Evolution of Wholesale Power Price Structures in the Western Power Market

Implications for US Power Markets

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The Western wholesale power market was the first in the US to be effectively deregulated. In 1987, the Federal Energy Regulatory Commission (Ferc) approved the implementation of the Western Systems Power Pool (WSPP), which gave utilities much greater latitude in setting bulk power prices and transmission rates in interstate trade. Marketers were allowed to enter the pool in 1993, and trading began in earnest. In May 1996, the New York Mercantile Exchange (Nymex) launched futures contracts for power traded at the California–Oregon Border (COB) and at Palo Verde, Arizona.

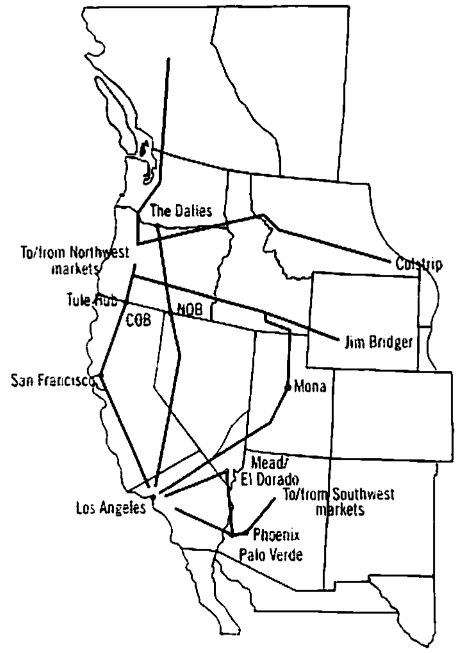
The change in the wholesale power market has been rapid and dramatic. Nevertheless, the region's institutions have accommodated this transition, with the market structure proving to be both flexible and efficient. Bulk power prices throughout the region have converged, which suggests that a single market exists, westward from the Rockies, north to Canada and south to Mexico. No single institution dominates generating capacity or sales to power marketers in the region. Over 100 companies either buy from, or sell power to, marketers within the region; and not one of these has a market share greater than 15%. The Bonneville Power Administration has the largest generation capacity, standing at just below 15%. The synchronous movement of prices within the region, combined with a fragmented and diverse group of suppliers, indicate that there is substantial competition in the market.

Wholesale power prices in the Western market tend to be only a small fraction (sometimes less than one fifth) of retail rates. Power prices are determined through bilateral negotiations among the utilities and marketers of the region, without an organised exchange or any central authority being involved. Low prices and the competitive nature of wholesale trading should result in substantial benefits for retail customers once direct access is allowed. Such access, however, must be granted by state regulators, since it is not normally under the control of federal authorities.[1]

Despite the obvious success and importance of the market it helped to found, the WSPP is rarely held out as a model for other regions. Clearly, wholesale and retail markets differ significantly; similarly, the wholesale structure and history differ from region to region. There may, however, be lessons from the Western region that can inform the process of regulation. The current debate may be too closely focused on complex and potentially costly power pool alternatives, with some of these proposals likely to result in the exchange of one form of regulation for another.

The emphasis on the detailed and highly structured pool approach, rather than direct reliance on market forces, may derive partly from the assumption that deregulation requires restructuring of the industry. Vertical integration has been a primary organisational feature in the power industry, brought about partly by the service requirements imposed through regulation itself. When a utility's franchise was contingent upon fulfillment of an obligation to serve all comers, the maintenance of specific reserve levels, etc, the incentives for vertical integration were clear. This integration also solved many of the

1. Major transmission lines in the Western Systems Coordinating Council



technical concerns regarding grid operation and reliability. Thus, if deregulation and divestiture are to proceed together, a mechanism must be found to replace not only the functions performed by regulation, but also those performed by an integrated industrial structure.

We must therefore evaluate the extent to which market forces can efficiently perform these functions. Is extensive restructuring a necessary adjunct to deregulation and a competitive market, or is divestiture necessary or desirable? These questions, still unresolved, are beyond the scope of this chapter. However, in our view some of the answers may be found in existing market institutions. The Western wholesale power market, while still evolving quickly and open to improvement, deserves close study.

Background and structure of the Western power market

The Western power system includes all or a portion of 14 separate states, with additional linkages to Western Canada and Mexico.[2] The region has over 100,000 miles of transmission lines, connecting five major areas: Northwest/Northern Rockies; Northern California; Southern California; Central Rockies; and inland Southwest. The generation types and capacities (supply), and load profiles (demand), vary enormously among these sub-regions. It is this considerable diversity that first created the incentive to trade.

The Western system's generating capacity is approximately 150,000 megawatts (MW), about 19% of total capacity in the US, with production being dominated by hydroelectric resources (at 42% of the total), followed by gas and coal (each close to 24%). Figure 1 depicts the Western region and some of the major transmission lines within that system. Most of the transmission lines are capable of moving power in either direction. As a general rule, however, California imports more power than the other regions. Figure 2 shows transmission capabilities among the major sub-regions of the West.

The US portion of the Pacific Northwest (Washington, Oregon and Idaho) is dominated by an enormous set of federally sponsored and operated hydroelectric dams, located in the Columbia River drainage area. It is further characterised by the large volume of retail power (with over half of the consumption in Washington State) sold by public agencies: municipalities, electricity cooperatives and public utility districts. Partly due to the long history of public power development, electricity in this region has been perceived as the cornerstone of economic development. As with the petroleum industry in Alaska and Texas, the politics and economics of power development and control in the Pacific Northwest cannot be easily separated. Moreover, because half of the power supply is from federal

2. Transmission capability between the regions of the Western Systems Coordinating Council

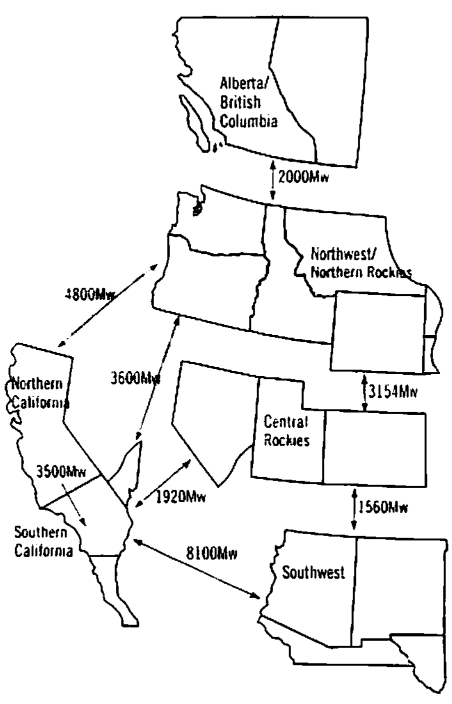


Table 1. Estimated average revenue per kilowatt-hour for US electric utilities by sector, census division and state, 1994 and 1995 (Cents /kilowatt hour)

