Does Current Electricity Network Regulation Actively Minimise Demand Side Responsiveness in the NEM?

A report

for the

Total Environment Centre

Prepared by

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Executive Summary

Under the current regulatory arrangements for network service providers (NSPs) in the National Electricity Market (NEM), there is a disincentive for demand management (DM) through the use of the **Building Block** (BB) approach. The BB approach incentivises NSPs to seek network solutions as these raise its profitability. There is an active incentive for the NSP to find network solutions through new capital expenditure proposals. This occurs because many DM programs are opex based, and the allowance for opex is provided for only at cost and does not include any profit. This creates an active disincentive embedded in the BB approach against DM.

This disincentive is further reinforced when the BB is combined with a **price cap** (as opposed to a revenue cap), as it encourages consumption and demand. Using a price cap approach with a DM program requires an ability on the part of the regulator to identify any revenue lost to the NSP from a DM program and to implement a program to allow the NSP to recover this lost revenue. Such an approach has the potential to increase the "gaming" an NSP might undertake to maximise its revenue stream.

A **revenue cap** approach suffers from the inherent dis-incentives in a BB approach to DM, but as the BB approach allows transparency and for programs to operate in parallel, a BB approach combined with a revenue cap provides a "least worst" outcome for implementing a DM program which has some prospect of real success.

A **total factor productivity** (TFP) approach has the potential to be neutral in relation to DM, but as it requires the use of a price cap approach (which incentivises greater demand and consumption) it also encourages consumption and demand. A TFP program also has a number of other disadvantages that need to be assessed in light of the overall goals of encouraging DM. In particular, it is not a tool which provides transparency and therefore might not provide the necessary transparency required to encourage DM options (and energy efficiency).

There would appear to be no simple solution to overcoming the inherent disadvantages that the BB, TFP, revenue cap and price cap approaches impose in providing dis-incentives to DM. The most likely approach to be successful in the NEM is that used by the ESCoSA for its pilot program for DM, which provides a parallel program supervised by ESCoSA to bring about defined outcomes. But it is, nonetheless, a rather modest program, and it still does not address the essential element that DM is likely to reduce the potential of revenue increases inherent in a price capped NSP.

Overseas demand management approaches such as the Californian Public Utilities Commission scheme appear to be more successful than most. This scheme operates under an energy efficiency policy framework mandated by the government. The regulatory framework established by the CPUC to meet the policy goals, provides a high powered incentive scheme with financial penalties for poor performance coupled with financial incentives for out performance.

This program operates across the entire operation of the Utility and so allows the Utility to accrue benefits from each element of its activities. Such an approach is significantly weakened under the disaggregated approach used in the NEM. It should also be noted that the program addresses much more than DM, as it incorporates the renewable energy program and energy efficiency goals, which includes consumer efficiency and network efficiency. Notwithstanding these observations, it is possible that such an approach could be tailored to incentivise NSPs to improve network and consumer efficiency within the NEM.

Consideration needs to be given to combining mandated energy efficiency targets in the NEM with the DM measures currently implemented by ESCoSA and the CPUC, to drive a more powerful DM approach in the NEM.

DM programs could be even more effective if they were driven by an over-arching energy policy requirement for achieving energy efficiency targets across the entire electricity supply chain.

This report makes the following recommendations:

1. Separate and parallel demand management incentive schemes, established and overseen by regulators, are the most effective way of ensuring demand management initiatives by network businesses

2. The use of a revenue cap, removing the incentive for networks to increase demand and consumption, would be required in addition to DM incentive schemes

3. Demand management programs for each network business might contain the following features:

    a. Identification of demand management options and target outcomes and to establish a pact between regulators and network businesses

    b. To include a fixed amount of funding for DM to be included in the allowed revenue for the network business

   c. Incorporate a program of benefit sharing, and financial incentives and penalties

   d. To operate as part of the regulatory reset

4. An overarching energy policy requirement should be set by government for actioning energy efficiency targets across the entire electricity supply chain.

5. Consumers should engage in regulatory reviews where the Building Block approach is used and to contest network business' capital expenditure and rate of return claims

6. Consumers should engage in regulatory reviews using the price cap form of regulation (under the Building Block approach) to contest claims with respect to pricing methodologies and cost allocation mechanisms

1. Introduction

This report has been initiated by the Total Environment Centre (TEC)[1] to assesses the relative merits of the price cap [including Total Factor Productivity (TFP)] and the revenue cap, taking into consideration the goals of the participating groups and the range of matters that the Australian Energy Regulator (AER) must consider when assessing the merits of a revenue reset application for electricity distribution networks. The report is also aimed at increasing the capacity of consumer groups to understand and critique the various regulatory approaches in use in the National Electricity Market (NEM).

The TEC considers that there is a strong need for a regulatory approach that provides stronger economic signals for all concerned with the use of electricity (including governments, regulators, supply side businesses and consumers) and to encourage demand management, including an overall reduction in electricity usage.

TEC is looking to play a greater role in reducing network constraints and improving the operation of the electricity supply system. DM has essentially two basic elements to it. The first is to improve efficiency in the use of electricity and the second is to improve the use of existing electricity assets by improving the load factor in the system.

One of the causes for the increasing cost of electricity in recent times has been the increasingly common reduction in the average load factor in electricity supply systems largely due to the impact of the high penetration of air conditioning and heating in the domestic residential market. This reducing average load factor increases overall costs to consumers from two main sources, generation and networks:

- As the load factor reduces, there is a greater need for more **generation** which operates for increasingly shorter periods (e.g. to meet summer and winter peak demands) in order to meet the needs of consumers. This is currently economically inefficient as the result is significant amounts of generation plant lying idle for extended periods of time.[2] This idle plant incurs costs even when not operating, and this cost must be recovered from consumers, thereby increasing the overall cost of electricity.

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[1] Funding for this report has been provided by the National Electricity Consumers Advocacy Panel.
[2] Introduction of carbon trading is likely to have a commercial impact on which generation plant lies idle, as including carbon costs will vary the dispatch ranking of generation, and the resultant increased costs are likely to affect power demand.

- To meet these short term spikes in demand the **networks**, which transport electricity from generators to consumers, must be sized to meet these short term demands for electricity, or loss of supply will result. This requires the networks to invest in order to have the capacity to carry higher levels of electricity. Again, this is economically inefficient and augmenting networks for these short term peaks in demand also increases overall costs to all consumers.

There are a number of ways that the average load factor can be increased:-

1. Reduce demand during periods when the system demand is at the highest levels (peak time demand reduction)
2. Encourage consumers with a poor load factor to generate power to meet their needs and so use the network less (self generation)
3. Move demand from high demand periods to low demand periods (load shifting)

Reducing overall energy consumption by carrying out permanent energy efficiency improvements is a goal that provides distinct environmental benefits and should be seen as a fundamental element of demand management.

Collectively, these represent the main demand side responses that are possible in the electricity system.

However, the opportunity for demand side responsiveness is being minimised (and even discriminated against) under the current regulatory environment.

All consumers have the ability to provide demand side responses, but there are impediments to their doing so. Such impediments include the capital resources required to implement some solutions; an inability to know (or even being able to recognise) when the system needs their assistance; and the limited alternatives to using electricity at certain times, such as for lighting, heating or cooking of meals.

In addition to the general burgeoning use of electricity over recent years, there is a strong trend in the use of electricity in ever increasing amounts for very short periods of time. This has created a need for the building of more energy infrastructure overall, and a need to provide increased amounts of fast start generation (which frequently is quite energy inefficient) to operate for short periods of time (demand spikes). This demand pattern also imposes a need to augment the electricity networks to facilitate these demand spikes.

The current tools available to the economic regulator in assessing applications from distribution network service providers are prescribed by the National

Electricity Rules. Using what is generally described as the "Building Block" approach, the regulator has the task of determining how much cash the regulated business is allowed to have each year (for a period of five years) to provide the service that consumers require. The determination is arrived at after each cost element of the business is added up and an appropriate rate of return applied to arrive at the maximum required revenue for the business.[3]

A transmission network service provider is only permitted (under the National Electricity Rules) to use a revenue cap approach to recover the allowed revenue, whereas a distribution network business is able to recover its allowed revenue using either a **revenue cap** or a **price cap**. The decision to use a revenue cap or a price cap for the recovery of distribution network revenue is left to the regulator, the jurisdiction or the business, or a combination of these.

The reason behind using a **revenue cap** is that the revenue allowed to be collected is fixed by the regulator, regardless of any change in the amount of electricity carried by the network during the regulatory period, which is commonly a period of five years. Any over or under recovery of revenue in one year is adjusted in the following year to ensure that the business only recovers the actual revenue determined by the regulator. Effectively, a revenue cap therefore places the risk with consumers for the amount of electricity carried as it provides an incentive on consumers to increase usage, but any reduction in usage provides no benefit to consumers at all.

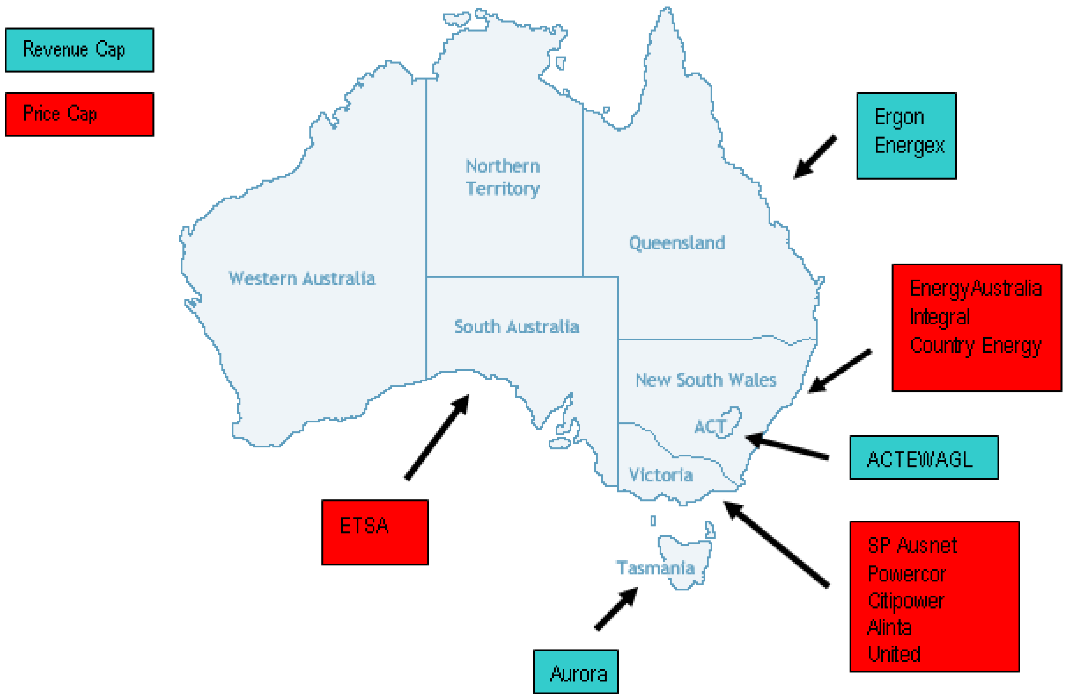
A **price cap** allows the regulated business to vary the amount of revenue it collects depending on the amount of electricity carried by the network. If the network carries more electricity then the revenue collected by the business will be higher than the revenue estimated by the regulator. The business is permitted to retain the over recovery, thereby incentivising the business to increase the amount of electricity carried on the network. Equally, if there is less electricity carried, then the business will recover less revenue.

This approach provides an incentive for the business to encourage consumers to use more electricity, but passes the risk of the estimated amount of electricity carried on the network from consumers to the business.

The following map shows where the price cap and revenue cap forms of regulation are used for distribution networks in the NEM jurisdictions.

[3] A more detailed explanation of the **Building Block** approach, the **revenue cap**, the **price cap** and **TFP** are included in Appendices 1,2,3 and 4 respectively, together with an assessment of the advantages and disadvantages of each approach. These explanations were prepared to inform participants at the second forum run by TEC to critique the various regulatory approaches used.

Price Caps / Revenue Caps for Distribution Businesses across the NEM



There has been a recent move towards supplementing the Building Block approach for setting revenue with an approach called **Total Factor Productivity** (TFP)**.** TFP is a more streamlined approach to regulation and is applicable only to the price cap form of regulation.[4]

The TEC commissioned Bob Lim & Co and Headberry Partners (consultants) to identify whether one regulatory approach provides a better basis than another in providing the optimum signals to network owners to encourage the greater incidence of demand management (and by doing so achieve the defined NEM goals of improved efficiency in the use of electricity). At the same time, the TEC recognises that varying the approaches that have been in use in the different NEM jurisdictions to encourage more DM, might increase the cost of electricity supplies to consumers and the impact of this would fall more heavily on disadvantaged consumers.

This report assesses the relative merits of the different regulatory approaches used in the NEM in relation to DM[5], as well as reviewing some of the primary approaches used overseas to engender DM. The report covers the issues and

[4] Appendix 5 contains a description of the use of TFP in some overseas jurisdictions.
[5] See in particular Appendix 5 which discusses DM as used in some overseas jurisdictions

questions raised in the TEC's terms of reference to the consultants (Appendix 12), and reflect the outcomes of two forums conducted by TEC which discussed these issues amongst organisations advocating increased efficiency in electricity use and production, and organisations advocating for consumers, in particular, disadvantaged consumers.

The report is structured to reflect the brief provided to the consultants by TEC and is as follows:

Section 2	Regulatory mechanisms and demand management
Section 3	What incentive schemes might deliver DM best?
Section 4	Which approaches are best for consumers, especially vulnerable consumers?
Section 5	Which overseas DM incentive schemes deliver better outcomes?
Section 6	What approach best meets the intent of the Rules?
Section 7	Conclusions and recommendations

2. Regulatory mechanisms and demand management

Which mechanism better encourages more efficient use of electricity and demand management, end user consumption and prices, and the balance between network costs and revenue?

Demand management within a network is characterised by a need to prevent demand exceeding the capacity of the network. The implicit incentive in network demand management is that the cost of providing network demand management will be lower than the cost of augmentation of the network to manage the increases in demand and consumption.

The National Electricity Rules (the Rules) currently require the AER to establish the revenue permitted for a network using the **Building Block** approach, applying a **revenue cap** for transmission networks and a **revenue cap** or a **price cap** for distribution networks.

2.1 The Building Block (BB)

The BB approach does not of itself discriminate for or against any specific aspect of the regulatory process. All it does is consolidate amounts of revenue required for a network to provide the service expected of it. It is the way that the regulator addresses each of the components of the BB that provides the discrimination.

The Rules prescribe principles emphasising the importance of providing incentives to the networks to operate efficiently (in economic terms). Thus, it is essential to assess each element of the BB to determine if there is a basis for any view that there is discrimination within the Rules and in the way they are applied.

In the BB approach, the separate main elements[6] determined by the regulator are:

- Return on capital
- Return of capital
- Capital Expenditure (capex)
- Operating Expenditure (opex)
- Efficiency incentive (EBSS – efficiency benefit sharing scheme)

[6] See glossary for an explanation of each term used.

- Service performance penalty/bonus

Of the above elements, the regulator can (intentionally or unintentionally) discriminate against demand management through application of the following:

- The determination of the rate of return of capital
- The ex ante approach to capex determination
- The service performance determination
- The application of the EBSS

2.1.1 The rate of return of capital

The rate of return of capital (the weighted average cost of capital – WACC) has embedded in it all of the base profit the Network Service Provider (NSP) receives for providing the service. Compared to this, the allowance for opex is provided for only at cost, and therefore does not include any profit to the NSP for spending on any element included in the opex allowance. This approach, therefore, implicitly incentivises spending capital.

Therefore, the BB approach has an active incentive for the NSP to find network solutions through new capital expenditure proposals, and as many DM programs are opex based rather than network based, there is an active disincentive embedded in the BB approach against DM.

2.1.2 The ex ante approach to capex

The ex ante capex program provides the NSP with the ability to spend capital within the regulatory allowance but with no subsequent assessment of its economic efficiency or prudency, i.e. there is no ex-post audit at the next regulatory reset. The BB approach permits the NSP to provide the regulator with its anticipated capex needs (i.e. capex forecasts for the new regulatory period) but there is no compulsion on the NSP to spend on the projects it used to develop its capex allowance, and it is able to use the capex allowance on any project it sees appropriate.

The Rules allow an automatic roll forward of all capex regardless of whether the capex was within or exceeded the allowance in the regulatory reset. Even if the capex exceeded the regulatory allowance, the capex will be rolled forward as if it had been approved in the previous regulatory period.

The regulator is not permitted to penalise the NSP if the capex program does not follow the program used to develop the revenue, even if the actual program provides an additional net financial benefit to the NSP arising from any delays in implementation (e.g. when capex is implemented in the fourth year instead of the planned first year of a regulatory period). Thus the actual capex program can be skewed to maximise the commercial benefit of delaying the investment program and by “back end” spending. Another example is where a network solution is preferred by the NSP but the capex was not included in the regulatory program. In this case, the risk to the NSP can be minimised by implementing the capex in the final year of the regulatory period. As assets have a 40+ year life (and therefore the return on the asset will be over that period) the loss of one year’s (or even two years) return on an asset could be readily offset by **not** implementing a project which delivers no profit at all (such as if it was included in the opex).

Provided that the total amount of capex is spent within the regulatory period, there is no assessment as to whether the capex achieved its expected result, whether the timing was implemented to minimise any risk to the NSP, or whether the capex was spent wisely[7].

Therefore, the ex ante approach to capex in the BB has an active incentive for the NSP to find network solutions and, as many DM programs are opex based rather than network based, there is an active disincentive embedded in the BB against DM. The higher the level of capex and the higher the rate of return determined, ceteris paribus, the higher the profitability of NSP.

