.

7.2.11 Large scale peak load management program

Objective:

To curtail or shift discretionary loads at times of peak demand.

Projects:

Supported by results of DLC and Demand Response trials, to prepare a business case and project plan to undertake a system wide load management program.

7.2.12 Aurora staff training

Objective:

To raise the awareness of internal staff, including field personnel, of demand management concepts and Aurora’s strategic direction in relation to demand management.

Projects:

Development and presentation of training packages for internal staff, starting mid 2011.

7.3 Specific Area Programs

The following location specific programs are proposed for the 1 July 2012 to 30 June 2017 regulatory control period:

7.3.1 Kingston

Background:

The Kingston and Blackmans Bay area is supplied by the Kingston terminal substation which comprises 2 x 35 MVA 110/11 kV transformers (continuous nameplate rating) providing a firm capacity of 35 MVA and 12 x 11 kV distribution feeders. The load at Kingston currently exceeds the firm N-1 rating.

Analysis of the load duration on Kingston substation shows that the top 3.5 MVA (or 10%) of the load occurs for less than 10 hours per year. A comparison of the peak day profile to a mild weekday day shows that there is a 12 MVA difference in magnitude between the maximum demand and mild day evening peak load. This difference is attributed to temperature-dependant load, predominantly residential space and hot water heating.

Uncontrolled loads on the N05 tariff, such as residential electric space heating and uncontrolled water heating are significant contributors to the peak and are estimated to account for 16.4 MVA or 41% of the evening peak. There will also be additional uncontrolled space heating and water heating load supplied under the PAYG. This is estimated to account for an additional 1 – 2 MVA. Other significant residential end-uses, supplied under the N01 tariff, likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

Without an alternate non-network solution, including dynamic rating of feeders, a network solution to address the exceedance of firm rating of the terminal substation and the projected growth of ~ 1 MVA per annum is to establish a new 33/11 kV zone substation at Kingston in association with a new 110/33 kV connection point at Kingston terminal substation.

Assessment of demand side management and distributed generation potential, indicate the following potential load reductions:

- 1.5 MVA from controlling water heating;
- 1 – 2 MVA from encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period;
- 0.5 MVA from load curtailment opportunities from the C&I sector; and
- 0.4 MVA per annum through incorporation of demand side management into new buildings.

7.3.1.1 Pilot DLC trial

Proposed to undertake the pilot DLC trial outlined in 7.2.5 in association with the rollout of the NBN in the Kingston/Blackmans Bay area.

7.3.1.2 Water heating load control program

A program is to be developed to facilitate a switch to off-peak storage, off-peak heat pump and/or off peak boosted solar water heating. The program is to be supported by:

- Investigation into end use loads in the Kingston area;
- Linking to broad based demand response programs; and
- Development of an incentive based rebate scheme.

7.3.1.3 Residential, small commercial and industrial, new construction demand management program

Development and implementation of a program to encourage take up of off-peak tariffs and energy efficiency technologies in new construction.

7.3.1.4 Larger commercial and industrial curtailable loads and embedded generation program

Although the contribution to peak demand from the large C & I sector in the Kingston area is relatively small there may be existing embedded generation and/or curtailable load opportunities available from the two large customers supplied off Kingston terminal substation. This includes a fish farm, which may have processing and pumping loads, and the Antarctic Division head office; both sites may offer opportunities for load curtailment. It is assumed that 0.5 MVA of curtailable load is available from these customers.

7.3.2 Wynyard

Background:

The Burnie region is supplied by the Burnie terminal substation which comprises 2 x 60 MVA 110/22-11 kV transformers (continuous nameplate rating)and 12 x 22 kV feeders. The terminal substation serves a diverse mix of customer types including urban residential, industrial, the Burnie airport, high density rural and low density rural. The Burnie CBD is supplied separately from the Emu Bay terminal substation.

The Burnie terminal substation is currently operating at 10 MVA above its N-1 firm capacity limit of 60 MVA. Peak loads are approaching the terminal station's cyclic rating of 72 MVA. With the closure of the Australian Paper Mill in July 2010, a new 22 kV connection point is proposed to be established from Emu Bay terminal substation which will effectively deload the Burnie terminal substation by around 10 -15 MVA.

The maximum demand on the Burnie terminal substation, following deloading of the 22kV feeders to Emu Bay terminal substation is expected to exceed 60 MVA by 2014.

Further, the Wynyard area is currently supplied from three feeders 91004, 91005, 91006 off the Burnie terminal substation. These feeders are currently operating at close to their maximum rating. The feeders mainly serve industrial and other large loads including Burnie Airport. A new industrial subdivision in Wynyard is also being established next to Burnie Airport which is located in Wynyard.