Census division and state	ALL SECTORS		RESIDENTIAL		COMMERCIAL		INDUSTRIAL		OTHER[1]	
	1994	1995	1994	1995	1994	1995	1994	1995	1994	1995
Mountain	6.2	6.1	7.7	7.6	6.8	6.6	4.4	4.2	5.6	5.6
Arizona	8.1	7.7	9.6	9.1	8.6	8.0	5.7	5.3	5.7	5.3
Colorado	6.1	6.2	7.4	7.5	6.0	6.1	4.6	4.5	7.9	8.2
Idaho	4.0	4.1	5.0	5.3	4.3	4.5	2.8	2.8	4.7	5.0
Montana	4.5	4.6	5.8	6.0	5.1	5.3	3.3	3.5	4.3	4.6
Nevada	6.4	6.1	7.2	7.2	7.0	6.8	5.4	5.1	5.2	5.0
New Mexico	7.2	6.7	9.1	8.9	8.4	7.8	4.7	4.3	5.7	5.8
Utah	5.4	5.3	6.9	6.9	5.9	6.0	3.8	3.8	4.4	4.5
Wyoming	4.2	4.3	5.9	6.1	5.0	5.1	3.5	3.5	7.1	6.4
Pacific (Contiguous)	7.6	7.7	8.9	9.0	9.1	8.9	5.2	5.5	5.0	4.8
California	9.8	9.9	11.4	11.6	10.9	10.6	7.0	7.5	5.8	5.2
Oregon	4.6	4.7	5.3	5.5	4.9	5.1	3.4	3.5	5.0	6.0
Washington	4.0	4.1	4.9	4.9	4.7	4.8	2.8	3.0	3.7	3.8
Pacific Non-contiguous (AK, HI)	10.5	10.9	11.9	12.5	10.7	10.9	8.8	9.1	11.7	13.3
New England	10.2	10.4	11.5	11.8	10.0	10.2	8.3	8.2	13.4	14.2
Middle Atlantic	9.5	9.7	11.5	11.8	10.3	10.5	6.1	6.2	9.3	9.6
East North Central	6.4	6.5	8.4	8.5	7.3	7.4	4.4	4.5	6.6	6.6
West North Central	6.0	6.0	7.4	7.4	6.3	6.2	4.4	4.3	5.4	5.8
South Atlantic	6.5	6.6	7.8	7.9	6.6	6.6	4.6	4.6	6.5	6.3
East South Central	5.1	5.1	6.2	6.2	6.3	6.2	3.9	3.9	5.9	5.7
West South Central	6.3	6.0	7.9	7.6	7.0	6.6	4.3	4.0	6.8	6.4
US average	6.9	6.9	8.4	8.4	7.8	7.7	4.7	4.7	6.8	6.7

Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions".

[1]Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and inter-deparmental sales.

Notes: Estimates represent weighted values. Weather-related phenomena, reclassification of retail sales, changes in number of customers, prior period adjustments and changes in billing procedures may contribute to substantial year-to-year changes in the data in this table. The average revenue per kilowatt-hour of electricity sold is calculated by dividing revenue by sales. Totals may not equal sum of components because of independent rounding.

projects, the debate has frequently been elevated to a national level.

In contrast to the Pacific Northwest, California's electricity system is dominated by private companies, the most prominent being Pacific Gas & Electric (PG&E) and Southern California Edison, and the smaller utility, San Diego Gas & Electric. Municipal utilities, such as Sacramento Municipal Utility District and the Los Angeles Department of Water and Power, are less significant, both in terms of the numbers of customers served and political consequence. The state's generation is predominantly fuelled by gas, with hydroelectricity next in importance. In the late 1970s, California's utilities invested in some high-cost nuclear power. In addition, state regulators saddled many of its utilities with high-cost PURPA (the federal Public Utility Regulatory Policies Act of 1978) contracts.[3] The combination of expensive power production and transmission (caused by high population density in urban areas) resulted in retail power rates in California being much higher than in any of the neighbouring states. Table 1 summarises power rates in the Western system by state, providing comparisons with other regions and the US average. As one can see, California's residential, commercial and industrial rates are the highest in the Western region, over twice those of Washington, Oregon, Idaho and Montana.

California's neighbours in the Central Rocky Mountain sub-region (Utah, Nevada and Colorado) have relatively low population densities and ready access to supplies of coal and gas for thermal generation. For years, California's utilities eyed the vast space to the east – in Nevada, Utah and Arizona – for potential generating sites. Often the sites were adjacent to coal mines or rail transportation. In most instances, California's stringent air quality standards could also be avoided by locating generation facilities in other states. The Hoover Dam, on the Colorado River at the corner of Nevada, California and Arizona, plus the development of nuclear facilities at Palo Verde, Arizona and the Intermountain Coal Project in Utah, necessitated a transmission infrastructure that would serve the California market.

The backbone of the Western power market is, however, the Pacific Intertie, whose construction began in 1966 (the project combines three AC and one DC lines, which connect the Pacific Northwest and California).[4] While the scheme made enormous economic sense, it was politically controversial from the start. Mistrust seems

These concerns are somewhat mitigated by the ability of the region to separate into self-contained islands when problems occur. The regional exchange of power does not, therefore, necessarily require the import and export of problems as well as power.[6]

Ferc deregulates the Western market

Active power trading began in 1971, with completion of the Intertie. Early trading did not really constitute a market, formal or otherwise; it was mainly a set of exchanges between large utilities. However, by the early 1980s the potential for trade was well recognised, as many private utilities throughout the West noted the opportunities for arbitrage. As this trade was conducted at the wholesale level, regulation fell to Ferc, rather than local jurisdictions.

In the early 1980s, Ferc began experimenting with energy deregulation: firstly with interstate gas pipelines, and then in selected power markets. In 1983, PG&E filed an application to Ferc on behalf of Western utilities, proposing the creation of the WSPP. The idea behind the pool was to establish a more relaxed framework for trading in the Western region and to allow member utilities greater discretion in setting bulk power prices and transmission rates. Ferc agreed to the creation of the pool, and trading under its rules began in May 1987. By the end of 1989, 11 public agencies and 12 private utilities had joined.

By the early 1990s, wholesale trade in the Western region was effectively deregulated for bulk power prices and transmission, the only such region in North America. This was advantageous for the market, as it increased the pace of its development. Although trade was vigorous, it was still confined to existing utilities that bought and sold power from one another. Independent power producers (IPPs), large industrial customers, brokers and marketers were barred from direct trading by custom and regulation. However, the transition was hastened as a result of the Energy Policy Act of 1992 (and its recognition of exempt wholesale generators and provision for Ferc licensing). In September 1993, WSPP membership was granted to its first marketer, the Louis Dreyfus Electric Power Company. Since then, 46 marketers have joined the WSPP.

