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Electricity Industry Restructuring in California and its Implications for Australia

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Summary

Electricity industry restructuring is a protracted, fragile and complex process because of the particular characteristics of the electricity industry. It requires consistent treatment of all steps in the energy conversion chain, from primary energy forms to end-use services, as well consistent treatment of competing industries, such as natural gas and market-compatible treatment of externalities. Careful attention must be paid to wholesale and retail market design and to achieving adequate levels of competition in generation, retailing and, to the extent that they can be made contestable, network services. One implication of restructuring is that consumers become exposed to and must manage greater price volatility. This, plus the "essential good" nature of electricity supply means that particular attention must be paid to consumer empowerment, metering and retail tariff design. Appropriate assistance must be provided to disadvantaged consumers.

This report discusses the recent experience with electricity industry restructuring in California and its implications for Australia. While there are significant differences between the Californian and Australian approaches to restructuring, there are also important lessons for Australia.

The US Federal Congress began the process of increasing competition in the utility industry with passage of the Public Utility Regulatory Policies Act (PURPA) of 1978, and later with the Energy Policy Act (EPA) of 1992. Given federal responsibility for interstate trade, these initiatives focussed on facilitating transmission access for independent power producers, with the intent of fostering wholesale electricity markets that extended beyond state borders. This approach adopted a bilateral model for wholesale electricity trading, a market structure that had previously been successful for gas industry restructuring[1]. One consequence of the EPA was to discourage regulated utilities from investing in new generating capacity, on the expectation that generation would become a competitive sector.

California was one of the first US states to commence electricity industry restructuring. A number of factors contributed, such as high electricity prices, poor experience with nuclear power stations and a culture of innovation. However the Californian electricity network (itself internally fragmented by divided utility ownership and planning responsibility) forms part of the Western System (WS), a vast, weakly interconnected network that extends from Mexico to Canada and involves 11 US states and two Canadian Provinces. Moreover, there is extensive trade in electricity across the borders of California.

As a result, external influences have had a significant effect on the outcomes of electricity industry restructuring in California. One important regional issue is incompatibility between the restructuring policies and timetables adopted by the States and Provinces spanned by the

[1] Key features of this model are bilateral "firm" contracts between generators and retailers (or large consumers) and "firm transmission rights" on a path that allows the energy to be "wheeled" from generators to loads. This is a very abstract model of the physical operation of an electricity industry.

WS. Others include population growth, network constraints and emerging environmental concerns throughout the area covered by the WS.

In California prior to 1997, three major investor-owned utilities (IOUs) – Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) – used to generate, purchase, transmit and distribute electricity to meet their customers' energy needs within their franchise service territories. Together, these investor-owned utilities supplied approximately 80% of California's electrical demand. In addition, publicly owned utilities, such as the Los Angeles Department of Water and Power (LADW&P) and the Sacramento Municipal Utility Department (SMUD) supplied particular franchise service territories.

On March 31, 1998, the electric power industry in California began a four-year, phased-in but rapid process of deregulation. The industry (including municipally owned electric utilities) is to be fully competitive by 2002, when all consumers will have choice of electricity retailer.

In response to this development, the three IOUs separated their generation, transmission, and distribution businesses and sold much of their thermal generation (at high prices). The transmission and distribution businesses remain regulated by the FERC and CPUC, respectively. Generators now receive market prices for their products subject to FERC oversight.

The IOUs' retail tariffs were capped at 90% of 1996 levels until 2002, or earlier if they had recouped approved sunk-costs. Their customers could buy from other retailers from March 1998, but not bypass sunk-cost payments. After SDG&E recouped its sunk-costs in 1999, its retail tariffs were unregulated until the legislature re-imposed a cap in the summer of 2000.

The philosophy of the Californian market structure is that long-term confidential bilateral trading arrangements are the primary driving force for economic efficiency. This is consistent with the FERC philosophy of an access-trading regime, the approach adopted for gas industry restructuring.

To implement this philosophy, the Californian wholesale market model is that the California Independent System Operator (CaISO) manages power system operation, interfering as little as possible with bilateral trading and transmission access organised by Scheduling Coordinators (SCs). Multiple SCs are allowed, both to give participants choice of SC and to allow for the mix of municipal utilities and IOUs in California. California uses a system of Firm Transmission Rights to manage access to congested transmission paths in a manner consistent with the bilateral trading model.

SCs prepare day-ahead balanced schedules of generation and demand and present them to the CaISO for aggregation and final implementation. Thus a SC's task is to support short-term "fine tuning" of long-term bilateral trades and the CaISO's task is to implement the aggregated result of the SCs' activities, accounting for network flow constraints and contingencies.

Specifically, the CaISO has the task of aggregating the day-ahead schedules submitted by CalPX and other SCs and implementing the resulting aggregate system-wide schedule, negotiating adjustments with the SCs if necessary to maintain system security in the face of operating constraints and contingencies. The CaISO is given little time in which to manage this process. Also, the CaISO hourly prices are determined on an ex-post basis so that they are not "avoidable" by demand-side participants. They are essentially cost-recovery instruments rather than prices, limiting their economic efficiency. Moreover, there is little public information about long-term trends, to support network planning and investment and to support the maintenance of overall supply-demand balance.

In addition to the California-specific initiatives, two exchange-based financial instrument markets run by the New York Mercantile Exchange (www.nymex.com) support inter-state electricity trade in the Western System. One of these markets is linked to electricity prices at a location at the California/Oregon border, the other is linked to electricity prices at Palo Verde in Arizona, also near the Californian border. Both trade futures and options.

Unfortunately, the bilateral trading model was not consistently implemented in California. In particular, the IOUs were initially required to trade through a designated SC (the California Power Exchange – CalPX) for a transition period. Moreover, the California Public Utilities Commission (CPUC) explicitly prohibited the IOUs from entering long term contracts with their recently divested generators.

Concerns about the California electricity industry restructuring process grew rapidly during 1999 and 2000. The concerns included fear of supply shortages; high wholesale market prices and suspicions of price manipulation; the parlous financial state of PG&E and SCE resulting from buying at high wholesale prices and selling at regulated retail tariffs; and the high electricity bills paid by SDG&E's customers while their retail tariffs were unregulated. This parlous situation has continued into 2001 with PG&E filing for bankruptcy.

Of the many investigations that have resulted, one of the most comprehensive is that undertaken by staff of the Federal Energy Regulatory Commission (FERC Staff, 2000). This report summarised the underlying problems as:

- A general shortage of generation throughout the Western System
- An over-reliance on spot market purchases by the IOUs in California
- A highly politicised process for setting price caps for the CaISO.

The FERC Staff investigation focussed on wholesale market issues and to its list of problems should be added the problem of de-regulating retail tariffs without providing retail customers with timely information on price behaviour or adequately preparing them for the responsibilities involved. Thus many of SDG&E's retail customers only realised that they had been exposed to retail high prices when their bills arrived long after the causal events. Other problems to add to the FERC Staff list are that it has proved particularly difficult in California to obtain approvals for generation and transmission projects in critical locations and that environmental constraints are now binding in important population centres.

In summary, the Californian situation illustrates the disastrous consequences that can arise from inconsistent and incomplete restructuring. In addition, California's problems were compounded multiple binding planning and operating constraints.

Australia's situation differs. For example, the National Electricity Code specifies pool rather than bilateral wholesale trading (except in Western Australia where bilateral trading is used) and it provides a more consistent framework for ancillary services, spot trading and risk management. However there are still important lessons for Australia from California:

- *Industry structure is important as well as market design:* market rules alone cannot contain a situation where the level of competition is inadequate and there are significant barriers to entry and high prices in related markets. There are legitimate concerns in Australia about the levels of competition in generation and retailing, and the lack of separation between retailing and distribution wires businesses.
- *Wholesale and retail market design should be consistent across a contiguous electrical network, including ancillary service, spot market and financial instrument trading:* otherwise inappropriate arbitrage opportunities will arise and the effective demand side participation essential to efficient market outcomes will not be achieved. Jurisdictions should adopt a consistent and efficient model for retail market implementation.

- *Market design should be as simple as possible but no simpler:* unnecessary complexity is likely to increase opportunities for participants to game the market outcomes.
- *Governance of key market bodies by participants can create problems:* in a competitive industry, participants have commercial incentives to game market rules and to distort the evolution of market rules.
- *Regulation will always be required:* the problems created by inter-temporal links and network constraints limit the extent to which markets alone can provide efficient outcomes. Restructuring must combine efficient markets with efficient regulation.
- *Regulators must be extremely careful when intervening in markets:* intervention can exacerbate market dysfunction and create regulatory uncertainty that discourages efficient participant responses to market signals for both operation and investment.

Specifically, the following aspects of Australian electricity restructuring could be improved:

- *Consumer empowerment:* Electricity restructuring is predicated on the concept of informed decision making by consumers and much more should be done to support this.
- *Retail market implementation:* Distribution and retailing should be fully separated to encourage the development of independent energy retailers that offer electricity, gas, renewable energy and end-use efficiency services in an even-handed manner. Profiling for small consumers may reward inefficient operating and investment behaviour. Instead, interval metering should be used with only the smallest and disadvantaged consumers remaining on traditional metering and tariffs. Small consumers with interval metering could then be provided with regulator-set forward contracts that specified quantity and price profiles, permitting them to continue to consume according to the profile when spot prices were high or to be rewarded for reducing demand (see Appendix B for more detail).
- *Network representation:* Locational spot prices, forward contracting and network pricing should accurately reflect, in an avoidable manner, incremental network losses and the likelihood of future network constraints to the extent that it is possible to do so. This is required to support efficient operation and investment decisions by network service providers, generators and consumers.
- *Spot market:* The hybrid 5-30 minute spot market in the National Electricity Market gives inaccurate pricing signals and creates opportunities for gaming. This could be improved by a more coherent design for spot, ancillary service and short-term forward markets.
- *Financial instrument trading:* More attention should be paid to nurturing efficient markets in financial instruments for both day-ahead and longer term trading. Mechanisms such as variable volume vesting contracts and the NSW Electricity Tariff Equalisation Fund may distort the efficiency of financial instrument trading.
- *Related industries:* gas industry restructuring should be implemented in a manner that is compatible with electricity restructuring.
- *Environmental externalities:* These should be internalised using market-compatible mechanisms such as tradeable permits or taxes, with support for sustainable technologies.

1. Introduction

Electrical energy is a secondary energy form that represents a step in an energy conversion chain from a primary energy form to an end-use energy form. Relevant primary energy forms include fossil fuels, renewable energy resources (eg hydro, wind, solar, biomass) and nuclear fission (in some countries). Traditionally, the electricity industry has been organised as a vertically integrated (in reality or by default) supply industry serving a disaggreated demand side (the multitude of commercial, industrial and residential end uses for electricity).