In addition, the lack of an ex poste approach to capex, particularly as it relates to DM alternatives, provides no oversight to ensure the NSP has implemented DM when more cost-effective than augmentation.

2.1.3 The service performance incentive scheme

The service performance program implemented by regulators is effectively divided into two elements:-

1. Performance of the network to provide the service expected of the regulatory bargain, in terms of the capacity of the network and its ability to consistently to supply the network service. The service performance incentive scheme is determined in terms of reliability and availability, and there is a penalty/bonus arrangement which incentivises the NSP to meet it side of the regulatory bargain.
2. Performance of the NSP in terms of its customer relations. This is usually related to “guaranteed service levels (GSLs)”. The GSLs are usually

[7] This is the intent of the Rules. The AER has advised that it will carryout some investigation of the capex program of the previous regulatory period as part of its assessment for future capex claims. This might provide some constraint on NSPs, but this is debatable.

based on a payment to a consumer if the NSP fails to carryout an agreed action.

The service performance scheme provides a bonus to the NSP for higher network reliability and availability than expected at the regulatory reset review, and so incentivises better service performance. This encourages the greatest level of reliability, which of itself is a reasonable approach and should in general be supported.

There have been wide ranging debates in the NEM comparing the reliability of non-network solutions to network solutions for network needs. The debates have included the claim frequently put by NSPs that embedded generation solutions are less reliable unless they are inclusive of 100% backup, and that demand response only can be provided if the DM responder is actually using the network at the time the DM response is required. This has resulted in the assertion that DM has implicitly less reliability than a network solution. Although these claims have not been substantiated by evidential support[8], the culture of support and familiarity with network approaches, combined with the performance incentive scheme, results in the favouring of network approaches over non-network solutions.

On the basis that network solutions are perceived to provide a higher reliability than non network solutions, the performance incentive scheme incentivises network solutions, as the NSP is required to take the risk (pay a penalty) if the performance is worse than the target, and is rewarded if performance is better than targeted.

Thus a side-effect of the performance incentive scheme is to discourage DM solutions by actively encouraging the approach that is perceived to be more reliable: ie by the use of network approaches.

2.1.4 The Efficiency Benefit Sharing Scheme (EBBS)

The purpose in applying the EBSS is to incentivise the NSP to spend less opex than has been allowed in the revenue reset. In principle, this approach encourages the NSP to operate at the level of opex that is most economically efficient, and therefore is to be supported.

The downside of this incentive scheme, however, is that any program that is included in the opex (such as DM) and which can be addressed in another way (such as by a network solution funded by the capex program) provides an incentive for network solutions over DM.

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[8] In fact there is little evidence that demonstrates that where a non-network solution has been used, that there has been a resultant reduction in the overall reliability of a network

The basis for such an observation is that the opex allowance excludes any profit for an NSP whereas the capex solution has embedded within it a profit element which is included in the rate of return on capital used for a network solution. As the EBSS rewards a NSP for reducing its opex below that allowed for in the revenue reset, a solution which reduces opex increases profit. As increased capex also rewards the NSP, there is no countervailing pressure on the NSP to find an opex solution for a network need.

The EBBS therefore creates a disincentive for DM by encouraging NSPs to exchanging potential DM programs funded by opex for capex programs where profits are greater.

2.1.5 Assessment of BB

Assessment of the above four elements used by the regulator in the building block approach shows that there is potentially an in-built discrimination against demand management.

The first two elements – return of capital and capex forecasts – provide the NSP with its main profitability drivers and, therefore, incentivise capital programs. The obverse to this is that they dis-incentivise DM. This discrimination is further enhanced by the other two elements of incentive regulation (service performance and efficiency benefits schemes) which are intended to encourage the NSP to be economically efficient and improve service performance. However, a service performance scheme would tend to encourage network augmentations and capital upgrades under the guise of increased reliability, whilst an EBSS would tend to steer an NSP away from opex based solutions and, therefore, towards network solutions.

2.2 The revenue cap (RC)

When the allowed revenue has been decided (eg under a BB approach) a revenue cap form of regulated recovery of revenue requires the NSP to develop a set of tariffs which will return the allowed amount of revenue. These tariffs change from year to year to allow the NSP to recover only the allowed amount of revenue an NSP can recover. This therefore insulates the NSP from any variation in demand or consumption within the network. Because of this, except in through the derivation of the revenue included in the development of the BB approach, a revenue cap of itself does not incentivise or dis-incentivise the NSP to provide DM approaches.

If a demand management incentive program is to be introduced, then a revenue cap approach provides a neutral background for such a program to be implemented. Thus the form of revenue recovery is neutral to either

DM or network solutions, even if the development of the allowed revenue might provide a bias against DM (as does the BB approach) in the way it assesses the amount of revenue that can be recovered.

2.3 The price cap (PC)

Once a revenue is determined under a price cap form of regulatory recovery, the NSP develops a set of tariffs which in theory will recover the allowed revenue based on the demand and consumption expected in the network over the regulatory period. If the demand and consumption vary then the NSP accepts the risk and/or benefits for such variation.

A price cap, therefore, provides an incentive mechanism for the NSP to **actively increase** demand and consumption in its network, as by doing so it will receive more revenue than was assumed in the regulatory reset. The NSP is permitted to retain this increase in revenue, effectively increasing its profitability.

Increased utilisation of the network (ie a higher load factor, and/or operating closer to the maximum capacity of the network) is the driver behind a price cap approach. Increased utilisation of the assets has the benefit of reducing the unit costs to consumers for using the network, but, if the increase usage results in higher usage at times when the network is near or at capacity, the approach will result in higher long-term infrastructure costs.

Demand management has a number of objectives, but principally these are to use less electricity and/or to improve the system load factor and/or to provide economically more efficient outcomes than by implementing network solutions. As noted in section 1, load factor can be improved by load shifting, self generation, and peak time demand reduction. Implicitly there are many benefits from an overall reduction in energy use which is also a focus of DM.

Self generation and peak time demand reduction have the overall effect of reducing network-based consumption, whilst load shifting does not reduce consumption.

Thus of the four primary actions that DM seeks (reduce consumption, peak time demand reduction, load shifting and self generation) only load shifting is considered to be neutral with regard to a price cap model as load shifting does not impact on the amount of electricity consumed, whereas the others all reduce the amount of electricity transported on the network, and an NSP would consider that these will reduce its revenue. A reduction in revenue (with its corollary a reduction in profitability) provides a strong disincentive on the NSP operating under a price cap regime to implement DM.

Therefore any approach which is likely to reduce the total amount of electricity carried on the network will be considered by an NSP to be against its commercial interests. Thus the only aspect on which a DM proponent and a price capped NSP are likely to concur would be where there is an increase in consumption during off peak times, such as might be achieved by load shifting.

A price cap incentivises the NSP to increase demand and consumption of electricity to raise its profitability, and to reduce unit costs to consumers, and is therefore a strong disincentive to DM.

2.4 Total Factor Productivity (TFP)

As a variation on using the BB approach to developing tariffs under a price cap, there has been a move in Victoria to simplify the regulatory approach using TFP to adjust the tariffs used by a network to recover their revenue.[9]

The simplicity of the TFP approach removes the detailed analysis of costs required under the BB approach. Effectively, the TFP approach assumes that the tariffs developed under a BB approach were efficient and, based on the comparative performance of similar NSPs, the agreed future tariffs will be adjusted annually using an average performance factor.

In theory, the TFP approach should drive the NSP to use the lowest cost solution to any network need, and would not discriminate between a DM solution and a network solution. The disadvantages for DM implicit in the BB approach are largely eliminated because:-

- The driver to use network solutions (as the NSP profit is embedded in the WACC applied to capital) is avoided
- The problems associated with the ex ante capex approach are removed
- There is no requirement for an EBSS, thereby eliminating this disincentive
- The incentive for network solutions under the service performance program are balanced by the incentive to use the lowest cost solution

Whilst TFP might appear to be supportive (or at least not unsupportive) of DM, the TFP approach is only applicable to a price cap regime, which is itself incentivised to increase demand and consumption, and which therefore negates most of the focus of DM and the approaches by which DM can be achieved.

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[9] TFP does not apply to revenue cap regulation.

A TFP program has a number of other disadvantages that need to be assessed in light of the overall goals of encouraging DM. In particular, it is not a tool which provides transparency and therefore might not provide the necessary transparency required to encourage DM options (and energy efficiency).[10]

2.5 Current NEM approaches to DM

2.5.1 The South Australian model

In 2005, the South Australian jurisdictional regulator (ESCoSA) developed its own approach to the lack of DM being undertaken by the SA distribution NSP (ETSA Utilities).

It determined that a number of specific DM actions could be trialled and recovered by ETSA up to the amount of $20 million. ESCoSA applied a number of constraints on ETSA, including the requirement that underspend of the $20 million would be returned to consumers.

ESCoSA also implemented some other close controls on ETSA when it stated that:

> "The Commission will closely monitor the outcomes of each demand management initiative. The Commission envisages establishing specific reporting requirements for each of the pilot programs. Table 4.1 outlines expected outcomes to be monitored for the major pilot programs.
>
> From the Commission's perspective, it is important that value is achieved from the programs that are funded. The programs suggested above have the potential to achieve positive returns for ETSA Utilities and the community. The Commission is committed to achieving progress in the area of demand management and will work with ETSA Utilities, consumer groups and the Government in the realisation of this potential."

The program that ESCoSA embarked on examined a number of aspects that it considered ETSA could properly develop value from on behalf of consumers, and these were included in Table 4.1 of the Final Determination.

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[10] As noted in appendix 4, TFP has a number of other disadvantages that would need to be balanced against any positive aspects of TFP.

Table 4.1: Outcomes to be monitored for major demand management pilot programs

PILOT PROGRAM	OUTCOMES
Power factor correction	Improvements in power factors at customer installations; size of capacitors installed; cost of installing capacitors at each site; level of incentive payments; administrative costs.
Standby generation	Nature and cost of generator modifications; number of times that generators are used for network or system demand support; duration of support periods; kWh generated; peak load reduction outcomes; level of incentive payments; administrative costs.
Residential DLC	Details of the DLC system selected and reasons for that selection; details and costs of modifications to customer installations; cost components of the DLC system; number of customers involved; type and size of customer equipment controlled by the DLC system; times and duration that the system is used for network or system support; number of kW interrupted and the duration of interruptions; level of incentive payments; administrative costs.
Aggregation	The Commission will monitor ETSA Utilities performance in aggregating demand management resources within the NEM.

ESCoSA also considered the inclusion of aspects addressing critical peak pricing (a disincentive to consumption at times of peak demand), voluntary load control (where consumers decide whether they will reduce demand when network peaks are occurring) and interval metering (which allocates usage to time and the costs applicable at each time interval)[11]. For various reasons it considered that these should not be included in the current ETSA program.

Prior to this determination, ESCoSA reviewed many of the DM approaches used throughout the world, including the 'D-factor' scheme developed and implemented by the NSW jurisdictional regulator IPART. ESCoSA observed in its reset of ETSA Utilities in 2005[12]: (page 58):-

> "Recent national reviews of the NEM have commented that there is significantly less demand response in the electricity market than might have been expected, given the price signals available in the market. These reviews have identified certain barriers to demand management in the electricity market, which include the fact that net margins and the length of the typical retail electricity contract preclude retailers from making significant investment in either time or equipment to facilitate demand management initiatives. **In addition, the disaggregation of what were once vertically integrated organisations into independent businesses makes it extremely difficult to realise all the benefits of demand**

[11] There is a wide acceptance that CPP, VLC and IM will reduce use at peak times, but they are seen to be more related to system needs (in the case of CPP and IM) rather than network needs, and VLC is seen as sufficiently uncertain by networks so as not to be accepted as sufficiently reliable to avoid network overloads.

[12] 2005 - 2010 Electricity Distribution Price Determination, Part A - Statement of Reasons, April 2005

> **management initiatives and hence to offset the costs involved"**. (Emphasis added)

ESCoSA also observed that:-

> "As a result there is relatively little demand management available in the market for any application – network augmentation deferral, energy market arbitrage, or ancillary services."

ESCoSA could have further concluded that the BB approach, with its built-in disincentives for DM, especially using the price cap form of regulation, was also a contributory factor in discouraging DM. To counter the disincentive that reduced electricity sales was likely to bring to the trial fund, ETSA introduced a 'correction factor' to reduce the financial risk to ETSA Utilities of reduced energy sales.

This approach is readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation.

It is currently too early to ascertain to what degree the ESCoSA approach has led to the successful implementation of DM programs.

2.5.2 NSW's 'D-factor' approach to DM

NSW's Independent Pricing and Regulatory Tribunal (IPART) implemented a scheme prior to that of ESCoSA. In the NSW approach, IPART took a different approach to DM with its 'D-factor' scheme. Under this scheme, the NSP has a small incentive to implement DM, which includes the ability of the NSP to recover both the cost of the DM project and the revenue foregone due to reduced consumption. While the benefits of the DM that has been initiated under this regulatory incentive have been considerable, with a 3.8:1 benefit to cost ratio,[13] the total amount of DM delivered has been modest. The NSW distribution NSPs delivered peak demand reductions of 29.4 MVA in 2004/05 and a further 12.4 MVA in 2005/06, equivalent to about 7% and 3% respectively of the average annual growth in summer peak demand in NSW.[13]

As the ISF report for TEC concludes, the D-factor approach has been only a qualified success, with expenditure by the NSPs on D-factor DM being equivalent to only 0.13% of their revenue, one fifth the amount of average US utility spending on DM and even less compared to the leading US utilities.[13] The ISF concludes that for the D-factor approach to work, a range of complementary changes are also needed to compensate for other disincentives to DM. These recommendations are listed in Appendix 7.

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[13] Institute for Sustainable Futures for Total Environment Centre, *Win Win Win: review of the NSW D-factor and alternative mechanisms to encourage demand management*, Jan 2008, p. 6.

The Energy Markets Reform Forum concurs on the limitations of the D-factor approach. In its response the AER proposed NSW transitional guidelines[14] for distribution regulation it stated:

> "Unfortunately, the EMRF considers that there are much greater impediments to gaining the full benefits of DM than could ever be addressed by the D-factor scheme. …the EMRF does not support the implementation of the D-factor scheme as proposed as it would have to operate in an environment where the outcomes it is supposed to provide have too much opposition from other sources and it is unproven to provide sufficient benefit to consumers for the costs it imposes on them."

The EMRF recommended to the AER[15] that an approach as used by ESCoSA would have been a preferable approach to DM, as it provided its targeted program and was developed after ESCoSA reviewed the IPART D-factor scheme. The EMRF noted that:

> "A targeted scheme (like that used by ESCoSA) can be much more clearly benchmarked than the more indirect scheme like the D-factor scheme. The results of the ESCoSA scheme are available to all whereas the D-factor scheme does not lend itself to sharing the benefits learned by one DB with others. As the NSW/ACT region has four DBs, sharing experiences in a formal manner as the ESCoSA scheme does, has much to recommend it."

The D-factor approach is readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation. However, in balance a targeted scheme, such as the ESCoSA approach, is more transparent and able to be more widely used than the D-factor scheme which has the focus of ensuring the DB remains financially whole, in that there is more focus on ensuring the NSP receives the full benefit of any lost revenue rather than a focus on the implementation of DM programs.

Using TFP will make this defined program approach less transparent (or even not occur), and as a result, require a parallel but separate approach similar to the service performance scheme to be implemented.

2.5.3 Disaggregation and split benefits

In addition to the disincentives to DM that emanate from the BB and price cap forms of regulation mentioned above, is the final problem of the disaggregation of

[14] Comments on the proposed [AER] Pricing Guidelines, December 2007
[15] Op cit

the supply side elements of the electricity supply chain. This results in the benefits of DM having to be determined in relation to two or more elements – the overall system benefit and the network benefit, and as noted above, ESCoSA recognised this difficulty when developing its DM program.

By disaggregating the electricity supply chain, the benefits of DM are divided into two different markets, and when DM benefits for networks are considered in isolation from the system market (as is required by the network regulator), it faces considerable difficulty in demonstrating benefits specific to the network, whilst the benefits to the overall electricity market may be compelling.

2.6 Summary

The BB approach as used in the NEM is based on incentive regulation. The BB and the incentive regulatory approach both tend to incentivise network solutions and therefore disadvantage DM solutions

Of the two forms of regulation for recovery of the allowed revenue (revenue cap and price cap) the revenue cap is indifferent to DM whereas, on balance, the price cap approach has an inbuilt dis-incentive for DM.

As an alternative to the BB approach, the use of TFP would seem to be indifferent to DM (not unlike the revenue cap approach). It is the concerns with other aspects of TFP that imply that TFP might not be in the overall interests of consumers and DM. In particular, TFP is applied under a price cap approach and therefore it suffers from the implicit dis-incentive that a price cap revenue recovery method has towards DM.

The outcomes of the two DM programs implemented in the NEM so far (in NSW and SA) have been inconclusive, and further review is needed. Both approaches are readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation.

Using TFP will make the defined programs already in use less transparent (or even not occur), and as a result, might require a parallel but separate approach to DM similar to the service performance scheme to be implemented.

On balance, a targeted scheme like the ESCoSA approach for SA provides greater transparency than the NSW D-factor approach, although both approaches are readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation.

Overall, the regulatory approach used in the NEM has not provided a strong focus on DM, and when this is combined with the inbuilt incentives for network solutions, it is not surprising that implementation of DM approaches have resulted in very modest outcomes.

3. What incentive schemes might deliver DM best under the current regulatory settings?

The second question sought in this review is what can be altered to improve DM under the various regulatory settings currently in place in the NEM[16].