Without an alternate non-network solution, a network solution to address the exceedance of firm rating of the terminal substation and the projected growth of around 0.5 MVA per annum is to establish a new 2 x 60 MVA 110/22 kV terminal substation at Wynyard by 2015. The Wynyard terminal substation will deload feeders 91004, 91005, 91006, 91009 and 91012 and remove 28 MVA off the Burnie terminal substation.

The electrical load served by the Burnie terminal substation comprises a mix of residential, and small/medium commercial loads and several large industrial spot loads.

Uncontrolled loads, including residential electric space heating and water heating, supplied on tariff N05 are estimated to account for 16 MVA or 27% of the evening peak. There will also be additional 5 – 6 MVA of uncontrolled space heating and water heating loads supplied under the PAYG. Significant end-uses on the N01 tariff likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

The large C & I sector, comprising around 19 customers, accounts for an estimated 12 MVA of peak demand. Significant industrial customers in this segment include the Fonterra dairy processing plant at Wynyard which has a winter demand of 0.8 – 1 MVA, the Burnie Airport and several other dairy processing plants including Bonlac and Lactos.

It is assumed that the over firm load up to 2014 will be taken up by Emu Bay via deloading and that DSM will address annual load growth. Annual load growth is estimated at 0.5 MVA. Therefore, 0.5 MVA is required to achieve a 1 year deferral and 1.9 MVA is required to achieve a 4 year deferral of the Wynyard terminal substation. A 4 year deferral is required to shift the project into the next PD period. The load reduction targets represent around a 1 – 3 % reduction in peak demand.

Assessment of demand side management and distributed generation potential, indicate the following potential load reductions:

- there is 2.5 MVA of customer owned embedded generation from the Fonterra plant and possibly other sites including the airport that could potentially be secured under a load curtailability arrangement;
- if a third of the N05 load and 25% of the N13 (PAYG) load is comprised of water heating then water heating contributes about 8 MVA to the peak. If water heating is mostly made up of medium to large storage tanks and 25% of this load could be shifted away from the peak, potential load reductions from controlling water heating are estimated to be in the order of 2 MVA;
- a further 1 – 2 MVA of load reduction could be obtained by encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period; and
- assuming that each MVA of new load growth has a similar composition to the existing load, load growth could be reduced by more than 0.15 MVA per annum by simply encouraging take-up of off-peak tariffs and load shifting technologies.

Projects:

Negotiation of a network support agreement with Fonterra at Wynyard for standby of existing 2.5 MW embedded generator.

This has been initiated by Network as Aurora was aware of generation capacity not currently being utilised when network is constrained & presents a least cost solution.

Subject to impact of broad based demand management programs, it is anticipated that network support will be needed for beyond 2015.

7.3.3 Bridgewater

Background:

The Bridgewater 110/11 kV terminal substation is equipped with 2 x 35 MVA transformers (continuous nameplate rating), providing a firm capacity of 35 MVA. The adjacent Claremont zone substation, which is supplied by the Creek Rd 110/33 kV terminal substation is equipped with 2 x 22.5 MVA 33/11 kV transformers providing a firm capacity of 22.5 MVA. Bridgewater terminal substation is forecast to exceed firm capacity in 2014, and Claremont zone substation has already exceeded its firm capacity.

Without an alternate non-network solution, a network solution is to install 2 x 60 MVA 110/33 kV transformers and switchgear at the existing Bridgewater 110/11 kV site and establish a new 2 x 25 MVA 33/11 kV transformer zone substation at

Austin's Ferry supplied from Bridgewater. This will deload Bridgewater, Creek Rd and Claremont substations.

By 2016 the primary peak at Bridgewater is expected to have reached the terminal substation's firm rating, while Claremont will be over firm by 4 MVA in the evening and 1 MVA in the morning. Therefore, at Claremont a DSM solution will need to address both the morning and evening peaks to maintain load below firm.

Uncontrolled loads, including residential electric space heating and water heating, supplied on tariff N05 is are estimated to account for over 18 MVA or 32% of the evening peak. There will also be additional uncontrolled space heating and water heating loads supplied under the PAYG tariff. It is estimated that there is an additional 6 – 8 MVA of uncontrolled space and water heating load supplied under this tariff. Other significant end-uses on the N01 tariff likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

The large C&I sector, comprises 11 customers and accounts for an estimated 7 MVA of peak demand.

The current load forecast for Bridgewater and Claremont combined indicates a load growth rate of 0.85 MVA per annum.

For the purposes of this analysis it is assumed that the over firm load ramping up to 5 MVA by 2016 will be addressed by load transfers away to other substations in the group. Therefore, 0.85 MVA of DSM and DG capacity is required to achieve a 1 year deferral and 1.7 MVA is required to achieve a 2 year deferral of a new Austin's Ferry zone substation. This represents around a 1.5 – 3 % reduction in peak demand.