The term "electricity industry restructuring" is used to describe a process of breaking up vertically integrated electricity utilities and introducing commercial interfaces between the functions of generation, transmission, distribution and retailing. The motivation for restructuring is to disaggregate the electricity supply industry and harness competitive pressures to improve its economic efficiency. However successful restructuring also requires consideration of the primary energy and end-use steps in the energy conversion chain as well as alternative energy conversion chains such as that based on natural gas.

Electricity industry restructuring is a protracted and complex process because of the particular characteristics of the electricity industry:

- *Ephemerality:* Due to the lack of cost-effective storage for electrical energy, the supply-demand balance in the industry can change instantaneously at a particular location or network-wide.
- *Fungibility & spatial continuity:* The electrical energy arriving at a particular consumer's premises is a mix of the energy from all operating power stations. The mix is determined by the physical laws of electrical circuits and may change continuously. Moreover there is an electrical continuum between all components in an electricity industry across the full reach of a network, from the internal wiring of generators to that of electrical appliances.
- *Technical breadth:* Electrical energy may be created and used in a wide variety of ways that continues to expand with technical progress. For example, plausible electricity generation options now range from a 1 kW photovoltaic panel to a 1000 MW steam-cycle generator, a size ratio of one million to one. It is unlikely that a vertically integrated utility could efficiently install and operate such a wide range of generation options.
- *Shared accountability:* The properties of ephemerality, fungibility and spatial continuity mean that successful delivery of end-use energy services is the shared responsibility of all sectors of the electricity industry – generation, transmission, distribution, retailing, end-use and equipment design[2]. Electric power systems are explicitly designed and operated so that, if one item of generation or network equipment fails, other comparable items of equipment will automatically substitute if they have the capability to do so.
- *Essential good:* Electrical energy has become essential to many aspects of modern life. This has important implications for reliability and quality of supply, demand elasticity and appropriate use of price as a rationing mechanism.
- *External impacts:* The industry has significant atmospheric, water, solid waste, land-use, health, social and visual impacts. These may lead to restrictions on operation and investment decisions related to electricity generation, transmission and distribution.
- *Inter-temporal links:* The importance of ephemerality, capital intensity, construction lead time and externalities in the electricity industry mean that advance preparation is essential to maintaining short- and long-term supply-demand through activities such as unit dispatch and commitment, maintenance scheduling and investment decision making.

[2] For example, in most applications the benefits of reducing the sensitivity of small computers to brief supply interruptions and poor supply quality would far exceed the costs of doing so.

As a result of these characteristics, it is likely that an appropriate combination of competitive and cooperative decision making will deliver better outcomes than either fully centralised monopoly or fully competitive industry structures[3]. Moreover, the most appropriate mix of competition and cooperation may be culturally dependent and may evolve with time.

Important characteristics of successful electricity industry restructuring will include:

- An industry structure that achieves adequate levels of competition and minimised barriers to entry in generation, retailing and network services, considering primary energy forms and end-use services as well as competing industries such as the gas industry
- Adequate representation of the technical properties of electrical energy in commercial trading arrangements, with efficient management of short and long term risks
- Consistency in the design of markets for primary energy forms, wholesale and retail electricity and end-use services
- Consistency in economic, technical and environmental regulation
- Active demand-side participation in wholesale and retail electricity markets, supported by spot prices that are avoidable (ie real-time or forward-looking), liquid markets in financial instruments and consumer empowerment programs that address technical, social and environmental issues.

Neither a traditional nor a restructured electricity industry can guarantee perfect supply availability and quality. In situations where efficient markets are feasible and appropriate, supply availability can become largely a matter of demand price-elasticity. In other situations, the objective should be to achieve a socially desirable level and distribution of risks associated with unavailability of supply. Supply quality must remain regulated for the present.

No country has yet reached the end-point of electricity industry restructuring. This report discusses the recent experience with electricity industry restructuring in California and its implications for Australia. Sections 2 and 3 review the restructuring process in the USA and California respectively; Section 4 discusses current issues in California and proposed solutions; Section 5 discusses the implications of the Californian experience for Australia and Section 6 contains conclusions. Appendix A discusses the treatment of networks in electricity industry restructuring and Appendix B discusses some insights from electricity pricing theory.

2. Electricity Industry Restructuring in the USA

Electricity industry restructuring in the USA has been driven by a number of factors:

- Consumer complaints in states with high electricity prices
- Declining public acceptance of nuclear power, large hydro schemes and coal-fired power stations due to their external impacts
- Prior experience with gas industry restructuring that (for a time at least) delivered cheap and plentiful gas
- Expectations that the electricity industry could be successfully restructured along similar lines to the gas industry

State and federal governments in the USA share responsibility for the electricity industry but, as in Australia, their objectives and priorities for industry restructuring may differ. The US context is particularly complex:

- Many more States than in Australia

[3] See Appendix B for a discussion of relevant insights from electricity pricing theory.

- A complex prior industry structure, involving a mix of private and publicly owned utilities and divided regulatory responsibilities
- Vast and fragile transmission networks created by connecting individual utility networks in a manner designed more for bilateral trades between specific utilities than for open competition
- Substantial "sunk costs", particularly in nuclear power stations, that create difficult transition issues
- An unresolved debate between proponents of pool-based and bilateral trading models (see Appendix A).

In broad terms, the US Federal Government has responsibility for interstate trade while State governments have responsibility for intra-state matters. At the federal level, regulatory responsibility is split between the Federal Energy Regulatory Commission (FERC), which is responsible for economic regulation and the National Electricity Reliability Council (NERC), an industry body responsible for overseeing power system security[4].

The US Federal Congress began the process of increasing competition in the utility industry with passage of the Public Utility Regulatory Policies Act (PURPA) of 1978, and later with the Energy Policy Act of 1992. Given federal responsibility for interstate trade, these initiatives focussed on facilitating transmission access for independent power producers, with the intent of fostering wholesale electricity markets that extended beyond state borders. This approach adopted a bilateral model for wholesale electricity trading, a market structure that was successful for gas industry restructuring[5]. However the ephemerality and fungibility properties of electricity networks mean that a pool model is more appropriate than the bilateral trading model for short-term or "spot" trading of electrical energy. Also, the complexity of the bilateral trading model effectively excludes small participants.

California was one of the first US states to commence electricity industry restructuring. A number of factors contributed, such as high electricity prices, poor experience with nuclear power stations and a culture of innovation.

However the Californian electricity network (itself internally fragmented by prior utility ownership and planning responsibility) forms part of the Western System, a vast, weakly interconnected network that extends from Mexico to Canada and involves 11 US states and two Canadian Provinces (Figure 1). Moreover, there is extensive trade in electricity across the borders of California (Figure 2).

As a result, external influences have had a significant effect on the outcomes of electricity industry restructuring in California. One important regional issue has been incompatibility between the restructuring policies and timetables adopted by the States and Provinces spanned by the Western System. Others include population growth and environmental and network constraints. Kahn et al (1995) reviews the complex issues and considers the available models for electricity restructuring in California in the context of the Western System.

[4] NERC is in the process of changing its nature and name to be more compatible with the restructured industry. It will become the National Electricity Reliability Organisation (NERO).

[5] Key features of this model are bilateral "firm" contracts between generators and retailers (or large consumers) and "firm transmission rights" on a path that allows the energy to be "wheeled" from generators to loads. This is a very abstract model of the physical operation of an electricity industry.

3. Electricity Industry Restructuring in California

California's restructured electricity industry and its pre-cursor is described in California Power Exchange (1999). The material in this Section draws extensively from that reference.

Californian electricity industry prior to 1997

Prior to 1997, three major investor-owned utilities (IOUs) – Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) – used to generate, purchase, transmit and distribute electricity to meet their customers' energy needs within their franchise service territories. Together, these investor-owned utilities supplied approximately 80% of California's electrical demand. In addition, publicly owned utilities, such as the Los Angeles Department of Water and Power (LADW&P) and the Sacramento Municipal Utility Department (SMUD), supplied particular franchise service territories.

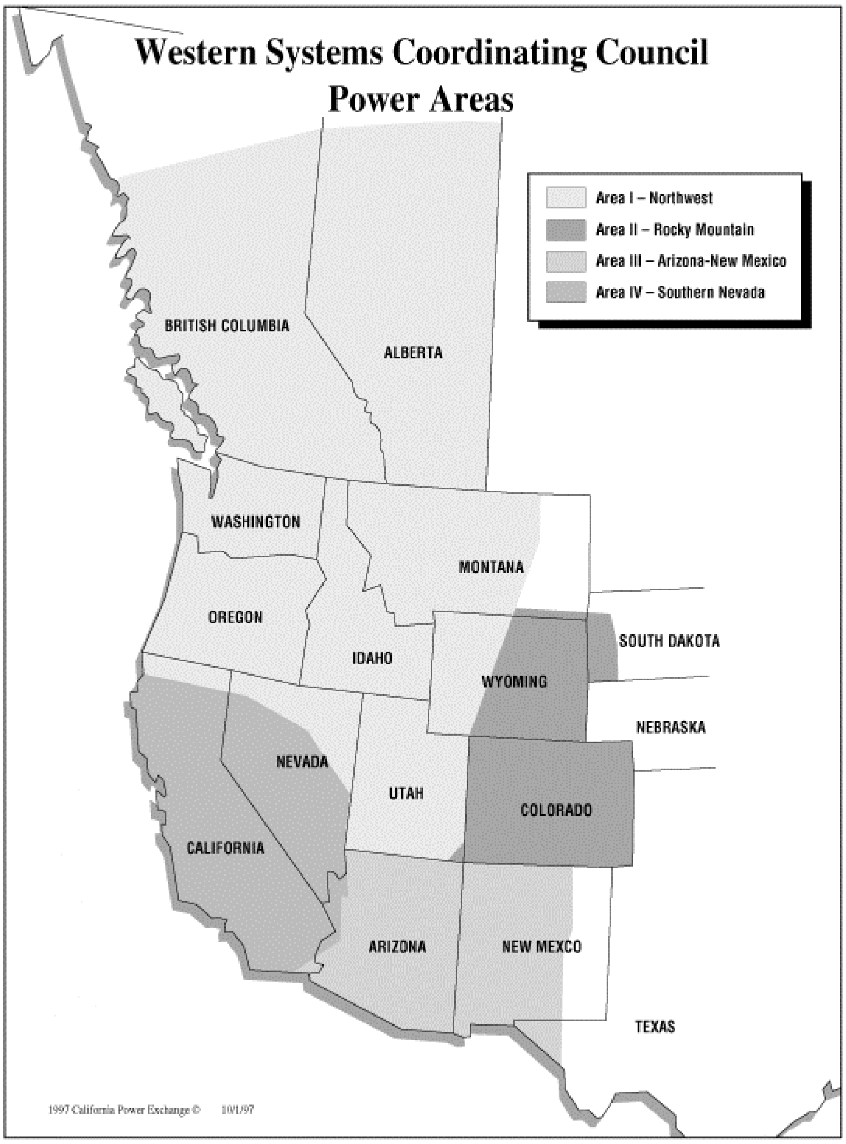

Figure 1. US States and Canadian Provinces covered by the Western System (California Power Exchange, 1999)

Each utility was responsible for matching its own load and resources to maintain frequency, and for matching scheduled and actual flows at the tie-points where it was connected to others. Given their obligation to serve all electricity requirements within their respective service areas, the utilities developed their own generation and demand forecasts, operated generating plants, and entered into long-term procurement contracts for the fuel used to generate electricity. They also participated in short- and long-term bilateral contracts for electric power amongst themselves and with other utilities and independent power producers in California and the surrounding states. IOU investment in generation declined from the 1980s due to the anticipated introduction of competition in generation.

