Demand-side management in restructured electricity industries: An international review

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1. Introduction

The South African electricity industry is soon to be restructured. Many other countries around the globe have already restructured, or are in the process of restructuring, their electricity industries. Generally, the rationale behind these revolutionary initiatives has been that restructuring will promote economic efficiency within national electricity sectors that, if achieved, should deliver notable benefits to societies. Depending to some extent on ownership and governance structures prior to restructuring, countries have sought to achieve economic efficiency in various ways (see section 2 below). Generally, though, the global trend shows a movement away from the state-owned, vertically integrated natural monopoly structure, historically characteristic of the electricity supply industry, towards private sector participation and the establishment of competition in the generation and distribution of electrical power. As a result of these movements in structure and ownership, changes in the regulatory oversight of energy sectors are also occurring.

In countries where restructuring processes have progressed, it is becoming clear that the provision of 'social benefits' or 'public purpose' goods such as energy efficiency, public-interest research and development, environmental protection, rural electrification and the extension of minimal services to low-income households, is at risk. Traditionally, this has been the responsibility of the public sector. As electricity industries are privatised (and the public sector roles diminish), and as more competition is introduced into this sector, however, it is likely that the provision of these societal benefits will only be guaranteed if adequate mechanisms to encourage or compel non-government investment in public goods provision are established. In some countries, appropriate mechanisms to do this have been put in place; in others they are yet to be established.

The aim of this report is two-fold. First, it intends to develop an in-depth understanding of the impact electricity industry restructuring has had on investment in demand-side management (DSM) in different countries. Secondly, it seeks to report on how these different countries have (or have not) tried to promote DSM investment within the new contexts.

This report will investigate what international experience can offer the South African electricity supply industry as it lies on the verge of transformation. As one of the important international lessons demonstrates, the 'rules of the game' should be established now, and preferably not once the game has already begun. This report seeks to make initial contributions to the new debate on what investment in DSM could and should look like in South Africa's coming context, as well as how the future of this societal benefit could be secured.

In section 2 to follow, electricity industry global restructuring trends are outlined. Section 3 describes the source material utilised in this review. Section 4.1 describes the experiences of the United States in designing and implementing DSM programmes. While the United States experience with restructuring is more recent (and by no means complete), it is able to contribute significantly to the debate on DSM. The review of DSM in the United States is followed by discussions of DSM in the context of restructuring processes in England and Wales, Norway and New Zealand (sections 4.2 to 4.4). In these countries, restructuring is generally well advanced, to the extent that customers all have choice of supplier. There has also been opportunity to evaluate, reassess and refine the processes first adopted to introduce more competition into the electricity industries, including the mechanisms put (or not put) in place to ensure investment in DSM. Finally, brief discussion on the DSM experiences of Brazil, Ghana, Chile and Argentina, and Thailand are presented (sections 4.5 to 4.8). As will be shown, Chile and Argentina, while well advanced in their restructuring efforts, have not placed DSM on the restructuring agenda at all. Thailand, Ghana and, to some extent, Brazil have had rich experiences in the design, implementation and provision of DSM, but are yet to undertake large-scale restructuring initiatives. The final section draw lessons for the implementation of DSM in other countries around the world, including South Africa, and summarises the lessons learnt from the international experiences reviewed in the report.
2. Global restructuring trends

Generally, electricity industry restructuring has involved changes in the ownership patterns of the electricity industry and/or in its structure i.e. ownership and regulation. Trends in the changes of these dimensions are illustrated separately in Figures 1 and 2 below.

![Diagram of ownership dimensions of electricity industries in transition](source: Adapted from Hunt & Shuttleworth (1996); Davis (1997))

The broad direction and nature of electricity industries in transition is illustrated in Figure 3 below. The horizontal axis represents competition and choice (structure), and the vertical axis, the degree of governmental ownership.

As illustrated, industry restructuring processes around the world have emerged from varying industry structures and patterns of ownership. The structure and ownership dimensions of electricity industries are further complicated by widely diverging regulatory regimes, and economic/business contexts. The implications of these differences, for this study, are that:

- Some governance, ownership and regulatory structures will have more relevance to South Africa, than others. In response to this, this review will seek to draw out the more relevant DSM experiences.

- It is difficult to investigate the impact that this industry re-organisation has had on investment in DSM (as well as to draw lessons for South Africa) without first examining the contexts out of which restructuring has emerged, as well as where restructuring is headed. In this report, selected individual country restructuring experience is presented prior to a discussion on its impact on, and initiatives chosen to promote, DSM investment.

3. Source material

In searching for material describing the impacts that electricity industry restructuring has had on global DSM investment and programmes around the world, various observations are made. These help to contextualise the report and are as follows. Firstly, restructuring initiatives in some industrialised and developing countries – in particular, the United Kingdom, Norway, New Zealand, Chile and Argentina – are well documented. Secondly, while impacts of restructuring initiatives on DSM programmes are generally not as well documented, more information about industrialised-country (as opposed to developing-country) experience is available. In some cases this is because these experiences do not seem to have been written about extensively, in others because DSM has not received much priority on countries’ restructuring agendas. Thirdly, and interestingly, most of the literature written on industrialised country experience was generated during the period, roughly 1992 to 1996 (with a peak in 1994). It could be argued that during this period, debates about the prospects for DSM programmes in restructured environments were at a peak. It could further be argued that fair

1 Since then associated, and other debates (for example, the stranded costs and benefits of restructuring, open access etc) have predominated.
amounts of this literature originated in the United States where DSM programmes were first developed and that this was the precise period in which the threat of electricity industry restructuring was becoming more relevant, and where the potential effects of the restructuring were just beginning to be internalised by industry stakeholders.²

These various observations have shaped the way in which this review has been presented. Keeping in mind that since the review's purpose is to bring together international experiences and approaches in lessons and/or guidelines for South Africa, experiences of both industrialised and developing countries would clearly be important sources of information. A weakness of this report is that it is not adequately able to report on developing country experience — that is, where social upliftment is high on the policy agenda, development finance is scarce, investor confidence is low, institutional structures are generally weak, the ESCO industry is underdeveloped, etc. As noted above, this may be because experiences have not been recorded or alternatively because DSM is not a key priority. This said, it is still important to recognise that the experiences of industrialised countries are also deeply insightful for South Africa. Even if the mechanisms employed in industrialised countries to ensure the survival of economically viable DSM are too context-specific, or require resources which South Africa cannot right now dedicate to DSM, these do show us in what direction we may seek to head.

4. Country case studies

4.1 United States: ‘Pioneering and popularising DSM’

While other countries, including England and Wales, Norway, New Zealand, Chile and Argentina, have progressed further in restructuring their electricity industries than the United States has, its experiences are recounted in this review because the United States is the pioneer of DSM, and has substantial experience in this regard — indeed, DSM was first introduced in United States. While it could be argued that the North American electricity sector context is very different from that in South Africa, it is also clear that United States’ extensive and rich DSM experience can offer important pointers to us. Note that the experiences presented for the United States relate not only to DSM in restructured markets but also to the evolution of DSM.

4.1.1 Turmoil in US electricity markets

The 1970s and 1980s in the US electricity industry were characterised by mismatches in supply and demand. Following dramatic increases in the prices of oil and gas in 1974 and again in 1979, the US electric industry sought to reduce its dependence on these fuels by constructing large coal and nuclear units, with relatively high capital costs but low fuel costs. Failing to anticipate slow-downs in growth, the industry ultimately constructed more capacity than was needed to meet demand with adequate reliability. Moreover, health, safety and environmental concerns surrounding both technologies drove the costs of these alternatives far above that anticipated when the commitments to these plants were made. When oil and gas prices began to fall after 1983, the industry found itself with both excess capacity and fixed capital costs far in excess of the marginal cost of production. Disparities between the marginal and fixed costs were further accentuated by technological changes which improved the operating efficiency and lowered the capital cost for new gas-fired combined cycle plants (Perl 1997; Gilbert & Kahn 1997). Utilities began to cancel plans for capacity expansion.³ These crisis decades brought forth many proposals for the restructuring of the electricity industry in the US.

² Even though other countries are well ahead of the United States in restructuring the electricity sector, the DSM experiences of the United States are documented in this review, because of it being a dominant leader in integrated resource planning DSM and the ESCO industry.

³ Between 1972 and 1984, for example, plans for 113 nuclear, and 67 coal-fired, plant projects were cancelled (Brennan et al 1996).
The current structure and performance of the US electricity industry is the result of nearly ninety years of government regulation and countless pieces of legislation designed to improve the system or meet some political goal (Bennan et al 1996). Unlike most other countries reviewed here, the electricity industry has been heavily shaped by federal as well as state regulatory authorities. Traditionally, the method used in most states to set retail electricity prices has been cost-of-service or rate-of-return regulation. This type of regulation means that tariffs are set so that the revenues from retail sales of electricity will cover the full costs of supplying that electricity, including generation, transmission and distribution costs, plus a fair rate of return on invested capital. According to this approach, new plant costs are not included into tariffs until commercial operation, when costs are placed into the ‘rate base’ and become part of the total cost of service to be recovered by tariffs. A crucial step in this process is the determination that costs are ‘prudently’ incurred and that the projects are ‘used and useful’ (Gilbert & Kahn 1997). The drawback of this method is that it does not provide the regulated utility with any incentive to minimise costs. If a utility is guaranteed revenues sufficient to cover its reasonably regulated costs and furthermore, if its efforts to reduce the costs result in a commensurate reduction in utility revenue, then a utility has little incentive to reduce costs (Brennan et al 1996).

One of the tools US regulatory authorities have utilised to counter this cost minimisation disincentive has been through disallowing some cost recovery. During the period 1983-1987, ‘disallowances’ in the range of 10 to 40 per cent became frequent. The total disallowance during this period has been estimated at $10 billion5 (Gilbert & Kahn 1997). There is now broad agreement that this particular tool does not have its intended effect. Importantly, it has resulted in a search for other tools to improve the efficiency requirements on regulated utilities. More recently, state regulators have begun to rely upon incentive regulation as a substitute or complement to the traditional approach. It is also thought that efficiency can be achieved through various forms of competition.

Also characteristic of the US electricity industry is the great variety of organisational forms that together comprise the industry. Within this variety of publicly and privately owned utilities, however, the highly regulated investor-owned utility has emerged as the dominant model.

Most electric utilities in the US are vertically integrated monopoly suppliers of generation, transmission and distribution in their service areas. Each company seeks to construct sufficient capacity to meet anticipated load within its franchise service territory with a margin of reliability. In order to reduce the reserve margins needed to maintain reliability, utilities have constructed interlocking transmission facilities, permitting adjoining utilities to rely upon each other when their own facilities are inadequate to meet load. In many regions, extensive transmission networks have also been constructed to exploit permanent cost advantages. Having constructed these broad regional grids, existing utilities have not only expanded the electricity market but also created the potential for a competitive generation market within each region. Viewed in this way, pressures for regulatory reform in the electricity industry have been driven by a tendency for technological change, and growth in market size and geographic scope to increase the feasibility of competition in the industry. Differences in the pace of reform are currently

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4 Since 1996, the Federal Energy Regulatory Commission (FERC) is the primary federal regulator of electricity policy. It regulates tariffs for wholesale power sales, regulates tariffs for electricity transmission, and has the authority to approve or disapprove utility mergers. However, (and perhaps most of) the important regulatory impetus and initiatives to bring competition to the electricity industry is taking place at the state level. Tariffs paid by most electricity customers are set by public utility commissions (PUCs). While state PUCs generally do not regulate the retail tariffs charged by municipal utilities and rural cooperatives, they do regulate the tariffs charged by investor-owned utilities. State PUCs not only set retail electricity prices, but also set most of the rules regarding entry into the generation business, as well as the boundaries that define a utility’s exclusive service territory. Moreover, in many states, a utility wishing to construct a new generating facility or new transmission line must obtain a certificate of public convenience and necessity from the PUC. In addition, other state regulatory agencies, including environmental agencies, may have an oversight role with regard to siting new generation and transmission facilities (Brennan et al 1996).

5 Justification for cost disallowance include ‘imprudence’ or excess capacity.
resulting almost entirely from the ease or difficulty with which the competitive portions of these industries can be separated from those which remain natural monopolies (Perl 1997).

In sum, the era of vertically integrated utilities is ending, although the final result is more likely to grow out of co-operation than coercive state action (that is, mandatory divestiture of generation or any other assets is seen as an undesirable approach). The electric service industry is moving toward the separation of integrated utilities into at least three independently owned and operated enterprises encompassing generation, transmission and distribution functions. Generation is set to become a highly competitive business that ultimately will operate without traditional price regulation, while transmission and distribution are likely to remain natural monopolies with regulated prices (Cavanagh 1996).

There have been many important moves by federal and state regulators to introduce more competition in the electricity sector in the United States. Initial efforts in electricity reform were embodied in the Public Utilities Regulatory Policy Act (PURPA) of 1978, the thrust of which was to create increased competition within the generating sector by requiring utilities to purchase power from co-generators (or Qualifying Facilities), renewable resource developers and small independent power producers (IPPs) at avoided costs. Merely offering to pay constructors the avoided cost of new generation capacity did not, however, stimulate much new private investment. Regulators responded to this problem by requiring utilities to offer, through competitive bidding processes, both PURPA suppliers and other independent power producers long-term contracts, under terms sufficient to assure that these projects could obtain financing (Perl 1997). In some states, the terms of purchase were so attractive that development of this capacity overwhelmed expectations, and utilities and/or regulators sought mechanisms to ration the supply efficiently. Also, although long-term contracts for this new class of supplier has clearly produced large suppliers of power, the power produced is turning out to be very expensive (Perl 1997). Some argue that the competitive bidding process has illustrated the wide gap between this process and a genuinely competitive generating market.

The move toward restructuring and increased competition in generation begun by PURPA was accelerated considerably by the Energy Policy Act of 1992, under which the US Congress required that FERC enforce transmission-owning utilities to deliver power from generators to other utilities and electricity wholesalers at reasonable, non-discriminatory, cost-based tariffs. To carry out this mandate, in April 1996, FERC issued Order 888, which specifies the conditions under which all utilities must provide such access to the US transmission system (Brennan et al 1996).

Notwithstanding the importance of the above federal legislation, much of the far-reaching regulatory impetus and initiatives to bring competition to the electricity industry has been taking place at the state level. In response to the emerging weaknesses of the competitive bidding process (see above), California, for example, has tentatively adopted a far more radical approach to industry restructuring. Proposals include the deregulation of the generating sector and the creation of a state-wide power pool to which all generators can offer supplies of power and from which all buyers can purchase power at the spot price. These reforms would also allow customers to enter into contracts for power with generators or with independent power marketers who could be financially responsible for assuring reliable supplies. Some states, including Massachusetts and Rhode Island have chosen to proceed with full-scale restructuring while others, including Michigan, New Hampshire, Nevada, and Wisconsin are proceeding with limited experiments in which selected customers can purchase electricity from any provider (Nadel 1996).

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6 This mechanism was later broadened to include exempt wholesale generators (EWGs).

7 In some cases, long run avoided cost was offered, while in others, a price floor was established.
4.1.2 DSM: Then and now

Today's DSM programmes trace their roots back to the utility customer service programmes begun in the late 1970s. In response to extensive customer complaints of high energy bills linked to the decade's two energy crises, utilities' first move toward a customer focus involved the introduction of conservation and load management (CLM) programmes which centred around reducing customers' electricity use at the time of high utility system loads. The rationale for these programmes was to restrain electric demand growth through conservation, and technological improvement was seen as the primary driving force (Sioshansi 1996).

The term 'demand-side management' was only coined in the mid-1983 when the Electric Power Resource Institute (EPRI) used it to describe a broad range of programmatic efforts by utilities to shape total customer demand to better match system generation requirements and costs (Messenger 1996). DSM represented the first marketing strategy that specifically recognised and promoted a customer focus. It was initially defined 'as the planning, implementation and monitoring of those utility activities designed to include customer use of electricity in ways that would produce desired changes in the utility's load shape' (Gellings 1985). Later, it was suggested that that definition be altered to: 'DSM involves the planning and implementation of utility activities designed to influence the time, pattern, and/or amount of electricity demand in ways that would increase customer satisfaction, and co-incidentally produce desired changes in the utilities' load shape' (Gellings 1989).

The nature of DSM programmes has changed significantly since they were first introduced. In the mid 1980s, DSM programmes mainly comprised information and loan programmes designed to educate consumers and businesses, under the rationale that if electricity end-users were educated, they would invest in cost-effective DSM measures. Educational efforts focused on energy audits and printed materials. To help encourage customer investments, some utilities offered loans for DSM investments, often at subsidised interest rates. Utilities also encouraged customers to work with energy savings companies (ESCOs) geared towards helping customers install measures offered, often under shared energy savings arrangements. Also during this period, utilities, through load management programmes, began to encourage customers to reduce energy use during peak demand periods.

Gradually, however, utilities learnt that education alone results in limited energy savings and that loans, or shared savings agreements, did not suffice. In the late 1980s, states and regions began implementing integrated resource planning (IRP) processes that, among other considerations, looked at DSM as a planning resource that could provide conserved power and energy at a lower cost than would be incurred by installing a new power plant. Many IRPs included DSM as a central programme element, and many of these DSM programmes involved rebates. While these programmes were fairly effective at promoting certain specific types of efficiency equipment, they were not effective in promoting the integrated packages of measures that represented a large portion of the savings potential. Also, while many customers participated in rebate programmes, the majority of eligible customers did not, which left a gap between the savings achieved and the economic savings potential (Nadel & Geller 1995).

Funding for cash rebate programmes has been declining because:

- Utilities are concerned about the impact of these programmes on tariffs (see section 4.1.3).
- There has been an overall decline in the forecasted value of energy savings, and thus, perception of future earnings from these programmes.
- There is a growing recognition that the use of cash rebates as a design strategy may be counter-productive in the long run because the rebates themselves may not develop a sustainable increase in customer demand for more efficient products (Messenger 1996).

