

CODE OF PRACTICE

DEMAND MANAGEMENT
FOR
ELECTRICITY DISTRIBUTORS



28 OCTOBER 1999

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1. PURPOSE

The licencing regime established under the *Electricity Supply Act (1995)* places environmental protection and other obligations on participants in the electricity supply industry in New South Wales.

This Code of Practice on Demand Management builds on the policy context of the *Act*. It sets out practices that are appropriate for electricity distributors to carry out in fulfilling the demand management obligations imposed in their licences issued under the *Act*.

In particular, the Code is intended to:

- give appropriate recognition to the value of demand management in the rational planning of electricity industry infrastructure;
- represent best practice;
- promote cost-effective outcomes;
- reflect the electricity industry's environmental responsibilities;
- assist electricity distributors to identify and address the range of opportunities and constraints arising in all areas of their businesses and their business environments, that:
 - ◆ impact on the cost effectiveness of their demand management strategies; or
 - ◆ have scope to adapt in response to such strategies;
- provide for effective reporting and appraisal;
- specify use of methodologies that are generally consistent with other licence obligations on electricity distributors;
- minimise regulatory burdens (and consequential costs);
- provide guidance on setting reasonable limits, beyond which further investigation would be unlikely to identify alternatives that will yield materially improved economic, environmental or competition outcomes.

2. DEMAND MANAGEMENT OBLIGATIONS

The *Electricity Supply Act* establishes a licencing regime under which an electricity distributor operating in New South Wales is required to hold an electricity distributor's licence. The licences are subject to conditions imposed by the *Act* and by Minister for Energy.

The *Act* includes broadly among its objects

- efficient and environmentally responsible production and use of electricity;
- open access to electricity distribution networks, with customer choice and customer rights promoted in relation to electricity connection and electricity supply.

Consistent with these objects, the *Act* requires that the Minister for Energy impose a condition on each licenced electricity distributor to conduct investigations on the cost effectiveness of implementing demand management strategies that may permit distribution network augmentation work being deferred or avoided.

Specifically, Schedule 2(6)(5) of the *Act* states:

Without limitation, the Minister must impose the following conditions on each electricity distributor's licence:

- (a) a condition requiring the holder of the licence, before expanding its distribution system or the capacity of its distribution system, to carry out investigations (being investigations to ascertain whether it would be cost-effective to avoid or postpone the expansion by implementing demand management strategies) in circumstances in which it would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion by implementing such strategies,*
- (b) a condition requiring the holder of the licence to prepare and publish annual reports in relation to the investigations carried out by it as referred to in paragraph (a).*

In accordance with the *Act*, the Minister has imposed Licence Condition 3.1 in all electricity distributors' licences. This condition substantially repeats the wording from the *Act*.

The objective of the requirement in the *Act* is to secure the best value for customers and other stakeholders in the planning and operation of electricity distribution networks, particularly in relation to:

- network augmentation decisions;
- demand management alternatives to network augmentation.

Distributors face related obligations under the National Electricity Code, and through assessment of their revenue caps by the Independent Pricing and Regulatory Tribunal in conjunction with the Australian Competition and Consumer Commission. There are also more general obligations under the Trade Practices Act and National Competition Policy. These related obligations should be kept in mind in applying this code.

3. APPLICATION AND OBJECTIVES

This Code of Practice has been developed to assist electricity distributors carry out investigations to ascertain whether it would be cost effective to avoid or postpone the expansion of the electricity distribution system by implementing demand management strategies. Where they are proved to be cost effective, these strategies must be implemented by the electricity distributor and reported as part of the distributor's *Licence Compliance Annual Report*.

This Code provides assistance to:

- ensure compliance with the distributor's licence condition 3.1;

- suggest various methodologies which can be used in determining the cost effectiveness of network expansion options as compared to demand management options;
- detail the minimum level of information required when reporting on demand management initiatives in the electricity distributor's *Licence Compliance Annual Report*;
- recommend a standard reporting methodology which all distributor licence holders must follow in the production of the *Licence Compliance Annual Report*.

While this Code suggests methods by which individual demand management investigations can be carried out, it is not intended to be a prescriptive model. The level of detail used in investigating demand management programs depends on individual circumstances. However, this level of detail must always be sufficient to ensure that the decisions made can be substantiated and justified. The detailed record of each individual investigation is to be retained by the distributor for audit purposes.

4. SCOPE

This Code of Practice stipulates when demand management investigations are to be conducted and suggests a process to follow. Also described are the consultation process, applicable environmental considerations and the treatment of externalities which electricity distributors need to consider when investigating demand management strategies. A distributor's perspective is used in determining the commercial costs and benefits associated with investigating demand management alternatives.

Demand management strategies, are to be specifically investigated for major infrastructure investments. Major infrastructure investments include the following:

- new zone and transmission substations;
- new transmission and subtransmission feeders;
- major augmentation of zone and transmission substations and transmission and subtransmission feeders;
- substantial new distribution system backbone feeders.

Minor network expansion projects on distribution networks are predominantly associated with connecting new customers. Demand management strategies associated with these works are still required, but may be covered by general programs such as off-peak load control.

Detailed definitions of major infrastructure investments and minor network expansions are included in Appendix A.

It should be recognised that electricity retailers, as part of their licence conditions, adopt demand management strategies relating to individual customers. The primary purpose of these retailer initiatives is to meet targets in greenhouse gas reduction. Retailers also pursue demand

management initiatives as a value-added service to customers. Distributors play a role in assisting retailers implement customer-related demand management programs. Electricity distributors should ensure that all retailers and energy service companies have an equal opportunity to access such support programs or contract to provide demand management services and network support. These activities assist in minimising or avoiding minor network expansions and should be included in the *Licence Compliance Annual Report*.

5. DEMAND MANAGEMENT INVESTIGATIONS

The purpose of carrying out demand management investigations is to identify demand management alternatives to network augmentations which are more cost-effective than the “build” option.

The *Electricity Supply Act* requires that the investigations be carried out:

- prior to distribution network augmentation or expansion; and
- when it is reasonable to expect that there would be cost-effective alternatives.

Clearly the investigations should also be managed to allow for the action required to implement cost-effective demand management alternatives, and to dismantle barriers to the implementation of these alternatives.

Demand management investigations should form an integral part of each distributor’s network planning processes. In NSW, network planning is now carried out by distributors in the context of the major changes in the structure and operation of the electricity supply industry instituted by the passage of the *Electricity Supply Act* and the establishment of the National Electricity Market.