Assessment of demand side management and distributed generation potential, indicate the following potential load reductions:

- if a third of the N05 load and 25% of the N13 (PAYG) load is comprised of residential/small business water heating load then water heating contributes about 9.5 MVA to the peak. If water heating is mostly made up of medium to large storage tanks and a conservative 25% of this load could be shifted away from peak times, potential load reductions from controlling water heating is estimated at 2.5 MVA;
- a further 1.5 – 2.5 MVA of load reduction could be obtained by encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period;
- although the contribution to peak demand from the large C & I sector is relatively small there may be discretionary curtailable load and existing embedded generation opportunities off the two substations that could be contracted under a curtailable load agreement; and
- assuming that each MVA of new load growth has a similar composition to the existing load, load growth could be reduced by more than 0.3 MVA per annum by simply encouraging take-up of off-peak tariffs and load shifting technologies.

7.3.3.1 Water heating load control program

A program is to be developed to facilitate a switch to off-peak storage, off-peak heat pump and/or off peak boosted solar water heating, specific to the area served by the Bridgewater terminal substation. The program is to be supported by:

- Investigation into end use loads in the Bridgewater, Austins Ferry and Brighton areas;
- Linking to broad based demand response programs; and
- Development of an incentive based rebate scheme.

7.3.3.2 Residential, small commercial and industrial, new construction demand management program

Development and implementation of a program to encourage take up of off-peak tariffs and energy efficiency technologies in new construction.

7.3.3.3 Curtailable loads and embedded generation program

There may be DSM capacity in the form of embedded generation and/or load curtailment available from the large C&I sector customers in the area, such as Cadburys. This potential opportunity should be investigated and confirmed as a first priority, before detailed planning of the small customer DSM program is undertaken. This should include scoping analysis of site load characteristics (from interval meter data), availability of curtailable loads and/or embedded generation and preliminary discussions with customers.

7.3.3.4 Trial of micro CHP embedded generation units

Aurora has initiated discussions with Ceramic Fuel Cells Ltd to undertake a trial of the Bluegen ceramic fuel cell embedded generator/CHP unit.

Opportunity also appears to exist to trial the Stirling engine WhisperGen micro CHP home power generation system.

The objective of a trial or a series of trials, of these (or similar) units would be to:

- Gain an understanding of their operational profiles and grid related operational issues;
- Assist in the development of control/optimisation systems;
- Identify customer benefits and acceptance; and
- Develop an ownership model.

Potential exists through initial discussion to trial these units in partnership with TasGas.

Although not specifically identified Table 2, this project falls within the criteria for DMIA funding.

7.3.4 South Arm

Background:

The load at Rokeby terminal substation is currently above firm N-1 rating. The substation supplies the suburb of Rokeby and other eastern shores suburbs including Lauderdale and the South Arm peninsula. The current configuration at

Rokeby includes 2 x 35 MVA 110/11 kV transformers (continuous nameplate rating) providing a firm capacity of 35 MVA and 10 x 11 kV distribution feeders.

Load transfers to Howrah zone substation and Rosny in 2011 and 2012 will deload Rokeby and defer the need for additional capacity until around 2017. There are also two 11 kV feeders from Rokeby to Lauderdale and South Arm which are expected to exceed their planning ratings by 2015. The maximum demand on the Rokeby terminal substation is expected to reach 34 MVA by 2016/17.

Without an alternate non-network solution Aurora’s planned network solution would require capex in the order of $11.9 million in 2016/17 to establish the Sandford zone substation and associated underground 33 kV works.

The electrical load served by the Rokeby terminal substation comprises a mix of residential, small to medium C & I loads and several large C & I loads.

Uncontrolled loads, including residential electric space heating and water heating, supplied on tariff N05 are estimated to account for 11 MVA or 31% of the evening peak.

There will also be additional 1 – 2 MVA of uncontrolled space heating and water heating load from the PAYG segment. Significant end-uses on the N01 tariff likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

Significant end-use loads in the small / medium C&I sector contributing to the peak will include commercial lighting, water heating, space heating, cooking and refrigeration. The large C&I sector, comprising 3 large customers, accounts for an estimated 4 MVA of peak demand.

The load forecast for Rokeby terminal substation shows that load is growing at the rate of 0.79 MVA per annum. The over firm constraint in 2011 is relieved by load transfers to Howrah and Rosny.

Based on the annual load growth rate at Rokeby, 0.8 MVA of non-network capacity is required to achieve a 1 year deferral and 1.6 MVA is required to achieve a 2 year deferral of the Sandford zone substation. This target represents a 2 to 5 % reduction in peak demand.

