Economics of Greenhouse Gas Limitations

HANDBOOK REPORTS

Implications of Electric Power Sector Restructuring on Climate Change Mitigation in Argentina

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Executive Summary

This report investigates the prospects for implementation of climate change mitigation options within the context of Argentina's restructured electric power industry. The study was undertaken as a joint effort between IDEE/FB in Argentina and the UNEP Collaborating Centre on Energy and Environment (UCCEE) in Denmark, under the auspices of the UNEP/GEF Project "Economics of Greenhouse Gas Limitations."

A related study was carried out by IDEE/FB under the above-mentioned UNEP/GEF project to identify potential climate change mitigation options in Argentina and to analyse their incremental costs. That study identified a number of mitigation options relating to the electric power sector, including increased development of hydroelectric power, nuclear power, wind energy, and improved energy efficiency at the end-use level.

The Argentine electricity industry has undergone fundamental reforms since 1992, involving large-scale privatisation, and competition in generation and wholesale power markets. In terms of climate change mitigation, these reforms have had the beneficial effect of encouraging improved generation efficiency among thermal power plants and improved end-use consumption efficiency among large industrial firms. However, the reforms have also had the negative effect (from a climate change perspective) of encouraging an ever-increasing use of natural gas combustion for electricity generation, greatly diminishing the role of hydroelectric power which had previously played an important role in the Argentine electricity sector.

This report examines the current structure and regulations of the Argentine electricity system and analyses the forces at work which are influencing current technology choices, both in terms of power generation and end-use consumption. The report goes on to examine international experiences in promoting renewable energy and energy-efficiency technologies; and finally, the report considers the applicability of these various policy mechanisms within the Argentine context.

1 The Argentine Electricity System

This report concentrates on analysis of the Argentine Inter-Connected System (SADI), which covers most of the country with the exception of the Patagonian Region, and handles over 90% of the country's total electricity. Within SADI, the wholesale electricity market (WEM) is characterised by two types of electricity sales: through contracts between buyers and sellers, or through the spot market.

In the contract market, generators sell power to purchasers, either through direct bilateral contracts or through a broker. Contracts can be not only for the supply of electricity but also for cold reserve. Any sales not taking place through contracts occur instead in the spot market. Generators and brokers bid power into the spot market on an hourly basis, and the spot market price is determined based on the hourly system marginal cost, adjusted for transmission constraints. Power may also be imported from or exported to neighbouring countries, with Brazil being the primary international market.

Consumers with a demand of as small as 50 kW are authorised to contract directly for their power with generators or brokers of their choosing, though specific rules vary between those for major large users (> 1 MW), minor large users (100 kW - 1 MW), and private users (50 kW - 100 kW). Consumers with a demand of less than 50 kW are required to purchase their electricity from the local concession holder, i.e., the local distribution utility. In the future, it is planned that all consumers, regardless of size, will become eligible to choose their electricity provider.

Generators are free to enter and exit the WEM as they choose, subject to certain conditions. There is no centralised generation planning process; and it is expected that the open market will provide sufficient economic incentives to ensure that sufficient generation capacity is available at all times.

The high-voltage electricity transmission system is operated as a regulated quasi-monopoly on a concession basis. However, major expansions of transmission capacity cannot be determined by the transmission companies alone. Rather, expansions are carried out either under direct agreement of (and paid for by) the specific agents requiring the specific network expansion (i.e., generators, brokers, consumers, etc.), or through a public procedure approved by the majority of "beneficiaries" of the expansion and paid for by each beneficiary in direct proportion to benefits received. Given that generation facilities are scattered throughout the country, but over 50% of electricity demand is concentrated in the Buenos Aires metropolitan area, availability of transmission capacity is a major issue and has significant influence on competition within the generation market. In fact, delays in the expansion of transmission links have been one of the key causes of generation dispersion around the country in search of non-transmission-constrained access to the Buenos Aires metropolitan market.

Between the beginning of the reform process in 1992 and 1997, installed generation capacity increased by 6900 MW, equivalent to 58% of peak generation in 1997. More than half of this increase has been due to the completion of hydroelectric facilities already under construction with public funds before 1992. Nevertheless, private investors have installed approximately 2400 MW of thermal plants using natural gas. This increase in capacity has led to a reserve margin of 54% of peak demand, resulting in significant over-capacity and causing a steady drop in spot market prices. By late 1997, spot electricity prices reached a low of US$13 per MWh.

The existing over-capacity and low prices have forced thermal generators to improve their competitiveness in order to survive, and three primary strategies have been used for this purpose: 1.) improve thermal efficiency (e.g., upgrade from open-cycle to combined-cycle); 2.) secure a cheap natural gas supply; and 3.) locate in areas free of transmission constraints. The need for a cheap and reliable natural gas supply has favoured oil companies and has encouraged a new vertical re-integration up the supply chain, with single oil companies owning fuel supply, pipeline, and power plant. Furthermore, the need to improve thermal efficiency and the need to find new locations free of transmission constraints has led to continued investment in new capacity in spite of already existing over-capacity and falling prices.

Given the over-capacity in Argentina, some generators pin their future hopes on exporting power to Brazil. However, such exports, to be made possible by improved transmission links between the two countries, will also increase the possibilities for imports from Brazil into the Argentine market. Brazil's electricity system is almost completely dominated by hydroelectric power; and the Brazilian generation planning process is based on the criterion of reservoir capacity being sufficient to meet Brazil's full energy requirements with 95% reliability. In other words, 95% of the time, Brazil may in fact have excess electricity from its hydro reservoirs available for export to the Argentine spot market. Thus, an improved transmission link with Brazil may not necessarily help Argentine generators and is expected to further increase the volatility of the Argentine market.

Given these factors, the power generation business has become both risky and unprofitable. Under such circumstances, investors will invest in only the most economically competitive plants. The climate change mitigation options of interest in this report (hydro, nuclear, and wind) all suffer from high up-front capital costs which serve to deter investors under the existing risky business conditions. Wind and nuclear power also suffer from lack of operational flexibility; and nuclear power is further faced with risks regarding safety, decommissioning, waste disposal, and general public hostility.

Hydroelectric facilities also face significant obstacles in addition to cost. These include stringent environmental regulations and concerns regarding flooding of fertile land, displacement of populations, and spread of diseases from stagnant water bodies. Not only do these raise the cost of building hydro facilities, but they also serve to constrain hydro plants' operation regarding minimum flows, maximum flows, reservoir levels, etc. Restrictions on hydro facilities are imposed not only by the basin authority but also by the power plant dispatching body, which determines hydro plants' dispatch based on its calculated value of stored water.

In wet years, high hydro availability will contribute to a fall in spot market prices, but hydro generators can partially compensate for this price drop through greater sales volume. Thermal generators theoretically suffer most during wet years because they cannot increase their sales volume to make up for low prices, and in fact they may be excluded from selling to the spot market altogether due to abundant and cheap hydro power. However, in order to prevent the bankruptcy of thermal generators in wet years (since they are crucial to system reliability during dry years), thermal generators are paid for the base-load reserve capacity which they provide as insurance against non-hydro availability in dry years.

During dry years, thermal generators are the ones who benefit most, as they can raise their sales volumes and charge high prices. Hydro plants, on the other hand, benefit from increased prices but suffer from low sales volume due to water scarcity.

Thus, thermal generators are protected from fiscal adversity in wet years (through base-load reserve payments) and profit handsomely during dry years, while hydro generators enjoy neither protection from downside risk during dry years nor large profit potential during wet years. Thus, the variable nature of hydro flows and the regulatory mechanisms put in place to cope with this variability result in an overall competitive advantage for thermal generators.

2 Energy Efficiency

The economic reforms carried out in Argentina since 1992 have had a mixed effect on end-use energy efficiency. On the one hand, falling electricity prices have reduced the impetus for introducing energy saving measures. On the other hand, greater competition throughout the economy has led many organisations, particularly large industrial firms, to upgrade their production technology and improve their energy efficiency in a search for competitive advantage. Overall, therefore, large firms have improved both their competitiveness and efficiency, while small and medium sized firms have often been unable to do so. As a result, there has been increasing economic concentration toward large firms.

Electricity distribution companies selling power to captive customers within their concession areas may purchase electricity from either the contract or spot market. Power purchase costs from the spot market may be passed on to consumers. Regarding the contract market, distributors may retain any profit which results from signing power purchase contracts which are lower than the spot market price; but on the other hand distributors lose money any time their contract price is higher than the spot price. Given an environment of steadily falling spot prices, distribution companies have had very little incentive to sign long-term contracts, since they would be unlikely to obtain such contracts at below the future spot market price.

The result of this is that distribution companies have been purchasing electricity almost entirely through the spot market and have been passing on the risk of fluctuating spot prices entirely to their customers. Regarding electricity price risk, therefore, distributors have little incentive to work with their customers to manage this risk (for example by reducing end-use consumption).

Distributors do have an obligation to meet all electricity demands within their concession areas, however; and given that distribution capacity has high up-front fixed costs, distributors are interested in maximising load factor and minimising peak demand growth. In this regard, distribution companies do have some incentive to assist their customers with load management measures.

However, the regulatory authorities intend to eventually extend the free choice of electricity supplier to all consumers, regardless of size (down from the current minimum size of 50 kW demand). This planned elimination of captive customers would necessitate renegotiation of the current concession agreements. This uncertainty regarding future revenue leads distribution companies to be conservative in incurring additional costs, particularly regarding load management and energy efficiency on customers' premises, which may not be recoverable by the distributor. This is exacerbated by the fact that distribution companies already claim that they face unfair competition from other wholesale power marketers due to differential tax treatment.

On the other hand, both electricity and gas distribution companies are already offering energy efficiency advice as part of their competitive strategy to increase market share in new construction projects where customers are able to choose between installing either electric or gas appliances (e.g., space conditioning). The advent of such practices suggests that utilities may in the future increasingly use energy efficiency as a marketing tool as the level of competition for customers grows.

Regarding supply-side efficiency, electricity industry reform has encouraged increased experimentation with co-generation, both in terms of generators selling heat to nearby industrial facilities, and in terms of generators signing contracts with industrial firms to build, operate, and maintain a co-generation plant on the industry's premises. However, declining spot market prices have reduced the incentive for firms to participate.

Regarding distribution losses, distribution companies are entitled to increase their tariffs by a certain factor to account for such losses. Reductions in incurred distribution losses translate into profit for the distributors, as these savings do not have to be passed on to consumers. As a result, distribution losses have been reduced significantly since the implementation of industry reform.

3 International Experience

International experience in promoting renewable energy includes the provision of guaranteed power purchase contracts, production subsidies, tax credits, market set-asides, externality adders, carbon taxes, green marketing programs, preferential finance, and RD&D grants. Electric power sector restructuring leaves the applicability of some of these mechanisms unaffected, while other mechanisms become more difficult to sustain. Green marketing programs are particularly well-suited to markets with retail competition, for example, while externality adders in the generation planning process become inapplicable when the open market replaces centralised generation planning.

The reduced availability of guaranteed power purchase contracts in competitive markets provides one of the most severe challenges for renewable energy such as wind. The UK has addressed this challenge by reserving a certain proportion of its electricity market for renewable energy. Within this reserved market, renewable generators compete with each other (on a price basis) for guaranteed long-term contracts. Thus, the UK system shields renewable generators from competition against conventional thermal generators and continues to provide long-term contracts for renewables; yet renewable generators are still subject to the forces of competition against other renewable generators.

Similar mechanisms are in use and under further consideration in the Netherlands and USA. The Netherlands requires that electricity utilities purchase a certain percentage of their electricity from renewable generators. The Dutch system is underpinned by a system of tradable "green labels" issued to renewable generators in proportion to the number of kWh they generate. Utilities can fulfil their renewable energy obligations either by generating with renewables themselves, purchasing renewable energy from others, or by purchasing green labels independently of the electricity itself. A similar mechanism, under various stages of consideration / implementation in several US states, is known as the Renewables Portfolio Standard, in which renewable generators are issued tradable renewable energy credits. Such market set-aside mechanisms can operate in conjunction with other mechanisms such as tax credits and carbon taxes.

Regarding promoting end-use energy efficiency, international experience includes the use of energy labelling, energy efficiency standards, energy conservation centres, voluntary programs, energy taxes, performance contracting / ESCOs, and demand-side management. Most of these mechanisms continue to be applicable in restructured electricity markets, though the effectiveness of many of them could decline if restructuring leads to substantially lower electricity tariffs.

Much attention has been focused on the decline of utility-based demand-side management (DSM) in the USA after the onset of electricity industry restructuring. The primary reason for this decline has been related to DSM causing higher electricity tariffs and utilities' desire to avoid any such programs which make them vulnerable against low-cost competitors. Other reasons include the fact that, with the unbundling of previously vertically-integrated utilities, utilities lose the incentive to avoid capital-intensive power plant construction through DSM. On the other hand, restructuring has led to the increased use of "business-based" DSM, where utilities and energy service providers use energy efficiency as a competitive and marketing tool to win new business and retain customer satisfaction. Such activity is also beginning to appear in Argentina, where electric and gas utilities have used energy efficiency advice as a tool to compete for new customers.

4 Applicability of Incentive Mechanisms to Argentina

In examining the applicability for Argentina of the various mechanisms used to promote renewable energy and energy efficiency around the world, one must first examine the rationale for such promotion within the context of the United Nations Framework Convention on Climate Change (UNFCCC). Not only is Argentina not obligated to reduce its emissions of greenhouse gases (GHGs) under the UNFCCC, but Argentina's emissions of GHGs are expected to remain far below those of other industrialised countries in the foreseeable future. In this context, the Argentine electricity consumer should not be obligated to face higher electricity tariffs to finance GHG limitation schemes. Rather, one would expect that Argentina's climate change mitigation programs would be financed by international mechanisms currently being discussed under the UNFCCC process, such as the Clean Development Mechanism.

Therefore, one of the considerations in determining the applicability of certain renewable energy and energy efficiency promotion mechanisms in Argentina should be the compatibility of the mechanisms with available international financing mechanisms. For example, a preferential financing scheme for renewable energy would be more compatible with international funding mechanisms than would a carbon tax imposed on electricity consumption.

Market set-aside systems, like the UK's Non Fossil Fuel Obligation or the USA's proposed Renewables Portfolio Standard, appear to be some of the most effective means of guaranteeing an increased use of renewable energy on a cost-effective basis. Such a system could be applicable in Argentina as well for promoting the increased use of wind energy. These systems are primarily applicable for promoting technologies which command a marginal market share, however. As such, their applicability toward promoting large-scale hydroelectricity and nuclear power are much more questionable.

Even if one were able to determine an acceptable quota for large hydro and nuclear power, other questions would remain. These include whether the quotas should apply to only new or also existing plants, how to limit the market distortions which the quotas would create, how to introduce an acceptable emission-free certificate trading system, and how all of this would interact with electricity imports and exports between Argentina and Brazil, Uruguay, and Chile.

Other options for encouraging renewable energy in Argentina might include a reimbursement of the value-added tax to renewable generators, or the creation of a financing mechanism to provide financing at below-market rates for non-GHG-emitting resources. However, given the size of many hydroelectric options in Argentina, such a financing mechanism would likely have to be very large to successfully stimulate private investor interest.

Another option would be for the state to solicit bids for the construction of new large-scale hydro plants, in which the bidder requesting the lowest capital subsidy would be awarded the concession. Once the concession and subsidy are awarded, the private agent would then be responsible for all subsequent construction, operation, and survival within the competitive electricity market.

Regarding energy efficiency, the restructuring of the Argentine economy has had a positive effect on energy efficiency through an upgrading of production technologies, primarily in large companies. Small and medium sized companies have been less successful in making this transformation, however, and the overall economy has witnessed increasing economic concentration in large firms.

The day-to-day functioning of the economy therefore appears to provide sufficient incentives for large firms to improve their energy efficiency, and no further state-sponsored incentives are deemed necessary. Incentives may be necessary for smaller companies, however. This is particularly the case because energy service companies (ESCOs), which have been widely touted as the provider of choice for energy efficiency services in competitive markets, may not exhibit much interest in serving smaller customers.

A program for providing energy efficiency information, audits, recommendations, and even implementation services for small and medium sized companies should therefore be considered, possibly through the Argentine Industrial Technology Institute, and in co-operation with Argentine universities. The program could perhaps be financed through a modest charge on energy bills, though great care must be taken that any such charge not actually harm the companies that were meant to be helped in the first place. A similar program may also be appropriate for the promotion of co-generation in smaller industrial establishments.

Traditional demand-side management programs may not be compatible with the restructured Argentine market, but it may be appropriate to oblige the concession holders of distribution networks to provide energy efficiency services, funded by a wires charge on all consumers, as has been done in Norway. Though utilities in Argentina currently have no obligation to provide energy efficiency services, some are already beginning to do so as part of their business strategy for attracting new customers. Such activities may naturally grow in the future as competition further increases.

For low-income residential customers, whose electricity bills are largely driven by lighting needs, it may be appropriate to directly subsidise the purchase of high-efficiency light bulbs, possibly through a technology procurement program similar to that carried out in Sweden. Such a program would help reduce costs for buyers and reduce risks for producers by organising a pool of buyers and guaranteeing a minimum purchase volume to producers who are able to meet the required specifications at the lowest price.

Improving access to financing for small and medium sized customers in both the residential and commercial sectors will also be important for stimulating energy efficiency, as such customers have generally experienced much greater difficulty in accessing credit than have larger organisations. Promotional credit lines through official banks may be appropriate for this, possibly financed through international climate change mitigation funds.

The implementation of such mechanisms to support the use of renewable energy and increased energy efficiency is highly complex, and many details would need to be worked out. This study represents merely a first step in analysing how electricity industry restructuring can be made more compatible with the implementation of climate change mitigation options.

I Introduction

As a complement to the study on the Argentine potential to mitigate greenhouse-effect gases (GHG) under the UNEP / GEF project Economics of Greenhouse Gas Limitations, it was decided to analyse the implications of electricity industry reform on the implementation modes of eventual mitigation actions, both at final-use as well as electricity-generation levels.

For this purpose, a joint study was carried out with the UNEP Collaborating Centre on Energy and Environment at Risø National Laboratory, Denmark (UCCEE), the results of which are summarised in the present report.

The said co-operation consisted of an initial survey by UCCEE on the mechanisms used worldwide to promote end-use energy efficiency and to encourage the use of renewable energy sources for electricity generation.

On the basis of the results of this survey, IDEE / FB carried out an in-depth analysis of the regulations in force in Argentina for the electricity industry, focusing on those aspects which could promote or hamper the use of such mechanisms within the Argentine market.

The following is the organisation pattern for the present Report. Chapter II provides a summary of the regulatory and institutional characteristics of the Argentine electricity system, as well as a brief outline of the dynamics shown by the different agents since the reforms were implemented in 1992.

Chapter III outlines the regulatory aspects which lead to and support the behaviour observed among electricity-industry agents. This analysis is complemented with an outline of the policies in force in Argentina with respect to the use of energy resources within the electricity sector and energy efficiency, given in Chapters IV and V, respectively.

A profile on the international experience on promotion of renewable energy and energy efficiency is provided in Chapters VI and VII, with special attention paid to incentive mechanisms within competitive electricity markets. With a view to facilitating an understanding of the context in which the surveyed mechanisms were implemented, a brief outline of the current organisation of the electricity industry in the respective nations is also included.

Finally, Chapter VIII analyses the opportunities and obstacles to using these mechanisms within the Argentine electricity system, in view of their special composition and of the fact that they would actually represent voluntary greenhouse gas mitigation actions, the costs of which should not be borne by local consumers.

This study represents only a first step in the analysis of implementation issues within competitive economic environments in non-Annex 1 nations of the United Nations Framework Convention on Climate Change. In this respect, the aim is to specially point out the necessary precautionary measures to prevent certain types of market mechanisms from destroying the principle of “shared but differentiated responsibility” of developing countries with respect to the climate change issue.

Moreover, it must be emphasised that the opinions given in the present report only represent the view of their authors and are not necessarily shared by Argentine authorities or the institutions taking part in the present study.

II The Argentine Electricity System

The present chapter delves into the institutional organisation and regulation of the Argentine electricity industry since the reform put into practice in 1992. It must be noted that frequent adjustments of electricity system regulations were registered since its implementation to date, in some cases holding significance with respect to opportunities and obligations for wholesale market agents. To give an idea of the pace registered for these modifications, let it just be said that twelve versions of the procedures to operate the system were generated throughout the six years during which the reform has been in force. Hence, it must be noted that the comments included here describe the situation in force by the middle of 1998.

This outline will serve as a conceptual framework for a detailed analysis of the regulatory aspects that influence the decisions of electricity industry agents, provided in Chapter III of the present report.

In order to give a more-detailed idea of the degree of development reached by the system to date, Section 4 provides a view of the situation of the system by the end of 1997 in terms of energy supply and demand, its geographical location, and the layout of the transport network.

Finally, Section 5 presents a summary of the dynamics of the system agents operating under the new competitive system, especially as regards the expansion of generating capacity and of the high-voltage transport system.

1 Institutional Organisation

In view of the federal nature of the Argentine Republic, federal and provincial bodies are involved in regulating electricity supply service. The Federal Government deals with all those activities involving international and inter-provincial trade. Power generation channelled through the wholesale market and the high-voltage electricity transmission network fall within this category. In the same way, federal authorities are required to intervene whenever a hydroelectric station is installed in inter-provincial or international waterways.

Generally speaking, distribution is organised around distributing companies working within the provincial field. Nevertheless, and on account of historical reasons, electricity distribution within the Buenos Aires metropolitan area (41.5% of the public service electricity demand in Argentina during 1997) falls within federal jurisdiction, and in certain provinces there are municipal companies acting as private electricity co-operative associations.

Although several provinces have adhered to the principles of the federal electricity law (1992), provincial governments enjoy the autonomy to set the terms under which they grant concessions for the supply of electricity service within their territories, with the exception of inter-provincial electricity purchases, for which they have to adjust to federal regulations. From this viewpoint, local authorities may have an active role in the promotion of energy efficiency in final use within their territories, as well as in that of the use of renewable sources for the generation of electricity for their own markets.

Notwithstanding this potential autonomy of the provinces, federal authorities regulate practically the entire installed electricity generation capacity (97% of the electricity generated throughout the country during 1997), basically because federal companies were the ones in charge of expanding electricity service throughout the federal territory after the Second World War. This percentage also includes generation by companies belonging to the provincial governments which trade their production through the electricity wholesale market.

Strictly speaking, there are two electricity markets in Argentina associated with two inter-connected systems which remain in isolation one from the other, namely:

1. the Argentine Inter-Connected System (SADI, in its Spanish abbreviation) covers practically the entire country, with the exception of the Patagonian Region, in southern Argentina. 91% of the total electricity generation was channelled through SADI in 1997.
2. The Patagonian Wholesale Electricity Market (WEMPS) which supplies the Patagonian Region, with the exception of the Argentine southernmost region. WEMPS represented in 1997 6% of total generation.

Both markets observe similar operating regulations, although prices differ depending on the specific supply and demand conditions of each market. Unless otherwise indicated, we will focus on SADI's situation for the remainder of this report.

As Figure N° 1 shows, the highest authority at the federal level is the Secretariat of Energy and Ports, in charge of the following:

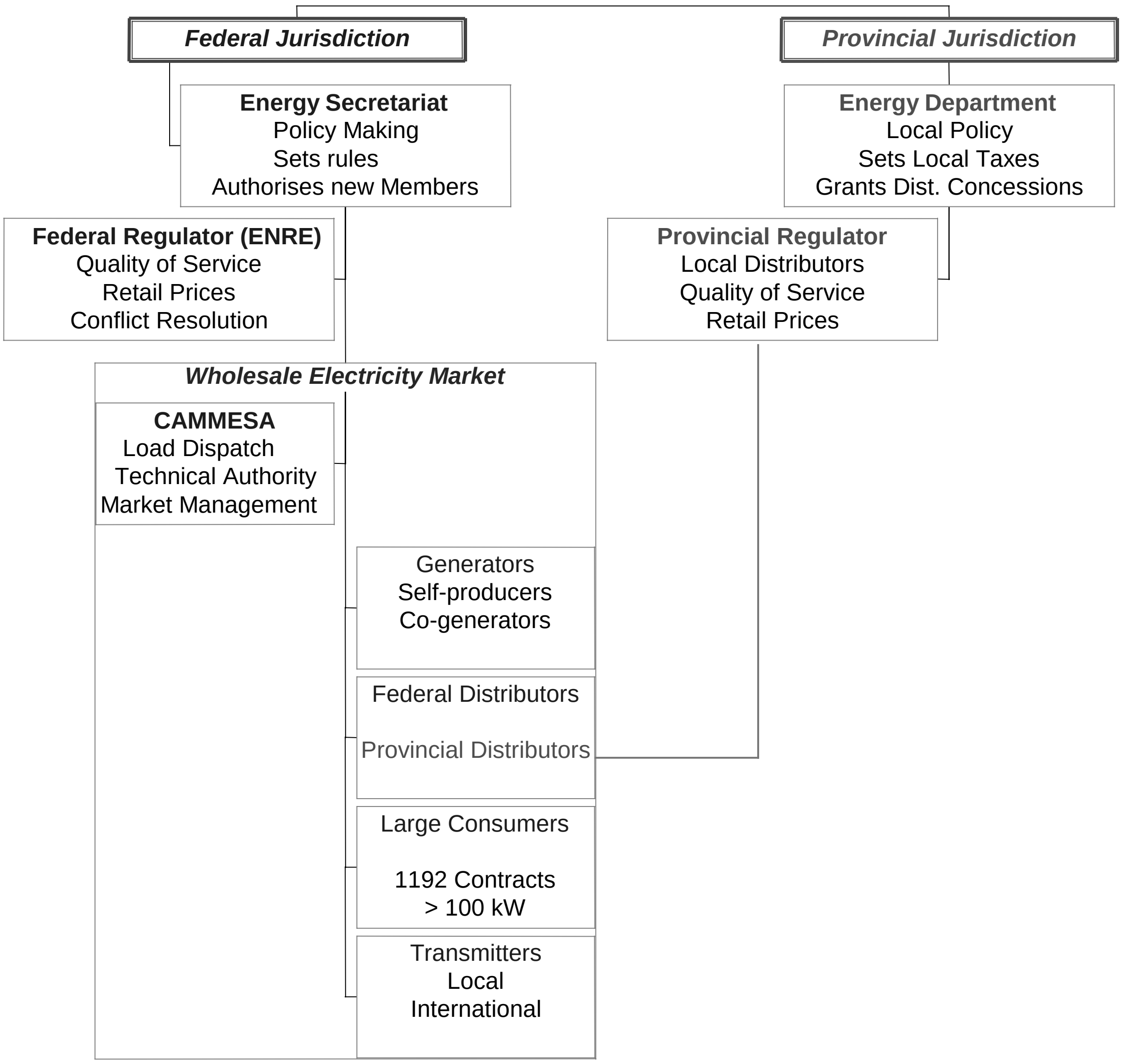
- determining and implementing energy policies
- setting regulations for electricity-industry agents
- authorising the entry and exit of agents to the wholesale electricity market (WEM)
- awarding concessions for the utilisation of hydroelectric resources within inter-provincial waterways, with prior agreement with the authorities of the provinces involved
- authorising foreign electricity trade contracts

Although the system's dynamics and expansion rest on the initiative of the agents operating in the electricity market, particularly as regards generation and transmission expansion, the Energy Secretariat periodically carries out a prospective analysis through which it follows-up the evolution of the system with a view to anticipating eventual problems in future supply. Nonetheless, these activities have not resulted so far in active public policies which could change the agents' own dynamics and preferences. This is partly due to the downward trend in electricity prices within the wholesale electricity market (WEM), which concealed the deficiencies of these dynamics in the promotion of harmonious development of the system. Nevertheless, the prospective studies aim at making the electricity market clearer by providing all interested parties with an overall view of the system which the individual agents could hardly obtain by themselves in a highly atomised industry.

Within the framework given by the legislation in force and the regulations passed by the Energy Secretariat, the fiscal comptrolling of the regulated activities (transport and distribution) is carried out by the Electricity Regulatory Bodies. There is a Regulatory Body at the federal level (the ENRE), in charge of the following:

- seeing that the terms of the concession agreements awarded by the federal government are observed (extra high-voltage transmission network, regional transmission networks and electricity distribution within the metropolitan area), especially as regards the quality of the technical and commercial service supplied by the concession-holders;
- authorising periodical modifications of the rates (tariffs) for regulated services corresponding to concessions awarded by the federal government;
- preventing non-competitive behaviour on the part of the agents, particularly as regards concentration of ownership of companies' share capital;
- monitoring the environmental management of the agents in the electricity industry subject to federal jurisdiction;
- taking part in the eventual conflicts which may arise among WEM agents and upholding the rights of captive consumers, organising public hearings to deal with the conflicting issues prior to issuing rulings.

Figure N° 1: Institutional Organisation of the Argentine Electricity System



Most provincial jurisdictions have their own regulatory body to control compliance with the terms of the respective concession agreements for electricity distribution within their territories, previously awarded by provincial authorities. The most important duties of these regulatory bodies are the control of the quality of the service supplied by the concession-holders and the authorisation of rate adjustments within the respective provincial territory.

It is necessary to note that in some provincial jurisdictions concessions awarded to provincial distributors include the supply of the electricity service in areas which remain isolated from the inter-connected system, in which the distributor has the entire monopoly over all electricity industry stages. Although demand registered in these isolated regions is low compared with the country's total electric consumption (1% of total consumption in 1997), isolated demand has a substantially higher share in the market of the distributor in some provinces. Hence, the characteristics of the concession agreements must deal with the obligations and economic equation of the distributors in two essentially different markets, which makes the work of the provincial regulatory bodies more difficult.

The constitutional autonomy of the provinces to establish their own conditions for the supply of public services, as well as to set taxes and levies on economic activities carried out within their territories, has resulted throughout history in many conflicts between federal and provincial jurisdictions which the new organisation of the electricity industry has proved incapable of solving. On the contrary, the coexistence of this autonomy with the compulsory opening of the provincial electricity distribution networks to allow the access of large users from the provincial territories to the wholesale market has fuelled conflicts associated to unfair competition between WEM generators and local distributors.

Electricity regulatory bodies are grouped within the Association of Electricity Regulatory Bodies (ADERE), in its Spanish abbreviation), a second-degree institution which allows co-ordinating actions among the different jurisdictions and submitting proposals on eventual future supply problems.

Since its actual establishment in 1992, the number of agents within the wholesale market has registered a rising trend. Table No. 1 shows the situation in force on 31 December 1997 both at SADI (WEM) as well as the Patagonian system (WEMPS).

Table N° 1: Number of Agents within the Wholesale Market

	WEM	WEMPS	TOTAL
Generators	40	4	44
Self-producers and Co-generators	13		13
Transmitters	24	1	25
Distributors	28	3	31
Large Users	1125	23	1148
Total	1230	31	1261

It is necessary to note that the values included in Table N° 1 correspond to the classification carried out by the body in charge of the technical management and administration of the wholesale markets. According to this classification, electricity co-operative associations are not considered distributors even when they supply public electricity service and are subject to concession agreements awarded by local governments, either provincial or municipal, depending on the provinces in which they may be located. Electricity co-operative associations acquire the status of wholesale market agent only when they sign supply agreements with generators, and in this case they are accounted for as large users.

Thus, the three distributors listed in Table N° 1 for the Patagonian market correspond to the provincial bodies acting as intermediaries between generators and true distributing companies (co-operative associations).

Only 350 (30%) of all large users were full WEM members. The remaining 70% were "minor large" users (defined in Section 2) whose supply agreements are managed by the respective distributor, even when they sign supply agreements with generators.

At the beginning of 1997, a difference was established between WEM agents and participants. All entities in charge of electricity generation, transmission, distribution and consumption fall within the category of members, while WEM participants are those with just a commercial link with the electricity market. Companies trading generation and/or demand from third parties (traders) are considered WEM participants, as well as the provincial states which trade hydroelectric royalties received in kind and the foreign companies which purchase or sell electricity within the Argentine market.

The establishment of the trader character is an attempt to stimulate the electricity contract market by reducing trading costs faced by generators and at the same time facilitating eventual electricity imports. Nonetheless, no substantial changes have been noticed in trading modes during the first year of application of the regulation.

The said regulation seems to have enhanced commercial reliability in wholesale transactions rather than the promotion of new activity, forcing traders to set up a warranty fund for an approximate value of 10% of their trading commitments, which could be modified in the future in accordance with payment delays which traders may register.

With a view to preventing the excessive concentration of electricity trading from hampering competition among suppliers, each trader is enabled to sell a maximum of 5% of the system's total demand through the series of trading agreements.

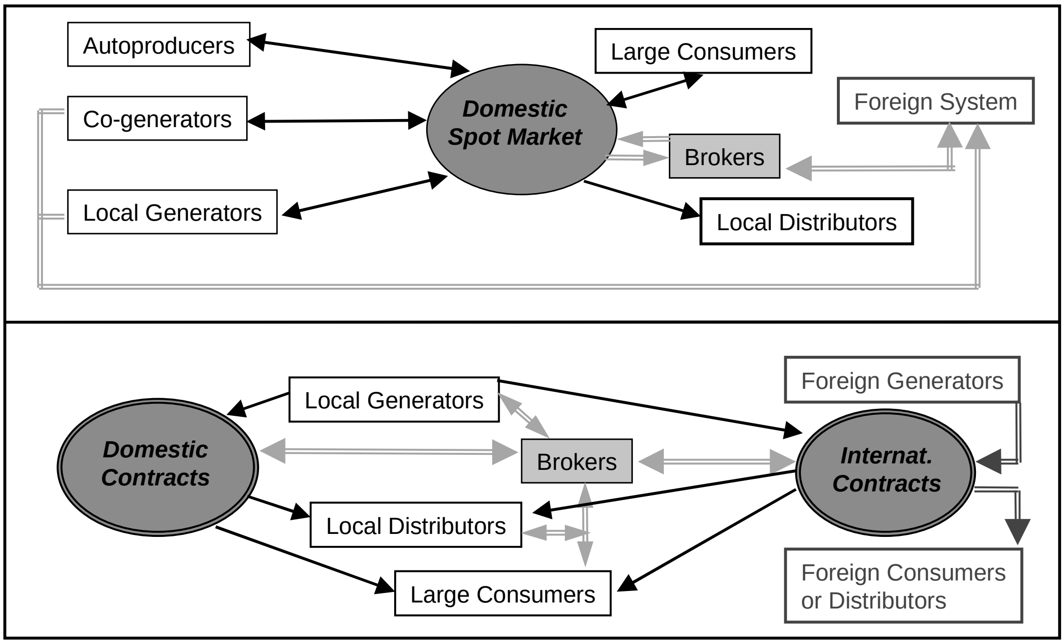
WEM members are grouped in second-degree associations representing each one of the electricity industry processes (generators, transmitters, distributors, and large users) within WEM's administrating company (CAMMESA). Although every member holds an individual relationship with the market, there is no doubt that the existence of these associations allows an organic debate on the issues affecting the electricity industry and facilitates the search for consensus on the most appropriate solutions.

The technical authority in the operation of the system is the Compañía Administradora del Mercado Mayorista Eléctrico Sociedad Anónima (CAMMESA) which, apart from carrying out the monthly settlements of payments and collecting from the agents, is in charge of load dispatch and acts as consultant to ENRE in transmission studies within the high-voltage network.

2 Organisation of the Wholesale Market

As shown in Figure N° 2, the wholesale trading of electricity may be carried out through supply agreements or within the spot market. Market members may choose between trading their electricity directly or acting in the market through a trader (broker). Supply agreements may cover not only specific power stations, but also particular units within a power station. Furthermore, brokers can represent not only suppliers but buyers as well. However, these trading agreements do not exempt the members from their technical responsibility in the operation of the system (frequency control, reactive power, etc.).

Figure N° 2: Wholesale Electricity Market



2.1 Contract market

For the supply of local electricity demand, parties may contract both the supply of electricity as well as that of cold reserve, freely agreeing on prices and contract duration, except for the case of two-nation electricity companies or state-owned ones, for which this trading mode is banned.

The parties must specify in the terms of the respective agreement not only the amounts and prices but also how transmission costs will be shared. When the purchasing party must use the facilities of another member to receive the energy contracted, he must previously agree on the toll price for such use. The parties may agree on the toll price, as long as it does not exceed the value set by the dispatching company.

The minimum power demand enabling a consumer to freely contract his supply has been gradually reduced since the implementation of the new system. The 5 MW originally required fell initially to 1 MW, then to 100 kW and more recently to 50 kW, the authorities aiming at totally freeing the market in the coming years. Nevertheless, options and responsibilities for the large users differ in accordance with the magnitude of their demand.

Major large users (with a demand exceeding 1 MW) fully participate in WEM and interchange information with the dispatching body managing their contracts, as long as they contract the supply of at least 50% of their demand. It is understood that any deviation between the actual demand and that contracted results in transactions in the spot market, either the purchase of deficits or the sale of surpluses. In the case of a generation deficit within the WEM, its supply must have priority, as long as the generator has the contracted units available and there are no failures in the transmission and distribution system necessary for the supply.

Contrary to this, minor large users (between 1 MW and 100 kW) as well as private users (between 100 and 50 kW) may only contract their entire demand and under no circumstance are they allowed to operate in the spot market. Their supply contracts are managed by the distributor of the respective area and their priority in supply is the same as that of the distributor’s direct customers. Minor large users and private users mainly differ in the obligations of the area distributor with respect to the measuring of their consumption. While distributors are forced to measure the consumption of minor large users for each time period (peak, valley and remaining hours), in the case of private users they may estimate the share of each time period and total energy consumed, unless the user requests otherwise.

The fact that a generator may have signed supply or cold reserve agreements does not influence the dispatch of his units. The dispatching body determines the operation of the system's units without considering the contracts signed. Hence, it is understood that if a generator's production exceeds its sales obligations, the surplus is sold at the spot market, where it would also purchase any deficit to meet demand for electricity sold through contracts.

From the point of view of its commercial operations and the calculation of the sums to collect by each generator, the wholesale electricity market managing company is in charge of calculating the operations registered in each market segment and carrying out the corresponding settlements.

When a generator contracts part of its capacity as cold reserve with another WEM agent, this does not disqualify the same units from supplying their production at the spot market when they are not required by the contracting party. In this case, he will collect in the spot market for just the electricity delivered, since capacity is rewarded by the cold reserve contract. In the same way, units contracted to sell electricity in the contract market may not take part in WEM cold reserve bids.

It is worth noting that the reserve guarantee offered by a generator in a cold reserve contract is limited to the availability of the units committed, for it could be affected by restrictions in the transmission equipment necessary to provide the contracted supply. Hence, the agents requiring higher supply security and thus contracting cold reserve with some generator must make certain that the transmission link between them is of good quality.

As Figure N° 2 shows, WEM agents may sign contracts for the exportation or importation of electricity with companies from neighbouring nations. These contracts, known as firm capacity contracts, require the authorisation of the Energy Secretariat and a transmission capacity backup in the international link which may guarantee the technical feasibility of the expected interchange. The phrase *firm capacity* used in these contracts means that they represent a commitment on the part of the seller to put the contracted capacity at the disposal of the buyer. The buyer will then decide based on his own judgement and convenience whether to actually require the contracted capacity at real time, and this uncertainty must be anticipated for the purposes of the advance planning of the Argentine system's load dispatch.

Transmission facilities (lines, transformer stations, converting stations, etc.) are considered international transmission links when they join the domestic high-voltage transmission network with the electricity system of a neighbouring country, even when they are located within Argentine territory. The node in which the international link connects with SADI is known as a *border node*. One or more local agents holding preliminary importation or exportation contracts may act as triggering agents for the construction or expansion of the international links, known as firm expansion through toll.

Unlike the local transmission network, the transmission capacity of an international link is allocated to agents with importation and exportation contracts, who may sell their surplus transmission capacity to third parties or charge a toll (agreed-upon or regulated) to the eventual users of the facilities. The installation, operation and maintenance costs for the international links are paid exclusively by the agents taking part in the international electricity transactions and do not affect other WEM agents, except when they use it to connect themselves to the Argentine market.

When a generator, co-generator or trader signs a firm capacity exportation contract, he endorses the commitment with his own units, which are specified in the contract. However, he may purchase a deficit in the Argentine spot market as long as this additional demand does not result in a deficit in the supply of the local Argentine demand. The guarantee offered by the seller to his foreign customer is restricted to his generating capacity, and the exportation is subject to restrictions in the transmission system in SADI as is the case with any other local demand.

From the point of view of the operation of the system, a firm export contract is considered an additional demand located at the border node and characterised by the load curve expected for the dispatch period. The generator may not receive rewards for capacity in the Argentine market on account of the capacity committed by contract. Contrary to this, he may bid at the spot market the energy not delivered to his foreign customer and collect the spot price in force at each moment. The capacity not contracted, even when it is from the same unit, may be traded by the generator on the WEM without any restriction.

Distributors, large users and traders, in turn, may sign a firm capacity importation contract with a foreign bidder. From an operational viewpoint, the contract is equivalent to a forced-operation fictional unit located at the border node. Although the purchasing agent may trade eventual contract surpluses or deficits at the spot market, the purchaser may not contract an amount exceeding its own demand with a foreign company.

All contracted international interchanges are subject to transmission restrictions within SADI, and security in domestic supply has priority over importation / exportation contracts. In the case of hydroelectric generation surpluses at the WEM, importers may choose to cut down their imports at the request of the dispatching body to prevent water spilling within the country.

2.2 The spot market

Suppliers may choose to sell their electricity on the spot market at the hourly prices issued in accordance with market conditions. The hourly-price of electricity at the "market node" (system's load centre) is defined as the cost which would be incurred to supply an additional unit to the demand registered at that hour. In other words, this is the lowest variable cost declared by the generators which would be in a position to increase their supply, considering both thermal as well as hydro generators.

Strictly speaking, the price actually paid for electricity could be higher if the risk of not being capable of supplying the actual demand is detected in the weekly operational forecast, both in normal conditions as well as in the simulation of contingent failures. In this case, there would be a special reward on account of failure risk, the value of which depends on the magnitude of the expected non-supplied electricity.

The electricity bid into the system which is not committed through contracts is paid at this spot price transferred to the node in which the supplier is connected to the network. In other words, price is affected on account of transmission losses. The only exceptions are the eventual electricity imports and the units with forced operation due to transmission system stability restrictions.

Traders - the only WEM participants enabled to supply eventual electricity imports - are paid the price bid at the border node in which the imported electricity is injected to

SADI. When the importation does not set the market price (the importation is not the marginal unit and the border node price is higher than the import price), there is a surplus importation profit which is transferred to a special reliability fund.

Forced-operation units - which would not be operated in an optimum dispatch without restrictions - are rewarded according to their running costs, as the corresponding generators declare them. The associated cost overrun is absorbed by the consumers from the area generating the restriction.

There are two categories of purchasers within the spot market, namely: distributors and eventual purchasers. Eventual purchasers are all those who are in deficit in the contract market (be they either generators whose own generation does not cover their total sales through contracts, or large users with a demand higher than the supply contracted) and self-generators who do not meet their entire own demand. Eventual purchasers buy electricity on the spot market at the hourly price of their connection node to SADI.

Distributors, instead, pay the mean price estimated for each three-month period, differentiated in three time-of-day periods (peak, valley and remaining hours), known as seasonal prices. To cover any deviation between prices actually paid to the suppliers and seasonal prices charged to the distributors, it is necessary to maintain a minimum balance in the Stabilisation Fund in order to guarantee normal payment to suppliers. Balances exceeding this minimum value which are accrued over one year - when generated - are returned to the distributors during the following three-month period through the establishment of a seasonal price below the one resulting from the scheduling of the operation for that three-month period. When the balance of the Fund does not cover the minimum value established, the seasonal price is set above that resulting from the scheduled operation.

It is important to point out that in the Argentine system, differences between seasonal scheduling forecasts and real operations are more influenced by fluctuations in water inflows to the hydroelectric stations than by the stochastic nature of demand and the forced outages of facilities. In fact, most of the hydro generation corresponds to run-of-river stations located in rivers fed by rainwater, which reduces certainty in the forecast of future inflows.

On the spot market, purchasers also pay for the capacity truly demanded in that market during each hour outside the valley hour on a working day. The sums gathered on this account must offset the payment made to the generators for the sale of non-contracted-operated capacity.

However, capacity reward to generators also includes other concepts associated to supply reliability. Generators charge for the spinning reserve and the cold reserve of the system, and for maintaining the base-load thermal capacity installed to guarantee supply in hydrological-poor years.

It is understood that such reserve capacity contributed by the generators serves as such to all consumers and distributors, whatever their connection mode to the WEM (purchases at the spot market or through contracts). Since reserve requirements are anticipated in accordance with the maximum load which consumers and distributors expect to demand, all pay an amount for capacity reserve calculated on the basis of the maximum expected load, unless actual demand proves higher than expected.

In the same way, all consumers and distributors must pay for other services rendered by the generators of the system, which are deemed as capacity-associated services. These include the following:

- frequency regulation
- costs associated with unit start-up and shutdown
- cost overrun of forced-operation units (only in the area which creates the obligation to operate non-competitive units)
- the cost overrun of keeping steam-turbine units in operation at the base of the load curve when they are required only to supply the peak demand
- taxes on fuel transfers not included in the variable production costs

All WEM agents (suppliers and demanders) must pay for the use of transmission networks on account of power and energy transported, for the transmission capacity put at their disposal and for a connection fee to the network. Transmission costs for each agent depend on its way of connecting to the public network. In the extreme case of a large user connected to the distribution network, he must accrue payments to the high-voltage network transmitter, the regional transmitter, and the toll for the distributor for the use of his facilities.

The control of reactive power in the system falls on each WEM member, who must thus have the necessary facilities to maintain reactive and voltage levels in the network within preset ranges. Every time a member fails in this regard, he is subject to a penalty, the amount of which goes to the agent who has covered the deficit with his own facilities.

Finally, all WEM agents pay administration costs to take part in the market in accordance with their share in the total operations registered at the WEM, an amount which is used to cover the expenses of the dispatching body (CAMMESA).

3 Regulated Activities

Due to their characteristics, electricity transmission and distribution are regulated activities subject to the concession awarded by the relevant authorities in accordance with the corresponding jurisdiction. Nevertheless, this fact does not necessarily mean that the concession-holder will have monopoly rights for the rendering of the corresponding service in the geographical area covered by the concession.

3.1 Electricity distribution

As previously explained, the terms of the electricity distribution concession register the widest variety of situations, depending on the degree of development reached by the different systems and their electricity load dispersion levels. Unless otherwise stated, the following comments on the outstanding characteristics of the regulation of electricity distribution have to do with the concessions awarded by the federal government or by the provincial authorities which adhered to such guidelines.

Within the electricity industry, and on account of its closer relation with final consumers, the distributor has been implicitly awarded the role of "driver" for the capacity expansion in all processes to accompany the rise in electricity demand within his concession area. He is the only one among all electricity industry agents having the obligation of supplying all the demand requested by the users within his area.

Generators do not have to guarantee the availability of their units nor remain in the long run as suppliers in the market, although they have to give a one-year notice prior to their withdrawal from the WEM. It is expected that economic incentives will be sufficiently strong to promote the proper maintenance of their stations and their permanence in the market.

Each transmitter is in turn forced to maintain his units available but is not enabled to decide by himself on the major expansion of the transmission network. As will be shown later, it was expected that the initiatives to this respect were to be taken by the users of the network rather than by its technical manager.

Distributors, instead, must answer for any power cutoffs which their customers may experience, whatever their cause. Should these power cutoffs lower the quality of the service rendered below minimum standards fixed in the concession agreements, distributors suffer an economic penalty regardless of the fact that their facilities may be available and that the power cutoffs may have to do with generation deficits or failures in the transmission system.

In this way, it was expected that distributors would encourage generators to install new units through the signing of supply contracts, promoting higher levels of spinning reserve and the operation of the transmission network with adequate reliability levels. As will be shown in Section 5, the continuity of public investment to complete hydroelectric works under construction at the time the reform was implemented, as well as the business opportunities given to certain investors, made the active participation of distributors unnecessary to promote the expansion of generating capacity in recent years.

The concession agreements for electricity distribution establish a rate schedule which sets the rates to be charged by distributors to final consumers in each consumption category. Distributors are not allowed to agree with their customers on different tariffs than those specified in their rate schedule, since such behaviour would discriminate against other customers falling within the same category. As will be shown in Chapter III, this regulation restricts the capacity of the distributors to compete with other WEM bidders for the supply to large users within their concession areas.

Legislation establishes that the rates charged to final consumers must cover all distribution costs, basically supply costs at the WEM (capacity and energy), transmission service costs and distribution costs. Unit costs alien to the distributor (those generating payments to other WEM agents) are multiplied by a factor representing maximum distribution losses admitted for each category of final users.

The rate schedule applies for five years, after which it is reviewed in accordance with the contracts to adjust the composition of the costs faced by the distributor. Final rates are adjusted every three months with different indexes for each distributor cost component. Purchases at the WEM are adjusted with the variations experienced in the three-month period by the seasonal prices on the spot market, while distribution costs are adjusted with the United States price index.

As a greater opening of the final electricity market to competition among WEM suppliers was registered, the type of services rendered by electricity distributors was diversified and, hence, so were the items for which they receive special rewards.

All customers choosing to contract their supply with a WEM generator or trader and using the facilities of the distributor to allow the supply must pay a toll to the distributor on account of the rendering of the technical transmission service, the value of which depends on the voltage level at which it is connected to the distribution network. The user may choose to agree with the distributor on the priority use of the distribution facilities (firm transmission) or to accept having less priority than firm users and distributor customers (non-firm transmission).

Logically, the reward to the distributor and the penalties for the case the service is not rendered differ in both alternatives. In both cases, the load dispatching body sets the maximum values in force for each distribution area every three months, and the parties may agree on lower values for the rendering of the technical transmission service.

Large users contracting capacity of less than 100 kW at each supply point (i.e., minor large users and private users) must add to the toll cost for the use of the distribution network a charge on account of administrative and technical contract services which is transferred to the area distributor.

Distributors also act as retaining agents for all taxes (either federal or provincial) and rates (municipal or to cover the expenses of the regulatory bodies) which may be imposed on electricity consumption. This obligation was precisely a cause of certain conflicts among distributors and generators, since some direct transactions within the wholesale market prevented the payment of certain provincial taxes. Distributors understood that maintaining such a situation represented a discrimination against their customers and a reduction of their competitiveness in the market with respect to other bidders.

3.2 Electricity transmission

The grouping of the existing transmission facilities for the purpose of awarding the respective concessions for their operation was performed mainly on account of the work they carry out in the operation of the system rather than on the voltage level. Thus, all facilities associated to electricity transmission between regions of the country were grouped in a single business unit and were awarded to the federal transmitter. Hence, the high-voltage transmitter operates nearly 4375 miles of 500 kV lines and some 312 miles of 220 kV lines, together with the corresponding auxiliary and transformer-station units.

The necessary facilities to transport electricity within an electricity region which were not owned by any of the provinces were grouped into a regional business unit (trunk distribution transport in the region) and awarded to a regional transmitter to provide the transmission service to all agents from the corresponding region. Depending on the region in question, there may be an overlapping between the voltages handled by regional and federal transmitters.

In the case of the concession of existing facilities, the reward to the transmitters is aimed at covering network operation and maintenance costs as well as corporate earnings. For this purpose, transmitters receive a reward per unit of power and electricity transported and another for putting at the disposal of network users the transmission capacity of the lines and units of the transformer stations.

The amounts to be received by the transmitters on account of the transported power and electricity are set for 5-year periods in accordance with the expected flows through the transmission lines operated by each of them. The amounts corresponding to the availability of the facilities are periodically set by the authorities on the basis of an estimate of their operation and maintenance costs.

Every time a line or a connection or transformation unit fails, the transmitter is penalised and this amount is later transferred to the users of such unit as the only compensation for the transport unavailability experienced.

The regulation is aimed at having the users of the transmission network pay the amounts which the transmitter must collect according to his concession agreement in direct relation to the use made of the facilities. We shall not specify here the complex mechanisms used for this purpose. Nevertheless, and in view that these mechanisms are also used to determine the responsibility of WEM agents in the payment of expansion works to the transmission network, it should be mentioned that there has been certain difficulty to assess the true benefits which the network yields to each agent.

In general terms, the responsibility in such payment is established in accordance with the influence held by each agent on load flows rather than with respect to the economic benefits which the network yields to him. Hence, payment commitments do not always correspond with the economic profit obtained by each WEM agent. This difference has resulted in some inconveniences in the network expansion pace.

In exchange for these rewards, transmitters are responsible for the technical operation of the facilities awarded to them through concession and must render the service to the other market agents without any form of discrimination. Every time there is a restriction in some transmission lane, the dispatching body must fairly determine who are the agents affected.

This mode is different from that used to regulate the transport of natural gas and that recently adopted for international electricity interconnections, where the interested agents have to contract transport capacity to guarantee the observance of the international supply contracts.

As previously mentioned, transmitters are not allowed to decide by themselves on major network expansion. Nonetheless, the federal network transmitter is responsible for holding prospective studies on the transmission network to anticipate eventual problems in the future operation of the said network. These studies must be submitted to all WEM agents.

Every expansion of the transmission system may give origin to the appearance of an independent transmitter in charge of the construction and operation of the new facilities, although under the technical supervision of the concession-holder for the transmission network. The independent transmitter must pay a reward to the network concession-holder for this supervision, both in the construction stage as well as during the operation period of the new facilities.

Expansions may be carried out through an agreement between the parties or through public bidding. Although in the case of agreements between the parties the only one responsible for the repayment of the investment in the new facilities is the contracting party, the remaining WEM agents may make use of these facilities paying a cost similar to that rewarded to the transmission concession-holder for the use of existing facilities.

The expansions carried out through public bidding must be subject to a procedure which may guarantee the approval of the project in a public hearing by the majority of the “beneficiaries” of the expansion. Once the execution of the works is approved, an invitation for public bidding is issued to select the independent transmitter which will be in charge of the construction and further operation of the expansion. All agents identified as beneficiaries must pay the repayment royalty during a period of 15 years in direct proportion to their share of the “benefits”.

The regulation in this respect differs when it has to do with the expansion of the network from a border node of SADI to the geographic border where the Argentine system would be connected to the network of a neighbouring country. In this case, initiators must hold previously-agreed importation or exportation contracts to act as initiators of the expansion. As initiators, they are in charge of paying the levy during the investment repayment period in direct proportion to their share in the booked capacity of the facilities.

The costs of the international links both during repayment as well as operation periods are solely borne by WEM agents taking part in the international transactions channelled through such link. The only exception to this rule are WEM agents who use these facilities to connect to SADI for their usual transactions within the Argentine market.

4 The Current Situation of the Argentine Electricity System

We shall refer here solely to the operation registered within SADI during 1997, leaving aside isolated systems and the Patagonian system, since SADI represents over 90% of the total electricity industry.

The net electricity demand within SADI (demand measured in the connection nodes of WEM consumer agents to the network) reached 62.2 TWh in 1997, with a simultaneous peak load of 10.6 GW.

As shown in Figure N° 3, demand within SADI is distributed in seven geographic regions, although there is a high level of demand concentration in the central region of the country (over 85%). Close to 44% of the total net demand was registered in the Buenos Aires metropolitan area, which, together with the rest of the Buenos Aires province, concentrates 57% of the electricity demand within SADI.

With respect to electricity supply, and as may be observed in the Figure, the peak load registered in 1997 represented only 58% of the installed capacity in the system, which clearly shows the existence of a certain degree of over-capacity within the system.

The same Figure also shows the total capacity installed in each region, as well as the regional contribution to SADI's simultaneous peak load. As may be noted, the maximum surplus of installed capacity is registered in Comahue, where low-price natural gas availability led to the installation of gas stations which joined the hydroelectric stations installed in the area.

At the Argentine northeastern region - the second region in importance with respect to capacity surpluses -the supply is concentrated in a run-of-the-river hydroelectric station shared with the Republic of Paraguay. The surplus from the Argentine northwestern region, on the contrary, is recent and originated from the decision of private investors to install thermal stations to make use of the relatively abundant natural gas in the area.

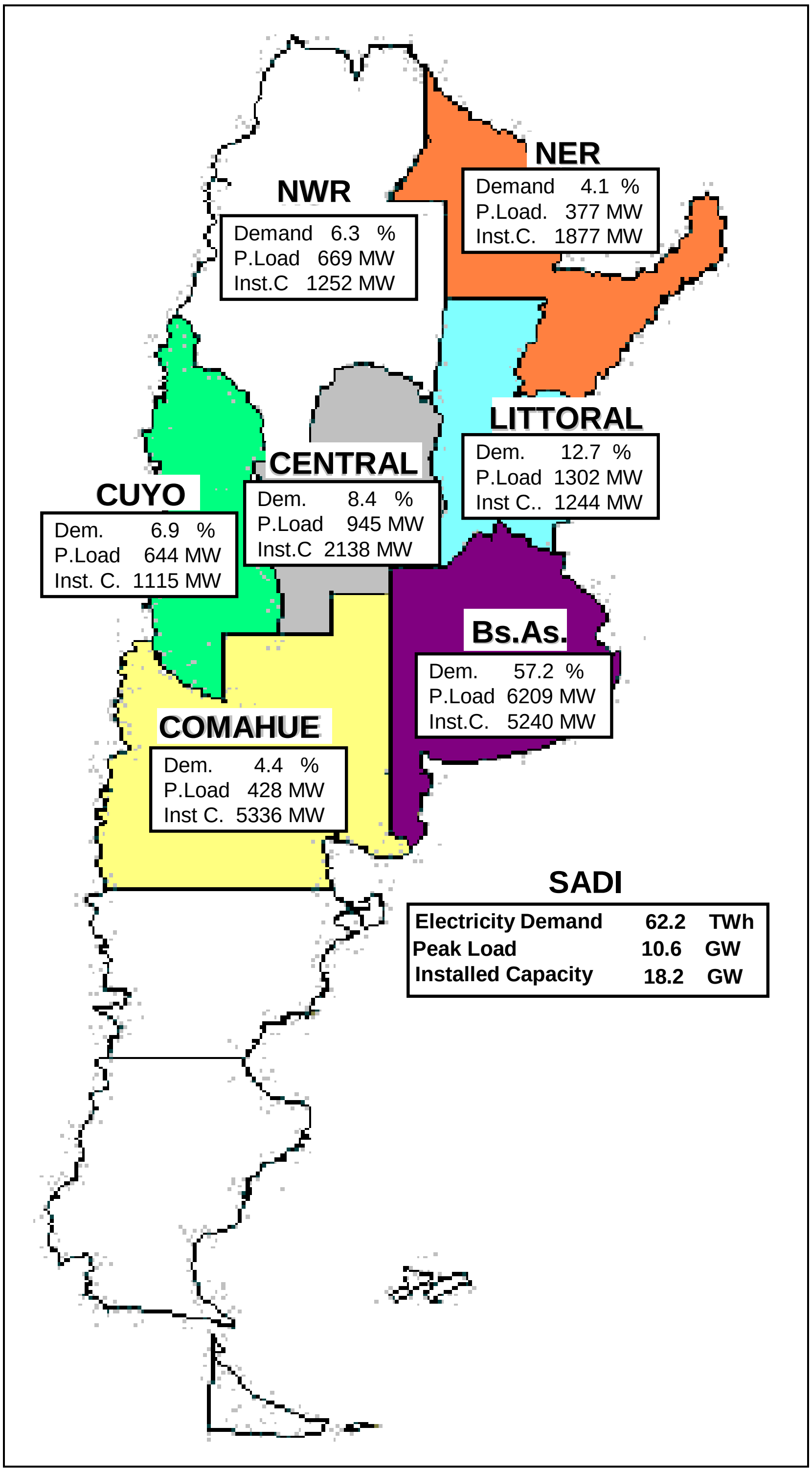
The stations installed in these three regions are highly competitive in the market, particularly those of Comahue and the northeastern region. Thus, these capacity surpluses translate into constant export flows towards Littoral region and Buenos Aires. Practically the entire surplus from the Central region is concentrated in less-competitive pumping-storage and gas-turbine stations, resulting in lower export flows, though the nuclear station installed in the area may bring about exports during load curve valley hours.

This space distribution of electricity supply and consumption turns the transmission system into a critical element for the reliability of the supply, especially as regards the Comahue-Buenos Aires and northeastern-Littoral-Buenos Aires lanes.

Figure N° 4 shows SADI's transmission network, in which only 500 kV lines and transformer stations are marked. As may be noted, the network has a mainly radial layout with its centre at the Buenos Aires metropolitan area.

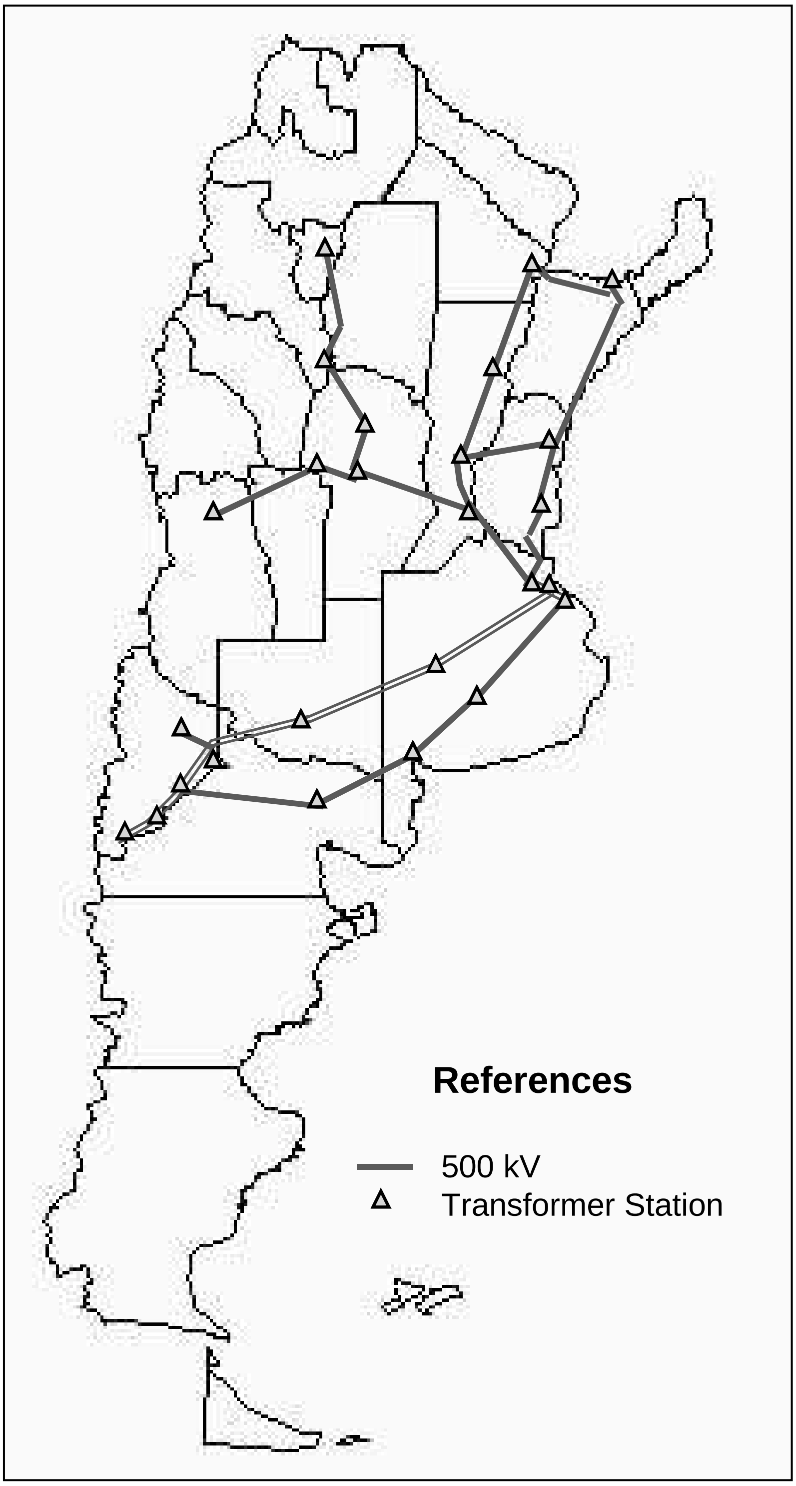
The distances separating the Comahue stations from the load centres (an average of 750 miles) make the capacity of the three lines installed insufficient and impose restrictions on the release of the capacity bid in Comahue, a problem which is intensified since two of the lines may be simultaneously affected by weather phenomena.

Figure N° 3: Space distribution of demand and supply within SADI



It is expected that transmission restrictions in this lane will be solved with the start of operations of the fourth line currently under construction. Although this transmission deficit has registered a certain permanence over the last four years, the process to reach the agreement of the network users to expand took more time than was expected.

Figure N° 4: SADI high-voltage transmission network



Capacity surpluses registered in the Argentine northeastern region will be even higher in the next years, when complementary works in the Yacyreta hydroelectric facility are expected to be completed and the operation of the station may be adjusted to designed head level. In these conditions, the station's installed capacity would reach 3100 MW, that is, 1400 MW more than those accounted in Figure No. 3 for the end of 1997.

The two existing lines would not guarantee the placing of surplus in the market, specially since one of them is shared with another two-nation hydroelectric station, which supplies 945 MW to the Argentine market. In this case, the mechanisms anticipated in the regulation for the expansion of the transmission network require that the initiative be taken by the agent operating the station, who would be its main user. So far, no initiative of this kind has ever been made public. Instead, the possibility of closing a ring on the northern region has been analysed, interconnecting both the Argentine northeastern and northwestern regions. The capacity to release power from the Argentine northeastern region through this line will depend on the competitiveness of the stations from the northwestern region, and especially on the availability of natural gas in the area.

Some analysts have high hopes that a future interconnection with the Brazilian system - depending on the chosen route - will help release the supply from Yacyreta without need of fully expanding the northeastern-Buenos Aires lane.

Nonetheless, interchange with Brazil could prove of little help in wet periods in that country, for in that case the capacity contracted in the Argentine system could not be required by the Brazilian customer. In those periods, and even without assuming the importation of Brazilian hydro surpluses, the transmission capacity of this lane could jeopardise the utilisation of energy from Yacyretá, the only destination for it being the spillway.

With reference to supply per type of technology, by the end of 1997, 48% of the total installed capacity in SADI corresponded to hydroelectric stations, while conventional thermal stations contributed with 46%, and nuclear stations with the remaining 6%.

Total gross generation from SADI during 1997 was slightly higher than 69 TWh, of which 43% corresponded to hydroelectric stations, 45% to thermal stations and 12% to the two existing nuclear stations.

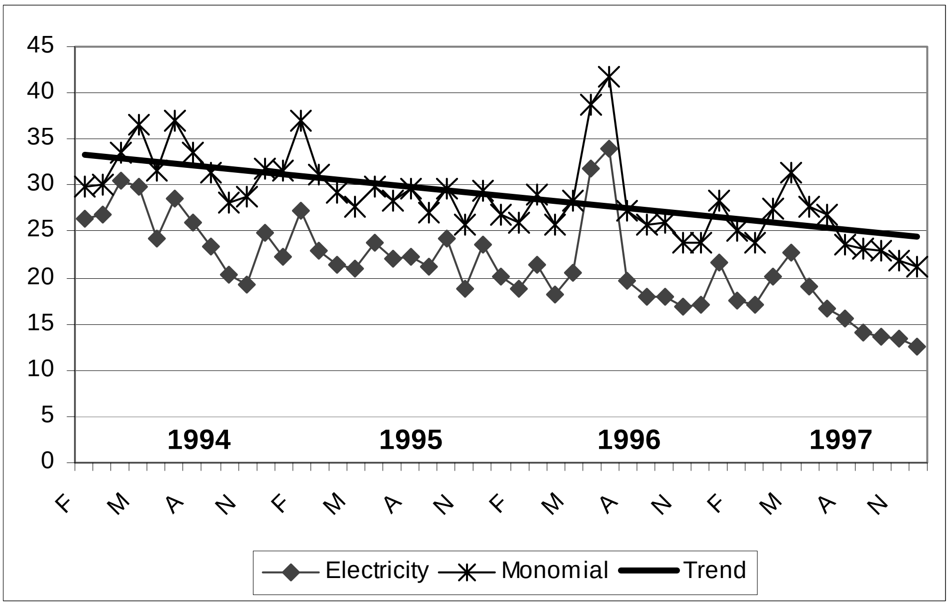
In accordance with the statistical report from the Energy Secretariat, 17% of the WEM's net demand during 1997 corresponded to large users contracting their electricity supply. Adding the purchases through contracts carried out by the distributors, the contract market share reached in 1997 60% of WEM transactions.

5 The Dynamics of the Argentine Electricity System within a Competitive Environment

In a context of electricity consumption growth exceeding an annual 6%, installed generating capacity has notably expanded since 1992, when the industry's reform was implemented. In fact, during the first five years after the reform, some actual 6900 MW were installed, representing 58% of the gross peak power generated during 1997, increasing reserve margin to 54% of peak demand within SADI. Nevertheless, it must be pointed out that 65% of the added generating capacity corresponded to hydroelectric stations which were already under construction with public funds prior to the reform.

Precisely, the start of operations of these hydroelectric stations resulted in a substantial drop in spot electricity prices, reaching values which are expected to remain during the next years upon completion of complementary works, which would allow Yacyretá's reservoir level to reach its design level. The evolution of the spot price during these years is shown in Figure N° 5.

Figure N° 5: Evolution of the spot price within WEM



This Figure shows three curves. The first is identified as “Electricity” and represents the mean monthly price paid to WEM bidders for their sales of electricity. The second curve is identified as “Monomial” and represents the total monthly payment to generators on account of capacity and electricity expressed per sold electricity unit. The “Trend” curve corresponds to a linear adjustment of the evolution of monomial prices.

As may be noted, and except for exceptional situations during the winter of 1996, mean monthly prices show a clear downward trend without any significant fluctuation. However, it must be said that the price of electricity seems to have reached a bottom of some US$ 13/MWh, since operational costs of the thermal stations would not be covered below such price. Actually, operation during the first months of 1998 shows a slight rise in electricity prices, influenced by the low hydro contribution in the Comahue region.

Notwithstanding this unfavourable (for generators) context of the electricity market, which could have discouraged private investors, private companies have put in operation 2400 MW in thermal stations which have co-operated to reduce spot prices even more.

The new thermal stations enjoy significant advantages from an operational viewpoint with respect to existing thermal stations. Initially, such advantage lied in the availability of natural gas at a lower price and without seasonal restrictions rather than in a substantially-higher thermal efficiency than that of the existing stations.

In fact, the heat rate of the stations incorporated until 1995 was of some 2600 kcal/kwh, which, although relatively low in view of the fact that they are open-cycle gas-turbine stations, exceeds the consumption of many steam-turbine stations which they displaced as regards operation. As from 1996, we notice a substantial improvement in the performance of the new thermal units, after combined-cycle generators were chosen, with a declared heat rate of 1600 kcal/kWh.

The first private investments were focused on the Comahue area trying to make the most of the availability and low cost of natural gas in that region. Evidence of the clear understanding which private investors had of this comparative advantage is given by the fact that 71% of the added capacity until 1995 by the new thermal stations is installed in Comahue. Of these, nearly half are well-head stations built by oil companies with a view to using previously flared natural gas.

Nevertheless, the rise in both thermal and hydro supply in Comahue rapidly precipitated the breakdown of the transmission system, jeopardising the quality of the business of certain hydro agents in the area. The complexity of the mechanisms established for the expansion of the transmission network and the differences of interests among local generators themselves has delayed the incorporation of the fourth line in the Comahue-Buenos Aires lane.

Higher competition began to take place among generators from 1995 not only as regards the attraction of customers to the fixed-term market but also in investments to improve competitiveness. In the first place, there was a movement of new investments towards the Argentine northwestern region, especially to the Tucumán province, where there is also natural gas availability at a low price throughout the year as well as lower restrictions in the electricity transmission network. Part of the expected facilities in this area are already under commercial operation, the rest being expected to be operating in the near future. By the end of 1997, these stations represented 23% of the total thermal capacity incorporated since 1992.

In the second place, we notice a higher interest on the part of the generators located within the large consumption areas in improving their competitiveness against new generators. The key for this is to improve their thermal efficiency and achieve a natural gas supply at a competitive price, having the advantage of lacking restrictions from the configuration of the transmission network and lower transmission costs. Over 50% of the thermal capacity added in the last 2 years corresponds to combined-cycle natural gas stations installed within the Buenos Aires metropolitan area.

This process to expand installed capacity in the metropolitan area seems far from being discouraged by the low prices of the spot market. Several agents have already contracted the supply of new combined-cycle units with a module close to 700 MW each and an efficiency exceeding 56%, as declared by manufacturers.

As may be noted, the initial vigour of the oil companies to expand their electricity-generating capacity is promoting greater competition among generators and in turn leading to new investments. The unusual aspect of this is that these investments take place within a context of falling prices in the electricity market sustained by a certain over-capacity which generators themselves increase in their search for higher competitiveness.

This process is leading the electricity industry towards a rising dependency on natural gas both as regards availability as well as price. Hence, there is in practice a reversal of the historical policy of granting more independence to the electricity sector with respect to the oil industry, which is currently dominating the natural gas market.

In this context, and as an offsetting strategy, generators are trying to widen their borders through electricity exports to neighbouring nations. From the surrounding systems, the Brazilian one is undoubtedly that which offers higher opportunities on account of its size (the Brazilian central-southeastern system has a demand equivalent to 3.5 times that of the Argentine SADI).

The institutional and regulatory reforms of the Brazilian system have favoured the holding of agreements among agents from both nations which nonetheless have to overcome the obstacles put forward by the frequency difference between both systems and the lack of interconnection lines with sufficient transmission capacity.

Notwithstanding this, contracts have already been signed for the exportation of 1000 MW of firm capacity, which could expand to 2000 MW in the future.

As long as the prices contracted cover the repayment of the investments in the international transmission link, the operation improves the economic equation of the exporter, who is still able to bid his electricity in the Argentine spot market when the contractor does not require the contracted units. The remaining Argentine generators would also be favoured by the price rise which the actual demand of the Brazilian buyer would bring about.

However, the mere existence of the physical link between both systems would enable importation operations of eventual Brazilian hydro surpluses. In this case, the Argentine spot price would fall by a magnitude which will depend on the imported volume, affecting all suppliers trading their production through the spot market. The frequency of these cycles of ups and downs in the spot market - as well as its extent - will mainly depend on the future situation of the Brazilian system and on the transmission capacity of the international link.

As previously mentioned, the construction of an international link may be initiated only if there are contracts previously agreed upon between the parties which require the expansion of the existing capacity. But once it is operational, access to the remnant capacity after the contracts are complied with is free to all agents who may wish to promote a spot operation.

It is to be expected that the construction of this type of link will encounter fewer obstacles than proposals for the expansion of SADI's high-voltage network, since regulations for international links tie the payment for their installation costs directly to the users who promote such links.

The experience gathered during these years with respect to the treatment of SADI's transmission network shows that the mechanisms proposed to decide and pay for the expansion register failures which delay the execution of the works. The Argentine regulating body (ENRE, in its Spanish abbreviation), in its annual 1996 report, issued strong criticism to the planned procedure and clearly pointed out the aspects which hamper the dynamics of the decision-taking process.

It is to be expected that these regulations will experience in the near future changes which will allow decisions with respect to the transmission network to go hand in hand in time and way with the dynamics of the generators and that they may guarantee adequate reliability to the rendering of the electricity service.

III Influence of Regulation on Decision-Making

This chapter will delve into the analysis of those regulations which explain the behaviour shown by the agents of the electricity wholesale market and which could represent obstacles for the implementation of climate-change mitigation actions in Argentina.

From this viewpoint, the following sections analyse the aspects affecting the technological decisions of electricity generators (Section 1), as well as the incentives and obstacles for the electricity distributor to engage in more active participation in energy efficiency programs (Section 2).

1 Electricity Generation

The interest here is to pinpoint the elements of the regulations in force which may influence the quality of the business of WEM generators depending on the generating technology they choose. From this viewpoint, the following are of special interest:

- market access conditions
- "product and/or service" type which may be supplied
- specific restrictions to their competition to supply these products and/or services
- specific costs associated to each technology

The following paragraphs analyse each of these elements, with special emphasis on hydroelectric and nuclear generation against conventional thermal generation, since they were deemed climate change mitigation options in the Argentine Mitigation Study of the UNEP/GEF project Economics of Greenhouse Gas Limitations.

1.1 WEM Access Conditions

The regulation in force is aimed at favouring the initiative and election of private investors in the expansion of electricity generating capacity. However, the obtainment of a concession awarded by the relevant authority is required when these decisions involve the use of certain resources, the use of which by a certain agent prevents or restricts its shared use by other potential agents.

Such is the case of the utilisation of waterways for hydroelectricity generation, where concessions for the commercial exploitation of the existing stations were awarded for a period of 30 years. Although from private perspective horizons shorter than this period are used as the capital return period, the duration of the concession is itself substantially shorter than the actual life cycle of the facilities. The impact of this difference (between the concession period and the life of the facility) on the calculated cost of generated electricity depends greatly on the discount rate used in the evaluation. At a 12% discount rate, the percent increase in generation costs resulting from assuming a 30 year concession life rather than a 50 year physical life is 3%. But with an 8% discount rate, the increase in electricity price due to the difference in assumed life is 9%, a substantial amount.

The installation of nuclear stations also requires a concession, although for different reasons. In this case, commitments on operation safety and the further dismantling of the station, as well as the handling of radioactive material, hold an essential influence.

Although every new facility is subject to the observance of environmental regulations, hydroelectric and nuclear stations are especially affected. In the first place, we must mention a rising resistance to these types of works from certain groups, in view of the poor handling made in the past as regards local impact and risks posed by these types of works.

The adequate handling and protection of the waterways represents one of the most significant environmental problems which should be dealt with in Argentina. Perhaps the most problematic from this viewpoint are the works at the River Plate basin, which were precisely considered as greenhouse gas mitigation options in the UNEP/GEF study on account of the volume of energy which would be generated.

It is important to point out that this is a plain crossed by two plentiful rivers - especially the Parana river - until their outlet into the River Plate and Atlantic Ocean. There are many hydroelectric stations located at the high Parana basin and its branches in Brazil, which - notwithstanding their reservoir capacity - prove incapable of regulating the flow of both rivers, characterised by a rainfall regime.

There has been much said on the risks of disease spreading favoured by stagnant water environments (schistosomiasis) among the population of the area, and the issue is periodically brought to public consideration. However, the highest concern of the people in the area is the flooding of fertile soil and the displacement of the population on account of the dams, water drainage and flood prevention.

The area cyclically experiences serious economic damages on account of floods caused by heavy precipitation throughout the basin. The weather variability associated with the El Niño phenomenon appears to be reducing the duration of the cycles and increasing their intensity, which makes the people call for the construction of works to mitigate their effects. As a matter of fact, on certain occasions defence works were built which only served to worsen water drainage conditions and brought about conflict among neighbouring populations.

It is evident that due to the topographic characteristics of the region and river module, reservoirs would add very little capacity to regulate the rising wave. Nevertheless, one of the works establishes the construction of a side dam for the protection of productive land at the lower river bank. There are however certain doubts on the effects which this side dam would have on the behaviour of the water table and the way the area drains.

Hence, hydroelectric works should be part of a general plan for the adequate handling of hydro resources in each region. Only the seriousness of prior studies and the wide participation of social organisations would allow to cast away all fears from the local population on the harm which these works could bring about.

Thus, the design of the works cannot remain solely subject to the economic profit of the investors carrying them out but will also demand ample State commitment to guarantee that all local impacts and desires are contemplated. Otherwise, the feasibility of the works would be highly compromised.

With respect to public opinion regarding the risks posed by nuclear energy, the situation has also changed drastically during recent years. The new constitutions in several jurisdictions include statements in opposition to this technology, usually declaring their territories free from nuclear elements. The higher resistance is produced as regards the possibility of being repositories of nuclear waste, notwithstanding the fact that the operation of existing nuclear stations has been generating nuclear waste for almost 25 years.

The restoration of public trust in this technology will prove not an easy task. There are too many questions on the long-term safety of final high-radioactivity waste repositories. Wide debate and the participation of local organisations will also be required in this case to make feasible this non-GHG-emitting technology.

In the special case of hydroelectric stations, the use of water and the control of floods have priority over hydroelectricity generation, and the concession-holder must strictly comply with the restrictions on flow distribution and reservoir regulation capacity. Hence, every hydro generator is subject to the simultaneous control of electricity bodies (regulatory body and dispatching body) and the basin authority.

Although the observance of the restrictions on the maintenance of minimum flows downstream of the dam is the responsibility of the concession-holder, this does not enable him to increase turbined flows above what is requested by the dispatching body. His responsibility must be to comply with the dispatching body's request by spilling any excess flow, even when this may bring about eventual economic damage due to the waste of the resource.

The concession-holder may choose not to acknowledge the orders from the load dispatch only when the request implies an operation which acts against his commitments on maximum flows and / or instant flow variation.

1.2 Supplied Products and Services

Although all private generators have equal opportunities to take part in the fixed-term contract market, it must be emphasised that so far (end of 1997), and given the dynamics shown by the expansion in generation, supply contracts signed at a fixed price were for brief periods in comparison with the life cycle of the works.

Within a context of falling prices at the spot market, distributors have been reluctant to sign long-term fixed-price commitments for their electricity purchases. It must be said that this attitude is indirectly encouraged by the regulations.

Considering the diversity of the concession agreements, in general, regulation aims at having distributors assume the risks of these transactions. Even when distributors are allowed to freely choose the mode in which to operate within the WEM, their corporate risk is minimised when they are supplied from the spot market. In fact, the indicator used to adjust the price of the total electricity purchases on the part of the distributor is the price variation registered at the spot market. Should its supply be totally or partially contracted through the fixed-term market, the distributor does not have to transfer to retail tariffs the economic profit which would result when spot prices are higher than contract prices. At the same time, should contracted prices prove higher than those in the spot market, the cost overrun must be absorbed by the distributor, with clear harm to the distributor.

Although this regulation is aimed at protecting captive consumers from collusion between distributors and generators, the truth is that it discourages the signing of fixed-price supply contracts in a context of falling prices in the spot market. On the other hand, generators are reluctant to sign them when it is expected that prices will show an upward trend.

The reluctance shown by distributors to assume risks within this context creates the result that all risks of possible future fluctuations in electricity prices at the wholesale market are absorbed by generators who may not contract with large consumers, and by captive final consumers in the concession area of distributors, whose rates will go hand in hand with spot market price variations.

Hence, the distributor's inclination to commit to long-term purchase prices will depend on the prospects regarding spot price trends and their variability (volatility). As previously mentioned, the volatility of prices in the Argentine spot market is mainly associated with the variability of the hydro contribution, and could increase in the future due to electricity interchanges with neighbouring nations. Thus, the analysis of the influence of generating technology on the income of the generator will be carried out considering sales in the spot market.

The monetary income of the generators depends on the services they may sell in the electricity market and on the competitiveness of their facilities for the rendering of such services, basically with reference to the following:

- electricity sales
- capacity sales
- regulating reserve margin (for primary and secondary frequency regulation)
- spinning reserve
- cold and base-load reserve

Not all generating technologies have equal opportunities to supply these products in the WEM. In the first place, cold and base-load reserve may only be supplied by conventional thermal stations. In the case of cold reserve, the transaction is established on the basis of a weekly price bidding in which the bidder must guarantee the availability of the bid units and set the minimum time in which his units are capable of reaching maximum capacity when shut down.

The notion of base-load reserve was introduced in the regulation to reward the service rendered by base-load thermal generators when making their facilities available to guarantee normal supply in a dry year, even when their units do not operate in normal conditions. The base-load reserve contributed by a thermal unit (conventional or nuclear) is calculated as the mean power dispatched from that unit in the operation of the system throughout the driest year in the history series. All thermal generators receive a minimum reward equivalent to that mean power on account of capacity sales to the market. The base-load reserve sold is the difference between the mean operated power in an extra-dry year and the total capacity sold on other accounts (operated, contracted for cold reserve and cold reserve sold at the spot market), should such difference exist.

The mechanism to determine the contribution of each thermal generator to face unfavourable hydrological conditions seems adequate and necessary in a system with high hydro share such as the Argentine one, although it could be stated that considering the driest year in a 70-year historical flow series seems quite an extreme condition.

From the point of view of thermal generators, to collect such reward holds a certain significance, since prices in force for the sale of available capacity reach US$ 10/MW per hour outside a valley hour on a working day. By the end of the year, this reward is equivalent to some US$ 43/kW sold, a figure which is quite significant when considering the investment cost reduction operated at gas-turbine stations.

The spinning reserve both for frequency regulation as well as to face forced outages is covered with those units which have the quickest response in load taking. As far as possible, it is a task assigned to hydraulic units, as long as this does not imply increasing the number of units operating in a hydroelectric station above what is necessary to cover the power requested by the dispatching body for covering the demand at that hour.

The prices actually charged by each generator for capacity and energy sales depend on their location at the high-voltage network and on the quality of the transmission link joining it with the system's load centre (capacity and electricity node prices). Node prices are higher when closer to the load centre and the more strongly interconnected they are. Since hydroelectric generators depend on the geographical location of the resource, they cannot use the location of their facilities as an element to improve their market competitiveness, as done by thermal generators.

If they try to avoid high transmission costs by under-investing in transmission capacity, the hydro generators run the risk of having their node prices disconnected from market prices due to transmission restrictions to place their supply at the load centre. Regulation establishes that every time there is a restriction at a transmission lane, prices at the affected area (local prices) are disconnected from market prices, showing the supply surplus or deficit in the area, according to whether it is an electricity exporting or importing area. From the point of view of the hydroelectric generator, the risk is that local electricity prices may fall to very low values if there is no sufficient local demand for their supply. These prices shall logically be maintained depending on the duration of the failure of the transmission facilities.

Consequently, the design of the transmission network and its costs is no minor issue for the quality of the business of the hydroelectric generators, especially in the case of new large stations which will certainly require the expansion of the high-voltage network to place their production in the market.

1.3 Competition Limitations

Besides the location restrictions already mentioned, there are differences on the treatment of hydroelectric and thermal stations in the scheduling of the operation of the system which affect the capacity of the agents to supply their production to the market in a competitive way.

Load dispatch procedures are aimed at appraising the hydro resource according to the contribution which each hydroelectric station may make to reduce future electricity supply costs. Thus, a key element for water appraisal is the capacity to store it in order to prevent the future operation of more expensive thermal stations. From this viewpoint, run-of-the-river hydroelectric stations are attributed a zero water value and given absolute priority in the turbining of water inflows.

Should hydroelectric availability exceed power demand at WEM, the stations closer to the load centre are considered the most competitive ones, and the spilling water is authorised to be bid as spot supply in the interconnected foreign markets with available transmission capacity.

In the case of stations with seasonal reservoir capacity, the dispatching body seasonally determines the minimum water backup volume which must be kept at each reservoir to guarantee future supply. This minimum backup volume corresponds to a water volume which serves as top limit for the seasonal value of water which the station's operator may declare to compete with the other generators at SADI. Hence, the hydroelectric generator only controls the policy on reservoir-emptying between minimum backup level and maximum design level.

The operation schedule determines the hydroelectricity volumes to be produced by each station until reaching a water value declared equal to or lower than the price of the system's marginal unit. In the actual operation of the system, the peaking of each hydroelectric station is carried out giving priority to the stations from the regions closer to the load centre, and within each region giving priority to those stations with a lower plant factor (according to the design of the station and considering operational restrictions).

As long as there is a significant difference between peak and non-peak electricity prices, this operational rule may have significant consequences on the income of certain hydroelectric generators on account of their sales at the spot market to the benefit of other hydroelectric generators.

In the same way, hydroelectric generators with a higher reservoir capacity may face economic damage in the case of transmission restrictions forcing the setting of local prices at the area of the generator.

Although these regulation prescriptions could influence the design of future hydroelectric stations, the higher impact on design variables would be certainly given by how private investors view hydrological risk, which also affects other generators.

In wet periods, the agents of run-of-the-river hydroelectric stations may partially offset the price fall with higher generation, although the net result of their income will depend on the magnitude of both phenomena.

Nuclear generators will hardly see their electricity production modified under these system operating conditions on account of the comparative advantage of their low variable costs. Hence, the income of nuclear station agents would go exactly hand in hand with spot price fluctuations if they sell their production in that market.

Conventional thermal generators would be theoretically the ones suffering most of the damage in the case of high hydro contribution, for they would simultaneously reduce their sale prices and sold amount, and in some cases they would be fully excluded from the market. In order to mitigate this damage and prevent the bankruptcy of generators operating their stations in adverse hydrological conditions, their base-load reserve capacity mentioned in the previous paragraph is paid to them.

On the contrary, in dry hydrological years, thermal generators are precisely those earning the highest income (more thermal generation sold at higher prices). Dry periods will also represent higher income for nuclear generators, mainly associated with higher prices, since their production experiences little variation with the prevailing hydrological conditions. The impact of dry years on the income of hydroelectric generators will depend instead on the magnitude in which their own generation will fall and on the price rise at the spot market.

The magnitude of the fluctuations in hydroelectric generation between wet and dry years will depend of course on the maximum turbinable flow installed at the stations. To this respect, it must be noted that in all stations designed and built by State companies, the installed capacity was that allowing to make use of most of the hydro potential. Thus, in wet years, there is generally sufficient installed capacity to turbine most of the contribution, expanding the variability range of hydro supply in accordance with hydrological conditions.

It is doubtful that private investors will be willing to follow this design rule. The equipment level will surely be that which allows to offset investments in additional units with higher income notwithstanding the eventual price drops. It will be necessary to analyse for each case in particular the true meaning of this decision rule in terms of the hydro energy not used on account of spilling.

The future interconnection with the Brazilian system could increase price volatility in the Argentine spot market on account of variations in the hydrological contribution in the neighbouring nation. It must be pointed out that the Brazilian system is almost entirely supplied with hydroelectric generation and, thus, the supply is subject to flow distribution. The need to expand Brazil's generating capacity is determined assuming a 95% supply guarantee. This means that 5% of the time Brazilian supply could be compromised on account of lack of water at the reservoirs, but the remaining 95% could experience a capacity surplus without sufficient domestic Brazilian market to place the surplus supply. This electricity, the magnitude of which depends on the hydrological conditions of each particular year, is known as secondary or non-firm electricity.

The economic value of this secondary electricity is zero in terms of its marginal generation cost, for it corresponds to a spilling situation. Hence, the price at which it would be supplied to the Argentine market as contingent importation could be very low, on the condition that it may cover transmission costs.

It is clear that this context conspires against the construction of capital-intensive stations demanding long construction periods, since corporate risk leads investors to demand higher investment-return rates. All technologies considered as climate change mitigation options share this characteristic of high capital costs. In the case of hydroelectric stations, distances to consumption centres force hydroelectric generators to additionally face higher transmission costs.

1.4 The Specific Costs of Each Technology

Besides the risks and limitations already mentioned, there are particular conditions of the regulations which increase the costs faced by generators depending on the technology they use. We shall solely refer here to those costs which are specific to nuclear and hydroelectric stations and which are not shared with conventional thermal generators.

In the case of nuclear stations, we must include as costs the establishment of special funds for waste treatment and the further dismantling of the station, as well as the insurance and contribution for maintaining the Argentine nuclear activity control body.

In the case of hydroelectric stations, the following must be mentioned:

- *the payment of royalties to the provinces yielding the use of the hydroelectric resource*, representing 12% of the gross income on account of electricity sales, either in cash or kind;
- *the taking of insurance*, to cover damage to third parties on account of dam failure,
- *the transmission-network expansion mechanism*, which forces repayment of the cost of installing new lines within a maximum period of 15 years.

These elements affect the way private investors view the economic profit they would obtain with the construction of the works. Hence, they should be considered when calculating incremental climate change mitigation costs every time a change in the technological choice of the generators is sought.

2 Electricity Distribution

This Section will only deal with the elements of the regulation in force which could favour or hamper the participation of distributing companies in the programs to promote higher efficiency in electricity end use. The aspects related to the energy efficiency of the distributors themselves in handling the network will be dealt with in Chapter V of the present Report.

In general terms, the concession agreements for electricity distribution lack specific prescriptions to force or encourage companies to take part in end-use efficiency programs. Nevertheless, and considering that distribution costs have a high fixed-cost component, it will be in the interest of the distributing companies to maximise the utilisation factor of the distribution networks.

Actions aimed at improving the load factor of consumption are thus favoured by the distributors. In the same way, tempering the growth rate of the peak load in their concession areas would allow distributors to reduce their network-expansion investment requirements.

From a regulatory viewpoint, the interesting issue is how to reconcile the distributor's obligation to meet any demand requested within his concession area at a minimum quality standard with the opening of the retail market to competition with traders and generators.

In accordance with official statements, the aim is to expand customer choice of electricity supplier to eventually reach all consumers in the coming years. Such modification would necessarily imply the re-conversion of the concession agreements already awarded to the distributing companies with a view to a new determination of their obligations and rights in the rendering of the public electricity service.

Until this determination is clear, it is to be expected that the companies will show conservative behaviour as regards incurring costs, the recovery of which is not guaranteed through their roster of customers, which are subject to rising competition.

For the time being, distributors maintain the final obligation of supplying every demand requested with a minimum service quality to avoid economic penalties. Opportunities to compete with generators and traders within their concession areas are limited.

In the first place, they may not agree with selected customers on special conditions for the supply of electricity without such behaviour being considered discriminatory with respect to other customers within the same consumption category. This does not mean that they cannot act as traders outside their concession area and compete with the rest of the suppliers to attract new customers. In fact, a distributor from the metropolitan area has recently signed a contract for the supply of electricity to a very large iron & steel company located outside its concession area.

In the second place, distributors are in worse conditions within their concession area with respect to competitors as regards the tax treatment of electricity consumption. As previously mentioned, the distributing companies are forced to act as retention agents for all taxes and rates on electricity consumption within their jurisdiction.

This obligation is for the time being not imposed on other electricity suppliers within the WEM, with the exception of the value-added tax and the contribution to finance the dispatching and regulatory bodies. Provincial and municipal taxes, on the contrary, only affect at present distributing companies' customers. This has been the subject of debate among WEM agents, and distributing companies argue quite reasonably that they face unfair competition to attract customers within their concession area.

Several analysts have expressed their doubts on the true possibilities that electricity distributors may take active part in the promotion of higher efficiency in electricity end-use (through integrated resource planning, for example) when they operate in retail markets open to competition. Uncertainty on the future maintenance of their customer base may hold a negative influence, especially when unfavourable conditions with respect to their competitors persist.

We must point out the fact that the reform of the energy industries in Argentina has expanded the range of products and services for which suppliers compete. A clear example of this is co-generation, where generators are in better conditions than their competitors to reach commercial agreements with industrial companies for the joint supply of process heat and electricity.

Another example is the advice given to potential new customers on the types of facilities to build in the new premises to meet their energy requirements. This is basically a competition between electricity and natural-gas distributors to attract markets associated to certain uses, particularly space conditioning (both heating as well as cooling). Although the areas in which this competition may exist are limited, the behaviour of the distributors seems to anticipate a future identification of new markets and diversification of products.

IV Incentives for the Use of Renewable Resources within Argentina

We will refer here to the promotion of the use resources solely for electricity generation, particularly hydroelectricity, wind energy and solar energy. Moreover, and even though it may not be strictly a resource, some comments will be made regarding nuclear generation, in as far as it may be a climate change mitigation option, for it does not emit GHGs.

The following sections analyse the policies in force for each one of these sources and the market trends within these policies and regulations in force.

1 Hydroelectricity

Given the federal nature of the Argentine Republic, we shall analyse the policies and incentives in force both at the federal and provincial level, whenever they may correspond.

Even when hydroelectric resources within their territories correspond by the Constitution to the respective provinces, the federal government rules on the use of inter-provincial waterways, awarding concessions for the construction and exploitation of the works, although the provinces take part in controlling the flows released and their impact.

Most of the hydroelectric stations already built and of the still-unused hydro potential is found in inter-provincial waterways, and thus subject to concession by the federal government. Nevertheless, and particularly for the construction of new stations, riverside provinces must grant their consent to the works.

As previously mentioned, some provinces have taken a truly-opposite attitude with respect to the construction of certain works. Nonetheless, whether such opposition has to do with the site of certain works in particular or affect every new work is something yet to be determined. In any case, should a policy to promote the nation's hydro resources be determined, an agreement should be reached with all interested parties - particularly the inhabitants affected by the works - on the essential characteristics of these works so as to make their construction feasible and take all necessary precautions to reduce local impacts to levels acceptable to all parties.

The view on the convenience to carry out hydroelectric works is not homogeneous in all provinces. Some provincial governments have promoted the construction of hydroelectric works within their respective territories. In the cases registered so far, the provincial governments have accepted to take part in the financing of the works, even when the execution and final exploitation remains in the hands of private investors. Through this mechanism, the concession to build, operate and maintain the stations was awarded to the investor group which requested lower State investment.

Within this context, the federal government has not implemented specific mechanisms to promote the construction of new hydroelectric stations. However, it maintains the responsibility for the availability and transparency of all public information on opportunities for the construction of new hydroelectric stations, which presupposes the following:

- The constant evaluation of the hydroelectric potential of national hydrographical basins and the measurement of flows;
- The updated maintenance of the list of possible hydroelectric undertakings throughout the Argentine territory;
- The determination of possible siting and design variables for the new works, optimising the use of the hydro resource in each basin;
- The holding of basic studies on the new works (pre-feasibility level study) and the submission of these studies to all possible interested parties.

As previously stated, private investors have clearly shown, since the reform, their preference for the use of natural gas for electricity generation, resorting at first to open-cycle natural gas turbines and more recently to combined cycles.

Except for the interest in the privatisation process of already-built hydroelectric stations, there has been no private initiative to continue the path begun by State companies towards the use of the nation's hydroelectric potential. To this respect, the only positive experiences were the construction of certain small hydroelectric stations made feasible through State subsidies from provincial governments.

2 Wind and Solar Energy

There is an explicit promotion for the use of these sources only for the supply of small dispersed systems, both at the federal level as well as in some provinces. However, these measures are essentially aimed at expanding electricity service to dispersed populations which are still not supplied.

The national program is similar to that put into practice in some northwestern provinces and consists in awarding a supplier a concession for the installation of the necessary units in a decentralised manner, the concession-holder being responsible for the maintenance and operation of the units. The generating technology may be chosen by the concession-holder depending on the energy resources in the area, but this is mainly aimed at facilitating the penetration of photo-voltaic generation.

The program establishes the granting of subsidies to the concession-holder for the first three years of the concession, which may cover up to 50% of the electricity bill of the new users during that period. The program, with funds from the World Bank, is still too recent to draw conclusions on its results.

The use of wind energy in Argentina was quite widespread in rural areas, especially as motor power for the conveyance of water for cattle. Wind turbines for electricity self-production in dispersed rural areas without electricity supply from the public network experienced much lower penetration. Only in recent years were wind turbines incorporated as public-service facilities in certain areas of the country.

Since there have been no promotion mechanisms nor subsidies for the installation of this type of unit, actual incorporation depended on the specific conditions of local electricity service (purchasing cost of electricity for the distributor, transmission costs from the federal network and trunk distributor and retail rates), apart from the availability of the resource.

These factors have allowed several electricity co-operative associations to install in recent years some 11.6 MW of wind turbines, notwithstanding the fact that the cost of the energy produced more than doubles the electricity spot price during the period of investment repayment. Some of these units registered a utilisation factor close to 34% during 1997, which shows the abundance of the resource.

60 % of the capacity installed in wind turbines is located in Patagonia, where the wind resource is highly abundant; most of this belongs to the Comodoro Rivadavia electricity co-operative association. The remaining 40% is to be found in the province of Buenos Aires.

Should the retail market fully open to competition in the future, the permanence of these types of units could be jeopardised unless specific subsidies are provided, for the price difference could lead consumers to contract their supply with other generators, and the current rate protection enjoyed by electricity co-operative associations would disappear.

A bill was submitted to Congress recently to set a federal subsidy to wind energy, of some US$ 10 per generated MWh. Notwithstanding the fact that the bill was passed in Congress, it never came in force, as it was vetoed by the Argentine Executive Power.

3 Nuclear Energy

Issues concerning nuclear energy correspond to the federal government, and a concession is required to operate and / or build nuclear facilities. So far, the existing nuclear stations remain under the jurisdiction of the federal government, even when a law has already been passed to authorise the executive power to privatise them.

The state company operating the nuclear stations receives the same price at the wholesale market as other generators, though it is not empowered to sign supply contracts. The new law establishes a series of responsibilities for an eventual private agent as regards the following:

1. Risk of a nuclear accident and corresponding insurance;
2. Provision fund for the construction of a final repository for the irradiated elements;
3. Provision fund for the dismantling of the station at the end of its life cycle;
4. Rate to maintain the Nuclear Regulatory Authority;
5. Rate to contribute with the Argentine Atomic Energy Commission.

Moreover, the investor interested in operating the existing stations must commit himself to complete the ongoing construction of a third nuclear station, the works being practically suspended at present.

Within the current electricity price context in the wholesale market, these conditions notably reduce the interest of investors in taking charge of the Argentine nuclear stations, which on the other hand lack a homogeneous technology. It seems that the very government which promoted the passing of the privatisation law has doubts on the interest which could be gathered through this mechanism and is delaying the call to bidding.

Naturally, the construction of new nuclear stations poses a series of special conditions with respect to safety issues, for which authorisations from different bodies are required prior to the award of the concession, involving both federal and provincial bodies.

In any case, it would seem that investing in the construction of new nuclear stations appears to be unattractive to private investors, since their costs prove uncompetitive within the current context of the wholesale electricity market. Lack of competitiveness of nuclear electricity rises as nuclear safety regulations become stricter, and the latter are influenced in turn by a growing resistance to its use on the part of certain social groups.

It is necessary to observe that the debate on nuclear policy in Argentina is still pending, notwithstanding the recent passing of the nuclear law. By the end of the 1960s, Argentina reaffirmed its intention to move forward in the handling of nuclear technology, deciding on the construction of its first nuclear station, which began commercial operation by the end of 1974, on the basis of the use of natural uranium.

During these years, significant progress was reached in the handling of the fuel cycle, the manufacturing of heavy water and the re-processing of irradiated fuel elements, apart from the design and construction of low-power experimental reactors.

However, and besides the impact the program had on the nation’s technological development, the role of nuclear energy in the supply of local energy requirements is widely questioned as in other regions of the world, mainly on the basis of the implicit risks of this technology. Before deciding on the promotion of nuclear energy, wide consensus will be required on its convenience, and this may only result from a deep debate on its risks and on other available alternatives.

V The Promotion of Energy Efficiency in Argentina

This chapter analyses mechanisms in Argentina to promote energy efficiency in the final use of electricity and in electricity supply activities. Final use has also incorporated the situation in force with respect to co-generation, notwithstanding the fact that energy savings are mainly reached in the fuels used in the production of process heat. However, it is interesting to point out the extent to which the regulation in force for the electricity industry promotes co-generation. In both cases, the policy in force is summarised, as well as the incentives used and the results obtained so far.

1 Promotion of Energy Efficiency in Final Use

The guiding notion for Argentina's economic reform is, as already stated, to make all goods markets transparent and to use international prices as the reference, in the hope that importation could become an unlimited supply option to the domestic market and an alternative to domestic production. In this way, prices should show the relative scarcity of all tradable goods used in the economic process, promoting the corresponding replacements and / or savings.

Although this mechanism served to discipline the domestic prices of most tradable goods - even at the cost of a significant imbalance in the Balance of Trade - it did not produce the same effect in all energy markets.

In the first place, the markets for energy products distributed through physical networks, such as electricity and natural gas, may not quickly replace their supply sources (domestic versus imported). On the contrary, the economic feasibility of importation projects depends on the costs of the necessary infrastructure to materialise such importation, and investments are in general of such magnitude that they restrict the possibility of resorting to importation as a contingent supply to discipline domestic prices.

But even in the case of oil products, generally thought of as more conducive to this type of price-regulation mechanism, serious imbalances have been registered between domestic and international prices. The oligopolistic character of oil refining within the country is reproduced in the retail trading of such products, especially as regards motor fuels. The low participation of independent gas stations (not exclusively linked to a local oil product producer) places importation under the sphere of local producers, eliminating it as a competitive option.

These difficulties were more clearly appreciated when the domestic prices of oil products did not accompany the fall of the international crude oil price, as local oil companies tried to offset their own economic damage by maintaining high domestic prices for oil products.

Even when energy authorities closely follow the behaviour of these markets, it is worth mentioning that they resist using mechanisms for the regulation of domestic prices which do not rely strictly on an increase in competition. However, differences in regulatory philosophy do continue to exist. In light of oligopolistic practices by oil companies, certain sectors within the government, particularly in the Energy

Commission of the Congress, are pushing for greater government intervention in the markets through the setting of maximum prices linked to importation costs.

In the particular case of electricity, domestic prices in the wholesale market experienced a significant reduction during recent years, as shown in the previous chapters. Retail electricity rates are set by local authorities from each jurisdiction, which has led in the past to a wide rate dispersion even for the same category of consumers. Although local authorities maintain this power, the opening of the retail market to competition has forced a reduction in the dispersion levels of prices which had been reached prior to the reform, at least for non-captive power consumers.

Consequently, the price reduction registered at the WEM was transferred to a greater or lesser extent to final rates in nearly all jurisdictions. Such electricity-price evolution, although favouring consumers, may discourage actions to increase energy efficiency in electricity end-use.

Within such context, three programs related to the promotion of energy efficiency and climate-change mitigation in energy end-use are kept in force, namely: the substitution of motor fuels with compressed natural gas (CNG) in the transport sector, the promotion of co-generation, and the program on rational use of energy. The present analysis will set aside the promotion for the use of compressed natural gas in the transport sector, since it has no contact with electricity consumption. Thus, we shall focus on the other two programs.

Programs on co-generation and rational use of energy are based on market mechanisms. With respect to co-generation, studies were carried out to determine its potential in certain industrial branches. However, the downward trend registered by electricity prices at the wholesale market over the last years, as well as the liberation of the market to contract electricity supply by large industrial consumers, conspired against the spreading of this option.

Nonetheless, the generating companies themselves have shown certain interest in taking part in some co-generation activities in industries, resorting to two different modes. On the one hand, a thermal-station operator reached an agreement with an industrial customer located very near the station to sell him not only electricity but also residual heat from the thermal station. Although the experience proves interesting and new to Argentina, it may only be applied with customers located close to a thermal station.

The other way for generators to participate in the promotion of co-generation was through a contract signed with an industrial company to build, operate and maintain a co-generation facility at the premises of the industrial firm. Through this contract, the industrial company purchases heat and electricity services from the generator, yielding the use of part of its premises and the rights to trade electricity surpluses at the wholesale market.

The regulation in force allows the participation of co-generators in the WEM as one more supplier and, as such, they are enabled to sign supply contracts in local or exportation markets, in addition to selling to the spot market. However, the evolution of WEM prices has made the electricity business less attractive to industrial companies. As evidence of this, very few co-generators entered the market as members in recent years.

The price drop at the wholesale market, together with the vertical disintegration of the electricity supply industry, also discouraged at first the active participation of electricity distributing companies in programs on the rational use of energy for final consumption. Although some companies had begun to review this initial position -

especially to control the growth rate in electricity demand - the official aim to open all consumer segments to competition, re-converting concession agreements, seems to have altered these plans.

In any case, the official position on the energy conservation issue seems focused on the improvement of the information level of consumers through the labelling of electric appliances and on the transfer of the decision to consumers, allowing the free expression of their preferences.

As previously stated, the economic opening has brought significant transformations as regards energy end-use. In the first place, all economic activities subject to foreign competition experienced a restructuring which represented - in the successful cases - the renewal of processes and technology used in the production process. It is evident that such renewal improved the energy efficiency of these activities.

The restructuring was aimed at improving the quality and presentation of the products and at the same time at substantially reducing production and trading costs to compete in the domestic market without the tariff protection enjoyed in the past. Except for energy-intensive activities, energy costs did not have a determining role in this process. However, manufacturing companies made use of all available opportunities to also reduce their energy bill. But the energy-price context itself would not have justified the large investment made on technology and production-process updating.

Contradictory results were registered with respect to the appliances used by families and the tertiary sector of the economy to meet their energy requirements.

It is true that the opening to the importation of appliances increased local market options and forced local manufacturers to adapt to international standards with respect to energy efficiency, particularly electric ones.

However, the diversification of supply of appliances does not always respond to cultural traditions nor rationality in the use of energy sources, considering the availability of resources in the country. The most evident example of this is given by the increased presence of electric appliances for food cooking, both in home use as well as in the baking industry.

In the domestic case, and leaving aside the penetration of microwave ovens which provide a special service, there has appeared in the market a large number of cookers and electric ovens of ordinary use in Europe, their design attracting high-income sectors. The penetration of these appliances, although still incipient, means to displace the direct use of natural gas for cooking, which had previously been practically the only fuel used for this purpose.

If we consider the full chain from production to the energy service supplied, in terms of useful energy, electricity efficiency would be lower that that of natural gas, notwithstanding the high performance of the electric cooking appliance itself. The loss of efficiency is even higher when the user is not familiar with the use of electricity and repeats the habitual practices of natural gas cooking.

We could expect that this loss of efficiency will be finally reflected in the energy cost for the user, making him review his initial decision. However, this mechanism would only prevent the habit from expanding to sectors with lower income, since energy costs do not represent a determining factor in the election by the other consumers.

In the case of the use of electricity for baking, the electricity penetration is associated to changes in the food trade mode, from specific shops (bakeries) to supermarkets and market chains selling special baked goods. In this case, the penetration of electric ovens is associated to space and infrastructure problems which offset the higher costs of the energy used. To cut down electricity penetration in the baking activity seems a difficult task when solely resorting to the relative price of energy sources.

Competition between natural gas and electricity for heat purposes is expanding as a result of the reform due to the strategy of the distributing companies of both energy sources to expand their markets. Within such strategies, natural gas companies have aimed at attracting a large portion of the air conditioning market, so far considered as exclusively an electric use. In turn, certain electricity distributors have come out to compete with their natural gas counterparts for a portion of the room heating market.

This dispute is restricted to specific sectors within the new users. In other words, it aims at guiding the initial decision on the infrastructure to be built in the new premises rather than leading to a substitution among already-existing users. In the tertiary sector, it is restricted to shopping centres, supermarkets and office buildings, while in the household sector it is limited to new housing buildings.

It is still premature to draw final conclusions on the results of this dispute, although it is important to point out that the success of one or the other will be mainly determined by the differences in investment in the infrastructure of the new premises rather than by the relative prices of both sources. This is strengthened by the fact that the person deciding on the infrastructure and facing its capital costs is not usually the same person who will have to pay the energy bill resulting from such decisions, except for the case of supermarkets.

2 Energy Efficiency in Electricity Supply

The official policy in the case of energy supply also relies on the notion that free markets will bring about a gradual rise in the efficiency of the energy industry, at least in those markets which have given evidence of higher competition levels.

So far, the experience gathered in the electricity industry both as regards generation as well as distribution show that the companies are trying to make use of all opportunities to improve their competitiveness in the market and their corporate profit by reducing system losses.

In the case of electricity generators, there is growing interest in increasing the thermal efficiency of the units. It is sufficient to state that the first stations installed by private investors after the reform registered a 33% efficiency. Three years later, in 1997, the stations being incorporated to the system register a 54% efficiency.

The competition level reached by suppliers within the wholesale market seems sufficiently wide to force generators to make use of all opportunities which technology makes available to cut down fuel consumption within power stations.

With respect to distribution losses, the current situation is quite dissimilar. The rate schedule of the distributing companies from the Buenos Aires metropolitan area allows them to transfer to final consumers the costs of purchasing electricity at the wholesale market, increased by 14% on account of low-voltage distribution losses. Given this mark-up, the metropolitan distribution companies break even on electricity sales when they have distribution losses of 12% of the energy sent to the network.

At the time concessions were awarded, losses registered 27% of the energy injected into the distribution network. Thus, the companies tried to improve consumption metering and eliminate clandestine connections as quickly as possible to prevent the economic losses this situation represented.

After 5 years, they managed to reduce distribution losses to 10% of the energy sent to the network. In this way, they were able to revert the economic losses registered during the first years and gather the profits resulting from higher efficiency in electricity distribution. Every additional reduction which they may prove capable of achieving in the future will be fully to their own benefit, since they are not obliged to transfer it even partially to final consumers through a rate reduction.

In view of the evolution registered, the established 12% top limit for distribution losses seems excessively high, although a significant part of the distribution network is aerial. It is to be expected that the companies will try to cut distribution losses down to below the current level of 10%, as long as the cost of saved energy exceeds the necessary investment cost to achieve such loss reduction. In the future, the incentive for distributing companies will be to maximise the portion of the final market which they may keep captive within their concession area.

The average percentage of distribution losses throughout the country during 1997 was of 13% of the energy sent to the network. However, these averages are highly influenced by low losses within the metropolitan area, since losses are still high in several distributing companies from the hinterland. Although all of them have shown concern to cut losses drastically, the respective concession agreements have different clauses for the treatment of losses and their influence on rates, depending on the corresponding jurisdiction. The truth is that in certain provinces losses registered during 1997 were as high as 33% of the energy sent to the network.

VI International Experience in the Promotion of Renewable Energy

1 Barriers to Renewable Energy

Different types of renewable energy sources face different barriers, though unlike with energy efficiency, the most significant barriers to renewables are primarily economic. This chapter focuses on two renewable energy sources of particular interest in Argentina (wind energy and hydroelectric power) and examines the barriers they face and how other countries are attempting to support these technologies within liberalising electricity industries.

1.1 Barriers to Wind Energy

Wind energy has been utilised for centuries for functions such as mechanical water pumping, but the modern technologies for harnessing wind for electricity generation have been largely developed during the past two decades. The modern wind energy industry was essentially created in response to legislation in the USA starting in the late 1970s which mandated that utilities purchase power produced by wind energy generators and other independent producers at their avoided cost and which provided generous tax credits for renewable energy investments. The resulting boom in the USA and subsequent large wind energy programs in Europe have accounted for the bulk of wind energy facilities in place today.

In the last two decades, wind technology has advanced dramatically and costs have come down to the point where wind-generated electricity is roughly competitive on a total cost basis with conventional coal or nuclear power. Nevertheless, wind energy still faces a number of strong barriers which prevent it from becoming a truly mainstream energy technology in most countries. Some of these barriers are summarised below:

- *Costs:* In spite of great advances, wind energy still has difficulty competing on a total cost basis with conventional power sources, particularly gas turbine-based electricity. This is exacerbated by the low natural gas prices which have prevailed in recent years.
- *Dispatchability:* Even where wind power can compete with conventional power on a total cost basis, lack of dispatchability is another significant disadvantage, reducing the reliability that the wind energy will be available at times of actual demand.
- *Small Scale:* Wind turbines generate electricity on a dispersed small-scale basis, with individual turbines delivering less than 1 MW of capacity. Even when grouped into wind farms, the farms are typically less than 10 MW. This small scale makes financing more difficult and costly; and transaction costs for small projects can be prohibitive. Though small scale distributed resources can provide benefits of avoiding transmission, these have not traditionally been recognised in pricing policies.

- *Environment:* Wind energy has not generally been rewarded for avoiding environmental impacts such as air pollution. On the other hand, the (perceived and real) visual impacts of wind turbines have led to planning difficulties at many sites, particularly in the UK.
- *Institutional Bias:* Utility practitioners often have little experience with wind energy and continue to view it as "alternative" despite the great advances which have taken place in the field. Countries such as Denmark now receive more than 7% of their total electricity from wind and plan to increase this share; nonetheless many countries' utilities retain a philosophical bias against renewable energy in general.

1.2 Barriers to Large-Scale Hydroelectric Power

Large-scale hydroelectric power is a mature technology widely implemented throughout the world. Nevertheless, construction of large hydro projects is limited by two significant factors: high capital costs and environmental constraints.

Large hydroelectric dams are highly capital intensive and require long planning and construction lead times. Once constructed, however, their operating costs are minimal. In this regard, large hydro facilities have similar characteristics to nuclear and coal plants, both of which also have high capital costs and low operating costs. While such large baseload plants were previously favoured by utilities, the structure of the power generation industry has been changing due to several factors including technological advances in gas combustion and increased uncertainty in electricity demand. These changes have served to favour construction of simple cycle or combined cycle gas turbine power plants with low construction costs but higher operating costs.

The preference for low capital cost projects is being greatly accentuated by the ongoing liberalisation of power generation industries and the onset of competition. As long as utilities were confident of earning a guaranteed rate of return on generation investments, high capital costs were not an insurmountable barrier generation technologies. However, with monopolies being dismantled and generators having to compete to sell power on the wholesale or retail markets, the profitability of investments in generation projects has become increasingly uncertain. As a result, investors have become wary of projects with high investment costs and long lead times because of their added financial risk. This investor preference for small cheap projects is one of the greatest barriers to large-scale hydroelectric power investment today.

Environmental considerations are the second major stumbling block for hydro power. Hydro power provides something of an environmental paradox. In terms of air pollution, hydro energy is one of the cleanest energy forms, emitting no sulphur oxides, nitrogen oxides, nor carbon dioxide, though it may cause emissions of methane due to decomposing organic matter. But large hydro plants' environmental credentials are tarnished by the other impacts of dams, including large-scale flooding of valleys and resulting displacement of people, severe impacts on migratory fish species, and impacts on downstream ecology due to changed sedimentation patterns. As a result of such environmental considerations, the allure of large hydro plants has been declining in developed countries, and many developing country projects have also faced significant opposition including the Three Gorges dam in China and the Sardar Sarovar dam complex in India. Large scale hydro projects are only likely to return to environmental favour if the global considerations of climate change begin to outweigh the local considerations of population displacement and local ecological damage.

2 Policy Mechanisms to Overcome Renewable Energy Barriers

2.1 Wind Energy

A wide variety of incentive mechanisms have been developed to support wind energy. A brief review of the dominant mechanisms is provided below.

2.1.1 Power Purchase Agreements

Perhaps the single most critical requirement of a successful wind energy project is a reliable market for selling the electricity produced. As the majority of wind power development is typically carried out by independent power producers unaffiliated with any monopoly utility, a mechanism is necessary by which the wind developer can sell its generated electricity to the utility or directly to consumers. Without a reliable market for power, no development (wind or otherwise) can take place. Creation of stable markets has thus been a prime legislative objective, and countries such as the USA, UK, Denmark, Germany, and India have all developed explicit rules for providing guaranteed power purchase agreements for wind-generated electricity.

2.1.2 Production Subsidy

Where electricity generated by wind is more costly than that generated by conventional sources, wind energy may not be economically attractive at the going electricity rate. In that case, a production subsidy, paid per kWh of electricity generated, can lower the cost of wind energy and make projects economically viable. The subsidy could be paid by the government from the general tax base or by utility customers through a surcharge on utility bills. Countries using production subsidies include the UK, Denmark, and Germany.

2.1.3 Tax Credits

Tax credits are another common mechanism for stimulating investment in wind energy by lowering project investors' tax liabilities. Tax credits can either be provided based on the capital cost of the project or on the basis of kWh generated. Investors prefer tax credits based on capital cost because the tax credit can be claimed regardless of the project's performance in generating electricity. For highly risky projects, investors might only be willing to provide finance under such generous conditions. However, capital cost-based tax credits can be open to abuse because investors primarily interested in a tax shelter have little incentive to ensure that their projects actually produce electricity. Production tax credits per kWh of electricity generated reduce the scope for abuse by making payment contingent on project performance, thus increasing the risk to project investors. India provides capital cost-based tax incentives for its wind projects, while the USA has switched from capital cost-based tax credits to production tax credits.

2.1.4 Renewables Set-Aside

A renewables set-aside mandates that a certain percentage of total electricity generated must come from renewable sources. This percentage can be further broken down into separate allocations for different technologies, such as wind, solar, biomass, etc. A set-aside policy thus creates a guaranteed market for electricity generated by renewable energy technologies which might not otherwise be able to compete in the prevailing generation market. The renewables set-aside provides the basis of the UK's wind energy program.

2.1.5 Externality Adders

As traditional energy planning has largely ignored the environmental externalities of power production, this has favoured technologies with high environmental impacts and discriminated against more environmentally benign technologies. One way for regulators to address this issue has been by increasing the hypothetical cost of conventional power plants through an environmental externality charge or "adder" in the planning stage. Such adders can improve the likelihood of wind energy plants being built by increasing the apparent cost of conventional technologies. Typically, externality adders are included only in the planning stage for resource selection but are not actually charged on operations, thus not affecting power plant dispatch once projects are built.

2.1.6 Carbon Tax

Like the externality adder, the carbon tax adds to the cost of fossil fuel based energy by imposing a per-kWh tax on the basis of the carbon content of fuels and their likely impact on global climate change. Carbon-free energy sources like wind energy can thus become considerably more competitive against fossil fuels due to such a tax. Unlike the externality adder, however, the carbon tax involves actual payment of money and is not merely a hypothetical charge used for planning purposes only. Carbon taxes have been implemented in all Scandinavian countries and are an integral part of Denmark's wind energy policy, for example.

2.1.7 Green Marketing

Green marketing (also called green pricing) is a concept in which consumers voluntarily agree to pay a higher price for electricity generated by "green" environmentally friendly energy sources. Surveys carried out in many developed countries repeatedly indicate a willingness by the general public to pay a higher price for clean energy (see, for example, Wind Energy Weekly #710, 1996), and green marketing provides customers with the choice to do precisely that. As the ultimate "market-driven" approach to environmental protection, green marketing is likely to receive increased emphasis in liberalised markets; and in fact, as one of the few non-price means of distinguishing one's service in a commodity market, green energy could well become a major marketing strategy for energy companies in the competitive market. On the other hand, emphasis on such voluntary means of promoting renewable energy could also hurt renewables by allowing free riders to obtain the environmental benefits of renewables without paying for them and by generally consigning renewables into an "environmental ghetto" separate from mainstream energy policy. Experiments with green marketing are still new but are being implemented in several countries including the USA, Netherlands, and Australia.

2.1.8 Preferential Finance

Various means can been employed to reduce the cost of power plants through preferential finance. Measures can include concessional loans at below-market interest rates, official co-financing to attract commercial lenders, loan guarantees to ensure loan repayment in the event of default, etc. Preferential finance schemes can benefit wind energy projects by lowering the cost of raising finance and by convincing otherwise reluctant lenders of the credit-worthiness of projects. Preferential finance through a special financing agency has been utilised in India for supporting wind and other renewable energy technologies (IREDA, 1997). Examples of other preferential finance programs include the Iowa Energy Centre's Alternate Energy Revolving Loan Program, in which 50% of project cost is financed through a zero interest loan for a period of up to 20 years, and the remainder of the cost is financed by a private lending institution at a negotiated rate (Wind Energy Weekly #748, 1997)

2.1.9 Research, Development, and Demonstration Grants

Many governments provide or have provided research, development, and demonstration (RD&D) grants for wind turbine technologies as well as for resource assessment, environmental considerations, and other related areas. According to the International Energy Agency, the USA had the largest wind R&D program in 1996, followed by Japan, Netherlands, Denmark, and Italy. Total wind energy research and development funding by OECD governments amounted to approximately US$ 70 million in 1996 (IEA, 1997). Caution must be exercised in making cross-country comparisons due to countries' different accounting systems. In addition, high RD&D spending does not in itself lead to wind energy success. Between 1973 and 1988, the USA and Germany spent roughly US$ 380 million and US$ 79 million, respectively, on wind RD&D, but Denmark came to dominate the world turbine manufacturing market spending only US$ 15 million on RD&D during the same period (Righter, 1996). Successful RD&D spending must be carefully integrated with reliable long-term markets for wind-generated electricity.

2.2 Large-Scale Hydroelectric Power

As described above, a wide variety of support mechanisms have been developed for small-scale renewable energy technologies like wind power. In most cases these mechanisms have been implemented within the context of a monopoly regulated utility; but many of the mechanisms are also compatible with competitive generation markets. However, such mechanisms have been primarily designed to support small resources on the margin of the overall market; and as a result their distortionary impact on the market has been limited. Trying to implement such support mechanisms for large scale hydroelectric power with plant generating capacities of thousands of megawatts would severely distort the market and would not be practical. As a result, the options for supporting large scale hydro are much more limited than for supporting small-scale renewables. The following discussion outlines some options.

2.2.1 Subsidies

Large-scale hydro power is a mature technology which is not generally considered in need of special policies or subsidies to overcome market barriers. Nevertheless, hydro power's competitiveness in the market place is influenced by various subsidies provided on a wide variety of energy sources. Whether hydro power is favoured over other sources such as oil or gas or nuclear in terms of government subsidies will differ in each country and is difficult to determine due to the vast array of mechanisms typically in place.

The US Department of Energy's Energy Information Administration (EIA) conducted an in-depth review of both direct and indirect subsidies provided by the US government for the following energy types: oil, gas, coal, nuclear, renewables, electricity, and conservation (EIA, ~1992). Subsidies for hydro power are not clearly delineated within these categories, but hydro appears to account for a very small portion of the "renewables" category and a very large proportion of the "electricity" category due to the dominance of hydro power in electricity provided by Federal government institutions such as the Bonneville Power Administration, Western Area Power Administration, Tennessee Valley Authority, Army Corps of Engineers, Bureau of Reclamation, and others.

EIA identifies the following range of subsidy types:

- Tax subsidies including tax credits for certain energy-related investments; tax deferrals such as through expensing of exploration and development expenditures; and favourable tax treatment of capital recovery such as depletion allowances.
- Direct government expenditures on support programs such as the Low Income Home Energy Assistance Program.
- Government sales of energy at prices less than the market price or less than the cost of production.
- Low-interest loans from the government or guaranteed by the government, and tax-exempt borrowing rights for publicly-owned utilities.
- Assumption of environmental, safety, and health liabilities by the government.
- Research and development funding.
- Provision of regulatory services at taxpayer expense.

Different subsidy types are distributed unevenly across fuel types. Most tax subsidies are directed toward oil and gas production, while R&D spending concentrates on nuclear and coal with secondary emphasis on renewables and conservation. EIA estimates total subsidies by energy type to be as follows in 1992 (EIA, ~1992):

Oil	-$1509 million
Gas	$1137 million
Coal	$1071 million
Nuclear	$899 million
Renewables	$847 million
Electricity	$1801 million
Conservation	$635 million

However, the above summary of subsidies does not necessarily capture the impact of subsidies on the competitiveness of different energy types. For example, oil shows a substantial negative overall subsidy as a result of a $3132 million excise tax levied on motor fuels. In other words, in 1992 the government provided subsidies to oil producers of $1623 million, but this was offset by the motor fuel excise tax of $3132 million, resulting in a net overall oil subsidy of -$1509 million. However, the $1623 million subsidy went directly to oil producers, while the $3132 tax was paid by consumers of transportation fuel who by-and-large had no alternative to oil-based transportation. In this sense the net negative subsidy on oil paid for by consumers masks a large positive subsidy which was paid to oil producers.

In terms of hydroelectric power, subsidies for hydro power are almost entirely contained within the $1801 million subsidy for electricity, though how much of this electricity subsidy can be attributed to hydro is not clear. Much of this electricity subsidy was calculated as being due to predominantly hydro-based Federal power agencies selling power at below market rates. The Federal agencies' ability to do this can be attributed to a variety of factors including their government status and resulting low interest rate, and their not-for-profit operations. Furthermore, Federal dams were mostly built between 1935 and 1965 when interest rates were in general much lower than recent interest rates charged on newer fossil fuel-based plants.

Overall, current US government subsidies for hydro power largely reflect past investments and old policies and do not stimulate any new hydro development. By contrast, subsidies on fossil fuels come in forms which encourage further exploration and R&D, thus stimulating new development. Current US government policy could thus be said to favour fossil fuel development over hydro development, though it must be emphasised that most viable large-scale hydro resources in the USA have already been developed.

The main point of the above discussion is to emphasise that government subsidies for energy can be large; and even if the subsidies are small in comparison to the total size of the energy market, the subsidies can still have a strong impact in channelling investment and setting the overall development "tone." For countries wishing to encourage development of hydro power through private investment, it is important to clarify where government energy subsidies are being channelled and to ensure that subsidies for fossil fuels or nuclear power do not undermine the competitive prospects for hydro power.

2.2.2 Taxation and Regulation

Environmental taxation is becoming an increasingly popular means of protecting the environment. Many OECD countries have implemented a variety of environmental charges on items such as air pollutants, CFCs, solid waste, motor fuels, plastics, and many others; and many developing countries are beginning to following suit (OECD, 1991).

Taxation on air pollutant emissions offers one possible means of encouraging hydroelectric power development. Direct taxes on CO_2 emissions are not yet common but have been implemented in Denmark, Finland, Netherlands, Norway, and Sweden, and are being considered in many countries. Taxes on sulphur oxides or oxides of nitrogen are more common and also serve to raise the price of fossil fuel-based electricity. Sweden, for example, imposes taxes on CO_2, SO_2, and NO_x, as well as a value added tax on energy (EEA, 1996). In competitive electricity generation markets, taxation which reflects the environmental impacts of different energy sources may be the most politically acceptable means of promoting a "level playing field" for non-polluting renewable energy.

Regulation, such as imposition of SO_x or NO_x emission limits, represents a form of "hidden" taxation. Such regulations do not impose an explicit tax on energy but do force generators to install expensive pollution control equipment which raises the price of electricity generated using fossil fuels. Such regulations can also be an attractive stimulus for hydro power because the regulations may be justified purely for local pollution reasons unrelated to global climate change but nevertheless have the effect of making CO_2-free energy like hydro power more competitive in the electricity market. In California, for instance, where much of the state is in violation of national and state ambient air quality standards, air pollution regulations could be considered to play a major role in limiting coal-based electricity generation within the state.

2.2.3 International Trade

International trade in electricity is becoming increasingly common throughout the world. As markets of different countries are integrated into ever larger entities, the prospects for large scale generation projects improve. A large hydro project which would create severe overcapacity in a small country may be highly viable if serving the region as a whole. Such regional approaches provide the primary justification for conceptual dam projects like Inga Falls in the Democratic Republic of Congo. In mature markets as well, such as in Norway, the current rationale for further hydro development appears to hinge on the prospect of serving the entire European electricity market, though this is still in a relatively conceptual stage. Hydro development can be particularly suitable in regional markets if different parts of the region are composed of different complementary resources. For example, the large baseload coal and nuclear capacity in continental Europe is expected to be highly compatible with the flexible peak load capacity of Norwegian hydro.

In addition to international electricity markets, there is increasing discussion of possible international trade in carbon emissions. This has taken the form of internationally tradable emissions permit schemes and as individually negotiated joint implementation schemes. Such discussions are still highly theoretical, and any participation might initially be limited to Annex I (OECD plus Eastern Europe) countries within the UN Framework Convention on Climate Change. However, pressure for developing countries to actively participate in such programs could greatly increase in the future; and large hydro projects may provide opportunities for developing countries to obtain significant emissions reduction credits. The directions which any such trading programs are likely to take are still highly uncertain but will be watched with great interest by both developed and developing countries.

3 Impact of Industry Restructuring and Liberalisation on Renewable Energy

Liberalisation of the electricity industry and introduction of competition within the generation sector can have a significant impact on the viability of renewable energy. This section discusses the impact of restructuring on the applicability of the renewable energy support mechanisms discussed in the previous section.

Many support mechanisms, such as production subsidies, tax credits, preferential finance, and RD&D grants, should not be fundamentally affected by industry restructuring. Governments will continue to have the option of providing incentives for technologies deemed desirable for their non-market benefits such as environmental protection. Some observers may argue, however, that subsidies of any sort are antithetical to concept of the deregulated market and that the purpose of liberalisation is precisely to eliminate such subsidies and market distortions. Nevertheless, the ongoing lack of explicit consideration of environmental externalities in existing markets creates a clear bias against renewable energy and provides a rationale for continued support. Furthermore, as demonstrated by the EIA (~1992) study discussed in the previous section, large subsidies continue to exist for all types of technologies including mature options such as natural gas and coal.

Other mechanisms for supporting renewable energy, such as the externality adder, become inapplicable in competitive markets as the centralised generation planning process is replaced by the market-driven decisions of individual generation companies. On the other hand, environmental taxation based on the estimated damage value of pollution remains fully compatible with the competitive market. Other concepts like green marketing are explicitly based on the premise of customer choice and are often an integral part of industry liberalisation.

The most significant threat to renewable energy from liberalisation lies in the area of power purchase agreements. Long-term fixed price contracts, which previously provided the fundamental basis for project viability, become increasingly difficult to obtain in competitive markets. This is the case not only for renewables but for conventional power plants as well, as witnessed by the increasing number of “merchant” natural gas power plants in the USA without long term contracts. For renewable energy plants with above-market prices, utilities will be particularly reluctant to sign long-term power purchase agreements, as such high cost power will reduce their market position against other competing power sellers.

Even in cases where renewable energy is economically competitive against conventional power plants, the lack of dispatchability of resources like wind may continue to cause difficulties in selling the generated power. Power purchasers will have little incentive to sign bilateral power contracts with non-dispatchable generators, as such generators would not be effective in reducing the purchaser's potential exposure to volatile spot market prices. And while a wind generator could sell its electricity directly to the spot market, this could also be hampered by the variability of the resource and the typical need to bid power into the spot market a day ahead of actual delivery. The ability of variable resources such as wind, solar, and run-of-river hydro to function in the spot market is therefore critically dependent on the availability of accurate resource prediction techniques and also on the specific rules of the spot market regarding penalties for over- or under-generation.

Given the importance of long-term power purchase contracts for the viability of many renewable energy projects, one option is therefore to create a separate reserved market for renewable energy, i.e., a renewables set-aside. Such a set-aside program could continue to provide long-term contracts for renewables in parallel with the more volatile market for conventional electricity. This is precisely the method which has been chosen by the UK with its NFFO system (described in the following section). By awarding long-term contracts to renewable generators on a competitive auction basis, the NFFO system harnesses the forces of competition for renewables while shielding them from having to operate within the main power pool. The renewables portfolio standard in the USA and the green labels program in the Netherlands provide similar parallel competitive markets for renewable energy. Such set-aside mechanisms may offer the best compromise between the need to enforce competition among generators and the need for long term contracts to keep renewable energy projects financially viable. Set-asides are primarily applicable for marginal resources such as wind and solar, however, and not for large-scale hydroelectric power. Creating a set-aside for large hydro power would result in significant distortions in the generation market.

4 Country Experiences in Promoting Renewable Energy

4.1 Wind Energy

In analysing support mechanisms for wind energy, one must be careful to distinguish between those mechanisms which are applicable only to monopoly utility industry structures and those which are applicable within a competitive generation market. The countries which have been most successful in promoting wind energy, such as Germany, Denmark, and India, have done so within a monopoly utility structure. However, the support mechanisms which they have used are not necessarily incompatible with a competitive market. The following analysis looks at efforts to support wind energy within competitive generation markets in the UK, USA, Netherlands, Sweden, and Finland, followed by prospects for wind in Germany and Denmark as their market liberalisation proceeds.

4.1.1 UK

The UK has promoted wind and other renewable energy technologies through its Non Fossil Fuel Obligation (NFFO), first introduced in 1990 subsequent to the privatisation of the electricity supply industry. The NFFO was originally created as a support scheme for the country's existing nuclear power plants which could not otherwise survive in the new competitive electricity market, but the NFFO has also emerged as a powerful mechanism for promoting renewable energy. The renewables NFFO sets aside a certain portion of the electricity market to be supplied by designated renewable energy technologies. Within each technology band (wind, biomass, landfill gas, etc.), developers submit bids of proposed projects; and the projects with the lowest per-kWh price are awarded power purchase contracts. Regional electricity companies (RECs) are mandated to purchase power from NFFO-awarded renewable electricity generators at a premium price. The RECs are reimbursed for the difference between the NFFO premium price and their average monthly power pool purchasing price through the Fossil Fuel Levy by the Non-Fossil Purchasing Agency (Mitchell, 1995).

The NFFO is implemented through periodic auctions, of which four had been carried out and another was under preparation in late 1997. Under the NFFO, over 600 MW of wind capacity had been contracted as of December 1996, of which approximately 70 MW had been commissioned; and the competitive bidding process successfully reduced average wind contract prices per kWh from 10p / kWh to approximately 3.5p / kWh (5.7 US cents per kWh) between 1990 and 1996 (Mitchell, 1997). The NFFO has been successful in stimulating a significant amount of wind energy development at reasonable cost and in creating a viable renewable energy industry where none previously existed. However, Mitchell argues that the competitive system used in awarding contracts has been bureaucratic and in many cases expensive compared to the non-competitive systems used in Denmark, the Netherlands, and Germany (Mitchell, 1995). Therefore, though one cannot necessarily equate “competitive” with “cheap,” the NFFO does demonstrate one of the few successful working models for providing stable wind energy contracts within a privatised competitive electricity industry structure.

Mitchell has further identified a variety of lessons learned from the NFFO process including the following (Mitchell, 1995):

- In early NFFO rounds, contract duration was limited to end in 1998, resulting in very short contracts which greatly raised the cost of finance. In general, small renewable energy projects have had difficulties in attracting finance even in spite of the NFFO. A successful financing mechanism is therefore critical, especially for small projects.
- The highly competitive nature of the NFFO, its stop-start auction process, and the initial limitation of premium payments up to 1998 required projects to be developed very quickly with limited public planning input at sites with very high wind speeds often located in scenic areas. The lack of co-ordination between the NFFO and local planning procedures has been significantly responsible for the well-publicised local backlash against visually intrusive wind power developments. The competitive process also has favoured more visually intrusive (but more cost-effective) wind farm projects over the single-turbine co-operatively owned projects frequently found in Denmark which are much more acceptable to local communities.
- There has been limited overlap between the technologies supported by the NFFO and those supported through government R&D funding. As a result, few of those technologies supported in the R&D stage have found subsequent commercial markets. Better co-ordination of R&D and market support programs like the NFFO could result in more effective spending on renewables, as also highlighted earlier in the discussion on wind R&D.
- Vast oversubscription of the NFFO auctions has meant that many developers who prepared projects did not ultimately secure contracts, resulting in significant uncertainty, wasted effort, and hardship on the emerging industry.

- Despite its success in lowering renewable energy prices, a transition strategy has still not been identified for many renewable energy technologies to move from the protected NFFO world to the competitive open market. How wind energy will fare once NFFO subsidies end is still not clear. Concerns about the ultimate transition to the open market has also served to highlight the need for clear and fair pricing in all areas of the electricity grid, including appropriate compensation to locally generated renewable electricity for avoiding transmission and distribution requirements.

4.1.2 USA

The USA is in the midst of a major restructuring process in its electric utility industry, and changes are occurring at widely varying paces in different states. As such, restructuring in the USA must be examined on an individual state basis rather than nationally. The most drastic and well-publicised changes have been occurring in California. The key reform in California is the advent of retail competition such that, as of March 1998, all electricity customers in the state are free to choose their electricity supplier. Utilities have lost their retail monopolies but continue to operate as a regulated supplier of last resort with an obligation to serve any customers who so desire. However, utilities' unregulated affiliates can pursue any markets in competition with any other supplier. California utilities have substantially divested of their generation assets, and generation contracts are now structured as bilateral direct access contracts or sales to the California Power Exchange spot market. Utilities continue to own their transmission grids but have transferred control to the California Independent System Operator who manages the entire state's transmission grid. Distribution grids remain under local utility ownership and control.

Regarding wind energy and all other forms of renewable energy, utilities are required to continue to honour historic above-market long-term contracts which were signed as a result of 1978 PURPA (Public Utility Regulatory Policies Act) legislation. However, the utilities are not required to extend any such contracts as they expire, and inasmuch as any such remaining contracts hamper the utilities' ability to compete in the market, the utilities can recover losses from such above-market stranded assets through a non-bypassable transition charge collected from all users of the California electricity system (California AB 1890 Ch. 854, Sec. 367, 1996). As a result, preferential contracts for renewable energy mandated by PURPA are disappearing. However, there is significant concern that, without some form of continued government-mandated funding, the entire established California renewable energy industry may not survive. The California restructuring process has therefore undertaken to find new market-oriented support mechanisms for renewable energy.

The new support mechanism adopted under AB 1890 directs the collection of a total of $540 million from electricity customers between 1998 and 2002 to support existing, new, and emerging renewable electricity generation technologies (California AB 1890 Ch. 854, Sec. 381, 1996). These funds are to be collected by the utilities through a non-bypassable charge on distribution service (often called a "system benefits charge" or SBC). Allocation of these funds to individual projects has been made the responsibility of the California Energy Commission (CEC), which issued its recommendations in a March 1997 report (CEC, 1997) which was later adopted by the California Legislature as Senate Bill 90.

The CEC has divided the funds into 4 primary categories: existing technologies (i.e., projects operational before Sep. 23, 1996), new technologies, emerging technologies, and consumer credits. The existing technology funds are meant to provide support to projects which are already existing and which continue to require financial support to remain operational. The existing technologies are further divided into three tiers, in which Tier 1 (least currently cost-effective) includes biomass and solar thermal, Tier 2 includes wind, and Tier 3 (most currently cost-effective) includes geothermal, small hydro, digester gas, landfill gas, and municipal solid waste. For the existing technologies, incentives are paid on a per-kWh production basis, and the amount is determined by the lesser of a.) the administratively determined target price minus the market clearing price, or b.) available funds divided by generation, or c.) specified production incentive caps. The target price is set the highest for Tier 1 (5 cents/kWh in 1998 declining to 3.5 cents/kWh in 2001), while the Tier 2 and 3 target prices are 3.5 cents/kWh and 3.0 cents/kWh, respectively. Furthermore, the production incentive cap for all tiers is 1.0 cent/kWh except for Tier 1 in 1998-1999, for which the cap is 1.5 cents/kWh.

For new technologies (i.e., projects operational on or after Sep. 23, 1996), all technologies will be treated within the same category, and funds are to be allocated based on a simple auction, with funds allocated to those projects requiring the least support, and paid out over a 5 year period subsequent to project commissioning. Emerging technologies (as defined in Senate Bill 90) include photovoltaics, solar thermal electricity, small wind turbines of 10 kW or less, and fuel cells using renewable fuels; and funds for this category will be distributed on a project-by-project basis through issuance of specific requests for proposals.

The fourth category, consumer credits, are meant to help stimulate an active retail market in which consumers choose to purchase electricity from renewable energy suppliers. Consumers who choose such “green” power can receive an incentive applied to their electricity bills which is determined by the lesser of a.) available funds divided by eligible renewable generation, or b.) a 1.5 cent/kWh incentive cap.

The CEC’s distribution allocation is based on the need to support technologies with widely differing characteristics and levels of maturity and to keep the renewable energy industry’s existing projects alive while stimulating new additional developments. How successful the strategy will be is unclear as its implementation is just beginning. However, the level and duration of funding do raise significant concerns. The Union of Concerned Scientists has argued that the overall $540 million funding level will be insufficient to maintain the present aggregated level of non-hydro renewables in California (CPUC, 1997). Though nothing prevents funding levels from being increased in the future, there is no current sign of this happening; and in any event the uncertainty over future funding beyond 2001 is likely to place great strain on financing any new projects. Furthermore, the CEC’s guidelines for new projects stipulate that new projects will receive funding for only 5 years after commissioning. However, the UK’s early experience with the NFFO showed that contracts of even 7 years were too short to obtain reasonably priced finance for projects. In other words, the short funding provided by the California legislation may in itself prevent renewable energy projects from developing sufficiently to become competitive.

In addition to the AB 1890 funding, however, the other interesting (and possibly more important) development in California is the emergence of the “green” power market. As described earlier in Section 2.1.7, green marketing allows consumers to voluntarily choose to pay higher electricity prices to guarantee that their electricity is generated using renewable energy technologies. In the competitive California retail electricity market, environmental friendliness could potentially become one of the major marketing tools for electricity retailers, particularly for serving residential and small commercial customers whose energy consumption is relatively low and not very sensitive to energy prices. As of January 1998, three major energy service providers in the new California market (Edison Source, Enron Energy Services, and Green

Mountain Energy Resources) had all announced green power programs for the retail market (EDF, 1998), while others such as PacifiCorp and Foresight Energy Company had established green power services for the wholesale market (Green-e, 1998), and other major players such as PG&E Energy Services followed suit shortly thereafter. However, concern exists that green power marketers may in fact be purchasing such green power from regulated (e.g., out-of-state) utilities for whom the renewable energy is already being paid for by ratepayers through the regulated ratebase, thus making a windfall profit from green customers without generating any renewable electricity which is not already being generated anyway. Protection from such abuses will be essential if consumer confidence is to be maintained that paying for green energy is truly stimulating new renewable electricity.

Beyond California, several utilities around the USA are implementing green marketing programs for wind energy. These include Public Service Company of Colorado, Central and Southwest Corporation in Texas, Fort Collins Lighting & Power in Colorado, Dakota Electric in Minnesota, and Traverse City Light and Power in Michigan (Wind Energy Weekly, 1996-1997). Many utilities have also offered green marketing programs for photovoltaics (Wiser & Pickle, 1997b). In general, such green marketing programs have so far been modest; and though some programs have been enthusiastically received and others are still just getting started, overall customers do not appear to be joining green marketing programs at the high rate indicated by customer responses to surveys of their willingness to pay for renewable energy. Such programs may therefore still require more time and publicity before beginning to have a real impact; but increased marketing associated with liberalisation in states like California could significantly increase this momentum.

In addition to the above California “system benefits charge”-based renewables program and green marketing campaigns, the third support mechanism for renewables receiving significant attention in the USA is the Renewables Portfolio Standard (RPS). Under the RPS, all retail power suppliers would be required to obtain a certain minimum percentage (e.g., 10%) of their electricity from renewable energy, in the form of “renewable energy credits” (RECs). A REC would be a type of tradable credit representing one kWh of electricity generated by renewables. Electricity retailers could obtain RECs in three ways. 1.) They could own their own renewable energy generation, and each kWh generated by these plants would represent one REC. 2.) They could purchase renewable energy from a separate renewable energy generator, hence obtaining one REC for each kWh of renewable electricity they purchase. Or, 3.) they could purchase RECs, without purchasing the actual power, from a broker who facilitates trades between various buyers and sellers. In other words, RECs are certificates of proof that one kWh of electricity has been generated by renewables, and these RECs can be traded independently of the power itself. The basic idea of the RPS is to ensure that a certain minimum percentage of electricity is generated by renewables but to encourage maximum efficiency by allowing the market to determine the most cost-effective solution for each electricity retailer: whether to own renewable generation, purchase renewable electricity, or buy credits, and what type of renewable technology to use (Rader, 1996).

The idea for trading RECs is based on the emissions trading concept used in the 1990 Clean Air Act Amendments in which total national sulphur emissions are capped, and emission permits are issued to allocate the total allowed emissions amongst polluters. Those who are able to reduce their sulphur emissions cheaply can do so and sell their excess emission permits, while those for whom emission reductions are costly can avoid reducing emissions by purchasing excess permits from others, thus encouraging the most cost-effective overall emission reductions. With the RPS, because each REC would represent one kWh of electricity generated somewhere with renewables, an electricity retailer who purchases RECs from a broker without actually purchasing renewable electricity would still be ensuring that the renewable electricity is generated somewhere within the state or country. Under a national RPS system, RECs generated from wind energy in Texas, for example, could be sold in New York. Utilities with a large renewable resource could thus be compensated for the environmental benefits they provide by other utilities with a shortage of renewables. The RPS would thus guarantee a certain percentage of the electricity market for renewables, and the competitive REC market would ensure the lowest possible prices for renewable energy, thus enhancing renewables within a competitive market structure.

The RPS was considered and ultimately rejected in California in favour or the system-benefits charge system described above. However, various versions of the RPS have been approved by state legislatures and / or public utility commissions in several US states including Maine, Nevada, Massachusetts, Vermont, and Arizona (solar only) (Windpower Monthly, 1998, Rader, 1997). Several federal utility restructuring bills currently under consideration by the US Congress also include provisions for an RPS.

The RPS is similar to the NFFO concept used in the UK, in that both are competitive least-cost mechanisms. However, the NFFO relies on a government agency to award contracts at a guaranteed fixed price for a fixed term, while the RPS would leave all such contracting details to the market and would rely on the government merely to set the total market percentage to be allocated to renewables. However, while the RPS is attractive in its conceptual simplicity, in reality a completely open REC market could end up promoting only one or two of the most currently cost-effective renewable technologies to the exclusion of all others. To avoid such technology concentration could require the implementation of technology bands, which would make the RPS even more similar to the NFFO, and would eliminate some of attraction of the RPS's simplicity. The RPS does have some other attractions over the NFFO, such as the avoidance of the stop-start auction system which makes the NFFO so cumbersome. On the other hand, however, NFFO contracts offer greater long-term price certainty for renewable projects and may thus be better at attracting financing for renewables investments compared to the RPS (see Mitchell 1996, Wiser & Pickle 1997a).

4.1.3 Netherlands

The Netherlands have traditionally been one of the leaders in wind energy, and through the 1980s the Netherlands ranked third in the world in installed wind capacity after the USA and Denmark. Support for wind energy in the Netherlands has included both R&D grants (starting in the 1970s) and a variety of market stimulation mechanisms. Initial market stimulation programs in the 1980s included the Integrated Programme Wind Energy (IPW), which provided a subsidy of 35-40% of investment costs for newly built turbines, and the "MilieuPremie" environmental bonus from the Ministry of VROM (housing, physical planning, and environment) which provided capital subsidies for wind turbines in selected suitable areas and a bonus for low-noise turbines. The IPW was then replaced in 1990 by the Support Programme for Application of Wind Energy in the Netherlands (TWIN) which provided further subsidies for technology development and market stimulation and which lasted until 1996 (Wolsink, 1996).

In addition, in 1990 the Dutch government set new goals to reduce CO_2 emissions and encouraged utilities to introduce Environmental Action Plans (MAP) to invest in energy conservation, renewables, and CO_2 reduction. The MAP were funded by a tax on distributed electricity and resulted in significant new wind capacity, though efforts were hampered by utilities' difficulties in securing adequate sites and their reluctance to purchase power from independent generators (Wolsink, 1996).

More recently, significant changes have occurred in Dutch renewable energy policy, and this is being reinforced by liberalisation of the Dutch electric utility industry. Direct subsidy programs such as the TWIN were eliminated in 1996, but several other mechanisms are in place to encourage the development of an "environmentally conscious" economy. These include (Kwant, 1996, Novem, 1998):

- *Green Funds.* Since January 1995, several banks have been offering Green Funds in which the public can invest at an average interest rate of approximately 4% per year. This interest is free of income tax for investors, allowing banks to pay a lower interest rate to investors than for other investments. In return, the Green Funds are obliged to invest a minimum of 70% of their capital in "green projects," which include most renewable energy technologies including wind. Project developers must apply for "green certification" from the Ministry of Housing and Environment before they can access capital from Green Funds, which can be borrowed more cheaply than standard loans due to their tax-free status. As of late 1996, the public had invested NLG 900 million in Green Funds, and these investments are primarily supporting wind energy and district heating projects.
- *VAMIL.* The Accelerated Depreciation on Environmental Investments Scheme (VAMIL) was introduced in September 1991, and as the name suggests, allows environmental investments (including many renewable energy technologies) to be depreciated more rapidly than under normal depreciation rules, thus reducing taxable income during projects' initial years and improving cash flow.
- *Regulating Energy Tax.* This tax was introduced in January 1996 and is imposed on households and small businesses for electricity and natural gas consumption when their consumption rises above a certain minimum level. In addition to encouraging energy conservation, the tax also supports renewable energy because the Regulating Energy Tax collected on electricity generated renewably is paid to the renewable generator as an incentive rather than to the government.
- *Green Electricity.* This concept is identical to the green marketing concept outlined in the discussion on the USA above, in which customers voluntarily choose to pay a higher price for electricity generated by renewable technologies. The World Nature Fund monitors and certifies the renewable energy content of the green electricity schemes. The Dutch government is also proposing to reduce the value-added tax rate for green electricity from 17.5% to 6% which would offset the price premium paid by the consumer.

All of the above measures are compatible with electricity industry liberalisation since they do not affect utilities' ability to compete in the market. However, unlike in California, where green marketing is being pursued as a competitive strategy to attract customers in the liberalised market, in the Netherlands residential and small commercial customers (the main purchasers of green electricity) will not have a choice of electricity supplier until 2008 (Minister of Economic Affairs, 1996). The Dutch liberalisation, which commenced in 1998, will only offer free choice of supplier to the largest customers in the early years and will be gradually extended to smaller customers over the next 10 years. As a result, green electricity is not yet a competitive tool for utilities in the Netherlands but does allow utilities to improve customer satisfaction while simultaneously helping utilities meet their covenant with the government to increase electricity sales from renewables.

In addition, as part of the liberalisation process and as part of the covenant between the government and utilities to increase renewable electricity's market share, a tradable "green labels" market has started as of January 1998 (Windpower Monthly, 1997). Under the law, local energy distribution companies (LEDCs) must purchase renewable electricity from independent power generators at a price determined based on the current market price of electricity and the Regulating Energy Tax refund. However, in addition, the LEDCs must issue green labels to the renewable generator equal to the number of renewable kWh sold to the grid. The renewable generator can then sell these green labels on an open market to distribution utilities who will all be required to own a certain quota of green labels. Utilities can fulfil their quota commitments in three ways: by developing their own wind farms, by negotiating bilateral agreements with independent producers, or by purchasing green labels on the open market. This mechanism is similar to the Renewables Portfolio Standard (RPS) mechanism being contemplated in the USA and essentially reserves a certain percentage of the electricity market for renewable energy within an otherwise liberalised market. However, unlike the RPS, the Dutch green labels scheme guarantees that all renewable generators can sell power to the grid at an assured price, thus removing some of the market uncertainty of the RPS but simultaneously perhaps reducing the economic incentive to reduce renewable energy costs.

4.1.4 Sweden

Sweden has liberalised its electricity market, and the generation and retail markets are now fully competitive. Though investment subsidies of 35% of capital cost expired in 1996, two primary mechanisms still exist for supporting wind energy and other renewables within the competitive market. Prior to electricity market reform, holders of regional power concessions were required to purchase electricity at the utility's avoided cost from all small power projects (including wind) with generation capacities of up to 1500 kW. This requirement continues to exist under the new law, in which local distribution utilities must still purchase all electricity generated by projects of less than 1500 kW within their service territories. The price now paid to small generators is equal to the residential tariff plus a credit for reduced transmission and distribution losses minus reasonable costs for utility administration and profit (IEA, 1996b). However, this power purchase requirement for small generators is limited in duration to 5 years, and subsequently all power producers are expected to compete on the open market. Whether small power producers can continue to survive at that time remains to be seen. During this 5 year transition period, the competitive position of utilities obliged to continue purchasing high-cost small power could conceivably be hurt if the utilities are not compensated appropriately; but the additional cost burden to utilities may in fact be small, and to-date few retail-level customers have switched providers.

The second support mechanism is an environmental bonus (SEK 0.138 / kWh in 1997) paid from the government to wind energy generators (IEA, 1996b). The amount of this bonus corresponds to the tax charged for household electricity consumption.

In addition to these direct support mechanisms for wind energy in the electricity marketplace, the Swedish government also funds a wind energy research program as well as a development and demonstration program which provides support of up to 50% of cost for demonstration plants. The National Board for Industrial and Technical Development (NUTEK) has also organised a technology procurement program to try to further reduce the cost of wind power by forming a consortium of purchasers, clearly specifying technical and economic requirements, developing a financing scheme with a bank consortium, and guaranteeing a minimum purchase order to the turbine manufacturer who wins the bidding competition. This process is based on the successful technology procurement concept practised by NUTEK in promoting energy efficiency (described earlier).

As the full brunt of market liberalisation will only be felt by wind generators after elimination of the 5 year guaranteed purchase price, how wind energy will fare in the competitive market is not yet clear. However, several factors serve to improve the future prospects for wind power in Sweden. First, Sweden's energy policy emphasises environmental sustainability as one of its key goals, as in most of Scandinavia. Second, Sweden's commitments in the Kyoto Protocol require an 8% reduction in greenhouse gas emissions from 1990 levels by 2008 to 2012 (UNFCCC, 1997). Third, almost 90% of Sweden's electricity is generated by either nuclear energy or hydro power, and little additional hydro potential remains. Fourth, the Swedish population voted in a 1980 referendum to phase out all nuclear power by 2010, but as of 1996 nuclear power still accounted for 50% of Sweden's electricity generation (IEA, 1996b). These factors suggest that Sweden will be under heavy pressure to further develop its renewable resources, though even then the achievability of the above four goals is doubtful. Though biomass is expected to provide the bulk of Swedish renewable energy, wind energy should also increase substantially over the coming years.

4.1.5 Finland

Finland, like Norway and Sweden, is a member of the liberalised Nordic power market. Within this context, Finland maintains two primary mechanisms for supporting wind energy and other small power producers (i.e., biomass of less than 40 MW electric capacity, and small hydro of less than 1 MW capacity). First, as in Sweden, Finland provides a tax subsidy such that small-scale renewable energy is exempt from the electricity tax. This amounts to a subsidy of 0.016 FIM / kWh and has been approved for a transitional period of 5 years during which time small power producers are expected to adapt to the competitive market (Finland Ministry of Trade and Industry, 1997b).

Secondly, Finland provides investment assistance for wind energy projects of up to a maximum of 40% of capital costs, though the amount of assistance given is determined on a case-by-case basis depending on the nature of the project and its innovativeness or location. For a typical wind energy project, the government has granted investment aid of approximately 30% of capital cost. For biomass projects, similar incentives are provided up to a maximum of 30% of capital cost (Aalto, 1997).

The general trend in other countries has been to move away from capital cost subsidies and toward per-kWh production subsidies in an effort to maximise the incentive for efficient power production. However, the Finnish government's position has been to provide the bulk of its assistance as up-front investment assistance and to then require the renewable energy plant to subsequently survive in the open competitive market. This reduces the risk for project developers by eliminating the danger that ongoing production incentives can disappear at any future time due to shifting political objectives. However, to-date, Finland's installed wind energy capacity has been very small, so it remains to be seen whether the incentive program will be sufficient to entice investors in the liberalised market. The Finnish government also provides research and development support for wind power.

4.1.6 Others

Germany and Denmark are two of the world leaders in wind energy. Their policies are not reviewed in detail in this paper because their electricity industries have not yet been liberalised to the point of forcing market competition on wind energy plants. However, the current status of their wind energy and liberalisation programs are briefly highlighted here.

Both Germany's and Denmark's wind energy support programs are underpinned by requirements for local utilities to purchase all electricity generated from wind power at a set power purchase price of 85-90% of the residential electricity tariff. Germany's wind energy support further includes investment subsidies and below-market loans, while Denmark provides exemptions from energy and CO_2 taxes (Redlinger, et. al., 1998).

While investment subsidies, below-market loans, and exemptions from CO_2 taxes could all be compatible with a liberalised generation market if they do not distort competition among market participants, the mandatory power purchase requirements imposed on utilities could conflict with upcoming liberalisation and have been the subject of significant recent debate. In Denmark, the new electricity supply law, which took effect in January 1998 and introduces wholesale competition, will not affect wind power since all utilities will continue to be required to purchase all wind energy under previous conditions (Windpower Monthly, 1998). However, it is not yet clear whether this exemption from competition for wind energy will remain sustainable as Danish utilities become forced to compete with other European utilities within the unified European market. In Germany, in response to European liberalisation, a law is being debated to put a cap on the amount of wind energy which utilities must purchase at the premium price. Though this law has passed the lower house of parliament, its fate in the upper house and during subsequent review remains unclear (Windpower Monthly, 1997, 1998).

The fate of wind energy policies in Germany and Denmark will have an enormous impact on the future prospects for the worldwide wind energy industry. However, the countries' current policy of requiring utilities to purchase all wind power for a set price is not necessarily in conflict with a more liberalised market. In fact, the UK NFFO system, often held up as the model of support for renewables in a competitive market, also requires utilities to purchase above-market-cost renewable electricity. What makes the NFFO compatible with the liberalised market is the fact that the utilities are compensated from a centralised fund for purchasing the high-cost renewables; and this centralised fund is supported by a non-bypassable Fossil Fuel Levy charged on electricity nationwide. Thus, all electricity customers pay for the above-market cost of renewables regardless of where they live and from whom they purchase their power, so utilities' competitiveness is not affected.

The German and Danish systems requiring utilities to purchase wind energy could also be structured like the UK system such that the utilities are compensated from a non-bypassable nationwide levy which eliminates competitive market distortions (though this would not eliminate problems for Germany's and Denmark's competitiveness within the overall unified European market). And though the current German and Danish renewables support mechanisms lack the competitive bidding element prominent in the UK NFFO, similar cost efficiency improvements could be obtained in Germany and Denmark by gradually reducing the support price. Mitchell (1995) argues that such standard payment systems as exist in Germany and Denmark involve significantly less bureaucracy than the competitive bidding system of the NFFO and can in fact be cheaper. Thus, a continued guaranteed standard payment system for wind energy, perhaps ratcheted down over time to stimulate efficiency improvement, and funded by a nationwide non-bypassable levy on electricity sales, could be a promising mechanism for continued support of wind energy until wind becomes fully cost competitive with conventional technologies over the next decade or so.

4.2 Large-Scale Hydroelectric Power

Support for large-scale hydro power is very different from support for small-scale renewables like wind energy, as outlined earlier. Market set-asides and guaranteed purchase prices for large hydro are not possible without introducing severe distortions to the competitive generation market. Nonetheless, severe distortions may often already exist in the form of hidden subsidies for specific technologies and industries; and simple elimination of such existing subsidies could provide a competitive boost for hydro power. No experience exists in actively promoting large-scale hydro power within a liberalised competitive electricity market. As such, there are few lessons available from examining the international experience. Nevertheless, some other countries experiences can provide some valuable insights and are highlighted below.

4.2.1 Norway

Norway's electricity generation system is composed of virtually 100% hydro power. When Norway liberalised its electricity market in the early 1990s, development of hydro generation facilities virtually stopped. This can be attributed to a number of factors. First, with excess generation capacity already in place and very low electricity prices (average residential tariff approximately 3 US cents / kWh in Jan. 1996)[1], there was little reason to further expand capacity at the time. Secondly, the market reforms introduced significant uncertainty and utilities, over 90% being publicly owned, were highly risk averse (Johansen, 1997).

However, since that time, interest in hydro power development has been increasing again. The reasons for this include increased electricity demand in Norway, increasing potential electricity trade within the Scandinavian Nord Pool as well as with continental Europe, and improved ability and confidence to address market risk and uncertainty. Some of the new Norwegian hydro investment is being channelled toward upgrading existing facilities, partly due to limited availability of new sites, but interest is also increasing in developing new sites.

Norway is also one of Europe's largest producers of natural gas and thus has the potential to develop significant gas-fired electricity generation plants. There is some investor interest in this option, and one license has been issued to Naturkraft to build a 700 MW combined cycle plant on the west coast of Norway. However, the development of gas-based generation is likely to be constrained by political factors. Norway's commitments regarding the emission of greenhouse gases under the Kyoto Protocol allow Norway to emit 101% of its 1990-level emissions in the years 2008-2012 (UNFCCC, 1997). Given that virtually 100% of Norwegian electricity is currently hydro-generated, any increase in gas-based generation would severely limit Norway's ability to meet its Kyoto Protocol commitments. Furthermore, Norway has one of the world's highest taxes on CO_2 emissions (US$ 205 / ton of CO_2 in 1993$ [EEA, 1996]) which further limits natural gas's ability to compete with hydro power. No large-scale development of gas-based generation is therefore currently envisioned in Norway.

In fact, climate change is a major political issue throughout Europe which will favour gas-based generation in currently coal-dominated countries like Germany but will limit gas generation in hydro- and nuclear-dominated countries like Norway, Sweden, France, and Belgium. There is also currently little prospect of cheap gas-based electricity from continental Europe competing to provide significant amounts of power in Scandinavia.

The prospects for hydro power in Norway are further helped by the institutional structure of the Norwegian electricity sector, in which liberalisation introduced competition but did not fundamentally change the industry's ownership structure which is primarily public-based and often includes formal ownership linkages between generators and distributors. While the market reform did create pressure for

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[1] Based on IEA (1996a) rate of 0.178 NOK / kWh and approximate conversion rate of 6 NOK / USD.

electricity retailers to renegotiate power purchase contracts for more attractive terms, it did not completely break the traditional institutional ties which has previously existed. Thus, though some electricity retailers did choose to completely switch their suppliers from whom they purchased power, many others have renegotiated their contracts but remained essentially loyal to their traditional suppliers (Midttun and Summerton, 1998). Over 90% of electricity sales in Norway continue to be based on bilateral contracts between suppliers rather than through the spot market (Moen and Hamrin, 1996). As a result, the Norwegian electricity industry reform has certainly increased the level of competition but has not fundamentally broken the cosy ties between generators and distributors which previously existed. Sophisticated spot, regulation, and forward markets and new derivative instruments allow all players to further manage their risk.

In conclusion, there are several factors favouring the continued development of large-scale hydroelectric power in Norway:

Significant export potential is anticipated within Scandinavia and to continental Europe.

1. CO_2 reduction commitments and high CO_2 taxes limit the ability of abundant natural gas to establish a significant foothold in the Norwegian electricity generation market.
2. Overall European commitments to reduce CO_2 emissions should favour Norwegian hydro power in the coming liberalised European electricity market.
3. The Norwegian electricity industry's institutional structure allows suppliers and retailers to effectively reduce and manage risk, thus allowing hydro developers to actively pursue new business opportunities.

4.2.2 Finland

Finland's Ministry of Trade and Industry has carried out an analysis on the prospects of nuclear energy in the deregulated electricity market (Finland Ministry of Trade and Industry, 1997b). While this study does not directly relate to hydro power, nuclear energy faces many of the same constraints confronting hydro power in the liberalised market: high capital costs and long lead times, but low operating costs. Therefore, this study of Finnish nuclear energy may provide some perspectives for hydro power development as well.

In Finland as elsewhere, nuclear power plant development within a liberalised generation market is severely constrained by long lead times and high capital costs which make nuclear power highly vulnerable in case of excess generation capacity. Nuclear power is also subject to other risks associated with technical problems, potential accidents, and associated political pressure. Independent power producers who have no guarantee of recovering their investment in power plant construction are unlikely to invest in such long term high risk projects.

Nevertheless, the study argues that the fundamental reason for Finland building nuclear plants prior to liberalisation, i.e., to ensure the availability of inexpensive baseload power for energy-intensive industries and particularly the forest products industry, has not changed. In a market where investors are likely to favour low capital cost plants with higher operating costs, industry's need for cheap reliable baseload power may not be adequately met. For this reason, the study argues that large energy-intensive industries may find it attractive to invest in large scale baseload nuclear power. Construction of the Olkiluoto Nuclear Power Plant was in fact based on this model, in which the power company was owned primarily by a large industrial company with the primary objective of providing inexpensive power for the owners.

The study also envisions the possibility of exporting electricity to Norway, Sweden, and Russia, where little activity is occurring in terms of building large-scale inexpensive baseload power. Thus, while the immediate prospects for constructing new nuclear power plants in Finland are poor, the study argues that the longer term prospects for nuclear power could still be positive as current excess capacity declines.

Though the study's conclusions are open to debate, and the future of nuclear power in Finland as elsewhere remains highly uncertain, the concept of constructing large baseload power plants to meet industrial energy needs is not new. In Ghana, for instance, construction of the 900+ MW Akosombo Dam in the 1960s was based primarily to meet the energy needs of one aluminium company, VALCO. Though new thermal power plants have since been built, the Akosombo Dam continues to dominate power generation in Ghana, and VALCO continues to consume approximately 50% of the dam's electricity output. For large industrial facilities, therefore, construction of large baseload power plants can be an attractive means of securing reliable long-term energy while also allowing profit-making opportunities in selling any excess power on the market.

VII International Experience in the Promotion of Energy Efficiency

1 Barriers to Energy Efficiency

Special policy mechanisms to promote energy efficiency at the end-use level have been justified on the rationale that there are a wide variety of market barriers which prevent market price signals alone from being sufficient to induce energy consumers to implement the "socially optimal" level of energy efficiency. Some of these barriers include, among others, the following:

- *Lack of Information:* Consumers often lack information on the availability of energy-efficient technologies and their savings potential. Information on energy consumption is often not readily available when purchasing appliances or major energy-consuming equipment.
- *High Initial Cost / Lack of Finance:* High efficiency equipment typically costs more than standard equipment. Even though subsequent energy cost savings may more than compensate for the higher initial capital cost, customers are nevertheless often deterred by the high initial cost. This is particularly problematic if loans or other finance are not readily available to cover the high up-front cost.
- *Lack of Confidence:* Given the lack of information on performance and the high capital cost discussed above, consumers are often unwilling to risk purchasing more expensive technologies in return for future savings which they fear might not materialise in practice.
- *High Discount Rates:* Given the above uncertainties, consumers tend to have very high discount rates for investments in energy efficiency. Consumers may be willing to invest in energy efficiency only if the additional investment can be recovered within 2 or 3 years, implying a discount rate of approximately 30-50%. In contrast, the general societal discount rate, evidenced by the rate of return on government bonds, is typically on the order of 5%; and the rate of return on power plant construction is typically below 15%. With the much higher discount rates demanded by consumers for end-use energy efficiency, investments which are clearly cost-effective from a societal perspective are not undertaken by private consumers.
- *High Transaction Costs:* Transaction costs of learning about energy efficient products, finding reputable suppliers, installing the new products, etc. may be high, thus reducing the attraction of the energy cost savings provided by high efficiency products.
- *Energy Price Distortions:* Often energy prices will not reflect the full societal cost of energy. This is often due to subsidies which reduce the market price of energy. In addition, the environmental damage caused by pollution or other by-products of energy is rarely factored into the energy price. As a result, energy prices are typically lower than their actual societal cost and therefore encourage greater consumption than the societally optimal level. This can also

occur if tariffs are based on average costs which are lower than long-run marginal costs, thus obscuring the long-run price signal to the consumer and encouraging over-consumption in the short term.

- *Lack of Importance of Energy:* Energy is likely to be only one of many factors considered by a consumer in purchasing a product. Other product features such as performance, convenience, comfort, or appearance may be far more influential on a consumer's choice of product than energy consumption. This is particularly true if energy represents only a small and insignificant fraction of the consumer's total costs.
- *Lack of Market Value:* Investments in energy efficiency for a home, for example, may not raise the market value of the home sufficiently to justify the extra investment in the home.
- *Owners vs. Tenants (Disconnected Decision-Maker):* Often the decision-making process separates the potential beneficiaries of energy efficiency investments from those that have to pay for such investments. For example, owners of buildings are typically responsible for installing energy-efficient equipment; but the tenants occupying the buildings pay the utility bills and therefore reap all benefits from energy efficiency. There is therefore little incentive for the owner to invest in energy-efficient products.

2 Policy Mechanisms to Improve End-Use Energy Efficiency

As a result of barriers such as those listed above, it is generally acknowledged that market forces alone have not induced as much investment in end-use energy efficiency as would be societally optimal. A variety of policy measures have therefore been used to try to remedy this situation and improve end-use energy efficiency. Some of these mechanisms are described below.

2.1 Energy Labelling

One of the major barriers to energy efficiency discussed above is the lack of information. Consumers often simply do not know how much energy a particular piece of equipment will consume and therefore how much its operation will cost. This is particularly problematic with household appliances such as refrigerators, water heaters, and air conditioners because residential consumers rarely have the ability to accurately analyse energy consumption without special assistance.

To help remedy this, some countries require that energy consumption of appliances (and / or approximate annual energy costs) be clearly labelled at the time of sale to allow the customer to make an informed decision about the benefits of energy efficiency vs. the higher capital cost of efficient equipment. Such labelling represents the "lightest" form of intervention in the market, merely providing information to the consumer and leaving all decision-making in the hands of the consumer without providing any additional incentives or mandates. However, as labelling depends entirely on the consumer to take action, its effectiveness in promoting actual implementation of energy efficiency is questionable.

2.2 Energy Efficiency Standards

Energy efficiency standards are regulations mandating a certain minimum level of energy efficiency in appliances and / or buildings. Building standards address buildings' thermal loads and typically apply to insulation levels for ceilings, walls, and floors, as well as to window glass construction and limitation of total glass area. Appliance efficiency standards apply to energy-consuming devices such as refrigerators, air conditioners, heat pumps, gas furnaces, space heaters, water heaters, clothes washers/dryers, and fluorescent lamp ballasts. In the USA, California has been the leading state for energy efficiency standards; and between 1977 and 1994 the estimated statewide electricity savings from building and appliance standards have been estimated at 15,000 GWh per year and 5900 MW. This amounts to approximately 68% of GWh and 81% of MW of the total energy efficiency gains estimated in California over this period. Statewide natural gas savings over the same period due to building and appliance standards are estimated to be approximately 61% of total statewide gas savings (SRC, 1992). With the US federal government having enacted nationwide standards essentially identical to California's, energy efficiency standards have been responsible for vast energy savings throughout the USA. Europe and Japan also enforce strict efficiency standards, while some developing countries including much of Southeast Asia are also increasingly implementing them.

Energy efficiency standards have the following merits: 1.) As mandatory regulations, they help ensure that all buildings and appliances achieve a certain minimum level of energy efficiency. 2.) Such regulations serve to permanently alter the marketplace for appliances and construction materials, thus eliminating inefficient products from the market over time. 3.) Because many energy efficiency options are highly cost-effective from a societal perspective, prudently designed standards can in fact have a positive overall economic effect, reducing the need for costly investments in energy supply and channelling investment resources to other more productive uses.

On the other hand, energy efficiency standards are subject to the following shortcomings: 1.) Prescriptive standards reduce flexibility and individual consumers' choice of their own optimal level of energy efficiency, while performance-based standards are more flexible but also complex. Both can thus potentially reduce overall consumer welfare. 2.) Standards only affect new buildings and new equipment, thus leaving existing facilities in their previous inefficient state. This is a major drawback in developed economies with a vast existing infrastructure, though it is less of a problem in developing countries where the new construction market is growing rapidly. 3.) Standards only set a minimum level of efficiency but provide no incentive for consumers to achieve even higher levels of efficiency than those mandated by the standard. 4.) Standards are only effective if they are adequately enforced and implemented. Adequate enforcement can be difficult to achieve in practice. In particular, in many Southeast Asian countries where standards have been voluntary, such codes have had minimal impact.

2.3 Energy Conservation Centres

Energy conservation centres can provide one-stop shops for energy efficiency services, providing audits, public education, and specialised consulting services for industry. This has been a particularly popular approach in Asia, initiated by Japan in 1978 and subsequently emulated throughout much of Asia, including China, Indonesia, Pakistan, and Thailand. Some of the services provided by the Energy Conservation Centre, Japan (ECCJ) include the following (IIEC, 1995): 1.) *Public Relations:* co-ordinates advertising and special events to raise public awareness; 2.) *Research:* gathers data on emerging efficient technologies and energy-use patterns; 3.) *Education and Training:* trains industrial energy managers; 4.) *Technical:* provides consulting services on the effective use of waste heat; 5.) *International Co-operation:* provides technical assistance to developing country projects; 6.) *Publications:* publishes books and magazines related to energy efficiency; 7.) *Examinations:* conducts examinations for qualified industrial energy managers. Other countries have also established energy efficiency centres including, for example, Pacific Gas & Electric's Pacific Energy Centre and Southern California Edison's Customer Technology Application Centre, both in California.

Energy conservation centres are popular due to their relative ease of establishment and funding, one-stop convenience, economies of scale due to concentration of expertise, and autonomy from government intervention. Furthermore, well-run centres are capable of being mostly, if not entirely, self-supporting. For example, only 18% of ECCJ's budget comes from government funds, while 7% comes from membership fees, and 73% comes from fees for services provided to customers (IIEC, 1995). Nevertheless, the actual effectiveness of energy conservation centres is not easy to establish. Serving a fundamentally information-providing role, they are not typically capable of actually implementing or financing projects; and the onus is still on individual consumers to seek and implement the centres' advice.

2.4 Voluntary Programs

A wide variety of programs exist which involve voluntary co-operation to improve energy efficiency. Often such programs are undertaken by industry associations and, unlike standards and regulations, voluntary programs promote partnerships between traditional adversaries such as between industry and government, or between corporate competitors within an industry. Some examples of successful voluntary programs include the following (UNEP IE & US EPA, 1997).

In the USA, the Environmental Protection Agency's (EPA) Green Lights and Energy Star Buildings programs encourage energy efficiency in lighting, HVAC (heating, ventilating and air conditioning), and office equipment in commercial buildings. The EPA provides technical assistance, training, and public recognition and awards to participating companies; and the companies also save money on their energy bills. In return, companies sign a Memorandum of Understanding with EPA committing to participation and upgrades of their facilities.

In the Netherlands, the Long Term Agreements (LTA) program is a partnership between government and industry associations and some individual companies to improve energy efficiency. By signing LTAs, industries are able to design their own plans for achieving energy efficiency goals rather than be subject to mandatory government regulation. In addition, signing LTAs results in simplified issuance of environmental permits to participating companies by the government, and the companies receive a tax reduction for investing in specified efficient technologies and accelerated depreciation of such investments. By working together through industry associations, the companies also reduce their risk associated with introducing new technologies.

The Canadian Industry Program for Energy Conservation is a partnership program between the government and industry associations to develop industry sector-wide energy efficiency initiatives. Individual companies can then make individual commitments to implement economically viable energy efficiency investments, provide an action plan, and provide an annual review of performance. In return, companies receive technical assistance, increased employee awareness, training, and industry-wide monitoring. Norway has a similar program (the Industrial Energy Efficiency Network) modelled on the Canadian program.

In Australia, the Greenhouse Challenge program was started by Australian industries interested in developing a voluntary co-operative agreement to improve energy efficiency and implement no-regret climate-change reduction options. The program is a significant component of Australia's National Greenhouse Response Strategy. In return for signing a letter of intent and agreeing to monitor and report emissions, assess opportunities for emission reductions and actions to be taken, and provide annual reports of emissions and progress, participating companies receive recognition and publicity, a forum for information exchange, and technical assistance.

While voluntary programs are understandably popular with industry due to their flexible nature and lack of coercion, these same advantages are also the root of the programs' weakness. Unless the voluntary programs are backed up with credible and likely regulatory alternatives, the voluntary programs may not garner sufficient participation to meet the desired energy efficiency goals. It is notable that many of the countries listed above pursuing voluntary strategies, such as the USA, Canada, Norway, and Australia, are highly energy-intensive nations with some of the highest per-capita energy consumption in the world.

2.5 Energy Pricing and Taxation

Energy prices are frequently subsidised and thus fail to reflect the true cost to society of providing energy services. Even where no explicit subsidies exist, lack of consideration of environmental externalities in energy prices means that the cost of environmental damage caused by energy consumption is borne by society at large rather than by individual energy consumers. Low energy prices induce consumers to use more energy than they otherwise might. This problem is exacerbated by energy market liberalisation programs, one of whose primary goals is typically to reduce energy prices.

One means of combating this incentive for high energy consumption is to increase energy prices by removing subsidies and also by accounting for environmental externalities through increased taxation. CO_2 taxes for the specific purpose of combating climate change are not yet common but have been introduced in a number of countries. For example, in Denmark, a general energy tax of 0.17 DKK/kWh plus an explicit tax on CO_2 of 0.10 DKK/kWh are imposed on all electricity sales (Redlinger, et. al., 1998). At an exchange rate of DKK 6.5 per US dollar, this amounts to a total tax of US$ 0.026 per kWh for the direct purpose of discouraging energy consumption and particularly that derived from fossil fuels. In Finland, energy taxes are based directly on the carbon content of fuels. For residential electricity, the CO_2-based energy tax is 0.033 FIM/kWh, or US$ 0.0063 per kWh based on an exchange rate of 5.275 FIM per USD. For industry, the CO_2-based energy tax is 0.0145 FIM/kWh, or US$ 0.0027 per kWh (Finland Ministry of Trade and Industry, 1997a).

Other essentially taxation-based mechanisms also exist with similar objectives, such as tax credits for efficient technologies. One proposed mechanism, the "feebate," offers a rebate for products exceeding a certain efficiency level while charging a fee for products under the specified efficiency level (IEA, 1996a).

2.6 Energy Service Companies / Performance Contracting

Energy service companies (ESCOs) provide energy efficiency services under what is commonly known as "energy performance contracting." Performance contracting is based on the concept that a customer hires an ESCO for a given result, typically a certain amount of energy savings, and the ESCO is paid based on its performance in achieving these savings. To obtain the energy savings, an ESCO specifies and installs new building equipment such as lighting and HVAC; and in this sense an ESCO is not fundamentally different than a standard engineering company. A primary difference lies in the conditions under which payment occurs. While a standard engineering company will be paid based on the time and materials spent on a project (essentially regardless of the completed project's performance), a performance contractor or ESCO is paid according to the project's performance in saving energy, with high upside earning potential for good results and correspondingly high downside risk in the event of poor performance.

ESCOs offer complete energy services, including project development, financing, design, installation, and maintenance. ESCOs typically offer “shared savings contracts,” in which the customer essentially pays the ESCO through a portion of the money saved through reductions in end-use energy consumption. By tying payment directly to energy savings, most of the performance risk can be borne by the ESCO rather than the customer. Typically, an ESCO will receive between 50 and 95 percent of savings resulting from the energy retrofit project over a period of 5 to 15 years (SRC International, 1995). After this contract period is over, the customer will receive 100 percent of the energy savings benefits for the remainder of the installed equipment’s life.

By providing the full range of energy services including equipment specification, financing, and performance guarantees, ESCOs can be highly effective at reducing many of the barriers to energy efficiency outlined at the beginning of this report, including lack of information, high initial cost, lack of confidence, and high discount rates.

The customer’s high transaction costs of gathering information about energy-efficient products are also reduced, but these transaction costs are replaced by others: legal costs, energy monitoring costs, and credit analysis costs associated with negotiating a long-term performance contract. As a result, ESCO projects tend to be large to make the negotiation costs worthwhile.

A fundamental strength of ESCOs lies in their ability to analyse buildings as integrated systems in which lighting, heating, air conditioning, etc. are all related. For example, a well-designed daylighting system can increase natural light, which reduces artificial lighting needs, while also reducing direct solar heat gain which then reduces air conditioning requirements as well. Furthermore, reducing the overall artificial lighting level and using high efficiency lamps not only reduces lighting energy consumption but also reduces the amount of waste heat from the lamps, thus allowing further reductions in air conditioning loads. Optimising all building systems in this integrated manner allows energy savings often in excess of 50% of total building energy use, far greater than anything achievable by retrofitting each piece of equipment individually.

A further advantage of performance contracting is its flexibility and its market-based nature, reducing the need for regulatory intervention or complex cross-subsidies as occur in utility demand-side management schemes, described below. Nevertheless, building up an ESCO industry requires time and significant expertise. The success of performance contracting is also critically dependent on elimination of subsidies so that energy prices reflect the full market cost of energy.

The ESCO industry now does several hundred million dollars of business per year in the USA and Canada. Nevertheless, the industry is confronted with many challenges; and overcoming entrenched barriers to energy efficiency is a time-consuming and costly business. ESCOs typically survive by packaging their energy efficiency services within the context of total “solutions” to customers’ needs to improve “productivity, environmental compliance, indoor air quality and health / safety concerns, aging equipment in need of replacement, facility renovation and modernisation, equipment reliability, and occupant comfort” (Goldman and Dayton, 1996). Energy efficiency is thus one component in the value chain provided by ESCO projects. ESCO projects are generally most viable with large institutional customers who own many buildings with aging infrastructure, are capital-constrained, have a long investment horizon, and lack in-house expertise to deal with complex energy and facility management issues. Such customers typically include governments, universities, school districts, and hospitals.

ESCO projects normally involve retrofits of existing facilities. With payment being based on actually achieved energy savings, detailed documentation of pre- and post-retrofit energy consumption is necessary, making the concept less applicable for new construction. Though ESCOs have often been heralded as the ultimate "market solution" to public energy efficiency policy, they have not in fact been a panacea. They offer a specific strategy for specific markets and often work best in conjunction with other programs, such as DSM described below.

2.7 Demand-Side Management

Demand-side management (DSM) generally refers to intervention by the utility on the "customer side of the meter" to change the magnitude or load profile of customer energy demand. These customer load modifications are meant to provide alternatives or additions to traditional utility supply-side resource planning. DSM represents a partnership between the utility and its customers to meet customers' energy service needs at the lowest overall cost. This partnership often involves utilities providing incentives to consumers to modify their demand in ways which allow both parties to benefit. Though DSM can refer to any type of customer demand modification through utility involvement, including load *growth*, the common usage of the term DSM mostly implies load *reductions*, either through conservation or load management.

For a publicly owned utility, the rationale is clear for meeting society's energy service needs at the lowest overall cost, whether through increasing supply or by reducing demand. For privately owned profit-making utilities, however, profits are earned through selling energy; and the idea of utilities encouraging customers to consume *less* energy through DSM can appear antithetical to the fundamental premise of the utility's existence. However, the concept of DSM was developed in the USA where privately owned utilities dominate the electricity industry. To understand why DSM can make sense even for private profit-making electric utilities, it is important to understand the basic theoretical underpinnings of DSM as outlined below:

- Customers are not interested in energy per se, but rather in the useful services such as lighting and heating which energy provides. If customers can obtain the same level of useful energy services while consuming less actual energy, then customers' and society's welfare is improved. However, utilities profit from selling energy and therefore may have an inherent incentive to encourage maximum energy consumption and discourage energy efficiency. There may thus be a fundamental conflict between utilities' profit-maximising behaviour and society's interest in maximising energy services while minimising actual energy consumption. Society would be better served if utilities' and society's interests were aligned such that utilities could profit from selling useful energy services without increasing actual energy consumption.
- Utilities typically earn a rate of return (ROR) of approximately 10% per year on their investments in electricity supply capacity. Often, rather than increasing energy supply, the same level of energy services could be achieved more cost-effectively by investing in improved end-use efficiency. For example, an energy efficiency investment with a simple payback of 4 years and a lifetime of 10 years provides an ROR of approximately 21%. From a society's perspective therefore, it would be better to invest in the energy efficiency option rather than the energy supply option. However, energy consumers' decision-making criteria are different than those of utilities. Consumers will often demand an

ROR of over 30% on energy efficiency investments, though utilities are willing to settle for 10% on supply investments. As a result, consumers fail to invest in the energy efficiency option providing a 21% return; and instead, energy service needs must be met by the utility constructing the supply option with 10% ROR. This gap in ROR required by consumers and utilities means that society as a whole is under-investing in energy efficiency compared to the "optimal" amount.

- For utilities who have a regulatory "obligation to serve," utilities must anticipate future electricity demand growth and construct supply capacity in order to meet all future demand. Yet utilities only make money if the supply capacity they build is actually used, so building over-capacity is financially ruinous for utilities. In times of uncertain energy demand growth, high power plant capital costs, and long construction lead times (particularly as was the case in North America during the late 1970s), building new supply capacity is highly risky for utilities.
- Given the above, if through a partnership between the utility and the customer (i.e., through DSM), customers can be induced to invest in more energy efficiency, then all parties benefit: customers receive their desired level of energy services for lower cost, utilities avoid constructing risky supply capacity, and society's overall resources are allocated more effectively while simultaneously reducing pollution from energy consumption.

The above points represent the underlying rationale behind DSM. Utilities provide customers with incentives to invest in energy efficiency and thus meet their customers' energy service needs at lower overall cost while reducing the risks of building new energy supply capacity. To further induce utilities to pursue DSM, often for the purposes of environmental protection, regulatory structures were altered in many North American states to provide the following incentives to utilities: 1.) utilities could recover expenses incurred in administering DSM programs; 2.) utilities could recover lost revenues from reduced energy sales due to DSM; and 3.) utility shareholders could earn a rate of return on investments in customer end-use energy efficiency. These mechanisms were critically important and highly successful in overcoming utility opposition to DSM.

As a result of the above changes, North American utilities were spending several billion US dollars per year by the mid-1990s providing incentives to customers to reduce energy consumption. Though the bulk of spending and energy efficiency gains from DSM in North America have been through rebate programs in which utilities pay incentives to customers, many other types of DSM programs also exist, including information programs, energy audits, and incentives to manufacturers.

Many DSM programs work in conjunction with other mechanisms described earlier. For example, market transformation programs have been implemented in countries as diverse as the USA ("Super Efficient Refrigerator Program"), Brazil (PROCEL refrigerator and freezer project), and Thailand (EGAT thin tube lighting project) where *voluntary agreements* between utilities and manufacturers were used to introduce new high efficiency products to the market and phase out older less efficient models (Swisher, et. al. 1997, UNEP IE & US EPA, 1997). In DSM bidding programs, *ESCOs* may bid for DSM contracts with utilities, in which ESCOs are paid incentives by utilities in return for achieving a specified level of energy savings.

Though DSM is considered to have provided significant societal benefits through more efficient energy use, several controversies emerged. These include the following:

- *Cross-subsidies.* Utility lost revenue recovery and shareholder profits from DSM were accrued to the utility through increases in tariffs. For participants in DSM programs, their energy consumption declined sufficiently to offset any increase in tariffs, so their overall energy bills declined. However, for non-participants, tariffs increased while consumption remained constant, so their overall energy bills increased. As a result, significant cross-subsidies were occurring from non-participants to participants.
- *Free riders.* Free riders are those customers who would have installed energy efficiency measures even if no utility incentives were available, but who take advantage of the incentives because they happen to be available. The utility and society do not gain from providing incentives to these free riders, but they too must be subsidised by ratepayers. Quantifying the number of free riders and reducing their number through improved program design can be difficult.
- *Declining marginal costs.* One of the primary benefits of DSM was meant to be the deferral of costly and risky new energy supply capacity construction. However, declining marginal supply costs through technological advances and stabilising demand growth in the 1990s meant that the economic benefits of avoiding supply-side investments were declining.
- *Program evaluation.* As a result of issues such as free riders, determining the true effectiveness of DSM in achieving energy savings is difficult in spite of complex and time-consuming evaluation procedures. Such thorough evaluation is necessary because many utilities earn substantial profits on their investments in DSM, but substantial evaluation costs also reduce the cost-effectiveness of the DSM program without necessarily alleviating fears that the money is being misspent.

Critics argue that investments in DSM represent a misallocation of ratepayers' funds and distort the energy market without providing demonstrable benefits. Some also question whether it is the utility's appropriate role to persuade consumers to reduce energy consumption. However, the most serious challenge to utility DSM has come from a different angle: the prospect of utility deregulation, unbundling, and competition. The impacts on energy efficiency of utility industry liberalisation are discussed below.

3 Impact of Industry Restructuring and Liberalisation on Energy Efficiency

Significant debate has taken place regarding the impact of utility industry liberalisation on end-use energy efficiency. However, the concern that liberalisation would hurt energy efficiency efforts has focused largely on its effects on utility-based DSM. This is due to the fact that DSM accounted for a very large share of total North American public investment in energy efficiency. In fact, many energy efficiency mechanisms described above remain largely unaffected by utility restructuring. Even in cases where energy efficiency mechanisms have been funded through utilities, funding can continue through other means in a restructured industry, such as through a non-bypassable public goods charge, which is essentially a tax on energy consumption, set aside for specific public-purpose programs such as energy efficiency. The following discussion briefly examines the impacts of liberalisation on each of the mechanisms discussed.

3.1 Energy Labelling

Implementation of energy labelling should not be affected by utility industry liberalisation. Requirements to label the energy consumption of appliances are imposed on manufacturers and would not be influenced by utilities. In some cases, labelling programs are funded through utility DSM programs such as in Thailand (Swisher, et. al., 1997), but they could be readily funded by other means as well. In fact, as the smooth functioning of a liberalised market depends upon customers being well-informed, labelling could be viewed as a fundamental component of ensuring efficient energy market operation in a liberalised regime. However, though the *implementation* of labelling programs should not be affected by liberalisation, the *effectiveness* of labelling may be affected. If liberalisation serves to drastically reduce energy prices, then the incentive for customers to use the labels to rationalise their energy consumption would decline. In fact, given that the effectiveness of energy labelling is questionable to begin with, lower energy prices would reduce this effectiveness even further.

3.2 Energy Efficiency Standards

Energy efficiency standards should theoretically not be affected by utility liberalisation since efficiency standards apply across the entire market and should not affect competition between utilities. In fact, given that standards have been some of the most effective mechanisms to improve energy efficiency to-date in developed countries, they may continue to play a very important role in liberalised markets as well.

On the other hand, as standards do serve to distort the “natural” market, some would question the appropriateness of imposing strong efficiency standards on an otherwise deregulated market. In a truly competitive market in which energy prices reflect their true social cost and in which consumers are well-informed, standards should ideally not be necessary for customers to make their own appropriate choice of balancing efficiency and consumption. Nevertheless, some market barriers to end-use efficiency will always remain, such as the owner/tenant division in decision-making or perhaps the lack of importance of energy in customer decision-making. Competition also does nothing to reduce the existence of environmental externalities. Therefore, efficiency standards continue to be justified in deregulated energy markets. In the USA, there is no prospect of relaxing or eliminating energy efficiency standards as part of the utility industry restructuring process.

However, implementation of new energy efficiency standards is often opposed by appliance manufacturers and the construction industry due to their fear that standards will raise equipment and building costs and thus lower overall demand for their services. This opposition could increase in the light of liberalisation if lower energy prices mean that customers see fewer cost savings from energy efficiency and so become less amenable to paying higher prices for efficient equipment and buildings.

Efficiency standards should therefore not be too stringent and should be implemented gradually to lessen the cost to manufacturers and builders in meeting them. Standards are typically not an effective or viable way to push for maximum energy savings but are rather used to eliminate the more inefficient products and practices and ensure a reasonable minimum level of performance.

3.3 Energy Conservation Centres

The impact of utility restructuring on energy conservation centres depends to a large degree on how dependent the centres are on utilities for their funding. In the case where centres are owned and operated directly by utilities, as in California, liberalisation may serve to lessen utilities' interest in end-use efficiency (see DSM discussion below) and therefore lessen the centres' viability as utility-funded operations. On the other hand, utilities may begin to see energy efficiency as a competitive tool for enhancing customer satisfaction, and in this case their interest in maintaining energy conservation centres could increase. Utility energy efficiency centres could also be spun off into independent organisations funded by a public goods charge on energy sales.

Government funding for energy conservation centres should not be fundamentally affected by liberalisation. In fact, the government should have a stake in adequately informing consumers about energy efficiency options to ensure a properly functioning energy services market; so, as with labelling programs, the justification for government funding of energy conservation centres may be high in a restructured energy industry.

Well-run centres such as the Energy Conservation Centre, Japan rely on their clients for most of their funding through fees for services provided. In this case customers' demand for energy efficiency services will be a significant determinant of energy conservation centres' financial viability. If liberalisation serves to lower energy prices significantly, then demand for such services may also decline.

3.4 Voluntary Programs

Voluntary programs through government and industry should not be fundamentally affected. Though lower energy prices due to liberalisation may reduce industries' incentive to participate, governments can still provide other inducements. For example, the Netherlands' approach of easing issuance of environmental permits to program participants would continue to be a strong incentive. In addition, participation in voluntary programs is likely to continue to be seen by industry as a means of staving off more restrictive mandatory programs and regulations, for example in terms of greenhouse gas emissions. Lastly, industries are likely to recognise the growing importance of enhancing their public image of environmental friendliness by participation in voluntary programs. In general, in highly competitive industries where branding, image, and product differentiation are important, environmental friendliness can be a powerful marketing tool to be exploited through voluntary programs.

3.5 Energy Prices and Taxation

One of the fundamental objectives of energy industry liberalisation is normally to lower energy prices through increased competition. These lowered prices are likely to lead to reduced consumer interest in energy efficiency. This is perhaps the most fundamental danger of liberalisation in terms of its environmental impact and can affect the effectiveness of many other measures such as labelling, standards, energy conservation centres, etc. On the other hand, given that price-elasticity of energy demand tends to be fairly low and that modest increases in energy prices typically do little to reduce energy demand, it may be that modest decreases in energy prices may do little to reduce interest in energy efficiency. Furthermore, with lower prices brought about by competition, it will likely be more societally palatable to impose a modest energy tax or public goods charge to set aside funds specifically for energy efficiency and other public purpose programs. As long as such a charge is not set too high, consumers could still gain substantial energy price reductions, while funding for energy efficiency programs could be sustained.

In California, which has traditionally led the USA in energy policy trends, the law resulting from the state's recent restructuring process mandates a public goods charge amounting to $228 million per year to be collected by the investor-owned utilities for at least the next three years, targeted exclusively for energy efficiency activities (California AB 1890 Ch. 854, Sec. 381, 1996). This amounts to approximately US$0.001 per kWh. The law also mandates an immediate rate reduction of at least 10 percent for residential and small commercial customers in 1998 (California AB 1890 Ch. 854, Sec. 330, 1996). With modest tariff reductions on the order of 10-20% combined with a public goods charge for energy efficiency programs, it may be possible to sustain energy efficiency improvements in spite of tariff reductions stemming from liberalisation.

3.6 Demand Side Management and Energy Service Companies

This section discusses demand-side management (DSM) and energy service companies (ESCOs) together because the fate of the two in a liberalised industry is likely to be increasingly linked. The general trend is for "market solutions," of which ESCOs are a prime example, to replace "regulatory solutions," of which utility DSM is a prime example. Nevertheless, there has been significant overlap between the services offered by the two.

In the USA, perhaps the "home" of both DSM and ESCOs, the trend of the mid-1990s has been for utility DSM activities to decline following its spectacular rise in the early 1990s. This decline has been primarily due to the uncertainties introduced by the prospect of industry restructuring and, in particular, the desire to avoid any programs which result in higher tariffs and which thus make the utilities vulnerable to attack from low-cost unregulated competitors. This is compounded by the fact that, once vertically integrated monopoly utilities are broken into separate competitive generation markets and distribution markets, the regulated utility's incentive to avoid constructing power plants disappears. Furthermore, in a competitive generation market, risks for generators will increase, leading to higher discount rates for generation projects and thus reducing the payback gap between supply-side and demand-side investments that previously justified regulatory intervention in the market.

These pressures to reduce DSM activity have been countered by public pressure to continue funding for energy efficiency activities in light of continued existence of market barriers and environmental externalities. As a result, the US tendency has been to continue utility ratepayer-funded energy efficiency programs, but in a modified and generally reduced form.

Two trends in the direction of "public policy-based" DSM can be identified. First, the nature of DSM is concentrating increasingly on informational programs to better inform consumers of their energy- and money-saving options, and on market transformation programs which attempt to move the entire market for energy-consuming products such that high efficiency products become the norm. Incentive programs which provide benefits to specific customers rather than to the market as a whole are being reduced under the rationale that the competitive energy market should be able to provide such services. This is the approach being taken by the California Public Utilities Commission, for example. The second trend is that, where customer-specific DSM incentive programs do continue, they are focusing increasingly on residential and small commercial customers where the market barriers to energy efficiency are considered particularly high. This is the strategy advocated by several investor-owned utilities in Wisconsin (Eto, et. al., 1996).

In the USA, funding for such utility-based "public policy" electricity energy efficiency programs within restructuring states is generally being pursued through a non-bypassable non-discriminatory public goods charge, or "wires" charge, levied on all users of the electricity system at the distribution (or possibly transmission) level. By imposing such a charge on all users of the system, consumers cannot avoid paying the public goods charge by switching service providers from the regulated utility to an unregulated competitor. This type of wires charge is also being used in Norway and Canada (IEA, 1996a). It is essentially an energy tax which is earmarked for specific activities to improve general public welfare including environmental protection.

However, another trend is emerging quite separately from the "public policy" DSM discussed above. This has been termed "business-based" DSM (IEA, 1996a) in which utilities use energy efficiency services as a fee-for-service business in its own right and/or as a strategy for enhancing customer satisfaction and customer retention in light of competition. In essence, utilities are moving directly into the ESCO business, either by creating, purchasing, or partnering with ESCOs.

The effect of utility industry restructuring on ESCOs is unclear. As discussed above, where ratepayer-funded customer-specific DSM incentives continue to exist at all, they are likely to focus on residential and small commercial customers, areas in which relatively few ESCOs currently operate. The large commercial and industrial sectors typically favoured by ESCOs are likely to see DSM incentives disappear, in which case ESCOs could no longer use utility DSM funds to sweeten the economics of their energy efficiency projects. Combined with general energy price reductions brought about by liberalisation, many energy efficiency projects could become increasingly difficult to justify, especially given the high transaction costs associated with negotiating ESCO contracts.

On the other hand, a liberalised and thriving energy market may also create consumers who are better informed and more eager to avail themselves of money-saving services on offer, including energy efficiency. For utilities, retaining customers within a competitive market will increasingly require providing high value-added services; and the ESCO model of providing total solutions to not merely energy efficiency problems but also to concerns such as aging equipment, financing, comfort, and environmental compliance may provide a superior market-driven strategy for customer retention. This is evidenced by the fact that many utilities in the USA are entering the ESCO business in anticipation of the new market. If the experience of the US telecommunications industry is any guide, energy utility competition is likely to be fierce and could spawn a wide variety of new energy products.

Whether these business products will in future be provided by utilities, utilities' ESCO affiliates, or independent ESCOs is not clear. One of the primary reasons that energy efficiency programs have been promoted through utilities in the first place is due to the utilities' superior financial resources, customer access, staff availability, and public accountability. If utilities leave the energy efficiency field and become exclusively energy commodity providers, it is difficult to imagine how energy efficiency activities could be carried out by non-utility organisations on the scale with which they have been pursued in the USA during the last decade. However, transmission and distribution network monopoly businesses may still have reasons to try to avoid capacity expansion through demand management, especially if peak demand is increasing greatly at low load factor. And tradable greenhouse gas emission permits, which are being contemplated in the USA and Australia, could give generation or retail utilities further incentive to cost-effectively reduce emissions through demand reduction.

On the other hand, depending on the liberalised industry's structure, there may be drawbacks to continuing to rely on utilities as the engines of energy efficiency services. Naturally, to be successful, DSM programs will have to allow utilities to profit from providing these services rather than merely from maximising energy sales. The price cap formula for distribution utilities originally established in the UK after liberalisation provided a strong incentive for utilities to maximise sales and discourage conservation. Other dangers include the possibility of the remaining regulated utilities using their regulated status to confer unfair competitive advantages on their unregulated energy service subsidiaries or of distribution companies affiliated with generation companies discouraging energy efficiency in order to reduce their risk of stranded generation assets. The key to continuing energy efficiency success through DSM and ESCOs in the future may be to continue to harness the depth and reach of utilities for profitable energy efficiency services without distorting the competitive functions of the market.

4 Mechanisms for Promoting Energy Efficiency in Restructured Electricity Markets

This section provides specific examples of programs being pursued in various countries to promote energy efficiency in competitive electric utility industries. Comparison between countries is complicated by the variations in the nature of industry structure. For example, in the generation market, England & Wales have three major privately-owned generators, New Zealand has predominantly two state-owned generators, Norway has approximately 60 generators of primarily public but some private ownership, and Finland has approximately 120 generators, of which the largest two include one private and one public. In the distribution market, England & Wales have 12 privately-owned regional electricity companies with local monopoly franchises for small customers; New Zealand has approximately 40 distributors which are primarily owned by non-profit community trusts but which face full retail-level competition for customers; Finland has approximately 115 (but declining) distribution utilities, three-quarters of which are owned by local authorities, and all of which face competition and consolidation; and Australia varies by state, with some states continuing with government-owned monopolies, and others having established wholesale market competition and moving to full retail competition. Nevertheless, various countries in various stages of industry restructuring have established a track record of promoting end-use energy efficiency which can provide useful lessons.[2]

4.1 UK

The England and Wales electricity system is characterised by three large privatised generators and multiple independent power producers which all sell their generated electricity to the power pool operated by the National Grid Company. Twelve Regional Electric Companies (RECs) operate the local distribution grids and have had monopolies on serving their local franchise (small) customers. “Large” customers have been able to choose to purchase their electricity from their local REC, competing RECs from other regions, other licensed generators and traders, or directly from the pool, with non-discriminatory distribution access provided by the local REC. “Large” customers were initially defined as those with over 1 MW of demand, but this was lowered to 100 kW, and from 1998 choice of supplier is being extended to all customers.

The Energy Saving Trust (EST) was established in 1992 as a private limited company to propose, develop, and manage programs to promote energy efficiency and to help meet the UK’s greenhouse gas reduction goals. EST is funded explicitly by the government (£50 million over 3 years) through the national government budget. Some of the activities carried out by EST include: 1.) market transformation programs to

[2] Information in this section has been obtained from IEA, 1996a, unless otherwise noted.

work with manufacturers, retailers, installers, trade associations, and other organisations to stimulate the market for energy efficient products and services; 2.) grants for installation of CHP in multi-residential buildings funded by a temporary levy on natural gas sales; 3.) creating an “energy efficiency brand” whose logo assures customers of high quality products which save money and energy; 4.) providing energy efficiency information and advice to schools and to domestic and small/medium enterprises; 5.) developing a network of Local Energy Advice Centres throughout the UK which provide impartial advice on energy saving measures, with over 30 centres operating as of 1996.

Electricity Standards of Performance (SoP) are energy efficiency programs implemented by RECs and monitored by EST and the electricity regulator OFFER. The programs are designed to meet energy savings targets mandated by OFFER in the franchise market and have been funded by a £1/account annual charge on all franchise market customers. A variety of incentive schemes have been developed for equipment including compact fluorescent lamps, home insulation, and high efficiency refrigerators. The SoP programs will end in 1998 when franchise markets are eliminated and full retail competition is established.

Other programs include central government-funded publicity and awards schemes including corporate commitment campaigns and energy efficiency awards, and the Best Practice Programme to provide R&D support, demonstration project support, and information dissemination to the commercial and industrial sectors. Business-based DSM in the UK has included RECs trying to defer distribution system investments through demand reductions, interruptible/curtailable contracts with customers to minimise REC exposure to the pool, and other innovative contracts to reduce load at times of high pool price.

4.2 Australia

Australia began restructuring its electricity industry in the late 1980s but has followed different paths for different states. An interconnected competitive electricity market has been established in southern and eastern Australia which is being steadily extended, while remote areas such as Western Australia, Tasmania, and the Northern Territory remain un-interconnected and retain state monopoly structures. Victoria and New South Wales are establishing retail-level competitive markets with customer choice of supplier being progressively extended to smaller customers, while South Australia’s market is competitive at the wholesale level only. Privatisation of state-owned industries had occurred only in Victoria as of 1996, but all government-owned utilities have been corporatised and must compete in the open market where such a market has been established.

The competitive wholesale market incorporates three levels of trading: 1.) bilateral long-term contracts covering fixed amounts of energy over specified time periods under set prices; 2.) short term forward market trading in which buyers and sellers lock in energy prices by trading buy/sell offers similar to those used in other financial markets; 3.) spot trading with energy traded through a commodities-type pool and a spot price set every half hour by the last, most expensive, generator selected to run.

Australia’s energy efficiency initiatives are funded and implemented primarily by the federal government. Federal government programs include the following:

- The Building Energy Code of Australia (BECA), a voluntary energy efficiency code for commercial buildings, released in 1997
- The National House Energy Rating Scheme (NatHERS), designed to assist prospective home builders and renovators to choose energy-efficient home

designs. The Australian Capital Territory mandates a minimum efficiency rating in new home construction, while the state of Victoria, which initiated the original HERS several years ago, runs its program as a voluntary scheme. Implementation of the NatHERS is up to each individual state.

- The Enterprise Energy Audit Program provides a rebate of up to 50% of the cost of an energy audit to commercial and industrial participants who commission an audit by a registered energy auditor.
- Minimum Energy Performance Standards (MEPS) for a range of domestic appliances are being introduced in 1998. Standards include those for household refrigerators, freezers, and household water heaters. Standards for commercial equipment may also be introduced for electric motors, fluorescent lamp ballasts, packaged air conditioners, and office equipment.
- Appliance Energy Labelling. New South Wales and Victoria have had mandatory appliance energy labelling programs for major domestic appliances such as refrigerators, freezers, dishwashers, air conditioners, clothes washing machines, and clothes dryers since the mid 1980s. This program has been extended to the national level. Victoria has also recently introduced labelling for gas central heaters.
- Co-operative Voluntary Agreements with Commerce and Industry. As part of its strategy for meeting Australia's commitments to the Framework Convention on Climate Change, this program aims to encourage industrial and commercial enterprises to undertake measures to improve energy efficiency within their operations on a voluntary basis. As of 1996 more than 50 letters of intent had been signed by individual companies and industry associations.

The state government of New South Wales (NSW) has also implemented a number of energy efficiency initiatives which include the following:

- The Electricity Supply Act of 1995 stipulates that all retail suppliers of electricity must, as a condition of holding a license: 1.) develop plans and strategies for demand management and for purchasing energy from renewable sources, including cogeneration; 2.) implement strategies to help meet national greenhouse gas reduction goals; 3.) prepare and publish annual reports on the implementation of demand management strategies, CO_2 emissions arising from the electricity supplied by its operations, and the sources of electricity supplied.
- A Sustainable Energy Fund was created in February 1996, with an initial commitment of $65 million of state government funds to the Sustainable Energy Development Authority over three years, to help reduce greenhouse gas emissions through investing in the commercialisation of energy efficiency and renewable energy technologies. The activities available for possible funding include commercialisation of technologies through direct investment of funds; market transformation programs to increase certain technologies' market share through financial assistance to purchasers of certain products; industry assistance to provide financial and other assistance to sustainable energy industries; and information, education, and training programs.

The NSW Electricity Supply Act's provisions for mandatory DSM for retail electricity suppliers are hampered by the lack of financial motivation for utilities to actively pursue energy efficiency. The NSW Independent Pricing and Regulatory Tribunal has been investigating the biases against energy efficiency resulting from regulations which reward increases in electricity sales. The Tribunal has proposed revenue regulation for the franchise (monopoly) market of the retail market and to the distribution wires business which would decouple profits from electricity sales, making utilities indifferent to whether energy service needs are met through supply enhancement or demand management. This is similar to the decoupling mechanism implemented in many US states. However, the practicality or sustainability of such revenue regulation is not clear as New South Wales moves to eliminating its franchise market and allowing full retail-level competition. Distribution wires businesses may still benefit from demand management in a revenue-regulated environment, but the wires business would be dependent on retail electricity suppliers to carry out the demand management activities; and the retail suppliers may not be interested in DSM under full retail competition.

The government of the state of Queensland has also established requirements for energy efficiency in its publicly owned utilities. Through its Office of Energy Management energy efficiency rebate programs are offered for a variety of end-uses including domestic lighting, hot water heating, stand-alone power in remote areas, solar hot water heaters, commercial building window films, and commercial lighting. One of the purposes of these programs is to maintain a high profile for DSM as Queensland proceeds with restructuring and removal of franchise monopolies, in which Queensland has not yet proceeded as far as New South Wales or Victoria; but how these programs will coexist with retail competition is not clear.

Some other state governments such as Victoria also provide energy efficiency programs such as energy information centres, corporate publicity and rewards campaigns, publications, etc. As can be seen from the descriptions above, most Australian energy efficiency initiatives are driven by the government and do not significantly rely on the competitive electricity sector. The Australian government’s programs incorporate many of the non-utility mechanisms described at the beginning of this chapter including labelling, efficiency standards, and voluntary agreements.

Some business-based DSM ideas for utilities have been proposed such as “demand-bidding” in which distributors and large customers can bid planned load reductions into the wholesale pool. Proposals have also been put forward for a tradable greenhouse gas emission permit system in which retail electricity providers or generators could contract with customers for energy reductions to limit greenhouse gas emissions and in which successful emission reductions would allow utilities to sell excess permits on an open market. None of these proposals have been implemented to-date, however.

4.3 Norway

Norway has been one of the pioneers of electric utility restructuring in which The Norwegian Electricity Act of 1 January 1991 instituted open non-discriminatory access of the transmission and distribution grid, creation of a new monopoly transmission grid company, competition at the wholesale and retail levels, and establishment of a power pool and bilateral energy contracts between suppliers and customers. Like much of Australia, restructuring in Norway has not been accompanied by privatisation, and the majority of Norwegian utilities remain publicly owned. Vertical integration of utilities is also still common, with approximately half of all distribution companies also owning generation facilities. While such vertical integration may reduce some of the intended benefits of competition, full retail-level competition does mean that electricity suppliers who purchase high cost power from their own generators may risk losing customers to rival providers (though few retail customers have in fact switched suppliers to-date). Many ownership issues regarding public vs. private, vertical unbundling, and separation between distribution “wires” and “retail sales” businesses are still under debate.

Unlike the UK and Australia, most power in Norway is traded through bilateral contracts between suppliers and customers, with only a small (but growing) share of electricity being traded through the power pool. The power pool market is characterised by three distinct markets: 1.) the weekly or forward market is a week-ahead financial market; 2.) the 24-hour or spot market is a day-ahead market with power priced for five daily intervals during the week and three intervals for the weekend; 3.) the regulation market, which is a balancing market where bids are used to price imbalances between buyers and contracted generators. The Norwegian power market, formed as STATNETT Marked, merged with Svenska Kraftnät of Sweden in 1996 to form Nord Pool; and this has since been extended to Finland and Denmark to create a power market serving all of Scandinavia.

Furthermore, new standardised contract forms have been introduced to allow greater trading flexibility. These include price guarantees to hedge against volatility in the spot market, bilateral options to buy / sell a certain amount of power at a specific price at a specific time, and term contracts allowing standard bilateral contracts to be traded. Market risk is a great concern in the Norwegian market, particularly given the great variability of hydro availability and Norway's virtually 100% dependence on hydroelectric power. Much attention is therefore now given to risk management by Norwegian utilities.

In terms of DSM, grid owners are required, as part of the conditions of their distribution license, to undertake certain DSM functions such as information, demonstrations, and audit programs. The distribution utility can recover actual costs related to these public policy DSM programs through a wires charge up to a maximum of approximately 0.0004 USD / kWh. Because complete separation is not required between distribution wires utilities and electricity retail suppliers, there is little to prevent distributors from using this levy for marketing activities and customer retention. In order to limit such abuse of the public purpose levy, the regulator NVE has established a number of Regional Energy Efficiency Centres (REECs) funded by the DSM wires charge which are jointly owned by utilities and third parties in each region and which provide impartial energy efficiency advice. REEC services include general information on energy efficiency, historical electricity consumption data, simple audits, information on the environmental impact of energy consumption, and energy efficiency advice especially for residential customers, small commercial customers, small industries, and public institutions.

Government-funded programs are also limited mostly to targeted information campaigns, training materials, energy management advice for large commercial buildings, and the Industrial Energy Efficiency Network voluntary program. Utilities also use business-based DSM concepts such as real-time pricing to help customers avoid high peak time prices, which also improves customer satisfaction and customer retention; but these metering schemes do little to reduce energy consumption or improve energy efficiency.

4.4 Sweden

Sweden was the first Scandinavian country to join Norway in liberalisation of the power sector and creation of the Nordic power pool. The basic feature of the Swedish system is that, like Norway, generation and retail supply are competitive, while transmission and distribution are regulated monopolies. Ownership varies between the state (e.g., Vattenfall, the largest generator, is a state-owned limited liability company), industry, municipalities, and private owners.

The most prominent Swedish energy efficiency activities are being undertaken by NUTEK, the Swedish National Board for Industrial and Technical Development.

NUTEK is the regulator of the power sector, and its energy efficiency activities amount to SEK 900 million (approximately USD 120 million) over seven years and consist of three components: technology procurement, incentive agreements, and voluntary purchasing standards.

Technology procurement is a "market transformation" type program, in which a group of purchasers, organised by NUTEK, indicate a willingness to purchase a certain minimum amount of a product if certain efficiency conditions are fulfilled. Equipment suppliers then compete on design and price to obtain the order. NUTEK arranges the tendering process and supports the clients in purchasing the first order, thereby guaranteeing a set quantity of purchases to the manufacturer. The program thus works to stimulate development of energy-efficient equipment by providing an assured minimum market for the successful winner of the competition.

Incentive agreements are agreements signed between NUTEK and industrial companies, property administrators, and utilities. These agreements provide monetary grants from NUTEK to cover a specified proportion of the incremental costs of installing energy-efficient equipment. The resulting installations must be available for demonstrations so that information about the project benefits can be disseminated to a wider audience.

Voluntary purchasing standards provide examples of energy efficiency products and applications for wide range of end-uses including lighting, ventilation, and office equipment. NUTEK encourages customers to purchase these high efficiency devices, and the purchasing standards are also used within the incentive agreement programs.

Apart from NUTEK, the government is establishing regional energy efficiency centres around Sweden for the purpose of information dissemination related to energy efficiency and alternative energy sources. The centres are jointly funded by the Swedish government and the European Union. Sweden also has some of the strictest building thermal standards in the world which have been responsible for drastic reductions in energy use for heating purposes.

Utilities have not been particularly active in DSM following restructuring, partly due to uncertainty over the resulting industry structure and whether DSM costs can be recovered. The Swedish Department for Energy Efficiency has created a collaboration of 170 utilities for information exchange on energy efficiency, and agreements were made with 30 of these to deliver DSM services to their customers, of which 15 had started to do so as of 1996.

4.5 Finland

Finland has joined the Nordic power pool, and its restructuring efforts have been similar to those of Norway and Sweden, with competitive generation and retail sales, and monopolies on transmission and distribution wires. The Finnish power industry is diffuse, with approximately 120 companies involved in generation (including cogeneration), but the two largest generators, IVO (public) and PVO (private) each account for approximately 40% of the generation sold to the domestic market. There are approximately 115 distribution utilities, mostly owned by local authorities, but this number is declining steadily through consolidation as retail competition increases.

Finland has emphasised voluntary programs and co-operative agreements between government and industry for energy efficiency. These include negotiated agreements in which actors in the energy market agree to achieve certain specific energy efficiency targets. The main groups involved in such negotiated agreements have been the pulp and paper industry, the basic metals industry, and the municipal sector.

MOTIVA is a government-financed centre for energy efficiency and provides information and audits. Customers can request energy audits from independent energy audit providers who are approved by MOTIVA, and the government will typically cover 30-40% (but up to a maximum of 50%) of the audit cost. MOTIVA also facilitates training of auditors and provides a format for audits.

The government also provides certain funding support (average 19.5%) to industrial, private, and municipal energy users for investments in energy conservation; and the government also supports R&D on energy efficiency research. In 1995 the total government funding for energy conservation was FIM 140 million (approximately USD 30 million), of which 60 million was for R&D, 50 million was allocated to support for building renovations, and approximately 10 million each went to commercialisation of new technology, funding for energy audits, and information dissemination. Finnish energy taxes are also explicitly based on environmental considerations and directly reflect the carbon content of fuels.

The Finnish Ministry of Trade and Industry has also advocated more stringent building codes, regular energy audits in industry and buildings, individual metering of energy and hot water (district heating) of consumers in new flats, and energy labelling for appliances and vehicles.

Regarding utility involvement in energy efficiency, the energy act states that energy companies operating in the power market are “responsible for providing their customers with services relating to the supply of electricity and for promoting the electricity efficiency and conservation in their own business operations as well as in those of their customers.” However, there are no mandatory requirements to accompany this text, and utility involvement in providing energy efficiency services to customers is limited.

4.6 New Zealand

In New Zealand, complete retail competition was introduced in April 1994, with all customers now able to choose their energy supplier without constraint. The government-owned generation and transmission functions have been split into different organisations; and generation was further split into two large state-owned enterprises which account for approximately 87% of the market, with independent producers providing the remaining 13%.

The Energy Efficiency and Conservation Authority (EECA) is an independent government agency established in 1992 and is responsible for many of New Zealand’s energy efficiency programs. EECA’s funding comes from a combination of government funding and fees for services, and its 1995 budget was NZ$ 5 million (approximately USD 3 million). EECA’s activities include: 1.) the Energy Saver Fund, an NZ$ 18 million pool of government-funded finance for household energy efficiency programs, administered by EECA and awarded on a competitive basis to projects which achieve cost-effective energy efficiency improvements; 2.) the Energy Wise Companies Campaign voluntary campaign (with over 250 participating organisations) to encourage companies to make a commitment to improve energy efficiency in their organisations; 3.) the Crown Energy Efficiency Loan Scheme which provides loan finance to government organisations for energy efficiency investments; 4.) investigation of the need for minimum energy performance standards for selected commercial and industrial technologies and preparation of draft building code provisions for new residential and commercial buildings.

The Electricity Corporation of New Zealand (ECNZ) is the larger of the remaining two government-owned generation companies, owning the large hydro stations which account for 60% of the country's capacity. ECNZ is also conducting some energy efficiency programs through partnerships with individual power companies, which include the Home Energy Rating Options (HERO) scheme to offer energy audits, recommendations, and possible project financing to households, and the Electric Motors and Drives Programme which provides high efficiency motor selector software, motor testing services, and technical publications.

ECNZ has also established an investment fund for assisting commercial and industrial customers to increase their efficiency and productivity. These investments are made based on their profitability to ECNZ and are funded on a commercial basis. However, how ECNZ in fact profits from end-use energy efficiency is not clear. As a state-owned generating company controlling the majority of generating capacity and with legal constraints imposed on its growth, ECNZ's strategy for the competitive market and its reasons for pursuing DSM are not immediately evident.

The electricity regulator (ESANZ) and ECNZ have both expressed the belief that DSM services will be pursued by electricity retailers for attracting and retaining customers. However, these services will be required to earn a commercial return, and no cross-subsidies will be allowed. Nevertheless, experience on this front is still limited, and most activities to-date have been pursued through government initiatives.

4.7 USA

Electricity industry restructuring is evolving on a daily basis in the USA and differs widely by state. This section discusses the USA primarily in the context of California, which has traditionally led the nation in energy policy developments and innovations. First, restructuring of the electricity industry will not fundamentally alter any non-utility energy efficiency schemes. These include energy labelling, energy efficiency standards, and voluntary programs like EPA's Green Lights and Energy Star Buildings programs, all of which will continue and should remain important components of the overall US energy efficiency strategy.

In California, three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) account for approximately three-fourths of statewide electricity sales. In 1994, these three investor-owned utilities' spending on energy efficiency DSM peaked at $269 million; and this declined to $160 million by 1996 (Energy Efficiency Working Group, 1996). To preserve the momentum for improved energy efficiency, the California Legislature has approved the collection of at least $228 million annually for the years 1998 - 2000 and $188 million in 2001 for cost-effective energy efficiency activities through a public goods surcharge on electricity bills. This surcharge will be levied in the form of a non-bypassable wires charge on all electricity at the distribution level. All customers at the distribution level in the investor-owned utilities' service areas, whether they obtain electricity service from the local utility or a competing provider, must pay this surcharge on a per-kWh basis. Publicly-owned (e.g., municipal) utilities must also collect an equivalent public goods charge (California AB 1890 Ch. 854, Sec. 381, 1996).

As a result, significant energy-efficiency activity should continue in California. However, how these funds are to be spent has not yet been worked out in detail. The California Public Utilities Commission (CPUC) has ordered that the above energy efficiency funds from the public goods surcharge be administered by a newly created independent board: the California Board for Energy Efficiency. The board is composed of members of the public and state officials from the CPUC and the California Energy Commission. The Board is also to be assisted by a Technical Advisory Committee, appointed by the Board and composed of members of the public. The Board will articulate policy and programmatic guidelines on how energy efficiency funds are to be spent; and the Board will issue a Request For Proposals to solicit organisations to develop and implement programs. Utilities are no longer the automatic choice to implement ratepayer-funded energy efficiency programs, but the utilities (both the remaining regulated portions as well as new unregulated affiliates) are allowed to bid in competition with others for contracts to implement the programs. Any decision by utilities to pursue implementation of energy efficiency will be based on utilities' own business strategy in the competitive market; and utilities will no longer receive ratepayer-funded shareholder incentives for energy efficiency (CPUC, 1997). During the transition period while the new structure is becoming fully operational, utilities will continue to administer existing energy efficiency programs and will receive appropriate shareholder incentives as previously authorised. In general, customer-specific incentive programs are to be replaced by information and market transformation programs which target the market as a whole.

Other states are also pursuing non-bypassable, non-discriminatory wires charges to fund energy efficiency activities in restructured electricity industries, including Massachusetts, Rhode Island, and Wisconsin. Other mechanisms to promote energy efficiency are also being discussed. In the global warming debate, the US has been the most prominent advocate of using tradable emissions permits; and such a scheme could provide a significant boost for energy efficiency. Many details of how such a system would function have yet to be worked out. However, in the US electricity industry, presumably emissions permits would be allocated to generators who could obtain emission reduction credits through energy efficiency by either creating an ESCO to implement demand-side efficiency projects or by teaming with a retail electricity supplier to implement the projects.

VIII Applicability of Incentive Mechanisms to the Argentine System

This chapter briefly analyses the opportunities and obstacles in Argentina to applying the mechanisms which have been widespread at the international level (as outlined in Chapters VI and VII) for promotion of renewable resources and the improvement of energy efficiency.

The incentives used for both purposes may be classified as either *prescriptive or inductive*, depending on whether they set obligations or opportunities which agents may choose. The prescriptive category includes the setting of minimum energy-efficiency standards for appliances and buildings and the reservation of a portion of the electricity market for renewable resources (i.e., market set-asides). Inductive mechanisms are more frequently used in competitive markets, and include subsidies, tax incentives, financing at preferential rates, carbon taxes, and the establishment of special markets for environmentally “clean” products (i.e., green markets).

Nevertheless, this initial categorisation does not prevent the use of market mechanisms to promote the actual implementation of prescriptive regulations. Hence, the analysis in the following sections will comment on a wide range of possible mechanisms for both renewable electricity and for energy efficiency.

1 Incentives for the Use of Renewable Resources in Electricity Generation

Before moving on to the specific analysis of each type of incentive, it is appropriate to comment on the implications of promoting construction of power stations with greenhouse gas (GHG) emission-free technologies, as regards the following:

- who should absorb the higher costs caused to electricity generators
- how to channel subsidies
- how to combine the private initiative of generators with the obligation to implement mitigation actions

Certain nations included in Annex I of the United Nations Framework Convention on Climate Change have implemented different types of mechanisms to promote the use of renewable resources, often specially conceived to operate within competitive markets. These include carbon taxes, market set-asides for clean technologies (either centrally administered or with a related market for clean generation certificates), tax exemption or reduction, financing under more favourable conditions than those available in the market, creation of a green electricity market for final consumers, etc. All of these promotion mechanisms are financed in the end by final consumers, either directly through higher electricity rates or indirectly as tax-payers.

But in the case of a country like Argentina, which is not immediately obliged to reduce its GHG emissions and whose emission levels are and will remain for many years far lower than those from the industrialised world, the question is whether the application of these fund-gathering mechanisms corresponds with minimum international equity principles in the effort to mitigate climate change.

It is our opinion that Argentina's willingness to contribute and take part in the international effort to mitigate climate change should not represent a financial or economic burden on the local population.

Consequently, we shall only comment on the efficiency or obstacles to implement mechanisms for promoting clean technologies within the present context of the Argentine electricity system, assuming that the necessary funds for this purpose will come from any of the modes to channel international funds which are still being debated at the Conference of the Parties. In this sense, the carbon tax, green electricity market, and any other instruments which transfer higher costs to consumers are not considered applicable to the current Argentine context.

1.1 Prescriptive mechanisms to promote renewable sources

The most important and widespread mechanism within this category is the setting-aside of a portion of the generation market to be supplied from renewable sources. The experience gathered in the application of this mechanism both in Europe and the US refers to marginal portions of the market and has been used to support independent generators with a marginal individual stake in the market (wind turbines, mini-hydro, photo-voltaics, etc.). There are serious doubts as to whether these mechanisms are equally applicable in the case of large hydroelectric and nuclear stations as they have been for the promotion of decentralised wind generation.

In the case of the Argentine system, given that large-scale hydroelectricity and nuclear power are considered the most promising options for reducing greenhouse gas emissions from the power sector, the establishment of supply quotas by technology type should include hydroelectricity and eventually nuclear energy, in addition to new technologies. This is in contrast to countries who are already experimenting with quotas, such as the Netherlands and USA. Even in the UK, where its NFFO mechanism was originally created to support nuclear power, it has evolved into a mechanism for primarily supporting small-scale renewables. But some of the more economically competitive hydroelectric plants in Argentina may individually represent some 20% of the domestic market, which generates supply blocks that pose difficulties for true competition on account of the indivisible nature of the stations.

Moreover, the question is whether it is legitimate to exclude current hydroelectric and nuclear generators in the consideration of quotas for these technologies, since they contribute 50% of the current electricity supply. Both their inclusion and exclusion from quotas could have distortionary impacts on competition. Differential treatment of new and existing hydro plants with respect to quotas should not be allowed to provide an undue competitive advantage to new hydro facilities. On the other hand, including existing facilities in quotas should not in any way provide a channelling of subsidies towards them, since these investments were paid for with public funds in the first place.

Once the technologies to promote and the quotas to assign to each of them are decided upon, the determination of proper mechanisms for fund collection and distribution appear as a practical problem, as well as the allocation of responsibilities in the observance of the quotas. Both issues are in fact closely related.

There are four possibilities with reference to who would have to comply with the quotas established, namely: generators, traders, distributors and final consumers. Final consumers are ruled out in this analysis because we have established that they should not bear the incremental climate change mitigation costs, and it is more difficult to channel funds towards them to promote the use of renewable sources.

Distributors would in theory represent the most appropriate point of quota imposition if they traded a substantial part of the market. But the trend to separate the physical distribution activity (network handling) from the trading one within an unrestricted competitive environment in the retail market could conspire against their effectiveness in controlling the observance of the quotas. Regarding traders, there are still doubts as to the portion of the market which traders could attract for this commitment to be exclusively and effectively assumed by them, since some generators may choose to directly sign supply agreements with final consumers. Similarly, the observance of production quotas per type of technology cannot be imposed on generators on the basis of their own generation, given the atomisation level reached by supply.

Thus, it would likely be necessary to impose renewables quotas on all agents selling to final consumers. A mechanism of this type would necessitate the implementation of an emission-free certificate market in which each agent could guarantee that its quota of clean electricity has been generated. But in this case, allocation of certificates to already existing hydro, nuclear and wind generators would be problematic as it would represent a windfall profit for them, amounting to a subsidy without any investment counterpart. However, their participation would be essential to the functioning of the certificate market.

The mechanism presupposes that the obligation for emission-free certificates would allow non-emitting generators to obtain extra income on the sale of energy which would be sufficient to offset their higher costs. Nevertheless, the existence of specific international funds to cover incremental climate change mitigation costs presupposes that the agents who acquired the certificates will be compensated for this extra cost.

Another problem is how to measure and check that this extra cost be reasonable and that non-emitting generators do not receive excessive profits. When the non-emitting generator contracts its sale of clean energy with a distributor at a higher price than that of the open market, as is the case in Great Britain, the spot price may be taken as a reference of the alternative supply cost, and the magnitude of compensation to the distributor may be determined. But when transactions are carried out in a secondary certificate market, there would be no signals from the electricity market. Opportunities for excessive profits in the certificate market would likely be erased over time as more renewable generators entered the market to try to reap these profits, but in the early stages when the market is thin, certain price caps may be necessary, the establishment of which is itself no simple task.

International experience in the implementation of these mechanisms is limited and varied, but the obligation to ensure compliance with renewables purchase quotas always falls on all agents selling electricity to final consumers. Should this be the case with the Argentine system, the treatment to be given to electricity imports and exports would also have to be determined.

Interchange with neighbouring countries, especially Brazil, could bring fluctuations in local generation on account of the hydrological situation of the Brazilian system. In fact, local Argentine generation would fluctuate between local demand plus firm export commitments in dry years in the Brazilian basins and local demand minus spot imports from Brazil in wet years.

It does not seem reasonable to impose quotas for emission-free electricity within the Argentine system onto exports to neighbouring nations, that is, Brazil, Chile and Uruguay. Nor does it seem reasonable to ignore the availability of clean energy from hydroelectricity surpluses in Brazil and Uruguay which could be imported by Argentina.

Given these many considerations, it may be concluded that the issue calls for a much deeper analysis on all instrumental complexities of this type of mechanism and its effectiveness in the promotion of non-emitting large-scale generation technologies without creating undue distortions in the market.

1.2 Inductive mechanisms

Among the options of inductive mechanisms to change the expected choices of electricity generators, we shall exclude those involving the establishment of specific taxes and tariffs on the burning of fossil fuels as a mechanism to incorporate environmental considerations into private decisions. This is on account of the reasons given previously, to prevent Argentine consumers from bearing the brunt of climate change mitigation costs.

Both the US and the Netherlands promote using the willingness of the consumer to voluntarily contribute towards the protection of the environment, allowing the consumer to freely express himself in the electricity market through product differentiation (via price) according to its source. The “green market” for electricity can serve as a complementary mechanism to mandatory market quotas which allows constant testing to see whether the minimum quota levels established correspond to the expectations or desires of consumers. In both cases, consumers choosing clean electricity are given a certain type of reimbursement to offset - at least partially - the higher prices paid for the green product.

In Argentina, the differentiation of products on an ecological basis has already begun, at least in the case of agricultural products (produced without agrochemicals and inorganic fertilisers), other foodstuffs (without preservatives or additives), paper (recycled), etc. Nonetheless, these “ecological” products have so far attracted only a small portion of their respective markets.

The applicability in Argentina of this voluntary mechanism for the trading of electricity from non-GHG-emitting sources registers the same difficulties previously mentioned for the production quotas per generating technology, such as regarding support for new vs. existing power plants.

A widely used inductive mechanism to promote generation with renewable sources is the reduction of taxes on electricity production and consumption related to renewable generators. Different nations have chosen plans compatible with their respective tax systems, including a reduction in income tax for renewable generators, exemption from the electricity tax for renewable electricity consumption, etc.

In the case of Argentina, the only national-level tax on electricity consumption is the tax on added value, which represents 21% of the final price, and which could be reimbursed to the new hydroelectric generators and to all wind generators. Although the tax on corporate profit has a 33% tax rate, a discount on this tax could prove ineffective if the higher costs faced by generators with renewable sources prevents their obtainment of corporate profit.

The granting of specific financing at below-market rates could also contribute to the improvement of corporate profit. But once again, the size of certain hydroelectric stations and the investment amounts involved would force the establishment of a considerable fund for the financial aid to have any positive effect.

A higher state participation could be sought to promote the construction of large hydro stations. This could involve a call for bids for the construction of the works, setting the maximum limit for subsidies at the incremental cost calculated by the relevant body for each case. Under such a system, bidders may compete on the basis of the requested subsidy within the admissible range, the levy which the investors may be willing to pay for the concession, complementary works bid, and other improvements in the area. As previously mentioned, this was the promotion mechanism chosen by several provinces to promote the construction of new hydroelectric works within their territories.

This more traditional and apparently simpler mechanism is nevertheless not exempted from difficulties, the main ones being the amount of room reserved for private initiative (technological choice, detection of new opportunities, etc.) and the impact on competition in the electricity market.

The competition issue is especially important because the stations to be bid could have a strong impact on the conditions in which the overall system operates. Should a mechanism of this type be chosen, special attention should be paid to transparency and informational lead time with a view to preventing unnecessary risks for market agents. In any case, a process of this type would require sufficient lead time to reconcile positions and achieve a minimum consensus from local populations ultimately affected by the works.

These comments on the different types of mechanisms to promote non-emitting technologies are not applicable in the case of wind generation, for which a rising portion of the electricity market may be reserved with fewer complications than in the case of hydro power. A quota for wind generation with subsidies awarded on a bidding basis appears to be the simplest mechanism for promoting wind energy.

2 Incentives to Improve Energy Efficiency

In most countries, efforts to promote a rise in energy efficiency have evolved from the establishment of minimum energy performance standards for appliances and buildings since the 1970s, to inductive-type mechanisms in which consumers may express their preferences more freely. Hence, we shall focus in this case solely on the analysis of the most common inductive mechanisms, especially those aimed at a natural insertion in energy markets or the creation of new markets.

Although this analysis is intended to pinpoint opportunities and obstacles posed by electricity deregulation in the promotion of efficiency in the final use of electricity, it is difficult in many cases to isolate electricity from the other energy sources which may compete with it in the supply of energy requirements. Hence, and particularly for certain types of incentives, we shall refer to energy efficiency in general, without limiting the discussion to solely electricity. However, we shall try to spot the possibilities for electricity distributors to insert themselves into this efficiency-enhancing process.

Three aspects may be distinguished in the promotion of the most efficient processes and technologies which are of key significance to contain the rise in energy consumption, namely: awareness of new technological developments, energy saving opportunities at the consumer's premises, and relevant aspects for consumer choices.

Every voluntary action in this direction by consumers requires a thorough knowledge of the opportunities posed at the moment the decision to install new equipment is made. To facilitate such knowledge, several nations (United Kingdom, Finland, New Zealand) have established, with official support, centres specialising in energy conservation, apart from the mandatory labelling of machines and appliances regarding their consumption and energy efficiency. In other nations (United States and Japan), the private sector finances these centres, i.e., either energy suppliers or the consumers who hire their services.

With a view to tapping the potential market of industrial and large commercial consumers in their demand for this type of service, the United States witnessed the establishment of *energy service companies (ESCOs),* which are substantially replacing the actions of the electricity distributing companies for carrying out load management.

An ESCO is essentially a company which offers an audit and diagnosis of potential energy savings for an organisation or industrial firm, and on this basis establishes an agreement to materialise such savings in exchange for a certain percentage of the savings in the energy bill. Known as “performance contracting,” this has been one of the most touted mechanisms in recent years on account of its alleged superior adaptation to competitive environments. In the USA, ESCOs have been particularly active in facilitating energy efficiency improvements in organisations which lack either the expertise, capital, or both to achieve the improvements on their own, including government facilities and school districts.

Some ESCOs may also specialise in particular industrial segments, and the existence of these companies facilitates a constant updating of the most efficient technologies and processes internationally available. ESCOs are often affiliated with large engineering companies, equipment manufacturers, or utilities and do not necessarily rely solely on performance contracting for their business. Nevertheless, the very survival of the performance contracting business model rests on the existence of large potential money savings in customers’ energy bills and the possibility of recovering the capital investment required within a relatively short period to be able to recycle investments and multiply their business.

In the case of Argentina, as previously stated, the restructuring of the economy had a positive result in terms of energy efficiency due to technology updating and a rise in production scale, though this process led to a significant economic concentration. To rely solely on the inducing force of competition to improve efficiency would pose the risk in the future of intensifying already high economic concentration levels, putting at risk the survival of small and medium sized companies.

In view of the fact that these small and medium sized companies are the ones which contribute most to the sustaining of employment within the secondary sector of the economy, their gradual disappearance would bring about an intolerable social cost. Thus, state-supported mechanisms to promote energy efficiency in manufacturing activities should be aimed towards small and medium sized companies which face difficulties in achieving their own production re-conversion.

Under such circumstances, the question is what mechanism is truly effective in building upon the already existing economic incentive for productive companies to improve their energy efficiency. In principle, it seems that not too many hopes should be placed on ESCOs for the promotion of energy efficiency in small and medium sized companies. It is highly unclear as to what extent such companies represent an interesting market to ESCOs, given the higher transaction costs and higher risks associated with serving smaller customers.

The Argentine Industrial Technology Institute (INTI) was specially conceived to provide support from the state for the nation’s industrial development. This structure could well be strengthened, and efforts could be increased to systematise and spread information on new technologies and more efficient processes. Even if indispensable, however, information alone proves insufficient for carrying out the re-conversion of small and medium sized companies, given the diversity of specific situations. For this purpose, it is desirable to implement a program to support small companies which may include the provision of energy audits for recommending specific measures in each company analysed. Under the supervision of INTI itself, this program could include the participation of Argentine universities, as has been previously the case in pilot experiences.

These programs would facilitate awareness of energy saving potential and other advantages of restructuring production processes in small and medium sized companies. Nonetheless, it is necessary to analyse two additional aspects, namely: how to finance the program and how to move beyond the diagnosis stage to the action stage.

Raising energy tariffs or taxes and mandating energy audits, as has been done in other countries, would increase the economic incentive for firms to improve their energy efficiency. Yet, the short term financial burden of such a program could jeopardise the survival of the very companies which are to be aided. However, a carefully designed program of energy efficiency audits and implementation / financing services, funded through a modest charge on energy bills, could provide for a self-sustaining energy efficiency program with actual economic benefits for participants.

This same mechanism could be used for co-generation promotion in the case of smaller industrial establishments not grouped in industrial parks. For the promotion of co-generation in large industrial establishments, an in-depth analysis should be conducted on the economic results obtained by the parties in recent contracts between generators and industrial customers in co-generation projects.

The sale of co-generation services in Argentina is not widely promoted yet. It is true that co-generators have an open possibility of selling their electricity surpluses to the network, but market conditions do not seem sufficiently attractive for this potential to materialise. As far as there are available international funds to implement climate change mitigation actions in Argentina, the use of complementary mechanisms could be analysed, such as tax benefits and preferential financing.

A mechanism which registered significant results in improving the efficiency of electricity consumption for small consumers (families and small businesses) in the early 1990s in the United States was the obligation established for electricity distributing companies to implement electricity demand management programs. Nevertheless, the opening of the retail market to competition among suppliers seriously calls into question the applicability of this mechanism.

In the past, distributing companies were enabled to recover the costs they incurred on account of these programs through a rise in the rates charged to all consumers. The higher rates now act as an obstacle to the competition of local distributors against other suppliers. Several authors have analysed the underlying incompatibility of this mechanism with the opening of retail electricity markets to competition.

An interesting example in this respect is given by Norway, where there is an obligation to carry out load management programs notwithstanding the opening of the retail market. In this case, the obligation is imposed on the concession-holder of the distribution networks and not on the electricity seller, which facilitates the observance of this regulation.

However, the scope of the programs is modest, solely restricted to the supply of information to potential beneficiaries of the program, the holding of energy audits, and at most the development of demonstration projects to attract consumers. The funding of these actions is guaranteed through a wires charge applied to electricity at the distribution level, regardless of the supplier. This financing mode guarantees a fair treatment of consumers, for it does not place the entire cost on distributor customers within the concession area.

In the case of Argentina, distributors are not forced to provide this type of service, although some distributing companies are showing interest in expanding their range of services to potential customers by incorporating this type of consultancy, as has been previously described, as part of their competition against natural gas distributors to attract certain markets.

In any case, the improvement of the network utilisation factor is of economic interest to the electricity distributing companies, and in this task they are not aided by rate regulation for small consumers. In fact, electricity rates for this type of consumers do not differ in accordance with the hour in which the consumption takes place, even when purchasing prices within the wholesale market differ.

After the reform, peak and base-load prices did not differ much at first, for peak hydroelectric stations allowed the balancing of marginal fuel prices throughout the day. It is important to stress that the value of water with which hydroelectric stations compete against thermal ones is determined in accordance with the volumes of turbined water but is independent from the hours of the day in which water is turbined.

The procedures to determine the operation of the stations tend to encourage the highest peaking use of the hydroelectric stations within the limits allowed by their design conditions and out-flow restrictions. This way, the minimisation of the system's operational cost is guaranteed.

Since this situation conspired against the appraisal of peak energy and, consequently, against the expansion of the transmission network which was necessary to place hydroelectricity in the market in an optimum way, the regulation was modified by cutting down base-load costs associated with the spinning of thermal units to meet peak demand.

The current difference between valley and peak prices would allow the setting of time-of-use retail rates. Nevertheless, this distinction would force a change in the entire consumption metering system for small customers. It seems that the investment associated with this change restricts the interest of the distributors to promote changes in regulation towards this end.

It must be borne in mind that a time-of-use rate would especially harm consumers with little possibility of transferring their consumption to outside of peak hours, that is, low-income consumers whose electricity bill is highly influenced by lighting purposes. The fairest thing for this type of consumer seems to be the promotion and subsidising of the use of highly-efficient lighting units, inaccessible today on account of their high cost.

In this regard, the mechanisms implemented in Sweden to reduce the cost of purchasing more efficient technology and units prove quite interesting. These essentially consist of organising a pool of buyers willing to acquire the same efficient facility or unit. Unit suppliers compete on the basis of price and efficiency, increasing their market possibilities. This mechanism allows reductions in purchasing costs for buyers, while at the same time helping to bring down the market price of new technology by increasing the production scale.

The other key element for the implementation of energy saving measures will be the financing conditions, both as regards interest rates as well as debt repayment terms. It is important to point out that, to-date, small and medium companies as well as families have experienced quite unfavourable credit access conditions in comparison with large economic groups.

The establishment of promotional credit lines through official banks could prove a good mechanism to mitigate this situation, while it would also allow the channelling of part of the internationally available funds toward voluntary climate change mitigation actions within the developing world.

IX Conclusions

There is no doubt that the Argentine economy is showing a trend towards the improvement of energy efficiency, both in final consumption as well as in electricity-supply activities. The technological re-conversion caused by the economic opening and the favourable prospects brought about by the MERCOSUR economic integration process have improved production and energy efficiency in several production activities within Argentina, although at the cost of increasing economic concentration.

This favourable process is nevertheless producing rising gaps between the performance of large establishments and that of small and medium sized companies, both with respect to competitiveness in the markets as well as regarding production and energy efficiency. Promotion mechanisms should be aimed towards small and medium sized enterprises, which show evident difficulties in carrying out their production re-conversion. For large companies, the full operation of market forces appears to provide sufficient incentives for energy efficiency.

Rising competition levels within the electricity industry are on their part favouring efficiency in electricity supply both at the generation as well as distribution levels. However, and from the point of view of climate-change mitigation, market trends show a rising dependency on natural gas to the detriment of non-GHG-emitting technologies like hydro power, nuclear, and wind energy.

Several obstacles will have to be overcome to modify these trends, which naturally respond to business opportunities for private investors. In the first place, and before even posing the analysis of mechanisms for the promotion of these technologies, a debate must be engaged in regarding the acceptability of each of these alternative technologies in accordance with their local impacts.

In the second place, it is necessary to carefully analyse the alternative methods to attract and distribute funds for the promotion of the selected technologies. To adhere to mechanisms simply because they are compatible with the free expression of market forces could lead to clear unfairness in the absorption of the additional costs involved in mitigation actions. Thus, these mechanisms should allow pinpointing of the costs involved and facilitate a refund system to reduce the financial impact of the mitigation actions on the parties most severely impacted.

In the third place, it should be borne in mind that although the implementation of every policy presupposes an explicit intervention in the markets, all necessary precautions should be taken so as not to distort the markets' operation. In this respect, special attention should be paid in avoiding undesired cost overruns and excessive profits to certain agents.

All promotion mechanisms worldwide used for these purposes presuppose the establishment of certain types of subsidies to lead to a behaviour different than that expected. Hence, every intervention of this type should have an indisputable equity basis and be transparent enough that all agents involved may avoid incurring unnecessary risks.

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