To answer this question, each of the regulatory approaches used needs to be examined to determine what mechanisms are needed under each form of regulation to maximise the likelihood of networks to utilise the full potential of DM.

3.1 Compensating for the building block approach

As noted above, the building block approach has a natural bias towards implementing network solutions rather than alternative solutions (eg non-network support).

To avoid network solutions being implemented in preference to non-network solutions under the BB approach would require the business to carry out a rigorous examination of the options under regulatory oversight.[17] Further, the regulator would have to recognise that there are in-built biases towards network solutions in the BB model itself, the ex ante capex approach, the EBSS and the performance standards incentive schemes, and develop appropriate mechanisms to counter these. In particular, a holistic approach examining both system and network requirements, with DM as a primary objective, needs to be part of the regulatory reset and explicitly factored irrespective of the forms of regulation (price cap or revenue cap) adopted.

Such an approach will require the Rules to be modified to allow the regulator to:

- Reward the business for implementing a non-network solution which is included in opex (or to replace the profit lost by the business from not having a network solution)

- Open up the elements of the ex ante capex approach where a non-network solution might apply

- Segregate out of the opex EBSS all allowances relating to non-network solutions

[16] At the second forum, a listing of specific questions was identified. These are included in appendix 8
[17] TEC has proposed a Rule change package that outlines some elements of such regulatory oversight. The AEMC is currently considering these proposals.

- Address allegations that non-network solutions deliver lower performance by ensuring NSP implement systems to identify if reliability has actually been reduced by the implementation of DM solutions. If the allegation can be sustained, an alternative approach might be to require a two tiered approach to setting performance targets within the bonus/penalty arrangements.

- Require DM to be a separate and definable part of the BB development. This then provides the transparency necessary for all to see the costs and encouragement provided to engender the DM program.

3.2 Compensating for the price cap

As discussed in section 2 a revenue cap form of regulation on revenue recovery is neutral with regard to demand and consumption (and hence DM). It has been noted that many jurisdictions have reverted to a revenue cap (or basically similar) form of regulation so that DM programs are not negatively impacted

In jurisdictions where the price cap has been retained, the approach has been to allow the network business to be paid for the loss of revenue it incurs due to a DM option being implemented. This is the current approach under NSW's D-factor. This reduces the **dis**-incentive inherent in the price cap approach, but still does not remove the incentive for rewards which come from increasing demand and consumption. In other words, while DM may not negatively affect revenue, increases in demand and consumption will definitely increase revenue, and therefore provides more certainty for networks.

The price cap approach, however, also lends itself to tariff manipulation, so that cost reflectivity of pricing, which is essential for economic efficiency, is lost along with the essential element for the efficient implementation of demand side responsiveness. If the prices for a service do not reflect the cost to provide the service then there will be an anomaly in the outcomes.

This issue has particular relevance as the network then has the ability to set prices which could prevent a reduction of consumption (to avoid a reduction in its revenue) and allow networks (both price capped and revenue capped) to implement network options in preference to other options for providing the service.

3.3 Capacity Market versus Energy Only Market

Eminent international economists[18] consider that an energy only market has an essential flaw in that it will not allow a generator to recover its long run marginal cost (LRMC)[19] and therefore cannot make an adequate return. This forces the generator to exercise its market power or to undertake tacit collusion with other generators to create price spikes and so distort the market. Payment for providing capacity to be available in the market is a tool which both allows a generator to recover its LRMC and provides an incentive for new generation, including self generation.

In this regard it should be pointed out that government incentives to build renewable generation in the NEM under the MRET scheme actually provide a similar degree of certainty for a return that a capacity market does. Similarly, the incentive of paying feed in tariffs from micro generation is another form of capacity payment, especially if the feed in tariff is oversized (see appendix 9) to reflect the non-commercial benefits (eg. greenhouse, community) it provides the system market or network.

One of the key arguments provided by NSPs against non-network solutions is a view that they tend to be less reliable than network solutions. This may be a plausible argument when a non-network solution is considered in isolation or when the DM provided is demand side response (DSR) and aggregators are not required to carry the financial risks of failure to provide the agreed support.[20] However, where many non-network solutions are implemented then the aggregate of these will match (even exceed) the reliability of a network solution[21].

Thus in consideration of non-network solutions, the NSP should be required to asses the impact of having a number of non-network solutions as part of its required analysis of non-network solutions.

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[18] Such as Jaskow of MIT and Tirole of University Toulouse. The views of these economists are denied by the proponents of the NEM.
[19] See glossary for a definition of LRMC
[20] Which, for example, may result in providers accessing DM well in excess of what is actually required to ensure an adequate buffer
[21] For example, in the case where there are many self generators, then the network assessment does recognise the network benefits afforded by the diversity of many such generators. This results in the paradigm that unless there are many concomitant self generators provided, then there is no assessed network benefit. The benefit comes from having a number of self generators but this never occurs because each self generator is assessed in isolation. This then becomes a "Catch 22" issue – until you have it you can't get it.

3.4 Economic Efficiency and the NEM Objective

The objective of the [National Electricity] Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:-

(a) price, quality, safety, reliability and security of supply of electricity; and
(b) the reliability, safety and security of the national electricity system.

Although the Objective makes reference to "…the efficient use of electricity…" as being part of the objective, the second reading speech introducing the Law specifically identifies that 'use of electricity services will be efficient when services are supplied in the long run at least cost', and that efficiency should be read in terms of the electricity market economics, rather than in terms of technical efficiency of the electricity system.[22] Thus the Market Objective for the NEM is predicated on the premise that economic efficiency will provide the basis for the electricity market that "…is in the long term interests of consumers".

It is debateable whether the supply of services delivered on the basis of "economic efficiency" will automatically deliver efficiency in the use of electricity. In fact it has been noted that the overall thermal efficiency of generation in the NEM has fallen since the advent of deregulation[23]. What is clear, however, is that efficiency in the use of electricity is unlikely to be achieved if the above regulatory disincentives to DM remain, and without any external policy intervention to increase efficiency.

A number of consumer advocates have pointed to an inadequacy of the implicit "economic efficiency driver" in the Law to deliver equitable outcomes for different classes of consumer (eg in regional areas where costs are higher, those with consumption patterns which are beyond their control to change, etc). Whilst these concerns have validity, they are not necessarily an issue for DM except where DM has the ability to reduce network costs due to those perhaps unique features applying to specific classes of consumer.

Economic efficiency in the NEM is already being distorted (including some measures introduced to meet social objectives) by:

- The impact of generator market power

[22] National Electricity (South Australia) (New National Electricity Law) Amendment Bill, 9 February 2005.
[23] Bardak Ventures Pty Ltd, The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Market May 2nd 2005, page 55

- Tariff manipulation by the regulated businesses which returns a revenue above levels assessed by the regulators

- The Commonwealth government imposing a requirement on large energy consuming businesses to undertake programs to increase the efficiency of energy usage

- Governments mandating increased renewable generation which is a transfer of wealth from consumers to renewable generators in the short term in order to reduce long term carbon costs and the other economic impacts of climate change

- Governments mandating “feed in” tariffs for micro generation which require all electricity consumers to pay more than they would for conventional generation (see appendix 9)

- Governments introducing subsidies on energy bills for disadvantaged consumers

- Regulation that encourages inefficient infrastructure augmentation, such as the ex ante approach to capex, and the automatic roll in of actual capex, regardless of demonstrable optimisation

- Regulators allowing networks to recover costs incurred in the provision of demand management, as an incentive

- With the impending introduction of greenhouse gas emissions trading, the expectation is that the cost of electricity will increase, and that disadvantaged consumers will need to be protected as will manufacturing businesses exposed to imports from countries without equivalent greenhouse emission reduction obligations

- Subsidies for the production and consumption of fossil-fueled electricity generation, (eg R&D for carbon capture and storage technologies[24]).

These are just some examples of situations where economic efficiency is being distorted in order to achieve other objectives. It becomes an issue of the standpoint of the assessor of these distortions, as to which are considered “good” and which are considered “bad”.

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[24] Institute for Sustainable Futures, *Energy and Transport Subsidies in Australia*, Chris Reidy, April 2007.

It has been noted that TEC and other NEM advocacy groups have repeatedly made the case that the NEM objective, which is currently focused on economic efficiency, should be supplemented by environmental and social sub-goals, as is the case in the UK and the New Zealand electricity markets.[25] It is argued by them that this would give regulators the scope to take into account these objectives when undertaking economic regulation. Proponents have stated that, in the NEM there is a tendency to dampen some environmental and social policies initiated external to the NEM[26]. The recent MCE direction for the AEMC to review NEM barriers to emissions trading and the Mandatory Renewable Energy Target (MRET) scheme implies that the NEM is, in fact, porous to external policy programs.

It is a TEC contention that rather than maintaining the NEM operation in isolation from broader energy policy, it is preferable that it acknowledges its place at the centre of Australia's greenhouse emissions problem and work with, rather than against, external actions. Equally, if economic efficiency is to be removed as the basis for the National Electricity Law (NEL), then it is questionable as to what other basis could be used. Electricity is an essential service, and must therefore be available to all. When considered in this way, then the prime basis, on which the objective should be based, is economic efficiency. This tension between economic efficiency and external energy goals has to be acknowledged.

Nevertheless, the requirement to achieve economic efficiency has not detracted policy makers from applying other objectives applying to the electricity supply system. For example, the existing Mandatory Renewable Energy Target scheme requirement on retailers, and the impending costs on emissions of carbon are very valid examples. Overall, it is considered that economic efficiency must still remain the basis of the NEL, and that its efficiency should be assessed within the parameters of externally set impacts on the energy supply chain.

If the NEL objective remains unchanged, new goals (such as increased energy use efficiency, or an overall reduction in electricity consumption) would continue

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[25] For example: Total Environment Centre in consultation with Gilbert + Tobin, *How Should Environmental and Social Policies be Catered for as the Regulatory Framework for Electricity Becomes Increasingly National?*, November 2006; Total Environment Centre, Consumer Utilities Advocacy Centre, Business Council for Sustainable Energy, Australian Council of Social Services, WWF, Australian Conservation Foundation, St Vincent de Paul Society, *Power for the People Declaration,* May 2007; *The National Electricity Law Amendment Package*, (signed by 21 community organisations), August 2004.

[26] For example, despite the existence of the Mandatory Renewable Energy Target scheme, there remain major barriers to the connection of distributed generation to the monopoly networks; despite ongoing policy statements in support of DM, non-network solutions continue to be hampered in the NEM.

to be treated as a separate Law[27]. By taking this approach, the NEL will continue to be requiring the most economically efficient outcomes when considered within the external parameters imposed by the new Law.

If DM continues to be dis-incentivised by the regulatory framework, as outlined above, then it may be preferable to have DM explicitly encouraged external to the Law. This may be a better method of ensuring the target outcomes are realised, with minimal opportunity for gaming within the Law and Rule.

This imposition of external requirements on the core aspect of the NEM would replicate the approach used in California, an approach which is discussed more fully in section 5.1 below

3.5 Network issues and demand side response (DSR)

Network costs are currently driven by the need to provide for the maximum demand. This means that network revenue should be determined by the demand of each consumer, rather than the amount (consumption) of each consumer. Therefore, cost reflective pricing would imply that demand alone should be used as the basis for revenue recovery. By following such a practice, it would impose the cost of providing the network in proportion to the maximum demand each user makes of the network. When viewed from this position, network pricing on the basis of consumption is not cost reflective.

Long term demand is penalised by “ratcheting”. This is the process where a network business measures the single highest demand used in the previous twelve month period, and charges the consumer regardless if the demand is reduced in this period. This approach does not encourage DSR.

If a consumer has a demand which is used only occasionally and at times when the network has spare capacity, the network charges for use of the network as if the demand was continuous. This approach is based on the assumption that if the assets are available and used (even if occasionally) then the full cost should be recovered from that consumer.

In this regard the Rules would appear to be contradictory. In one part of the Chapter 6A Rules this view holds sway, yet in another part, the Chapter 6A Rules seem to imply that a consumer’s demand should be measured at times when the system is experiencing peak usage. Chapter 6 of the Rules for distribution networks is also similarly not clear.

[27] For example, California mandates electricity use targets and requires that the CPUC implements a program within the regulatory approach applying to the regulated businesses to achieve the desired outcome

The AER resolved this dichotomy in its transmission revenue guidelines, by allowing the regulated business to determine which approach they consider best suits their needs. This must be considered an abrogation of the responsibility of the regulator to enforce the Rules. If the regulator has a concern regarding the Rules, then it should seek to give direction as to what the Rules are intended to achieve.

It would appear from the Rules that if occasional use is made of the network, and at times when the system is not operating at peak demand, then occasional use of the network should be provided at a lesser cost. Such an approach would be significant in supporting DSR options because most DSR options are not "schedulable" and may need occasional support from the network. If that use is sufficiently infrequent and occurs at times of low usage of the network, then it is appropriate that the cost for the use of the network when it has available capacity could be provided at a discount, to reflect the usage pattern of the DSR option.

At first blush, such views would appear to be contradictory. On the one hand, even if only used occasionally a user should still pay full value for using the network. On the other hand, if used when system (and network) demand is low, why should there be a payment as if the network is used continuously? This dichotomy lies at the heart of DSR, especially self generation. If the DSR is scheduled not to be available (eg. is scheduled for maintenance) at times when there is not a need for the DSR (ie when the system demands are low), or alternatively put, it is available when there is a need for it, then both the needs of the DSR provider **and** the network provider can become coincident. It is not so much that the arguments are contradictory, but more about the **timing** when the DSR can provide the needed service by the network provider.

Thus an approach for incentivising acceptance of what is seen by NSPs as a less reliable DSR solution, might be based on the following:-

- For DSR to be provided on a capacity basis, and penalised if it is not provided when called upon (following the practice used for generation in an electricity capacity market)

- For demand to be measured and charged for in accordance with the peak demand registered in each billing period, which incentivises DSR to use the network only at times of low system demand

With such an approach DM should be treated as the benefit it is to the network.

3.6 Potential to improve DM under the various regulatory settings currently in place in the NEM

There is no doubt that DM is being constrained by the regulatory approaches used, and when combined with the limited but under-powered DM schemes in operation, the modest outcomes are not unexpected. It is difficult not to conclude that regulators have not given sufficient weight to DM measures.

There would appear to be no simple solution to overcoming the inherent disadvantages that the BB, TFP, RC and PC approaches impose in providing dis-incentives to DM. The most likely approach to be successful in the NEM is that used by the ESCoSA for its pilot program for DM, which provides a parallel program supervised by ESCoSA to bring about defined outcomes. But it is, nonetheless, a rather modest program, and it still does not address the essential element that DM is likely to reduce the revenue of a price capped NSP. The fact that a price cap provides an incentive to **increase** consumption (and hence revenue) is not addressed by the regulatory approach to compensate for revenue lost by the implementation of a DM program. The most obvious approach to address this problem is to implement a revenue cap which totally disassociates the NSP from the need for compensation for lost revenue, and eliminates the incentive to increase consumption as a means to increase revenue..

The ESCoSA scheme bears many similarities to the successful CPUC program used in California (which is discussed in section 5) but would need substantial modification to overcome the remaining deficiencies – the most obvious of which is that the CPUC scheme provides the mechanism to achieve the externally set policy objective of increasing energy efficiency.

4. Which approaches are best for consumers, especially vulnerable consumers?

The supply of electricity must be considered to be an essential service. Without electricity supplies most of the current day activities and accepted standards of living would not be possible. Thus the supply of electricity on a reliable basis must not only be made available, but it must be available on terms and prices which allow it to be accessible to all sectors of the community. It is not acceptable to price the supply of electricity at such a level and without discrimination that certain sectors of the community cannot afford it its use.

It is important that it be recognised that supplies of reliable electricity can be made available to the community at prices which are generally within the capacity of all to afford without the need for cross subsidies. Despite many advantages accruing from the disaggregation of electricity supply chain and the partial privatisation that ensued, unfortunately the current regulatory regime for electricity supplies does allow for publicly and privately owned businesses in the supply chain to use the current market structure to either increase profits for shareholders or to extract additional revenues from electricity users.

To make DM occur, however, it is essential that those who are prepared to provide a benefit to the system to reduce stress on it should be rewarded and those that use power when the system is stressed should provide that reimbursement. Under such an approach, the cost to all consumers is reduced if workable DM programs are introduced, as by doing so there will be a benefit to all consumers by minimising costs and improving reliability.

Thus the issue for vulnerable consumers is whether the implementation of a DM program is in their interests and if such a program will either increase their costs, reduce reliability or prevent them from using power when they need it? Further, if vulnerable consumers see that they can benefit from providing DSR, then they should be encouraged to do so, especially if this would reduce their average cost of power.

To ensure that vulnerable consumers are not disadvantaged requires the implementation of a DM program which acts to prevent the implementation of capacity increases in generation and networks which are used only for short periods (thereby reducing overall costs) but could also allow such consumers to participate and garner the rewards of providing for a DSR program which acts to achieve these outcomes. Allowing disadvantaged and vulnerable consumers easy access to implement a DSR should allow them to reap full value from it, and so reduce their overall cost of the electricity supply service.

The ISF report notes with regard to the D-factor incentive, it allows networks to recover from consumers' revenue forgone by reduced electricity sales:

> "In principle, the D-factor will always benefit consumers because, in the short term, the price increase due to the Distributor's recovered lost revenue is much lower than the retail price of electricity saved by the consumer, and in the longer term, the cost of the DM measure is lower than the network costs avoided. In addition, the D-factor encourages energy savings that avoid both the environmental costs associated with greenhouse gas emissions and the financial costs associated with adapting to and offsetting these emissions."[28]

A DM program which results in using the lower of costs for a network solution and DM solution should result in lower costs overall and all consumers should benefit.