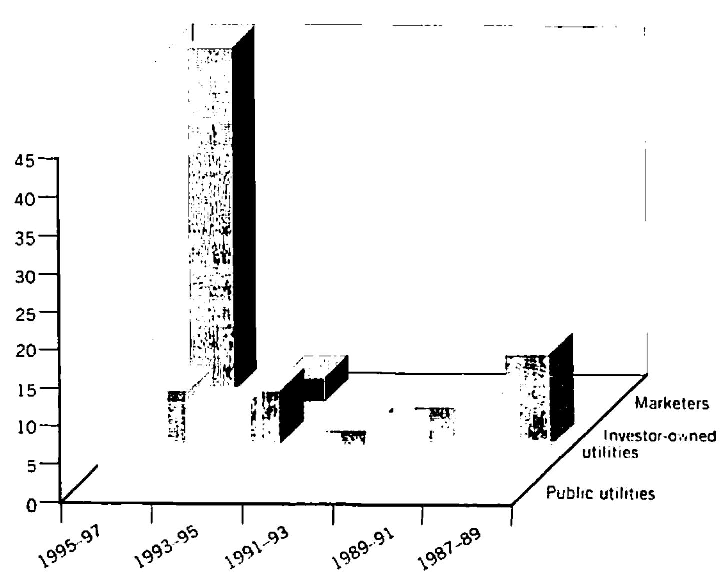
The participation of public utilities in the WSPP is substantial. It now contains 54 such organisations, including municipalities, public utilities districts (Puds), co-operatives and federal agencies. Some of these entities are quite small and not actively trading. The growth in membership is highlighted in Figure 3.

Nymex establishes the electricity futures market

Interest in power trading in the Western system has expanded rapidly since 1993. To a large extent this growth was force-fed by three factors: the advent of futures trading; California's "Blue Book" plan in 1995,[7] which was aimed at deregulating its power market; and the keen interest of energy-trading companies.[8] It is worthy of note that a number of the region's key utilities (such as PG&E, PGE and the BPA) openly embraced and supported the change. Even though California's deregulation plan has thus far proven to be less sweeping than anticipated, Nymex was able to launch electricity futures and options in a remarkably short period of time.

For an electricity futures market to operate, there must be a transparent connection between the physical market for the commodity and futures trading in it. This requires product standardisation and price "discovery", the collection and wide dissemination of objective price information. In 1994, PG&E led an industry committee aiming to collect and publish daily prices at COB. The object was to establish an "index", around which traders could negotiate contract prices, with Dow Jones being selected to publish the index in the *Wall Street Journal*. Recently, the Dow Jones index was expanded to include Palo Verde and Mid Columbia. In addition, there are three newsletters providing detailed price and market information.[9]

3. New membership in the WSPP



In May 1996, Nymex launched its COB and Palo Verde futures contracts.[10] Futures trading in the electricity market had been anticipated ever since the successful initiation of Nymex's natural gas contract. The actual launch of the electricity contract, however, was a signal to brokers, marketers, independent power producers and industrial buyers that the deregulation movement was both genuine and impending. So far, the response in interest, if not in trading, has been substantial.

Trading in today's market

The current structure of the wholesale electricity market in the Western system is characterised by bilateral negotiations, as compared with the more formal bidding systems of the UK or that proposed for California. The bilateral trading system is an extremely sensible one for the Western region, given the geographic differences and generating diversity that creates opportunities for gains from trade. On the morning of each business day, traders, power marketers and utilities negotiate prices for power. Buyers evaluate their own contract situation, trying to find the correct combination of generating and transmission charges that will give the lowest cost for a delivery objective, just as each seller tries to find the highest.

These sales and purchases can be made, depending on the preferences of the individual trader, through direct telephone contacts, with or without information from electronic bulletin boards. Under Ferc Order No 889 (April 1996), public utilities that own, control or operate interstate transmission facilities must participate in an information network, providing information on available transmission capacity, prices and other information to open-access customers. These OASIS (Open Access Same-Time Information System) networks allow customers to view and purchase available transmission capacity and ancillary services, which are posted on an hourly, daily, monthly and yearly basis. These systems, most of which began operation in early 1997, are the means by which non-discriminatory transmission access to wholesale sellers and purchasers of electricity can be provided. Although it is too soon to assess the effectiveness of these innovations, they underscore the commitment of federal regulatory authorities to deepen and broaden power market deregulation.

Most power in the Western system is now being traded on a short-term basis, for one year or less. In this short-term market, two types of purchase/sale contracts are the most popular – daily and monthly. For both of these contracts, pricing is well known and widely published in the indexes and publications mentioned earlier in this chapter. Longer-term sales or exchange contracts are increasingly being negotiated with pricing terms linked to the daily or monthly prices.

In many monthly and daily sales contracts, the industry divides the day into peak and off-peak periods. Peak hours (and thus peak power) are defined as the 16 hours from 6am to 10pm, six days a week. Off-peak hours (and power) are the eight hours from 10pm to 6am, and all day Sunday. This approach is quite different from that of many other regions in the US (and the proposed California exchange) and internationally, where prices are determined on an hourly or even half-hourly basis. In general, power prices in the Western system are at constant levels across these hours within the two basic time groupings.

There are two principal reasons for the present structure. Firstly, the West has a large share of hydro generation, not only in the Pacific Northwest, but also in Nevada, California and the Rocky Mountain states. Hydro power can be used to shape the generation economically, given costs that are relatively stable from hour to hour within and between the peak and off-peak periods. Secondly, the purpose of frequent pricing (every half-hour or hour) is to attain an efficient result where prices closely follow the "system lambda", or marginal generating cost of a pool or utility. Using a "block" pricing structure reduces transaction costs (compared with half-hourly or hourly pricing), making it economical to sell power in larger blocks.

Both monthly and daily prices are forward prices, being negotiated in advance of generation and delivery. Daily prices are referred to as "prescheduled" (in the UK they are called "day-ahead"). As power is generated, dispatchers will often negotiate "real-time" prices to fill gaps in scheduled power flows or in the event of an emergency. The real-time market is, however, episodic and does not constitute the focus of marketing and planning activity; that role lies with the daily prescheduled market.

The Western system has also seen rapid changes in the level and structure of pricing for capacity (the back-up generators that modify non-firm power in a thermal system, so that it can be sold as firm). Originally, it was thought that a daily or monthly contract to sell firm

PANEL 1

COMMODITISATION

Samuel A. Van Vactor

In recent years, traders and market pundits have described the "commoditisation" of certain markets that have undergone technological or regulatory evolution.[1] In the marketplace, commoditisation can mean many things. To some, it simply means greater competition and lower profit margins. The term should be used more profoundly, however, to denote the fundamental change in the market structure for particular goods and services. In this sense, commoditisation may be described as a transition from a "closed" to an "open" market. In the last few decades, such structural changes have occurred in the markets for foreign currency, air travel, long-distance telecommunications, personal computers, petroleum and natural gas. The petroleum and natural gas markets are of particular interest, as they are similar in structure to the power market and that active futures trading has accompanied (if not provoked) their market transition.[2]

In the view of many power company executives, their industry is poised for sweeping change, which will include full-scale commoditisation. This transformation could encompass regulatory change, mergers, vertical disintegration, a host of new competitors and an explosive upturn in trading as new markets are opened. If this supposition becomes reality, much can be learned from those predecessors who faced the same plight.