In particular, following the commencement of the National Electricity Market on 13 December 1998, the market behaviour of electricity distributors in NSW is now regulated by the *National Electricity Code*. In relation to the development of distribution networks within a region, the *National Electricity Code* states:

5.6.2 (a) *Each Distribution Network Service Provider must analyze the expected future operation of its distribution networks over an appropriate planning period, taking into account the relevant forecast loads, any future generation and transmission developments and any other relevant data.*

5.6.2 (f) *.....the [Distribution] Network Service Provider must consult with affected Code Participants and interested parties on the possible options, including but not limited to demand side and generation options, to address the projected limitations of the relevantdistribution system.*

In addition to introducing competition into the generation and retail sectors of the industry, both the *Act* and the *National Electricity Code* signal that stakeholders are to become much more involved in the operations of the non-competitive sectors of the industry. For electricity distributors, this

means that network planning processes, which previously were carried out almost entirely within the business, are now to be open to stakeholders involvement. Contractual arrangements for the provision of network services (including connection contracts) should provide incentives for appropriate distributed resource options such as embedded generation.

The following subsections detail the matters which should be considered, and where appropriate reported on, in carrying out demand management investigations under this Code of Practice. While this Code of Practice outlines requirements to meet the NSW licence conditions in regard to demand management, the processes are equally applicable to the consideration of other 'non-network' options such as distributed generation resources and storage. Indeed the use of these processes to consider the full range of options may be an efficient and effective means of meeting the requirements under the National Electricity Code.

5.1 Determining the Reason for Network Expansion

Valid reasons for considering network expansion or augmentation include:

- to meet increasing customer electrical demand;
- to improve the reliability and flexibility of the network;
- to improve the quality of supply.

The electricity distributor must determine the planning standard to be adopted in assessing the need for network expansion. In particular, the proposed expenditure must be justified in terms of the distributor's financial approval criteria and customer expectations. These criteria should consider the time value of money and all income and expense streams. In addition, the assessment of the need for network expansion must be based on sound industry practice.

Reporting Requirements

The results of the assessment of the need for network expansion should be reported briefly in the distributor's *Licence Compliance Annual Report*. In addition, complete records of such assessments must be maintained by the electricity distributor as part of their internal audit trail and should be able to withstand an external audit.

5.2 Carrying Out Risk Analysis

Certain network expansion projects may be postponed with the acceptance of an increased level of risk. This is associated primarily with the "do nothing" option. The acceptable risk level will vary depending on the load and customer profiles. The quantification of the level of risk relies on plausible assumptions about likely failure rates. Standard industry outage rates may be used, similar to those stipulated in the report *Guidelines for Reliability Assessment Planning* published by the Electricity Supply Association of Australia in April 1995.

Other variables in performing risk analysis include:

- the methodology used to calculate the energy or demand at risk;

- the level at which the risk is assumed to be unacceptable;
- the price per kilowatt-hour used in quantifying the dollar value of the energy or demand at risk.

In evaluating whether a required network expansion can be postponed, the distributor should consider the following factors which reflect the impact on customers:

- the load at risk;
- the energy at risk;
- appropriate Values of Lost Load (in consultation with customers);
- the proportion of time firm capacity constraints may be exceeded.

As load continues to grow and the risk is forecast to move beyond an acceptable level, electricity distributors will need to investigate alternative options which include demand management strategies and/or “build” options.

This highlights the difference between the financial and economic analysis carried out by a distributor. While a financial analysis may indicate a project is not viable, an economic analysis, which considers the energy or demand at risk, may prove otherwise. Therefore, it is important to consider the value of supply to customers as part of the economic analysis. The economic regulatory framework should recognise the quantifiable level of risk as a justification to proceed to investigate demand or supply side options. Therefore, a reasonable allowance for the efficient costs of these investigations should be included as an allowable expense by the distributor.

Reporting Requirements

The results of the evaluation of whether a required network expansion can be postponed should be reported briefly in the distributor’s *Licence Compliance Annual Report*. In addition, complete records of such evaluations must be maintained by the electricity distributor as part of their internal audit trail and should be able to withstand an external audit.

5.3 Developing Demand Management Strategies

Electricity distributors must investigate and/or seek expressions of interest in demand management strategies as alternatives to major investments in network infrastructure (as defined in section 4 above and Appendix A below). Appendix B contains some case studies of demand management strategies.

Figures 1 & 2, over the page, outline in general terms how an electricity distributor should approach investigating demand management strategies. Further detail is provided in the following subsections.

5.3.1 Determining the Appropriateness of Demand Management

The initial test that should be performed by the distributor is to determine whether a demand management strategy is likely to be appropriate compared with the network expansion option.

If the reason for expanding the network is to increase capacity to meet increasing customer demand, then demand management strategies are deemed to be appropriate for investigation.

However, if the reason for network expansion is to improve quality of supply, reliability or flexibility, then demand management strategies may not always be appropriate. However other distributed resource options such as embedded generation, fuel switching, UPS etc. may be cost-effective. In certain circumstances embedded generation may improve reliability. This should be investigated as part of the distributor's normal planning process.

In all cases the intention is that demand side options will receive equal consideration to supply side options from the earliest stage of any investigation. As part of this process, all relevant stakeholders will be kept informed in an appropriate manner throughout the process.

Two alternative processes are outlined in Figures 1 and 2 below. The first is more reliant on traditional network planning processes and forms the basis of the discussions in the following sections. The second approach is a market-based approach whereby the distributor seeks expressions of interest at the earliest possible opportunity.

At this stage either approach may be acceptable for demonstrating compliance with the network licence requirements for distributors. In the medium to longer term the second approach may provide the most certain and cost-effective means of determining the appropriateness of demand management and other alternatives. It relies on public disclosure of planning criteria and capital expenditure proposals together with a call for expressions of interest in alternatives. This may be a simpler process which reduces the extent of investigation and planning required to be undertaken by the distributor. However, the full realisation of the relative benefits of this approach is dependent on the depth of the market for energy management service providers and other options. In the interim the trialling of such a process is to be encouraged.

Reporting Requirements

The results of the determination of whether a required network expansion can be postponed should be reported briefly in the distributor's *Licence Compliance Annual Report*. In addition, complete records of such determinations must be maintained by the electricity distributor as part of their internal audit trail and should be able to withstand an external audit.