Funding for cash rebate programmes has been declining because:

- Rebates generally consisted of fixed payments for use of specified energy efficiency measures (i.e a $5 rebate for each CFL installed)
In an effort to capture a greater share of the savings potential, many utilities then chose to offer customers comprehensive/direct installation programmes. These seek to assist individual customers in identifying, financing and installing comprehensive packages of DSM measures, and are frequently referred to as 'smart-DSM' programmes (Geller, Nadel & Pye 1995; Smyser 1994; Goldman & Kito 1995). Due to the comprehensive services provided and the low cost to the customer, comprehensive/direct installation programmes generally have impressive participation rates. Because of this, and the programme nature, savings per customer are generally high. These programmes are, however, time and capital costly to the extent that many utilities cannot justify them. Also, as the issue of increased competition comes to the forefront in the US, many of the budgets of the remaining rebate and comprehensive package/direct installation programmes have been cut (Nadel & Geller 1995) (see also section 4.1.3 below).

Within the context of more competition being introduced, utilities are now offering energy services to customers on a tailor-made basis and are requiring customers to pay for the cost of utility services rendered. This new era of services is often referred to as 'energy services management' (ESM). Tailored energy planning assistance includes: design assistance, economic analysis, equipment selection support, building re-commissioning, benchmarking, verification of savings from equipment, and energy audit services all on a fee-for-service basis (Messenger 1996). See section 4.1.4 below.

Some utilities have also chosen to focus on market transformation strategies. This approach centres on 'trade ally' with manufacturers and distributors to eliminate market barriers to the customer adoption of specific technologies on a more permanent basis. Most of these new programme designs have been targeted at the residential sector as a whole, because it has become apparent that a broader focus is more effective than spending scarce money to reach, and then influence the purchasing decisions of, thousands of individual customers (Messenger 1996).10

In addition, some utilities are returning to first era DSM - information, loans and shared savings - in part because these programme approaches are less expensive to the utility, and in part due to the belief that more effective programmes than those designed during the 1970s and 1980s can be designed now (Nadel & Geller 1995). Figure 4 below summarises the evolution of DSM programmes in the United States.

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10 An example of a trend towards a market transformation focus was the Southern Californian Edison (SCE) CFL programmes. Initially designed in early 1991 as a cash rebate programme, the CFL programme gave customers a $5 to $10 rebate to reduce the initial $20 to $30 purchasing price of the lamp. In 1992, programme participation was not reaching the company's expectations, so the utility met with CFL manufacturers to try to design a more cost-effective approach. Based on those discussions, SCE then decided that manufacturer interest and customer participation would be increased in the utility paid manufacturers a smaller direct rebate for lamps delivered to the relevant distribution channels. This programme design also had the advantage of producing permanent changes in the methods used by manufacturers and distributors to promote CFLs. The end result of the new programmes design was that programme participation increased from 88 000 lamps in 1990 to 1 195 000 lamps in 1992. More importantly, the retail cost per lamp decreased from a range of $10 to $28 in 1991 to $2 to $12 in 1993 (Messenger 1996).
Figure 4: DSM programmes (1970s to 2000)

4.1.3 Utility DSM investment: late 1980s to today

As described in section 4.1.2, the energy conservation industry in the US has recently undergone a tremendously fast and intensely focused period of learning-by-doing DSM. The spectacular developments in this industry have occurred not only because of changing customer needs, but also because of significant movements in economic conditions and also changes in federal and state regulatory regimes in the US during this period. In this section, an account of these different contexts is given, together with a brief assessment of the impact they have had on utility DSM spending. Broadly, there have been three different phases to utility DSM thus far. A further phase is presently being ushered in and this is described in section 4.1.4 to follow.

In the late 1970s, PURPA identified and helped to focus the electricity industry's attention on the benefits of the 'increased conservation of electric energy' and 'load management techniques'. By the early 1980s, government regulators and some utilities became interested in using energy efficiency and load management programmes to reduce the need for new power plants and the electricity bills of customers. Supported by the National Association of Regulatory Utility Commissioners (NARUC), the federal government, through the 1992 Energy Policy Act, endorsed the approach that electricity utility DSM investments should be backed by appropriate financial incentives. Regulators were encouraged to design electricity tariffs so that utility DSM investments were 'at least as profitable, given appropriate consideration to income lost from reduced sales as investments in supply-side equipment' (Tellus Institute Newsletter 1995).

As noted, in the early days of DSM in the US, electric utilities were encouraged under rate-of-return or cost-of-service regulation to sell more electricity. While from a financial perspective this was considered the best course of action, it was also at odds with a socially efficient, least cost planning outcome – that is, to maximise net resource benefits, which often meant sales should be reduced. While this regulatory approach did allow utilities to recover DSM programme costs, it discouraged utilities from pursuing customer energy efficiency programmes because: (i) utilities were not allowed to recover DSM programme expenses when these expenses had not been included in a previous tariff-setting process; (ii) utilities lost revenues from successful customer energy-efficiency programmes; and (iii) utilities lost earnings opportunities because resources were devoted to DSM programmes rather than to other profit making activities (Nadel et al 1992).\footnote{The rate-of-return regulatory approach was also criticised because, in allowing utilities to recover the cost of DSM programmes through tariff increases, it amounted to DSM programmes being funded through a broad tax on all customers, thus benefiting a particular group of customers at the expense of others (Brower, Thomas & Mitchell 1996).}
To address utilities' reluctance to implement DSM programmes (i.e. to make provision for the reduced electricity sales, and thus reduced utility profit), various regulatory reforms were applied. These reforms, listed below, fall under the umbrella of a 'performance-based ratemaking' approach, whereby utilities' rewards are based on their performance. Most state regulators sought not only to remove the regulatory disincentives to invest in DSM but also to offer additional incentives if utilities invested in DSM. In other words, regulators have allowed utilities to profit from DSM programmes.

To remove the disincentives associated with traditional rate-of-return regulation, the following mechanisms have been utilised.

- **Decoupling of sales from revenues and profits.** Regulatory tariff structures often link energy sales (kWh) with utility revenues and profits, which is a clear disincentive for the utility to engage in any DSM that reduces sales. As a means of overcoming this disincentive, regulatory authorities can design the tariff structure such that the income to the utility is not dependent on sales volume (in kWh) but on some other measure of service (such as growth in number of customers). In other words, instead of letting revenues grow with increasing kWh sales, decoupling allows revenues to grow with other factors that are independent of changes in actual electricity use. Decoupling ensures that actual revenues exactly match an established revenue requirement, regardless of the sales level. Every decoupling mechanism consists of two parts. First, all decoupling mechanisms use balancing accounts to guarantee the exact collection of authorised revenues over time. Second, all decoupling mechanisms work in conjunction with an explicit method for changing the level of authorised revenue during years between general tariff reviews.

- **Net lost revenue adjustments.** NLRAs are also designed to compensate utilities for changes in revenues associated with utility DSM programmes. To implement an NLRA, the utility first estimates the energy and load reductions caused by its DSM programmes for the year in question. These GWh and MWh savings are then multiplied by the difference between retail price and short-term costs (both energy and capacity) and the two products (lost energy and lost capacity revenues) are added together. This sum is the net lost revenues caused by the utility's DSM programme. It is called 'net' because it is equal to the difference between the reduction in utility revenue minus the reduction in utility costs (fuel and variable O & M costs).

A comparison of the effects and impacts of the decoupling and NLRA mechanisms is given in Appendix A. Generally, decoupling is likely to be appropriate for utilities that run (or plan to run) large DSM programmes and for which the difference between retail price and short-term costs is large. Decoupling also makes sense where the regulator only has limited staff resources to monitor the utility's DSM programmes. NLRAs, which are more narrowly focused than decoupling, tend to encourage utilities to operate DSM programmes that 'look good on paper' but fail to produce energy savings in practice (Hirst & Blank 1994). Thus NLRAs are probably best suited for utilities that operate only small programmes, or where the difference between price and short run marginal costs is small. Both of these factors reduce the amount of money flowing through the NLRA and relieve some of the problems associated with evaluation and definition of energy savings (Hirst & Blank 1994).

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12 These responses correspond well with the regulatory approaches that the United States, England and Wales have adopted vis-à-vis DSM in competitive markets: federal and state regulators in the United States have played a major role in this area, while in England and Wales, OFFER has chosen to be more passive.

13 See Appendix A for an explanation of the balancing account.

14 For a more detailed account of these mechanisms, see Eto, Stoft and Belden (1997) and Weil (1994).

15 For a more detailed account of NLRAs see Baxter (1995) and Hirst and Blank (1994).
The following mechanisms were also utilised to provide utilities with additional incentives to invest in DSM. Note that these incentives have been applied to investor-owned (as opposed to public-owned) utilities. Note also that hybrids of these mechanisms are often used.\(^\text{16}\)

- **Shared-savings mechanisms.** The shared-savings incentive mechanism provides utility shareholders with a share of the energy savings benefits, or 'net benefits'. Shared savings are the most common mechanism used to reward utilities for investing in DSM programmes.

- **Bonus mechanisms.** Bonus mechanism reward utility shareholders on a per-unit basis for energy and demand savings. Bonus mechanisms are less common than shared savings.

- **Mark-up mechanisms.** Mark-up mechanisms provide a mark-up on DSM programme expenditures, generally varying from five to ten per cent. Mark-up mechanisms frequently apply to a subset of utility programmes, where energy savings benefits are particularly difficult to measure (i.e. information programmes) or where the programmes undertaken are based on equity rather than efficiency considerations (Eto, Stoft & Kito 1998).

These performance-based reforms mark a distinct motion towards eliminating the bias between the utility's incentive to build power plants and its incentive to invest in efficiency. Despite this, cost-of-services regulation is still used to treat utility investment in plant and equipment. Cost of services regulation is thus likely to continue to bias utility decisions governing investment capital.

To qualify for these incentives noted above, most utilities have been required, for each programme category and customer class, to estimate data for:

- **Incremental energy effects and incremental peak load reductions.** This includes the effects caused by new programme participants and new DSM programmes during a given year.

- **Current and projected annual energy effects and peak load reductions.** This means the total effects and peak load reductions caused by all participants (new and existing) in all DSM programmes.

- **Current and projected annual costs.** This includes the costs of DSM programmes for the reporting year, the next year, and fifth year following the reporting year.

- **Type of energy efficiency end-uses and programmes** (US DoE 1997; Nadel 1996; Nadel, Reid & Wolcott 1992).

Evaluations of the impact of these reforms have found that, generally, the desired impact was achieved: utilities affected by these reforms significantly increased spending on DSM programmes, which in turn delivered significant energy savings. From 1989 through 1993, utility DSM programmes exhibited steady or accelerating growth in energy savings and utility expenditures. Figure 5 illustrates this growth during the period 1980 to 1994.

\(^{16}\) For a detailed account of these mechanisms see Eto, Stoft and Kito (1998); Haaland and York (1994); Weil (1994).
The largest share of utility expenditures and energy savings was associated with energy-efficiency programmes funded by investor-owned utilities (Hadley & Hirst 1995). These programmes supplied substantial peak load reductions, although large potential peak load reductions also occurred as a result of interruptible load programmes (Department of Energy 1997).

Data compiled by the Energy Information Administration (EIA) for 1994 (the last year that this data is available for), however, showed the beginning of a reversal of this trend, thus ushering in another era of utility DSM spending in the United States. For the first time since the EIA began tracking DSM activity, utility DSM expenditures decreased approximately one per cent from $2.74 billion in 1993 to $2.72 billion in 1994. Most of these decreases in incremental energy savings occurred in energy-efficiency programmes. Figure 6 below illustrates the marked decline in funding in Californian utilities, starting in 1994.

Incremental energy savings decreased 8.4 percent from the 1993 level of 8 980 million kWh to 8 229 million kWh in 1994 (EIA web page).
It is expected that DSM spending will continue to decline ($2.6 billion in 1995 to $2.5 million in 1999) (EIA 1997). Explanations for this dramatic decline in investment include the following:

- A shift away from rebates, low-cost loans and other financial incentive programmes to ‘one time’ efficiency opportunities (new building construction, CFL replacement, and new equipment investment), market transformations, codes and standards, innovative financing mechanisms (such as efficient equipment leasing), and working directly with equipment manufacturers to develop and stimulate a market for more efficient equipment (see section 4.1.2 above).

- Avoided costs of generation have been falling, thus making some DSM options no longer cost-ineffective.

- Uncertainties associated with the introduction of competition and the impending restructuring of the electricity industry (see below) (EIA 1997; Nadel 1996; Hadley & Hirst 1995) (see below, and section 4.1.4).

Utilities are now concerned that they will soon be plunged into an era of uncertain levels and rules of competition. It has been argued that confidence in DSM has been undermined by the propositions that increased competition could:

- **drive utilities to concentrate on lower prices rather than on lowering the overall cost of electricity services.** Energy efficiency seems to be at cross purposes with utilities’ efforts to prepare for cut throat competition by cutting commodity prices (Cavanagh 1996);

- **increase the potential of utilities being left with current grid networks and running costs spread over a lower customer base has undermined confidence in DSM investment.** Utilities are determined not to incur additional stranded investments at a time when tens of billions are already at risk.

- **make it unclear who is responsible for DSM.** Currently state regulatory commissions have a substantial influence on the nature and extent of utility DSM programmes, but if competition erodes the retail monopoly franchise, it is unclear that regulators will be able to impose DSM requirements on utilities (Geller 1995; Geller et al 1996; Hirst et al 1995; Hadley & Hirst 1995; Boyle 1996).

Utilities are responding to these threats by cutting expenses considered ‘non-essential’. Among the areas receiving large cutbacks are long-term research and development programmes, services to low-income customers, cost-effective renewable energy acquisition programmes, and investor-owned utility DSM programmes (Hadley & Hirst 1994). To reduce the rate impacts of DSM programmes, some utilities have been lowering energy savings targets and placing more emphasis on benefit/cost tests to measure rate impacts as opposed to a reduction in overall costs. In other words, some utilities have shifted their criteria for acceptable DSM programmes from passing the total resource cost (TRC) test to the rate impact measure (RIM) test. 18

Against the backdrop of this restructuring, there is now agreement that the current form of utility DSM cannot survive. 19 A DSM metamorphosis is also called for by other important (and

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18 There are several points of view from which to consider whether DSM has lowered costs. DSM can lower the utility’s total costs to service (revenue requirements) as measured by the utility cost test, the utility’s cost per unit (tariffs) as measure by the ratepayer impact test (RIM), total resource costs or total energy service costs across all ratepayers as measure by the value test or under some assumptions, by the total resource cost test (TRC), or societal costs as measured by the societal value test or under certain assumptions the societal test. More specifically the TRC test judges the worthiness of a DSM programme based on the overall cost for the energy service, while the RIM test is based on the DSM programme’s effect on electricity prices to non-participants. Programmes that pass the RIM test generally place more of the cost burden of DSM on the participant. To the extent that customer cost limits participation, then programmes will have lower participation, and fewer DSM programmes will be judged cost effective. If more utilities utilise the RIM test because of worries about competition, utilities many reduce their DSM programmes (Chamberlain & Herman 1996; Hadley & Hirst 1995).

associated) movements in the United States electric industry. There have been changes in the fuel mix and technologies to generate electricity, different technologies and practices have been applied to reduce power-plant emissions, different methods to regulate utility planning and tariffs have been used, electricity prices have declined, and a reversal in the relationship between electricity prices and avoided costs has occurred20 (Hirst et al 1996).

Principles for DSM remain unchanged: it improves economic efficiency and thus reduces environmental impacts associated with the electrical system. On these grounds, it is argued that DSM should hold an important place in the future of the electricity supply industry. Because of the significant contextual changes, however, it is generally agreed that the economics and nature of the traditional DSM approach must now be different. Importantly, it has become unclear, as market forces begin to play a stronger role in electricity markets, whether utilities should continue to play a dominant role in DSM investment. On the one hand, it is argued that DSM investment is best handled by utilities because utilities know their customers, their energy usage patterns, and have developed sophisticated payment collection mechanisms. Some argue that DSM investments are best determined through specific contracts between utilities and individual buyers of their services, and utility activities should be limited to these types of DSM arrangements. Others question: if utilities do not remain responsible for administering public funds for social benefits, who will? ESCOs are surely not in a position to do so.

One the other hand, it is argued that, utility investments are shaped by their ‘bottom lines’ and therefore utilities cannot be objective. What is to prevent utilities applying public funds to general marketing or customer retention programmes when the funds should be used for educating customers about energy efficiency? Others contend that, just as multiple decision-makers cannot operate a transmission system reliably, utilities are unequipped to orchestrate a diversified mix of resources for meeting the economy’s electrical service needs at the lowest possible life-cycle costs. Furthermore, it has been argued that:

- **Today’s utility DSM programmes tend to stifle competition.** Utility companies, not customers, typically decide who will benefit from DSM and who will pay. Under today’s DSM programmes, expenditures are based on rigid annual conservation budgets that are pre-approved by regulators whereas in a truly competitive environment, expenditures and levels of output are based on prices and profitability – on the programme’s ability to add value in excess of risk-adjusted, project specific capital costs. Essentially, today’s utility programmes rely on top-down, command and control planning which ‘conscripts’ the use of customer capital (Houston 1994).

- **Today’s DSM programmes offer too little customer choice.** DSM programme participants are rarely allowed to act rationally and to select improvements that create the greatest value under their unique circumstances. Trade-offs regarding customer satisfaction, product suitability and durability, and long-term capital replacement alternatives are complex and project-specific. Individuals must be free to make such choices without major constraints from their utility.

