INTERNATIONAL BEST PRACTICE IN USING ENERGY EFFICIENCY AND DEMAND MANAGEMENT TO SUPPORT ELECTRICITY NETWORKS

David Crossley
Energy Futures Australia

Report #4 of the Australian Alliance to Save Energy Research Project

Scaling the Peaks: Demand Management and Electricity Networks

December 2010
ACKNOWLEDGEMENTS

We would like to thank those who provided financial support for the project including the New South Wales Office of Environment and Heritage, the Victorian Department of Primary Industries and the Consumer Advocacy Panel.

The support of the Queensland Office of Clean Energy, the Northern Territory Office of the Chief Minister and the South Australian Department of Transport, Energy and Infrastructure and the NSW Minister for Energy, Mr Paul Lynch and the Federal Parliamentary Secretary for Climate Change and Energy Efficiency, Mr Mark Dreyfus are also gratefully acknowledged.

We also wish to express our appreciation to the guidance and advice of the Steering Committee of the Australian Alliance to Save Energy (A2SE) Research Project on the Potential for Energy Efficiency, Demand Side Management and Distributed Generation in Electricity Network Planning, for which this research was undertaken.

The Australian Alliance to Save Energy (A2SE) is a not-for-profit coalition of prominent business, government, environmental, and consumer leaders that has come together to raise the profile of energy efficiency and to ensure that the best possible information on energy efficiency finds its way into the hands of decision makers. The A2SE’s work addresses research, awareness and policy issues relating to the reduction of all wasteful and non-productive uses of energy across the Australian economy.

DISCLAIMER

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

While this document has been prepared to the best of the author’s knowledge and understanding and with the intention that it may be relied on by the client, Energy Futures Australia Pty Ltd and the individual author of the document make no representation or warranty as to the accuracy or completeness of the material contained in this document and shall not have, and will not accept, any liability for any statements, opinions, information or matters (expressed or implied) arising out of, contained in or derived from this document or any omissions from this document, or any other written or oral communication transmitted or made available to any other party in relation to the subject matter of this document.

PRINCIPAL AUTHOR

Dr. David Crossley
Managing Director
Energy Futures Australia Pty Ltd
11 Binya Close
Hornsby Heights NSW 2077
Australia
Phone: + 61 2 9477 7885
Mobile: + 61 411 467 982
Fax: + 61 2 9477 7503
Email: efa@efa.com.au
Website: http://www.efa.com.au

Please cite this report as:

CONTENTS

EXECUTIVE SUMMARY ........................................................................................................... iii

1. INTRODUCTION ............................................................................................................... 1

2. NETWORK-DRIVEN DEMAND MANAGEMENT ................................................................ 2
   2.1 Characteristics of Network Constraints ................................................................ 2
   2.2 Characteristics of Network Operational Services .................................................. 3

3. EFFECTIVENESS OF NETWORK-DRIVEN DM MEASURES ........................................ 3
   3.1 External Success Factors .................................................................................... 4
      3.1.1 Government Policies ................................................................................ 4
      3.1.2 Regulatory Regimes ............................................................................... 5
      3.1.3 Market Structure .................................................................................... 6
      3.1.4 Commitment by Project Proponent .......................................................... 7
      3.1.5 Technology Availability ......................................................................... 8
      3.1.6 Commercial Considerations .................................................................. 9
      3.1.7 Public Relations Benefits ............................................................. 10
   3.2 Internal Success Factors ..................................................................................... 11
      3.2.1 Project Objectives ................................................................................... 11
      3.2.2 Target Market ....................................................................................... 12
      3.2.3 Demand-side Measures Used ............................................................... 13
      3.2.4 Barriers Addressed ............................................................................... 14
      3.2.5 Outreach and Marketing ....................................................................... 15
      3.2.6 Participation Process and Customer Service ......................................... 16
      3.2.7 Delivery Mechanisms ............................................................................ 17
   3.3 Effectiveness of Specific Network-driven DM Measures ....................................... 18
      3.3.1 Direct Load Control ............................................................................... 18
      3.3.2 Distributed Generation .......................................................................... 19
      3.3.3 Demand Response ............................................................................... 21
      3.3.4 Energy Efficiency ............................................................................... 23
      3.3.5 Fuel Substitution .................................................................................. 25
      3.3.6 Interruptible Loads ............................................................................... 26
      3.3.7 Integrated DM Projects ....................................................................... 28
      3.3.8 Load Shifting ....................................................................................... 29
      3.3.9 Power Factor Correction ..................................................................... 31
      3.3.10 Pricing Initiatives ............................................................................... 32
      3.3.11 Smart Metering ................................................................................... 34
   3.4 Conclusions on the Effectiveness of DM Measures ................................................. 36

4. OPTIONS FOR MODIFYING NETWORK PLANNING PROCESSES ..................... 38
   4.1 Forecasting Future Demand ............................................................................... 38
   4.2 Communicating Information about Network Constraints ................................... 39
   4.3 Developing Options for Relieving Network Constraints ....................................... 40
   4.4 Establishing Policy and Regulatory Regimes ....................................................... 42
      4.4.1 Policy and Regulatory Incentives ......................................................... 44
      4.4.2 Policy and Regulatory Obligations ............................................................. 47
5. BEST PRACTICES IN EVALUATING AND ACQUIRING NETWORK-DRIVEN DM RESOURCES
   5.1 Assessing the Need for DM Resources
   5.2 Identifying and Evaluating Available DM Resources
   5.3 Contacting Potential Providers of DM Resources
   5.4 Negotiating the Provision of DM Resources
   5.4 Acquiring and Implementing DM Resources

6. CONCLUSION

APPENDIX: CASE STUDIES OF DEMAND MANAGEMENT PROJECTS
Case Study 01 Chicago Energy Reliability and Capacity Account - USA
Case Study 02 California Critical Peak Pricing Tariff for Large Customers - USA
Case Study 03 Separation of Agricultural Feeders for Load Control - India
Case Study 04 PEF Direct Load Control and Standby Generator Programs - USA
Case Study 05 PJM Load Response Programs - USA
Case Study 06 Load Interruption Contract - Spain
Case Study 07 California Energy Cooperatives - USA
Case Study 08 Olympic Peninsula Non-wires Solutions Pilot Projects and GridWise Demonstration - USA
Case Study 09 LIPAedge Direct Load Control Program - USA
Case Study 10 Mad River Valley Project - USA
Case Study 11 Paradip Port Substitution of Cooking Fuel Project - India
Case Study 12 French Riviera DSM Program - France
Case Study 13 Baulkham Hills Substation Deferral Project - Australia
Case Study 14 Castle Hill Demand Management Project - Australia
Case Study 15 Tahmoor Fuel Substitution Project - Australia
Case Study 16 Maine-et-Loire DSM Project - France
Case Study 17 TU Electric Thermal Cool Storage Program - USA
Case Study 18 Espanola Power Savers Project - Canada
Case Study 19 Queanbeyan Critical Peak Pricing Trial - Australia
Case Study 20 Efficient Lighting Project DSM Pilot - Poland
Case Study 21 Carbon Trust Advanced Metering Trial - United Kingdom
Case Study 22 Binda-Bigga DSM Project - Australia
Case Study 23 Tempo Electricity Tariff - France
EXECUTIVE SUMMARY

This report reviews international best practice in using energy efficiency and demand management to support electricity networks. The report covers four main topics:

- a definition and description of network-driven demand management;
- the effectiveness of a range of network-driven demand management measures;
- options for modifying network planning processes to take into account the use of demand-side measures; and
- best practices in evaluating and acquiring network-driven demand management resources.

Network-driven Demand Management

Network-driven DM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators. In this report, network-driven DM is defined as follows:

Network-driven demand management is concerned with reducing demand on the electricity network in specific ways which maintain system reliability in the immediate term and over the longer term defer the need for network augmentation.

Effectiveness of Network-driven DM Measures

The report identifies a number of external and internal factors that may contribute to the success of network-driven DM projects. External factors establish the context within which a network-driven DM project operates, while internal factors are specific to each individual project and determine how the project is implemented.

The success or otherwise of the DM measures that are components of network-driven DM projects is intimately bound up with the success of the projects themselves. Projects containing the same DM measures (such as energy efficiency, load shifting, direct load control or pricing initiatives) tend to have a common set of factors which contribute to their success and to this extent it is possible to identify sets of success factors that apply to each category of DM measure. These are shown in Table 1 (page 37).

The challenge in designing a network-driven DM project that will ultimately be successful in achieving its objectives is to clearly identify the success factors for each of the DM measures included in the project and then concentrate on optimising each of these factors. For example, if the delivery mechanism is a success factor for a DM measure included in the project, the project designer should choose an appropriate delivery mechanism and then concentrate on optimising the effectiveness of that mechanism.

Modifying Network Planning Processes

The report identifies four key areas in which changes could be made to network planning to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks.
Forecasting future electricity demand. Forecasting methodologies frequently reduce global load forecasts by an assumed (usually small) amount to take account of demand management activity. Such methodologies discount the potential contribution by DM towards supporting electricity networks. Forecasting methodologies for network planning should be modified to recognise more accurately the potential contribution of DM.

Communicating information about network constraints. Information about future network constraints is often retained inside network businesses. It is then very difficult for anyone else to propose options for relieving network constraints. Network businesses should make this information publicly available so that other organisations with the required expertise can develop DM options to relieve the constraints.

Developing options for relieving network constraints. Network businesses should provide formal opportunities for third parties with expertise in DM to participate in the development of options that use demand-side resources to relieve network constraints.

Establishing policy and regulatory regimes for network planning. Governments and regulators should change policy and regulatory regimes to reduce the disincentives faced by network businesses that use demand-side resources to support electricity networks. There are two ways in which this can be achieved: by providing policy and regulatory incentives to network businesses; and/or by imposing policy and regulatory obligations on network businesses.

Evaluating and Acquiring Network-driven DM Resources

Good demand-side resource acquisition processes include the following stages:

- assessing the need for DM resources;
- identifying and evaluating available DM resources;
- contacting potential providers of DM resources;
- negotiating the provision of DM resources; and
- acquiring and implementing the DM resources.

Best practices within each of these stages are tailored to the nature of each DM resource and to the specific purpose for which the resource is required.

Conclusion

At present, the use of demand-side resources to support electricity networks is not common, occurring mainly in Australia, the United States and in specific geographical areas in France. However, in the future, as electricity loads increase, network infrastructure ages, and the costs of augmenting and expanding networks continue to rise, it is likely that the use of cost-effective DM resources to support electricity networks will become much more widespread.
1. INTRODUCTION

The Australian Alliance to Save Energy (A2SE) is a not-for-profit coalition of prominent business, government, environmental, and consumer leaders that has come together to raise the profile of energy efficiency and to ensure that the best possible information on energy efficiency finds its way into the hands of decision makers. The A2SE’s work addresses research, awareness and policy issues relating to the reduction of all wasteful and non-productive uses of energy across the Australian economy.

The A2SE has contracted a consortium of organisations to carry out a study on the role of energy efficiency and demand management in energy network planning. This study is considering the network investment currently being planned by the energy industry, the planned national trajectory for reducing emissions, and the opportunity to both reduce the required investment and reduce emissions through energy efficiency improvements, load shifting and distributed generation.

The study is also investigating best practices for demand management globally and the rationale for making demand management the preferred investment option for the energy supply industry, including an examination of the risks of investing in stranded assets and the cost/benefits of investing in demand management compared to current supply investments. The study will produce clear and specific recommended changes to the regulation relating to the Australian electricity supply industry.

This report contributes to the larger study by reviewing international best practice in using energy efficiency and demand management to support electricity networks.

The report is based on a four year international research project carried out by the International Energy Agency Demand Side Management Programme. This research project was called “Task XV: Network-driven Demand Side Management”1. Task XV included detailed case studies of 64 projects in which demand management measures were, or could be, used for network support2. A selection of 23 of these case studies is included in the Appendix to this report (see page 55).

This report covers four main topics:

- a definition and description of network-driven demand management;
- the effectiveness of a range of network-driven demand management measures;
- options for modifying network planning processes to take into account the use of demand-side measures; and
- best practices in evaluating and acquiring network-driven demand management resources.

---

1 The results of the Task XV international research project can be accessed at: http://www.ieadsm.org/ViewTask.aspx?ID=16&Task=15&Sort=0
2 These case studies can be accessed directly at: http://www.ieadsm.org/TaskXVNetworkDrivenDSMCaseStudiesDatabase.aspx
2. NETWORK-DRIVEN DEMAND MANAGEMENT

In the electricity industry, the terms 'demand management' (DM) and 'demand-side management' (DSM) are used to refer to actions which change the electrical demand on the system. This report is concerned with a particular type of demand management – “network-driven DM”.

Network-driven DM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators. In this report, network-driven DM is defined as follows:

Network-driven demand management is concerned with reducing demand on the electricity network in specific ways which maintain system reliability in the immediate term and over the longer term defer the need for network augmentation.

The following network-driven DM measures are considered in this report:
- direct load control;
- distributed generation, including standby generation and cogeneration;
- demand response;
- energy efficiency;
- fuel substitution;
- integrated DM projects;
- interruptible loads;
- load shifting;
- power factor correction;
- pricing initiatives, including time of use and demand-based tariffs; and
- smart metering.

There are two prime objectives for network-driven demand management:
- to relieve constraints on distribution and/or transmission networks at lower costs than building ‘poles and wires’ solutions; and/or
- to provide services for electricity network system operators, achieving peak load reductions with various response times for network operational support.

2.1 Characteristics of Network Constraints

To be effective in relieving network constraints, demand management measures must be capable of addressing the particular characteristics of these constraints. Network constraints have both timing and spatial dimensions.

---

In relation to timing, network constraints may be:

- **narrow peak related** – occurring strongly at the time of the system peak and lasting seconds, minutes or a couple of hours; or
- **broad peak related** – less strongly related to the absolute system peak, occurring generally across the electrical load curve and lasting several hours, days, months, years or indefinitely (eg where the network is close to capacity).

In relation to the spatial dimension, network constraints can:

- occur generally across the network in a particular geographical area; or
- be associated with one or more specific network elements such as certain lines or substations.

### 2.2 Characteristics of Network Operational Services

Demand management measures have the potential to contribute to a range of network operational services, including:

- voltage regulation;
- load following;
- active/reactive power balancing;
- frequency response;
- supplemental reserve; and
- spinning reserve.

In addition, power factor correction may be regarded as a DM measure.

With the exception of power factor correction, network operational services provided by DM are required for relatively short periods of up to a couple of hours. They may also have a strong spatial component, with some services (such as voltage regulation) often being required in a specific location. Other network services (such as frequency control) are usually required generally across the network. The required response times also vary from minutes to almost instantaneous.

### 3. EFFECTIVENESS OF NETWORK-DRIVEN DM MEASURES

There are two types of factors that may contribute to the success of demand management projects that aim to support electricity networks:

- **external factors** that establish the context within which a network-driven DM project operates; and
- **internal factors** that are specific to each individual project and determine how the project is implemented.

---

3.1 External Success Factors

The context within which a network-driven DM project operates is shaped and governed by a number of factors external to the project itself. Some of these comprise broad geographic and socio-economic factors such as climate change, economic conditions and the political situation. While such broad external factors can affect the outcome of a project, their influence on the project occurs indirectly and cannot easily be taken into account when the project is being designed. Therefore, such factors will not be considered further here.

A second group of external factors exert more direct influences on whether a network-driven DM project is successful. These factors can be taken into account when a project is being designed. It is possible to identify seven types of external success factors that may directly contribute to the success of network-driven DM projects:

- government policies;
- regulatory regime;
- market structure;
- commitment by project proponent;
- technology availability;
- commercial considerations; and
- public relations benefits.

3.1.1 Government Policies

Government policies can contribute to the success of network-driven DM projects in two ways:

- they can create a favourable context in which network-driven DM projects are seen as viable alternatives to supply-side options; and/or

- they can impose obligations requiring the use of network-driven DM projects instead of supply-side options.

The role of government policies in creating a favourable context for network-driven DM projects can be seen in many of the case studies of overseas DM projects developed by the IEA DSM Programme. In these projects, government policies were generally in favour of energy efficiency and DM but the government did not specifically require the implementation of demand-side options.

Stronger government intervention through imposing a requirement for demand-side options can be seen in the more recent direct load control, energy efficiency and integrated DM projects in Australia. Most of these programs were implemented in the New South Wales, where the State Government has imposed a condition on the licences of electricity distributors that requires them to take demand-side options into account when planning network augmentations. In response to this requirement, the electricity industry itself developed a voluntary Code of Practice that specifies how electricity

distributors could incorporate DM into their planning of network augmentations\(^7\). The Code was first developed in 1999 and has been revised several times since then; each revision is authorised by the relevant government department before it is published. The Chicago Energy Reliability and Capacity Account (Case Study 01, page 57) and the California Critical Peak Pricing Tariff (Case Study 02, page 60), both in the United States, are interesting examples of government actions requiring the implementation of network-driven DM. In Chicago, the local government, the City of Chicago, sued the local utility for not providing an adequate electricity network and the court ordered the utility to establish a fund of money to be used for demand-side options. In California, the State Government, working through the electricity industry regulator and the California Energy Commission, required the local utilities to establish a range of demand-side responses to the 2001 “energy crisis”, including the development of critical peak pricing.

A somewhat unusual case of government intervention is the Separation of Agricultural Feeders for Load Control project in India (Case Study 03, page 67). The project was initiated by the Government of Gujarat and implemented by electricity distributors in the State of Gujarat. In 2003, the Government of Gujarat announced a scheme called "Jyotigram Yojana" (JGY) to provide continuous three phase power supply to rural areas of the State to improve the quality of life of the rural population. Under the JGY scheme, the Gujarat Government decided to separate agricultural pump set connections from domestic light and fan (DLF) connections by constructing separate 11 KV feeders for agricultural loads. This enabled electricity distributors to implement direct load control of agricultural pumps by establishing schedules specifying the times during the day when each agricultural feeder would be energised. The main objective of implementing this direct load control program was to flatten the load curve to provide sufficient network capacity for the morning and evening peaks.

3.1.2 Regulatory Regimes

Regulatory regimes act in a similar way to government policies in contributing to the success of network-driven DM projects:

- they can create a favourable context in which network-driven DM projects are seen as viable alternatives to supply-side options; and/or
- they can impose obligations requiring the use of network-driven DM projects instead of supply-side options.

The role of regulatory regimes in creating a favourable context for network-driven DM is demonstrated in a 2004 determination by IPART, the electricity industry regulator in New South Wales\(^8\). The regulator introduced a D-factor into the weighted average price cap control formula that allowed distribution network service providers to recover:

- approved non-tariff-based DM implementation costs, up to a maximum value equivalent to the expected avoided distribution costs;

---


● approved tariff-based DM implementation costs;
● approved revenue foregone as a result of non-tariff-based DM activities.

This determination provides significant incentives that enable electricity distributors to recover virtually all the costs they incur in implementing network-driven DM projects, including the revenue foregone from lower quantities of electricity being transported through the network. The allowable cost recovery is capped at a maximum value equivalent to the expected costs of the alternative network augmentation option (e.g., building a new line or substation). All network-driven DM projects recently implemented in New South Wales benefit from these incentives.

The role of regulatory regimes in imposing a requirement for demand-side options can be seen in the actions of many state-based regulators in the United States. From the 1980s to the mid-1990s, the regulators required electricity utilities to carry out energy efficiency DM programs and also provided some financial incentives to enable them to do so. Regulators in some US states still impose similar requirements which can apply to network-driven DM projects; an example is the direct load control and standby generator programs implemented by Progress Energy Florida in response to requirements by the Florida Public Service Commission (see Case Study 04, page 72). In California, the regulator had a role in requiring the local utilities to develop critical peak pricing (see Case Study 02, page 60).

3.1.3 Market Structure

The structure of the electricity market can be an important factor in enabling the implementation of network-driven DM projects. This is most evident where a network-driven DM measure is closely linked to the market structure. Typically, such measures aim to influence the behaviour of end-users. There are two types of these measures:

● measures that provide market-linked incentives to end-users;
● measures that impose market-linked penalties on end-users.

Market-linked incentives reward end-users for behaviour that increases network reliability. In the United States, most of the independent system operators (ISOs) have developed programs that enable end-use customers to receive payments for reducing their loads at times when there are high market prices or network capacity shortages; an example if the demand response programs implemented by the PJM Interconnection (see case Study 05, page 78). Individual utilities in the United States have also developed similar measures. The transmission system operator in Spain has also developed similar measures, mostly based on various forms of interruptibility contracts (see Case Study 06, page 90).

California Energy Cooperatives (Case Study 07, page 95) are an interesting example of an initiative that uses market-linked incentives. An Energy Cooperative comprises a group of end-users who have banded together to offer load reductions to an electricity utility. The load reductions can be called by the utility and the cooperative ensures that the required level of reduction is delivered by aggregating the reductions achieved by individual cooperative members. The utility pays the cooperative for both the availability of the load reduction and any reductions actually delivered. The cooperative distributes these payments to its members.
Market-linked penalties discourage end-users from behaviour that decreases network reliability. These penalties mostly take the form of time of use prices with high prices during peak periods lasting several hours. The purpose of these measures is to encourage end-users to shift their use of electricity away from the peak period. There is also increasing use of critical peak pricing in which very high electricity prices are set for short periods (one or two hours) at the time of the system peak (see Case Study 02, page 60).

### 3.1.4 Commitment by Project Proponent

Commitment by the proponent of a network-driven DM project may be an important factor in ensuring the success of the project. Because network-driven DM is not the usual or generally accepted way in which network problems are resolved, strong commitment by the project proponent is usually important in most network-driven DM projects.

Commitment by the project proponent is particularly important:
- where distributed generation is used as an alternative to network augmentation;
- in integrated network-driven DM projects; and
- in most direct load control, demand response, interruptible loads and load shifting projects.

Network-driven DM initiatives by the Bonneville Power Authority (BPA) demonstrate the importance of commitment by a project proponent. BPA operates the transmission network in much of the Pacific Northwest region of the United States. In 2001, BPA started considering measures other than building new transmission lines to address load growth, constraints and congestion on the transmission system. Currently, BPA, along with others in the region, is exploring “non-wires solutions” as a way to defer large construction projects. BPA defines non-wires solutions as a broad array of alternatives, including demand response, distributed generation, energy efficiency measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. BPA and its consultants have developed a screening process and checklist to evaluate a transmission problem area to determine whether it is a candidate for a non-wires solution.

BPA has focussed particularly on the Olympic Peninsula area in north-west Washington State (Case Study 08, page 101). The Peninsula has received particular attention because it is an environmentally sensitive area with increasing demand for electricity and limited transmission capacity. The capacity of the transmission lines on the Peninsula may become inadequate as early as December 2007, if there is a forced outage of one line during peak periods of cold weather. A significant transmission construction project, including a new 20-mile 230 kV line, is being contemplated on the Peninsula. In an attempt to defer the construction of this line, BPA is carrying out a number of non-wires solutions pilot projects on the Peninsula, including direct load control, demand response, voluntary load curtailments, networked distributed generation and energy efficiency.
3.1.5 Technology Availability

In some network-driven DM projects, the availability of a particular type of technology is crucial to the success of the project. Indeed, some network-driven DM projects are designed specifically to take advantage of a particular type of technology.

This is particularly the case with direct load control and demand response projects. These types of network-driven DM projects require specific types of technology to enable remote communication with, and control of, appliances and equipment and near real-time monitoring of the load reductions achieved.

The availability of a particular type of technology is also crucial for distributed generation projects, fuel substitution projects, and some projects employing time of use pricing.

The LIPAedge Direct Load Control Program (Case Study 09, page 110) is an example of a network-driven DM project built around the availability of a particular type of technology. Long Island Power Authority (LIPA) developed the LIPAedge program to use central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction. The program uses the programmable ComfortChoice thermostat designed by the Carrier Corporation with associated communication infrastructure provided by Silicon Energy.

The system operator uses an internet-based system to control a demand-side resource comprising about 20,000 thermostat-controlled air conditioners. Two-way pagers are used to transmit a curtailment order to the thermostats and to receive acknowledgment and monitoring information. The thermostats take immediate action or adjust their schedules for future action, depending on what the system operator ordered. The thermostats log the order and respond via pager, enabling LIPA to monitor the response to the event.

For a summer load curtailment, the system operator might send a command at 9:00 am directing all thermostats to move their set points up 4 degrees, starting at 2:00 pm and ending at 6:00 pm. Alternatively, the system operator could send a command directing all thermostats to completely curtail immediately. The command would be received and acted upon by all loads, providing full response within about 90 seconds. This is far faster than generator response, which typically requires a 10-minute ramp time. Thermostats can be addressed individually, in groups, or in total; this provides both flexibility and speed.

End-use customers also receive benefits. The thermostat is fully programmable and remotely accessible, with all of the associated energy savings and convenience benefits. A web-based remote interface is provided for customer interaction. Customers can also override curtailment events. This feature appears to be important to gain customer acceptance and it probably increases the reliability of the response.
3.1.6 Commercial Considerations

Most network-driven DM projects are justified on the basis that they are more cost-effective than supply-side options. For some specific projects, commercial considerations are the most important success factor.

This is particularly the case where DM measures are used to defer proposed network augmentations. In these types of projects, the main justification for implementing network-driven DM measures is that they are more cost-effective than the network augmentation “build” option. Commercial considerations are also important in projects where DM measures are used to target peak load reductions generally on the network and particularly in countries such as India where there are acute shortages of both network and generation capacities.

A good example of a project where commercial considerations were important is the Mad River Valley Project in the United States (Case Study 10, page 117). The Mad River Valley is a region in central Vermont which is home to growing ski resort developments. In 1989, the Valley was served by a 34.5kV distribution line extending in a long “U” down one valley, across a ridge and back along the other side of the ridge. Sugarbush Resort, the largest load on the line, was located at the base of the “U”, its weakest point. The resort informed the local electricity utility that it was planning to increase its load to accommodate a new hotel and conference centre and significant new snowmaking equipment. An increase in load at that location would have impaired the reliability of the line, requiring an upgrade. Under Vermont’s line extension rules at the time, it was likely that a major portion of the cost of the upgrade would be charged to the customer. Neither the customer nor the utility wanted to pay for the line. Instead, a network-driven DM project was negotiated with two major elements: a targeted utility energy efficiency program in the Mad River Valley, and a customer load management commitment under which Sugarbush committed to ensuring that load on the distribution line would not exceed the safe level.

Commercial considerations were also important in the Paradip Port Substitution of Cooking Fuel Project in India (Case Study 11, page 120). The project was initiated and funded by the Paradip Port Trust which administers the port of Paradip. The Trust purchases electricity in bulk under a maximum demand contract and then supplies electricity directly to its employees for household use. The objective of the project was to reduce system peak demand by introducing LPG as a domestic cooking fuel through replacing electric stoves used by Trust employees. The project was targeted at cooking in the residential sector because this activity comprised approximately 60% of the electrical usage in each household. Almost 90% of the households in the residential facility provided by the Trust used electric stoves for cooking, adding 3 to 4 MW to the electricity demand. Because electric stoves were the largest contributors to the peak demand, replacing these with LPG cooking stoves resulted in considerable electricity and cost savings.
3.1.7 Public Relations Benefits

In some cases, achieving public relations benefits for the project proponent is a major success factor for a network-driven DM project. Public relations benefits may include: increased customer loyalty, increased credibility for the project proponent, and improved relations with governments and/or regulators.

There is no particular type of project for which public relations benefits are always a success factor, though public relations issues tend to be important in projects that require participation by large numbers of end-users.

The California Critical Peak Pricing Tariff for Large Customers (Case Study 02, page 60) was implemented in the aftermath of the 2001 “energy crisis” in the state in which all the major investor-owned utilities filed for bankruptcy protection and electricity prices doubled for some customers over a matter of months. It was imperative that the state government and the regulator be seen to be doing something to relieve the situation. In June 2002, the California Energy Commission adopted an Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing". In June 2003, the Commission authorised a Critical Peak Pricing (CPP) tariff for large customers proposed by the three California investor-owned utilities, as well as several other demand response-related programs. A statewide demand response measurement and evaluation (M&E) effort also began in 2003, comprising a comprehensive monitoring and evaluation plan. The plan outlined M&E activities in an effort to provide information that would improve the cost-effectiveness of demand response activities going forward.

The goal underlying all of the demand response programs was to provide California with greater flexibility in responding to periods of high peak electricity demand. The objective in rolling out these specific programs relatively quickly with limited formal rate design research was to achieve a "quick win" that would:

- take advantage of the new interval meters installed in customers premises;
- give both customers and utilities experience in implementing statewide demand response programs;
- deliver significant load reductions for summer 2004; and
- make a significant contribution to achieving the California Public Utilities Commission’s overall price-responsive demand response goals.

A different type of public relations benefit is evident in the French Riviera DSM Program (Case Study 12, page 123). In this case, a very large DM project is being implemented to defer the need to upgrade a major transmission line serving the eastern part of the Provence-Alpes-Côte d'Azure region of France. For the past 20 years, there has been very strong local opposition to the upgrading of the line because the line would pass through the classified scenic gorges of the Verdon Regional Park. In May 2006, the state court, after a complaint from an environmental group, refused planning permission for the upgrading of the line. Therefore, at present, the DM program is the only way to secure supply to this region by keeping load growth within the capacity of the existing line.
3.2 Internal Success Factors

Internal success factors are specific to each particular network-driven DM project and determine how the project is implemented. In general, projects that demonstrate a clear “story” and understanding of the market and have developed the right linkages and partnerships to successfully target that market are likely to be more successful than projects that lack such characteristics. Successful network-driven DM projects require well thought-out processes and procedures. Projects that clearly articulate the steps involved in implementation as well as clearly delineate management responsibilities and structures have a higher likelihood of succeeding relative to those that do not.

Seven types of internal success factors can be identified:

- project objectives;
- target market;
- demand-side measures used;
- market barriers addressed;
- outreach and marketing;
- participation process and customer service; and
- delivery mechanisms.

Each of these factors is a component of most network-driven DM projects. However, depending on the specific project design, some of the factors are more important than others in contributing to the success of individual projects.

3.2.1 Project Objectives

Defining the project objectives is a fundamental first step in designing a network-driven DM project. Clear and well-defined objectives are an important factor in determining whether or not a project is successful. Indeed, for many projects, the clarity with which the project objectives are defined determines whether or not the project is successful. In particular, the way in which the objectives for a project are defined often drives the design of the project and the selection of the individual project components.

Project objectives are important success factors for all network-driven DM projects, and particularly important for direct load control projects, demand response projects, integrated DM projects, interruptible loads projects, load shifting projects, and some pricing initiative projects.

The Baulkham Hills Substation Deferral project in Australia (Case Study 13, page 134) is a good example of a network-driven DM project where the project objective was an important success factor. The project had a very clear objective: to defer an AUD 1.7 million network augmentation project to construct the Baulkham Hills zone substation, which had become necessary as a result of the growth in summer afternoon peaks. This objective was achieved very simply by reaching an agreement with one major industrial customer who uses large furnaces and puts a substantial peak demand of 12 MVA on the network. Under the agreement, the customer is given 24 hours notice to shed load between 1 pm and 5 pm the following day. The customer is able to implement load shifting by speeding up production prior to the event and then slowing it down during the

---

peak. The agreement with this one customer achieved peak load reductions of between 3.5 and 4.5 MVA. The project was highly cost-effective. The majority of the cost of the project was the payments made to the participating customer which totalled AUD 70,000. An additional cost of approximately AUD 10,000 was incurred in setting up and initiating the project.

### 3.2.2 Target Market

For a network-driven DM project to be successful, the target market chosen for the project should be directly related to achieving the project objectives. In the Baulkham Hills Substation Deferral project (Case Study 13, page 134) referred to in the previous section, the target was a single customer whose ability to shift peak load was all that was required to achieve the project’s objective.

However, targets will rarely be as small and well-defined as in the Baulkham Hills project. Frequently, the target market will comprise a mix of end-use customers, market intermediaries and trade allies (such as appliance and equipment suppliers), each of whom has the ability to make a small contribution to achieving the project’s objectives.

The mix of participants in a target market often plays a role in the cost-effectiveness of network-driven DM projects. For example, at present, a project in a market comprising larger commercial customers will tend to be more cost effective than an identical project in a market of smaller commercial or residential customers. There will be higher costs involved in marketing the project to a large number of small customers as compared with a small number of larger customers.

However, this may change in the future. A large number of small loads has a greater reliability than a few large ones, and with today’s communication technologies, the small loads can be easily programmed to respond to meet the requirements of both the household and the network operator. In particular, if householders themselves can nominate the loads to be automatically switched and the circumstances which trigger switching, this provides a one-stop ‘set and forget’ system that is likely to produce a much more reliable load reduction response than systems that require customers to make a decision to manually switch loads during every trigger event.

The target market is an important success factor in all types of network-driven DM projects, with the exception of distributed generation. In distributed generation projects, the target market is usually all the customers in the area served by the network to which the generator is connected.

The Castle Hill Demand Management Project in Australia (Case Study 14, page 136) provides a good demonstration of the importance of the target market as a success factor in network-driven DM projects. The objective of the Castle Hill project is to defer capital expenditure of AUD 3.2 million to build a new substation scheduled for 2005/06. The substation is required because of increasing penetration and use of air conditioners in the Castle Hill commercial centre and surrounding residential areas, resulting in summer peak loads that will exceed system capability by about 2008. The Castle Hill project is focussing on the commercial sector and the target market is well-defined and easily located. The majority of end-use customers approached for the project are retail tenants of one major shopping centre located in the area that would be served by the new substation. The program is targeting interruptible loads, the use of existing standby
generators, the installation of high efficiency air conditioning (and the upgrading of existing air conditioning systems), and the installation of efficient lighting and power factor correction equipment in new and replacement applications.

### 3.2.3 Demand-side Measures Used

The specific demand-side measures used in the project is a crucial success factor for all network-driven DM projects.

For a project to be successful, the demand-side measures must be:

- capable of achieving the objective set for the project; and
- targeted at the project target market.

Consequently, the selection of the demand-side measures to be used in a project is primarily driven by the project objective and the project target market. A third major driver is the cost of each demand-side measure, including the cost of any equipment involved and installation and maintenance costs.

Some network-driven DM projects use only one demand-side measure. The Tahmoor Fuel Substitution Project in Australia (Case Study 15, page 144) is an example of a project that used a single measure. The purpose of the Tahmoor project was to defer augmentation of the distribution network by controlling growth in the winter evening peak demand and combating a low load factor. The project promoted the use of bottled gas by residential customers for cooking and space heating. Customers were contacted via a letterbox drop with a personalised letter providing details of subsidies available from the local electricity distributor and the costs of bottled gas appliances. The distributor arranged the installation of bottled gas and appliances and provided subsidies to reduce the cost of these installations.

The Tahmoor project succeeded in flattening load growth to a degree, but take-up was less than had been hoped. One reason may have been that at the time the program was underway, the state’s primary gas distributor made public overtures about extending reticulated natural gas to the area. These plans never materialised, but the possibility of using mains gas may have delayed and ultimately prevented customers from making decisions in favour of the electricity distributor’s bottled gas alternative. As a result, the program deferred the distribution network augmentation for a shorter period than had originally been forecast.

Other network-driven DM projects use several different demand-side measures and integrated DM projects use a range of measures. For example, the Maine-et-Loire DSM Project in France (Case Study 16, page 146) used a range of DM measures undertaken both on the network side, and on the customer side, of the electricity meter to address voltage drop problems on rural distribution feeders.

The network-related DM measures in the Maine-et-Loire project included:

- installing voltage regulators on the feeders;
- installing voltage regulators on the network side of the meter at customers' premises;
- use of three phase/single phase transformers to distribute the single-phase current loads of customers across three phases;

and the customer-related DM measures included:
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

- shifting the use of electric household appliances and water heaters to off-peak periods;
- installing inverters for lighting and data processing end-uses;
- implementing electronic "soft" starters for electric motors;
- distributing compact fluorescent lamps;
- implementing automatic controllers for domestic boilers;
- installing a wood-fired boiler;
- using portable diesel generators for intermittent generation at selected sites; and
- installing a 40 kVA diesel generator at a pig breeding farm.

3.2.4 Barriers Addressed

The underlying objective for all network-driven DM projects (with the exception of distributed generation projects) is to change the ways in which end-use customers use electricity or purchase electrical appliances and equipment. This change can usually be achieved most effectively if the specific factors preventing the change ("barriers") can be identified and action taken to overcome these barriers. Frequently, this will involve providing incentives to encourage the desired behaviour change or disincentives to discourage undesirable behaviour.

To a greater or lesser extent, most network-driven DM projects are explicitly or implicitly designed to overcome barriers. Usually, the most successful network-driven DM projects are those that clearly identify the relevant barriers and implement actions that are targeted to directly overcome those barriers.

The Texas Utilities Electric Cool Storage Program (Case Study 17, age 154) is a good example of a network-driven DM program that identified specific barriers and provided incentives targeted at removing these barriers. During the late 1970s, TU recognised the need to address the increasing air conditioning load of commercial buildings. Thermal cool storage was seen as a promising means of flattening commercial air conditioning load shapes. In 1981, TU realised that offering financial incentives would eliminate many barriers to installation of thermal cool storage systems. These barriers included a high initial system cost, a long payback period and the large physical size of a thermal cool storage system compared to a standard system.

TU’s Thermal Cool Storage program was the first non-residential DM program offered by TU Electric, beginning full-scale in 1982. The program provided cash incentives to customers who installed thermal storage systems to provide space and/or process cooling during TU’s on-peak periods. The incentives were based on the load shifted from on-peak to off-peak hours.