Figure 1
Demand Management Investigation Flow Chart

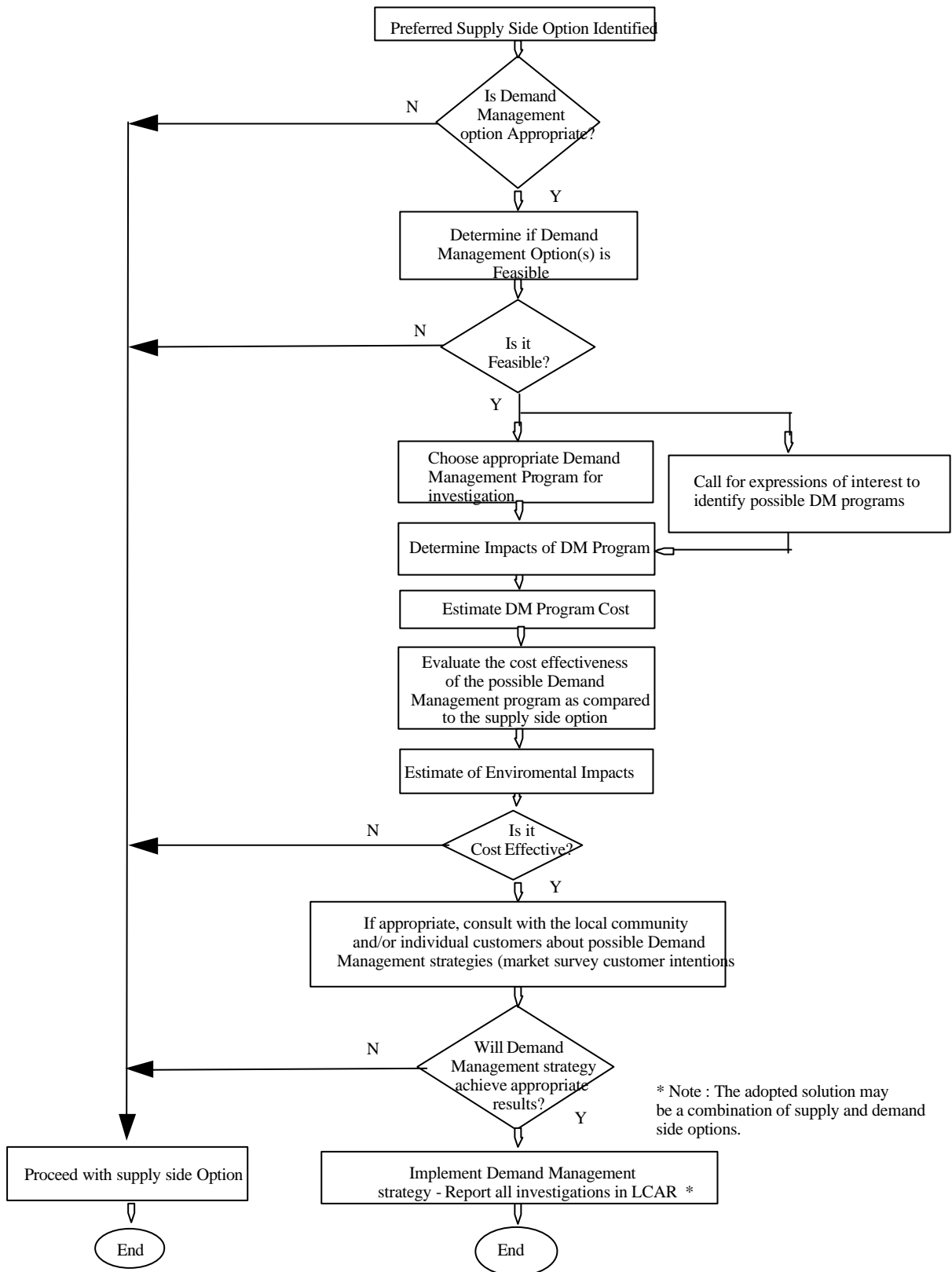
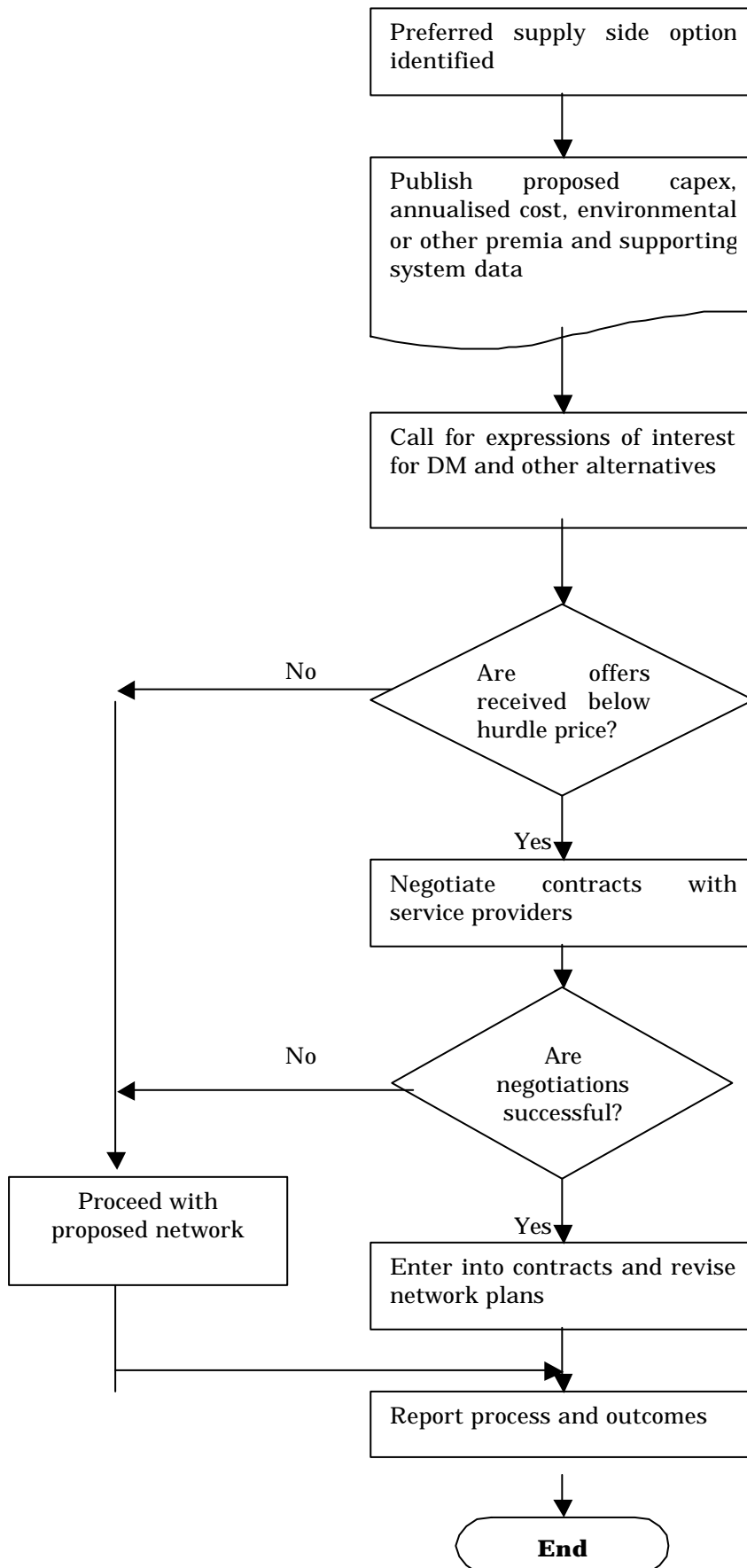