- **Today’s utilities are resistant to long-term conservation project financing.** Utility companies fear that current cost recovery promises may be broken by future public utility commissions (PUCs). The result of this could be large and growing stranded benefits reflecting the loss of highly cost-effective investments. Rather than use capital markets to provide liquidity and judge risks, utility companies require franchise customers to provide short-term finance for DSM programmes. Franchise customers are generally unable to provide the flexibility and funding required to make a success of DSM. This approach urges customers to adopt high effective discount rates for DSM projects, thus greatly reducing their willingness to share costs (Rouse 1994; Hirst et al 1996).

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20 Avoided costs are far below what they were 10 to 15 years ago.
4.1.4 Uncertain futures for utility-administered DSM

It is likely that in the future DSM will become a highly decentralised market-based tool that offers real-cost advantages to energy providers and customers. This new DSM is likely to face ‘broad entrepreneurial challenges that are stimulated by end-user choice’ (Houston 1994). Table 1 below summarises the characteristics of past and future DSM. Essentially, the likely primary distinction between today and tomorrow’s DSM will be the return of responsibility for economic decisions in energy matters to customers, realigning incentives to invest in energy-using capital with the ownership of capital (Houston 1994)

<table>
<thead>
<tr>
<th>DSM characteristic</th>
<th>Traditional DSM</th>
<th>DSM of the future (i.e. market based or for profit services)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service provider</td>
<td>Regulated entity</td>
<td>Regulated utility as well as unregulated company (i.e. utility, energy service company, equipment manufacturer etc)</td>
</tr>
<tr>
<td>Driver for offering service</td>
<td>Obligation to service</td>
<td>Profits</td>
</tr>
<tr>
<td>Target market</td>
<td>Local utility customers (customers are captive)</td>
<td>Not limited to service territory boundaries (customers have many alternatives).</td>
</tr>
<tr>
<td>Programme targets</td>
<td>Conservation of energy resources.</td>
<td>All resources, and could promote additional energy use as easily as energy conservation.</td>
</tr>
<tr>
<td>Product</td>
<td>Utility resources defined in terms of kWh and kW reductions</td>
<td>A product or service offering defined in terms of money savings and value to customers</td>
</tr>
<tr>
<td>Project financing/funding</td>
<td>Generally, short-term and limited; DSM expenses and costs passed on to all customers through tariff increases.</td>
<td>Long term; enormous, diverse, competitive private capital markets tapped into, individual customers contribute to the services they desire</td>
</tr>
<tr>
<td>Risk burden</td>
<td>Borne by the utility companies, and customer</td>
<td>Borne by regulated utilities, private investors and lenders, and a portion by customer</td>
</tr>
<tr>
<td>Explicit subsidies</td>
<td>Significant incentives to adopters, paid from general revenue requirements.</td>
<td>None, or few directed at informing, not targeted.</td>
</tr>
<tr>
<td>Implicit subsidies</td>
<td>Closed retail markets exclude many choices, including use of potentially lower-priced energy.</td>
<td>DSM must compete with numerous substitutes in the market, including potentially lower-price energy to end-users.</td>
</tr>
<tr>
<td>Measurement (test) of effectiveness</td>
<td>Regulators’ attempts to establish objective benefits, costs, and risks; market choices presumed to be in error.</td>
<td>Accumulation of market decisions by users, predicated upon subjective appreciation of benefits, costs and risk; market presumed not to falter.</td>
</tr>
<tr>
<td>Marketing and promotion</td>
<td>Technology based (i.e. focus on customer’s use of energy, rebates)</td>
<td>Value or solutions based (i.e. focus on all aspects of end-use services; performance contracting).</td>
</tr>
</tbody>
</table>

Table 1: Comparison of traditional DSM with DSM of the future

Source: Adapted from Houston (1994); Chamberlin & Herman (1996); Rouse (1994)

Indeed, the pending changes in the United States electric industry and in DSM are likely to be so profound that it seems misleading to refer to this emerging energy services industry as DSM (unless the term is modified to underline the vast conceptual differences in contextual settings). Hence, as noted earlier, the suggested new names for DSM: ‘smart-DSM’, ‘energy services management’ (ESM), and ‘market-based DSM’. These services will probably be provided by utility DSM programmes, and the emerging ESCO industry.
Over the last few years, the ESCO industry in the United States has grown phenomenally – by 25 per cent per year (Geller, Nadel & Pye 1995). ESCOs now contribute towards the increasing level of efficiency occurring largely through the private sector. They offer a variety of innovative financing options which help customers to bear the cost of efficiency improvements. These options include equipment financing by dealers, leasing options, shared savings or guaranteed performance contracting, contracted energy services, and packaged energy services (Chamberlain & Herman 1996). Typically, the different types of ESCOs are as follows:

- **Vendor ESCOs.** Deal directly with large customers and are not involved in utility DSM programmes. Some are in the controls business.
- **Utility ESCOs.** Bid to serve as a provider of utility sponsored DSM programmes. Paid by utilities to achieve guaranteed levels of MW and MWh savings. Called ‘demand-side bidding’.
- **Contractor ESCOs.** Work with companies that construct new buildings. Offer to install more energy-efficient technologies that might not otherwise be installed.
- **Engineering ESCOs.** Perform design and engineering services for clients and rarely offer performance contracting or shared savings programmes to customers (Shippee 1996).

Without any utility support, about 90 per cent of all ESCO projects are implemented in the institutional (schools, hospitals, and government buildings), commercial and some industrial sectors. ESCOs now compete with utilities for premium commercial and industrial customers. ESCOs, however, are having minimal impact on the residential sector. This is because sales cycles in the ESCO industry are long and transaction costs are high. Thus, transactions have to be worthwhile – that is, this generally tends to exclude customers with utility bills under $5000 per month (Shippee 1996).

As more competition is introduced into the electricity industry in the United States, time- and location-dependent prices associated with a competitive electricity industry will likely send powerful signals to customers to save energy at certain times and places when and where electricity is expensive to produce and deliver. This, together with the possibility of a futures market for electricity being established, will make it increasingly feasible for the private sector to participate in DSM. On the other hand, changes in price structures that lower the commodity charge (c/kWh) will also reduce customer incentives to invest in energy efficiency (Hirst et al 1996).

Notwithstanding the importance of the private sector in providing DSM services, it is also likely that distribution utilities (probably retail – as opposed to wires – businesses) will continue to play a key supporting and complementary role in promoting cost effective energy efficiency. With widening competition, it is likely that utilities will focus on providing customised energy efficiency service packages to key customer classes more effectively (i.e. adopting a ‘smart-DSM’ type approach), while simultaneously pursuing the role of administering public funds aimed at transforming (and thereby perhaps cultivating) future markets. In this regard, load management programmes will probably survive, as will energy efficiency programmes that pass the RIM test. For large commercial and industrial customers, utility DSM programmes will be used primarily as part of a strategy to provide enhanced value and service to customers and attract new customers from other service providers. Services to residential and small commercial and industrial customers will be the most at risk (Nadel & Geller 1996).

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21 Is it suspected that DSM bidding is responsible for a considerable amount of this growth. It thus follows that if utility DSM programmes decline, this growth may slow down. Very small ESCOs that specialise in one particular facet of DSM are likely to be effected by this, while most of the larger ESCOs that do not bid to support DSM will not (Shippee 1999).


In the future, utilities may choose to meet all of a customer’s energy (and other resource-based) service needs rather than just their energy efficiency needs. This is already occurring in California where utilities are moving away from programmes that focus on creating resource value for their generation system and spending more time on creating value for individual customers in anticipation of the potential for retail wheeling in the next five years (Messenger 1996). To reduce DSM-associated costs, utilities are likely to continue to seek partnerships with other entities including governments in promoting energy efficiency standards, and with manufacturers in encouraging market transformation, and most importantly with ESCOs (Hirst et al 1996). This is already occurring throughout the United States. Because ESCOs have already made significant inroads into forming performance contracting relationships with large long term customers, it is likely that the next few years will witness many more utility-ESCO acquisitions/mergers, or ESCO launches of utilities. Utilities are already facing decisions on whether to spin off some of their DSM programme activities into unregulated, for-profit subsidiaries.

Thus, in this brave new world, it is possible that utility DSM programmes will be shaped and thus funded in two different ways. Utilities will compete against, or work with, ESCOs to secure contracts with individual customers, who will generally pay for most of the service they receive from utilities or ESCOs. In essence, these activities will be determined by market forces. The services rendered will aim to improve customer comfort, convenience and productivity and reduce customer costs by saving electricity. Depending on the state regulatory frameworks of the future and on how distributor utilities are restructured, utilities may acquire public funding for more broad-based social benefits programmes which are likely to be targeted at the residential and small commercial and industrial sectors and funded, perhaps, out of a non-bypassable public-purpose systems surcharge (see section 4.1.5 to follow).

4.1.5 Regulatory possibilities for the new context
While the regulatory regime in the US enabled DSM programmes to flourish for some time, it is now unclear, as competition is introduced, what DSM investments state regulators will require from utilities. Since, however, regulators in the US have never operated in a political and economic vacuum, it is likely (given the current dominant context of falling avoided costs, excess generation capacity, and the desire of the public to have access to energy at the lowest tariffs possible) that major budget cuts for DSM will be agreed to. It is also likely, though, that regulators will continue to require a minimal amount of social-benefit DSM from utilities in the transition period. Types of DSM programmes that may be encouraged include: market transformation programmes, shared savings programmes, programmes that favour low-income and elderly customers, lost opportunity and customer retention programmes (Keating 1996). The strategy of choosing to spin-off some DSM programmes into the private market, while continuing to use public funds to pursue market transformation and other forms of customer education programmes, has been tentatively endorsed by some state regulators.

To sustain productive energy efficiency investment during the transition period of the electric utility restructuring, a promising solution to the funding question associated with this public purpose DSM lies, perhaps, in the adoption of a non-bypassable, system benefits charge on electric distribution services. An advantage of distribution charges for the US is that it avoids potential disputes over state jurisdiction.24 Such charges are generally based on usage (kWh),

24 As clarified in FERC Order 888 (at 436-437):
First... we believe that states have authority over the service of delivering electric energy to end users. Second, through their jurisdiction over retail delivery services, states have authority not only to assess stranded costs but also stranded benefits, such as low-income assistance and demand-side management.... (E)ven where there are no identifiable local distribution facilities, states nevertheless have jurisdiction in all circumstances over the service of delivering energy to end users. Under this interpretation of the state/federal jurisdiction, customers have no incentive to structure a purchase so as to avoid using identifiable local distribution facilities in order to by-pass state jurisdiction and thus avoid being assessed charges for stranded costs and benefits.
demand (kW) or a combination of these two, and utilised to pay for various public benefit
including energy efficiency, low-income programmes, R&D and renewables. This 'new' cost
recovery approach does not necessarily require a change in current tariffs, rate structures or
cost allocations amongst customer classes. State regulators would simply be making explicit that
those who use integrated power systems may not bypass their share of contributions to system
benefits by designating a new supplier of kilowatt hours over the integrated grid (Hirst et al
1996; Cavanagh 1996, Messenger 1996). This approach is currently being implemented in
Arizona, California, Connecticut, Idaho, Illinois, Maine, Massachusetts, Montana, New
Hampshire, New York, Oregon, Pennsylvania, Rhode Island, Vermont, Washington and
Wisconsin, and is under consideration in other states (Meyers & Hu 1999).

Notwithstanding the usefulness of this systems benefit charge, it should however be borne in
mind that it is no longer obvious that regulators of the future will allow full cost recovery for
DSM programmes or, at least, will permit utilities to profit from DSM as they have done in the
past. This regulatory regime has been heavily criticised as 'regulatory excess of the worst sort',
and, indeed, is one of the reasons why the NLRA, probably the most commonly used
regulatory mechanism used to re-imburse utilities for lost revenues resulting from successful
DSM programmes, will be re-examined. To cover utility costs, NLRA mechanisms lead to
higher tariffs, and because net lost revenues from DSM programmes tends to accumulate over
time, the sustained use of these mechanisms generally leads to increasingly higher tariffs, which
in turn are at odds with a competitive electricity context. In response to this, regulators may
choose to cap the total net lost revenues that a utility may recover over a specified period.
Alternatively, regulators can allow recovery of a portion of lost revenues from DSM (Baxter
1995). This approach is under consideration in some states in the US.

Ultimately, the long-term survival of DSM in America's restructured electric industry will depend
on a number of factors including the continued belief by utilities that DSM is a valuable
customer service, the ability of the regulators to shape the new market so that socially cost-
effective programmes are maintained, and the creativity of DSM practitioners to modify DSM
programmes to take advantage of the new market structure. Indeed, the future of DSM is being
created daily (Hadley & Hirst 1995).

### 4.2 England and Wales: 'Iterative attempts to make DSM happen'\(^{26}\)

The electric industry in England and Wales was re-organised starting in the early 1990s in the
belief that competition is more effective than central planning in achieving economic efficiency.

#### 4.2.1 Bold privatisation

Starting in March 1990, the state owned Central Electricity Generating Board (CEGB) was split
into four public limited companies: National Grid (a monopoly transmission company),
PowerGen, National Power, and Nuclear Electric. In December 1990, the twelve existing area
boards (or distribution companies responsible for building and maintaining the local medium-
and low-voltage distribution system in specific areas) were privatised intact (and with shares in
National Grid) as regional electricity companies (RECs) with no change in their commercial

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\(^{25}\) NLRA mechanisms effectively address the short term problem of revenue losses between tariff cases.
NLRA does not address a long-term problem, which is that energy efficiency erode the revenue base of
the utility. Ultimately, this erosion will result in fixed costs being spread across a smaller revenue base the
utility would experience without DSM. This relative erosion in the utility's revenue base will lead to tariff
increases. The source of utilities' concern is that independent power suppliers are not faced with these
same upward pressures on their costs and the resulting prices that they can charge for electricity (Baxter
1995).

\(^{26}\) Privatisation and restructuring of the power sector has occurred throughout the United Kingdom.
However, different regulatory schemes are employed in Scotland and Northern Ireland. Regulatory
consideration of utility involvement in energy efficiency within the UK occurred first in England and Wales,
and this review is limited to these countries.
scope of activities. However, an accounting split between the monopoly distribution side of the business (i.e. the physical infrastructure or 'wires' business) and the potentially competitive supply business (i.e. the purchasing and sale of power to end users) was required. In March 1991, 60% of National Power and PowerGen was sold to the public, and the remaining 40% was sold in February 1995. In June 1996, parts of the two state-owned nuclear companies Nuclear Electric and Scottish Nuclear were privatised (Newbery 1998).

For the purposes of this study, other important developments in the UK electricity supply industry include:

- The establishment of an Office of Electricity Regulation (OFFER) which provides advice to the Director General of Electricity Supply (DGES) to establish a regulatory system for the electricity supply industry. Under this regulatory framework, monopoly elements of the electricity supply system – transmission, distribution and supply to franchise customers – were to be regulated using the general RPI-X price cap. The roles of OFFER and the Office of Gas Supply (Ofgas) have since merged (1999).
- Competition for supply to retail customers has been phased in. From the outset of the process, customers with a maximum demand of more than 1 MW were allowed to purchase power from any licensed supplier. In 1994, the limit was lowered to 100 kW and in 1998 removed altogether. Customers wishing to change supplier are subject to a small fee for doing so.
- A spot market and power pool have been created. The NGC is responsible for operating the power pool, establishing merit order dispatch and transmission planning and construction. Electricity is bought and sold through the Electricity Pool on a half-hourly basis. All generators, including National Power, PowerGen, Scottish Nuclear, Nuclear Electric, other foreign plants in Scotland and France, and the considerable number of independent power producers (IPP) plants built since Vesting Day sell electricity into the pool.

4.2.2 Light-handed regulation

In the aftermath of privatisation, the prospect of power companies increasing or even maintaining their investments in DSM seemed bleak. The performance-based price-cap formula that existed at the time – whereby electricity companies' allowed revenue was directly linked to the number of units sold – posed a strong incentive to RECs to maximize sales, but an equally strong disincentive to RECs to institute DSM. The DGES had been given large discretionary power to influence the level of energy efficiency activities in the industry (no statutory targets existed), yet he noted that: 'The issues surrounding energy efficiency in the context of the electricity industry are complex. Changes designed to have a beneficial effect in relation to energy efficiency may have unintended effects on other areas where I have important duties.'

27 Under this formula, the price of the regulated service is allow to rise by the level of general inflation, the retail price index, less an incentive factor, X, which the regulated companies must recover by increasing its efficiency or lowering its costs.
28 All generators are paid the pool's highest accepted bid price to serve each specific half-hour period. All generators providing power for the same half-hour period are paid the same price, irrespective of the actual costs of operation for any specific generator. The pool input price (PIP), the price paid to the producer, is equal to the system marginal price plus the capacity payment (if any). The pool output price (POP), equal to the PIP plus an 'uplift' charge to cover overhead, spinning reserves etc. is paid by buyers (http://www.electricity.org.uk/about_ea/bic_pub/rep_62.html; King et al1995).
29 The power pool in its current form has only one year left to live. The new system will involve self dispatch, with contracts up to 24 hours, then from 24 to 4 hours, bi-lateral screen trading at the offered price, then the ISO takes over and buys spinning reserves, gets rid of bottlenecks and so on. In the new system, there will be no official market price (Thomas, 1999).
30 Since the distribution function has a high degree of fixed cost, each additional kWh sold generated a high degree of profit once fixed costs were covered. Consequently energy efficiency programmes directly resulted in a high loss of margin (King et al1996).
(OFFER 1992; Eikeland 1998). The DGES did, however, take some concrete action. Firstly, the NGC was instructed to install efficient equipment, even where such equipment had a higher initial cost. The NGC has also been directed to take full account of losses when selecting overhead line conductors and when evaluating transformer tenders (Eikeland 1998).