4.1 Network service performance

Network service performance is measured and rewarded regardless of whether a BB or TFP approach is used or if a revenue or price cap revenue recovery mechanism is applied. Performance is measured across the entire network's performance and applied as a penalty/bonus scheme in parallel to the main revenue setting approach. This means that networks average out the poorly performing feeders with those of high performance feeders. As a result, the network does not have sufficient incentive to address the needs of consumers on poorly performing feeders[29].

In some cases, the consumer might get a small payment from the customer service performance arrangement. Unfortunately, this payment bears no relationship to the costs a consumer might incur.

Network tariffs use a combination of demand and consumption elements, so loss of supply on poor performing feeders is in part recognised by consumers not having to pay for consumption that they might otherwise have had to pay for and therefore the DB gets a lesser revenue.

In the case of payments for the demand element of the tariff, the network is still paid even if the service is interrupted.

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[28] Institute for Sustainable Futures for Total Environment Centre, *Win Win Win: review of the NSW D-factor and alternative mechanisms to encourage demand management*, Jan 2008, p. 5.
[29] ESCV has introduced performance measures on a feeder basis but this approach has not been implemented in other regions of the NEM.

Despite the service performance program being separate to the main revenue setting approach, it is only by actual performance that consumers can identify that they are being provided with their half of the regulatory bargain – the regulatory bargain is that consumers will get a defined service for an agreed amount of money.

Service performance results from a number of issues – some of which are within the control of the NSP (such as meeting timeframes for maintenance and implementing replacement early enough not to lose a network element through using equipment that is too old) and others with are exogenous (such as weather conditions, demands from consumers, generator failures). Despite not being able to control all elements which lead to service performance, the NSP is rewarded or penalised regardless.

One of the main concerns about the service performance measures concerns a reduction of performance that is within the power of the NSP. This could stem from a deliberate program of not investing in capex or not spending opex as allowed as it will show up as poor performance only well after the actions are taken. For example, lack of opex and capital investment might not show up for a number of years after this deficiency was detected.

To assess whether a NSP might deliberately not invest opex and capex needs an understanding of the way any business operates in the current business climate. Businesses are assessed for financial performance on a quarterly basis by their investors, and after 12 months clear impressions are drawn[30]. After between 2 and 3 years investors will take action regarding their investments and if the financial performance is deemed to be lacking investors will sell down their shareholdings and seek better performing businesses to invest in. Thus short-termism in investing in businesses has created a 2-3 year window of performance.

Senior management of NSPs are being rewarded by share options which require a financial performance hurdle for them to be exercised. The concept behind this is to incentivise management to look to the interests of shareholders. Thus management is also committed to short-term rewards. This incentive on management runs counter to the interests of network customers who are affected by a much longer term view of performance.

Business incentives act as a dis-incentive to achieving long term service performance of the network. This is compounded in practice by the rewards for

[30] Although the investment outlook for government-owned utilities might not be the same as for privately owned utilities, nevertheless, short-term revenue gains are also a priority for such government owners.

service performance limited by the regulatory guideline (AER) to 1% of allowed revenue, although the Rules (AEMC) allow this constraint to be as high as 5%.

Using such a low powered service incentive does not overcome the business financial performance incentive which would show much higher reward for reducing capex and opex.

To overcome the disparity of incentives, the service performance incentive should equal the business incentive. To achieve this, the 1% constraint against revenue must be increased. One way of doing so would be to require the NSP to pay consumers in equal measure if there is a failure of supply.

Ideally, such a penalty would require the business to pay the consumer the same amount that the consumer has to pay if supply had been provided. As the network tariffs have a mix of fixed payments (a payment related to the level of demand and a payment related to that amount of consumption) it would seem appropriate that the network would pay to all consumers an amount using the same bases (ie as if the supply had not been interrupted) for the entire billing cycle, including the ratcheting effect on demand.

4.2 Demand Response for Reserve Trader

The NEM has the ability to ensure system security by the use of "Reserve Trader" powers. Reserve Trader is where the NEM operator (NEMMCo) directly contracts with suppliers in order to secure additional generation. As part of Reserve Trader, NEMMCo also contracts with end users to reduce their demand at critical times when asked to by NEMMCo.

When NEMMCo identifies that Reserve Trader is necessary, it calls for both increased generation (usually from generation that is not committed to the electricity market) and for consumers to reduce their demand when called on to do so. Reserve Trader has been initiated three times in the NEM (although it has not been called upon). NEMMCo have identified that the cost of Reserve Trader has been based on a mix of capacity payments and energy payments. Even though the Reserve Trader has not been dispatched, consumers have been required to pay for the capacity payments that were contracted for.

Although the cost for providing this demand side responsiveness is higher than the normal cost of generation in the short term, in the long term augmentation costs are reduced, making the DM option potentially more cost-effective than supply.

Consumers do not necessarily consider that their electricity supplies are seen in isolation – they also consider the impact of **not** being supplied. Whether a consumer is a business or a residential consumer, the loss of amenity can be considerable. If a consumer elects to reduce demand (ie lose its amenity) then it needs to place a value on this loss. Whilst it is relatively easy to value the loss of amenity in a business context, this must not cloud the view that loss of amenity in a residential context has no value.

Whilst not being readily quantifiable as each consumer has its own cost structure for offering a DM response, DM is likely to cost more than conventional supply methods.

Providing that there is a balanced approach to costing both options (and this is discussed in sections above), then even though both options will increase costs, a DM option might cost less. When this occurs the party offering the DM will receive a benefit. While all other consumers will be required to pay more for the service, the costs of infrastructure augmentation will be less in the long term.

Providing the concept of economic efficiency has been applied, consumers will receive the optimum outcome from whether a DM or a network approach has been used.

Thus demand side management should not impose a cost premium on consumers.

4.3 System security

The supply of electricity is now an essential service. Although some consumers can tolerate loss of supply for short periods, the loss of supply for extended periods can be devastating – the loss of refrigeration is an example of this type of supply loss. Some consumers, once having lost supply can manage for many hours without resumption of supply.

The timing of the loss is also influential. Loss of supply during the early hours of a morning for a short period is unlikely to have a major impact on a domestic consumer, but loss of supply during a meal preparation is critical.

As discussed above, there are some that consider that a network solution will provide the greatest reliability of supply. The issue that must be addressed is at what cost point is a less reliable but lower cost option preferable to a highly reliable but higher cost supply option.

This issue is not necessarily one of DM solution versus network solution but the degree to which one will provide a benefit over the other, and the cost to achieve the marginal gain. In fact, in many cases the overall difference in reliability between options might be negligible or one option might increase reliability by a relatively insignificant amount. What is essential is that in assessing an option both the change in reliability and the cost need to be assessed, so that a high but perhaps unnecessary cost premium for achieving a modest reliability benefit is not automatically accepted without assessing the cost to achieve that modest increase.

Effectively, such an approach requires the placing of a value on the relative changes in reliability. Thus it is essential that the increase in reliability is assessed against the cost of providing that increase.

Consumers do want a high security for their electricity supplies, but are prepared to accept less than 100% reliability because the cost of achieving 100% reliability can be too high. All options for network development should seek to balance the cost of the augmentation against the level of reliability that can be achieved for the cost.

4.4 Costs incurred by consumers in attempting DM

Some consumers have attempted to implement their own DM by investing in approaches to reduce overall demand and consumption. Of these the most well known is the implementation of residential energy efficiency ratings and the energy rating efficiency for household appliances.

Large energy consuming businesses are required to implement energy efficiency programs mandated by the Commonwealth government.

Consumers do incur costs as a result of these programs but the requirements for this energy efficiency are exogenous to the regulatory approaches used for assessing network businesses, even though they do have an impact on the networks.

Improving national energy efficiency is a goal which is to the benefit of the nation as a whole, and, while laudable, it is not an aspect which is related to the benefits DM can provided to networks, and the costs consumers should carry as part of the regulatory bargain with the network businesses.

4.5 Conclusions on aspects of benefits for consumers

The regulatory bargain requires a reasonable payment for the provision of a reasonable service. If a network is to be incentivised to provide a better level of service, then the incentive needs to match the business financial incentives to seek short term financial gains. The current low powered service performance incentive program does not match the higher powered incentives on a business to take short term gains.

If a consumer loses supply, part of the service performance penalty should be to pay the consumer what the consumer would be expected to pay the NSP, using the same tariffs and ratcheting approaches. After all, why should a consumer have to pay a fixed and demand charge regardless of whether they receive supply or not?

Provided the mechanism for assessing a DM approach from a network solution is made on economic efficiency grounds, then consumers are not worse off from having a DM solution, provided that this does not result is a lesser reliability of supply when compared to the costs for providing that higher reliability.

5. Which overseas DM incentive schemes deliver better outcomes?

The introduction of DM incentive schemes has been a vexed question for a number of reasons. The most critical is that by disaggregating the retail, networks and generation functions, this creates artificial barriers to giving full value to DM.[31]

A number of overseas DM programs specifically targeting incentives to networks would appear to be based on a revenue cap (or it's near equivalent cost-of-service) approach, combined with reimbursement of the distribution business for lost revenue.

Our international colleagues, EEE, make the point that DM is not successful in many disaggregated systems, and has marginal success in many aggregated systems. The key point is that DM has not been the focus in many jurisdictions.

5.1 California

The TEC sponsored forum on 19 May 2008 was addressed by the Chairman of the California Public Utilities Commission (CPUC), who drew attention to the successful demand management program in California. The Californian State Government, through its utility regulator the CPUC, has introduced a strong incentive program for energy efficiency and demand management, and this program has been operating successfully for a number of years.

The CPUC regulatory approach is based on a number of significant differences from that used in the NEM, and these need to be fully understood. Notwithstanding this note of caution, these differences do not necessarily make the CPUC program unable to be introduced into the NEM, subject to appropriate policy and regulatory adjustments.

The CPUC program is based on the following elements:

1. The Californian government has mandated that the energy Utilities must provide a demand management program with set goals to be achieved within a fixed time

2. The Utilities the CPUC supervises provide a "fully bundled" service from vertically integrated utilities which comprises energy, transport and retail functions, thereby enabling an integrated approach for DM

[31] See the ESCoSA comment included in section 2.5 above

3. The Utilities operate on a cost of service (CoS)[32] basis rather than the incentive regulatory approach used in Australia

The CPUC program is based around a legislated defined target of very specific outcomes concerning the goals of reducing consumption and incentivising energy efficiency, DSR and renewable energy. Demand management is one of the mechanisms that is used to achieve these goals.

Each Utility proposes an energy efficiency (with a DM component) and renewable generation program and requests an amount of funds for its implementation to be added to the revenue set from the cost of service (CoS) regulatory approach used in California. The CPUC assesses the funds requested and the program proposed. It then fixes the amount to be included within the approved tariffs of the Utility, and for the approved amount the Utility must deliver the outcomes proposed in the program. This program is to meet the longer terms goals legislated by the Californian government.

In turn, the approved CoS revenue is converted into approved tariffs. Thus embedded in the tariffs used by consumers, is an amount of money specifically targeted to provide increases in energy efficiency (and the DM program) and renewable generation.

The programs included by the Utility are wide ranging and encompass the impact on generation needs, increases in renewable energy supplies, network optimisation and overall reductions in energy use.

To encourage the Utility to meet the agreed outcomes, the CPUC has recently introduced an incentive reward program and appendix 7 provides some detail.[33]

The incentive program operates as follows:-

- There is agreement of the energy savings goal to be achieved and an agreed cost to achieve these savings
- These savings after the costs are deducted are assessed as a net benefit to consumers
- If less than 65% of the energy savings goal is achieved then the utility incurs a financial penalty

[32] See glossary
[33] Full details of the program are included in CPUC document "Rulemaking 06-04-010 (Filed April 13, 2006)" and titled Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs.

- If the energy savings goal achievement is greater than 65% but less than 85%, there is no penalty, but no bonus

- If the energy savings goal achieved is greater then 85% but less than 100%, the Utility is paid a bonus which is 9% of the net benefit that would accrue to consumers from the energy saving

- If the energy savings goal achieved is greater than 100%, the Utility is paid a bonus which is 12% of the net benefit that would accrue to consumers from the energy saving

This program operates across the entire operation of the Utility and so allows the Utility to accrue benefits from each element of its activities. Such an approach is significantly weakened under the disaggregated approach used in the NEM. It should also be noted that the program addresses much more than DM, as it incorporates the renewable energy program and energy efficiency goals, which includes consumer efficiency and network efficiency. Notwithstanding these observations, it is possible that such an approach could be tailored to incentivise NSPs to improve network and consumer efficiency within the NEM.

As a precursor to developing such a program for the NEM, it would require:-

- The mandating by government of an agreed level of efficiency improvement to be achieved

- The mandating of the AER to incorporate in its networks decisions, the costs for achieving these mandated goals

- A decision to discard the price cap approach in order to eliminate the need to reimburse an NSP for loss of revenue incurred as a result of implementing the DM response to improve efficiency levels[34]

Because, in the NEM, the renewable generation target is separately mandated and proportionate reductions in net generation are separately measured (and managed by retailers), incorporation of such goals is not required for the NEM at the current time. However, to convert the CPUC program to apply to network regulation is made quite difficult due to the disaggregation of the supply chain in

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[34] Retention of a price cap will require a mechanism to assess the revenue lost due to implementation of the program apart from the loss of revenue from other sources, and to overcome the incentive to increase demand and consumption implicit in the price cap revenue recovery. This is the current arrangement under NSW's D-factor regulation under a price cap. A revenue cap approach does not have this need to recompense revenue loss.

the NEM and the inability to recognise the aggregated benefits of DM to the supply chain.

5.2 Other overseas approaches to network support of DM

EEE identifies that all networks operating with a price cap approach suffer from the need to increase power flow so as to ensure recovery of the needed revenue, and as a result a price control methodology is replaced with a revenue control approach. The **Massachusetts DPU** addresses this issue specifically, and keeps businesses "financially whole" due to the imposition of the DM program. As with the California example, the Massachusetts program applies to a cost-or-service model of tariff setting.

Con Edison, which is an integrated utility operating in New York State provides another approach. As with the California program established by the CPUC, there is a defined target established for Con Edison to reduce demand in its area. It is compensated for the costs it incurs from the lost revenue and is paid a fixed amount for each MW of demand is reduced, up to a cap, as an incentive.

The **Commerce Commission in NZ** applies a different approach to DM by using the allocative mechanism for transmission into distribution, by imposing a greater risk on the DNSP for recovering the transmission charges it has to pay for, but without it being able to pass through these onto consumers as applies in the NEM.

5.3 Conclusions on overseas DM incentive schemes

DM has been implemented in a number of overseas jurisdictions although more so in the US than in Europe. The impediment faced with using the US models in the NEM revolve around the need to mandate energy efficiency targets and the different structures (integrated in the US, disaggregated in the NEM) that apply.

The implementation of <u>DM approaches within network businesses</u> has not received much attention in overseas jurisdictions and thus the DM approach implemented by ESCoSA might be considered to be leading in this respect.

Consideration needs to be given to combining mandated energy efficiency targets in the NEM with the DM measures currently implemented by ESCoSA and by the CPUC, to drive a more powerful DM approach in the NEM.

6. What approach best meets the intent of the Rules

What mechanism best delivers the new revenue and pricing principles

a. *"A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations"*
b. *"A network should be given effective incentives to promote the economically efficient investment in and provision and use of network services"*
c. *"The regulator must have regard to the regulatory asset base adopted in previous determinations"*
d. *"The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services"*
e. *"That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network"*
f. *"The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network"*

The following subsections provide comments against each of the principles raised.

6.1 Revenue and Price caps

Both a revenue cap and a price cap approach meet the requirements of the Rules, and are permitted for use by the Rules.

Rule element	Revenue cap	Price cap
A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations	Provides exactly what the regulator determines are efficient costs	Exposes the business to over or under recovery of efficient costs related to actual demand and consumption
A network should be given effective incentives to promote the economically efficient investment in and provision and use of network	Separate incentive programs are required	Separate programs are required, although the NSP is incentivised to

services		increase demand and consumption, in theory so as to increase utilisation of the network
The regulator must have regard to the regulatory asset base adopted in previous determinations	Not impacted	Not impacted
The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services	Provides exactly what the regulator determines is an appropriate return	Incentivises the NSP to increase demand and consumption so as to maximise the return
That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network	The regulatory approach (including the EBSS) incentivises the NSP to under invest in the network	The regulatory approach (including the EBSS) incentivises the NSP to under invest in the network
The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network	Provides no incentive to increase utilisation, and provides no penalty for under utilisation	Provides an incentive to increase utilisation, and a penalty for under utilisation

6.2 BB and TFP

Only the BB approach complies with the Rules, although a Rule change is proposed to allow TFP to be utilised in the future

Rule element	BB	TFP
A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations	The BB approach provides certainty of this	There is no certainty that this will occur
A network should be given effective incentives to promote the economically efficient investment in	Provided	Not certain. The TFP **assumes** this has occurred and that the

and provision and use of network services		annual adjustments will retain this feature
The regulator must have regard to the regulatory asset base adopted in previous determinations	Provided	Not necessary
The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services	Provided	The TFP approach does not ensure that this will occur
That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network	Provided	The TFP approach does not ensure that this will occur
The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network	Provided	Provides an incentive to increase utilisation, and a penalty for under utilisation via the price cap. There is a risk that the TFP approach (being less transparent) will incentivise less opex and capex – see timing risk under section 4.3

6.3 Conclusions

The Building Block and revenue and price caps are written into the Rules as forms of regulation, and therefore are considered to comply with the Rules.