Figure 2

Alternative Demand Management Flow Chart



5.3.2 Determining the Feasibility of Demand Management

The second test to be performed is to determine the feasibility of using demand management and other distributed resource options as alternatives to network augmentations or expansion. For major augmentation projects distributors may proceed to a call for expressions of interest in demand management and other alternatives. In such cases it is not necessary for the distributor to undertake its own investigation of demand management options.

With respect to investigations of demand management, the distributor should commence the test by analysing the system load profile to determine the network peak characteristics. A study is then performed on the end-use load pattern to determine the significant contributors to the peak load. The distributor then investigates the potential to manage end-use loads to achieve sufficient peak load reduction to defer or avoid the network expansion. From this investigation, the distributor determines whether demand management is a feasible alternative to network expansion.

Other distributed resource options, such as embedded generation, energy efficiency measures, fuel switching, power factor correction, uninterruptible power supplies (UPS), etc., should be investigated in a manner appropriate to their characteristics.

Reporting Requirements

The results of the determination of the feasibility of demand management should be reported briefly in the distributor's *Licence Compliance Annual Report*. In addition, complete records of such determinations must be maintained by the electricity distributor as part of their internal audit trail and should be able to withstand an external audit.

5.3.3 Identifying Demand Management Opportunities

In accordance with the requirement for public consultation in the *National Electricity Code*, once the feasibility study is successfully completed the distributor will publish a *Call for Expressions of Interest* in relation to the specific project under investigation. This document will include but not be limited to:

- provide a general description of the distribution network operated by the distributor in the geographic area under investigation;
- identify the location and nature of network constraints which are currently being experienced in the area or which are expected to develop within the planning parameters in the National Electricity Code;
- describe the general characteristics of the load profile in the area, including the major end-uses and customer classes;
- identify the major contributors to peak load in the area, including the major end-uses and customer classes;
- forecast the load growth expected in the area over the planning period;

- identify the major network augmentations which the distributor expects will be required in the area over the planning period, together with the date by which the distributor estimates each augmentation will be required to be in service;
- describe the distributor's estimate of the potential for demand management to provide feasible alternatives to the identified network augmentations;
- invite submissions from interested stakeholders which may comprise either:
 - ◆ comments on the contents of the *Call for Expressions of Interest*; or
 - ◆ expressions of interest in providing goods or services to the electricity distributor in relation to the network augmentations identified in the *Call for Expressions of Interest*, or alternative augmentations proposed by the stakeholder. This invitation should include a specific invitation to stakeholders to submit expressions of interest for demand management programs as alternatives to network augmentations.

The purpose of requiring distributors to publish a *Call for Expressions of Interest* is to enable interested stakeholders to gain access to appropriate information. Once they have this information, stakeholders will be in a position to determine the economics of the alternatives and whether they wish to become involved in the network augmentation process.

Stakeholders may be interested in network augmentation in relation to "build" strategies, demand management strategies, or both. This Code of Practice is concerned only with demand management strategies.

Interested stakeholders in relation to demand management may include:

- electricity retailers and energy service companies who may wish to provide demand management services to end-use customers and/or to contract with an electricity distributor to provide a particular level of load reduction;
- end-use customers who may wish to contract with an electricity distributor to provide a particular level of load reduction;
- community groups and individuals who may wish to contribute to decision making by an electricity distributor on the strategy for network augmentation.

The electricity distributor must take reasonable action to ensure that interested stakeholders are made aware of the opportunities for network augmentation within its service area. This action may include:

- publicly advertising the availability of the *Call for Expressions of Interest*;
- directly contacting likely interested stakeholders;
- holding public meetings about network augmentation opportunities.

Expressions of interest received in response to the *Call for Expressions of Interest* will comprise an important source of possible demand management

alternatives to network augmentations. Investigation of these expressions of interest will form part of the demand management investigation required by the *Energy Supply Act*. Each distributor should establish a process for investigating all expressions of interest and for pursuing those which appear to have merit. The process adopted by the distributor must be described in the *Call for Expressions of Interest*.

Reporting Requirements

Distributors must include in reports of demand management investigations descriptions of the actions they took to ensure that interested stakeholders were made aware of opportunities for network augmentation.

5.3.4 Estimating the Load Impacts of Demand Management Programs

This step is primarily concerned with estimating the potential of particular demand management programs to achieve the required objectives. This includes performing studies of likely customer participation rates and technical estimates of the likely load impact per customer. This study requires an in-depth understanding of the load profile and the contributors to load peaks.

Studies that may be required include:

- customer surveys;
- reviews of major customers;
- reviews of appliance types and usage patterns;
- reviews of customer demographics;
- sensitivity analyses.

Reporting Requirements

Distributors must include in reports of demand management investigations the results of estimating the load impacts of potential demand management programs and a description of the methodology they used to estimate load impacts.

5.3.5 Estimating Demand Management Program Costs

When a list of possible demand management programs that meet the required objectives has been compiled, the cost associated with each program should be estimated. This will involve:

- determining the required penetration level of each program;
- estimating the per unit cost of each program;
- determining the subsidy level of each program, if applicable.