TU focused on marketing the concept and benefits of thermal cool storage and did not sell any thermal cool storage equipment. For customers who were interested in thermal

---

10 The term “barrier” is employed here in its common usage to mean something that is preventing end-use customers from changing the ways in which they use electricity or purchase electrical appliances and equipment. Economists have a stricter definition that describes barriers in terms of “market failures”. Under this stricter definition, many of the factors that are commonly identified as barriers to DSM and energy efficiency would be excluded.
cool storage, equipment manufacturers presented formal proposals that included costs and equipment options. The final decision on choice of equipment was up to the customer.

TU’s marketing efforts for the Thermal Cool Storage program were geared toward the three predominant parties in the decision making process: the developers/owners of commercial buildings, engineers, and architects. TU field representatives marketed the program to customers and to trade allies (architects, engineers, equipment manufacturers and distributors) by explaining the benefits of thermal cool storage and the customer incentives that TU offered. TU also provided customer building audits which included an analysis of various HVAC system types and system estimated operating costs.

### 3.2.5 Outreach and Marketing

For certain types of network-driven DM projects, outreach and marketing are critical to the success of the project. This is a success factor particularly in those projects where achieving the project objectives involves encouraging a large number of small end-use customers, typically in the commercial and/or residential sectors, to change the ways in which they use electricity or purchase electrical appliances and equipment. Most energy efficiency projects, integrated DM projects and pricing initiatives fall into this category, as do most direct load control, demand response and load shifting projects.

The Espanola Power Savers Project in Canada (Case Study 18, page 158) is an example of a DM project where outreach and marketing was an important success factor. The Espanola project was a community-based energy efficiency project which mounted a full-scale effort to extract the maximum possible reduction in electricity consumption from a geographically concentrated area.

The Espanola project used a two-pronged approach. First an extensive, cost effective list of energy conservation measures and installation specifications was established to maximise energy savings. Second, the project used a market saturation approach to elicit attitudinal and behavioural change that optimised energy savings and then maintained the energy efficiency built into the community.

A community assessment was carried out in the spring of 1991 to obtain a comprehensive understanding of the environment in which the program was to be launched. Besides collecting and analysing traditional demographic data, the assessment attempted to discover the formal and informal networks/power structure within the community.

A detailed marketing/communication plan was developed and implemented. It emphasised cultivation of community interest and support to achieve a maximum participation rate and uptake of recommended energy efficiency measures and to achieve a community "culture shift" to wise electricity use over the long term. A cornerstone of the plan involved the formation of a Community Advisory Committee at the outset of the project which consisted of over 30 representatives from organisations within the town. The committee had two primary functions:

- to provide advice and guidance to the project on ways to promote the wise use of electricity; and
● to provide direct community feedback to the project on existing and potential project-related issues.

Additional community involvement/communication mechanisms included: project newsletters, open house/information nights, presentations to community organisations, an energy conservation week, radio/newspaper advertising, municipal council presentations, a curriculum based energy conservation educational package, a spring writing contest, high school presentations, Energy Conservation Corner in the Public Library, logo/slogan contest, opening ceremonies, picnics and displays, energy saving tips contest, electricity bill inserts, direct mail, and cable TV community service announcements.

3.2.6 Participation Process and Customer Service

The participation process and customer service component of a network-driven DM project comprises the procedures, forms, communications, and other interactions that occur among prospective and ultimate participants in the project and the project proponent and project implementers. The ease or difficulty of a project’s participation process, and the effectiveness of the associated customer service support, can both be critically important success factors for some types of projects, particularly those projects involving interactions with a large number of electricity end-users. This includes most direct load control projects, demand response projects, fuel substitution projects, integrated DM projects and pricing initiative projects.

The Queanbeyan Critical Peak Pricing Trial in Australia (Case Study 19, page 164) is a pricing initiative in which the participation process and customer service is crucial for the success of the project. The project is investigating the feasibility of promoting peak load reductions by residential sector customers to relieve distribution network constraints in a particular geographical area.

The Queanbeyan project involves applying seasonal time of use and critical peak pricing tariffs to about 200 households. Two seasonal tariff schedules are applied – for summer and winter. Critical peak periods are called by the electricity retailer when the load on the local network is reaching maximum capacity or when high price events occur in the competitive wholesale electricity market. Critical peak periods may be called for a maximum of 12 times per year; customers are given a minimum two hours notice.

In the Queanbeyan project, implementation of time of use and critical peak pricing tariffs requires the installation of interval meters and in-home information display units in participants’ dwellings. The installation of this new technology is paid for by the local electricity retailer. The interval meters measure energy use in half hour blocks. Each meter is directly connected to a two-way communications unit using mobile phone technology that enables the retailer to send and receive messages to and from the meter. This technology is used both for automatic meter reading and to signal an upcoming critical peak period and instruct the meter to adjust its tariff.

The in-home information display unit, the Home Energy Monitor, communicates with the interval meter through power line carrier technology. It plugs into any power socket and is about the size of a regular wall phone. The Monitor comprises a LED alphanumeric display which provides customers with specific information about the amount of electricity they are using, and how much it is costing. It also includes green, amber, and
red LED lights which show customers whether they are using electricity at low, medium, or high prices, corresponding to off peak/shoulder, peak and critical peak tariffs. A beeping sound alerts customers to the start of a critical peak period.

Customers who participate in the trial are instructed to keep an eye on the Home Energy Monitor and adjust their electricity usage to avoid high tariff periods and capitalise on the lower tariffs. Some tips are provided about how to reduce electricity usage during high price periods. Customers are also provided with a Participant Gift Pack that includes compact fluorescent lamps, energy timers, an energy efficiency thermometer, an energy wise calculator, CD-ROM, and an energy wise brochure.

### 3.2.7 Delivery Mechanisms

The delivery mechanism of a network-driven DM project picks up the implementation process at its finale and comprises the actual mechanism whereby the end-users’ electricity-related behaviour is changed. Delivery mechanisms are very varied and may include, for example, the provision of targeted information and/or financial incentives, and the physical installation of hardware such as energy efficient appliances, and metering, communications and direct load control equipment.

The effectiveness of delivery mechanisms is an important success factor for many network-driven DM projects. Delivery mechanisms are crucial for projects involving direct load control, demand response and smart metering. The effectiveness of the delivery mechanism is also an important success factor in projects that involve the payment of a financial incentive to reward changed end-user behaviour. Finally, the delivery mechanism is also an important success factor in projects that involve the provision of information.

The Efficient Lighting Project DSM Pilot in Poland (Case Study 20, page 169) used a highly targeted delivery mechanism. The project provided financial incentives for residents of network-constrained areas in three cities to install compact fluorescent lamps (CFLs). The cost of CFLs sold through the project was subsidised. The subsidies were directed at participating CFL manufacturers in exchange for their agreement to certain negotiated wholesale prices and delivery arrangements. The subsidised lamps were made available to the residents of the three cities using discount coupons. There were three types of coupons, labelled A, B, and C. The A and B coupons, which offered the highest price discounts (about 55% and 45% respectively), were delivered only to those residents living in the target network-constrained areas. The C coupons (about 35% discount) were delivered to the remaining residents of the participating cities. In all three cities, the A and B coupons were valid only for the first two weeks of the project’s operation. This timeframe was established to encourage residents in the target areas to make their CFL purchases quickly so that it would be easier to measure the effect of a massive CFL installation on the electricity networks in the target areas (where measurements of electricity use were focused). The C coupons were valid for six weeks, after which the CFL sales by the project ceased.

The delivery mechanism was also important in the Carbon Trust Advanced Metering Trial in the United Kingdom (Case Study 21, page 174). The trial aimed to demonstrate the potential benefits of advanced metering and understand the business case for encouraging widespread adoption of the technology by small and medium enterprises.
(SMEs). In addition to installing advanced meters at sites, a variety of different types of energy saving advice were provided to sites during the trial. These services ranged from basic data provision to detailed advice on energy saving communicated through emails, phone calls and site visits. The trial found that the level of energy savings achieved was highly correlated with the delivery mechanism.

### 3.3 Effectiveness of Specific Network-driven DM Measures

Each of the categories of network-driven DM measures will now be reviewed to: identify the network problems that each category can address; characterise the success factors which apply to each category; and examine how the DM measures in each category should be implemented for them to be most effective in achieving network-related objectives.

#### 3.3.1 Direct Load Control

With direct load control, customers pay reduced tariffs and/or receive other incentives in return for allowing the network operator to remotely shut down or cycle selected electrical equipment owned by the customer (e.g., air conditioners, water heaters). Direct communication links are connected between the network operator and the customers’ electrical equipment. These links enable the network operator to remotely switch the customer’s loads at short notice in response to particular problems on the electricity network.

**Network Problems Addressed**

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

Direct load control can also provide most types of network operational services. The effectiveness with which direct load control provides some network operational services, such as frequency response and spinning reserve, depends critically on the speed with which remote switching of customer loads can be implemented in response to an event. Because the network operator has direct control of customer loads, the response to an
event is usually more reliable than with load management measures that must be implemented by customers.

**Applicable Success Factors**

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

As with load shifting, commercial considerations on the part of the end-use customer are a major success factor for direct load control. However, once a customer is happy with the proposed arrangements and the rewards provided by the project proponent, the actual switching of loads is controlled remotely by the network operator without any involvement by the customer. Therefore direct load control may be less disruptive and therefore more attractive to the customer than load shifting without remote switching.

Commitment by the project proponent (the network owner or operator) and supportive government policies and regulatory regime are also important external success factors for direct load control. In addition, most of the identified internal success factors come into play when direct load control is used for network support.

**Effective Implementation**

Direct load control, like all load management measures, is best suited to achieving short-term load reductions (up to a couple of hours) to relieve network constraints and to provide network operational services at peak times.

An effective direct communication system between the network operator and the controlled loads located in the customer’s premises is essential for direct load control. Ideally, the communication system should be two-way so that the network operator can receive information in real-time or near real-time about the load reductions actually achieved. However, the response to an event is usually quite reliable because the load switching is controlled remotely by the network operator.

**3.3.2 Distributed Generation**

Distributed generators are relatively small and modular and are usually connected directly to the local distribution network, rather than to the transmission network. Distributed generation can inject energy into the electricity network close to the load it serves and in this situation reduces demand on the portion of the network which would otherwise supply the load.
Network Problems Addressed

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

Some types of distributed generation which operate continuously can be used to reduce overall demand across the whole electrical load curve. Other types which operate intermittently, such as standby generators, can be used to reduce demand at the time of the system peak. Distributed generation facilities installed to provide network support can be deployed strategically in geographical areas where network constraints occur or can be installed in particular localities to reduce demand on a specific network element. Distributed generation can also reduce network losses, improve utilisation (load factor) of existing transmission and generation assets, provide voltage support on long rural lines and also, with appropriate technology fitted to larger distributed generation plant, provide automatic frequency response.

Applicable Success Factors

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

The major success factor for the use of distributed generation for network support is commitment by the project proponent (in this case the network owner and/or operator). The network owner/operator must be prepared to accept that distributed generation can be used to achieve network-related objectives as an alternative to traditional network augmentation solutions.
Once this position has been reached, other relevant success factors include: the availability of suitable generation technology; commercial considerations (i.e., is there a business case for the use of distributed generation?); and clear definition of the network-related objectives to be achieved by installing distributed generation.

**Effective Implementation**

Using distributed generation for network support can be achieved in two ways:

- by implementing a new distributed generation installation at an appropriate location; or
- by making use of existing distributed generation installations (e.g., standby generators).

Implementing a new installation is likely to be capital expensive and relatively inflexible, particularly if the generator is installed at a particular location to relieve a network constraint. If the constraint is subsequently relieved by other means (e.g., when load growth justifies building a network augmentation), the generator may become a stranded asset. This can be overcome by implementing installations where the generator can be subsequently removed and relocated.

Making use of existing distributed generation installations can be a cheaper and more flexible option. However, there can be significant costs involved in carrying out the technical modifications required to enable an existing generator to synchronise to the system and to enable the generator to be dispatched. In addition, because the generator is not owned by the network owner/operator, changes in the business requirements of the generator owner can adversely affect the availability of the generator for network support.

### 3.3.3 Demand Response

Demand response comprises actions taken by end-use customers to change (usually reduce) their electricity use in response to problems on the electricity network and/or high prices in the electricity market.

**Network Problems Addressed**

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

Demand response is typically used by network operators to provide targeted load reductions on their networks. Applied during peak periods, demand response can be used both to relieve network constraints and to provide most network operational services.
Demand response can address all types of network constraints. It can be deployed strategically in geographical areas where network constraints occur and can also be implemented in particular localities to reduce demand on a specific network element.

Demand response can also provide most types of network operational services. The effectiveness with which demand response provides some network operational services, such as frequency response and spinning reserve, depends critically on the speed with which demand response can be implemented in response to an event. Where the network operator has direct control of demand response, the response to an event is usually more reliable than with load management measures that must be implemented by customers.

**Applicable Success Factors**

As with the other types of load management measures, commercial considerations on the part of the end-use customer are a major success factor for demand response. However, because the customer usually has the ability to opt out of demand response events, they are usually less disruptive and therefore more attractive to the customer than the other types of load management measures.

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

Commitment by the project proponent (the network owner or operator) and supportive government policies and regulatory regime are also important external success factors for demand response. In addition, most of the identified internal success factors come into play when demand response is used for network support.

**Effective Implementation**

Demand response, like all load management measures, is best suited to achieving short-term load reductions (up to a couple of hours) to relieve network constraints and to provide network operational services at peak times.

Demand response, can be implemented in one of three ways:

- the network operator implements time of use electricity pricing and customers may voluntarily respond to changes in prices with significant changes in their electricity usage (usually load reductions at times of high prices);
- the network operator gives notice of a demand response event to the customer, then relies on the customer to reduce their electricity usage; or
Remote switching by the network operator produces the most reliable response while the response from the first two methods can be quite variable. In particular, where demand response relies on the customer to change behaviour or to carry out load switching, the level of response tends to decay over time as the novelty of the situation wears off and/or the customers lose interest.

An effective communication and notification system between the network operator and end-use customers is essential for all types of demand response except for voluntary response by customers to time of use pricing. Ideally, the communication system should be two-way so that the network operator can receive information in real-time or near real-time about the load reductions actually achieved.

### 3.3.4 Energy Efficiency

The objective of energy efficiency projects is to reduce the quantity of energy used per unit of output or delivered service. As a DM measure, energy efficiency leads to reduced load levels on the electricity network.

#### Network Problems Addressed

Most energy efficiency projects reduce overall demand across the whole electrical load curve and can be used to combat the effect of general load growth on the network. It may also be possible to use energy efficiency to reduce demand at the time of the system peak if loads which contribute to that peak can be identified and energy efficiency measures applied specifically to those loads.

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

Energy efficiency projects can be deployed strategically in geographical areas where network constraints occur or can be implemented in particular localities to reduce demand on a specific network element. However, energy efficiency projects are difficult to target accurately enough to provide network operational services.
**Applicable Success Factors**

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

Because they are difficult to target accurately, energy efficiency projects are not often implemented specifically to achieve network-related objectives. Energy efficiency may be implemented primarily to achieve another purpose, such as to meet regulatory requirements or to achieve public relations benefits. The use of energy efficiency for network support is then incidental to this primary purpose.

One important consideration is whether there is a business case for the use of energy efficiency to achieve network-related objectives. Energy efficiency projects result in reduced electricity usage by customers and this will adversely impact the financial position of network businesses whose revenue is dependent on the volume of electricity transported through the network.

If an energy efficiency project is used for network support, most of the identified internal success factors come into play.

**Effective Implementation**

Establishing clear objectives and effective targeting is the key to successfully using energy efficiency projects to achieve network-related objectives. The objectives to be achieved must be within the capability of the project and the project must target specific loads, end-uses and customers that will contribute to achieving these objectives.

For example, if the objective is to defer the augmentation of a particular network element (e.g., a line or substation), the loads targeted by the project must be physically located on that element, the end-uses must be occurring during peak times on the element, and the customers must be willing and able to increase the energy efficiency of those particular end-uses.

Once the objectives and targeting of an energy efficiency project have been determined, overcoming any barriers to increasing energy efficiency, and developing effective outreach and marketing and delivery mechanism all become important.
3.3.5 Fuel Substitution

As a DM measure, fuel substitution from electricity to other fuels operates in a similar way to energy efficiency. However, fuel substitution results in loads being lost to electricity, probably permanently, whereas with energy efficiency the end uses continue to be served by electricity but at a reduced load level.

*Network Problems Addressed*

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related √</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s) √</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network √</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

Most fuel substitution projects reduce overall demand across the whole electrical load curve and can be used to combat the effect of general load growth on the network. It may also be possible to use fuel substitution to reduce demand at the time of the system peak, if loads which contribute to that peak can be identified and fuel substitution applied specifically to those loads. Fuel substitution projects can be deployed strategically in geographical areas where network constraints occur or can be implemented in particular localities to reduce demand on a specific network element. As with energy efficiency, fuel substitution projects are difficult to target accurately enough to provide network operational services.

*Applicable Success Factors*

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives √</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market √</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used √</td>
</tr>
<tr>
<td>Commitment by project proponent √</td>
<td>Market barriers addressed √</td>
</tr>
<tr>
<td>Technology availability √</td>
<td>Outreach and marketing √</td>
</tr>
<tr>
<td>Commercial considerations √</td>
<td>Participation process and customer service √</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms √</td>
</tr>
</tbody>
</table>

The major success factor in using fuel substitution to achieve network-related objectives is commitment by the project proponent (in this case the network owner and/or operator). The network owner/operator must be prepared to accept that fuel
substitution can be used to achieve network-related objectives as an alternative to traditional network augmentation solutions.

Once this position has been reached, other relevant success factor include: the availability of suitable technology that uses an alternative fuel for the targeted end-uses; commercial considerations (ie is there a business case for the use of fuel substitution, including the probable permanent loss of the load?); clearly defining the network-related objectives to be achieved through fuel substitution; identifying the target market; outreach and marketing to targeted customers; the participation process and customer service; and the delivery mechanisms.

**Effective Implementation**

Similarly to energy efficiency, establishing clear objectives and effective targeting is the key to successfully using fuel substitution to achieve network-related objectives. The objectives to be achieved must be within the capability of the fuel substitution project and the project must target specific loads, end-uses and customers that will contribute to achieving these objectives.

For example, if the objective is to defer the augmentation of a particular network element (eg a line or substation), the loads targeted by the fuel substitution project must be physically located on that element, the end-uses must be occurring during peak times on the element, and the customers must be willing and able to purchase new appliances or equipment and switch to an alternative fuel for those particular end-uses.

Once the objectives and targeting of a fuel substitution project have been determined, overcoming any barriers to fuel substitution, and developing effective outreach and marketing, participation processes and customer service, and delivery mechanisms (especially the purchase and installation of new appliances or equipment) all become important.

### 3.3.6 Interruptible Loads

Interruptible loads confer the right on a network operator to interrupt supply to a customer based on an existing contract, tariff, or agreement, typically during a system emergency.

**Network Problems Addressed**

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>
During peak periods on a network, interruptible loads can be used both to relieve network constraints and to provide most network operational services.

Interruptible loads can address all types of network constraints. They can be deployed strategically in geographical areas where network constraints occur and can also be implemented in particular localities to reduce demand on a specific network element. They can also provide most types of network operational services. The effectiveness with which interruptible loads provide some network operational services, such as frequency response and spinning reserve, depends critically on the speed with which customer loads can be interrupted in response to an event. Where the network operator has direct control of interruptible loads, the response to an event is usually more reliable than with load management measures that must be implemented by customers.

**Applicable Success Factors**

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

In common with direct load control and load shifting, commercial considerations on the part of the end-use customer are a major success factor for the deployment of interruptible loads. By definition, interruptible loads require a change in the customer’s pattern of electricity use. Because interruptible load events often occur at very short notice they are inherently more disruptive and inconvenient to customers than other types of load management measures. Therefore, interruptible loads will only be attractive to customers if appropriate rewards (eg incentive payments and/or lower tariffs) are available to compensate for the time, effort and costs involved.

Commitment by the project proponent (the network owner or operator) and supportive government policies and regulatory regime are also important external success factors. In addition, many of the identified internal success factors come into play when interruptible loads are used for network support. However, outreach and marketing, participation and customer service, and delivery mechanisms may be less important because customers will only accept the inherent disruption and inconvenience of interruptible loads if they are happy with the rewards offered.

**Effective Implementation**

Interruptible loads, like all load management measures, are best suited to achieving short-term load reductions (up to a couple of hours) to relieve network constraints and to provide network operational services at peak times.
Interruptible loads can be deployed in one of two ways:

- the network operator gives notice of an interruptible load event to the customer, then relies on the customer to reduce their electricity usage; or
- the network operator gives notice to the customer, then unilaterally interrupts supply to the customer.

The former method may have a less severe impact on the customer’s operations, but can provide a less reliable response, particularly if no sanctions are applied to customers who fail to reduce their electricity usage. This is the situation with some of the interruptible load arrangements applied by the transmission network operator in Spain.

An effective direct communication system between the network operator and the customer is essential for the deployment of interruptible loads. At a minimum, the communication system will be used to provide notification to the customer of upcoming interruptible load events. Ideally, the communication system should be two-way so that the network operator can receive information in real-time or near real-time about the load reductions actually achieved.

### 3.3.7 Integrated DM Projects

Integrated DM projects employ a range of individual DM measures appropriate to the objectives they are aiming to achieve.

#### Network Problems Addressed

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

Integrated DM projects are used both to reduce overall demand across the whole electrical load curve and to reduce demand at the time of the system peak. Typically, such projects are deployed strategically in geographical areas where network constraints occur but can also be implemented in particular localities to reduce demand on a specific network element. Depending on the specific individual DM measures employed, integrated DM projects may also be used to provide network operational services.
Applicable Success Factors

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

The range of possible integrated DM projects is very diverse. Consequently, while some success factors did not apply to the particular integrated DM projects included in the Task XV database, potentially any of the success factors can apply to such a project. However, the particular mix of applicable success factors will vary from project to project, depending on the specific individual DM measures employed.

Effective Implementation

Because an integrated DM project can include a diverse range of individual DM measures, establishing clear objectives for the project is essential. Without a clear objective, such projects can lose focus and individual DM measures may be poorly targeted. On the other hand, the strength of integrated DM projects lies in the ability to deploy a range of DM measures to achieve particular network-related objectives.

3.3.8 Load Shifting

Load shifting involves altering electricity use patterns so that on-peak electricity use is shifted to off-peak periods. To achieve network-related objectives, load must be shifted away from the peak period on the whole network or on the relevant network element. The timing of the peak period on a network element may be different from the timing of the peak on the network as a whole.

Network Problems Addressed

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>
Load shifting applied during peak periods on a network can be used both to relieve network constraints and to provide most network operational services.

Load shifting can address all types of network constraints. It can be deployed strategically in geographical areas where network constraints occur and can also be implemented in particular localities to reduce demand on a specific network element.

Load shifting can also provide most types of network operational services. The effectiveness with which load shifting provides some network operational services, such as frequency response and spinning reserve, depends critically on the speed with which load shifting measures can be implemented in response to an event.

**Applicable Success Factors**

Commercial considerations are a major success factor for load shifting, particularly from the perspective of the end-use customer. Load shifting, by definition, requires a change in the customer’s pattern of electricity use and this will only be attractive to the customer if appropriate rewards (e.g., incentive payments and/or lower tariffs) are available to compensate for the time, effort and costs involved.

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

Commitment by the project proponent (the network owner or operator) and supportive government policies and regulatory regime are also important external success factors. In addition, most of the identified internal success factors come into play when load shifting is used for network support.

**Effective Implementation**

Load shifting, like all load management measures, is best suited to achieving short-term load reductions (up to a couple of hours) to relieve network constraints and to provide network operational services at peak times.

An effective communication and notification system between the network operator and end-use customers is required so that customers can receive notifications from the network operator and make the necessary arrangements to implement load shifting. Ideally, the communication system should be two-way so that the network operator can receive information in real-time or near real-time about the load reductions actually achieved.
3.3.9 Power Factor Correction

Power factor in alternating current circuits is the ratio of actual energy consumed (watts) versus the apparent power (volt-amps). In other words, power factor is the percentage of energy used compared to the energy flowing through the wires. Power factor correction aims to reduce the difference between the energy consumed and the apparent power so as to reduce energy wastage.

**Network Problems Addressed**

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related √</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s) √</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network √</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction √</td>
</tr>
</tbody>
</table>

Most power factor correction projects reduce overall demand across the whole electrical load curve. It may also be possible to use power factor correction to reduce demand at the time of the system peak if loads which contribute to that peak can be identified and power factor correction applied specifically to those loads. Power factor correction can be deployed strategically in geographical areas where network constraints occur or can be implemented in particular localities to reduce demand on a specific network element.

**Applicable Success Factors**

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives √</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market √</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures used √</td>
</tr>
<tr>
<td>Commitment by project proponent √</td>
<td>Market barriers addressed √</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing √</td>
</tr>
<tr>
<td>Commercial considerations √</td>
<td>Participation process and customer service √</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms √</td>
</tr>
</tbody>
</table>

The major success factor in using power factor correction to achieve network-related objectives is commitment by the project proponent (in this case the network owner and/or operator). The network owner/operator must be prepared to accept that power factor correction can be used to relieve network constraints.
Once this position has been reached, other relevant success factors include: commercial considerations (i.e., is there a business case for the use of power factor correction?); clearly defining the network-related objectives to be achieved through fuel substitution; identifying the target market; outreach and marketing to targeted customers, participation process and customer service and delivery mechanisms.

**Effective Implementation**

As a DM measure, power factor correction usually involves improving power factors at customer premises by installing capacitors. Distributed generation, synchronous motors, or adjustable speed drives with controllable front ends can also be used to correct power factor at customer premises. However, it is possible to achieve network-related objectives by installing power factor correction equipment outside customer premises on the network side of the customer’s electricity meter.

Where power factor correction is required at customer premises, customer outreach and marketing are crucial. Power factor is a highly technical subject which is hard to explain and the marketing of a power factor correction program is correspondingly difficult. A successful approach may involve drawing customers’ attention to their obligation to maintain an acceptable power factor and then providing a packaged solution that they can easily implement.

### 3.3.10 Pricing Initiatives

As a DM measure, pricing initiatives aim to change customers’ energy-using behaviour, particularly to alter the times at which electricity is used.

**Network Problems Addressed**

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

Pricing initiatives are typically used to support electricity networks by changing customers’ energy-using behaviour to reduce demand at the time of the system peak. Typically, pricing initiatives are applied to particular customer classes across a whole electrical system and are therefore usually not targeted to geographical areas where network constraints occur. However, some work is now being carried out on congestion pricing in which electricity prices are increased in constrained network areas.

Because of the inherent difficulty in targeting pricing initiatives, they are not used to provide network operational services.
Applicable Success Factors

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

Many success factors are applicable to pricing initiatives. Such initiatives can only be implemented if they conform with government policies and regulatory regimes. Pricing initiatives must also be closely linked to the structure of the electricity market. Acceptance by the network owner/operator that pricing initiatives will be effective in achieving network-related objectives is also required and the business case for implementing particular pricing initiatives must be sound. In addition, technology that enables customers to take advantage of time-related electricity pricing can greatly increase the effectiveness of pricing initiatives in achieving network-related objectives; such technology may vary from simple time clocks to complex load control equipment.

Important internal success factors include: specifically-defined objectives to be achieved through pricing initiatives; a clearly-identified target market; and effective outreach and marketing to targeted customers.

Effective Implementation

There are three main price structures used to encourage end-use customers to alter the times at which they use electricity:

- **Time-of-Use (TOU):** Comprises different unit prices for electricity during different blocks of time, usually defined for a 24 hour day. TOU tariffs reflect the average cost of generating and delivering electricity during those time periods.

- **Real-time Pricing (RTP):** The electricity price fluctuates throughout the day reflecting changes in the wholesale price of electricity. Customers receive day-ahead or hour-ahead notification of RTP prices.

- **Critical Peak Pricing (CPP):** This is a hybrid of TOU and RTP. The basic rate structure is TOU and provision is made for replacing the normal peak price with a much higher CPP price under specified trigger conditions (e.g., when system reliability is compromised or wholesale prices are very high).

If implemented by themselves, the effectiveness of these pricing structures in achieving network-related objectives can be highly variable because customers change their behaviour on a voluntary basis, in response to the pricing signals. The level of customer response may be increased by establishing a very high multiple (between 10 and 20
times) for the electricity price during critical peak periods as compared with the price during shoulder periods. Such a ‘shock’ critical peak price provides a strong stimulus for customers to manage or reduce electricity consumption during critical peak events.

The effectiveness of pricing initiatives can also be increased by installing enabling technology that automatically switches customer loads in response to pre-set price levels. If customers themselves can nominate the loads to be automatically switched and the price levels at which switching will occur, this provides a one-stop ‘set and forget’ system that is likely to produce a much more reliable load reduction response than systems that require customers to make a decision to manually switch loads during every high price event.

3.3.11 Smart Metering

Currently, recording the quantities of energy consumed by end-users is mostly carried out by using accumulation meters which simply record energy consumption progressively over time. However, more advanced meters are increasingly being used. Interval meters record the quantities of energy consumed over set, frequent time intervals. Smart meters include, in addition to the interval metering capability, one-way or two-way communications between the energy supplier and the meter.

Network Problems Addressed

<table>
<thead>
<tr>
<th>Network Constraints</th>
<th>Network Operational Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Narrow peak related</td>
<td>Voltage regulation</td>
</tr>
<tr>
<td>Broad peak related</td>
<td>Load following</td>
</tr>
<tr>
<td>Specific network element(s)</td>
<td>Active/reactive power balancing</td>
</tr>
<tr>
<td>Generally across the network</td>
<td>Frequency response</td>
</tr>
<tr>
<td></td>
<td>Supplemental reserve</td>
</tr>
<tr>
<td></td>
<td>Spinning reserve</td>
</tr>
<tr>
<td></td>
<td>Power factor correction</td>
</tr>
</tbody>
</table>

There are two ways in which smart metering can be used to support electricity networks

First, smart meters enable the implementation of time-varying pricing which sends price signals to customers that reflect the underlying costs of generating, transporting and supplying electricity. Price-based demand response programs can reduce or shape customer demand and particularly can reduce peak loads on the electricity network and therefore reduce the amount of investment required in network infrastructure.

Second, analysing data from smart meters provides end-users with detailed information about the ways in which they use electricity and can enable businesses to identify and implement energy, cost and carbon savings. Energy savings reduce the overall load on the electricity network, therefore contributing to supporting the network.
Applicable Success Factors

<table>
<thead>
<tr>
<th>External Success Factors</th>
<th>Internal Success Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government policies</td>
<td>Project objectives</td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>Target market</td>
</tr>
<tr>
<td>Market structure</td>
<td>Demand-side measures</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>Market barriers addressed</td>
</tr>
<tr>
<td>Technology availability</td>
<td>Outreach and marketing</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>Participation process and customer service</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td>Delivery mechanisms</td>
</tr>
</tbody>
</table>

In many jurisdictions around the world, governments and/or regulators have mandated the mass roll-out of smart meters. In jurisdictions where this has not occurred, the effective use of smart meters to reduce loads on electricity networks is assisted by supportive governments and regulators. In the absence of a government mandate, there must be a strong business case for electricity distributors to implement a mass roll-out of smart meters. The business case may include other benefits to the distributor unrelated to network support, such as automated meter reading. Effective deployment of smart meters is also dependent on active commitment by project proponents (usually electricity distributors) and on appropriate smart metering technology being available.

Clear project objectives and a well-defined target market must be established if network-related objectives are to be achieved through deployment of smart meters. Accompanying demand side measures, particularly time-varying pricing must also be developed and implemented. Outreach and marketing, participation processes and delivery mechanisms are also crucial internal success factors for smart metering network-driven DM programs.

Effective Implementation

Installing smart meters will, by itself, do nothing to achieve load reductions for network support purposes. To achieve network-related objectives, any roll-out of smart meters must be accompanied by the introduction of time-varying electricity prices and the provision of appropriate information and education programs for end-use customers. Implementing remote switching of customer loads linked to changing electricity prices will also improve the effectiveness of network-driven DM projects involving smart meters.
3.4 Conclusions on the Effectiveness of DM Measures

This section 3 has identified a number of external and internal factors that may contribute to the success of network-driven DM projects. External factors establish the context within which a network-driven DM project operates, while internal factors are specific to each individual project and determine how the project is implemented.

The success or otherwise of the DM measures that are components of network-driven DM projects is intimately bound up with the success of the projects themselves. Projects containing the same DM measures (such as energy efficiency, load shifting, direct load control or pricing initiatives) tend to have a common set of factors which contribute to their success and to this extent it is possible to identify sets of success factors that apply to each category of DM measure. These are shown in Table 1 (page 37).

The challenge in designing a network-driven DM project that will ultimately be successful in achieving its objectives is to clearly identify the success factors for each of the DM measures included in the project and then concentrate on optimising each of these factors. For example, if the delivery mechanism is a success factor for a DM measure included in the project, the project designer should choose an appropriate delivery mechanism and then concentrate on optimising the effectiveness of that mechanism.
**TABLE 1. SUCCESS FACTORS FOR NETWORK-DRIVEN DM MEASURES**

<table>
<thead>
<tr>
<th>Success Factors</th>
<th>Network-driven DM Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Load Control</td>
</tr>
<tr>
<td><strong>External Success Factors</strong></td>
<td>√</td>
</tr>
<tr>
<td>Government policies</td>
<td></td>
</tr>
<tr>
<td>Regulatory regime</td>
<td>√</td>
</tr>
<tr>
<td>Market structure</td>
<td>√</td>
</tr>
<tr>
<td>Commitment by project proponent</td>
<td>√</td>
</tr>
<tr>
<td>Technology availability</td>
<td>√</td>
</tr>
<tr>
<td>Commercial considerations</td>
<td>√</td>
</tr>
<tr>
<td>Public relations benefits</td>
<td></td>
</tr>
<tr>
<td><strong>Internal Success Factors</strong></td>
<td>√</td>
</tr>
<tr>
<td>Project objectives</td>
<td>√</td>
</tr>
<tr>
<td>Target market</td>
<td></td>
</tr>
<tr>
<td>Demand-side measures used</td>
<td>√</td>
</tr>
<tr>
<td>Market barriers addressed</td>
<td>√</td>
</tr>
<tr>
<td>Outreach and marketing</td>
<td>√</td>
</tr>
<tr>
<td>Participation process and customer service</td>
<td></td>
</tr>
<tr>
<td>Delivery mechanisms</td>
<td>√</td>
</tr>
</tbody>
</table>
4. OPTIONS FOR MODIFYING NETWORK PLANNING PROCESSES

The primary function of electricity network businesses is to build, manage and operate network infrastructure assets, such as poles, wires, transformers and control and communication equipment. Typically, these businesses have little knowledge about, or expertise in, using demand-side resources as alternatives to network augmentation or more generally to support electricity networks. Therefore, left by themselves, network businesses would be unlikely to include consideration of demand-side resources in network planning. This section reviews the changes that will be required to encourage network businesses to take demand-side resources into account in their network planning.

There are four key areas in which changes could be made to network planning to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks:

- forecasting future electricity demand, both in relation to the network as a whole and on particular network elements (e.g., lines and substations);
- communicating information about network constraints;
- developing options for relieving network constraints;
- establishing policy and regulatory regimes for network planning.

4.1 Forecasting Future Demand

The first step in any electricity network planning process involves forecasting future demand for electricity, both across the service territory of the network business as a whole and in relation to individual network elements.

Frequently, demand management is taken into account during this forecasting process by assuming a particular level of energy efficiency activity, and reducing the global load forecasts by a corresponding (usually quite small) amount. Following is a typical methodology for including DM in load forecasts adopted by Tri-State Generation and Transmission Association, a wholesale supplier of electricity to 44 member distribution systems throughout Colorado, Nebraska, New Mexico and Wyoming:

The econometric method used to prepare the forecasts accommodates changes in technology or customer preferences that impact the energy use per account through the use of time-trend variables. There is not sufficient data to explicitly model these impacts. Tri-State sponsors an ‘Energy Efficiency Credits’ program, which encourages certain levels of building insulation efficiency and/or provides incentives for the purchase of high-efficiency motors. It is not possible to quantify with confidence the amount of load reduction as a result of these programs.

---


Such methodologies have the effect of discounting the potential contribution by DM towards supporting electricity networks. In particular, they assume that DM will have a similar, small effect on demand across the whole of the network and that the resulting load reduction will be undifferentiated in relation to both the geographical location and the time at which it occurs.

As the IEA DSM Programme worldwide survey of network-related demand management projects\(^\text{13}\) has shown, DM projects can be designed to deliver load reductions at specific locations and at particular times of the day, particularly at peak load times. The treatment of demand management in demand forecasting for network planning should be modified to recognise more accurately the potential contribution of DM.

### 4.2 Communicating Information about Network Constraints

The second step in network planning is to compare the demand forecasts with the available capacity on the network elements that will be used to transport the required electrical energy. From this information, likely future constraints on the network are identified and characterised according to their specific timing and geographical locations.

Information about future network constraints is often not published, but instead is retained inside network businesses. Where this is the case, it is very difficult for anyone outside electricity businesses to propose options for relieving network constraints. Demand management is rarely considered in developing such options because the staff of network businesses usually do not have expertise in DM program development and implementation. However, if information about network constraints was made available outside network businesses, it is possible that other organisations with the required expertise may be able to develop DM options to relieve the constraints.

In Australia, the National Electricity Rules require both transmission and distribution network businesses to publish information about likely future network augmentations. The Rules also require demand-side options to be considered when such augmentations are being planned.

Some Australian states take this process further, particularly New South Wales and South Australia. In NSW, electricity distributors are subject to a Demand Management Code of Practice\(^\text{14}\) that requires them to publish annual Electricity System Development Reviews. These documents identify likely future constraints on the distribution network. Before augmenting or reinforcing the network, the Code specifically requires distributors to carry out investigations to ascertain the cost-effectiveness of avoiding or postponing this work by implementing DM strategies.