To some extent, deregulation provoked the transformation of many industries that were previously regulated. In particular, the North American natural gas industry (which has the closest parallel with the power industry) was heavily regulated. Federal deregulation of interstate gas transport created an open market for wholesale gas with much lower prices. Deregulation also fostered competition in the long-distance telecommunications market at the retail level – telephone rates have fallen dramatically, due, in part, to increased competition. It has been the success of gas and telecommunications deregulation that has provided much of the political incentive to deregulate the power market.

Deregulation is not, however, the only explanation for the complex structural changes that have taken place in these markets. The ubiquitous penetration of inexpensive electronic computing and comprehensive information systems has provided the technological base necessary for an open market. Petroleum, gas and power are complex commodities which have many gradations of market value, dependent as they are on such factors as quality variations, location or timing of delivery, etc. In the 1970s, for example, it would have been very difficult for thousands of traders to keep a daily track of the relative values of hundreds of different types of crude oil. Likewise, the natural gas market involves thousands of delivery points, differing levels of pressure and, in the commodity's raw state, a variety of impurities and thermal values.

As we will show, the experience of the oil and gas industries suggests that there are five major components in the transition from a closed to an open market:

- ❑ as markets are opened, a commodity typically becomes *unbundled* from other products and services normally associated with its sale;
- ❑ this unbundling accompanies *price discovery*: the collection and dissemination of pricing information;
- ❑ price discovery necessitates some sort of *product standardisation*, in order that prices can be reliably compared;
- ❑ dissemination of prices that identify geographic and other quality differences creates the opportunity for quick profits, which, in turn, attract traders and new firms to the industry, increasing the *liquidity* of the marketplace;

power required continuous back-up reserve capacity as well as generation. As power marketers entered the business, however, they calculated that such an extensive back-up was not required. In most cases, it was only necessary to contract for one hour of back-up capacity. This means that, in the event of a power outage, the power supplier will have one hour to find an alternative in the real-time market. Although the power in such a situation may be expensive, the likelihood of the event is low and the average cost of performing will be cheaper. The consequence of this behaviour has been a narrowing of the difference between "firm" and "non-firm" power prices, with one-hour firm becoming the most common product category.

- if prices prove to be volatile (as most energy prices are), inefficient companies will face financial peril, having to transform themselves to survive. As a consequence, forward markets develop and futures trading becomes a necessity, *allowing price risk to be separated from contracts for physical delivery.*[3]

Unbundling

The dramatic change in the computer market is a primary example of unbundling. The hardware underlying many computers is considered a "commodity" – parts are interchangeable and practically anybody can get into the business. A couple of decades ago, computers were sold primarily as mainframes in a proprietary package, with hardware, software, maintenance and training being bundled together under a single fee. Economic rent in the industry is now garnered from specific components (such as the processor chip) or from specific operating systems and application software.[4]

During the period of natural gas deregulation, the term "unbundling" was mostly used to advocate the pricing of gas separately from transportation and inventory services. In the 1970s, industrial customers often paid a single price throughout a utility's service district. The regulated price sometimes reflected the cross-subsidisation of the residential sector, and usually failed to account for the economies or diseconomies of particular customers. It seldom, if ever, matched the utility's marginal cost of delivery.

Separating the market value of a product from the price of associated services and other products in a closed market is a complex and often impossible task, as independent prices for the goods and services bundled together are seldom available. Moreover, the entire package often includes a complex term structure, where the sales price is an amalgam of current market conditions and expectations about the future. Prices in one contract (or regulated market) are not usually comparable with prices in another, which may leave buyers and sellers in a state of confusion and prices not satisfactorily performing their equilibrating role. The consequence of this may be an endless cycle of mismatch between demand and supply.

Price discovery

Efficient markets require reliable information about prices, as they facilitate trade and investment decisions. The bulk power market in the Western US was exchanging power at average prices of $20–30 per megawatt hour (MWh) in the late 1970s and early 1980s. At the same time, power utilities reckoned their avoided costs at more than $100, while state and federal authorities were approving or coercing[5] investments that would be viable only at such prices. There was no connection between price signals and investment decisions. This is partially responsible for today's "stranded cost" regulatory problem.

Price discovery and unbundling go hand in hand. In the case of the energy markets (oil, gas and power), mismatches in demand and supply necessitated a small, flexible and largely unbundled "spot" market to fill the void. In the oil market, this was initially the Rotterdam market; in gas, it was the Texas Intrastate market; and in power, the Western Systems Power Pool's (WSPP) day-ahead pre-scheduled bulk power market provided that function. Spot markets, however, do not operate effectively to smooth regulatory and contractual irregularities unless spot prices are transparent. As trade increases and balancing becomes important, traders are willing to pay for the collection and publication of price information. Initially, participants in the contract or regulated markets can ignore spot markets and spot pricing. Ignorance is not bliss, however, as the prices set in the spot market ultimately influence contracts and the regulated markets.

Product standardisation

Price discovery may be stillborn unless it can describe a standard product. Everybody has a

The results of these bilateral negotiations become the core of the Western system's next-day generating plan. Each of the scheduling utilities, market hubs and responsible system operators calculate the net flow of power in and out of their system, to equate demand and supply. No single entity needs to know all the intermediate marketing arrangements associated with each block of power. It is a fully decentralised and workable market, where an individual participant, "by directing that industry in such a manner as its produce may be of the greatest value … intends only his own gain, and he is in this, as in many other cases, led by an invisible hand to promote an end which was not part of his intention."[11]

general idea of the price of a hand-made oriental rug, but that does not help much with the bargaining.[6] Subtleties of size, fibre, dye and density aid pricing only for those with a highly trained eye. Oriental carpets will always be highly diverse and, indeed, would lose their charm if they were not. However, such diversity is neither necessary nor desirable for energy products. Active trading requires common standards on volume, thermal content, credit and term structure for each product. Futures trading requires a further step: the identification of an actively traded product in the physical market to which futures contracts can be tied and the whole market effectively indexed.

As markets refashion themselves from closed to open, a commonly traded standard product will emerge. In the crude oil market, the standard is barrels of West Texas Intermediate (at 42 gallons per barrel) at Cushing, Oklahoma in the US and North Sea Brent in Europe. Natural gas is measured in million Btu, at Henry Hub, Louisiana. Electricity is now standardised to megawatt hours at COB or Palo Verde, Arizona.

Personal computers have made it much easier for traders to reconcile the bewildering heterogeneity of transactions in the physical market with the need for a standardised index or market commodity with which to track general price movements. Individual sales contracts at different locations, with different terms and conditions (or with slightly different product specifications), can then be marked against general price movements. When futures markets are used for hedging, such differences are known as basis: their basis risk is variable.