There is a risk that some demand management programs may not achieve the target load reduction in magnitude or duration thus imposing risks on the network infrastructure. To account for this, a safety margin in the form of a diversity factor of end-use appliances or safety factor for customer

curtailable load programs should also be considered when costing programs. The safety margin or diversity factors selected should adequately cover the risks involved but should not be at a level that prejudices the particular demand management program. Such safety margins and the underlying assumptions should be specified in the distributor's report of the process. When dealing with retailers, energy service companies or large customers, contracts with appropriate penalty clauses can be used.

Reporting Requirements

Distributors must include in reports of demand management investigations the results of estimating the costs of potential demand management programs and a description of the methodology they used to estimate costs.

5.3.6 Determining the Cost Effectiveness of Demand Management Programs

The Guidelines and Requirements Policy issued by the Minister pursuant to section 5.4.2(b) of the *Electricity Supply Act* requires that demand management investigations identify:

...outcomes that are economic and offer value for money to customers and others affected by the distributor's operations.

To achieve economic outcomes from demand management investigations, distributors must determine the cost-effectiveness of the demand management alternatives under investigation as compared with network augmentation. However, the decision whether or not to implement a particular alternative should be a commercial decision made in the context of the financial position of the distributor.

Where there is effective competition and an efficient market for providing demand management alternatives to network augmentation, a distributor's determination of the cost-effectiveness of the alternatives should be based on prices and standards prevailing in the market.

Where effective competition or market efficiency is lacking, a distributor's determination of cost-effectiveness should be based on:

- estimating total costs, ie costs incurred by all stakeholders (including persons or groups affected under the demand management alternative) as well as the costs incurred by the distributor in efficiently delivering the alternative;
- estimating all costs:
 - ◆ on a life-cycle basis and weighted for risks;
 - ◆ in consultation with the stakeholders affected;
- disregarding factors which may distort the level of costs, such as subsidies, taxes and social programs;
- considering the sensitivity of costs and benefits to the service standards delivered under the proposed demand management alternatives;

- presuming that the distributor will be able to recover the costs that it efficiently incurs in delivering the demand management alternative (see section 6 below); and
- adopting an appropriate planning time horizon.

In both cases, any reductions in distribution system energy losses resulting from the demand management alternative should be costed and included in the distributor's determination of cost-effectiveness.

The electricity distributor must economically evaluate and compare the network expansion option and feasible demand management programs in order to determine the least cost option. The relevant cost-effectiveness test specified in the *National Electricity Code* should be used in determining the least cost option. This test should determine the net present value of the project over the planning period of both the supply and demand-side options. Other financial criteria may be used that meet the distributor's individual needs.

The concept of including externalities in the planning process should be explored. However, practical ways of internalising them do not exist in the current regulatory regime in NSW. Externalities, in this context, are those costs external to a distributor, ie costs not directly attributable to the operation of an electrical network, including:

- costs associated with greenhouse gas emissions;
- cost of energy losses;
- cost of the visual impact of infrastructure;
- cost of physical constraints, eg. loss of usable land;
- cost of environmental impact on floral and fauna.

The costs of meeting the environmental and planning requirements in regard to the last three elements are included in project costs which can be recovered through the current regulatory arrangements.

One option is a 'planning approach' to the inclusion of externalities. Under this approach a full economic evaluation requires:

- community value assessments of the various externalities (though these are highly variable and hard to quantify), and;
- a cost recovery mechanism in the regulatory framework to give distributors financial incentives to promote demand management options.

If the cost-effectiveness test specified in the *National Electricity Code* does not include consideration of externalities, distributors could include such a consideration in determining the demand management program(s) to be implemented. Once a demand management option is determined to be cost-effective using the test specified in the *National Electricity Code*, externalities should be costed and included as part of the program analysis. However, there may be difficulties in costing the externalities. Where it is not possible to cost externalities, they should be acknowledged and reported.

Reporting Requirements

Distributors must include in reports of demand management investigations the results of determinations of the cost-effectiveness of demand management alternatives and descriptions of the methodologies they used to determine cost-effectiveness.

5.3.7 Valuing Environmental Impacts

Demand management programs are primarily driven by their cost-effectiveness in postponing or avoiding network expansion. However, there are positive environmental impacts associated with demand management strategies as their main purpose is to defer or avoid supply side options by reducing demand and/or energy consumption, either on a temporary or permanent basis. Therefore, it is recognised that distributor-developed demand management programs have an additional effect in producing positive environmental and greenhouse gas benefits.

In carrying out demand management investigations, distributors should ensure that they allocate appropriate values to the environmental impacts which would result from proposed demand management alternatives.

Possible environmental impacts to be considered may include:

- local impacts, such as the visual impact of distribution network infrastructure, and impacts on local flora and fauna;
- global impacts, such as greenhouse gas emissions;
- impacts on resources, such as energy losses and loss of usable land.

Environmental impacts should be valued using standard methodologies where possible. There may be difficulties in allocating monetary values to some environmental impacts due to the lack of standard methodologies. However, where possible, impacts should be allocated monetary values and included as part of the cost-effectiveness determination. Where it is not possible to allocate a monetary value, the impact concerned should be reported.

Reporting Requirements

Distributors must include in reports of demand management investigations the results of valuing the environmental impacts of demand management alternatives and descriptions of the methodologies they used to value these environmental impacts.

5.3.8 Carrying Out Public Consultation

The Guidelines and Requirements Policy issued by the Minister pursuant to section 5.4.2(b) of the *Electricity Supply Act* require that in relation to demand management investigations:

There is to be reasonable opportunity for affected persons or representative groups to be consulted and to make submissions to be considered in the investigation process.

Before a demand management investigation is completed, the distributor will carry out public consultation on the interim results of the investigation,

particularly the results of the evaluation of demand management alternatives.

The primary purpose of this public consultation process is information gathering on the community acceptance of the proposed demand management programs. The process may also provide some indication of the likely success of the programs in achieving the distributor's required load impacts. However, the primary source of this latter information is the customer surveys carried out earlier during the estimation of the load impacts of the demand management programs.

The public consultation process should be conducted in such a way as to:

- obtain responses by stakeholders (including customers) in relation to demand management alternatives that may be cost-effective, prior to the distributor making a commitment to carry out a network augmentation;
- demonstrate clearly to Government, persons and groups affected by the alternatives considered, and the community generally, the distributor's compliance with its relevant obligations under the *Electricity Supply Act* and electricity distributor licence.