Secondly, as part of the first review of the distribution services price cap, OFFER examined whether significant market imperfections that would lead to undeveloped cost-effective energy efficiency resources existed. OFFER also investigated mechanisms that could promote greater REC involvement in DSM. It found that market barriers inhibiting investment in energy efficiency remained following restructuring. These imperfections were seen to exist particularly in the franchise market that had not yet been provided with choice of supplier. In the non-franchise market, OFFER did not believe that sufficient time had elapsed for customers to respond to price signals or for the ESCO market to develop. Hence, OFFER concluded that intervention in the market should be limited to the franchise market.

OFFER acknowledged that as a result of the prevailing price cap mechanisms, RECs faced numerous disincentives to carrying out energy efficiency programmes. An adjustment to the price cap formula which would increase the productivity factor (hence increasing the cost pressures on the distributors) was rejected as being too indirect. A wires charge to fund DSM programme expenses, and possibly lost revenues was considered too broad (King et al. 1996). Ultimately, OFFER chose to amend the manner by which the price cap formula was to be applied. In the 1993 Supply Price Control review, the volume-related element of the revenue allowance was reduced dramatically. The 1994 Distribution Price Control also initiated a similar partial 'decoupling' of volume sales from profit. About 50 per cent of the revenues allowed through the price cap would be collected through fixed charges (Curtis 1995; King et al. 1996).

Thirdly, OFFER elected to adopt a special revenue allowance to be used by RECs to achieve end-use energy savings on behalf of their customers. This special revenue allowance was to be raised by collecting the equivalent of £1 from each franchise customer account over the period 1994 to 1998 and used to carry out over £100 million of energy efficiency activities for customers through the efficient use of electricity with lifetime (discounted) savings of 6,103 GWh (Curtis 1995; King et al. 1996). OFFER considered suggestions that the funds be administered by an independent body such as the Energy Savings Trust (EST) (see section 4.2.3 below) but, in order to exercise regulatory oversight, opted to channel the funds through the RECs.

Forthly, OFFER established the 'standards of performance' (SoP) requiring each REC to achieve certain energy savings levels. In 1994, the RECs were required, for example, to save 0.675% of distributed energy. As part of the 1993 Supply Price Control, the DGES

31 The new price control for NGC specifies levels of demand in advance (in accordance with NGC forecasts), entailing that NGC’s maximum revenue level during the next control period is fixed thus removing any artificial incentive to boost peak demand for electricity and disincentives to co-operate in load-management initiatives (Eikeland 1998).

32 Recently, the new joint regulator announced an extension and revision of this revenue allowance. The levy amount is now £1.20 to reflect inflation. For the first time, the levy will include gas (Chesshire 1999).

33 The nature of the mechanism is such that it could be interpreted as performance-based tariff making for DSM. If the REC can produce the energy savings for less than the amount of the levy, then it could pocket the excess cost. If, on the other hand, the savings cannot be achieved within the levy amount, the REC must pay for the excess out of shareholder funds (King et al. 1996).

34 The SoP emphasise projects that exert downward pressure on the charge per kilowatt-hour to customers. All domestic and commercial franchise customers must be addressed, but the interests of the elderly, disabled, and those on low incomes and those living in rural areas should be encouraged. Only projects under which benefits to customers exceed costs are permitted and the effect on the environment must be defined. Finally, projects have to be designed so as to minimise free rider activity. This means that use of the mass media is not viable in most cases. If nation-, or region-wide television or newspaper advertising is used, the accredited energy savings for the estimated numbers of free riders must be deducted from the total scheme savings.
stipulated that utilities should provide impartial, high quality energy advice where requested by customers. In addition, OFFER retained the services of the EST to assess whether projects proposed by the RECs meet the requirements of the SoP (King et al 1996).

The impact of these measures has been mixed. While the 1994 distribution review sought to create a more favourable climate for energy efficiency by going some way towards decoupling volume sales from profit, indications from the RECs are that the reduction in volume incentive lead to a dramatic reduction in the level of the marketing of electricity to commercial customers. Under this new framework, the RECs did not consider the acquisition of new business to be profitable (Curtis 1995).

Recently, the Committee for Public Accounts released an assessment of the operation of SoP1 (1994 to 1998). During this period OFFER and the Energy Savings Trust approved over 500 SoP projects, giving a total lifetime energy saving of 13.5 TWh (10 per cent greater than the target savings, and leading to a reduction of over 6 million tonnes of CO₂, £102 million (or £25 million per annum) has been invested by RECs in these projects. Other parties, including customers and local authorities, have committed a further £40 million. Customers have benefited by £4.60 for every £1 of programme investment, in reduced energy costs. The programme has directly stimulated the equivalent of 400 jobs per year over 4 years. It is noted that:

the electricity companies (RECs) are to be congratulated on the outstanding performance work they have done in delivering energy efficiency to customers since 1994. Companies are set to exceed their energy saving targets by, on average 12 per cent, while a net benefit of £250 million has been achieved. In addition, comfort improvements of £250 million have been secured. These successes demonstrate that with proper planning and execution, energy efficiency delivers environmental, social and economic benefits simultaneously. (Energy Savings Trust 1999a)

Interestingly, it is also noted in this assessment that these results have been largely achieved through RECs recycling the levy funds, and not in general through the use of their own funds. Where RECs did contribute their own funds to energy efficiency programmes, it was generally in the name of corporate image spending (joint ventures with charities to assist those suffering from fuel poverty, etc) (Chesshire 1999).

The Committee's inquiry focused on the first phase of the SoP scheme. The main recommendations - on the need to ensure a consistent percentage investment by the respective companies on programmes to assist low-income customers, and on minimising the disparity of costs per measure between the respective companies, have both been addressed for SoP2 which began in April 1998 and will run to March 2002. For example, in the first phase, the companies spent between 40 per cent and 70 per cent of their SoP funds on low-income customers with an average of 60 per cent. For SoP2, the agreed range is between 57 per cent to 69 per cent with an average of 65 per cent (Energy Savings Trust 1999a). Energy efficiency SoPs are now acknowledged as a key mechanism for the government to achieve its target of reducing CO₂ emissions by 20 per cent by 2010.

4.2.3 Collaboration with the Energy Savings Trust

The Energy Savings Trust (EST), a private government-guaranteed company, was established in 1992 as a means to meet the United Kingdom's obligations under the Rio Declaration. Its members include the 12 RECs, British Gas, Scottish Power, and Scottish Hydroelectric (Brower, Thomas & Mitchell 1996). As noted above, OFFER retains EST's services to:

- negotiate with OFFER and the RECs to set each company's energy saving targets;
- evaluate all projects ensuring compliance;
- assist in the development of projects in association with the RECs;
- develop and manage national projects on behalf of RECs (Energy Savings Trust 1999d).
Thus, EST plays a role not only in assisting RECs in implementing specific projects but also in promoting energy efficiency more widely. To this end, EST works in association with a network of Energy Efficiency Advice Centres (EEACs) based throughout the United Kingdom. Established in 1993, the network currently comprises 43 centres around the country. This network provides ‘free, expert, and impartial advice to households and small businesses’ on energy efficiency (Energy Savings Trust 1999b). The RECs also linked up with these organisations to market energy efficiency measures to local groups/people (Curtis 1995). To date, this network has assisted over half a million households, in saving on average £23 per annum on fuel bills (Energy Savings Trust 1999c). Importantly, the EST has organised a number of fairly successful market transformation programmes (King et al 1996).

Since its inception, funding for the EST has consistently been uncertain. As early as 1994, the Trust faced a cash crisis since gas and electricity regulators had become increasingly reluctant to force utility companies to pay (Eikeland 1998). In response to this the Secretary of State for the Environment announced that, from 1996, it would make up to £25 million a year available to the EST until the gas and electricity markets had been fully liberalised (Brower, Thomas & Mitchell 1996). Funding for 1999 to 2000 has only recently been secured: the Department of Environment, Transport and the Regions has pledged to provide £22 million for EST programmes for these two years.

4.2.4 Product differentiation and a slowly emerging energy service industry

The Standards of Performance were only seen as means to provide a short-term solution to the increased application of energy efficiency measures in the United Kingdom (i.e. the SoPs are seen as the essential means of not only stimulating but transforming the market for energy efficiency goods and services in the UK). A recognition has always prevailed that in the longer term, market forces, operating in an increasingly competitive energy market, are a vital mechanism in achieving sustained energy efficiency benefits (Swinden 1995).

As more competition has been introduced into the electricity sector, RECs have become careful about the type of DSM programme chosen for implementation. This is because RECs are increasingly wary of the need to secure investment opportunities that generate unambiguously favourable economic returns. As a representative of Eastern Electricity (a REC) notes:

Eastern Electricity has identified limited, but finite scope for the application of traditional DSM techniques to reduce costs of maintaining and operating the distribution system network.

The solutions chosen are dependent upon customer needs, regulatory decisions and technology costs. Eastern has conducted one DSM programme involving over 500 domestic customers. The objective of the scheme was to transfer load from the peaking load period whereby deferring the need for capital expenditure to reinforce the network. The exercise was based upon our knowledge of typical load shapes for customers supplied and a knowledge of the profile of the loading on the major substation.... The exercise of changing demand profile has successfully reduced peak demand by 3.3 MW, and has thus enabled us to remain within our security of supply criteria without network reinforcement... Generally, we have sufficient capacity, on most of the system, not to use DSM extensively, but the techniques will be used where they provide demonstrably good business solutions. (Swinden 1995).

Interestingly, there are slight indications that investment in energy efficiency services is now not only occurring as a result of the very modest regulatory requirements imposed on RECs, and as a means to defer investment in distribution networks. Over and above these requirements, RECs and other energy service businesses are hesitantly beginning to recognise the value of voluntarily adding energy efficiency and environmental services to their business portfolios. This recognition is being driven by the notion that energy price, although generally the single most important factor, is not always the only determinant in choosing an energy supplier. Other value-added services, such as advice on energy efficiency and the environment are slowly becoming regarded as key benefits. An example of this is as follows: Eastern Electricity recently
I won the UK contract to supply McDonald's' retail outlets with electricity, not because of the price on offer but because a computer software package was provided to the company which would remotely monitor energy use in their restaurants 24 hours per day. This allowed McDonalds to manage their overall energy consumption more efficiently (Swinden 1995). Clearly, this represents a significant departure from the traditional (and almost exclusive) electricity load management approach adopted by electric utilities.

4.3 Norway: 'Leaning on the market'

Prior to the new Energy Act (effective January 1991), the electricity industry in Norway was characterised by over-capacity, low export prices, large regional variability in prices, and excessive distribution charges. Key goals of restructuring were to minimise regional price equities, halt inefficient capacity expansion, improve system co-ordination and plant utilisation and boost electricity exports (King et al 1996).

4.3.1 Competition without privatisation

Competition was introduced to the Norwegian electricity industry as a result of the Energy Act of 1991. Until this time, over 230 electricity utilities, most of them owned by local municipalities or local councils, were not only obliged to deliver but had a monopoly on electricity delivery within their own areas. As far as utilities were concerned, the electric system functioned well: the cost of developing new power stations or new distribution capacity could be shifted on to the customer (Pedersen & Gilje 1995). Current market structure now allows all customers a choice of energy suppliers. Similar to England and Wales, customers wishing to change suppliers are subject to a nominal fee for doing so (Thomas, 1999).

In contrast to England and Wales, restructuring of the Norwegian power sector did not include industry privatisation – 55% of generation and most distribution companies are in municipal and county ownership, and the state owns 30% of Norway's generation capacity. A majority of Norwegian distribution companies have been made into public limited companies (Eikeland 1998). The Energy Act does not require utilities to separate distribution and supply functions into separate corporate entities, but rather requires a separation by accounting only (King et al 1995).

Other characteristics of the Norwegian power sector are as follows:

- The Nordic power market is based primarily on bilateral hourly trade between suppliers and customers. Approximately 80% of all bilateral contracts are cleared through the Nordic Power Exchange, the world's only multinational exchange for trading electric power (http://193.69.80.130/eng98/nordpool/nordpool_content.html). The power market, administered by Nordpool (formerly Statnet Marked) consists of three distinct markets – the regulation market, the daily spot market, and the weekly or forward market.

- Transmission and distribution industries are regulated by the Norwegian Water Resources and Energy Administration (NVE). Regulation used to be based on a rate-of-return calculation. More recently NVE has sought to combine the latter with incentive-based

35 Nordpool is owned by the two national grid companies, Statnett SF in Norway (50%) and Svenska Kraftnet in Sweden (50%).

36 The Nordic pool is much cheaper to operate than the power pool in England and Wales. This is primarily because the Nordic pool operates on an hourly basis where the pool in England and Wales operates on a half hourly basis. The problem for small customers is that it is not financially viable to install meters that transmit data consumption every 30 minutes which is what would be needed to reconcile costs accurately with pool costs (the result of this is standard demand time profiles). In England and Wales, the process of first assuming demand, then forecasting demand, then reconciling this with the actual demand is highly complex. Each distribution area meters how much power is taken off the grid and goes into that area. The generation cost is then allocated between the supply companies in that area. In Norway, the overall demand profits is worked out for the entire region and is assumed to be the same for each company, so there is only one demand profile and not a lot of need for reconciliation (Thomas, 1999).
revenue caps for individual network companies (Grasto 1998). NVE is responsible for technical regulations including quality and reliability of supply, while the competition authority and the 'ombudsman' (sometimes supported by the NVE) handles customer complaints (Horvei, 1999).

- The national transmission network (above 130 kV) is operated by STATNETT SF, which is state-owned and responsible for providing open transmission access to facilitate wholesale and retail competition. The regional network (130 kV and 60 kV) is owned by regional utilities, and the local grid (20 kV) is owned by distribution utilities.

4.3.2 Passive governmental response to DSM investment

Since the energy crisis in the late 1970s and 1980s, many Norwegian electricity companies had voluntarily set up a sustained range of DSM efforts designed to reduce the electricity demand in their own supply areas (Boyle 1996). A 1992 survey by the Norwegian Water Resources and Energy Administration (NVE) showed comprehensive activity by the companies in the late 1980s in the form of information, advice, audits and education of customers. About one third of the companies offered grants or soft loans for end-use investment to their customers (Eikeland 1998).

A similar survey conducted in 1994 found that the number of electricity companies providing financial aid to customers for energy savings had been halved from 1990 to 1994 (Energidata 1994). The explanation given for this was that government policies had significantly changed. The government initiated a scheme providing financial aid for energy-efficient end-use investments for the year 1990. This scheme ‘crowded-out’ the investments offered by electricity companies: it made no sense for industry to duplicate governmental funding. Because it was found that this new policy was not a cost-effective way to achieve energy savings, these aid schemes were gradually removed, and by 1994 had totally disappeared (Eikeland 1998).

The new Energy Act of 1991 stated that the government should assume a more passive role in the electricity market, and that the main responsibility for energy efficiency investments rested with customers. The Act’s strongest disincentive for DSM lay in the fact that electricity companies would no longer be responsible for supplying their own area with electricity. In so doing, price became the most important issue (Pedersen & Gilje 1995). Initially, the 1991 Energy Act included an obligation to undertake integrated resource planning (IRP). This requirement, however, was strongly resisted by the industry and the obligation was removed in 1994. The Act does, however, mandate that distribution utilities (monopoly function) undertake certain DSM activities such as information programmes, demonstrations and audits (the requirements for subsidies and grants were not re-established). Norway’s 1993 White Paper No.41, entitled Energy Efficiency and New Renewable Energy Sources, reinforces this requirement. A DSM distribution charge of 0.0003 NOK/kWh has been imposed to fund these activities and to counterbalance the disincentives for DSM brought about by deregulation. The utility was permitted to use the levy price to recover costs of performing activities as specified in the interpretation of the Act (Veum 1999; King et al 1995).

Partly because the Act does not require a complete separation of utilities into distribution and retail supply functions, there was nothing initially that prevented distributors from using the wires charge to support marketing activities such as customer attraction/retention, strategic marketing and load building. NVE has since taken actions to better ensure that the funds are spent consistently with the objectives of the Energy Act. In 1994, a decision was taken to

37 It has been pointed out that since the competitive changes were introduced into the electricity sector, there has been a 25 per cent reduction in industrial electricity prices (Boyle 1996).

38 Interestingly, the White Paper officially notes that energy efficiency measures should be redirected towards information, education and motivation campaigns and a grant scheme for the introduction of energy efficient technology instead of grant schemes for energy efficiency investments in various sectors. This suggested redirection was based on studies showing that the main barrier to energy efficiency activities in Norway was a lack of information and knowledge (Veum, 1999).
establish Regional Energy Efficiency Centres (REECs) (by 1999, 19 REECs had been established) funded by the DSM wires charge. These are jointly owned by utilities and third parties in each region. The primary motive behind creating the REECs was to reduce potential anti-competitive behaviour by removing the monopoly-funded energy efficiency activities from the distribution utility. NVE believes that these REECs are in a position to offer more objective advice than was likely to be provided by the distributors, and encourages the distribution companies to transfer their activities required by statute to them. In addition, the REECs are likely to reap economy of scale benefits from merging the regional DSM activities into one regional centre. REEC activities include:

- general information on energy efficiency;
- historical electricity consumption data;
- energy advice, particularly on the efficiency of individual residential customers;
- simple audits and analysis indicating which energy efficiency actions are likely to be most cost-effective, and how to have them installed;
- information on environmental impacts from energy consumption (King et al 1995).

The REECs have been established relatively recently. There is little information available on their operational effectiveness.

Overall, the impact of these governmental measures on investment in DSM has not been positive. According to Norwegian electricity supply industry representatives, there is little incentive to engage in any form of voluntary activities. The statutory requirements are in fact linked to the monopoly part of the business – the operation of the grid. As long as there is sufficient capacity in the grid (which is the case for most of the time) there is no incentive for DSM. In addition, according to the Energy Act, revenues collected cannot be used for activities connected to marketing of energy-efficiency packages or demand-side investments, since cross-subsidisation of distribution and supply is banned. Demand-side investments have to be funded by profits earned from the competitive part of the business. The companies have so far regarded such an allocation of profits as too risky, since customers are free to change supplier whenever they wish (Eikeland 1998).