Liquidity

Liquidity refers to the ease and speed with which an asset may be bought or sold. These factors may, in turn, rest on the underlying market characteristics that determine such aspects as speed and efficiency: the number, heterogeneity and (de)-concentration of participants; the transparency of transaction; the quality of market information; and, ultimately, the proportion of the stock or flow of the relevant product that is negotiable (ie "in play" or potentially drawn into play by new information). When trade volume is low and the number of traders constrained, the market may be dominated by a single company, with it potentially proving extremely costly to close out a futures contract. Successful futures trading and the commoditisation of a market depends on substantial increases in liquidity. In the case of oil and gas, liquidity has been achieved by the rapid growth of short-term spot markets at the expense of long-term contracts and regulated markets.

Before 1979, spot trading in crude oils was never more than 5% of total international trade. By the time that the futures market was established in 1983, the volume of spot trading had increased substantially, perhaps to as much as half of total trade. The number of trading companies had grown exponentially, reaching several thousand – a similar pattern to that which occurred in the natural gas industry and is presently obvious in the power markets. At the beginning of 1994, there were nine marketers registered to trade electricity with the Federal Energy Regulatory Commission (Ferc); three years later there are 275, with another 18 pending certification. When markets open, they do so with great speed.

In the oil and gas industries, spot markets emerged as a balance wheel, bringing unexpected dislocations of demand and supply into balance, by serving as secondary markets for surplus volume. These volumes had originally been subject to long-term contracts or sale at regulated prices, and were resold at different prices. The greater the difference between the regulated or contract price and the potential resale price, the greater was the incentive for buyers to seek arbitrage gains in the spot market (and, concomitantly, the more rapidly these markets grew). In the Western US, the short-term power market – as the day-ahead prescheduled market – has grown geometrically, at the expense of exchanges and long-term contracts.

The pre-scheduled market accommodates diverse and changing contractual arrangements; it is not limited to daily bidding. Buyers and sellers can contract for daily, weekly, monthly or yearly power blocks in any combination. Prices are also flexible, as they can be tied to daily indexes, Nymex prices or set outright. Flexibility in terms, being accommodated by the bilateral trading system, tends to enhance efficiency, compared with a structure where trades are constrained to one (or a few) particular types.[12]

Bilateral, non-centralised markets also exist for other complex commodities, such as oil and gas (see Panel 1 on commoditisation). Although formal exchanges are used to trade oil and gas futures contracts, trading in the physical market is

This development, combined with the rapid entry of power marketers, has largely resolved liquidity problems.

Separating financial and physical risk

An open commodity market does not progress by stages – advancement occurs simultaneously (although this may occur at different rates), including the evolution of forward and futures trading. As trading expands, commodities are standardised and unbundled, and reliable price information becomes available, allowing buyers and sellers to separate price and physical risk.

Prices often seem stable in closed markets, although this may be illusory. Pricing in the commodity markets is actually erratic from day to day and week to week, although often less volatile over the long-term cycle. Market prices in the energy industries are particularly volatile, with both buyers and sellers having made expensive investments in the specialised equipment necessary to produce and utilise specific forms of energy.[8] It takes time to respond to the price signals; for example, in the short term, natural gas cannot be substituted for petrol in a motor vehicle.

In closed markets, buyers and sellers try to protect themselves from unexpected changes in market conditions by implementing long-term contracts that fix both volume and price. When markets shift unpredictably, as energy markets did between 1973 and 1986, the contract structure becomes untenable, and it becomes difficult for buyers and sellers to agree on long-term prices. The needs of both can be satisfied, however, by implementing two measures: by contracting for physical supplies, with prices pegged to the spot market; then, if either the buyer or seller wishes to set a firm price over the period of the contract, they do so through a third party that is willing to accept the price risk. This can be accomplished with options, swaps and futures, either in the over-the-counter (OTC) market or in a futures exchange.

In the US, futures trading has contributed enormously to the commoditisation of the oil and gas markets, with substantial benefits to both consumers and the industry. The contracts allow producers, refiners, processors and large energy consumers to manage energy price and supply risk separately. In addition, the development of the futures exchange has greatly increased liquidity and competition. It was not so long ago when energy industries were constrained by regulation; the price of world oil was shrouded in secrecy, with a Middle East crisis entailing long queues at the petrol stations and a crippled economy.[9] Similarly, only two decades ago the demand and supply of natural gas was balanced by closing down schools and hospitals. Energy issues have since moved from the front page to the business page, where they should have been all along.

1 See, for example, Bob Mango and John A.C. Woodley, 1994, "The Inevitable Commoditisation of Electric Power Markets", *Public Utility Fortnightly*, February 1.

2 The first successful large-scale futures market outside the agricultural industry was established for foreign currency by the Chicago Mercantile Exchange in 1972. This was prompted by the end of the gold standard and the resulting extreme volatility in foreign exchange markets at the time. Futures trading in oil was attempted in the 1950s, but the contract failed. See Gregory J. Millman, "Futures and Options Markets", The Fortune Encyclopaedia of Economics, p. 575.

3 Arlon R. Tussing and David B. Hatcher, 1994, "Prospects for an Electricity Futures Market: Lessons from Petroleum and Natural Gas", *Resources Policy*, 20 (2), p. 135.

4 It is ironic that the two greatest sources of IBM's market power, operating systems and processor chips, were inadvertently transferred to Microsoft and Intel.

5 As in the case of the Bonneville Power Authority, the WSPP and the federal Public Utility Regulatory Policies Act of 1978 (PURPA) contracts in California.

6 The author once spent two days in Delhi negotiating the price of a Kashmir carpet. After settling on a price, the retailer refused to accept a credit card prominently displayed in his window and negotiations had to start over again. During the negotiations, much was learned about the retailer's family circumstances and very little about the carpet.

7 The physical markets for gas and oil are complex and highly heterogeneous. In contrast, the defined commodity in futures market contracts is perfectly homogenous. Daily trading volume in crude oil futures is 100 to 200 times greater than trade in West Texas Intermediate, the specific crude oil it tracks. Futures contracts trade on an exchange and the physical market trades through bilateral negotiations. This is precisely the opposite structure that some have proposed for the electricity market, where an hourly or half-hourly bidding system is intended to account for each and every trade in a power pool through a formal exchange. Presumably, bilateral trade would not be allowed and, without a physical product (23 days of peak power, 16 hours a day) that matched the futures contract, it is hard to understand how futures trading would be viable.

8 Samuel A. Van Vactor and Arlon R. Tussing, 1997, "Retrospective on Oil Prices", *Contemporary Policy Issues*, Western Economic Association, July, p. 3.