Reporting Requirements

Distributors must include in reports of demand management investigations the results of public consultations they undertook and descriptions of the public consultation processes they used.

5.4 Incorporating Outcomes into Business Planning

The outcomes of investigations of demand management alternatives to network augmentation should be incorporated into a distributor's normal business planning processes. Once cost-effective demand management programs are identified and evaluated and a decision is taken on whether a demand management alternative is to be implemented, any implementation of demand management programs should be undertaken through similar business planning processes which would be employed for network augmentations.

Of course, the detailed processes for implementing demand management programs may be very different from those used to implement network augmentations, particularly if the demand management implementation is being carried out by the distributor itself. Nevertheless, the high level business planning processes used by the distributor should be similar for both types of implementation. The purpose of using similar processes is to ensure that implementation of demand management alternatives to network augmentations becomes, over time, part of the 'standard practice' of distributors.

Reporting Requirements

Distributors must include in reports of demand management investigations descriptions of the business planning processes they used to implement cost-effective demand management programs.

6. RECOVERY OF DISTRIBUTOR COSTS

Electricity distributors are subject to monopoly price regulation. Therefore, they should expect to be permitted to secure from their customer bases adequate revenues to cover the costs of efficiently and sustainably delivering cost-effective service standards.

Where demand management alternatives to network augmentation are cost-effective, distributors have two mechanisms through which they are able to recover the costs of delivering these alternatives:

- through price regulation;
- through contestable business activity.

6.1 Recovering Costs through Price Regulation

The form of financial regulation of the businesses can have an important impact on the incentives to invest in or contract for demand management. Tensions between the incentives established through financial regulation and the broader policy objectives of government (implemented through the electricity distributor licence conditions) may lead to poor outcomes and/or inefficient regulatory add-ons designed to bridge the regulatory tensions.

To date, IPART has sought to reduce the disincentive to demand management by using revenue regulation and avoiding a heavy reliance on rate-of-return regulation. However, distributors are concerned about certainty in the regulatory regime in evaluating network expansion and demand management options. Key issues include:

- how and when expenditures on demand management may be recovered within the regulatory regime;
- the requirements for "roll-in" of capital expenditure.

IPART will have regard to compliance with an appropriate demand management strategy as evidence that expenditure on augmentation, extension or demand management was justified when the capital expenditure programs are reviewed at each periodic review. Automatic roll-in cannot be guaranteed, but compliance could be an important positive factor. The regulatory framework may also need to consider how expenditures on demand management can be treated on a comparable basis to capital expenditure on the network.

IPART may also consider the pricing strategies adopted by the electricity distributors. Prices that are economically efficient and reflect network constraints may provide a degree of confidence in the subsequent network investments or demand management strategies that respond to end users' needs.

6.2 Recovering Costs through Contestable Business Activity

Where a distributor is involved in joint programs with other stakeholders, there may be opportunities for the distributor to recover from the other

stakeholders a portion of its costs in delivering demand management alternatives to network augmentation.

Electricity retailers operating in NSW have, under their licences, greenhouse gas emission reduction obligations. To enable them to comply with these obligations, retailers may be willing to substantially contribute to meeting the costs of demand management programs proposed by distributors.

Specialist energy services companies may also be willing to share with distributors part of the reduction in costs achieved through their more efficient delivery of demand management programs in return for access to the distributor's customer base.

7. ANNUAL REPORTING

The Guidelines and Requirements Policy issued by the Minister pursuant to section 5.4.2(b) of the *Electricity Supply Act* requires holders of NSW retail and distribution licences to submit to the Minister each year a *Licence Compliance Annual Report*.

Each distributor should provide, as part of its *Licence Compliance Annual Report*, statements as to:

- the demand management investigations carried out, including a summary description of each investigation;
- the methods and procedures used in the demand management investigations;
- the investigation results, and decisions made following the completion of demand management investigations, including the incorporation of investigation outcomes into demand management strategies;
- the interactions between distributors and regulators, customers, retailers and other stakeholders that:
 - ◆ are relevant to demand management investigations; and
 - ◆ reflect potential or actual opportunities for, or constraints on, cost-effective demand management strategies;
- the business outcomes resulting from implementation of demand management strategies;
- any inconsistencies between methods and procedures used by the distributor on the one hand and on the other hand of any relevant industry Codes of Practice recognised by the Ministry of Energy and Utilities.

Appendix C contains a sample list of the information to be included by distributors in reports on demand management investigations in their *Licence Compliance Annual Reports*. However, the inclusion of this information should not be regarded as complete fulfilment of the annual reporting requirements in relation to demand management investigations.

Instead, distributors should ensure that their reports include statements in relation to each of the items listed above in this section 7.

Other data to be reported may include:

- number of demand management programs implemented;
- number of demand management programs investigated;
- number of demand management programs which proved not to be cost-effective;
- percentage of controllable load;
- summary of community consultation
- summary of environmental impact evaluation;
- any assistance given to electricity retailers in implementing demand management programs at customer sites.

Other general ongoing programs may also be reported, such as off-peak control of hot water systems, distribution system automation, marketing programs, sponsorship of energy audits and general energy efficiency programs. These general demand management efforts, while not “demand management investigations” within the meaning of the *Electricity Supply Act*, contribute to deferring network expansion.

Details of each individual demand management investigation must be maintained by the electricity distributor as part of their audit trail to show compliance with the electricity distributor’s licence conditions.

Only one report of demand management investigations is required to be compiled per year. The report is to be included in the electricity distributor’s *Licence Compliance Annual Report* to be issued at the end of each financial year.

8. INDEPENDENT APPRAISAL

Each distributor’s *Licence Compliance Annual Report* must include:

...an appraisal of the integrity of the information presented in the report by independent persons qualified to make it.