Thus, the creativity and enthusiasm for energy efficiency which had existed within distribution companies prior to 1991 has disappeared, to the extent that, currently, only the minimum activity required by the new Energy Act is now carried out. Correspondingly, utility staff involved in electricity DSM have been cut by 33 to 50% (Haaland & York 1995).

As indicated above, there have been biased motives for utilities to pursue DSM. Suppliers have tended to focus on cost as the primary determining competitive factor. Some customers, however, value services in addition to low commodity products. For example, suppliers see a benefit in providing certain customers with customised metering and billing services that provide insight into electricity costs. Such services are useful, for example, for franchise customers to compare costs and profitability among outlets (King et al 1995).

The Ministry of Petroleum and Energy has current overall responsibility for the Norwegian government's energy efficiency work. Its role is to ensure that state funds are allocated rationally, to draw up a long-term strategy for energy efficiency and evaluate changes in the use of energy-efficiency instruments. The Norwegian Water Resources and Energy Administration (NVE) is responsible for the administration of government efforts (information, training and education, campaigns, company specific introduction, energy efficiency network for buildings and the industrial energy efficiency network) in this field. It delegates responsibility for practical implementation of the various measures to institutions and organisations outside of central government (Veum 1999).
4.4 New Zealand: ‘Centralising energy-efficiency efforts’

Prior to restructuring, the state-owned New Zealand Electricity Division controlled generation and transmission. Electricity distribution authorities or Electricity Supply Authorities (ESAs) comprised a mixture of departments within local governments and local Electric Power Boards. Retail sales were administered by these distributors, totalling over 60.

4.4.1 Gradual industry transformation

While restructuring in New Zealand was also introduced to facilitate wholesale and retail competition, the approach chosen was far more gradual than the ‘shock treatment’ adopted in England and Wales. In 1987, the Electricity Corporation of New Zealand (ECNZ) was formed as a state-owned enterprise and the corporatisation of generation and transmission took place. It was followed, in 1988, by the deregulation of generation and the removal of the obligation to supply imposed on ECNZ. In 1992, under the Energy Companies Act, the deregulation of electricity continued with the corporatisation of the Electric Power Boards and Municipal Electricity Departments. Franchise restrictions on distribution and retail for small consumers were also removed (franchise restrictions for large customers were removed in 1994). In 1994, TransPower was separated from ECNZ and formed as a state-owned enterprise. In 1995, ECNZ was further divided by splitting out approximately 40 per cent of its generation capacity: 30 per cent was transferred to a state owned enterprise named CONTACT, and the remaining 10 per cent of the assets – mostly hydro – were sold off. The Electricity Market Company (EMCO) owned by TransPower, ECNZ, CONTACT and the Electricity Supply Association of New Zealand (ESANZ), was also established. EMCO is now owned by Rand Merchant Bank (RMB) and is called M-co, The Marketplace Company. M-co co-ordinates the electricity market through the establishment of an electricity exchange including a physical spot market and forward markets for short and long term tradable contracts for electricity (Bergara & Spiller 1997; NZEM 1998). In 1996, a fully competitive private sector wholesale market was established. Recently this year, the government sold its cornerstone shareholding in State-owned generator/retailer Contact Energy. The remaining 60% was sold via a public float. Furthermore, ECNZ was split into three. The Electricity Industry Reform Act of 1998 also came into effect in 1999, whereby ownership separation of lines and transmission from generation and retail was enforced. Finally, the electricity industry launched a profiling system to enable domestic customers to switch retailer (http://www.moc.govt.nz/ers/electric/sector/sector-01.html).

Restructuring has, again, resulted in a strong incentive for ESAs and electricity traders to maximise electricity sales. Competition for retail sales exists among ESAs, but there is almost no competition in generation. Therefore, distributors are somewhat limited in terms of being able to differentiate retail prices. Competition is based primarily on non-price factors such as customer service.

There is no formal body to regulate the industry. While disclosure is required of audited financial statements that distinguish monopoly activities from competitive activities (i.e. as stipulated in the Commerce Act, 1986), contract information, information on pricing policy and methodology and other relevant information, the electricity industry, within the context of various pieces of legislation, ultimately is left to regulate itself. If power is abused government can intervene. Increasingly, though, light-handed regulation is seen not to work very well – Indeed, the government has recently strengthened its position, threatening to regulate the ‘wires’ business (it is suspected that the electricity industry is moving towards a CPI-X regime but there is still debate on whether this will apply to the wires business only or whether other businesses also need some oversight) (Everett 1999).

39 Since corporatisation, some distributors have followed the privatisation route while others remain under trust ownership – i.e. the shares are owned by the public with a public trust managing it. The central government has retailed ownership only of ECNZ and TransPower.
4.4.2 DSM investment in a regulatory vacuum

Until ECNZ was split up in 1995, all suppliers essentially had an equivalent cost of supply. While restructuring initially resulted in a strong incentive for ESAs and electricity traders to maximised sales, distributors were somewhat limited in terms of being able to differentiate retail prices (because there was no competition in generation). The result of this was that competition became based primarily on non-price factors such as customer service. Several suppliers used efficiency services as a mechanism for differentiating themselves. While no documentation can be found to support this view, it is likely that when competition was introduced into generation, service differentiation may have shifted to becoming price based.

In 1992, as a direct consequence of government policymakers' ongoing recommendations for the need for publicly funded energy-efficiency programmes, the Energy Efficiency and Conservation Authority (EECA) was established. The EECA is an independent government agency (officially, a division of the Ministry of Commerce and responsible to the Minister for Enterprise and Commerce) and is responsible for encouraging energy efficiency and conservation strategies within New Zealand. The primary objective of the EECA is to achieve governmental energy and environmental policy goals, particularly with respect to CO₂ emission reductions. Its programmes are designed to help overcome barriers to energy efficiency by informing the public and private sector about opportunities that improve the efficient use of energy, enhance the uptake of renewable energy sources and have positive environmental impact.

The programmes of the EECA range over most sectors and levels of energy use. On a policy and regulatory level, EECA is mandated with ensuring that all government policies enhance energy efficiency. As examples, EECA assisted EMCO in planning for energy efficiency aspects related to the development of the wholesale electricity market. EECA has also made submissions to the Ministry of Transport on land transport pricing and light vehicle strategies, and to the Ministry of Environment on strategies to reduce carbon emissions. Spearheaded by EECA, an Energy Efficiency Bill, defining the place of energy efficiency in environmental and energy policy and development, is currently being considered by Parliament. EECA has made significant progress in developing and/or revising energy efficiency standards in residential and commercial buildings, and minimum energy efficiency standards for a range of appliances and equipment. On an operational level, the EECA has developed a series of co-operative programmes on energy usage by agreement with industry (Energy-Wise Companies), with government (Government Leadership Programme) and with energy industry contractors (Energy-Wise Contractors). The Crown Loan Scheme has enabled local authorities and many hospitals to upgrade their energy equipment. The Energy-Wise Practice programmes seek to service the Energy-Wise Companies with practical engineering and management advice. Finally, the Energy-Saver programme and fund, intends to accelerate the adoption of residential energy efficiency through awareness seminars and financial assistance to groups with effective energy efficiency projects. Residential energy use knowledge is updated by the EECA in collaboration with the Building Research Association of New Zealand and the Industrial Research Limited (Bridger 1999; EECA 1999).

One of the EECA’s key tools is the establishment and facilitation of networks. These networks link energy professionals and experts as well as provide room for extensive discussion and information dissemination on energy efficiency and renewables.

Originally, EECA was to be funded through a ‘wires’ charge levied on all customers. Due to the complaints from business consumers and marketers, the wires charge was re-designed to apply only to residential customers. It was then abandoned altogether as political pressure mounted. EECA is now funded entirely through general-purpose tax funds. During the period 1995 to 1998, $NZ 8.45 million was allocated to the EECA. EECA continues to struggle for funding — indeed, in recent years, its funding has declined significantly. As a result of this, the

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40 EECA’s funding, as noted emanates from a general purposes tax. It is allocated in two different ways: through baselines and new initiative funding using discretionary money in each year’s Budget. Because it
organisation notes that it will have to increasingly attract funding from both the public and private sectors by demonstrating the tangible benefits of its services (Everett, 1999b).

During 1997, an independent review of EECA’s activities was commissioned. The review found that core EECA activities such as information programmes, commercial and industrial partnerships and the Energy Saver Fund are highly regarded by intended audiences, but smaller programmes have questionable benefits (Everett, 1999b). It has also been noted that the EECA has been very successful in developing the energy efficiency and renewables network in New Zealand, though less successful in stimulating ESCO activity (in fact, it has been contended that in seeking to stimulate activity by energy service companies (ESCOs), EECA may have simultaneously been competing with young ESCOs (Swisher 1994), and thus simultaneously crowding out potential investment).

In addition to the investments made by EECA, a few ESAs (including South Power and Trust Power) have implemented DSM initiatives targeted at avoiding transmission and distribution capital investment. For example, in Christchurch and Orion, the lines companies use a system of ‘control periods’ and penalty pricing to deal with its winter peak demands (Everett 1999). In residential markets, some utilities offer time-of-use tariffs and ripple control. In addition, some utilities, through purchase of interest in LPG businesses, are encouraging fuel substitution (generally away from electricity to other fuels). In the commercial and industry market, some ESAs offer audit services and feasibility studies, time-of-use tariffs, assistance with the installation of energy efficient industrial equipment, software packages programme according to customer specification, and load shedding facilities on behalf of TransPower (King et al 1996). There is not much evidence of a move to value-added energy (efficiency) services in the mass market — and it is perhaps more likely that the way electricity retailers add value to their products is to enter into arrangements with other service providers. One retailer, for instance, recently employed a discounted joining fee to Sky digital TV as a hook for switching customers (Everett 1999).

As noted, in the past few years, the distribution industry has been reformed and changed dramatically. As a result there is not much scope for them to consider anything other than core ‘boardroom’ business including survival, ownership changes, mergers, market share, etc. Relations with EECA are said to be cordial but not substantive.

4.5 Brazil: ‘Progress threatened by restructuring’

Prior to restructuring, the Brazilian electricity industry was dominated by Eletrobras — a state-owned utility responsible for generation and transmission. In addition to Eletrobras, other utilities — some vertically integrated, others not — existed.

4.5.1 Privatisation for economic efficiency

Broadly, Brazil’s electricity industry reform involves the transfer of ownership of electric utilities from the public to the private sector. Restructuring began in Brazil with changes in the legislation to allow for the concession of electricity services to private entrepreneurs. The privatisation process has been delayed many times for political reasons but, importantly, in 1994 the first utility — serving Rio de Janeiro — was sold to Electricité de France. Since then, several states have privatised their distribution utilities (it is estimated that approximately 40% of all distributors are now privatised). Some generating companies are currently being sold. Eletrobras is still the major public generating company. Currently there is no competition amongst utilities which all operate in franchise areas within the country. Four years after the
privatisation process was initiated in Brazil, a national regulatory authority (ANEEL) was established (Jannuzzi 1999).

4.5.2 DSM investment shaped and driven by a utility

The concern with the efficient use of electricity in Brazil began in the mid-eighties. Led by the power sector, the objectives were to reduce the need for new investments due to power sector financial problems. Consequently, the government of Brazil established PROCEL in December 1985. PROCEL funds or co-funds conservation projects carried out by state and local utilities, universities, state agencies, private companies, and research institutes. These projects involve research and development, demonstrations, education and training, marketing, direct installation of conservation measures, support of ESCOs, development of legislation, and DSM programmes. Also, PROCEL helps utilities obtain low-interest financing for major energy efficiency projects from a low-interest loan fund within the electricity sector. PROCEL is managed by an Executive Secretariat subordinate to Eletrobras (Jannuzzi, Geller & Schaeffer 1997).

During its initial years (1986 to 1993), PROCEL spent a total of about US$24 million on over 100 projects. PROCEL also received an equivalent amount for staff, overheads, and travel from Eletrobras. However, Brazil’s electricity sector experiences severe financial difficulties during the early 90s (low electricity prices, high debt, and economic recession). Between 1990 to 1992, PROCEL’s activities, with the exception of some load management initiatives, were significantly downscaled. From 1993, PROCEL started to regain its momentum. This growth has continued through 1995/6, when its core budget of grant funds and staff support increased to around US$10 million per year. In addition, PROCEL arranged about US$21 and US$42 million for utility energy efficiency projects in 1995 and 1996 respectively (Geller, Jannuzzi & Schaeffer 1997; Jannuzzi, Gouvello & Cauret 1998).

It is estimated that PROCEL can take credit for about 790 GWh per annum of electricity savings due to actions in 1996 alone and about 2,360 GWh per annum of electricity savings as of 1996 based on cumulative actions. This is equivalent to about 0.9 per cent of total annual electric consumption as of 1996 (Geller et al 1997). Interestingly, savings from PROCEL actions in 1996 were estimated to be about four times as large as the savings achieved in 1993. This increase is attributed to the rapid growth in PROCEL’s budgets, projects and influence, as well as the cumulative impact of working in some areas for more than a decade (Geller, Jannuzzi & Schaeffer 1997).

In designing its programme of action, PROCEL has attempted to reduce barriers to investment in energy efficiency. A number of the barriers prevalent when PROCEL was established have been reduced. It has been argued, however, that much more can be done to reduce these barriers. There are no regulations, for instance, requiring the adoption of efficiency standards. Neither are there building codes demonstrating good building practices. While many ESCOs have begun operating, there is little experience in performance contracting so most projects are client-financed.

As restructuring goes ahead in Brazil, it has become clear that governmental focus has been with the privatisation directly, and that energy efficiency has been neglected. Even though provision for energy efficiency was made in privatisation legislation, PROCEL budgets are continually being re-assessed. Indeed, some energy-efficiency activities have been suspended or terminated, and staff working on DSM has also been reduced.

Even though privatisation legislation includes a clause calling for the setting aside of 0.25 per cent of annual utility revenue for investment in end-use conservation projects, this has not yet materialised. State and local utilities currently do undertake some DSM activity though this is primarily aimed at reducing peak load in specific regions in order to postpone new investment in transmission and distribution networks. For the most part, Brazilian utilities conduct token energy efficiency programmes. It has been argued that this is primarily due to a lack of experience, inability to recover programme costs, and concern about the reduction in sales.
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revenue. Federal regulations do allow utilities to recover DSM costs in tariffs: in practice, however, this is not occurring. This is complicated by the difficulties utilities find in recovering the net loss revenues or receiving a portion of the societal benefits generated by their DSM programmes.

4.6 Ghana: ‘Putting DSM on the agenda before restructuring’

4.6.1 Encouraging private sector investment

The development of the Ghanaian energy sector, particularly the power and petroleum sectors, has traditionally been concentrated in the hands of the government through state-owned enterprises which have focused their activities on the production and supply of energy. Ensuring efficiency at the end use level has not received much attention.

In 1995, however, the government of Ghana embarked on an energy sector reform process to introduce and encourage private sector participation in the energy sector. The reforms include, ultimately, the removal of price subsidies and the introduction of competition in the supply and distribution of energy, primarily through the institutionalisation of statutory and regulatory processes.

In 1997, two milestone Acts of Parliament were introduced to establish the Public Utilities Regulatory Commission (Act 538), which charges the PURC with the setting of tariffs and the regulation of power utilities. The Energy Commission Act (Act 541) also empowers the Energy Commission to licence energy sector operators like utilities and petroleum and gas pipeline operators and marketing establishments. In line with the government policy of encouraging the private sector to actively participate in the development of the energy sector and building local capacity in the private sector, the Ministry of Mines and Energy has re-directed its efforts at developing that sector to execute energy efficiency projects on its behalf.

4.6.2 DSM initiatives supported by government

In 1997, the Ministry of Mines and Energy in collaboration with the Private Enterprise Foundation (PEF) established the Energy Foundation, mandated to promote energy efficiency and conservation, sustainable development of energy and protection of the consumers from the inefficiencies of the utilities. Specific objectives of the Energy Foundation are:

- to promote sustainable development of energy resources and efficient consumption of energy in all its forms;
- to educate consumers through publicity campaigns, educational programmes and seminars about their rights and responsibilities, the benefits of reducing energy waste, and assist residential, commercial and industrial customers in improving energy efficiency;
- to advocate for policies that address customer service issues and promote national policies for the sustainable development of the energy sector and the adoption of energy-savings technologies;
- to strengthen the private sector, to improve economic productivity by developing energy efficiency, renewable energy and productive uses of electricity programmes and businesses;
- to undertake other energy related research and development activities for itself and on behalf of other entities.

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The PEF brings together the major consumer groups including the Association of Ghana Industries, the Ghana Chamber of Mines, the Ghana Chamber of Commerce, the Ghana Employers Association, the Federation of Associations of Ghanaian Exporters and others.
Under a co-operation agreement, the Ministry has transferred its role in the promotion and execution of energy efficiency programmes to the Energy Foundation. Under this agreement, the Energy Foundation is responsible for projects previously administered by the Ministry including the management of the Electricity Demand Management Project, and the promotion of energy efficiency among customers and other demonstration projects. This leaves the Ministry to concentrate on policy formulation activities.

Since its establishment, the Energy Foundation has undertaken a number of activities aimed at educating the public on measures that can be undertaken to improve the efficiency of energy use at the national level. Some of the activities include national-level workshops on energy efficiency in industry, commerce, buildings and domestic appliances; load management in industrial zones to mitigate effects of the 1997/8 power crisis; site visits to advise on electrical load management and other energy related issues; monitoring and targeting energy management in industry; and public education campaigns to educate the public in methods and technologies that can be used to reduce energy waste.