9 In contrast, during the Gulf War of 1991 a full-scale invasion and bombardment in the Persian Gulf prompted a relatively modest market response.

undertaken through bilateral negotiations. Many sales contracts in the physical market (in terms of commodity definition, volume, duration and delivery point) are similar to the ones that underpin futures trading, although the vast bulk are not; differences may be great or small, depending on the circumstances of each individual transaction. In the case of crude oil, only two types or markers (West Texas Intermediate and North Sea Brent) are traded in the futures market. In the physical oil market, there are over 200 types of crude oil of differing quality (ranging from tar to natural gasoline) in hundreds of locations.

Unlike crude oil, electricity is a homogeneous commodity. However, the situation is complicated by its immediate spoilage. Even more critically, power supply must be matched to demand within a close tolerance, or the grid collapses. The "all-or-nothing" nature of the power market may be unique when compared to other commodities, but the Western system demonstrates that decentralised decision making for price determination is not inconsistent with reliable electricity supply. Moreover, the wide experience gained over the last two decades suggests that reliability need not be tied to one particular type of market structure.

The razor-thin edge required to match demand and supply, and the high cost of inventory, have important implications for price movements in the electricity market.[13] The consequence for open power markets may be extreme price volatility. In the UK power pool, typical daily peak prices are about six times those of off-peak prices, with typical peak firm power prices being about \$100 per megawatt-hour (MWh).[14] The maximum firm power price recorded, however, was over \$1,000 per MWh, which was 20–25 times the maximum price observed in the Western power market in the US.

The UK power pool may be an extreme case; it does not, of course, have extensive hydro facilities, and it is dominated by two power suppliers that set the spot price for 90% of the time.[15] Prices in the Western US are much lower and less volatile. Nevertheless, the market still has sudden price movements, driven primarily by the weather.

The Western market's response to a cold snap in early January 1997 was a good example of the pace at which prices can change (and the process by which they do). On January 10, weather in the West was relatively mild, although a cold front was forecast for the following week. The highest pre-scheduled peak price set on Friday morning for COB or Palo Verde was \$17.50 per MWh for that weekend, and \$21 for the following Monday. The cold front arrived with greater gusto than expected, however, moving the highest peak power price to \$53 per MWh for the Tuesday. In the course of one trading day, therefore, prices roughly tripled.

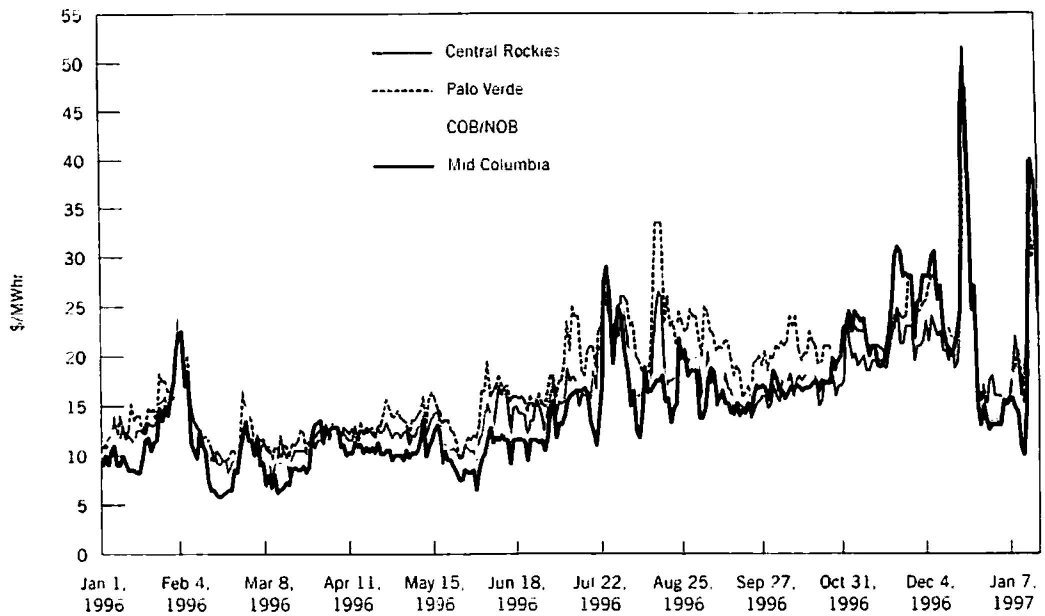
Competition in the Western power market

In the Western market, the principal barriers to further trade do not lie in access to transmission lines or with Ferc's regulations. A broad mix of participants have ownership shares of transmission capacity at Palo Verde and to and from COB: multiple entities own the transmission rights, with each having the right to use the capacity or sell transmission rights. Additionally, as we have seen, Ferc is strengthening access rights by implementing non-discriminatory open access to transmission. To the extent that non-competitive pricing is exercised, it is within specific service territories where individual companies or agencies hold exclusive franchises. This is primarily the regulatory bailiwick of local public utility commissions or municipal boards, not the federal government. In this respect, the looming deregulation of the power market differs substantially from the experience in the natural gas industry (where the perceived problems were with the federally regulated interstate pipeline monopolies). In that case, such companies were subject to federal regulation, with their gas supply contract problems aiding their co-operativeness towards Ferc. For wholesale trading, the Western power market has already been deregulated.

A competitive market requires freedom of entry. This means that, for the power industry, qualified buyers and sellers must have access to the transmission grid on equitable terms. Much of the federal and state deregulation is aimed at achieving this simple objective.[16] It is true that, in many instances, the infrastructure necessary for power transmission and distribution involves significant economies of scale and may exhibit features of a natural monopoly. This difficulty may be alleviated where expanding trade and multiple interconnections result in the development of alternative routes. Trade between individual service territories (mainly intrastate) and among certain sub-areas of the Western region (interstate) appears to involve sufficient generation and transmission alternatives to be competitive.

Bulk power prices appear to move in tandem across the Western region. Figures 4 and 5 show the daily average peak and off-peak prices for non-firm power in four areas of the Western market.[17] Although there is clearly day-to-day and seasonal volatility, the similarity in the patterns of price movement is evident. Major price spikes result from unit outages, unusual or extreme weather conditions, transmission constraints, or occasionally a combination of all of these factors. In Figure 5, average off-peak prices show a divergence for the price patterns in the Spring and the late Autumn/early Winter months. In Spring, significant regional differences result when surplus hydro power drives prices in the Pacific Northwest to seasonal lows, and transmission capacity