Some third parties have used the information in the Electricity System Development Reviews to enhance the availability of information about network constraints. For example, Figure 1 shows a map of likely future network constraints in the Sydney region prepared from published information.

---


4.3 Developing Options for Relieving Network Constraints

As noted in section 4.2 (page 39), if specific information about electricity network constraints is made available outside network businesses, this provides an opportunity for third parties with expertise in demand management to participate in the development of options that use demand-side resources to relieve the constraints.

The Demand Management Code of Practice\(^\text{16}\) in force in New South Wales requires electricity distributors to provide specific opportunities for third parties to take part in option development. Opportunities are provided through a formal process for procuring demand-side resources for network support, as shown in Figure 2 (page 41).


Figure 2 Electricity System Development Procedure for Distributors in New South Wales, Australia

There are two types of procurement offers that may be made to providers of DM: negotiable offers and standard offers.

For negotiable offers, the distributor and the proponent of a DM project (who may also be a network customer) negotiate a contract specifically designed for that particular project. Negotiable offers are more appropriate for larger-scale, relatively complex DM projects where the transaction costs and time associated with negotiating a unique contract are relatively insignificant compared with the benefits from the project.

Standard offers specify the conditions for the provision of demand-side resources in advance. Standard offers are usually made on fixed prices, take it or leave it, first come first served basis. Standard offers may be targeted to shorter-term network constraints or to capture demand reduction opportunities that provide longer-term distribution network benefits by delaying future, less well-defined constraints.

A standard offer may be made in conjunction with, prior to, or in place of, a negotiable offer being issued or a constrained area being identified. A subsequent negotiable offer or Request for Proposal may revise the standard offer as the details of the constraint and the requirement to overcome the constraint are more clearly defined.

The Code suggests that distributors make standard offers where the firm rating of the local distribution network will be exceeded within a ten year forecast period. A standard offer can be made during the early period of a constraint being identified and may be re-evaluated and incorporated into a Request for Proposals in accordance with the timeframe shown in Figure 2 (page 41).

A somewhat similar process may be established in the United States under the February 2007 ruling (Order No 890) by the Federal Energy Regulatory Commission (FERC) which permits demand-side resources capable of performing the needed functions to participate in the transmission planning process on a comparable basis to demand-side resource. The Order also provides a forum for stakeholders to come forward with demand response project proposals that they wish to have considered in development of the transmission plan18.

4.4 Establishing Policy and Regulatory Regimes

The policy and regulatory regimes under which electricity network businesses operate can create significant disincentives to businesses using demand-side resources to support electricity networks. This can occur particularly when the regulatory regime remunerates network businesses on the basis of a rate of return on the value of network infrastructure assets they own; and/or the quantity of electrical energy transported through the network.

In these cases, the revenues of network businesses can be significantly reduced if they make use of demand-side resources that defer or eliminate the need to construct additional network infrastructure assets; and/or reduce the quantity of energy transported through the network. This is illustrated in Figure 3 (page 43).

Figure 3 shows the case of a distribution network service provider (DNSP), ie an electricity distributor, whose revenue is dependent on sales volume. The distributor has an opportunity to undertake a DM network support project which is less expensive than a network solution that produces an equivalent result.

Frame 1 in Figure 3 presents the base case, where the distributor undertakes no DM during the regulatory period. For simplicity, it is assumed that revenues and costs remain constant over the regulatory period, in the absence of DM. The difference between revenue and costs represents the distributor’s profit.

Frame 2 illustrates the case in which the DM project achieves a reduction in costs with no impact on sales, as might be the case with a load shifting or distributed generation DM project. In this case, the distributor’s profit is increased by the amount of the cost saving.

Frame 3 shows what happens when a DM project leads to a small reduction in sales for the distributor. This reduction is revenue forgone by the distributor as compared with the revenue it would have received in the absence of the DM project. In this case, the foregone revenue is smaller than the cost saving achieved by the distributor through

implementing the DM project. Therefore, while the increase in profit is smaller than when there is no foregone revenue, the profit is still larger than in the base case. In this scenario, there is still an incentive to undertake DM, but it is smaller than if there were no impact on revenues.

Frame 4 illustrates the scenario where the DM project results in a reduction in revenue that matches the reduction in costs. Here, there is no change in the distributor’s profit relative to the base case. In this situation, there would be no financial incentive for the distributor to undertake a DM project rather than the higher cost network solution. However, the community’s welfare would be improved if the distributor undertook the demand management project because the project would lower the total resource cost of meeting the demand for electricity.

Governments and regulators can make changes to policy and regulatory regimes to reduce the disincentives faced by network businesses that use demand-side resources to support electricity networks. There are two ways in which this can be achieved:

- by providing policy and regulatory incentives to network businesses; and/or
- by imposing policy and regulatory obligations on network businesses.

### 4.4.1 Policy and Regulatory Incentives

Various policy and regulatory mechanisms have been deployed to provide incentives for network businesses that use demand-side resources to support electricity networks. The following mechanisms are described below:

- revenue regulation;
- recovery of revenue foregone and DM program costs;
- direct incentives to encourage the use of demand-side resources for network support.

#### Revenue Regulation

Under revenue regulation, the total ‘allowable’ revenue of an electricity network business is set each year at a particular dollar figure. Within this revenue cap, the business is free to set the structure and levels of network charges in any way it chooses. Any over- or under-collection of revenue in one year is corrected in determining the ‘allowable’ revenue for the following year.\(^{20}\)

Revenue regulation can be used to ‘decouple’ revenue from the volume of sales (ie the quantity of energy transported through the network). The formula used for calculating the allowable revenue can be set to achieve various percentages of decoupling from 0% to 100%. With 100% decoupling, the network business becomes indifferent to the sales volume, and the disincentive to use demand-side resources for network support is therefore removed.

For example, in 1994 the electricity regulator in New South Wales proposed a revenue regulation formula to apply to the distribution ‘wires’ businesses in that State. The formula had the following form:\(^{21}\):

\[
R = a + b_rN_r + b_cN_c + b_iN_i + cM + dL
\]

where

- \( R \) is the annual allowable revenue for a distributor set by the regulator
- \( N \) is the actual number of customers served by the distributor in the residential (\( N_r \)), commercial (\( N_c \)) and industrial (\( N_i \)) sectors
- \( M \) is the actual number of megawatt-hours sold per annum by the distributor
- \( L \) is the actual length in kilometres of network lines owned by the distributor
- \( b \) is the allowable number of dollars per customer in the residential (\( b_r \)), commercial (\( b_c \)) and industrial (\( b_i \)) sectors as set by the regulator
- \( c \) is the allowable number of dollars per megawatt-hour sold as set by the regulator
- \( d \) is the allowable number of dollars per kilometre of network line as set by the regulator
- \( a \) is a residual term capturing other costs; this term would be set specifically for each distributor.

Since this formula includes a term for allowable dollars per megawatt-hour sold, it does not achieve 100% decoupling of revenue from sales volume. The actual level of decoupling would depend on the value of \( c \) set by the regulator. Application of the formula was expected by the regulator to reduce the bias against implementation of DM by distributors in New South Wales.

During the second half of the 1990s and the early 2000s, revenue regulation was used for electricity businesses in Australia, the United Kingdom and the United States. However, it has since fallen out of favour with some regulators.

**Recovery of Foregone Revenue and DM Program Costs**

As illustrated in Figure 3 (page 43), when a network business is remunerated on the basis of the quantity of electrical energy transported through its network, any reduction in this quantity caused by the implementation of DM results in revenue foregone by the business. Also network businesses incur costs in implementing DM, including project design and testing costs, marketing costs, costs of purchasing and installing DM-related equipment, and annual operating costs.

There are two views among policy makers and regulators about how foregone revenue and DM program costs should be treated. One view maintains that both foregone revenue and DM program costs are entirely the responsibility of the network business and should be fully taken into account when the business is evaluating the cost effectiveness of DM versus network augmentation options. A second view maintains that the network business should be allowed to recover at least some of the foregone revenue.

revenue and DM program costs and the value of this recovery should not be included in the cost benefit analysis of DM versus network augmentation options.

In New South Wales, the introduction of revenue regulation (see page 44) did not result in a major increase in the implementation of DM by electricity distributors. For the five year regulatory period to 2009, the regulator changed its method of regulating distributors from revenue regulation to price control but also allowed distributors to recover foregone revenue and DM project costs. To achieve this, the regulator introduced a D-factor into the weighted average price cap control formula that allowed distributors to recover:

- non-tariff-based DM implementation costs, up to a maximum value equivalent to the expected avoided distribution costs;
- tariff-based DM implementation costs;
- revenue foregone as a result of non-tariff-based DM activities.

These provisions are regarded as generous and have stimulated distributors in New South Wales to increase their implementation of DM measures to defer network augmentations. However, the provisions only operated for five years. Responsibility for carrying out distribution network pricing determinations in the State has now been transferred from the State-based regulator to a national regulator.

**Direct Incentives for DM**

Direct incentives for electricity network businesses to implement demand management usually take the form of direct payments to the businesses. These payments may be made from a special fund established for this purpose.

In South Australia, the electricity industry regulator provided AUD 20 million for DM initiatives to be implemented by the sole electricity distributor in the State over the five-year regulatory period beginning July 2005\(^{23}\). The distributor was required to submit to the regulator for approval a program for implementation of DM initiatives and expenditure of the approved funding over the regulatory period. The approved funding is being treated as operating expenditure, and does not impact on the regulator’s consideration of approved capital expenditure for network augmentation purposes in the regulatory period.

In Victoria, the electricity industry regulator, has allowed specific provision for DM initiatives of AUD 0.6 million for each distributor\(^{24}\). This provision provided additional revenue for the trial of DM initiatives during the 2006 to 2010 regulatory period. The


regulator requires distributors to report on an annual basis the demand-side activities that have been undertaken and the outcomes that have been delivered.

In France, an incentive is provided for DM measures in particular geographical areas through the recently implemented energy efficiency certificates (“white certificates”) scheme. Under the scheme, eligible energy efficiency measures are assigned particular levels of energy savings (kilowatt-hours reduced) calculated according to a standard methodology. The energy savings are then converted to tradeable energy efficiency certificates, thus providing a monetary value for the energy savings. Energy efficiency measures implemented in areas where the electricity network is constrained (specifically Corsica, Réunion, Guadeloupe, and Martinique) are assigned double the number of kilowatt-hours reduced, thereby also doubling the monetary value of the energy savings achieved in these geographical areas.

In the United States, many states that adopted electricity industry restructuring also created public benefits funding mechanisms to help ensure the continued implementation of DM programs. Public benefits funding mechanisms for electricity DM typically involve the collection of a small per-kilowatt-hour public benefits charge (also often known as a ‘system benefits’ or ‘wires’ charge) as a part of the revenues of an electricity utility (typically an electricity distributor). These revenues are used to fund DM programs implemented either by utilities or by designated government or independent organisations.

By the end of the 1990s, public benefits funding had emerged to be perhaps the most significant new policy supporting energy efficiency DM in the United States in a decade. Since that time, although the move toward electricity industry restructuring has largely stalled, public benefits funding for energy efficiency DM has continued unabated. Every state (18 in all) that initiated public benefits energy efficiency DM programs continues to operate those programs today.

The required funding level across these 18 states varies from USD0.00003 to USD0.003 per kilowatt-hour with a median value of between USD0.0011 and USD0.0012 per kilowatt-hour. Combined annual expenditures are over USD900 million and annual incremental savings are nearly 2.8 million megawatt-hours. Cost-effectiveness estimates from nine of the most active states show the programs, in aggregate, to be very cost-effective with median benefit/cost ratio in the range of 2.1 to 2.5 and median cost of energy savings equal to USD0.03 per lifetime kilowatt-hour saved.

4.4.2 Policy and Regulatory Obligations

Early DM programs in the United States were driven by electricity regulators who actively supported any DM program which saved energy at a lower societal cost than the electricity industry could deliver kilowatt-hours. In many states, regulators pressured electricity utilities to undertake extensive DM programs.

---

26 No additional states have passed restructuring since 2000, and several have repealed or suspended their restructuring policy.
From the mid-1980s to the mid-1990s, the imposition of regulatory obligations resulted in DM becoming a major activity in the US electricity industry. State-based regulators imposed stringent requirements on electricity utilities to implement broadly-targeted, environmentally-driven DM programs. DM was seen as being more cost-efficient than supply-side resources and it also had environmental and social benefits. Many US utilities were required by regulators to undertake “integrated resource planning” (aka “least cost planning”) in which supply-side and demand-side options were compared to determine which were the most cost-effective from the societal perspective.

Most regulators in the United States did not require utilities to implement DM specifically targeted to relieving network constraints. Consequently, until the late 1990s, only a few specifically network-driven DM programs had been developed. More recently, as problems with ageing network infrastructure become more apparent, increasing numbers of network-driven DM programs are being implemented and are being supported by regulators. Some of these recent programs use short-term demand response to ameliorate transient network problems.

In other countries, regulators generally have not imposed obligations on the electricity industry to implement DM. However, in those countries with ageing network infrastructure, regulatory obligations may be considered in the future as a mechanism for encouraging network businesses to use DM for network support.

5. BEST PRACTICES IN EVALUATING AND ACQUIRING NETWORK-DRIVEN DM RESOURCES

There is a range of processes for evaluating, acquiring and implementing demand-side resources to provide support for electricity networks. These processes vary depending on:

- the purpose for which the DM resources were being acquired;
- commercial practices within the electricity network business acquiring the resources; and
- the applicable regulatory framework.

Given the variation among these factors, it is not possible to identify a single “best practice” for acquiring DM resources to provide support for electricity networks. However, it is possible to identify the stages involved in a good DM resource acquisition process.

These stages comprise28:

- assessing the need for DM resources;
- identifying and evaluating available DM resources;

---

● contacting potential providers of DM resources;
● negotiating the provision of DM resources; and
● acquiring and implementing the DM resources.

5.1 Assessing the Need for DM Resources

The first stage in using demand-side resources to provide support for electricity networks is to assess the need for the resources. The method used to carry out this needs assessment depends on the specific purpose for which the resources are required.

Projects that aim to use DM resources to relieve specific network constraints (including projects aimed at deferring network augmentations) require information about the timing and geographical locations of those constraints that are likely to become binding over the lifetime of the project. This information can be obtained by analysing network element load profiles and modelling the likely impacts of expected future load growth.

In France, two methods have been developed for incorporating DM measures into distribution network planning.

The first method is based on a local micro-economic analysis of the network, which identifies the technical and financial dimensions of “tailored” DM measures required to avoid costly reinforcements to supply only a limited number of consumers. This approach offers good economic efficiency, but requires complex studies and is suitable for only a limited number of network situations. A small number of investigations using this method have been undertaken or are in progress in Maine et Loire (see Figure 4, page 50), Loire and Bourgogne.
Figure 4. Disaggregation of the Synchronous Daily Peak Using the Equipment Simulation Program EVE, Maine et Loire, France

The second method is based on a macro-economic analysis covering a geographical area whose network/consumption characteristics enable “tailored” DM activities to be developed before being proposed to all consumers in the area. This geostatistical type of analysis can be a powerful tool for use in network planning studies. However, the geographical localities in which DM measures will be implemented must be properly defined. The economic efficiency of the analysis will be reduced if some of the DM measures are applied to parts of the network which are not subject to constraints. The method is still experimental and one study has been carried out in the Oise Département in France (see Figure 5, page 51).

---

Using DM resources to provide network operational and ancillary services requires information about the precise nature and timing of the services to be provided. Typically, the demand-side resources are replacing existing supply-side resources and, in these cases, such information is often readily available from the system operator.

5.2 Identifying and Evaluating Available DM Resources

In making a decision to use demand-side resources to provide support for electricity networks, detailed information about the available DM resources is crucial. The type of information required again depends on the specific purpose for which the resources are required.

Projects that aim to relieve specific network constraints require detailed information on the quantity and geographical location of DM resources, and their availability over time. Such information is usually not readily available and considerable effort may be required to obtain it. Some information about available DM resources may be obtained from analyses of customer billing records to identify loads that may be interruptible and/or curtailable. However, detailed information is best obtained from on-the-ground customer surveys.

In the Binda Bigga DSM Project in New South Wales (Case Study 22, page 181), a survey of residents in the communities of Binda and Bigga was carried out to identify households that had electrical room heaters and cooking stoves. Use of these appliances was causing unacceptable voltage fluctuations on a local feeder during winter evenings.

---

The household survey identified the quantity of load that could be removed from the feeder on winter evenings by replacing the electrical appliances with gas ones.

The following information is required about a DM resource that is used to provide network operational services:

- the quantity of the resource;
- the availability of the resource over time; and
- the extent to which the resource can be relied on (ie its “firmness”).

Most DM resources used to provide network operational services are acquired through open market transactions. The required information about a particular DM resource is usually made available by the resource provider as part of their market bid.

5.3 Contacting Potential Providers of DM Resources

Once a decision has been made to use demand-side resources to provide support for electricity networks, the first step in actually acquiring a resource is to contact potential resource providers. There are several methods that can be used to do this.

One method often used in projects that aim to relieve specific network constraints is to publicly release detailed information about the constraints and the DM resources required (ie the results of the needs assessment). Potential DM resource providers are then invited to submit proposals either in response to a detailed Request for Proposals or more generally in response to the publicly released information. In Australia, national and State regulatory regimes specify in detail how this must be done.

Another method for contacting potential providers of DM resources is to actively canvass individual providers. Projects that carry out on-the-ground surveys of potential providers often also encourage identified providers to consider providing DM resources at the same time as, or soon after, the survey is carried out. Alternatively, known customers with loads that may be interruptible or curtailable can be approached directly.

A third method for contacting potential providers is to establish an open market for DM resources. Typically, this method is used for DM resources that provide network operational services. In the United States, most Independent System Operators and Regional Transmission Operators have established markets for ancillary services that now accept bids from providers of DM resources. New Zealand has an ancillary services market that accepts bids involving interruptible loads and distributed generation. The Spanish transmission system operator has also established a market for interruptible loads to provide network operational services.

Finally, large numbers of potential DM resource providers can be contacted by building into tariff schedules signals for end-use customers to reduce loads at particular times. The Tempo tariff in France is an example of a critical peak pricing mechanism that can be used to markedly increase electricity prices during times when the transmission system is constrained (see Case Study 23, page 189). Time of use and critical peak pricing is now being used routinely by many electricity utilities in the United States.
5.4 Negotiating the Provision of DM Resources

Once a network operator has identified a suitable demand-side resource and the resource provider has agreed to provide it, the detailed terms for the transaction must be negotiated and settled. The details of these terms are highly dependent on the nature of the resource and the specific purpose for which the resource is required.

For DM resources that are required only intermittently, typically two types of payments are made: an availability payment for the capacity of load reduction or additional generation made available (measured in MW); and a dispatch payment for the quantity of load reduction or additional generation actually provided in response to a call (measured in MWh). These payments may be negotiated on a case by case basis, or the network operator can specify a schedule of payments through a standard offer. For large loads or generators, contracts with the network operator may include highly specific conditions about the availability of the resource, prior notice of calls, discretion in responding to calls, etc.

Terms for DM resources that are provided permanently vary widely, depending on the particular circumstances. For example, in the Bind Bigga DSM Project (Case Study 22, page 181), the network operator provided householders with discounted gas room heaters and cooking stoves (a maximum of two appliances per household); free installation of gas appliances and gas bottles, and removal of electrical appliances for metal recycling; and gas credits of AUD 170 per appliance – equivalent to free gas for a year.

5.5 Acquiring and Implementing DM Resources

Once the terms for providing a demand-side resource have been agreed and settled, the network operator has to actually acquire and implement the resource. The methods for doing this are highly dependent on the nature of the resource.

For DM resources that are provided permanently, acquisition and implementation is usually a once-only operation, eg the replacement of electrical appliances with gas ones in the Binda Bigga DSM Project.

For DM resources that are required only intermittently, the network operator must have some method for signalling when the resource is required and the provider must have a method for providing the resource in response to the call.

The provision of the resource may be done automatically, as in the LIPAedge program that uses central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction (see Case Study 09, page 110). In other cases, particularly with large loads, some prior notice from the network operator may be required, and the resource provider may have some discretion specified in their contract with the network operator over whether or not to respond to the call.

Finally, in the case of time varying pricing, it is entirely up to the end-use customer to decide whether or not to respond to the price signal. In this case responses by individual end-users have a much lower level of “firmness” than other types of demand-side resource. However, because this type of DM resource is provided by a large number of individual end-users, the reliability of the aggregate load reduction may be relatively high. With experience over time, it may be possible for the network operator to forecast reasonably accurately the amount of aggregate load reduction that will be achieved in each call.
6. CONCLUSION

This report reviews international best practice in using energy efficiency and demand management to support electricity networks. The report covers four main topics:

- a definition and description of network-driven demand management;
- the effectiveness of a range of network-driven demand management measures;
- options for modifying network planning processes to take into account the use of demand-side measures; and
- best practices in evaluating and acquiring network-driven demand management resources.

At present, the use of demand-side resources to support electricity networks is not common, occurring mainly in Australia, the United States and in specific geographical areas in France. However, in the future, as electricity loads increase, network infrastructure ages, and the costs of augmenting and expanding networks continue to rise, it is likely that the use of cost-effective DM resources to support electricity networks will become much more widespread.
APPENDIX:

CASE STUDIES OF DEMAND MANAGEMENT PROJECTS
CASE STUDY 01
CHICAGO ENERGY RELIABILITY AND CAPACITY ACCOUNT - USA

IEADSM Task XV Case Study No  DG04
Last updated                   26 August 2005
Location of Project           Chicago, Illinois, USA
Year Project Implemented      Progressively from May 1999
Year Project Completed        26 August 2005
Name of Project Proponent     City of Chicago/Commonwealth Edison
Name of Project Implementor   Commonwealth Edison
Type of Project Implementor   Distribution utility
                                  Transmission utility
                                  Electricity retailer/supplier
                                  Local government (municipality)
Purpose of Project            Deferral of network augmentation
Timing of Project             Post contingency
Focus of Project              Network capacity limitations
Project Objective             Overall load reduction
Project Target                Whole network
DSM Measure(s) Used           Standby generation
                                  Other distributed generation
                                  Energy efficiency
Specific Technology Used      Energy efficiency measures, standby generation
                                  and photovoltaic distributed generation
Market Segments Addressed     Commercial and small industrial customers
                                  Large industrial customers
                                  Non-customer related

DRIVERS FOR PROJECT
Commonwealth Edison (ComEd), as a vertically integrated utility has a franchise to supply electricity in the City of Chicago. When the franchise came up for renewal in 1992, problems with aging distribution infrastructure were known to be serious. Part of the 29-year franchise renewal was a commitment by the utility to spend USD1 billion on transmission and distribution upgrades over the following 10 years.

When it appeared that ComEd was not on schedule with these upgrades, the City of Chicago sued, and obtained a settlement that included, among other things, a commitment by ComEd to spend USD1.25 billion in transmission and distribution infrastructure by the year 2004. ComEd also made payments totalling USD100 million to the City of Chicago to establish a Chicago Energy Reliability and Capacity Account to fund reliability-enhancing projects within the City.

Additional impetus for action by both ComEd and the City came from a series of outages across Chicago neighbourhoods, including the downtown Loop, in July and August of 1999. Aging distribution plant, overloaded in the midst of a heat wave, repeatedly failed or was taken out of service to prevent failure. The resulting public outcry led to an intense focus both on upgrading distribution facilities and on lowering growth in peak demand in stressed distribution areas.
DESCRIPTION OF PROJECT

The USD100 million Energy Reliability and Capacity Account is administered by the Energy Division of the City of Chicago’s Department of Environment. The program has several major elements, enhancing reliability both through efficiency investments, and through investments in distributed generation.

The “Rebuild Chicago” program assists commercial and industrial firms to upgrade the efficiency of their facilities. As of early 2001, one million square feet of commercial and industrial space had been upgraded under this program, with 25 million square feet enrolled and being treated. In addition 15 million square feet of public facilities is targeted for efficiency-related upgrades.

There is also a distributed generation program. In preparing to deal with electrical outages, the City constructed a list of all of the “critical facilities” that would need attention, and discovered over 8,000 sites on the list. About 6,000 of these involved traffic lights at key intersections, but there are also 2,000 critical buildings: schools, high rises, police stations, hospitals, and so on. An inventory of these facilities revealed a large number of on-site standby generators. Although most of these generators are diesels that the City does not want to deploy regularly, there are also a total of 13 MW of natural-gas fired standby generators in public buildings (12 MW in units over 400kw each). To make these units available as a network of distributed generators, the City developed a SCADA system to link them to a central operating facility. This will provide a dispersed network of reliable distributed generators for use in system emergencies. The City also expects to dispatch the standby generators, to the degree permitted by air quality permits, at periods of high system prices. Income from power generation at peak periods will help to pay for the costs of the program.

Finally, the Energy Reliability and Capacity Account is supporting development of distributed renewable resources within the City. The leading initiative here is in photovoltaics. The Energy Division negotiated an arrangement with a PV manufacturer to locate a manufacturing plant in Chicago and has purchased 250 kW in PV arrays at six schools (10 kW each) and several prominent museums (approximately 50 kW each) throughout the City. ComEd also committed to a purchase of $12 million in PV arrays for deployment in Chicago. The Energy Division has also constructed a “Renewable Energy Farm” on a brownfield site, which hosts a wind turbine, an advanced fuel cell, and a large PV array – at 2.5 MW, said to be the world’s largest PV installation.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2.75 MW</td>
</tr>
<tr>
<td>Peak Load</td>
<td>Peak Load Reduction</td>
<td>Duration of Peak Load Reduction</td>
<td>Overall Load Reduction</td>
<td>Energy Savings</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Network Augmentation Deferral</td>
</tr>
</tbody>
</table>


International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

ACTUAL PROJECT COSTS
USD 100 million (contribution by ComEd)

CONTACTS
Antonia Ornelas
Energy Division
Department of Environment
City of Chicago
Tel: + 1 312 744 7203
Fax: + 1 312 744 6451
Email: aornelas@cityofchicago.org

SOURCES

CASE STUDY PREPARATION
Name: David Crossley   Email: crossley@efa.com.au
CASE STUDY 02
CALIFORNIA CRITICAL PEAK PRICING TARIFF
FOR LARGE CUSTOMERS - USA

IEADSM Task XV Case Study No  PI01
Last updated  5 October 2008
Location of Project  California, USA
Year Project Implemented  2003
Year Project Completed
Name of Project Proponent  California Energy Commission
Name of Project Implementor  Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), Southern California Edison (SCE)
Type of Project Implementor  Distribution utility
Transmission utility
Purpose of Project  Deferral of network augmentation
Timing of Project  Pre contingency
Focus of Project  Network capacity limitations
Generation capacity limitations
Project Objective  Peak load reduction
Project Target  Whole network
DSM Measure(s) Used  Pricing initiatives
Specific Technology Used
Market Segments Addressed  Commercial and small industrial customers
Large industrial customers

DRIVERS FOR PROJECT
In 2000 and 2001, California experienced a so-called "energy crisis" that comprised short-term shortages of electricity generation capacity following the failure of the introduction of a competitive electricity market in the State. By 2002, the immediate short-term problems had been resolved, but longer-term shortages of both generation and transmission network capacity remained.

One of the lessons gleaned from California’s energy crisis was that the lack of demand response in retail markets makes it very difficult to clear wholesale markets at reasonable prices. One method for introducing demand response in retail markets is time-varying pricing.

With this in mind, the California Public Utilities Commission (CPUC) in June 2002, adopted an Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing" and initiated a proceeding in July designed to introduce demand response into California’s electricity market.

As part of this proceeding, three working groups were charged with developing specific tariff proposals to achieve increased demand response in the state. The objective of Working Group 2 was to evaluate demand response programs for large customers with demand exceeding 200 kilowatts.
In June 2003, the Commission authorized a Critical Peak Pricing (CPP) tariff for large customers proposed by the three California investor-owned utilities, as well as several other demand response-related programs. Large customers are defined by the Commission as having average monthly demands of 200 kW or greater.

A statewide demand response measurement and evaluation (M&E) effort also began in 2003, comprising a comprehensive monitoring and evaluation plan. The plan outlined M&E activities in an effort to provide information that would improve the cost-effectiveness of demand response activities going forward.

The goal underlying all of the demand response programs is to provide California with greater flexibility in responding to periods of high peak electricity demand. The objective in rolling out these specific programs relatively quickly with limited formal rate design research was to achieve a "quick win" that would:

- take advantage of the new interval meters installed in customers premises with peak demand over 200 kW (100kW for SDG&E);
- give both customers and utilities experience in implementing statewide demand response programs;
- deliver significant load reductions for summer 2004; and
- make a significant contribution to achieving the California Public Utilities Commission’s overall price-responsive demand response goals (which ramp up to 5 percent of system peak by 2007).

**DESCRIPTION OF PROJECT**

The CPP tariff for large customers comprised increased prices during 6 or 7 hours of up to 12 "Critical Peak Pricing Days" each year and reduced prices during non-critical-peak periods. A CPP event could only be activated during summer. For PG&E customers, the reduced prices applied in summer only; for SCE and SDG&E customers, the reduced prices applied year-round.

To participate in the CPP tariff for large customers, all customers had to have metering capable of recording electricity usage in 15-minute intervals. If customers did not have interval metering at the start of the CPP trial period, each utility provided and installed this free of charge. PG&E and SCE customers had to have an annual maximum demand greater than 200 kW; for SDG&E customers the threshold was 100 kW of annual maximum demand. The CPP tariff was not available to direct access customers. Customers had remain on the CPP tariff for a minimum of 12 months; after participating in the CPP tariff for 12 months, customers could opt-off at any time.

There were two levels of Critical Peak Pricing periods. In SCE’s and PG&E’s programs they were High-Price Periods (3 to 6 pm) and Moderate-Price Periods (Noon to 3 pm). In SDG&E’s program, they were Period 1 (3 to 6 pm) and Period 2 (11 am to 3 pm).

Specific price levels in the tariff were applied based on participating customers’ Otherwise Applicable Tariff (OAT). The amounts and percentages of rate credits and charges varied among the utilities:

- **PG&E’s** energy rates during the High Price Periods were five times the Otherwise Applicable Tariff (OAT) and three times the OAT during Moderate Price Periods. At
other times during the summer, PG&E’s On-peak and Part-peak energy rates for CPP participants were reduced by over 22 percent and over 3 percent respectively.

- SCE’s rates were about 6.7 times the OAT during CPP High Price Periods and 2.0 times the OAT during CPP Moderate Price Periods. At other times during the year, the CPP rates were about 9.3 percent less than OAT energy rates.

- SDG&E’s energy rates were 10.0 times the OAT during CPP Period 1 (i.e., the high price period) and 3.79 times OAT for CPP Period 2. At other times during the year, the CPP rates were about 9.5 percent less than OAT energy rates.

Bill Protection was available to customers during the first 14 months the customer was participating in the CPP tariff. Bill Protection provided that participating customers would pay no more for energy than they would have had they remained on their OAT.

Each utility determined the day before whether there would be a Critical Peak Pricing Day the next day. There were a number of ‘triggers’ that might activate a CPP event, including high system demand and/or low generation supply, system emergency testing, high market prices, and forecasted temperature reaching a set threshold level at specific locations. A utility could adjust the temperature threshold up or down over the course of the summer, as necessary, to achieve the targeted program event maximum of 12 CPP events per summer season. A utility could also activate a CCP event at its discretion.

Each utility notified CPP participants of Critical Peak Pricing Days according to slightly different schedules. SDG&E e-mailed its participants by 4pm the day before, SCE telephoned and e-mailed or paged starting at 3pm and PG&E e-mailed and paged its participants by 5pm.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>206</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Peak Load</th>
<th>Peak Load Reduction</th>
<th>Duration of Peak Load Reduction</th>
<th>Overall Load Reduction</th>
<th>Energy Savings</th>
<th>Network Augmentation Deferral</th>
</tr>
</thead>
<tbody>
<tr>
<td>44,000 MW</td>
<td>8.3 MW</td>
<td>6 hours</td>
<td>8.3 MW</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

HOW LOAD REDUCTION WAS MEASURED

Interval meter. 15 minute intervals.

RESULTS ACHIEVED

CPP Events

The number of CPP Events called in 2004 ranged from five and six for PG&E and SDG&E, respectively, to 12 for SCE (see Table PI01/1, page 63). However, three of the PG&E events were called on consecutive days during which time temperatures significantly decreased.
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

Table PI01/1. Critical Peak Pricing Events in 2004

<table>
<thead>
<tr>
<th>Utility</th>
<th>Event</th>
<th>Event Type</th>
<th>Event Trigger</th>
<th>Event Date</th>
<th>Event Hours</th>
<th>Participants</th>
</tr>
</thead>
<tbody>
<tr>
<td>SDG&amp;E</td>
<td>CPP #1</td>
<td>day-ahead notice</td>
<td>Utility Discretion</td>
<td>07/12/04</td>
<td>11-6 pm</td>
<td>41</td>
</tr>
<tr>
<td></td>
<td>CPP #2</td>
<td>day-ahead notice</td>
<td>Utility Discretion</td>
<td>07/22/04</td>
<td>11-6 pm</td>
<td>42</td>
</tr>
<tr>
<td></td>
<td>CPP #3</td>
<td>day-ahead notice</td>
<td>Utility Discretion</td>
<td>08/11/04</td>
<td>11-6 pm</td>
<td>47</td>
</tr>
<tr>
<td></td>
<td>CPP #4</td>
<td>day-ahead notice</td>
<td>Utility Discretion</td>
<td>09/01/04</td>
<td>11-6 pm</td>
<td>47</td>
</tr>
<tr>
<td></td>
<td>CPP #5</td>
<td>day-ahead notice</td>
<td>Utility Discretion</td>
<td>09/10/04</td>
<td>11-6 pm</td>
<td>47</td>
</tr>
<tr>
<td></td>
<td>CPP #6</td>
<td>day-ahead notice</td>
<td>Utility Discretion</td>
<td>09/22/04</td>
<td>11-6 pm</td>
<td>48</td>
</tr>
<tr>
<td>SCE</td>
<td>CPP #1</td>
<td>day-ahead notice</td>
<td>Temperature</td>
<td>07/14/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #2</td>
<td>day-ahead notice</td>
<td>System Constraint</td>
<td>07/22/04</td>
<td>12-6 pm</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>CPP #3</td>
<td>day notice</td>
<td>Temperature</td>
<td>08/11/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #4</td>
<td>day notice</td>
<td>Temperature</td>
<td>08/12/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #5</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/03/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #6</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/09/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #7</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/10/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #8</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/12/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #9</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/14/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #10</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/23/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #11</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/24/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>CPP #12</td>
<td>day notice</td>
<td>Temperature</td>
<td>09/27/04</td>
<td>12-6 pm</td>
<td>8</td>
</tr>
<tr>
<td>PG&amp;E</td>
<td>CPP #1</td>
<td>day-ahead notice</td>
<td>Temperature</td>
<td>08/27/04</td>
<td>12-6 pm</td>
<td>112</td>
</tr>
<tr>
<td></td>
<td>CPP #2</td>
<td>day-ahead notice</td>
<td>Temperature</td>
<td>09/03/04</td>
<td>12-6 pm</td>
<td>119</td>
</tr>
<tr>
<td></td>
<td>CPP #3</td>
<td>day-ahead notice</td>
<td>Temperature</td>
<td>09/09/04</td>
<td>12-6 pm</td>
<td>119</td>
</tr>
<tr>
<td></td>
<td>CPP #4</td>
<td>day-ahead notice</td>
<td>Temperature</td>
<td>09/10/04</td>
<td>12-6 pm</td>
<td>119</td>
</tr>
<tr>
<td></td>
<td>CPP #5</td>
<td>day-ahead notice</td>
<td>Temperature</td>
<td>10/12/04</td>
<td>12-6 pm</td>
<td>129</td>
</tr>
</tbody>
</table>

Participation Levels

Only 1 percent of eligible accounts participated in CPP for summer 2004; however, participation was higher among larger customers. Participation varied greatly by utility, 2 percent of eligible PG&E accounts signed up (146 accounts), 1 percent of SDG&E (52 accounts), and only 0.1 percent (8 accounts) for SCE. Although there are some differences in tariff design across the utilities, the differences in potential customer savings for PG&E and SCE are similar and do not explain the difference in program penetration levels.

Load Reduction Impacts

A 10-day baseline methodology was used to calculate each customer’s baseline energy usage. The baseline was determined on an hourly basis using the customer’s own average energy usage for the three highest total energy usage days out of the 10 days prior to a CPP Event (excluding other CPP days or days the customer was paid to reduce power or the customer was subject to a rotating outage). The baseline was then subtracted from the actual amount of kWh used for that hour during the CPP Event to determine the actual kWh reduction.

The overall estimated load reduction across all three utilities attributed to the CPP tariff in 2004 is roughly 8 MW (see Table PI01/2, page 64). PG&E accounts for 60 percent of the estimated impact, SDG&E 30 percent, and SCE 10 percent. On a percentage basis, the average impacts range widely across the three utilities. For PG&E and SDG&E, which had the vast majority of CPP participants, average percent savings ranged from a few percent up to 20 percent depending on the utility and event.
For planning purposes and reporting to the California Public Utilities Commission, the utilities used an impact estimate for CPP that was 15 percent of load.

For SDG&E, the average impact using the 10-Day Adjusted Baseline across six CPP events was 15 percent.

For PG&E, the 15 percent figure was on the higher end of what might be expected, for the particular customers in the 2004 participant cohort. The mean impact estimated using the 10-Day Adjusted Baseline was 5 percent of load based on the first two event days (event days for which there is more confidence in the estimates). Even if all four event days were used (of which the latter two were believed to be overstated), the mean impact was 9 percent.