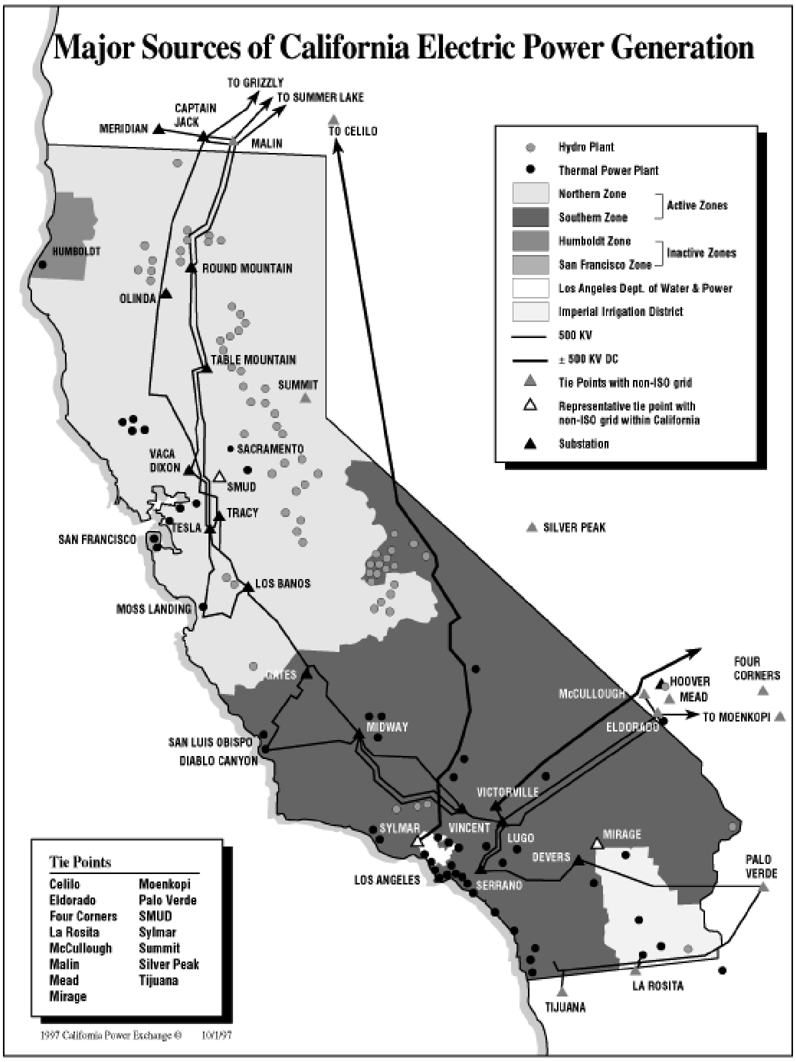

Figure 2. Major sources of electricity generation for California with key transmission lines and California network zones (California Power Exchange, 1999)

State Law to Deregulate California Utilities, 1996

State Law AB 1890, 1996 called for the deregulation of California's investor-owned electric utilities, opening up the state's \$23-billion electricity market and guaranteeing an initial rate freeze at 90% of 1996 levels and a 20% rate cut for residential and small business customers by 2002. The law established an Electricity Oversight Board, an Independent System Operator (CaISO), and the California Power Exchange (CalPX).

State Law AB 1890 modified a plan passed in December 1995 by the California Public Utilities Commission (CPUC) to lower the price of electricity and end excessive and expensive "over-regulation." These modifications introduced a number of politically inspired compromises into the earlier design. According to the San Jose Mercury, 1 December 2000, one lobbyist labelled the final result as "the mother of all sausages".

Transition to the new arrangements

On March 31, 1998, the electric power industry in California began a four-year, phased-in but rapid process of deregulation. The industry (including municipally owned electric utilities) is to be fully competitive by 2002, when all consumers will have choice of electricity retailer.

In response to this development, the three IOUs separated their generation, transmission, and distribution businesses and sold much of their generation (at high prices). The transmission and distribution businesses remain regulated by the FERC and CPUC, respectively. Generators now receive market prices for their products subject to FERC oversight[6].

The IOUs' retail tariffs were capped at 90% of 1996 levels until they recovered approved sunk-costs or until 2002. Their customers were permitted to buy electricity from independent retailers from March 1998, but still had to pay for sunk-costs. SDG&E's retail tariffs were unregulated from 1999, when it recovered its sunk-costs, until the legislature re-imposed a cap during the summer of 2000 in the face of customer complaints about high retail prices.

California adopted a bilateral trading model to implement wholesale competition. The concept of this model is that an independent system operator manages power system operation, while participants organise their bilateral trading through Schedule Coordinators (SCs), which in turn develop balanced schedules of generation and demand. Multiple SCs are allowed, both to give participants choice of SC and to allow for the mix of municipal utilities and IOUs in California. However, the IOUs were initially required to trade through a designated SC (the California Power Exchange) for a transition period.

To support this model, two new organisations were created:

- California Power Exchange (CalPX), which has no Australian equivalent and has recently ceased operation
- California Independent System Operator (CaISO), roughly akin to Australia's NEMMCO

These organisations are discussed in the following sub-sections. Their rules and service charges are regulated by the FERC.

In addition to the California-specific initiatives, two exchange-based financial instrument markets run by the New York Mercantile Exchange (www.nymex.com) support inter-state electricity trade within the Western System. One of these markets is linked to electricity prices at a location at the California/Oregon border, the other to Palo Verde in Arizona, also near the Californian border. Both trade futures and options.

California Power Exchange (CalPX)

CalPX was a non-profit, public benefit corporation open to all suppliers and purchasers on a non-discriminatory basis. Its primary purpose was to provide an efficient, competitive energy market that met the needs of its customers at market prices. CalPX markets determined the

[6] FERC has recently determined that some generator prices "appear unjust and unreasonable and either refunds must be made or sellers must justify their prices" [FERC new release 9 March 2001].

price of electricity on an hourly basis for the Day-Ahead and Day-Of markets, according to the demand and supply bids submitted by CalPX participants.

PG&E, SCE and SDG&E were initially required to buy and sell electricity through CalPX. This requirement was dropped recently and the volume of energy traded through CalPX then fell from about 85% to less than 20% of the CaISO balance market volume, indicating that the IOUs preferred to make their own scheduling arrangements. As a result, CalPX ceased operation. Other market participants, such as independent power producers (IPPs), municipal utilities, utilities located outside of California, aggregators, etc., always had the option of buying from or selling electricity through an alternate Scheduling Coordinator (SC).

California Independent System Operator (CaISO)

The task of the CaISO is to maintain secure power system operation and to ensure that all electricity producers have an equal opportunity to send their electricity through the transmission system to their customers. To do this, the CaISO prepares a system-wide schedule after the SCs submit their schedules. Although PG&E, SCE and SDG&E continue to own their electric transmission facilities, operational control of these facilities was turned over to the CaISO on March 31, 1998.

The new industry structure in California may be summarised as shown in Table 1.

Table 1. Participants in the Californian restructured electricity industry

Participant	Role
California Power Exchange (CalPX), which was a Scheduling Coordinator (SC) until its demise	Created & settled electricity markets, submitted schedules to CaISO
Scheduling Coordinators other than CalPX	Prepare & submit balanced schedules to CaISO
California Independent System Operator (CaISO)	Aggregates SC schedules into a system-wide schedule; manages system security, generation dispatch, ancillary services & transmission access
Generator	Generates & sells electricity via an SC
Utility Distribution Companies (UDC)	Distributes & sells retail electricity
Retail Marketer (RM)	Provides competitive retail energy services
Customer	Purchases electricity services from UDC or RM

The roles of the CaISO and CalPX are summarised in Table 2. Further details are given in California Power Exchange (1999), California Independent System Operator (1999), and Moore and Anderson (1997).

Table 2. The roles of the California Independent System Operator and California Power Exchange

California Independent System Operator	California Power Exchange
• Co-ordinate day-ahead scheduling & real-time balancing for all market participants • Comply with NERC and WSCC operating and reliability standards • Dispatch transmission facilities and manage transmission network congestion • Procure and dispatch ancillary services	• Receive supply and demand bids for day-ahead, day-of and block-forward markets • Determine market clearing prices and zonal prices • Submit balanced schedules to the CaISO • Operate a settlement & billing system

Specific markets operated by CalPX

During its existence, the CalPX managed two exchange-based "spot" markets:

- The Day-Ahead Market, in which participants submitted supply offers and demand bids on a portfolio basis for each of the next day's 24 hours. The Day-Ahead Market started at 6 a.m. on the day ahead of the trading day, and closed at 1 p.m. on the day ahead of the trading day, when the CaISO issues the final day-ahead schedule with an aggregate quantity and market clearing price for each hour. The accepted portfolio bids & offers in the CalPX Day-Ahead Market were then broken down into unit-specific quantities and submitted to the CaISO as a dispatch schedule along with adjustment offers (for managing network congestion) and ancillary service offers. The CaISO then aggregated the proposed CalPX dispatch schedules with schedules from all the other schedule coordinators to assess transmission congestion. If necessary, the CaISO used the adjustment bids and offers to determine revised dispatch schedules that comply with transmission constraints. These were then returned to the CalPX and other schedule coordinators for consideration and re-submission to the CaISO. The intent is that, so far as possible, the schedule coordinators will voluntarily resolve transmission constraints in a decentralised fashion with minimum central intervention.
- The Day-Of Market (originally introduced as the Hour-Ahead Market) permitted participants to conduct transactions nearer to the delivery hour, when generation and energy use conditions might require changes in trading positions to minimise schedule imbalances. The Day-Of Market included 24 auctions conducted in three batches during the course of the day – at 6 a.m. (for the period 11 am to 4 pm), noon (5 pm to midnight) and 4 p.m (1 am to 10 am the following day). These determined market-clearing prices in the same way as the Day-Ahead Market.

