ELECTRICITY MARKET RESTRUCTURING:

INTERNATIONAL PERSPECTIVES ON CONSUMER EXPERIENCE, SYSTEM RELIABILITY AND SYSTEM INVESTMENT

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Acronyms

ACCC	Australian Competition and Consumer Commission
CENS	cost of energy not supplied
COAG	Council of Australian Governors (Australia)
CRR	congestion revenue right
ECNZ	Electricity Corporation of New Zealand
ENS	energy not supplied
FERC	Federal Energy Regulatory Commission
FNP	full nodal pricing
HVDC	high-voltage direct current
LMP	locational marginal pricing
MPE	Ministry of Petroleum and Energy (Norway)
SMD	standard market design
PJM	Pennsylvania-New-Jersey-Maryland Independent System Operator
NECA	National Electricity Code Administrator (Australia)
NEM	National Electricity Market (Australia)
NEMMCO	National Electricity Market Management Company (Australia)
NOPR	notice of proposed rulemaking
NVE	Norwegian Energy and Water Resources Directorate
NYISO	New York Independent System Operator
NZEM	New Zealand Wholesale Electricity Market
VAT	value added tax

Units of Measurement

W	watt	Power
h	hour	Time
Wh	watt-hour	Energy
k	kilo	1,000. Used in kW and kWh.
M	mega	1,000,000. Used MW and MWh.
G	giga	1,000,000,000. Used in GW and GWh.
T	terra	10. Used in TWh.

Units of Currency

NOK	Norwegian Kroner
A$	Australian Dollars
NZD	New Zealand Dollars

I. Executive Summary

During the last decade more than a dozen countries have ventured into the restructuring of their electricity supply industries. The United States began its major foray into restructuring in 1996 with the Federal Energy Regulatory Commission's Order 888, followed by Order 2000 in 1999. FERC has taken its pursuit of a wholesale electricity market to the next level with the release of its Standard Market Design Notice of Proposed Rulemaking in April, 2002. It is expected to make a decision by mid-2003.

The SMD proposal aims to establish a nationwide standard competitive wholesale power market, as well as to make significant changes to the provision of transmission services. There are concerns in Washington State, shared by others throughout the Northwest and the nation, about the implications of the SMD proposal. A major concern for Washington relates to the applicability of SMD to Washington State's hydro-dominated power system. In particular, might SMD adversely impact the consumer experience, the system's reliability, and the system's investment?

FERC, in its comments, has suggested that hydro-based countries such as New Zealand illustrate the compatibility of SMD and hydro-based power systems. This report examines the experience of New Zealand and two other countries utilizing hydropower, Norway and Australia, and asks what Washington State can learn from the international restructuring experiences of these hydro-influenced electricity markets, in terms of consumer experience, system reliability, and system investment.

Success in the reform of electricity service regulation and markets can only be measured against the original objectives of those reforms. In some cases the reform was intended to privatize electricity service and get the government out of an ownership and risk-taking role. Against this objective, experience has been mixed. Many electricity functions in New Zealand, Norway, and Australia have been shifted out of government hands. However, New Zealand has been forced to reintroduce some government oversight and Australia left in place regulatory protections for small customers.

In other cases the reforms have been touted as a way to improve customer service, improve reliability, lower costs, and encourage investment. Again, the record is mixed. Norway and New Zealand have implemented new ways to respond to customer needs and ensure delivery reliability. But cost-reductions have been modest at best and cost-shifting and equity problems have been apparent in all three cases. None of the three cases indicate that a reformed and market-driven electricity system is superior to a regulated one for attracting investment in transmission or generation.

The experiences of Norway, New Zealand, and Australia in electricity market reform suggest several implications for Washington State:

- One of the main appeals of market reform is the benefit of low-cost electricity. If it is found that Washington's consumers are already enjoying low-cost electricity, any alternative to the current market must be closely examined in terms of its costs and benefits to Washington's consumers. Any alternative, be it SMD or any other form of market restructuring, must provide a better alternative than does the existing system in terms of consumer experience.
- Experience in New Zealand and Australia indicates that governments are better suited for ensuring a reliability of supply in the long run than commercial market participants. The Washington Utilities and Transportation Commission can find encouragement from this, and continue in its commitment to advocating for the reliability of Washington's supply. The Federal Energy Regulatory Commission would do well to ensure that any proposal preserves and promotes the short or long term reliability of *each region's* electricity supply system.
- With the problems experienced by Norway, New Zealand, and Australia, Washington State can expect challenges in securing stable investment. Particularly troubling is the experience of Australia with merchant investment in transmission interconnects. With Washington's immediate need for transmission investment, reliance on commercial investors does not bode well for the electricity network.

II. Background

International Restructuring Overview

More than a dozen countries worldwide have introduced competition to their electricity markets in the past decade. This challenging process requires an overhaul of market structures and regulatory frameworks. While most of these countries have opened up their markets to industrial customers, some have opened up competition to retail customers, including Finland, Germany, New Zealand, Norway, Sweden, England and Wales, Australia, and several states in the United States.

Market reform was originally driven by a concern that the electricity industry was not providing the lowest possible prices to consumers. This has been attributed to everything from simple inefficiency to government politics. Some of the symptoms of inefficiency that have been identified include excess generating capacity; price differentials within a nation's borders between regions and generators; and price differentials between countries.

One of the main goals of market reform is the increased economic efficiency of electricity markets, and competition has been seen as a way to accomplish this. Competition has the potential to effectively provide incentives that keep costs and prices down. In principle, competition increases productivity, lowers prices, and fosters innovation.

While electricity reforms tend to share a number of common economic goals, including an increase in efficiency and improved long-term investment decisions, there are other factors influencing the push for electricity reform which vary from country to country. In Europe, pressure to create an internal European Union market has influenced reform efforts; in New Zealand electricity reform was part of a broader effort to privatize government-owned utilities to address budget problems; in the UK, reform was used to diffuse the power of coal mining unions; in the U.S., states experiencing relatively high electricity prices, such as California and Massachusetts, saw the gap between regulated rates and long-term marginal costs as an impetus for reform; and in a number of countries, electricity reform has been part of an overall drive for broad-based economic reform.

Many different approaches have been taken to reform of electricity markets, and each of country varies as to which activities have been liberalized, how non-liberalized activities have been regulated, and which actors are allowed to participate in the various markets. A typical reform will include structural reforms—separating potentially competitive activities from non-competitive activities—as well as institutional reforms—providing the legal, regulatory, and financial framework for a successful reform.

In general, many countries have reported short-term gains from restructuring including productivity increases—closely linked with the privatization and corporatization of state-owned utilities—and low wholesale prices in regions where market power is not a factor. It should be noted that countries that have not introduced reforms also experienced a decrease in electricity prices, making it difficult to determine the effect of reform on prices.

Long-term gains in investment have yet to be realized; this has been attributed to inadequacies in market design as well as a short timeframe since market inception.

Regulatory reform has been found to be a key component of competition, but not sufficient to provide a robust market. An illustration of this can be found with market structure; markets with a high concentration of generation assets such as England and Wales have not proven to be as strong as those with less concentrated markets.

Key Dates in International Restructuring

The restructuring of electricity markets began in the U.S. in the 1970's with the Public Utility Regulatory Policies Act (PURPA). For the first time, PURPA allowed new entrants into electricity generation. Eventually, competition was allowed between generators by establishing a market that determined the dispatch and wholesale price of electricity; England and Wales established the first such competition between generators in 1990 with the opening of their electricity pool. Norway followed in 1991 with the opening of its competitive electricity pool, which was eventually opened to Sweden in 1996, and renamed NordPool. Today, in addition to Norway and Sweden, NordPool includes Finland and Denmark. New Zealand began a series of reforms in the 1980's which led to the corporatization of generation in 1987, the corporatization of distribution and the introduction of consumer choice in 1994, and finally the introduction of the Wholesale Electricity Market in 1996. Australia merged two state markets, the Victoria Pool established in 1994, and the New South Wales Pool established in 1996, to create the National Electricity Market of Australia in 1997.

In addition to the development of wholesale electricity markets, there has been a simultaneous development of retail markets. Some countries and states have opened up their retail markets to the point where all consumers are able to choose their suppliers[1]:

- Norway (1991)
- New Zealand (1994)
- Sweden (1996)
- Finland (1997)
- California (1998)
- England and Wales (1999)
- New South Wales (1999)

National Restructuring Overview

On July 31, 2002, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) on standard market design (SMD). This rulemaking was designed with the goal of creating a nationwide wholesale power market, and builds upon FERC's earlier Order 888 and Order 2000.

[1] IEA, (2001), "Competition in Electricity Markets, P.30. Retrieved March 15, 2003, from http://www.iea.org/public/studies/compele.htm.

Order 888, also known as the Open Access Rule, was issued in 1996 to establish open access transmission requirements. Order 2000, issued in 1999, promotes the formation of regional transmission organizations (RTOs). Despite the efforts of these rulemakings, FERC has alleged that ongoing discrimination exists in the provision of transmission services, and maintains that this is an impediment to the realization of efficient competitive power markets. This alleged continued discrimination is the stated legal basis for the SMD proposal issued in July of 2002 by FERC.

The SMD proposal significantly changes the regulation of transmission services, establishes a nationwide standard for the design and operation of spot markets, and expands FERC's role in the regulation of the power industry. The NOPR, some 600 pages long, provides a great deal of detail on FERC's vision of SMD. The following summary highlights the points that are relevant to an international comparison of markets, but is not meant as a comprehensive summary of all salient points regarding the NOPR.

- The proposal identifies locational marginal pricing (LMP) as the model by which to determine congestion charges, a model that is currently used in the United States in the PJM and NYISO markets. With LMP, the transmission network identifies "nodes" where electricity is entered onto the grid and taken off of the grid; a separate spot market price is calculated for each node, factoring in any costs due to congestion between nodes.

- To implement LMP requires the formation of electricity markets; the proposal establishes the independent transmission providers (ITPs) as the market administrators of both day-ahead and real-time auction markets. Participation in the day-ahead market is voluntary, while participation in the real-time balancing market is mandatory. Market participants will be able to engage in bilateral contracts

- Congestion revenue rights (CRRs) provide holders the right to receive any revenues based on transmission congestion that are tied to specific delivery and receipt points on the transmission network.

- FERC relies on merchant investment as opposed to regulated investment to maintain and expand the existing transmission network.

Changes to the NOPR?

Upon releasing the SMD NOPR in July of 2002, FERC accepted comments until the end of February, 2003. Stakeholders from around the country weighed in on the proposal, ranging from state regulators to industry participants. After reviewing the comments, FERC released a white paper in late April of 2003, making several concessions and further clarifications. One of the concessions made by FERC was to allow for greater regional flexibility. Other changes include abandoning the concept of a single nationwide tariff for transmission, the requirement for transmission-owning utilities to form independent transmission providers, and the requirement of locational marginal pricing to manage congestion. Opponents of the original proposal are divided in relation to FERC's concessions; the chair of the Arkansas Public Service Commission lauds the concessions, while the chair of the Washington Utilities and Transportation Commission suggests that they are not "meaningful."[2]

Washington State and SMD

The United States, over time, has developed into distinct regional electricity systems. These systems have formed themselves as a result of topography, climate, load distribution, generation system type, ownership patterns, and legal and historical backgrounds. There are good reasons for the differences between regions, which many stakeholders in the Northwest would argue call for a regional approach to wholesale market design.

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[2] Davis, Tina, "Opponents Split on FERC Concessions," *The Energy Daily*, Retrieved June 1, 2003, from LexisNexis.

Unlike other regions of the country, most notably the east, the Pacific Northwest does not have a history of centrally dispatched generation, or a tight power pool with day-ahead unit-commitment. Washington State is part of the Western Interconnect which covers 591, 324 square miles and includes close to 600 generating stations. If an LMP model was adopted through SMD as originally proposed, it is estimated that the western region would include between 2,500 and 4,000 separate nodes and a diverse resource mix.

The Western Interconnect includes both federal and non-federal hydro systems operated in compliance with a number of statutory obligations: the Pacific Northwest Coordination Agreement (PNCA), the federally mandated Biological Opinions under the Endangered Species Act, tribal treaty trust obligations and an international treaty with Canada. This has the consequence of providing additional demands of the river besides electricity market supplies and demands.

Stakeholders, in the Northwest—including lawmakers, regulators, investors, publicly-owned utilities, industrial customers, the Bonneville Power Administration, and consumers groups--have a number of concerns regarding the implementation of SMD as proposed:

- Western lawmakers, in a plea to the Energy Secretary to evaluate the regional impact of SMD on each of the nation's distinct regions, maintained that SMD "imposes a complex and costly model in an effort to solve problems…that either do not exist in the Northwest or, to the extent they do, can be resolved using existing institutions."[3]
- There is a concern that the proposed pricing model, LMP, is incompatible with the Northwest's hydropower system. Implementing LMP in the region is expected to result in undesirable cost shifts.
- Increase price volatility.
- Lower level of reliability.

[3] Inside FERC, April 7, 2003, "Still Suspecting the Worst from the SMD Plan." Retrieved March 29, 2003, from LexisNexis.

- Overall economic harm.
- Introduce large administrative costs.
- Under-investment similar to that occurring in New Zealand with an LMP model.

General Electricity Markets

There are a series of functions that make it possible to deliver electricity to end-customers. Some of these functions have the potential to be supplied competitively, for instance generation and retail, while other functions are better suited to some form of regulation, including transmission and distribution. Table 1 shows each of the functions and their potential for competition. Competition in generation is often referred to as wholesale competition.

Electricity is different from other commodities in that, once it has been produced, it cannot be stored. This requires that the electricity that is generated equal the electricity that is consumed for any given moment. Another feature of electricity is that its demand fluctuates over time: by day, by season, and by business cycle. This fluctuation is both random and non-random in nature.

This variation in demand has several implications for generation: generating capacity that is needed to meet the system demands during periods of peak demand may be unused during periods of low demand; reserve capacity is needed to supply electricity during unexpected demand increases or generation shortfalls.

Table 1: Functional structure of the electricity supply industry

Function	Key Economic Characteristics	Implications
Generation	• Limited scale economics at the plant level • Co-ordination economics at system level • Complementarity with transmission	• Potentially competitive
Transmission	• Network externalities • In general not a natural monopoly • Large sunk costs	• Investment incentives need special attention • One grid but possibly several owners
Distribution	• Often a natural monopoly • Large sunk costs	• No competition
System Operation	• Monopoly (due to technical constraints)	• No competition
End-user Supply	• Limited scale economies • No special features	• Potentially competitive
Related Services: • Power exchanges • Financial contracts • Construction and maintenance of assets	• No special features	• Potentially competitive

Source: IEA, (2001), "Competition in Electricity Markets," p.18. Retrieved March 15, 2003, from http://www.iea.org/public/studies/compele.htm.

Generation

As indicated in table 1 above, generation is one of the supply functions that has been identified as potentially competitive. There are a variety of generating technologies—hydropower, nuclear, cycle gas turbines, thermal—which require varying degrees of capital. Hydropower is often characterized by relatively large fixed costs and relatively small variable costs over time; in other words, the marginal cost of producing another unit of electricity is minimal. Hydropower generating facilities also require a long lead time for construction, and have a relatively long lifespan.

When speaking generally about generating technologies, economies of scale do not seem to be a significant factor, opening generation to the possibility of competition. This does not exclude, however, the possibility that *coordinated* economies of scale may occur in generation, which may be in effect with the Federal Columbia River Power System (FCRPS). The Columbia River Treaty between the United States and Canada, set out to, among other goals, increase the storage of the system. This coordinated approach to storage has increased the firm load-carrying capability of the entire Columbia system, which not only benefits both the U.S. and Canada equally, but must be shared equally by the terms of the treaty.

This approach to water resource management results in what some may argue is characteristic of a system with *coordinated* economies of scale. This may weaken the FCRPS's suitability for competition.

Worldwide, generation activities have been the first focus of reform due to apparent inefficiencies, and the potential for improvements in both operational and investment efficiency. Inefficiency in the generation sector is argued to stem from poor planning decisions and economic incentives that have resulted in an overcapacity of generating capability. In most markets, generation accounts for nearly half of the total cost of electricity; if the market forces of competition can create downward pressure on the cost of generation, the overall cost for consumers has the potential to decrease significantly.

Transmission

The transmission function of the electricity supply industry can be characterized as the transportation of electricity over high voltage lines. The transmission network is shared by all users of the network, in contrast to the distribution network, which is used only by its specific end-users. The transmission grid, therefore, benefits all users, and guarantees secure transport to all users.

Because the transmission grid is a shared network, it experiences what economists refer to as 'network externalities'—in this case, if one party invests in the maintenance, expansion, or reliability of the grid, all users will benefit, perhaps at no cost. This has the tendency to discourage investment in the transmission grid because an investor must share the benefits with others who can “free-ride” on his investment. Another characteristic of the transmission grid is that it benefits from system-wide economies of scale; this ultimately means that transmission is a function that is best left to regulators. Thus, even though transmission is not considered a natural monopoly; it can be economical for two lines to run parallel to each other, and two nodes can be connected through different transmission lines as a means of providing reliability. This means that it is possible for multiple owners to operate with a single transmission network.

Distribution

The distribution function of the electricity supply network can be characterized as the transportation of electricity over low voltage lines directly to end-users. Because it would be inefficient to duplicate the distribution lines, distribution is regarded as a natural monopoly; this means that it is a function that is typically left to regulators.

Retail

Retail includes the *sale* of electricity and services to end-user customers; services might include billing and metering. Retail has been historically bundled together with distribution services (and with generation and transmission), but can be separated out to stand alone. Retail services are considered to be potentially competitive, and are sometimes referred to as “end-user supply.”

Market reformers are increasingly looking toward retail supply as a way to improve the price signals needed to create an efficient market.

Related Services

In addition to generation, transmission, distribution, and retail services, there are a number of related electricity services, some monopolistic and some potentially competitive. An example of a monopolistic service is system operation. System operation is required to ensure that electricity demand is met with electricity supply, and that the system is constantly in a state of equilibrium. Because the benefits of a centralized system operation such as increased reliability and lower costs can only be realized with a single owner, system operation is inherently monopolistic. However, system operation involves a number of "products" referred to as ancillary services—operating reserves, reactive power, voltage regulation and other activities necessary to keep the electric grid operating reliably. The system operator may be able to obtain some of these ancillary services competitively, others are not well-suited to competitive supply. In addition, still other potentially competitive services include construction and maintenance, power exchanges, and financial instruments.

Commercial Markets

The development of financial contracts has occurred simultaneously with the development of competition in electricity markets. These include spot electricity markets, power exchanges, bilateral contracts, capacity mechanisms, and financial markets.

Spot Markets

Electricity and its physical properties do not allow for a true spot market whereby electricity is delivered immediately. The physical nature of electricity requires that market transactions take place at some predetermined time in advance of its scheduled physical delivery, whether it's one day, half an hour, or five minutes. The imbalance between the *scheduled* and *actual* supply are handled through a set of established procedures that may or may not be competitive. Competitive pools or power exchanges take the place of true spot markets. The pool selling price is determined by accounting for any imbalances as well as factoring in any ancillary service costs, capacity payments, or other costs. Prices that are determined from the *scheduled* supply and demand are known as ex ante, while prices that are determined from *actual* supply and demand are known as ex post.

Power Exchanges

There is a wide range of approaches to the design of power exchanges. Markets vary as to whether participation is mandatory or not, whether demand-side bidding is allowed, whether or not the bids are based on a simple price per KWh, whether the prices are ex ante or ex post, whether or not capacity payments to generators are required, and whether or not there is an unconstrained dispatch. See Table 2 below. England and Wales are included as a comparison.

Table 2: Organization of various electricity exchanges

Market	Participation	Demand side bidding	Simple Bids*	Pricing**	Capacity Mechanisms	Integrated Dispatch***
England & Wales	Mandatory	No	No	Ex ante	Yes	No
NordPool	Voluntary	Yes	Yes	Ex ante	No	No
Australian NEM	Mandatory	Yes	Yes	Ex post	No	Partially
New Zealand	Voluntary	Yes	Yes	Ex post	No	Yes
California PX	Voluntary	Yes	Yes	Ex ante	No	No
PJM ISO	Voluntary	No	No	Ex post	Yes	Yes

* "Simple" means that bids are price-quantity pairs; "not simple" means that prices may have additional terms.
** Ex ante means that prices are calculated for scheduled supply and demand; ex post means that prices are calculated for actual supply and demand.
*** Integrated dispatch means that the system optimizes join use of generation and grid resources; otherwise there is unconstrained dispatch that ignores possible transmission constraints.
Source: IEA, (2001), "Competition in Electricity Markets," p.83. Retrieved March 15, 2003, from http://www.iea.org/public/studies/compele.htm.

Bilateral Trades

There is a growing consensus that trade outside of power exchanges should be permitted, and may even increase the overall efficiency of the market. Bilateral trades occur between a generator and a consumer, and are facilitated by a system operator. Concerns about bilateral trades have traditionally included:

- Incompatibility with a centralized form of dispatch. If all trades are not processed through the pool, it has been argued, the opportunity for a centralized optimization of dispatch is not allowed to occur. This concern may have been a driving force between England and Wales original adoption of a mandatory pool. The Norwegian power exchange, NordPool, demonstrated that non-centralized dispatch can work, however, which has led to a reconsideration of mandatory pools.

- Lack of transparency in pool prices and price distortion. If a high number of traders are using bilateral contracts, there is a concern that it may be difficult to regulate end-user tariffs when the price of wholesale electricity is not clear.
- Market power brought on by long-term contracts. The concern here is that long-term bilateral contracts can develop into a form of vertical integration between generators and distributors that is harmful to the market. This appears to be a growing concern in New Zealand.

Capacity Payments

Capacity payments are made to generators to compensate them for making their generation capacity available. This is designed to improve the overall reliability of the system, which may or may not be provided by the market. Capacity payments encourage a higher reserve margin, and when introduced by regulators, suggest a form of market failure. Types of possible market failure include:

- Shifting investment cycles. If investors alternate between short-term and long-term investment horizons, incentives can be introduced to make the cycles less pronounced.
- Investment in reserve capacity is considered too risky. Electricity systems that require large investments, particularly hydro based systems, require reserve capacity that is used infrequently and unpredictably. These types of investments may be viewed as too risky by investors.
- Investment discouraged by the high cost of capital. Because generating assets tend to be capital-intensive and long-lived in nature, their cost of capital could be high enough so as to discourage investment. This could ultimately result in a lack of investment and low security of supply.
- Unsustainable prices. It has been argued that competitive prices would be below cost, which would in turn discourage investment. Others argue that competitive prices can be expected to cover all costs, while others point to a concern that prices are actually too high.

Financial Markets

Market participants use financial markets to insure against the volatility of the electricity market; financial contracts allow the risk of price and quantity to be reallocated. Contracts tend to be made in financial markets, and don't require electricity specific rules. Contracts can take one of several forms, including forward contracts, futures contracts, option contracts, or Power Purchase Agreements (PPA)[4].

- Forward contracts are one of the simplest forms of risk transfer, and guarantee the delivery of electricity at a given price. The parties determine a "strike" price at which a certain amount of electricity will be delivered at a later time. At the time of delivery, if the market price is higher than the strike price, the seller compensates the buyer. Conversely, if at the time of delivery, the market price is lower than the strike price, the buyer compensates the seller. This process of settlement is also known as "contract for differences."
- Futures contracts are similar to forward contracts. The difference between the two is that futures contracts are standardized and traded in an organized market.
- Option contracts give the right but not the obligation to purchase a given quantity of electricity at a given price.
- PPAs, unlike the three financial contracts above, are associated with a specific plant. Since they specify which plant will provide power, they essentially exclude plant from the overall pool. PPAs are not permitted (or are restricted) in countries that operate mandatory pools.

[4] IEA, (2001), "Competition in Electricity Markets," p.98. Retrieved March 15, 2003, from http://www.iea.org/public/studies/compele.htm.

III. Findings

Introduction

This report examines three markets that have been referenced in relation to Washington's hydro system: Norway, New Zealand, and Australia. Each of these countries has a different physical, institutional, and political history. Washington State shares similarities with each of the countries: Norway has a history of public ownership like Washington State; Australia has a federal form of government like the United States; and New Zealand relies on hydropower for roughly 65% of their generating capacity, a similar proportion as Washington State. No country is a perfect match to Washington State in terms of its power framework; these findings are more rightly viewed as case studies.

Beginning with an overview, the report reviews the historical context of each country's market restructuring, followed by an overview of the physical, institutional, and commercial systems that frame the electricity supply industry. Three outcomes of market restructuring are of particular interest to Washington State and are explored for each country: consumer experience, system reliability, and system investment.

- *Consumer experience* includes prices, conservation efforts, and consumer opinion.

- *System reliability* refers to the short-term capacity of the industry to continuously meet demand. Previous to the development of competitive power markets, ensuring short-term security was the responsibility of governments; competitive markets shift this responsibility to market participants. Exploring system reliability includes a look at how markets deal with establishing security standards, as well as metrics that indicate the reliability of a system, including power outages, price separation, length of outages, and customer complaints.

- *System investment* refers to the long-term capacity of the industry to generate electricity. Prior to the development of competitive power markets, countries had a tendency to operate with large capacity margins. Sometimes these margins were more than 20%, which is considered to be inefficient in competitive markets. Governments historically made decisions concerning investment; this responsibility shifts to market participants in competitive markets. Cost overruns are no longer passed along to consumers; utilities are penalized for overestimating demand, raising the business risk of electricity investment. This section examines how investment is incentivized by the market and the government, as well as observable trends in generation and transmission investment.

Norway

Source: CIA Factbook 2002

Introduction

Norway is an energy resource-rich country with ample reserves of crude oil, natural gas, and water and wind power.

Norway operates within an integrated Nordic power market, with competitive generation and retail and free trade across its national borders with Sweden, Finland and Denmark.

It has the world's most significant hydro market with 99% of the country's electricity generating capacity filled by hydro systems. With reforms initiated in the early 1990's Norway provides more than a decades worth of reform experience from which to draw. Although its population and that of the other Nordic countries is relatively low, Norway and its Nordic counterparts have the highest per capita demand for electricity—this results in a high national consumption of electricity.

Several years after Norway restructured its market, it created the world's first international electricity market, by initiating an exchange with Sweden. In the subsequent years, Finland and Denmark have joined the pool to create the Nordic exchange known as NordPool. Despite market restructuring, Norway remains to be dominated by public ownership. This includes the two public corporations administering state generation and transmission, Statkraft and Statnett.

In 2001, the overall Nordic power market was a 380 TWh per annum market, which is comparable to the market in England and Wales.[5]

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[5] Bergman, Lars, (2001), "Regulation and Competition on the Nordic Power Market," p.1. Retrieved April 16, 2003, from http://www.worldenergy.org/wec-geis/publications/default/tech_papers/18th_Congress/downloads/ds/ds16/ds16_3.pdf.

Historical Context of Restructuring

Norway has grown to depend heavily on electricity with its electricity intensive industries, cold climate, long and dark winters, and its high ratio of electricity to total energy consumption. Blessed with abundant energy, Norway has built its country on cheap and plentiful electricity.

Physical System

Generation

Norway has approximately 4,000 river systems. To increase production capacity, it is a common practice to channel water from one part of a river system to another, or even to a nearby system. There is often more than one power plant on the same river system. There are approximately 550 plants with an output of greater than 1 MW, and there are 250 dams of a height greater than 15 meters.

Differences in topography, precipitation, and climate have resulted in a variety of river types. In Western Norway, parts of Troms, and Nordland, the rivers are short, steep, and have many waterfalls. In contrast, the rivers in Eastern Norway, Trondelag and Finnmark are longer, drop more gradually, and carry a larger water volume. Listed below are the ten largest rivers in Norway.

Table 3: The 10 largest rivers in Norway

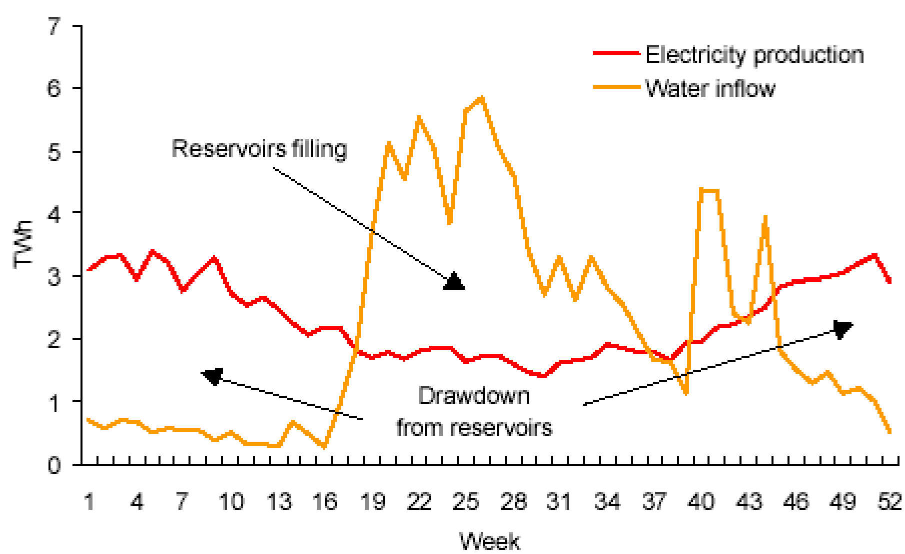
Name of river	Catchment area (km2)	Mean annual flow (m3/s)	Maximum flow (m3/s)
Blaama	41,820	728	3,542
Drammenselva	17,096	326	2300
Skiensvassdraget	10,767	287	1,800
Namsen	6,282	270	2,811
Ranaelva	3,857	220	1,600
Tana	16,386	187	3,500
Maalselva	6,041	180	1,700
Pasvikelva	18,354	170	850
Vefsna	4,019	161	1,700
Otra	3,740	148	1,400

Source: IEA Hydropower Agreement. “Norway.” Retrieved May 29, 2003, from http://www.ieahydro.org/Hy-Genl/Hy-Norway.pdf.

The inflow from precipitation varies between regions, seasons and years. Precipitation is greatest in the coastal and central parts of Norway, and tends to increase with higher elevations. Inflow into the river systems is highest during spring from snow thaw, and typically decreases during the dry summer months. Rainfall in the fall normally increases the inflow prior to the beginning of winter, when overall inflow is low.

Electricity demand also varies between seasons, with higher demand occurring during the cold winter months. This increase in demand is directly opposite of the inflow patterns, as illustrated in Figure 1.

Figure 1: Variations in water inflow and electricity production during a year



Source: IEA Hydropower Agreement, “Norway,” p.19. Retrieved May 29, 2003, from http://www.ieahydro.org/Hy-Genl/Hy-Norway.pdf.

Norway's installed generating capacity is 27,596 MW at 740 hydro plants of greater than 1 MW. Production in a normal year is currently 119 TWh.[6] As shown in Table 4, Norway is second to Sweden in total production in the Nordic states.

Table 4: Comparison of Electricity Production (TWh) in the Nordic Countries in 1999

	Denmark	Finland	Norway	Sweden
Hydro Power	0	13	122	70
Wind Power	3	0	0	0
Nuclear Power	0	22	0	70
Fossil Fuels	24	7	1	0
Combined Heat and Power	10	25	0	10
Total Production	37	67	123	150

Source: Elmarknaden 2000 (The Electricity Market 2000), Swedish National Energy Administration

The amount of electricity produced in Norway depends largely on the amount of annual precipitation. For example, in 2001, actual production was 120.9 TWh. This is in contrast with a low of 105 TWh in 1996 and a high of 143 TWh in 2000[7]. This production occurs in a wide variety of plant sizes, as illustrated in Table 5.

[6] Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p. 21. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html,
[7] ibid, p.10.

Table 5: Hydropower plants in operation on 1 January 2002 by size and total installed capacity*

MW	Number	Total installed capacity MW	Mean annual production GWh/year
0 – 0.1	74	3	18
0.1 – 1	98	14	74
1 – 10	252	915	4,321
10 – 100	246	8,917	40,666
100 –	77	17,764	73,316

* Figures for power plants <1 MW are based on a study of micro and mini power plants connected to the grid, carried out by SKM Energy Consulting and completed in 2000.
Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.24. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

The ten largest power plants maintain roughly 25% of the country's production capacity, and are listed in Table 6.

Table 6: The 10 largest power plants in Norway, 1 January 2002

Power plant	County	Max. capacity MW	Mean annual production GWh/year
Kvilldal	Rogaland	1,240	3,517
Tonstad	Vest-Agder	960	4,169
Aurland I	Sogn og Fjordane	675	2,003
Saurdal*	Rogaland	640	1,291
Sy-Sima	Hordaland	620	2,075
Rana	Nordland	500	2,123
Lang-Sima	Hordaland	500	1,329
Tokke	Telemark	430	2,221
Svartisen	Nordland	350	1,996
Brokke	Aust-Agder	330	1,407

*Pumped storage power plant

Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.23. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

The figures in Table 6 indicate that there is storage capacity factor of between 32 and 50 percent, similar to Pacific Northwest hydropower. This means that the Norway system is water-limited, or energy-limited, rather than capacity-limited. If they could store enough water they would be able to run the plants at higher plant factors.

Transmission

The Ministry of Petroleum and Energy characterizes Norway's transmission network as falling into three categories: central grid, regional grid, and local distribution grid. The regional grid in this instance connects the central grid with the local distribution grid. All told, there are more than 200,000 km of power lines included in Norway's transmission grid.

In the western and northern regions of Norway, electricity production exceeds electricity consumption. This is in contrast with the southern and eastern regions of the country, where consumption exceeds production. Transmission lines make it possible for the surplus of the west and north to meet the needs of the deficits of the south and the east.

Without adequate cross-border transmission, the Nordic market dissolves into separate national markets. This results in an aggregation of market power, and is not an uncommon occurrence.

Distribution/ Retail

As of 1997, there were approximately 200 distribution utilities. These utilities can buy power on the spot market, but primarily sell to consumers in their geographic region. Because consumers can purchase from any distributor, distribution utilities are in effect exposed to competition. Small consumers can buy electricity from distribution utilities and electricity trading companies.

One of the central goals from the outset of market reform was that all consumers be able to select their supplier. Initially, it was the larger consumers who took advantage of their ability to renegotiate contracts or switch suppliers. Over time, aided by a series of policies that helped smaller consumers, there has been an increase in small consumers entering the market. By 1996, roughly 30% of the market on a volume basis had traded suppliers.[8]

Institutional System

The Storting

The Norwegian parliament, known as the Storting, establishes the overall energy and water resources management goals for Norway.

The Ministry of Petroleum and Energy

The Ministry oversees the administration of the energy and water resource sectors, and is responsible for ensuring that the wishes of the Storting are fulfilled. Charged with developing an integrated energy policy, the Ministry is organized into four departments: the Energy and Water Resources Department (under which hydropower falls), The Petroleum Department, the Exploration and Production-Market Department, and the Administration, Budgets and Accounting Department.

The Ministry directly authorizes the issuance of permits for foreign electricity imports and exports in accordance with Norway's 1990 Energy Act.

The Norwegian Energy and Water Resources Directorate

The objective of the Energy and Water Resources Directorate[9] (NVE) is to "ensure sound management, in both economic and environmental terms, of water and hydropower resources and other domestic energy sources[10]." The Directorate performs the ownership function of two state-owned enterprises, Statnett SF, overseeing grid construction and

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[8] IEA, (1997), "Energy Policies of IEA Countries: Norway 1997 Review." Retrieved March 15, 2003, from http://www.iea.org/pubs/reviews/files/nor97/nor10.htm.

[9] While a *department* within the Ministry of Petroleum and Energy, the organization is referred to as the Energy and Water Resources *Directorate*.

[10] Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p. 12. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html

operation, and Enova, promoting efficient and renewable energy use. In addition, the Directorate guides system emergency response to flooding and dam failure, and is responsible for the planning of contingency power supplies.[11] The Directorate, or NVE, includes several sections:

- Water Resources Section
- New, Renewable Energy Sources and Energy Use Section
- Power Market Section
- Energy Section
- Energy Law Section
- International Section

The Directorate has largely been tasked with the responsibility of making decisions about the 1990 Energy Act, including the licensure of construction and operation of electrical installation, "electricity trading, control of monopoly operations…metering, settlements and invoicing, the physical market for trade in power, system coordination, rationing, electricity supply quality, energy planning and contingency planning for power supplies."[12]

The construction of duplicate transmission grid is considered inefficient, as transmission is considered to be a natural monopoly. Since competition is not an option in this sector, the state provides for the control of the monopoly transmission operations. To that end, the Directorate is also responsible for monitoring grid management and operations. The legal basis for this authority stems from the 1990 Energy Act. The grid owner is required to provide grid services to all customers as well as non-discriminatory point tariffs.

Regulations also require companies that are involved in both monopoly and competitive operations to separate the accounts and to have end-user bills reflect separate prices for the separate operations.

[11] ibid, p.14.
[12] ibid, p. 69.

The Directorate provides for the control of monopoly grid operations with two activities: income caps and point tariffs. Income caps are determined for each company, and include factors that affect the transmission costs in each area served, for instance climate, topography and settlement patterns. Companies are not allowed to earn an income that is greater than the maximum allowed by the Directorate. This framework is designed to prevent the monopoly grid companies from making unreasonable profits.

Grid companies are required to charge point tariffs of all their customers for transmission services. Point tariffs are charged uniformly and without regard for the consumer's or the producer's location in the network. The cited benefits of point tariffs include ease of access for consumers, and the establishment of a nationwide transmission network.[13]

Statnett SF

Statnett SF was established in 1992 during the reorganization of the public corporation Statkraft. Prior to 1992, Statkraft owned and operated installations in electricity generation and electricity transmission. With the reorganization, the state separated its generating and transmission capacity into two organizations: Statnett currently manages transmission and Statkraft manages generation.

Statnett owns roughly 87% of Norway's central grid, is the system operator for the national grid, and manages short- and long-term system coordination. As a state-owned enterprise of a monopoly operation, the revenues of Statnett are regulated by NVE.

Enova SF

Enova SF is responsible for the state's efforts to shift patterns of energy production and use. This is accomplished through the promotion of energy efficiency, renewable energy production, and environmentally-sound natural gas use.[14] The agency is funded through a

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[13] ibid, p. 92.
[14] ibid, p.14.

levy on the distribution tariff and grants from the state budget. In 2002 this amount was approximately NOK 430 million.[15]

Enova SF was established in 2001 and is subordinate to the Ministry of Petroleum and Energy.

Statkraft SF

Since 1992, Statkraft SF has focused entirely on electricity generation. Statkraft has 690,000 electricity and local grid customers, a power production of 58 TWh, and ownership, both full and partial, in 132 hydropower plants.[16] In 2002, the state-ownership function of Statkraft SF was transferred from the Ministry of Petroleum and Energy to the Ministry of Trade and Industry.

Legislation

Two pieces of legislation have been instrumental in Norway's current energy sector: the 1990 Energy Act, and the 2000 Water Resources Act. The Energy Act opens generation and trading to competition while the Water Resources Act approaches Norway's waterways from a resource-oriented approach.

Market Power

Competition responsibilities are divided between the regulator and the competition authority; the regulation authority, NVE, oversees the sector-specific regulation of the distribution companies while the competition authority oversees the overall market competition. Both entities cooperate in areas of overlapping responsibility, including access issues and foreign trade. Both entities trade information on market competition.

Corporatization separates the financial functions of the state and the corporatized entity so that they are transparent and at an "arms length" from the State. It has been argued that corporatization does not provide the full benefit of market incentives that promote

[15] ibid, p.59
[16] Statkraft, "Statkraft in Brief." Retrieved May 19, 2003, from http://www.statkraft.no/wbch3.exe?p=2146.

efficiency, and that corporatization must be coupled with incentives to ensure efficiency. For some countries, corporatization is a step on the way towards privatization. For other countries, privatization is not politically feasible; Norway is such a country.

Norway has a tradition of publicly owned natural resources, as well as publicly operated infrastructure; privatization was not a political option in electricity market reform and is not forecasted to be an option in the future. Instead, Statkraft SF and Statnett SF are what are known as "statsforetak," a state enterprise that is independent of the government and obligated to operate on commercial terms.[17] Sweden has a similar structure and tradition of public ownership.

In Norway and the other Nordic countries, a key component of the reform legislation centers on regulated third party access (rTPA) to the grid and separation of the competitive and monopolistic portions of the industry.

Commercial System

Ownership

Norway is characterized by a predominance of public ownership in production capacity: about 85% of the capacity is publicly owned, with 55% owned by municipalities and 30% owned by the state.[18] Ownership of individual facilities is considered to be private if the public ownership drops below 2/3 of the overall ownership share.[19]

Statkraft SF and Statnett SF manage Norway's involvement in state ownership. Companies that are classified as 'state enterprises' must be state-owned, and are provided

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[17] IEA, (1999), "Electricity Market Reform: An IEA Handbook," p. 45. Retrieved March 15, 2003, from http://www.iea.org/pubs/studies/files/elemar/elemar.htm.

[18] Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p. 11. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

[19] ibid, p.67.

with a guarantee for liabilities by the state. This guarantee for liabilities is the main difference between state enterprises and 'limited companies.'

More than 70 percent of all companies in the power sector are considered to be limited companies. Many of these companies were previously municipal companies, but have in recent years changed their form of business organization to limited status. Limited companies protect the owners from personal financial responsibility; owners are not liable for any debts the company acquires.[20] One of the reasons for the shift in business organization has been attributed to the Energy Act and its requirement of licensees to comply with the accounting standards of the Accounting Act. Former municipal companies changed their organization to limit their liability.

Trading licenses are required for any company in Norway that trades or supplies electricity, as well as those companies involved in monopoly operations. As of January 2002, 307 companies were licensed. Table 7 shows the distribution of these licensed companies in terms of ownership.

Table 7: Ownership of companies holding trading licenses, January 1, 2002

Ownership	Share of ownership	Single owner
Municipal	223	136
County	42	9
State sector	23	4
Private	126	65

Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.79. Retrieved 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

The state owns a large portion of the central transmission grid, while counties and municipalities own a majority of the regional and local grids. The central grid is managed

[20] ibid, p.80.

by the state enterprise Statnett SF and Statkraft SF manages the state ownership of production assets.

Private ownership, while represented in all portions of the electricity supply sector, is most prevalent in trading. Over half of all private companies are exclusively focused on trading.

Production Companies

There are 156 companies involved in electricity generation, and of these, only 29 are exclusively involved in generation. Statkraft is the dominant producer, and the 10 largest producers account for roughly two thirds of Norway's total mean production capacity.[21] Table 8 lists the 10 largest electricity producers.

Table 8: The 10 largest production companies as of January 1, 2002

Production company	Mean annual production		Installed capacity	
	TWh	Percentage	MW	Percentage
Statkraft*	36.2	30.7	8,673	31.4
Norsk Hydro	7.1	6.0	1,440	5.2
BKK	6.8	5.8	1,541	5.6
E-CO Vannkraft	6.8	5.7	1,891	6.9
Agder Energi	6.5	5.5	1,414	5.1
Lyse Energi	5.9	5.0	1,544	5.6
Skagerrak Energi	4.3	3.7	1,122	4.1
Trondheim Energiverk	3.2	2.7	746	2.7
Hafslund	2.6	2.3	504	1.8
Nord-Trondelag Elektrisitetsverk	2.6	2.2	568	2.1

*Not including stakes in Sydkraft and Norwegian companies

Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.83. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

[21] ibid, p.84.

Counties or municipalities own a majority of the production companies, and the twenty that are privately owned are primarily industrial companies that have been granted simplified trading licenses.

Grid Companies

A total of 178 companies are involved in grid management, which may include local, regional and/or central grid components. Of these 178 companies, 42 operate exclusively as grid operators; the remaining companies are also involved in generation and/or trading. Statnett SF, the state-owned enterprise, owns about 87% of the central grid. Table 9 shows the 10 largest grid companies.

Table 9: The 10 largest grid companies (distribution grid) as of January 1, 2001

Grid Company	No. of customers	Quantity transmitted GWh/year
Viken Energinett AS	306,071	8,445
BKK Nett AS	172,188	4,495
Lyse Nett AS	101,678	3,632
Ostfold Energi Nett AS	91,662	2,168
Trondheim Energiverk Nett AS	84,988	2,205
Nord-Tronderlag Elektrisitetsverk	74,832	1,973
Energiselskapet Asker og Baerum Nett AS	72,578	2,179
Akershus Nett AS	71,034	2,032
Aust-Agder Energi Nett AS	62,633	1,397
Troms Kraft Nett AS	60,623	1,976

Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.84. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

Trading Companies

Trading companies are those companies that resell power from the market to end-users, similar to the activities of traditional distribution utilities. A total of 218 companies are engaged in trading, of which 68 are not involved in any other activities. Table 10 shows the 10 largest trading companies.

Table 10: The 10 largest energy trading companies as of January 1, 2001 (GWh/year)

Company	Total Turnover	Households and Holiday cabins	Other Activities*
Statkraft SF	18,998	0	18998
Norsk Hydro Produksjon AS	13968	17	13950
Oslo Energi AS	7492	3109	4383
Tindra AS	6588	3774	2814
BKK Kraftsalg AS	4820	2461	2359
Lyse Marked AS	3446	1575	1870
Vestfold Kraft Energi AS	2661	1409	1251
Ostfold Energi Kraftsalg AS	2317	1028	1289
Nord-Trondelag Elektrisitetsverk	2199	809	1390
Troms Kraft Marked AS	2021	879	1142

Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.85. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

Norway and the Nordic Countries

Between the Nordic countries, there is a range of general ownership patterns as shown in Table 11, as well as various degrees of horizontal and vertical integration, as shown in Table 12.

Table 11: Ownership patterns in Nordic countries

Predominantly Public	Mixed	Predominantly Public
Norway	Denmark	
	Finland	
	Sweden	

Source: IEA, (1999), "Electricity Market Reform: An IEA Handbook," p.29. Retrieved March 15, 2003, from http://www.iea.org/pubs/studies/files/elemar/elemar.htm.

Table 12: Electricity sector structure of Nordic countries

Country	Degree of Horizontal Integration			Vertical Integration
	Generation	Transmission	Distribution	
Norway	low	high	low	low
Sweden	moderate	high	moderate	low
Finland	moderate/high	moderate/high	moderate	moderate**
Denmark	low	moderate	low	moderate**

**"Moderate" means that the four main activities (generation, transmission, distribution and supply) are not fully vertically integrated within each utility.

Source: IEA, (1999), "Electricity Market Reform: An IEA Handbook," p.27. Retrieved March 15, 2003, from http://www.iea.org/pubs/studies/files/elemar/elemar.htm.

NordPool

The power exchange of Norway, NordPool, is an international voluntary exchange that includes Sweden, Finland, and Denmark. Electricity is traded in one of two ways: with bilateral contracts or in the power exchange that NordPool provides. Bilateral contracts can be brokered using standardized contracts through independent firms or, as a growing number of bilateral contracts, traded in NordPool's markets. The majority of trading occurs in the form of bilateral contracts.

Contract for Differences (CFDs) are also available through NordPool, and provide an opportunity to manage risk associated with the difference in price between the Elspot system price and the price of electricity in a specific Elspot service area.

NordPool ASA is owned equally by the system operators of Norway (Statnett SF) and Sweden (Svenska Krafnat). Approximately 300 participants are active in at least one of NordPool's markets, and Norwegian participants account for 55% of NordPool's total customers.[22]

Nord Pool Spot ASA, a subsidiary of NordPool ASA, began operating in 2002. Nord Pool Spot manages the physical trade in power for the Nordic countries, and determines the spot price in the physical market on an hourly basis. This spot price serves as a reference for bilateral and financial contracts, as well as markets.

NordPool offers clearing services for the power market, which means that NordPool acts as the middleman in all contracts. This is designed to reduced risks associated with credit and settlement between parties. NordPool cleared 2,769 TWh in 2001.[23] NordPool offers four separate markets: Elspot, Eltermin, Elbas, and Eloptions.

Elspot

Elspot manages the physical trade of electricity for delivery on the following day. The price that is determined by Elspot establishes the system price to be used throughout the market. The price is determined by the quantity of electricity that market participants want to buy and sell. Statnett SF relies on Elspot to fulfill its responsibilities as the system operator. The bids consist of simple price-quantity pairs detailing how much quantity a bidder is prepared to buy or sell at a given price, and are made for each of the twenty-four hourly periods.

[22] ibid, p. 98.
[23] ibid, p.98.

Eltermin

Eltermin is a financial market that includes futures and forward and contracts. Market participants are allowed to use these contracts to hedge their risks in the purchase and sale of electricity for up to three years. The primary difference between futures and forwards has to do with the method of settlement that is used during the contract's trading period. Futures are traded daily up to the time of delivery; forwards have no settlement in the period prior to delivery. Futures and forwards are available for up to four years in advance, and are offered in a number of variable sized periods of days, weeks, years, seasons—soon to be quarters—and blocks, soon to be months.

Eloptions

Eloptions provides a financial tool for risk management with the trade of power options. Options in this market are standardized, with clearly defined conditions.

Elbas

Sweden and Finland use Elbas as a supplement to Elspot. Elbas is a physical market that trades continuously for balancing purposes, or closer to the time of delivery than Elspot. Elbas is administered from Helsinki, Finland.

Grid Congestion

NordPool manages grid congestion through the use of area prices. When a bottleneck occurs, price areas are determined on either side of the transmission restriction. These are known as Elspot price areas. In areas where there is a surplus, the area price is lower than the system price; in areas where there is a shortage, the area price is higher than the system price. This pricing model is designed to account for bottlenecks while promoting balance within the overall system.

Norway uses price areas both within its borders and between countries to deal with congestion. In contrast, Sweden and Finland only use the price area model to manage external bottlenecks. Both Sweden and Finland use counterpurchases to manage any internal bottlenecks. In a counterpurchase, the system operator will contract with producers to increase or decrease electricity production to balance the market.

Any difference between the system price and the area price is known as the capacity fee. The Nordic system operators share the income generated from the capacity fees.

The Balancing Market

As the system operator in Norway, Statnett SF uses what is known as a balancing or regulatory market to maintain a balance between production and consumption of electricity. After price and quantity have been determined in Elspot, this balancing market opens. Producers or consumers that are willing to change their generation or consumption on short notice then submit their quotes to Statnett SF—in this way Statnett is able to adjust the amount of power on the grid to an equilibrium point.

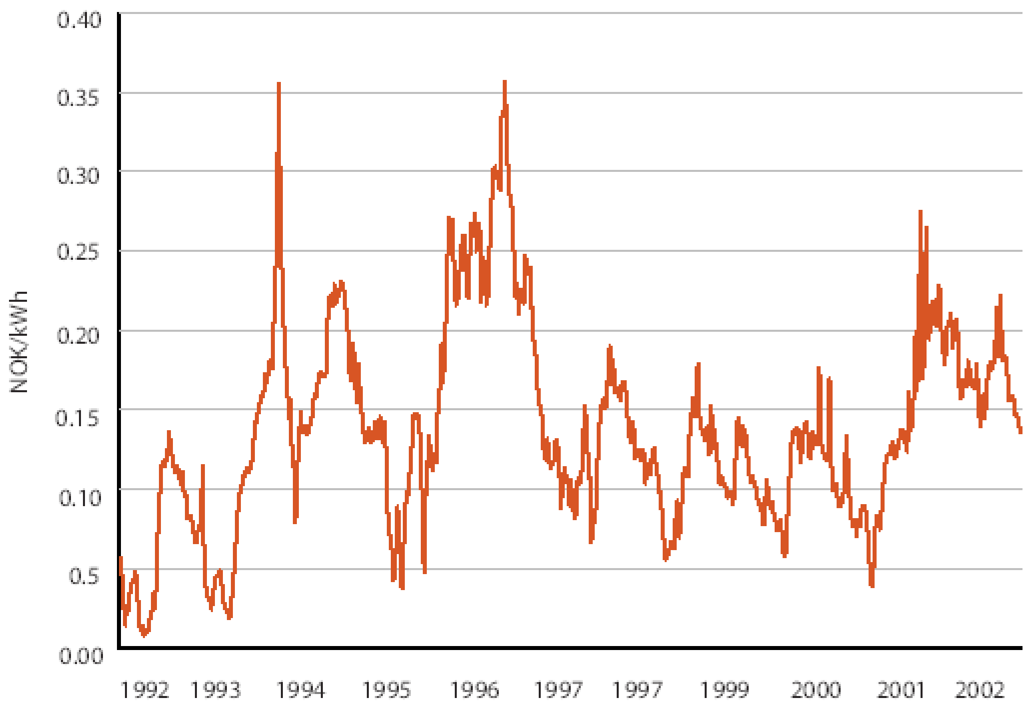
To make sure that production and consumption are in equilibrium even when the market is tight, Statnett organizes a national options market. In this market, participants enter into contracts with Statnett that guarantee a certain amount of supply for a given period of time. These options contracts were first used in 2000.

Price Determination in the Nordic Market

There is a range of generation mix in the Nordic countries; Norway is predominately hydro, Sweden a mix of hydro and nuclear, and Finland and Denmark are predominately fossil fuel-based. The production costs for hydropower and nuclear power are much lower than those for gas-fired generation, and as such, the thermal power plants often balance out the overall Nordic market. Thus, when the reservoirs are at an average level, electricity prices are by and large determined by the price of the production of electricity from coal.[24] Figure 2 illustrates the nominal Elspot price in the years 1992-2002.

[24] ibid, p.104.

Figure 2: Spot prices in Nord Pool's spot market 1992-2002



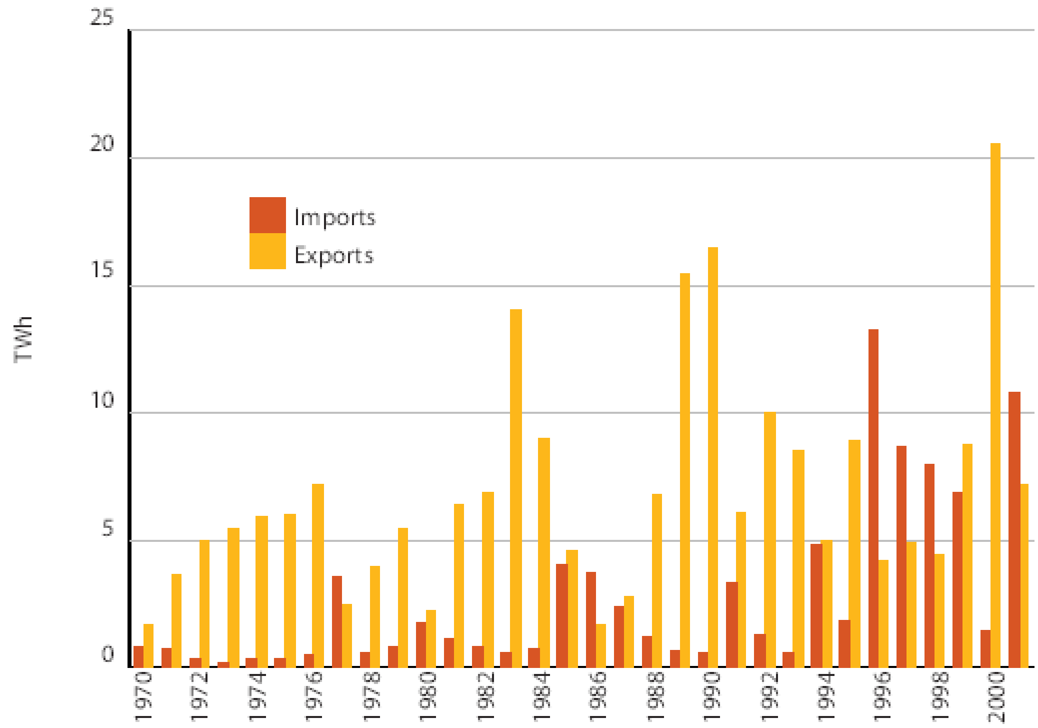
Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.105. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

Power Trade Between Countries

The trade in power between the Nordic countries is largely determined by the production and consumption patterns in those countries. Norway had traditionally been a net exporter to its neighbors. Figure 3, however, shows that since the late 1990s, Norway has become a net importer. This shift has been attributed to a combination of Norway's increasing demand and the recent lack of investment in hydropower development.[25]

[25] ibid, p.104.

Figure 3: Norway's imports and exports of power (1970-2001)



Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.105. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

Norway, with its reliance on hydropower, is sensitive to variations in precipitation and reservoir inflow. The ability to trade power with its neighboring countries provides a measure of stability, and reduces the need for Norway to construct a large reserve capacity to meet its power needs in dry years.

Norway has transmission connections with Sweden, Finland, Denmark, and Russia. The connection between Norway and Sweden, at 3,000 MW, is the largest in terms of transmission capacity.

Outcomes

Consumer Price

Industrial prices have stayed more or less stable since the formation of NordPool. There was a price spike in 1996, concurrent with the opening of the market, but this has subsequently been attributed to unusual dry seasons in the years 1995 and 1996. Prices have since dropped down below the pre-1995 levels.

Late summer and early fall 2002 was markedly dry, creating below normal levels of water in hydro reservoirs in Norway and Sweden. The dryness combined with an early and cold winter season to create price spikes in late 2002 at NordPool's physical and financial markets. In reaction to the sharp price increases, several generating plants that had been offline were brought online, and domestic and industrial consumers curbed consumption. The end result was a jittery market with lower trading volumes than the year before. NordPool received a significant amount of media coverage.

According to NordPool, the market functioned as predicted to the low inflow and low temperatures: reserve generating capacity was brought on-line, imports increased, and power consumption decreased.

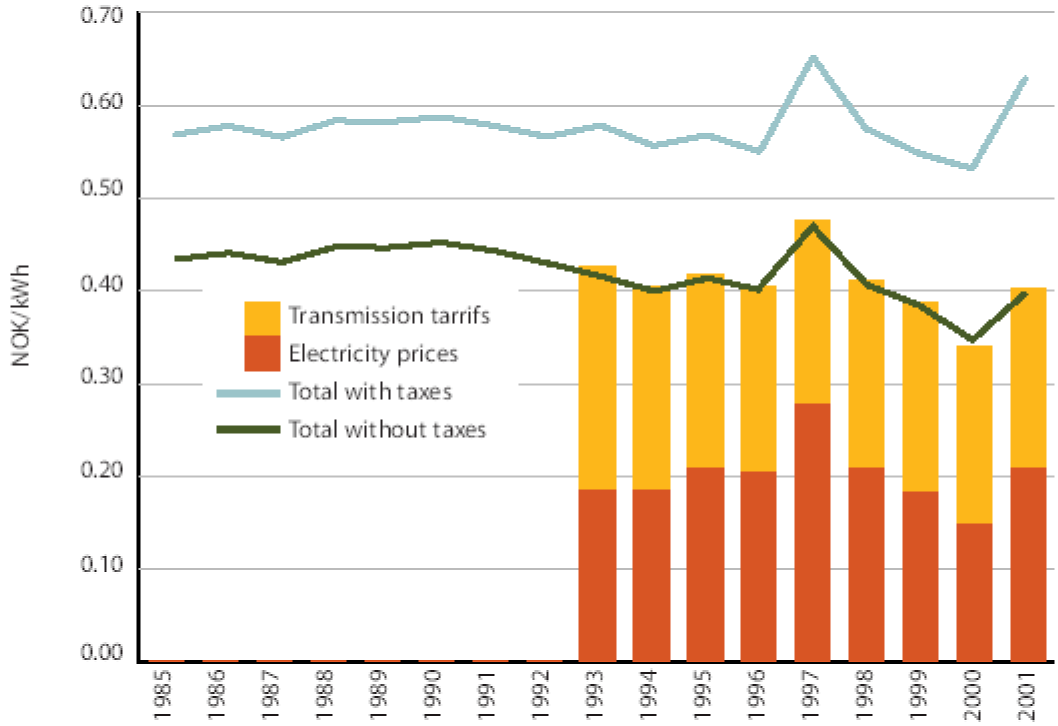
Consumer prices are composed of 5 charges:

- Price of electricity, including generation, distribution, and retailing costs
- Transmission tariff
- Electricity tax
- Value added tax (VAT)
- Levy on transmission tariff for Energy Fund

Figure 4 shows the electricity prices for households in 1985-2001. Prices have been fairly stable for households; most variances are explained by precipitation and winter temperatures. The price spike in 1997 is a reflection of a cold winter in 1995-1996 followed by low precipitation in 1996. The decrease in price from 1997-2000 reflects above normal rainfall for those years.

Figure 4: Electricity prices for households 1995-2001

(NOK per kWh in fixed 2001 NOK)



Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.103. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

System Reliability

The restructuring of electricity markets has brought new attention to concerns about system reliability. Have market mechanisms been able to ensure the reliable delivery of market reform?

In 1997, incentive-based monopoly regulation of distribution services was introduced to Norway that included fixed revenue caps. While the goal of the regulation was to improve efficiency and provide the benefits of cost reductions to customers, an undesirable side effect concerned regulators: poor system reliability. In an effort to combat the externalities of the fixed revenue caps, the Norwegian Water Resources and Energy Directorate (NVE) introduced a Cost of Energy Not Supplied (CENS) arrangement in 2001. NVE now uses a theoretical cost of electricity interruption to customers to adjust the revenue caps.[26] The goal is to provide utilities with incentives to provide an adequate level of system quality.

CENS is the product of the average interruption costs and the ENS caused by interruption of greater than three minutes. There are different cost rates for residential/agricultural end-users, commercial/industrial end-users, and notified and non-notified interruptions.[27]

Since 1995, the Norwegian Water Resources and Energy Directorate (NVE) has required the reporting of interruption statistics from network companies; this has provided valuable information on the power system's quality of supply. From 1995 to 1999, data was collected from 200 network companies which covered 115,000 delivery points. During this time, the number of interruptions appears to be relatively constant. The aggregated results are displayed in Table 13.

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[26] Heggset, Jorn, Gerd Kjolle, Frode Trengereid, and Hans Ween. "Quality of Supply in the Deregulated Norwegian Power System." Retrieved May 19, 2003, from http://www.nve.no/FileArchive/190/paper2.pdf.

[27] ibid, p.1.

Table 13: Summary of key figures reported from 1995-1999

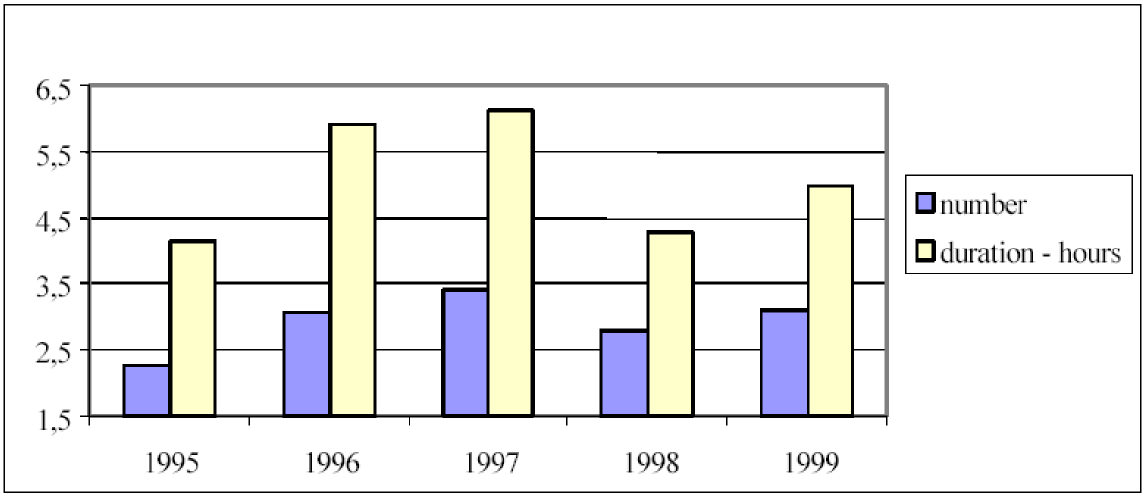
	Number of interruptions per delivery point	Annual duration per delivery point (hours)	Duration per interruption (hours)	ENS per Energy supplied (%)	Interruption Costs (million E)
Total average per year	2.9	5.1	1.7	0.03	100
Average for notified interruptions	0.8	2.3	3.0	0.01	33
Average for non-notified interruptions	2.2	2.8	1.3	0.02	67

Source: Heggset, Jorn, Gerd Kjolle, Frode Trengereid, and Hans Ween, "Quality of Supply in the Deregulated Norwegian Power System," p.3. Retrieved May 19, 2003, from http://www.nve.no/FileArchive/190/paper2.pdf.

While figure 5 shows that there is not a large variance in the number of interruptions, or ENS, the figure also shows that when the ratio of ENS to ES is examined, the downward trend is a result of the declining occurrence of notified interruptions. NVE speculates that this decrease in notified interruptions may be a result of reductions in preventative maintenance, brought on by cost reductions that were influenced by the incentive-based regulations introduced in 1997.[28]

[28] ibid, p.6.

Figure 5: Number of interruptions and annual interruption duration (average per delivery point)



Source: Heggset, Jorn, Gerd Kjolle, Frode Trengereid, and Hans Ween, "Quality of Supply in the Deregulated Norwegian Power System," p.3. Retrieved May 19, 2003, from http://www.nve.no/FileArchive/190/paper2.pdf.

The data collected to implement CENS, in addition to monitoring overall reliability, allows NVE to track any tendency of utilities to give priority to heavy load regions at the cost of rural regions. Statistics show that the duration of system interruptions is much greater for northern and western Norway; this is speculated to be a result of rough weather, rough terrain, and great distances between populated areas.

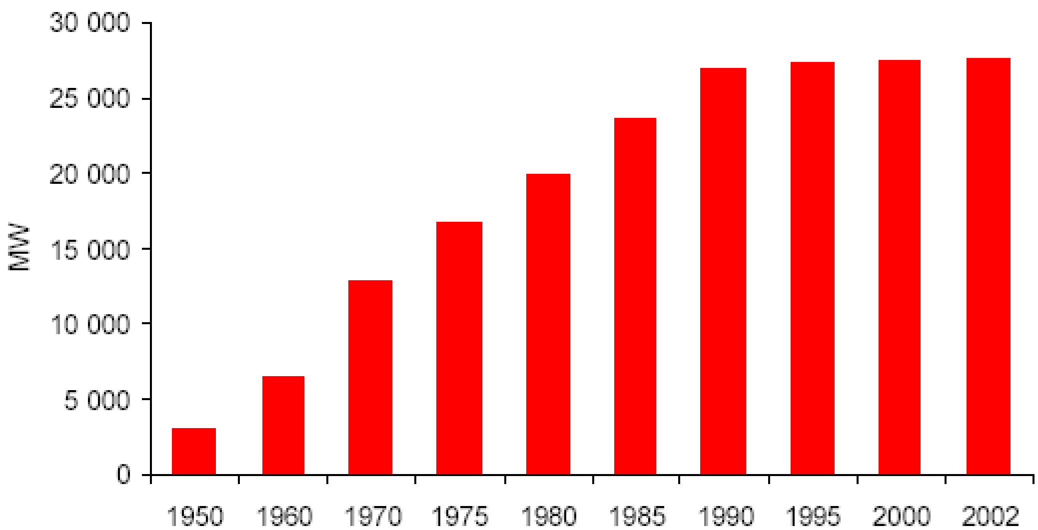
Since its inception, NordPool has experienced several events testing its overall system reliability, including the unusually dry year of 1996 and the abnormally low winter temperatures of 2001. In 1996, the system handily dealt with the shock to its supply; the market continuously cleared with no adverse impact on the system's stability. Prices did spike, and small consumers were particularly affected, but the system was viewed to have successfully handled the dry year. In 2001, several days of cold temperatures increased the demand for electricity. In Sweden, the load came close to the system's capacity and there were fears that the system operator would be forced to shed load. Appeals to the public to conserve power, in combination with the high electricity prices, curbed the demand for electricity enough to avoid any need to shed load.

System Investment

NordPool has identified a need for investment in both generation and transmission assets. Although there has been a pan-Nordic market since 2000, transmission constraints within and between countries create bottlenecks. A single system price applied throughout the Nordic Power Exchange only 35% of the time in 2002.

Historically, Norway's installed capacity experienced its greatest increase between 1970 and 1985, and has leveled out since then. See Figure 6.

Figure 6: Installed capacity

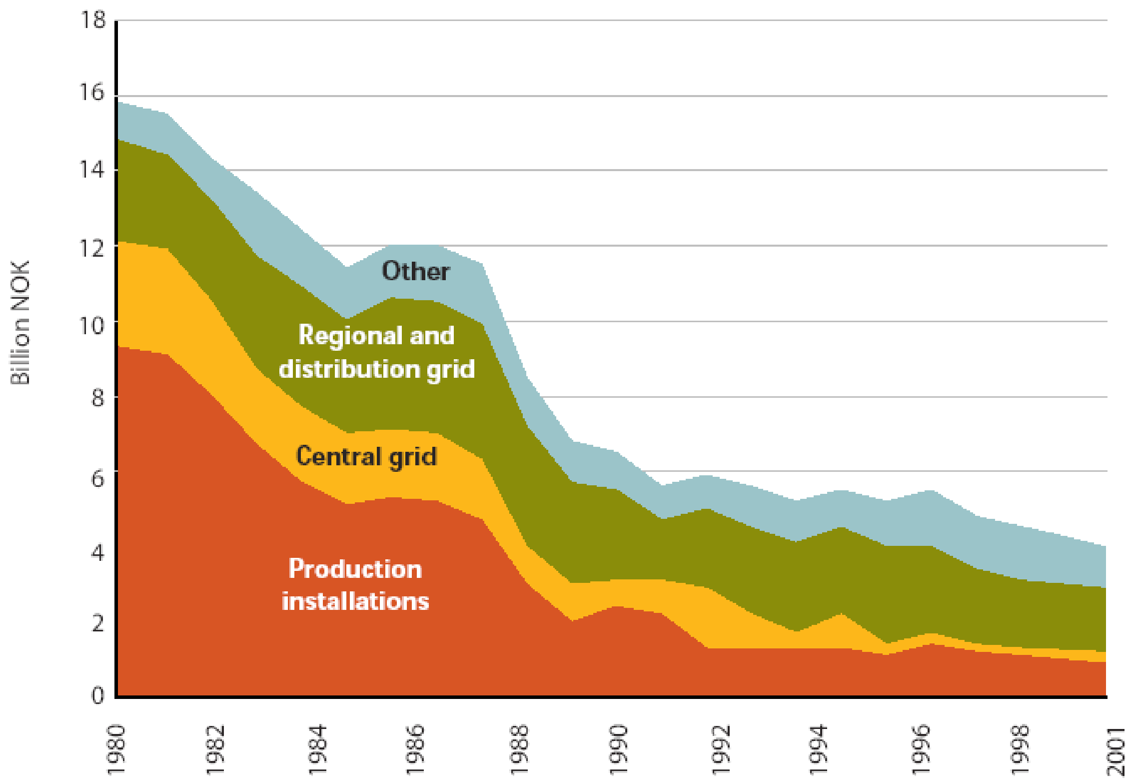


Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.22. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

Areas of potential investment in generation include upgrading existing hydropower plants, expanding plant capacity by transferring water from one catchment area to another, enlarging existing reservoirs, and building new reservoirs.

Norway has experienced a large drop in power supply sector investment in the past 15 years. Figure 7 shows this declining trend in investment, which has been particularly striking in the decline in of new generating plant investment.

Figure 7: Gross investments in the electricity supply system*. Fixed 2001 NOK.



Source: Ministry of Petroleum and Energy, (2002), "The Energy Sector and Water Resources in Norway 2002," p.34. Retrieved May 6, 2003, from http://www.dep.no/oed/engelsk/p10002017/p10002019/026021-120007/index-dok000-b-n-a.html.

New Zealand

Source: CIA Factbook 2002

Introduction

New Zealand is often cited as an example of a successfully restructured hydropower market; FERC has recently pointed to New Zealand in public and staff statements related to its Standard Market Design Notice of Proposed Rulemaking (RM01-12-000).[29]

New Zealand covers an area of roughly 104,000 square miles, and consists of 1.7 million electricity customers. Current electricity production is approximately 38,000GWh/year from an 8,600MW production capacity.

The wholesale power market is known as the New Zealand Electricity Market, or NZEM, and was launched October 1, 1996. It was not mandated by specific legislation, and has a reputation as having established a system of "light handed regulation."

Historical Context of Restructuring

In the early 1980s, there were increasing public concerns about New Zealand's economic performance, with a governmental debt that had reached unsustainable heights. The new Labour government set out to overhaul the country's economy with an emphasis on public sector accountability. It was in this context that restructuring occurred in a number of industries including telecommunications, ports, banking, some postal services, air traffic control, and gas and electric utilities. Through market restructuring, the government aimed to foster economic growth by enabling a more efficient use of electricity resources, driven by clear price signals and competitive electricity markets where possible.

[29] See *SMD and Hydro in the West*, Sarah McKinley, FERC State Relations. August 22, 2002.

Table 14: Expected market outcomes of restructuring

Expected Outcomes
Efficient Short-Run Operation
Efficient Long-Run Operation
Ability to Manage Risk
Effective Retail Competition
Competitive Price Discovery

Source: NZEM, (2002), "Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM," p.iii. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

The initial stages of restructuring began in 1987 with the formation of the state-owned enterprise, Electricity Corporation of New Zealand (ECNZ).[30] ECNZ initially acted as the sole generator, transmitter, distributor, and retailer of electricity for all New Zealanders using a profit-making model. The transmission operations were separated out from ECNZ in 1994 with the formation of the state-owned enterprise, Transpower. In 1996, a wholesale electricity market was formed when ECNZ was further split into 2 state-owned enterprises, ECNZ and Contact Energy. In 1999, another major step in reform included the privatization of Contact Energy.

Physical System

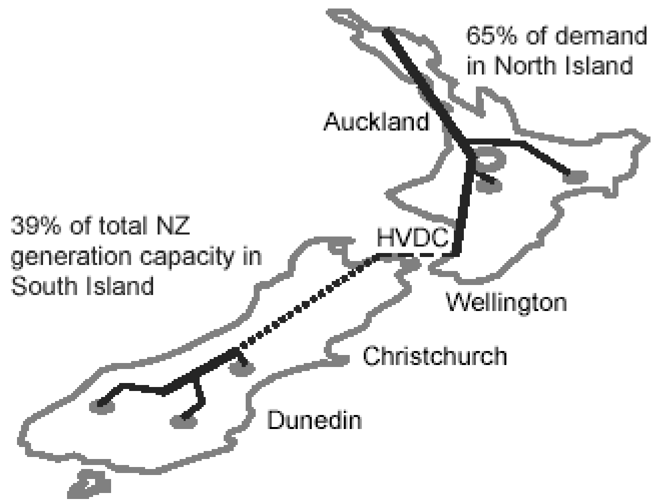
Generation

New Zealand's capacity is dominated by hydropower, and is largely generated on the South Island. The bulk of the load, however, is located on the North Island. With the

[30] Following the enactment of the State Owned Enterprises Act of 1986, New Zealand formed a number of State Owned Enterprises (SOEs) as part of its state-sector reform efforts. The Act requires that the state own all of the shares of an SOE. The primary goal of an SOE is to operate as a successful business as defined by the act by being: "as profitable and efficient as comparable businesses that the Government does not own; as good employer; and an organization which exhibits a sense of social responsibility." Crown Company Monitoring Advisory United, "State Owned Enterprises." Retrieved 2003, from http://www.ccmau.govt.nz/soe/overview.asp.

exception of several large-scale industrial consumers, the majority of the load is located in urban centers such as Auckland.

Figure 8: New Zealand's generation and load



Source: M-co, "How do New Zealand Electricity Prices Work?" Retrieved May 15, 2003, from http://www.nzelectricity.co.nz/downloads/NZEMPricing.pdf.

The national hydro plant consists of river-flow systems as well as water stored in natural and man-made lakes. 39% of the total hydro capacity is located on the South Island, while 65% of the demand is located on the North Island. The South Island generally fills its lakes during the spring with snow melt, while the North Island fills its lakes during the winter with rainfall.

In a normal hydrology year, New Zealand's generation is dominated by hydro followed by gas then geothermal and coal, as shown in Table 15.

Table 15: Percentage share of fuel type

Fuel Type	Percentage Share
Hydro	63%
Gas	22%
Geothermal	7%
Coal	4%
Other	3%

Source: Ministry of Economic Development, (2002), "Electricity: Supply and Demand Issues," Retrieved April 3, 2003, from http://www.med.govt.nz/ers/electric/supply-demand/index.html.

According to government calculations, a 1 in 20 dry year results in up to a 15% reduction in hydro generating capability, which is covered by an increase in gas and coal generation.[31]

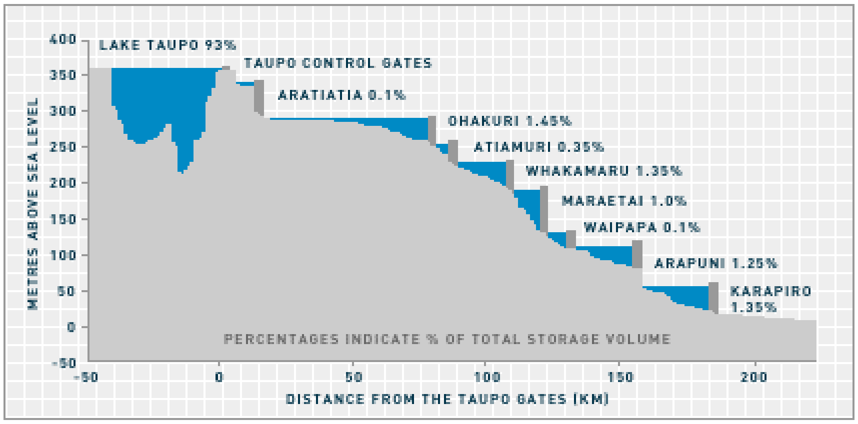
North Island Catchments

The Waikato Hydro System begins at Lake Taupo on the North Island, and includes 9 power stations on its run to the Tasman Sea. The system is dependent on regular inflows from rainfall into Lake Taupo. The total capacity of the system is 1,058 MW.The diagram below shows the storage capacity for each of the lakes as a percentage of the overall hydro system. The system provides about 13% of New Zealand's electricity, and represents about 22% of the nation's generating capacity.[32] Mighty River Power, the owner and operator of the nine power stations located along the river, has a regulatory requirement for the daily spill of water to meet the recreational and tourism needs of the river. The system contributes 4000 GWh annually to the national electricity system.

[31] Ministry of Economic Development, (September 24, 2002), "Electricity: Supply and Demand Issues, Media Briefing." Retrieved April 3, 2003, from http://www.med.govt.nz/ers/electric/supply-demand/index.html.

[32] Might River Power, "Hydro Spill." Retrieved May 10, 2003, from http://www.mightyriverpower.co.nz/lakes_power_stations/hydro_spill/.

Figure 9: Waikato Hydro System



Source: Mighty River Power, "Lakes and Power Stations." Retrieved May 10, 2003 from http://www.mightyriverpower.co.nz/lakes_power_stations/.

The Tongariro hydro scheme is operated by Genesis Power, a state-owned enterprise[33], and includes two power stations, Tokaanu at 240 MW, and Rangipo, at 120 MW. The system uses water collected from a catchment area of over 2600 square kilometers which includes the North Island's central upper plateau. Water is channeled through the Rangipo and Tokaanu power stations before being released into Lake Taupo.

The Waikaremoana hydro scheme consists of three power stations—Kaitawa, Tuai, and Piripaua—that are within 8kms of each other. The scheme produces 142 MW of electricity and is operated by Genesis Power Ltd. For the 1998/99 year, the Kaitawa power station generated 87 GWh, the Tuai power station generated 194 GWh, and the Piripaua power station generated 131 GWh.

South Island Catchments

Meridian Energy operates two separate hydroelectric systems on the South Island: Waitaki and Manapouri. The electricity produced in the Waitaki system relies on the snow and rainfall in the Southern Alps and its neighboring mountain regions. The system consists of eight power stations along the river that have a combined capacity of approximately 1,760 MW.[34] The Manapouri power station has a capacity of 700 MW[35] from 7 turbines, and is located within the Fiordland National Park. It relies on water and snow from the Fiordland catchments to produce electricity.

The Clutha hydro scheme is owned by Contact Energy Limited and consists of the Lake Hawea Control structure and two power stations, one at Clyde and one at Roxburgh.

Generation by Load Type

Base-load generation is supplied mostly by geothermal plants, and is running at all times. Mid-range generation is a mix of hydro and gas-fired combined cycle stations, and is running most of the time; its output ranges from 70% to 100% of its capacity. Load demands and spot prices determine how much mid-range capacity is utilized. Emergency and peaking load are supplied by gas turbine peaking stations at Stratford and Whirinaki, and are rarely used.

Hydropower provides generating capacity for all load types; while most hydropower generation is mid-range, some is base-load and some is peaking. One of the challenges that New Zealand's hydro systems face is limited storage capacity. Unlike Norway or Tasmania, two hydro-dominant power systems with two to three years of storage capacity, New Zealand can run its lakes dry in two to three months. To address this shortcoming, New Zealand operates what is known as "hydro-firming" plant.

Hydro-firming stations operate in late summer to allow the lakes to fill up before winter. They also run at full capacity during dry years. The Huntly and New Plymouth stations, both located on the North Island, were designed as hydro-firming stations. Huntly was commissioned in 1987, and at 1000 MW is the country's largest thermal power station.

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[34] Ministry of Economic Development, (April 7, 1998), "Competition in Electricity Generation." Retrieved May 19, 2003, from http://www.med.govt.nz/ers/electric/ecnz.html.

[35] ibid.

[36]New Plymouth is the second largest thermal station, is designed to use either natural gas or fuel oil, and was commissioned in 1974.[37]

Transmission

Transpower, a state-owned enterprise, owns and operates the New Zealand Electricity Grid. Its 11,000 miles of line connect generators and distributors. The transmission grid consists of two alternating current subsystems, one each for the North and South Islands.

The foundation of the grid is based upon a network of 220kV lines on each island, which connect the largest power stations with the load centers. Regional centers and smaller power stations are connected with lines operating at 110kV, 66kV and 50kV.

The islands are connected with an underwater 1200MW High-Voltage Direct Current (HVDC) known as the Cook Strait Cable. This connection presents a transmission constraint that plays an important role in the supply of electricity throughout New Zealand. As a result of transmission uncertainty between the islands, one of the larger generating units on the North Island is forced to maintain spinning reserve to ensure against a loss of supply.

Distribution

Approximately 30 distribution "lines" businesses serve New Zealand. They generally provide electricity to retailer suppliers and not to end-use consumers. Retailers then in turn sell electricity services to consumers, which include services such as billing. Distributors provide equal access to distribution services and electricity supply to retail customers.

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[36] Genesis Power, "Thermal." Retrieved June 10, 2003, from http://www.genesispower.co.nz/education/index.html.

[37] Contact Energy, "The Energy Behind Contact." Retrieved June 10, 2003, from http://www.mycontact.co.nz/view?page=/forinvestment/aboutus/energygeneration.

Retail

In April of 1999, New Zealand's lines and energy businesses were separated. This reform was intended to increase competition in, among other activities, retail supply of electricity. Contact Energy is the largest retailer, generating approximately 30% of the country's electricity.[38]

Institutional Systems

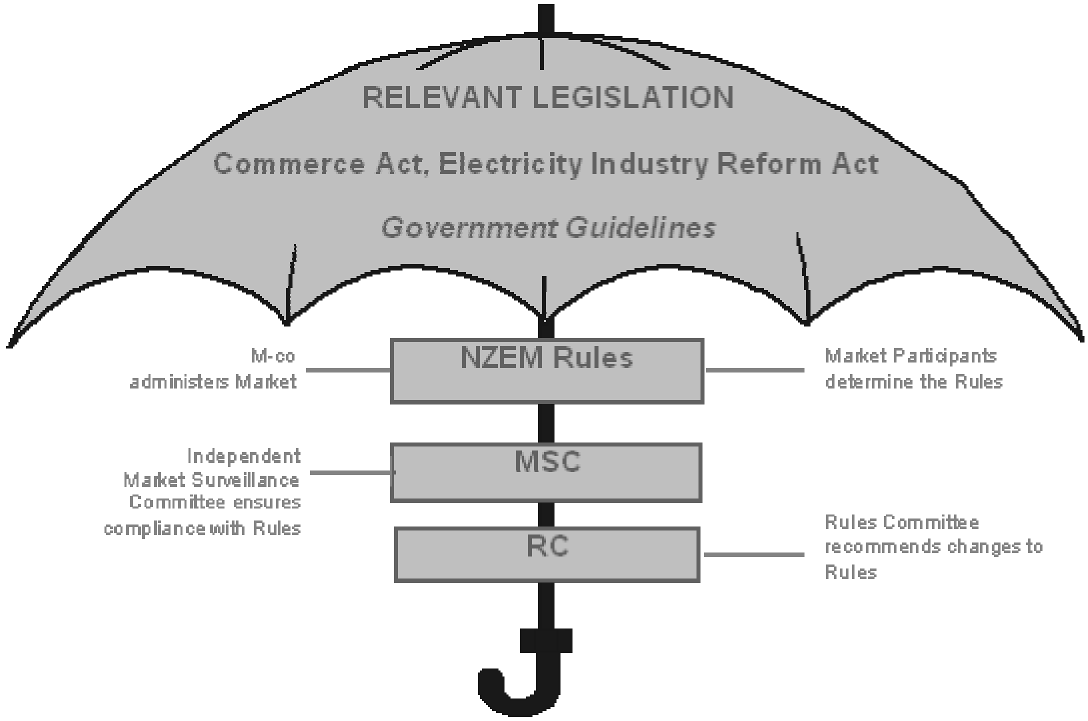
The New Zealand Wholesale Electricity Market, or NZEM, was created in 1996 as a mechanism for the price discovery of electricity. A majority of electricity sales take place in this voluntary multi-lateral power exchange.

NZEM is restricted by only a handful of government laws, including the Resources Management Act 1991, the Commerce Act 1986, and the Fair Trading Act 1986. NZEM is self-regulated; market participants formed the NZEM Rules, which act as a contract between participants. The Rules cover all aspects of the market, including market entry criteria, procedures for receiving bids and offers, and settling financial transactions.

NZEM is governed by the Rules Committee, and surveillance and compliance is administered by the Market Surveillance Committee.

[38] Contact Energy, "New Zealand Electricity Industry." Retrieved May 5, 2003, from http://www.mycontact.co.nz/new_zealand_electricity_industry.htm.

Figure 10: Overview of NZEM structure



Source: NZEM. "What is NZEM?" Retrieved April 3, 2003, from http://www.nzelectricity.co.nz/C2Overview.htm.

Transpower

The national transmission grid is owned and operated by Transpower. Its 12,300 km of high-voltage transmission line transport power from 40 major power stations to over 200 grid exit points. In addition to ownership and systems operator responsibilities, Transpower oversees common quality of the electricity supply, performs scheduling and dispatch services for the NZEM, and provides information for those market participants making bids and offers.

Transpower maintains real-time security by making contracts with generators for ancillary services.

M-co

The NZEM market is administered by M-co. Established in 1993, M-co's roles include market administrator, clearing manager, pricing manager, and COMIT administrator.

COMIT

Commodity Market Information Trading System, or COMIT, is the online trading system gateway for market participants. COMIT is used by market participants to actively trade electricity as well as to obtain market data for decision-making.

COMIT Free to Air, a website that provides information for non-market participants, was established at the request of the Rules Committee. The website is designed to provide greater transparency on electricity prices, and includes information about hydrology, demand, and final prices.

Electricity Commission

On May 20, 2003, the government of New Zealand announced that it would establish an Electricity Commission, charged with stabilizing wholesale electricity prices. As proposed, the Commission would be comprised of seven members, and would focus on ensuring the supply of power in dry years without dramatic price spikes. The Commission would purchase reserve generating capacity from generators to ensure supply for a 1 in 60 dry year, paid for by a levy paid by consumers. The reserve capacity would be released to the market at an as-yet-to-be identified trigger price. While the details of the Commission and its proposed security mechanisms have yet to be determined, early responses include grudging acceptance by generating companies, open-armed welcoming by the Major Electricity Users' Group, cautious welcome by the single privately-owned generating company, and outright rejection by the opposition National Party and the Federated Farmers.[39]

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[39] New Zealand Press Association, (May 20, 2003), "Market Accepts Government Power Market Plan While Business Welcomes It." Retrieved May 29, 2003, from LexisNexis.

Market Power

New Zealand's approach to regulation is often referred to as "light handed," referring on their reliance on standard competition law and mandatory information disclosure as opposed to sector specific regulation.

Commercial Systems

Ownership

Because of excess generating capacity, little market entry took place after 1996.
The 3 largest retailer/generators operate 71% of the market share, while the 4 largest operate 86% of the market share. Table 16 lists the retail/generators and their share of the market.

Prior to restructuring, New Zealand operated a centrally dispatched generation system. There are currently 4 major generating companies raising significant questions about market power in the generation side of the market.

Table 16: Market share of retailers/generators (December 2002)

Owner	Generation capacity (MW)	% Total generation	No. of customers	% Total customers
Contact Energy	1,940	23%	465,000	26%
Genesis Power	1,596	19%	450,000	25%
Independent	112	1%	0	0%
King County	13	0%	23,000	1%
Meridian Energy	2,448	29%	230,000	13%
Mighty River Power	1,217	15%	279,000	15%
NGC	386	5%	0	0%
Todd Energy	166	2%	65,000	4%
TrustPower	413	5%	280,000	16%
Tauropaki Trust	56	1%	0	0%
TOTAL	**8,347**	**100%**	**1,792,000**	**100%**

Note: This information was collated by M-co in December 2002 from information provided by the companies listed above

Source: NZEM. (2002). "Participation and Performance: Enhancing the Efficiency and Effectiveness of the New Zealand Electricity Market," p.6. Retrieved May 29, 2003, from http://www.nzelectricity.co.nz/C2Wholesale/SECURE_mktrpt.pdf.

Pricing

The majority of New Zealand's wholesale electricity is bought and sold on the New Zealand Wholesale Electricity Market (NZEM) which functions with voluntary multilateral contracts. NZEM was formed in 1996 as a mechanism by which to "discover" wholesale prices. It was through the price signals on the wholesale market that the government sought to encourage efficient generation, demand management, and system investment.

The electricity supply system has roughly 250 nodes where generators put electricity onto the grid and where purchasers take electricity off of the grid. It is at these nodes that prices are set on a half-hourly basis. The advantage of nodal pricing, in theory, centers on its reflection of the total cost to provide electricity to a specific node. This results in a separate price at each of the 250 nodes which factors in both generation and transmission costs (including congestion). Nodal pricing offers the potential for price signals to guide future investment of generation plant and to influence consumer behavior.

The price at each node reflects its marginal price, or the price to produce an additional unit of electricity at that location. Included in the marginal price are various costs including the distance from generation, grid constraints, and the cost of reserve.

The greater the distance that electricity has to travel through the grid, the greater the loss that occurs. This loss is referred to as transmission loss. The nodal price factors in the amount of electricity that needs to be generated to make up for the loss that occurs during transmission; this component of the price will be greater for further flung nodes. Losses are greater or less depending on the age, capacity, and location of the lines, as well as the weather; the system experiences greater transmission loss during periods of warmer weather.

New Zealand's market operates in a similar fashion to Australia's VicPool. Generators submit their bids for the following day, giving the amount of electricity that they'll supply given the price for all half-hours of the next day. Offers and bids can continue up until 4 hours before dispatch. Dispatch uses least-cost principles, such as economic dispatch, to the greatest extent possible, while at the same time meeting the demand for actual loads and transmission system constraints. Prices are determined *ex post* by resolving the market-clearing model for actual metered load, and are based on a single market price as opposed to pay-as-bid. Due to concerns about the capacity of the Cook Strait Cable, spot market prices are set separately for the North and South Islands.

At the time that market-based competitive structures were introduced to New Zealand in 1996, full nodal pricing was seen as the best pricing method to achieve economic efficiency.

Outcomes

New Zealand's hydro-dominated market was put to the test in early 2001. With a record low rainfall, hydro generators suffered from a shortage of water for their electricity generation. As a result, electricity prices sky-rocketed along with customer complaints. In the aftermath, a large retail supplier, On Energy, exited the market.[40] This dry year event heightened the scrutiny of the existing market structure, and initiated a series of government reports. This process is ongoing, and may ultimately bring about changes to New Zealand's nodal pricing system.

In September 2001, after five years of operation, the institutional body charged with market oversight initiated a review of reform outcomes. The main focus of its review centered on nodal pricing, and whether it had achieved all that was hoped. The NZEM Rules Committee commissioned a report by Trowbridge Deloitte.

In the report, NZEM attributes the actual outcome of spot prices to three factors: market design, industry structure, and market size.

Final prices have not risen significantly since the implementation of reform.[41] The average spot prices have been below what would be considered economically efficient for the construction of new generating plant, and have been relatively stable.[42]

An overview of spot prices is provided by Figure 11; it illustrates the daily national price and load from the establishment of the NZEM in 1996 to 2001. The significant price spike in 2001 is tied to the unusually dry winter.

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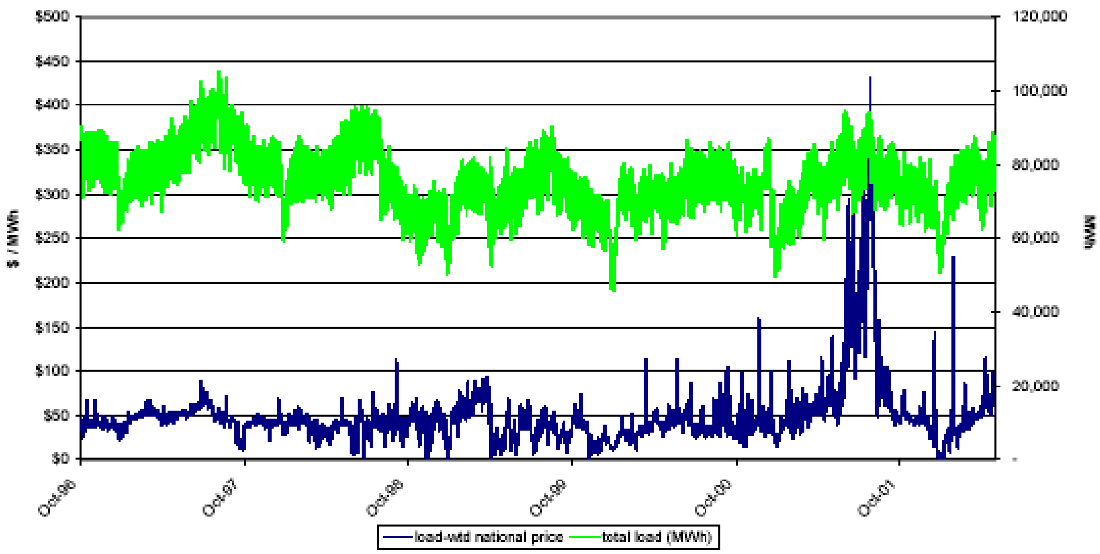
[40] The Commerce Commission ruled that the reason for On Energy's problems was its decision to not obtain sufficient hedging, and not an abuse of market power by its state-owned competitors. The National Business Review, (May 9, 2003), "How to keep the lights on energy crisis Part ll." Retrieved May 29, 2003, from LexisNexis.

[41] IEA, (2001), "Competition in Electricity Markets," p.51. Retrieved March 15, 2003, from http://www.iea.org/public/studies/compele.htm.

[42] ibid, p. 51.

Figure 11: Spot prices from 1996 to 2001



Source: NZEM, (2002), "Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM," p.8. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

Consumer Experience

With a supply system dominated by hydro, New Zealand's electricity prices are relatively low by international standards.

Since 1995, industrial electricity prices have experienced a rising trend, and domestic electricity prices have experienced an even larger rise in price. Commercial prices held steady in nominal terms and fell in real terms. Wholesale electricity prices fell between 1997 and 1998, and then again with the restructuring of ECNZ in 1999[43]. So while there have been increases and decreases in the wholesale price of electricity, there has not been a significant lowering of price for end consumers. In fact, the Ministry of Economic Development had this to say in their "Briefing to Incoming Ministers 2002":

[43] World Energy Council. (2001). "Electricity Market Design and Creation in Asia Pacific." New Zealand Chapter. Retrieved April 16, 2003, from http://www.worldenergy.org/wec-geis/publications/reports/emd/status/newzealand/default.asp.

“The industry still has a significant way to go to convince consumers that competition is effective, prices are fair, and customer service is satisfactory. In two network areas there is only one retailer and in 20 network areas (out of 43) there are only two retailers. Consumers have expressed concern that retailers do not always pass on reductions in line charges.”[44]

Distribution and supply companies have consistently improved profits over time for their shareholders, while electricity consumers have not seen a drop in electricity prices. This has led to a debate over equity and regulatory requirements.

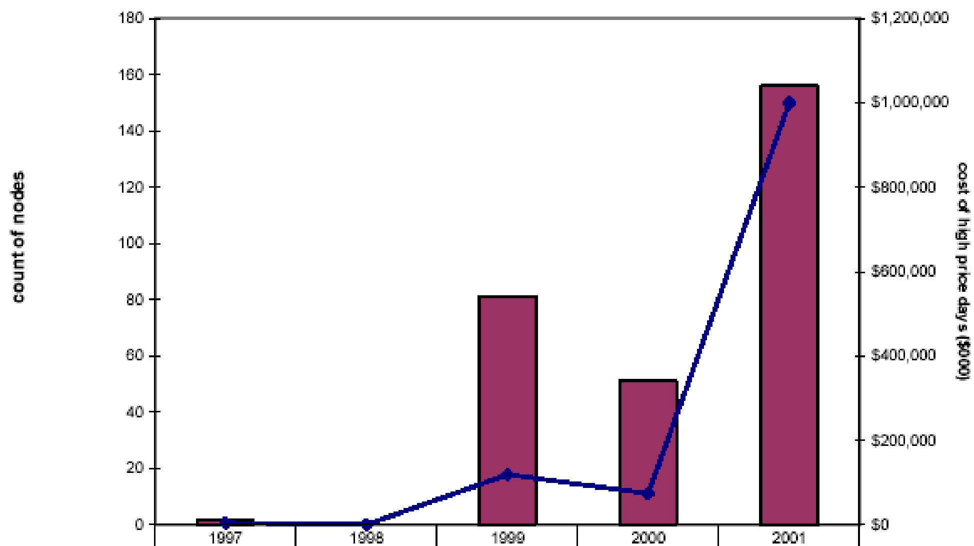
NZEM sought to determine if the FNP model had delivered competitive pricing at each node as expected, and did so with an investigation into the number of “high price days”[45] experienced at each node. The results are illustrated in Figure 12. The figure identifies not only an increase in high price days since 1999, but also identifies an increase in the number of days that account for a financially significant[46] price increase.

[44] Ministry of Economic Development, (2002), “Briefing to Incoming Ministers 2002.” Retrieved April 3, 2003, from http://www.med.govt.nz/about/bim2002/energy/.

[45] High price days are considered to be those where the” (load-weighted) daily price at a given node was greater than twice the (load-weighted) average annual price for that node.” NZEM, (2002), “Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM,” p.41. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

[46] Nodes experiencing a day where the “cost of energy purchased on high price days exceeded 10% of the total cost of energy purchases at the node over the relevant calendar years.” ibid, p.41.

Figure 12: High price events and high price days, 1997 to 2001



	1997	1998	1999	2000	2001
count of high price nodes	2	0	81	51	156
cost of high price days ($000)	$3,907	$0	$118,596	$74,355	$1,000,254

Source: NZEM, (2002), "Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM," p.42. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

While wholesale prices may ease for periods when surpluses occur (e.g. in wet periods and/or following substantial generation investment), electricity prices overall are likely to rise over the next few years. Higher electricity prices are particularly likely if gas prices rise significantly. This will reduce or reverse New Zealand's competitive energy price advantage, especially with Australia."[47]

Some analysts attribute the rise in wholesale prices to the lack of demand side response. Without meters, smaller businesses and residential customers have no way to make informed decisions about their electricity use. As of 2001, only 2% of customers had changed suppliers, despite reported savings of up to 20% on bills. [48] This indicates either

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[47] Ministry of Economic Development. (2002). "Briefing to Incoming Ministers 2002." Retrieved April 3, 2003, from http://www.med.govt.nz/about/bim2002/energy/.

[48] World Energy Council. (2001). "Electricity Market Design and Creation in Asia Pacific." New Zealand Chapter. Retrieved April 16, 2003, from http://www.worldenergy.org/wec-geis/publications/reports/emd/status/newzealand/default.asp.

that there are barriers to switching, or that the benefits are not deemed to be worth the effort.

Efforts are being made on the aggregate level, particularly during dry years, to encourage conservation. The Winter Power Taskforce is charged with motivating the public to sustain an energy savings of 10% in this dry year of 2003, and is doing so through as many media means as possible. The Target 10% campaign publishes daily savings results in newspapers, and social pressure is encouraged. A recent survey found that 91.7% of the population is taking steps to reduce their electricity consumption during this current dry year.[49] Despite this, it has been a struggle reach the target of 10% savings. Not surprisingly, over 70% of those surveyed were not happy with the Government's handling of the current power crisis. This demonstrates the effect of system reliability on consumer experience.

System Reliability

"New generation capacity needs to be built soon to ensure security of supply. Demand is increasing at around 2% per annum (about 800 GWh per annum), requiring over 150 MW of new generation capacity each year. Transpower has recently forecast that, by 2005, assuming high load growth, existing generation is likely to be insufficient to meet demand in a dry year…The Ministry has signaled diminishing electricity supply security for some years."[50]

New Zealand has faced challenges to its electricity supply system's reliability particularly in dry years. In 2001, and once again in 2003, New Zealand has been hit hard by record-setting years of low rainfall. This year's threatened winter power shortage is exacerbated by the dwindling reserves of the Maui gas field, the fuel source for thermal generating plant and New Zealand's main alternative to hydropower. As New Zealand looks

[49] Taylor, Kevin, (May 19, 2003), "Government expected to pay for standby power plants." New Zealand Herald. Retrieved May 29, 2003 from LexisNexis.

[50] Ministry of Economic Development. (2002). "Briefing to Incoming Ministers 2002." Retrieved April 3, 2003, from http://www.med.govt.nz/about/bim2002/energy/.

forward, any efforts to increase system reliability will have to factor in the depletion of Maui gas.

In a longer-term effort to improve system reliability in dry years, the government recently announced its plan to establish an Electricity Commission charged with the responsibility of ensuring the availability of dry-year reserve plant.

The Commission will contract with generators to ensure that plant is available for a 1 in 60 dry year, and release the plant only when a certain trigger price has been reached. The proposal is still new, so the trigger spot price has yet to be determined. Critics have pointed out that while reliability will certainly improve there are drawbacks to the government's plan. These drawbacks include situations in which the trigger price is reached, but there is not a drought; not addressing the more fundamental problem of a shortage of base-load plant; and an increase in consumer prices.

Another measure of system reliability includes customer satisfaction. The Electricity Complaints Commission was formed to provide customers with a vehicle to voice complaints. As of February, 2003, the Commission had logged 2500 phone calls, including 1000 inquiries, 1500 complaints, 110 completed investigations, and 145 cases open for investigation or conciliation.[51] Table 17 shows the percentage of complaints in each category.

[51] Electricity Complaints Commission. "Decisions and Statistics." Retrieved April 15, 2003, from http://www.electricitycomplaints.co.nz/decisions.htm.

Table 17: Customer complaint categories (as of February 26, 2003)

Issue	Percentage
Billing	76.2%
Customer service	3.6%
Disconnection	1.1%
General	1.6%
Land	0.5%
Lines	0.1%
Meter	4.7%
Privacy	0.2%
Provision	2.2%
Supply	2.9%
Switch	6.8%

Source: Electricity Complaints Commission. "Decisions and Statistics." Retrieved April 15, 2003, from http://www.electricitycomplaints.co.nz/decisions.htm.

System Investment

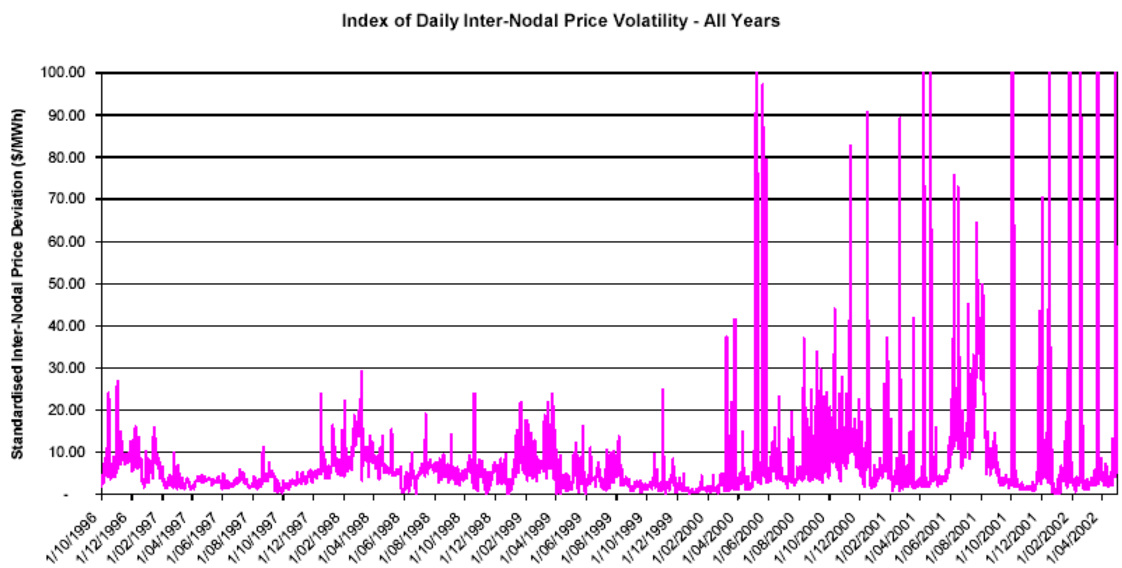
LMP price signals are designed to promote efficient investment. While there are instances of new investment that follow efficiency prescriptions—building generating plant closer to load—the pattern of investment since the opening of the market suggests that *efficient* investment may not meet all of the electricity needs of the nation.

With the opening of the wholesale market, the responsibility of investing in generation shifted from the government to generating companies. While the government-managed delivery of electricity supply had been accused of such inefficiencies as over-capitalization and under-investment, it had also attended to a number of social priorities, including security of supply. Companies on the other hand, build generating plant only when their investment will be rewarded with an adequate rate of return. This is a measure of efficiency that risks neglecting other objectives that are important for society, including security of supply.

At the outset of market reform, one of the goals was to develop efficient long-term investment signals that would improve the location and timing of investments in generation, transmission, and other infrastructure. NZEM's 2002 report evaluated the achievement of this goal by reviewing the variability of spot prices between nodes as well as changing patterns of demand between nodes.

Figure 13 illustrates increasing inter-nodal price volatility over time;[52] this is in apparent contradiction with what FNP hoped to deliver in terms of long-term investment. It could be that five years is not a sufficient enough time for investment to respond to price spikes. Regardless, the trends point toward increasing price separation between nodes.

Figure 13: Index of daily inter-nodal price volatility – all years



Source: NZEM, (2002), "Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM," p.17. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

52 The inter-nodal price variability statistic "measures the deviation of prices at each node from the national load-weighted average price for the day." NZEM, (2002), "Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM," p.15. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

NZEM's report made a number of conclusions about how FNP affects the overall goal of fostering efficient long-run operation:[53]

- Investment in new generating plant has been located closer to load; specifically, new plant has been built closer to Auckland since 1996
- There have been no major investments designed to relieve growing transmission constraints
- NZEM argues that FNP contributes to an illiquid contract market, resulting in significant barriers to entry for new generators

Investment in generation can be evaluated by reviewing the location of new investment, as well as the timing of new investment. Ideally, FNP promotes the siting of new generation plant close to load; this results in reduced transmission costs. NZEM found that the investments in generating capacity close to Auckland—Otahuhu, Soughdown, and Glenbrook—were influenced by the FNP pricing regime. Other investments, however, demonstrate that the incentives of FNP are not the only factors influencing investors; the construction of up to 570 MW of hydro generation capacity on the lower portion of the South Island points to the importance of fuel proximity and the relatively low cost of transmission in comparison to fossil-fuel transportation costs.[54]

FNP does not appear to have sent signals that encourage the timely investment in generating capacity; the pre-2001 electricity prices have been cited as discouraging to investors. This is in contrast with the forward projections of supply and demand that indicate an inability to mitigate the risk of dry year shortfalls.

There are four types of generating plant in New Zealand: base-load, mid-range, hydro-firming, and peaking. One of the investment shortcomings that have been identified in

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[53] NZEM, (2002), "Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM," p.vi. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

[54] NZEM, (2002), "Assessment of Outcomes Achieved by Full Nodal Pricing in NZEM," p. 21. Retrieved April 16, 2003, from http://www.ksg.harvard.edu/hepg/Papers/NZEM_nodal.pricing.assessment_12-18-02.pdf.

New Zealand is an uneven approach to the various generating plant types. With the advent of market competition, hydro-firming and peaking plant was either sold off or shut down. While these plants were considered to be "uneconomic" by market forces, their value lay in the ability to provide security of supply in dry years. Those plants would have gone a long way towards minimizing the impacts of the dry year of 2001 as well as the current dry year of 2003.

Investment in transmission has not been stimulated by FNP. Prior to market establishment, the Dispatch Review Working Group (DRWG) expected that any nodes experiencing price spikes due to transmission constraint would be responded to with transmission grid investment by a coalition of users, similar to what FERC suggests in the proposed rulemaking. This has not been the case, however, and it appears unlikely that the competitive market will address the issue.

A number of obstacles to private investment have been identified, including an inability to capture the benefits that other users enjoy in terms of avoided cost of transmission investment, or a free-rider problem, and the inherent lumpiness of a network investment, from a complex system of network effects as well as economies of scale.

Investment in transmission is critical, and will result in a number of benefits including a reduction of risk management costs by decreasing the need to protect against the volatility of prices at certain nodes, as well as a reduction in the instances of market power created by transmission constraints, which in turn create islands of local market power. As the system currently operates, transmission constraints are creating a fragmented market that dilutes the potential for competition.

Recent signals from the government have made the investment environment even more uncertain—Prime Minister Helen Clark has said she is considering significant, if unspecified, changes to the sector, and Energy Minister Pete Hodgson has threatened to revoke the generating companies framework of self-governance.[55] At the same time, after two years effort by the electricity industry to develop a self-governance proposal, members of the industry voted overwhelmingly against self-rule.[56]

The Energy Minister disputes the belief that there has not been enough planning and investment in generation as a whole. He points to the 500 MW of commissioned generation since 1999, and the plans for an additional 900 MW by 2006; he asserts that this is more than enough to offset the growth in demand of 150 MW per year due to growth in population and the economy.[57] The Minister also disputes the notion that investment has been thwarted by the Resource Management Act or the Kyoto protocol; any delays in the construction of generating plant have been due to uncertainties in gas supply, not any environmental standards.

The Energy Minister points to the lack of stand-by generation for dry years as the main problem with New Zealand's generation. In this view, there is not a shortage of generating plant, but of generating fuel, or water.

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[55] The National Business Review, (May 9, 2003), "How to keep the light on energy crisis part 2." Retrieved 2003, from LexisNexis.

[56] Taylor, Kevin, (May 19, 2003), "Government expected to pay for standby power plants," The New Zealand Herald. May 19, 2003. Retrieved 2003, from LexisNexis.

[57] The Dominion Post, (May 14, 2003), "." Retrieved 2003, from LexisNexis.

Australia

Source: CIA Factbook 2002

Introduction

Australia, like the United States, has a federal form of government. It is roughly the size of the United States excluding Alaska, with a majority of its population located on the Southern and Eastern seaboard in the states of Victoria and New South Wales. Sixty percent of the country's population lives within five of its cities: Sydney, Melbourne, Brisbane, Perth, and Adelaide. Population density in the central region of Australia remains low.[58]

The National Electricity Market (NEM) was established across the states in the east and southeast of Australia in 1998, and includes Victoria, New South Wales, Queensland, Australian Capital Territory (ACT) and South Australia. The market has been disaggregated into the separate activities of generation, transmission, distribution, and supply or retail. While Victoria privatized its assets and South Australia has put its assets under private management through long-term leases, New South Wales, Queensland, and ACT continue to be dominated by public ownership.

In addition to the NEM, there are three independent power systems, one each in Western Australia, Northern Territory, and Tasmania. Western Australia is supplied primarily by Western Power, the state-owned corporation, which operates 5 ring-fenced networks that include generation, transmission, distribution and sales. Additional systems within Western Australia include the Pilbara interconnect and several isolated regional systems. The Northern Territory has a small and geographically dispersed electricity load. There has been little grid development, and electricity is supplied primarily by a state-owned corporation known as the Power and Water Authority. The predominately hydro-based Tasmania had, until 1998, been served by a single vertically integrated state-owned company. The Tasmanian industry was restructured in 1998 into three separate businesses: generation, transmission, and distribution and supply.

[58] IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.17. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

Australia boasts an abundance of high grade coal reserves. Hydropower provides roughly 9%[59] of Australia's electricity, and is dominant in the state of Tasmania.

Historical Context of Restructuring

Prior to restructuring of the electricity supply industry, Australia was characterized by vertically integrated state-owned supply, excess generating capacity, limited interstate trade, and a perception of limited labor productivity.

In the early part of the twentieth century, Australia's power industry was owned by a large number of private power companies. Beginning in the 1930's, however, state-ownership increased to the point that by the 1950's nearly all private power companies had been eliminated. For the next forty years, electricity production would be dominated by public ownership.

In the 1980's, electricity prices began to increase in real terms, which was attributed to over-investment in generation capacity and poor plant performance. Growing concerns regarding industry inefficiencies led to a series of state-level public inquiries as well as an inquiry by a Commonwealth government organization, the Industry Assistance Commission (IAC), in 1989.

The Industry Assistance Commission found that over A$1 billion dollars could be saved if the best international practices were adopted by the Australian power industry. The IAC criticized the lack of coordination between states in the Southeast, recommended the development of a national grid, augmentation of transmission lines between states, increased participation in the industry by private companies, and open and non-discriminatory access to all participants.

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[59] World Energy Council, (2001), "Electricity Market Design and Creation in Asia Pacific," Australia chapter. Retrieved March 19, 2003, from http://www.worldenergy.org/wec-geis/publications/reports/emd/status/australia/default.asp.

In 1990, the IAC was reformed into the Industry Commission (IC), a federal economic research agency, which launched a year-long inquiry into electricity and gas industries. It produced a report titled “Energy Generation and Distribution” in 1991 that recommended the restructuring of the energy supply industry. Specifically, the report recommended separating the ownership of generation, transmission, and distribution assets, gradually selling off of state-owned generation and distribution assets, corporatizing the public utilities, and opening transmission and distribution networks to access by third parties.

Concurrent to the IC “Energy Generation and Distribution” report, the Prime Minister of Australia formed a body to review the entire range of federal/state relationships in an attempt to increase efficiency. Known as the Council of Australian Governments (COAG), this body identified the reform of the electricity industry as a priority at its first meeting.

In 1991 COAG created the National Grid Management Council (NGMC), which in turn established a code of conduct for all market participants to follow. The code, known as the National Electricity Code, was adopted in 1996 by the state’s participating in the NEM. At that time, the two bodies charged with implementing the code were established: the National Electricity Market Management Company (NEMMCO) and the National Electricity Code Administrator (NECA).

The state’s have an important role in overseeing the NEM, by virtue of their ownership of NEMMCO and NECA. The federal government has sought to encourage the states by providing financial incentives to the state governments to promote participation in market reform. The federal government established payments to the states through 2006 that are to total A$4.2 billion that are conditional upon the implementation of energy sector reforms.

Historically, there was little incentive to interconnect Australia's states and its disparate population centers with high-cost transmission lines—each of the states had an abundance of local energy sources ranging from brown coal to hydropower. Overtime, the nature and resource mix of each of the states resulted in divergent electricity costs.

In 1997 the Victoria Pool, established in 1994, and the New South Wales Pool, established in 1996, merged to create the National Electricity Market (NEM) of Australia. Today the NEM includes Victoria, New South Wales, Queensland, ACT and South Australia.

Physical Systems

Generation

Electricity generation neared 186 TWh in 1999, with roughly one-third of generation occurring in New South Wales and the ACT. The amount of generation and trade in electricity by state is shown in Table 18 below.

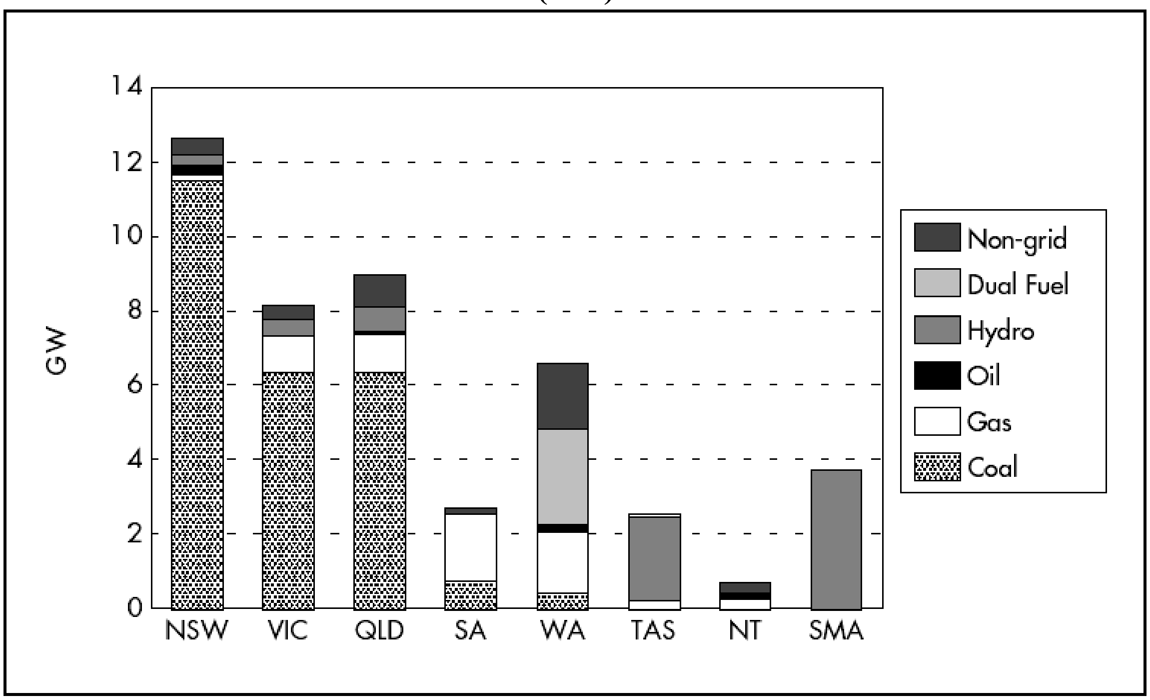
Table 18: Electricity generation and trade, 1998/99

	NSW & ACT	Victoria	Queensland	South Australia	Western Australia	Tasmania	Northern Territories	SMA**
Total generation (GWh)	60,058	49,442	40,230	8,304	12,152	9,879	1,612	4,573
Net imports (GWh)	5,634	-4,558	-345	3,686	0	0	0	-4,573

*New South Wales and Australia Capitol Territory
**Snowy Mountains Hydroelectric scheme
Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.121. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

Coal is the dominant fuel for electricity generation in Australia. Hydro resources account for roughly 9 percent of the total electricity generation share in 1999, which is down from 10 percent in 1990. Fuel mix varies widely by state, as shown in Figure 14 below. Coal dominates in New South Wales, Victoria, and Queensland; Gas-fired generation has a greater influence in Western Australia, the Northern Territory, and Southern Australia; and hydro resources dominate in Tasmania.

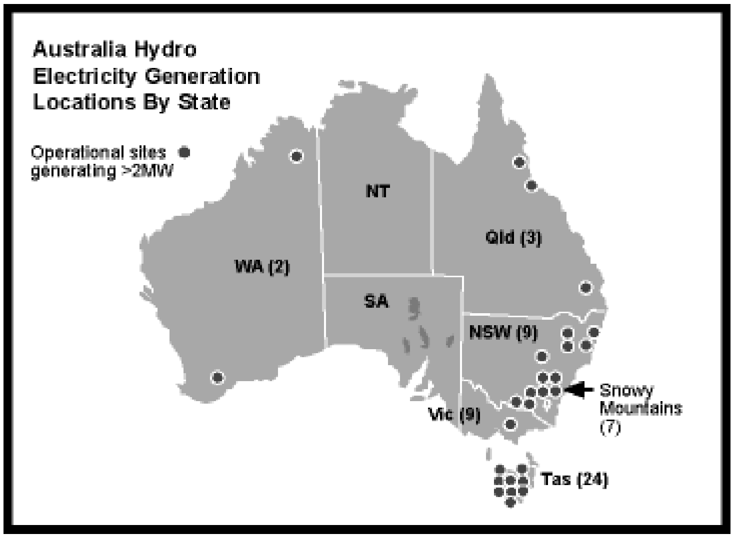
Figure 14: Installed capacity by state and by fuel type, 1999 (GW)



Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.122. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

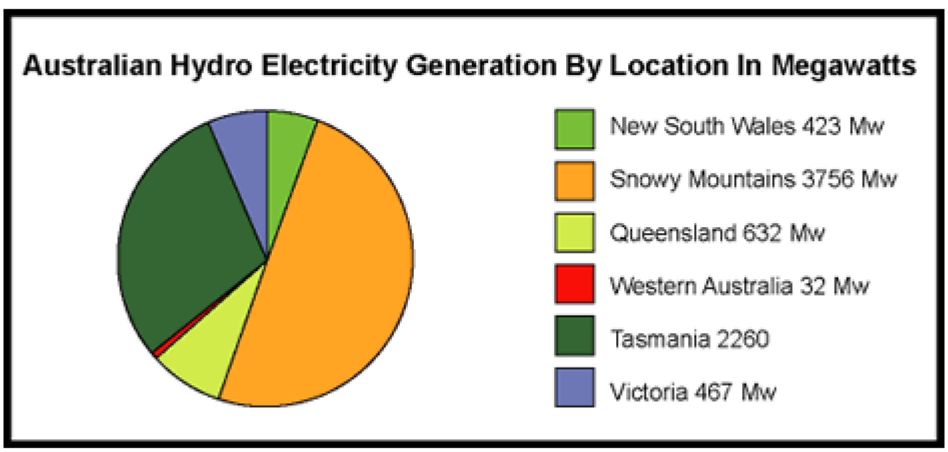
The majority of Australia's hydropower is generated on its East coast, where river systems run into the sea. Tasmania and New South Wales (with the Snowy River Hydroelectricity Scheme) are the main producers of hydroelectricity. Figure 15 illustrates the number of hydro projects per state, Figure 16 shows the relative hydro-based production by state, and Figure 17 shows the nationwide energy production by fuel.

Figure 15: Australia's hydro electricity generation locations by state



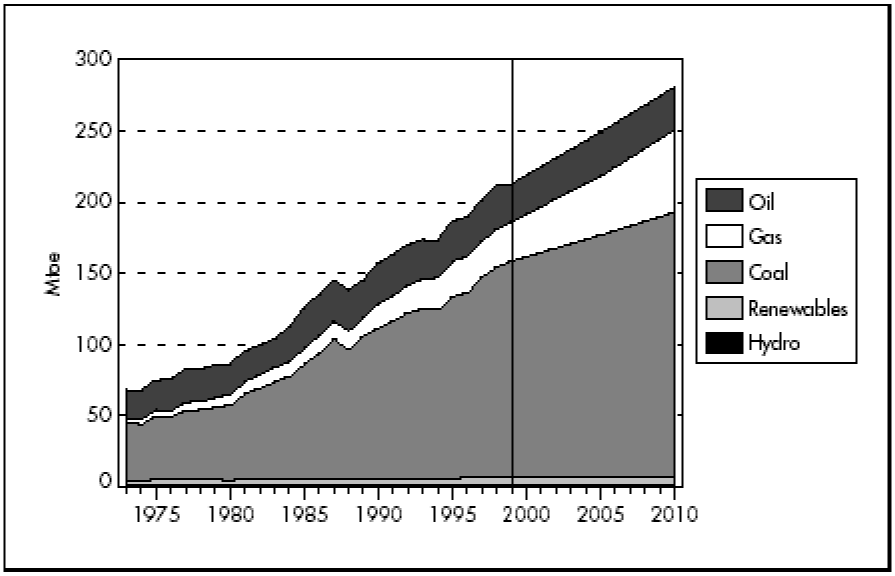
Source: ActewAGL, "Hydro Electric." Retrieved May 19, 2003, from http://www.actewagl.com.au/education/electricity/generation/hydroelectric.cfm.

Figure 16: Relative hydro electricity generation by state



Source: ActewAGL, "Hydro Electric." Retrieved May 19, 2003, from http://www.actewagl.com.au/education/electricity/generation/hydroelectric.cfm.

Figure 17: Energy production by fuel, 1973-2010



Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.122. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

The Snowy Mountains Scheme

The Snowy Mountains Scheme is located in Australia's Southern Alps, and includes an integrated system of sixteen dams, seven power stations, a large pump station, 80 kilometers of aqueduct and 145 kilometers of interconnected tunnels.[60] The Scheme serves a dual purpose of supplying power and providing for irrigation.

The Scheme diverts waters from the heads of the Snowy, Eucumbene, and Murrambidgee Rivers. Lake Eucumbene provides the Scheme's main storage, and is connected to two separate interconnected diversions, the Snowy-Murray and the Snowy-Tumut. At Murray 1 and 2 power stations, water is pumped up from Lake Jimbadyne for generation; water is also pumped back uphill at Tumut 3 power station after it has been used to generate electricity.

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[60] Snowy Mountains Scheme, "Snowy Vision." Retrieved March 28, 2003, from http://www.snowyhydro.com.au/recreation/powerofwater/vision.cfm.

The Snowy Mountains Scheme has a generating capacity of 3,756 MW. Over a twelve month period, the Scheme produces 5,000 GW, or roughly 3% of the National Electricity Market's total energy.[61]

Hydro Tasmania

Hydro Tasmania administers operations in seven catchments. Although not currently a member of the NEM, an undersea interconnect is being built between Tasmania and Victoria.

Transmission

Australia's transmission grid reflects the distribution of population along the coast and in the southeast. With great distances between population centers, the evolution of the grid has developed into a series of weakly connected and independent areas (see map in appendix). With a generating capacity of approximately 31,400 MW, the map reflects the relatively small amount of interconnection capacity. In fact, electricity exchanges between NEM regions amounted to only 7% of all the total amount of energy generated in 1998/99, as reflected in Table 19. In contrast, the international Nordic power exchange transacted 14% of the energy generated in 1998.

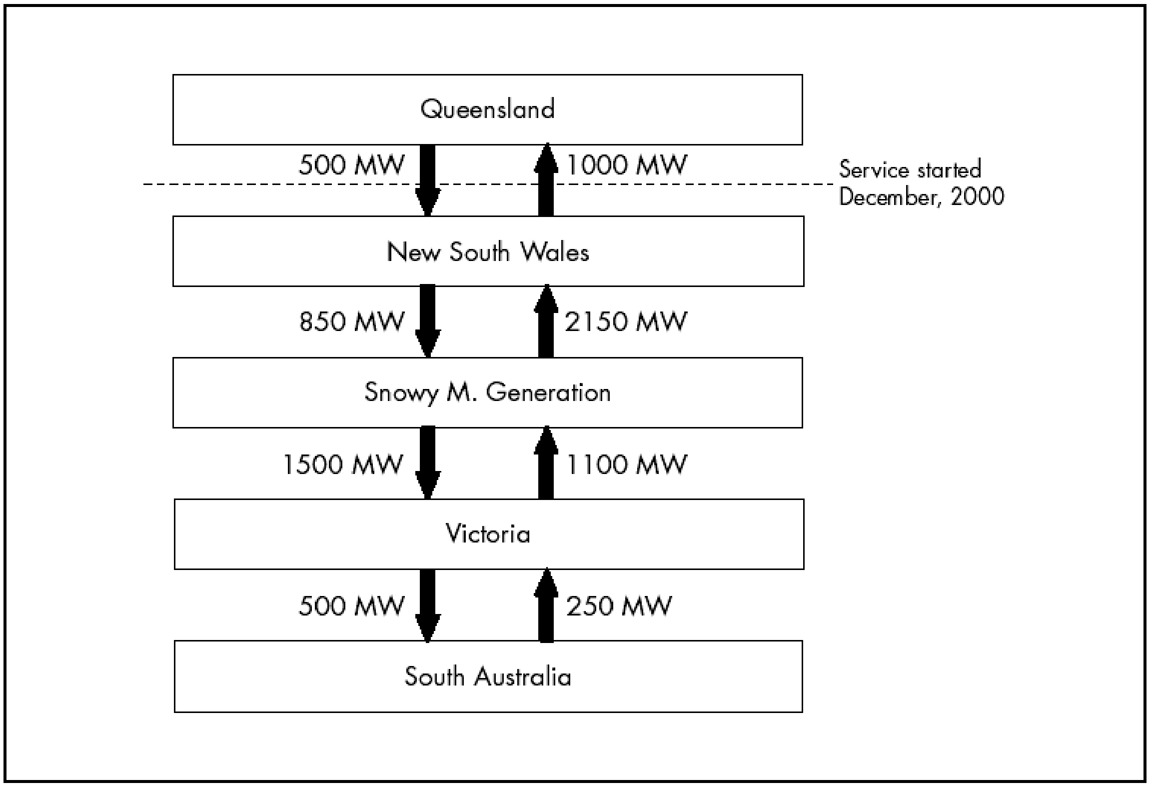
Table 19: Trade across interconnectors, 1998/1999

Interconnect	GWh	Percent of total NEM generation
Snowy—New South Wales	2,754	3
Victoria—South Australia	2,044	2
Victoria—Snowy	1,800	2

Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.125. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

[61] Snowy Mountains Scheme, "Energy." Retrieved March 28, 2003, from http://www.snowyhydro.com.au/recreation/powerofwater/energy.cfm.

Figure 18: Interregional links between Australian National Electricity Market regions, 2000



Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.127. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

Australia's legacy transmission network was built based on regional markets, and did not include interconnections between regions. With the establishment of the NEM, the development of adequate interconnects will enable a common market, as opposed to five separate markets. When presented with proposed interstate links, the ACCC places a priority on those that are unregulated as opposed to those that are regulated. Two unregulated or merchant links have been built since inception of the NEM: DirectLink and MurrayLink.

Retail

Establishing retail choice for consumers has been a gradual process that began in 1994 with large consumers, and is yet to be realized by consumers of all sizes. See Table 20 for the time table of retail market opening.

Table 20: Timetable for market opening

	Date for eligibility	*Site thresholds ≥*
New South Wales	1-Oct-96	40 GWh
	1-Apr-97	4 GWh
	1-Jul-97	750 MWh
	1-Jul-98	160 MWh
	1-Jan-2001	100 MWh
	1-Jul-2001	40 MWh
	1-Jan-2002	All sites
Victoria	30-Nov-94	5 MW
	1-Jul-95	1 MW
	1-Jul-96	750 MWh
	1-Jul-98	160 MWh
	1-Jan-2001	40 MWh
	1-Jan-2002	All sites
Queensland	29-Mar-98	40 GWh
	1-Jan-99	4 GWh
	1-Jan-2000	200 MWh
	1-Jan-2002 (or later)	All sites
Australian Capital	1-Oct-97	20 GWh
	1-Mar-98	4 GWh
	1-May-98	750 MWh
	1-Jul-98	160 MWh
	?	All sites
South Australia	20-Dec-98	4 GWh
	1-Jul-99	750 MWh
	01-Jan-2000	160 MWh
	01-Jan-2003	All sites
Western Australia	1-Jul-97	10 MW
	1-Jul-98	5 MW
	1-Jan-00	1 MW
Nothern Territory	20-Apr-00	4 GWh
	1-Oct-00	3 GWh
	1-Apr-01	2 GWh
	1-Apr-02	750 MWh

Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.141. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

While regulated tariffs are maintained for the smallest of consumers in all states, there are no tariffs for large consumers. The difference between the two is identified as "mandated contestability," and has gradually been lowered over time.

Metering would allow for the possibility of demand side management of electricity. The NEM states are still discussing the role of metering and profiling within the retail market. Proposals have been made that include making the installation of meters a precondition to changing retailers. There is a concern, however, that the high cost of implementing metering may act as a barrier to competition.

Institutional Systems

Australia, like the United States, is a federal country. The central Commonwealth government has limited constitutional powers over matters related to the energy economy; the six self-governing states and two territories shoulder the main responsibilities of the energy supply industry.

The Commonwealth is responsible for the taxation of companies and income, interstate and foreign trade, oversight of foreign investment and compliance with international treaties. The state and territory governments are responsible for energy generation, land use, transport, and environmental assessment.[62] With the exception of the Snowy Mountain Hydroelectric Scheme, the central government is not directly involved in electricity supply.

Regulation

The regulatory functions are performed by both the federal government and the state governments. This process of coordination is often viewed as complex. Areas of overlap include the ACCC and the state regulators, and the ACCC and NECA. ACCC makes the open exchange of information a priority with the state regulators, in an attempt to

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[62] IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.17. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

minimize jurisdictional questions. Attempts are made to actively bridge the information gap between the various agencies. This framework is similar to other federal countries including the United States and Canada. The federal government focuses on the regulation of transmission and wholesale markets, and state regulators focus on distribution and retail.

National Electricity Code Administrator (NECA)

NECA is the rule-making body. Like NEMMCO, NECA is a corporation that is owned by all of the state governments participating in the NEM. In 1996, the National Grid Management Council developed a code of conduct, known as the National Electricity Code (NEC), to which all power market participants must adhere. When NSW, Victoria, South Australia, Queensland and the ACT adopted the NEC in 1996, two bodies were created to implement the code: NEMMCO and NECA. NECA includes a reliability panel that establishes and monitors system security and reliability standards. NECA monitors compliance with the National Electricity Code.

National Electricity Market Management Company (NEMMCO)

NEMMCO is the independent systems operator, or ISO. NEMMCO is a corporation that is owned by the state governments participating in the NEM: Victoria, New South Wales, Australian Capital Territory, and South Australia. NEMMCO coordinates system planning between the states, maintains system security, and operates the National Electricity Market (NEM). As the NEM operator, NEMMCO administers the spot market, pricing, metering, and settlements. It also registers market participants.

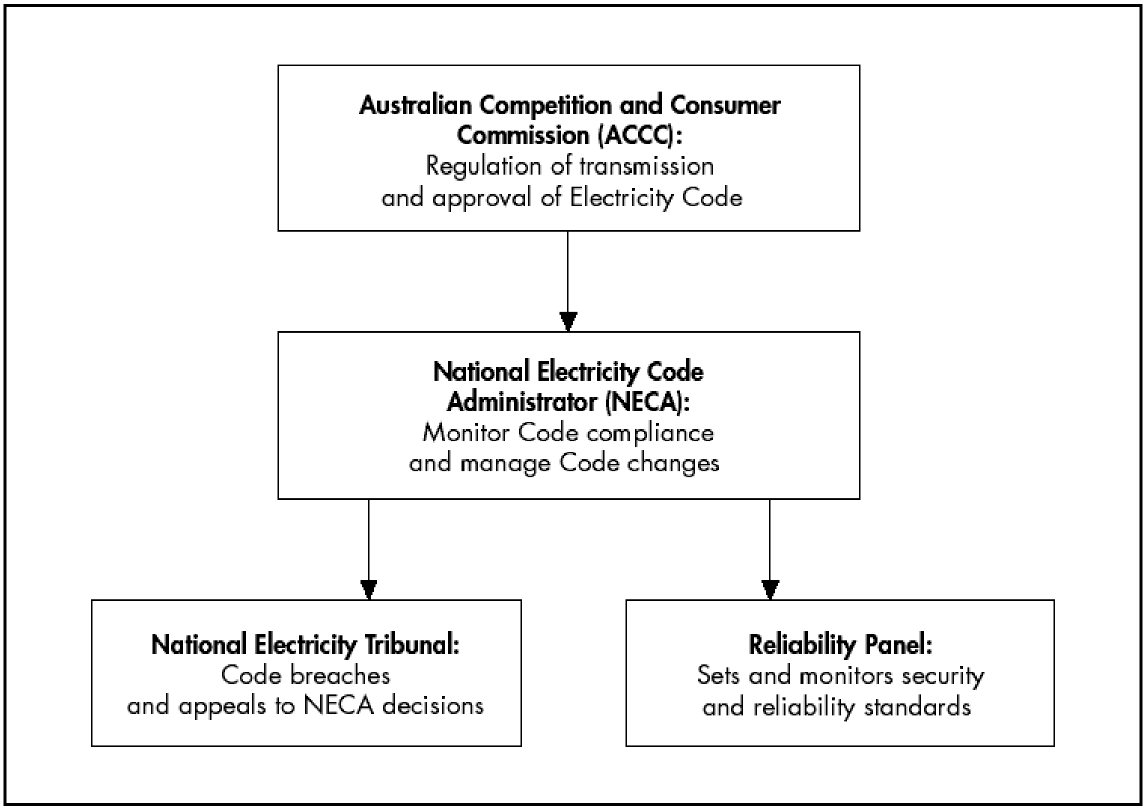
Australian Competition and Consumer Commission (ACCC)

In 1995, Australia formed an independent regulator with the merger of the Trade Practices Commission and the Prices Surveillance Authority. This new regulator, known as the Australian Competition and Consumer Commission, or ACCC, is different from other similar national agencies in that it oversees regulation *and* competition, and that it is responsible for a variety of industries. Other OECD countries[63] typically have regulatory agencies that are responsible for a specific sector. It enforces the Trade Practices Act, which deals unfair practices and anti-competitive market behavior for all sectors including electricity.

The ACC's electricity sector responsibilities include the regulation of the transmission network, the organization of the market through the National Electricity Code, and promotion and defense of market competition. See Figure 19 below for a flow chart of the agencies and brief descriptions of their responsibilities.

[63] The Organization for Economic Cooperation and Development (OECD) is a group of 30 member countries that have market economics and pluralistic democracies; OECD countries were historically Western European and North American, but with the addition of Japan, Australia, New Zealand, and others, have begun to expand their geographic membership. Members include those among the most developed of nations.

Figure 19: National bodies involved in the regulation of the electricity market



Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.132. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

State Regulators

Like the United States and its federal system of government, Australia's Commonwealth government coordinates with state regulators to manage the electricity supply industry. The state regulators primarily address distribution and retail supply. Distribution regulation involves setting price controls, establishing service standards, monitoring for compliance, and approval of tariffs. Retail regulation involves approving tariffs for customers that don't have a choice of retail suppliers, standard setting and monitoring for compliance. Other responsibilities include issuing licenses for electricity companies operating within the state, and introducing competition markets for additional electricity supply services such as metering.

Snowy Mountains Authority

The Snowy Mountains Authority was established in 1949 with the task of investigating, designing, and building the Scheme. The Scheme supplies electricity to Victoria, New South Wales, and ACT, and is managed by the central government. This is similar to the Bonneville Power Administration, a federal agency that markets wholesale power and markets and operates transmission services in the Pacific Northwest.

Commercial Systems

The organization of the National Electricity Market's wholesale market is similar to the original mandatory electricity pool of England and Wales. Where the models differ from each other is that NEM calculates prices ex post, there are no capacity payments, and bids are firm.[64]

Ownership

With market share of the two largest generation companies below 40 percent, overall market share is low in Australia's NEM. Transmission constraints, however, often separate the NEM into five separate markets, and market share of the two largest generating companies in all states except Victoria is above 50 percent. See Table 21 below.

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[64] IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.135. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

Table 21: Generation market structure and ownership in NEM jurisdictions and Tasmania

Jurisdiction	Owner	Nature of Ownership	Capacity (MW)	Share of total Capacity (%)	Cumulative Total (%)
NSW	Macquarie Generation	Public	4690	37.1	37.1
	Delta Electricity	Public	4240	33.5	70.6
	Eraring Energy	Public	3132	24.8	95.4
	Sithe Energies	Private	162	1.3	96.7
	National Power (US)	Private	150	1.2	97.9
	Other Embedded Generation	Mix	270	2.1	100.0
Victoria	Loy Yang Power	Private	2000	23.6	23.6
	Hazelwood Power	Private	1600	23.6	23.6
	Yallourn Energy	Private	1450	17.1	59.5
	Mission Energy	Private	1300	15.3	74.8
	AES Transpower	Private	966	11.4	86.1
	Southern Hydro	Private	473	5.6	91.7
	Energy Brix	Private	170	2.0	93.7
	AGL	Private	150	1.8	95.5
	Alcoa	Private	150	1.8	95.5
	Duke Energy	Private	80	0.9	98.2
	Other Embedded Generation	Private	153	1.8	100.0
Queensland	CS Energy	Public	2974	27.3	27.3
	Enertrade	Public	2657	24.4	51.6
	Tarong Energy	Public	1915	17.6	69.2
	Stanwell Corporation	Public	1622	14.9	84.0
	Intergen	Private	852	7.8	91.9
	Callide Power Trade	Private	420	3.9	95.7
	Orgin Energy	Private	108	1.0	96.7
	Other Embedded Energy	Private	360	3.3	100.0
South Australia	TXU Torrens Island	Private	1280	36.6	36.6
	Australian National Power	Private	877	25.1	61.7
	NRG Flinders	Private	700	20.0	81.8
	Origin Energy (& CU Power)	Private	260	7.4	98.2
	AGL	Private	220	6.3	95.5
	Other Embedded Generation	Private	158	4.5	100.0
Snowy Region	Snowy Hydro	Public	3756	100.0	100.0
Tasmania	Hydro Tasmania	Public	2509	99.0	99.0
	Amcor Paper	Private	16	0.6	99.6
	BHP	Private	10	0.4	100.0

Source: COAG, (2002), "Towards a Truly National and Efficient Energy Market," p.55. Retrieved April 3, 2003, from http://www.energymarketreview.org/FinalReport20December2002.pdf.

In two states, Queensland and New South Wales, the government is the largest owner of generation capacity; this concentration of ownership raises the possibility of market power within the NEM.

Concentration of ownership is not the only condition that facilitates market power; competition in the NEM relies on the existence of free-flowing trade between regions, and weak regional interconnects can thwart such trade. A recent study by ABARE Consulting finds that there is a significant potential for generators to exercise market power within NEM.[65]

Victoria pursued an aggressive sell-off of state assets. New South Wales, in contrast, has not followed the same course as Victoria, and is not likely to—active unions in NSW are adamantly opposed to the privatization of state electricity assets.[66]

Pricing

Australia adopted a zonal pricing system, in which the prices are set to equal the supply and demand in each of a number of established zones. Separate markets are operated in each region to account for system congestion.

Table 22: Australian Wholesale Market

Pool Participation	Pool Capacity Payments*	Pool Pricing**
Mandatory	No	Ex post

*Payments made to generators in order to guarantee their availability to generate electricity in case of need.
**Ex post: pool purchasing price determined from actual demand and supply
Source: IEA, (2001), “Competition in Electricity Markets,” p.31. Retrieved March 15, 2003, from http://www.iea.org/public/studies/compele.htm.

[65] COAG, (2002), “Towards a Truly National and Efficient Energy Market,” p.109. Retrieved April 3, 2003, from http://www.energymarketreview.org/FinalReport20December2002.pdf.

[66] The Australian, (April 26, 2003). Retrieved 2003, from http://theaustralian.news.com.au/common/story_page/0,5744,6337743%255E643,00.html

Transmission Pricing

Transmission assets in Australia can either be regulated and subject to revenue caps, or unregulated and earn market rates. Currently, a majority of Australia's transmission assets are regulated.

The price cap applied to regulated assets is fixed for at least five years, with the maximum annual revenue limited to a CPI-X cap. End-users bear all transmission charges with a two-part tariff including fixed costs and variable costs based on actual network use.

Transmission companies may receive revenues from inter-regional congestion. When congestion creates a constraint between two regions, the price is higher in the importing region. The excess revenues in the importing region are used to balance financial contracts and to reduce transmission charges for customers.

The states vary in their approach to averaging total costs across all consumer groups, regardless of their location. Victoria employs a locational pricing model with a price cap, South Australia averages all costs, and New South Wales and Queensland employ an even split between postage stamp charges and cost-reflective charges.

Power Exchange

The National Electricity Market operates a mandatory gross pool. Bids consist of simple price-quantity pairs, and ten pairs can be submitted per day. In addition, two "revenue bids" are allowed to establish a minimum payment if the generator runs below a certain level. The bids are used to create a merit order of generation as well as to create a demand schedule; it is from the merit order that generation is schedule, and spot prices are in turn calculated ex post for each five-minute interval. Generators are paid this ex post spot price; there are no capacity payments or mechanisms. A bid cap is set at A$5,000 per MWh.

There is disagreement between market participants as to the efficacy of the gross pool arrangement. Large consumers point to price spikes and price volatility as a symptom of a deficient mechanism, and maintain that the market mechanism has facilitated the transfer of income from consumers to generators. In contrast, generators, retailers, and a number of jurisdictions maintain that the current mechanism is functioning appropriately.

Risk Management

In tandem with the development of the NEM, a series of financial contracts have developed including two futures contracts traded on the Sydney Futures Exchange and contracts for differences traded bilaterally between participants. These contracts are an important component of the market as they provide participants with the opportunity to manage their risk exposure.

In addition to financial contracts, there are two non-market jurisdictional arrangements that were originally designed to minimize risk during the transition from the old supply system to the new supply system: the Electricity Tariff Equalization Fund (ETEF) of New South Wales; and the Benchmark Pricing Agreement (BPA) of Queensland.

The NSW Government formed the ETEF to manage risk for retail suppliers serving retail consumers who take electricity with regulated tariffs; the ETEF is solely designed for government-owned generators and government-owned retailers. The Queensland BPA has similar objectives to ETEF in risk management, but is implemented in a different manner. BPA seeks to manage risks for retailers providing consumers with a fixed rate, while they themselves are facing variable electricity costs.

Table 23: Electricity sector structure of Australia

Degree of Horizontal Integration			Vertical Integration
Generation	**Transmission**	**Distribution**	
mixed*↓	high	mixed*↓	mixed*↓

*"Mixed" means that different utilities have wildly variable degrees of integration

Source: IEA, (1999), "Electricity Market Reform: An IEA Handbook," p.27. Retrieved March 15, 2003, from http://www.iea.org/pubs/studies/files/elemar/elemar.htm.

Outcomes

In 1998, the year following the establishment of the National Electricity Market, prices experienced a 1% decrease. The wholesale market experienced an even larger price drop. Prices remained low on average in 1998 and 1999, which may be attributed to the onset of competition as well as the large reserve margins of generating capacity in the Australian market[67].

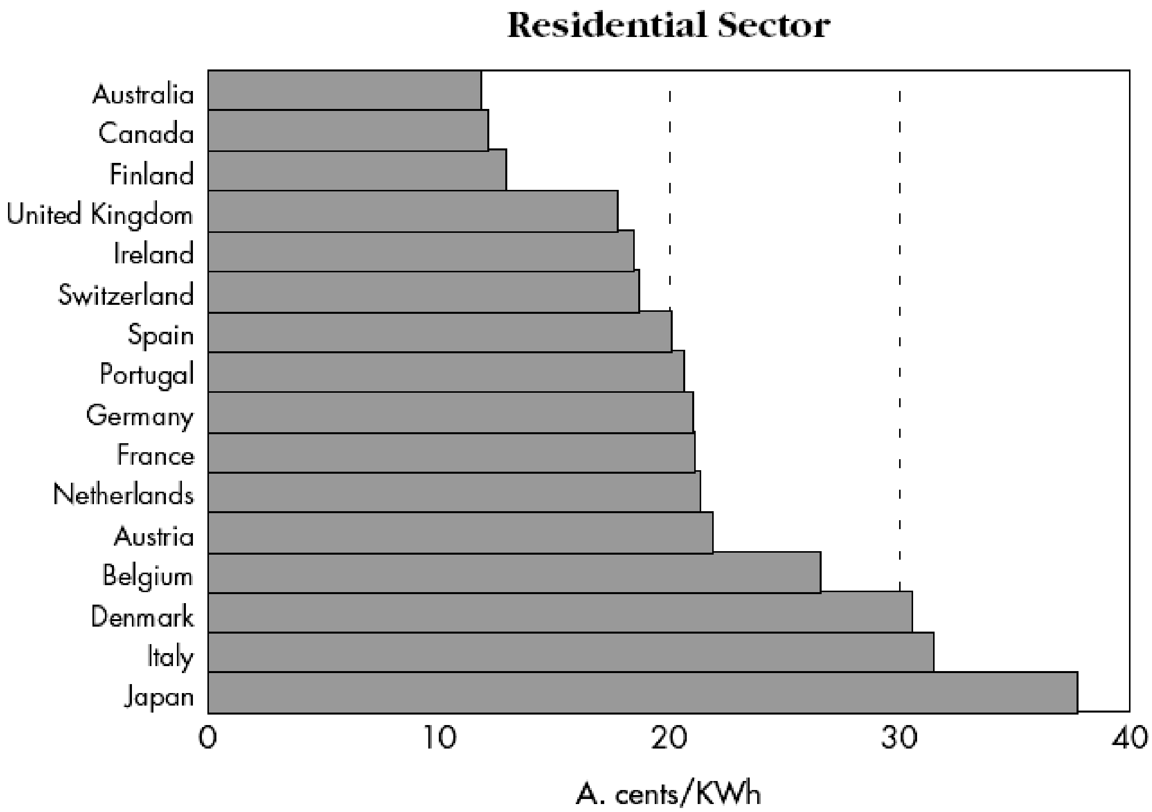
Consumer Price

Australia's electricity prices in general are low by international standards as illustrated in Figure 20 below. This is attributed to the low cost of fuel for electricity generation. The U.S. is in the neighborhood of Australia, Canada and Finland, with electricity prices at roughly 11.1 cents A$.

[67] IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.51. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

Figure 20: Select international electricity prices, January 2000

(In Australian cents per KWh)

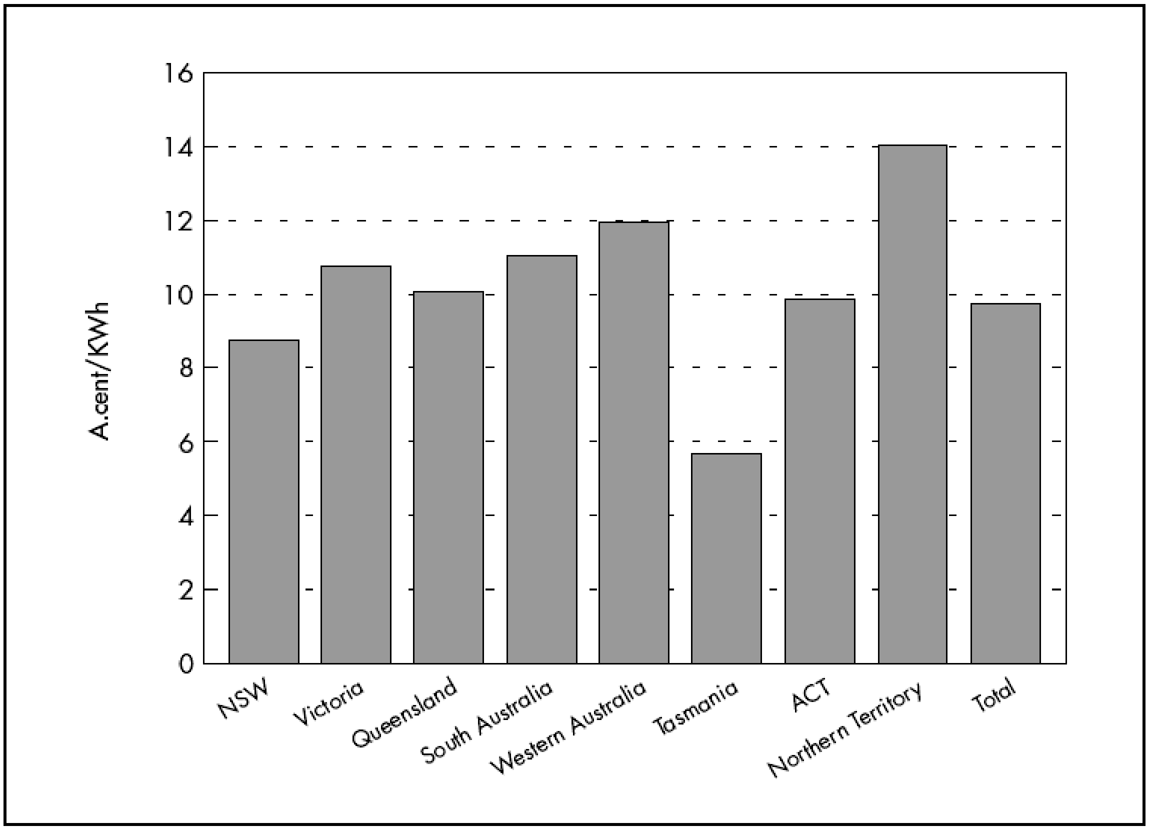


Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.129. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

While overall prices are low by international standards, there is wide price variation between the states as a result of transmission constraints, differences in fuel mix, and differences in competitive conditions. The retail prices by state are compared in Figure 21 below.

Figure 21: Average retail prices by state, 2000/2001

(estimated prices in Australian cents per kWh)



Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.130. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

On the measure of consumer price, market restructuring has produced an initial success, with electricity prices falling for industrial, commercial, and residential customers.

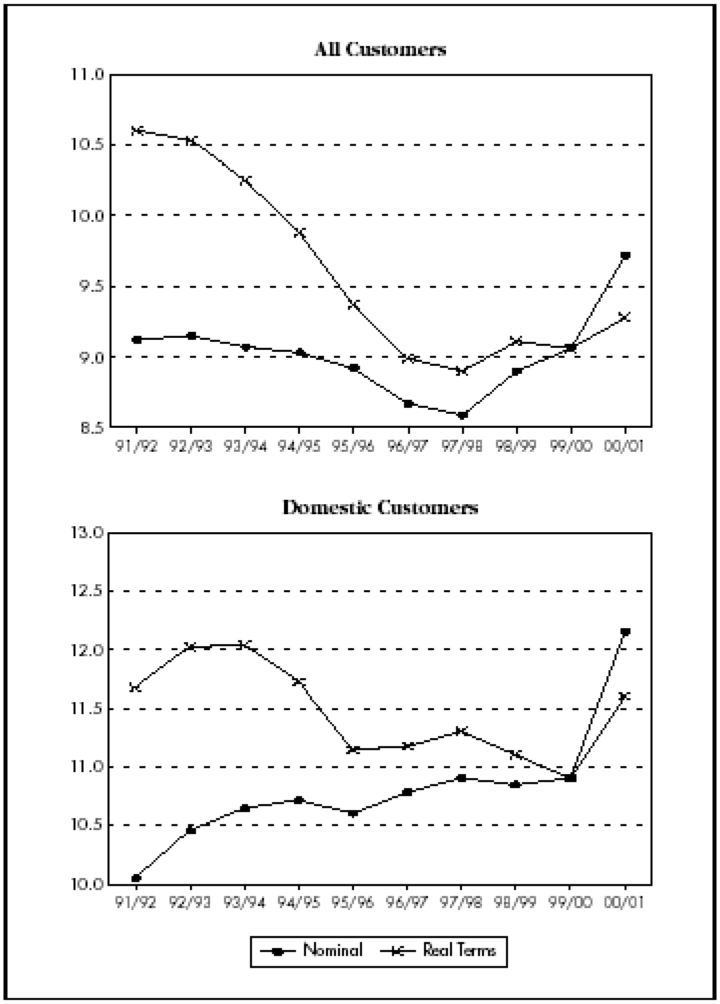
Table 24: Average real prices

	Residential Prices	**Business Prices**
1993	13.12 c/kWh	10.55 c/kWh
2002	12.53 c/kWh	9.19 c/kWh
% Change	-4.5%	-12.9%

Source: The Australian, (April 26, 2003). Retrieved 2003, from http://theaustralian.news.com.au/common/story_page/0,5744,6337743%255E643,00.html

The changes in price have affected business and residential consumers differently. From 1991/1992 to 2000/2001, residential prices have increased in nominal terms, and remained about the same in real terms. In contrast, business prices have decreased in nominal and real terms over the same time period. Figure 22 illustrates the average prices of all customers and domestic customers.

Figure 22: Average electricity prices, 1991 to 2000
(in Australian cents per KWh)



Note: 1999/2000 and 2000/2001 are based on projections
Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.142. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

In addition to variable prices for electricity by state, there have been variable changes to the real price of electricity by state, as shown in Table 25 below.

Table 25: Real price changes by state (percent)

	Residential		Business		Total	
	97/98	**98/99**	**97/98**	**98/99**	**97/98**	**98/99**
New South Wales	2.10	-4.80	-3.00	4.30	-1.40	2.60
Victoria	0.20	-2.50	-5.30	5.10	-2.70	4.60
Queensland	-0.70	-1.10	2.00	-3.50	0.40	0.50
South Australia	7.60	0.70	-3.80	2.20	0.80	1.10
Western Australia	-3.50	-0.90	1.70	-3.50	0.00	-2.40
Tasmania	1.70	9.40	0.60	-2.70	1.20	-0.50
ACT	-0.95	0.10	-16.05	-2.10	-10.28	-1.10
Northern Territory	0.00	4.60	-6.50	1.50	-5.00	2.40
Australian average	**1.10**	**-1.80**	**-6.50**	**2.50**	**-4.10**	**2.30**

Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.143. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

System Reliability

In its 2001 review of Australia, the IEA identified the weak interconnections as an impediment to robust competition and reliability. They point to the significant price difference between the NEM regions as an indicator of interconnect weakness. The experience between the states in terms of reserve capacity and transmission outages is also quite varied, as illustrated in Tables 26 and 27.

Table 26: Generation capacity and reserves, 1998/99

	NSW & ACT	Victoria	Queensland	South Australia	Western Australia	Tasmania	Northern Territories	SMA*
System peak load (MW)	11,424	7,480	5,994	2,500	2,331	1,566	218	--
Installed capacity (MW)	12,641	8,135	8,957	2,726	5,043	2,534	686	3,756
Reserve Margin	23%	18%	23%	3%	38%	60%	22%	--

*Includes capacity of Snowy Mountains Hydroelectric for both New South Wales and Victoria; excludes pumped storage.

Source: IEA, (2001), "Energy Policies of IEA Countries: Australia 2001 Review," p.123. Retrieved March 27, 2003, from http://www.iea.org/public/reviews/austral2001.htm.

Table 27: Transmission outages submitted to NEMMCO

Region	Queensland	New South Wales*	Victoria	South Australia	Total
Total outages**	1470	1543	1095	628	4667
Scheduled with less than 4 days notice	22%	32%	33%	20%	28%
Forced outages***	9%	11%	7%	12%	9%

* The NSW TNSP arranges Snowy outages

** Only primary plant outages (affecting load carrying capability) are included

*** Outages not previously notified to NEMMCO, including failure and amendments by TNSPs in response to unforeseen extreme conditions.

Source: NECA, (2002), "Reliability Panel: Annual Report 2001-2002," p.21. Retrieved May 25, 2003, from http://www.neca.com.au/ReliabilityPanel.asp?CategoryID=35&SubCategoryID=206.

System Investment

NEM is in the process of reviewing the approach to transmission pricing and development, and is expected to present its findings in June of 2003. NEM has been operating with interim arrangements for the past five years.

NEMMCO forecasts new investments in generation of between 2,500 MW and 6,200 MW by 2010.[68] This is well below the forecasted increase in demand, issued by ESAA, of around 2.8% per year during this decade; such growth would require 7,000 MW in generation investment.[69]

In addition to the need for generation investment, there is a system-wide need for investment in transmission interconnects. The NEM operates two forms of transmission interconnects; regulated tariff-based interconnects, and merchant interconnects. This mix of regulated and market-based is of particular interest to Washington as it considers the SMD NOPR, as one of the elements of the proposed rulemaking includes a reliance on private, merchant-based investment in transmission.

Since the opening of the NEM, two merchant interconnects have come on line. Directlink opened in 2000, connecting New South Wales and Queensland. Murraylink began operating in 2002, and connects Victoria and New South Wales. An additional interconnect is under construction, known as Basslink, and will connect Tasmania with Victoria. No regulated interconnects have come on line since the opening of the NEM.

TransGrid, a for-profit transmission company in New South Wales, submitted comments to FERC regarding the SMD proposed rulemaking. In particular, TransGrid commented on the experience of Australia and transmission merchant-investors. While merchant investment in Australia would not be a direct equivalent with merchant investment under the SMD proposal, some commentators have looked at Australia's experience as an

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[68] COAG, (2002), "Towards a Truly National and Efficient Energy Market," p.101. Retrieved April 3, 2003, from http://www.energymarketreview.org/FinalReport20December2002.pdf.

[69] ibid, p.101.

example of initial success; TransGrid would argue otherwise, and suggest that merchant investment in Australia has been "problematic."[70]

In TransGrid's experience, merchant investment has resulted in legal controversy, delays in the planning and construction of transmission, disruption to transmission investment, and an inability to deliver transmission investment where and when it is needed. TransGrid has identified four outcomes: too little investment, too much investment, inefficiently early investment, and investment in rent-seeking.

There are two ways that too little investment is manifested; either through inefficiently small investments, or through lack of investment altogether. The two merchant interconnections MurrayLink and DirectLink provide examples of inefficiently small investment. Almost immediately after construction of MurrayLink, its owners appealed to the regulators to have its status changed from merchant to regulated status. The appeal confirms that the present value of the gross benefits is *less* than the construction costs of the interconnect. The owner, TransEnergie, sees converting to tariff-based revenues as in its interest, as opposed to earning merchant, CRR-type revenues.

TransGrid also argues that DirectLink is an example of inefficiently small investment. Within seven months of DirectLink coming on line, a regulated interconnect known as QNI began operating that has up to four times the capacity of DirectLink. Despite the difference in capacity, the regulated interconnect was able to pass the government's required cost-benefit test of all regulated interconnections; this suggests that DirectLink was built inefficiently small.

Too much investment can occur in regions where there is a concentration of generators. In this case, transmission investment detracts from the public benefit. An example of this might be generators cooperating with transmission investment that would export cheap electricity from one region to another; this may result in costs that are greater to the

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[70] TransGrid, (January 1, 2003), "Comments of TransGrid on Standard Market Design," Docket No. RM01-12-000. Retrieved May 22, 2003, from http://www.stoft.com/e/lib/papers/TransGrid-2003-SMD.pdf

exporting region than any benefits gained by the importing region. TransGrid has not identified any instances of too much transmission investment, but notes that Hydro Tasmania is an example of transmission investment that will benefit a sole generator.

Inefficiently early investment is a result of the interplay between merchant investors and regulated plans. Regulated interconnects are required to pass a rigorous and time-consuming cost-benefit test, while merchant interconnects are not. There is a strong incentive for merchant investors to rush construction before it is efficiently appropriate, in an effort to beat any regulated projects to market. If a merchant can begin construction, it will affect the cost-benefit test of the regulated project, and may ultimately discourage the tariff-based investment. An example of this can be found in MurrayLink. MurrayLink began construction during the planning stages of SNI, a tariff-based interconnect, and subsequently reduced the probability that SNI would pass a cost-benefit test.

TransGrid suggests that the experience of MurrayLink may be interpreted as rent-seeking behavior. It points to the projected inability of the investment to earn a commercial rate of return, in addition to the appeal objecting the construction of the tariff-based SNI interconnect, the application to convert to regulated status, and additional appeals, as potential indicators of rent-seeking.

Reliance on average cost and postage stamp pricing has been identified by COAG as an impediment to clear investment signals in transmission and generation. The two pricing principals serve to cloud locations that would benefit from investment.

Analysis

Washington State shares a number of characteristics with the countries reviewed in this report. Like Norway, Washington has a long-standing history of public-ownership, particularly in its reliance on the federal Bonneville Power Administration. New Zealand has a hydropower capacity that is similar to Washington State's, and a physical system with generation far from load. And like Washington State's relation with the United States, the states of Australia employ a variety of fuel mixes, some using hydro resources, and most using fossil fuel resources.

As many commonalities as there are between Washington and these countries, there are even more differences. While Washington is in need of transmission investment, Norway had an overcapacity in both transmission and generation prior to the establishment of its competitive market. New Zealand's supply system is fairly simple in comparison to Washington's, with electricity traveling south to north from generation to load, and relatively few buyers and sellers. And Australia, like New Zealand and Norway, have multiple river catchments that allow for independent operation of hydropower facilities in contrast to Washington's single large catchment—the Columbia and Snake River drainage. The Snowy River system in Australia is government operated like the BPA and was constructed to meet a number of objectives besides electricity generation like the FCRPS in Washington. On the other hand, much of the operation of hydropower capacity in Norway and New Zealand is optimized for power generation .

Despite these differences, there are lessons that can be learned from studying the experiences of these countries and others. They must be put in the appropriate framework, that of case studies.

There are several experiences with electricity market reform common to all three countries:

- It is a complex and time-consuming process that requires mindful planning. While Norway, New Zealand, and Australia are considered early reformers on the worldwide stage, each country is still grappling with whether or not the promised short and long term benefits have been realized;

- It is also an iterative process. All three countries continue to re-evaluate and fine-tune their implementation of market reform. Current adjustments include New Zealand's formation of the Electricity Commission, and Australia's examination of impediments to a truly national electricity market; and
- Averages do not tell the story. While there have been successes on some measures in terms of national averages, there have been significant regional differences experienced in terms of price, reliability, and investment.

The following pages review the successes and failures in consumer experience, system reliability, and system investment, as well as the lessons of particular interest to Washington State.

Consumer Experience

If the market reforms of Norway, New Zealand, and Australia can be said to have experienced a common success, it would have to be that of decreases in *wholesale* prices. These price decreases, however, have not always been passed on to consumers, as in the case of New Zealand. Norway and parts of Australia have experienced lower consumer prices, but it should be noted that not *all* consumers in *all* locations have experienced the same price decreases; in addition, prices occasionally spike to extraordinary heights.

Beyond consumer prices, each of the countries has experienced minor successes in other aspects of the consumer experience. New Zealand, in response to customer complaints, formed a Complaints Commission that provides New Zealanders with a forum in which to air their grievances. This is similar in fashion to the Washington State Attorney General's Public Counsel. New Zealand also created a centralized database for customers that make it easier to switch power companies. All companies switch power consumers via the registry.

Australia, in another example of consumer success, has maintained regulated tariffs for small end-users. This pro-consumer policy ensures that customers who may otherwise be neglected by market mechanisms, will have access at rates that are not burdensome.

Despite these successes, there have been aspects of reform implementation that have adversely affected consumers. In all three countries, *price volatility* has been viewed by the public as a downside to market reform. Some of this perception is likely due to a lack of understanding about competitive electricity markets in general, and the inherent volatility of their nature. Regardless, there is great public dissatisfaction with periods of unusually high power bills.

New Zealand and Norway, with their high proportions of hydropower capacity, have also been forced to make demands on the electricity habits of their customers during dry years. With hydropower generating plant dependent upon water as its fuel, these *conservation campaigns* aim to preserve water behind the dams as long as possible.

This year, New Zealand formed the Winter Power Taskforce to lead its conservation campaign, known as "Target 10%." The daily aggregate power savings are widely published, and tips on how to cut back on electricity are distributed through all manner of media. Popular press reports about McDonald's turning of its golden arches in Auckland and similar stories convey the severity of the reserve problem. Despite these efforts, the public has fallen short of the 10% target. Norway has also asked the public to cut back.

The consumer experience is closely tied to the overall robustness of the network; shortcomings in system reliability and system investment ultimately matter because they erode the experience of consumers. Several instances of reliability and investment shortcomings illustrate how consumers can be impacted. In all three countries, *transmission weaknesses* have the effect of creating separate markets in different locations. While this will ideally encourage investment where it needs to be made, it can result in higher prices for consumers in the meantime. The Australian NEM is essentially five separate markets with five separate prices; New Zealand's Cook Strait interconnect divides the country in two and FNP further separates electricity prices for consumers; and NordPool only operates a single market 35% of the time due to transmission constraints. These separate markets open up the possibility of regionalized market power and introduce price separation between markets. Market designers and market regulators need to carefully consider the impact of price differentials on consumers and address issues of cost shifting and equity.

The *horizontal integration* of generating plant also affects the consumer experience. Countries and states with a larger number of generators are considered better able to provide a larger number of their customers with lower prices; in cases where there are fewer generators, such as New Zealand and New South Wales, market power can become an issue when combined with weaknesses in the transmission network. Consumers that are located within a so-called load pocket will be less likely to benefit from lower prices than those consumer located in well-connected regions.

Washington State and Consumer Experience

In Washington State, consumers are interested in the same benefit of competition that appealed to the consumers of these three countries prior to their own market reforms; low-cost electricity. If it is found that Washington's consumers are already enjoying low-cost electricity, any alternative to the current system must be closely examined in terms of its costs and benefits to Washington consumers. Any alternative, be it SMD or any other market restructuring, must provide a better alternative to the existing system in terms of consumer experience.

System Reliability

System reliability is a characteristic of short-term system security, or the ability of the system to meet demand at all times. There has been a mix of small successes amongst the three countries, largely in market design measures taken to enhance system reliability.

Although Australia introduced the concept of merchant investment for new transmission interconnects, it did not abolish the existence of regulated interconnects. This provided a measure of safety, while venturing forth with an untested market mechanism. This is not to say that the NEM's interconnect investment has been a success, but rather to highlight a cautious approach taken by the market designers. The overall lack of interconnect investment will surely lead to adjustments of both regulated and merchant incentives.

Norway, with the adoption of its Cost of Energy Not Supplied (CENS) adjusted price cap, has created a mechanism by which to incentivized reliability. In addition to the incentive that it provides electricity suppliers, it has facilitated the collection of data that can be used to monitor overall system reliability.

Norway also has demonstrated a stable number of power interruptions over time. This may be attributed to Norway's pre-market-formation overcapacity in both generation and transmission. Australia and New Zealand did not have overcapacity in generation and transmission prior to market formation, and their system reliability has been adversely impacted in the years since their markets opened.

In New Zealand, generating plant that was not economical on the market was either sold off or closed down. These plants were primarily hydro-firming and peak loading plants, which greatly impacted New Zealand's electricity security during dry years. The government of New Zealand has recently made a proposal that seeks to address the issue of dry-year security, with the formation of the Electricity Commission. By contracting with generators, the Commission will guarantee reserve capacity for a 1 in 60 dry year. There may be shortcomings to the proposal, which has yet to be fleshed out in detail, but it is expected to increase system reliability.

Australia's reliability is hampered by weak interconnects. The transmission constraints often result in five separate markets. Victoria and South Australia have experienced power outages while there has been electricity on the NEM.

Washington State and System Reliability

The issue of short-term security of supply does not appear to be a primary concern of commercial market participants; experience in New Zealand and Australia indicates that after initial experimentation with market mechanisms, governments are best suited for ensuring a reliability of supply in the long run. The Washington Utilities and Transportation Commission can find encouragement from this, and continue in its commitment to advocating for the reliability of Washington's supply. The Federal Energy Regulatory Commission would do well to ensure that any proposal preserves and promotes the short or long term reliability of *each region's* electricity supply system.

System Investment

Electricity supply systems have been built over time, and were originally designed around the generating and transmission needs of vertically-integrated utilities. With the advent of competition, the market was to determine where and when investments should occur, based on what investments would produce a satisfactory return. Investment, particularly in transmission, has been a challenge for all three of the examined markets.

The successes are few and far between in terms of investment; in New Zealand, there have been several instances of generation investment that have been located closer to load, and South Australia has had generation investment that has reduced demands on regional interconnects.

However, stable investment has proven to be problematic in all three markets. Generation investment has declined in Norway for the past 15 years. New Zealand has not experienced investment in the type of generating plant needed for system security—hydro-firming and peaking plant—resulting in an intervention by the Government. New Zealand has experienced another investment outcome that, while not necessarily detrimental, does not follow the prescriptions of market theory; hydro-generating plant has been built at great distance from load, due to the location of adequate water resources.

Transmission investment has also been in decline in Norway, and problematic in Australia. Australia's use of merchant investment is of particular interest to Washington as it is an important component of FERC's SMD proposal. Only two merchant interconnects have been brought into operation since the opening of Australia's National Electricity Market, and neither appears to be profitable; the owners of the MurrayLink interconnect have even gone so far as to apply for regulated status. TransGrid described four shortcomings of Australia's merchant investment:

- Too little investment, either in the form of inefficiently small investment, or an outright lack of investment;
- Too much investment, especially in areas of generation concentration;
- Inefficiently early investment, in an effort to discourage regulated investment; and
- Rent-seeking, as evidenced by substantial resources applied towards ensuring sole operator status, particularly in the case of the MurrayLink.

Washington State and System Investment

With the problems experienced by Norway, New Zealand, and Australia, Washington State can expect challenges in investment. Particularly troubling are the experiences of Australia with merchant investment in transmission interconnects. With Washington's immediate need for transmission investment, reliance on commercial investors does not bode well for the electricity network. This ultimately impacts system reliability and customer experience.

Conclusion

Success in the reform of electricity service regulation and markets can only be measured against the original objectives of those reforms. In some cases the reform was intended to privatize electricity service and get the government out of an ownership and risk-taking role. Against this objective, experience has been mixed. Many electricity functions in New Zealand, Norway, and Australia have been shifted out of government hands. However, New Zealand has been forced to reintroduce some government oversight and Australia left in place regulatory protections for small customers.

In other cases the reforms have been touted as a way to improve customer service, improve reliability, lower costs, and encourage investment. Again, the record is mixed. Norway and New Zealand have implemented new ways to respond to customer needs and ensure delivery reliability. But cost-reductions have been modest at best and cost-shifting and equity problems have been apparent in all three cases. None of the three cases indicate that a reformed and market-driven electricity system is superior to a regulated one for attracting investment in transmission or generation.

V. Appendix

Glossary of Terms

Bilateral contracts	Contracts made between two private parties for trade.
Capacity payment	A payment made to generators to compensate them for making their generation capacity available.
CENS	Cost of energy not supplied.
Contract for differences	A contract in which the buyer pays the seller for any difference between the contract price and the market price, usually the spot price.
CPI-X	Consumer price index minus "x" is a type of price cap. CPI is a measure of inflation, and "x" represents a productivity factor.
CRR	Congestion revenue rights. This form of contract provides the holder with the right to receive any revenues based on transmission congestions that are tied to specific delivery and receipt points on the transmission network.
Disaggregate	In the case of electricity markets, separating the electricity supply activities--generation, transmission, distribution, and supply--into their component parts.
Dispatch	To operate and control a power system. Also, the collection of generators that are providing output at any given time, and their output levels.
Distribution	The transportation of electricity over lower voltage lines.
Economies of scale	A situation where a company can increase its output more than proportional to its input cost. Where economies of scale exist, larger companies have cost advantages over smaller companies.
ENS	Energy not supplied.
Ex ante	In the instance of electricity markets, a spot price that is set before the power trade occurs.
Ex post	In this instance of electricity markets, a spot price that is set after the power trade occurs.

FERC	Federal Energy Regulatory Commission. The branch of the federal government that oversees power sold in interstate commerce and most transmission services.
FNP	Full nodal pricing.
Forward contract	A financial agreement that arranges for the future delivery of electricity at an established price.
Free-rider problem	When no participant is excluded from the benefits of an investment, private markets will have difficulty providing the investment. This is due to participants who have an incentive to underestimate the value of the investment in order to receive its benefits at a reduced cost, or zero cost.
Futures contract	A financial agreement that requires traders to buy or sell electricity at an established price on a specific future date. Futures differ from forwards in their standardization, daily settling, and other requirements.
Generation	The production of electricity.
Grid	The transmission network.
Gross Pool	A power pool that processes all power transactions.
HVDC	High-voltage direct current.
Interconnection	The transmission facilities that connect two systems or control areas.
LMP	Locational marginal pricing.
Load	A device or customer that receives power from the network. Load is often used interchangeably with demand.
Load shedding	The process by which customers are involuntarily removed from a power system. Load shedding is in response to abnormal conditions, and is needed to maintain the system's integrity.
Marginal costs	The cost of supplying one additional unit of electricity.
Market failure	A flaw that prevents the market from operating in an efficient manner.

Market power	Market power occurs when the market price can be altered to one other than the competitive price. When suppliers exert market power they are not acting as price takers, but price makers.
Market-clearing	The price at which supply equals to demand.
Merit order	The ranking in order of generators from those with the lowest variable costs of production to those with the highest variable costs of production.
Natural monopoly	An industry is considered to be a natural monopoly if output is more efficiently created by one large producer as opposed to a number of smaller producers.
Net Pool	A power pool that only includes those transactions not accounted for in bilateral trading.
Nodes	Nodes are a component of a nodal pricing system, either full nodal pricing or locational marginal pricing. A node is where electricity is injected onto the transmission grid and where it is taken off of the grid.
NOPR	Notice of proposed rulemaking.
Power exchange	Also known as an exchange market, power exchanges do not except side payments. Bids are based on simple price and quantity, occasionally a minimum supply time or startup cost. Exchanges are typically less complicated than the multi-part bids made in power pools.
Power Pool	A centralized market that makes side payments. Pools solve the unit-commitment problem to manage dispatch. The resulting market price in combination with the side payment clears the market.
Spot market	The real-time electricity market.
Tariff	The body of regulations governing a power market.
Unit commitment	The starting of a generator.
Variable cost	The cost that varies with the level of output, for example, fuel or labor.

VAT	Value added tax.
Zonal pricing	Prices are set equal to the supply and demand in each of a number of established zones.

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