For SCE, it is difficult to assess if the 15 percent value used by the utilities was appropriate due to the small number of participants in the CPP tariff. Although the impact was estimated to be 55 percent of load, this value was driven primarily by a single customer. The median impact was 9 percent and the inter-quartile range was zero to 73 percent. Therefore, for SCE, 15 percent was likely to be a better value for planning purposes than 55 percent.

### Level of Compensation

The monetary incentive to customers to reduce load in the CPP tariff program was relatively small, particularly as compared to customers’ annual electricity bills and other costs of doing business. Savings were roughly 1 to 2 percent for most customers. A market survey of non-participants showed very low levels of customer willingness to make load reductions in exchange for bill savings of a percent or two a year.

There is evidence that the levels and form of compensation may not have motivated a larger share of the eligible market to participate in the CPP tariff program because customers believed that their costs of participating in the programs and taking associated demand response actions might exceed the corresponding financial incentives.

There was consistent evidence that end users faced both fixed and variable costs associated with demand response actions.
Fixed costs were associated with developing a demand response action plan, which may require a variety of engineering and financial analyses, as well as implementation of fixed elements of the plan (for example, programming energy management systems or other control systems, purchase of new equipment, modification of existing equipment, etc.).

Variable costs included costs associated with carrying out the demand response actions, which could include costs associated with lost or deferred production, decreased worker productivity, as well as the costs of physically carrying out the reductions (in cases where they were not automated).

Barriers to Participation

Based on the results of the non-participant survey, customers indicated that there are numerous barriers that limit their ability and willingness to participate in demand response programs. In rating potential barriers to participation and implementation, the number one concern for the market as a whole was "Effects on Products or Productivity". The next largest concerns were "Amount of Potential Bill Savings", "Level of On-peak Prices or Non-performance Penalties", and "Inability to Reduce Peak Loads". The least significant concern reported was "Inadequate Program Information".

CONFIDENCE LEVEL IN ACHIEVING RESULTS

When each of the CPP participants was asked about their likelihood of taking demand reduction actions in future CPP events, 84 percent responded that they were either somewhat or very likely to take actions for future events. Only 4 percent of participants reported they were not at all likely to take action and 7 percent reported they were somewhat unlikely.

WEATHER DEPENDENCE

One issue relating to the low frequency of CPP events was the appropriateness of the temperature trigger that determined how often the program was called. There were indications that the triggers for some regions were set relatively high, resulting in the program being rarely called. In SDG&E’s territory, for example, the CPP program was triggered when the forecast temperature for a certain location reached 91 degrees Fahrenheit (33 degrees Celsius); however the forecast temperature for that location had not been as high as 91 degrees in the preceding five years.

OVERALL PROJECT EFFECTIVENESS

The evaluation results pointed to significant challenges associated with achieving high levels of participation in, and load reduction from, the CPP tariff program. At the same time, the process of designing, marketing and implementing the 2004 CPP tariff program provided all the utilities with valuable experience and customer feedback that would help them to continue to improve the demand response portfolio in the future.

Although adoption takes time and this program was actively marketed only from late 2003, the evaluation results showed that the CPP tariff did not make as large a contribution to achieving overall demand response goals as desired. Based on the evaluation results, the market required stronger motivation, knowledge, and capability in order for the CPP tariff program to make large contributions to the price-responsive demand response goals.
However, the narrow range of CPP events in 2004 and, in some cases, small potentially unrepresentative mix of participant types, limited the extent to which summer 2004 experiences and program impacts could be projected into the future.

CONTACTS
PG&E: Susan McNicoll (415) 973-7404

SOURCES

CASE STUDY PREPARATION
Name: John Kueck / David Crossley Email: kueckjd@ornl.gov / crossley@efa.com.au
## CASE STUDY 03

**SEPARATION OF AGRICULTURAL FEEDERS FOR LOAD CONTROL - INDIA**

<table>
<thead>
<tr>
<th>IEADSM Task XV Case Study No</th>
<th>DC09</th>
</tr>
</thead>
<tbody>
<tr>
<td>Last updated</td>
<td>2 October 2008</td>
</tr>
<tr>
<td><strong>Location of Project</strong></td>
<td>Northern parts of the State of Gujarat, India</td>
</tr>
<tr>
<td><strong>Year Project Implemented</strong></td>
<td>2005/06</td>
</tr>
<tr>
<td><strong>Year Project Completed</strong></td>
<td>2006/07</td>
</tr>
<tr>
<td><strong>Name of Project Proponent</strong></td>
<td>Government of Gujarat</td>
</tr>
<tr>
<td><strong>Name of Project Implementor</strong></td>
<td>Uttar Gujarat Vij Company Limited (UGVCL)</td>
</tr>
<tr>
<td><strong>Type of Project Implementor</strong></td>
<td>Distribution utility, Electricity retailer/supplier</td>
</tr>
<tr>
<td><strong>Purpose of Project</strong></td>
<td>Deferral of network augmentation</td>
</tr>
<tr>
<td><strong>Timing of Project</strong></td>
<td>Post contingency</td>
</tr>
<tr>
<td><strong>Focus of Project</strong></td>
<td>Network capacity limitations, Generation capacity limitations</td>
</tr>
<tr>
<td><strong>Project Objective</strong></td>
<td>Peak load reduction, Overall load reduction</td>
</tr>
<tr>
<td><strong>Project Target</strong></td>
<td>Whole network</td>
</tr>
<tr>
<td><strong>DSM Measure(s) Used</strong></td>
<td>Direct load control</td>
</tr>
<tr>
<td><strong>Specific Technology Used</strong></td>
<td>Timing schedules for energising agricultural feeders</td>
</tr>
<tr>
<td><strong>Market Segments Addressed</strong></td>
<td>Agricultural customers</td>
</tr>
</tbody>
</table>

### DRIVERS FOR PROJECT

The Separation of Agricultural Feeders for Load Control project was initiated by the Government of Gujarat and implemented by Uttar Gujarat Vij Company Limited (UGVCL), as well as other electricity distributors in the State of Gujarat.

UGVCL is an electricity distribution/retailing utility owned by the Government of Gujarat. UGVCL provides distribution and retail supply of electricity to a service territory of 49,950 square kilometres in northern parts of the State of Gujarat, supplying 1.9 million customers in 67 talukas (administrative areas), 61 towns and 4,617 villages.

In 2003, the Government of Gujarat announced a scheme called "Jyotigram Yojana" (JGY) to provide continuous three phase power supply to rural areas of the State to improve the quality of life of the rural population. To receive the benefits of JGY, a village Panchayat (local government body) pays a registration fee of INR1000 and up to 30% of the estimated cost of building any augmentation or expansion required to the electricity network, with a maximum payment of INR25,000. The balance of the cost is paid by the Gujarat Government.

Under the JGY scheme, the Gujarat Government decided to separate agricultural pump set connections from domestic light and fan (DLF) connections by constructing separate 11 KV feeders for agricultural loads. This enabled electricity distributors to implement direct load control of agricultural pumps by establishing schedules specifying the times during the day when each agricultural feeder would be energised.
The main objective of implementing this direct load control program was to flatten the load curve to provide sufficient network capacity for the morning and evening peaks.

Water pumping load in the agricultural sector in India is important for several reasons. Agricultural pump sets are often supplied by long rural lines which are costly to build and maintain and have large line losses. The electricity supply to pumps is often unmetered and electricity is effectively supplied free of charge. In these cases, electricity distributors have to bear the supply cost and there is no incentive for agricultural customers to use electricity efficiently.

In the particular case of northern Gujarat, UGVCL was facing a power shortage during the morning peak hours. For example, the maximum demand on the UGVCL system during the month of December 2005 was 2100 MW during the morning peak. There was a shortage of capacity during the morning and UGVCL was not able to supply quality power to all consumer categories, leading to load shedding. Load shedding in rural areas was affecting the economic growth of the rural economy.

DESCRIPTION OF PROJECT

To capture the benefits of the Jyoti Gram Yojna scheme and to provide continuous supply to all non-agricultural consumer categories, UGVCL decided to separate agricultural feeders at the 11 kV level. UGVCL commenced implementation of the project in April 2005 with prior planning and close monitoring to achieve a target of providing a reliable eight hours of supply to all agricultural customers by the end of financial year 2006/07.

To achieve the separation of agricultural feeders, UGVCL constructed the following new electricity network infrastructure:

- 15,461 kilometres of high voltage lines;
- 2,044 kilometres of low voltage lines;
- 2,088 transformers.

This new infrastructure enabled UGVCL to rearrange the power supply timing schedules for 28 agricultural customer groups across a total of 1,950 separate agricultural feeders, as shown in Table DC09/1 (page 69).

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load</td>
<td>Peak Load Reduction</td>
<td>Duration of Peak Load Reduction</td>
<td>Overall Load Reduction</td>
<td>Energy Savings</td>
</tr>
<tr>
<td>2100 MW</td>
<td>250 MW</td>
<td>4 hours</td>
<td>1521.37 GWh over two years</td>
<td>Network Augmentation Deferral</td>
</tr>
</tbody>
</table>


### Table DC09/1. Timing Schedule for Staggered Operation of Agricultural Feeders

<table>
<thead>
<tr>
<th>District (Area)</th>
<th>Agricultural Customer Group</th>
<th>Number of Feeders</th>
<th>Maximum Load (MW)</th>
<th>Timing of Power Supply (Three Phase)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Mehasana</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A11</td>
<td></td>
<td>86</td>
<td>125</td>
<td>00:00 to 08:00</td>
</tr>
<tr>
<td>A12</td>
<td></td>
<td>84</td>
<td>120</td>
<td>23:45 to 07:45</td>
</tr>
<tr>
<td>B11</td>
<td></td>
<td>80</td>
<td>135</td>
<td>10:30 to 18:30</td>
</tr>
<tr>
<td>B12</td>
<td></td>
<td>90</td>
<td>130</td>
<td>12:00 to 20:00</td>
</tr>
<tr>
<td><strong>Ahmedabad and Gandhinagar</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C11</td>
<td></td>
<td>65</td>
<td>90</td>
<td>05:15 to 13:15</td>
</tr>
<tr>
<td>C12</td>
<td></td>
<td>62</td>
<td>85</td>
<td>05:45 to 13:45</td>
</tr>
<tr>
<td>C13</td>
<td></td>
<td>48</td>
<td>80</td>
<td>03:45 to 11:45</td>
</tr>
<tr>
<td>D11</td>
<td></td>
<td>65</td>
<td>85</td>
<td>20:45 to 04:45</td>
</tr>
<tr>
<td>D12</td>
<td></td>
<td>60</td>
<td>95</td>
<td>20:15 to 04:15</td>
</tr>
<tr>
<td>D13</td>
<td></td>
<td>44</td>
<td>63</td>
<td>20:30 to 04:30</td>
</tr>
<tr>
<td><strong>Banaskantha (Palanpur)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>K11</td>
<td></td>
<td>88</td>
<td>110</td>
<td>11:15 to 19:15</td>
</tr>
<tr>
<td>K12</td>
<td></td>
<td>79</td>
<td>115</td>
<td>05:30 to 13:30</td>
</tr>
<tr>
<td>L11</td>
<td></td>
<td>78</td>
<td>120</td>
<td>21:30 to 05:30</td>
</tr>
<tr>
<td>L12</td>
<td></td>
<td>76</td>
<td>122</td>
<td>23:30 to 07:30</td>
</tr>
<tr>
<td><strong>Banaskantha (Kansari)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>K13</td>
<td></td>
<td>68</td>
<td>105</td>
<td>04:00 to 12:00</td>
</tr>
<tr>
<td>K14</td>
<td></td>
<td>70</td>
<td>104</td>
<td>02:15 to 10:15</td>
</tr>
<tr>
<td>K15</td>
<td></td>
<td>64</td>
<td>94</td>
<td>00:15 to 08:15</td>
</tr>
<tr>
<td>L13</td>
<td></td>
<td>77</td>
<td>103</td>
<td>23:15 to 07:15</td>
</tr>
<tr>
<td>L14</td>
<td></td>
<td>65</td>
<td>108</td>
<td>20:00 to 04:00</td>
</tr>
<tr>
<td>L15</td>
<td></td>
<td>66</td>
<td>110</td>
<td>13:00 to 21:00</td>
</tr>
<tr>
<td><strong>Sabarkantha</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>M11</td>
<td></td>
<td>105</td>
<td>140</td>
<td>12:45 to 20:45</td>
</tr>
<tr>
<td>N11</td>
<td></td>
<td>100</td>
<td>135</td>
<td>04:45 to 12:45</td>
</tr>
<tr>
<td>M12</td>
<td></td>
<td>35</td>
<td>45</td>
<td>14:00 to 18:00 &amp; 03:00 to 07:00</td>
</tr>
<tr>
<td>N12</td>
<td></td>
<td>39</td>
<td>50</td>
<td>08:00 to 12:00 &amp; 21:30 to 01:30</td>
</tr>
<tr>
<td><strong>Patan</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P11</td>
<td></td>
<td>76</td>
<td>105</td>
<td>03:15 to 11:15</td>
</tr>
<tr>
<td>P12</td>
<td></td>
<td>73</td>
<td>100</td>
<td>21:15 to 05:15</td>
</tr>
<tr>
<td>Q11</td>
<td></td>
<td>69</td>
<td>104</td>
<td>12:15 to 20:15</td>
</tr>
<tr>
<td>Q12</td>
<td></td>
<td>69</td>
<td>98</td>
<td>21:45 to 05:45</td>
</tr>
</tbody>
</table>
RESULTS ACHIEVED

The rearrangement of the power supply timing schedules for agricultural feeders reduced the maximum demand on the UGVCL system from 2100 MW to 1850 MW and increased the minimum demand from 900 MW to 1450 MW, thereby flattening the load curve throughout the day. This is shown in Figure DC09/1.

![Figure DC09/1. UGVCL System Load Curve in December 2005 and December 2006](image)

Table DC09/2 shows that, over the period 2005/06 to 2006/07, despite increases in customer connections, and in energy sales, there was a significant saving of 102 GWh in the quantity of energy that UGVCL purchased and injected into the system to meet customer demand.

<table>
<thead>
<tr>
<th>Table DC09/2 Comparison of UGVCL Annual Energy Account</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total no of customer</td>
</tr>
<tr>
<td>Total energy purchased/injected</td>
</tr>
<tr>
<td>Total energy sales</td>
</tr>
</tbody>
</table>

Other benefits of the project included:

- a reduction in line losses by about 13.5%, resulting in financial savings to UGVCL of INR4,597 million over two years, which was more than the total cost of constructing the new network infrastructure;
- reduction in overloading of feeders and failure of distribution transformers;
- increased quality of the power supply leading to reduced failure of agricultural pump sets.

ACTUAL PROJECT COSTS

Total expenditure by UGVCL on the construction of new electricity network infrastructure was INR2,980 million.
OVERALL PROJECT EFFECTIVENESS

By implementing the Jyoti Gram Yojna scheme, UGVCL was able to provide a continuous high quality power supply to all non-agricultural consumers in rural areas. This lead to a marked improvement in the standard of living of villagers.

CONTACTS

Mr. A.C. Patel
Superintendent Engineer (Tech - 4)
Uttar Gujarat Vij Company Limited
R&C Office, Visnagar Road
Mehsana 384001
North Gujarat
India
Phone: + 91 2672 222880
Fax: +91 2672 223574
Email: corporate@ugvcl.com

CASE STUDY PREPARATION

Name: Balawant Joshi/David Crossley  Email: balawant.joshi@abpsinfra.com
CASE STUDY 04
PEF DIRECT LOAD CONTROL AND STANDBY GENERATOR PROGRAMS - USA

IEADSM Task XV Case Study No: DC05
Last updated: 12 September 2005
Location of Project: Florida, USA
Year Project Implemented: 1981
Year Project Completed: Ongoing
Name of Project Proponent: Progress Energy Florida (PEF) - formerly Florida Power Corporation
Name of Project Implementor: Progress Energy Florida (PEF)
Type of Project Implementor: Distribution utility
Purpose of Project: Deferral of network augmentation
Timing of Project: Pre contingency
Focus of Project: Network capacity limitations
Project Objective: Peak load reduction
Project Target: Whole network
DSM Measure(s) Used: Standby generation, Interruptible loads, Direct load control
Specific Technology Used: Radio one way paging network
Market Segments Addressed: Residential customers, Commercial and small industrial customers, Large industrial customers

DRIVERS FOR PROJECT
The Florida Energy Efficiency and Conservation Act, passed in 1980, requires the Florida Public Service Commission to adopt goals to increase the efficiency of energy consumption, increase the development of cogeneration, and reduce and control the growth rates of electric consumption and weather-sensitive peak demand.

The Commission must review a utility's conservation goals not less than every five years. Within 90 days of a final Order establishing goals, a utility must submit a demand-side management (DSM) plan which contains conservation and DSM programs designed to meet its numeric goals.

By an Order issued in August 2004, the Florida Public Service Commission approved PEF’s latest DSM Plan for meeting its energy conservation goals established by the Commission. The Plan consists of a portfolio of individual DSM programs which include direct load control and standby generator programs in the residential, commercial and industrial sectors.
DESCRIPTION OF PROJECT

PEF's direct load control and standby generator programs cover

- centrally ducted space heating and air conditioning systems, water heaters and pool pumps in the residential sector
- central cooling and chiller systems, interruptible and curtailable loads and standby generation in the commercial and industrial sectors.

Direct load control is achieved through a one-way radio paging network for all sectors. Some SCADA control is used on dedicated feeders serving larger industrial customers who are on interruptible tariffs.

The direct load control programs allow PEF to reduce peak demand and defer the construction of additional generation and network capacity.

Residential Energy Management Program

The Residential Energy Management program is a voluntary customer direct load control program that commenced in 1981 and was modified in 1995, 2000 and 2004.

Peak demand is reduced by PEF using radio controlled switches installed on the customers’ premises to turn off selected electrical equipment. These controlled interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand.

Commencing in 2004, PEF is currently only accepting new enrolments in a winter-only component of the Residential Energy Management program. The winter-only component represents a modified, cost-effective version of the previous year-round program. It provides for direct load control of customer’s electric water heater and centrally ducted electric space heating systems during the period November through March.

To participate in the winter-only component of the Residential Energy Management Program, customers must:

- utilize both an electric water heater and a centrally ducted electric space heating system; and
- have a minimum average monthly usage of 600 kWh for the months of November through March.

Participants in the winter-only component must include both a central heating system and a water heater in the load control program. Participants in the year-round component were previously able to include any or all of a central heating system, a central air conditioning system, a water heater and a pool pump in the load control program.

PEF installs free of charge a control unit, called an "Energy Management Box", in participants' dwellings. The control unit receives radio signals from PEF's control centre which instruct it to switch the controlled equipment off and on.
During the period November to March, PEF may implement the following interruptions during peak usage periods (6 am to 10 am and 6 pm to 10 pm):

- water heaters: continuous interruption for up to five hours;
- space heating systems: up to 16.5 minutes out of each 30 minute interval.

Participants do not have the ability to override the control unit during a load control event.

Participants receive credits on their electricity bills of up to USD 11.50 per month from November to March. Credits are pro-rated according to monthly usage above 600 kWh. No credits are given for months when usage is below 600 kWh.

**Commercial/Industrial Energy Management Program**

The Commercial/Industrial Energy Management Program is a voluntary customer direct load control program that is restricted to existing customers as of 20 July 2000.

Peak demand is reduced by PEF using radio controlled switches installed on the customers’ premises to turn off central cooling and chiller systems during specified time periods, and coincident with hours of peak demand.

Similarly to the Residential Energy Management Program, participants receive credits on their electricity bills.

**Interruptible Service Program**

The Interruptible Service Program is a voluntary customer direct load control program that commenced in its present form in 1996.

The program is available throughout the entire territory served by PEF to any non-residential customer who is willing to have their power interrupted by PEF. PEF has remote control of the circuit breaker or disconnect switch supplying the customer’s equipment.

To participate in the Interruptible Service Program, commercial and industrial customers must have an average billing demand of 500 kW or more.

Participants receive a monthly interruptible demand credit based on their billing demand and billing load factor. In 2005, this credit is USD 3.08 per kW against a demand charge of USD 4.70 per kW. Participants who choose not to reduce their load during an interruption event are charged by PEF for their electricity usage at the price paid at that time by PEF for purchased power.

**Curtailable Service Program**

The Curtailable Service Program is a voluntary customer direct load control program that commenced in its present form in 1996.

The program is available throughout the entire territory served by PEF to any non-residential customer who agrees to curtail 25% of their average monthly billing demand when required by PEF. PEF has remote control of the circuit breaker or disconnect switch supplying the customer’s equipment.
To participate in the Curtailable Service Program, commercial and industrial customers must have an average billing demand of 500 kW or more.

Participants receive a monthly curtailable demand credit based on their curtailment demand and billing load factor. In 2005, this credit is USD 2.31 per kW against a demand charge of USD 5.56 per kW. Participants who choose not to reduce their load during a curtailment event are charged by PEF for their electricity usage at the price paid at that time by PEF for purchased power.

Standby Generation Program

The Standby Generation Program commenced in 1993 and was modified in 1995. It is a demand control program that reduces PEF's demand based upon the indirect control of customer equipment.

The program is a voluntary program available to all commercial and industrial customers who have on-site generation capability and are willing to reduce their PEF demand when PEF deems it necessary. PEF has no direct control of the customer's equipment, but relies upon the customer to initiate the generation upon being notified by PEF and continue running it until PEF notifies the customer that the generation is no longer needed. PEF does not restrict other use of the equipment by the customer.

To participate in the Standby Generation Program, commercial and industrial customers must have at least 50 kW of standby generation that will allow facility demand reduction at the request of PEF.

Participants receive a monthly credit on their energy bill according to the demonstrated ability of the customer to reduce demand at PEF's request. The credit is based upon the load served by the customer's generator, which would have been served by PEF if the Standby Generation Program were not in operation.

**RESULTS**

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>400,000</td>
<td>460</td>
<td>170</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Peak Load</th>
<th>Peak Load Reduction</th>
<th>Duration of Peak Load Reduction</th>
<th>Overall Load Reduction</th>
<th>Energy Savings</th>
<th>Network Augmentation Deferral</th>
</tr>
</thead>
<tbody>
<tr>
<td>10,500 MW</td>
<td>1,000 MW</td>
<td>Varies with need</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**HOW LOAD REDUCTION WAS MEASURED**

Estimate. Estimates were based on the time/temperature matrix and verified with system load data.
RESULTS ACHIEVED

PEF’s direct load programs are able to reduce system load by approximately 10%.

The direct load control programs:
  • improve system reliability;
  • have deferred the construction of several generating plants;
  • are used to meet State Reserves sharing group obligations;
  • meet state regulator requirements for DSM programs.

CONFIDENCE LEVEL IN ACHIEVING RESULTS

The performance of the direct load control programs varies depending on time of day and temperature. Results are predictable through the use of a time/temperature matrix which was developed by PEF through end-use studies.

REPEATABILITY OF RESULTS

Results of the direct load control programs are predictable through the use of the time/temperature matrix.

TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Because of the size of the direct load control and standby generator programs, they are dispatched according to the load reduction needed. However, the maximum time to drop all enrolled load is less than 5 minutes.

WEATHER DEPENDENCE

Because participants are not able to override load control signals, customer response in the direct load control programs is not dependent on weather conditions. However, the amount of load reduction required by PEF is very much affected by time of day and temperature.

AVOIDED COSTS

As measured with the Rate Impact Measure (RIM) test, the benefits of these programs exceed the cost, as required by the State regulator.

ACTUAL PROJECT COSTS

Annual program costs:
  • commercial/industrial: USD 21 million including incentives;
  • residential: USD 22 million including incentives.

In 2003, the cost to PEF of purchasing and installing each control unit in the Residential Energy Management Program was USD 182.

PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Since these programs pass the Rate Impact Measure (RIM) test, they are beneficial to all customers including participants and non-participants.
OVERALL PROJECT EFFECTIVENESS

The programs provide needed reserve margins and reliability in a cost-effective manner.

CONTACTS

Peter M. Kazuba
Progress Energy, Florida
727-344-4104
Email: peter.kazauba@pgnmail.com

SOURCES

Progress Energy website at:

http://www.psc.state.fl.us/library/FILINGS/03/10458-03/10458-03.pdf


Progress Energy Florida, Inc. (2005). Commercial/Industrial Rate Schedules. Available at:

CASE STUDY PREPARATION

Name: John Kueck / David Crossley  Email: kueckjd@ornl.gov / crossley@efa.com.au
### CASE STUDY 05
### PJM LOAD RESPONSE PROGRAMS - USA

<table>
<thead>
<tr>
<th>IEADSM Task XV Case Study No</th>
<th>DR03</th>
</tr>
</thead>
<tbody>
<tr>
<td>Last updated</td>
<td>12 September 2005</td>
</tr>
<tr>
<td>Location of Project</td>
<td>Implemented as allowed by regulatory agencies in Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia</td>
</tr>
<tr>
<td>Year Project Implemented</td>
<td>2002</td>
</tr>
<tr>
<td>Year Project Completed</td>
<td>Continuing</td>
</tr>
<tr>
<td>Name of Project Proponent</td>
<td>PJM Interconnection LLC</td>
</tr>
<tr>
<td>Name of Project Implementor</td>
<td>Load Serving Entities</td>
</tr>
<tr>
<td>Type of Project Implementor</td>
<td>Curtailment Service Providers</td>
</tr>
<tr>
<td>Purpose of Project</td>
<td>Provision of network operational services</td>
</tr>
<tr>
<td>Timing of Project</td>
<td>Pre contingency</td>
</tr>
<tr>
<td>Focus of Project</td>
<td>Network capacity limitations</td>
</tr>
<tr>
<td>Project Objective</td>
<td>Peak load reduction</td>
</tr>
<tr>
<td>Project Target</td>
<td>Network region</td>
</tr>
<tr>
<td>DSM Measure(s) Used</td>
<td>Standby generation</td>
</tr>
<tr>
<td></td>
<td>Cogeneration</td>
</tr>
<tr>
<td></td>
<td>Other distributed generation</td>
</tr>
<tr>
<td></td>
<td>Interruptible loads</td>
</tr>
<tr>
<td></td>
<td>Pricing initiatives</td>
</tr>
<tr>
<td></td>
<td>Other: Customer response to hourly locational marginal price.</td>
</tr>
<tr>
<td>Specific Technology Used</td>
<td>Website and email</td>
</tr>
<tr>
<td>Market Segments Addressed</td>
<td>Commercial and small industrial customers</td>
</tr>
<tr>
<td></td>
<td>Large industrial customers</td>
</tr>
</tbody>
</table>

#### DRIVERS FOR PROJECT

PJM Interconnection LLC is a regional transmission organization (RTO) that serves all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

The PJM Interconnection:

- ensures the reliability of North America’s largest centrally dispatched control area by managing the movement of electricity;
- operates the largest competitive wholesale electricity market in the world;
- plans generation and transmission expansion to ensure reliability; and
- provides real-time information to its members and customers to support their decision-making.

PJM operates two load response programs:
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

• the Emergency Load Response Program; and
• the Economic Load Response Program.

The PJM load response programs do not focus directly on network capacity limitations, but are designed to ensure the effective operation of an energy market. Nevertheless, the programs do support the electricity network during times of system constraints.

DESCRIPTION OF PROJECT

Participation

End-use customers who wish to participate in the PJM load response programs may offer one or both of two types of distributed resources:

• load reductions; and
• distributed generation.

End-use customers are enrolled in PJM load response programs by one of four types of qualified participants in the PJM wholesale electricity market:

• transmission owners (utilities); or
• Curtailment Service Providers (CSPs); or
• Load Serving Entities (LSEs) - eg electricity retailers; or
• the independent system operator (ie PJM).

End-use customers must complete a registration form which states the kW quantity of load reduction or distributed generation they are offering to the program and the Locational Marginal Price (LMP), in $/MW, at which the load will be reduced or the generation supplied.

Payments under load response programs are made by PJM to the end-use customer or its representative (LSE/CSP). In the event the CSP or LSE is the party to be paid but is not the load reducer, the portion of the payment that will be transferred from the LSE/CSP to the end-use customer that actually reduced load is arranged between the LSE/CSP and the end-use customer.

End-use customers may not be registered simultaneously in the Economic Load Response Program and the Emergency Load Response Program. However, an end-use customer may switch programs upon one day notice if it has participated in the same load response program for 15 consecutive days.

End-use customers participating in the PJM load response programs must have interval metering capable of hourly measurements.

The actual load reduction achieved by a program participant is measured by comparing metered load against a Customer Baseline Load (CBL). The CBL is determined using an average of the last five weekdays. There is also a weekend/holiday CBL.

PJM also considers customers without hourly metering for participation in a pilot load response program for up to two years per customer, provided the customers or their representatives propose an alternate method for measuring hourly load reductions.
Alternate measurement mechanisms are approved by PJM on a case-by-case basis. Participation in the non-hourly metered customer pilot is limited to 25MW aggregate load reduction over the PJM region and across all load response programs.

Load Response Programs
Table DR03/1 presents a comparison of the PJM load response programs.

Table DR03/1. Comparison of PJM Load Response Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Participation</th>
<th>Cost to Energy Market</th>
<th>Risks to Load Reducer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emergency Load</td>
<td>Emergency event</td>
<td>Costs recovered for emergency purchases in excess of LMP are allocated among PJM market buyers in proportion to their increase in net purchases</td>
<td>No Charges for Non Performance</td>
</tr>
<tr>
<td>Response Program</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economic</td>
<td>Day-Ahead Market</td>
<td>If Zonal LMP &lt; $75/MWh, PJM pays LMP - Retail Rate (Retail Rate + Generation + Transmission)</td>
<td>Charges for Non Performance: If load reduction is committed in Day-Ahead Market and does not perform in real time Real-Time LMP Shortages Balancing Operating Reserve Charges</td>
</tr>
<tr>
<td></td>
<td>Real-Time Market</td>
<td>If Zonal LMP &gt; $75/MWh, PJM pays LMP</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Real-Time Market only</td>
<td>Costs recovered from Operating Reserves in the Real-Time Energy Market</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Must be dispatched by PJM</td>
<td>Payment for reducing load is based on the actual kWh relief provided plus an adjustment for losses. The magnitude of relief provided could be less than, equal to, or greater than the kW amount declared on the Emergency Load Response Program Registration form.</td>
<td></td>
</tr>
</tbody>
</table>

Emergency Load Response Program
The PJM Emergency Load Response Program enables participants that reduce load during emergency conditions to receive payment for those reductions.

To participate in the program, the distributed resource must:

- be capable of reducing at least 100 kW of load; and
- be capable of receiving PJM notification to participate during emergency conditions.

PJM initiates a request for load reduction following the declaration of Maximum Emergency Generation. A request is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM web site and through automatically generated emails. The minimum duration of a load reduction request is two hours.

Payment for reducing load is based on the actual kWh relief provided plus an adjustment for losses. The magnitude of relief provided could be less than, equal to, or greater than the kW amount declared on the Emergency Load Response Program Registration form.
PJM pays the higher of the appropriate zonal Locational Marginal Price (LMP) or $500/MWh to the PJM Member that nominates the load. Payment is equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the higher of the appropriate zonal Locational Marginal Price (LMP) or $500/MWh.

**Economic Load Response Program**

The PJM Economic Load Response Program is designed to provide an incentive to customers or curtailment service providers to enhance the ability and opportunity for customers to reduce consumption when PJM locational marginal prices (LMP) are high.

The Economic Load Response Program purposefully incorporates incentives that are greater than strict economics would provide for the same curtailment. This departure from economics is justified to overcome initial barriers to end-use customer load response. This program is not intended to be a permanent fix to the lack of load response seen in the PJM markets today. The designers of this program contemplate that when the existing market barriers are removed and end-use customers are better able to respond to real time prices, the need for this program and others like it will disappear. Until that happens, however, programs like this are necessary for fully functioning markets.

The Economic Load Response Program is not based on the declaration of emergency conditions in PJM, but rather on the economic decisions of the PJM market participants. That is, the participants in the program are responsible for determining the conditions under which load reductions will actually take place and implementing the reductions should those conditions arise. The prime indicator of such conditions is assumed to be the locational marginal price (LMP) of energy on the PJM system.

In order to maintain adequate system control, PJM operators must know the amount of load expected to be reduced at varying price levels. These amounts may change on a daily basis. An end-use customer or its representative (LSE/CSP) is therefore responsible for maintaining the load reduction information associated with the end-use customer signed up for the program, including the amount and the price at which load might be reduced.

The Load Response Program Registration/Update web site is used for this purpose. PJM utilizes the data that has been submitted via the web site to compile daily aggregate load reductions on a zonal basis for use in operations.

**Real-time Option**

The Real Time Option of the Economic Load Response Program provides a mechanism by which any qualified market participant may offer customers the opportunity to commit to a reduction of the load they draw from the PJM system during times of high prices and receive payments based on real time LMP for the reductions.

End-use customers participating in the Real-time Option may choose to reduce load whenever their zonal LMP dictates that it is economically beneficial for them to do so, or they may choose to be dispatched by PJM. Load reductions under this program are not eligible to set real time price on the PJM system unless metered directly by PJM.
The end-use customer or its representative (LSE/CSP) sends an email to PJM concurrent with, or up to one hour immediately prior to, beginning the load reduction and also sends another email to PJM at the end of the load reduction.

Reimbursement for reducing load is based on the actual kWh relief provided in excess of committed day-ahead load reductions plus the adjustment for losses. If the real-time LMP is less than $75/MWh, the end-use customer (or its representative (LSE/CSP)) that curtails load in real time is paid by PJM the real-time LMP less an amount equal to the applicable generation and transmission charges. If the real-time LMP is greater than or equal to $75/MWh, the payment is the real-time LMP.

In cases where the load response is dispatched by PJM, payment is not less than the total value of the load response bid, including any submitted start-up cost.

**Day-ahead Option**

The Day Ahead Option of the Economic Load Response Program provides a mechanism by which any qualified market participant may offer customers the opportunity to reduce the load they draw from the PJM system in advance of real time operations and receive payments based on day ahead time LMP for the reductions.

PJM accepts demand reduction bids from an end-use customer or its representative (LSE/CSP) for a specific MW curtailment (in minimum increments of 0.1 MW). The demand reduction bid include the day-ahead LMP above which the end-use customer will not consume, and may also include a start-up cost and/or a minimum number of contiguous hours for which the load reduction must be committed.

The objective function for day-ahead commitment software is to reduce the day-ahead bid load by the amount of a demand reduction bid when the total cost over the 24-hour dispatch day is reduced compared to serving that load. The total cost includes paying the demand reduction bid for the length of the minimum commitment time as well as any start-up cost. Thus, curtailments are not scheduled unless they reduce total day-ahead production costs.

Demand reduction bids can set day-ahead LMP in the same way as a comparably bid generator.

Reimbursement for reducing load is based on the reductions of kWh committed in the Day Ahead Market.

An end-use customer or its representative (LSE/CSP) that submits a day-ahead demand reduction bid that is accepted by PJM when the day-ahead LMP is less than $75 MWh is paid by PJM the day-ahead LMP less an amount equal to the applicable generation and transmission charges. If the day-ahead LMP is greater than or equal to $75/MWh, the payment is the day-ahead LMP.

Total payments to end-use customers or their representatives (LSEs/CSPs) for accepted day ahead load response bids will not be less than the total value of the load response bid, including any submitted start-up cost.
RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>6,324</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>130,580 MW</td>
<td>3,902 MW</td>
<td>4,123 hours per annum</td>
<td>3,902 MW</td>
<td>31,719 MWh</td>
<td></td>
</tr>
</tbody>
</table>

HOW LOAD REDUCTION WAS MEASURED

Interval meter. 60 minute intervals.

RESULTS ACHIEVED

Participation

Participation in the PJM load response programs grew significantly during the period 2002 to 2005, as measured by total number of participants and MW enrolled in the program (see Table DR03/2). The number of participants in the Emergency Program increased from 61 to 4,301 over this period and in the Economic Program the increase was from 116 to 2,023 participants. The enrolled capacity in the Emergency Program increased from 548 MW to 1,738 MW between 2002 and 2005 and in the Economic Program the increase was from 337 MW to 2,119 MW.

<table>
<thead>
<tr>
<th>Year</th>
<th>Emergency Program</th>
<th>Economic Program</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>New Registered Sites</td>
<td>Additional MW</td>
</tr>
<tr>
<td>2002</td>
<td>61</td>
<td>548</td>
</tr>
<tr>
<td>2003</td>
<td>168</td>
<td>659</td>
</tr>
<tr>
<td>2004</td>
<td>4,147</td>
<td>1,124</td>
</tr>
<tr>
<td>2005*</td>
<td>4,301</td>
<td>1,783</td>
</tr>
</tbody>
</table>

* To 1 June 2005
Load Reductions

Table DR03/3 shows the actual load reductions and associated payments under the Economic Program from 2002 to 2004. The level of load reductions increased from 6,462 MWh in 2002 to 31,719 MWh in 2004. Consistent with lower system LMPs, payments per MWh decreased 64 percent from 2002 to 2003, and 19 percent from 2003 to 2004. The MWh of actual load reductions per MW enrolled in the Economic Program increased about 40 percent in 2003 and about 10 percent in 2004.

<table>
<thead>
<tr>
<th>Year</th>
<th>Total MWh</th>
<th>Total Payments</th>
<th>$/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>6,462</td>
<td>USD 761,977</td>
<td>USD 118</td>
</tr>
<tr>
<td>2003</td>
<td>19,290</td>
<td>USD 827,179</td>
<td>USD 43</td>
</tr>
<tr>
<td>2004</td>
<td>31,719</td>
<td>USD 1,096,573</td>
<td>USD 35</td>
</tr>
</tbody>
</table>

Figures DR03/1, DR03/2 and DR03/3 (pages 85 to 87) show the actual load reductions achieved in the Economic Program over the first seven months of 2004 on a daily basis and compared with the level of the LMP and with the total load on the PJM system. During this period there were no requests for load reduction in the Emergency Program.