4. Regional comparison – average peak daily prices, 1996

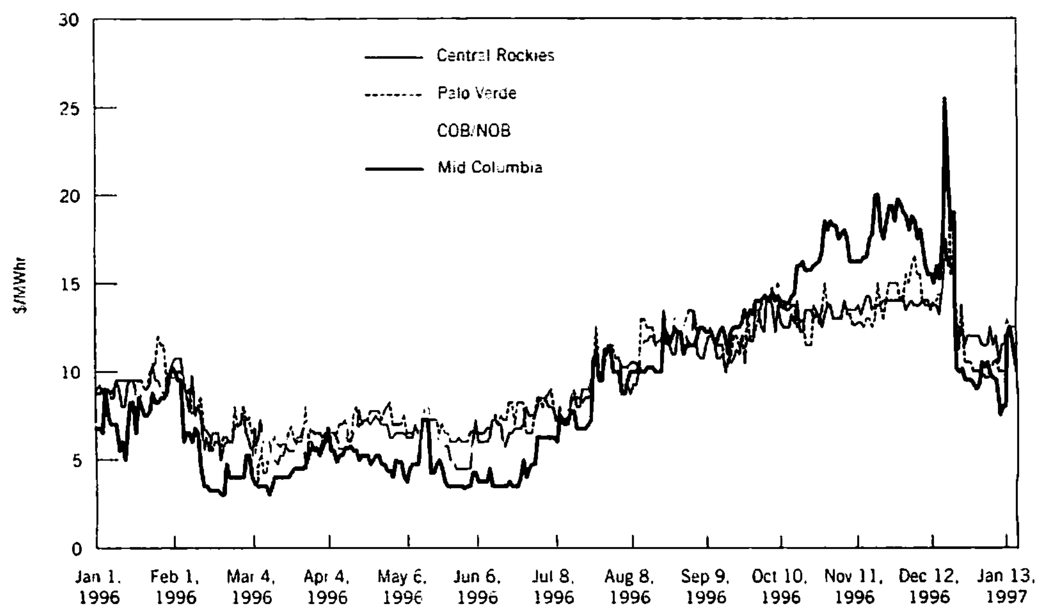


Source: *The Energy Market Report*; Economic Insight, Inc.

southward is filled. In November and December, demand for electricity for heating in off-peak hours drives up prices in the North; this cannot be remedied by the import of power from the southern California and Palo Verde regions, due to loop-flow problems (a common difficulty with physical delivery), which hamper the transmission of power from South to North.

Price data for 1995 and 1996 suggest that power prices have tended to fluctuate between the marginal generating costs of coal- and gas (occasionally falling below these prices), reflecting surplus water conditions coupled with moderate energy demand. To illustrate, Figure 6a shows gas price trends since January 1994, while Figure 6b compares the price of non-firm power at Palo Verde and COB to the approximate cost for delivering Canadian natural gas to California.

5. Regional comparison – average off-peak daily prices, 1996



Source: *The Energy Market Report*; Economic Insight, Inc.

Gas and power prices do not track one-for-one, although gas prices (which are the primary determinant of the marginal cost of generation from gas turbines) are frequently an effective ceiling to power prices. Power prices above this "ceiling" would ensure additional power production from gas-fired facilities, increasing supply and placing downward pressure on prices.

Detailed price data also provide a way to examine the extent of market integration in the Western system. A rigorous test of whether various locations are in the same market can be made by analysing the correlation of price movements over time. We have compared the logarithms of first differences of average weekly prices at COB/NOB (Nevada/Oregon Border) and Palo Verde in 1995 and 1996, based on daily data developed by Economic Insight, Inc and published in *Energy Market Report*.[15] For all six price series tested for these two locations, the resulting correlations were higher in 1996 than in 1995. Prices converged more in the peak period than in the off-peak (which can be partially explained by the regional divergences discussed above). The correlation results suggest increased integration is occurring. Furthermore, the correlations are high enough (0.86 for percentage change in weekly average peak prices) to establish that COB/NOB and Palo Verde are in the same market. Similar results (some had higher correlations) were obtained by looking at other pairs of locations in the sub-regions of the Western market. Table 4 contains results for the COB/NOB and Palo Verde, and COB/NOB and Central Rockies locations.

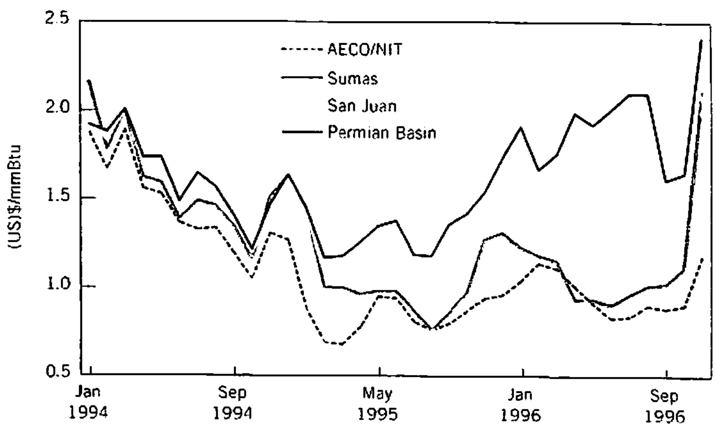
Price movements are only part of the story - a monopoly could also synchronise its prices. To analyse whether or not the Western market is competitive, the market share of each of the major competitors needs to be compiled. However, clear and unambiguous data on total trade within the Western region are not available, although important indicators of market share are. The first of these are sales to power marketers by utilities and other marketers, the data for which are filed with Ferc on a quarterly basis. Table 5 lists the 10 companies making the largest volumes of sales to marketers in the third quarter of 1996. The largest is BPA, with 14% of the total; the next largest are Pacificorp, with 12% and Washington Water Power with 8%. The Herfindahl-Hirschman Index (HHI) of sales (a measure of market concentration) is less than 1,000, which is a benchmark for anti-trust concerns. Similar calculations are made for generation capacity, with parallel results (see Table 6). Thus, when the market is as defined as the Western region, standard concentration measures indicate that there is substantial competition in the market. However, the usual caveats must be given. Some sellers may have market power in

Table 4. Price correlation results

	COB/NOB and Palo Verde prices			
	Peak		Off-peak	
	1995*	1996	1995*	1996
Low	0.578	0.857	0.456	0.649
High	0.367	0.810	0.515	0.551
Average	0.550	0.862	0.465	0.635
	COB/NOB and Central Rockies prices			
	Peak		Off-peak	
	1995**	1996	1995**	1996
Low	0.679	0.879	0.762	0.603
High	0.558	0.874	0.615	0.586
Average	0.622	0.908	0.600	0.703

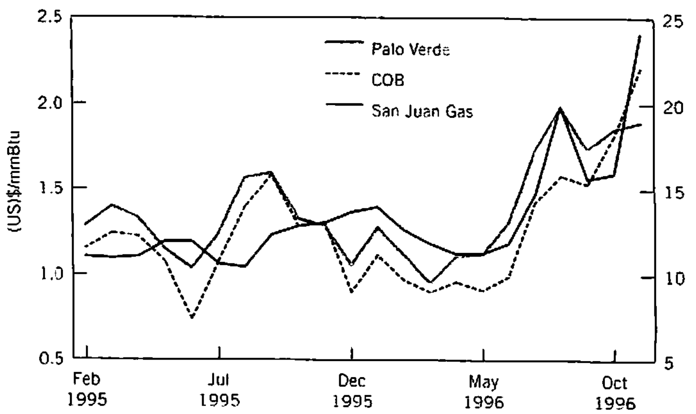
*Data for partial year, February 24–December 31
**Data for partial year, April 21–December 31
Source: Price data from *Energy Market Report*, Economic Insight Inc.