An assessment of the DSM and DG potential within the area supplied by the Rokeby terminal substation indicates that:

- if a third of the N05 load and 25% of the N13 (PAYG) load is comprised of water heating then water heating contributes about 5 MVA to the peak. If water heating is mostly made up of medium to large storage tanks and a conservative 25% of this load could be shifted away from the peak, potential load reductions from controlling water heating are estimated to be in the order of 1.5 MVA;
- a further 1 – 2 MVA of load reduction could be obtained by encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period;
- curtailable load and embedded generator arrangements with one or more of the customers in the large C & I sector could provide an additional 0.5 – 1 MVA of load reduction opportunities; and

- Assuming that each MVA of new load growth has a similar composition to the existing load, load growth could be reduced by more than 0.25 MVA per annum by simply encouraging take-up of off-peak tariffs and load shifting technologies.

7.3.4.1 Water heating load control program

A program is to be developed to facilitate a switch to off-peak storage, off-peak heat pump and/or off peak boosted solar water heating. The program is to be supported by:

- Investigation into end use loads in the Lauderdale, Acton Park and South Arm areas;
- Linking to broad based demand response programs; and
- Development of an incentive based rebate scheme.

7.3.4.2 Residential, small commercial and industrial, new construction demand management program

Development and implementation of a program to encourage take up of off-peak tariffs and energy efficiency technologies in new construction.

7.3.4.3 Community load response program

Development of a community load response program to encourage shifting discretionary appliance use away from peak periods.

7.3.4.4 Curtailable loads and embedded generation program

There may be DSM capacity in the form of embedded generation and/or load curtailment available from the three large C&I sector customers in the Rokeby area. This potential opportunity should be investigated and confirmed as a first priority, before detailed planning of the small customer DSM program is undertaken. This should include scoping analysis of site load characteristics (from interval meter data), availability of curtailable loads and/or embedded generation and preliminary discussions with customers.

7.3.5 Bruny Island

Background:

Bruny Island is supplied by two submarine cables; Cable 1 (Fdr 33271) is supplied from Kingston terminal substation and is around 60 years old, while Cable 2 (Fdr 33275), currently supplied from the Electrona terminal substation, is around 50 years old. Cable 2 supports around 80% of the load on the island and serves to reduce load and subsequent stress on the older cable. Cable 1 is used as a back up for Kermandie terminal substation or Feeder 006 and current constraints are such that it is not possible to run the entire island off cable 1 during winter. Both cables are rated at 76 amps per phase continuous. The peak cyclic rating is 106 amps (2.02 MVA @ 11,000 volts nominal).

Load growth of the island has been steadily increasing and has been driven by changes in demographics and tourism. When both Cable 1 and Cable 2 loads are combined present peak loadings are approaching 100 amps or 95% of the cyclic load.

A proposal to replace the ageing Cable 2 has been considered in the past, and the indicative cost of replacing the cable is in the order of $4 million.

The maximum demand on Bruny Island based on the combined loading of the two cables was 1,810 kW (95 amps) and occurred at 7:30 pm on Good Friday, 10 April 2009. Typical peak demand in the period leading up to the holiday period is in the order of 0.8 MW. This MD equated to 270 kW above Aurora Energy's preferred combined cable loading of 1,540 kW (80 amps). This load exceeded 1,540 kW (80 amps) for only 10 hours of the entire year, or just over 0.1% of the time. All these hours occurred over the Easter long weekend. The load above firm also represents 4,706 kWh of energy at risk.

There are no load forecasts derived specifically for the Bruny Island cables. Based on load forecasts developed for Electrona, load on Bruny Island is expected to increase at 2.8% per annum.

To minimise risk to the submarine cables, maximum demands on the combined cables need to be kept at or below 80 amps. The load reduction target for the island loading is estimated as: maximum demand of 1,810 kW (95 amps) – 1,540 kW (80 amps) = 270 kW. This represents a 15% load reduction relative to peak demand based on current loads excluding load growth.

There is limited information on the characteristics of end-use loads on Bruny Island at the present time to support an accurate calculation of the DSM potential. However, an indicative analysis based on "best guess" assumptions suggests that:

- if half to three-quarters of the N05 load is comprised of water heating then water heating contributes about 400 – 600 kW to the system peak. If water heating is mostly made up of medium to large storage tanks and a conservative 25% of this load could be shifted to non-peak periods potential load reductions from controlling water heating are estimated to be in the order of 100 to 150 kW;
- a further 100 kW of load reduction by encouraging shifting of discretionary appliance usage away from the peak periods as part of a community load response program;
- 0.1 MVA reduction in new load expected to occur over 5 years based on annual load growth of 2.8%, by simply encouraging take up of off-peak tariffs and technologies in new construction; and
- given the short frequency and duration of peak loads distributed storage technology, such as sodium sulphur (NAS) or zinc-bromide battery systems, could be effective as a peak shaving strategy.

7.3.5.1 Water heating load control program

Potential reduction in peak load from controlling water heating on Bruny Island is estimated to be in the order of 100 to 150 kW.

A program is to be developed to facilitate a switch to off-peak storage, off-peak heat pump and/or off peak boosted solar water heating. The program is to be supported by:

- Investigation into end use loads on the island;

- Linking to broad based demand response programs; and
- Development of an incentive based rebate scheme.

7.3.5.2 Residential, small commercial and industrial, new construction demand management program

Development and implementation of a program to encourage take up of off-peak tariffs and energy efficiency technologies in new construction.

7.3.5.3 Community load response program

Development of a community load response program to encourage shifting discretionary appliance use away from peak periods, including fuel substitution to gas.

7.3.5.4 Peak shaving with distributed storage/generation project

Background:

Energy storage provides a tool to balance supply and demand through the day and provides a good opportunity to integrate renewable energy. Energy storage technologies can be used as an alternative to traditional network augmentation, particularly in locations where network investment is driven by infrequent, but sharp short term peaks and the cost of network augmentation is high.

Projects:

Installation of peak shaving generator/s.

- Aurora to install a 350 kVA bio-diesel embedded generator to address impending peak load constraints; and
- Negotiate with developers and other new larger load customers installation of additional embedded generation to address their contribution to peak demand.

Trial of distributed storage technology, such as sodium sulphur (NAS) or zinc bromide system.

- Deployment of a small scale system of around 200 kVA;
- Key R&D objectives of this project would be to:
    - Demonstrate the role of energy storage in rural networks integrated with grid supply and / or renewable based distributed generation;
    - Provide the business with practical experience in planning and implementing alternative network support solutions;
    - Provide operational and cost data to support business cases for energy storage technologies in other parts of the network;
    - Achieve network support and reliable supply from renewable energy sources; and
    - Develop intelligent management methods for the integration of multiple storage technologies in the network.

- Aurora intends to cooperate with other businesses that have experience in this area, such as Hydro Tasmania and their experience on King Island;
- This project would be supported through DMIA funding.

7.4 Demand Management Incentive Scheme (DMIS)

Aurora proposes to apply the DMIA funding allowance to the implementation of a range of programs and studies that facilitate development of demand management strategies during and beyond the regulatory control period.

Programs that are proposed to be promulgated under the DMIA funding and incorporated into the broad based and specific location programs are:

- Institutional partnership demand side response trials (refer to section 7.2.9);
- Research and analysis of residential and small business water heating usage and demand patterns;
- Studies, trials and evaluation of appropriate load control architecture;
- Energy storage research and development;
- Conduct of trials to evaluate the peak demand reduction benefits and cost effectiveness of replacing traditional street lighting technologies with solid state lighting technologies (SSL), such as Light Emitting Diode (LED) luminaries (refer to section 7.2.6);
- Studies and evaluation of potential benefits of power factor correction greater than code requirements (refer to section 7.2.8); and
- Development of broad based educational materials to engage and teach customers about the benefits of demand management, and engender participation in tariffs and trials aimed at managing peak demand on the network (refer to section 7.2.4).

Aurora is required to provide annual reports in accordance with the AER's DMIS applicable to Aurora.

8. PROPOSED OPEX PLAN

Aurora's proposed operational expenditure for demand management activities for the 2012/13 financial year is $0.5 million. The primarily component being staff costs associated with developing and running pilot trials, and development of projects proposed for the 2012/13 – 2016/17 regulatory control period.

Aurora's proposed operational expenditure for demand management activities, excluding that funded through the DMIA, for the 2012/13 – 2016/17 regulatory control period is $3.87 million.

Aurora's operational expenditure for demand management activities funded through the DMIA for the 2012/13 – 2016/17 regulatory control period is $2.0 million.

	2012/13	2013/14	2014/15	2015/16	2016/17	Total $m
Broad based Programs	270	270	270	270	270	1,350
Residential & small business load response project	**200**	**200**	**200**	**200**	**200**	**1,000**
internal resource	80	80	80	80	80	400
external resource/materials/incentives	120	120	120	120	120	600
Curtailable / DG program with large C&I customers	**40**	**40**	**40**	**40**	**40**	**200**
internal resource	10	10	10	10	10	50
external resource/materials/incentives	30	30	30	30	30	150
LED streetlight trial	**30**	**30**	**30**	**30**	**30**	**150**

Location specific DM & EG initiatives	333	378	468	628	713	2,520
Blackmans Bay zone substation deferral	**106**	**106**	**106**	**106**	**106**	**530**
Water heating load control						
internal resource	30	30	30	30	30	150
external resource/materials/incentives	36	36	36	36	36	180
Residential / small C&I - new construction						
internal resource	20	20	20	20	20	100
external resource/materials/incentives	10	10	10	10	10	50
Large C&I curtailable loads / gens	10	10	10	10	10	50
Bruny Island feeder constraints	**88**	**53**	**53**	**53**	**53**	**300**
Water heating load control	16	16	16	16	16	80
Community load response program	15	15	15	15	15	75
Residential / small C&I - new construction						
internal resource	5	5	5	5	5	25
external resource/materials/incentives	7	7	7	7	7	35
Peak shaving with distributed storage/gen	45	10	10	10	10	85
Sandford zone substation deferral	**74**	**84**	**94**	**104**	**114**	**470**
Water heating load control						
internal resource	17	17	17	17	17	85
external resource/materials/incentives	20	20	20	20	20	100
Community load response program	15	15	15	15	15	75
Residential / small C&I - new construction						
internal resource	10	10	10	10	10	50
external resource/materials/incentives	12	12	12	12	12	60
Curtailable loads/gens						
internal resource		10	10	10	10	40
external resource/materials/incentives			10	20	30	60
Wynyard terminal substation deferral	**0**	**70**	**150**	**250**	**300**	**770**
Curtailable loads/gens						
internal resource		50	50	50	50	200
external resource/materials/incentives		20	100	200	250	570
Bridgewater 33kV & Austins Ferry zone substation deferral	**65**	**65**	**65**	**115**	**140**	**450**
Water heating load control	32	32	32	32	32	160
Residential / small C&I - new construction						
internal resource	20	20	20	20	20	100
external resource/materials/incentives	13	13	13	13	13	65
Curtailable loads/gens						
internal resource				15	10	25
external resource/materials/incentives				35	65	100

Demand side engagement strategy						
Review & updating of DS Engagement Strategy	**10**	**10**	**10**	**10**	**10**	**50**
internal resource	10	10	10	10	10	50
Develop & maintain guidelines	**110**	**110**	**110**	**110**	**110**	**550**
internal resource- non-network processes	10	10	10	10	10	50
internal resource - embedded connection processes	10	10	10	10	10	50
Aurora staff training	**80**	**80**	**80**	**80**	**80**	**400**
internal resource	10	10	10	10	10	50
external resource/materials	30	30	30	30	30	150
Maintain database of non-network proposal case studies	**20**	**20**	**20**	**20**	**20**	**100**
internal resource	20	20	20	20	20	100
Maintain register of interested parties	**10**	**10**	**10**	**10**	**10**	**50**
internal resource	10	10	10	10	10	50
Total	**603**	**648**	**738**	**898**	**983**	**3,870**

Table 1: Demand Management OPEX for the 2012/13 – 2016/17 period

	2012/13	2013/14	2014/15	2015/16	2016/17	Total $m
Study into appropriate load control architecture		0.25				0.25
Residential & small business water heater study (what's installed)	0.25					0.25
PF correction potential study (at customer level)				0.10	0.05	0.15
Energy storage R&D	0.10	0.10	0.10			0.30
Institutional partnership trial (market research, educational materials etc)	0.05	0.05	0.05	0.05	0.05	0.25
LED streetlight R&D, monitoring and reporting	0.04	0.04	0.04	0.04	0.04	0.20
Other programs			0.20	0.20	0.16	0.56
DMIA reporting		0.01	0.01	0.01	0.01	0.04
Total	**0.44**	**0.45**	**0.40**	**0.40**	**0.31**	**2.00**

Table 2: Proposed DMIA funded OPEX for the 2012/13- 2016/17 period

A total of approximately $700,000 has been included in the program of work (POW) for the regulatory period for external service provision; the remaining $1.3 million is covering cost of internal resources.

Aurora is required to provide information to the AER so that it may assess expenditure incurred under the DMIA. As set out in Table 2 Aurora proposes expenditure of $40,000 across the regulatory control period to cover annual reporting against the criteria established in the scheme. As expenditure on DMIA activities is either approved or rejected on the basis of this assessment Aurora needs to prepare a robust justification for this expenditure.

9. PROPOSED CAPEX PLAN

Aurora's proposed capital expenditure for demand management activities for the 2012/13 financial year is $120,000. This is principally associated with installing generation to provide network support on Bruny Island.

Aurora's proposed capital expenditure for demand management activities for the 2012/13 – 2016/17 regulatory control period is $3.15 million. This excludes the cost of the metering and communications infrastructure, which are included in the Metering Management Plan and the IT Roadmap.

	2012/13	2013/14	2014/15	2015/16	2016/17	Total $m
Broad based Programs	**190**	**180**	**160**	**160**	**160**	**850**
Residential & small business load response project	150	150	150	150	150	750
LED streetlight trial	40	30	10	10	10	100
Location specific DM & EG initiatives						
Blackmans Bay zone substation deferral	**106**	**106**	**106**	**106**	**106**	**530**
water heating load control	66	66	66	66	66	330
residential / small C&I - new construction	30	30	30	30	30	150
large C&I curtailable loads / generators	10	10	10	10	10	50
Bruny Island feeder constraints	**544**	**74**	**44**	**44**	**44**	**750**
water heating load control	16	16	16	16	16	80
community load response program	15	15	15	15	15	75
residential / small C&I - new construction	13	13	13	13	13	65
peak shaving with distributed storage/gen	500	30				530
Sandford zone substation deferral	**74**	**74**	**74**	**94**	**104**	**420**
water heating load control	37	37	37	37	37	185
community load response program	15	15	15	15	15	75
residential / small C&I - new construction	22	22	22	22	22	110
curtailable loads/generators				20	30	50
Wynyard terminal substation deferral	**0**	**30**	**20**	**0**	**0**	**50**
curtailable loads/generators		30	20			50
Bridgewater 33kV & Austins Ferry zone substation deferral	**85**	**85**	**85**	**105**	**190**	**550**
water heating load control	43	43	43	43	43	215
residential / small C&I - new construction	42	42	42	42	42	210
PF correction					95	95
curtailable loads/generators				20	10	30
Total	**999**	**549**	**489**	**509**	**604**	**3,150**

Table 3: Demand Management CAPEX for the 2012/13 – 2016/17 period

10. RESPONSIBILITIES

Maintenance and implementation of this management plan is the responsibility of the Non-Network Solutions Manager.

Approval of this management plan is the responsibility of the Network Development Manager.

11. REFERENCES

1. Australian Energy Market Commission, *National Electricity Rules*
2. State of Tasmania, *Electricity Supply Industry Act 1995*
3. Office of the Tasmanian Energy Regulator, *Tasmanian Electricity Code*
4. AER, *Final Decision Regulatory Test version 3 & Application Guidelines*, November 2007
5. AEMC, *Final Report Review of National Framework for Electricity Distribution Network Planning and Expansion*, September 2009
6. MCE, *National Framework for Electricity Distribution Network Planning and Expansion – Response to Australian Energy Market Commission's Final Report*, September 2010
7. AER, *Demand Management Incentive Scheme Aurora Energy*, October 2010
8. AER, *Final Framework and approach paper Aurora Energy*, November 2010
9. Aurora Energy, Capacity Management Plan NW#30131340

Appendix A

DRAFT DEMAND SIDE ENGAGEMENT STRATEGY DOCUMENT

The Demand Side Engagement Strategy aims to facilitate co-operative engagement in network planning between distribution network service providers and proponents of non-network solutions.

Aurora Energy's Demand Side Engagement Strategy covers three broad areas:

- network planning and development
  - to provide increased efficiency and improved reliability in the development of the distribution network, provide formal opportunities for non-network proponents to raise alternative options to supply-side investment, and improve transparency regarding Aurora Energy's decision making processes
- connection of embedded generators
  - to develop optimal and streamlined procedures that promote the efficient use of embedded generation and provide embedded generator proponents with clarity on Aurora Energy's requirements for connection to the distribution network
- information transfer
  - to provide proponents of non-network solutions with simple and effective mechanisms for obtaining information on Aurora Energy's non-network activities

1. Network planning and development

Aurora Energy's approach to non-network solutions is both delineated in our network planning policy. and supported by procedures to integrate non-network solutions such as demand management and embedded generation options into the planning and expansion of our distribution network.

The Aurora Energy Distribution Annual Planning Report details load forecasts and identified limitations or constraints for major network elements (sub-transmission lines, zone substations and transmission distribution connection points) over the following five years. Planned major investment to manage identified network limitations or constraints with an estimated capital cost of $5 million or more is also presented. The document indicates whether for these major projects a Regulatory Investment Test for Distribution (*RIT-D)* process has been implemented, is completed, or planned for implementation, and reports on relevant outcomes. A summary of Aurora Energy's non-network activities including those considered in the past year, actions taken to promote non-network initiatives in the preceding year, and our plans for demand management and embedded generation over the next five years is presented. The *DAPR* also provides a description of the outcomes of joint planning undertaken with Transend, network performance standards and compliance against those standards, and a summary of Aurora Energy's load forecasting and network planning management methodologies.

Aurora Energy applies the *RIT-D* to proposed network augmentation projects where there is a technically and economically feasible proposal with a capital cost of over $5 million. This process involves three steps: *a Specification Threshold Test (STT), a project specification stage, and a project assessment stage:*

- *the STT* – this is a high level assessment to determine whether undertaking a non-network alternative could be viable and whether further investigations are warranted
- *a project specification stage* – for projects where there appears to be material likelihood that viable non-network options exist, Aurora Energy will issue a request for proposal (RFP) inviting interested parties to make submission on alternative demand management or embedded generation solutions to meet the identified investment need
- *a final project assessment stage* – where Aurora Energy will evaluate all credible options in relation to all applicable costs and benefits, and select the option that maximises the economic of the *RIT-D*. The *RIT-D* also stipulates the formal processes that are to be used to resolve disputes in relation to Aurora Energy's final project assessment report.

Aurora Energy has prepared a guideline detailing our planning, consultation, and negotiating processes for non-network solutions. The document also sets out the information that non-network proponents need to include in proposals, the criteria that will be used by Aurora Energy to evaluate them, and applicable payment schemes and incentives. These guidelines will provide transparency in our planning processes and regulatory obligations, which will assist non-network proponents to develop targeted proposals that address all relevant information. Ultimately, this process will provide the framework for an efficient and cost-effective process that ensures that supply-side and non-network solutions are given equal consideration in the development of solutions to meet limitations or constraints on our distribution network.

For more information on Aurora Energy's planning policies and procedures please download the document below.

[link to] Customer Guidelines for Network Planning Policies and Procedures

2. Connection of embedded generators

Connection of micro embedded generators

To make the process as streamlined and cost-effective as possible, Aurora Energy has developed standard connection agreements for two types of small embedded generators:

- AS 4777 compliant solar PV generators of 10kVA or less (single phase) and 30kVA or less (three phase); and

- Non AS 4777 compliant generators without an inverter of 10kVA or less (single phase) and 30kVA or less (three phase).

For detailed information on the process used by Aurora Energy to connect small embedded generators please download document below.

[link to] Customer Guidelines for Connection of Small Embedded Generators

Connection of large embedded generators

Large embedded generators are defined as single units with nameplate capacity greater than 10kVA (single phase) or 30kVA (three phase).

Chapter 5 of the National Electricity Rules (the Rules) provide the framework used by Aurora Energy to progress an embedded generator *connection enquiry* and *application to connect* to the distribution network. Additional information on the process described in the Rules can be found at ***[link to] the AEMC's website***.

Before entering into an agreement to connect an embedded generator to our distribution network, there are a number of things that proponents will be required to do to enable Aurora Energy to process a *connection enquiry* and an *application to connect*. This will include providing all necessary technical data and other information to Aurora Energy to enable us to properly assess the suitability of the proposed connection.

Embedded generation facilities also need to comply with certain standards to be acceptable for connection. Aurora Energy will provide you with information on the required standards and advise you on any standards that are negotiable.

Aurora Energy will define the scope of the Capital Works required for the connection of an embedded generator, and provide a design brief and contract for the Works. We will also work with proponents to negotiate the terms and conditions of the *connection agreement* contract required for the embedded generator.

A fee will be incurred for an embedded generator's *application to connect*, to cover the reasonable cost of all work undertaken by Aurora Energy arising from the investigation of the application and negotiation of the connection agreement. In addition, proponents will need to reimburse Aurora Energy for the cost of carrying out all necessary technical investigations.

Aurora Energy has prepared a customer guideline that outlines the process for lodging for an embedded generation *connection application*, the process used and regulatory requirements for setting charges and the terms and conditions of *connection agreements*, and the factors taken into account when negotiating *connection agreements* with proponents of embedded generator proposals. Our methodology for determining *avoided customer transmission use of system charges* is also presented. The guideline, by providing non-network proponents with information on the requirements for connecting embedded generators to our distribution network, and the factors considered by Aurora Energy in relation to connections, in advance of the actual process, will provide increased clarity and transparency, and will result in a more efficient outcome for both parties.

For more information on the processes used by Aurora Energy to progress, evaluate, and connect large embedded generators to our distribution network please download the document below.

[link to] Customer Guidelines for Connection of Large Embedded Generators

3. Information transfer

Sources of information on Aurora Energy's non-network activities

Aurora Energy produces a variety of reports of relevance to proponents of non-network solutions that are updated regularly. Some of the most important of these are:

- The Distribution Annual Planning Report ***[link to] DAPR;***
- The results of joint planning activities undertaken with Transend ***[link to] Transend's APR;***
- Applications for major investment under the RIT-D ***[link to] the STT reports, the project specification reports, and the project assessment reports;***
- Compliance reports prepared under the requirements of the AER's Demand Management Incentive Scheme ***[link to] the AER's website*****.**

Case Studies on non-network proposals

Aurora Energy has developed a series of case studies of proposals that have been received from non-network providers in response to the consultation processes undertaken through the RIT-D. These case studies demonstrate the processes used by Aurora Energy to consider and evaluate non-network project proposals put forward as potential solutions to address limitations or constraints on our distribution system.

[link to] Database of Proposals and Case Studies on Non-network Solutions

Register of interested parties

Individuals, private companies, and government departments wishing to receive information on the progress of Aurora Energy's non-network activities can make an online application to our *Register of Interested Parties*. The Register is intended to facilitate public consultation on future network constraints in a timely fashion, and to inform stakeholders, and other interested parties about potential non-network opportunities.

Registered interested parties will be informed when a new Request for Proposal under the RIT-D has been posted on Aurora Energy's website ***[link to] Proposals requested under the RIT*****.**

You will also be advised when the *Distribution Annual Planning Report* has been published ***[link to] the DAPR*** on the website.

[link to] Registration Form

[link to] Register of Interested Parties

4. Contact us

If you have questions on any aspect of Aurora Energy's Demand Side Engagement Strategy, please contact:

[mail to] Title of Aurora's Non-network Representative