Payments

Table DR03/4 shows the payments to participants in the Emergency Program and the Economic Program. Payments have steadily declined in the Emergency Program, reflecting the continuing reduction in the number of requests for load reduction in emergency situations. In contrast, payments to participants in the Economic Program have increased progressively, reflecting the continuing increase in voluntary load reductions by participants under this program.

<table>
<thead>
<tr>
<th>Year</th>
<th>Emergency Program</th>
<th>Economic Program</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>USD 282,756</td>
<td>USD 761,977</td>
<td>USD 1,044,753</td>
</tr>
<tr>
<td>2003</td>
<td>USD 26,613</td>
<td>USD 827,179</td>
<td>USD 853,792</td>
</tr>
<tr>
<td>2004</td>
<td>USD 0</td>
<td>USD 1,096,573</td>
<td>USD 1,096,573</td>
</tr>
</tbody>
</table>
Figure 1: 2004 Daily Economic Reductions and Credits
Figure 2: 2004 Economic Program Reductions vs. LMP
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks
CONFIDENCE LEVEL IN ACHIEVING RESULTS
In the Economic Program, the results were achieved by customers making their own choice to curtail based on market conditions. There is a high confidence level that customers will continue to respond to economic incentives.

REPEATABILITY OF RESULTS
Participation and load reductions in the Economic Program have grown steadily over the years.

TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED
Not applicable.

WEATHER DEPENDENCE
There is a Weather Sensitive Adjustment (WSA) to increase or decrease the customer baseline. PJM has an analysis method to determine the WSA, or the customer may suggest an alternate method.

AVOIED COSTS
The benefits of the Economic Program when measured as the impact in reducing overall market prices were much larger than the costs. These benefits are a direct function of prevailing market price levels and will thus increase if prices rise compared to 2004 levels or decrease if prices decrease compared to 2004 levels.

The evaluation of the benefits associated with overall market price reductions must consider that these benefits do not necessarily represent an increase in market efficiency but represent a transfer from generation to load over the short term. Whether this results in a lower overall market cost in the long run remains to be seen.

Regardless, the potential benefits of increasing demand side responsiveness in improved efficiency of the market are extremely large and certainly exceed the relatively small program costs by a wide margin. These benefit calculations do not include any calculation of reliability benefits of the demand side programs. It was not necessary to make such a calculation to demonstrate that there are substantial net benefits to the Economic Program.

ACTUAL PROJECT COSTS
In summary, direct administrative costs for the PJM Economic Program were about USD 1 per MWh of actual load reductions during the period 2002 to 2004. Payments to participants were about USD 13 per MWh of load reductions in 2002, about USD 6 per MWh of load reductions in 2003, and about USD 4 per MWh of load reductions in 2004. Thus, total program costs were approximately USD 14 per MWh of load reductions in 2002, about USD 7 per MWh in 2003, and about USD 5 per MWh in 2004.

PROJECT COST FROM THE SOCIETAL PERSPECTIVE
There is no cost, but rather a benefit from the societal perspective. The impact on overall market prices provided a much larger benefit than the program cost.
OVERALL PROJECT EFFECTIVENESS

The program is effective at providing a consumer response to price on a locational basis.

CONTACTS

Susan Covino
Manager, Demand Side Response
PJM Interconnect LLC
+1 610 666 8829
Email: covins@pjm.com

SOURCES


CASE STUDY PREPARATION

Name: John Kueck / David Crossley   Email: kueckjd@ornl.gov / crossley@efa.com.au
CASE STUDY 06
LOAD INTERRUPTION CONTRACT - SPAIN

IEADSM Task XV Case Study No. IL01
Last updated 27 October 2006
Location of Project Spain
Year Project Implemented 1983
Year Project Completed
Name of Project Proponent Red Eléctrica de España, S.A. (REE)
Name of Project Implementor Red Eléctrica de España, S.A. (REE)
Type of Project Implementor Transmission utility
Purpose of Project Provision of network operational services
Timing of Project Pre contingency
Focus of Project Network capacity limitations
Generation capacity limitations
Project Objective Peak load reduction
Project Target Whole network
DSM Measure(s) Used Interruptible loads
Pricing initiatives
Specific Technology Used
Market Segments Addressed Large industrial customers

DRIVERS FOR PROJECT

The Load Interruption Contract was conceived to provide a demand-side mechanism for large industrial customers. However, until now, it has only been applied as an operational service.

DESCRIPTION OF PROJECT

The Load Interruption Contract is an agreement through which large customers receive a discount on their electricity bills in return for being available to reduce their consumption on request from the System Operator.

The transmission system operator (REE) is responsible for issuing, controlling and supervising all interruption orders. Customers participating in the Load Interruption Contract will must submit to REE monthly schedules for hourly energy demand and maintenance planning.

Only customers with a specific high voltage tariff contract or with an Hourly Power Tariff contract can participate in a Load Interruption Contract. They include iron, steel and other metal industries, cement and chemical industries, airports, etc.

Customers participating in the Load Interruption Contract will must submit to REE monthly schedules for hourly energy demand and maintenance planning.

There are four types of interruptions possible under the Load Interruption Contract depending on the interruption duration and the warning time:

- Type A. Maximum interruption time: 12 hours Minimum warning time: 16 hours
- Type B. Maximum interruption time: 6 hours Minimum warning time: 6 hours
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

- Type C. Maximum interruption time: 3 hours Minimum warning time: 1 hour
- Type D. Maximum interruption time: 45 minutes Minimum warning time: 5 minutes

Under the Load Interruption Contract, the maximum number of interruptions that can be requested by the System Operator are as follows:
  - 1 per day (12 hours maximum per day)
  - 5 per week (60 hours per week)
  - 120 hours per month
  - 240 hours per year.

Customers are permitted to refuse up to three interruption orders per year. If they have more than three refusals, customers are compelled to return the discount already invoiced which can comprise a large amount of money.

The Load Interruption Contract includes the following provisions:
- Tariff: Hourly Power Tariff or High Voltage General Power Tariff;
- Billing mode;
- Contracted demand level for each period in MW (Pc);
- Maximum demand level during interruption in MW (Pmaxi);
- Interruptible load offered in MW (Pof); this is the difference between the contracted demand level for each period (Pc) and the maximum demand level during the interruption (Pmaxi);
- Hourly discrimination mode;
- Interruption types chosen;
- Following year energy consumption forecast;
- Discount: this is an annual discount expressed as a percentage of the total electricity bill invoiced monthly, and is proportional to the base consumption and the interruptible load offered.

For example, a customer with 5,400 MW of contracted power, all of it interruptible (ie zero consumption during the interruption period) may receive a discount of EUR 433,658:

**Electricity cost without any discounts:** EUR 1,717,798  
**Interruptibility discount:** EUR 433,658  
**Total annual bill:** EUR 1,284,140

Note that this is a rough estimate only of the amounts payable; in practice the discount may be a different figure because there is uncertainty in calculating the discount. It is calculated as the difference between the same tariffs with and without discount and this is not a realistic hypothesis. If customers had no discounts available on their bills, they would probably select another kind of tariff.
RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
</tr>
</tbody>
</table>

Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral

| 38,067 MW | 1,274 MW | 3 hours | 1,272 MW | 3816 MWh |

HOW LOAD REDUCTION WAS MEASURED

Interval meter. 5 minute intervals.

RESULTS ACHIEVED

In 2005, 187 customers opted for the Load Interruption Contract. The total interruptible load offered by these customers under the Load Interruption Contract was 4,656 MW in high season. However, the system operator considered that the interruptible power available in real time was 80% of that amount (3,700 MW). Maximum interruptible power is calculated from contracted power data, but customers are not usually consuming the contracted power in peak periods, when interruptible capacity may be required by the operator.

An interruption order was sent by the System Operator on 21 June 2005. The order to interrupt load was sent to 97 clients and 84 (87%) responded by reducing load. The Type C interruption order was sent at 10:15 am and the interruption period went from 11:15 am to 2:15 pm. The load reduction achieved through this interruption was 1,274 MW and the energy saving was 3,816 MWh (see Figure IL01/1, page 93).

CONFIDENCE LEVEL IN ACHIEVING RESULTS

The overall confidence level regarding achieved results may be considered to be high. However, responses from contracted customers are not assured as they are permitted to refuse up to three interruption orders per year. Another factor which reduces the confidence level is the possibility of failure of the communication system. When the interruption order was sent on 21 June 2005, four customers' communication systems failed (4%) and they did not receive the load interruption order.

REPEATABILITY OF RESULTS

On 21 June 2005, the Load Interruption Contract was applied fairly well and system load was significantly reduced.

TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Depends on the warning time which can be 16 hours, 6 hours, 1 hour or 5 minutes.
WEATHER DEPENDENCE
Not applicable, except to the extent that customers' load levels are dependent on temperature.

AVOIED COSTS
On 21 June 2005, the weighted average marginal price of energy was EUR 80/MWh. REE estimated that the load interruption order achieved an energy saving of 3,816 MWh which resulted in a cost saving of EUR 305,280 for the system. However, this was not an accurate figure, as there were many factors affecting the price and there was uncertainty because REE did not know not know exactly what the energy consumption would have been without the load interruption order.

ACTUAL PROJECT COSTS
There are no costs for REE. Discounts to customers under the Load Interruption Contract are paid by all customers through the tariff as an operational cost.
OVERALL PROJECT EFFECTIVENESS

Prior to 2006, because of a lack of information about large industrial customers' load levels in real time, the Load Interruption Contract was not an accurate mechanism as an operational service for reducing load. The System Operator sent an order "blindly" without knowing the actual electricity consumption at that time by the customers under contract.

In real time, when interruption orders are sent to customers, they reduce their consumption to the level agreed in their contracts, at the time the interruption begins. However, the actual load reduction achieved on the transmission network depends on the customers' load levels just before the interruption begins. That information was not available to the System Operator at that time, and was provided by the customers only when the interruption is finished.

A new communication, execution and control system between the System Operator and large industrial customers for interruptible orders was implemented in 2006. This system provides data on customers' loads at the time of interruption and gives the System Operator more confidence about achieving specific levels of load reduction from the Load Interruption Contract.

CONTACTS
Carmen Rodriguez Villagarcia
DSM Department Manager
Red Eléctrica de Espana
Plaza de los Gaitanes 177
La Moraleja
28109 Madrid
SPAIN
Phone + 34 1 650 8500
Fax: + 34 1 650 4542
Email: carmenrodri@ree.es

SOURCES
Ministerial Decree January 12th 1995
REE Interruption Reports

CASE STUDY PREPARATION
Name: Beatriz Gómez   Email: bgomez@ree.es
CASE STUDY 07  
CALIFORNIA ENERGY COOPERATIVES - USA

IEADSM Task XV Case Study No IL05  
Last updated 26 August 2005  
Location of Project San Francisco, USA (currently)  
Year Project Implemented The Energy Coalition was formed in 1981 and is still continuing

Year Project Completed  
Name of Project Proponent The Energy Coalition  
Name of Project Implementor The Energy Coalition  
Type of Project Implementor Third party aggregator  
Purpose of Project Provision of network operational services  
Timing of Project Pre contingency  
Focus of Project Network capacity limitations  
Project Objective Peak load reduction  
Project Target Network region  
DSM Measure(s) Used Interruptible loads  
Specific Technology Used  
Market Segments Addressed Commercial and small industrial customers  
Large industrial customers

DRIVERS FOR PROJECT
The Energy Coalition is a non-profit organisation that was originally formed in 1981 to pool together major end-users into ‘energy cooperatives’. Members of these cooperatives worked together to provide load management services to electricity utilities.

The Energy Coalition coordinated the energy use of large commercial and industrial customers and brokered this service to Southern California Edison and other utilities. The Coalition was created by and for large commercial and industrial energy users who wanted to act responsibly to shed load at times of utility capacity constraints through sophisticated management of their facilities. By coordinating their efforts, these users could respond collectively with a high degree of individual flexibility and reliability to calls by the utility to shed load.

When the Energy Coalition was originally established, there was a shortage of generation and network capacity in southern California. During the late 1980s, the situation changed from a shortage to an excess of capacity and in the 1990s interest in the original energy cooperatives faded away. However, interest was revived during the California energy crisis in the early 2000s.

DESCRIPTION OF PROJECT
Original Energy Cooperatives Program
The first energy cooperative, built under the auspices of John Phillips’ Engineering Supervision Company, was developed in 1975 for the Los Angeles Department of Water and Power and was supported by the federal Energy and Research Development Agency. The California Energy Coalition – as The Energy Coalition was originally formally registered – was developed in 1981 when Southern California Edison sought John Phillips’ expertise to develop energy cooperatives in Orange
County. The Energy Coalition became the facilitator of the energy cooperatives process and worked with large users to develop load-shedding strategies that were sensitive to times of day, times of year, and special processes.

The Energy Coalition also built energy cooperatives for Pacific Gas & Electric, Long Island Lighting Company, Boston Edison, Commonwealth Edison, and in Sweden.

As members of an energy cooperative, large commercial and industrial customers worked together to shed loads at critical peak times when called upon by their serving utilities. Each member was paid to do so at a cost far less than the utility would have to pay to buy electricity generation peaking capacity. By bringing together end-users and by pooling customers with highly diverse load profiles, energy cooperatives used ‘smart’ load management strategies with the least impact on participants. This allowed for customer control and flexibility in load curtailment. For example a cooperative member who undertook critical energy-using processes that would otherwise prohibit them from participating in load curtailment programs could participate in an energy cooperative because, when necessary, their contribution could be provided by another member.

Energy cooperatives were based on computer networks which continuously monitored the individual and collective energy use and load reductions of large users and provided a system for dispatching load reduction capacity. A central computer located at the cooperative's headquarters linked each member of the cooperative to the utility control centre. When the utility requested a load curtailment, the central system evaluated the proportionate load reduction required from each cooperative member to fulfill the utility's requirement. The load reduction ‘game plan’ (or strategy) was then defined, and each member was advised of their respective targets. The central system monitored each member’s load reduction path to assure compliance. If a particular member could not meet their target, the system automatically reallocated that load reduction to other members based on pre-existing priority agreements. In this way, the energy cooperative met its load reduction obligations expediently and with minimal impact on its members.

During a load curtailment, the utility had no information about which cooperative members were providing what levels of load reductions. It was the responsibility of the cooperative to get members to ‘ramp down’ their power consumption to firm service levels, and to organise compensating load reductions by other members for members who could not achieve their targets.

In the original energy cooperative set up in 1982, The Energy Coalition established a contractual 15 year agreement with Southern California Edison (SCE) for load management capabilities. The Coalition was paid an incentive for every kilowatt of peak demand that the Coalition could reliably reduce to the firm (or minimum) service level. Of that fee, the Coalition retained 15% for its management and 5% to enhance its capabilities. The Coalition then wrote cheques to its members based on their agreed prorated share of the overall capability. On average, members agreed to achieve a load reduction of 10% up to fifteen times a year for periods of up to six hours. If, by compensating for another member, a member exceeded their agreed level of load reduction, they received a prorated share of the resulting incentives.
The original agreement with SCE did not limit the size of the first cooperative. However, by 1986 when the Coalition wanted to add two additional cooperatives, the capacity situation in Southern California had changed from a shortage to an excess. Consequently, SCE was far more cautious about the energy cooperative approach and limited the size of the additional cooperatives as well as their geographic distribution. Each of the two new cooperatives were limited to a maximum of 10 MW of curtailable capacity. In addition, each member had to be located within a ten-mile radius of a central point mutually established by SCE and the Coalition.

Business Energy Coalition Pilot Program

After the decline of interest in energy cooperatives in the 1990s, interest was revived during the California energy crisis in the early 2000s, particularly as a method of providing short-term network operational services.

The Business Energy Coalition Pilot Program is an initiative between Pacific Gas & Electric (PG&E) and major San Francisco business and civic leaders, facilitated by The Energy Coalition, to demonstrate group load curtailment of 10 MW from the group’s coincident peak demand. The one-year test project will recruit San Francisco’s 200 biggest energy users, representing 304 MW of demand.

The pilot program is operating from 1 July through 31 December 2005. If it is successful, the Business Energy Coalition will seek California Public Utilities Commission authorization for long-term agreements.

The pilot program incorporates Day-Ahead and Same-Day program objectives. Group curtailment will be triggered to alleviate state, regional, local or feeder-level electricity network constraints.

Eligibility

PG&E’s Bundled, Direct Access, and Wholesale customers within the City of San Francisco are eligible to participate in the pilot program. Participants must be able to reduce their demand by a minimum of 200 kW. Customers with a blend of cogeneration and utility services or customers participating in demand response programs will be evaluated on a case-by-case basis. Customers with cogeneration will be eligible based on their utility demand. Non-Firm and Base Interruptible Program customers are not eligible to participate. Standby or back-up generators cannot contribute to demand savings during a program event.

Methodology

An engineering assessment provided and paid for by The Energy Coalition, will be conducted at each participant’s facility to identify load that can be curtailed during program events. An engineer will meet with facility operating personnel and help them develop a series of load-shedding protocols, all of which will be tested on a non-critical day.

The evaluation will also determine each member’s Firm Service Level (FSL). During a program event, each member will reduce its load to the prescribed Firm Service Level. The load reduction will be the delta between each facility’s annual average peak demand for the three previous years and the Firm Service Level.
**Verification and System Tests**
In late June 2005, the Business Energy Coalition conducted a system test to assure program delivery. If there are no actual curtailments, two-hour tests will be conducted every other month throughout the pilot program period.

**Notification Time**
Business Energy Coalition members will be given as much advance notice as possible ranging from Day-Ahead to a minimum of an Hour-Ahead. Customers will be notified by pager, email, fax, and phone.

**Curtailment Frequency Limits**
Maximum frequencies:
- Five hours per program event; one program event per day
- Five program events per month; twenty-five hours per month
- One hundred hours throughout the pilot period

**Curtailment Window**
12 pm – 8 pm, Monday – Friday, excluding holidays.

**Incentive Payments**
Each member will receive a capacity payment of $50/kW annually. A payment of 50% will be provided at the end of October 2005, with the balance distributed in January 2006. The average payment for curtailment will be USD 85 per kilowatt-hour.

**Non-Performance**
Penalties are assessed on the group’s load curtailment level rather than individual performance. If the group fails to meet the group’s established FSL, the group will draw from its Shortfall Reserve Fund (supported with an additional USD25/kW) to pay Independent System Operator charges and imbalance penalties. Any outstanding balance in the Shortfall Reserve Fund will be proportionately distributed to members at the completion of the pilot program or carried over for an extended program.

**Triggers**
The program will be triggered for actual or forecasted statewide, regional Northern California, Area 1, or local circuit congestion, failures and shortages throughout the pilot program period. Specifically, the Business Energy Coalition’s group load curtailment may be triggered when any of the following occur:
- California Independent System Operator calls a Stage 2 emergency
- California Independent System Operator declares that PG&E’s spinning reserves are below 7%
- Forecasted or actual San Francisco temperatures exceeds 78 degrees Fahrenheit
- PG&E declares a localized system emergency
- California Independent System Operator’s total forecasted load is greater than 43,000 MW
RESULTS ACHIEVED

Results for the energy cooperatives established by The Energy Coalition for Southern California Edison (SCE) from 1982, when the first cooperative was formed, to 1991 were published in a report by the Results Center (see Sources below).

Each summer month the Coalition set a coincident peak level for each energy cooperative. This peak level was measured during SCE’s on-peak tariff period, which in 1991 was noon to 6pm every Monday through Friday. (This period was subject to change.) Whether there was a load curtailment or not, SCE paid the margin between each energy cooperative’s monthly coincident peak demand, measured every five minutes, and the firm service level for load reductions established for each cooperative on 1 May, prior to the summer, each year.

Between 1982 and 1991, the energy cooperatives were able to provide SCE with between 3.9 MW and 18.2 MW of peak load reduction capacity. In 1991, an unusually cool summer, the cooperatives were able to provide 14.0 MW. However, because SCE was in a situation of excess capacity, it did not call a load curtailment by the energy cooperatives between 1983 and 1991.

ACTUAL PROJECT COSTS

There are two types of cost for energy cooperatives. First, are the startup costs which are not included in the Results Center report. Second, are the utility payments to the energy cooperatives which are detailed below.

In 1991, SCE paid The Energy Coalition USD 6.90/kW per month for the amount of dispatchable load reduction the Coalition had available for the four months of summer. Whether there was a curtailment or not, the utility paid the Coalition USD 27.60/kW/year (USD 6.90 x 4 months) for the ability to curtail power to firm service levels. In 1991, SCE paid the Coalition a total of USD 364,899. for this service. From 1982 to 1991, SCE paid a total of USD 4,095,301 (1990$).

Prior to 1988, the formula for payments was slightly different and SCE paid for peaking load reduction capacity for the winter as well. The Coalition’s members were paid USD 2.08/kW/month for the eight winter months, plus USD 4.16/kW/month for the four summer months. This gave a grand total of USD 33.28/kW/year.

If an energy cooperative could not meet its aggregate firm service level it was penalised four times the payment charge, a penalty of USD 27.60/kW in 1991. Whichever member failed to meet its firm service level was responsible for the shortfall. Other members had the opportunity to make up the shortfall and avoid the penalty.

Between 1982 and 1991, SCE paid the Coalition a total of USD 275/kW for dispatchable load reduction. This compares with costs at that time of USD 300 to 700/kW for electricity generation peaking plant (usually gas turbines).
CONTACTS
The Energy Coalition
15615 Alton Parkway, Suite 245
Irvine, California 92618
Phone (949) 701-4646
Fax (949) 701-4644
contact@energycoalition.org

SOURCES
The Energy Coalition web site at: http://www.energycoalition.org


CASE STUDY PREPARATION
Name: David Crossley   Email: crossley@efa.com.au
CASE STUDY 08
OLYMPIC PENINSULA NON-WIRES SOLUTIONS PILOT PROJECTS AND GRIDWISE DEMONSTRATION - USA

IEADSM Task XV Case Study No: IP04
Last updated: 30 August 2005

Location of Project: East side of the Olympic Peninsula, north-western Washington State, USA

Year Project Implemented: 2004

Name of Project Proponent: Bonneville Power Authority (BPA)
Name of Project Implementor: BPA & Pacific Northwest National Laboratory

Type of Project Implementor: Transmission utility

State or federal government agency

Purpose of Project: Deferral of network augmentation

Timing of Project: Pre contingency

Focus of Project: Network capacity limitations

Project Objective: Peak load reduction

Project Target: Network region

DSM Measure(s) Used: Standby generation
Direct load control
Other short-term demand response
Energy efficiency
Other: Grid-Friendly™ appliances

Specific Technology Used:

Market Segments Addressed: Residential customers
Commercial and small industrial customers
Large industrial customers

DRIVERS FOR PROJECT

The Bonneville Power Administration (BPA) owns and operates 75% of the Pacific Northwest’s electricity transmission system that includes more than 15,000 miles of high-voltage transmission lines and 285 substations. At peak usage, the system transports about 30,000 MW of electricity to customers in Oregon, Washington, Idaho and Montana, as well as to parts of Wyoming, Nevada, Utah and California.

In 2001, BPA started considering measures other than building new transmission lines to address load growth, constraints and congestion on the transmission system. Currently, BPA, along with others in the region, is exploring “non-wires solutions” as a way to defer large construction projects (see Figure IP04/1, page 102).

BPA defines non-wires solutions as a broad array of alternatives, including demand response, distributed generation, energy efficiency measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. BPA and its consultants have developed a screening process and checklist to evaluate a transmission problem area to determine whether it is a candidate for a non-wires solution.
The Olympic Peninsula has received particular attention since it is an environmentally sensitive area with increasing demand for electricity and limited transmission capacity. The capacity of the transmission lines on the Peninsula may become inadequate as early as December 2007, if there is a forced outage of one line during peak periods of cold weather. A significant transmission construction project, including a new 20-mile 230-kV line, is being contemplated on the Peninsula.

BPA is carrying out several pilot projects to determine whether it is possible to use non-wire solutions to defer the transmission construction project. A peak load reduction of 50 MW is required to achieve a five year deferral. All projects must pass the total resource cost test before they can be implemented.

DESCRIPTION OF PROJECT

Non-Wires Solutions Pilot Projects

The following non-wires solutions pilot projects are being carried out on the Olympic Peninsula:

- direct load control;
- demand response;
- voluntary load curtailments;
- networked distributed generation;
- energy efficiency.
Direct Load Control

The overall target for direct load control on the Olympic Peninsula is 20 MW.

The objectives of the pilot phase of the direct load control project are to demonstrate the reliability and technical feasibility and measure the peak load reduction impacts of direct load control.

To participate in the pilot phase, residential customers must have an electric water heater and heat pump, forced air furnace or baseboard space heating. The pilot phase aims to obtain 5 MW (2500 sites X 2kW) of curtailable loads in the residential sector by 1 December 2005 from one distribution utility or a combination of utilities.

Direct load control will be accomplished through the use of a one-way radio pager network linked to a direct load control unit located in the dwelling (see Figure IP04/2). The control unit communicates with appliances though power line carrier signals. Controlled end-uses include water heaters, pool pumps and space heating.

Demand Response

The target for demand response on the Olympic Peninsula is 16 MW.

The objectives of the pilot phase of the demand response project are:

- to demonstrate the reliability and technical feasibility and measure the peak load reduction impacts of demand response;
- to use incentives to test the value proposition of demand response for customers; and
• to test the use of Grid-Friendly™ appliance concepts, hardware and responses to automatically reduce load in response to stress on the grid.

To participate in the pilot phase of the demand response project, residential customers must have an electric water heater, heat pump or forced air furnace, a minimum of three people in the dwelling, and a fibre or cable high speed internet connection.

The pilot phase aims to install 250 two-way internet gateways in the residential sector (see Figure IP04/3). The gateways enable automatic control of space heating, air conditioning, water heating and pool pumps in participating dwellings. The gateways also measure the load from individual end-uses in the dwelling.

![Figure IP04/3. Olympic Peninsula Demand Response System](image_url)

Demand response will be accomplished through the use of two-way broadband to communicate with the internet gateways. Customers can use the internet to set price levels at which automatic load switching occurs and also to override the automatic settings. This will enable customers to lower energy use and reduce electricity costs.

In addition, 250 Grid-Friendly™ appliances (200 clothes dryers and 50 water heaters) will be installed in 200 participating dwellings. Controllers installed in each Grid-Friendly™ appliance sense frequency disturbances in the electricity network and control the appliances to act as spinning reserve – no communications technology is required beyond the network itself.

The Grid-Friendly™ appliance controller developed at Pacific Northwest National Laboratory is a simple computer chip that senses network conditions by monitoring
the frequency of the system and provides automatic demand response in times of disruption. The controller can be installed in appliances that regularly cycle on and off during normal use, so that consumers do not notice when the Grid-Friendly™ device is in operation.

Grid-Friendly™ appliances allow customers to become an integral part of electricity network operations. Grid-Friendly™ controllers can be programmed to autonomously react in fractions of a second when a disturbance is detected. Demand can be rebalanced to match available supply almost instantaneously (within a half-second). This is an improvement over the approximately 30 seconds it currently takes for power plants kept on standby to come up to speed. Grid-Friendly™ controllers can also be programmed to delay restart instead of all coming on at once after a power outage.

**Voluntary Load Curtailments**

BPA operates a Demand Exchange (DEMX) program that provides commercial and industrial customers with the ability to curtail their load during system emergencies and volatile market conditions.

Under the DEMX program, BPA works with customers to define their load curtailment capability and determine the benefits of participation. DEMX aggregates customers' curtailment potential and represents the aggregated load in the wholesale energy market as a reliability option. DEMX has built an internet-based auction site where participants are alerted to hourly, one day-, and two day-ahead price signals associated with peak load events, and are able to post their willingness to participate at a set price.

In March 2004, BPA ran a successful test using DEMX to reduce congestion on transmission lines on the Olympic Peninsula. A local utility, two paper manufacturing companies and the US Navy voluntarily reduced their transmission loads during a simulated period of severe weather and critical peak demand. The test occurred over four days. During the test, BPA posted an hourly price per megawatt, giving test participants the chance to accept, reject or counter the offer. Participants then bid to reduce their demand by using backup generation or by shifting load to other hours. BPA was able to purchase an average of 22 MW of peak demand reduction during each hour of the simulated event. This is about one year's load growth on the Olympic Peninsula.

**Networked Distributed Generation**

The target for distributed generation on the Olympic Peninsula is 4 MW. This will be achieved with 12 units in 10 locations. All units have been identified.

In the pilot phase of the distributed generation project, backup generators will be used at one commercial and one industrial site:

- Sequim Marine Sciences Lab - 0.5 MW backup generators for load shed and transactive control demand response integrated with the generators;
- Port Angeles municipal water supply system - 0.9 MW backup generators in parallel with 0.9 MW demand response from pumps.
Energy Efficiency

The target for energy efficiency on the Olympic Peninsula is 15 MW.

As a general policy, BPA ensures development of all cost-effective energy efficiency in the electrical loads BPA serves across the Pacific Northwest. BPA treats energy efficiency as a resource and defines goals in terms of megawatts of energy efficiency acquired. The bulk of the energy efficiency acquired by BPA is pursued and achieved at the local level in association with local distribution utilities.

BPA will apply these general principles to acquiring peak load reductions on the Olympic Peninsula through energy efficiency programs across the residential, commercial and industrial sectors developed in association with local distribution utilities.

Olympic Peninsula GridWise Demonstration

The demand response, voluntary load curtailment and distributed generation pilot projects on the Olympic Peninsula will be aggregated by Pacific Northwest National Laboratory into a demonstration of how a future electricity network might function. This demonstration is part of a project of the United States Department of Energy known as GridWise.

The GridWise Project

The GridWise project is intended to demonstrate how a modernized electric infrastructure framework with open but secure system architecture, communication techniques, and related standards employed throughout the electricity network can provide value and choices to electricity consumers.

Gridwise envisages a future electric system built upon the fundamental premise that information technology will profoundly transform the planning and operation of electricity networks. Information technology will form a "nervous system" that integrates new distributed technologies—demand response appliances, distributed generation, and storage—with traditional generation, transmission, and distribution assets to share responsibility for managing the network as a collaborative "society" of devices.

Olympic Peninsula GridWise Demonstration

The Olympic Peninsula GridWise demonstration involves testing a system, not just one technology. The intent of the demonstration is to illustrate how a future GridWise electricity network can operate and explore key issues associated with that operation. Field resources, operating with all the associated real world operating challenges, will be dispersed throughout the Olympic Peninsula on various elements of the area’s distribution system.

Objectives

The objectives for the Olympic Peninsula GridWise demonstration include:

- to illustrate how the future power grid envisioned by GridWise will function in the next decade;
- to show how a common communications framework can provide economic dispatch of multiple types of resources, integrating them to provide multiple benefits;
- to implement “real-time” economic dispatch through communication of market-like incentives to obtain voluntary, collaborative response from customers;
to develop an understanding of how multiple resources perform individually and when interacting in near real-time to meet common objectives;

• to understand how economic structures influence the participation of multiple resources;

• to achieve multiple benefits at various levels of the electricity network, including lower generation and wholesale costs, reduced transmission congestion, improved distribution asset utilization and avoided capacity expansion, and better ancillary services and network stability.

Technical Approach
The technical approach for the Olympic Peninsula Gridwise demonstration includes:

• real, in-the-field, operating distributed resources – both distributed generation and demand response;

• a virtual, near real-time market operating environment focussed on residential customers backed with real cash consequences to participants;

• provision of incentives to operate the resources in collaboration with the network operator;

• use of computer software to create, in cooperation with local distribution utilities, a "virtual" distribution feeder, as if the non-wires resources involved were literally co-located on a single feeder;

• real-time and historical display of resource operations and costs.

Virtual Feeder
Real non-wires assets will be integrated into a “virtual” distribution environment and will appear to perform as resources on a capacity-constrained feeder. Actual measured substation feeder loads from the SCADA system on the Olympic Peninsula will be used as the baseline load. The assets will be managed to an arbitrary limit below the actual physical capacity. A shadow market will dispatch project resources to limit demand below the level of constraint. A "virtual" physical environment with commercially-available power systems analysis tools will simulate impacts on power flows, voltages, etc.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>2,750</td>
<td></td>
<td></td>
<td></td>
<td>4</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Peak Load Reduction</th>
<th>Duration of Peak Load Reduction</th>
<th>Overall Load Reduction</th>
<th>Energy Savings</th>
<th>Network Augmentation Deferral</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,150 MW</td>
<td>50 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
CONTACTS

Brian Silverstein  
Vice President, Operations and Planning  
Bonneville Power Administration  
Transmission Business Line  
PO Box 61409  
Vancouver, WA 98666  
USA  
Email: blsilverstein@bpa.gov

Mike Weedall  
Vice President, Energy Efficiency  
Bonneville Power Administration  
PO Box 3621  
Portland OR 97208-3621  
USA

Pacific Northwest National Laboratory  
902 Battelle Boulevard  
P.O Box 999, MSIN K5-20  
Richland, WA 99352

Olympic Peninsula GridWise Demo:  
Rob Pratt  
Pacific Northwest National Laboratory  
Email: rob.pratt@pnl.gov

Grid Friendly Appliance Demo:  
Donald Hammerstrom, Ph.D.  
Pacific Northwest National Laboratory  
Email: donald.hammerstrom@pnl.gov

SOURCES

Website of the Bonneville Power Authority Non-Wires Solutions Roundtable at:  
http://www.transmission.bpa.gov/PlanProj/Non-Wires_Round_Table

Pacific Northwest National Laboratory GridWise website at:  
http://gridwise.pnl.gov/


**CASE STUDY PREPARATION**

**Name:** David Crossley  **Email:** crossley@efa.com.au
CASE STUDY 09

LIPAEDGE DIRECT LOAD CONTROL PROGRAM - USA

IEADSM Task XV Case Study No: DC03
Last updated: 2 March 2006
Location of Project: Long Island, New York, USA
Year Project Implemented: 2001
Year Project Completed: 2003
Name of Project Proponent: Long Island Power Authority (LIPA)
Name of Project Implementor: Long Island Power Authority (LIPA)
Type of Project Implementor: Distribution utility
Purpose of Project: Provision of network operational services
Timing of Project: Pre contingency
Focus of Project: Network capacity limitations
Project Objective: Peak load reduction
Project Target: Whole network
DSM Measure(s) Used: Interruptible loads
Direct load control
Specific Technology Used: Carrier Comfort Choice Thermostats
Market Segments Addressed: Residential customers
Commercial and small industrial customers

DRIVERS FOR PROJECT
To reduce peak demand when generation is insufficient or there are network constraints.

DESCRIPTION OF PROJECT
Long Island Power Authority (LIPA) developed the LIPAedge program to use central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction. The program commenced in early 2001 and is still operating in late 2005. However, from 31 July 2003 the program was closed to new participants because LIPA has enough air conditioner load under direct load control.

Technology
The LIPAedge program uses the programmable ComfortChoice thermostat (see Figure DC03/1, page 111). This was designed by the Carrier Corporation with associated communication infrastructure provided by Silicon Energy to provide emergency peak reduction for utilities.

The system operator uses an internet-based system provided by Silicon Energy to control a demand-side resource comprising about 20,000 thermostat-controlled air conditioners. Skytel two-way pagers are used to transmit a curtailment order to the thermostat and to receive acknowledgment and monitoring information. One or more pager signals are generated and transferred to the SkyTel pager network (see Figure DC03/2, page 111). Commands go via satellite to pager towers, where they are broadcast to the thermostats. The thermostats take immediate action or adjust their schedules for future action, depending on what the system operator ordered. The
thermostats log the order and respond via pager, enabling LIPA to monitor the response to the event. The thermostats also collect data every minute on temperature, set point, and power consumption (hourly duty cycle). They retain this information as hourly averages and report it to the utility. The thermostat itself holds 7 days of hourly data.

![Figure DC03/1. ComfortChoice Thermostat Used in the LIPAedge Program](image1)

For a summer load curtailment, the system operator might send a command at 9:00 am directing all thermostats to move their set points up 4 degrees, starting at 2:00 pm and ending at 6:00 pm. Alternatively, the system operator could send a command directing all thermostats to completely curtail immediately. The command would be

![Figure DC03/2. The Carrier/Silicon Energy Direct Load Control System](image2)
received and acted upon by all loads, providing full response within about 90 seconds. This is far faster than generator response, which typically requires a 10-minute ramp time.

Thermostats can be addressed individually, in groups, or in total. This important advantage provides both flexibility and speed. System operator commands that are addressed to the entire resource are implemented through a single page that all thermostats receive. Similarly, 15 subgroups can be addressed if response is required in a specific area to alleviate a transmission constraint. Thermostats can be addressed individually as well. This capability is useful for monitoring the performance of the system (each thermostat is checked weekly for a “heartbeat”).

The customer also receives benefits. The thermostat is fully programmable and remotely accessible, with all of the associated energy savings and convenience benefits. A web-based remote interface is provided for customer interaction. Customers can also override curtailment events. This feature appears to be important to gain customer acceptance and it probably increases the reliability benefit.

The system operator can block overrides if necessary. Typically, this is not done for demand curtailment events, but it may be useful for spinning reserve events.

Two-way paging communication enables the utility to monitor load performance both during response events and under normal conditions. Response from the thermostats is staggered over a time period set by the utility to avoid overwhelming the paging system. It typically requires 90 minutes for 20,000 thermostats to respond. Thus the system provides for performance monitoring but not in the 2 to 8-second intervals typical for large generators.

Communication is more reliable from the system operator to the thermostat than from the thermostat to the system operator. The pager tower has a 500-W transmitter, while the thermostat’s transmitter is only 1 W. The thermostat makes four attempts to report back if the pager tower fails to receive any of its signals. The thermostat continues to take control actions and respond to new commands even if return communication is lost. Hence the system is more reliable than would be indicated by the list of “failed” units generated by the "heartbeat" report. About 4% to 5% of the thermostats fail to report back.

