

ANNUAL PERFORMANCE REPORT FOR FISCAL YEAR 2000



FEDERAL ENERGY REGULATORY COMMISSION

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Chairman

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INTRODUCTION

This report details the Commission's success at meeting its performance goals for FY 2000. The Commission designed the performance measurements that are the basis of this report to reflect its mission and vision. How the Commission achieves success in its performance measures is a function of the Commission's values. The Commission's mission, vision, and values are discussed on page 2.

The Commission in Brief

The Federal Energy Regulatory Commission (the Commission) was created through the *Department of Energy Organization Act* on October 1, 1977. Its predecessor, the Federal Power Commission (FPC) established in 1920, was abolished, as the new agency inherited most of FPC's regulatory responsibilities.

The Commission administers laws and regulations involving key energy issues. These include the transportation and sale of natural gas in interstate commerce; regulation of electric utility wholesale rates and transactions; licensing, inspection and administration of non-federal hydroelectric projects; and oversight of related environmental matters.

The Commission consists of five members appointed by the President, with the advice and consent of the Senate, to five-year staggered terms. No more than three members may belong to the same political party. The President designates one member to serve as Chairman and administrative head of the Commission. Commissioners have an equal vote on regulatory matters.

The Commission generally meets twice a month to transact business. It considers, on a case-by-case basis, licenses and certificate applications, rate filings, and other matters submitted by regulated entities, and sets industry-wide rules. Meetings are open to the public under the provisions of the *Government in the Sunshine Act*.

The Commission collects the full cost of its operations from annual charges and fees authorized by the *Federal Power Act (FPA)*, the *Omnibus Budget Reconciliation Act of 1986*, and other laws. Congress annually adopts a budget appropriation that gives the Commission the authority to use funds from the Treasury to meet operating expenses. The Commission must return to the Treasury all revenue from annual charges and fees, therefore, there is no direct taxpayer funding.

Mission, Vision, and Values

In addition to developing mission and vision statements, the Commission has also expressed a series of eight values. FERC’s values set the parameters for how the Commission will pursue its work.

FERC Mission

The Commission regulates key interstate aspects of the electric power, natural gas, oil pipeline, and hydroelectric industries. The Commission chooses regulatory approaches that foster competitive markets whenever possible, assures access to reliable service at a reasonable price, and gives full and fair consideration to environmental and community impacts in assessing the public interest of energy projects.

FERC Vision

Promoting Competitive Markets
Protecting Customers
Respecting the Environment
Serving and Safeguarding the Public

FERC Values

- C *Employees* – People are our most valued asset. We provide the support needed for all employees to excel.
- C *Integrity* – We maintain the highest level of professionalism and an environment of fairness, trust, respect, and honesty.
- C *Diversity* – We value diversity in people and ideas.
- C *Working Together* – We clearly communicate expectations, encourage cooperation and teamwork, and share responsibility.
- C *Progress and Innovation* – We are creative and flexible, and seek out opportunities to improve.
- C *Action* – Prompt and fair resolution of matters before the Commission is essential to our mission.
- C *Reaching Out* – Two-way communication with the public is key to our effectiveness.
- C *Public Service* – Our ultimate objective is to provide valued services to the public.

The Commission’s Goals

When developing goals for the strategic plan, the Commission recognized that a number of its responsibilities and approaches to meeting those responsibilities were

similar across industries. The Commission grouped its goals for each industry into several broad categories that cut across industries. Those broad categories are:

- C regulation of markets and rates, terms, and conditions of energy services;
- C authorizing and monitoring energy projects; and
- C Commission administration.

During the Commission’s reinvention effort in FY 1998 and FY 1999, the Commission recognized the need to realign itself to meet the changing needs of the energy industry. The Commission has moved from traditional regulation to a model more representative of the rapidly evolving energy industry. Through its reinvention efforts, the Commission is shifting its organization and program structure to reflect a more contemporary regulatory model. During FY 2000, the Commission changed its program and organization structure to match these process categories.

Regulating Energy Markets

The Commission will regulate **electric transmission and bulk power markets** to

- a) foster the growth of efficient, competitive commodity markets, and
- b) protect customers from abuse of market power.

The Commission will regulate **natural gas pipelines** to

- a) ensure that pipeline transportation service supports efficient, competitive commodity markets, and
- b) protect customers from excessive transportation rates and service discrimination.

The Commission will ensure fair access to the **oil pipeline systems** for all customers under just and reasonable rates, terms, and conditions.

Authorizing and Monitoring Energy

The Commission will regulate interstate **natural gas pipelines** to ensure that adequate capacity and reliable, flexible service is available in the interstate natural gas transportation systems.

The Commission will regulate nonfederal **hydropower** projects to

- a) ensure that sustainable hydropower resources are licensed for the public’s benefit,
- b) maintain the nation’s existing hydropower development to serve all water resource interests, and
- c) ensure dam safety through inspection of facilities and operations.

Commission Administration

The Commission will reduce regulatory burden by

- a) reducing the processing time for docketed workload and for resolving disputes,
- b) minimizing filing burden, and
- c) generating better information for use by industry and the public.

FY 2000 Performance Measurements Results

Regulating Energy Markets

Overview

Market Assessment Activities During and After FY 2000. Beginning in the summer of 2000, the Commission faced unprecedented and sustained market problems in California. One of the Commission's first responses to the developments in California was to undertake a series of intensive studies of bulk power markets in all regions of the country to understand market developments better and to help guide policy. These studies covered not only developments in California and the West but in the rest of the country as well. The studies form the backbone of the Commission's market evaluation program for FY 2000 reported here. They are:

- C Part I of the Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities (October 2000)
- C Part II of the Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In the United States (October 2000):
 - < Northeast Region
 - < Midwest Region
 - < Southeast Region
 - < ERCOT
- C Staff Report to the FERC on Northwest Power Markets in November and December 2000 (February 2001)

The Commission has also issued two recent reports addressing topics related to market performance in the California power markets:

- C Report on Plant Outages in the State of California (February 2001)
- C Staff Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market (March 2001)

All are available from the Commission's web site.

The Nature of this Report. This performance report largely describes the bulk power market reports and extracts a few issues that serve as examples of the Commission's progress. These excerpts show how the Commission uses market information to understand market dynamics and improve agency performance.

The issues raised in the bulk power market reports are presented under the indicators that best fit them. Since the markets developed in unprecedented ways during the year, the fit is not always exact. Moreover, in the current environment, the Commission, as well as virtually all industry participants, is still working to develop a full understanding of how newly emerging electric markets operate. For that reason, the bulk power market reports focus on presenting as much information as possible about how prices in bulk power markets have behaved over the last year. Many conclusions have been necessarily somewhat tentative.

Taken together, the performance report and the bulk power reports on which it draws have received far more effort and attention during the past year than ever before in the Commission's history. The Commission believes that the purpose of performance measures is to recognize what is working well and to remedy what is not. In that sense, the Commission's performance measurement program for markets has been a great success this year. More information has been available faster than ever before, and discussion of what is happening in energy markets (especially for electric power) has helped the Commission formulate its responses daily.

The development of the regional bulk power market reports absorbed virtually all of the resources the Commission would normally have devoted to performance evaluation for the markets program - and many more resources besides. As a result, the Commission has not undertaken a separate *State of the Markets Report* this year, as it did last year. To do so would necessarily have duplicated much of the material already available and distracted staff efforts from pressing issues in analyzing markets during the winter and spring of 2001.

A major lesson of the past few years has been that the unpredictability of energy market development prohibits the use of simple target-oriented performance measurements. The Commission views its monitoring of energy markets more as basic economic research than typical performance measurement. Consequently, the Commission has applied to the Office of Management and Budget, under Section 220.15 of OMB Circular A-11, to use an alternative form of performance measurement. Approval is pending.

**Efficient,
Competitive Markets**

Performance Indicator: *Customers will have more new products and a reasonable range of suppliers from which to choose in both the electric and natural gas industries. This will indicate that commodity markets are reasonably competitive as well as responsive to customer needs.*

Variety of products. Both the natural gas and electric industries have developed many new service offerings in recent years. For example, last year's Performance Report noted the following service innovations for *natural gas*:

- unbundling of pipeline transportation and commodity gas supply;
- development of pipeline marketing affiliates;
- increasing numbers of unaffiliated wholesale shippers;
- spot markets for commodity gas supply;
- no-notice service for unanticipated demand changes;
- firm and interruptible storage service;
- contracts for swing supplies and storage through third parties;
- secondary markets in pipeline capacity;
- 'parking' and 'loaning' of natural gas; and
- short-term imbalance services for gas-fired power plants.

The Commission responded to such innovations by issuing Order No. 637 late in 1999. This order allows for a period of experimentation until 2002 in the secondary markets for gas transportation. Implementation orders and technical conferences have followed. An intensive process of evaluating these secondary markets is underway and will serve as a basis for future policy in short-term gas transportation.

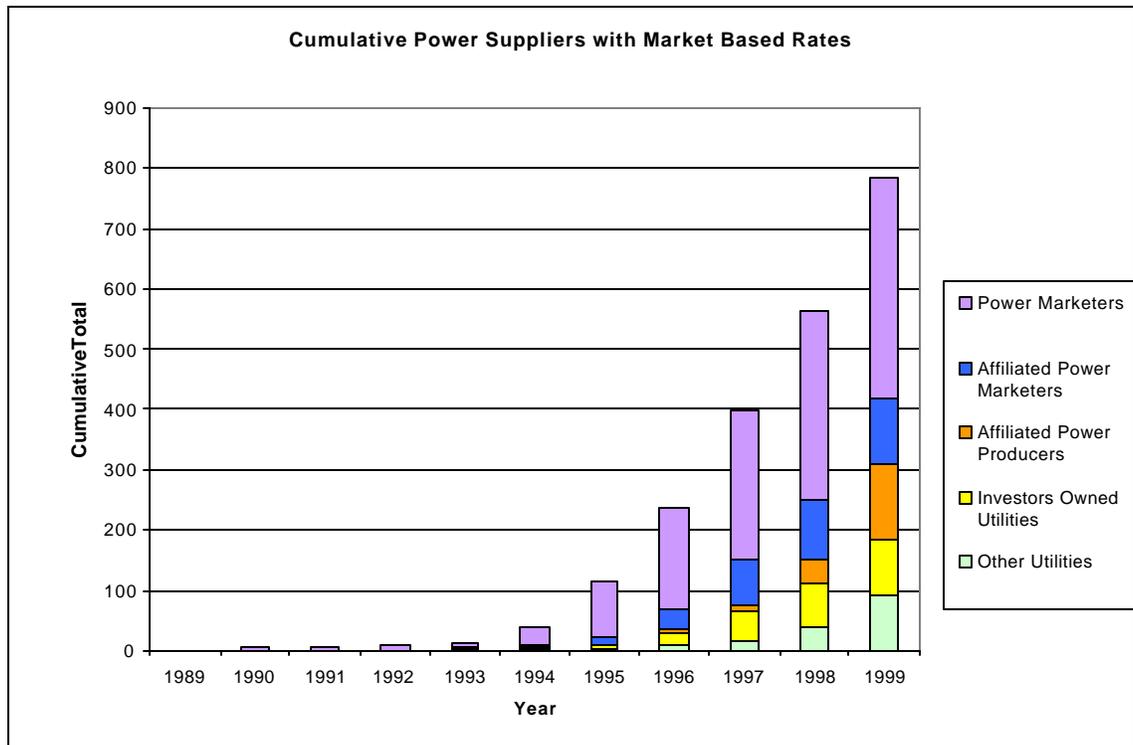
Order No. 637 encouraged pipelines to propose new services. Although most filings under Order No. 637 are still subject to negotiation between pipelines and their customers, the number of pipeline tariffs offering innovative rate and service offerings continues to increase. So does the number of market offerings that do not come to the Commission but that reflect the further development of natural gas markets under the Commission's policies. These include, for example, the wealth of financial derivatives that now characterize the industry.

In *electric power*, market institutions have developed rapidly. Buyers may purchase in spot markets that quote prices at many points on the grid. Many also have access to longer-term contracts from a wide array of sources in the bilateral market. A large variety of derivatives and risk management options also are available. Several companies have established nation-wide online trading services for both electricity and natural gas. Finally, Order No. 2000

invited regional transmission organizations (RTOs) to file innovative transmission services and tariffs with the Commission as part of establishing themselves. The Commission is now reviewing the implementation filings for RTOs.

Range of Suppliers. This performance indicator also refers to reasonable ranges of suppliers. Last year the Commission made a start at quantifying the growth of market participants in competitive energy markets. Existing Commission tracking reports on market-based rate applications helped create a more informative data base on market participants, including their type and when they received the authority to market services.

The following figure illustrates the rapid growth in new market participants, and thus customer choices:



Another way to consider the range of suppliers in a market is by tracking the shares of spot market, bilateral contract, and other types of transactions. A variety of “market locations” for trading can indicate that market participants have supplier options. The table below, from the Northeast staff investigation, shows the transaction shares in the New York ISO in 2000:

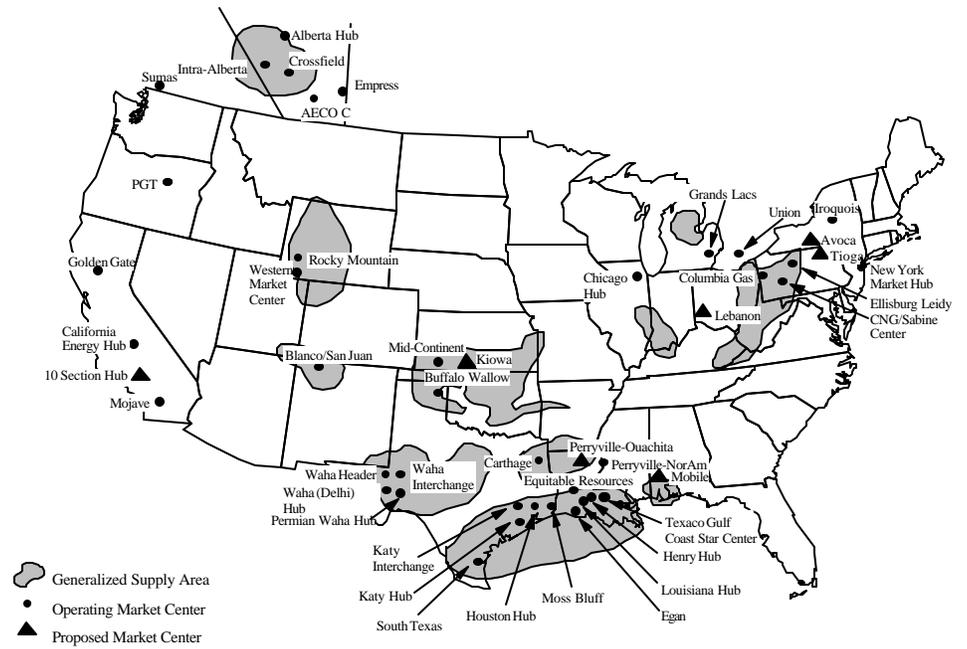
**Relative Shares in New York Energy Markets
(Percentage of Total Electrical Load)**

Month	Energy Spot Market	Internal Bilaterals	Import plus Export Bilaterals	Wheels Through
January 2000	30	64	3	2
February 2000	31	63	3	3
March 2000	35	60	3	1
April 2000	37	58	3	1
May 2000	42	52	2	4
June 2000	44	51	2	3
July 2000	45	50	3	3
August 2000	45	51	2	2
September 2000	50	45	3	2

Source: New York ISO. Note that numbers may not add to 100 percent.

Natural gas markets, while more mature than electric markets, still change each year. Private marketers develop new pricing points, reflecting the conditions in supply, demand and transportation that can result in price disparities between different areas. These new pricing points provide important information about the relative cost of natural gas and thus the value of transporting gas between places. The development of new pricing points thus indicates the development of supply options.

The figure below shows current and proposed market centers for natural gas. Their number has grown from 5 to 38 since 1992.



Beyond these physical pricing points, electronic trading is growing in scale and also offers market participants a range of pricing points. Electronic trading creates a more efficient market by expanding the number of buyers and sellers interacting and reducing the time and resources needed to obtain price information and consummate trades. Further, it provides anonymity so traders do not have to disclose their market positions, and gives traders more confidence in the prices they obtain.

The figure below shows the electronic gas trading points for Altrade and Natural GasExchange.



Performance Indicator: *Natural gas and electric power prices will become more responsive to market conditions – that is, prices will reflect changing supply and demand conditions more clearly and more quickly.*

During FY 2000, natural gas and, especially, electric prices showed themselves to be extraordinarily responsive to changing market conditions. During periods when supply was tight relative to demand, prices rose rapidly. When such conditions remained in place over time, so did high prices – and price volatility as prices responded to even very small changes in market conditions. Indeed, in California’s electric market, prices rose higher for longer periods than almost anyone in the industry imagined possible.

Such dramatic price responsiveness has three major implications:

- Markets are working, and prices rise and fall in response to supply and demand signals.
- Price volatility is extremely high, in part because of the nature of electricity as a commodity, but also in part because of flawed market rules (in California) and in part because of a paucity of demand response to price at peak (almost everywhere).

- Price volatility can have negative consequences for ratepayers (as in San Diego) and for distributors (in the rest of California, where rate caps shielded consumers at the price of building up very large liabilities for distribution companies). An over-reliance on the spot market greatly exacerbates the price risk for both customers and distributors.

Reduce price volatility and/or its effects on customers will require three types of action:

- Increase supplies. Generators must find it much easier to bring new capacity on line and must be better able to transmit power over a distance. Many obstacles to new generation arise at the state and local level. However, the Commission will do all in its power to help. For example, it will review the rate of return allowed for transmission projects to ensure that no artificial financial barriers exist to upgrading the transmission system.
- Increase demand response to high prices. Customers must be able to know when prices are high and to respond to those prices by reducing consumption. While the demand side of electric markets is traditionally a matter for state jurisdiction, all electric markets will remain more fragile than necessary until demand response to price becomes more of a reality. Accordingly, the Commission ordered on March 14, 2001 that it will allow retail customers, as permitted by state laws and regulations, and wholesale customers to reduce consumption for the purpose of reselling their load reduction at wholesale.
- Improve risk management opportunities. Price volatility has far smaller effects on customers to the extent that they hedge their positions through long-term contracts or in other ways. The Commission is encouraging companies overexposed to spot markets to enter more long-term contracts and is pleased to note that California is following a similar approach.

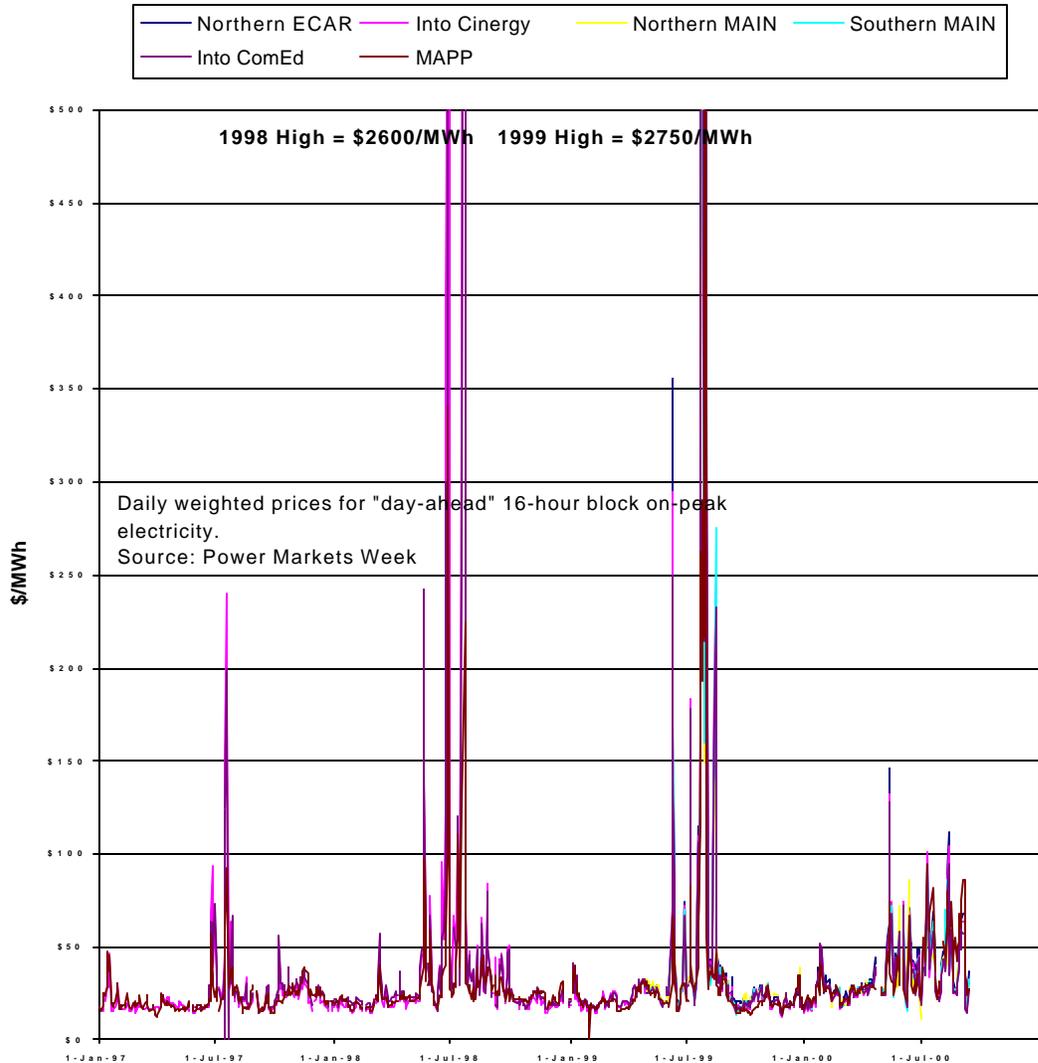
The rest of this section shows illustrations of the Commission's work in following electric markets during the year from the bulk power reports it has published.

Midwest Region: The first chart from the Midwest staff investigation report depicts wholesale power prices from 1998-2000. As the report explains:

“The summer of 2000 was relatively calm for Midwest wholesale prices. A number of factors contributed to this situation. As will be shown, the weather was cooler than normal, especially in the upper Midwest. Also, there were no widespread generation outages, as in the 1998 price spike when many nuclear plants were simultaneously down for maintenance. More generation facilities have been built in the Midwest, too. Finally, except for TLRs, [transmission loading relief] there were no major transmission problems like the central Ohio voltage sag

or the loop flow problems in 1998 which threatened to isolate the Midwest from the rest of the grid.”

Daily Price Indices: Midwestern Market Hubs, 1997-2000



Looking at the price information in isolation can yield a misleading picture. Understanding how the transmission grid and market prices interact is an important goal for evaluating energy market performance. The next table shows the incidence of transmission curtailments in the Midwest for the same period. Included in the count are transmission loading relief (TLR) measures that actually curtailed transactions or prevented additional transactions.

The report continues: “Table [2-10] shows the number of Level 2 TLRs and above, by region for each summer from 1998 to 2000. It tabulates the monthly and yearly totals for each region. The bottom row shows the total for each year and the grand total for all 3 years. There has been an enormous increase in TLRs between the summer of 1999 and the summer of 2000. Specifically, TLRs have grown from 86 during the summer of 1999 to 492 for the summer of 2000, an increase of 472 percent. For this analysis, Staff only counted a TLR at its highest level. When a TLR escalated in Level while it was active, Staff only measured it as one occurrence.”

Level 2 TLRs and Above, Summer 1998-2000

Region	1998	1999	2000	Monthly Totals	Region Total
ECAR					
June	13	8	51	72	
July	4	24	102	130	
August	4	15	66	85	
ECAR Total	21	47	219		287
MAIN					
June	40	10	31	81	
July	25	3	92	120	
August	21	12	75	108	
MAIN Total	86	25	198		309
MAPP					
June	0	0	0	5	
July	0	0	12	12	
August	0	0	0	0	
MAPP Total	0	0	12		17
SPP					
June	0	4	27	31	
July	0	6	20	26	
August	0	4	11	15	
SPP Total	0	14	58		72
All Regions	107	86	492		685

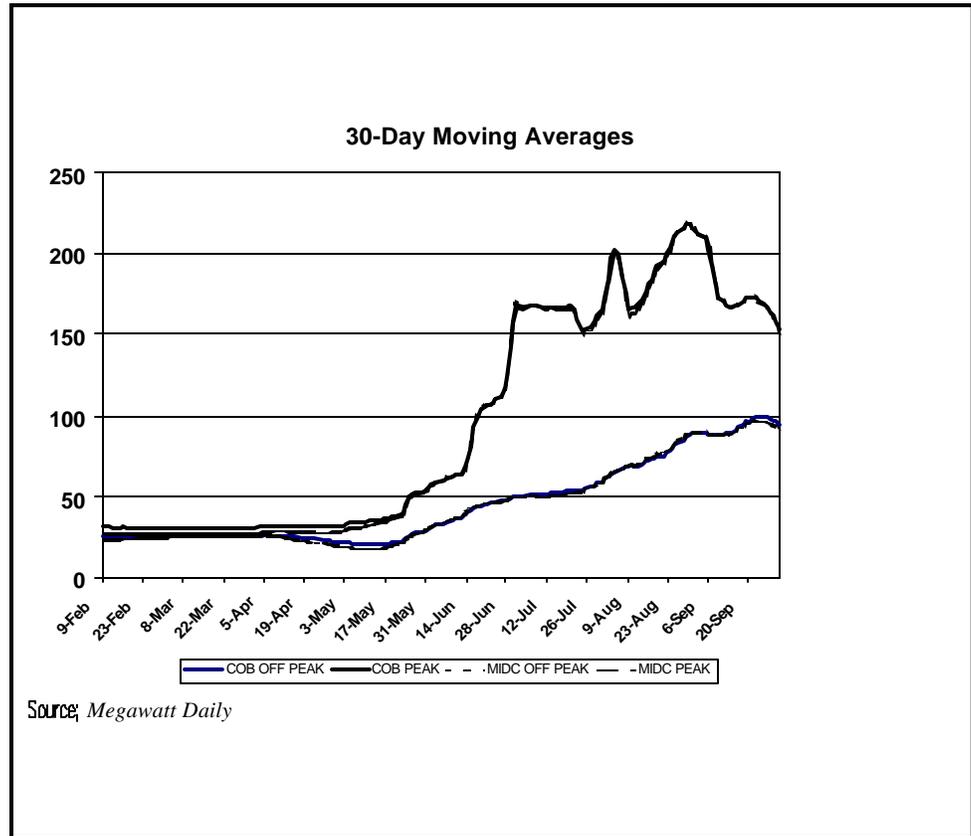
Source: FERC Congestion Management Team Reports compiled from NERC’s website.

Western Region: The most recent staff report, released in March 2001, analyzes electric markets in the Northwest. It is a follow-up to the Western region investigation. The two charts presented here show electric power prices at two Western market hubs (California-Oregon Border and Mid-Columbia) between February and September of 2000, followed by prices for both natural gas and electric power in November and December of 2000.

According to the report: “Although power market prices spiked at certain points over the summer, the recurrence of high prices over the longer term may have a greater impact on customer bills. Prices spiked less frequently as the summer progressed and California imposed price caps at lower levels, but average prices continued to climb. This climb in prices can be observed in the spot prices at the

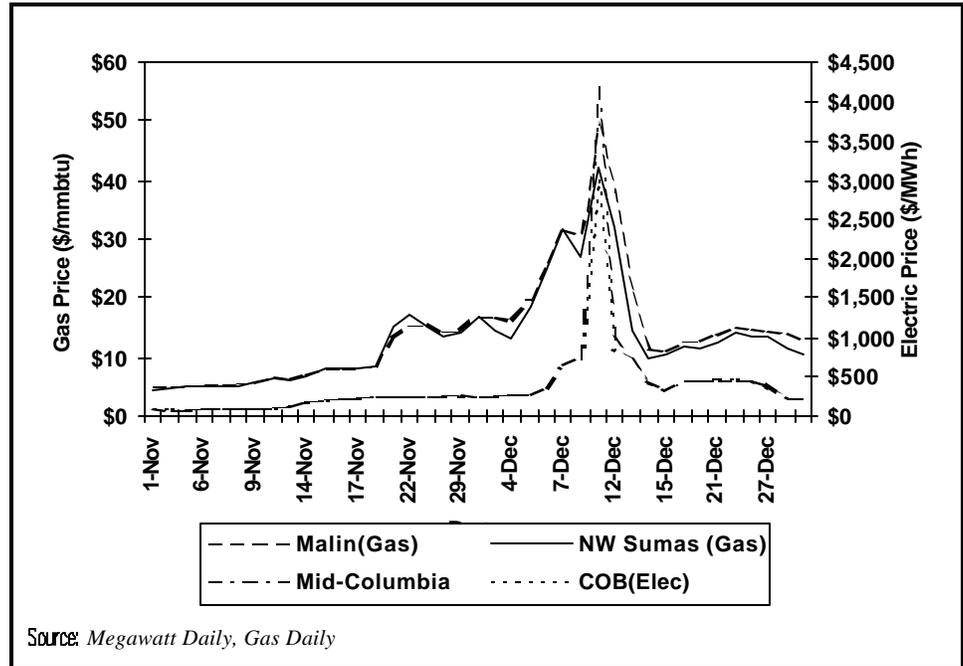
California-Oregon Border (COB) and at receipt points along the Columbia river (Mid-C) by averaging the daily prices over the previous 30-day period and plotting the trend as shown in Figure 5. A large, but short-lived spike in prices will appear as a jump in the 30-day average, followed by a gradual reduction in the average price. Figure 5 shows a very different pattern: average prices jump up, but they stay at the higher level until the middle of September.”

Figure 5: Mid Columbia and COB Prices, February to September 2000



The report continues: “In September and October, power prices appeared to be moderating from the sustained high levels of the summer. Prices continued to fluctuate considerably, but the trend was clearly downward from late August prices over \$200 (\$225 at Mid-Columbia on August 29) to prices under \$100 in early November (\$75 on November 4.) In mid-November, prices for natural gas and electricity started to rise again (see Figure 10.) The increases at first were small enough to be attributed solely to anticipation of the winter peak season, but then gas prices jumped over \$10 per MMBtu and electricity prices rose to over \$200. This significant trend was punctuated by dramatic increases in early December, but returned after the spikes subsided to close around \$300 during the last week of December.”

Figure 10: Northwest Spot Gas and Electric Prices
November and December 2000



Northeast Region: In the Northeast region, the staff investigation examined three subregional markets (New England, New York, and Pennsylvania-New Jersey-Maryland or PJM). The discussion includes three charts instead of all price indicators from these subregions. The first and second show wholesale prices for the PJM market, while the second shows the prices for ancillary services in the New York market.

According to the report: “Figure 1-4 shows the monthly average energy price from April 1999 to May 2000. The prices for the day-ahead and real-time markets, from June to September 2000, are shown in Figure 1-5 . With the moderate temperatures in summer 2000, and some market design changes undertaken to inhibit exercise of market power, energy prices have been lower in summer 2000 than summer 1999.”

Figure 1-4. Wholesale Market Prices, PJM Monthly Average Single Settlement Energy Prices, April 1999 to May 2000

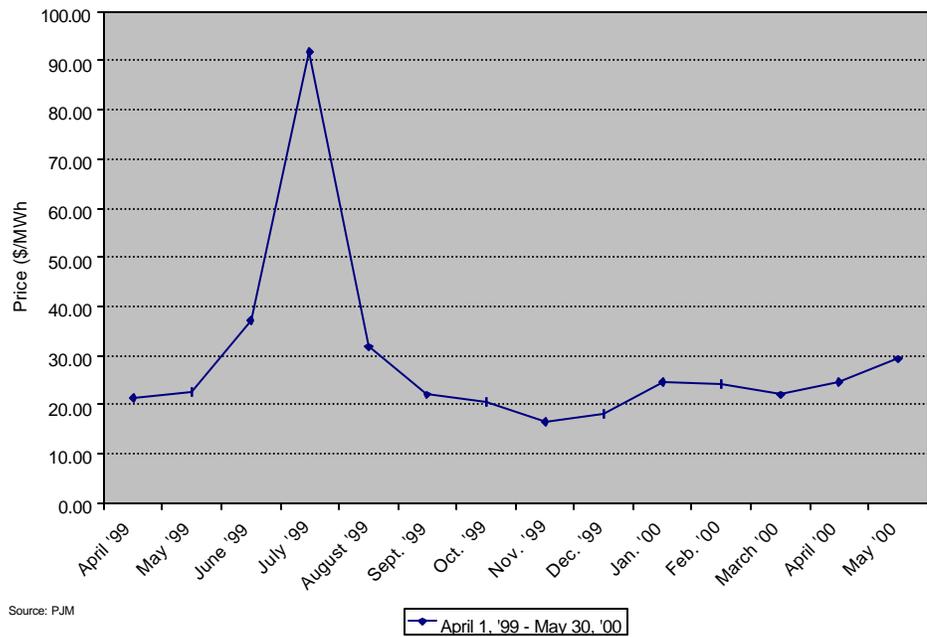
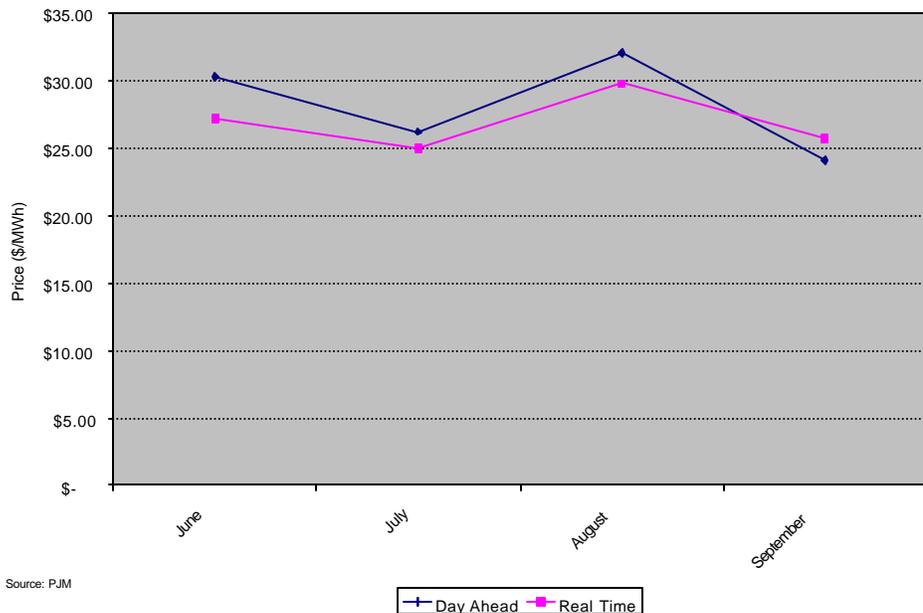


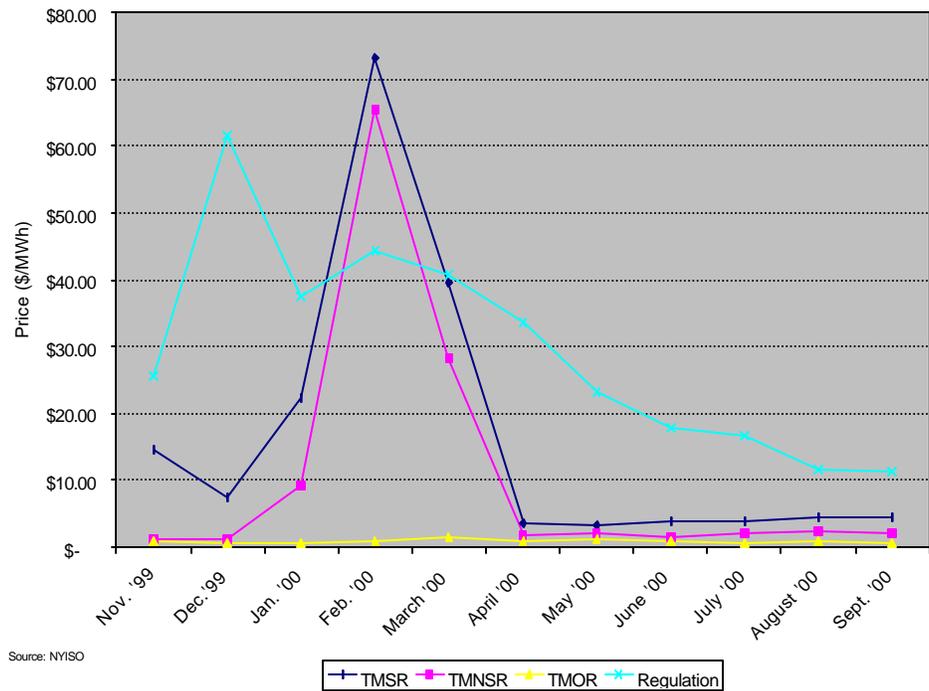
Figure 1-5. Wholesale Market Prices PJM Monthly Average Day-Ahead and Real-Time Energy Prices June 2000 to September 2000



The report continues: “The New York ISO has experienced major problems with its operating reserve markets. Prices remained reasonable from the start of the market until mid-January 2000, when prices for both 10-minute operating reserves climbed dramatically. The ISO suspended both markets in late March and applied a price cap.

“As shown in Figure 1-9, the monthly average price for 10-minute spinning reserve prices hit a peak of \$73.27/MW in February 2000. Following the application of a price cap of \$6.68/MW, prices declined substantially in April 2000, to a monthly average price of \$3.51/MW. That price cap was later rejected by the Commission and removed. The monthly average price has ranged between \$3.10/MW and \$4.45/MW from April to September 2000.”

Figure 1-9. New York ISO Monthly Average Day-Ahead System Price for Ancillary Services November 1999-September 2000

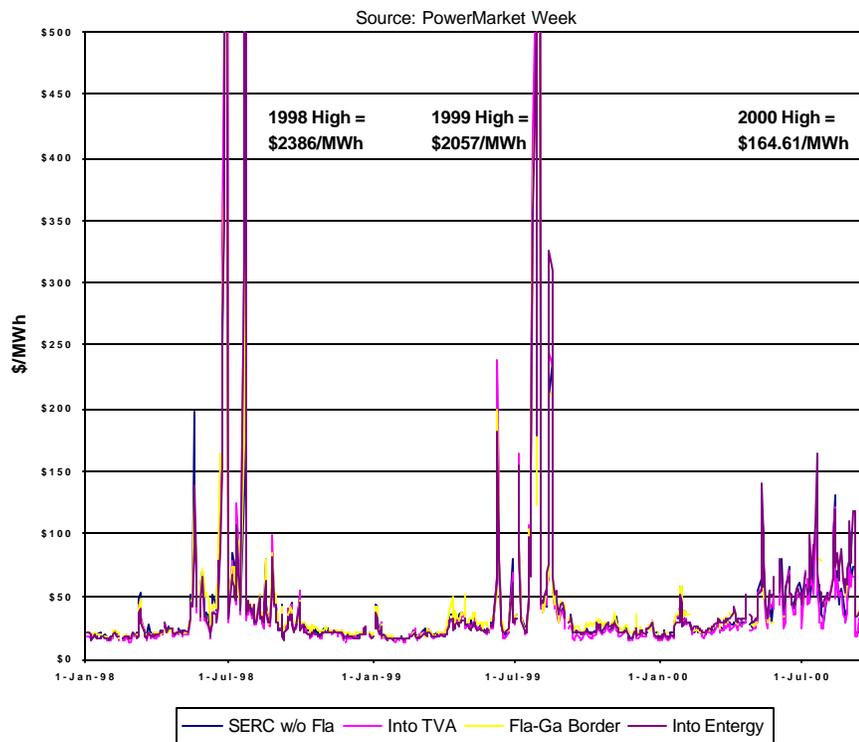


The report continues: “A similar pattern holds for 10-minute non-synchronous, or non-spinning, reserves. The average monthly price hit a peak of \$65.58/MW in February 2000. Following application of a price cap of \$2.52/MW in April, average prices declined substantially in this market as well, to \$1.75/MW in April 2000. The monthly average price has ranged between \$1.47/MW and \$2.30/MW from April to September 2000.

“Until summer 2000, the average regulation price was higher than the average energy price. This reflects a market inefficiency. However, regulation prices have dropped over the course of summer 2000.”

Southern Region: *From the Southern regional report:* “Peak prices were radically lower in the summer of 2000 than they were in the past two summers. Figure 3-8 shows that the peak price in the region in 1998 was \$2,386 per MWh. In 1999 it was \$2,057 per MWh, but it was only \$165 per MWh in 2000. This figure depicts daily prices at four hubs in the Southeast from 1998 through August 2000.”

Figure 3-8. Daily Price Indices: Southern Market Hubs, 1998-2000



The report continues: “The lower peak experienced this summer was due mainly to relatively lower temperatures for much of the summer in the Midwest. Lower temperatures in the VACAR subregion relative to other regions in the Southeast increased the availability of generation to serve customers elsewhere in the Southeast. In addition, utilities appear to have been better prepared for peak events in the summer of 2000. According to utility interviews with the Commission staff, superior preparation took the form of increased hedging through the use of forward contracts, increased generation capacity on line and a reduced number of forced outages.”

Conclusion: The Commission made great progress during FY 2000 in developing better access to a wide range of price data in response to the volatility in many electricity markets. Indeed, the Commission's greatest efforts in performance evaluation came in examining and reporting on prices from all regions of the continental United States. In a market-based system, prices provide the most important source of information on market performance because of the key roles they play in energy markets, including:

- allowing transactions to occur between many buyers and sellers simultaneously;
- providing information about underlying supply and demand conditions;
- establishing incentives for short-term operating and long-term investment decisions;
- delivering economic outcomes to producers and consumers; and
- allowing for evaluation of market rules and conditions during the transition to competition.

For prices to play these roles effectively, market participants must have maximum flexibility. However, fully independent and credible market institutions are also necessary. The Commission's regulatory role is to balance these considerations.

Performance indicators in the area of price information should reflect the main features of price behavior in network industries. They also should show how the Commission uses price information to learn about the markets, identify problems, and make reasoned decisions. At the same time, the use of such performance indicators cannot be as simple goals or 'hard targets,' because the energy markets will not develop in predictable ways. Any quantitative price targets the Commission sets would quickly become obsolete or counterproductive.

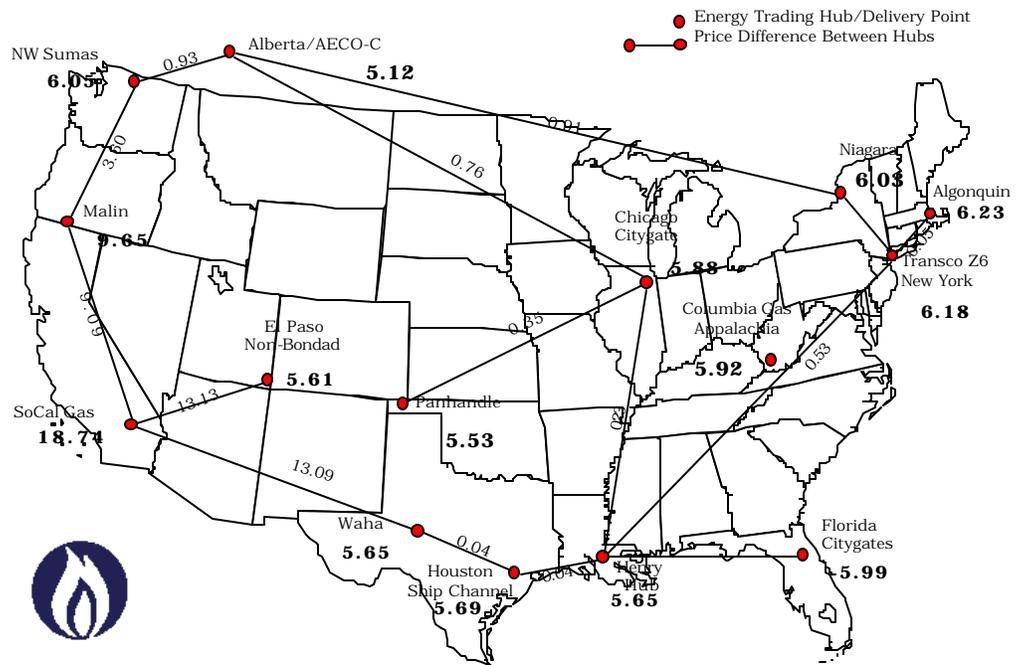
State of the Markets 2000 and the staff investigations into wholesale electric prices over the summer of 2000 and into 2001 represent the best efforts so far. By providing public information on a variety of prices in regional energy markets, the past year's work made a significant advance toward the goal of measuring energy market performance. The staff investigation reports provide pricing information for each of four main regions of the country, and selected subregions (Texas and the Pacific Northwest). Representative examples from several of the staff reports are presented below, along with report conclusions for these regions. For a more complete picture, please refer to the reports in their entireties.

Performance Indicator: *Natural gas prices within each trading region will tend to converge, except to the extent there are demonstrable transportation constraints or costs. Wholesale electricity price differences will also tend to narrow.*

This performance measure suggests that price differentials between natural gas sold at different points should develop only to the extent that there are real transportation costs or constraints that would explain them. At other times, well-functioning markets would likely arbitrage away any price differences by moving gas from the less expensive to the more costly point. Once the market has used all available transportation capacity, no further arbitrage can take place, so prices begin to diverge.

The following chart shows the divergence of natural gas prices between California and the rest of the West in February 2001. During FY 2000, a major price differential opened between producing areas and the West Coast. Initially, in August 2000, the price differential arose in the wake of an outage on a major pipeline into California. Later the differential remained as electric generators in the West added significant demand to more traditional winter heating season peaks.

Average Natural Gas Prices For February 2001



Gas Prices (\$/MMBtu)

Source: Gas Daily, midpoint averages of the daily ranges for the most common prices.

The explanation for this type of phenomena invokes several factors, including local demand conditions (largely driven by weather and space conditioning needs), local and interregional transportation constraints, facility outages, and storage conditions. Some of these are more transient than others. However, persistent price differentials reflect an implicit value of transportation that may signal the need to build new capacity. What is clear, however, is that price differentials opened only when pipeline capacity was short from an outage or when demand was high enough to place major stresses on the transportation system. In short, it appears that the market was reflecting real stresses in exactly the way contemplated by this performance measure.

One implication of the events of FY 2000 is that demand for additional natural gas transportation capacity can arise quickly and can have a major effect on prices. That puts a premium on being able to build new capacity quickly. That is why the Commission is moving to ensure the quickest possible issuance of certificates for new pipeline construction (see performance measures in the Energy Projects section of this report).

The use of price information in evaluating energy market performance is improving for two reasons. First, regional wholesale electric markets are more fully developing. The Commission intends its continuing implementation of Order No. 2000 on regional transmission organizations (RTOs) to help create these markets, which will include ancillary service markets. These regional markets should lead to better price information. Second, the Commission is continuing to improve its own market evaluation capability for both electric and natural gas markets. Although it would be unwise to become tied to simple quantitative measures of market performance, being able to present clearly the entire range of market information and showing how the Commission uses this information to make informed policy is critically important.

Performance Indicator: *It will be less costly, administratively, to transact business on the interstate natural gas transportation grid.*

This indicator relates to the development of new services and price information in the natural gas and electric power industries. As more players enter the markets, and as new services develop, it becomes more important commercially to have access to information about the pricing and availability of services. As a result, a rapidly growing set of information services has appeared. These information services include e-commerce, in which many traditional energy companies, new market participants, and others offer Internet-based information services. The regional markets themselves offer extensive information on system conditions and prices in real time. The participation of major financial institutions such as the New York Mercantile Exchange bring new resources to bear on information provision.

Over the past two years, several highly competitive national online markets have developed. This shows the ability to put market information in the hands of buyers and sellers almost instantaneously.

As a result, consumers of energy services have access to information with unprecedented speed. A set of computers can replace hundreds or thousands of telephone calls to potential suppliers and middlemen, with which marketing agents track prices across the country in real time. Over time, the benefits of this type of information access will spread to more customers, as experience, competition, and technological improvements reduce the costs of access.

The Commission's new Strategic Plan for FY 2000 – 2005 reinforces policies directed at making market information available. Through actions such as the development of real-time transmission information requirements (the OASIS system) and sponsoring industry-wide technical standards (the GISB initiative), the Commission is enabling market participants to gain access to the information they need with greater ease and assurance. These efforts will continue.

During FY 2000, the Commission has not placed a high priority on measuring transactions costs directly. Instead, it has focused its efforts on understanding the basic dynamics of how prices change in emerging electric power markets. This focus was sensible, since the very high price volatility in many electric markets can overwhelm transactions costs in the short term. As market participants gain experience with the underlying nature of power markets, they will develop better strategies for addressing volatility and markets will mature. As that happens, transactions costs will become an increasingly important indicator of overall market performance and the Commission will focus more attention on measuring such costs. One fairly direct measure may be to examine the spread between bid and ask prices in bilateral markets. More indirect approaches may also be useful. Increasing participation in markets suggests that more parties can make transactions economically, while increasing transportation distances could often reflect a decline in the cost of transacting business.

Constraining Market Power

Performance Indicator: *Market participants will have confidence that natural gas markets, electric markets, and oil transportation services are working fairly and that they are not subject to abuses of market power. That is:*

- C *Broad customer classes (not necessarily every customer) will agree that buyers and sellers have access to competitively priced commodity markets in the national gas transportation and electric transmission grids.*

- C *Customers will generally agree that gas pipeline, electric transmission and oil transportation rates and services are just and reasonable, fairly balancing the competing interests of the transporting or transmitting companies and their customers.*

These performance indicators refer to the Commission's success in eliminating unnecessary market power and in fairly balancing the interests of all when market power cannot be eliminated. In both cases, the performance indicators refer to customer perceptions of how much competition and fairness they see.

The Commission continues to believe that in the long term, the best performance indicator of market power will come from discussions with the industry and its customers. However, the Commission decided not to try to survey customers during FY 2000. The contention surrounding bulk electric markets, especially in California, meant that any formal effort at surveying customers would likely intrude on ongoing, very difficult, contested, on-the-record proceedings and might also needlessly add to the conflicts inherent in the situation.

Instead, the Commission examined the issue of market power in its regional bulk power reports. Some key conclusions from those reports follow:

From the Western Region report: "Prices in some hours appear to be above those that would have prevailed in a competitive short-term market, if prices were determined from short-term marginal costs.

"Section 5 discusses the issues that were raised as possibly causing the high prices of this summer. These fall into three general categories: (a) competitive market forces, (b) market design problems and (c) market power. The data clearly show that a general scarcity of power in the West and increased costs to produce power were factors causing these high prices. It is also clear that existing market rules exacerbated the situation and contributed to the high prices. The data also indicate some attempted exercise of market power, if the standard of bidding above marginal cost is used, and some actual market power effects, to the extent that prices, at least in June, were significantly above competitive levels. However, the data do not isolate specific exercises of market power or suggest that the exercise of market power was more important than other primary explanatory factors."

From the Northeast Region report: "Although prices were generally lower in 2000 than in 1999, high hourly prices still occurred during capacity deficiency periods, in certain constrained submarkets, and under some designs for specific product markets. These factors contributed to conditions of scarcity or limited competition, conditions conducive to price increases and increased potential for market power exercise. Measures to mitigate market power and correction of market design problems can limit the price effects during these periods."

From the Midwest Region report: “Because of the inability to obtain critical information concerning general problems, such as the causes of TLRs, we are unable to definitively determine whether transmission access problems are systemic and wide-spread in the Midwest or whether the problems represent a collection of isolated incidents. Because of this lack of clarity, we were also unable to determine whether the appropriate regulatory response to these problems should be more aggressive enforcement of existing rules (if the problems are isolated incidents) or whether the rules need to be adjusted (if the problem is systemic). The lack of this information, in itself, creates a market inefficiency, because neither market participants nor regulators can fully analyze market conditions in real time in order to make decisions on what actions to take.

“As discussed in this report, at the very least, the volume and variety of complaints by market participants indicate a lack of confidence in the bulk power market in the Midwest. The perceived lack of clarity in the current rules and procedures, as well as the allegations of specific instances of discrimination, harms the liquidity of the market by hindering the ability of market participants to rely on transmission access. As a result, market participants seem to have become risk-averse, eschewing long-term deals for short-term transactions.”

From the Southeast Region report: “Staff has not verified the accuracy of all the complaints it has received regarding transmission access, ATC postings and TLRs. The lack of precise, readily available information, the real time nature of transactions, the resources required to investigate individual complaints and the operational discretion accorded IOUs retards the staff’s ability to discern the truth in the substantial number of complaints that were brought to it. Nonetheless, market participants appear to have less confidence in the Southeast market, in terms of the ability to conduct wholesale transactions without discrimination, than market participants have in other regions of the country. This lower degree of confidence appears to be justified based on investigations that the staff has undertaken and its evaluation of other complaints. Market participants’ reduced confidence weighs heavily on the maturation of markets into competitive zones of enterprise because it discourages the investment and participation needed to spur this development. The widespread perception that non-IOU entities do not receive treatment equal to that of IOU-affiliated entities frustrates the Commission’s open access goals.”

Authorizing and Monitoring Energy Projects

The Commission licenses nonfederal hydropower projects and certificates for construction of and authorizes the abandonment of interstate natural gas facilities and services. These projects have economic, environmental, and other societal implications, all of which must be considered in the licensing or certificating

process. In addition, the Commission is responsible for the safety of hydropower projects, environmental compliance of natural gas pipeline facilities, and the operational safety and reliability of liquified natural gas (LNG) storage facilities. The Commission seeks to optimize the economic and environmental benefits of energy projects.

Adequate Natural Gas Pipeline Capacity

With growing demand for natural gas, the Commission received more complex applications. The Commission will encourage efficient gas pipeline construction to provide individual customers and market entrants with increased choice and reliability of service by giving them multiple supply and delivery options. At the same time, the Commission will continue to balance and protect the competing interests of pipelines, new and existing customers, organizations, landowners, other agencies, and the environment.

Performance Indicator: *The Commission's certification program will allow the appropriate amount of new pipeline capacity to be available to serve the market when needed.*

Performance Indicator: *Certification of new pipelines will be timely, while fairly balancing the interests of the gas market, project sponsor, landowners, and the environment.*

The Commission has linked these performance indicators directly to its ability to process pipeline certificate cases fairly and timely. Generally, depending on the complexity, the number of opposing parties, and the type of opposition (e.g., landowner complaints), the Commission acts expeditiously and issues construction certificates to allow service to commence on the date the applicant requested.

In FY 2000, the Commission's actual time to process certificate applications was less than the target time in every case category. The Commission established target times within which 82 percent of the cases in each of the following categories should be processed:

- C Prior notice filings – small, uncontested cases;
- C Unprotested filings – cases not protested that have no precedential issues;
- C Protested filings – protested cases that have no precedential issues; and
- C Cases of first impression – cases with policy and precedential issues.

Here, the use of 82 percent signifies the percentile of filings that represent a significant break point in processing. The remaining 18 percent of cases are those that, for various reasons, will take extraordinarily long to process and would thus distort the processing times of most cases. The actual dates represent the total processing time for the case in the 82nd percentile. Actual processing days for cases up to the 82nd percentile are less than those shown.

Results for FY 2000 are as follows:

Type of Case	Case Count	Days to Complete 82%	
		Target	Actual
Prior Notice Filings	42	56	55
Unprotested Filings	93	159	127
Protested Filings	10	304	218
Cases of First Impression	42	365	272

The Commission regularly inspects natural gas pipeline construction projects to ensure that the projects comply with the environmental provisions of the Commission’s orders, recognizing the need to complete projects expeditiously. In FY 2000, the Commission met or exceeded its inspection targets, as shown in the table below:

Type of Inspection	Number of Projects	Projects Meeting Inspection Criteria	Target Percentage	Actual Percentage
Onshore construction projects more than 2 miles in length inspected at least once	89	88	90%	99%
Major onshore construction projects inspected at least once every four weeks during ongoing construction activity	6	6	100%	100%

During FY 2000, Commission staff made 386 inspection trips to ensure compliance with the Commission’s environmental conditions.

In FY 1999, the Commission piloted a third party monitoring inspection program. The program allows pipeline companies to hire third party compliance monitors who work under the Commission staff’s direction, performing daily inspections. Having full-time inspectors in the field results in fewer construction delays and in more frequent compliance inspections, benefitting the company, the environment, and landowners. Given the program’s success, the Commission in FY 2000 made it available to more pipeline applicants wanting to participate.

Licensing and Administering Hydropower

The Commission issues licenses for nonfederal hydropower projects and monitors the projects to ensure that license conditions are met. Hydropower facilities provide tangible benefits to the regions where they are located. These benefits include additional recreational opportunities, economic benefits from commercial development, and the generation of electricity without use of fossil fuels. At the

same time, hydropower projects can adversely affect resources such as water quality, fishery resources, water-based recreational uses, terrestrial resources, and cultural resources. The Commission must balance the interests of the licensees, customers, affected stakeholders, and the environment

The Commission shares its licensing conditioning authority with numerous state and federal agencies which poses unique challenges to the Commission in issuing timely and balanced licenses.

Performance Indicator: *The Commission will reduce processing time under its control, particularly through the use of collaborative procedures and early involvement of staff.*

The average processing time to issue a license using the non-collaborative or traditional procedure compared with the average processing time to issue a license using the alternative licensing procedure (ALP), a formal collaborative procedure, is as follows:

Licensing Process	Average Processing Time (Filing to Issuance)
Non-collaborative, traditional	2.77 Years
Alternative Licensing Procedure	0.99 Years

The Commission calculates the average processing time for licenses issued using the traditional process that were filed and issued from October 16, 1986 (the date Congress passed the Electric Consumers Protection Act) through the end of FY 2000. The Commission calculates the ALP average processing time for licenses issued using the ALP that were filed and issued from October 1997 (the date the Commission codified the ALP in its regulations) through the end of FY 2000.

The voluntary ALP combines the environmental analysis and the required pre-filing process. Commission staff's early involvement guides the process and provides Commission expertise and guidance to participants. Also, license applicants work closely with all affected government resource agencies, non-governmental organizations, and local citizens to identify and resolve issues before filing an application with the Commission. The ALP uses cooperative approaches, such as alternative dispute resolution (ADR) techniques, to resolve issues, and encourages settlements before filing with the Commission to avoid protracted licensing proceedings. Since 1992, ten projects have used the ALP process.

Besides settlements resulting from the ALP, licensees develop settlements through other less formal collaborative methods. As in the ALP, settlements reached before filing with the Commission reflect the desires of the local constituency and

result in fewer legal challenges. In FY 1997, 15 percent of the 46 licenses issued involved settlement agreements, resulting from the ALP or other collaborative processes. Of the 48 licenses issued in FY 1998 and FY 1999, 17 percent involved settlements agreements. In FY 2000, of the 10 licenses issued 40 percent, a significant increase, involved settlements.

Performance Indicator: *Licensing conditions will protect and enhance beneficial public uses, both developmental and nondevelopmental.*

In issuing or renewing licenses for hydropower projects, the Commission builds into those licenses certain conditions under which the licensee must operate the project. These conditions may be developmental (power-related) or non-developmental (environmental). In the 1990s, the Commission began requiring licensees, as part of their relicense conditions, to develop plans to monitor the results of the licenses' environmental resource protection conditions. The Commission designs these conditions to determine if environmental measures are effectively achieving specific levels of resource enhancement and protection. Knowing the effectiveness of certain measures will help the Commission learn whether such environmental measures are protecting, mitigating, and enhancing environmental resources appropriately. The Commission developed an evaluation system to track the effectiveness of the required measures and to identify the most effective measures. The Commission will disseminate the effectiveness information to licensees, potential licensees, and other interested parties.

The Commission has developed databases and is reengineering them into an information system that will be critical in gauging the outcome of the required measures. The Commission is attempting to relate facility, infrastructure, resource, and related-inventory information. Through this reengineering effort, the Commission will be able to evaluate more effectively and comprehensively whether required conditions are protecting and enhancing beneficial public uses. In FY 2000, the Commission further automated the information, allowing staff to retrieve the information easily and use it to make the best comprehensive decisions. In FY 2000, the Commission reviewed more than 800 environmental plans and reports from licensees for input into this effort.

Performance Indicator: *Administration of hydropower developments will accommodate increasing public use without diminishing key water resource values.*

Hydropower facilities provide tangible benefits such as recreational opportunities, economic benefits through commercial development, and electric generation from a renewable resource. However, hydropower projects also can adversely affect resources such as water quality, fishery resources, water-based recreational uses,

terrestrial resources, and cultural resources. The Commission’s challenge is to optimize both economic and environmental benefits. