ETSA Utilities

DEMAND MANGEMENT PROGRAM

We do everything in our power to deliver yours

INTERIM REPORT No 2 SEPTEMBER 2008

Disclaimer

The purpose of this Interim Report (Report) is to impart an understanding of the Demand Management Program (DM Program) undertaken by ETSA Utilities and the status of specific projects within its portfolio as of May 2008 and is not intended to be used for any other purpose, such as making decisions to invest in generation, transmission or distribution capacity. It has been prepared using information provided by, and reports prepared by, a number of third parties.

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GLOSSARY

Acronym	Descriptor
°C	Degree Celsius
%	percentage
$	Australian Dollar
m	mere
mm	millimetre
m^2	square metres
A	Ampere (Amp)
ACT	Australian Capital Territory
ADMD	After Diversity Maximum Demand
AM	Amplitude Modulation
AMI	Advanced Metering Infrastructure
AREMA	Air Conditioning and Refrigeration Equipment Manufacturers Association of Australia
Accent	Brand Name and Airconditioner OEM
Actron Air	Airconditioner OEM
Adelaide Airport	Adelaide Airport Ltd, West Torrens - Adelaide's international airport
Airconserve	Air Con Serve Pty Ltd
Airwell	Brand Name and Airconditioner OEM
Astec Paints	Astec Paints Australia Pty Ltd - manufacturers of reflective coatings
BMS	Building Management System
CEO	Chief Executive Officer
CLC	Curtailable Load Control
COAG	Council of Australian Governments
CPP	Critical Peak Pricing
CRA	Charles River Associates Asia (Asia Pacific) Pty Ltd
Carrier	Brand Name and Airconditioner OEM
CitiPower/PowerCor	Electricity Distributor & Retailer, Victoria
Clipsal	Clipsal Australia Pty Ltd
Comverge	A US company which delivers demand management solutions
DM	Demand Management
DNSP	Distribution Network Service Provider
DLC	Direct Load Control
DRED	Universal Demand Response Enabling Device Interface
DaNM	ETSA's Demand and Network Management Organisation
DM Program	Demand Management Program
Daikin	Brand Name and Airconditioner OEM
DeLonghi	Brand Name and Airconditioner OEM
Distribution Code	Electricity Distribution Code (EDC) as issued by ESCOSA
EDC	Electricity Distribution Code
EDPD	Electricity Distribution Price Determination
EMNP	Eligible Major Network Projects
EPA	Environmental Protection Authority of South Australia
ESAA	Electricity Supply Association of Australia
ESCOSA	Essential Services Commission of South Australia
ESDP	Electricity System Development Plan developed annually by ETSA Utilities and published by 30th June
EST	Eastern Standard Time
ETSA Utilities	South Australia's principal Distribution Network Service Provider (DNSP) responsible for the distribution of electricity to all distribution connected customers within the State under a regulatory framework. ETSA Utilities is a partnership of Cheung Kong Infrastructure Holdings Ltd (CKI) and Hong Kong International Ltd (HEI) and Spark Infrastructure
E-Drawings	Electronically generated and stored drawings
Immanuel College	Immanuel College, Novar Gardens
EnergyAustralia	Electricity & Gas Distributor, New South Wales
FM	Frequency Modulation
Fujitsu	Brand Name and Airconditioner OEM
Guideline 12	ESCOSA Electricity Industry Guideline 12 – Demand Management for Electricity Distribution Networks
HIA	Housing Industry Association of South Australia

Acronym	Descriptor
HVAC	Heating, Ventilating & Air Conditioning Control Systems
Hills Industries	Hills Industries Limited
Honeywell	Honeywell Limited
IKEA	IKEA Stores, West Torrens
IMRO	Interval Meter Roll Out
k	Kilo
kV	Kilo Volt
kVA	Kilo Volt Amp
kVAr	Kilo Volt Amp reactive
kW	Kilo Watt
LCU	Load Control Unit
LG	Brand Name and Airconditioner OEM
LMC	Land Management Corporation of South Australia
LMS	Load Management System
LSM	Load Supply and Management Device
LV	Low Voltage
M	Mega
MCE	Council of Australian Governments' Ministerial Council on Energy
MVA	Mega Volt Amps
MW	Mega Watt
MWh	Mega Watt Hour
Mercedes College	Mercedes College, Springfield
Micromet	Micromet Pty Ltd
Minda Homes	Minda Home Incorporated, Brighton
Mitsubishi	Brand Name and Airconditioner OEM
Myer Centre	Myer Centre, Rundle Mall
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
NESS	ETSA's Network Sites System
NMI	National Metering Identifier
NPV	Net Present Value
NSW	New South Wales
NT	Northern Territory
OEM	Original Equipment Manufacturer
PF	Power Factor
PFC	Power Factor Correction
PLC	Power Line Carrier
P1	Peakbreaker Load Control Unit
P2	Peakbreaker Load Control Unit with additional Daikin Interface Card
P3	Peakbreaker Load Control Unit with additional Thermistor Evaluator (emulator)
Panasonic	Brand Name and Airconditioner OEM
Peakbreaker	SAAB manufactured Load Control Unit
Qld	Queensland
Q1	The first quarter of a calendar year
RF	Radio Frequency
R&D	Research and Development
SA	South Australia
SAAB	Saab Systems Pty Ltd
SCADA	System Control and Data Acquisition
SEC	ETSA Utilities' Skills Education Centre
SFE	Sydney Futures Exchange
SME	Small to Medium Sized Enterprise
SMWG	Ministerial Council on Energy's Smart Meter Working Group
Seeley	Seely International Pty Ltd
Spotless	Spotless Group Limited
St Halletts Wines	Winery located in the Barossa Valley of South Australia
TAFE	Colleges of Technical and Further Education
TES	Thermal Energy Shifting
Tas	Tasmania
ToU	Time of Use
Temperzone	Brand Name and Airconditioner OEM
Type 1	Peakbreaker Load Control Unit
Type 2	Peakbreaker Load Control Unit with additional Daikin Interface Card
Type 3	Peakbreaker Load Control Unit with additional Thermistor Evaluator (emulator)
UID	Underground Industrial Development

Acronym	**Descriptor**
UK	United Kingdom
UPS	Uninterruptible Power Supply
URD	Underground Residential Development
US	United States
V	Volt
VLC	Voluntary Load Control
Vic	Victoria
WA	Western Australia
Westfield Marion	Major shopping centre in the Adelaide’s south western suburbs

1. EXECUTIVE SUMMARY

This is ETSA Utilities second Interim Report (Report) dealing with an electricity demand management program (DM Program) in South Australia which has been in progress for the past three years that is in accordance with the Essential Services Commission of South Australia's (ESCOSA) 2005-2010 Electricity Distribution Price Determination (EDPD).

The EDPD came into effect on 1st July 2005 and is to apply until 30th June 2010. It sets out ESCOSA's decisions on the prices that ETSA Utilities may charge for network services and corresponding service levels to be provided to customers. The EDPD makes an allowance for expenditure of up to $20.4 million (denominated in December 2004 Australian dollars) by ETSA Utilities during the 2005-2010 regulatory period on specific demand management trial initiatives.

As it is ESCOSA's intention to publish demand management progress reports[1] on an annual basis, ETSA Utilities will update the information provided in this Report, as necessary, for incorporation into ESCOSA's annual progress reports. As this is ETSA Utilities' second report on the DM Program it does not include an overview of the events and rationale that has led to ESCOSA's demand management decision within the EDPD. This has been provided in Interim Report No 1[2]. The core of this Report focuses on the individual demand management trials and their status as of May 2008.

As of June 2008, ETSA Utilities had in place a total of 27 trials and projects as part of the DM Program, of which 22% had been completed, 59% were in an "active" state, 7% were in the "implementation" stage and 11% were at a "pre-implementation" stage. This proportional makeup will change as projects in the "active" state progress to completion and those in the "implementation" and "pre-implementation" state become active.

The DM Program is now just past the half way mark and some important observations and learnings are coming through. These are summarised by category in this Executive Summary but discussed in detail in the relevant sections of this Report.

Power Factor Correction

Of significance in these trials is ETSA Utilities' "Excess kVAr Incentive Charge" which has been instrumental in prompting some of the State's largest consumers to commit to and begin installing power factor correction (PFC) equipment. However to entice the majority of eligible customers it continues to be imperative that tariffs provide the appropriate incentive and that innovations in PFC equipment be commercially available, have commercialisation potential, be cost effective and be appropriate to the South Australian business sector.

Standby Generation

These trials continue to confirm the requirement for: (i) data to be captured through an innovative form of metering that allows a generator to make its capacity available to any market participant as well as the NEM; (ii) technology such as that demonstrated by some of ETSA Utilities' load reduction trials to be used to showcase and promote its future applications throughout South Australia and (iii) financial and contractual incentives to be properly structured to provide the opportunity for aggregation of revenues from the various market participants.

Direct Load Control (DLC)

Projects and trials grouped under this category have progressed substantially since the publication of Interim Report No 1 as the following discussion illustrates.

The Phase I DLC trial confirmed that forced cycling of an air-conditioner compressor, by attaching a controller (Peak Breaker) to it, reduced aggregate demand in the sample group by an order of 17% from a peak of approximately 30 kW and provided ETSA Utilities with

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1 c.f. Essential Services Commission of South Australia, ETSA Utilities Demand Management Program, Progress Report, June 2007 http://www.escosa.sa.gov.au/site/page.cfm?u=4&c=2257.

2 ETSA Utilities, Demand Management, Interim Report No 1, June 2007.

useful experience on the roll out and operation of the controllers. The trial also validated the controller's functionality and suitability for its intended application.

The larger Phase II DLC trial required an extensive media marketing "Beat the Peak" campaign to source volunteers in the selected Glenelg trial area of suburban Adelaide. It elicited more than 4,000 calls of support and interest from a total of approximately 12,000 customers, in participating in the trial.

The Phase II trial also found that of the 2,392 air conditioners suited to DLC from the 4,000 respondents 1,158 units (approximately 50%) were what is termed "new generation" units. These units have advanced diagnostics which require the installation of a more sophisticated controller. The size of this market penetration of "new generation" units was unexpected. This had important implications in terms of an eventual roll out, in that controllers that are simply attached to the external compressor could be installed in an average of 30 minutes but the more sophisticated controllers for "new generation" units would take an average of 60 minutes and require access to the inside of the home and its roof space.

The Phase III DLC trial flows from the Phase I and II trials and drawing on the learnings of those trials focused on continuing trialling Glenelg and instigating new trials in the suburbs of Mawson Lakes, Northgate and the regional centre of Murray Bridge. The outcome of these trials during the summer of 2007/08 has enabled ETSA Utilities to:

- Develop a technique (mathematical model) for predicting the actual reduction in total load that could occur because of a DLC event for varying numbers of households.

- Use this technique to get statistically robust estimates for the savings that a DLC event would be expected to give under similar conditions to those of the trial.

Contemporaneously with this work has been the development of a detailed cost benefit analysis (CBA) model for a DLC roll out. The results of the CBA model utilising the load reduction inputs from the mathematical model points to a negative societal Net Present Value (NPV). However, the learnings from the DLC trials have pointed to a possible alternative solution that enhances the Peak Breaker with technology that does more than just activate DLC. The CBA results of the enhanced Peak Breaker shows a positive societal NPV. A trial of the enhanced Peak Breaker will be undertaken to encompass the Adelaide metropolitan area and a regional area to prove up the technology and the CBA for this option.

In the commercial arena of DLC, building owners and property managers are interested in saving energy (kWh) or reducing greenhouse gas emissions but are generally unaware or uninterested in reducing capacity (kW). These stakeholders need to be educated that DLC also has the capability of reducing greenhouse gas emissions and that an adjustment to their Building Management System (BMS) to reduce or limit demand will not only result in an overall aggregate peak load reduction but greenhouse gas abatement too.

Critical Peak Pricing (CPP)
ETSA Utilities has reviewed the body of knowledge on CPP and ToU and concluded that more research is needed into consumer behaviour to electricity price signals. To this end a trial targeting approximately 100 volunteers was designed for deployment in the Adelaide suburb of Novar Gardens during the summer of 2007/08. The small (14%) volunteer take up rate attained from residents resulted in the trial being brought to a halt for this area. It will however, be resumed in another suburb of Adelaide during the summer of 2008/09.

Voluntary and Curtailable Load Control for Large Customers
Projects in this category have focussed on Domestic Load Shifting Time of Use and Commercial Load Shifting Thermal Energy Storage (TES) amongst industrial, commercial and small to medium sized enterprise customer categories. Important outcomes in these trials have been achieved demonstrating the applicability of the technology and the trials have continued over the summer of 2007/09 at; St Hallett Winery in the Barossa Valley, the IKEA store at Adelaide Airport and the University of South Australia's Magill Campus. These trials will continue over the summer of 2008/09 and conclude with a cost benefit analysis of the

technology in an operational setting. Also, during this trial, customers with suitable loads and Building Management Systems (BMS) will be recruited in an effort to harvest load during peak demand periods through the mechanisms of BMS operation and tariffs.

Interval Meters

Since the publication of Interim Report No 1 in June 2007, considerable progress has been made at the national level in relation to the roll out of smart meters in jurisdictions where the benefits exceed the costs. The consultants engaged by the Commonwealth of Australian Governments' (COAG) Ministerial Council on Energy's (MCE) Smart Meter Working Group (SMWG) to conduct the cost benefit analysis released their Phase 1 Report in September 2007 and Phase 2 Report in February 2008. For South Australia, the consultants' findings were highly qualified and did not point to a conclusive result in the benefits outweighing the costs. ETSA Utilities engaged the international firm, KEMA International (KEMA) to develop a detailed CBA model using their pre tested models as the framework for a cost benefit analysis for South Australia. The models test the CBA for Advanced Metering Infrastructure (AMI), DLC, AMI and DLC and the alternative solution to these options being enhanced Peak Breaker. The results of this study inform that the societal NPV for South Australia is negative for AMI and AMI and DLC.

Aggregation

Modelling and execution of demand aggregation can only be put into place after knowledge has been gleaned about the success, or otherwise, and applicability of specific demand management trials currently being undertaken in the DM Program. Therefore the phasing of the demand aggregation lags most of the other trials but will commence once suitable data and information becomes available. The DM Program is now reaching a point where learnings have been derived from other trials pointing to areas of demand aggregation that may be fruitful for investigation.

Demand Management Organisation Within ETSA Utilities.

Within ETSA Utilities a dedicated Manager Demand Management reports to the General Manager Demand and Network Management who in turn reports to the CEO. Relevant ETSA Utilities staff continue their internal training on demand management to improve their understanding of demand management and its relevance to ETSA Utilities, particularly in the area of customer applications for supply. Assessment of demand management benefits are now part of ETSA Utilities standard operational guidelines.

Ongoing capture of real time data as well as data relating to customer profiles in terms of their electricity usage is in hand and its analysis has commenced using specialised proprietary ETSA Utilities software systems and mathematical models developed by TRC Mathematical Modelling of the University of Adelaide. An audit of the air conditioner population in the Adelaide metropolitan area is planned for later this year.

ETSA Utilities forecasts that by the end of calendar 2008, it will have spent approximately $10.2 million of the $20.4 million budget. An analysis of this expenditure shows that Direct Load Control has been the focus of the DM Program accounting for just over half the expenditure (51%) with Demand Management Organisation Within ETSA Utilities at 13%, Power Factor Correction at 9%, Standby Generation at 5% and the other categories of demand management trials accounting for the remainder.

As of June 2008, all trials and projects were on track to deliver tangible conclusions for the 2005-2010 regulatory period.

2. INTRODUCTION

This Report is intended to provide an up to date statement of position, as of June 2008, of the DM Program of trial initiatives and activities of demand side management of electricity in South Australia. This research is funded through the Electricity Distribution Price Determination (EDPD) as ETSA Utilities' operating expenditure over the 2005-2010 regulatory period. The work is being undertaken by ETSA Utilities and has been in progress since late 2005.

The genesis of the DM Program dates back to 2001 when the Government of South Australia (the Government) formed the Electricity Demand-Side Management Task Force (Task Force) comprised of members of the electricity industry, business, government and the community to investigate demand side management as a tool for deferring network augmentation and reducing the cost of electricity to the consumer.

Since that time it has become apparent that demand side management is an important adjunct to supply side management in the efficient and cost effective augmentation and operation of the electricity network to meet South Australia's unique electricity demand requirements.

Interim Report No 1 discussed in summary form some of the history of the key events leading up to the launch of the DM Program and the reasons for them. In doing so, it put the DM Program's portfolio of projects into the context of significant past events and the peculiar South Australian demand drivers for them.

This Interim Report No 2 (Report) does not repeat the summary to be found in Interim Report No 1 but discusses and amplifies on the material contained in Interim Report No 1 only if the discussion makes a meaningful contribution or events have changed since the date of Interim Report No 1.

2.1 Electricity Industry Guideline 12

Electricity Industry Guideline No 12 (Guideline 12)[3] published in September 2003 addresses demand side management in South Australia. In Guideline 12, ESCOSA outlines how ETSA Utilities is required to meet its obligations in: reporting and consulting on its system constraints; demand management plans and encouraging all customers and interested parties to participate in the process of determining how emerging constraints in ETSA Utilities' network are to be addressed. To this end, Guideline 12 requires ETSA Utilities to regularly disclose information on possible network constraints through the:

- Publication by the 30th June of each year, of an annual Electricity System Development Plan (ESDP) that identifies actual and forecast constraints on ETSA Utilities' network.
- Maintenance of a Register of Interested Parties, who have an interest in ETSA Utilities' long term planning, demand management activities and/or in providing ETSA Utilities with alternative solutions to address emerging network constraints.
- Consultation with proponents of network support and non-network support options so they can offer relevant proposals related to Eligible Major Network Projects (EMNP), which is any proposal to augment or upgrade ETSA Utilities' network that would have a total capital cost of $2 million or more.
- Calling of a Request for Proposal for all EMNP's and consideration of whether consultation is required/desirable for all projects with an estimated capital cost in excess of $1 million. The consideration of each application must be documented and the outcomes of the evaluation made publicly available.
- Production of an Annual Demand Management Compliance Report[4] for the year ending 30th June to be published by the 31st August of each year that documents; the activities

[3] Essential Services Commission of South Australia, Demand Management for Electricity Distribution Networks, Electricity Industry Guideline No. 12, September 2003

[4] For example, refer to ETSA Utilities, Annual Demand Management Compliance Report, In accordance with Demand Management for Electricity Distribution Networks, Electricity Industry Guideline No. 12, August 2004.

undertaken, their outcome and the actions taken in order to comply with Guideline 12 in the preceding financial year.

An update to Guideline 12 has increased the scope of demand side management requirements placed on ETSA Utilities. This new scope is aimed at exploring the potential of network demand side management for the purpose of reducing electricity costs to South Australian customers. ESCOSA's Draft Determination relating to demand management initiatives is contained in 'Draft 2005-2010 Electricity Distribution Price Determination' of November 2004.

2.2 Key Stakeholders

While there are numerous stakeholders affected by the DM Program of trial initiatives, in particular the entire South Australian community, the key stakeholders in ensuring that tangible outcomes are derived from the DM Program effort are ESCOSA and ETSA Utilities.

2.2.1 ESCOSA

ESCOSA is the regulator of the electricity distribution sector in South Australia and is a key stakeholder in the successful implementation of demand management initiatives. Specifically, it can provide funding for certain demand management programs in its approval of the regulated revenue of ETSA Utilities or it can take other regulatory action to motivate ETSA Utilities to implement demand management programs.

2.2.2 ETSA Utilities

ETSA Utilities is the South Australian electricity distribution business. Its prime role is the safe and reliable delivery of electricity from high voltage transmission connection points to residential and business customers throughout the majority of populated areas of the State. It serves over 792,000 customers and supports a network comprising physical assets such as substations, powerlines and transformers valued at over $2.4 billion. ETSA Utilities is the 4th largest distributor in Australia employing more than 1,600 people and ranks among the nation's top 300 businesses on the basis of revenue.

As a provider of an essential service that is not subject to direct competition, ETSA Utilities' revenues are established by ESCOSA. The level of these allowances ultimately determines the distribution network prices payable by electricity consumers. Therefore, as part of a Price Review process, ETSA Utilities must submit its expenditure forecasts for a regulatory period. Following submission, the forecasts are independently reviewed by consultants on behalf of ESCOSA. The outcomes of the review, in combination with a range of other factors, are then used by ESCOSA to determine ETSA Utilities' allowable network prices over the next regulatory period.

2.3 Lead in to the DM Program

Although ETSA Utilities had a range of demand management capabilities prior to the activation of the DM Program, the incentives underpinning a significant effort in demand management research and implementation had been lacking. In order to redress this situation ESCOSA invited ETSA Utilities to propose a range of pilot initiatives related to technologies, regulatory and economic frameworks that would be funded as operating expenditure in the forthcoming regulatory period. A detailed history of the lead in to the DM Program is to be found in Interim Report No 1.

2.4 Demand Management in South Australia

2.4.1 Peak Demand Characteristics

South Australia's electricity distribution system reflects the local geographic, customer, economic, energy market and climatic characteristics, which combine to create a high peak demand and a corresponding high peak demand per capita.

South Australia, with a population of approximately 1.5 million (8% of the national total) has approximately 1.1 million residing in the metropolitan area, where the electrical load is most heavily concentrated. Beyond the metropolitan area of Adelaide/Outer Adelaide, the load is widely dispersed and accounts for only a small portion of the total. The network service area covers approximately 178,200 square kilometres

The State is the driest in Australia and only in the south-eastern region is rainfall reliable, although still mostly light. Average annual rainfall in Adelaide is 585 mm and the weather is characterised by hot, dry summers with relatively mild nights and cool winters. The Figure below illustrates both the magnitude and longevity of the recent March 2008 heatwave which set a new record for Australian capital cities.

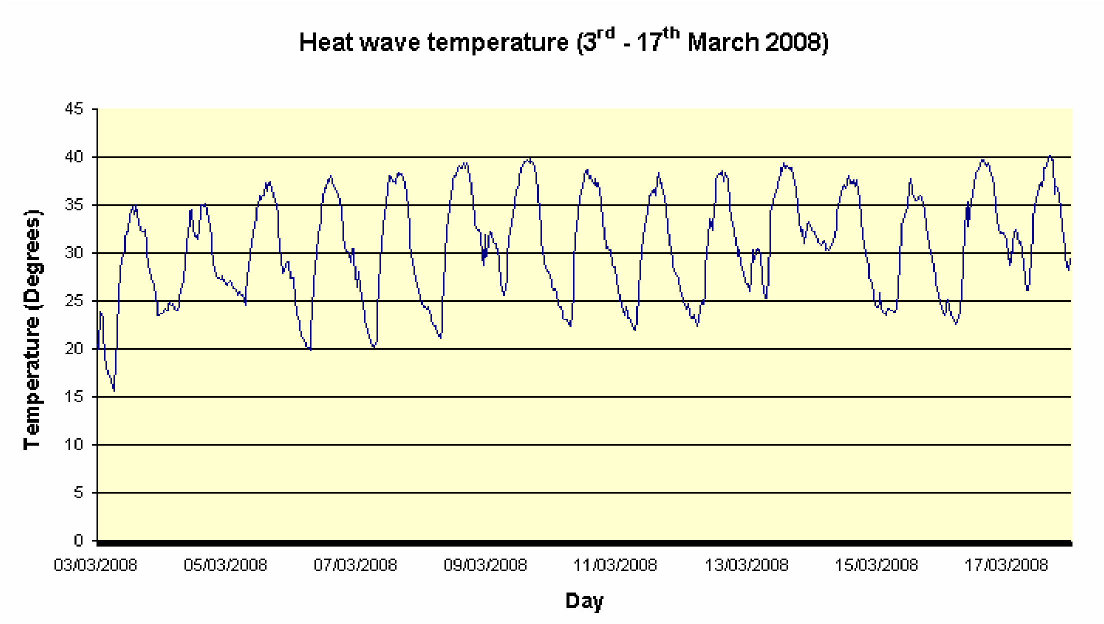

Figure: March 2008 Heatwave for Adelaide, South Australia

Such climatic characteristics contribute to high peak demand per customer. ETSA Utilities' highest recorded peak demand was 2,847 MW[5] on the last day of the heatwave on 17th March 2008 at 16:00 EST.

As a summer-peaking State, the peak demand consists of a base demand that is temperature-insensitive and a cooling demand, which is temperature sensitive and which has been driven by a reliance of households on air conditioners. The "peakiness" of the demand is the highest in the nation and ranks among the highest in the world, with peak capacity required for only 1% to 2% of the year. The demand for an average day as opposed to a peak day is illustrated graphically in the Figure below.

[5] 2,847 MW is ETSA Utilities' distribution system peak demand which includes self generation such and wind and solar power.

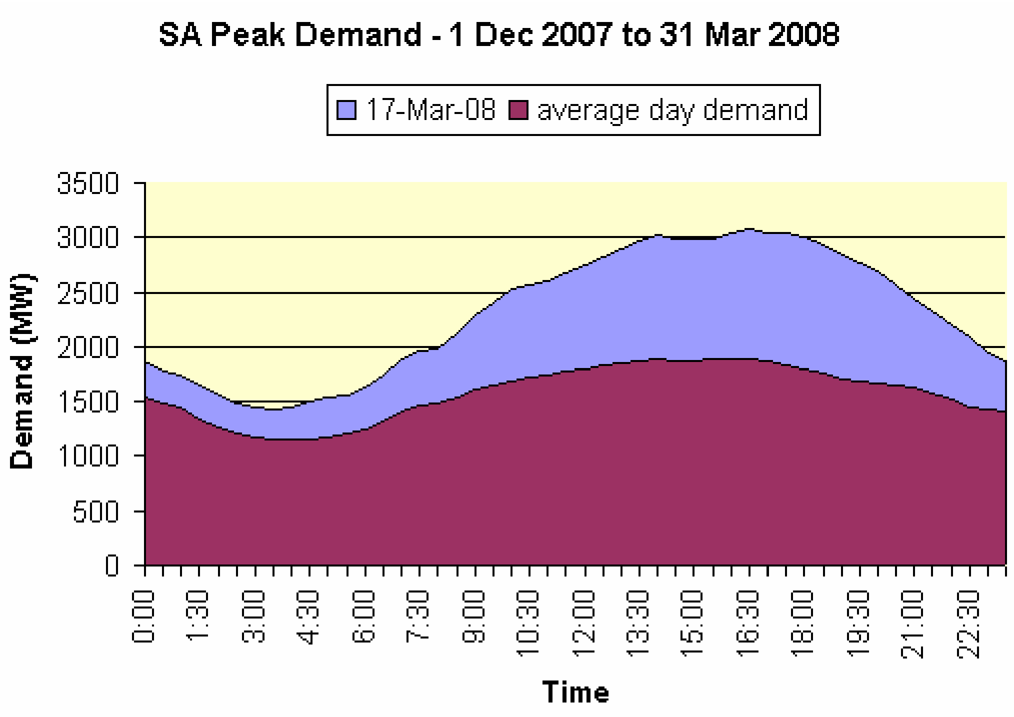

Figure: South Australia's Peak Demand on 17th March 2008

Also, because of the high penetration of air conditioning units in households, the growth in peak demand has been further exacerbated by a trend towards the upgrading of the existing residential air conditioner stock to more powerful models. The Figure below shows the significant upward trend in sales of air-conditioning units in South Australia between 1991 and 2003 sourced from industry sales data[6].

Figure: Sales of Air-conditioning Units in South Australia

This trend to more powerful air conditioning systems as well as the increased usage of electrical appliances has contributed to a steadily increasing peak kW per customer over the past 25 years as illustrated in the Figure below. Also, a peak demand of 4.0 kW per customer over the entire network places the South Australian network's average customer capacity requirement at the high end of the range within Australia, excepting for pure CBD networks.

[6] ETSA Utilities, Expenditure Submission 2005/06-2009/10, undated.

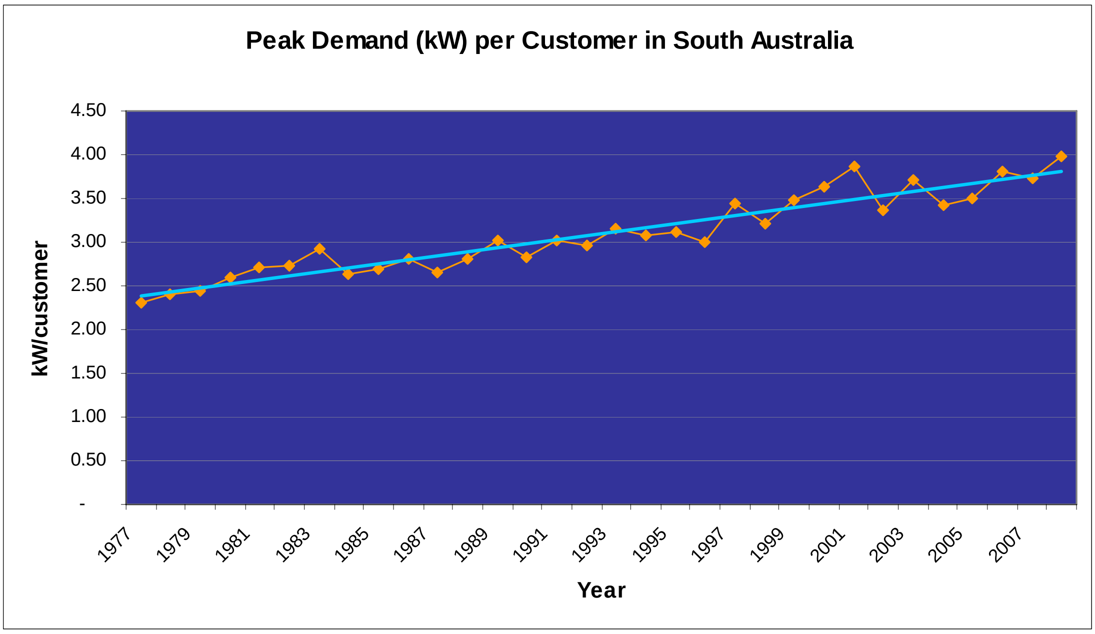

Figure: Peak Demand (kW) per Customer in South Australia

2.4.2 The Deteriorating Load Factor

The electricity load factor is defined as the average demand (proportional to energy sales) divided by the peak demand of the system and is a key measure of network utilisation. Long term historic trends in system peak demand and energy sales point to peak demands having increased at a greater rate than energy sales, as can be seen from the Figure below of average and peak demand trends.

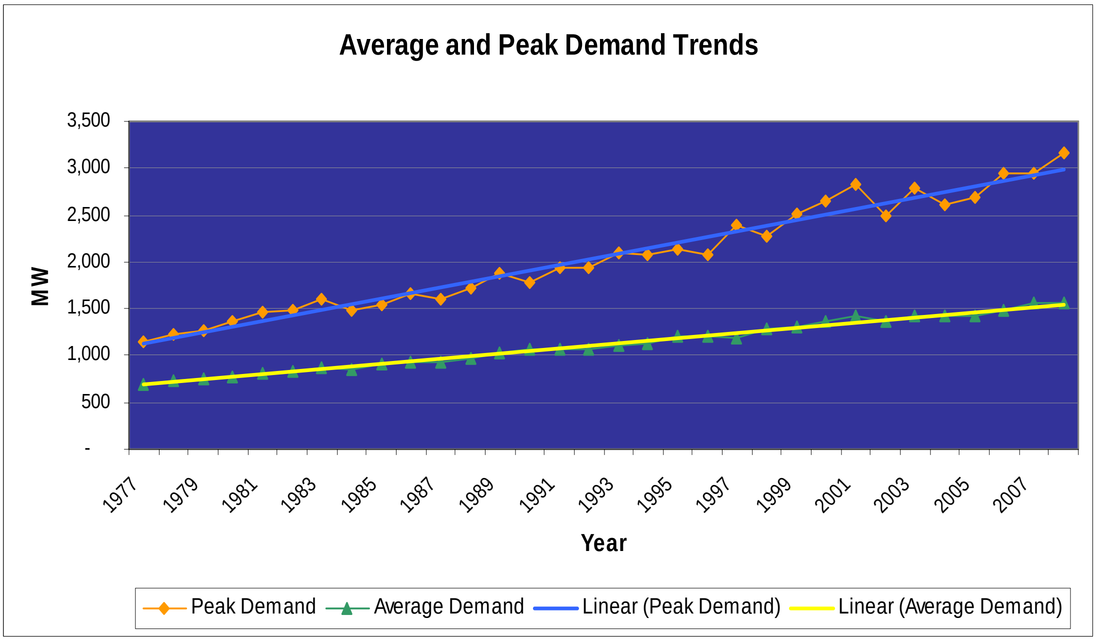

Figure: Average and Peak Demand Trends

Using these trends it is possible to calculate the declining load factor, which has fallen from just over 60% in 1977 to about 50% in 2008 (with the lowest recorded value of 48% in 2003) as shown in the Figure below of South Australia's long term trend in system load factor.

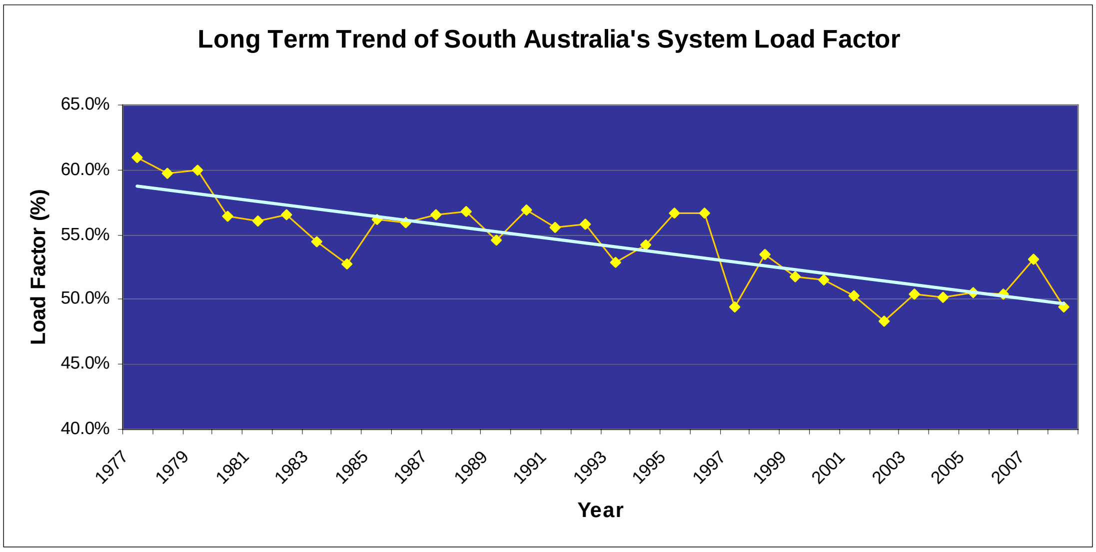

Figure: Long Term Trend in South Australia's System Load Factor

2.4.3 Residential and Network Load Duration Curves

As well as the move to more powerful air conditioning units highlighted above, trends in modern housing design in South Australia add to the deteriorating load factor. The Figure below shows the load duration curves of established Adelaide suburbs compared to that of a new housing development and the small proportion of a year for which peak network capacity is required is clearly evident. New home designs tend to weight their passive design attributes towards reduction of heating requirements rather than towards limiting summer cooling. The result is a peakier load duration curve and reduced load factors.

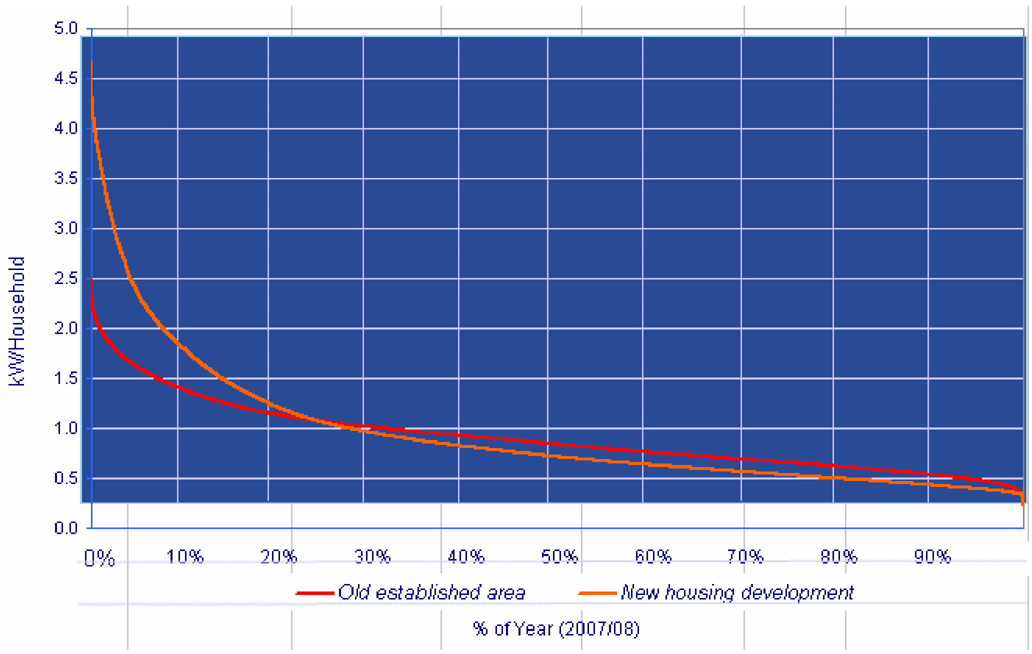

Figure: Comparative Suburban Household Load Duration Curves

The aggregation of all consumer categories' peak demand, of which residential is a significant part, gives a network wide load duration curve[7] as depicted in the Figure below. It is clear that

[7] Note that the peak demand includes customers drawing directly from the transmission network and is therefore greater than the distribution network peak demand.

the network wide load duration curve exhibits similar characteristics to that of residential customers with peak demand required for only 1% to 2% of the year.

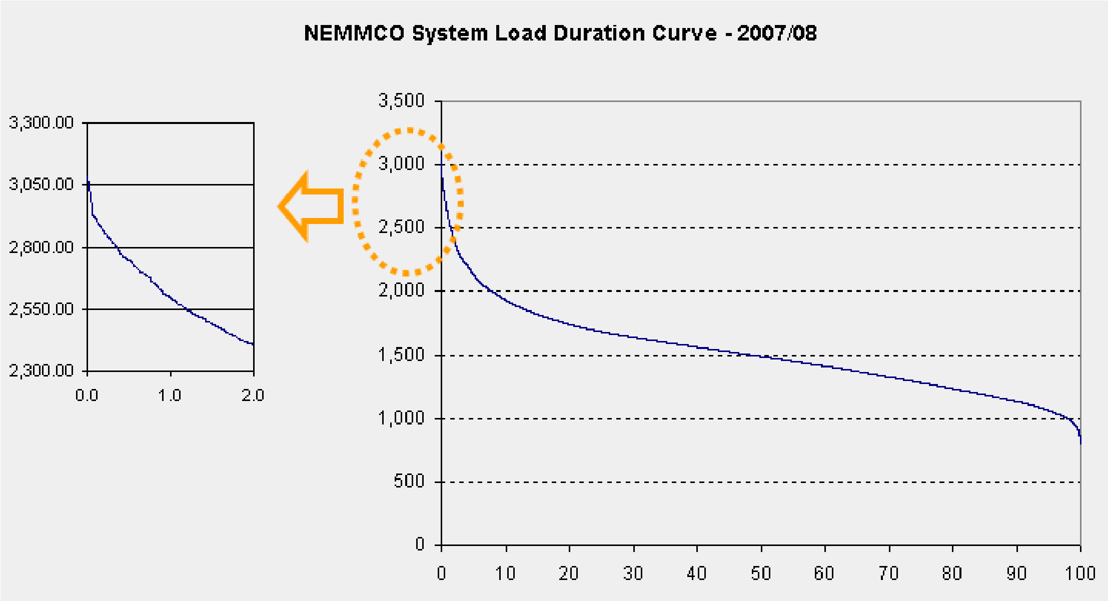

Figure: South Australia's Network Wide Load Duration Curve

2.4.4 Characteristics Contributing to Peak Demand and its Implications

It is seen how the peculiar characteristics of demand on the South Australian electricity network conspire to make it inefficient in terms of assets deployed and energy usage. This leads to customers paying more for electricity in South Australia than in Victoria and New South Wales by a margin of 19% to 45%. The electricity price trends illustrated in the Figure below highlight this fact and are based on data assembled by the Sydney Futures Exchange (SFE) as of 12th May 2008.

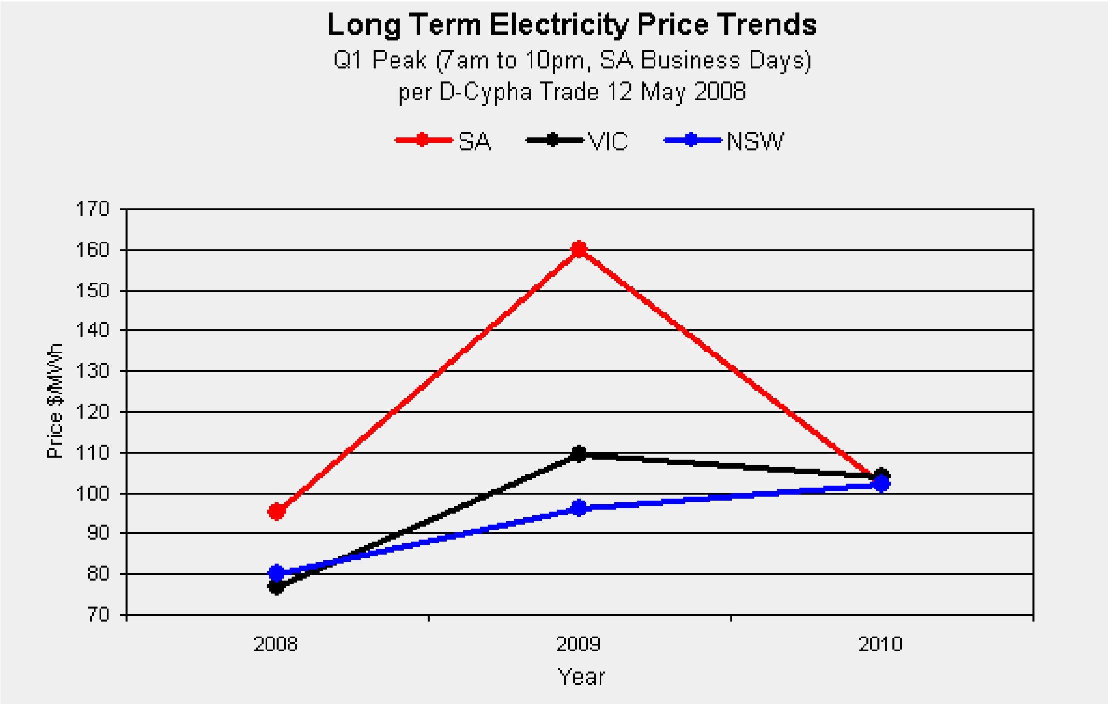

Figure: Electricity Price Trends in SA Compared to Vic and NSW

Further information on electricity future prices at the SFE is broadly supportive of the above trends in a time frame after 2010. This is illustrated in the graph of future price trends for New South Wales, Victoria, Queensland and South Australia shown in the Figure below.

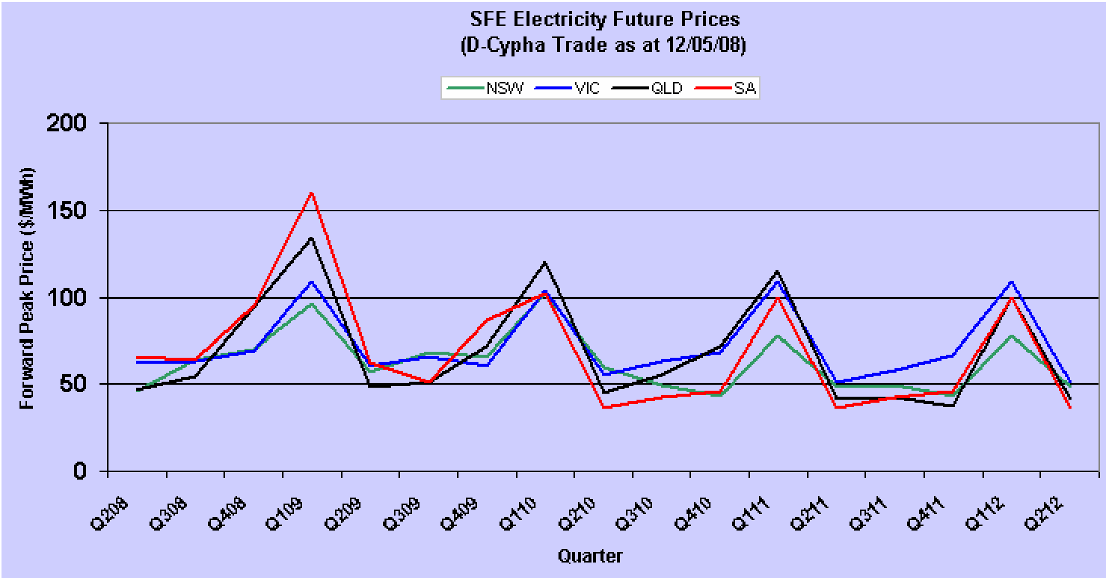

Figure: Sydney Futures Exchange Electricity Future Prices as at 12th May 2008

Understanding these characteristics and trends is important in identifying which demand management measures will have the most impact in improving the network characteristics and energy usage and therefore lead to lower costs for the consumer.

Observation

ETSA Utilities has long recognised the opportunities and challenges of demand management to manage the high peak demand on the network and, within the regulatory framework prior to this DM Program, had taken pro-active steps aimed at reducing peak demand.

Thus with this DM Program of pilot trial initiatives, ETSA Utilities is well placed to build on its knowledge and to be instrumental in taking advantage of demand management opportunities to delay network augmentation and operate the network more efficiently and cost effectively.

3. BACKGROUND TO DEMAND MANAGEMENT

3.1 What is Demand Management?

In Australia, demand management refers to actions by consumers to alter their consumption of electric power as a reaction to an external signal or combination of external signals, generally in the form of prices, incentives or physical external intervention from an entity such as an electricity network operator. ESCOSA in its Guideline 12 defines demand management as:

> *"Management of the level or pattern of energy use on the transmission/ distribution network, so as to minimise the supply costs to customers, whilst maintaining or enhancing customer service levels. Supply costs include costs of projects associated with the augmentation of, or extension to, the transmission or distribution network and include electrical losses. This definition includes such initiatives as:*
>
> 1. *embedded generation*
> 2. *fuel switching*
> 3. *energy efficient appliances or*
> 4. *alternative network options e.g. new transmission support"*

In South Australia there is the potential of reducing both short and long term network costs and prices through the application of two key strategies that improve load factor:

- Strategy 1 – Curtail peak demand growth to delay network augmentation.
- Strategy 2 – Improve asset utilisation by increasing average demand to reduce long-term energy costs.

Strategy 1 reduces overall distribution costs and therefore electricity prices through the deferral of capital expenditure whereas Strategy 2 reduces unit energy prices by spreading the largely fixed cost of operating a distribution network across a higher sales volume of energy. Success in either or both strategies ultimately leads to lower electricity prices.

Demand management is aimed at both strategies through changing customers' usage patterns. The range of demand management approaches is extensive and an integrated program that employs a variety of these approaches is required to achieve the desired energy consumption patterns.

Such demand management approaches often target specific geographical regions, or periods of time, when customer peak demand is nearing, or risks exceeding, the capacity of the distribution network. In such situations, the network is termed as being "constrained", meaning that it has insufficient capacity to meet the customers' peak demand. Traditionally, constraints have been dealt with by building more infrastructure, however demand management seeks to remove constraints by altering customer behaviour. Widespread customer communication and education programs are a pre-requisite to influencing overall community attitudes and customer energy usage patterns.

3.2 Types of Demand Management

Examples of potential demand management approaches, illustrating their complexity, diversity and most importantly, their dependence upon successfully influencing customer behaviour are given in Interim Report No 1 together with some of the obstacles to be overcome to the implementation of demand management approaches

> **Observation**
>
> Demand management has a significant potential to reduce network costs but there are obstacles to be overcome to its successful implementation and application. Application of demand management to distribution networks is a complex field, requiring sophisticated expertise and it is prone to deliver benefits that are not easy to target to, or share with, any particular stakeholder group.

3.3 ETSA Utilities' Use of Demand Management in South Australia

Because of the significant barriers it is not surprising that demand management initiatives have, in the past, met with limited application in Australia. Nevertheless, demand management's promise to deliver substantial benefits has led ETSA Utilities, along with other distributors, to continue to explore its application in the period prior to this DM Program. As ETSA Utilities' prior demand management initiatives have and continue to influence the portfolio of projects selected for the DM Program, they were revisited in summary form Interim Report No 1.

> **Remark**
>
> Demand management initiatives historically undertaken by ETSA Utilities have either resulted in peak demand minimisation, improved asset utilisation or outcomes that contribute to a net benefit in both. Towards the beginning of the current regulatory period 2005-2010, ETSA Utilities had conducted exhaustive evaluations of possible demand management strategies and their potential to deliver desirable outcomes for both its business and the community.

Key amongst these initiatives was a kVA based network tariff for business customers, which was introduced in 2001. This provided the first broad-based price incentive for peak demand reduction in South Australia, since the introduction of controlled load water heating tariffs in the 1980s. In parallel with this, strategies influencing residential customers' behaviour and their appliance and home design choices had been pursued. These initiatives were detailed in summary form in Interim Report No 1 under the following headings:

3.3.1 Controlled Load Water Heating Tariffs

3.3.2 Controllable Load Contracts

3.3.3 Water Heater Time Clock Manipulation

3.3.4 Smart Metering Trial

3.3.5 Introduction of a kVA Tariff

3.3.6 Power Factor Solutions Product (ETSA Utilities & Clipsal JV)

3..3.7 Demand Management Education

3.3.7.1 Sensible Building Design

3.3.7.2 Energy Efficient Home Design

3.3.7.3 Landscaping

3.3.7.4 Air-conditioner Zoning

3.3.7.5 Home Ideas Centre

3.3.7.6 Direct Mail Campaign

3.3.7.7 Web Showroom

3.3.7.8 Controlled Load Tariff Water Heating

3.3.7.9 Housing Industry Association (HIA)

3.4 ESCOSA's Demand Management Categorisation

The demand management initiatives being pursued by ETSA Utilities were to be considerably enhanced by the DM Program. ESCOSA considered that submissions received from the public together with the CRA study provided a good indication of the range of programs that would be suitable for reducing peak demand and that should be considered for funding.

ESCOSA views are outlined in "Part A – Statement of Reasons, Section 4 - Demand Management, 2005-2010 Electricity Distribution Price Determination" wherein it states "These are mostly pilot programs for specific initiatives, as well as activities designed to build ETSA Utilities' demand management capabilities and to aggregate the benefits of demand management across the industry." The specific categories of demand management initiatives identified by ESCOSA during its extensive deliberations are:

- Power Factor Correction
- Standby Generation
- Direct Load Control
- Critical Peak Pricing
- Voluntary Load Control and Curtailable Load Control for Large Customers
- Interval Meters
- Aggregation
- Demand Management Organisation within ETSA Utilities

Section 4 discusses the portfolio of projects within the DM Program being undertaken by ETSA Utilities and it is in that Section that ESCOSA's rationale for the above category selection is more fully described with direct paraphrasing from the EDPD.

3.5 Enabling Technology

Most demand management strategies are time based and are therefore reliant on enabling technology to discern the time differential of demand. As is the norm with technology in general, prices to implement time based rates and automated customer responses have been falling as their capabilities have been rising. Examples of enabling technologies include:

- Interval meters with two way communications allowing customer bills to reflect actual usage patterns rather than average load profiles.
- Multiple communication pathways to notify customers of load curtailment events.
- Load controllers and building energy management systems that are optimised for load response and provide for load curtailment.
- On site generation equipment, traditional and renewable, for either back up or primary power needs of a facility.

Observation

Enabling technology needs to be used with discretion as the case of interval meters illustrates. If demand management is to rely primarily on interval meter technology, then the meters will need to be rolled out on a community wide basis, (capital cost of roll out), the data will need to be transmitted (communications costs) and the data will have to be managed (operational costs). Clearly before any wide scale implementation of a demand management strategy using enabling technology is contemplated, all of the associated costs and benefits must be addressed in a comprehensive cost benefit analysis.

3.5.1 Smart Metering and Price Signals

In Australia the case for smart metering in the residential sector is gathering momentum with some distribution network operators, such as EnergyAustralia, in New South Wales, having begun the installation of interval meters (but not inclusive of advanced metering functionality) as part of their normal replacement policy and the Victorian Government overseeing the roll out of interval meters to all electricity customers in that State.

Independently of the Victorian initiative, in April 2007, the Council of Australian Governments (COAG) endorsed a staged approach for a national mandated roll out of electricity smart meters as determined by the results of a cost benefit analysis which was completed at the end of 2007.

These initiatives were discussed in some detail in Interim Report No 1 and are revisited in Section 4.3.6 – Interval Meters, particularly in regard to progress that has been made during 2007 both in terms of the COAG cost benefit analysis and ETSA Utilities' own cost benefit analysis for the South Australian jurisdiction.

In terms of price signals, there is still little evidence to suggest that customers will adapt their consumption patterns to the price signal they are given. In fact, experience and research would suggest that a customer's reaction to price signals diminishes over time, particularly short term price signals such as Critical Peak Pricing (CPP). And herein lies a dilemma because CPP works if electricity is strongly price elastic. ETSA Utilities' experience is that after three to four days of temperatures above 40°C electricity is, in fact, price inelastic.

Observation

As far as the question of tariff innovation that smart metering can facilitate is concerned, interval meters have been installed in commercial and industrial premises in Australia for nearly a decade and apart from a few exceptions there does not appear to have been any noticeable increase in the volume of innovative tariffs during this period. Subjective evidence in South Australia suggests the opposite, that simpler tariffs with less user intervention are preferred by consumers.

In relation to peak demand and a corresponding high price to reflect the peak demand, because of the vagaries and complexities of electricity markets in Australia, there does not appear to be a high degree of correlation between peak demand and a high pool price. A conclusion to be drawn here is that price signals may in reality not impact on customer behaviour when it comes to their electricity usage.

4. TRIALLED DEMAND MANAGEMENT PROJECTS

The DM Program is made up of individual projects grouped under particular categories of trial activity put forward by ESCOSA and agreed with ETSA Utilities. This trial activity is designed to one: build ETSA Utilities' demand management capabilities and two: aggregate the benefits of demand management across all consumer categories in South Australia

Individual projects come into being through a specific process which is broadly described in the following way.

ETSA Utilities' Demand Management Team (Team) described in Section 4.3.8 has a significant collective body of knowledge of issues associated with demand side management and calls upon this knowledge to draw up an initial list of projects.

Using this initial list of projects a short list is prepared that fits within the EDPD Determination[8] of meeting budgetary expectations and having a good prospect of producing benefits greater than the incurred costs in a widespread network roll-out.

Projects from the short list are then allocated to an individual expert within the Team for more detailed scrutiny. The short list is then reviewed and the agreed-to projects incorporated into a final project list which can be added to or deleted from as the DM Program progresses.

Each of the projects on the final project list is then scoped by the relevant Team expert and the project initiated. New projects coming to light after the composition of the initial project list are required to go through the same culling process.

This Section describes the individual projects currently comprising the portfolio of projects for the DM Program as of June 2008.

4.1 DM Program Composition

The DM Program is comprised of individual projects which are classified under headings, identified by the EDPD Determination in conjunction with ETSA Utilities' expenditure submission, as follows:

- Power Factor Correction
- Standby Generation
- Direct Load Control
- Critical Peak Pricing
- Voluntary Load Control and Curtailable Load Control for Large Customers
- Interval Meters
- Aggregation
- Demand Management Organisation within ETSA Utilities

Projects not able to be categorised under any of the above headings have been placed under a generic heading labelled:

- Other

As of June 2008, the DM Program portfolio consisted of 27 individual projects. This total may be added to as the DM Program unfolds in 2008, prior to the summer of 2008/09 trials, and as the learnings from the existing projects point to other initiatives that will benefit the demand management research effort.

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[8] Essential Services Commission of South Australia, 2005-2010 Electricity Distribution Price Determination, Part A – Statement of Reasons, Section 4 – Demand Management, 2005.

4.2 Individual Project Status

After having drawn up an initial project list in late 2005, projects commenced in March 2006 and have been progressively added to since then. These projects are at various stages of development. In order to broadly identify the stage of development of each project, status indicators have been assembled. These indicators are listed below together with a description of their respective characteristics.

- **Status 1:** Project Pre-implementation Phase.
  - Project currently being scoped.
  - Cost-benefit exercise underway.
  - Pre-implementation engagement of participants and stakeholders.
  - Technology being sourced.

- **Status 2:** Project Implementation Phase.
  - Project defined and initiated.
  - Technology procured.
  - Supplier and participant agreements negotiated.
  - Installation and commissioning underway.

- **Status 3:** Active Project.
  - Customer and supplier contracts and agreements endorsed.
  - Technology deployed.
  - Data collection underway.
  - Analysis of data in hand.
  - Production of final project report in progress.

- **Status 4:** Project Complete
  - Learnings analysed.
  - Reporting complete.

Detailed "project scope" and "project management" documentation has been created for all Status 2 and 3 projects. Status 1 projects and those other projects under consideration, will as the DM Program evolves, have detailed "project scope" and "project management" documentation drafted as each project passes the acceptance criteria described above. Status 4 projects are reported upon individually in the form of case studies to be appended to the Final Report on the DM Program.

4.3 DM Program Portfolio

As of June 2008, the DM Program portfolio comprised a total of 27 projects grouped under the categories defined in Section 4.2. These projects are tabulated below:

Category & Project Count	Project	Status as at 31/05/07	Status as at 31/06/08
Power Factor Correction			
1	Pole Top Low Voltage (LV) Capacitors	1	3
2	Tariff Rationalisation Project	3	3
3	Keswick Building Improvements	1	3
Standby Generation			
4	Load Reduction Trial	2	3
5	Embedded Generation Trial 1	2	2
Direct Load Control			
6	Direct Load Control Phase I	4	4
7	Direct Load Control Phase II	4	4
8	Direct Load Control Phase II(a)	3	4
9	Direct Load Control Phase II(b)	2	4
10	Direct Load Control Phase III	1	3
11	Regional Discretionary Load Trial	1	4
12	Universal Demand Response Enabling Device (DRED) Interface	1	3

Category & Project Count	Project	Status as at 31/05/07	Status as at 31/06/08
13	Commercial Building Management System (BMS) Trial	1	3
14	Domestic Load Limitation – Lochiel Park	2	4
15	Commercial Load Limitation	3	3
Critical Peak Pricing			
16	Residential Critical Peak Pricing (CPP) Tariff Trial	1	3
17	Commercial Critical Peak Pricing (CPP) Tariff Trial	1	1
Voluntary and Curtailable Load Control for Large Customers			
18	Domestic Load Shifting Time of Use (ToU) Trial	1	1
19	Commercial Load Shifting Thermal Energy Storage (TES) Industrial Trial	3	3
20	Commercial Load Shifting Thermal Energy Storage (TES) Commercial Trial 1	3	3
21	Commercial Load Shifting Thermal Energy Storage (TES) SME Trial	1	3
Interval Meters			
22	Interval Meter Approach	2	3
Aggregation			
23	Load Reduction Trial 1	2	2
24	Aggregation of Benefits to Electricity Market	1	1
Demand Management Organisation Within ETSA			
25	Demand Management Team and Organisation Structure	3	3
Other			
26	Painted Roof Trial 1	2	3
27	Passive Demand Reduction Trial	1	4

Table: Categorisation of Individual Projects and Their Status Indicator

Status

As of June 2008, of the 27 projects 26% had been completed, 56% were active 7% were in the implementation stage and 11% were at the pre implementation stage.

The Table below compares the project status as of June 2008 with that of May 2007.

Project Achievement	Number	(%) as at 31/05/07	(%) as at 31/06/08
Status 4 - Complete	7	7	26
Status 3 - Active	15	26	56
Status 2 - Implementation	2	26	7
Status 1 - Pre-Implementation	3	41	11
Total	27	100	100

Table: Project Achievement of the 2005-2010 Demand Management Program

4.3.1 Power Factor Correction (PFC)

This category was deemed appropriate for the DM Program because under voluntary kVA tariffs eligible customers are offered lower charges for the energy components of the tariff but have the demand component charged on a kVA basis. The rationale for the choice of this category is best explained by paraphrasing sections of the EDPD Determination.

"In 2001, ETSA introduced a number of voluntary kVA (power factor dependant) tariffs.

To date customers who have accepted these tariffs are generally those with relatively good power factors[9]. While such customers have thereby received a more cost-effective price, it could be concluded that the kVA tariff program of ETSA Utilities has not induced many customers to improve their power factors. In response, ETSA Utilities has revised the kVA tariff program to include a requirement that the customer makes a commitment to improving its power factor in order to qualify for the tariff.

The Commission believes that there is a case to mandate the use of kVA tariffs for all customers with annual electricity consumption greater than 750 MWh.

To encourage customers to take corrective action and improve their power factor, the Commission has decided to provide funding for ETSA Utilities to develop an assistance program, to be approved by the Commission, for customers who opt to go on a kVA tariff, by mid 2008. The assistance program is expected to include direct financial assistance from ETSA Utilities to the customer for the installation of the required power factor equipment and metering (if required)."

Trials conforming to the ESCOSA Determination as expressed above were identified and resulted in the selection of the following three projects:

- Pole Top Low Voltage (LV) Capacitors.
- Tariff Rationalisation.
- Keswick Building Improvements.

4.3.1.1 Pole Top Low Voltage (LV) Capacitors

As of June 2008, this was an active Status 3 project that was selected to determine whether Low Voltage PFC technology at a network level is a viable option for reducing load on the network.

Low voltage capacitance is installed on the low voltage network but since the variation in PF on the network is highly dependent on each individual customer load, the selection of suitable sites is difficult as it must be ensured that the capacitor does not lead to over-voltage problems. A LV capacitor beneath a transformer is shown in the Illustration below.

Illustration: Typical LV Capacitor and Street Transformer

Various areas of Salisbury, Gawler and Elizabeth were investigated for a suitable feeders and an area of Gawler was selected which comprised a mixture of both small industrial and

9 Power factor is essentially the ratio of the useful work performed by an electrical circuit to the maximum useful work that could have been performed at the supplied voltage and amperage. A low power factor is generally considered to be anything less than an 80% to 90% power factor rating.

commercial customers. Transformers were monitored prior to the trial to identify and select those with poor power factors. The larger industrial areas with recently installed 11kV PFC were disregarded.

The trial consisted of mounting 9 LV capacitors on pole top transformers on a single feeder. The feeder loads were then monitored at various pole top positions and at the supply substation to determine the effect of the capacitors.

Monitoring, which occurred from January 2008 to March 2008 indicated that the PF improved slightly from an average of approximately 85% to 95% (i.e. a 12% improvement) with a commensurate load reduction in kVA.

The capacitors had not been used in Australia previously but discussions with the manufacturer revealed that in other countries their installations appeared to be a simpler affair primarily because of the more lenient occupational health and safety and quality of supply requirements.

Installation cost was approximately $1,200 per capacitor (depending on size).

Learnings

The trial has demonstrated that specific transformers identified during any quality testing could be singled out for a temporary fix but that a large roll out would not be cost effective compared to ETSA Utilities ongoing work in this area. It is more cost effective to focus on high voltage PFC at 11kV and to instruct customers with poor power factors to install in-house PFC equipment as per the Tariff Rationalisation Trial discussed below.

This project is due for completion in mid 2008 by which time one months continuous monitoring will have been recorded, which along with the 4 weeks of data already accumulated with polyloggers should be sufficient to enable final conclusions on this Trial to be drawn and reported upon.

4.3.1.2 Tariff Rationalisation

As of June 2008, this was an active Status 3 project, which seeks to improve the PF of ETSA Utilities' largest customers as their non-compliant power factor puts additional strain on the network during the summer peak demand period and impacts on network reliability. The network therefore needs to be of larger capacity than would be the case if customers were power factor compliant.

Specifically the Trial's aim was to:

- advise customers via letter of their non-compliance and the potential tariff savings available by improving their PF;
- introduce an Excess kVAr Incentive Charge (the charge) for non compliant customers;
- advise customers of the introduction of the charge as well as a reminder of their obligations under the Code with respect to PF;
- apply the charge to non-compliant customers effective from the 1st July 2007.

Introduction of the charge was announced in January 2007 that it would come into effect on the 1st July 2007 at a value of $40 per annum per excess kVAr.

ETSA Utilities identified about 600 of its largest 1,500 customer connection points that required power factor correction. Residential and small businesses generally have a PF of 90% or greater, which exceeds the requirements of the Code. No action from this group was therefore required. Of the 600 customers only the non-compliant customers assigned to a network demand tariff were targeted as only these customers' metering had the ability to record PF, measured in kVAr.

Approximately 80 of these 600 customers avoided the charge as a result of their required PF correction being less than the threshold 10 kVAr and a further 60 avoided the charge as a result of shutting down, drastically reducing their load or being compliant in the 2006/07 summer period. Customers will often swing between compliance and non compliance during the peak summer period purely due to the dynamic nature of their operation.

Customer response to the letters was strong, however actual installation of PFC equipment was low as it is generally difficult to engage customer interest when their electricity bill is not a significant input cost to their operation. Furthermore it was observed that the direct letter writing campaign to as high a level as possible (i.e. CEO, MD) yielded the best response. In addition, an assertive letter (i.e. you are not Distribution Code compliant) as opposed to the softer letter (i.e. Hi, here is an opportunity to save on your electricity bill) was the more successful.

Of the 460 customers subjected to the charge, 120 installed PFC by the 1st December 2007. These included some of the larger customers whose PFC installations led to large load reductions. The remaining 340 customers account for an estimated 60 MVAr due to PFC if they were to correct to Distribution Code compliance. However, experience shows that once customers make the decision to install PFC, some install more than the minimum PFC required to become Code compliant. This can result in a higher than expected load reduction. Nevertheless, although a customer may have installed suitable PFC equipment and reduced their physical demand, most opt to keep their original contracted capacity with the associated demand charges as a long term hedge against future capacity increase as a result of business expansion.

ETSA Utilities is conducting an annual review, post the summer 2007/08, of all demand tariff customers, which will identify PF compliance over the summer period. Reset of customer Excess kVAr Incentive Charges will take effective from 1st July 2008 and is likely to yield new customers who will be subjected to the charge.

Trial Observation

Importantly, the incentive charge has prompted some of South Australia's largest electricity users to install PFC equipment and become compliant.

The estimated correction to date from the 120 customers installing PFC equipment is 50 MVAr, 22 MVAr more than what was required to reach compliance for this group. 50 MVAr translates to approximately 24 MVA of demand. The PF for this group improved from 80% to 93%.

Based on the results of these 120 customers, the actual kVAr correction for the remaining 340 customers is likely to be greater than 60 MVAr.

This project is on schedule, however its completion date is dependent on positive customer response and action as PFC is not mandated in South Australia. Subject to customer response, it is expected that final reporting on this trial can commence in the near future.

4.3.1.3 Keswick Building Improvements

As of June 2008, this was a Status 3 project at the implementation stage that aims to:

- Improve the building's power factor.
- Use the standby generator for peak load reduction.

Standby generation synchronisation has been completed on the 313 kVA diesel generator. It is now capable of being synchronised to the network, providing support and/or running in an emergency supply mode to pick up essential building services as necessary. While the maximum capacity of the generator is 313 kVA, when it is operated as a peak reduction plant, the load able to be supplied to the network is limited to 200 kVA. This is due to the configuration of the connected switchboards and the protection and distribution network safety requirements.

The generator was dispatched 6 times in March 2008 as a demand side management measure reducing the peak building load by 200 kVA each time thus demonstrating that standby generators can be successfully utilised for peak load reduction in commercial buildings.

Trial Outcome

This trial demonstrates that standby generators can be run in a manner that achieves peak load reduction in commercial buildings. However, the operation of a standby generator as a supplementing embedded generator for the network can be quite different to its operation in a normal emergency mode. Issues of synchronisation and the control strategy to ensure that maximum safe loading of the generator is achieved will require a detailed knowledge of each installation.

4.3.2 Standby Generation

ESCOSA is of the view that it is appropriate to initiate a standby generation pilot program. The first stage would be an assessment of the technical and environmental barriers of connecting and operating existing embedded generation equipment in parallel with the distribution network with the generators then providing network support during peak load periods. If the outcomes of these assessments prove favourable, ETSA Utilities would then proceed with the implementation of a pilot program.

The ESCOSA Determination goes on to say.

> *"It is envisaged that, subject to reaching suitable funding arrangements, two to three generators would be upgraded with the required protection and synchronising equipment to allow these units to operate in parallel with the distribution network.*
>
> *The Commission would expect that the participating generators be modified and available for commercial use by the end of 2007, and that they operate as part of the pilot program for a minimum of two years, with the aim of identifying the embedded generators providing network support and/or generation capacity during peak load periods.*
>
> *The Commission expects ETSA Utilities to work with developers constructing new buildings/facilities, during the planning stage, to examine the feasibility of installing embedded generator(s) for demand management purposes during the construction phase."*

Projects identified to date by the Team's experts that conform to the EDPD Determination are the:

- Load Reduction Trial
- Embedded Generation Trial

As standby generation is typically employed on sites where there is a requirement for an uninterrupted power supply (i.e. call centres, essential services, hospitals, data centres, etc) it requires electricity generating plant to be on the customer's premises. This plant may supply the entire premises or portions of the premises at times of network outage and will remain idle at other times.

Because of its traditional application, the use of standby generation (or embedded generation) within the National Electricity Market (NEM) has been dependent on the customer's retailer being prepared to accept the generator's output as part of the energy contract. Additionally the suitability of the customer's electrical installation, generating plant and ETSA Utilities' infrastructure has limited the ability for standby generation to be efficiently utilised.

From a technical and operational standpoint, typically the electricity supply would be briefly interrupted before the standby generator control system senses the loss of supply and automatically starts to replace the supply. Uninterruptible Power Supply (UPS) which is essentially a large battery bank can maintain essential services until the generator is on line and able to take up load, but it is expensive to deploy and maintain. So to be able to use the generator during normal supply periods, there are two options available.

The first option is to transfer a suitable amount of load from the network supply to the generator supply. This is a multi stage process which requires the load to be switched off, isolated from the grid supply and then reconnected to a running generator. This is suitable for HVAC plant which can be shutdown and restarted on the generator supply with little or no noticeable disruption but is obviously not suitable for equipment requiring continual operation such as computers, essential services and some industrial processes.

The second option is to allow the generator to first start and connect in parallel with the incoming electricity supply. This reduces the amount of electricity supply required from the network. If the generator is large enough, it can actually supply electricity into the network if there is surplus capacity left over after serving the customer's needs. This form of operation requires some modification to the customer's equipment and the installation of synchronising control systems to automate the connection process. Any attempt to connect a generator set without first synchronising can have catastrophic effects on the generator and the electrical system both on the customer's site and on the electricity network. As synchronising systems are relatively expensive they are not generally installed.

4.3.2.1 Load Reduction Trial

As of June 2008, this was an active Status 3 project aimed at:

- reducing demand from existing refrigerated air conditioners;
- gathering data on the impact of the new technology on load reduction;
- using the project as a reference site for promoting and showcasing the technology.

The trial is being conducted by Seeley International Pty Ltd with new evaporative technology that reduces the load on existing refrigerated air conditioners by pre-cooling the outside air before it enters the main HVAC plant.

This new technology uses "Dricool" evaporative units installed on an outside air path of ETSA Utilities' Marleston building. Located in the middle of the building the air conditioning system draws in and exhausts air at each end of the building's longitudinal axis. Two Dricool units at one end of the building and at right angles to the longitudinal axis pre-cool the air before it flows through the air conditioning system.

The system was tested in March 2008 during the 2007/08 summer heat wave with preliminary results indicating that the units accounted for only a small percentage of the air flowing into the plant room. Such a small percentage of contributing air flow could account for the reason that the temperature at the filters was the same as the return air temperature and had little impact on peak load reduction.

Important Outcome

The Dricool technology is capable of cooling the outside air temperature to a level comparable with the return air temperature but this does not seem to be accompanied by a reduction in peak electrical load.

A detailed report on the findings of this trial will follow its completion.

4.3.2.2 Embedded Generation Trial

As of June 2008, this was a Status 2 project at the implementation stage.

The project seeks to test the potential of using embedded generation from commercial and industrial customers who have standby generation plant available for demand side management. In order to do this it is necessary to not only source and dispatch the plant but also to negotiate back to back contracts with a wholesale market participant as well as end use customers.

Specifically this project aims to:

- Gain experience in valuing, drafting and negotiating contracts with the wholesale market counterparts.
- Gain experience in drafting and negotiating service contracts with customers.
- Investigate the opportunities for automated dispatch of generation assets.
- Assess the performance of embedded generation for reducing peak loads.
- Assess the capability of customers to respond to dispatch instructions.
- Assess the potential of the widespread utilisation of embedded generation.

ETSA Utilities' initial trial with its own network support generation at Cowell on the Eyre Peninsula produced some excellent learnings with regard to financial models, counterparty relations and contracting.

> **Learnings**
>
> The trial to date has demonstrated that, given the right financial and contractual incentives, there is a definite opportunity for aggregation of revenues from the various market sources. In the case of Cowell, ETSA Utilities was able to derive revenue from a form of exotic cap contract with the retail sector and also to participate in the NEMMCO Reserve Trader process.

This trial has highlighted that there are significant hurdles to overcome, in particular issues associated with: metering; data capture, storage and interpretation; settlement of contracts; control; resourcing; value adding of third party participants (e.g. brokers); the operation of the Reserve Trader auction system and problems arising from the lack of correlation between the National Energy Market and the local peak demand on ETSA Utilities' distribution network.

For embedded generation to be considered a realistic option at urban substations it will be necessary to confront issues such as carbon emissions, noise and exhaust fumes pollution. As such, alternative embedded generation sources need to be investigated. Technologies showing promise are those of the flow battery and the hydrogen fuel cell.

The flow battery technology is commercially available in the US but is expensive and has a relatively low kW value (250 kW) as well as a finite discharge period (2 hours at 250 kW, lower discharge rates provide a longer period of availability, for example 5 hours at 100 kW) before needing to be recharged.

New hydrogen fuel cell technology can provide up to 400 kW for as long as hydrogen fuel is supplied. It delivers lower capacity than a comparable diesel generator but has no noise or emission pollution and can provide a Combined Heat Power (CHP) option as a result of the hydrogen recombining after use.

Further work in this trial will concentrate on recruiting standby generation plant that can be used when requested. The incentive funding is to allow for a total of 6 MW of capacity to be harvested and technically modified, for example, by making necessary technical changes to synchronising equipment or transfer switches to allow the plant to be utilised effectively and its impact to be reported on. In addition to this it is proposed that carbon offset certificates be purchased and provided to customers in order to cover their additional running time.

To explore these issues the trials are to be scoped in more detail and launched in the coming year with initial customer contract scheduled from mid 2008.

4.3.3 Direct Load Control

Primarily, and on the basis of the CRA study ESCOSA, in 2004, approved funding to pilot a direct load control (DLC) program of 1,000 to 2,000 residential customers with suitable air-conditioning units, pool pumps and other suitable equipment. The ESCOSA Determination views DLC in this way.

> *"The need for such a pilot program (DLC) is underscored by the major contribution to peak electricity demand made by residential air-conditioners. Important issues to be addressed in this pilot will include an assessment of:*
>
> - *the cost-effectiveness of different DLC control technologies;*
> - *customer receptivity and take-up at various types and levels of initiative;*
> - *load reduction impacts (as compared to projections);*
> - *impact of cycling on air-conditioning operation;*
> - *customer comfort;*
> - *customer satisfaction; and*
> - *the willingness of customers to stay on the program.*
>
> *The Commission believes that it is appropriate to pilot suitable DLC initiatives under SA conditions for a minimum of two years."*

Trials aimed at confirming the above were put forward by the Team's experts for consideration by the Program Steering Committee. The 10 projects that resulted from this process were:

- Direct Load Control Phase I
- Direct Load Control Phase II
- Direct Load Control Phase II(a)
- Direct Load Control Phase II(b)
- Direct Load Control Phase III
- Regional Discretionary Load Trial
- Universal Demand Response Enabling Device (DRED) Interface
- Commercial Building Management System (BMS) Trial
- Domestic Load Limitation – Lochiel Park
- Commercial Load Limitation

4.3.3.1 Direct Load Control Phase I

This project which was completed in March 2006[10] was reported in some detail in Interim Report No 1. It sought to:

- determine customer perception of change in comfort levels resulting from the remote management of domestic air conditioners;
- determine the impact on aggregate demand for the sites in the trial;
- gain experience in the installation and operation of proprietary technology;
- test the performance of selected control technology;
- gain experience in quantification, metrics and verification.

A sample size of 20 customers was selected from a pool of 50 customers in the Adelaide metropolitan area that represented a cross section of the community in terms of: house type; age of house; occupants' lifestyle; metropolitan geographic location and size and type of air conditioner.

[10] ETSA Utilities, Case Study 1, Report of Customer Response to the Remote Management of Domestic Air-conditioners, 26th April 2006.

Learnings

In terms of aggregate demand, the trial confirmed that forced cycling of air-conditioner compressors reduced aggregate demand in the sample group by an order of 17% from a peak of approximately 30 kW. Also ETSA Utilities gained useful experience, albeit on a limited scale of: roll out of controllers; control cycle times; customer behaviour; communications reliability and management and storage of metered data.

These learnings were incorporated into the larger scale Phase II & III trials.

Important Outcome

The DLC controller functionality worked well and provided ETSA Utilities with important information with regard to: internal fault diagnostics, inverter technology; external control logic; external control interfaces; siting of external control interfaces and specification of installer contracts.

4.3.3.2 Direct Load Control Phase II

This project follows on from the Direct Load Control Phase I and was discussed in some detail in Interim Report No 1. It began with a marketing and community education program[11] by ETSA Utilities entitled "Beat the Peak". The trial footprint in the Glenelg area, shown in the Figure below, has a significant penetration of air conditioners serviced by two substations, which will be constrained within the next few years.

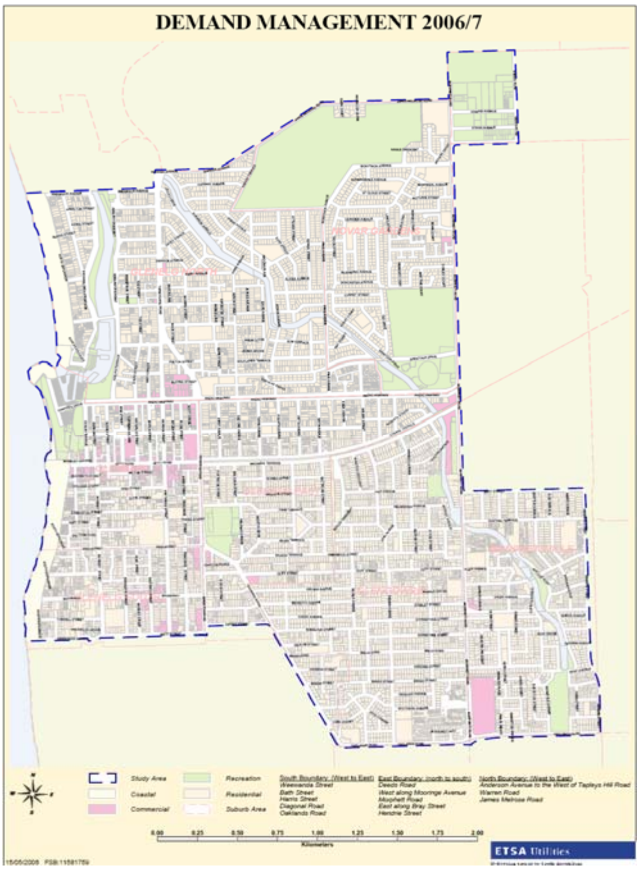

Figure: The Trial Study Area for Phase II, II(a) and II(b)

[11] ETSA Utilities Media Release, "Beat the Peak" Summer Demand Management Trial for Glenelg, June 2006.

The marketing and education campaign targeted approximately 12,000 residences and commercial premises using messages[12] designed to engage the customers sense of "what's in it for me" and community mindedness as well as a cash incentive of $100 to participate in a demand management trial.

Trial Outcome - Media

The result of the media marketing campaign was that of 47 features in the local media and 16 in the national media only one negative commentary was recorded. Importantly, no media disputed the demand side message, or raised any issue about the demand side rather than the supply side management focus. The message of demand side management requirement was accepted and repeated as a fact, not a question, not a debate.

Trial Outcome - Volunteers

The message inherent in the "Beat the Peak" campaign resonated with the community in that more than 4,000 calls of support and interest in participating in the trial were received from occupants of the residences in the Glenelg. Each of these contacts received a personal letter from ETSA Utilities thanking them for registering and was later followed up with a phone call.

From the 4,000 contacts 1,691 air conditioners, which were either split or ducted refrigerated systems were identified as suitable for the trial. Visits to every commercial premises enlisted a further 701 air conditioners. This total of 2,392 air conditioning units was distributed throughout a total of approximately 1,570 residential and commercial locations. A representation of the community response by proportional makeup of air-conditioning units is illustrated in the Figure below.

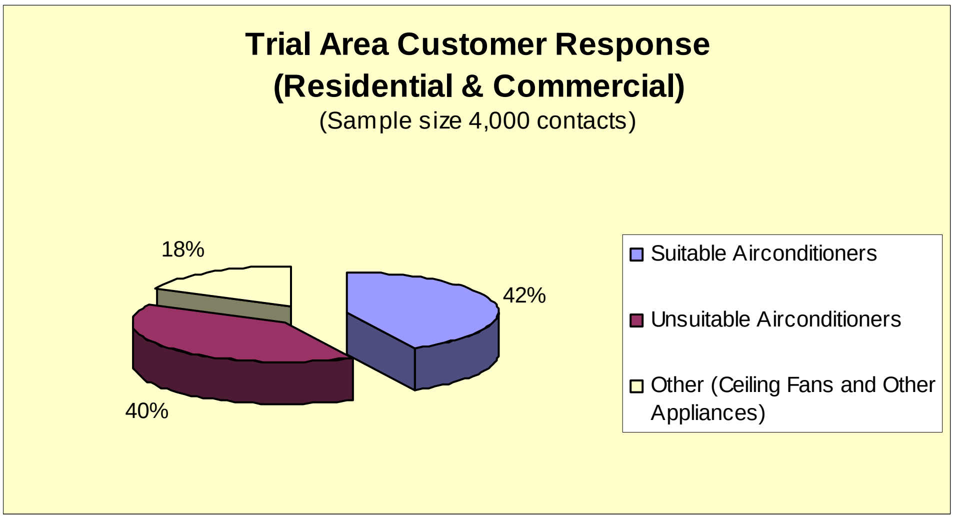

Figure: Glenelg Area Sample Population

The trial sample of 2,392 air conditioners was monitored for response to DLC events during the summers of 2006/07 and 2007/08. Monitoring equipment installed on some of the air conditioners and at ten 11 kV sub station feeders and 86 street transformers supplied data for analysis and interpretation.

[12] ETSA Utilities, Initial customer response to residential demand management as a new project and ETSA Utilities engagement methodologies, November 2006.

Important Outcome

Of the 2,392 suitable air conditioners available, 1,158 (approximately 50%) were found to be what is termed "new generation units". These have advanced diagnostics which require a changed installation scope to that of simply attaching a "Peakbreaker" to an external compressor. This market penetration of "new generation units" was not expected and was at odds with the figure of 10% advised by the air conditioning industry.

This required the Phase II project to be subdivided into Phase II(a) and II(b) catering for both "Type 1" and "new generation" units. These projects, which are discussed below, also required some on site interval meters in addition to the metering equipment at the sub stations and street transformers.

Also, of the total sample of 2,392 air conditioners, approximately 128 could not be categorised and were listed as "unknowns". These units were not utilised in the trial but counted in the 2,392 sample total. The Figure below puts these numbers into perspective. In addition it shows the monitoring regime set up to collect the necessary peak load data.

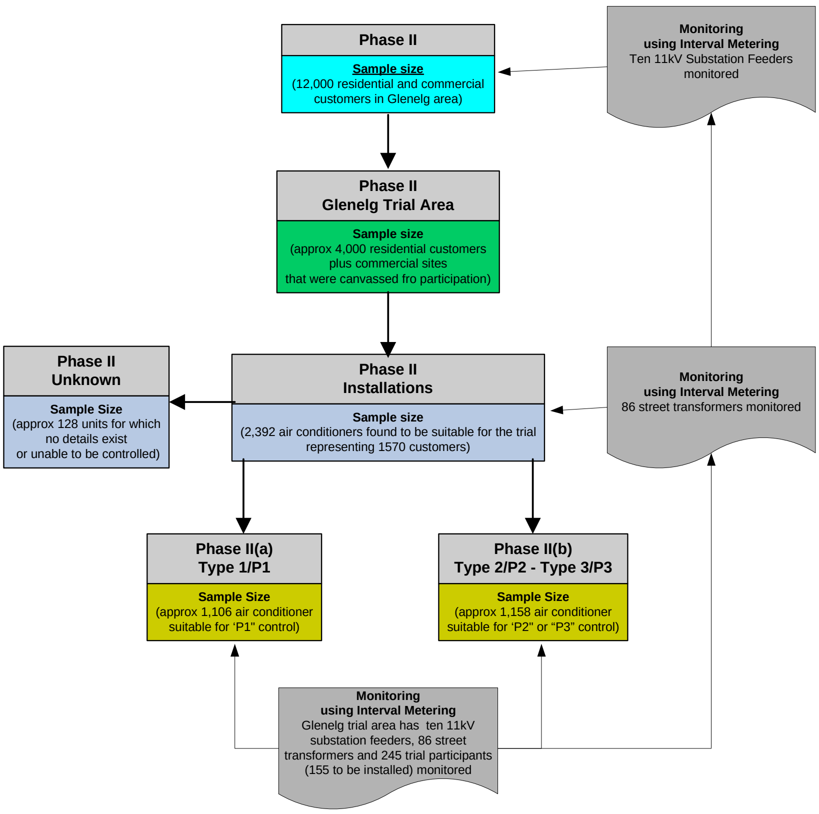

Figure: Phase II Trial Sample Population and Monitoring Regime

In terms of customer category the 2,392 air conditioners were distributed between residential customers and commercial customers in the proportion illustrated in the Figure below.

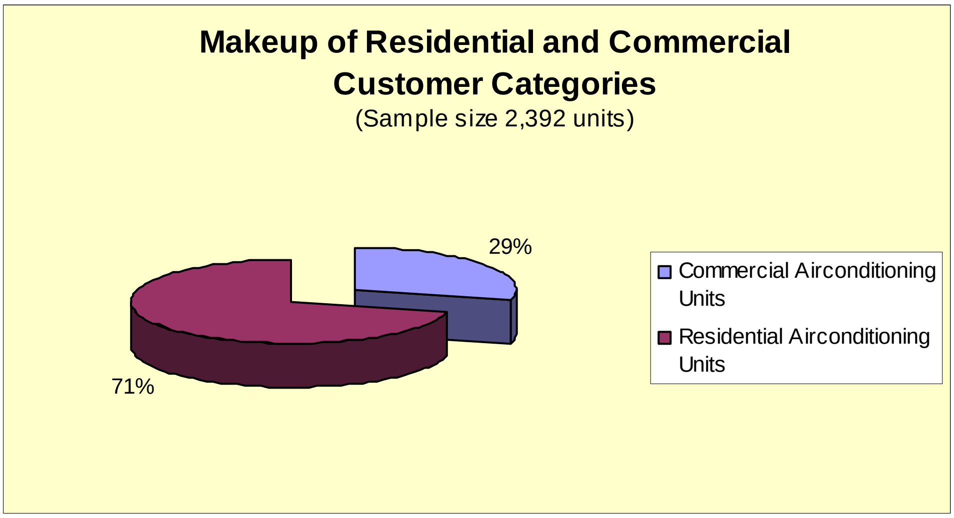

Figure: Glenelg Trial Area Customer Categories

> **Important Learning**
>
> The Phase II trial detected a change in community attitude in that it is now open to new ways of thinking about power and how to manage peak demand. This is evidenced not only by the response within the Glenelg trial but in the positive media comment from customers when the "fortunes" of the State as a whole was included in the demand side messages.

Also, in securing a solid community response to its campaign for DLC in Glenelg, ETSA Utilities has shown that customers can be diverted from their entrenched supply side view of peak demand and high power prices. In fact, it is not too hard to get through to the community the difference between paying for their electricity supply and paying for that electricity supply to be delivered to them through poles and wires. The community understands this and accepts it easily when the message is not thwarted by jargon and is divorced from excuses of pricing. That the community does "get it" is a clear "cut through" for ETSA Utilities' demand management research.

> **Important Learning**
>
> The community responds to inclusion on a journey by way of simple explanations of why, and invitations to see for itself. The inclusive and totally non-threatening style of community participation engendered by ETSA Utilities in Phase II is clearly a key to altering long held erroneous views regarding electricity pricing.

Finally the community values direct and simple communication that avoids technical, market and political emphasis and is prepared to respond with a strong ethos of contribution and involvement in "doing their bit" as long as they understand where the value lies in their contribution. The every little bit helps message is one the community feels comfortable with.

Trial outcomes for the 2007/08 summer period for the Glenelg area have now been amalgamated with the Mawson Lakes, Northgate and Murray Bridge trials and presented in Section 4.3.3.5 - Direct Load Control Phase III.

4.3.3.3 Direct Load Control Phase II(a)

This project focuses on the Type 1 air conditioners and as of June 2008 was a completed Status 4 project that continued to provide data from the DLC and monitoring infrastructure now in place. The project draws from a total pool of 1,108 suitable air conditioners, of which

754 have a simple uni-directional “Type 1” or “P1” Peakbreaker fitted to the external compressor of the air conditioners as shown in the Photo below.

Photo: “Peak Breaker” Fitted Externally To The Compressor

Control of the demand response enabling device (DRED) is achieved via a commercial radio-frequency carrier with the DRED switching the compressor directly.

> **Important Learning**
>
> Learnings derived from the installation of the “P1” controllers have been reported[13] and highlight that volunteers in a trial, need to be given a significant level of control over the installation time. Installers can not expect volunteers to act like customers and to be available in a schedule that suits the installer rather than the volunteer. Volunteers have control in any trial, the opposite to a customer requiring a repair or install where the control rests with the service provider.

ETSA Utilities’ network assets most impacted by DLC are the distribution transformers (i.e. 415 V street mains) located in residential areas and the 11 kV feeders at the substations. If sufficient load reduction is achieved there may also be a measurable effect at the 66 kV sub transmission network that supplies the substations.

Any actual impact at the transmission exit point level (i.e. 132 kV and 275 kV networks) is not likely to be seen due to the meshed supply arrangements for the Adelaide metropolitan area. The transmission supply points for the metropolitan area are interconnected so any load reduction will be distributed across the 5 major exit points and difficult to detect unless the reduction is quite large.

Switching the “P1” controllers is performed by ETSA Utilities personnel who have access to the switching system. The switching signals are sent via FM radio from a radio transmitter tower at Mt Lofty.

Monitoring equipment consists of a combination of ETSA Utilities’ System Control and Data Acquisition (SCADA) system and interval metering equipment. SCADA data provides load information that can produce load profiles to show the impact on load levels at 66 kV during demand management events. This data is available as a live feed into ETSA Utilities’ Network Operations Centre.

[13] ETSA Utilities, Beat the Peak – February 2007 Report, March 2007.

The distribution transformers and 11 kV substation feeders have been equipped with suitable current transformers to allow interval meters to operate. These meters are the same as those used to meter customer supply points and provide interval data that can be analysed with the current ETSA Utilities systems. The meters also have remote communications capability allowing interval data to be collected as required, but as a minimum, once a week, generally at 4:00 am each Monday morning.

The distribution transformer installations use current line hardware adapted where necessary for their new use. The current transformers are of the standard equipment type normally used within electrical switchboards and mounted using connection droppers on the low voltage mains so as to prevent any weight being applied to the line tap and associated fuses.

The metering equipment is housed in a metal enclosure mounted on the stobie pole and monitors the energy flow with connections via a standard service point and the current transformers.

The interval data is stored within the interval meters at 15 minute intervals at all points on the network infrastructure. The metered residential sites have interval data stored in 15 minute intervals for the larger three phase connected customers and 30 minute intervals for the smaller single phase connections. The remaining meters are capable of storing data at 15 minute intervals.

This data is retrieved using both remote communications and on site reading for the interval meters. Metering on the network infrastructure uses remote communications exclusively so as to reduce injury risk, because of the equipment's location, to meter reading personnel. A diagrammatic representation of the Phase II(a) trial, its monitoring regime and data collection is illustrated in the Figure below.

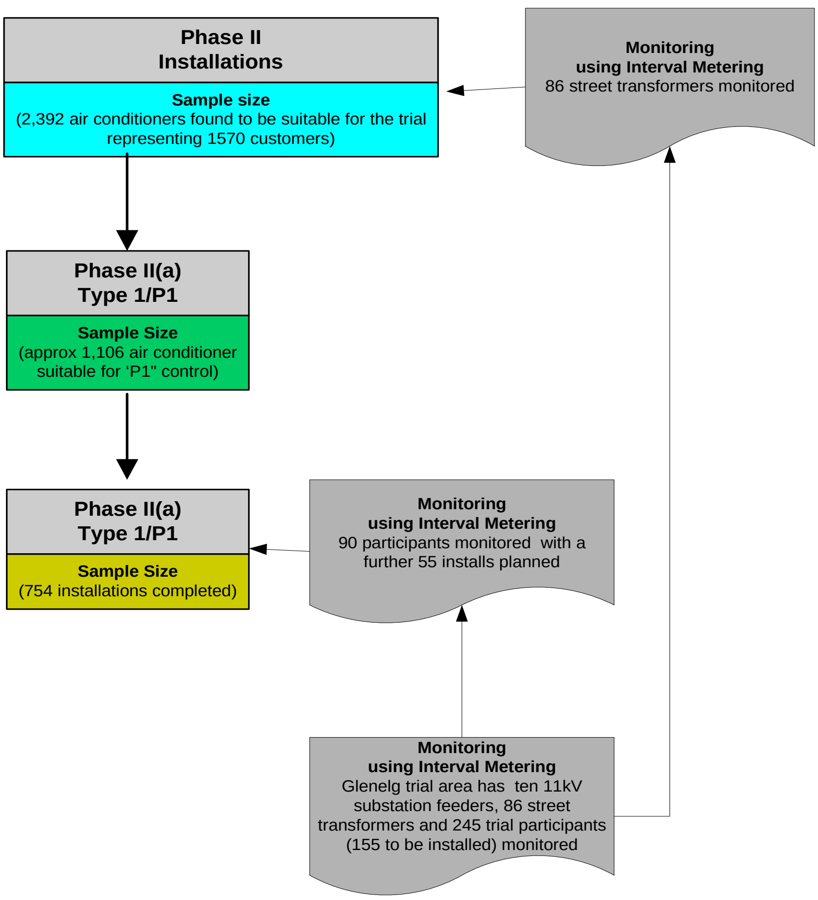

Figure: Phase II(a) Trial Sample Population and Monitoring Regime

The interval data once retrieved and validated within the metering systems is stored in ETSA Utilities' Network Sites System (NESS). This allows for data to be widely available to all users within ETSA Utilities' Demand and Network Management (DaNM). It also allows for basic reporting and load profiling to be available almost immediately after data collection.

Specifically, the Phase II(a) project seeks to:

- test customer acceptance of DLC and gain knowledge of DLC technology;
- gain experience in the application and installation and roll out of DLC technology;
- gather data on the impact of DLC on the distribution and transmission networks.

The collection of data is at 3 levels: (i) from the substations; (ii) from the street transformers, and (iii) where applicable, from interval meters in the house. The data collected to date is in the process of being analysed in detail.

Important Outcome

Randomised switching of individual loads requires monitoring to ensure that the managed load is evenly distributed throughout the entire switching period. Early simultaneous switching gives rise to a 'sawtooth' effect on the demand profile, with repetitions of a majority of the load switching early and little load switching later.

The 'sawtooth' effect, which in essence negates any peak reduction, is illustrated in the Figure below.

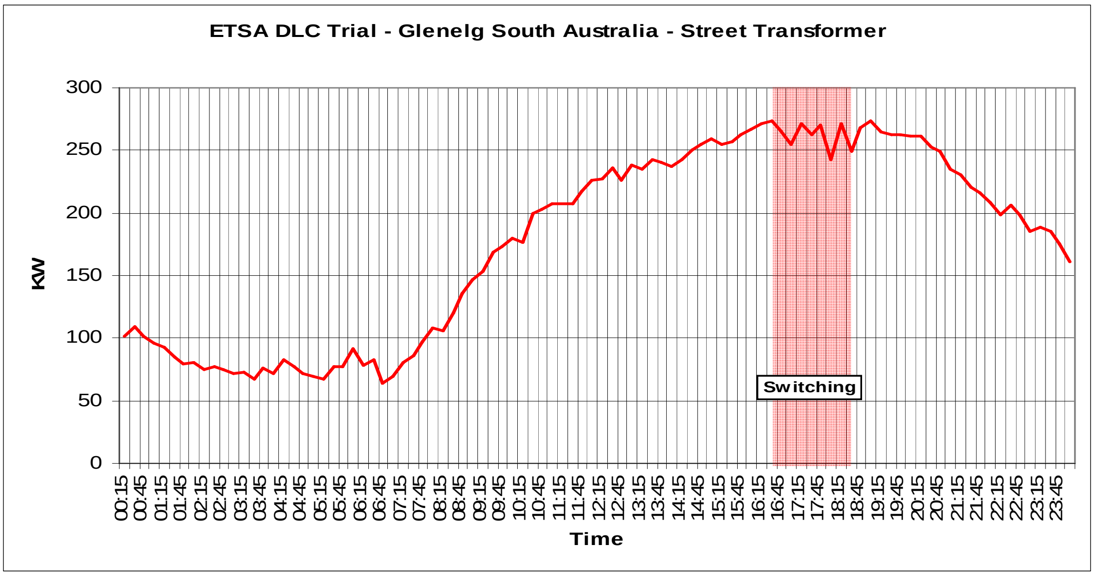

Figure: Example of "Sawtooth" Effect

A process reassigning the DLC units into distinct controllable segments, so as to overcome the 'sawtooth' effect, allowed the load to be more evenly switched during each control interval.

In terms of the impact of a DLC event on the peak load profiles for a group of 68 homes participating in the trial, the Figure below is instructive. First it illustrates the significant impact of external temperature conditions on the peak demand for 35°C days and 40°C days. Next it shows the average load curve of those two peak demand days and finally it illustrates the significant effect of a switching regime on peak demand.

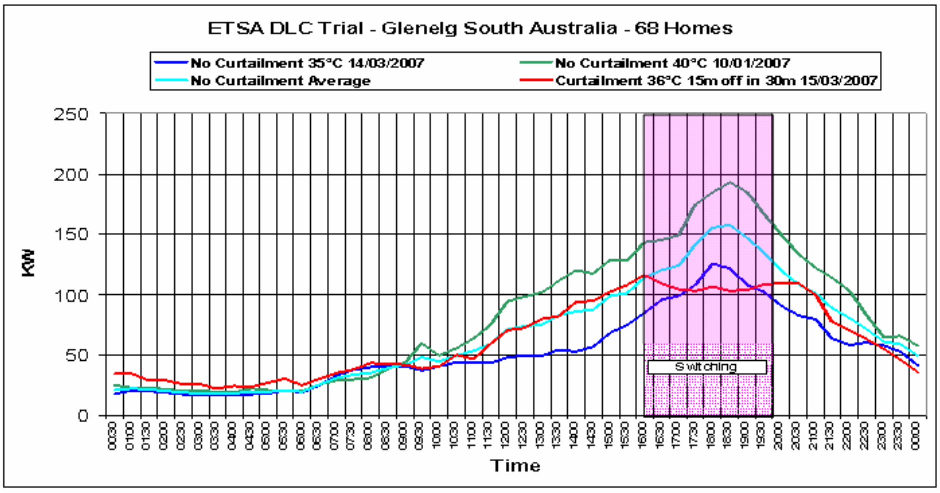

Figure: The Effect of a Switching Regime on Peak Demand

Important Outcome

A larger than expected penetration of "new generation" air-conditioners calls for the development of variations to the DRED switching technology.

Therefore, future trials focussed on large air-conditioner loads (i.e. ducted systems in excess of 2.5 kW), which is the Phase II(b) trial discussed in Section 4.3.3.4.

Monitoring of DLC events during the 2007/08 summer period generated data from residences with interval meters, the street transformers and the substations. These data sets from the summers of 2006/07 and 2007/08 have been analysed with an enhanced mathematical model developed by TRC Mathematical Modeling of the University of Adelaide and are discussed in Section 4.3.3.5 – Direct Load Control Phase III.

4.3.3.4 Direct Load Control Phase II(b)

This project has come about because of the high incidence of "new generation" air conditioners found in the initial trail sample. As of June 2008, this was a completed Status 4 project. Its aim was to trial the operation and installation of enhanced DLC systems on "new generation" air conditioners using "Type 2" or "P2" and "Type 3" or "P3" DLC controllers.

"Type 2" or "P2" controllers are installed on "new generation" Daikin ducted air conditioners and require an additional component to the "P1s", an interface card, a standard Daikin accessory to be installed at the same time as the "Peakbreaker".

Important Learning

"P2" installations require access to the ducted air conditioning system's head unit which is situated in the home's roof space. This requires access to the home and the roof space via a man hole. It typically takes an average of 60 minutes to install.

An important recent development is that the interface card is now able to be installed in the outdoor unit on new Daikin ducted air conditioners supplied since late 2007.

"Type 3" or "P3" controllers are for "new generation" air conditioners and require an additional device known as an "emulator" to be an integral component of the "Peakbreaker" installation. The installation is different for different air conditioning systems.

Important Learning

For ducted systems the installation requires entry into the home and access to the head unit for the air conditioner inside the home's roof space. The initial installations took up to 120 minutes.

The following diagram illustrates the proportional makeup of air-conditioner "Types" in the sample population of 2,392 units in Glenelg.

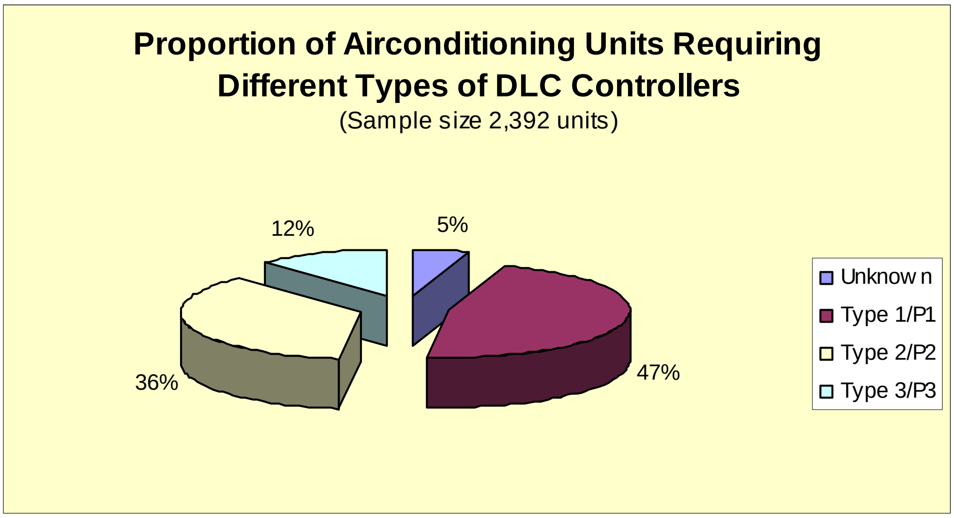

Figure: Proportional Makeup of Air-conditioning Types

As of June 2008, of a total pool of 1,158 volunteers with suitable air conditioners, approximately 294 with air conditioners capable of accepting Daikin interface cards registered for the trial. These were all personally contacted by phone in November/December 2006 and had the changed scope, including the delayed installation to early 2007, explained to them. They were also asked if they were prepared to stay in the trial, allow for internal access to their home and a longer installation time. Finally it was explained to them that the installation would be undertaken by Daikin.

The result of these personal contacts was that just over 6% of those called withdrew from the trial, principally citing concern over damage to their ceiling. The customer information sheets filled out during each phone conversation show clearly that having a Daikin service agent do the installations was the deciding factor in volunteers' willingness to accept the changed project scope as they were generally protective of their Daikin systems (costing between $8,000 and $15,000) but were trusting that no issues would arise for them if Daikin was involved. A Figure illustrating the sample populations for “P2” and “P3” installations as well as the monitoring regime is shown below.

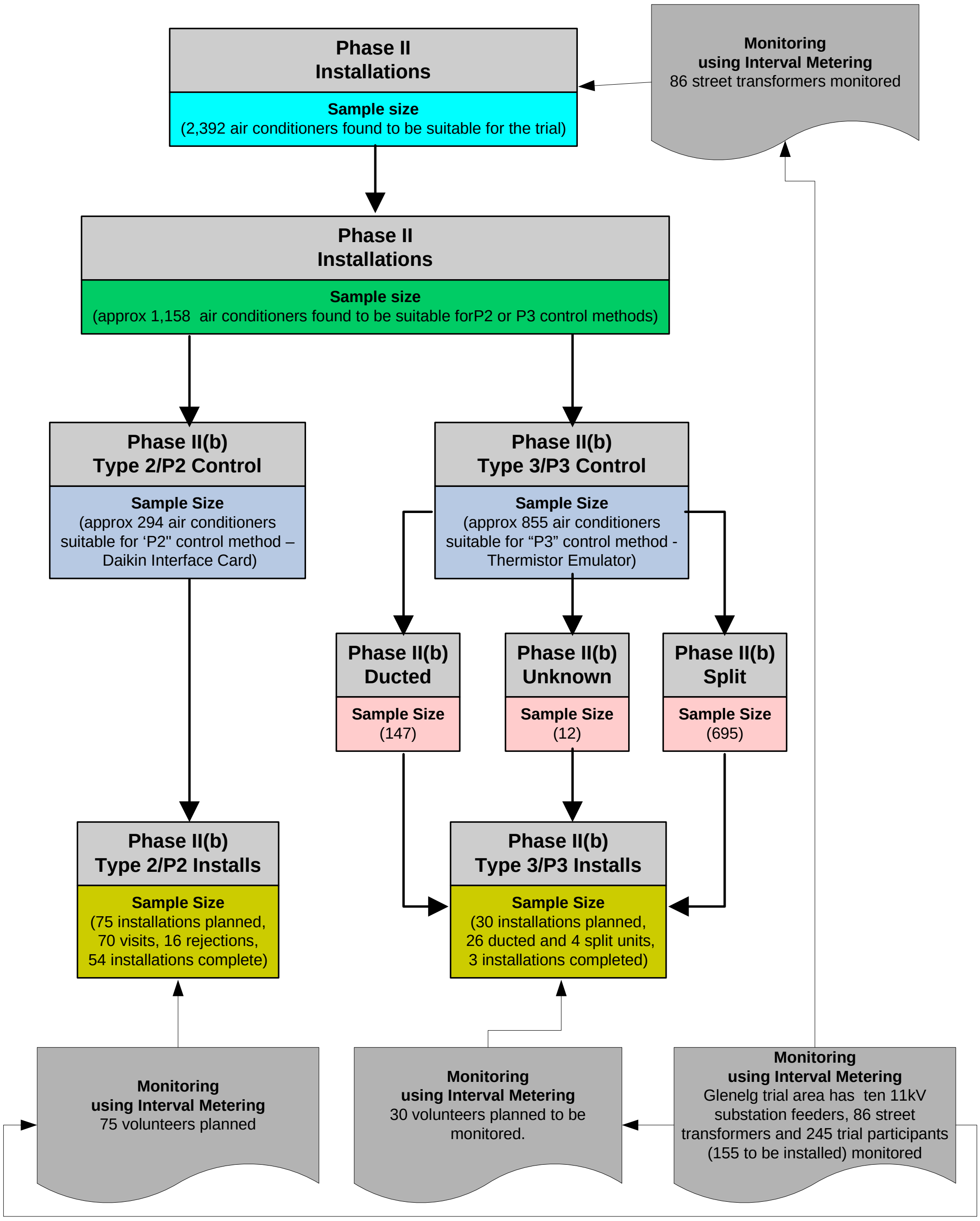

Figure: Phase II(b) Trial Sample Populations and Monitoring Regime

Early trials of a small sample gave an indication of the load data that would benefit a larger roll-out and led to a decision to install the “P2” controllers on only 75 Daikin units. As of May 2007, 70 site visits resulted in 54 installations and 16 rejections because of technical incompatibilities. Volunteers whose units were not to be installed with a controller were advised of this by letter[14].

[14] ETSA Utilities, letter with salutation ‘Dear “Beat the Peak” volunteer’, 17 April 2007.

For the “P3” installations, the total sample pool totalled 855 units comprising 147 ducted, 695 split units and 12 unknown. All of these volunteers were notified by letter[15] that their air conditioner was a “new generation” unit and that this entailed a change in the installation procedure as well as a delayed installation. A cheque for $100 was enclosed with the letter.
The installation for “P3” ducted systems proved to be more complex and take considerably longer than for “P1” installations. Additionally, for split systems, “P3” installations would be further complicated by the head unit’s location and the possibility of damage to the unit. Taken together, these factors determined the trialling of only a minimal sample comprising 30 volunteers. For these 30 volunteers, it was decided to modify relatively few of the split systems as they; (i) were generally of low load value, (ii) required considerable time and effort to modify and (iii) the location of the internal head unit and easily broken head unit covers could lead to claims for damages.

In May 2006, of the 30 volunteers, with split systems, contacted by telephone only 7 agreed to continue with the trial and have a “P3” emulator installed. A representative P3 air conditioning system is shown in the illustration below.

Illustration: A typical “P3” Residential Air conditioning System

This trial is to continue in the Glenelg area over the summer of 2008/09.

4.3.3.5 Direct Load Control Phase III

As of June 2008, this was an active Status 3 project. This trial draws on the findings of Phase II(a) and II(b) projects but targeting the areas of Mawson Lakes, Northgate and the regional centre of Murray Bridge.

Specifically this project aims to:

- Gain more information on the cost benefit of DLC for large ducted air-conditioners.
- Gain further information on the effect of DLC on distribution networks.
- Gather information on the possible maximum customer participation in DLC programs.
- Compare the impact of DLC relative to other trial areas.

The total sample pool for all three areas was 1,100 potential participants, selected on the basis of their network connection type, tariff assigned and summer consumption. All of the potential participants are characterised by having three phase power, being on residential tariffs and having high summer consumption compared to their annual consumption.

Of the 1,100 customers the most suitable comprised 465 units in Mawson Lakes, 300 units in Northgate and 40 units in Murray Bridge having either “P1”, “P2” or “P3” controller requirements. Ultimately after a concerted recruitment campaign, 125 units at Mawson Lakes, 12 at Northgate and 5 at Murray Bridge were installed as illustrated in the Figure below. These installations were monitored by interval meters.

[15] ETSA Utilities, letter with the salutation ‘Dear valued ETSA customer’, 30 November 2006.

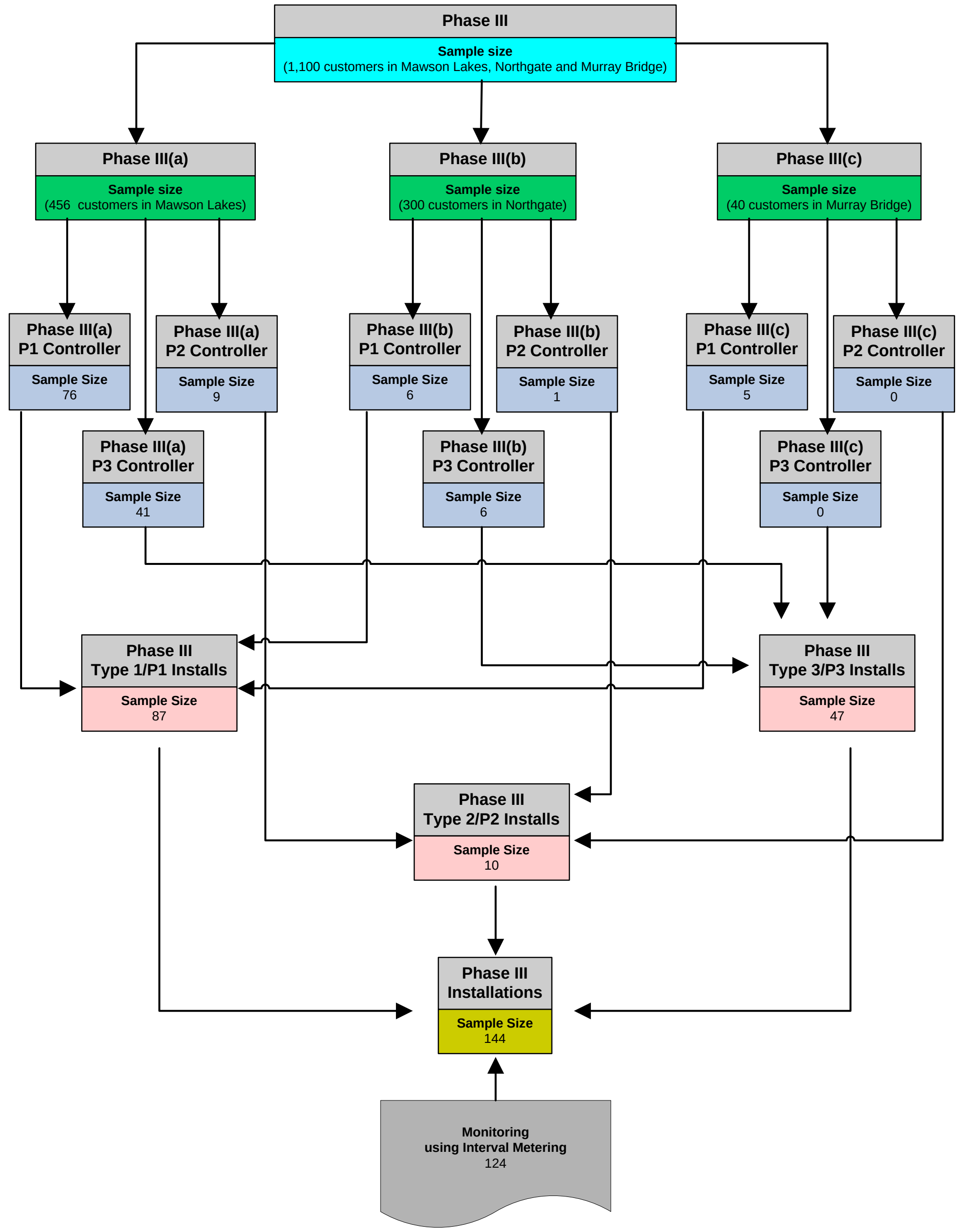

Figure: Phase III Trial Sample Populations and Monitoring Regime

As regards the recruitment campaign in Mawson Lakes and Northgate, it failed to meet expectations despite an intensive recruitment effort conducted between September 2007 and November 2007. After October 2007, ETSA Utilities embarked on a "cut through" strategy in a further effort to recruit volunteers in Mawson Lakes with an article appearing the in Adelaide Advertiser[16] on the 10th October 2007.

The strategy, whilst increasing the number of volunteers, continued to disappoint. Specific homes, with prominent air conditioning units, were then door-knocked but with similar "ordinary" results. The "ordinary" outcome of the campaign seems to be a function of the socio-demographic of the area, but despite this, the sample size has been deemed statistically significant for key learnings to be derived.

[16] The Advertiser, ULTIMATUM, ETSA chief's warning to new home owners, Cut your power or we'll cut it for you, Wednesday, October 10, 2007.

Mawson Lakes is a new suburb located on 620 hectares in the northern Adelaide metropolitan area about 12 kilometres from the CBD and 10 kilometres inland from the coast. Glenelg on the other hand is an old established Adelaide suburb, dating back to the founding of Adelaide in 1836, on the Adelaide coast with a diverse mix of house styles, construction and architecture.

Some of the housing styles to be found in Mawson Lakes are depicted in the illustrations below and these are contrasted with those to be found in Glenelg.

Illustration: Housing in Mawson Lakes

Illustration: Diverse Housing Mix in Glenelg

In general the housing mix in Mawson Lakes tends to be of a construction type and of larger indoor open plan area that is reliant on air conditioning to maintain comfort levels during temperature peaks of either heat or cold. Also, temperatures in Mawson Lakes during the summer tend to be two to three degrees higher than those experienced in the coastal Glenelg area and importantly Mawson Lakes tends not to have the cooling effects of an afternoon sea breeze.

In terms of the load reduction for the 2007/08 summer period, the Figure[17] below illustrates some of the observed results.

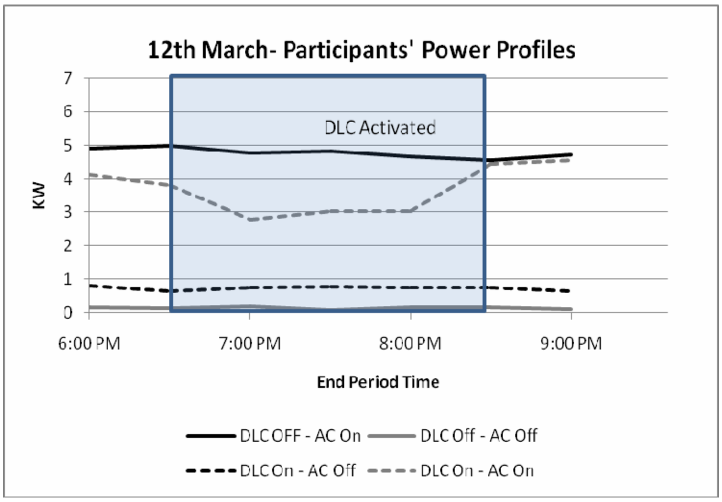

Figure: Load Profiles for Individual Participants

The above Figure illustrates the impact of DLC on an individual household during a DLC event and the Figure below illustrates the impact of a DLC event on a group of trial participants. It can be clearly seen that DLC has an impact under all circumstances but that its impact, because of housing composition, mix and diversity and distance from the coast was more pronounced in Mawson Lakes than in Glenelg.

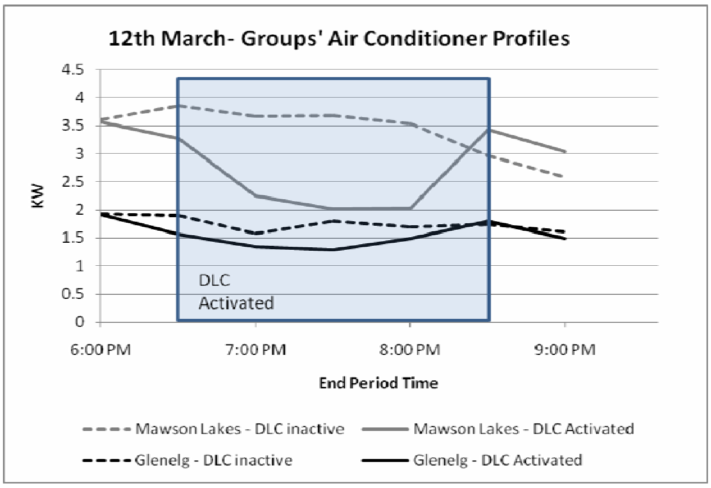

Figure: Load Profiles for a Group of Participants

Another important feature highlighted by the Figure for the group profile is that as Mawson Lakes is a newer suburb with homogeneity of housing style and reliance on air conditioning,

[17] The University of Adelaide, TRC Mathematical Modelling Report, Direct Load Control – Data Analysis, 4th June 2008.

more load can be harvested there during a DLC event than in more established suburbs such as Glenelg.

A more complicated plot of DLC activated households in the period immediately prior to a DLC event and during the DLC event is shown in the Figure below.

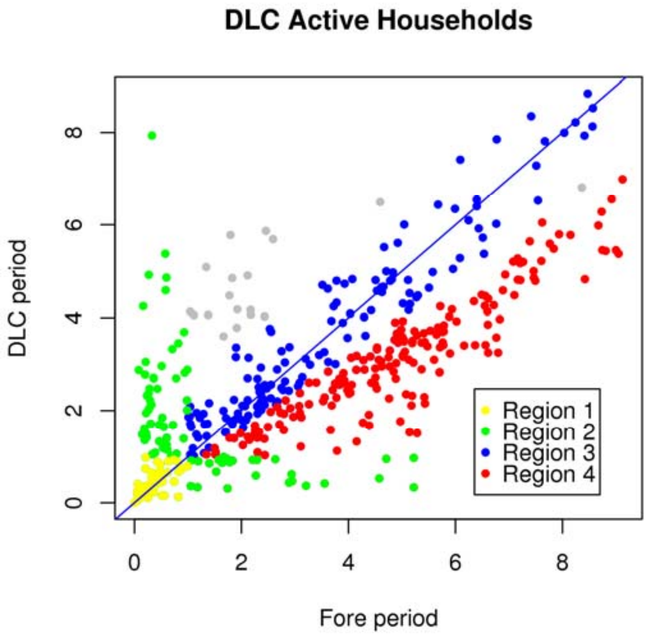

Figure: Power Demand (kW) for DLC Activated Households

To understand the distribution of the plot in the above Figure it is useful to consider the labeling of the data shown to have the following meaning:

- **Region 1:** These are households with low demand in both periods. It is reasonable to infer that no significant air conditioner usage occurred in these households and that a DLC event did not reduce load.

- **Region 2:** These are households with low demand in one of the two periods. This could happen if, for example, the air conditioner was off in the fore period and on in the DLC period.

- **Region 3:** These are households where the demand was high and differed little between the two periods. It is reasonable to infer that for these households there was a significant source of load not controlled by DLC.

- **Region 4:** These are households where the demand was high in both periods but significantly lower in the DLC period. It is reasonable to infer that these were the households in which DLC had the intended effect.

The interpretation of the patterns of demand suggests that the impact of a DLC event is likely to be lower than its theoretical maximum (i.e. 50%) because not all houses will be using their air conditioners during a DLC event. In terms of estimating the impact of a DLC event, it is not necessary to quantify this phenomenon separately and estimates of load reduction can be drawn from the data on a per capita basis[18].

[18] Glonek, Dr Gary, Prediction for Demand Reduction in Large Scale DLC Deployment, TRC Mathematical Modelling, The University of Adelaide, 12th June 2008.

In summary, the analysis of the trial data that TRC Mathematical Modeling performed has indicated that:

- There is a discernable decrease in load when DLC is activated. The average reduction for Glenelg and Mawson Lakes is shown in the Table below.

Location	Average A/C Capacity	Average kW Reduction per A/C	Standard Deviation kW Reduction per A/C	95% Confidence Interval for Proportion of A/C Capacity Reduced by DLC
Glenelg	3.08	0.45	1.88	(0.057, 0.214)
Mawson Lakes	5.07	1.34	3.01	(0.155, 0.354)

Table: Average Load savings Per Participant in the DLC Trials

- The load reduction from a DLC event is highly dependent on location.

- The load reduction is highly variable as illustrated by the standard deviation of the load reduction in the above Table.

- Estimates of the average proportion of an air conditioner's capacity that can be saved using a DLC event have been determined. The 95% confidence intervals for each location's results are shown in the above Table.

- The trend in the variation in the load reduction due to DLC varied with substation demand and was more evident in Glenelg than in Mawson Lakes.

- A technique[19] for predicting the actual total load reduction that could occur because of a DLC event for varying numbers of households was created.

- This technique can be used to get statistically robust estimates for the load reduction that a DLC event would be expected to give under similar conditions to those of the trial.

These are significant findings that have been fed into a CBA[20] model prepared by KEMA International and ETSA Utilities. The modeling points to a negative societal NPV for a DLC roll out with a 10% volunteer participation with the most sensitive parameters being:

- Average load reduction per DLC event;
- Percentage cycling time per DLC event;
- Take up rate of volunteers for a DLC device.

In addition to this, it is unlikely that, in a wide scale roll out, volunteers would be clustered around a substation facing constraint and therefore deferral of network augmentation would not necessarily occur in practice. To overcome this dilemma the learnings from the technological developments during these trials suggested a possible solution.

This is an enhanced Peak Breaker with two way communications that is fitted alongside the customer's conventional meter. The enhanced Peak Breaker is able to communicate with a DLC device that is integral or retro-fitted to the air conditioner. It will, eventually, be provided to every customer as a composite item of terminal operating equipment. The net effect is that the enhanced Peak Breaker will provide embedded technology for network optimisation.

The CBA modeling for the enhanced Peak Breaker yields and positive societal NPV[21]. For the summer of 2008/09 it is proposed to trial the enhanced Peak Breaker in Adelaide metropolitan

[19] ibid
[20] KEMA Limited, ETSA Utilities, Socio Economic Assessment of Smart Metering and DLC for South Australia, Rev 1.0, 17th August 2008.
[21] For a more detailed discussion of the enhanced Peak Breaker solution see Section 4.3.6 – Interval Meters.

suburbs and regional centres in order to prove up the technology and NPV of the enhanced Peak Breaker.

4.3.3.6 Regional Discretionary Load Trial

As of June 2008, this was a completed Status 4 project, which aimed to test the efficacy of radio pager technology to remotely control discretionary loads in non metropolitan areas where RF reception is not available. The trial proposed to use commercially available radio pager technology as the communication medium.

The trial was terminated as the proposed technology did not meet with ETSA Utilities requirements.

4.3.3.7 Universal Demand Response Enabling Device (DRED) Interface

As of June 2008, this was an active Status 3 project. The outcome of this project stems from work being done under the auspices of Standards Australia and findings of DLC Phase II, II(a) and III trials.

As a widespread rollout of DLC devices depends on the cost per kVA of reduced peak load, factors which decrease the cost of a widespread roll out are important to its viability.

> **Important Conclusion**
>
> The cost of deploying DLC devices could be significantly reduced if it is mandated that all air conditioners sold in Australia have a standard interface that allows them to be controlled by a DRED.

This project therefore aims to:

- assess the costs and benefits of universal interfaces for air conditioners with an externally mounted DRED;
- ensure that the specifications for such devices take into account ETSA Utilities' requirements;
- create interest in the industry in the commercial development of DRED interfaces.

As of June 2008, a working group set up to examine the DRED consisting of: The Australian Greenhouse Office; ETSA Utilities; AREMA; SEMITECH and other interested organisations had been established with its first meeting held on 18th April 2007. Major manufacturers are supportive of a simple interface for a DRED and connection points to switch air conditioners into different modes of operation, such as fan only mode or limiting speeds of inverter compressors to preset levels. The latest meeting of Standards Australia dealing with the DRED was held in Sydney on 29th April 2008. The draft Standard is now nearing completion.

The project is expected to be completed by the latter part of 2008.

4.3.3.8 Commercial Building Management System (BMS) Trial

As of June 2008, this was an active Status 3 project.

Building management systems have the potential to deliver substantial efficiencies and reduce maximum demand through the use of integrated controls that take a holistic view of the building's environment. The more sophisticated modern systems have a high level of built in intelligence so that a central "brain" is in charge, but each part of the system can operate independently for a time without reference to the central "brain".

These systems can therefore be used to monitor and control HVAC, security, access, lighting, fire services and lifts as well as other ancillary services. Additionally they can be used to incorporate energy management processes for both cost savings and more efficient energy usage but which until recently have been an afterthought rather than an integral part of the system.

Observation

Building owners and property managers are interested in saving energy (kWh) or reducing greenhouse gas emissions but are generally unaware or uninterested in reducing capacity (kW) and the consequential reduction of network load. A BMS adjustment to reduce or limit demand can result in a peak demand reduction and associated savings.

This project tests the feasibility of interfacing a DLC device with a BMS to initiate a load reduction in commercial premises specifically by:

- testing customer acceptance of DLC in the commercial sector;
- gaining experience in the application and installation of DLC technology in the commercial sector;
- gaining experience of the interface between DLC technology and the BMS;
- gauging the potential of DLC for widespread roll out in the commercial sector.

As of June 2008, the State Library of South Australia agreed to participate and their BMS was programmed to cycle the air handling units throughout the precinct for short periods for a load reduction of up to 270 kVA. The programming was completed and a Peakbreaker fitted as a signalling device.

On initial trialling, the BMS did not respond as intended and subsequent investigations revealed that insufficient loads were being controlled. Also the Peakbreaker encountered problems due to the density of communications traffic in the precinct blocking communication signals and forcing the system to be triggered manually. The BMS was activated on Friday 14/03/2008, Monday 17/03/2008 and Tuesday 18/03/2008 between 1:00 pm to 4:00 pm but did not yield meaningful results. An assessment of the trial and data is underway and a report is in the course of preparation.

Other potential sites identified for similar trialling include the following:

- Regency TAFE School of Hospitality.
- Commonwealth Law Courts.
- Dame Roma Mitchell Building.

The assessment of potential sites and customers and the evaluation of a buildings' potential is an ongoing process.

4.3.3.9 Domestic Load Limitation

As of June 2008, this was a completed Status 4 project.

This trial intended to have load limiting devices installed in approximately 106 new homes in an eco-village development. The technology makes use of miniature circuit breakers in series with an in home energy management system. The project specifically aimed to:

- Test customer acceptance of load limitation.
- Develop expertise in the design of load limitation tariffs.
- Source and adapt, where necessary, suitable existing technology for use in South Australia.
- Assess the potential of load limitation for widespread deployment in the residential sector in South Australia.

Load limitation on a residential land development site is a means of controlling load and as such reduces the actual load capacity to be provided to the site. The electricity network infrastructure is therefore reduced. Developers have recognised this as an opportunity to lower their costs and use load limitation to negotiate a reduction to the normal ETSA Utilities capacity requirements for residential land development sites.

ETSA Utilities' current design standards for underground residential development sites use an "After Diversity Maximum Demand" (ADMD) of a minimum of 8 kVA per allotment. Depending on the size of the development site, the electrical network augmentation charge can form a major part of the overall project cost. For example, site developments over 90 kVA have an augmentation charge of $1,016 per allotment as the standard augmentation charge calculated on the basis of $127 per kVA. If the site development is seeking more than 5% of the total substation capacity or is situated at a distance greater than fifteen kilometres from a substation, a site specific augmentation calculation is required which may result in the developer paying some of the costs of augmenting the electricity distribution network and/or substation.

In terms of peak demand on the development site, the major contribution comes from the building's design such as orientation, insulation and summer shading with the building's single largest electrical load generally being the air conditioner. These parameters determine the building's peak demand and, taken together, the sites' aggregate peak demand. Used judiciously load limitation can be used to reduce the sites' peak demand and consequent augmentation requirements.

In 2006 a developer approached ETSA Utilities with a view to applying load limitation at its development site. The initial concept proposed a project with evaporative air conditioning installations up to 2 kVA and no reverse cycle air conditioning. The proposal further envisaged that ETSA Utilities would develop a load management system, a "first" for the industry, which would be deployed and trialled. The system was to provide the ability to preset an agreed maximum peak demand of up to 6 kVA per allotment and to actively monitor this demand. If this preset level was breached, then the system would automatically turn off selected electrical circuits in order to avoid the peak demand level being exceeded. The circuits targeted for control included the air conditioner, wall oven and non essential power circuits. A tariff was developed that would result in customers making savings on their bills when compared to the existing tariff provided they limited their demand to 6 kVA or less.

Subsequently the original specification was relaxed to allow for reverse cycle air conditioning. In time the maximum demand for reverse cycle air conditioning was changed from less than 2 kVA to 3 kVA and on to 4 kVA per allotment. The final specification allowed for the air conditioning units to be specified on the basis of dwelling size. This move resulted in load limitation being abandoned as a viable option for this site development as it was expected that on extreme summer days the load limiting device to an individual allotment would be almost constantly switching circuits thus becoming more of a hindrance than a help to the occupants. Because of the relaxation in specifications, the original concept to limit maximum demand to 6 kVA per allotment had to be modified. This led to the site development's padmount transformers having to be upgraded and line infrastructure reconfigured to provide for the "current design standard" 8 kVA capacity per allotment.

Learning

The principle learning from this project was that a purchaser of an allotment could not make savings by agreeing to an allotment capacity of 6 kVA or less. This is because of the relaxation in the specification for the size of the air conditioner. With larger capacity air conditioners a purchaser would only experience savings with frequent disrupting load management events. This was not how the project was intended to operate. It was envisaged that a load management event would be a rare occurrence designed to educate the consumer as to their impact on electricity demand.

From the developers' perspective, ways of reducing a development site's ADMD have included:

- Designing small country style houses with little or no air conditioning.
- Designing green environmentally friendly houses with little or no air conditioning.

- Giving consideration to the air conditioning installation as it is the single largest load.
- Negotiating with ETSA Utilities as to why they will not require the standard of 8 kVA per allotment installation.

> **Important Observation: ETSA Utilities Perspective**
>
> ETSA Utilities is required to provide a robust and reliable network but inherits the network that is configured by developers, it then has to deal with all customer connections on an individual basis. In the long run therefore, it is ETSA Utilities that deals with the consumer and not the developer.

ETSA Utilities will now act in an advisory capacity on this project, which is scheduled for completion post the 2008/09 summer period.

4.3.3.10 Commercial Load Limitation

As of June 2008, this was an active Status 3 project.

The project employs a logical controller in conjunction with power-line carrier technology to manage multi-split commercial air-conditioner installations. To date four customers have had the logical controller installed. They are Immanuel and Mercedes Colleges, Minda Homes and Unley High School. Further installations are planned at selected state schools.

This project set out to test the technical and financial viability of load limitation via a BMS on the HVAC plant in a commercial building. A HVAC load reduction strategy is to be determined for each site. Specifically the project aims to:

- Test customer acceptance of load limitation.
- Source and adapt, where necessary, suitable existing technology for use in South Australia.
- Assess the potential of load limitation for widespread deployment in the commercial sector.

The “BryLyn” system installed at Unley High School has 300 kVA of load under management. Of this a 100 kVA load reduction was achieved during trailing during the March 2008 heatwave. It is expected that on further trialling, 150 kVA (50% of the capacity under control) of load reduction will be achieved.

> **Important Outcome**
>
> To date, ETSA Utilities has gained up to 50% of the load capacity under control and finessing of the BMS operation under load conditions will provide ETSA Utilities with further learnings.

On the basis of the Unley High School experience, it is expected that more state schools will be recruited and site installations completed during 2008 for trialling during the 2008/09 summer.

4.3.4 Critical Peak Pricing (CPP)

In order to reflect “resource scarcity” peak electricity prices on critical peak demand days should be significantly higher than on non-critical peak demand days. Sending such price signals to consumers and having them modify their consumption patterns accordingly is the basis of CPP. The strategy has been trialled in the US and found to be of use in network demand side management.

As ESCOSA notes, “under a CPP strategy, customers are notified in advance (usually a day or two ahead) of when a critical pricing period will be put in place. Peak prices on critical days are significantly higher than on non-critical days – often four to six (or more) times as expensive. This approach reflects the fact that peak demand only occurs on a handful of occasions and that additional capacity to meet this demand is very expensive.”

The ESCOSA Determination goes on to say:

> *"Implementation of CPP requires interval metering, though remote reading capabilities are not necessarily required.*
>
> *Given the significant costs involved in the installation of interval meters for all customers, the Commission has decided that a CPP trial be undertaken with customers that already have interval meters. The program will include technical and possibly financial assistance to end-use customers.*
>
> *For the purposes of this program ETSA Utilities will be required to develop by December 2006 for approval by the Commission, CPP tariff(s) for large customers that currently have NEM compliant meters installed. Customer participation in this trial would be voluntary. It would also be necessary to develop an associated information and marketing strategy for all eligible customers.*
>
> *The Commission recognises the difficulty in introducing a CPP trial for this group of customers and therefore the Commission will work with ETSA Utilities to develop appropriate CPP tariff(s) and incentives for customers that currently have interval meters installed. The Commission expects that this will require close cooperation between ETSA Utilities and active SA retailers."*

As of June 2008, trials identified for consideration have resulted in the selection of the following two projects:

- Residential Critical Peak Pricing Tariff Trial.
- Commercial Critical Peak Pricing Tariff Trial.

4.3.4.1 Residential Critical Peak Pricing (CPP) Tariff Trial

As of June 2008, this was an active Status 3 project.

The project envisaged the use of an in-home display unit in the suburb if Novar Gardens to assist with; (i) the design of a residential tariff incorporating price increments at times of high system peak, and (ii) testing customer acceptance of such a product together with the price elasticity, response persistence and overall efficacy.

In specific terms this project sets out to:

- Determine customer acceptance of CPP tariffs amongst residential consumers.
- Develop ETSA Utilities' expertise in the design of CPP tariffs.
- Develop systems and processes for signalling CPP periods.
- Collect data on price elasticity, response persistence and overall efficacy of CPP tariffs.
- Assess the potential of CPP tariffs for widespread deployment amongst residential consumers.

The signal to the customer is sent to an in-house display with a visual and/or audible alarm. Alternatively an SMS message can be sent notifying of the peak event and an interval meter records the consumption.

To date, the trial characteristics in Novar Gardens can be summarised as follows:

- Volunteers were offered $100 to participate.
- To receive the $100 volunteers were asked to respond positively to 10 peak events.
- For each event to which they chose not to respond, the $100 reduced by $10.
- A positive response was a reduction in household demand during a nominated period by an amount communicated to the volunteer.
- Volunteers were to receive information, education and support so that they could judge what appliances (and permutation thereof) must be turned off.

- Volunteers were to receive event information by sms to a mobile phone and via a sound and light display unit attached temporarily to a kitchen wall.

These systems are already in use around the world and in Australia several utilities are already undertaking trials.

Project's Future Direction

The 2007/08 summer period trial only had a 14% response rate in the Novar Gardens area. A report on this seemingly low response rate is in the course of preparation.

Currently the aim is to identify a new area in suburban Adelaide in which to install the in-house displays and trial consumer behaviour during the summer of 2008/09.

4.3.4.2 Commercial Critical Peak Pricing (CPP) Tariff Trial

As of June 2008, this remained a Status 1 project at the pre implementation stage.

The project aims to determine for commercial premises; (i) the design of a commercial tariff incorporating price increments at times of high system peak that is acceptable to customers, and (ii) testing customer acceptance of such a product together with price elasticity, response persistence and overall efficacy.

Internal discussions within ETSA Utilities about possible tariff configurations to provide the desired response are in train. A stepped energy tariff applying during the summer with high prices targeting the hours under consideration is being considered. Contemporaneously ETSA Utilities is identifying commercial customers who, because of their load composition, would respond to CPP and who can be trialed before approaching them directly.

4.3.5 Voluntary and Curtailable Load Control for Large Customers

Voluntary (VLC) and Curtailable (CLC) load control programs are demand management initiatives designed to provide business customers with the opportunity of reducing electricity usage during peak demand periods. For participating, business consumers are rewarded with a financial benefit. Primarily these programs are aimed at business users with the VLC program targeting medium businesses and the CLC program large businesses.

With these programs, businesses can select load reduction strategies such as thermal energy storage (TES) devices that reduce their demand on the network and are provided with an incentive payment for doing so. Normally participants would be given notification of a load reduction event in advance enabling them to elect whether or not to reduce electricity demand. Compliance would be measured by comparing interval meter data recorded during the load reduction event against a baseline load curve.

ESCOSA estimates that about 50 MW of curtailable loads exists in South Australia through contracts between large customers and retailers. Thus the ESCOSA Determination calls for the following.

> *"The Commission believes that there are more opportunities to either shed loads or to shift such load to non peak periods. Therefore the Commission supports funding ETSA Utilities to further investigate both CLC and VLC programs for application to business customers with interval meters already installed.*
>
> *The Commission will work with ETSA Utilities to develop such initiatives. It notes that there is potential to involve retailers in the design and implementation of such programs.*
>
> *The Commission notes that the scope for use of technologies designed to shift peak loads in certain business facilities is greatest during the construction*

phase of such facilities. For example, a thermal storage system can generally be installed more easily during construction of an office building than as a retrofit. Therefore ETSA Utilities will be encouraged to work with developers to assess such possibilities at the development stage of new projects. The Commission's new arrangement for charging for augmentation of the network will encourage and reward developers who reduce the peak-demand requirements of a project."

As of June 2008 the projects identified that meet the EDPD Determination in relation to Voluntary and Curtailable Load Control for Large Customers have resulted in the following four trials:

- Domestic Load Shifting Time of Use (ToU) Trial.
- Commercial Load Shifting Thermal Energy Storage (TES) Industrial Trial.
- Commercial Load Shifting Thermal Energy Storage (TES) Commercial Trial 1.
- Commercial Load Shifting Thermal Energy Storage (TES) SME Trial.

4.3.5.1 Domestic Load Shifting Time of Use (ToU) Trial

As of June 2008, this remained a Status 1 project at the pre implementation stage designed to test the efficacy of ToU tariffs for reducing peak demand in the residential sector using ToU metering. To do this it is necessary to (i) design a residential tariff incorporating multi-rate prices, and (ii) test customer acceptance of the product as well as the price elasticity, response persistence and overall efficacy. Specifically the project should:

- Test customer acceptance of ToU tariffs.
- Source and adapt suitable existing technology for use in South Australia.
- Assess the potential of ToU tariffs for widespread deployment in the domestic sector.

The project is now being scoped and is scheduled for completion post the 2008/09 summer trial period.

4.3.5.2 Commercial Load Shifting Thermal Energy Storage (TES) Industrial Trial

As of June 2008, this was an active Status 3 project using a brine refrigeration circuit installed at St Hallett Wines in the Barossa Valley as shown in the Photo below.

Photo: 45,000 Litre Insulated Tank at St Hallett Wines

A comprehensive case study for this project has been completed[22]. For this winery the TES had an additional 45,000 litre insulated brine storage tank with Cristopia phase change nodules, interconnected pipework and a control system. Operation of the refrigeration unit is

[22] ETSA Utilities, Case Study, St Hallett Wines – Load Shifting Project, Thermal Energy Storage (TES) Technology, Ice Storage, February 2007.

semi automatic with each plant cycling as needed but the selection of the individual plant being left to an operator. A screen dump of the refrigeration unit is provided in the Illustration below.

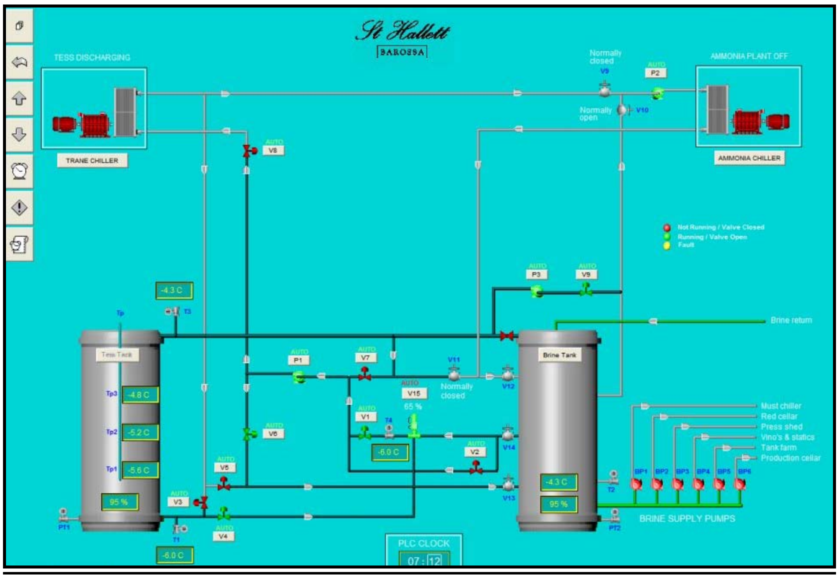

Illustration: Screen Dump of St Hallett Wines Refrigeration Plant

Specifically the aim of the project is to:

- test customer acceptance of TES technology;
- test the technology for use in South Australia;
- assess the potential of TES for widespread deployment in the industrial sector.

From ETSA Utilities' perspective this trial provided:

- Validation of reduction in peak electricity usage.
- Experience in the use of TES to lessen demand.
- Validation of reduction in energy and distribution costs by shifting load to off-peak.
- Confirmation of the possibility of offsetting possible future augmentation of the street supply.

In addition to reducing demand by shifting peak cooling load to off peak, further demand reduction was achieved by improving the site power factor. The customer invested in correcting its power factor as part of this plant overhaul and installed 150 kVAr of power factor correction in December 2006.

The improvement in power factor at the site after the installation of 150 kVAr PFC equipment is illustrated in the Figure below.

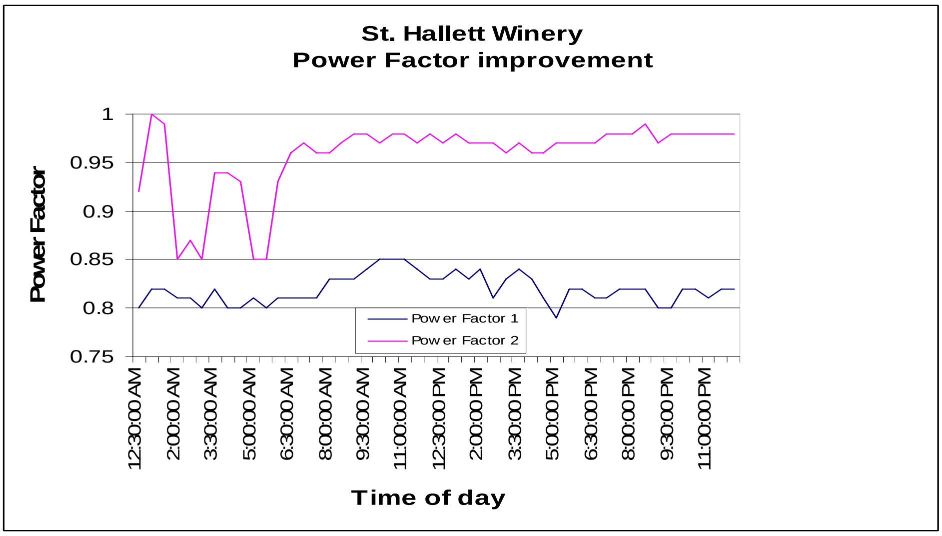

Figure: Power Factor Improvement after Installation of PFC Equipment

The Figure below illustrates the typical site load profile before and after the installation and commissioning of the TES plant.

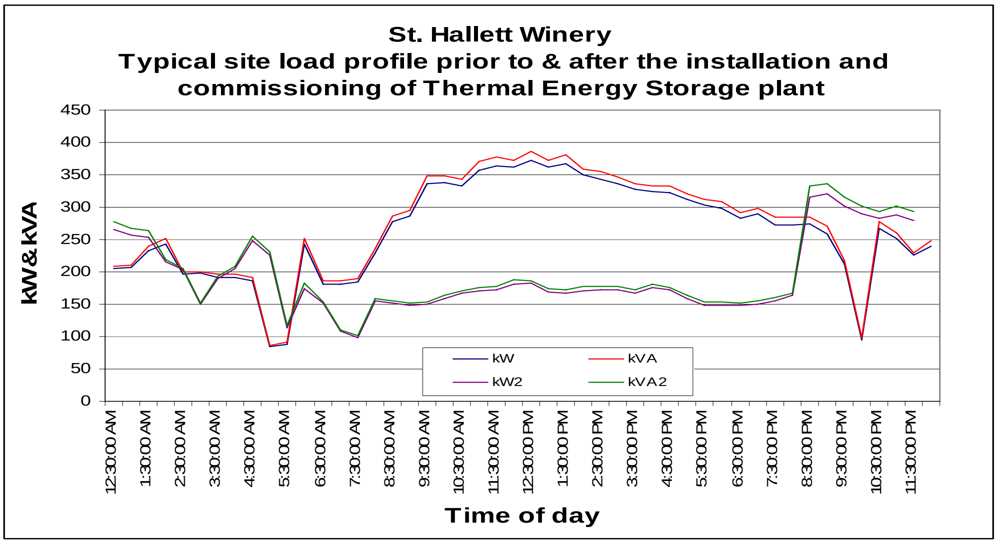

Figure: Typical Site Load Profile Before and After Installation of the TES Plant

Important Outcome

Installation, testing and commissioning of the TES plant and installation of the PFC equipment has been completed. Promotion of demand management initiatives has resulted in good initial outcomes for both the client and ETSA Utilities, however trials in the mode of plant operation are continuing and it will be post the 2008/09 summer when conclusions can be drawn for this trial.

4.3.5.3 Commercial Load Shifting Thermal Energy Storage (TES) Commercial Trial 1

As of June 2008, this was an active Status 3 project using an existing chilled water thermal store and glycol refrigeration circuit installed at the IKEA premises located at Adelaide Airport.

The project required ETSA Utilities to engage contractors to reprogram the BMS system operating the TES plant at the 23,500 m² IKEA retail store. Specifically the project sets out to:

- Reduce peak load demand.
- Test customer acceptance of TES technology.
- Test the technology for use in South Australia.
- Assess the potential of TES for widespread deployment in the commercial sector.

Installation, testing and commissioning of the BMS program operating the TES plant was completed prior to the summer of 2006/07 and the preparation of a comprehensive case study is being completed[23] to incorporate trialling during the 2007/08 summer.

In this project, the use of chilled water to store thermal energy was the option selected. A chilled water storage system using a chiller to cool the water solution to between 4°C to 6°C provided the necessary cooling to the building by circulating the chilled water through it. This TES trial validated that:

- Peak electricity demand was reduced at the site.
- Electricity consumption can be moved to off peak times with the selected TES.
- Operation at night with lower ambient temperatures was, in fact, more effective.
- The use of stored energy to meet peak demand reduced the size of the installed chilling capacity.

The resulting performance of the TES plant before and after the control system modifications were made is illustrated in the Figure below.

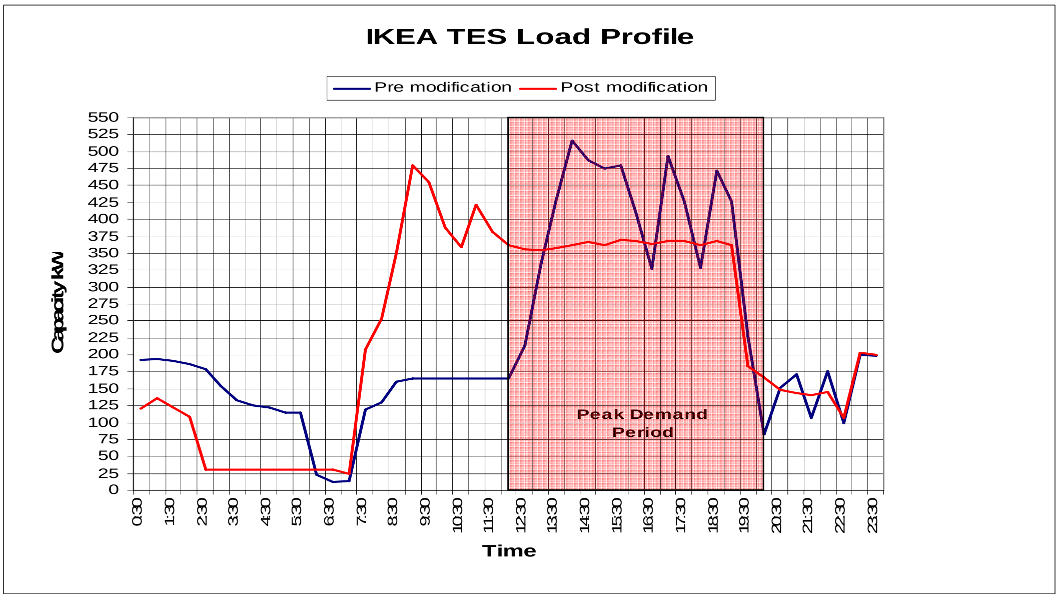

Figure: IKEA TES Load Profile Pre and Post Modification

Important Outcome

The load reduction achieved during peak times was approximately 150 kW to 190 kW during the network peak period (i.e. 12:00 noon to 8:00 pm). Whilst the IKEA site still uses its approximate normal peak demand, the relevance and importance to the network is that load has been shifted to off-peak time (i.e. 8:00 am to 12:00 noon).

[23] ETSA Utilities, Case Study, IKEA – Load Shifting Project, Thermal Energy Storage (TES) Technology, Chilled Water Storage, January 2007.

This frees up "peak" capacity on the supplying high voltage feeder and substation leading to a possible reduction in the need for network augmentation when new customers connect to the same feeder and substation.

4.3.5.4 Commercial Load Shifting Thermal Energy Storage (TES) SME Trial

As of June 2008, this was an active Status 3 project.

The project investigates the technical feasibility of using air conditioner off-peak energy to create a cold store which is then depleted during peak hours to provide cooling for a large residence or a small commercial application. The project located at the University of South Australia's Magill Campus aims specifically to:

- Test the technology for use in South Australia.
- Design a suitable tariff for use with such a system.

The "Ice Storage System" is designed for use with small air conditioner plant up to 12 kVA capacity. The system converts water to ice at night and during the day the ice cools the refrigerant needed to run the air conditioning unit, cutting overall energy consumption by about 30% and reducing peak electricity demand by up to 95%.

The system is in use in Japan and is undergoing further tuning of its operational parameters so as to provide optimum performance under Australian conditions. This has required adjustments to ice making and discharging times to ensure that an optimal period of peak demand can be managed.

Preliminary Trial Outcome

The 2007/08 summer trial has highlighted that it is possible to shift air conditioning load with this system (approximately 35%).

The project is scheduled for continued trialling during the 2008/09 summer period.

Other trial initiatives relate to recruiting:

- Customers with suitable loads that can be turned off when requested by ETSA Utilities.

- The use of customers' BMS that have inherent flexibility as to what is controlled and need little technical modification apart from software programming changes.

This trial is scheduled for commencement in the latter part of 2008.

4.3.6 Interval Meters

Interval metering is a technology that enables consumption to be monitored in discrete increments of time, usually 15 to 30 minutes. A technological evolution of interval metering termed "Advanced Metering Infrastructure" (AMI) is seen, amongst other things, as a mechanism for sending price signals to consumers and in doing so encouraging changed behaviour during times of high system peak demand as well as general energy conservation and thereby providing a demand side response to electricity consumption. However this strategy had been seen as being saddled with significant handicaps, namely the costs associated with roll out and data management, to the extent that the EDPD Determination noted.

> *Based on the CRA study, the Commission does not accept that the introduction of interval metering combined with pricing signals will provide sufficient certainty of a resulting demand reduction to permit the deferral of network augmentation. Therefore, the Commission has determined that it is not appropriate to have a "wide scale" roll out of interval meters to all customers at the present time."*

However, during 2007 significant developments took place, which may give support to the Commission's stance. These are discussed in more detail below.

4.3.6.1 Interval Meter Approach

As of June 2008, this was an active Status 3 project.

The evolution of interval metering in to AMI, when operating at full functionality, measures, monitors and reports on consumption, load and supply voltage at the customer level at half hour intervals with the generated data being ultimately used to settle the wholesale market and for customer billing. The potential for "time of use" (ToU) and critical peak pricing (CPP) tariffs becomes a reality with AMI.

Some distribution network operators have installed interval meters as part of their normal replacement policy. EnergyAustralia in New South Wales has fitted approximately 260,000 with a further 500,000 to be installed in 2008 but with functionality limited to the basics of monitoring and reporting of consumption and load and supply voltage at half hour intervals. The Victorian Government is currently overseeing the roll out of AMI in that State.

The Victorian Government's decision to roll out AMI was a cost benefit study completed in 2006. The roll out project will connect around 2.4 million customers between 2008 and 2012 with the meter's initial functionality limited to automated meter reading and remote connect/disconnect. Following this, a series of trials are and will be conducted to determine the benefits of extending the functionality of the meters to include:

- Supply capacity control.
- In home display.
- Controlled load.
- Communications failure indication (in lieu of outage detection).
- Quality and reliability of supply.
- Energy import/export.
- Reactive energy.

As with Victoria, the Council of Australian Governments (COAG) considers AMI to have the potential of providing a number of benefits ranging from changing the pattern and level of electricity demand to providing capabilities that enable cost efficiencies to be achieved by distribution and retail businesses. In April 2007, COAG endorsed a staged approach for a national mandated roll out of AMI to jurisdictions where benefits for consumers outweigh costs as determined by the results of a cost benefit analysis. This review was independent of the Victorian initiative which is to continue in its current form.

In July 2007, the Smart Meter Working Group (SMWG) set up by the Ministerial Council on Energy (MCE), appointed a team of consultants to undertake the cost benefit analysis required by COAG to provide the basis for future MCE decisions with regard to AMI.

Phase 1 of the analysis was released at the beginning of October 2007 and addressed the question of what functionalities should be included in a minimum national functionality for a roll out of AMI. At its meeting on 13 December 2007, the MCE agreed to establish a minimum functionality for meters in the AMI in the National Electricity Rules, in line with the recommendations made as part of Phase 1 of the study.

The focus of Phase 2 of the cost benefit analysis was on the fundamental question of whether the costs of rolling out AMI (or of undertaking an alternative demand management scenario) exceeded the benefits, given the particular circumstances of different jurisdictions and remote differences within those jurisdictions (i.e. urban, rural and remote areas). This assessment was intended to assist the MCE in determining any specific areas where replacement and roll out may be exempted or delayed, on the basis of local factors that are demonstrated to reduce net benefits for consumers.

The consultants hold that the Phase 2 analysis compiles the best information available on the likely costs and benefits resulting from a national AMI roll-out, and a DLC roll-out. But they say that as experience develops in the implementation of AMI and DLC in Australia, these costs and benefits will necessarily become clearer. They agree that costs and benefits associated with AMI and DLC may therefore change in the future as new information emerges particularly in relation to the current Victorian roll out.

The results of the cost benefit analysis for South Australia showed that for a roll out of AMI with the distributor as the responsible party, to have a net positive benefit, it is necessary to have costs at the low end of the range estimated. The NPV of the net benefits under an AMI roll out is an order of magnitude greater than the NPV of the net benefit of a DLC roll out (i.e. $213 m compared with $95 m). However, in relation to the ratio of benefits to costs, DLC has a much higher ratio than does AMI.

A decision to roll out AMI in South Australia therefore appears to be dependent both on a view as to the reasonableness of the estimates in relation to the distribution efficiency benefits and the installation costs as well as the likelihood of the estimated demand response benefits. However, the consecutive peak days experienced in South Australia may increase the uncertainty associated with achieving a sustained demand response, particularly via ToU and CPP tariffs.

The consultants caution against basing a decision on a national mandatory roll out of AMI on the results presented in their Report. These results are indicative of the likely benefits and costs of an AMI roll out for each jurisdiction, and highlight where further, and more detailed business case assessments of the costs and benefits should be undertaken.

Given the uncertainties associated with the likely demand response, the consultants would recommend that for South Australia a decision about an AMI roll out be further informed through undertaking specific jurisdictional trials of CPP/ToU and DLC. This will assist with informing whether the demand response benefits the consultants have estimated are realistic in the individual jurisdictional circumstances.

In order to conduct its own CBA of the DLC trials and to test alternatives to DLC, ETSA Utilities engaged the international firm of KEMA International (KEMA), which is internationally renowned for its work on AMI and DLC, to develop a CBA model specific to South Australia for both AMI and DLC as well as the enhanced Peak Breaker. The kick-off workshop for building the model was held in the last week of October 2007 with a visit to Adelaide by two senior representatives of KEMA to gather preliminary data and familiarise themselves with the local conditions. The workshop was structured in a way that gave KEMA the opportunity to interact with all of the relevant ETSA Utilities personnel who could provide appropriate data and information on AMI and DLC and also to draw on knowledge and expertise of other stakeholders such as ESCOSA, DTEI and ETSA Utilities' Victorian counterpart, Powercor.

Subsequent to the workshop detailed input templates were developed by KEMA in conjunction with ETSA Utilities and populated with data that had been supplied to COAG's consultants as well as the more detailed data required for the CBA model. Contemporaneously with the population of the input templates, KEMA constructed the CBA models for an AMI roll out, a DLC roll out, a combined AMI and DLC roll out and an enhanced Peak Breaker roll out.

It has previously been mentioned (see Section 4.3.3.5 – Direct Load Control Phase III) that the societal NPV for DLC was negative, however the societal NPV for AMI and AMI and DLC are also negative, and by a higher order. In both cases the most sensitive parameters are:

- Cost of the smart meter;
- Life of the smart meter;
- Installation time of the smart meter;
- Percentage of customers using one on one GPRS;
- Energy savings due to smart meter with display.

In the case of the enhanced Peak Breaker, the original Peak Breaker is to be replaced by a smaller lower cost relay with an incorporated interface that will communicate directly with the enhanced Peak Breaker within a local (home area) wireless network. The CBA analysis for this solution points to a positive societal NPV. On the basis of the extensive developmental work and outcomes of the of the CBA modelling, ETSA Utilities will trial the enhanced Peak Breaker in metropolitan Adelaide and some regional areas during the 2008/09 summer in order to prove the technology and firm up the CBA.

4.3.7 Aggregation

Given the business and regulatory climate in Australia and South Australia, in particular, aggregation of electricity demand is particularly difficult as the findings of the ESCOSA Determination highlight.

> *"Recent national reviews of the NEM have commented that there is significantly less demand response in the electricity market than might have been expected, given the price signals available in the market. These reviews have identified certain barriers to demand management in the electricity market, which include the fact that net margins and the length of the typical retail electricity contract preclude retailers from making significant investment in either time or equipment to facilitate demand management initiatives. In addition, the disaggregation of what were once vertically integrated organisations into independent businesses makes it extremely difficult to realise all the benefits of demand management initiatives and hence to offset the costs involved.*
>
> *As a result there is little demand management available in the market for any application – network augmentation deferral, energy market arbitrage, or ancillary services.*
>
> *The Commission is of the view that a means of re-aggregating the benefits of demand management should be investigated, especially if the market is to realise the demand management potential of smaller customers. The Commission believes that ETSA Utilities may be in a good position to act as a demand management aggregator. That is, it aggregates small and large loads/generating capacity so that it is in a position to bid this capacity into the NEM, like a large generator. Therefore, the Commission has decided to provide funding to ETSA Utilities to assess the opportunities, costs and benefits of becoming a demand management aggregator in South Australia."*

In order to address the question of aggregation, ETSA Utilities has been engaged in the following projects:

- Load Reduction Trail 1
- Aggregation of Benefits to the Electricity Market

4.3.7.1 Load Reduction Trial 1

As of June 2008, this was a Status 2 project at the implementation stage.

This trial involves collaboration between ETSA Utilities and an independent Demand Management Aggregator, to gain demand reduction from commercial and industrial customers and in so doing to:

- Gain experience in valuing, drafting and negotiating load reduction contracts with wholesale market counterparts.
- Gain experience in drafting and negotiating load reduction contracts with customers.
- Investigate opportunities for automating load reduction.
- Assess the performance of load reduction contracts for reducing peak demand.
- Assess the capability of customers to respond to curtailment instructions.
- Assess the potential for using load reduction contracts for widespread deployment.

To date, this project has been scoped, with a Heads of Agreement in place. A customer contract has also been drafted. As well as this, a model has been set up whereby the project might be effectively linked in with the commercial DLC and BMS projects.

4.3.7.2 Aggregation of Benefits to Electricity Market

As of June 2008, this was a Status 1 project at the pre implementation stage whereby ETSA Utilities' aims to collate data and construct possible financial models and business scenarios for the entire DM Program. For example, ETSA Utilities will create small scale trials of demand aggregation supporting specific projects such as the standby generation and load reduction trials. For these projects ETSA Utilities will need to engage and contract with third parties to provide a cash flow that will give an incentive to the customer to participate in the trial.

Aggregation of demand comes down to financial engineering whereby revenue from various electricity sources and even non-electricity sources is acquired to provide a financial basis for demand management. Such revenue may come from a number of entities, including but not limited to:

- Operators of the distribution network.
- Operators of the transmission network.
- Energy retailers.
- Electricity generators.
- Electricity wholesale market participants (e.g. traders, brokers and aggregators).
- Entities involved in carbon trading.
- Governments and agencies.

Because demand aggregation is not specific to any particular project or stakeholder, it is a complex interaction involving the customer, an aggregator and a purchaser that varies for each demand management scenario. Therefore factors affecting aggregation are many and varied and can include, for example:

- the volume, availability and reliability of the demand procured;
- the type, needs and capability of the provider;
- technical constraints;
- market rules;
- legislation; and
- quantification.

> **Remark**
>
> Modelling and execution of demand aggregation can only be put into place after knowledge has been gleaned about the success, or otherwise, and applicability of specific demand management trials currently being undertaken in the DM Program.

Therefore the phasing of the demand aggregation project will lag most of trials to some extent. As and when suitable data and information is available a report on the feasibility of demand aggregation will be prepared, which will include findings of the DM Program and prospective scenarios for establishing an aggregation business.

4.3.8 Demand Management Organisation Within ETSA Utilities

The requirements of "Demand Management Organisation Within ETSA Utilities" are best described by paraphrasing the ESCOSA Determination directly.

> *"The CRA study made a number of recommendations regarding developing and improving the demand management capability within ETSA Utilities. The Commission agrees with CRA that it is important to improve ETSA Utilities' understanding and responsiveness to demand management initiatives.*

Therefore the Commission will approve funding to ETSA Utilities in the 2005-2010 regulatory period to:

- *improve ETSA Utilities' understanding of demand management and use this knowledge in the network planning processes;*
- *integrate demand management strategies with traditional network supply-side planning;*
- *develop and information base about end-use loads; and*
- *re-analyse the nineteen network areas that were identified in Phase One of the CRA study and any others identified by ETSA Utilities."*

Aside from the DM Program, ETSA Utilities is obliged under Chapter 3 of the Distribution Code to provide commercial customers and/or developers with a formal offer for establishing new connections or modifying existing connections that require augmentation and extension.

In this regard, ETSA Utilities has established a quality assured process wherein prior to a formal offer being made the customer is assisted in defining its scope of works and resultant maximum demand. Since the inauguration of the DM Program, this speculative enquiry process has been enhanced with demand management initiatives that include:

- In-house training for ETSA Utilities' personnel in demand side management so that they can discuss demand side management opportunities at the initial meetings.
- Clauses in ETSA Utilities speculative letters designed to raise customer awareness of demand side management opportunities.
- ETSA Utilities personnel being pro-active in suggesting to customers that they consider their actual maximum demand requirements in terms of fiscal efficiency and the installation of the most effective electrical plant and equipment for their development (i.e. motor starting controls, PFC equipment, duty cycles, After Diversity Maximum Demand (ADMD), etc).
- ETSA Utilities personnel being pro-active in encouraging customers to correct their power factor beyond compliance, usually 0.85 or 0.90, to 0.97 so as to minimise their kVA demand by demonstrating the benefits available to them via the kVA tariff and reduced augmentation charge.
- For several projects, an offer to reduce charges if the customer is able to move their duty cycles away from the local networks peak load periods.
- Logging of all speculative and formal offers so as to monitor the impact of demand side management discussions and opportunities.
- Further enhancement of the logging report to make it more automated and to include any identified cost savings.
- Communicating with all large customers requesting supply upgrades suggesting they consider generation and energy management systems for their air conditioning loads (with defence projects, in particular, ETSA Utilities discussed using embedded generation).

As a consequence of these demand side management initiatives, for the whole of 2007 ETSA Utilities logged 1,918 contacts with customers leading to a potential saving of 20.24 MVA in installed capacity (c.f. discussion and Table in Section 4.3.8.3 – Demand Management Contacts January 2007 to December 2007).

4.3.8.1 Demand Management Team and Organisation Structure

As of June 2008, ESCOSA's requirements had been substantially complied with inasmuch as this is an active Status 3 project with a demand side management structure/team established within ETSA Utilities and with a dedicated Manager Demand Management reporting to the General Manager Demand and Network Management who in turn reports to the CEO of ETSA Utilities as illustrated in the organisation chart below.

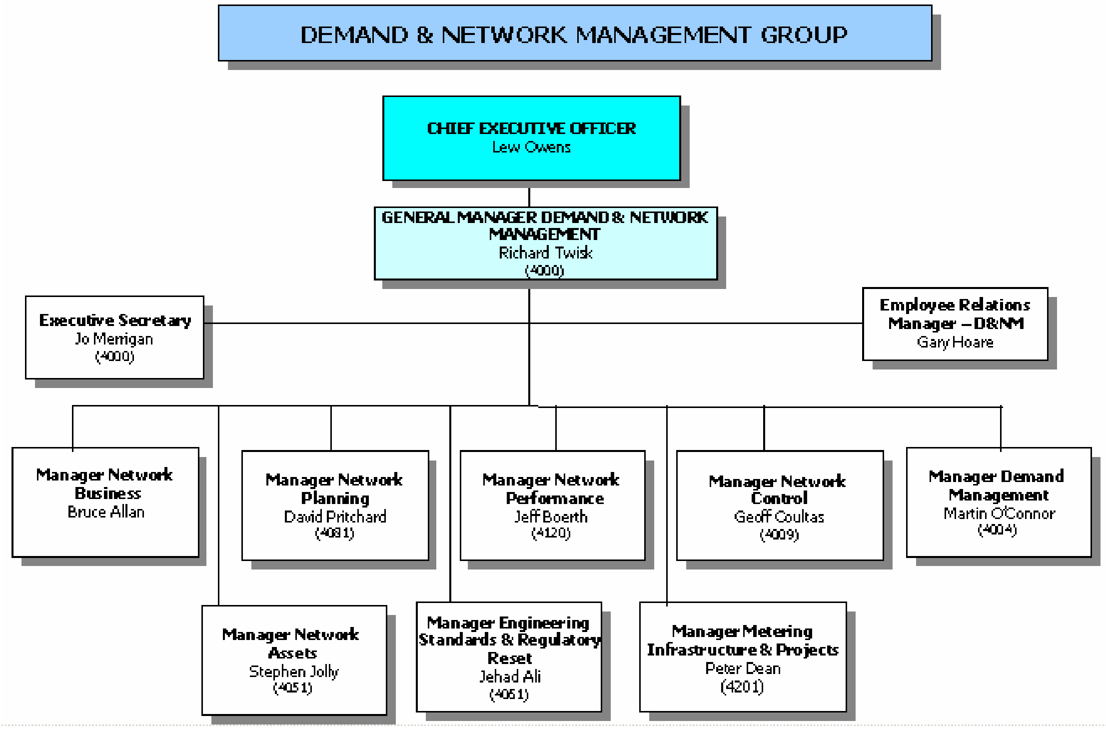

Figure: ETSA Utilities Executive Management

As of June 2008, the Team consisted of seven dedicated personnel responsible for managing the entire portfolio of projects discussed in this Section. The organisational chart depicting their roles is illustrated in the Figure below.

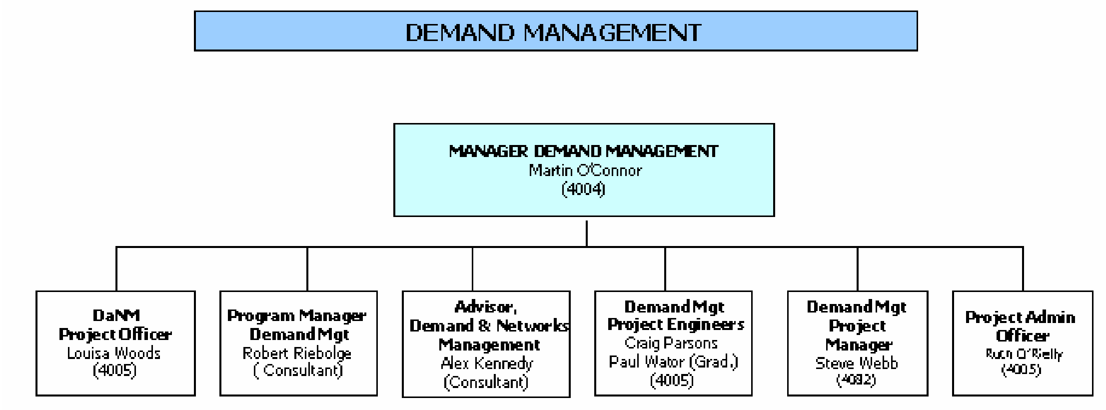

Figure: Demand Management Program Team Structure

Day to day operations of the Team is the responsibility of the Manager Demand Management who chairs the Program's weekly meetings as well as any ad hoc meetings that bring together a majority of the Team members.

As the DM Program consists of a portfolio of projects, which have to be collectively tracked, monitored and reported on, a Program Manager/Report Editor has been appointed to carry out these tasks. In addition to this the Program Manager oversees the inputs of external consultants such as TRC Mathematical Modelling and KEMA International and has carriage of the compilation of all major reports including the Draft Final and Final Reports to be delivered at the end of this DM Program.

At the operational level of the DM Program, personnel who report directly to the Manager Demand Management are the following:

- Communications Coordinator whose function it is to manage and prepare promotional information and presentations for demand management initiatives and who is also responsible for the projects identified in the Table below.
- Project Engineers who are responsible for the projects shown in the Table below.
- External Relations Advisor who manages the interface with government, the community and media in relation to demand management initiatives and who project manages the projects shown below.
- Demand Management Project Manager who manages the projects listed below.
- Demand Management Project Manager who oversees the projects shown in the Table below.

Category & Project Count	Project	Project Status	Responsibility
Power Factor Correction			
1	Pole Top Low Voltage (LV) Capacitors	3	Industry Education Coordinator
2	Tariff Rationalisation Project	3	Industry Education Coordinator
3	Keswick Building Improvements	3	Project Engineer
Standby Generation			
4	Load Reduction Trial	3	Project Engineer
5	Embedded Generation Trial 1	3	DM Project Manager
Direct Load Control			
6	Direct Load Control Phase I	4	
7	Direct Load Control Phase II	4	
8	Direct Load Control Phase II(a)	3	DM Project Manager
9	Direct Load Control Phase II(b)	3	DM Project Manager
10	Direct Load Control Phase III	3	DM Project Manager
11	Regional Discretionary Load Trial	4	
12	Universal Demand Response Enabling Device (DRED) Interface	3	DM Project Manager
13	Commercial Building Management System (BMS) Trial	3	Project Engineer
14	Domestic Load Limitation – Lochiel Park	4	Project Engineer
15	Commercial Load Limitation	3	Project Engineer
Critical Peak Pricing			
16	Residential Critical Peak Pricing (CPP) Tariff Trial	3	DM Project Manager
17	Commercial Critical Peak Pricing (CPP) Tariff Trial	1	Advisor Community & Media Relations
Voluntary and Curtailable Load Control for Large Customers			
18	Domestic Load Shifting Time of Use (ToU) Trial	1	Advisor Community & Media Relations
19	Commercial Load Shifting Thermal Energy Storage (TES) Industrial Trial	3	DM Project Manager
20	Commercial Load Shifting Thermal Energy Storage (TES) Commercial Trial 1	3	DM Project Manager
21	Commercial Load Shifting Thermal Energy Storage (TES) SME Trial	3	Project Engineer
Interval Meters			
22	Interval Meter Approach	3	Program Manager DM

Category & Project Count	Project	Project Status	Responsibility
Aggregation			
23	Load Reduction Trial 1	2	DM Project Manager
24	Aggregation of Benefits to Electricity Market	1	DM Project Manager
Demand Management Organisation Within ETSA			
25	Demand Management Team and Organisation Structure	3	General Manager DaNM
Other			
26	Painted Roof Trial 1	3	Industry Education Coordinator
27	Passive Demand Reduction Trial	4	

Table: Individual Projects and the Responsible Personnel

4.3.8.2 Data Management and Analysis

The effectiveness of the projects in the DM Program portfolio is predicated on availability and reliability of real time data and an understanding of the reasons for customers' specific patterns of energy usage. Without this data all demand management initiatives would be impossible.

Prior to the DM Program, ETSA Utilities had already compiled load data on 19 separate residential suburbs comprising of the order of 1,000 residences of different types of construction, ages and representing a variety of socio economic profiles. However, far more comprehensive data was required even before commissioning of the Phase I mini-trial. To get to this point, ETSA Utilities deployed significant resources to install real time metering with data storage facilities at strategic locations along the network and in individual homes and businesses.

The ongoing capture of real time data as well as data relating to customer profiles in terms of their electricity usage is now in hand and its analysis with both specialised proprietary ETSA Utilities software systems and statistical analysis performed by TRC Mathematical Modelling of the University of Adelaide will continue throughout the duration of the DM Program.

This analysis provides ETSA Utilities with an understanding of the impact of the demand management initiatives on both the customer and the network in terms of energy usage patterns and the drivers behind the usage. Importantly, this will be at both the level of the individual customer and at the aggregated level of strategic sites along the network, including the substations.

The team who installed the metering equipment is available to attend to faults and problems with the equipment if it occurs during the course of an individual project within the DM Program.

As discussed in the relevant projects above, data is collected both manually and remotely and provides:

- Customer load information prior to and after any demand management initiative is trialled.
- Research data on the penetration of different electrical appliances in homes and businesses.
- An estimate of the number of different types of customers served by each network.
- Information on the demand management opportunities in medium and large businesses.
- An assessment of the number, configuration and condition of standby generators within the ETSA Utilities network.

But to enhance this data collection exercise for end use customer loads, several options have been examined with one proposal being to engage primary schools in collecting information on air conditioners. This is still at initial concept stage, but in theory it would be in a form of a competition amongst children with the participation rate per school used to determine rankings. Children would not necessarily be limited to their own homes but there would be strict guidelines as to how the information is to be collected.

It is envisaged that the information would provide details of what air conditioning (i.e. none, evaporative or reverse cycle) was installed, the make, model and age of the air conditioner. This would then be able to be related to an address and allow installed air conditioners to be mapped, identify homes without air conditioners and assist with the forecasting of areas of potential growth and make predictions of the growth rates. This project is due to begin in the latter part of 2008.

4.3.8.3 Demand Management Contacts - January 2007 to December 2007

During the period of January 2007 to December 2007, ETSA Utilities DaNM's personnel made 1,918 contacts where aspects of demand management were discussed or negotiated with customers as shown in the Table below. Included in this Table are specific projects that impact on the network in a manner that reduces the system demand (e.g. system capacitors). In compiling this information data was gathered from:

- Projects accepted and issued for construction during the period January 2007 to December 2007 through ETSA Utilities' Network Assets.
- PFC equipment installations negotiated by ETSA Utilities' Major Customer and Metering Group.
- System projects identified by ETSA Utilities' Network Planning.
- Speculative responses made by DaNM to customer enquiries.

Demand Management Category	Number of contacts	kVA Reduction Negotiated	Comments
Maximum Demand Advice – Domestic	41	301	Projects where, by negotiation, domestic demand requirements have been reduced.
Maximum Demand Advice – Industrial	241	12,297	Projects where, by negotiation, industrial demand requirements have been reduced.
Power Factor Control	309	3,823	Negotiations leading to reduced demand through installation of PFC equipment.
Off peak Load Management	4	0	Projects where negotiations have resulted in customers adding load in off peak times. No net reduction on peak load demand.
Distribution System Capacitors	5	2,478	Installation of system capacitors resulting in net reduction in system demand.
Underground Residential Development (URD) Building Efficiencies	12	32	Specific URD's which have been negotiated, through proposed building efficiencies, leading to a reduction in demand.
Shifting Peak Load Times	0	0	No records for the period.
Customer Demand Limiting	39	1,293	Where customers or developers have voluntarily reduced demand to meet their requirements.

Demand Management Category	Number of contacts	kVA Reduction Negotiated	Comments
J Tariff Time Clock Change	0	0	One project is in the planning stage with respect to this category.
Speculative Enquiry Domestic	1,029	0	Part of any contact made with domestic customers is an effort to minimise the demand and final connection capacity being offered.
Speculative Enquiry Industrial	198	0	Part of any contact made with industrial customers is an effort to minimise the demand and final connection capacity being offered.
Speculative Enquiry URD/Urban Industrial Development (UID)	32	0	Increasing numbers of URD developers are seeking to reduce ADMD levels by conforming to environmentally friendly building requirements. UID developers have reduced service capacity to reduce augmentation demands.
TOTALS	**1,918**	**20,244**	

Table – Contacts Made and kVA Reductions Negotiated

In instances where the customers had been initially seeking a maximum demand less than was appropriate to their actual needs, ETSA Utilities personnel provided the requisite advice. These instances were counted as contacts but record no net reduction in kVA demand (e.g. Project Identifier CP006925 where the initial request was for 200 kVA but 346 kVA was connected).

4.3.9 Other

With the evolution of the DM Program a number of projects have been put forward by ETSA Utilities that while not falling within any of the above specified categories nevertheless contribute to demand management initiatives because they:

- Address network constraints, hence deferring network augmentation.
- Are in the nature of a pilot program rather than technology demonstration or research.
- Have reasonable prospects for successful application in addressing network constraints.

As of June 2008, these projects comprised:

- Painted Roof Trial 1
- Passive Demand Reduction Trial

4.3.9.1 Painted Roof Trial 1

As of June 2008, this was an active Status 3 project.

The aim of this trial is to gather data on the performance of a paint finish under Adelaide climatic conditions. The selected residence located in the Adelaide CBD was monitored for temperature ingress into the living spaces pre and post the application of paint finish to the roof provided by Astec Paints. The project sought specifically to:

- Test the efficacy of solar reflective paints as a tool for reducing peak demand.

- Assess the potential of solar reflective paints for widespread deployment in South Australia.

Monitoring was conducted during the March 2008 heatwave and a case study is in the course of preparation. Based on the single residential test site where monitoring was undertaken there was a noticeable decrease in the peak demand requirements and a reduction in the overall energy usage over the summer period. The occupant reported that the home felt more comfortable leading to a reduction in the air conditioner usage. This trial is scheduled for completion in May 2009. For further validation and to be able to directly attribute the demand reduction to the application of the reflective paint further test sites need to be assessed and monitored.

4.3.9.2 Passive Demand Reduction Trial

As of June 2008, this was a completed Status 4 project.

The project envisaged approximately 20 new dwellings employing existing insulation methods and having Type 5 meters for data logging. These meters would have been monitored to test the effectiveness of insulating the building envelope for the purpose of reducing peak load. The eventual aim of the project was to:

- Test the efficacy of utilising passive building elements for peak demand reduction.
- Assess the potential of passive demand reduction for widespread deployment in new housing in South Australia.

An agreement between ESCOSA and ETSA Utilities was arrived at in June 2007 not to proceed with this project as it would draw resources away from other DM trial initiatives having greater potential to deliver tangible results.

5. DM Program Monitoring

Ongoing monitoring of the DM Program is essential both from ETSA Utilities' perspective and ESCOSA's perspective as it is important that value is achieved from the trials that are funded and that positive results are achieved for the South Australian community.

The foregoing discussion in this Report has focussed on qualitative and some quantitative outcomes of the projects themselves. These outcomes will be further refined as information, learnings and conclusions come to hand. This Section therefore restricts itself to monitoring and reporting on the DM Program's expenditure in relation to its $20.4 million funding package and its performance time-wise in relation to the 2005-2010 regulatory period.

5.1 Cost Monitoring

As of August 2008, the expenditure on the DM Program amounted to $6.77 million and is forecast to reach $10.21 million by the end of calendar year 2008.

The Table set out below breaks down the expenditure by demand management categories. The sub totals for each demand category is the summation for all projects within that category, however the Estimated Total Cost to December 2008 is not the summation of the columns "Life to Date Cost 31/08/08" and "Work Plan 2008" as it has had to be adjusted for costs already incurred in calendar year 2008 and a realignment of ETSA Utilities' original categories to which projects were assigned and the ESCOSA categories with which this Report deals.

	Program Categories	**Life to Date Cost 31/08/08 ($)**	**Work Plan 2008 ($)**	**Estimated Total Cost Dec 2008 ($)**
	Administration and Reporting			
Sub Total		**1,300,000**	**252,000**	**1,301,000**
	Power Factor Correction			
Sub Total		**571,000**	**769,000**	**1,300,000**
	Standby Generation			
Sub Total		**312,000**	**495,000**	**798,000**
	Direct Load Control			
Sub Total		**3,386,000**	**2,314,000**	**5,500,000**
	Critical Peak Pricing			
Sub Total		**7,000**	**152,000**	**157,000**
	Voluntary and Curtailable Load Control for Large Customers			
Sub Total		**271,000**	**40,000**	**306,000**
	Interval Meters			
Sub Total		**0**	**0**	**0**
	Aggregation			
Sub Total		**4,000**	**0**	**4,000**
	Demand Management Organisation Within ETSA Utilities			
Sub Total		**917,000**	**64,000**	**831,000**
	Other			
Sub Total		**0**	**10,000**	**10,000**
TOTAL		**6,769,000**	**4,097,000**	**10,207,000**

Table: DM Program Expenditure to the End of Calendar Year 2008

An analysis of these costs shows that DLC has been the focus of the DM Program accounting for just over half the expenditure (51%) in life to date costs and an estimated expenditure to the end of 2008 of 54%. In terms of Life to Date Costs, Demand Management Organisation Within ETSA Utilities follows at 14%, Power Factor Correction at 8%, Standby Generation at 5%, and Voluntary and Curtailable Load Control for Large Customers at 4%. Virtually no expenditure has yet been devoted to projects in the Interval Meters, Aggregation and Other category. These figures are illustrated in the Table below.

Category Description	Life to Date Cost 31/08/08 (%)	2008 Work Plan (%)	Estimated Total Cost Dec 2008 (%)
Administration and Reporting	19	6	13
Power Factor Correction	8	19	13
Standby Generation	5	12	8
Direct Load Control	51	56	54
Critical Peak Pricing	0	4	2
Voluntary and Curtailable Load Control for Large Customers	4	1	3
Interval Meters	0	0	0
Aggregation	0	0	0
Demand Management Organisation Within ETSA Utilities	14	2	8
Other	0	0	0
TOTAL	**100**	**100**	**100**

Table: Proportional Makeup of Expenditure on the DM Program

Administration and reporting accounts for an estimated 19% of Life to Date Costs, which is very reasonable as it is here where a large proportion of all management, education, organisation, analysis and reporting costs are captured for all projects in all categories as well as the preparation and promulgation of information for the DM Program itself.

A work plan has been submitted to ESCOSA of the anticipated projects and expenditure for calendar year 2008 and thereafter for the whole of the 2005-2010 regulatory period. If at the end of this period the entire funding allocation of $20.4 million has not been spent, the balance of the funds will be allocated to the roll out of demand management initiatives that are supported by the business case(s) and which have been discussed and approved by ESCOSA.

5.2 Time Monitoring

ETSA Utilities monitors all of the individual projects within the DM Program using tracking and time monitoring software. The Diagram below shows the projects discussed in this Interim Report in a rolled-up summary format.

This monitoring process is used to keep track of major decision points and to ensure that milestones are kept firmly focussed by the Team and the project managers while overseeing their projects on a day to day basis and when reporting to the weekly DM Program meetings.

As of June 2008, all projects were on track to deliver tangible conclusions for the 2005-2010 regulatory period as has been discussed in the foregoing sections of this Interim Report.

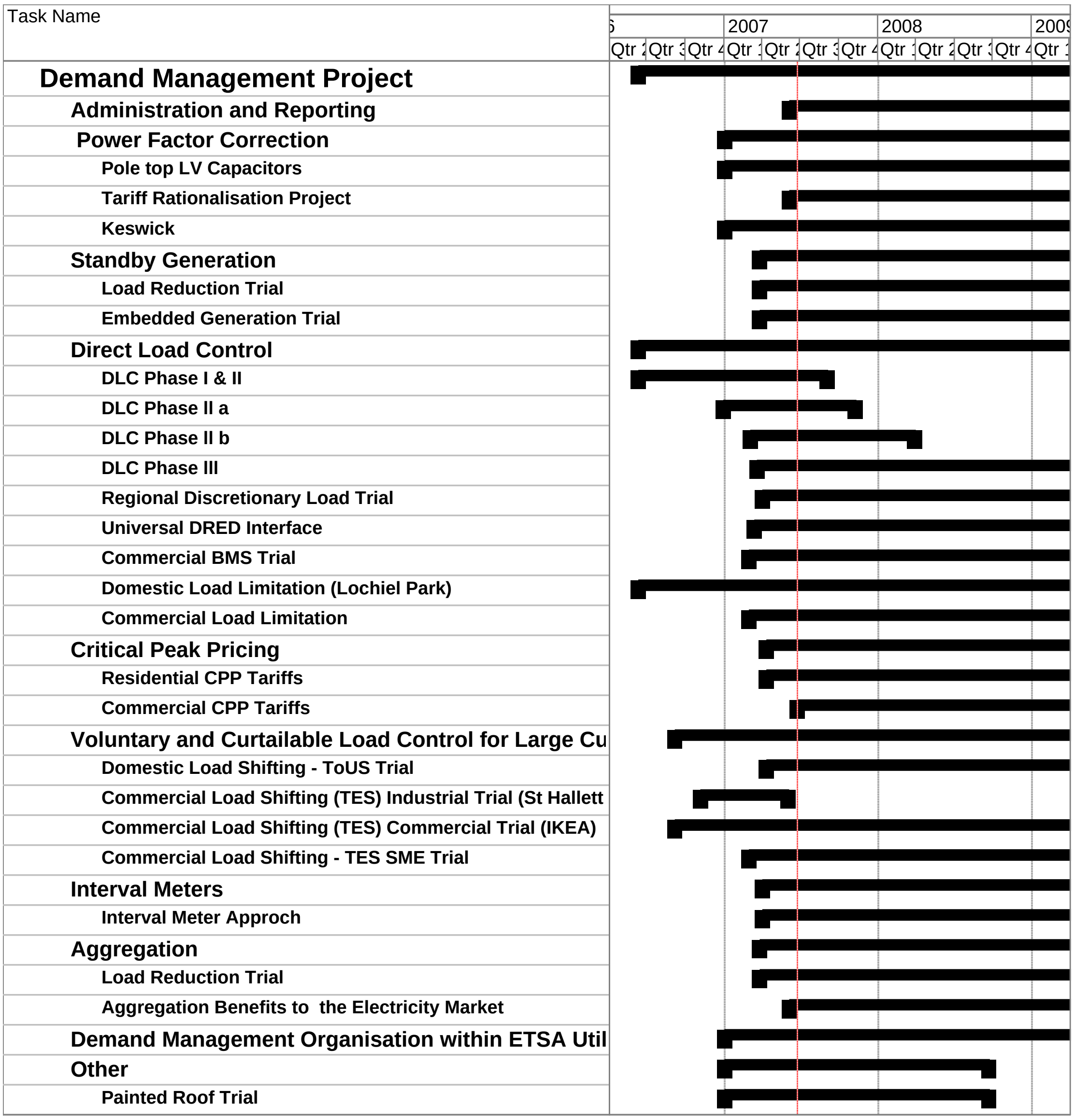

Diagram: Rolled up Summary Activities of the DM Program

ANNEX 1 – REFERENCE MATERIAL AND BIBLIOGRAPHY

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