The LIPAedge Program

The LIPAedge program is the largest residential direct load control program in the USA using two-way communication. Two-way communication allows LIPA to monitor capability and response. It also enables customers to control their individual thermostats via the Internet, a benefit that motivates participation.

The LIPAedge program is available for Residential Central Air Conditioning customers and Small Business customers, though the program is now closed to new participants. Customers who sign up to the LIPAedge program receive a ComfortChoice thermostat and installation free of charge. Customers also receive a one-time bonus payment of USD 25 (residential customers) or USD 50 (small commercial customers). During 2001, LIPAedge customers were offered an opportunity to earn a USD 20 cash reward for each LIPA customer referral they provided who installed a LIPAedge thermostat.
LiPAedge customers agree to have their central air conditioning system adjusted between the hours of 2 pm and 6 pm for a maximum of seven days throughout the four month summer season. Customers have access to a dedicated web page for their thermostat and are able to remotely change the set point of their air conditioner whenever they want.

LIPA initiates curtailment events by either increasing the set point on LIPAedge thermostats by 3 to 4 degrees, or by cycling air conditioner compressors off for a portion of each hour (see Figure DC03/3).

Customers can override curtailment messages sent to their thermostat, though LIPA encourages its customers not to override during a curtailment event. If the customer decides to override the curtailment, the change is recorded by the thermostat and a wireless message is then sent back to the central server.

Figure DC03/3. The Curtailment Process in the LiPAedge Program
RESULTS

<table>
<thead>
<tr>
<th></th>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load</td>
<td>20,400</td>
<td>3,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak Load Reduction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Duration of Peak Load Reduction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall Load Reduction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Savings</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Network Augmentation Deferral</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

HOW LOAD REDUCTION WAS MEASURED

Other. Thermostat reports hourly duty cycle.

RESULTS ACHIEVED

LIPA collected name-plate power consumption information on the air-conditioning equipment being controlled when it installed the ComfortChoice thermostats for the LIPAedge program. It also directly measured the power consumption of a subset of those loads to estimate the actual load of the aggregation. LIPA determined that the average capacity of residential air-conditioning units being controlled was 3.84 kW, while the average capacity of small commercial units was 6.38 kW. The total 23,400 individual loads had a peak capacity of 97.4 MW if all the units were on at 100% duty cycle.

LIPA monitored the performance of 400 units from 1 May 2002 through 29 September 2002. Hourly data were collected from each unit for duty cycle and facility temperature. Those data were used to estimate the performance of all 23,400 responsive loads. LIPA found that each controlled load provided an average of 1.06 kW of demand reduction (1.03 kW per residential air-conditioner and 1.35 kW per small commercial air-conditioner). LIPA expected 24.9 MW of peak reduction response from the full 23,400 controlled air-conditioners.

LIPA tested the actual performance of the system to reduce energy demand during peak hours on three days during the summer of 2002. It also monitored performance on seven other days to provide baseline data. The results are shown in Tables DC03/1 and DC03/2, page 115. Table DC03/2 shows that an increasing number of residential thermostats were overridden as the 14 August curtailment event continued; the proportion of units overridden increased from 5.7% at 3 pm to 20.8% at 6 pm.
Table DC03/1. Performance During Curtailment Events in Summer 2002

<table>
<thead>
<tr>
<th></th>
<th>3 July</th>
<th>30 July</th>
<th>14 August</th>
</tr>
</thead>
<tbody>
<tr>
<td>Participation (units)</td>
<td>15,943</td>
<td>17,051</td>
<td>17,474</td>
</tr>
<tr>
<td>Load reduction at 5 pm (MW)</td>
<td>15,852</td>
<td>16,076</td>
<td>16,273</td>
</tr>
<tr>
<td>Total energy saving over curtailment event (MWh)</td>
<td>65,883</td>
<td>66,493</td>
<td>67,463</td>
</tr>
</tbody>
</table>

Table DC03/2. Performance of Residential Units on 14 August 2002

<table>
<thead>
<tr>
<th>Hour ending</th>
<th>Units overridden at hour end</th>
<th>Adjusted net kW reduction per unit</th>
<th>Total kW reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 pm</td>
<td>5.7%</td>
<td>1.05</td>
<td>16,119</td>
</tr>
<tr>
<td>4 pm</td>
<td>11.5%</td>
<td>0.98</td>
<td>14,942</td>
</tr>
<tr>
<td>5 pm</td>
<td>17.2%</td>
<td>0.92</td>
<td>14,060</td>
</tr>
<tr>
<td>6 pm</td>
<td>20.8%</td>
<td>0.78</td>
<td>11,883</td>
</tr>
</tbody>
</table>

REPEATABILITY OF RESULTS
Results depend upon ambient temperature, day of the week, and time of day. Once characterized they are repeatable.

TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED
90 seconds.

WEATHER DEPENDENCE
Because this program controlled air conditioners, the response was highly dependent on temperature.

AVOIED COSTS
New peaking generation costs of approximately USD 500/kW.

ACTUAL PROJECT COSTS
The LIPAedge program cost was USD 515 per residential customer and USD 545 per commercial customer. This yielded a combined average cost of USD 487/kW of demand reduction. LIPA paid all costs.

CONTACTS
Michael Marks
Applied Energy Group
490 Wheeler Road, Suite 100
Hauppauge, NY, USA, 11788
+ 1 631-434-1414 ext 12
Email: mmarks@appliedenergygroup.com
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

SOURCES
LIPAedge program website at: http://www.lipaedge.com/index.asp
Carrier website at: http://www.mytstat.com


CASE STUDY PREPARATION
Name: Brendan Kirby / David Crossley   Email: kirbybj@ornl.gov / crossley@efa.com.au
### CASE STUDY 10
**MAD RIVER VALLEY PROJECT - USA**

<table>
<thead>
<tr>
<th>IEADSM Task XV Case Study No</th>
<th>LS04</th>
</tr>
</thead>
<tbody>
<tr>
<td>Last updated</td>
<td>26 August 2005</td>
</tr>
<tr>
<td>Location of Project</td>
<td>Warren, Vermont, USA</td>
</tr>
<tr>
<td>Year Project Implemented</td>
<td>1989</td>
</tr>
<tr>
<td>Year Project Completed</td>
<td>1996</td>
</tr>
<tr>
<td>Name of Project Proponent</td>
<td>Green Mountain Power/Sugarbush Resort</td>
</tr>
<tr>
<td>Name of Project Implementor</td>
<td>Sugarbush Resort</td>
</tr>
<tr>
<td>Type of Project Implementor</td>
<td>End-use customer(s)</td>
</tr>
<tr>
<td>Purpose of Project</td>
<td>Deferral of network augmentation</td>
</tr>
<tr>
<td>Timing of Project</td>
<td>Pre contingency</td>
</tr>
<tr>
<td>Focus of Project</td>
<td>Network capacity limitations</td>
</tr>
<tr>
<td>Project Objective</td>
<td>Peak load reduction</td>
</tr>
<tr>
<td>Project Target</td>
<td>Network element</td>
</tr>
<tr>
<td>DSM Measure(s) Used</td>
<td>Interruptible loads, Energy efficiency, Fuel substitution</td>
</tr>
<tr>
<td>Specific Technology Used</td>
<td>Conversion of electric hot water heaters and electric space heating in buildings to alternative fuels plus other technologies</td>
</tr>
<tr>
<td>Market Segments Addressed</td>
<td>Residential customers, Commercial and small industrial customers</td>
</tr>
</tbody>
</table>

**DRIVERS FOR PROJECT**

The Mad River Valley is a mountain/valley region in central Vermont which is home to growing resort developments associated with three ski areas, two operated by the Sugarbush Resort. The Valley is served by Green Mountain Power (GMP) by way of a 34.5kV distribution line extending in a long "U" down one valley, across a ridge and back along the highway on the other side of the ridge. Sugarbush Resort, the largest load on the line, is located at the base of the "U", its weakest point.

In 1989, the ski area was engaged in a major expansion project, and informed GMP that it was planning to increase its load by up to 15 MW to accommodate a new hotel and conference centre and significant new snowmaking equipment.

The reliable capacity of the 34.5 kV line was 30 MW, and a 15 MW increase in load at that location would impair reliability of the line or require an upgrade. Studies by GMP concluded that the appropriate upgrade would be a parallel 34.5kV line down the Valley, at a cost of at least USD 5 million.

The initial request by the customer, Sugarbush Resort, was for an upgrade by GMP, at GMP’s expense. However, under Vermont’s line extension rules, it was likely that a major portion of the cost of the upgrade would be charged to the customer. Neither the customer nor GMP wanted to pay for the line.
DESCRIPTION OF PROJECT

The details of the project were negotiated among GMP, Sugarbush Resort, the Public Advocate, and later approved by state regulators.

The project had two major elements:

- a customer load management commitment;
- a targeted utility efficiency program in the Mad River Valley.

Under the customer load management commitment, Sugarbush Resort and GMP entered into a customer-managed interruptible contract, under which Sugarbush committed to ensure that load on the distribution line, as measured at the closest substation, would not exceed the safe 30 MW level. Sugarbush installed a real-time meter at its operations base, and telemetry to monitor total local load at the substation. Sugarbush committed to manage its resort and snowmaking operations so as to keep total local load at all times below 30 MW. In general, Sugarbush managed load to move snowmaking operations off the Valley’s winter peak hours, which are coincident with GMP’s and the state’s peak load hours. Unlike the other interruptible contracts for snowmaking in effect at most of Vermont’s ski areas, this contract required the customer to manage its own load while taking the load of all other customers on the substation into account. In addition to avoiding the cost of the power line upgrade, Sugarbush received a discount for the electricity it purchased.

The targeted utility efficiency program was a concentrated effort by GMP to improve energy efficiency and lower peak demand in the community. At the urging of the Public Advocate, GMP focused some of its DSM programs on the Mad River Valley. In 1995, GMP and Sugarbush Resort funded the Mad River Valley Energy Project, a pilot project which conducted free evaluations of customers’ energy consumption. Commercial and industrial users were targeted, although residential users were encouraged to participate. Over a period of 18 to 24 months, GMP delivered a variety of DSM measures across all customer classes. The largest savings came from numerous conversions of electric hot water heaters and electric space heating in buildings to alternative fuels, but many other measures were installed. The pilot project was completed in 1996.

RESULTS ACHIEVED

Figures from GMP show that electrical demand in the Mad River Valley rose from 3.4 MVA in 1966 to 22.0 MVA in 1989 (an average annual increase of 24%). Between 1989 and 1996 demand stabilised at approximately 22 MVA. This compares with a Vermont state-wide growth rate in demand of 2.1% per year.

One criticism of the Mad River Valley Energy Project is that GMP largely abandoned the follow-on DSM work once the network problem was resolved, and may have missed additional cost-effective efficiency opportunities. Consequently, a singular focus on network-driven DSM may lead to lost opportunities for other energy efficiency savings, if not combined with a broad program design for energy efficiency generally.

The cost-effective solution to this network problem came about only when it was clear that much of the cost of the network upgrade would be charged to the customer driving the need for it. If the cost of this upgrade had been smeared across GMP’s
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

tariffs, it is much less likely that GMP would, on its own, have negotiated the unique load management contract with the customer, regardless of its cost-effectiveness.

SOURCES


CASE STUDY PREPARATION

Name: David Crossley   Email: crossley@efa.com.au
CASE STUDY 11
PARADIP PORT SUBSTITUTION OF COOKING FUEL PROJECT - INDIA

IEADSM Task XV Case Study No FS03
Last updated 4 October 2008
Location of Project Paradip Port, on the Bay of Bengal in Orissa, India

Year Project Implemented
Year Project Completed
Name of Project Proponent Paradip Port Trust
Name of Project Implementor Paradip Port Trust
Type of Project Implementor Bulk purchase customer of GRIDCO and supplier of electricity to end-users

Purpose of Project Deferral of network augmentation
Timing of Project Pre contingency
Focus of Project Network capacity limitations
Project Objective Peak load reduction
Project Target Network element
DSM Measure(s) Used Fuel substitution
Specific Technology Used Substitution of LPG cooking stoves in place of electric stoves

Market Segments Addressed Residential customers

DRIVERS FOR PROJECT
The Paradip Port Substitution of Cooking Fuel Project was initiated and funded by the Paradip Port Trust.

The Trust was set up by the Government of India to administer the port of Paradip, an autonomous body under the Major Port Trusts Act, 1963. The Trust purchases electricity in bulk from the Grid Corporation of Orissa Limited (GRIDCO) and then supplies electricity directly to its employees for household use. The Trust supplied electricity to its employees at a subsidised average flat rate of INR132 per month and had to bear an annual loss of around INR31 million.

The objective of the Paradip Port Substitution of Cooking Fuel Project was to reduce system peak demand by introducing LPG as a domestic cooking fuel through replacing electric stoves used by Trust employees. The project was targeted at cooking in the residential sector because this activity comprised approximately 60% of the electrical usage in each household. Almost 90% of the 3,592 households in the residential facility provided by the Trust used electric stoves for cooking, adding 3 to 4 MW to the electricity demand.

The maximum contract demand of Paradip Port under its supply contract with GRIDCO was 7.5 MVA. The peak demand often reached 9 to 10 MVA, resulting in penalty charges. The industrial load did not exceed 4 MVA at any point in time but the domestic use exceeded the contract quantity by 2 to 3 MVA during peak periods. Because electric stoves were the largest contributors to the peak demand, replacing these with LPG cooking stoves would result in considerable electricity and cost savings.
DESCRIPTION OF PROJECT

The replacement package offered by the Paradip Port Trust included both stoves and LPG cylinders. An LPG cylinder bottling plant, with assured gas supplies from Paradip Port, was also established in the area to ensure an adequate supply of LPG cylinders.

The Trust offered its employees the following incentives to move from electric stoves to LPG stoves:

- 100% subsidy on purchase and installation of an LPG stove;
- 100% reimbursement of the cost of the LPG cylinder;
- reduction in the flat rate electricity tariff from INR132 to INR80 per month;
- a limit on electricity consumption under the flat rate tariff fixed at 108 kilowatt-hours per month; consumption above this limit to be charged at the full price of INR3.37 per kilowatt-hour.

As the two-part tariff was introduced, meters were installed to monitor the electricity consumption by individual households and enable accurate charging for electricity consumption.

The Paradip Port Trust was the main stakeholder responsible for the financing, procurement, implementation and monitoring of the project. The housing department of the Trust was responsible for the entire project. The major investment in the project was the procurement and installation of the LPG stoves and electric meters in individual households. The entire cost was born by the Trust and was recovered through electricity and cost savings.

The end-users in this project were employees of the Trust and thus directly connected to the project implementor. Therefore, it was relatively easy for the Trust to create awareness, and market and control the project. The Trust motivated the end-users in the stove replacement project through various awareness programs.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>2,874</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak Load</td>
<td>Peak Load Reduction</td>
<td>Duration of Peak Load Reduction</td>
<td>Overall Load Reduction</td>
<td>Energy Savings</td>
</tr>
<tr>
<td>3.2 MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
RESULTS ACHIEVED
The Paradip Port Trust replaced a total of 2,874 electric cooking stoves with LPG stoves. The morning peak was reduced by 2.3 MW and the evening peak by 3.2 MW. The project resulted in ongoing annual savings to the Trust of INR15 million.

ACTUAL PROJECT COSTS
The total implementation cost for the Paradip Port Substitution of Cooking Fuel Project was INR19.7 million. A detailed breakdown of the implementation cost is shown in Table FS03/1. The additional cost of running the project was identified as INR200,000 per year.

<table>
<thead>
<tr>
<th>Expenditure Item</th>
<th>Cost (INR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LPG gas stoves for 2,874 houses</td>
<td>3.4 million</td>
</tr>
<tr>
<td>Enrolment fees for 2,874 houses</td>
<td>2.9 million</td>
</tr>
<tr>
<td>Fire resistant panels in huts</td>
<td>1.3 million</td>
</tr>
<tr>
<td>Fire extinguishers for huts</td>
<td>1.0 million</td>
</tr>
<tr>
<td>Security cages and pipes for LPG cylinders</td>
<td>1.0 million</td>
</tr>
<tr>
<td>Electricity meters for 2,874 houses</td>
<td>9.0 million</td>
</tr>
<tr>
<td>Publicity and safety training</td>
<td>1.1 million</td>
</tr>
<tr>
<td><strong>Total implementation cost</strong></td>
<td><strong>19.7 million</strong></td>
</tr>
</tbody>
</table>

The entire cost was born by the Trust and was recovered through electricity and cost savings.

OVERALL PROJECT EFFECTIVENESS
The project was successful in replacing a total of 2,874 electric cooking stoves with LPG stoves. The morning peak was reduced by 2.3 MW and the evening peak by 3.2 MW. The project resulted in ongoing annual savings to the Paradip Port Trust of INR15 million.

CASE STUDY PREPARATION
Name: Balawant Joshi/David Crossley Email: balawant.joshi@abpsinfra.com
CASE STUDY 12
FRENCH RIVIERA DSM PROGRAM - FRANCE

IEADSM Task XV Case Study No: IP08
Last updated: 31 July 2006
Location of Project: Provence-Alpes-Côte d'Azur (PACA) region of France
Year Project Implemented: 2003
Name of Project Proponent: Préfecture des Alpes-Maritimes and Région Provence-Alpes-Côte d'Azur
Name of Project Implementor: Agence de l'Environnement et de la Maîtrise de l'Energie (ADEME), Région Provence-Alpes-Côte d'Azur and Electricité de France (EDF)
Type of Project Implementor: Distribution utility
Purpose of Project: Deferral of network augmentation
Timing of Project: Pre contingency
Focus of Project: Network capacity limitations
Project Objective: Peak load reduction
Overall load reduction
Project Target: Network region
DSM Measure(s) Used: Cogeneration
Other distributed generation
Energy efficiency
Specific Technology Used: Residential customers
Commercial and small industrial customers
Non-customer related (eg installation of additional generation not on a customer site)

DRIVERS FOR PROJECT

The Provence-Alpes-Côte d'Azur (PACA) region of France is supplied from Tavel near Avignon, via two 400 kV transmission lines - a southern line which goes to Broc-Carros via Néoules and a northern line which goes as far as Boutre. A 225 kV line completes the ring by connecting Boutre to Broc-Carros (Figure IP08/1, page 124).

Planning for the upgrading of the Boutre-Carros line to supply increasing load growth in the area commenced in 1983. The initial plan comprised double 400 kV lines on separate easements over 170 km in length. Six route options for the upgraded line were proposed. However, there was strong opposition to this project because the lines would pass through the classified scenic gorges of the Verdon Regional Park.
In 1994, a petition against all the route options collected 3 000 signatures. In January 1997, a seventh route option was proposed. In July and August, a petition was circulated supported by local governments in the area. The petition requested studies of alternatives to the line and 23 000 signatures were obtained, including 12% of tourists in the European Union. In November, the Department of the Environment established a public commission of inquiry into the Boutres-Carros line and the project was suspended.

In 2000, a decision was made on an alternative solution. This comprised:
- replacement of the existing 225 kV line by a single 400 kV line, 100 km in length, on the same easement;
- removal of an existing 150 kV line which accompanied the 225 kV line; and
- implementation of an ambitious DSM and renewable energy distributed generation program called the “Eco-Energy Plan” to slow down the growth in demand.

In May 2006, the state court, after a complaint from an environmental group, refused planning permission for the upgrading of the Boutre-Carros line. Therefore, at present, the DSM program is the only way to secure supply to this region by keeping load growth within the capacity of the existing 250 kV line.

DESCRIPTION OF PROJECT
The Eco-Energy Plan comprises a very large integrated DSM project (including distributed generation). It is the largest DSM project in the European Union and possibly the world. It has three main objectives:
- to increase the efficiency of electricity usage and to create a critical mass of scientific and technological competence in relation to electricity DSM;
- to modify the electricity-using behaviour of consumers, and building owners and managers;
to contribute to the development of local renewable energies and to establish a solid basis for future energy choices.

The following description is based on the analysis and program design developed following the initial decision in 2000. Following the refusal of planning permission in 2006, the DSM program will have to be strengthened to meet the new constraints.

Preliminary Studies

Preliminary studies were carried out in 2001:

- to quantify the level of load reduction required, after the scheduled completion of the new 400 kV line in 2005, to avoid network constraints in the period to 2020;
- to understand the evolution and structure of peak demand in the eastern part of the Provence-Alpes-Côte d'Azur region;
- to quantify the potential load reductions achievable through implementing DSM and distributed generation; and
- to identify a detailed program of DSM and distributed generation measures.

Figure IP08/2 shows that, following the scheduled completion of the new 400 kV line in 2005, with a fault level of n-1 capacity constraints were likely to reappear in the winter of 2018. To avoid a further new line being required before 2020, the Eco-Energy Plan would have to reduce load by 35 MW in winter.

Figure IP08/3 (page 126) shows that with a fault level of n-2, capacity constraints were likely to reappear in the summer of 2016. An n-2 fault level is possible in summer because of the risk of forest fires under the southern double circuit 400 kV line. To avoid a further new line being required before 2020, the Eco-Energy Plan would have to reduce load by 130 MW in summer.
Figures IP08/4 and IP08/5 (page 127) show the end-use composition of peak demand in the region in winter and summer. In winter, peak demand is dominated by lighting and heating and in summer air conditioning is dominant with lighting also an important contributor to the peak.
Figure IP08/5. Summer Peak Demand by End-use in the Eastern Part of the Provence-Alpes-Côte d’Azur Region

Figure IP08/6 shows forecasts of the potential load reductions achievable through the Eco-Energy Plan by implementing DSM and distributed generation over the period 2005 to 2020. Figure IP08/7 (page 128) shows a breakdown of the forecast load reductions achievable in winter 2006. Based on these forecasts, the target load reduction to be achieved through the Eco-Energy Plan in winter 2006 was set at 45 MW.

Figure IP08/6. Forecasts of Potential Load Reductions Achievable through the Eco-Energy Plan 2005 to 2020
The Eco-Energy Plan was launched in March 2003. Initially six priority areas were identified:

- communication and information;
- new building construction;
- efficient lighting and domestic electrical appliances;
- large consumers and distributed generation;
- demonstration projects by the Eco-Energy Plan institutional partners; and
- public housing.

In 2004, a further two priority areas were added:

- existing buildings; and
- tourism.

Figure IP08/8 (page 129) shows the forecast impacts and costs of the identified DSM measures to be implemented through the Eco-Energy Plan.
Communication and information campaigns & 2.9 \\
Increasing awareness and training of engineering departments and installers & 3.6 \\
Demonstration energy management projects in State and local authorities, EDF and ADEME & 26 & 5.5 & 52.5 & 4.6 \\
Specific measures for new residential and commercial buildings & 1.2 & 0.1 & 2.5 & 7.6 \\
Large-scale dissemination of CFLs in social sector & 2.3 & 0.5 & 6 & 2 \\
Promotion of efficient lighting in commercial sector & 24 & 12 & 72 & 1.8 \\
Promotion of CFLs and energy efficient white goods & 57 & 8 & 115 & 3.6 \\
Energy efficient retrofitting in residential and commercial sectors & 41 & 11.5 & 125 & 9.1 \\
Energy efficient retrofitting in tourism sector & 3 & 2.3 & 9 & 2.6 \\
Domestic hot water & 15 & 5 & 3.3 \\
Wood heating & 8 & 7 & 2.1 \\
Specific measures for large industrial and commercial consumers & 16.5 & 11 & 2.3 \\
Cogeneration, biogas, hydro installations & 45 & 23 & 3 \\
Photovoltaic installations & 0 & 0.3 & 0.9 \\
Evaluation & 3 \\
**Total** & 224 & 89.2 & 394 & 52.4

**Figure IP08/8. Forecast Impacts and Costs of Identified DSM Measures**

**Communication and Information**

A general public information campaign was launched on 18 March 2003. Each year, the campaign is implemented in two waves on a seasonal basis: summer and winter. The campaign includes: paid advertisements in newspapers, and on radio and television; information booklets and posters; a quarterly newsletter; a telephone information centre; a website; energy audit software for residential dwellings; and displays in shopping centres and fairs (see Figure IP08/9, page 130).

Targeted educational material on energy saving has been produced for use by school children, including information on how to carry out energy saving projects at home. These projects are intended to influence whole families to save energy not just the children.
New Building Construction
Targeted information material on energy efficient lighting has been developed for engineering and building design firms. Software has been developed to enable the design of energy efficient communities. Promotional material has been produced to assist building designers to convince their customers to invest in energy efficient buildings.

Efficient Lighting and Domestic Electrical Appliances
Negotiations with lamp manufacturers enabled energy efficient lamps to be offered at a 20% discounted price in the Alpes-Maritime region. The Eco-Energy Plan has also made available loans to cover the cost of energy efficient lighting installations; loans of between EUR 2 000 and EUR 16 000 are available at interest rates of 2.5% over three years or 3.5% over five years.

Large Consumers and Distributed Generation
A working group on cogeneration has been established and a technical/economic study has been completed to identify the potential for the development of small cogeneration installations (200-300 kW) in the region. This study investigated simplifying procedures for connection to the low voltage network and examined tariff options for purchases of electricity generated by cogeneration plants.

A study of the potential for increased hydro-electricity generation in the region has also been completed. This study investigated increasing the capacity of existing hydro power stations and installing new power stations on irrigation canals, drinking water supply infrastructure and rivers.
Finally, ADEME and the regional government have financed the installation of 40 grid-connected photovoltaic modules in the region.

**Demonstration Projects**

A database of about 100 public sector buildings in the region has been established, including colleges, hospitals and offices owned by the national, regional and local governments, Electricité de France (EDF), Gas de France and ADEME. An initial analysis of the information in the database identified that some facility managers were interested in carrying out energy efficiency and DSM demonstration projects. Consequently, an initial program of feasibility studies has been launched. In particular, the regional government, EDF and ADEME are financing 80% of the cost of feasibility studies in hospitals. In addition 12 colleges in the Alpes-Maritimes have voluntarily agreed to undertake DSM feasibility studies.

In late 2004, EDF carried out energy audits of its highest energy-using buildings in the region. The first implementation of energy saving measures aims to save 7% of electricity usage (600 MWh) per annum. EDF is also carrying out an internal awareness campaign about energy saving for its staff. This initiative aims to change the behaviour of EDF staff in administrative buildings without implementing costly technical measures. At the completion of this program, EDF will prepare a kit about energy saving measures that will be made available to private sector companies and local communities.

In March 2003, the Eco-Energy Plan partners brought together 29 local communities in the Alpes-Maritimes region to encourage them to undertake effective DSM measures. The first stage of this program required the communities to take a simple action in one of three areas of their own operations: investigation of opportunities for interruptibility; the installation of energy efficient lighting in one or more of their facilities, or the management of street lighting. In the second stage, the communities could undertake basic measures directed to residents in their areas.

**Public Housing**

The Eco-Energy Plan has been working with managers of public housing to improve the energy efficiency of their properties so as to reduce the energy bills of their tenants. This is particularly important when existing properties are renovated. To assist the property managers, it is proposed to develop specific DSM measures for public housing, starting with quick energy audits of the properties to identify major DSM options.

**Existing Buildings**

The Eco-Energy Plan has developed a book of technical solutions applicable to the Mediterranean area that assist the design of buildings adapted to the local climatic conditions and which make use of local renewable energies.

To develop the energy services industry in the Alpes-Maritimes region, a database was constructed to identify a range of products and services that enable energy savings in residential and commercial buildings. The database is available on the internet and it is also possible to purchase the products on-line. Prior to the development of the database, there were few energy service companies (ESCOs) in the Alpes-Maritimes region. Now several new ESCOs have been established.
**Tourism**

In January 2004, an engineering and design firm Fludia was commissioned to assist the hotel sector to better understand and control their consumption of electricity. Individual hotels were provided by mail with small recording devices which they used for three weeks and then returned to Fludia. The recordings were analysed and individual reports were provided to each hotel detailing the characteristics of the hotel’s electricity use and identifying anomalies and opportunities for energy saving. Some hotels also benefited from individual telephone consultations. Some energy saving measures generally applicable across the hotel sector were identified, eg switching off coffee machines when not in use and reducing the use of water-heaters in the middle of the day and when the hotels had low occupancy rates.

**RESULTS**

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load</td>
<td>Peak Load Reduction</td>
<td>Duration of Peak Load Reduction</td>
<td>Overall Load Reduction</td>
<td>Energy Savings</td>
</tr>
<tr>
<td>Reduction of 7.5% in winter; no reduction in summer</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**HOW LOAD REDUCTION WAS MEASURED**

Estimate. The actual peak load is measured on the transmission network and compared to the initial estimate of the peak load if the DSM program were not implemented.

**ACTUAL PROJECT COSTS**

The budget for implementation of the Eco-Energy Plan is EUR 6 million. The project is financed by the regional government of Provence-Alpes-Côte d'Azur, Agence de l'Environnement et de la Maîtrise de l'Energie (ADEME) and Electricité de France (EDF).

**SOURCES**

Eco-Energy Plan website at: [www.planecoenergie.org](http://www.planecoenergie.org)


CASE STUDY PREPARATION

Name: David Crossley  Email: crossley@efa.com.au
CASE STUDY 13
BAULKHAM HILLS SUBSTATION DEFERRAL PROJECT - AUSTRALIA

IEADSM Task XV Case Study No LS05
Last updated 26 August 2005
Location of Project Baulkham Hills, Sydney, Australia
Year Project Implemented 1998
Year Project Completed 2005
Name of Project Proponent Integral Energy
Name of Project Implementor Integral Energy
Type of Project Implementor Distribution utility
Purpose of Project Deferral of network augmentation
Timing of Project Pre contingency
Focus of Project Network capacity limitations
Project Objective Peak load reduction
Project Target Network element
DSM Measure(s) Used Interruptible loads
Specific Technology Used Interruption of a major industrial load
Market Segments Addressed Large industrial customers

DRIVERS FOR PROJECT
This program was undertaken to defer a AUD 1.7 million network augmentation project to construct the Baulkham Hills zone substation, which had become necessary as a result of the growth in the afternoon summer peaks.

DESCRIPTION OF PROJECT
This DSM program is essentially an agreement with one major industrial customer who uses large furnaces and puts a substantial peak demand of 12 MVA on the network.

Under the agreement, the customer is given 24 hours notice to shed load between 1 pm and 5 pm the following day. The customer is able to implement load shifting by speeding up production prior to the event and then slowing it down during the peak.

RESULTS

<table>
<thead>
<tr>
<th></th>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load Reduction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Duration of Peak Load Reduction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall Load Reduction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Savings</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Network Augmentation Deferral</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4 MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
RESULTS ACHIEVED
The agreement with this one customer achieved peak load reductions of between 3.5 and 4.5 MVA.

The agreement with the customer was originally scheduled to operate from 1998 to 2003. The agreement was later extended by two years to 2005.

CONFIDENCE LEVEL IN ACHIEVING RESULTS
High.

REPEATABILITY OF RESULTS
High - provided the 24 hours notice is given by Integral, the customer is able to provide the load reduction when required.

ACTUAL PROJECT COSTS
The majority of the cost of the program was the payments made to the participating customer which totalled AUD 70,000. An additional cost of approximately AUD 10,000 was incurred in setting up and initiating the program.

OVERALL PROJECT EFFECTIVENESS
Very effective, relatively low cost program which depended on a unique situation where a single customer was able to interrupt a very large load.

CONTACTS
Frank Bucca
Demand Management & Utilisation Manager
System Development Department
Integral Energy
PO Box 6366
Blacktown NSW 2148
Tel: 02 9853 6566
Fax: 02 9853 6099
E-mail: bucca@integral.com.au

SOURCES

Personal communication, Frank Bucca, Integral Energy.

CASE STUDY PREPARATION
Name: David Crossley    Email: crossley@efa.com.au
CASE STUDY 14

CASTLE HILL DEMAND MANAGEMENT PROJECT - AUSTRALIA

<table>
<thead>
<tr>
<th>IEADSM Task XV Case Study No</th>
<th>IP02</th>
</tr>
</thead>
<tbody>
<tr>
<td>Last updated</td>
<td>11 July 2006</td>
</tr>
<tr>
<td>Location of Project</td>
<td>Castle Hill, Sydney, Australia</td>
</tr>
<tr>
<td>Year Project Implemented</td>
<td>2003</td>
</tr>
<tr>
<td>Year Project Completed</td>
<td>2006</td>
</tr>
<tr>
<td>Name of Project Proponent</td>
<td>Integral Energy</td>
</tr>
<tr>
<td>Name of Project Implementor</td>
<td>New South Wales Sustainable Energy Development Authority (SEDA)</td>
</tr>
<tr>
<td>Type of Project Implementor</td>
<td>State or federal government agency</td>
</tr>
<tr>
<td>Purpose of Project</td>
<td>Deferral of network augmentation</td>
</tr>
<tr>
<td>Timing of Project</td>
<td>Pre contingency</td>
</tr>
<tr>
<td>Focus of Project</td>
<td>Network capacity limitations</td>
</tr>
<tr>
<td>Project Objective</td>
<td>Peak load reduction</td>
</tr>
<tr>
<td>Project Target</td>
<td>Network region</td>
</tr>
<tr>
<td>DSM Measure(s) Used</td>
<td>Standby generation, Direct load control, Energy efficiency, Power factor correction, Other: Automated control (ie CO2 monitoring)</td>
</tr>
<tr>
<td>Specific Technology Used</td>
<td>Integrated project using a range of technologies</td>
</tr>
<tr>
<td>Market Segments Addressed</td>
<td>Commercial and small industrial customers</td>
</tr>
</tbody>
</table>

DRIVERS FOR PROJECT

Castle Hill is a rapidly developing suburb located 32km north west of the Sydney central business district. The Castle Hill local electricity network has 5,320 residential customer connections and 679 business and community connections. Over the five years from 2000 to 2005, electricity consumption in Castle Hill increased by 32% and Integral Energy forecasts showed that this would grow by a further 54% over the subsequent 10 years.

Increasing penetration and use of air conditioners in the Castle Hill commercial centre and surrounding residential areas would result in summer peak loads exceeding system capability. In 2003, Integral Energy forecast it would need to spend AUD 3.2 million to expand the Castle Hill zone substation by summer 2005 because of continued rapid development of the Castle Hill district.

Integral Energy wished to examine whether it would be cheaper to assist local consumers be more efficient in their use of electricity rather than upgrade the electricity network. If not, the Castle Hill substation would be upgraded to ensure growth in energy demand was met.

DESCRIPTION OF PROJECT

Castle Hill Local Network

Peak demand in the Castle Hill area is primarily driven by use of domestic and commercial air-conditioning on hot summer days, particularly when there have been several days in a row with temperatures exceeding 35 degrees Celsius (see Figures IP02/1 and IP02/2, page 137).
Figure IP02/1. Castle Hill Zone Substation Profile on a 35 Degrees Celsius Day

Figure IP02/2. Castle Hill Zone Substation Profile after Two Consecutive Days at 39 Degrees Celsius
The effect of air conditioning on peak electricity use on a mild summer day versus a hot summer day is illustrated in Figure IP02/3. Figure IP02/4 shows the forecast growth in demand on the Castle Hill zone substation.

**Figure IP02/3. Castle Hill Zone Substation Profile**  
Hot Day versus Mild Day

**Figure IP02/4. Castle Hill Zone Substation**  
Actual and Forecast Demand
Initial Investigations

Despite the high levels of load growth, initial investigations by Integral Energy indicated that sufficient demand could be curtailed to defer the upgrade of the substation. Reductions in summer peak demand of 1 MVA initially, and further reductions of 0.5 MVA per annum were required to achieve deferral. A notional three-year deferral would provide a budget of sufficient value to warrant proceeding with a DSM option.

Integral Energy determined that a Request for Proposals for DSM strategies was warranted. However, this was supplanted by an offer from a New South Wales Government agency, the Sustainable Energy Development Authority (SEDA), to conduct a DSM program focussed on the commercial sector.

The Castle Hill Demand Management Project was developed via direct negotiation with SEDA. Integral Energy provided information on the level and timing of the required peak demand reduction and the level of financial support available.

Contractual Arrangements

SEDA was contracted by Integral Energy to work with electricity customers to relieve the peak summer electrical demand on the Castle Hill zone substation by 1,350kVA, approximately 4% of the peak electrical load on the local network, over a 3 year period.

The aim of the contract was to defer the need for the upgrade of the Castle Hill zone substation by reducing the demand for electricity during peak periods, namely from 1pm until 5pm on summer weekdays when the temperature reached or exceeded 35 degrees Celsius.

The overall contract target of 1,350 kVA was divided into three milestones of 450kVA of demand reduction to be achieved by the start of summer each year. The contract allowed for a budget of AUD150 per kVA of peak demand reduction, that is a total of AUD202,500 plus an ‘establishment fee’ of AUD50,000, bringing the overall project cost to AUD187/kVA.

However, using the framework for treatment of network utilities' DSM expenditure developed by the New South Wales electricity industry regulator, the value of deferring the capital upgrades to the Castle Hill zone substation was worth up to AUD566 per kVA (ie a total of AUD764,000). Consequently, if the contract target of 1,350kVA was exceeded, Integral Energy agreed to make payments of AUD135 per kVA for up to a further 352kVA reduction.

Program Objectives

The following objectives were set for the Castle Hill Demand Management Project:

- reduce the peak electricity load on Integral Energy’s Castle Hill zone substation by 1,350kVA by summer 2005/2006;
- increase the energy efficiency of participating businesses and residents and decrease energy bills;
- reduce greenhouse gas emissions through energy efficiency and/or fuel switching to other energy forms;
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

- increase investment in sustainable energy technologies and services;
- demonstrate that DSM can be a profitable alternative to supply side solutions for an electricity distribution network facing peak demand constraints.