From June 1999, CalPX began offering monthly block forward energy contracts. Trading occurred through a telephone ordering process and a password-protected Internet Web site that allowed each participant to check current market prices and download their specific trading and clearing information. Energy delivery in the Block Forwards Market could be scheduled through CalPX's Day-Ahead Market or the bilateral market for either the Northern California (NP 15) or Southern California (SP 15) zones. Settlement of the Block Forwards Market occurred on a monthly basis following the delivery month of the purchased contracts. Participants were invoiced or paid based on their net position in the Block Forwards Market as compared to CalPX average Day-Ahead Market prices for the delivery month.

Initially, participants could enter into monthly on-peak energy contracts for delivery up to six months beyond the current trading month. In October 1999, CalPX extended this to 12 months, so that the Block Forwards Market then accepted bids for energy sales and purchases up to a year in advance. The market matched bids to buy with offers to sell. From Spring 2000, CalPX expanded block forwards trading outside of the state by offering contracts for delivery at the Mead substation in southern Nevada, the Palo Verde substation in western Arizona and at the California-Oregon border scheduling point known as COB. These delivery points represented the most visible energy-trading hubs not served by CalPX in the West and were CalPX's first trading products that were totally independent of the California energy marketplace.

The Block Forwards Market was open to all energy traders, including those who did not participate in CalPX's Day-Ahead Market. CalPX accepted block forward contract bids each weekday for energy delivery one to 12 months ahead of the current month, based on the following parameters:

- Every forward block contract consisted of 16 on-peak hours, from 6 a.m. to 10 p.m. daily for every day of a month (excluding Sundays and certain holidays).

- Each contract was based on a specific future month at a certain quantity (multiples of 1 or 25 megawatts), with trading ceasing two days before the start of the delivery month.
- When CalPX's Day-Ahead Market was used for delivery of energy bought and sold in the Block Forwards Market, Day-Ahead Market energy was scheduled independently of the block forward contracts, which enabled participants to schedule delivery based on their current marginal costs rather than their block forward positions.

Specific markets operated by CaISO

The CaISO operates an hourly energy balancing market and ancillary service procurement markets.

The hourly energy balancing market is designed to ensure physical generation/load balance while complying with network flow constraints and maintaining system security. Network congestion was to be primarily managed by dividing the transmission network into zones within which constraints were rare (see Figure 2) and limiting the flows between them to the assigned flow limits. However in practice, insufficient zones were established, leaving the CaISO to manage a significant number of intra-zonal constraints by means of "reliability must run" contracts with appropriate generators. Wolak and Bushnell (1999) discuss these contracts. There are provisions to change the zones but political factors limit their usefulness.

Zonal hourly prices are determined ex-post on the basis of the supply-side adjustment offers submitted by CalPX and other schedule coordinators. These prices apply to the imbalance energy between the dispatch schedules and actual hourly generation or consumption. The zonal prices take account of dispatch adjustments necessary to comply with transmission flow constraints as well as network losses and dispatch imbalance energy. The adjustment offers are also used to eliminate intra-zonal congestion.

The hourly ancillary service procurement markets are for regulation (upward and downward AGC), spinning reserve, non-spinning reserve and replacement reserve (available within 60 minutes). Scheduling coordinators have the option of self-providing these ancillary services.

Alaywan (1999) provides further discussion of the CaISO role and implementation.

Transmission rights

California uses a system of Firm Transmission Rights (FTRs) to manage access to congested transmission paths in a manner consistent with the bilateral trading model.

As implemented in California (Alaywan, 2000), FTRs are directional rights across zonal interfaces that apply for one year but are implemented on an hourly basis. The FTRs provide either scheduling priority or financial rights. The FTRs also provide a higher priority of scheduling services in the case where the CaISO has to allocate transmission capability in the absence of economic signals such as adjustment bids.

The CaISO initially auctions FTRs one year ahead and the auction proceeds go to transmission owners as part of their regulated revenue. The FTRs may then be scheduled by their owners in the Day-Ahead market (with adjustment bids if desired) or released for sale by the CaISO in the Day-Ahead market. Released FTRs that are not sold in the Day-Ahead market are offered in the Hour-Ahead markets. In either case, the original owner receives the proceeds from the CaISO sale.

Comments on the Californian Market Structure

The philosophy of the Californian market structure is that long-term confidential bilateral trading arrangements are the primary driving force for economic efficiency. This is consistent with the FERC philosophy of an access-trading regime, the approach adopted for gas industry restructuring. Thus a SC's task is to support short-term "fine tuning" of long-term bilateral trades and the CaISO's task is to implement the aggregated result of the SCs' activities, accounting for network flow constraints and contingencies.

Specifically, the CaISO has the task of aggregating the day-ahead schedules submitted by CalPX and other SCs and implementing the aggregate system-wide schedule, negotiating adjustments with the SCs if necessary to maintain system security in the face of operating constraints and contingencies. The CaISO is given little time in which to manage this process[7]. Also, the CaISO hourly prices are determined on an ex-post basis so that they are not "avoidable"[8] by demand-side participants. They are essentially cost-recovery instruments rather than prices, limiting their economic efficiency.

This bilateral-trade driven model creates both short-term and long-term difficulties:

- It provides little public information about long-term trends, to support network planning and investment and to support the maintenance of overall supply-demand balance.
- It under-estimates the importance of maintaining short-term system security, supply availability and quality of supply in an economically efficient manner. In particular, CaISO is given little lead-time in which to manage system security and the ex-post calculation of CaISO's hourly energy balance prices distorts demand-side participation.

Ironically, the CPUC prevented the IOU UDC's from entering forward contracts with generators (FERC Staff, 2000), apparently because it was thought that the CalPX and CaISO prices would be cheaper than long-term contract prices. This decision may also have been to prevent pseudo vertical reintegration between the UDC's and their recently divested generation. The prohibition of long-term contracts is inconsistent with the underlying market design philosophy. It left the UDCs exposed to high spot prices with regulated retail tariffs.

An alternative model for electricity industry restructuring, more consistent with electricity pricing theory (see Appendix B) and recognising the key properties of ephemerality, fungibility and continuity, is to describe the electricity industry as having a known present state evolving into an increasing uncertain future. This model regards an efficient real-time wholesale spot market (that models at least some network effects and in which prices are forward-looking so that they are avoidable by consumers) as a key element in achieving economically efficient outcomes. This spot market must be supported by efficient financial instrument markets to manage future uncertainty, and by efficient ancillary service arrangements to manage those aspects of system security, supply availability and quality of supply that can't be captured in the spot market.

This is the philosophy implemented in the Australian National Electricity Market (NEM) - see for example Outhred (2000). Note that there is still room for improvement in the NEM design and that retail market implementation in Australia does not yet adequately reflect the wholesale market design.

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[7] The FERC found the California congestion management system "fundamentally flawed" in December 1999. An intensive process to reform the market during 2000 was then overtaken by the events of the summer.

[8] Consumers could avoid paying a high price by reducing consumption if they knew the price in time to do so.

4. Current Issues in California and Proposed Solutions

Concerns about the California electricity industry restructuring process grew rapidly during 1999 and 2000. The concerns included fear of supply shortages; high wholesale market prices and suspicions of price manipulation; the parlous financial state of PG&E and SCE resulting from buying at high wholesale prices and selling at regulated retail tariffs; and the high electricity bills paid by SDG&E's customers while their retail tariffs were unregulated. This parlous situation has continued into 2001 with PG&E filing for bankruptcy.

Of the many investigations that have resulted, one of the most comprehensive is that undertaken by staff of the Federal Energy Regulatory Commission (FERC Staff, 2000). This report summarised the underlying problems as:

- A general shortage of generation throughout the Western System
- An over-reliance on spot market purchases by the IOUs in California[9]
- A highly politicised process for setting price caps for the CaISO.

The FERC Staff investigation focussed on wholesale market issues and to its list of problems should be added the problem of de-regulating retail tariffs without providing retail customers with timely information on price behaviour or adequately preparing them for the responsibilities involved. Thus many of SDG&E's retail customers only realised that they had been exposed to retail high prices when their bills arrived long after the causal events. Other problems to add to the FERC Staff list are that it has proved particularly difficult in California to obtain approvals for generation and transmission projects in critical locations and that environmental constraints are now binding in important population centres.

The FERC Staff report reached the following specific conclusions regarding the situation in California during 2000:

- Overall demand across the Western System (WS) increased significantly during 2000 driven by hot weather driving air-conditioning demand and increased economic activity.
- Exports from California increased significantly with little overall change in the level of imports.
- Outages (particularly unplanned outages) increased significantly compared with 1999.
- Increased quantities of demand and supply were left unscheduled in day-ahead and day-of markets, forcing the CaISO to buy substantial amounts of replacement reserves or out-of-market energy.
- Non-hydro generation resources throughout the WS were more heavily utilised in 2000 compared to 1999.
- Prices in the CaISO increased in May and then to record levels in June, with overall CaISO costs remaining high despite the imposition of price caps of 500 $/MWH in July and 250 in August.
- Prices at other trading hubs in the WS generally correlated with California, suggesting that opportunities to sell at high prices existed at those locations as well.
- Costs for fuel and environmental compliance (NOx credits) increased significantly in July and August.
- Prices in some hours appeared to be above those that would have prevailed in a competitive short-term market, if prices were determined from short-term marginal costs.

[9] As previously discussed, the CPUC prohibited the IOUs from entering into hedging contracts with generators apparently in the belief that spot prices would be low and to prevent what the CPUC saw as a form of vertical-reintegration between the IOUs and their recently divested generators

- Examination of bid patterns in the CalPX and CaISO replacement reserve markets and a review of CaISO out-of-market purchase activity does not suggest substantial or sustained attempts to manipulate prices in these markets.

FERC staff also proposed a range of options available to FERC or state agencies (some of these options were not recommended by FERC staff):

Encourage new investment:
- Adopt policies that encourage and facilitate investment in new generation and transmission, such as streamlining of siting approval processes in California and reviewing wholesale pricing policies.

Remedy over-reliance on the spot market:
- Eliminate the requirement that the three Californian IOUs must buy and sell through the CalPX.
- Require the IOUs to hedge and forward contract through the CalPX and bilateral trading.
- Require all in-California thermal generation to be bid into the forward Californian markets (day-ahead and block-forward).

Improve demand responsiveness:
- Implement policies to increase retail demand responsiveness to price such as through the implementation of retail markets.
- Require the CaISO to allow scheduling coordinators to bid load responses into the ancillary services markets.