4.7 Chile and Argentina: ‘DSM gets lost’

4.7.1 Pioneering the restructuring wave

The first experiment in transforming a government-owned and -operated power industry began in Chile in 1980. A 1982 law restructured the sector and defined the basic regulations, and utilities were privatised between 1986 and 1989 after financial and corporate restructuring. The sector had been operating fairly well, but was reformed as part of a broader rationalisation of the economy. In Argentina, by contrast, the market-based structure and privatisation introduced in 1992 was intended to improve the efficiency and reliability of the electric system and to attract the substantial investment needed to upgrade the system (Lalor & Garcia 1996).

The ‘Southern Cone’ model underlying the systems in Chile and Argentina is now being applied elsewhere in Latin America, including Peru (starting in 1993), Bolivia (1995) and Columbia (1995). This model divides the industry into five functions - generation, dispatch, transmission, distribution 'wires' and distribution 'supply' - and re-regulates the utility systems at both the wholesale and retail levels. The wholesale portion of the model, fully unregulated, relies on open competition in generation. The model’s retail portion ensures direct access to generators for medium-size and large-users under freely negotiated contracts, and regulated prices for smaller customers (Lalor & Garcia 1996).

Now over ten years old, the reforms in Chile and Argentina show that large economic efficiencies can be realised through restructuring. By any standards, both systems have improved. There has been active entry by new generators, the quality of supply has improved and prices have fallen in real terms. The reforms have also demonstrated the effectiveness of having a central dispatch and clearing system dispatching power produced privately.

4.7.2 Limited interest in DSM

No regulatory or other incentives for public purpose energy-efficiency improvements and DSM have emerged from the restructuring process in Chile and Argentina. Common to the experiences of other countries, it has been argued that this is because the priority of these processes was firmly on achieving economic efficiency improvements (as opposed to energy efficiency improvements).

The Chilean utility, which is an integrated utility, has not strongly embraced DSM. Indeed, it is constructing a major hydroelectric dam despite the great controversy surrounding it, and evidence that DSM alternatives would prove significantly cheaper (Valdes-Arrieta 1993). Municipalities have, however, invested in a range of DSM activities, particularly commercial and public street lighting (Boyle 1996).

Interestingly, it has also been argued that, given the general 'deregulation' trend pursued vigorously by the multilateral financial community, the Argentine government lacks the ability
to reassert any regulatory influence in the name of system reliability, energy efficiency or environmental protection anyway (Swisher 1994). In consequence, nascent energy efficiency programmes in existence in Argentina prior to the course of restructuring, were mostly stifled by this process (Swisher 1999). Today, DSM is not present in utility practice in an explicit form. Instead, utilities undertake DSM and particularly load management activities only when it makes economic sense to do so.

4.8 Thailand: ‘So far, so good’

Until 1997, the Electricity Generating Authority of Thailand (EGAT), owned by the Thai Government, controlled all generation and transmission of electricity in Thailand. EGAT’s electricity was (and continues to be) sold to the two state-owned distribution utilities responsible for providing electricity throughout the country (Sargent & Lundy 1997; DuPont 1999).

4.8.1 Pending restructuring

Restructuring plans in Thailand include, broadly, the corporatisation and privatisation of EGAT, the introduction of competition into generation, and the formation of a power pool. While this process has been delayed a number of times, some progress has been made. EGAT has initiated the restructuring of its organisation into business units as called for in the Government’s plan for privatising the power sector. The new corporate organisational structure consists of business units for generation, the transmission system, maintenance, mining, engineering and construction management and operative units for hydro plants, policy and planning, accounts and finance, administration and new business ventures. The plan is for these business units to be spun off as separate companies wholly owned by EGAT, except for the Transmission System Business, which will remain with EGAT. To date, electricity industry restructuring in Thailand has also involved, from 1997, the introduction of some IPPs and small power producers (SPPs). 42 Thailand’s National Energy Policy Office (NEPO) recently contracted out a major study on the restructuring process. It is hoped that this study will speed up full scale restructuring (du Pont 1999; Janssen n.d).

4.8.2 Energy efficiency that has worked in the past but remains a question mark for the future

In 1991, the Thai government entrusted EGAT and its power distributors with undertaking DSM. Prior to this, no developing country had implemented a comprehensive, national, utility-sponsored DSM programme. A subcommittee chaired by the prime minister’s National Energy Policy Council (NEPC) co-ordinates the Thai DSM programme through the NEPO and the Department of Energy Development and Promotion (DEDP) (Surprenant n.d; du Pont 1998). The 5-year DSM Masterplan was passed by the government in 1991 but implementation only began in 1993. Seed funding for the programme totalled US$189 million, of which $15.5 million was a Global Environment Facility (GEF) grant, $25 million an Overseas Economic Co-operation Fund (OECF) of Japan soft loan, and the balance funded out of the Thai electricity tariff (EGAT collects the cost of its DSM programme expenditures by adding the costs as part of the regular tariff adjustment). The five-year programme was extended to six years (du Pont 1998).

The Thai DSM programme is considered to be one of the government’s most successful programmes. Most acclaimed are the projects promoting efficient lighting, refrigeration, and thermal efficiency in the residential and commercial/industrial sectors. Successful implementation techniques include voluntary agreements with manufacturers, nation-wide advertising campaigns, interest free loans, market transformation and appliance labelling. To date, the programme has exceeded its targets months before schedule. During the period 1992 to 1996, peak demand was reduced (as a direct result of the DSM programme) by 398 MW and

42 In Thailand, SPPs are limited to a generating capacity of 50 MW or less and a portion of their electricity has to be produced from renewables.
avoided nearly 500 000 tons of CO₂. EGAT has estimated that the cost of saved energy for all of its DSM programmes has been US$0.012/kWh, compared to EGAT's long run marginal cost of US$0.05/kWh.

It has been speculated that when the DSM programmes current funding runs out at the end of 1999, the DSM programme will then be funded by the existing energy conservation promotion fund, which comes from a levy on petroleum products (du Pont 1999). However, it is also widely speculated that EGAT is currently considering significantly downsizing its DSM programme, in line with restructuring processes.

5. Lessons for South Africa

In this section, a brief overview of the more important lessons in implementing current DSM programmes are overviewed. Section 5.2 seeks to illustrate what international experiences outlined in this review say of the prospects for DSM at various stages of restructuring. Finally, section 5.3 draws specific lessons for South Africa and other countries on how to ensure that DSM survives future restructuring initiatives.

5.1 Implementing DSM programmes: approaches for success

During the last 15 years or so, utility planners in the US and elsewhere have learnt important lessons about implementing successful DSM programmes. These have been widely documented. The following statements summarise some of the most important of these.

- **Enormous effort is required to establish DSM infrastructure.** Programme implementation can be severely delayed in establishing the required infrastructure to run a programme successfully. It is thus important to 'start early' and not to become dissuaded if progress is seen to be slow (du Pont 1999).

- **DSM programmes often have a low impact in early phases of implementation.** This can expand rapidly once lessons are absorbed and pilot programmes widened and replicated (Boyle 1996).

- **A champion is needed in the utility to aggressively promote DSM.** Most utilities are supply-side oriented to the extent that even if a level playing field between supply and demand side investment is established, the tendency will be for utilities to install new capacity. Hence the need for a person within the utility to drive DSM. It has been argued that this is one of the major reasons why the utility DSM programmes in Thailand, Brazil and Mexico have been as successful as they have been (Boyle 1996).

- **Application and participation procedures and requirements should not be burdensome on prospective customers.** Many DSM programmes have failed because these have been onerous, confusing and/or over technical (Calhoun 1994).

- **Extensive market intelligence or research is a key component of any DSM programme.** Lack of adequate market research and analysis can contribute substantially to the loss of customers and other longer-term sales. The 'competition' should always be considered.

- **State-of-the-art programme records must be maintained.** This is important for evaluation purposes as well as responsible programme management. Involving external staff to fulfil this function is often useful.

- **Utilities should communicate clearly and consistently with its customers.** Customers should be notified timeously about all programme progress and requirements.

- **Pricing alone may not be the key driver of energy efficiency.** The classical economist argument that people will invest in energy efficiency if the prices are right, is not borne out in many countries. Price signals need to go hand in hand with a range of other policy initiatives to lead to successful DSM (Boyle 1996).
• **Utilities should plan as much for success as for failure.** Both possibilities can occur and building on opportunity for corrections including early exit or project extension, should always be considered (Calhoun 1994).

• **Utilities should ensure that ‘large customer’ and/or ‘free-rider participation does not crowd out or discourage small customer participation.** Large customer participation should be limited/controlled so that adequate resources remain available to provide small customers with good service and support. To this end, exclusive services could be offered to each customer segment (Calhoun 1994).

• **Utilities should avoid long delays in the launch of DSM programmes.** This can result in a loss of market share.

• **If possible, the parameters outlining programme design and/or participation should not be altered.** If this is unavoidable, the ‘economics’ of the programmes should be re-evaluated.

• **Failure to consult with relevant manufacturers and suppliers can threaten the success of the programme.** Manufacturers and suppliers need to be made aware of the programme and aware of the technology requirements, in advance of programme delivery.

• **Regional/local programme offers should be uniform and well co-ordinated.** Opportunities for arbitrage should be avoided.

• **Proper pricing techniques should be employed.** Incentive payments (loans, rebates, etc) should be carefully evaluated so as to achieve maximum participation and benefit. Often it is unnecessary to offer substantial customer incentives: sometimes it is more beneficial to aim, with available resources, for wider participation.

• **DSM resources do not necessarily need to be treated equally with supply resources.** One of the major benefits of energy efficiency is that it can be achieved at a much lower cost than a supply-side resource.

Nadel & Geller (1996) show that different programme approaches have filled specific market niches. These are presented in Table 2. While it should be noted that these have been applied to the energy services industry in the United States, they are now proving to have far wider relevance.
### DSM programme | Appropriate/best niches
---|---
Load management | Peak reduction; utilities concerned with the RIM test
Information audits | Provides customer service and contact; useful complement to incentive programmes
Labelling | Residential new construction in areas where prevailing construction practices are not very efficient
Rebate | Element in market transformation strategies; areas where DSM savings are needed quickly
Loans and leasing | Customers lacking capital; retrofit and new construction where longer lead times are acceptable
Performance contracting | Institutional customers and other large customers lacking capital; utilities looking to transfer performance risk to third parties
Comprehensive/direct installation | Low-income customers and other hard to reach customer segments; areas where substantial DSM savings are needed quickly
Market transformation | Equipment replacement and new construction measures; where savings are needed in the long-term.
Demand-side bidding | Utilities without expertise/human resources to implement programmes on their own; utilities looking to transfer performance risk to third parties.

Table 2: Summary of lessons learned on appropriate market niches for different DSM programme approaches


### 5.2 Prospects for DSM at different stages of restructuring

A sequence of models illustrating electricity industry restructuring processes in industrial and developing countries was described in section 2 of this review. Generally but not always, restructuring has involved a change in industry ownership (from public to private sector), and/or a change in industry structure (from monopoly to competition, as well as different regulatory regimes). The common goal behind these processes has been to achieve a greater degree of economic efficiency within the energy sector. As has been shown in the country case studies presented above, energy efficiency has generally not been identified as an important goal of these restructuring processes, even though in many cases it was prioritised in pre-restructuring periods. In fact, in most of the countries this review visits: (i) the restructuring process has given relatively little serious attention towards ensuring that investment in energy efficiency is maximised; and/or (ii) DSM programmes that existed prior to restructuring have now been down-scaled, sidelined, or 'crowded-out'.

'DSM' first emerged in North America. From the late 1980s onwards, investment in DSM in the United States increased substantially. For the most, this was because it was driven by federal and most state regulatory frameworks. Global restructuring initiatives have not involved a corresponding trend towards this proactive regulation that facilitated the adoption of DSM in the United States. As competitive pressures are introduced into the electricity system in the United States, investment in DSM has also declined significantly. It is now widely recognised that this reluctance towards allocating resources to DSM has occurred for the following two main reasons:

- Restructuring generally tends to fragment the market such that it is difficult to identify a major participant in the electricity market (supplier, distribution, customer or other) that perceives both the (potentially high) long run marginal costs of new supplies and the possibility of investing in energy efficiency improvements (Swisher 1994).
Restructuring seeks to harness competitive forces to improve the economic efficiency of the system. Achieving this goal makes it more difficult for players in the industry to invest in energy efficiency programmes and remain price competitive.

International experience shows that restructuring processes affect DSM investment differently and to varying degrees depending on the extent to which the sector is re-organised (and perhaps most importantly, the extent of competition). The various potential impacts can be described in terms of the restructuring models presented in section 2 of this review.

Where electric utilities are vertically integrated monopolies – as in Model 1 – DSM investment is more easily justified because of the clear institutional benefits associated with deferring new investment in the generation and transmission component of the utility business. This has certainly proved to be the case where there are capacity constraints within the system. The extent to which energy-efficiency initiatives will be administered also depends on individual utility-customer contracts, as well as on how the natural monopoly treats public interest issues, and the extent to which the monopoly takes responsibility for these issues.

In Model 2 – where independent power producers sell electricity to a single buyer, and where there is no competition in distribution – investment in DSM is generally less easily justified but certainly still viable. DSM benefits arising from individual IPPs’ DSM efforts would most likely be split between all IPPs. Hence the incentive to invest in DSM decreases. To defer investment in new infrastructure, transmission may choose to incentivise DSM investment on the distribution level. Distributor utilities may also choose to initiate DSM as a result of new pricing arrangements (i.e. resulting from a move towards marginal cost pricing). This would be feasible because distribution utilities continue to have a monopoly over sales to final customers, who have no choice of supplier, and therefore of price. In Model 2, generally, DSM activity would tend to focus on load management activities and away from public interest energy efficiency programmes. Model 1 and 2 are illustrative of the restructuring stages of many developing countries including Thailand, Brazil and Ghana, where the full impact of restructuring on utility-sponsored DSM programmes is still to be felt.

In an electricity industry context illustrated by Model 3 (i.e. where there is wholesale competition), generators compete against each other to sell electricity to a power pool, or generators sell power directly to large customers. Contractual agreements between generators and large customers can make provision for DSM where necessary. In this instance, DSM benefits would no longer accrue to all generators but would be shared only amongst contracting parties. Transmission may continue to incentivise DSM investment where appropriate. Distributors may or may not choose to initiate DSM activities in response to the price at which they purchase power from the pool. Indeed, as occurred in England and Wales, distributors not wishing to purchase power from the pool at marginal costs may choose to commission their own generation facilities. In this instance, patterns for DSM investment then follow those described by Model 1. Because, in this model, distributors still do not compete against each other, there is some room for the costs of DSM programmes to be passed on to the franchise customer. As illustrated conclusively in the United States, United Kingdom and elsewhere, DSM investment in a Model 3 context is also significantly reduced by the perceived threat of the
The introduction of retail competition: distributor utilities cannot risk investing in programmes which may later become stranded.

As demonstrated in Norway, the United Kingdom, New Zealand, United States, Chile & Argentina, DSM is most threatened by an electricity industry described in Model 4. This is primarily because companies distributing electricity must be extremely cautious about losing customers to competing distributors, especially non-participating customers harmed by tariff increases resulting from DSM programmes. While long-term contracts between generators and distributors or between distributors and their customers can make provision for some investment in DSM, in the context of Model 4, government stimulation of the energy service industry is especially important.

Internationally, restructuring processes have not always followed the sequence of events described by these models. In New Zealand, for instance, competition was introduced into the distribution sector prior to generation sector. During this transitional period, the level of investment in DSM notably increased. Interestingly, this offer of energy efficiency services was a way some distributor utilities could differentiate their product from the products of their competitors.

While the discussion above has focused on restructuring processes that have brought about changes in the structure of electric utilities, it is also important to address the impact changes in industry ownership have had on investment in DSM. As illustrated in section 1.3, the trend has been for the ownership of electricity industries to move from the government arena to the private sector. While ownership rests with government, energy efficiency programmes are justified because they are seen to enhance the social good and thus lie within the realm of government. When ownership is transferred to the private sector, those energy-efficiency DSM programmes are either required by the regulatory authority, are used as a way of differentiating a product in a market supplying a homogenous good, or simply cannot be justified because of their impact on the utility's bottom line. Interestingly, experience from New Zealand and Sweden indicates that perhaps the most undefined and/or precarious period for DSM is when the electricity industry is corporatised in preparation for privatisation. In this environment, the new monopoly is not subject to competitive market pressures or public oversight via binding regulation (Swisher 1994). In this context, the provision of 'social benefits' or public purpose goods are generally also minimised.

Around the globe, it has been demonstrated unambiguously that DSM yields important benefits to society. Now international experience has shown that this public good could be at risk. Through visiting specific contexts, this study has sought to observe other countries’ successes and problems in this field. Lessons on how investment in DSM can be maximised, which South Africa can benefit greatly from, are listed below. It should be noted that these guidelines pertain to utility administered DSM programmes, and not to the energy and load-shape changes arising neither from the normal operation of the marketplace nor from government-mandated energy-efficiency standards, codes and norms.

5.3 Guidelines for South Africa from the international arena

5.3.1 In competitive electricity markets, the spectrum of economically viable utility-induced DSM investment narrows significantly

As defined earlier, DSM involves all activities which plan and implement activities designed to influence the time, pattern, and/or amount of electricity demand in ways that increase customer satisfaction, and co-incidentally produce desired changes in the utility’s load shape (see section 3.1.3). This means that DSM includes 'interruptibility', 'load shifting', 'strategic growth' and 'energy efficiency' options. International experience shows very clearly that where it pays...
utilities to undertake interruptibility, load shifting and strategic growth activities, such investment will occur. Usually, this includes:

- programmes that ensure customer retention i.e. provide competitive advantage through DSM as a customer service option;
- programmes which are profitable in their own right – that is, DSM services which customers are prepared to pay for;
- programmes which cost effectively defer or limit generation and/or transmission and distribution capital expenditure and hence improve profitability (though due to poor systems information these opportunities are often not identified or not costed properly);
- environmentally-driven programmes as committed by national and regional governments or financed by international agencies (Surtees 1998).