DSM Strategies

Three DSM strategies were identified:

- **Commercial/Industrial DSM**: investigate using a modified version of SEDA’s award winning Energy Smart Business program to reduce peak demand by major commercial/industrial customers, primarily through implementation of energy efficiency measures;
- **Distributed Generation**: investigate using existing or hired standby generators to relieve the network at peak times;
- **Residential DSM**: investigate the potential for energy efficiency, appliance interruption and load shifting in local residences.

Commercial/Industrial DSM

Initial investigations into the top 20 energy users in the area served by the Castle Hill zone substation identified the Castle Towers Shopping Centre and its major retail tenants as potential targets for peak demand management initiatives. The top ten commercial energy users had a combined electrical load of greater than 10MVA. Consequently, 1.35MVA represented an average drop of 13% of their load.

Preliminary walk through energy audits of the shopping centre and the major retail tenants suggested good potential to improve the efficiency of lighting, ventilation and air-conditioning systems. These systems account for an estimated 70% of commercial sector electricity demand during times of the peak summer load on the New South Wales network.

SEDA modified its existing Energy Smart Business program to assist these major energy consumers to identify and implement cost effective peak demand reduction projects.

Business forums and one-on-one meetings with major retail businesses were held during 2003 to recruit partners for the Castle Hill Demand Management Project. Free energy audits were offered to businesses to assess the potential for peak demand reduction and ongoing energy savings.

Following the energy audits, businesses were encouraged to make a public commitment to implement cost effective projects within 2 years. Businesses making this commitment became official “Partners” in the Castle Hill Demand Management Project and were provided with:

- a Partner Support Manager to give ongoing support and technical assistance to implement projects;
- participation in two advertising campaigns on local bus shelters and inside the Castle Towers Shopping Centre, as well as promotion in the project newsletter; and
- a $60/kVA bounty for measured and verified peak demand reductions.
The Project targeted interruptible loads, the installation of high efficiency air-conditioning (and the upgrading of existing air-conditioning systems), and the installation of efficient lighting and power factor correction equipment in new and replacement applications. The contracts with electricity customers were performance based, with payment on verification of demand reduction.

**Distributed Generation**

Although initial estimates of peak demand reduction available from commercial businesses looked favourable, it was considered prudent to also investigate distributed generation as a complementary peak demand reduction option.

Recruitment of standby diesel generators able to dispatch at times of peak demand was the main distributed generation option investigated. Other generation options such as gas generation, cogeneration and solar power systems were not pursued because of the time constraints for project implementation and budgetary considerations.

Initial investigations found four standby generators in the Castle Hill area: two tenants at the Castle Towers Shopping Centre and two businesses outside the shopping centre.

The business with the largest capacity of standby generation (250kW) was considered to offer the best potential for a standby generation option. Initial discussions were held with the asset owner and a pre-feasibility study was undertaken based on manual start-up and synchronised, remote start-up options. The pre-feasibility study indicated the net return to the asset owner for generating less than 1MW at peak times in the network and/or at times of high pool prices in the National Electricity Market was negligible and did not warrant the risk or administration required to implement the standby generation option.

Preliminary discussions were also held with Integral Energy about the possibility of using hired generators. Issues such as siting, fuel storage, cabling and grid connection were raised. A hired generator was not considered the ideal option but could be used to generate during peak periods over one summer. This would give energy efficiency options more time to be implemented and/or would make up for any shortfall in the peak demand reduction achieved through these options.

**Residential DSM**

Integral Energy, in conjunction with SEDA, had previously undertaken an interruptible residential air conditioning trial with 90 residents in western Sydney. Although this was successful in delivering a demand reduction, the trial raised a range of other issues that needed to be addressed before this option could be a reliable, market accepted solution for peak demand reduction over multiple years and with larger numbers of participants.

Further, as the demand peak in Castle Hill dropped off at close of business around 5pm, it was considered that interrupting residential air-conditioners might not be very effective in reducing the early afternoon component of the peak.
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

Castle Hill has a high penetration of domestic swimming pools. Therefore, a basic investigation into shifting pool pump loads (approximately 1kVA each) to outside peak times was undertaken, including interviews with local pool equipment suppliers and a limited survey of pool owners.

Overall it was considered to be not financially viable to undertake residential DSM initiatives in the Castle Hill Project, given the budget of $187/kVA and that the commercial DSM initiatives looked more promising for the size, length and timing of peak reduction required.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>6</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Peak Load Reduction</th>
<th>Duration of Peak Load Reduction</th>
<th>Overall Load Reduction</th>
<th>Energy Savings</th>
<th>Network Augmentation Deferral</th>
</tr>
</thead>
<tbody>
<tr>
<td>33 MW</td>
<td>1.35 MVA</td>
<td>4 hours</td>
<td>0.9 MVA</td>
<td>3,800 MWh</td>
</tr>
</tbody>
</table>

HOW LOAD REDUCTION WAS MEASURED

Estimate.

RESULTS ACHIEVED

Fifty-four possible DSM projects were identified with an estimated total load reduction of 5.2 MVA. To achieve the required 1.35 MVA peak load reduction, the top 20 projects were selected. Most of the peak demand reduction projects identified involved lighting, heating, ventilation and air-conditioning (HVAC) or optimisation of building management control systems.

By June 2005, six project partners had been signed up and a total of 900 kVA peak load reduction had been achieved. The project was on track to achieve the target 1.35 MVA reduction by November 2005.

Based on projects with funding approved and currently underway the following results are expected:

- 1,350 kVA of peak demand reduction will be in place by summer 2005/06 at an average cost of $187/kVA;
- around $370,000 in annual energy savings to businesses;
- over $1 million worth of investment in sustainable energy equipment and expertise; and
- over 7,000 tonnes of greenhouse gas reductions per annum.

AVOIDEDED COSTS

AUD 320,000 for a one year deferral of the planned substation.
ACTUAL PROJECT COSTS

Integral Energy's costs are AUD200,000 to June 2005 and are expected to be AUD300,000 in total by the end of the project. The average budgeted project cost was AUD187/kVA.

CONTACTS

Frank Bucca
Demand Management & Utilisation Manager
System Development Department
Integral Energy
PO Box 6366
Blacktown NSW 2148
Tel: + 61 2 9853 6566
Fax: + 61 2 9853 6099
E-mail: bucca@integral.com.au

SOURCES


Personal communication, Frank Bucca, Integral Energy.

CASE STUDY PREPARATION

**Name:** David Crossley / Paul Myors  **Email:** crossley@efa.com.au / pmyors@energy.com.au
CASE STUDY 15
TAHMOOR FUEL SUBSTITUTION PROJECT - AUSTRALIA

<table>
<thead>
<tr>
<th>IEADSM Task XV Case Study No</th>
<th>FS01</th>
</tr>
</thead>
<tbody>
<tr>
<td>Last updated</td>
<td>31 August 2005</td>
</tr>
<tr>
<td>Location of Project</td>
<td>Tahmoor, about 70 km south of Sydney, Australia</td>
</tr>
<tr>
<td>Year Project Implemented</td>
<td>1998</td>
</tr>
<tr>
<td>Year Project Completed</td>
<td>2001</td>
</tr>
<tr>
<td>Name of Project Proponent</td>
<td>Integral Energy</td>
</tr>
<tr>
<td>Name of Project Implementor</td>
<td>Integral Energy</td>
</tr>
<tr>
<td>Type of Project Implementor</td>
<td>Distribution utility</td>
</tr>
<tr>
<td>Purpose of Project</td>
<td>Deferral of network augmentation</td>
</tr>
<tr>
<td>Timing of Project</td>
<td>Pre contingency</td>
</tr>
<tr>
<td>Focus of Project</td>
<td>Network capacity limitations</td>
</tr>
<tr>
<td>Project Objective</td>
<td>Peak load reduction</td>
</tr>
<tr>
<td>Project Target</td>
<td>Network element</td>
</tr>
<tr>
<td>DSM Measure(s) Used</td>
<td>Fuel substitution</td>
</tr>
<tr>
<td>Specific Technology Used</td>
<td>Bottled gas cooking and space heating appliances</td>
</tr>
<tr>
<td>Market Segments Addressed</td>
<td>Residential customers</td>
</tr>
</tbody>
</table>

DRIVERS FOR PROJECT

The purpose of the Tahmoor fuel substitution program was to defer augmentation of the distribution network by controlling growth in the winter evening peak demand and combating a low load factor.

DESCRIPTION OF PROJECT

The program promoted the use of bottled gas by residential customers for cooking and space heating.

Customers were contacted via a letterbox drop with a personalised letter providing details of subsidies available from Integral and the costs of bottled gas appliances. Integral arranged the installation of bottled gas and appliances and provided subsidies of AUD150 for the installation of bottled gas plus AUD150 per gas appliance.

RESULTS ACHIEVED

The program succeeded in flattening load growth to a degree, but take-up was less than had been hoped. One reason may have been that at the time the program was underway, the state's primary gas distributor made public overtures about extending reticulated natural gas to the area. These plans never materialised, but the possibility of using mains gas may have delayed and ultimately prevented customers from making decisions in favour of Integral's bottled gas alternative.

As a result, the program deferred the distribution network augmentation for a shorter period than had originally been forecast. Consequently, the augmentation was undertaken in 2003/04.

CONFIDENCE LEVEL IN ACHIEVING RESULTS

Low - customer response was less than expected.
REPEATABILITY OF RESULTS
May be repeatable with a more aggressive marketing program.

ACTUAL PROJECT COSTS
Integral Energy - AUD 40,000 subsidies paid to customers plus AUD 18,000 administrative costs.

CONTACTS
Frank Bucca
Demand Management & Utilisation Manager
System Development Department
Integral Energy
PO Box 6366
Blacktown NSW 2148
Tel: 02 9853 6566
Fax: 02 9853 6099
E-mail: bucca@integral.com.au

SOURCES

Personal communication, Frank Bucca, Integral Energy.

CASE STUDY PREPARATION
Name: David Crossley    Email: crossley@efa.com.au
CASE STUDY 16
MAINE-ET-LOIRE DSM PROJECT - FRANCE

IEADSM Task XV Case Study No IP06
Last updated 1 September 2005
Location of Project Maine-et-Loire Region, France
Year Project Implemented 1997
Year Project Completed 2000
Name of Project Proponent SIEML (association of local authorities), Electricité de France (EDF - generation and transmission utility), FACE (a funding body), ADEME (the French Government's energy efficiency agency)
Name of Project Implementor FR2E (project management consultant) and EDF
Type of Project Implementor Distribution utility
Transmission utility
Other: Project management consultant
Purpose of Project Deferral of network augmentation
Timing of Project Pre contingency
Focus of Project Network capacity limitations
Voltage fluctuations
Project Objective Peak load reduction
Voltage regulation
Project Target Network element
DSM Measure(s) Used Other distributed generation
Direct load control
Energy efficiency
Fuel substitution
Other: Voltage regulation with transformers
Specific Technology Used Voltage regulators, automatic controllers for domestic boilers, electronic soft starters for pump motors, compact fluorescent lamps, wood fired boiler, diesel generators
Market Segments Addressed Residential customers
Commercial and small industrial customers
Agricultural customers

DRIVERS FOR PROJECT

An average region (département) in Metropolitan France has 4,000 km of low voltage rural lines serving some 75,000 customers. In many regions, the cost of reinforcing certain overloaded rural feeders is much higher than the annual financial return from each feeder. This provides a significant opportunity for DSM as an alternative to network augmentation and reinforcement.

In rural areas of France, local authorities (municipalities) own the electricity distribution network and are responsible for the distribution of electricity and for network augmentation and reinforcement. Electricity is supplied by Electricité de France (EDF) under concessional contracts with the local authorities. Augmentation and reinforcement of the distribution network is usually undertaken by associations of a number of local authorities (Syndicats Intercommunal d'Electrification), generally at the regional level. (Note that these arrangements will change with the introduction of a
competitive electricity market in France.)

Faced with the financial costs of network augmentation and reinforcement, local authorities favour cost-effective alternatives such as DSM projects. Hence the regional association of local authorities Syndicat Intercommunal d’Electrification de Maine-et-Loire (SIEML) participated in the Maine-et-Loire DSM Project.

The funding body Fonds d'Amortissement des Charges d'Électrification (FACE) receives revenue from a tax on the earnings of electricity distributors at the low voltage level; in urban areas this tax is about 2.5% and in rural areas it is about 0.5%. Since 1995, FACE has supported projects aimed at using alternative technical solutions to the augmentation and reinforcement of the low voltage network, because these solutions are economically profitable.

The DSM project in Maine et Loire was one of the first DSM projects in France; it was carried out between 1997 and 2000. The project started due to the voltage drops (up to 35%) experienced by some users.

DESCRIPTION OF PROJECT

In the Maine-et-Loire region, two criteria were used to select feeders for the DSM project:

- estimated cost of reinforcement more than EUR 10,000 per customer;
- voltage drops between 20% and 35%.

In addition, feeders were sometimes included in the DSM project if they were more than 30 years old.

Four low voltage feeders supplying 26 customers with strong constraints were selected for multiple DSM measures. There were two categories of measures implemented:

- DSM measures undertaken on the network side of the meter;
- DSM measures undertaken on the customer side of the meter.

SIEML/FACE did not have authority to use public funds to undertake DSM measures on the customer side of the electricity meter. Therefore, SIEML/FACE paid for part of the costs of measures undertaken on the network side of the meter, the other part being paid by EDF. All costs for measures undertaken on the customer side of the meter were paid by EDF and Agence de l'Environnement et de la Maîtrise de l'Énergie (ADEME), the French Government's energy efficiency agency.

Network-related DSM Measures

The network-related DSM measures included:

- installing voltage regulators on the low voltage feeders (see Figure IP06/1, page 148);
- installing voltage regulators on the network side of the meter at customers’ premises;
- use of three phase/single phase transformers to distribute the single-phase current loads of customers across three phases (see Figure IP06/2. page 148).
These measures were financed by SIEM/FACE and EDF and implemented by EDF. The three phase/single phase transformers were owned by EDF; they could be recovered and installed on other constrained feeders.

Figure IP06/1. Voltage regulator

Figure IP06/2. Three Phase/Single Phase Transformer
Customer-related DSM Measures

The customer-related DSM measures included:

• shifting the use of electric household appliances and water heaters to off-peak periods;
• installing inverters for lighting and data processing end-uses;
• implementing electronic "soft" starters for electric motors (see Figure IP06/3);
• distributing compact fluorescent lamps (90 CFLs among six customers);
• implementing automatic controllers for domestic boilers;
• installing a wood-fired boiler (see Figure IP06/4, page 150);
• using portable diesel generators for intermittent generation at selected sites (see Figure IP06/5, page 150);
• installing a 40 kVA diesel generator at a pig breeding farm.

All equipment installed on the customer side of the electricity meter was owned by the customers. The customers chose the equipment installers and supervised them. The customers sent the bills to EDF and ADEME and were later reimbursed with a subsidy on the cost of the equipment and installation. Some customers installed equipment by themselves, they had to follow specifications from ADEME and EDF to receive the subsidy.

Figure IP06/3. Electronic "Soft" Starter for Electric Motors
Figure IP06/4. Wood-fired Boiler

Figure IP06/5. Portable Diesel Generator
Organisation of the DSM Project
A project management consultant (FR2E) was engaged to coordinate the whole project, including:

- planning of the project, administrative follow-up: visits to the customers, establishing of technical specifications and subsidy contracts;
- implementation of two measuring campaigns (before and after installation of the DSM measures), analysis of results;
- supervision during and after the implementation of the different DSM measures: assistance with choosing the best equipment, advising customers about selecting equipment installers, supervision and certification of works;
- phone assistance: FR2E were the single contact point for customers during the project;
- technical evaluation, writing technical reports for each feeder and writing the final report of the whole project.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>26</td>
<td>8</td>
<td></td>
<td></td>
<td>84 to 120 months</td>
</tr>
</tbody>
</table>

RESULTS ACHIEVED
Only the number and duration of voltage drop and unplanned outage events were measured. The results are shown in Tables IP06/1 and IO06/2, page 152.

CONFIDENCE LEVEL IN ACHIEVING RESULTS
Although the results just after the project was completed were positive, the safety margin for avoiding future network constraints is low because the four feeders selected for the project had very high voltage drops (between 20 and 35%).

REPEATABILITY OF RESULTS
To make the results reproducible, the selection criterion for voltage drops should be lower: between 10 and 20%.
Table IP06/1. Number of Voltage Fluctuation and Unplanned Outage Events

<table>
<thead>
<tr>
<th>Name of feeder</th>
<th>Number of Events*</th>
<th>Gains</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Before DSM</td>
<td>After DSM</td>
</tr>
<tr>
<td>La Jumelière</td>
<td>11,313</td>
<td>699</td>
</tr>
<tr>
<td>Coron</td>
<td>1,469</td>
<td>544</td>
</tr>
<tr>
<td>Chanteloup</td>
<td>3,049</td>
<td>81</td>
</tr>
<tr>
<td>Gennes</td>
<td>1,054</td>
<td>41</td>
</tr>
</tbody>
</table>

* Disturbances outside standards: micro outages, short outages; voltage fluctuations outside standards (230 V -10 %; 230 V +6 %). Sampling rate: 10 milliseconds (ms). All events with a duration higher than 10 ms were analysed and stored. Measurements carried out during seven consecutive days.

Table IP06/2. Duration of Voltage Fluctuation and Unplanned Outage Events

<table>
<thead>
<tr>
<th>Name of feeder</th>
<th>Total Duration of Events* (minutes)</th>
<th>Gains</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Before DSM</td>
<td>After DSM</td>
</tr>
<tr>
<td>La Jumelière</td>
<td>3,514</td>
<td>21</td>
</tr>
<tr>
<td>Coron</td>
<td>953</td>
<td>86</td>
</tr>
<tr>
<td>Chanteloup</td>
<td>1,098</td>
<td>6</td>
</tr>
<tr>
<td>Gennes</td>
<td>1,401</td>
<td>9</td>
</tr>
</tbody>
</table>

* Disturbances outside standards: micro outages, short outages; voltage fluctuations outside standards (230 V -10 %; 230 V +6 %). Sampling rate: 10 milliseconds (ms). All events with a duration higher than 10 ms were analysed and stored. Measurements carried out during seven consecutive days.

AVOIED COSTS
Cost of the avoided network reinforcements: EUR 158,818
Cost of DSM measures: EUR 71,040
Deferral of network reinforcement: 7 to 10 years
Benefit: EUR 7,978

ACTUAL PROJECT COSTS
SIEML/ FACE: EUR 10,247
EDF/ ADEME: EUR 24,145
ADEME: EUR 29,361
Customers: EUR 7,287
Total: EUR 71,040 (inclusive of taxes)
OVERALL PROJECT EFFECTIVENESS

For this experimental project, the results were technically very good. An investigation conducted six months after the end of the project showed that the customers were very satisfied with the improvement in the quality of supply. The farmers were particularly interested in the innovative nature of the project.

CONTACTS

Dominique FOURTUNE
Tel: 33 (0)5 55 10 27 49
E-mail: dominique.fourtune@ademe.fr

SOURCES


ADEME/EDF (2004). Catalogue des outils et techniques de MDE.


CASE STUDY PREPARATION

Name: Frédéric Rosenstein / David Crossley    Email: frederic.rosenstein@ademe.fr / crossley@efa.com.au
CASE STUDY 17
TU ELECTRIC THERMAL COOL STORAGE PROGRAM - USA

IEADSM Task XV Case Study No: LS03
Last updated: 2 March 2006
Location of Project: Dallas-Fort Worth and part of Texas, USA
Year Project Implemented: 1982
Year Project Completed: Late 1990s
Name of Project Proponent: TU Electric (now split into TXU Energy, an electricity retailer and generator and Oncor, responsible for electricity transmission and distribution; both are subsidiaries of TXU Corp)

Name of Project Implementor: TU Electric
Type of Project Implementor: Distribution utility
Transmission utility
Electricity retailer/supplier

Purpose of Project: Deferral of network augmentation
Timing of Project: Pre contingency
Focus of Project: Network capacity limitations
Project Objective: Peak load reduction
Project Target: Network region

DSM Measure(s) Used: Other short-term demand response
Specific Technology Used: Thermal cool storage using off-peak production of chilled water or ice
Market Segments Addressed: Commercial and small industrial customers

DRIVERS FOR PROJECT

During the late 1970s TU recognised the need to address the increasing air conditioning load of commercial buildings. Thermal cool storage was seen as a promising means of flattening commercial air conditioning load shapes. In 1981, TU realised that offering financial incentives would eliminate many barriers to installation of thermal cool storage systems. These barriers included a high initial system cost, a long payback period and the large physical size of a thermal cool storage system compared to a standard system.

TU's Thermal Cool Storage program shifted electrical load to off-peak hours, reducing peak demand, and provided space and/or process cooling during TU's on-peak periods (noon to 8 pm, weekdays, June through September).

DESCRIPTION OF PROJECT

A thermal cool storage system provides space and/or process cooling for commercial or industrial installations by running chillers at night and in the early morning to produce and store chilled water or ice, which is then used to provide cooling during the hottest part of the day.

The Thermal Cool Storage program was the first non-residential DSM program offered by TU Electric, beginning full-scale in 1982. The program provided cash incentives to customers who installed thermal storage systems. The incentives were based on the load shifted from on-peak to off-peak hours.
In 1993, TU offered incentives of USD 250/kW for the first 1,000 kW of load shifted plus USD 125/kW for all remaining load shifted. Incentive payments were limited to either the above schedule or to the customer’s capital investment minus one year’s estimated electric bill savings, whichever was lower. Qualifying customers had to have a payback for the thermal cool storage system exceeding one year. In addition to cash incentives, thermal storage customers could achieve additional savings by taking advantage of the Time-of-Day tariff option. This option was available to customers who shifted electricity use from on peak to off-peak hours.

Both new and retrofitted buildings qualified for the Thermal Cool Storage program. Partial storage systems that were expanded to take additional load off-peak received incentives based on the additional load shifted. Where a thermal storage system was intentionally oversized to allow for future expansion, the customer was eligible for the full cash incentives only upon completion of the expansion. While the majority of systems installed through the program provided all of the building’s cooling needs, customers using systems that provide only partial cooling were also eligible.

TU did not physically control the loads of customers participating in the Thermal Cool Storage program. Each customer was responsible for ensuring that their thermal cool storage system was switched off during TU’s peak demand period. The types of system controls used by thermal cool storage customers ranged from simple timers to complex computer systems. Achieving significant savings on the electric bill through reducing peak demand, especially in conjunction with the Time-of-Day rate option provided a very strong incentive for TU thermal storage customers to carefully monitor the operating hours of their thermal cool storage system.

TU focused on marketing the concept and benefits of thermal cool storage and did not sell any thermal cool storage equipment. For customers who were interested in thermal cool storage, equipment manufacturers presented formal proposals that included costs and equipment options. The final decision on choice of equipment was up to the customer.

TU’s marketing efforts for the Thermal Cool Storage program were geared toward the three predominant parties in the decision making process: the developers/owners of commercial buildings, engineers, and architects. TU field representatives marketed the program to customers and to trade allies (architects, engineers, equipment manufacturers and distributors) by explaining the benefits of thermal cool storage and the customer incentives that TU offered. TU also provided customer building audits which included an analysis of various HVAC system types and system estimated operating costs.

When the Thermal Cool Storage program began in the early 1980s, large office buildings were the most receptive to the program. Developers constructing buildings less than 500,000 square feet were generally not interested in the concept. Before 1986 a typical installation was in an office building exceeding 500,000 square feet.

By 1986 the construction boom in Dallas was slowing and the number of large construction projects dropped drastically. During 1987 and 1988 almost twice as many customers installed thermal storage systems as in the previous five years, but the load reductions added by the program in these two years were approximately half those achieved during the previous five years, which indicates a sharp drop in the size of
Space and process cooling thermal storage systems were installed in a wide variety of building types throughout the TU service area including hospitals, hotels, government facilities, churches, schools, food processing plants, and industrial manufacturing facilities. Many of the systems installed used chilled water rather than ice as the storage medium, which was different from most other areas of the United States.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>205 (in 1992)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

RESULTS ACHIEVED

Results for the Thermal Cool Storage program from 1982, when the program started, to 1992 were published in a report by the Results Center (see Sources below). During this period, the total load shifted from on-peak to off-peak increased from 3.8 MW in the first year of the program to 70.5 MW in 1992.

Peak load reductions per program participant fluctuated greatly over the lifetime of the program. In 1982, reductions were at their highest level with 1.9 MW of peak load reduction per participant joining the program that year, although only two participants were involved. Peak load reductions per participant were lowest in 1986 at 119 kW per participant joining that year. In 1992, peak load reductions per participant joining that year were 204 kW.

AVOIED COSTS

In 1992, the total annual cost of the Thermal Cool Storage program was USD 2.7 million. In that year, an additional 5.1 MW of peak load reduction was recruited by the program.

The Results Center calculated that TU spent USD 278/kW shifted in 1991 and USD 527/kW shifted in 1992. The average for this two year period was USD 351/kW. These figures compared favourably with USD 664/kW which would have been TU’s 1992 capital cost (plus O&M costs) to build an off-the-shelf combined cycle combustion turbine including an 18% simple cycle reserve margin.
SOURCES

CASE STUDY PREPARATION
Name: David Crossley  Email: crossley@efa.com.au
CASE STUDY 18
ESPAÑOLA POWER SAVERS PROJECT - CANADA

IEADSM Task XV Case Study No EE04
Last updated 20 September 2005
Location of Project Españoла, Ontario, Canada
Year Project Implemented 1991
Year Project Completed 1993
Name of Project Proponent Ontario Hydro/Españoла Hydro
Name of Project Implementor Ontario Hydro/Españoла Hydro
Type of Project Implementor Distribution utility
Transmission utility
Electricity retailer/supplier
Purpose of Project Deferral of network augmentation
Timing of Project Pre contingency
Focus of Project Network capacity limitations
Generation capacity limitations
Project Objective Overall load reduction
Project Target Network region
DSM Measure(s) Used Energy efficiency
Specific Technology Used A range of energy efficiency measures
Market Segments Addressed Residential customers
Commercial and small industrial customers

DRIVERS FOR PROJECT

The Espanola Power Savers Project was a community-based energy efficiency project which mounted a full-scale effort to extract the maximum possible reduction in electricity consumption from a geographically concentrated area. The project was designed to research the potential for this type of DSM approach in Ontario.

The Project's four main objectives were:

- to assess the community-based delivery concept as an additional, aggressive approach to DSM marketing;
- to determine the maximum attainable load reductions through the installation of cost effective retrofit and replacement measures, in the shortest period of time;
- to assess the "transferability" of the community-based delivery concept to the Ontario province;
- to collect and evaluate data to augment existing residential and commercial databases.

DESCRIPTION OF PROJECT

The township of Espanola is a pulp and paper community situated on the Spanish River in north eastern Ontario approximately 500 km north of Toronto. In the early 1990s, when this project was carried out, Espanola had a population of about 6,000.

Espanola was chosen for the project because it is geographically delimited, had a stable economy and the proportion of electric heating was representative of a northern Canadian community. Also it was evident from the outset that the town
officials and the citizens demonstrated civic pride and would be receptive to a community-based conservation program. Representatives from Ontario Hydro, the local distribution utility (Espanola Hydro), and the Town of Espanola took part in a signing ceremony which formalised the responsibilities of these three principal parties.

The Espanola Power Savers Project was carried out in both the residential and commercial sectors through implementing concentrated marketing, carrying out comprehensive energy audits and inspections, and providing incentives for the installation of energy efficiency measures.

The project had five key features:
- it was targeted to a specific geographic area;
- it used the community network to champion the energy efficiency effort;
- the electricity utility acted as the project manager and catalyst;
- incentive levels were high; and
- customers' decision making was facilitated.

**Approach**

The Espanola Power Savers Project used a two-pronged approach. First an extensive, cost effective list of energy conservation measures and installation specifications was established to maximise energy savings. Second, the project used a market saturation approach to elicit attitudinal and behavioural change that optimised energy savings and then maintained the energy efficiency built into the community.

The second aspect is one of the important elements of the Espanola Project – its "legacy". To avoid attrition and "take-back" effects after the project was completed, the project design included methods for maintaining the energy efficiency built into the community by the project over the short term. The aim was to achieve a long-term "culture shift" by saturating a specific geographic area, attracting high levels of interest and participation, encouraging community leaders to champion the project, and leaving the knowledge and skills within the community to promote sustained efficient energy use. The challenge was to motivate all residents in the town to change attitudes and make energy-saving behaviour a habit.

Unfortunately, there do not seem to have been any long-term follow-up evaluation studies to determine whether a persistent culture shift in energy using behaviour was achieved by the Espanola Project.

**Project Measures**

Selecting energy efficiency measures and calculating incentives were important tasks of the project design phase. All existing and new technology products were screened using the DSStrategist computerised cost-benefit model, initially without project costs. The cost effective measures were re-analysed and incentive levels established at the lesser of the incremental installed cost of the measure or its full system avoided cost.

In total over 100 energy efficiency measures were approved. A few measures, when considered on their own, did not pass the test. However when bundled with other measure(s) that were being installed at the same time, they became cost effective.
The measures ranged from energy efficient lighting to varying degrees of insulation for the entire building envelope, as well as energy efficient windows, doors, plus water and space heating options.

The range of measures offered was determined by the customer's classification. Customers were grouped as either all-electric or non-electric. The all-electric customers were offered more measures, as they had greater potential energy savings. Commercial customers received more extensive lighting measures.

Marketing

A community assessment was carried out in the spring of 1991 to obtain a comprehensive understanding of the environment in which the program was to be launched. Besides collecting and analysing traditional demographic data, the assessment attempted to discover the formal and informal networks/power structure within the community.

A detailed marketing/communication plan was developed and implemented. It emphasised cultivation of community interest and support to achieve a maximum participation rate and uptake of recommended energy efficiency measures and to achieve a community "culture shift" to wise electricity use over the long term.

A cornerstone of the plan involved the formation of a Community Advisory Committee at the outset of the project which consisted of over 30 representatives from organisations within the town.

The committee had two primary functions:

- to provide advice and guidance to the project on ways to promote the wise use of electricity; and
- to provide direct community feedback to the project on existing and potential project-related issues.

The Committee included representatives from a cross section of groups and organisations within the town including the Student Council, Chamber of Commerce, Senior Citizens, and the Lions Club. Membership included club chairpersons, local business owners, teachers, news and media people, as well as representatives from the town council and the utility. The Committee was organised prior to the formal launch of the project and provided direct community feedback to the project team in the field. Feedback on such issues as scheduling, inspections, and contractor performance all resulted in direct improvements to project delivery. The Committee was also instrumental in tasks ranging from increasing the comfort levels of seniors participating in the project, to scheduling presentations to various community groups and clubs. The Committee also helped to organize an energy saving tip contest, assisted in producing a newsletter, and helped to establish a recycling/reuse depot for project materials.

Additional community involvement/communication mechanisms included: project newsletters, open house/information nights, presentations to community organisations, an energy conservation week, radio/newspaper advertising, municipal council presentations, a curriculum based energy conservation educational package, a spring writing contest, high school presentations, Energy Conservation Corner in the Public Library, logo/slogan contest, opening ceremonies, picnics and displays, energy saving tips contest, electricity bill inserts, direct mail, and cable TV community service announcements.
Project Launch

The operational phase of the project began on 1 June, 1991, with the opening of a field office in Espanola. A community picnic was held which was partially sponsored by various conservation industry suppliers and associations. It was announced that householders and businesses in the community had until 31 May, 1992 to sign up for the project.

The sign-up process started early when interested citizens flooded an ad hoc information booth set up at the local shopping mall days after the project was announced. They requested more information and many were ready to participate. The project team quickly responded by having these "early adopters" sign a log and advising them that they would be re-contacted as soon as the project got underway. Later the residents were able to sign-up at the Sportsmen's Show, at the Espanola Hydro office and at the project store front. By the time the project began, almost 50% of the homes and businesses were signed up.

Project Delivery

For Espanola home or business owners, the Espanola Power Savers Project involved five main steps:

- making contact with the project office to request an energy audit;
- a visit by a qualified energy auditor/contractor team to recommend energy efficiency measures to be installed;
- approval of work by the home/business owner by signing an agreement with the general contractor;
- installation of energy efficient measures by qualified contractors; and
- inspection of all major work to ensure energy savings and customer satisfaction.

The Energy Audit

The energy audit was designed to identify the most complete set of energy efficiency measures that would result in the greatest reduction in electricity demand and energy efficiency savings. The audits were conducted by a two-person team made up of a qualified energy auditor and a representative of the general contractor. The auditor introduced the Espanola Power Savers goals and its potential benefits to the owner.

The type of audit conducted depended on the service classification of the customer. Each classification had its own audit form. The four main classifications were:

- residential all electric (which had electric space heating and water heating);
- residential non electric (which had space heating other than electric and optional electric water heater);
- commercial all electric (same as residential all electric); and
- commercial non electric (the same as the residential non electric).

The all-electric audit was based on the "whole-house approach," which included a full inspection of the building shell inside and out. Particular attention was paid to check for proper ventilation and for moisture problems. Working together, the auditor and contractor’s representative measured all windows, doors and areas to be insulated.
At the completion of the audit, the auditor presented a set of recommendations to the customer. At this point the contractor's representative took over the meeting and explained the costs of the recommended measures and the incentives available from Ontario Hydro. The customer was also made aware of Ontario Hydro's financing plan that allowed the customer to participate with no upfront costs. The customers usually took at least two weeks or longer to make their decision. When ready to proceed, the home or business owner signed a project application form and contract with the general contractor's representative.

Installation of Measures
The general contractor responsible for handling all the project's installations was selected by Ontario Hydro through a competitive bidding process which delineated the unit costs of specific retrofit and replacement measures. The general contractor in turn subcontracted to local and regional contractors for the installations. The general contractor’s tasks included scheduling and coordinating sub-trades and ensuring installations met project specifications.

The installation of energy-efficient measures was conducted by qualified tradespeople. All trades persons who worked on installations were certified by Ontario Hydro and a trade association to assure proper workmanship. Further on the job training was carried out daily to ensure quality work was being done. All work was covered by a warranty program.

Inspection of Work
Originally all major work was to have had one final inspection after the completion of the installation. Early in the project it was evident that this was not adequate. An interim inspection process was designed to allow up to seven progress inspections. The final inspection continued to be carried out. The inspector checked that each measure had been installed to specifications and reconciled the installed measures to the work order. The inspector also ensured that the owner was satisfied with the contractor's work. The customer then signed a release form that allowed Ontario Hydro to pay the utility's incentive money directly to the general contractor.

RESULTS ACHIEVED
The Espanola Power Savers Project achieved an overall very high 86% participation rate, defined as the number of energy audits completed compared to the total eligible sites. An eligible site was any building that was deemed suitable for possible participation in the project. The criteria used to determine eligibility included: the individual customer electricity consumption, the type of heating, size of building and type of end use.

Of the customers who underwent an energy audit, an overall 91% accepted at least one measure from the list of measures recommended by the auditor. The accepted measures represented 71% of the total estimated energy savings from all the recommended measures.

Detailed results are shown in Table EE04/1, page 163.
Table EE04/1. Detailed Results from the Espanola Power Savers Project

<table>
<thead>
<tr>
<th>Type of Site</th>
<th>Average Customer Contribution per Site (1992 Canadian dollars)</th>
<th>Average Ontario Hydro Incentive per Site (1992 Canadian dollars)</th>
<th>Average KW Reduction per Site</th>
<th>Average Annual kWh Saving per Site</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential all electric</td>
<td>2,684</td>
<td>4,200</td>
<td>1.87</td>
<td>6,832</td>
</tr>
<tr>
<td>Residential non-electric</td>
<td>17</td>
<td>194</td>
<td>0.12</td>
<td>1,071</td>
</tr>
<tr>
<td>Commercial all electric</td>
<td>3,323</td>
<td>8,411</td>
<td>6.99</td>
<td>24,904</td>
</tr>
<tr>
<td>Commercial non-electric</td>
<td>552</td>
<td>4,346</td>
<td>2.21</td>
<td>11,911</td>
</tr>
<tr>
<td>Average for all sites</td>
<td>1,237</td>
<td>2,454</td>
<td>1.20</td>
<td>4,873</td>
</tr>
</tbody>
</table>

ACTUAL PROJECT COSTS
USD 9.4 million (1992 dollars).

SOURCES


CASE STUDY PREPARATION
Name: David Crossley    Email: crossley@efa.com.au
CASE STUDY 19
QUEANBEYAN CRITICAL PEAK PRICING TRIAL - AUSTRALIA

IEADSM Task XV Case Study No PI03
Last updated 7 July 2006
Location of Project Queanbeyan and Jerrabomberra, New South Wales, Australia
Year Project Implemented 2004
Year Project Completed
Name of Project Proponent Country Energy
Name of Project Implementor Country Energy
Type of Project Implementor Distribution utility
Electricity retailer/supplier
Purpose of Project Deferral of network augmentation
Timing of Project Pre contingency
Focus of Project Network capacity limitations
Project Objective Peak load reduction
Project Target Network region
DSM Measure(s) Used Pricing initiatives
Specific Technology Used Interval meter and pricing information display unit
Market Segments Addressed Residential customers

DRIVERS FOR PROJECT
The Queanbeyan Critical Peak Pricing Trial was initiated to investigate the feasibility of promoting peak load reductions by residential sector customers to relieve distribution network constraints in the Queanbeyan area.

DESCRIPTION OF PROJECT
The trial involved applying seasonal time of use and critical peak pricing tariffs to about 200 households in Queanbeyan and Jerrabomberra, two suburbs located near the city of Canberra in eastern Australia.

Two seasonal tariff schedules were applied. In summer, the peak period was from 2 pm to 8 pm to coincide with the period of maximum use of domestic air conditioners. In winter the peak period was from 7 am to 9 am and 5 pm to 8 pm to coincide with the period of maximum use of domestic space heaters.

Critical peak periods were called by Country Energy when the load on the local network was reaching maximum capacity or when high price events occurred in the competitive wholesale electricity market. Critical peak periods could be called for a maximum of 12 times per year; customers were given a minimum 2 hours notice.

The tariff levels were as follows:

Off Peak: AUD 0.0703/kWh
Shoulder: AUD 0.127/kWh
Peak: AUD 0.1887/kWh
Critical Peak: 0.3774/kWh
The standard tariffs applied by Country Energy to residential dwellings were flat rate block tariffs based on readings from simple accumulation meters. In the trial, implementation of time of use and critical peak pricing tariffs required the installation of interval meters and in-home information display units in participants’ dwellings (see Figure PI03/1). The installation of this new technology was paid for by Country Energy.

![Ampy Email Advanced Metering System](image)

**Figure PI03/1. Technology Used in the Queanbeyan Trial**

The interval meters measure energy use in half hour blocks. Each meter was directly connected to a two-way communications unit using mobile phone technology that enables Country Energy to send and receive messages to and from the meter. This technology allowed automatic meter reading. It was also used to signal an upcoming critical peak period and instruct the meter to adjust its tariff.

The in-home information display unit, called a Home Energy Monitor (see Figure PI03/2, page 166), communicated with the interval meter through power line carrier technology. It plugged into any power socket and was about the size of a regular wall phone. The Home Energy Monitor comprises a LED alphanumeric display which provided customers with specific information about the amount of electricity they were using, and how much it was costing. It also included green, amber, and red LED lights which showed customers whether they were using electricity at low, medium, or high prices, corresponding to off peak/shoulder, peak and critical peak tariffs. A beeping sounds alerted customers to the start of a critical peak period.

Customers who participated in the trial were instructed to keep an eye on the Home Energy Monitor and adjust their electricity usage to avoid high tariff periods and capitalise on the lower tariffs. Some tips were provided about how to reduce electricity usage during high price periods.

Customers were also provided with a Participant Gift Pack that included compact fluorescent lamps, energy timers an energy efficiency thermometer, an energy wise calculator, CD-ROM, and an energy wise brochure.
Country Energy advised customers participating in the trial that, depending on their current tariff, they could expect to save between AUD 10 and AUD 120 per annum.

**HOW LOAD REDUCTION WAS MEASURED**

Interval meter. 30 minute intervals.

**RESULTS ACHIEVED**

Country Energy reported that the results of the trial showed mixed, but mainly positive results. The results varied from customer to customer with the majority achieving a saving. Illustrations of the impact of critical peak pricing (CPP) alerts are shown in Figures PI03/3 and PI03/4 (page 167). In both cases, demand decreased significantly during the CPP period, but increased after the end of the period. On 1 February 2006, the increase in demand resulted in a peak later in the evening that was higher than that on the comparison day without a CPP event. Detailed analysis is yet to be completed.
Figure PI03/3. Impact of 22 June 2005 CPP Event in the Queanbeyan Trial

Figure PI03/4. Impact of 1 February 2006 CPP Event in the Queanbeyan Trial
SOURCES


CASE STUDY PREPARATION

**Name:** David Crossley  **Email:** crossley@efa.com.au
CASE STUDY 20

EFFICIENT LIGHTING PROJECT DSM PILOT - POLAND

IEADSM Task XV Case Study No. EE01
Last updated 26 August 2005
Location of Project Cities of Chelmno, Elk and Zywiec, Poland
Year Project Implemented 1996
Year Project Completed 1997
Name of Project Proponent International Finance Corporation
Name of Project Implementor Municipal governments of Chelmno, Elk and Zywiec
Type of Project Implementor Local government (municipality)
Purpose of Project Deferral of network augmentation
Timing of Project Pre contingency
Focus of Project Network capacity limitations
Project Objective Peak load reduction
Project Target Network region
DSM Measure(s) Used Energy efficiency
Specific Technology Used Compact fluorescent lamps
Market Segments Addressed Residential customers

DRIVERS FOR PROJECT

The Poland Efficient Lighting Project (PELP) was developed by the International Finance Corporation (IFC), the private sector affiliate of the World Bank Group, and funded with USD5 million from the Global Environment Facility (GEF) to reduce greenhouse gas emissions by accelerating the introduction of compact fluorescent lamps (CFLs) in Poland. The DSM pilot was a component of PELP.

The DSM pilot was designed to use CFLs to help introduce DSM to Polish electric utilities, in particular, to introduce the concept of using DSM to defer distribution and transmission investments in the Polish electricity system.

The idea of using DSM to defer investments in distribution and transmission systems can be placed in the larger context of a utility planning concept known as distributed utilities (DU). The DU concept seeks to identify small-scale “distributed” electric resources both supply- and demand-side that can be alternatives to traditional electricity network and central power station investments. Both these resources are small relative to traditional central generation resources; and they are distributed throughout the electric system, located near the loads they serve. Locating resources near load centres allows electricity utilities to avoid or defer expensive transmission and distribution systems upgrades that would otherwise be needed.

The DSM pilot was intended to demonstrate to the Polish electricity industry, in real field conditions, the potential benefits of a demand-side program implemented in a DU analytical framework. Specifically, the pilot aimed to reduce peak power loads in geographic areas where the existing electricity network capacity was inadequate to meet existing loads or soon would be inadequate to meet future load growth.
DESCRIPTION OF PROJECT

The DSM pilot was initially designed to be led and implemented by selected electricity distribution companies in Poland, but their reluctance to engage in such a role forced the pilot to be redesigned. (Among other things, their reluctance was based on the belief that a project that would result in reduced electricity sales couldn't possibly be good for their business.) The new pilot design depended on the majority involvement and leadership of municipal governments, with electricity distribution companies providing a supporting role. Municipal governments were thought to be good candidates for majority involvement in the DSM pilot:

- they had a strong political interest in reducing the energy costs of their citizens;
- they had a public mandate to engage in activities that improved the environment;
- they had a legal responsibility to plan for and make investments in the electric distribution network within their jurisdictions, making them very interested in programs designed to defer such investments.

Three cities and their regional electricity utilities were selected to participate in the DSM pilot: Chelmno (a city of about 22,000 inhabitants in north-central Poland), Elk (a city of about 54,000 inhabitants in north-east Poland), and Zywiec (a city of about 35,000 inhabitants in south-central Poland). The cities were selected because they were willing and able to participate and they had areas with electricity network capacity problems. While the entire areas of all three cities participated in the DSM pilot, several target areas within the cities were established for intensive CFL promotion and electric load analysis. Engineers from the electric power distribution companies in Elk and Chelmno (Torun ZE and Bialystok ZE, respectively) identified the primary trouble spots in residential areas of their distribution systems. These areas had network components (cables or transformers) whose use was nearing their rated capacities. These neighbourhoods were selected as the target areas for the DSM pilot.

The backbone of the DSM pilot was a CFL subsidy/coupon system, which was designed to persuade large numbers of people in selected areas to purchase and install CFLs. The cost of CFLs sold through the pilot was subsidised with USD100,000 of PELP funding. The subsidies were directed at participating CFL manufacturers in exchange for their agreement to certain negotiated wholesale prices and delivery arrangements.

The subsidised lamps were made available to the residents of the three cities using discount coupons. There were three types of coupons, labelled A, B, and C. The A and B coupons, which offered the highest price discounts (about 55% and 45% respectively), were delivered only to those residents living in the target areas. The C coupons (about 35% discount) were delivered to the remaining residents of the participating cities. (A small number of C coupons were also delivered to residents in the target areas.) In all three cities, the A and B coupons were valid only for the first two weeks of the pilot’s operation. This timeframe was established to encourage residents in the target areas to make their CFL purchases quickly so that it would be easier to measure the effect of a massive CFL installation on the electricity networks in the target areas (where measurements of electricity use were focused). The C coupons were valid for six weeks, after which the pilot CFL sales ceased.
To achieve a high level of sales at the retail stores, a large-scale public education and promotion campaign was implemented. The campaign included numerous promotional events at local schools, public places, and included installing CFLs in the church of a popular parish priest, after which CFL sales surged.

The points on the electricity network serving the target areas in Chelmno and Elk were the focus of the load measurements and analysis completed as part of this pilot program. Load measurements were taken using meters that measured both real and reactive power at each of the measurement points. The meters recorded average power over every 15-minute interval. Short-term measurements were also taken of the current harmonic distortion, before and after CFL installation, on the low voltage (0.4 kV) lines. Measurements were taken continuously for a period of over 100 days, from mid-January to early June, in most cases.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>8,500</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak Load</td>
<td>Peak Load Reduction</td>
<td>Duration of Peak Load Reduction</td>
<td>Overall Load Reduction</td>
<td>Energy Savings</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

HOW LOAD REDUCTION WAS MEASURED

Modelled lighting load shapes.

RESULTS ACHIEVED

A high level of CFL sales was achieved in the three cities: more than 33,000 CFLs were sold in six weeks. A large number of CFLs were sold per household, which is especially notable given the low average incomes of the areas involved. There were larger numbers of CFL sold per household in the target areas, with the number varying from 9.66 per household in the Zywiec target area to 1.10 per household in all of Elk. Sales per household outside the target areas were achieved with strict limits on the availability of CFLs that could be purchased with coupons. Sales of CFLs per day to these areas continued to grow strongly until the supply limitation was encountered.

Estimates of the per-CFL peak lighting load reductions were produced using modelled lighting load shapes, data on the number and wattage of CFLs sold for each of the measured areas in Elk and Chelmno, and a procedure for allocating purchased lamps among the most used lighting points according to their pre-CFL installation installed wattage. Peak savings per CFL were highest in areas where lower CFL penetrations were achieved because most CFLs in these locations were installed in high-use fixtures, such as the kitchen and the largest room. Residents in locations with higher CFL penetrations installed the additional lamps in lower-use fixtures, such as bathrooms and halls, driving down the per-CFL peak savings.
Modelling results show that during the local peak hour of 20:00 on the peak day of the year (1 January), the end-use savings correspond to a 15% reduction in total electric peak demand for target area P4, a 16% reduction for P5, and a 15% reduction for P6.

Further modelling studies showed that if Torun ZE had paid all costs of promoting and distributing the CFLs in the P4 area, this program have been a cost-effective investment for Torun ZE.

Measurements were also made to assess the power quality impact of the CFL installations in the areas of Chelmno and Zywiec that achieved the highest level of CFL penetration. Measurement in both cities did not reveal any influence on voltage distortion from installing CFLs. Measurements of current distortion in Chelmno revealed a small increase after CFL installation, while measurements of current distortion in Zywiec made conclusions difficult to draw. Measured increases of current on the neutral lines in Chelmno were small, and total current on the neutral lines were still well within safety standards after the CFLs were installed.

CONFIDENCE LEVEL IN ACHIEVING RESULTS
Modelling was carried out of future net present cost outcomes and their probabilities, assuming a 10-year analysis horizon, for both a DSM and No DSM scenario at a particular site in Chelmno called Parkowa 2. The DSM scenario reflected the net present costs of grid upgrades, DSM program costs, and net lost revenues from pursuing a strategy of implementing the DSM pilot in the first year and then upgrading the grid only when subsequent load growth consumed existing grid capacity. The No DSM scenario reflected the net present costs of only grid upgrades, based on pursuit of a “business-as-usual” strategy.

The mode (most likely cost) of the distribution for the DSM scenario occurred at about PLN140,000 (about USD47,000) and had a probability of occurrence of about 20%. On the other hand, the mode of the No DSM distribution was substantially higher, at about PLN170,000 and had a much higher probability of occurrence at about 45%.

Therefore, it is highly probable that a DSM strategy would result in lower net present costs than a No DSM strategy for the Parkowa 2 site.

ACTUAL PROJECT COSTS
USD 100,000 (1996 dollars) of PELP funding paid by the project proponent, International Finance Corporation.

OVERALL PROJECT EFFECTIVENESS
Lack of quantitative data for the actual project results (as distinct from modelling results) makes it difficult to assess the effectiveness of this project as compared with other network-driven DSM projects. However, the project proponent appeared to be happy with the reductions in peak load of about 15% in the target areas. Unfortunately no information is available in the project reports about whether these peak load reductions resulted in the actual deferral of any planned network augmentations.
CONTACTS

Dana Younger
GEF Projects Coordinator
IFC Environmental Projects Unit
2121 Pennsylvania Avenue, NW
Room F-9K-148
Washington DC, 20433
Tel: (202) 473-4779 Fax: (202) 974-4349
E-mail: dyounger@ifc.org

SOURCES


CASE STUDY PREPARATION

**Name:** David Crossley  **Email:** crossley@efa.com.au
CASE STUDY 21
CARBON TRUST ADVANCED METERING TRIAL - UNITED KINGDOM

IEADSM Task XV Case Study No  SM01
Last updated  5 October 2008
Location of Project  Various locations throughout the United Kingdom
Year Project Implemented  2004
Year Project Completed  2006
Name of Project Proponent  The Carbon Trust
Name of Project Implementor  The Carbon Trust
Type of Project Implementor  Government-owned independent company
Purpose of Project  N/A
Timing of Project  N/A
Focus of Project  To understand the potential benefits of advanced metering for SMEs
Project Objective  Overall load reduction
Project Target  Whole network
DSM Measure(s) Used  Energy efficiency
Specific Technology Used  Advanced metering
Market Segments Addressed  Commercial and small industrial customers

DRIVERS FOR PROJECT

The Carbon Trust was set up by the United Kingdom Government in 2001 as an independent company and is funded by various government agencies. The Trust's mission is to accelerate the move to a low carbon economy by working with organisations to reduce carbon emissions and develop commercial low carbon technologies.

From 2004 to 2006, the Carbon Trust carried out the first UK field trial of advanced metering for small and medium enterprise (SME) end-users. The trial aimed to demonstrate the potential benefits of the technology and understand the business case for encouraging widespread adoption of advanced metering by SMEs.

The trial was devised with the following high-level objectives:

• to understand the potential benefits of advanced metering for SMEs;
• to stimulate market demand by demonstrating that advanced metering can reduce energy consumption and costs;
• to help understand the barriers to broader uptake and how they might be overcome;
• to identify the nature of advanced metering services which yield the best savings;
• to develop case studies, highlighting the advantages of advanced metering;
• to quantify the potential UK-wide carbon savings attributable to advanced metering in the SME community; and
• to identify potential policy measures to stimulate uptake.
The Carbon Trust advanced metering trial was unusual in that it was implemented by a government-owned independent company rather than an energy business and it focussed on savings in total energy use rather than peak load reductions. The trial is included in the Task XV case study database because it clearly demonstrates how advanced metering can enable businesses to identify energy, cost and carbon savings by providing detailed information about the ways in which they use electricity.

DESCRIPTION OF PROJECT

To deliver the field trial, the Carbon Trust contracted with seven consortia, all of which were already operating commercially in the metering market in the United Kingdom. The delivery consortia each recruited portfolios of SMEs or SME-like sites and installed advanced metering for electricity, gas and water at these sites as appropriate (not all utilities were metered at every site). A total of 582 sites across the United Kingdom were involved in the trial.

A total of 64 trial participants already had advanced electricity meters installed. For these sites no meter installation was necessary; all that was required was access to the existing half-hourly data. These sites were treated as a control group to investigate differences in use of advanced metering services between sites with and without existing interval metering. The findings from these sites were excluded from the bulk of the analysis in order to understand the potential for advanced metering in the SME sector where sites do not currently have interval metering in place.

Of the remaining sites, 73 made use of ‘pulsed-output’ meters with the capability to record half-hourly data through the use of clip-on readers. These readers enabled half-hourly data to be obtained without the need for upgrading the primary meter. At the remaining 455 sites, existing manually read meters were replaced with new advanced meters.

In addition to installing clip-on readers or new advanced meters at sites that did not already have interval metering in place, a variety of different types of energy saving advice were provided to sites during the trial. These services ranged from basic data provision to detailed advice on energy saving communicated through phone calls and site visits. Following are summaries of the types of energy saving advice provided.

Data Only. (134 sites, including 39 sites with pre-existing interval meters). The most basic offering was the provision of metered data only, normally via a website. Simple online tools were provided to allow sites to conduct basic analysis of their energy use profiles.

Data and Advice. (112 sites, including one site with a pre-existing interval meter). This intermediate level of service typically consisted of data provision together with a review of the site energy consumption and some basic energy saving recommendations relating to the site’s energy use profile. This information was normally communicated via email.

Personal Contact. (336 sites, including four sites with pre-existing interval meters). This level of service involved two-way communications with the site including detailed discussion of the energy use profiles, either via telephone or site visits. The delivery consortia provided site-specific recommendations and advice.
Figure SM01/1 shows how detailed half-hourly load profile data from advanced metering was used to identify opportunities for energy savings. Three key types of potential energy saving measures (corresponding to the numbers in Figure SM01/1) could be derived from advanced meter data:

1. **Base load reductions** – the overall base load of the site could be studied and reduced, for example, by identifying unnecessary constant energy use.

2. **Process optimisation** – the load profile could be used to identify what equipment is running and when. Altering the start-up and shutdown times of key processes and equipment could reduce consumption by limiting the duration of high energy usage at the start and end of working schedules.

3. **Peak usage reduction** – the load profile could be used to analyse timings and frequencies to identify the causes of peaks in energy usage, such as particular activities or equipment.

The consortia completed log books for each site, tracking the estimated energy savings for each recommendation and the extent to which each recommendation was successfully implemented.

A case study was also produced for each site to describe the overall actions taken and associated savings made. These case studies recorded the situation at the site prior to installation of advanced metering, including details about the organisation and annual energy consumption levels. Case studies included graphical data showing energy consumption and areas where potential savings had been identified. They also included the financial case for implementing energy saving actions and the levels of potential savings in terms of energy consumption, carbon emissions and costs.
As part of this process, the consortia reviewed the half-hourly meter data to identify and validate actual energy savings achieved. Where it was not possible to implement energy saving recommendations, the reasons for this were discussed with the site personnel and recorded for reference.

**Ow Load Reduction Was Measured**
Interval meter. 30 minute intervals.

**Results Achieved**
Detailed results of the energy savings identified and successfully implemented by the SMEs involved in the trial are shown in Figures SM01/2 and SM01/3 (page 178).

![Bar Chart]

**Figure SM01/2. Average Annual Energy Savings per Site in the Carbon Trust Advanced Metering Trial**

Figure SM01/2 shows that, on average, sites in the trial saved around 13,500 kilowatt-hours of electricity and 30,000 kilowatt-hours of gas per year by using the information gained from advanced metering. This equates to annual total savings across all sites in the trial of about 7,860 megawatt-hours of electricity and 17,460 megawatt-hours of gas.

Figure SM01/3 (page 178) shows the average cost savings identified and implemented per year. On average, sites in the trial saved around GBP870 on their electricity bills and GBP405 on their gas bills per year.
Figure SM01/3. Average Annual Cost Savings per Site in the Carbon Trust Advanced Metering Trial

Figure SM01/4 (page 179) shows the percentage carbon savings achieved by the type of energy saving advice provided. The way in which energy saving advice was delivered to SMEs resulted in marked differences in the savings achieved.

The Data Only service, where customers were simply provided with remote online access to their energy usage data, led to the lowest levels of savings. However, even here 10% energy savings were identified and 3% implemented on average. These were significant savings, especially as this service was considerably less resource-intensive for the service provider to deliver.

Most notably, the Data and Advice service, where energy saving advice was provided remotely via email, led to the highest levels of energy savings, with an average of 15% savings identified and 7.5% successfully implemented. These savings are higher than those achieved for the Personal Contact service, in which advice was provided directly via site visits and telephone calls, where an average of 12.5% savings were identified and 5% implemented successfully. This is a significant finding and there appears to be two key potential reasons for this result.
Firstly, when service companies provide advice via site visits and telephone calls, the advice is generally highly customised and there is a tendency to focus on high value-added recommendations. These are likely to lead to more complex process-based changes or more expensive investment-based actions. There is also less focus on providing generic energy saving recommendations, such as simple information-based or process-based changes. However, it seems that many SMEs, and especially those with limited prior experience of energy saving, can benefit from these "quick win" generic actions.

Secondly, energy saving advice which arrives via email is readily available and more likely to be looked at and acted upon directly than more conventional energy audit reports. This is especially true when the email contains simple, intuitive graphical information, such as daily energy consumption profiles. Also, the email format allows the information to be easily forwarded on to staff within the organisation to take the relevant actions, for example operations or facilities management personnel.

A key implication of this finding is the possibility of providing advanced metering services at significantly lower costs in the future. The email service model is highly scalable and it would appear feasible that automated systems could be used to analyse SME energy usage profiles, identify appropriate recommendations and automatically email these to the customer, with supporting graphical evidence. Such an automated service, backed up with call centre support, would allow for a significantly lower-cost service model than one involving on-site or telephone-based analysis and discussion.

This model for delivering energy saving advice could be easily adapted to deliver advice on reducing peak loads rather than reducing overall energy consumption.
OVERALL PROJECT EFFECTIVENESS

The Carbon Trust trial is a good example of what can be achieved if advanced meters are actively used for data monitoring, collection and analysis as part of a comprehensive program focussed on realising energy savings. The systems developed for the trial could be easily adapted to deliver advice on reducing peak loads rather than reducing overall energy consumption.

SOURCES


CASE STUDY PREPARATION

Name: David Crossley  Email: crossley@efa.com.au
CASE STUDY 22
BINDA-BIGGA DSM PROJECT - AUSTRALIA

IEADSM Task XV Case Study No  FS02
Last updated  12 July 2006
Location of Project  The rural communities of Binda and Bigga near Crookwell in New South Wales, Australia
Year Project Implemented  2004
Year Project Completed  2005
Name of Project Proponent  Country Energy
Name of Project Implementor  New South Wales Sustainable Energy Development Authority (now the Department of Environment and Climate Change)
Type of Project Implementor  Third party aggregator
Purpose of Project  Deferral of network augmentation
Timing of Project  Pre contingency
Focus of Project  Voltage fluctuations
Project Objective  Peak load reduction
Voltage regulation
Project Target  Network element
DSM Measure(s) Used  Energy efficiency
Fuel substitution
Specific Technology Used
Market Segments Addressed  Residential customers

DRIVERS FOR PROJECT

Binda and Bigga are two small rural settlements near Crookwell about 230 km southwest of Sydney. The Binda-Bigga area has about 250 electricity customers, mostly residential.

The electricity line that runs from Binda to Bigga and then further on to Grabine was installed several years ago by Country Energy. Overall load growth on the line was relatively low but, as peak electricity use increased in the area, the line was reaching its maximum capacity. The base electrical load used for the line was 750kVA, however peak demand had been registered at 1,000kVA.

Fault levels and voltage levels were a concern along the line, especially during storm events, due to the length of the line and the rugged country through which the line passes. Many customers in Binda and Bigga were experiencing unacceptable voltage fluctuations which could be resolved only by extensive reconductoring of the line.

Country Energy contracted SEDA in 2004 to relieve the electrical demand on the Crookwell to Grabine feeder during times of winter evening peaks. The aim of the contract was to defer the need for the upgrade of the Crookwell to Grabine feeder by reducing the demand for energy during the winter evening peak periods (the four hours from 6 pm to 10 pm).
DESCRIPTION OF PROJECT

Initial Investigation

There are two winter peaks on the Crookwell to Grabine feeder, one around midnight due to off-peak hot water controlled loads and an evening peak (see Figure FS02/1). The evening peak tends to occur on days when the minimum temperature drops as low as minus 9 degrees Celsius.

![Figure FS02/1. Peak Winter Demand on the Crookwell to Grabine Feeder](image)

In January 2004, SEDA conducted a survey of Binda and Bigga residents to explore what might have been causing the peaks in electricity demand during winter evenings. Results showed that a typical winter energy bill was over AUD 250 each quarter – a large percentage due to room heating and cooking end-uses.

Project Objectives

The following objectives were established for the project:

- to reduce the electricity load on Country Energy’s Crookwell to Grabine feeder by 200kVA by 2006 during winter evening peaks (the four hours from 6 pm to 10 pm);
- to deliver real benefits to rural customers through reducing their energy consumption and improving the quality of supply for residents on the Crookwell to Grabine feeder;
- to reduce greenhouse gas emissions through fuel substitution of electric appliances to gas.
DSM Strategies
Two DSM strategies were investigated:

- **Cogeneration Option:** the installation of a cogeneration plant at the Grabine State Recreation Park to achieve a reduction of 100kVA in peak electrical demand; and

- **Domestic Solution:** a range of strategies to facilitate the uptake of energy efficient products and measures, primarily achieved through fuel substitution of residential appliances from electricity to bottled gas to achieve a reduction of another 100kVA in peak electrical demand.

After an initial investigation, the Cogeneration Option proved uneconomic, so the Domestic Solution was the method by which the total required demand reduction of 200kVA was sought.

The Domestic Solution facilitated the uptake of energy efficient products and measures by residents through a range of residential DSM strategies. It integrated the following strategies:

- developing an Energy Saver Package;
- engaging local project partners;
- offering Energy Smart Home audits;
- implementing marketing and communications campaigns; and
- holding community forums in Binda and Bigga.

Energy Saver Package
The Energy Saver Package was developed as the primary mechanism to achieve the required demand management reduction of 200kVA. To reduce the demand on the electricity feeder during the peak time, the Package was structured around appliances that would reduce electricity demand from residents cooking an evening meal and heating their homes.

The Energy Saver Package enabled residents to affordably switch from electric to gas appliances (see Figure FS02/2, page 184). It offered residents:

- discounted gas room heaters and cooking stoves (a maximum of two appliances per household);
- free installation of gas appliances and gas bottles, and removal of electrical appliances for metal recycling; and
- gas credits of AUD 170 per appliance – equivalent to free gas for a year.

To achieve the peak demand reduction target of 200kVA, the installation of 98 gas appliances was required.
Customers were required to meet a number of conditions to qualify for the Energy Saver Package. They had to:

- be connected to the Crookwell to Grabine Feeder, and be a Country Energy customer;
- agree to surrender their electric heaters and stoves at the time of installation of the new gas appliances;
- commit to leaving gas appliances installed and operational for a period of 5 years; and
- submit signed a Customer Form and payment by 30 September 2004 (extended to 31 October 2004).

The Energy Saver Package was designed to be easy for residents. The new gas appliances were delivered to the customers' homes and the appliances and gas bottles were installed. The old electric appliances were removed during the same visit and taken for recycling.

Energy Smart Home Audits

Energy Smart Home audits were offered to residents in Binda and Bigga to facilitate the uptake of energy efficient products and measures. The audits also provided the opportunity for residents to have assessed the suitability of their home/appliances for the gas appliance offer.

The three components of an Energy Smart Home audit comprise a Star Rating, a virtual home audit and a personal visit from an Energy Assessor. The audit provides a measure of energy efficiency for a home by comparing its rating to an average. The result is a star rating between 1 and 5, with 5 being the most energy efficient. Moving up just one star can save AUD 150-300 per annum.
Residents were offered an Energy Smart Home audit for AUD 20, rather than the normal AUD 100, and the cost of the audit was redeemable against the purchase of a gas heater or stove (as part of the Energy Saver Package).

Marketing and Communications

The Energy Saver Package was promoted to residents through a brochure and poster detailing the Energy Saver Package options, advertising two community forums for residents and providing information on Energy Smart Home audits.

Two free community forums were held in Binda and Bigga. Topics covered included:

- the Energy Saver Package;
- Energy Smart Home audits;
- Green Power – electricity generated from renewable sources; and
- tips on saving energy around the home and reducing bills.

The Project Team was on hand to provide additional information on the Energy Saver Package products, gas connections and installations. Gas appliances were on display for residents to view the products included in the Package. Energy efficient prizes were on offer at the forums, including Energy Saver kits which featured a compact fluorescent light bulb, door snake, AAA-rated showerhead and toilet cistern weight.

Finally, a competition was held in which residents could win one of two solar hot water systems. All residents who purchased and qualified for an Energy Saver Package were entered into the competition.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Peak Load Reduction</th>
<th>Duration of Peak Load Reduction</th>
<th>Overall Load Reduction</th>
<th>Energy Savings</th>
<th>Network Augmentation Deferral</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2 MW</td>
<td>4 hours</td>
<td>0.2 MW</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

HOW LOAD REDUCTION WAS MEASURED

Recloser logs.
RESULTS ACHIEVED

Overall 70 customers purchased an Energy Saver Package, purchasing 106 appliances in total, between July and October 2004. This exceeded the target of 98 appliances and included:

- 60 unflued room heaters (56%);
- 42 cooking stoves (40%); and
- 4 flued room heaters (4%).

Of the 70 Energy Saver Packages purchased, the most popular package was the “unflued room heater + cooking stove package” (34 customers), followed by the sole purchase of an unflued heater (26 customers) (see Figure FS02/3).

![Figure FS02/3. Type of Energy Saver Package Purchased](image)

Only 17 customers were already connected to a bottled gas supply with 53 customers requiring gas connection including slab, bottle delivery, piping and wiring.

A total of 106 electric heaters and stoves (64 room heaters and 42 cooking stoves) were removed and recycled at the metal recycling facility at Crookwell Waste and Recycling Centre.

In the week of the 19th to 23rd July 2004, 13 Energy Smart Home audits were conducted, as well as a further six visits to homes to assess suitability of gas appliances being installed if residents purchased an Energy Saver Package. Residents at 16 of the 19 properties visited purchased the Energy Saver Package offer.

Figure FS02/4 (page 187) shows the reduction in the peak load on the Crookwell to Grabine feeder after implementation of the Binda-Bigga Demand Management Project.
AVOIED COSTS

The network augmentation solution to these problems was estimated to cost AUD 412,500 over a 5 year period.

The DSM budget was AUD 108,000 (average rate of $540/kVA reduced). This represents the cost savings of deferring the investment for five years.

ACTUAL PROJECT COSTS

AUD 108,000 paid by Country Energy.

AUD 28,412 contribution by residents to cost of gas appliances.

OVERALL PROJECT EFFECTIVENESS

Extremely high take-up rate for fuel substitution.

CONTACTS

Leith Elder
Country Energy
PO Box 718
Queanbeyan NSW 2620
02 4828 6807
Email: leith.elder@countryenergy.com.au
International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks

SOURCES

CASE STUDY PREPARATION
Name: David Crossley / Leith Elder   Email: crossley@efa.com.au / leith.elder@countryenergy.com.au
CASE STUDY 23
TEMPO ELECTRICITY TARIFF - FRANCE

IEADSM Task XV Case Study No PI06
Last updated 3 November 2010
Location of Project Throughout France
Year Project Implemented 1993
Year Project Completed Ongoing
Name of Project Proponent Electricité de France (EDF)
Name of Project Implementor EDF and Réseau de Transport d'Electricité (RTE)
Type of Project Implementor Electricity retailer / supplier
Electricity distribution (wires) business
Electricity transmission (wires) business
Purpose of Project Deferring augmentation of the electricity network
Project Objective Reducing peak loads
Project Target Whole electricity network
DSM Measure(s) Used Pricing initiatives
Specific Technology Used
Market Segments Addressed Residential electricity end users
Commercial and small industrial electricity end users

DRIVERS FOR PROJECT
European Union Directive 2003/54/EC required increased contestability of customers in the electricity market, ie customers could choose their electricity supplier from a range of electricity retailers. In France, customers contestability, was introduced in July 2004 for small business customers and in 2007 for residential customers.

Since the 1960s, EDF has been moving towards real-time pricing of electricity linked to marginal costs of supply. Consequently, electricity customers in France have been motivated to reduce their consumption when the generation costs are high and during congestion on the electricity network.
Tempo was the most sophisticated tariff for mass market customers the previous situation where EDF had a monopoly in the generation and retail supply of electricity in France.

The Tempo tariff enables smoothing of both the annual and daily electricity load curves, therefore reducing marginal generation and network costs.

DESCRIPTION OF PROJECT
In France, electricity bills for residential and small business customers include a standing charge determined by the level of maximum demand (in kVA) nominated by the customer (puissance souscrite), and an energy usage charge based on the type of tariff chosen by the customer (type d'abonnement).
There are three types of electricity contract from which residential and small business customers can choose:

**Option Base**
This is the simplest of the three contract types with the lowest standing charge and a flat rate for electricity usage all the time throughout the day and year. It is more suitable for lower usage, smaller homes and holiday homes with only occasional usage.

**Option Heures Creuses (Option HC)**
This is a two-part time-of-use tariff with normal (*heures pleines*) and off-peak (*heures creuses*) rates. The standing charge is slightly higher than that of Option Base, but this is offset against a lower off-peak rate for part of the day. The off-peak period is from 10 pm until 6 am each night and, in some regions, also at midday. Option HC is usually used in conjunction with a water heater operated by ripple control so that the heating element is switched on only during off-peak periods. Option HC suits the majority of houses used full time where heating is non-electric.

**Option Tempo**
This is a quite complicated charging system with six rates of electricity pricing based upon the actual weather on particular days and on hours of use.

Under Option Tempo, each day of the year is colour coded. There are three colours, blue (*jours bleus*), white (*jours blancs*) and red (*jours rouges*) which correspond to low, medium and high electricity prices.

The colour of each day is determined mostly by EDF based on the forecast of electricity demand for that day - the level of demand is mainly influenced by the weather. RTE, the French transmission network operator (formerly a division of EDF), also has the ability to determine the day colour if there is significant congestion on the electricity network.

In addition to a colour, each day also has normal and off-peak periods based on Option HC outlined above, with 10pm until 6am being the off-peak period. The rules for the Option Tempo are as follows:

- the Tempo year starts on 1st September;
- the Tempo day starts at 6 am;
- the number of days per year of each colour is fixed - there are 300 blue days, 43 white days and 22 red days;
- Sunday is always a blue day;
- red days cannot fall on a holiday, weekend or more than five weekdays in a row.

On blue days, the electricity price is by far the lowest - during the off-peak period on a blue day the price is extremely low.

On white days, the price is higher than under Option Base or Option HC.
On red days, the price is very high to encourage lower electricity usage - the normal rate on red days is nine times that of the off-peak rate on blue days. Red days are usually the coldest days in winter.

From 15 August 2010, the prices per kilowatt-hour for electricity purchased under Option Tempo are as follows (see Figure PI06/1):

- Blue days off-peak: 5.72 euro cents
- Blue days normal: 7.22 euro cents
- White days off-peak: 9.01 euro cents
- White days normal: 11.09 euro cents
- Red days off-peak: 18.48 euro cents
- Red days normal: 51.75 euro cents

![Figure PI06/1. Tempo Tariff Rates from 18 August 2010](image)

There are four different versions of Option Tempo, depending on the metering, communications and load control equipment installed at the customer's premises:

- standard Tempo (the customer has only an electronic interval meter);
- dual energy Tempo (the customer's space-heating boiler can be switched from one energy source to another);
- thermostat tempo (the customer has load control equipment which is able to adjust space heating and water heating loads according to the electricity price);
- comfort Tempo (the customer has a sophisticated energy controller).
Customers who choose Option Tempo are informed each night about the colour for the next day. At 8 pm a signal is sent down powerlines using a ripple control system. Most Tempo customers have a display unit that plugs into any power socket and picks up the signal. The display unit shows the day colour with lights, both for the current day and (from 8pm) for the next day. An (optional) beep informs the consumer if the following day will be a red day. The display unit also shows whether or not the current electricity price is at the off-peak rate.

For older systems without a display unit the information is available over the telephone or via the internet.

Customers can adjust their electricity consumption manually by switching off appliances, adjusting thermostat settings, etc. Some customers who have the necessary communications and load control equipment are able to select load control programs which enable automatic connection and disconnection of separate water-heating and space-heating circuits.

Option Tempo is for high use households, such as very large houses, and those with electric heating and full time occupation, and for small business customers.

RESULTS

<table>
<thead>
<tr>
<th>Residential Customers Participating</th>
<th>Commercial and Small Industrial Customers Participating</th>
<th>Agricultural Customers Participating</th>
<th>Large Industrial Customers Participating</th>
<th>Additional Generation Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>350,000</td>
<td>100,000</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Peak Load Reduction</th>
<th>Duration of Peak Load Reduction</th>
<th>Overall Load Reduction</th>
<th>Energy Savings</th>
<th>Greenhouse Emissions Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>450 MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Compared with blue days, the Tempo tariff has led to a reduction in electricity consumption of 15% on white days and 45% on red days, on average 1 kW per customer (see Figure PI06/2, page 193).

Tempo customers have saved 10% on average on their electricity bill and 90% of the customers are satisfied with the tariff. However, customers do not appreciate red days occurring consecutively.
ASSESSMENT OF OVERALL PROJECT EFFECTIVENESS

While the Tempo tariff has been successful, less than 20% of electricity customers in France have chosen Option Tempo. Tempo customers have very particular customer profiles and are interested in managing their energy use. They are prepared to constrain their lifestyles to make comparatively small financial savings relative to their incomes.

The Tempo tariff was designed specifically for the situation where EDF is a monopolistic generator and retail supplier of electricity. However, it is not adapted to an open market situation.

In the French open electricity market:
- the network use of system charge does not vary between seasons; and
- the value of peak load reduction is not reflected in spot prices for energy which are less volatile than the marginal costs of supply.

If EDF needs to manage its global load curve in an open electricity market, it will probably have to develop other types of dynamic pricing for mass market customers. The feedback from Tempo customers will be very useful in developing new customer which include electricity supply and services.

In July 2009, EDF discontinued the Tempo tariff for new customers and for customers who are on the tariff at their current residence and then move house.
CONTACTS

Eric Vidalenc
Service Observation, Economie et Evaluation
Agence de l'Environnement et de la Maitrise de l'Énergie
27 rue Louis Vicat
75737 Paris CEDEX 15
France
Tel: + 33 1 47 65 22 05
Fax: + 33 1 40 95 74 53
Email: eric.vidalenc@ademe.fr

SOURCES