Guidelines for independent appraisal have been issued. These guidelines state:

It is intended that appraisal will:

- *enable the Licence Compliance Annual Report information to be relied on by the Licence Compliance Advisory Board in assessing the extent of compliance (with the licence condition and relevant guidelines) by individual licence holders and reporting on that to the Minister for Energy;*
- *be used to assess the integrity of the information provided in annual licence compliance reports by individual licence holders. It will promote confidence in the information provided and will be reported on accordingly.*

The outcome of the independent appraisal must be an appraisal report by the person conducting the appraisal, to be reproduced in the Licence Compliance Annual Report, as to the person's satisfaction that:

- *the Board is informed on and properly able to authorise release of the Licence Compliance Annual Report;*
- *the Chief Executive of the licence holder is informed on and properly able to certify as to the correctness of the information contained in the Licence Compliance Annual Report;*
- *the Licence Compliance Annual Report meets the reporting requirements of the licence holder's licence and requirements, and is fair and reasonable based on the following considerations.*

Satisfaction that the Licence Compliance Annual Report is fair and reasonable must be based on consideration of the licence holder's systems and procedures, management accountability arrangements, training programs, and stakeholder consultation arrangements that are in place to ensure that licence compliance by the licence holder is properly planned, implemented, monitored, reported, reviewed and adjusted to systematically and comprehensively identify sources of inadvertent or systematic non-compliance, and to eliminate those sources.

The appraisal report must itemise those matters which prevent the person making the appraisal from reporting satisfaction in the terms stated above.

The appraisal included in the *Licence Compliance Annual Report* must assess the integrity of reported information relevant to the demand management licence condition, both generally and specifically in relation to the following matters:

- the processes that are appropriate to be followed for consistency with the relevant objectives of the *Electricity Supply Act*, and for compliance with the demand management licence condition and this Code of Practice on demand management;
- the investigation procedures and related business practices that are appropriate to establishing and implementing cost-effective demand management strategies;
- the integration of demand management strategies with other areas of the distributor's business, and the effectiveness of addressing the range of forces on the business that:
 - ◆ provide opportunities for, and impose constraints on cost effective demand management strategies, and
 - ◆ have potential for adaptation in response to distributors' demand management strategies and changing stakeholder interests.

9. REVIEW OF THIS CODE OF PRACTICE

This Code of Practice on Demand Management has been developed and drafted by the Industry Working Group, Energy Futures Pty Ltd and Couch & Associates with input from stakeholders including IPART.

The Code has subsequently been recognised by the Acting Director of the Ministry of Energy and Utilities subject to the following conditions.

Demand Management for Electricity Distributors

- The workability, use and impact of the Code being monitored by ;
 - ◆ The Industry Working Group, and,
 - ◆ IPART's Electricity Industry Consultation Group,
- to ensure its continued relevance and that it continues to take account of stakeholders' views. Recognition may be withdrawn at any time in the future where this is not the case.
- The Code being reviewed after one year particularly taking into account ;
 - ◆ Market based approaches for large projects;
 - ◆ Other developments in the National Electricity Code process; and
 - ◆ Distributor reports on Demand Management.

Following this, the Code will be reviewed every subsequent 12 months with a major review three years after its recognition. These reviews will be performed in consultation with all stakeholders with a view to modifying the Code where appropriate to improve the achievement of the policy objectives outlined in the Code.

Distributors and other stakeholders interested in participating in these reviews should contact:

Ministry of Energy and Utilities

Minerals and Energy House

PO Box 536

ST LEONARDS NSW 2065

DX 3324 ST LEONARDS

Telephone: (02) 9901 8888

Facsimile: (02) 9901 8777

APPENDIX A
DEFINITION OF
MAJOR NETWORK INFRASTRUCTURE AND
MINOR NETWORK EXPANSION

EXAMPLES OF MAJOR INFRASTRUCTURE INVESTMENT	
Network Area	Example
New zone and transmission substations.	New transformers, buildings and associated equipment.
New transmission and subtransmission feeders.	New conductor and poles or cables supplying zone or transmission substations
Major augmentation of zone and transmission substations and transmission and subtransmission feeders.	<u>Substations</u> The installation of additional transformers of similar size to existing transformers. The installation of major equipment that substantially increases the capacity of the substation. <u>Feeders</u> A substantial increase in the feeders capacity, e.g., major re-conductoring or increasing the operating voltage of a rural feeder.
Substantial new distribution system backbone feeders.	Major distribution development associated with new zone substations. New major distribution feeder associated with customer growth or rural supply.
EXAMPLES OF MINOR NETWORK EXPANSION	
Network Area	Example
Piecemeal augmentation of the distribution network.	Short lengths of feeder work or augmentation to cater for connection of customers.
Splitting of distribution feeders near the zone station.	Short lengths of feeder work to utilise a spare distribution circuit breaker at an existing zone substation.
General ongoing distribution system development.	Short lengths of feeder work associated with connecting customers.

APPENDIX B

CASE STUDIES OF DEMAND MANAGEMENT STRATEGIES

CASE STUDY 1: SMITHTOWN RESIDENTIAL/RURAL AREA

Smithtown is a residential/rural township approximately 50 km south west of a major city. Smithtown and the surrounding townships are supplied from the Smithtown Zone Substation. This station has a single 66/11kV 10 MVA transformer and is supplied via a single 66kV feeder.

The transformer is cyclically rated at 12.1 MVA and the substation is backed-up from the adjacent Menton Zone Substation via the 11kV network to a maximum level of 11.5 MVA before voltage drop becomes excessive at the extremities of the 11kV network. Peak winter demands are in the order of 12.5 MVA and growing at about 150 to 200 kVA per annum. The summer peak demand is in the order of 10.1 MVA and is not considered a problem.

Three options to overcome the network problem were investigated being:

1. install 11kV regulators,
2. build a second 66kV feeder and augment the zone substation; and
3. perform demand management to reduce the peak demand and maintain it at 11.5 MVA.

The first option was found to be technically unfeasible which left the remaining two options to be investigated further. The second option was estimated to cost \$1.7 million.

A survey was conducted to determine the main contributors to the winter peak demand and to gauge customer response to possible demand management programs. Following is a summary of the results:

- heating and cooking were the main contributors to peak demand;
- clothes dryers were frequently being used over the peak period;
- customers would consider changing to gas appliances given the opportunity;
- the penetration of air conditioning was not high;
- customers were generally interested in energy efficiency; and
- about 20% of electric hot water tanks were quick recovery.

From this it was determined that there was sufficient scope to cost-effectively reduce the peak winter demand via demand management to the required level to avoid network expansion (Option 3).

A number of demand management programs were designed to target the peak winter demand. These are summarised in Table 1 below.

Table 1. Demand Management Programs Identified in Smithtown

Program	Cost (\$)	Target Load Reduction (kVA)
Gas appliance conversion (targeting cooking & heating)	100,000	1,400
Quick recovery hot water tanks to off-peak control	40,000	400
*Controlling clothes dryers	60,000	420
Total	200,000	2,220

* There are technical difficulties associated with this program that need to be overcome. This is seen as a future program when these issues are resolved.