Analysis of the TFP approach under the six regulatory principles, would indicate that a number of the Rule provisions would have to be modified to allow the use of TFP.

7. Forum conclusions and recommendations

7.1 The Forum Outcomes

The TEC convened a second forum to analyse the issues raised at the first forum and, in the brief to consultants, to provide some guidance for the development of this report. As previously noted, the report is to inform and provide guidance to TEC and the participating groups. Arising from that forum, the Final Recommendations for Consultants on Further Research and Report are noted as follows:-

1. Explore external incentives for DM, in particular, the California dead-band targets

2. Explore options for decoupling revenue from consumption

3. High initial service standards are important

4. Needs to include holistic assessment (relative to values outlined above) of bottom line impacts

5. Identify what a network can or can't do well

6. Information on how overseas jurisdictions have used TFP

7. What is essential for TFP to work

8. How do consumers engage with TFP before and after its implementation

This report has provided responses to each of the above aspects, and the following observations are derived from the body of the report.

7.1.1 Explore external incentives for DM, in particular, the California dead-band targets

The analysis identifies that the current mechanisms used in the NEM for regulating networks have, either implicitly or explicitly, dis-incentivised NSPs from implementing DM. Effectively, ESCoSA had reached the same conclusion and consequently implemented a separate pilot scheme to determine actual benefits that can be derived by an NSP from certain DM activities. The Californian scheme is a high-powered DM scheme, which is greatly strengthened by related explicit Government policy targets for achievement of energy efficiency by electricity businesses.

7.1.2 Explore options for decoupling revenue from consumption

The earlier analysis identified that revenue can only be de-coupled from consumption by the implementation of a revenue cap approach, or by a separate mechanism that reimburses an NSP for revenue lost as a result of the implementation of DM.

In California, the successful DM programs have been developed in an environment of a cost-of-service model, which has many features (e.g. the built-up of capex and opex costs) akin to the revenue cap approach.

7.1.3 High initial service standards are important

Service standards are an important element of a regulatory regime as this provides the balancing half of the regulatory bargain – the NSP provides a service to the standards explicitly stated, for the amount paid by consumers.

However, care is needed in this aspect in regard to DM, as many DM options are considered to provide lower availability than network options. As a result, imposition of very high service standards could result in less DM, for marginal improvement of service performance that a network solution might provide.

7.1.4 Needs to include holistic assessment (relative to values outlined above) of bottom line impacts

In the disaggregated system used in the NEM, holistic approaches to energy efficiency and DM are difficult. For example, the regulator only reviews network businesses, and not the contestable areas of generation and retail. As a result, many of the DM approaches used elsewhere in the world (such as where electricity systems are not disaggregated) are not readily convertible to the NEM environment.

ESCoSA observed this in its 2005 determination on ETSA Utilities and approached the implementation of DM from a different angle. It is expected that in 2009 when the next regulatory review of ETSA Utilities is commenced, a better idea will be available of what can be realistically included within the network to encourage DM.

7.1.5 Identify what a network can or can't do well

ESCoSA has probably made the most in depth study of this aspect in the NEM, and from this determined that it would require ETSA Utilities, in the DM scheme, to focus on only four aspects – power factor correction, use of standby generation, residential direct load control and aggregation[35].

Of these, aggregation is arguably an aspect that might be one that the retailing function should manage, as retailers have the ability to aggregate demand from consumers in more than one distribution area. In the SA region of the NEM (as distinction from every other region), ETSA Utilities is the sole distribution business and therefore can act as an aggregator.

ESCoSA decided that for various reasons, critical peak pricing, voluntary load control and interval metering were not appropriate to be included in the ETSA program[36].

7.1.6 Information on how overseas jurisdictions have used TFP

TFP appears not to have been widely used in overseas jurisdictions. Where it has, it would appear that the sheer numbers of networks to be reviewed by the regulator predicated the need to implement such an approach (eg as in Germany).

Using a TFP approach might incentivise a network to use DM if a DM approach is the lowest cost option. Balancing this is that DM might not be as reliable as a network solution, and therefore placing the NSP at risk of not meeting service standards.

When service performance is incentivised under a "low powered" program[37] such as the AER currently uses, it is more likely that, under a TFP approach, the lowest cost option for network management might be implemented, regardless of whether this is a DM option or not.

7.1.7 What is essential for TFP to work?

A TFP approach needs:-

- A price cap approach to tariff setting which creates an incentive to increase demand and consumption

[35] These are discussed in some depth in section 2.5
[36] The reasons for ESCoSA not including these are discussed in section 2.5
[37] See discussion in section 4, particularly section 4.1

- Accurate and detailed data over a reasonable length of time to provide confidence in the data set
- Certainty that the starting point tariffs are correct, both from a fundamental value basis and that they are cost reflective
- Sufficient numbers of participants to ensure that collusion (passive and active) is not possible
- Similarity between the NSPs being regulated to ensure that no one NSP might be treated inappropriately

There is a residual concern that if TFP reduces the profit of an NSP, or that a “bow wave” capex program[38] is required, then the outcome for consumers might be a reduced service. EEE makes this observation in appendix 5.

7.1.8 How do consumers engage with TFP before and after its implementation?

Consumers have almost no input into the setting of tariffs under a TFP approach. The data is collected and analysed by the regulator and an annual adjustment of existing tariffs is made by the regulator.

A TFP approach is essentially a mechanical approach to tariff setting.

7.2 Other incentives and mechanisms

There are concepts for encouraging DM that are being implemented in various overseas jurisdictions. It would appear that the most successful require a number of pre-conditions which include:-

1. A mandated outcome of energy efficiency targets (which includes DM) as a subset) around which the regulator can construct a program
2. A vertically integrated Utility which has the ability to capture the combined effects of DM rather than the disaggregated model used in the NEM which effectively disperses the benefits of DM to different elements of the NEM structure, and makes the benefits of DM in any one structural element marginal
3. A strong incentive on the Utility to achieve the agreed outcomes, with penalties for sub performance

Whilst precondition 3 is achievable in the NEM at this time, action is required to implement precondition 1, and this is a policy issue and not one of regulation.

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[38] See glossary

The achievement of the benefits from precondition 2 will not be possible within the current NEM structure (although it is not impossible to assign targets to each disaggregated sector), but ESCoSA would have appeared to provide an option which has the potential for a longer term and successful approach to the provision of DM.

7.3 Conclusions

Under the current arrangements, there is a disincentive to DM using the Building Block approach, and this is further reinforced when the BB is combined with a price cap (as opposed to a revenue cap) model, as it encourages consumption and demand.

The BB approach, through the capex and WACC mechanisms incentivises the network business to seek network solutions as these raise its profitability. On the other hand, a BB approach is very transparent and allows implementation of concurrent programs such as a specifically targeted DM program.

A TFP approach has the potential to be neutral in relation to DM (as, in principle, it incentivises the lowest cost option to maintaining the service) but as it requires the use of a price cap approach (which incentivises greater demand and consumption) using a TFP approach has certain constraints with regard to reducing the amount of power used overall (the focus of energy efficiency, and therefore of some DM aspects which might be considered to be a subset of energy efficiency).

A TFP program has a number of other disadvantages that need to be assessed in light of the overall goals of encouraging DM. In particular, it is not a tool which provides transparency and therefore might not provide the necessary transparency required to encourage DM options (and energy efficiency).

Using a price cap approach with a DM program requires an ability on the part of the regulator to identify any revenue lost to the NSP from a DM program and to implement a program to allow the NSP to recover this lost revenue. Such an approach has the potential to increase the “gaming” an NSP might undertake to maximise its revenue stream.

A revenue cap approach suffers from the inherent dis-incentives in a BB approach to DM, but as the BB approach allows transparency and for programs to operate in parallel, a BB approach combined with a revenue cap provides a “least worst” outcome for implementing a DM program which has some prospect of real success.

7.4 Recommendations

Under the current arrangements, attempting to implement a regulatory regime in the NEM to encourage DM (or even to provide neutrality) is challenging, due to the loss of synergies from vertical integration.

The BB approach provides built-in incentives to expand network investments, and, indirectly, increase consumption and demand. Consumers, however, should seek to engage in regulatory reviews and contest network businesses' capex and WACC claims.

A price cap form of regulation under the BB approach encourages the network businesses to increase consumption and demand. Consumers should seek to engage in regulatory reviews to contest network businesses' claims with respect to pricing methodologies and cost allocations, especially to ensure cost reflective pricing e.g. pricing based on demand and not on consumption.

Separate and parallel DM incentive schemes are the most effective way of ensuring DM initiatives by network businesses, especially when supported by policy directives to achieve stipulated targets of energy efficiency. Consumers should focus on ensuring that the schemes are high-powered and that regulators take a holistic view of the various pull and push factors that encourage/discourage DM outcomes to ensure there are real net DM outcomes.

Of the approaches examined in the NEM, it appears that the program initiated by ESCoSA has the greater potential for achieving the maximum benefit from DM for consumers. The ESCoSA approach is a parallel program to the standard BB approach to regulation.

To avoid the inevitable tension that a price cap approach brings, it is recommended that a revenue cap approach would assist by removing the incentive to increase demand and consumption.

To overcome some of the dis-incentives inherent in the BB approach (even with a revenue cap), it is recommended that a DM program be developed for each NSP and implemented as part of the NSP revenue reset.

A DM program might exhibit the following features:-

- It would operate as a parallel program as part of the regulatory reset
- The NSP would identify those DM actions where it could deliver a benefit to consumers
- An agreed series of actions and target outcomes would be established between the regulator and the NSP

- A fixed amount of funding would be included in the allowed revenue for the NSP to achieve these outcomes
- There would have to be a program of benefit sharing (such as that used by CPUC) of sufficient “power” to overcome the dis-incentives inherent in the BB approach, with penalties for sub performance

The DM program could be even more effective, if it were driven by an over-arching energy policy requirement for achieving energy efficiency targets across the electricity supply chain.

APPENDIX 1

The Building Block approach

An economic regulator, such as the Australian Energy Regulator (AER), has the task of deciding how much cash a regulated business should be allowed to have each year to provide the service consumers want. Typically, the regulator will assess the cash needs of the business for the next five years and this is called the regulatory period.

In the Building Block approach, the regulator looks at each separate cost element of the business, and decides how much each part should cost each year. The regulator then adds up the costs for each element and the addition provides the allowed revenue for each year. This becomes the amount the business will be permitted to get consumers to pay through the tariffs set.

In a typical decision by a regulator, the regulator will look at the following cost elements.

- What is the value of the assets needed to provide the service now. This is called the start regulatory asset base (start RAB)
- What is a reasonable return for a business providing these assets to deliver the service. The regulator develops what is called the weighted average cost of capital (WACC) which will provide a reasonable rate of return on the cost of the assets needed to provide the service.
- How much was spent on new assets in the last regulatory period. This is called the past capital expenditure (past capex)
- What new assets need to be provided to replace worn out assets over the regulatory period, and to manage any expected increase in usage for the regulatory period. This is called the capital expenditure (capex)
- What will it cost to keep the assets in good working order over the regulatory period, and to ensure the assets provide the service. This is called the operating expenditure (opex)
- What was the difference between the allowed opex for the past period and the actual opex used. This provides the basis for the efficiency benefit sharing scheme.
- What was the loss in value of the assets as they aged over the past regulatory period. This is called the past depreciation.
- What will be the loss in value of the assets as they age over the regulatory period. This is called the new depreciation.
- What was the increase in costs due to inflation. CPI is most commonly used to value this.

- What is the likely increase in costs due to inflation over the regulatory period.
- How much better will the regulated business perform given some new assets and using improved techniques. This is called the efficiency improvement.

The regulator then carries out a series of calculations:

Calculation 1 - the value of assets at the start of the new regulatory period

Start RAB = RAB at the start of the old regulatory period + past capex - old depreciation

Calculation 2 – what is the RAB at the start of each year

RAB end year 1 = start RAB + start RAB*CPI + year1 capex – year1 depreciation

Calculation 3 – average RAB

Average RAB year 1 = (Start RAB + RAB end year 1)/2

Calculation 4 – return on capital

Return **on** capital = average RAB*WACC

Calculation 5 – valuing efficient opex

Efficient opex = assessed opex – efficiency improvement

Calculation 6 – smoothing the allowed revenue for each year

The "smoothing" is achieved by assessing amounts of equal change over the period which have the same net present value of the actual amounts calculated.

The building block for year 1

Cash allowed for year 1 = **average RAB*WACC**
+ average capex year 1*WACC
- average depreciation year 1*WACC
+ efficient opex year 1
+ efficiency benefit carryover

The cash for each year is calculated and then “smoothed” to reduce year on year volatility. This smoothing is achieved by calculating an “X” amount in the allowance that tariffs will be adjusted by using a factor of CPI –X each year.

The Building Block approach is the basis for the use of both the price cap and the revenue cap forms of regulation. It permits Demand Management initiatives to be built into both these forms of regulation.

Advantages –	**Disadvantages –**
• approach is clear • targeted to the specific business needs • flexible • future oriented • can reset tariffs to reflect changes	• time consuming • complex • higher regulatory cost • regulator involvement in business decisions • needs to be closely managed by regulator • open to debate • open to gaming • once tariff is set changes are more difficult • reviews every five years • encourages network capex rather than best option

APPENDIX 2

Revenue Cap approach

As with price caps, once the revenue needed by the regulated business has been determined, the regulator has to decide how the revenue will be recovered from the users of the regulated service.

The revenue cap approach sets the revenue recovery allowed by the regulated business for each 12 month period.

The difference from the price cap approach is that the tariffs under a revenue cap for the coming year are not adjusted to reflect the over- or under-recovery of revenue from the current year. The only adjustment to the amount of revenue that can be collected for the entire regulatory period is if actual inflation is different to the forecast of inflation used in the setting of the allowed revenue.

Thus the essential difference between the two approaches is that under a price cap, the regulated business takes the risk on the amount of consumption and demand, whereas under a revenue cap, consumers have this risk.

A revenue cap approach cannot use TFP as its basis for adjusting tariffs.

The advantages of a revenue cap are:-

- The amount of revenue to be recovered from users is known by consumers and the network business
- There is no incentive for the business to manipulate tariffs to improve its revenue
- The revenue cap approach readily accommodates large, "lumpy" investments in the network because of the certainty the DB will get its money for the investment. Under a price cap the revenue is dependent on consumption, which reduces the certainty that all revenue will be recovered from the tariffs and therefore that the investment will achieve its needed return.

The disadvantages of a revenue cap are:-

- It provides no incentive for tariffs to be cost reflective
- It does not provide any incentive on the regulated business to modify customer demand or consumption

- It provides no incentive to get better utilisation of the network from either improving load factor[39] or better maintenance practices
- It has no interest in encouraging demand management and might even have a disincentive in the long term as its profits come from the return on the assets its provides – more assets => greater profit

Currently a revenue cap approach is used for all 8 electricity transmission businesses (Powerlink, TransGrid, EA transmission, Directlink, SP Ausnet, Transend, Murraylink and ElectraNet).

It is also used for 4 electricity distribution businesses – Ergon and Energex in Queensland, Aurora in Tasmania and ACTEW/AGL in ACT.

Advantages –	**Disadvantages –**
• doesn't rely on forecast demands, reducing complexity • tariff manipulation prevented • has no incentive to prevent DSR	• more risk lies with consumers (cost risk) by paying for assets not required • tariffs change with demand levels (eg tariffs rise as consumption, demand reduces) • doesn't incentivise better economic efficient utilisation • low incentive for alternative solutions • tariff structure signals to consumers to change habits are very muted

[39] Load factor is the relationship between demand and consumption. A low load factor indicates that the network has "needle peaks" in demand, requiring the network to be built for high demands which operate for short periods. As the costs for a network are related to demand, a low load factor means a higher cost for consumers when related to consumption, which is the most common basis for assessing electricity costs

APPENDIX 3

The Price Cap approach

Once the revenue needed by the regulated business has been determined, the regulator has to decide how the revenue will be recovered from the users of the regulated service.

In Australia, the regulators use two approaches for controlling the recovery of the revenue from users – a revenue cap approach and a price cap approach.

The price cap approach sets the revenue recovery allowed by the regulated business for each 12 month period to be related to the **usage** of the network in terms of demand and consumption.

A price cap approach requires a method for adjusting tariffs to accommodate differences between expected inflation and actual inflation. The Rules allow for a number of methods to be used to address inflation adjustments to maintain the allowed revenue. These are by using:-

- a schedule of fixed prices; or
- caps on the prices of individual services; or
- caps on the revenue to be derived from a particular combination of services; or
- tariff basket price control; or
- revenue yield control; or
- a combination of any of the above

The most common approach used is the tariff basket price control approach, with a schedule of fixed prices for certain services.

With this approach the regulated business develops a set of tariffs intended to recover the allowed amount of revenue, but if these tariffs over or under recover the allowed revenue, then the regulated business is not permitted to adjust tariffs to reflect any over or under recovery in the previous year.

A price cap approach can use both the TFP and building block approaches as its basis for setting tariffs.

The main advantage of a price cap is:-

- It can provide a strong incentive to get better utilisation of the network by improving load factors[40] and better maintenance practices. This is because if consumption is increased using the same assets without increasing demand, then the cost to all consumers reduces on a consumption basis. If the network is better maintained, it will be available when consumers need it and so there will be greater consumption, and under a price cap this means more revenue to the business.