Generally, this type of investment occurs irrespective of the threat of pending competition, or new market structures and ownership arrangements. Indeed, in certain circumstances, the move to new market and ownership arrangements can encourage investment in these forms of DSM. The case for energy efficiency DSM options is more complex. This is because energy efficiency options tend to reduce overall kWh sales and not only those at peak periods (household electricity use for lighting may be an exception to this). This result, generally, goes against the business objective of utilities which wish to maximise kWh sales. Thus, utilities’ investment in energy efficiency initiatives are chosen on a very selective basis and, more often than not, are undertaken for the good of the utility and not necessarily for society as a whole.

Internationally, state-owned vertically integrated monopolies supplying power to franchise customers have tended to invest more in energy-efficiency DSM options than have unbundled utility companies. This is because the driving factor for distributor utility companies operating in competitive markets is to distribute power at the lowest possible price. These utilities cannot justify the risks associated with paying for the costs of public interest energy efficiency programmes that could also reduce kWh sales. Thus, in the context of competitive markets and the absence of regulatory or legislative frameworks, the spectrum of DSM options, which are economically viable utility investments, narrows significantly.

5.3.2 The public sector’s role in encouraging optimal investment in energy efficiency is critical

International experience indicates that without ‘some degree’ of public sector involvement it is unlikely that DSM (aside from DSM that demonstrates unambiguously that it will save on new investment in transmission and/or distribution investment, that is), will be given the go-ahead. This means that other DSM programmes such as information and education programmes, customer support services (including audits and demonstrations) and market transformation programmes will most likely be avoided. Thus, the role of the public sector is to create an ‘enabling environment’ that allows investment in this societal benefit to occur but without economically prejudicing the implementing agency (i.e. distributor utility, ESCO or other).

This enabling environment has been created either through legislative or regulatory action or through the public sector establishment/support of an organisation that ‘champions’ or promotes DSM. In Norway and Denmark, for example, the governments have enacted legislation that requires utilities to undertake a specified level of DSM. In Denmark, the Danish Parliament seeks to achieve this by requiring that all utility decisions are founded on principles of IRP. In Norway, the Energy Act (1991) initially included an obligation to undertake IRP. Against much resistance, this obligation was later removed although the Act still mandates distribution utilities to undertake some DSM. In both of these instances, the obligations are being met, although in Denmark the willingness on the part of utilities to do this seems greater. This is perhaps due to the fact that the Norwegian government plays a far more passive role in the electricity market than the Danish government does.
Regulation, which often complements or supports a legislative framework as well as allows for a greater degree of public involvement and pragmatism, has been widely used to ensure investment in DSM. The regulatory framework utilised in the United States for this purpose is illustrative of this. In fact, the impressive levels of DSM investment in the US are almost entirely attributed to this framework. In England and Wales, OFFER (the regulatory authority) was initially reluctant to make direct provision for DSM. Very little investment in DSM was consequently made. In response to this situation, OFFER published the Standards of Performance and retained the services of the Energy Savings Trust. DSM targets are now being reached.

The public sector can also create an ‘enabling environment’ through the establishment or support of an independent or dedicated organisation that seeks to promote DSM. These organisations tend, generally, to support prevailing legislation and regulation. This was done fairly successfully in England and Wales, and in New Zealand. It is perhaps too soon to assess the impact of Ghana’s Energy Foundation.

The tools described above facilitate investment in DSM. International experience shows that DSM does not necessarily fail if each of these different tools are not employed. In New Zealand and Denmark, for example, the electricity utilities are not subject to the requirements of the regulatory authorities but at the same time abide by prevailing legislation. Adequate DSM investment is being achieved. International experience does indicate that if there are no legislative or regulatory guidelines, or champion agency for DSM, it is very likely that public interest DSM investment will fall by the wayside. This is what appears to have happened in Chile and Argentina and is threatening to happen in Brazil.

5.3.3 ‘Rules of the game’ should be established prior to restructuring and, ideally, should be ‘right from the start’

If key roleplayers in the electricity sector are in any way uncertain about the direction or end-point of restructuring (and in particular, if retail competition is to be introduced or not), utility programmes delivering DSM services will be among the first to be downscaled. This has been the experience in a number of countries including the United States, United Kingdom and Norway. To avoid this dis-investment in DSM, it is important therefore that the end-point, goals and boundaries of the restructuring process are well defined prior to the commencement of the restructuring process. Furthermore, it is important that, early on, government and the regulatory authority define the role or place for DSM investment in the coming context (whether it is viewed as being an important outcome of the restructuring process or not). In other words, government’s approach to fostering the DSM context, whether it be through legislation or regulation, should be timeously announced. For the sake of industry stability, this should preferably be agreed upon prior to the ‘game beginning’. It should be remembered that establishing the regulatory (as well as human and physical) infrastructure for the electricity industry in general as well as for energy efficiency programmes more specifically is a formidable challenge which if not addressed timeously can delay the restructuring progress as well as DSM programme implementation for years.

In many of the countries this review has visited, regulatory and legislative frameworks have changed fundamentally over small periods of time since restructuring processes have begun. Examples of this include the following:

- In the early days of privatisation in England and Wales, the regulatory authority’s hands were somewhat tied. While OFFER was mandated with ensuring low energy prices, it was also given the responsibility of caretaking DSM investment. OFFER initially chose to adopt a fairly passive approach to DSM, contending that the market forces would result in an optimal amount of energy efficiency. As already mentioned, with the introduction of restructuring in England and Wales very little DSM investment occurred. It became increasingly obvious that OFFER would have to intervene if DSM were to survive. OFFER thus published the Standards of Performance and retained the services of the Energy Savings Trust which now represent the key drivers for energy efficiency in England and...
Wales. The early days of privatisation also saw a change in regulatory approach vis-à-vis DSM. Initially, the price cap mechanism provided distributors with strong incentives to maximise electricity sales with no associated mechanisms to claim DSM programme costs. Later, volume sales were decoupled from profit and provision was made for a special revenue allowance to be used for DSM activities.

- Traditionally, the regulatory framework in the United States was based on a cost-of-service approach for both supply and demand-related investment. When DSM was first introduced, state regulators generally allowed utilities to recover the cost of DSM programmes through general tariff increases. For profit-making purposes, it still made sense for utilities to maximise their sales, and thus to avoid DSM investment. In consequence, state regulators moved towards, not only removing the disincentives to invest in DSM, but also offering additional incentives for DSM. Supply-side investment continued to be treated on a cost-of-service basis.

- In Norway, the legislative framework originally called for utility decisions to be based on IRP principles. Due to extensive pressures from business and then the residential sector, this requirement was later diluted – requiring utilities to undertake a specified amount of DSM.

These and other country's experiences have shown that it is very difficult to rectify regulatory and legislative processes already in motion. Generally, amendments to legislative and regulatory frameworks take time to occur and are costly. Most importantly, changes usually create uncertainties and confusion in the market, they often do not improve the regulator or governments credibility record, and they slow the restructuring process down. These changes may even absorb a portion of the economic gains expected of the restructuring processes. In learning from these international pioneers, South Africa is in a promising position to ‘get the rules right before the game begins’.

5.3.4 Regulatory reforms can dramatically and rapidly change the strength and scope of utility DSM programmes

In some countries, regulators have chosen to ‘command and control’ utilities’ investment in DSM. According to this approach, the regulator specifies what the utility should do. The regulator then closely monitors subsequent utility actions for compliance. The way in which this approach has been most commonly administered is through licence requirements. To allow firms to operate the distribution/transmission network, or distribute electricity regulatory, regulatory authorities have required that a given amount of DSM activity be implemented. This mechanism is used in Norway, for example, where distribution utilities must undertake to inform customers about the electricity product as well as opportunities for efficiency. In Norway this regulatory requirement is combined with a DSM tax on all kWh sales which funds the information activity either by the utility or by a utility-sponsored organisation.

With very few global exceptions, the command and control approach has not encouraged any more DSM investment than is officially required by the regulatory authority. With little business business incentive to undertake DSM, utilities have often sought to manipulate the regulatory requirements, undertaking customer retention activities under the guise of DSM information and marketing campaigns, and making windfall profits. This has resulted in the establishment of unavoidable and impressively costly ‘DSM verification’ infrastructure. This has been the case in England and Wales, as well as in Norway. Hence, the move in the United States a few years ago towards providing economic incentives to utilities that run exemplary DSM programmes.

In the early days of DSM in the United States, England and Wales, electric utilities were encouraged by the prevailing regulatory regimes to sell more electricity. To address these DSM investment barriers, various regulatory mechanisms have been applied. In the United States, utilities were initially subject to traditional cost-of-service or rate-of-return regulation which discourages utilities from pursuing customer energy efficiency programmes because: (i) utilities may not recover DSM programme expenses when these expenses have not been included in some previous tariff-setting process; (ii) utilities may lose revenues from sales not made because
of the success of customer energy-efficiency programmes; and (iii) utilities may forgo earnings opportunities because resources are devoted to DSM programmes rather than to other profit making activities (Nadel et al 1992). To remove the disincentives associated with traditional rate-of-return regulation, US regulators sought to decouple utility sales from revenues and profits, and/or employ new lost revenue adjustments. To offer additional incentives to invest in DSM, shared-savings, bonus and market-up mechanisms were introduced (see section 3.1.3 for more detail). Experience with a combination of additional incentives and decoupling in many states of the US has shown clearly that regulatory reforms can dramatically and rapidly change the strength and scope of utility DSM programmes (Hirst & Blank 1994).

In England and Wales, distributor utilities' activities were initially subject to a performance-based price cap mechanism, which again, discouraged investment in DSM. As a result of poor ensuing investment performance in DSM, OFFER sought to partially decouple utility sales from revenues and profits. OFFER also introduced the Standards of Performance, and made provision for a revenue allowance to be collected and used to finance utility DSM programme activity. Interestingly, very little of the REC's own money has been spent and most of this has been on 'passive' services - that is, call centres, bill stuffers, etc, rather than actual or 'active' DSM (Thomas 1999).

Thus, while OFFER in England and Wales chose to partially remove the disincentives arising from the performance-based price cap mechanism, most regulators in the United States have sought not only to remove these investment disincentives but also to offer additional incentives to utilities investing in DSM. In other words, regulators in the United States have allowed utilities to profit from DSM programmes, while in England and Wales OFFER has permitted DSM programme cost recovery. As to be expected, more utilities have been willing to undertake DSM programmes in the United States than in England and Wales.

With pending electricity industry restructuring in the United States, spending on DSM has declined significantly, even though regulators continue to allow utilities to earn profits on DSM programmes. Utilities are now loath to invest in DSM because these investments translate into uncompetitive rate increases. In response to this, a number of state regulators have given initial indication that a non-bypassable systems benefit charge may provide a solution to this. All utilities would be obliged to collect a non-bypassable fee on a per customer or per kWh sales basis to fund a small amount of DSM activity. It is yet unclear whether utilities will be able to earn profits on these programmes: if utilities are not permitted to recover their costs, as well as additional benefits, it is likely that the same circumstances as have arisen in most other countries reviewed in this report will result - that is, only a minimal amount of DSM investment will be made.

5.3.5 It is unclear that utilities should continue to administer DSM programmes as they have done in the past

As explained in section 5.3.1 above, utilities will only voluntarily invest in DSM where it is financially viable to do so. In the absence of public sector intervention, DSM programmes incorporating 'interruptibility', 'load shifting', and 'strategic growth' activities are more likely to be invested in than 'energy efficiency' or public-purpose programmes. Experiences from all comers of the globe show that it is no longer obvious that utilities should be responsible for these energy efficiency programmes. On the one hand, it is argued that it is not a natural attitude of an electric utility to discourage in any way the use of electricity. Because utilities tend

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43 Treatment of lost utility revenues arising out of successful DSM programme implementation has received the most amount of attention in the United States, and elsewhere because this is generally where, in the short run, the largest negative financial consequence of a successful energy efficiency programme lies.

44 These responses correspond well with the regulatory approaches that the United States, England and Wales have adopted vis-à-vis DSM in competitive markets: federal and state regulators in the United States have played a major role in this area, while in England and Wales, OFFER has chosen to be more passive.
to give precedence to investments that are in their own self interest and not necessarily socially optimal, they are not best placed to orchestrate a diversified mix of resources for meeting the economy's electrical service needs at the lowest possible life-cycle costs. It is also argued, by virtue of the fact that utilities have not invested in energy efficiency programmes when more competition has been introduced, that utilities should not be responsible for these programmes at all. If energy efficiency programmes are viewed as yielding societal benefits, and therefore worthwhile investments for society as a whole, then surely a more reliable mechanism should be identified to ensure the provision of these particular services? Surely this would make it possible for utilities, consultancy firms and users to compete on delivering the best and cheapest energy conservation?

On the other hand, distribution utilities and supply utilities for large customers are in constant and automatic contact with end-users. They know who their customers are, know their energy consumption habits, communicate with them every month, and have well established payment collection mechanisms at hand, and are in a position to collect and analyse data. They are traditionally responsible for providing network energy services. They have the technical know-how and human, technical and often financial resources. They are therefore seen to be in a unique position to assist customers with energy efficiency. Many distribution and supply utilities are currently arguing that they want to undertake/administer energy efficiency programmes because they want to ensure that the 'right' messages gets across to their customers.

There is no conclusive answer to this. Countries have chosen to manage this dilemma in different ways. In the United States, regulators have required utilities to invest in energy efficiency programmes and have allowed them to profit from these programmes. This seems to work, although it should be noted that verification agencies have had to be established to ensure that utilities' activities genuinely lead to energy savings and are not just 'good on paper' or that utilities undertake the specific activities they receive incentives for. These verification activities have proven to be very costly, sometimes over 20 per cent of DSM costs. In an attempt to remove utilities' incentives to conduct anti-competitive behaviour, the Norwegian government strongly urges distributing utilities to transfer their energy efficiency obligations, together with the special revenue collected specifically for energy efficiency, to independent Regional Energy Efficiency Centres (REECs). The regulatory authority believes that these REECs are in a better position to offer objective advice than is likely to be provided by distributors. In the United Kingdom, OFFER has retained the service of the Energy Savings Trust to ensure that REC's investments in DSM comply with the Standards of Performance. In New Zealand, the government has established the Energy Efficiency Conservation Authority (EECA) to promote energy efficiency while leaving load management programmes to distributor utilities. Electrobras and EGAT in Brazil and Thailand respectively, have chosen to undertake energy efficiency programmes of their own accord, but it should be remembered that their restructuring initiatives are still in their infancy and it looks like they are threatening these utility initiatives.

5.3.6 Secured funding and independence are critical success factors for agencies/programmes dedicated to promoting energy efficiency

In Brazil, PROCEL was established to fund and promote energy conservation projects carried out by state and local utilities, state agencies, private companies and other research institutes. Over the last decade or so, PROCEL initiatives have gained considerable momentum, cumulatively achieving notable energy savings. These energy savings have been achieved, however, in direct proportion to the funding that Electrobras (the national generating and transmission utility) has allocated to it (PROCEL is managed by an Executive Secretariat subordinate to Electrobras). Practice has shown that when the electricity sector has been in financial crisis (i.e. sales are down), PROCELs budget and staff have been cut considerably. Conversely, when the outlook in the sector has improved, PROCEL's funding has been reinstated. Now that the electricity sector is being restructured, signs have already emerged that PROCEL's budget will be suspended once more. A similar situation has developed in Thailand, though their DSM programme has also been funded by the Global Environmental Facility.
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(GEF) and the Overseas Economic Co-operation Fund of Japan as well as through the electricity tariff and is therefore not as dependent on EGAT on funds as PROCEL is on Eletrobras.

This dilemma is characteristic of that faced by many energy efficiency programmes/agencies around the world. Programme activities are largely shaped by the strategic plans and perspectives of lead power sector utilities. Because of the problems associated with this, proponents of energy efficiency argue that these programmes or agencies should be made entirely independent and/or secure, or at least given more autonomy. In developing countries especially, DSM programme activities would probably not exist without the affiliation to and lifeline of utilities.

As electricity utilities are unbundled, the independence concern disappears to some extent. As shown around the world, with restructuring, it becomes less and less likely that utilities would support/fund programmes such as these. In New Zealand, when it became obvious that an 'energy efficiency service gap' was appearing, the government chose to set up the Energy Efficiency and Conservation Authority. The EECA is funded out of general purpose taxes, and is thus not directly dependent on utility funds. In Norway, Regional Energy Efficiency Centres have been established to undertake distributors' energy efficiency obligations. These REECs are funded by a DSM wires charge, so again are not entirely dependent on utilities' planning processes. In the United Kingdom, the Energy Savings Trust is funded by the Department of Environment, Transport and the Regions, although the special revenue allowance levied on energy sales for energy efficiency is still channelled through the RECs (distributor utilities). Originally, the utilities were expected to finance the activities of the EST. When the gas utility refused to do so government stepped in. Interestingly, it has been argued that the key to the success of Thailand's DSM effort was that a specific cost-recovery mechanism for the utilities (through a fuel-charge adjustment clause) was provided for up-front. Without this cost-recovery mechanism, full-scale implementation would have been delayed for years, as has been the case for DSM efforts in other Asian countries (du Pont 1998).

The agencies described here have been positioned quite differently. New Zealand's EECA seeks to promote energy efficiency in high-level government policy processes as well as 'on the ground'. The EST's main mandate is to act as an intermediary between OFFER and the RECs, ensuring that the latter's projects comply with the Standards of Performance. The Norwegian REECs undertake energy efficiency activities on behalf of the distributors. Thailand's energy efficiency programme promotes energy efficiency for the utility, EGAT, as does PROCEL for Eletrobras.

Key international lessons in establishing energy efficiency agencies/programmes are as follows:

- It is important for the energy efficiency agency to be given autonomy from other utility business – i.e. if possible, utilities should not directly influence the viability and nature of these agencies/programmes.
- Funding for the short term (at least five years) should be secured prior to the commencement of business. It is preferable that these funds come from either committed government or international funds, or through a wires/distribution charge. It is not desirable for utilities to fund these agencies at their discretion.
- The scope of activities of the agency/programme should be identified from the start, and should be focused on DSM objectives, rather than utility interests.

5.3.7 While very important, the ESCO industry cannot entirely replace utility-sponsored energy-efficiency programmes

As a greater degree of competition is introduced into electricity sectors around the world, and as the role of traditional utility DSM programmes becomes less clear (see section 5.3.5), it seems natural to assess the role of Energy Services Companies (ESCOs) in the newly shaped and rapidly emerging energy efficiency industry.
In the United States, various different types of ESCOs, which all seek to service the rapidly emerging energy service industry, have emerged. As illustrated in section 4.1.4, these include 'Vendor ESCOs', 'Contractor ESCOs', 'Engineering ESCOs' and finally, 'Utility ESCOs'. The first three types of ESCOs listed here work independently of utilities while 'Utility ESCOs' bid to serve as providers of utility-sponsored DSM programmes, and are paid by utilities to achieve guaranteed levels of MW and MWh savings (Shippee 1996). Interestingly, ESCOs' activities have all tended to be restricted to large commercial/industrial customers: because sales cycles in the ESCO industry are long and transaction costs are high, transactions have to be 'worthwhile'. Frequently, utilities and ESCOs compete to receive the rights to provide these services. Thus, importantly, energy efficiency services for the residential sector in the United States remain largely within the domain of distributor utilities (or government). As the electricity industry restructuring, and a non-bypassable systems benefit surcharge is possibly introduced, the distinct role for utilities and for ESCOs will become more evident. While it is widely agreed that the ESCO industry will not be an appropriate vehicle to administer public funds, it would make sense that ESCOs support utilities that could do so.

Other countries have also tried to foster the growth and development of the ESCO industry to assume a similar 'utility-supportive' role as has occurred in the United States. As yet, it is unclear though whether the impressive growth experienced in the ESCO industry in the United States would be achievable elsewhere. This is because the viability of many ESCOs in the United States has depended quite significantly on spin-off activities arising from utility DSM programmes. As competition is introduced into the electricity industry, spending on these programmes is now in decline. As similar restructuring processes occur in other countries around the globe, it is unlikely that the DSM wave as experienced in the United States during the '80s and early '90s could ever be replicated.

The Energy Savings Trust (EST) and the Energy Efficiency and Conservation Authority (EECA) have both been mandated to safeguard as well as promote energy efficiency in England and Wales, and New Zealand respectively. In establishing these agencies, these governments have officially recognised that energy efficiency services are valued by society, and that where new electricity industry structures have not naturally provided these services, government intervention would be necessary. In some respects, the activities and responsibilities of New Zealand’s EECA are viewed as being wider than those of the EST. While the services of the latter were retained primarily to oversee DSM investments made by the RECS but also to promote energy efficiency in general, the EECA undertakes many of the activities that RECs in the United Kingdom may have otherwise assumed. In other words, distributor utilities in England and Wales are expected to play a more active role in providing public purpose energy efficiency programmes than in New Zealand. This said, two of the main objectives of these independent agencies have been to (i) promote market transformation programmes which would completely alter the choice of technologies available on the market; and (ii) to foster the growth of the ESCO industry in the respective countries, such that the market would be able to service more of the societies' energy efficiency requirements. Both of these activities form part of a longer-term strategy of transforming consumer demand for energy as well as creating a vehicle to support this demand. Interestingly, in attempting to create a market for energy efficiency services, the EECA, and to a lesser extent the EST, have been charged with 'stunting' or 'crowding-out' emerging ESCOs!

The cases of the United States, New Zealand, England and Wales are illustrative of global attempts that have been made, primarily by the public sector, to establish a balance between utility-administered DSM programmes and initiatives led by private sector ESCOs, and in the cases of New Zealand, England and Wales, the contributions of independent energy efficiency agencies. The experiences of these countries illustrate that it is not easy to establish this balance but that it is important to try to do so. As suggested in section 5.3.5, it is no longer clear that utilities should continue to administer DSM programmes as they have done in the past. It is equally unclear that the ESCO industry should take on these programmes either. International
experience indicates that a collaborative effort to saturate the energy efficiency market is likely to be worthwhile.

6. Conclusion

International experience shows that, to have successful DSM, it is not necessary to have fully integrated utilities and heavy-handed regulation as has been the case in the United States in the recent past. Neither is it necessary to have expensive rebate programmes. Utility structure and ownership is important, but not necessarily fundamental to determining the success or otherwise of DSM. Where adequate policy and economic incentives to the utility and other actors in the investment processes are in place, DSM can occur in a widely varying range of circumstances. In the absence of removing DSM disincentives, or extending these to strong DSM incentives, a range of other measures would be needed to encourage DSM. Such measures could include minimum efficiency standards, building codes and regulations which emphasise energy efficiency, and procurement programmes opening up markets for energy efficiency products.

This review has visited a number of different countries that have sought to promote energy efficiency benefits in restructured electricity markets. This has been done through a combination of market forces operating within a supportive and selective framework of regulation and legislation, and/or through the establishment of independent energy efficiency agencies and national networks. The appropriate balance between these public sector interventions should be informed by the DSM market barriers pertaining not only to prevailing market barriers but also those likely to be introduced by restructuring.

As noted previously, this review represents the first in a series of reports emanating from a project which will ultimately deliver recommendations to the government, National Electricity Regulator, and Eskom on how to ensure that DSM is built into the restructuring process set to occur in South Africa. The second report in this series will investigate what the barriers inhibiting investment in DSM in South Africa currently are. Thereafter a series of scenarios describing possible electricity industry outcomes restructuring may bring about. An attempt will be made to assess which of the market barriers identified in the second report will remain as restructuring progresses as well as identify new barriers introduced by restructuring. The third report will also investigate what the prospects for DSM at each of the stages in these models could be. The fourth and fifth reports in this series will deliver recommendations on regulation, funding, institutional arrangements, and so on.
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APPENDIX

A brief explanation of regulatory approaches discussed in the review

Cost-of-service or rate-of-return regulation
According to this approach (which is widely adopted in the United States) tariffs are set so that the revenues from retail sales of electricity will cover the full costs of supplying that electricity, including generation, transmission and distribution costs, plus a fair rate of return on investment. New plant costs are not included into the tariffs until commercial operation when costs are placed into the 'rate base' and become part of the total cost of services to be recovered by the tariff. A crucial step in this process is the determination that costs are 'prudently' incurred and that the projects are 'used and useful'.

The drawback of this method is that it does not provide the regulated utility with any incentive to minimise costs. If a utility is guaranteed revenues sufficient to cover its reasonably regulated costs, and furthermore, if its efforts to reduce the costs result in a commensurate reduction in utility revenue, the utility has little incentive to reduce costs.

This approach allows utilities to recover DSM programme costs but discourages utilities from pursuing customer energy efficiency programmes because:
(i) utilities were not allowed to recover DSM programme expenses when these expenses have not been included in a previous tariff-setting process;
(ii) utilities lost revenues from successful customer energy-efficiency programmes; and
(iii) utilities lost earnings opportunities because resources were devoted to DSM programmes rather than to other profit making activities.

This approach is criticised because in allowing utilities to recover the cost of DSM programmes through tariff increases, it amounted to DSM programmes being funded through a broad tax on all customers, thus benefiting a particular group of customers at the expense of others.

Performance based regulatory approach
As part of an ongoing debate about competition in the electric utility industry, regulators are increasingly considering performance-based ratemaking as an alternative to traditional rate-of-return regulation. It is hoped that PBR will enable regulators to:
(i) provide more direct incentives for utilities to lower electricity costs
(ii) reduce the price disparities between high- and low-cost electricity producers, and
(iii) reduce the level of regulatory oversight of the electric utility planning process.

PBR mechanisms can be designed in a variety of different ways – each providing different signals and incentives to utilities. The mechanisms usually fall within two general categories: price caps and revenue targets.

Price caps
With price cap mechanisms, electricity tariffs are set up by the regulator at an initial level sufficient for the utility to recover its costs plus a reasonable profit. Over a certain period (e.g. five to six years), the utility would be allowed to increase its prices only to account for inflation, net of some allowance for increased productivity. If the utility can keep its cost increases below the net effect of inflation and productivity, then it can keep the difference as profits. If the utility’s costs escalate at a rate greater than inflation net of productivity, then its profits will suffer.
Price caps provide utilities with a powerful incentive to increase electricity sales, because additional units of sales will translate into additional profits, and lost sales will turn into lost profits. Therefore price caps create strong disincentives to DSM and incentives to promote load building. Price cap fixes allowed electricity prices for longer periods of time than generally occurs with traditional tariffmaking.

To partially remove this DSM disincentive, regulators in England and Wales initiated a ‘decoupling’ of volume sales from profits. According to this approach, the volume-related element of the revenue allowance was reduced by half for both supply price and distribution price cap mechanisms.

**Revenue targets**

With revenue targets, the regulator begins by setting an allowed level of revenues based on actual costs. Electricity prices are then derived from the allowed revenues and the expected level of sales. Over time, the allowed revenues can be adjusted to account for inflation and productivity, similar to price-cap mechanisms. If revenues deviate significantly from those forecast, the difference will be returned to, or recovered from, ratepayers through periodic adjustments. This reconciliation process differentiates revenue targets from price caps, and ensures that there are no windfall profits and losses due to unanticipated changes in sales. The reconciliation process is usually undertaken by way of a balancing account.

<table>
<thead>
<tr>
<th>Year</th>
<th>Expected price (R/kWh)</th>
<th>Expected sales (kWh)</th>
<th>Authorised revenue (Rs)</th>
<th>Price (R/kWh)</th>
<th>Collected sales (kWh)</th>
<th>Revenue (Rs)</th>
<th>Reported revenue (Rs)</th>
<th>% Error (Rs)</th>
<th>Balance account (Rs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRC1</td>
<td>Yr 1</td>
<td>0.100</td>
<td>1000</td>
<td>100.00</td>
<td>1100</td>
<td>110.00</td>
<td>100.00</td>
<td>10.00</td>
<td>(10.00)</td>
</tr>
<tr>
<td></td>
<td>Yr 2</td>
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<td>1000</td>
<td>0.090</td>
<td>990</td>
<td>89.10</td>
<td>100.00</td>
<td>(10.90)</td>
<td>0.90</td>
</tr>
<tr>
<td>GRC2</td>
<td>Yr 3</td>
<td>0.110</td>
<td>1010</td>
<td>0.111</td>
<td>1010</td>
<td>112.00</td>
<td>111.10</td>
<td>0.90</td>
<td>0.00</td>
</tr>
</tbody>
</table>

Table A1: Basic example of a balancing account
*Source: Eto, Stoft & Belden (1997)*

Assume that this mechanism operates in a region with a two-years general rate-case cycle and no other between-rate-case revenue adjustments. The basic mechanism requires three sets of numbers to track revenue and price. Columns A-C are established in the general rate case and remain fixed until the next general rate-case. Columns D-F represent what actually occurs during each year. Columns G-I represent the numbers that the utility reports in its income statements.

Year 1: General rate case no 1 (GRC1) authorizes revenue of R100 based on expected sales of 1 000 kWh. During the year, the utility sells 1100 kWh at R0.10 kWh, resulting in a collected revenue of R110. The mechanism ensures that the utility will only keep the authorised revenue of R100. Thus, - R10 is placed into the balancing account.

Year 2: Authorized revenue of R100 and expected sales of 1 000 kWh are still in effect from GRC1. In addition, the utility must return R10 to ratepayers from the previous year's overcollection. Accordingly, if the utility collects R90 this year, it will even with the ratepayers. So, the Year 2 price of R0.09/kWh is calculated by dividing the total revenue that the utility needs to collect (R90) by expected sales (still 1000kWh). However, in this case, the utility sells less electricity than expected, resulting in a collected revenue of R100, which covers the R89.10 collected from ratepayers this year, the R10 extra that was collected from ratepayers last year, and R0.90 that appears in the balancing account, representing money that the ratepayers will now owe the utility in Year 3.
Year 3: As a result of General Rate Case 2, authorised revenue has increased to R110.10 based on the expected sales of 1010 kWh. In addition, the utility is allowed to collect R0.90 from ratepayers because of the previous years' shortfall. Accordingly, it the utility collects R112 this year, it will be even with ratepayers. Thus, the Year 3 price of R0.11/kWh is calculated by dividing the total revenue that the utility wants to collect (R112) by the expected sales (now 1010 kWh). As it turns out, actual sales match expected sales, resulting in collected revenues of R112. The utility reports revenue of R111.10 for Year 3 and the difference in the balancing account (R0.90) means the utility has recovered the previous year's shortfall.

In the United States, regulators seek to achieve revenue targets through the use of net-lost revenue adjustments (NLRAs). These adjustments (used together with decoupling mechanisms) are intended to remove the disincentives associated with traditional rate-of-return regulation.

Decoupling sales from revenues and profits.

Regulatory tariff structures often link energy sales (kWh) with utility revenues and profits, which is a clear disincentive for the utility to engage in any DSM that reduces sales. As a means of overcoming this disincentive, regulatory authorities can design the rate structure such that the income to the utility is not dependent on sales volume (in kWh) but on some other measure of service (such as growth in number of customers). In other words, instead of letting revenues grow with increasing kWh sales, decoupling allows revenues to grow with other factors that are independent of changes in actual electricity use. Decoupling ensures that actual revenues exactly match an established revenue requirement, regardless of the sales level. Every decoupling mechanism consists of two parts. First, all decoupling mechanisms use balancing accounts to guarantee the exact collection of authorised revenues over time. Second, all decoupling mechanisms work in conjunction with an explicit method for changing the level of authorised revenue during years between general tariff reviews.

Net-lost revenue adjustments

NLRAs are designed to compensate utilities for changes in revenues associated with utility DSM programmes. To implement an NLRA, the utility first estimates the energy and load reductions caused by its DSM programmes for the year in question. These GWh- and MW- savings are then multiplied by the difference between retail price and short-term costs (both energy and capacity) and the two products (lost energy and lost capacity revenues) are added together. This sum is the net lost revenues caused by the utility's DSM programme. It is called 'net' because it is equal to the difference between the reduction in utility revenue minus the reduction in utility cost (fuel and variable O & M costs).45

Generally, decoupling is likely to be appropriate for utilities that run (or plan to run) large DSM programmes and for which the difference between retail price and short-term costs is large. Decoupling also makes sense where the regulator only has limited staff resources to monitor the utility's DSM programmes. NLRAs, which are more narrowly focused than decoupling, tend to encourage utilities to operate DSM programmes that look good on paper but fail to produced energy savings in practice (Hirst & Blank 1994). Thus, NLRAs are probably best suited for utilities that operate only small programmes, or where the difference between price and short run marginal costs is small. Both of these factors reduce the amount of money flowing through the NLRAs and relieve some of the problems associated with evaluation and definition of energy savings (Hirst & Blank 1994).

45 For a more detailed account of NLRAs see Baxter (1995); Hirst & Blank (1994).
<table>
<thead>
<tr>
<th><strong>Decoupling</strong></th>
<th><strong>Net-lost-revenue adjustments</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Removes incentives to sell more electricity and all DSM disincentives</td>
<td>Removes some DSM disincentives (extra sales caused by load-building programmes benefit shareholders)</td>
</tr>
<tr>
<td>Does not require evaluation</td>
<td>Requires sophisticated and precise evaluation methods and results</td>
</tr>
<tr>
<td>Utility does not profit from DSM programmes that produce less than expected energy savings</td>
<td>Utility may profit from DSM programmes that save less than expected</td>
</tr>
<tr>
<td>Compensates utilities for fixed DSM costs</td>
<td>Compensates utilities for fixed and variable costs</td>
</tr>
<tr>
<td>Eliminates utility disincentive to support public policies that increase efficiency (i.e. rate design, efficiency standards and education programmes)</td>
<td>Continues utility disincentives to support public policies that increase energy efficiency</td>
</tr>
</tbody>
</table>

Table A2: Comparison of decoupling and net-lost revenue adjustment mechanisms

*Source: Moskovitz, Harrington, & Austin (1992)*

**Mechanisms to provide additional DSM incentives**

The following mechanisms have been used in the United States to provide utilities with additional incentives to invest in DSM. Note that these incentives have been applied to investor-owned (as opposed to public-owned) utilities. Note also that hybrids of these mechanism are also sometimes used.⁴⁶

- **Shared-savings mechanisms.** The shared-savings incentive mechanism provides utility shareholders with a share of the energy savings benefits, or ‘net benefits’. Shared savings are the most common mechanism used to reward utilities for investing in DSM programmes.
- **Bonus mechanisms.** Bonus mechanism reward utility shareholders on a per-unit basis for energy and demand savings. Bonus mechanisms are less common than shared savings.
- **Mark-up mechanisms.** Mark-up mechanisms provide a mark-up on DSM programme expenditures, generally varying from five to ten per cent. Mark-up mechanisms frequently apply to a subset of utility programmes, where energy savings benefits are particularly difficult to measure (i.e. information programmes) or where the programmes undertaken are based on equity rather than efficiency considerations (Eto, Stoft & Kito 1998).

These performance-based reforms mark a distinct motion towards eliminating the bias between the utility’s incentive to build power plants and its incentive to invest in efficiency. Despite this, cost-of-services regulation is still used to treat of utility investment in plant and equipment. Cost of services regulation is thus likely to continue to bias utility decisions governing investment capital.

**References to Appendix**


⁴⁶ For a detailed account of these mechanism see Eto, Stoft & Kito (1998); Haaland & York (1994); Weil (1994).


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