The gas appliance conversion program was promoted first with the remaining programs to be implemented in subsequent winters. This program also has environmental benefits in reducing CO₂ emissions estimated to be 200 tonnes per annum.

Summary

- The community was consulted via a survey and discussion with local council town planners to incorporate energy efficiency into the development approval process.
- The chosen demand management program has environmental benefits in CO₂ reduction and avoidance of network expansion.
- The demand management program met the required targets in demand reduction.
- The demand management program was financially superior.
- The network expansion option was postponed beyond the 10 year planning period.

CASE STUDY 2: BLUE HILLS INDUSTRIAL AREA

The Blue Hills Zone Substation supplies the Blue Hills industrial and commercial areas and the surrounding residential area. This substation is supplied via two 33kV feeders which have a summer rating of 47 MVA each. The substation contains three 25 MVA 33/11kV transformers with a firm rating of 50 MVA. The peak demand at the substation is 45.5 MVA growing at about 300 kVA per annum. This peak demand is measured on the secondary of the transformers and relates to a load of about 50.5 MVA on the 33kV feeders. The duration of this overload is forecast to be 18 hours during the 1998/99 summer growing to 30 hours in 2001/02.

The problem is that a first level emergency during summer (an outage of one 33kV feeder) results in the remaining 33kV feeder being overloaded. The duration of the overload condition is considered to be an excessive risk. The options are to either augment the network or reduce the peak summer demand.

The preferred network expansion option is to establish a zone substation within the Brown Hills Transmission Substation to offload Blue Hills Zone Substation at a cost of \$1.4 million. If the summer peak demand could be reduced by 3 MVA growing to 4.5 MVA, the construction of the mini substation could be postponed by four years.

A major component of the summer daytime peak is the industrial load. The industrial area is zoned medium to heavy industry and contains several large electricity consumers. The majority of these customers were surveyed to determine their potential to shed load on request. It was determined that there was sufficient scope to shed load in order to postpone the construction of the mini zone substation by four years. Proposals were made to several customers to pay them an amount per kilowatt-hour to shed load for a three to four hour period when requested. Two customers were able to postpone processes, which included operating furnaces at a later period, and one customer agreed to use their back-up generator.

A second demand management program included offering rebates to customers for power factor correction. The results achieved from the second program were minor compared to the curtailable load program. However, it was an important part of improving the efficiency of the network.

The total cost of the demand management program is estimated to be \$300,000 resulting in total savings of \$450,000. The program cost included the appropriate safety margins and risk factors.

Summary

- The community was consulted via direct customer contact.
- The demand management program was chosen on its ability to target the summer peak problem.
- The power factor correction program has environmental benefits in reducing network losses. Reducing the peak demand also reduces losses.
- The demand management program met the required targets in demand reduction
- The demand management program was financially superior.
- The network expansion option was postponed by four years.

CASE STUDY 3: TAYLOR PARK/ST JOSEPHS RESIDENTIAL AREAS

The Taylor Park/St Josephs residential areas are supplied by two zone substations, one at St Josephs and one at Taylor Park. St Josephs Zone Substation is supplied via two 33kV feeders while Taylor Park Zone Substation is supplied via one 33kv feeder which is tee connected to the St Josephs feeder. With an outage on the teed 33kV feeder, St Josephs must back-up Taylor Park via the 11kV network. The 11kV back-up and the 33kV feeder are both approaching their design limits.

There is an industrial area proposed to the south of Taylor Park. The expected maximum load for this area is between 20 to 50 MVA. There are two options to supply this future load and the existing residential areas, being:

1. build a new zone substation in the industrial area; or
2. augment the existing Taylor Park Zone Substation and the subtransmission system and implement a demand management strategy to limit peak demand in the area.

Option 1 will cost in the order of \$6 million while Option 2 is expected to cost \$2.5 million plus approximately \$200,000 per annum demand management costs. On an NPV basis over a 20 year period, Option 2 is \$2.7 million less expensive than Option 1. However, the success of Option 2 depends upon limiting the peak demand of the proposed industrial area to 25 MVA and being able to control an estimated 4 to 5 MVA of demand at peak.

The limiting factor at Taylor Park/St Josephs is the summer rating of the 33kV and 11kV networks and transformer capacity at Taylor Park Zone Substation. The summer load at Taylor Park/St Josephs more than doubles (from 22 to 45 MVA) from a mild day (23°C) to a hot day (38°C), especially after a run of hot days. This is primarily due to domestic air conditioning.

This option is dependent on gaining control of a portion of this air conditioning load. A survey will be conducted to determine customer reaction to either:

- receiving a rebate to allow the local distributor to control their air conditioner on a limited basis; or
- receiving a special tariff to allow control of their air conditioner

The extent of the control that customers will allow will also need to be determined.

The second part of the demand management strategy is ensuring the local council insists on energy efficiency measures being incorporated into all new industrial developments. Coupled with this, the council will contact the local distributor to discuss energy fuel and energy application alternatives with the development applicant. Cooperation from energy retailers will be sought to make this program successful.

There are many variables with this option that may result in a demand management option being inappropriate. However, with cooperation from the local council and energy retailers, and with the right incentives, a demand management strategy has the potential of saving the network owner and the community millions of dollars. At the least, deferment of network expansion would be a successful outcome.

APPENDIX C
INFORMATION
TO BE INCLUDED BY DISTRIBUTORS IN THEIR
LICENCE COMPLIANCE ANNUAL REPORTS

	Demand Management Investigations	Demand Management Strategies Implemented	Cost of Demand Management Strategies	NPV of Distributor Operating Expenditure Saved	NPV of Distributor Capital Expenditure Deferred
Individual Demand Management Investigation	<i>Brief description of this DM investigation</i>	<i>Brief description of DM strategy implemented ('Nil' response possible)</i>	<i>Cost to distributor of DM strategy</i> <i>Total cost of DM strategy, including all stakeholder costs</i>	<i>NPV dollars saved in this investigation</i>	<i>NPV dollars deferred in this investigation</i>
Consolidated Annual Report	<i>Total number of DM investigation</i>	<i>Total number of DM strategies implemented</i>	<i>Cost to distributor of all DM strategies</i> <i>Total cost of all DM strategies, including all stakeholder costs</i>	<i>Total NPV dollars saved as a result of all DM strategies</i>	<i>Total NPV dollars deferred as a result of all DM strategies</i>