Provide temporary price-regulation while long-term measures take hold:
- Return to traditional cost-of-service regulation for generators in California (not recommended).
- Adopt limited term price caps for spot market sales (day-ahead and hour-ahead) in both the CalPX and CaISO (alternatively throughout the Western System).
- Adopt limited term price caps for long-term sales in addition to sort term sales, or price targets for long-term contacts. Alternatively, leave market prices unconstrained to stimulate new investment.
- Consider pay-as-bid rather than uniform price auction rules.

Improve regulatory stability:
- Replace the current stakeholder Boards of the CaISO and CalPX with independent Boards and abolish the California Electricity Oversight Board.
- Assign sole authority to FERC to impose price caps
- Require the CaISO and CalPX market monitors to report evidence of market abuse directly to the FERC without prior review by their Boards. Undertake specific investigation of generators with abnormally high outage rates or suspect bidding practices.

Other commentators have pointed to flaws in the CalPX and CaISO rules. For example, Borenstein et al (1999) found that "significant departures from competitive pricing" had occurred during the period June-November 1998. They also pointed out that the CalPX and CaISO markets were not independent. Effectively, the CalPX day-ahead and day-of markets function as forward markets to the CaISO balancing market because of the arbitrage opportunities between them. Thus the CaISO balancing market is the default electricity spot market in California[10]. This conclusion is reinforced by the reduction in volume traded through the CalPX market since the IOUs' compulsory trading requirement was rescinded.

Borenstein (2001) proposes real-time pricing, demand response and forward contracting as part of the solution to California's problems (these concepts have already been implemented in the Australian NEM, albeit all with room for further improvement).

Chandley et al (2000) concur with the importance of the CaISO market. They claim that it was deliberately designed to be inefficient because of the Californian emphasis on bilateral trade. They suggest expanding the CaISO role to one more akin to that of NEMMCO:

- The CaISO must operate, and provide open access to, short- run markets to maintain short- run reliability and to provide a foundation for a workable market.
- The CaISO should be allowed to operate integrated short- run forward markets for energy and transmission.
- The CaISO should use locational marginal pricing to price and settle all purchases and sales of energy in its forward and real- time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.
- The CaISO should offer tradable point- to- point financial transmission rights that allow market participants to hedge the locational differences in energy prices.
- The CaISO should simultaneously optimize its ancillary service and energy markets.
- The CaISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.

In a recent investigation of market power in the Californian electricity market, Joskow and Kahn (2000) found that "actual wholesale market prices far exceed competitive benchmark prices that reflect this [year 2000] summer's natural gas price, demand, and import conditions". After taking account of the rising price of tradable NOx permits, "our analysis leads us to conclude that truly competitive prices in the California electricity market would have been substantially lower than those observed this past summer." They recommend that action be taken to facilitate technical abatement and other measures to reduce prices in the NOx permit market[11].

In important recent studies on the control of market power in electricity markets, Rassenti et al (2000) demonstrate the critical role of demand-side bidding, while Wolak (2000) discusses the critical role of financial instrument trading. Similar conclusions were reached in an earlier experimental market study based on the Australian NEM design (Outhred and Kaye, 1996).

Problems have also been identified with the design of Californian Ancillary Service markets (Wolak, Nordhaus and Shapiro (1999); Oren (2001); Papalexopoulos and Singh (2001); Siddiqui, Marnay and Khavkin (2001)). Many of these problems appear to arise from the specification of ancillary services products to include non-spinning reserve and replacement reserve and the ensuing need for multiple procurement markets that in turn provide gaming opportunities for participants. In the Australian NEM, comparable services are managed

[10] Also, the CalPX markets are dysfunctional as technical forward markets because they are voluntary and thus don't provide reliable information on anticipated system-wide dispatch quantities. As a result, they can't accurately incorporate the effects of network flow constraints required to forecast zonal spot prices well. The NEM pre-dispatch process is much more effective in these tasks.

[11] Market power can be difficult to define and to detect in electricity markets. Electricity spot prices should rise above incremental operating cost when supply-demand balance is constrained. This supports the recovery of capital costs and provides signals to encourage new entrants. However consumers should be able to avoid high prices by reducing demand, and barriers to entry should be minimised.

within the hybrid five-minute, thirty-minute spot market (see Outhred (2001) for further discussion of ancillary service market design from an Australian perspective).

There is an active and unresolved debate in the USA over the representation of networks in electricity markets and over the commercial management of transmission constraints. There are two competing proposals – the California-style bilateral trading model (often characterized as the "Flowgate" model) and the pool-style locational marginal price (LMP) model. Outhred (2000a) provides a discussion of these models and compares them to the Australian approach. This document is included as Appendix A.

Finally, in a recent development in January 2001, an ad-hoc group of distinguished academics and commentators issued a manifesto on the California electricity crisis (Ad-hoc Group, 2001). The group referred to the seriousness of the crisis and recommended short term action to raise retail prices and de-politicise the situation as well as longer term reforms to free-up long-term contracting, improve wholesale and retail competition (with retail price flexibility), reduce barriers to entry and implement effective regulation.

5. Implications of the Californian Experience for Australia

The previous discussion of the Californian situation reveals the complexity of the issues. It also shows that there are both similarities and differences with respect to the Australian situation. In particular, the Californian wholesale market places greater emphasis on bilateral trading, whereas the Australian wholesale market design places greater emphasis on a pool-style spot market with forward projections. Table 3 provides a comparison of Australian and Californian implementations for key issues.

Table 3. A comparison of the treatment of key in Australian NEM and California

Issue	California	Australian NEM
Ancillary services	Complex market structure with evidence of gaming	A simpler design that is better integrated with the spot market, but with room for improvement
Independent System Operator	The separation of CaISO from CalPX and the other SCs, adds to the difficulty of system operation. Australia doesn't have an SC or CalPX equivalent.	NEMMCO contains both ISO and PX functions, integrating the functions. Pre-dispatch & PASA provide market-based projections for system operation.
Spot market	The optional day-ahead markets are dysfunctional, leaving the compulsory CaISO hourly balancing market as the default spot market. However its design makes it inefficient and vulnerable to gaming.	The NEM compulsory spot market is more robust to gaming than its California equivalent (the CaISO hourly market), particularly when pre-dispatch and PASA are taken into account. However there is room for improvement. For example, consideration should be given to converting pre-dispatch and PASA into compulsory forward markets.
Financial instrument (FI) trading	The NYMEX markets at the California borders are useful. The CPUC prohibition of IOU forward contracting appears to have contributed to the current problems.	There are no restrictions or FI trading with bilateral, OTC & exchange trading. However there are few public measures of the efficiency of trading. Variable volume vesting contracts and

		the NSW Tariff Equalisation Fund may reduce efficiency.
Network-wide consistency	A major task given the size of the US networks. FERC is promoting the concept of Regional Transmission Organisations	Provided at the wholesale level by the NEM but consistency yet to be achieved in retail markets
Retail market design	Ineffective retail market design and implementation appear to have contributed to the current problems. Few customers have switched retailer.	Retail market design for small consumers remains a high-risk issue. Profiling and lack of support for consumers are specific concerns, as are jurisdictional arrangements to shield market participants from risk.
Demand-side participation	Much more development needed	Demand-response in the wholesale market facilitated by avoidable spot pricing, high VOLL and FI trading. A problem for franchise consumers.
Governance	Participant representation on the Boards of CaISO and CalPX may have contributed to the current problems.	Jurisdictions that also own market participants must resolve conflicts of interest in market governance.
Regulation	Complex regulatory structure appears to be a contributory factor.	Regulatory complexity remains a problem.

The implications of the Californian experience to Australia must be carefully assessed and the appropriate response is to make incremental improvements rather than radical change. Nevertheless, some broad comments can be made:

- *Industry structure is important as well as market design:* market rules alone cannot contain a situation where the level of competition is inadequate and there are significant barriers to entry and high prices in related markets. There are legitimate concerns in Australia about the levels of competition in generation and retailing, and the lack of separation between retailing and distribution wires businesses.
- *Wholesale and retail market design should be consistent across a contiguous electrical network, including ancillary service, spot market and financial instrument trading:* otherwise inappropriate arbitrage opportunities will arise and the effective demand side participation essential to efficient market outcomes will not be achieved. Jurisdictions should adopt a consistent and efficient model for retail market implementation.
- *Market design should be as simple as possible but no simpler:* unnecessary complexity is likely to increase opportunities for participants to game the market outcomes.
- *Governance of key market bodies by participants can create problems:* in a competitive industry, participants have commercial incentives to game market rules and to distort the evolution of market rules.
- *Regulation will always be required:* the problems created by inter-temporal links and network constraints limit the extent to which markets alone can provide efficient outcomes. Restructuring must combine efficient markets with efficient regulation.
- *Regulators must be extremely careful when intervening in markets:* intervention can exacerbate market dysfunction and create regulatory uncertainty that discourages efficient participant responses to market signals for both operation and investment.

6. Conclusions

Electricity industry restructuring is a complex process that requires consistency in all aspects of restructuring to avoid outcomes such as those that have occurred in California. The high prices and other problems that have occurred in Californian electricity markets during the last year or so have multiple causes:

- A lack of investment in new generation and transmission during the last decade. Contributing factors include the prohibition of forward contracting by IOUs with retention of (low) regulated retail prices, uncertainties due to inconsistent electricity industry restructuring, and siting processes that reflect public concerns about such facilities in urban areas. As a result, the IOU's are now in or close to bankruptcy and there are binding generation and network constraints that may take years to resolve.
- Air-quality constraints that restrict the operation and increase the cost of fossil fuel generators in many parts of California, particularly in the important load areas of the Los Angeles Basin and the San Francisco Bay Area.
- High prices for NOx permits and, to a lesser extent, natural gas as well as declining hydro inflows that contributed to high electricity prices.
- Rapid growth in weather-sensitive demand, and a growing number of high-value commercial end-uses that have high expectations for supply reliability and quality.
- A market structure within California that is complex, with inconsistencies between the Californian approach to restructuring and the approaches adopted by some other states and provinces that participate in the Western System.
- Complex governance and regulatory structures with differing objectives and priorities.
- Lack of an efficient retail electricity market.

Some of these issues are more relevant to Australia than others. Their implications should be considered carefully, with the objective of improving the Australian restructuring design where there are opportunities to do so. There is no evidence for radical change to the design of the Australian National Electricity Market, however there is evidence for incremental improvement. Also, the Western Australian bilateral trading model should be reconsidered. There are also important lessons for other aspects of industry restructuring, such as the implementation of retail competition, financial instrument trading, governance and regulation.

Specifically, the following aspects of Australian electricity restructuring could be improved:

- *Consumer empowerment:* Electricity restructuring is predicated on the concept of informed decision making by consumers and much more should be done to support this.
- *Retail market implementation:* Distribution and retailing should be fully separated to encourage the development of independent energy retailers that offer electricity, gas, renewable energy and end-use efficiency services in an even-handed manner. Profiling for small consumers may reward inefficient operating and investment behaviour. Instead, interval metering should be used with only the smallest consumers remaining on traditional metering and tariffs. Small consumers with interval metering could then be provided with regulator-set forward contracts that specified quantity and price profiles, permitting them to continue to consume according to the profile when spot prices were high or to be rewarded for reducing demand (see Appendix B for more detail).
- *Network representation:* Locational spot prices, forward contracting and network pricing should accurately reflect, in an avoidable manner, incremental network losses and the likelihood of future network constraints to the extent that it is possible to do so. This is required to support efficient operation and investment decisions by network service providers, generators and consumers.

- *Spot market:* The hybrid 5-30 minute spot market in the National Electricity Market gives inaccurate pricing signals and creates opportunities for gaming. This could be improved by a more coherent design for spot, ancillary service and short-term forward markets.
- *Financial instrument trading:* More attention should be paid to nurturing efficient markets in financial instruments for both day-ahead and longer term trading. Mechanisms such as variable volume vesting contracts and the NSW Tariff Equalisation Fund may distort the efficiency of financial instrument trading.
- *Related industries:* gas industry restructuring should be implemented in a manner that is compatible with electricity restructuring.
- *Environmental externalities:* These should be internalised using market-compatible mechanisms such as tradeable permits or taxes, with support for sustainable technologies.

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Key Web Sites

Federal Energy Regulatory Commission	www.ferc.fed.us
North American Electricity Reliability Council	www.nerc.com
California Energy Commission	www.energy.ca.gov
California Public Utilities Commission	www.cpuc.ca.gov
California Independent System Operator	www.caiso.com
California Power Exchange	www.calpx.com
New York Mercantile Exchange	www.nymex.com

Appendix A: Observations on the Workshop on Markets for Electricity – Economics & Technology (MEET)

Stanford University, California, August 17-19, 2000

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1. Introduction

The MEET workshop brought together a wide range of influential thinkers to discuss network-related issues in electricity industry restructuring and, in particular, a proposal for "flow-based" network congestion management.

Following the MEET workshop, Hill Huntington suggested that I write an expanded version of the concluding remarks that I made at the workshop. This document is the result. It is written in the form of observations rather than prescriptions and from the more limited perspective of an external observer rather than an active participant in the US debate. It draws on insights from the Australian experience where these appear to be relevant. There is no claim of either omniscience or completeness and no claim that the Australian implementation of electricity industry restructuring is directly relevant to the USA. However network congestion is an important issue in Australia and has had to be considered carefully in wholesale electricity market design. This experience may provide useful insights.

The document is structured as follows. The key points that I made in my remarks are first summarised in terms of questions that it might be fruitful to examine further. These are then discussed in turn. The final section provides some general observations and conclusions. An epilogue was added on 11 October 2000.

Points made in my concluding remarks at the MEET workshop

In my concluding remarks I suggested that the following questions appeared to me to underlie the issues that remained contentious and/or unresolved at the end of the workshop:

- To what level of detail should networks be represented in commercial electricity trading?
- How does bilateral trading compare to simultaneous auction trading? When might each be appropriate?
- What network-related risks can be successfully commercialised and how is this best done?
- Is the preferred representation of network effects in the Western System likely to differ significantly from that on the East Coast?

To what level of detail should networks be represented in commercial electricity trading?

Both locational marginal pricing (LMP) and flowgate (FG) approaches to market implementation incorporate network models, however the models used differ greatly in their degree of abstraction.

In an ideal implementation of the LMP approach, each network element included in the scope of the market would be individually represented using an AC load-flow model. However, to the best of my knowledge, DC load-flow models are sometimes used and distribution networks are not included in any current implementations of LMP. At least in some cases, sub-transmission networks are not included. Thus practical LMP implementation involves some degree of modelling approximation. There are both engineering and economic arguments for avoiding the inclusion of distribution and sub-transmission networks in LMP markets and they will be discussed shortly.

The FG approach proposes a much more significant approximation in which the main transmission network is modelled by a relatively small number of potential transmission constraints or "flow gates". Also, power transfer distribution factors (PTDFs) are used to represent how a particular bilateral point-point transaction would map onto flows through the defined flow gates.

The flow gates are assumed to provide a sufficiently accurate representation of important constraints on transmission network operation and the PTDFs are assumed to provide a sufficiently accurate representation of how incremental point-point flows through the meshed transmission network map onto the much simpler flow gate model.

Moreover, it is assumed that there is sufficient linearity that bilateral transactions create flows that are additive through flow gates and that both the flow gates and PTDF coefficients associated with a bilateral transaction are reasonably stable.

Network losses are not included in the FG model and must be dealt with separately. Sub-transmission and distribution networks are considered only to the extent that they imply a need for additional flow gates.

I understand that the genesis of the FG model is the methodology used by NERC to relieve real-time transmission constraints, based on a "wheeling" model of power system operation. In this application, excellent information is available about the location of current operating constraints (flow gates) and measurements that allow accurate estimation of current PTDFs associated with "physical" bilateral trades. However these assumptions seem less reasonable in the forward market context envisaged in the FG model. There would not be a well-defined pattern of bilateral trades. Thus there would be considerable uncertainty about the location of future flow gates and the values of the associated PTDFs. Moreover it is not clear that participants would always have incentives to reveal accurate information about their intentions.

The LMP approach uses a more detailed network model than the FG approach but more detail does not always imply more accuracy so far as important aspects of market behaviour are concerned. For example, transient stability limits may not map well to main transmission network element flows because they may be strongly dependent on generator and load operating points and characteristics. Thus there can be ambiguity as to which network element(s) of a main transmission network to deem to be constrained when a transient stability limit is invoked. However the choice may have great commercial significance – for example an investment that would strengthen a particular network element deemed to be constrained might not relax the underlying transient stability limit.

Similar problems can arise in a sub-transmission network serving a particular load area, where low voltage levels following any one of a number of local network contingencies (or unexpected rapid load increases at any internal node) may be the limiting factor rather than flows on particular lines. Strengthening a particular line deemed to be constrained might not relax the underlying voltage constraint. Translating this problem to the LMP framework might require the creation of a sub-region in which all nodes were treated equally.

Significant approximations are made if a DC load flow model of a network is used for LMP calculations. On the other hand, if an AC load flow model is used, decisions must be taken about allowable nodal voltage ranges and the representation of reactive power control devices and their associated control strategies. Traditionally, nodal voltage limits have been set as technical constraints, however in the LMP approach these can have great commercial significance and affect nodal prices at surrounding nodes as well as at a particular node where the voltage limit had been reached.

An alternative approach to voltage issues that we have studied at UNSW is to incorporate voltage-value functions in bids and offers. However this concept has yet to be implemented in any practical market. It would require market participants to have a degree of sophistication that is probably unreasonable to expect in an initial market implementation. Other technical factors in LMP implementation include the representation of controllable network devices such as phase-changing transformers. Finally decisions must be made as to whether network contingencies should be considered and, if so, whether deterministic or probabilistic criteria should be employed.

LMP implementation must also consider commercial factors. Experimental electricity market simulations consistently demonstrate that adequate competition is required to achieve efficient market outcomes. To ensure efficient market outcomes in the presence of any network constraint would probably require four or more competitors at each end of each potentially constrained line. Furthermore, until active demand-side participation in spot markets is achieved, only generator participants can be counted. Such commercial considerations reduce the potential for LMP to be an economically efficient method of managing all network constraints. This is particularly true for sub-transmission and distribution network constraints, where “lumpy” network investment options should be compared with distributed generation or demand-side alternatives. Negotiation under regulatory supervision may then be a better approach.

Thus in practice, implementing the LMP approach involves approximations and matters of judgement that may have great commercial significance. However the use of more abstract network models such as flow gates involves problems and choices that are at least as difficult.

An alternative interpretation of the FG model is that the main transmission network can be represented as a series of relatively unconstrained regional networks (system control areas for example) connected by identifiable transmission corridors with limited capacity. It may be worth noting that the Australian National Electricity Market (NEM) currently uses a multi-region network model that has some similarities to this interpretation of the flow gate approach. However in the Australian NEM, marginal network losses are approximately represented both within and between regions and individual nodal prices are calculated. Thus the NEM design can be described as a hub and spoke approximation to LMP. NEM regions are defined such that any constraint in the main transmission network that occurs for more than 50 hours per year appears on the boundary between two regions. Intra-regional constraints are managed by other means unless they become sufficiently frequent to justify the formation of another market region.

The Australian market rules allow for the relocation of regional boundaries if the pattern of constraints changes and the intent is that further nodal detail will be implemented in the NEM as the market matures (in terms of market participant understanding, technology and effectiveness of financial instrument trading).

Factors that were important in adopting this evolving approach to market implementation include:

- Stability constraints that are not readily mapped to transmission network elements.

- Commercially significant losses in parts of the transmission network.
- A desire to implement real time pricing (while still avoidable) rather than ex-post pricing (as is currently done in "full nodal pricing"). This is to encourage short-term responsiveness by both supply- and demand-side participants. It is worth noting that a recent major review of experience with the New Zealand market recommended the adoption of real-time pricing. This may have implications for their implementation of nodal pricing.
- A desire to promote competition for regulated network service providers through entrepreneurial action by generation, network and demand-side participants. A market-based approach to this problem requires efficient price discovery (and thus adequate competition) on either side of any network constraint included in the real-time spot market. Australian now has a market network service provider in operation providing arbitrage between two market regions.
- Retention by state governments of responsibility for retail market design and important aspects of distribution network regulation, with differing priorities and timetables for implementation.
- The need for an initial implementation that was politically acceptable and that would facilitate a smooth transition from the traditional industry technology portfolio and culture to a competitive industry technology portfolio and culture.

How does bilateral trading compare to simultaneous auction trading? When might each be appropriate?

Experiments of market behaviour regularly demonstrate that inefficient market outcomes will occur without adequate competition. Typically, four or more similarly sized participants are required to deliver competitive outcomes. Thus bilateral trading is unlikely to give the best outcomes unless all participants have low-cost access to alternative trading options. However participants sometimes have specific (non-commodity) products that they wish to trade bilaterally. In this situation, trading in a similar commodity product would provide a useful benchmark.

These lines of argument point to the value of auction-style trading when standardised commodities can be defined, particularly when there are time constraints and accurate volume information is important in determining price outcomes, as in a lossy and potentially constrained electricity network. Moreover, modern computing and communication technologies allow auctions to be conducted rapidly and at low cost even when a complex auction algorithm is involved.

In the context of competitive electricity industries, there are strong arguments for treating electrical energy as a commodity if a network model is to be included in a real-time market (e.g. proposed energy production or consumption for the next half-hour):

- Power systems operate according to physical laws and, in particular, energy flows between generators and loads according to network admittances. Commodity trading provides a better match to this situation rather than bilateral trading if network effects are to be included in the commercial model. In particular, wholesale electricity trading can then be characterised as commodity trading at one, several or many locations in a network.
- If the commodity market is to solve in real-time or ex-ante rather than after the event, network flows must be forecast to assess whether there will be binding network flow constraints, to estimate network losses and, if relevant, to estimate nodal voltages. The inherent non-linearity of electricity networks means that accurate forecasting of network flows requires accurate estimation of nodal injections and off-takes.

- This can be achieved efficiently and rapidly if energy-only bids and offers are resolved simultaneously for all market participants by means of an auction algorithm that contains a network model.
- The transparency and simplicity of an energy-only bid/offer process, coupled with computer implementation, provides a detailed audit trail for assessing the exercise of market power.

Forward trading in futures that attempt to directly predict future real-time spot market outcomes should use the same algorithm and network model as the real-time market. However the predictive power of such a futures market will depend strongly on the accuracy of participant predictions of their future spot market bids and offers. Participants who wish to hedge are motivated to do that.

Assuming that uncertainty increases with increasing forward projection, it would be appropriate to use a hub and spoke trading model for both real-time and futures markets. Short-projection futures markets would use the same network model as the spot market. However network detail would be successively reduced in longer term futures markets by falling back first to hubs and then to super-hubs alone. At each step in this process, there would be location-specific risks that the market could no longer manage. These might then be best traded bilaterally, possibly under regulatory supervision, noting that only local participants would be able to offer anything approaching a traditional "physical" contract. For example, a local distribution company could offer network access insurance.

Other specific risk management instruments, such as bilateral point-point futures contracts, could be constructed from a hub and spoke futures market model (although these may not be fully firm). For example, the inter-regional settlement residue auctions implemented in the Australian NEM provide access to (non-firm) revenues from the real-time market that can be used by a generator to underwrite a bilateral futures contract to a consumer located in another market region.

In the traditional utility industry, the term "physical contract" was often used to imply a guarantee of future delivery of electrical energy at a pre-determined price. A perfect guarantee could, of course, not be given due to the fallibility of the energy supply chain to the customer's premises. In practice, a physical contract implied a promise of priority with respect to both physical and commercial risks. In a commodity-style real-time market, the equivalent of a physical contract would be a combination of a futures contract and network access insurance, coupled with priority in avoiding load-shedding and possibly special measures to protect quality of supply at the point of connection.

The outcomes of the Australian NEM shows that it is possible to design a sufficiently competitive electricity industry around a real-time wholesale commodity market that incorporates an approximate model of the main transmission network (noting that high prices still occur during times of supply constraint). This in turn provides a basis for risk management that employs exchange-traded financial instruments, OTC trading and specific bilateral contracts. Such an approach combines the strengths of both auction and bilateral trading. It can also provide an equivalent of the traditional bilateral physical contract. Finally, this approach can also provide an efficient interface between the real-time market and power system operation.

What network-related risks can be successfully commercialised and how is this best done?

For the purposes of this discussion, risk will be considered as the likelihood of an unintended event combined with its consequences. Sometimes this is monetarised by multiplying a probability by a damage value, although both may be difficult to quantify.

In a competitive electricity industry, it is useful to categorise risk as either physical risk or commercial risk, where physical risk is associated with unintended consequences of power system operation and commercial risk is associated with unfavourable outcomes from commercial trading. An example of a physical risk would be a blackout following the failure of a large generator or distribution line. An example of a commercial risk would be lower than anticipated profits for a generator or higher than anticipated electricity costs for a consumer due to unexpected market price behaviour.

In power system jargon, the causal events associated with physical risks are known as contingencies, and a core objective of power system operation is to minimise both the probabilities of contingencies and their consequences. This leads to operating strategies such as security-constrained dispatch.

Clearly there are links between physical and commercial risk as the following examples illustrate:

- Excessive zeal in implementing security-constrained dispatch may restrict network utilisation to the extent that unfavourable commercial outcomes (such as those listed above) occur in an associated LMP market.
- Conversely, reluctance to take precautionary measures to reduce threats to power system security may exacerbate commercial risks. For example, it is likely that the six-week Auckland blackout could have been reduced or even largely avoided by early intervention to reduce the thermal stresses on the underground cables that eventually failed catastrophically. Instead, a small commercial risk was converted into a much larger one through what in hindsight were inappropriate operating decisions.
- It is often true that physical risks can be reduced by increasing expenditure on equipment purchase and on power system operation and maintenance. Thus reduced physical risk may come at a cost. Moreover, taking network equipment out of service for maintenance may directly induce increases in LMP market prices, by lowering network flow limits and making it more likely that they will become binding.

Introducing competition into an electricity industry may increase many physical risks because of pressures to reduce supply industry costs. However the most direct change is with respect to customer risks associated with loss of supply or poor supply quality. Under the traditional regulatory compact, customers accepted regulator-supervised supply standards in return for regulated tariffs. Except for extreme events, traditional utilities were judged by their average performance by customer class or region. In a competitive market with individually negotiated contracts, customers expect direct accountability for the supply availability and quality that they experience. Moreover, customer expectations of availability and quality are rising with increasing value being derived from electrical technology and increasing equipment sensitivity to poor availability or quality. In response, demand-side options such as uninterruptible power supplies and stand-by generators are becoming more common.

In summary, the risks associated with unreliable or poor quality supply are growing and so is the interest in managing these risks commercially.

In most power systems, distribution and sub-transmission network events dominate the physical risks that customers experience from unreliable or poor quality supply. Inadequate generation capacity may sometimes be an important risk factor, particularly during summer or winter peak load conditions. Load-shedding or voltage reduction may be appropriate operator responses to some contingencies, in which case preferential treatment may be given to certain customers.

Distribution and sub-transmission networks are usually on the consumer side of wholesale electricity markets and thus the related consumer risks are matters for distribution industry regulators or retail market design rather than wholesale market design. Customer contracts or commercial law may provide some financial compensation to customers if they experience unreliable or poor quality supply.

A number of steps might be taken to commercialise the physical risks associated with transmission networks in wholesale electricity market design, including the following:

- Network service providers could be given commercial incentives to avoid network maintenance outages during high-price periods
- Network service providers could be required to offer generators and consumers "firm access contracts" that provide financial compensation if network access is constrained.
- Real-time wholesale market prices could be set to their price ceiling if load is about to be shed (this can provide compensation to those consumers holding futures contracts and encourage others with futures contracts to voluntarily reduce demand).

Is the preferred implementation in the Western System likely to differ significantly from that on the East Coast?

Differences might arise for a number of reasons including the following:

- Power system operating constraints might map more accurately to specific network elements in one case than the other.
- Traditional industry operating protocols and State-level regulatory policies may differ sufficiently to justify a different initial implementation of wholesale competition even if the long-term goal is similar.

General observations and conclusions

Electricity industry restructuring is a cultural process and theoretical analysis can only provide a guide not a detailed prescription. In particular, theoretical analysis is more useful in defining a preferred end-point than in choosing a transition path in a process that is likely to take a decade or more to complete. Having said that, I will venture the following opinions:

- A key feature of any wholesale electricity trading framework should be an efficient real-time (eg. half-hour ahead) commodity market that incorporates a network model of appropriate detail.
- The Balkanised nature of transmission networks in the USA means that there are significant transmission flow constraints that should be modelled in wholesale electricity markets. However these may not always map well to individual network elements.
- It may be worthwhile exploring hybrid trading models that contain features of both FG and LMP approaches.
- Risk management should be based on financial instrument trading rather than traditional "physical" contracts. It should combine auction-style futures trading with more specialised bilateral trading.

The following papers provide more background on the Australian implementation of electricity industry restructuring:

H R Outhred and R J Kaye, "Incorporating Network Effects in a Competitive Electricity Industry: An Australian Perspective", Chapter 9 in M Einhorn and R Siddiqi (eds), *Electricity Transmission Pricing and Technology,* Kluwer Academic Publishers, 1996, pp 207-228.

H R Outhred, "A Review of Electricity Industry Restructuring in Australia", *Electric Power Systems Research*, 44 (1998), 15-25.

Epilogue, October 2000

The debate between the proponents of Flowgates and Locational Marginal Pricing has continued since the MEET conference and shows only limited signs of convergence. This is not surprising, as it is not a simple either-or choice. In my view, electricity market design requires compromise choices between a range of design criteria that should be made in a broader context than that adopted for the "MEET debate". I believe that the set of questions defined above remain both relevant and yet to be fully addressed by proponents on either side of the debate.

Market design can be approached as an evolutionary process that may start from a range of initial implementations. As an (imperfect) example of this process, readers may wish to consider the following two references. The first of these references outlines the strengths and weaknesses of network representation in the Australian wholesale National Electricity Market (NEM) as of 1998 and proposes a number of improvements. The second reference is the current official proposal by the National Electricity Code Administrator (NECA) for improving network representation in the NEM. It largely adopts the strategy suggested in the first reference, recommending a staged implementation providing greater detail and other refinements for the existing hub-and-spoke model rather than (for example) the adoption of "full nodal pricing" because its net benefits are regarded as "arguable":

> "Without a firm hedging mechanism, which would be difficult if not impossible to devise, it [full nodal pricing] would expose participants to largely illiquid markets and therefore unacceptable risks. Moreover, nodal pricing that would allow the co-optimised despatch of active and reactive power is currently incompatible with five-minute despatch and pricing" (NECA Summary Draft Report, October 2000).

Rules for network pricing and regulation are being refined in parallel with the changes to network representation in the NEM. These refinements are designed to improve contestability of network augmentation by distributed resources. Information about these proposals is also available from the NECA web site (www.neca.com.au).

References to Epilogue:

H R Outhred, "Network Pricing - Proposals in the National Electricity Code", Australian Competition and Consumer Commission / University of Melbourne, Electricity Transmission Network Pricing Conference, 14-15 December 1998.

National Electricity Code Administrator (NECA), "The Scope for Integrating the Energy Market and Network Services", Draft Report (Summary Report plus Vols 1-4), October 2000 (www.neca.com.au – what's new?).

Appendix B: Some Insights from Electricity Pricing Theory

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Introduction

Electrical energy in an electricity industry has specific properties of ephemerality and fungibility that imply the potential for rapid change, as well as spatial continuity from the internal wiring of generators to the internal wiring of loads. However the commercial implementation of electricity markets requires discretisation in both time and space. Temporal discretisation is required to permit use of the concept of a spot market period sufficiently long to support commercial decision making in response to price signals, while spatial discretisation is required to allow use of the concept of commercial agents – generator, consumer and network service provider (NSP) decision makers. Electricity spot markets are thus an abstraction from the physical reality and provide an incomplete description of the physical reality. This discussion focuses on the temporal aspects of this abstraction. Outhred and Kaye (1996) provide further discussion of the spatial discretisation abstraction.

Theoretical electricity pricing results for electricity spot markets are obtained by finding the pricing formulation that maximises the industry benefits of trade[12] between electricity generators and consumers subject to mathematical constraints that represent physical power system behaviour. The key power system constraint is supply-demand balance. Network flow constraints may also be included in various forms as discussed in Outhred and Kaye (1996).

The theoretical results are derived as follows for an electricity industry with physical behaviour that can be adequately described by a sequence of spot markets. That is, ancillary services are neglected.

A single corporation that owned all electricity generating, network and consuming equipment in an electricity industry, and had accurate knowledge of all costs and values including externalities, could determine a set of decisions about equipment operation and investment that would maximise industry benefits of trade. The optimal electricity pricing policy is that which would cause autonomous generator, NSP and consumer agents respond to it in an identical fashion (Outhred et al, 1988). Note that active demand-side participation is required to achieve optimality.

Results when network effects and intertemporal links are neglected

Network effects can be neglected for a simple electricity industry model in which all generators and consumers are assumed to be at one location.

If it is also assumed that there are no inter-temporal links, decisions taken for the current spot market period do not restrict decisions that may be taken for later spot market periods. With these assumptions, the optimal pricing policy is short run marginal cost (SRMC) – the cheapest way to provide an additional unit of electrical energy in the current spot market period. Assuming an active demand side, SRMC is the lesser of:

- The incremental cost of increasing the output of the operating generator that has the cheapest incremental cost of those not yet operating at full capacity, and

[12] Assuming that participants' costs and benefits are independent, industry benefits of trade can be defined as the sum of the welfare derived by consumers from using electricity minus all operating costs of delivering electricity to consumers' premises, using existing equipment.

- The incremental loss of benefit to the least profitable consumer.

SRMC is the market-clearing price that applies to the energy produced or consumed by all generators and consumers in the spot market period. Given the lack of cost-effective storage of electrical energy, SRMC may change substantially from one market interval to the next, hence the use of the term “spot market”.

SRMC should be set at or prior to the start of the spot market period so that it can be determined by incremental loss of benefit (demand elasticity) as well as incremental cost. Each spot market period should be short, so that the set of operating generators and the level of demand are approximately constant during the period. However the spot market period should not be so short that sound commercial decisions cannot be made or that limits to the rate of physical response prevent them being implemented.

This pricing formulation assumes perfect information about costs and benefits, however in a competitive industry, participants will not wish to reveal this information (known as the participants’ preferences). Industry structures must achieve adequate supply- and demand-side competition. Practical market designs must elicit preference-revealing behaviour and incorporate all significant external costs and benefits. Industry regulators should monitor market behaviour.

Results when network effects are included

Outhred and Kaye (1996) discuss the inclusion of network models in the optimisation problem and Smeers (2001) provides a recent perspective on network representation in bulk electricity trading.

The optimal pricing policy is a set of nodal prices, with characteristics that depend on the type of network model employed (for example transport, DC loadflow or AC loadflow). Including a network model doesn’t create an insurmountable algorithmic problem, however it does introduce problems of other kinds. With more detailed network models it becomes harder to induce preference-revealing behaviour because the network-wide market becomes subdivided into local markets, each with fewer participants and thus less competitive pressure. Also, it becomes less likely that there will be local supply-demand balance, leaving the local NSP in a dominant position in each local market. Network flow constraints can be difficult to incorporate in a non-controversial manner because they may be probabilistic rather than deterministic and they may not map well onto specific network elements. Nodal voltage limits may determine flow constraints and should be represented by voltage-value functions rather than traditional technical criteria.

Results when intertemporal links are included

Inter-temporal effects also introduce additional complexity. On the demand side, inter-temporal effects may include product storage and startup or shutdown sequences. There are similar effects on the supply side including unit commitment, hydro scheduling and the management of fuel stockpiles or maintenance schedules. Investment decisions and environmental externalities may have particularly important long-term inter-temporal links.

To account for inter-temporal links, decisions must optimised over time, making rational trade-offs between present and future benefits of trade. The concept of long run marginal cost (LRMC) is a traditional example of inter-temporal pricing. Unfortunately, the calculation of LRMC requires the assumption of a perfectly known future, inappropriate for a restructured electricity industry. More realistically, uncertainty clouds the future in a manner that may not be well modelled by standard statistical techniques.

Kaye and Outhred (1989) describe the theoretical result that is obtained when inter-temporal links and future uncertainty are incorporated into the optimisation problem. The optimal pricing policy for each market period should then contain two terms:

- SRMC as previously defined but now bids and offers must take account of alternative future opportunities based on forecast SRMC probability distributions
- A participant-specific incentive term that is the marginal effect of the participant's present decision on the future benefits of trade via its effect on the forecast of future SRMC.

The first term in the optimal pricing policy with inter-temporal links implies that an efficient spot market must be supplemented by efficient markets in contracts for difference and options to produce forecasts of future SRMC probability distributions. The combined effects of electricity spot and forward markets on participant decisions and outcomes are discussed in Kaye et al (1990). Price discovery in forward markets will be difficult to achieve. Outhred and Kaye (1996) proposes the use of spatial and temporal aggregation to maintain adequate levels of competition as forward projection increases.

The participant-specific incentive term in the optimal pricing policy with inter-temporal links can be regarded as a societal response to the potential of a participant to exercise market power. Its practical implications require further study. There are some preliminary discussions in Kaye and Outhred (1989) and Outhred et al (1988). Some brief comments follow.

The participant-specific incentive term would be small for any participant that, because of its small size and behaviour that was uncorrelated with other participants, did not have an impact on future SRMC probability distributions. Such a participant would be a price taker in both spot and forward markets.

Electricity industries typically consist of relatively few large generators supplying relatively many small loads; therefore participant-specific incentive terms are more likely to be required for generators than retailers or consumers, for example large thermal power stations and hydro schemes. However participant-specific incentives may also be required on the demand side.

One likely demand-side example is temperature-sensitive load such as air-conditioning, where a large number of devices may consume in a correlated fashion. Other examples may arise when distribution network losses and constraints are taken into account, because embedded generators and large loads may then be significant in size relative to local network flow constraints, as well as affecting network losses, voltage profile and waveform purity.

Price-maker effects can also arise in the very short term, when some generators may be operating at ramp-rate limits and generators that are off-line are delayed from entering the market by start-up constraints. This is an important issue for the design of ancillary service markets (Outhred, 2001).

Network-related incentive terms may be required if network models are incorporated in electricity markets because network service providers are likely to be dominant players in local electricity markets. The industry model used in Kaye and Outhred (1989) is a single-node model that neglects network effects, however some inferences about networks can still be made:

- The results for the single node model should still apply for wholesale markets in strongly meshed transmission networks.

- The effect of binding network flow constraints is to divide a network-wide market into smaller markets, increasing the risk of price-maker effects. Therefore, binding network constraints increase the importance of the participant-specific term for NSPs and locally dominant generators or consumers.
- A dispatchable interconnector between two transmission regions can be regarded as a load in the sending region and a generator in the receiving region. The need for a participant-specific incentive for the interconnector should be assessed in both regions for each direction of flow.
- It seems unlikely that radial distribution networks could support efficient local electricity markets because of difficulties with obtaining adequate price-discovery and the need for participant-specific incentives.

Thus it seems likely that there will be situations in electricity industries where participant-specific incentive terms will be important for decision making with either short or long term inter-temporal links. However future uncertainty prevents accurate and objective calculation of incentive terms. A practical response may be to implement regulator-supervised negotiating frameworks to develop consensus investment or operating strategies as well as to consider allocation of costs and benefits, for example via forward price curves and forward contract quantities. Moreover, when inter-temporal links are important, regulators or governments must consistently initialise spot and forward markets (for example via vesting contracts) to avoid severe transients when the markets commence operation.

Summary

Electricity pricing theory provides important insights into the practical implementation of electricity industry restructuring but does not provide easy answers. These insights suggest that a pool-style model for wholesale electricity trading is likely to be more appropriate than bilateral trading. They also suggest that retail market design is as important as wholesale market design and that forward market design is as important as spot market design.

The following wholesale market processes specified in the Australian National Electricity Code seem to be a useful start in supporting decision making with inter-temporal links while capturing some of the public interest aspects inherent in the participant-specific incentive term. However these features are yet to be complimented by equivalent retail market features and they should be formalised in forward market processes:

- The “hub and spoke” regional spot market model with processes for adjusting market region boundaries and network loss factors that modify the network models in the market in line with evolving conditions. This model balances nodal detail with nodal aggregation sufficient pressure to reveal preferences. NECA’s recommendation to modestly increase the number of regions is appropriate subject to review of its implications for the exercise of market power.

- The pre-dispatch process, which requires participants to initially submit spot market bids one day ahead but allows “re-bidding” under defined rules until spot time. This could be formalised in a compulsory “technical” forward market as discussed in Outhred and Kaye, 1996.

- The “projection of system adequacy” (PASA) process, which projects supply/demand balance up to two years ahead based on “best endeavours” submissions by participants. This could be formalised in a “financial” forward market as discussed in Outhred and Kaye, 1996.

- The “statement of opportunities” process (SOO), which projects supply demand balance up to ten years ahead and identifies situations of potential supply constraint. As with the PASA process, this could be formalised in a forward market process.

Australian retail electricity markets are still in an immature state, with significant distortions due to vesting contracts and regulated franchise tariffs. There are important opportunities to improve the economic efficiency and environmental sustainability of these arrangements without forgoing social accountability. This could be done by adopting an ancillary service, spot and forward market model that was consistent with wholesale market design but suitably simplified and appropriately regulated.

For example, retail tariffs for small consumers could be based on regulator-set forward contracts that incorporated quantity and price profiles (including network-pricing components). These forward contracts could be in the form of vesting contracts to apply for a limited number of years, or be more permanent features of retail market implementation. An argument for the latter approach derives from the dominant role of distribution network service providers in retail markets.

The aggregated quantity profiles (along with similar profiles for larger contestable customers) would provide commercially consistent local demand forecasts to guide investment in network augmentation, embedded generation or demand management. Differences between forward and spot quantities, measured by interval metering, could be traded at a local spot price that included wholesale market and network pricing components. This would permit small consumers to be rewarded for reducing demand at times of local or system-wide constraint and also provide appropriate signals for investment in distributed generation or demand management. Very small consumers and disadvantaged consumers could remain on regulated tariffs without interval metering.

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