6a. Natural gas prices



Source: *The Energy Market Report*; ARTA, Inc; *Gas Daily*; *Canadian Natural Gas Focus*.

6b. Gas vs electricity



Source: *The Energy Market Report*; ARTA, Inc; *Gas Daily*; *Canadian Natural Gas Focus*.

Table 5. Measures of market concentration

	Sales to power marketers (MWh)	%	HHI
BPA	2,965,876	14	204
Pacificorp	2,508,345	12	146
WWP	1,721,863	8	69
Enron	1,450,507	7	49
PGE	1,190,364	6	33
Duke	1,066,078	5	26
Vitol	741,248	4	13
POWEREX	727,487	4	12
LG&E	583,984	3	8
Electric Clearinghouse	441,325	2	5
Other	7,350,968	35	35
Total	20,748,045	100	600

Source: Quarterly filings to Ferc by marketers.

Herfindahl–Hirschman index of concentration:

$$\sum_{i=1}^{N} S_i^2$$

where S_i is the market share of the ith firm.

Table 6. Measures of market concentration

	Power generation capacity (MW)	%	HHI
Federal Agencies	29,954	21	450
SCE	16,367	12	134
PG&E	15,771	11	125
Pacificorp	9,674	7	47
APS	9,212	7	43
LAWP	6,731	5	23
Salt River	4,862	3	12
PSC	3,936	3	8
PGE	3,708	3	7
Basin Electric Power	3,421	2	6
Montana Power Co	3,062	2	5
Other	34,443	24	24
Total	141,141	100	883

Source: Form EA-860, 1995, "Annual Electric Generator Report", US Department of Energy.

Herfindahl–Hirschman index of concentration:

$$\sum_{i=1}^{N} S_i^2$$

where S_i is the market share of the ith firm.

particular locations at particular times (as they do in the UK market). Nevertheless, the sheer diversity and size of the market suggest that market power cannot be routinely exercised.

Conclusion

Deregulation of the power market is now the principal energy policy issue before the US Congress and many state legislatures. As the debate continues, attention appears to be more focused on how to protect the stranded costs of many utilities during the transition than on the structure of the market once open access is allowed. This is unfortunate, as some of the proposals aimed at resolving stranded cost issues may inhibit the natural evolution of the market. Many regions may end up simply trading one form of regulation for another, rather than achieving open access and competition.

The policy dilemma is compounded by the rush to implement complex real-time exchanges, modelled on structures in the UK and other countries (California's Western Power Exchange, Wepex, is a good example of this). The enthusiasm for these institutions seems to have been acquired without careful consideration of their cost or their impact on the existing market. By all accounts, the Western power market works very well. If prices are any indication, the market seems to be allocating resources in a reasonably efficient and low-cost manner. More importantly, it has proven to be a flexible institutional arrangement, one that can adapt quickly to changing circumstances.

The WSPP has now been in place for a decade. During that time, it has accommodated the rapid growth in retrieval and publication of price information, the development of a futures market, improved transmission access and a vast increase in the number and types of traders. To the extent that the power market is inefficient or more expensive than necessary, the principal inefficiencies seem to concern retail rates, and involve individual service territories, which are currently subject to local regulation. In any case, it is time to fully analyse Ferc's experiment with WSPP in an objective fashion, before the adoption of alternative models, the cost and efficiency of which are unknown.

1 *This may change, however. Legislation proposed at the federal level would provide a date by which states would be required to provide for direct access at the retail level; if they did not, the process would be taken over by federal authorities.*

2 *The exact boundaries of the Western region vary depending on context. Here we are primarily concerned with the wholesale marketing region encompassed by the WSPP. However, much of the data is available for the somewhat larger area contained in the service area of the Western Systems Coordinating Council (WSCC), one of the 10 regional councils established under the North American Electric Reliability Council. The WSCC includes Alberta and British Columbia, a portion of northern Mexico and all or some of the 14 Western states in between.*

3 *PURPA was aggressively implemented by the California Public Utilities Commisson in the 1980s. This Act mandated that utilities buy power from independent producers at their avoided cost. California's regulators correctly determined that nuclear power was not cost effective, but erred in establishing "avoided cost" prices for its replacement that were much higher than necessary.*

4 *The DC line runs from the Columbia River through Oregon and Nevada to Los Angeles, while the three AC lines cross the California-Oregon Border near Malin, Oregon.*

5 *The data for this table come from the WSCC, whose reporting areas are the Northwest Power Pool Area (NWPP) - which includes British Columbia and Alberta, Rocky Mountain Power Area (RMPA), Arizona-New Mexico Power Area (AZ/NM), and the California-Southern Nevada Power Area (CA/SNV).*

6 *Widespread outages in the West on July 2 and August 10, 1996 sorely tested this hypothesis. Subsequent analysis of the outages identified certain actions that were needed to enhance reliability; they did not, however, attribute the problems to fundamental structural flaws in the system or to the market changes that were in progress. See the White Paper by Cauley, Gerry and Karl Stahlkopf, "Technical Issues Raised by the Western System Outages of July 2 and August 10, 1996".*

7 *For background on Californian proposals,* The Electricity Journal, *September 1994, Vol. 7, No. 7, contains several useful articles; see also, Robert J. Michaels, 1995,* Restructuring California's Electric Industry: Lessons for the Other Forty-Nine States, *Institute for Energy Research.*

8 *As of December 1996, 275 independent power marketers had been licensed by Ferc.*

9 Power Markets Weekly, Megawatt Daily *and* Energy Market Report.

10 *Both contracts were for 2 MW of peak firm energy delivered over 23 days, 16 hours per day during the month, for a total of 736 MW.*

11 *Adam Smith,* The Wealth of Nations.

12 *See, for example, previous papers by Robert Michaels on bilateral trading in electricity.*

13 *Power can be stored indirectly through pumped hydro or just by managing water inventories in a hydro system. However, it is very expensive to keep these facilities on standby, compared with the cost of inventorying either gas or oil.*

14 *David M. Newbery, 1995, "Power Markets and Market Power,"* The Energy Journal, *p. 43.*

15 *David M. Newbery, 1995, "Power Markets and Market Power,"* The Energy Journal, *p. 39.*

16 *We would not wish to imply that this objective is simple to achieve, however. Determining economically efficient transmission rates through regulation may prove very difficult.*

17 *Prices in the* Energy Market Report *are collected daily by telephone survey of traders from each of nine areas (regions or specific trading locations) within the Western market. Participants supply the prices at which they have transacted pre-scheduled power that day, the location of the sale/purchase and the region/location of the other party.*

18 *A logarithmic scale is used to put the prices on a consistent basis - ie, the weekly percentage change in prices over time.*