The disadvantages of a price cap are:-

- It can provide little or no incentive for tariffs to be cost reflective but can provide a strong incentive for tariffs to be manipulated to maximise revenue
- The amount of revenue actually recovered from users is not known by consumers
- As it can encourage greater consumption and demand, it has a disincentive to encourage demand management
- As its revenue is dependent on usage forecasts, there is an incentive to under-estimate forecast usage when developing revenue allowances, which can result in higher tariffs, and therefore revenue, being higher than necessary

Currently the price cap approach is used by 8 electricity distribution businesses (EnergyAustralia, Integral and Country Energy in NSW, SP Ausnet, Powercor, Citipower, Alinta and United in Victoria, and ETSA in SA)

Advantages –	**Disadvantages –**
• more risk lies with business • incentivises better economic efficient utilisation by encouraging more consumption • tariff signals can be stronger to change consumption habits	• revenue to business is variable, incentivising the business to find ways to ensure its revenue is maintained, for example, by encouraging consumption • business incentivised to understate future demand growth => more debate with regulator • encourages greater consumption as revenue is related to consumption • does not encourage DSR or reduced consumption • incentivises tariff engineering

[40] See glossary for definition of load factor.

APPENDIX 4

The Total Factor Productivity (TFP) approach

An economic regulator, such as the Australian Energy Regulator (AER), has the task of deciding how much cash a regulated business should be allowed to have each year to provide the services consumers want.

TFP is all about avoiding having the current five year regulatory reset review which is seen as cumbersome, expensive, confrontational and time consuming. Conceptually the TFP is an attractive low cost alternative to the building block approach. It is a move away from cost-based regulation (under price and revenue control approaches) and towards a less intrusive, and high-level approach based on externally-derived indicators.

With the TFP approach, the regulator:

- sets a new regulatory period, commonly of 5-10 years
- sets an accurate starting point of what constitutes the most efficient cost allowance for a network
- agrees on what constitutes the most cost reflective prices (tariffs) for the provision of the services offered
- allows the regulated business to adjust its tariffs using a CPI – X adjustment where X is determined from the movement of costs incurred by a large group of similar distribution businesses over a number of past years (commonly 3-5 years)
- will reassess the tariffs actually applying at the end of the regulatory period in order to be sure that the tariffs are efficient and cost reflective, and that the revenue resulting from the tariffs provides an efficient revenue based on the assets used and the cost to maintain them

The calculation of the TFP adjustment is carried out annually but is relatively straightforward and readily carried out. Because of the TFP uses trends, it is expected that a detailed review of tariffs could be carried out every 10 years or so to identify if the tariffs are still appropriate.

Calculation: New tariff = old tariff*(CPI – X) where X is the developed from the movement of costs in the electricity distribution industry peer group.

The TFP approach makes some basic assumptions to ensure the TFP approach delivers the outcomes expected. These are:-

- the starting point is correct – that the tariffs used at the start really do reflect an efficient and cost reflective price for providing the service
- there is a sufficiently large number of similar businesses to prevent one or two businesses to distort the overall trend (the Victorian government considers that the five electricity businesses in Victoria do constitute a large enough group for this purpose)
- collusion (active or passive)[41] between the businesses will not occur, although the likelihood of at least passive collusion increases over time and also as the number of businesses in the group decreases
- every regulated business will strive to minimise its costs even as their prices increase in the short term, increasing their profits, but knowing that by doing so this will reduce their prices in the longer term

There are a number of matters to consider about the use of TFP in the NEM

- TFP can only be used under a price cap approach, therefore it will only be used for distribution businesses
- When the application of TFP results in a reduction of profits, it could result in detriment to consumers
- Does the NEM provide sufficient convergence of electricity distribution businesses (DBs) activities to support TFP? In this aspect four issues are relevant:

    1. **Ownership**
    There are 12 electricity DBs in the NEM – 2 in Queensland owned by the Qld government (Ergon and Energex), 3 in NSW owned by the NSW government (EnergyAustralia, Integral and Country Energy), 1 in ACT (ACTEW/AGL), 5 in Victoria (SP Ausnet, Powercor, Citipower, Alinta and United) and 1 in both SA (ETSA) and Tasmania (Aurora). However, of these, Singapore Power has a significant interest in ACTEW/AGL, SP Ausnet, United and Alinta, and ETSA, Powercor and Citipower are owned by Spark Infrastructure of which CKI has a significant interest. Thus, these 12 DBs are effectively controlled by five separate entities. This raises the concern about whether there is adequate diversity for TFP

[41] Active collusion is where the businesses meet and develop a common approach. Passive collusion is where the businesses observe the actions and reactions of the other businesses under certain conditions, and then develop an approach which effectively replicates the outcomes of active collusion. Already in the NEM, generators in a region have been observed to practice passive collusion very successfully.

2. **Differences in Geography Affecting Operating Conditions**
   There is significant diversity between the geographic features of the DBs – 2 are regional/rural (Ergon and CE), 3 are city/regional (Energex, EA and Integral), 2 are regional (SP Ausnet and Powercor), 3 are city/rural (Aurora, ETSA and ACTEW/AGL) and 3 are city (Alinta, United and Citipower)

3. **Relevance of Revenue Caps for TFP Baseline**
   4 of the DBS are currently operating under revenue caps and are therefore not applicable for TFP (Aurora, ACTEW/AGL, Energex and Ergon) although it is possible the costs incurred by these businesses might be used for evaluating TFP for the other DBs

4. **Differences in Customer Base and Geographic Size**
   There is considerable diversity of size of the customer base for each DB and the geographic area each covers

- Specific demand management schemes should be able to operate within the operation of a TFP approach. As DM will be variable over time and within each DB, the TFP is unlikely to include adequate DM recognition. It is anticipated that therefore demand management will have to be treated in a similar way to the service performance incentive scheme. The TFP approach permits the use of parallel incentive schemes.

<u>Assessments of some overseas jurisdictional uses of TFP</u>

Appendix 5 provides a view of TFP as applied in other jurisdictions.

One of the concerns outlined in this report by EEE about the TFP approach as used in The Netherlands is that this:-

> "…simple approach is adequate when capex is in the trough of the investment cycle (as has been the case to date in the Netherlands), but it takes no account of the need for significant renewal investment. Indeed not only does the current approach provide a disincentive to investment by delaying the time at when the cost of investment is reflected into the control, but if one company invested heavily in a period while the others held off, the control would disbenefit the investing company and benefit those that did not invest. DTe and the companies recognise that this will become an issue to be addressed in the future. A solution may be to treat capex above a certain level as an addition to a TFP control."

This inability to accommodate a significant increase in legitimate capex needs could damage the longer term interests of both consumers and DM proponents.

EEE points out that it would appear that the use of TFP in New Zealand is more of a “hurdle” which if exceeded could result in the application of a Building Block approach. The examples quoted of the US experience would seem to highlight that there the application of TFP is more used as a stating point for continuing the tariffs developed under a “cost of service” model, and that a major element of the application of the discounting “X” factor is a negotiated “stretch” amount to force the “cost of service” tariffs towards economically efficient tariffs.

EEE also notes that the use of TFP in Germany is to regulate some 900 distribution businesses, and notes that statistical analyses are the basis for deriving the outcome. It would appear that statistically a data set of 900+ inputs should provide a sound comparative basis, and that the more rigorous BB approach would create a significant cost burden to consumers.

Advantages –	**Disadvantages –**
• simple • reduces gaming once initial baseline is set • reduces debate • little flexibility once parameters set • regulator minimal involvement in business decisions • lower regulatory cost • can be applied to large numbers of similar businesses, • less frequent reviews • business uses lowest cost solutions • encourages cost efficiency • provides competitive pressure	• relies on collation of longitudinal data from comparable businesses • needs to be closely managed by regulator • needs a large number of participants to develop representative data (is 9 or 13 enough across the NEM – if Vic alone only have 5?) • doesn’t address specific business’ needs • once tariff is set changes are more difficult • setting P_0 right is critical (are these correct now?) no EBSS has been applied symmetrically to give confidence Po is right. AER says need symmetry both to get Po right - only had EBSS for opex • service performance needs to be closely monitored to ensure the business is providing the service • encourages collusion over time • might not be appropriate if there is a need to ramp up capex • outcomes need to be verified after efflux of time

APPENDIX 5

Report from the overseas consultant

REGULATION OF DISTRIBUTION NETWORK SERVICE PROVIDERS –

EXPERIENCE WITH TOTAL FACTOR PRODUCTIVITY CONTROL

EXPERIENCE OF DEMAND SIDE MANAGEMENT

For the Total Environmental Centre

May 2008

Alex Henney

There is a debate in Australia about whether the building block approach (with which Australia has extensive experience and the method is incorporated into the National Electricity Rules) or the total factor productivity (TFP) [42] approach may be "better" for regulating distribution network service providers (DNSPs). Within the context of this paper "better" is taken to mean 1) achieving control that will promote economically efficient development and operation on the part of a DNSP, and 2) encouraging more efficient use of electricity including demand side management.

The disadvantages of the building block approach are the level of detailed analysis required; the informational advantage of the companies; and the difficulty of assessing the need for capex – particularly renewal capex. The advantages claimed for the TFP approach are that it is simple and that it mimics a market, see Annex 1. The first three sections this paper examines how the TFP approach has been applied[43] in:-

- The Netherlands
- New Zealand
- Some cases in the US

The Total Environmental Centre is also concerned to know what mechanics have been devised to encourage DNSPs to develop demand side response. This issue is discussed in the fourth section.

THE NETHERLANDS

Background

[42] A total factor productivity index refers to the productivity of all inputs – labour, capital, materials – as opposed to a partial factor productivity index which focuses on the level (or change in level) of one input such as labour – thus customers/employee is a partial productivity measure (supposing the number of customers is a relevant measure of output) that does not capture all the possible sources of productivity growth (labour may be substituted for capital or vice versa), while customers/total $ cost where $ total cost includes labour, materials and usage of capital is a measure of total factor productivity.

[43] Note that in all the examples there are also controls for service quality, but they are not discussed here.

The number of DNSPs reduced over the last 20 years from nearly 80 to 7 now, of which 3 are dominant each supplying around 2 million meter points and jointly supplying 93% of all the meter points in the Netherlands. All of the DNSPs are owned either by municipalities or provincial governments. A new regulatory authority, DTe, was created in 1998. DTe observed that there are two general approaches to benchmarking that have been used by regulators:-

- setting the X factor equal to the average total factor productivity growth rate of the relevant industry, which is an "unlinked" approach that "delinks" the setting of X from the behaviour of individual regulated utilities
- cost linked benchmarking such as used in the UK [and Australia]

Longer term DTe wanted to move to the unlinked method of "yardstick regulation" for the distribution companies, which means that the regulated prices are not linked to efficiency judgements based on the costs of the individual companies, but reflect the scope for efficiency of a typical or average company in the sector. As DTe observed "The aim is to simulate the operation of a competitive market through yardstick competition…Through its decoupling of the network company's own costs and the tariffs, the system of yardstick competition provides a strong incentive to reduce costs". This average is the yardstick. In this way companies performing better than average would make an above-average rate of profit, and conversely for those performing poorly where the return would be worse than the average.

For various reasons DTe's first attempt at setting controls for the period 2001-03 was a disaster that ended in the courts and chaos, but it got its act together for the second (2004-06) and third (2007) regulatory periods.

<u>The second (2004-06) and third (2007) regulatory periods</u>

For the second regulatory period of 2004-06 DTe consulted with the DNSPs and developed an approach for benchmarking them using a simple quasi total factor productivity index for each DNSP which it devised of:-

$$\frac{\text{total cost of inputs}}{\text{value of output}}$$

The cost of inputs includes a charge for capital based on a return on standardised assets equal to the weighted average cost of capital derived by assuming a debt/equity ratio of 60/40; calculating a debt premium above a risk free premium from comparable private undertakings; and using the capital asset pricing model to estimate the cost of equity capital. The result was a real pre-tax return of 6.6%. The value of output was derived by first calculating the average national unit charge for supply at each voltage level, and then applying the respective figure to the volume of supply at each voltage level by a particular DNSP.

DTe set an X for all distributors based on the average efficiency improvement for the whole sector (which it forecast as 1.5% p.a., but in the event it was 1.1% and so there were corrections made for the next period) plus catch-up factors for each company to achieve the level of efficiency of the most efficient company by the end of the period. The relative level of efficiency was measured by the ratio of the index for each company to that of the most efficient company.

DTe considered that the second regulatory period had brought total allowed revenues of distributors into line with their efficient costs, and consequently in the third regulatory period the underlying efficiency X factor was the same for all distributors and was based on the average annual change in productivity of *all* distributors during the years 2003-05 (viz 1.1% p.a.).

This simple approach is adequate when capex is in the trough of the investment cycle (as has been the case to date in the Netherlands), but it takes no account of the need for significant renewal investment. Indeed not only does the current approach provide a disincentive to investment by delaying the time at when the cost of investment is reflected into the control, but if one company invested heavily in a period while the others held off, the control would disbenefit the investing company and benefit those that did not invest. DTe and the companies recognise that this will become an issue to be addressed in the future. A solution may be to treat capex above a certain level as an addition to a TFP control.

<u>NEW ZEALAND</u>

In the mid 1990s, when restructuring its electricity industry, New Zealand did not create an industry regulator but relied on self-regulation (which is an oxymoron) coupled with (hoped for) cost transparency. Predictably the approach failed. In 2001 legislation was introduced that requires, among other things, the Commerce Commission (which is the general competition authority) to implement a "targeted control regime" for the 28 DNSPs. In the words of the Commission "the thresholds are a screening mechanism to identify lines businesses whose performance may warrant further investigation and, if required, control by the Commission".

The "thresholds" approach is unique. It is intended to be a mechanism for identifying DNSPs companies whose performance *may* warrant further examination, which - depending on the findings - could lead to formal control of prices and/or service quality levels. Control is "targeted" in the sense that a company can only become subject to control by breaching an established threshold.

In the scheme put in place from April 2004 the thresholds were set using X-factors that were based on:-

- a B factor of -1.0% p.a. reflecting expected industry-wide improvements in efficiency, determined through TFP analysis

- a C factor, reflecting the relative performance of groups of distribution businesses. DNSPs were ranked by relative efficiency (which was measured by TFP and other statistical methods) and allocated to 3 groups and given a supplementary C factor – more efficient (-1% p.a.); averagely efficient (0% p.a.); and less efficient (1% p.a.) Then X = B + C

To recap, the thresholds are like a "soft" price control – a DNSP can breach it, but if it does so then it may be subject to an investigation that will be building block like, and may be followed by an enforced control.

SOME TFP SCHEMES IN THE US

The US generally continues to use traditional cost of service regulation, but in the 1990s some states which unbundled generation from networks experimented with "performance based ratemaking" (PBR) which can incorporate a TFP approach. Unlike a price/revenue control regime, PBR involves setting a company a target rate of return on equity and a price control (US jurisdictions rarely use price caps, but see below) for a period of time, which is typically 5 years. There is then a sharing arrangement for the upside and downside for the actual return. For example in the case of San Diego Gas & Electric's scheme starting in 2000, the price control was based on a TFP of 0.92% p.a. to which a "stretch factor" of 0.7% p.a. was added to give a total X of 1.62%. The stretch factor was justified by the proposition that since the companies had been subject to cost pass through regulation they must be somewhat inefficient, and so a PBR incentive regime will squeeze out the inefficiency. The stretch factor is a deal. Shareholders retained all excess earnings up to 25 basis points above the target rate of return and above 300 basis points. Between those limits the shareholders earned from 25% progressively increasing to 95% of excess earnings; customers received the difference. Shareholders took any downside.

The first index scheme in Massachusetts was for Boston Gas, which indexed rates to the historic total factor productivity of the economy minus that of input prices for gas distribution utilities in the North East together with a stretch factor. The scheme for New England Electric System's merger with Eastern Edison Company agreed a small reduction of rates in the first year then fixed rates in nominal terms for the succeeding four years. Subsequently the rates were adjusted annually by an index based on an average of the distribution charges of investor owned electric utilities with unbundled rates in New England, New York, New Jersey, and Pennsylvania.

INCENTIVISING DEMAND SIDE MANAGEMENT

In many jurisdictions distribution charges are based on a mix of a capacity charge to reflect the local connection cost and possibly shallow reinforcement costs, and a power flow charge (kWh). The latter factor gives the DNSPs an interest in power flow increasing and consequently a disincentive to promote demand side measures. Where there are competitive markets very few jurisdictions appear to be looking to the DNSPs to implement demand side measures. Many European countries have no interest in the topic, while those that do look to the retailer (e.g. Britain, France) – there is no scheme in either country to incentivise demand side management by the DNSPs. There are few jurisdictions making the effort that the Electricity Services Commission of South Australia is requiring of ETSA Utilities.

Nonetheless there are some efforts which start with removing the DNSPs interest in power flow increasing by changing from price control of unit rates to either revenue control or compensating a DNSP for any loss of revenue from the implementation of demand side measures. The next step is to subsidise demand side measures. The final step is to devise a mechanism which provides DNSPs with an incentive to introduce demand side measures, which has been suggested in broad outline in New Zealand.

The Massachusetts Department of Public Utilities has been holding a hearing to devise a mechanism to “decouple” the revenue of network companies from reductions in powerflow. Essentially this means switching from multi rate price control to revenue control, and allowing compensation to the DNSPs for lost revenue through what it calls a “base rate revenue adjustment mechanism” (the method for which is explained in Annex 2). This adjustment reflects the mechanism by which the revenue cap is adjusted each year to manage the “unders and overs” of revenue recovered in the preceding year. The legislature is considering a bill to separately recompense utilities for investment in demand side measures.

There are three programmes for demand reduction/energy efficiency/distributed generation in the service territory of Consolidated Edison, the DNSP serving New York City:-

- a programme administered by Con Edison which is largely aimed at peak shaving to reduce investment in upgrading the network by measures such as programmable thermostats, higher efficiency lighting programmes, installing higher efficiency air conditioning systems. The objective is to reduce demand by 150MW

- a statewide programme run by the New York State Energy Research and Development Authority intended to conserve energy by getting customers to install more efficient equipment through direct installation and rebate programmes which are funded by a surcharge on bills. The programme aims to reduce demand by 550MW

- a programme by the Authority which is particular to Con Edison's service territory and is funded by a levy included in the rates which aims to reduce demand by 300MW

These programmes reduce customers' power consumption, and hence the revenue of Con Edison. It is compensated for the direct costs and associated lost revenues for the statewide programmes and the targeted (company) programme. It is paid $22,500/MW of demand management achieved up to a three year limit of $15.88m for the programme which it runs.

The Commerce Commission in New Zealand has a stated objective of incorporating an incentive for demand management into the pricing structure but, with impending legislation and an election, the reset of thresholds has been deferred from 2009 to 2010 and work on the reset has been deferred. The transmission charge has a significant charge related to peak demand, and currently the transmission charge is a pass through. The initial thinking was to allow (say) half of the charge as a pass-through and impose the other half on the DNSP. This would provide a sharp incentive for demand management.

Annex 1 <u>Pricing by TFP emulates pricing in a market</u>

For a competitive industry over medium to long term periods[44] the trend (symbol Ξ) in output prices (ΞP) equals trend in *unit* costs (ΞC), that is:-

$$\Xi P = \Xi C \quad (1)$$

Now the trend in unit costs in an industry equals the difference between the trends in input prices to the industry (ΞIP) and the trend in its "total factor productivity" (ΞTFP_{ind}) i.e.

$$\Xi C = \Xi IP - \Xi TFP_{ind} \quad (2)$$

Since ΞP=ΞC, then for a regulated process to mimic the competitive market standard prices should change year on year by the following formula:-

$$\Xi P = \Xi IP - \Xi TFP_{ind} \quad (3)$$

For the economy as a whole the change in input prices equals the change in output prices plus the change in the TFP for the whole economy (ΞTFP_{econ}).

Thus we have the following relationship:-

$$\Xi IP = (\text{either } \Xi CPI \text{ or } \Xi GDP\text{-}PI) + \Xi TFP_{econ} \quad (4)$$

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[44] Over the short term the relationship between prices and unit costs will fluctuate, and for a capital intensive business may fluctuate in a seemingly perverse way. Namely when the market is "soft" (demand is weak) prices will be relatively low while unit costs (i.e. <u>fixed costs</u> + variable cost/unit) will be high.
number of units

If (and only if) the measure of economy-wide inflation (e.g. CPI) reflects accurately the change in input prices to an industry, then substituting (4) into (3):-

$$\Xi P = \Xi CPI + \Xi TFP_{econ} - \Xi TFP_{ind} \qquad (5)$$

If, however, there is a difference between the trend of input prices to the industry and the index used to measure economy wide inflation (in this case ΞCPI), then there has to be a further adjustment equal to (ΞIP - ΞCPI) - call it the trend in differential input prices ΞDIP. Then equation 5 becomes:-

$$\Xi P = \Xi CPI + \Xi DIP + \Xi TFP_{econ} - \Xi TFP_{ind} \qquad (6)$$

(Note that the potential significance of the input price differential is not widely understood).

Annex 2 The proposed Massachusetts base rate revenue adjustment mechanism intended to promote efficient deployment of demand resources[45]

The key elements of the proposed "base revenue adjustment mechanism" are as follows:-

- Each company's base distribution revenues will be reconciled on an annual basis to ensure that they are closely aligned with costs. This reconciliation is intended to ensure that a company will not be harmed by reduced sales nor will it experience financial benefits from increased sales
- Each company will be allowed to recover a fixed amount of revenues per customer, for each customer class. This provision is intended to ensure that revenues are more closely aligned with a significant driver of costs on a company's system – the number of customers
- The Department of Public Utilities will determine each company's allowed revenues and allowed revenues per customer in the context of a base rate proceeding, using well-established ratemaking precedent including cost of service, cost allocation, and rate design. Allowed revenues will be collected through base customer, energy, and demand rates, established by customer class
- Every twelve months, each company will submit a reconciliation filing for Department review. Such filings will be used to make any reconciliation adjustments for the preceding year and to set the new base energy rates for the subsequent year
- Each company's reconciliation filing will compare actual revenues with allowed revenues for the preceding year and will adjust base energy charges up or down to reconcile for differences. The adjustment in base energy charges also will include the recovery of an appropriate level of revenues for the subsequent year, calculated by multiplying the allowed revenues per customer by the projected number of customers
- In its initial base rate proceeding establishing a new revenue recovery mechanism, each company will assess the extent to which the base revenue adjustment mechanism affects the company's risk profile and how any change in its risk profile should be incorporated in the company's rate structure

According to the Department the base revenue adjustment mechanism should be designed to meet or appropriately balance the needs to:-

[45] Docket No. DPU 07-50, 22 June 2007.

- better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives

- ensure that electric and gas distribution companies are not financially harmed by the increased use of demand resources

- meet the Department's rate structure goal of efficiency by more closely aligning company revenues with costs

- meet the Department's statutory obligation to investigate the propriety of gas and electric rates in a way that is consistent with Department ratemaking precedent, including the review of cost-of service studies, cost-allocation, and rate design

- be consistent with Department precedent related to rate continuity, fairness, and earnings stability

- appropriately balance the risks borne by customers and those borne by shareholders

- advance the goals of safe, reliable, and least-cost delivery service and promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden

- be applied uniformly across all electric and gas companies, to the extent appropriate and reasonable

- be simple, easily understood, and transparent

Under a base revenue adjustment mechanism, a company's revenues would be reconciled on a regular basis. If a company's sales volume changes over time, leading to lower distribution revenues than were allowed at the time rates were set, then the difference in revenues would be determined and periodically reconciled through distribution rates. This periodic reconciliation ensures that revenues would be more closely aligned with costs over time. Further, a company would not be financially harmed by or benefit from changes in sales.

Annex 3 Responses to specific questions

- Under a price cap, the DNSP is incentivised to increase consumption and demand which is an active disincentive to demand management

Response - agree

- A revenue cap provides no incentive for demand management, but neither does it incentivise demand management (DM)

Response - agree

- The DM approaches currently in place seem only to recompense the DNSP for the revenue they would lose by implementing the DM

Response – the reality is that in general people are merely playing with incentivising DNSPs

- Are the examples you provide based on incentivizing the demand and consumption reduction?

Response - Yes.

For example the $22,500/MW of demand reduction provided to Con Edison would seem to be well below the cost of new generation which is $0.8-2m/MW installed.

Response - Agreed, but the objective is not to pay for new embedded generators, but (for example) to encourage use of existing standby generators in commercial buildings and trimming of air conditioning systems at peak times

- Is the $22,500/MW payment for a reduction in demand (ie MW) additional to any compensation for the loss in revenue caused by reduced consumption (ie MWh)?

Response - Yes.

It can bee seen that there is a benefit from reducing demand as this would result in less capex for the DNSP, but if the consumption associated with this demand is merely time shifted, then there is no reduction in consumption (MWh) and hence no loss of revenue

- Currently the regulatory test used in Australia uses $10k/MWh (or $29.5k/MWh in Victoria) to justify new network investment. Do other jurisdictions use this sort of approach to justify investment? Do they use this as a cost indicator for DM (ie for the savings that DM would deliver)?

Response - The other countries cited with TFP do not have the NEM type of regulatory test figures for general DNSP investments, which are rolled into the TFP

With regard to TFP:

- It is understood that TFP is used in Germany as well. Does the German approach follow the Netherlands approach, and therefore could be equated with the Netherlands approach?

Response – I had not quoted for Germany because I have never analysed its regulation. Germany uses data envelopment analysis (DEA) and stochastic frontier analysis (SFA) to benchmark the 900 odd distributors

- In the Netherlands (and Germany), are the DNSPs considered to be reasonably similar in relation to terrain, population density, rural vs urban, etc or are there significant differences between them in relation to these factors. The concern is that if they are reasonably similar, then there might be a concern that where there are significant differences DNSPs like in the NEM, then maybe TFP is less appropriate.

Response - The Dutch DNSPs are considered similar except for one which serves the delta of the Rhine. As you probably know, the Netherlands is flat. Germany is flat in the northern plain and mountainous in the south

- You make reference to TFP in the Netherlands section to the capex trough. Was this issue one raised by DTe and do they make adjustments for variances between DNSPs with differing capex needs?

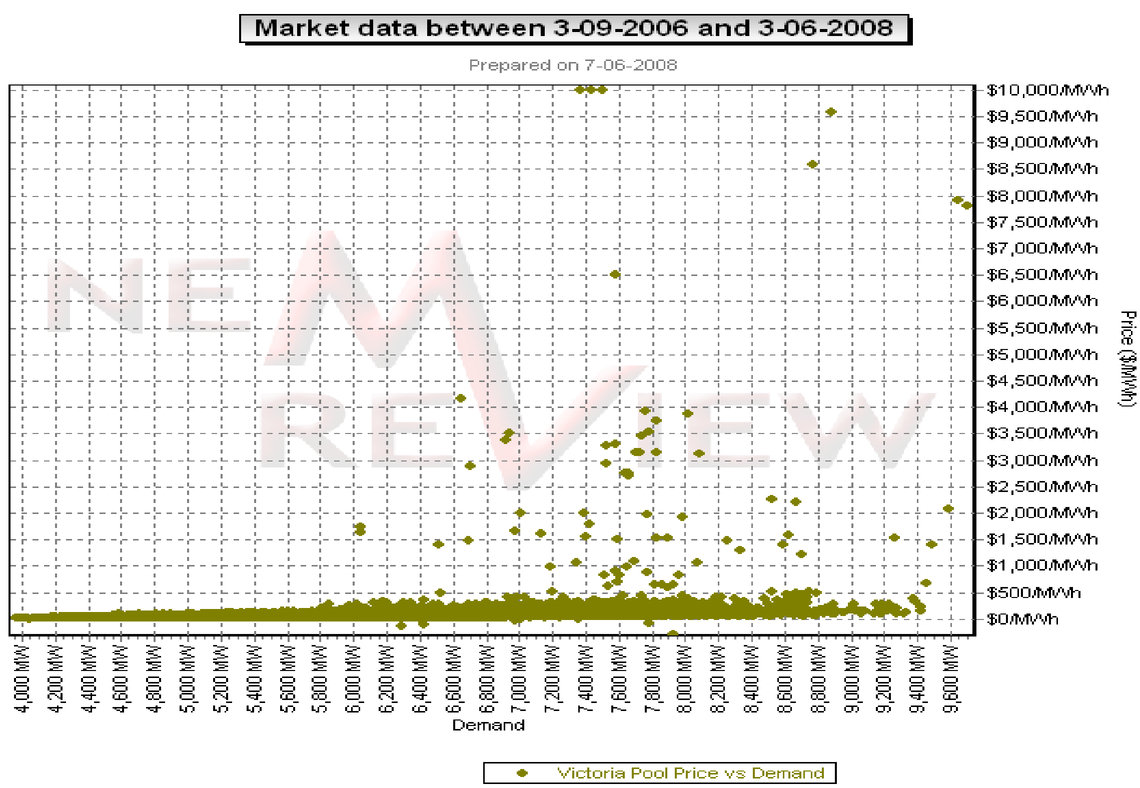
Response - They are in an investment trough (see p4), so the issue has not yet arisen. In Australia some DNSPs are spending up big because the regulator accepts their claims. Compare this to the Victorian DNSPs, after being permitted large capex allowances 2000-2004, actually spent only two thirds of what they were allowed, and the next period has only allowed them capex following the trend they set from the last period – this means that capex allowances are no longer being assumed to reflect the "bow wave" effect.

APPENDIX 6

System DM and the impact of a disaggregated market

Demand management has two basic effects – the first is on the supply of electricity and the second is on the transport of electricity. There are many times when these effects are not concurrent, and at other times when they do occur concurrently.

Demand management in relation to the supply of electricity is driven by the need to limit the amount of electricity being used when the generation available has reached its limit. A reduction in demand at such a time might be signalled by the price of electricity (but not always as can be seen in the chart below), by load shedding (ie by preventing some consumers from being supplied) or by the market operator entering into unique contracts to provide additional electricity from non-traditional sources (Reserve Trader).



As can be seen from the above chart, there is not a strong relationship between demand and price (especially very high prices). If system demand and price do not show a strong relationship, then this directly impacts on the efficacy of the spot market to incentivise demand management at any given point in time.

In the NEM the supply of electricity (generation) has been separated from the transport of electricity, with generation being considered to be a contestable function and the network to be a natural monopoly function. This separation means that the economic signals resulting from the system pricing element of the NEM (the contestable element) have a significantly reduced applicability to the network function (the monopoly element). The direct result of this separation is that the economic signals developed for the contestable element have marginal use for the monopoly element (networks) and therefore the economic signals for networks tend to be developed in isolation of the market as a whole.

This contrasts to the ability of demand management being able to benefit from the integration of both elements, such as occurs in many overseas electricity markets which are based on vertically integrated generation and network service providers (this aspect is discussed later in this report).

However, the purpose of this paper is not on system demand management but on the approach to network regulation and its impact on demand management.

APPENDIX 7

Win, Win, Win: Review of NSW D-Factor

A report for TEC by Institute for Sustainable Futures (ISF), UTS & Regulatory Assistance Project January 2008

ISF Recommendations:

1. Clarify government policy intent regarding efficient Demand Management.
In recognition of the scope of demand management (DM) both to advance the long-term interests of consumers and to enhance environmental sustainability, State, Territory and Federal Governments should ensure that the National Electricity Law and the National Electricity Rules:

- explicitly require the Australian Energy Regulator (AER) to make efficient regulatory determinations in relation to DM
- explicitly require Distributors to undertake all cost-effective DM, prior to network augmentation.

2. Align network incentives with consumer and public interest.
In making regulatory determinations, the AER should avoid creating incentives that set the financial interests of the Distributors in conflict with the interest of their customers. In particular, incentives against DM should be avoided in relation to:

- short-term incentives (within regulatory periods) associated with price/revenue control formulae (see Recommendations 3 to 8)
- long-term incentives (between regulatory periods) associated with prudence review and the incorporation of capital expenditure into the capital base and mechanisms for sharing efficiency benefits between shareholders and consumers (see Recommendations 9 to 11)
- network system development and planning requirements (see Recommendations 12 to 14).

3. “Decouple” Distributor profit from electricity sales.
In setting its year-to-year price control formula, the AER should as a key priority, decouple Distributor revenue and profit from electricity sales volume. That is, the AER should ensure that the profitability of a Distributor is not linked to the amount of electricity carried through its network and consumed by its customers.

4. Use Revenue caps to decouple network profit from electricity sales.
In order to decouple electricity consumption and Distributor revenue and profitability, the AER should apply a revenue cap in preference to a price cap in regulating Distributors.

5. Link revenue cap to economic growth.
In applying a revenue cap, the AER should consider applying adjustment factors to insulate Distributors from large divergence of actual peak demand from forecast peak demand. This could, for example, be applied by linking the annual revenue cap to movements in measures of economic activity, such as Gross State Product.

6. Use D-factor if revenue cap precluded.
In circumstances where it is not possible to apply a revenue cap (for example, where a commitment to a price cap has already been made, as in NSW for the forthcoming regulatory period), other revenue decoupling or "lost revenue adjustment" mechanisms should be applied (such as the NSW D-factor).

7. Create a "use it or lose it" component in the D-factor.
Where a "lost revenue adjustment" mechanism (such as the D-factor) is established, it should be applied with a default ex ante allocation on a "use it or lose it" basis that assumes some (non-trivial) level of DM will be undertaken by the Distributor. A D-factor of at least 2% of annual proposed capital expenditure could provide a reasonable default ex ante allocation.

8. Allow recovery of long-term DM costs in D-factor.
Distributors should be permitted to recover, through the D-factor, costs associated with low cost "long-term DM" opportunities that would otherwise be lost if they are delayed until a local network capacity constraint emerges.

9. Allow Distributor savings from DM to be carried forward.
The AER should ensure that Distributors are permitted to carry over efficiency benefits from DM, such as deferral or avoidance of capital expenditure, from one regulatory period to the next, on no less favourable terms than they are able to continue to earn a return on network capital investment from one period to the next.

10. Ensure balanced prudence review of capital expenditure.
Recognising that short-term incentives are likely to have little impact unless complemented by longer-term incentives, the AER should ensure that the review of prudence of past and projected capital expenditure involves a thorough all-sources assessment of the opportunities for deferring capital expenditure through DM, conducted by experts with a demonstrated balanced understanding of the theory and practice of DM.

11. Require Distributors to demonstrate efforts to procure DM.
The AER should require Distributors to demonstrate that they have undertaken reasonable efforts to identify and procure cost effective DM, particularly in the context of anticipated network constraints and proposed new network investment. Such efforts should include DM direct offers to consumers, DM programs developed by the Distributor and DM proposals solicited from other parties.

12. Inform the DM market.
The AER should seek to inform the market for DM options by requiring Distributors to publish detailed information annually about the current capacity of the distribution

network, current and projected demand and possible options to address any emerging constraints. (The NSW DM Code of Practice for Distributors and the South Australian Guideline 12 provide sound precedents for such information disclosure.)

13. Ensure consistent Distributor DM performance reporting.
The AER should require Distributors to report annually on DM activities undertaken in relation to: expenditure, peak demand and energy consumption reductions, value of electricity sales foregone, value of capital and operating expenditure avoided or deferred, and efforts to identify and procure cost effective DM. Such reports should be publicly available. The AER should issue a pro forma to encourage consistency in DM reporting. Reporting to the AER should be harmonised with any other DM reporting requirements.

14. Conduct and publish annual AER DM Reviews.
In recognition of the relatively underdeveloped state of DM in Australia, the AER should monitor DM data provided by Distributors and publish a consolidated annual review to encourage mutual learning and allow comparison of different policies and approaches between jurisdictions. (This will also assist in building understanding of DM potential within the regulatory community and among stakeholders.)

15. Apply complementary transitional measures to accelerate DM.
Recognising that the above measures are designed simply to address existing barriers to efficient DM in the economic regulatory environment, and that the DM market in Australia is currently underdeveloped, Federal, State and Territory Governments should establish complementary transitional measures to create positive incentives to develop DM quickly.

16. Put an appropriate price on greenhouse gas emissions.
In the interests of economic efficiency, and in recognition of the high economic cost that climate change is expected to impose on the Australian and global community, the Australian Government should ensure that the price of greenhouse gas polluting activities, such as fossil fuel-based electricity generation, includes the full cost of the associated greenhouse gas emissions. This could be achieved by introducing an emissions trading scheme or a carbon tax. (Recommendations 1 to 15 would be complementary to such action.)

APPENDIX 8

NEM Advocate Forum - key questions arising from evaluation of each of the approaches

In the tasks assigned to the consultants by TEC and in the two forums convened by TEC, a range of questions and issues were raised which participants considered were relevant in the context of evaluating each of the forms of regulation adopted by regulators. These questions are listed here:

- Is the building block approach appropriate for non-network solutions?
- Should the network be paid a profit element over and above the cost of a non-network solution?
- Is the BB approach better for DM programs because it is transparent?
- Does either a revenue cap or a price cap impact demand and consumption?
- Which revenue recovery mechanism has the best (less worse) consumer impact for reducing usage?
- How to overcome the disconnect between encouraging less consumption when a price cap implicitly encourages increased consumption?
- Is a capacity market more conducive to self generation (ie a DM approach) than an energy only market?
- Does either approach support or resist the likelihood of networks to undertake demand management?
- Should economic efficiency be the only element of the NEM objective in relation to networks? If not, how should the objective be re-written?
- Should the Rules provide an active incentive (another distortion from economic efficiency) to encourage more demand management and/or self generation?
- Should network costs be charged only for demand? If so, should there be higher demand tariffs for peak times and lower for off peak times?

- Should networks be required to charge only for the highest demand in a shorter period (eg a quarter, month, week)?

- Should network costs still be incurred for providing stand by capacity?

- Are the funds sufficient provided in current DM programs (eg in NSW D-factor scheme and SA funded trials)? Do these programs provide a result?

- How will such programs (as in NSW and SA) apply under a TFP approach?

APPENDIX 9

Excerpt from

PHOTOVOLTAIC ENERGY BAROMETER, April 2008

TOTAL EU INSTALLED CAPACITY IN 2007 4689.5 MWP

Thanks to a German market at its peak associated with the rise in importance of the Spanish and Italian markets, the European Union established a new record for photovoltaic installations.

According to first estimates, 1 541.2 MWp were installed in 2007 (+57% with respect to 2006), bringing total EU installed capacity up 4 689.5 MWp.

The German market recovers
It must be admitted that the estimates of photovoltaic capacity installed in Germany during the year 2006 got carried away. AGEE Stat, which produces the renewable energy statistics for the BMU (Ministry of the Environment), revised its estimate published last May downward, with 830 MWp installed in 2006 (vs. 950MWp initially announced). In this way, this body corroborates the final figures from *Photon International* magazine, published last December, resulting from their annual inquiry and survey with German power grid managers. Very far indeed from this magazine's first estimate published in March 2007 (1 150 MWp) which was based on the number of inverters sold in Germany.

2006 will thus have been marked by a stagnation of the German market, with 866 MWp having been installed in 2005. This stagnation can be explained more by a shortage of equipment than by a downturn in demand. As proof of this situation, the recovery which was announced for 2007 with a first estimate of the BSW (German Solar Industry Association) of 1 100 MW. This estimate, which is judged credible by Christel Linkhor of AGEE Stat, shall bring Germany's total installed capacity to 3 846MWp, i.e. nearly 82% of total European Union installed capacity.

More than ever, the German market is thus a moving force behind world photovoltaic growth. It continues to be largely ahead of the Japanese market which should, according to EPIA, remain stable in 2007 (286.6MWp installed in 2006) and the American market, estimated at 205 MWp in 2007 (143 MWp installed in 2006) according to a source (Sherwood Associates, member of the Board of Directors of the Interstate Renewable Energy Council) reported by *Photon International* magazine.

The performances of the German market are explained by the stability of the incentive system which made it possible to give investors more clarity and so structure the market. Since August 2004, the renewable energies law (EEG) obliges electricity suppliers to buy photovoltaic electricity. The tariff applicable for a period of 20 years decreases by 5% each year for systems linked to a construction and by 6.5% for systems not linked to a construction. The tariff varies according to the capacity of the installation. On buildings, it is established in 2008 at between 0.4675€/kWh ($0.78/kWh) for power plants smaller than 30 kW and 0.4399€/kWh ($0.73/kWh) for power plants larger than 100 kW. A 5 €c bonus ($0.08) is added for power plants that are integrated in building façades. Ground based PV systems benefit from a tariff of 0.3549€/kWh ($0.59/kWh). A revision of the EEG law should take place in the next few months. In particular, negotiations concern a rise in the yearly price decrease rate.

APPENDIX 10

CPUC news release, 20 Sep 07

PUC CREATES INNOVATIVE NEW PLAN FOR ACHIEVING STATE'S GROUNDBREAKING ENERGY EFFICIENCY GOALS

SAN FRANCISCO, September 20, 2007 - The California Public Utilities Commission (PUC) today approved an innovative new framework for achieving and exceeding the state's aggressive and groundbreaking energy efficiency goals. This new plan is critical in California's efforts to fight global warming.

Today's decision establishes a new system of incentives and penalties to drive investor-owned utilities above and beyond California's aggressive energy savings goals. The new program provides incentives of sufficient level to ensure that utility investors and managers view energy efficiency as a core part of the utility's regulated operations that can generate meaningful earnings for its shareholders.

At the same time the new framework:

- Protects consumers' financial investment;
- Ensures that program savings are real and verified; and
- Imposes penalties for substandard performance.

Earnings to shareholders accrue only when a utility produces positive net benefits (savings minus costs) for ratepayers. The shareholder "reward" side of the incentive mechanism is balanced by the risk of financial penalties for substandard performance in achieving the PUC's per kilowatt, kilowatt-hour, and therm savings goals.

PUC President Michael R. Peevey said, "The culture of a business is often, if not always, defined by how that business makes money. As a result, in the utility world, energy efficiency has traditionally played second fiddle to the generation and transmission side of the business. Today's decision changes that view. It's my hope that California's innovation serves as a template for other states around the Nation."

"We must adopt aggressive new tools to fight global warming. Today's decision is part of California's commitment to make energy efficiency 'business as usual' in California," said Commissioner Dian M. Grueneich. "The risk/reward incentive encourages utilities to invest in energy efficiency the same way they would invest in a power plant. Our efforts will reduce global warming by an estimated 3.4

million tons of carbon dioxide by 2008, which is equivalent to taking about 650,000 cars off the road."

"This decision puts energy efficiency on an equal footing with utility generation. It will align utility corporate culture with California's environmental values," said Commissioner Timothy Alan Simon.

Earnings begin to accrue at a 9 percent sharing rate if the utility meets 85 percent of the PUC's savings goals. If performance achieves 100 percent of the goals, the earnings rate increases from 9 percent to 12 percent. Each earnings rate is a "shared-savings" percentage. This means, for example, if the combined utilities achieve 100 percent of the 2006-2008 savings goals and the verified net benefits (resource savings minus total portfolio costs) at that level of performance is $2.7 billion, then $2.4 billion (88 percent) of those net benefits goes to ratepayers and $323 million (12 percent) goes to utility shareholders. If utility portfolio performance falls to 65 percent of the savings goals or lower, then financial penalties begin to accrue.

Today's decision builds upon California's landmark policies to advance clean air and energy, such as the Global Warming Solutions Act (Assembly Bill 32), the Low Carbon Fuel Standard (Executive Order S-01-07) and Emissions Performance Standard (Senate Bill 1368), and follows the direction of the state's Energy Action Plan.

For more information on the PUC, please visit www.cpuc.ca.gov.

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APPENDIX 11

Glossary of Terms

Bow Wave capex program
The bow wave capex program is the name given to the rapid increase in capex needed as a result of lower than required spending in previous years. It particularly is referred to in relation to the supposed low capex by the NSPs when owned by government prior to corporatisation (and even privatisation). The new corporate bodies observed that there was a need to increase capex after the transition. It is interesting to note that some NSPs have not spent all the capex the regulators granted in response to the bow wave effect

Building block
A technique used to assess a network's reasonable needs for revenue. See appendix 1

Capacity market
A capacity market is one where the capacity to generate is paid for as well as a payment for the amount of electricity that is provided. The WEM (electricity market in WA) is a capacity market. See energy only market.

Capex Capital expenditure: This is the amount of new capital invested in the network for replacing old assets and building new assets

Capital This is the sum of debt and equity used by a network

Cost of service regulation
Cost of service regulation is an approach in which the actual costs for providing the service are reviewed by the regulator, and used to set tariffs. It is closest in analogy to the BB with revenue cap. This approach is considered to be even more invasive than the approach used in the NEM, which is based around incentive regulation.

Debt This is funding provided by a lender to a network

Demand This is the rate at which electricity is consumed and is measured in kilowatts (kW)

Demand management (DM)
The technique used for managing the demand of a consumer and includes permanent demand reductions, for example, from the retrofit of major developments. It is also referred to as demand side management (DSM). Demand side responsiveness (DSR) falls under the umbrella of DM.

Demand side responsiveness (DSR)
This is a term referring to the responsiveness a consumer makes to signals in the market to modify the demand of the consumer. The most common forms of DSR are: short-term load curtailment provided on a contractual basis to networks or demand side aggregators, and on-site generation.

Depreciation
This is the loss of value of the assets of a network over time. It is referred to as the return of assets.

Efficiency Benefit Sharing Scheme (EBSS)
This is a scheme developed by the regulator to encourage a regulated business to reduce its costs over time. It allows the business to retain over a longer period, the benefits of reducing its costs

Energy only market
The NEM is an energy only market. In an energy only market, all electricity is trading by the amount of electricity used in a half hour basis. See capacity market

Equity This is funding provided by shareholders of a network

Externally Derived Indicators
These are indicators derived exogenously to the electricity industry, but could be used to set new tariffs. The most common one used in the electricity industry is CPI, but also include producer price indices and labour indices

Gearing This is the relation between debt and equity used by a network

kW kilo watt. A demand of one kW for one hour provides one kWh

kWh kilo watt hour. This is a unit of consumption of electricity

Load Factor Load factor is the relationship between demand and consumption. A low load factor indicates that the network has "needle peaks" in demand, requiring the network to be built for high demands which operate for short periods. As the costs for a network are related to demand, a low load factor means a higher cost for consumers when related to consumption, which is the most common basis for assessing electricity costs

LRMC Long run marginal cost, The cost a business needs to recover its costs for providing the service, including a reasonable return on the assets it provides and the risks it faces by providing the service

NEM National Electricity Market, which provides the electricity supply in Queensland, NSW, ACT, Victoria, SA and Tasmania

Network This is the "poles and wires" needed to transport electricity from a generator to a consumer

NSP Network service provider – the business that provides the network including augmenting it to meet the needs of consumers

Opex Operating expenditure. This is the amount of money expended by the network for managing the network

Price cap See appendix 3

Ratcheting This is the process where a network business measures the single highest demand used in the previous 12 month period, and charges the consumer regardless if the demand is reduced in this period

Regulation The approach use to ensure that providers of monopoly services receive a reasonable (but no more) income for providing the monopoly service

Regulatory period
This is the period for which a regulatory decision will apply. It is most commonly a period of five years

Regulated Rate of Return
This is a rate of return on the supply of assets developed by the regulator, and is based on the financial structure of a network which the regulator considers is appropriate for providing regulated services

Reserve Trader
This is an action by the NEM operator (NEMMCo) to contract directly for electricity supply from some electricity generators not usually providing electricity into the NEM, and/or with some consumers to reduce their usage at the demand of NEMMCo

Revenue This is the amount of money paid to the network by users

Revenue cap
See appendix 2

Tariff The rate at which a network charges for its services. This could be based on $/time, $/kW, $/kWh or a combination of these

TFP Total factor productivity: See appendix 4

RAB Regulatory asset base: This is a value a regulator places on the network provided

WACC Weighted average cost of capital. This is the cost a network has to pay for the use of money. It is the return the network needs on its combination of debt and equity. It is referred to as the return <u>on</u> assets

APPENDIX 12

TEC Terms of Reference

"Price Caps, Total Productivity Factor, Building Blocks or Revenue Caps - which better encourages more efficient use of electricity in the long term interests of consumers?"

1. Project Background

Different forms of regulation are now set to be used by the Australian Energy Regulator (AER) across the NEM without robust discussion about the relative benefits of the various methods. The patchwork approach has arisen as a result of stakeholder pressure and jurisdictional preferences, not necessarily because different forms match geographical markets.

A patchwork approach exists across the NEM. For example:

- while transmission networks continue to operate under revenue caps, the National Electricity Rules give jurisdictional regulators the option to choose either revenue or price caps, or a hybrid model for distribution networks;
- in NSW, the IPART 2004/05 determination abandoned the revenue cap in favour of a price cap, but put in place the 'D-factor' incentive for demand management;
- while Queensland currently retains a revenue cap, the next determination will test the new 'propose and respond' approach;
- in Victoria there is a strong push for the total productivity factor (TPF) approach to setting price caps for the upcoming determination, despite revenue caps being in place for transmission networks.

There has been no rigorous assessment of the outcomes of these forms of regulation, particularly in relation to efficiency in the use of electricity and the resulting impacts on consumers. In particular, no comprehensive analysis of the relative benefits of price cap (with or without TPF) versus revenue cap regulation has been undertaken since 1994[46]. As a result, the capacity of consumer groups to understand and contribute to decisions in the application of the various regulatory options is limited.

Incentives for demand management (DM) are a focus of this project. Current investment in network services is highly inefficient, as network augmentations are usually built to service peak demand that occurs for only a few hours of the year. It is likely that a move to price cap regulation for distribution networks will worsen this situation.

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46 Government Pricing Tribunal (now IPART), *Price Regulation and Demand Management*, September 1994.

Recent proposals at the national level for regulation of distribution networks have tended towards a less precise regulatory climate where the Australian Energy Regulator, in consultation with the distribution network service provider (DNSP), will determine what form of economic regulation to apply in each case ('propose and respond').[47] In the many issues papers of the last two years there has been a general assumption that revenue caps are not appropriate for DNSPs, but there has been minimal evidence presented for that assumption. This project aims to clarify and contrast the benefits for consumers.

2. Project Summary

This project will increase the capacity of consumer groups to understand and critique the various regulatory approaches. The project will assess the relative benefits of price caps (including TPF) and revenue caps, taking into consideration the goals of the participating groups and the range of matters that the AER must consider, including:

1. Which mechanism better encourages more efficient use of electricity, impacts on demand management, end user consumption and prices, and the balance between network costs and revenue?

2. What incentive schemes are possible under the mechanisms to encourage demand management?

3. Which mechanism better caters for the needs of vulnerable consumers?

4. What incentive schemes are possible under the mechanisms that will reward network companies for reducing the number and duration of outages that have a market impact, and for providing more advanced notice of outages?

5. What mechanism best delivers the new revenue and pricing principles recently introduced to the National Electricity Law, including:

    a. "A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations"

    b. "A network should be given effective incentives to promote the economically efficient investment in and provision and use of network services"

    c. "The regulator must have regard to the regulatory asset base adopted in previous determinations"

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[47] For example, the proposal presented in the MCE Electricity Amendments package, January 2007.

   d. "The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services"

   e. "That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network"

   f. "The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network".

6. What other mechanisms and incentives may be needed to support either form of regulation to secure the best long-term interests of consumers?

The report will provide a timely contribution to current decision making as responsibility for regulatory functions is transferred from the jurisdictions to the new national bodies.

The forums, briefing notes and final report (see below) on the costs and benefits of price cap versus revenue cap regulation could be expected to directly influence the content of the National Electricity Rules, the approach to DM by the AEMC, and the regulatory approaches taken by the AER.

3. Detailed Project Description

3.1 Initial Scoping Forum

TEC will organise a facilitated, preliminary half-day forum, with participation from the consultant, the Major Energy Users Association Inc, the Consumer Action Law Centre, the Consumer Utilities Advocacy Centre and Total Environment Centre (TEC) to scope out the key issues of concern with regard to form of regulation. This forum will provide the focus for the rest of the project.

3.2 Briefing Notes

The consultant will produce a series of briefing notes on the key issues emanating from the initial scoping forum and pertaining to the form of regulation. The briefing notes will also address the range of matters the AER must consider. Briefing notes may include:

- Plain English overviews of the key forms of regulation
- Demand management in the context of price caps and revenue caps
- Implications for low income consumers of price caps and revenue caps
- Total productivity factor versus building block regulation and price caps
- Impacts of price caps and revenue caps on all other matters that the AER must consider (outlined in Section 2 above)

These will be distributed in draft form to a range of non-government groups representing NEM consumers 1 week prior to the following public forum.

3.3 Public Forum

TEC will organise a facilitated one day public forum for a wider range of non-government groups representing NEM consumers. This will also be attended by the consultant to flesh out the remaining issues and identify areas for additional research.

3.4 Final Report

The consultant will carry out additional research identified in the public forum and compile a draft report with recommendations for TEC's feedback, and then a final report. TEC will disseminate the report to relevant NEM participants.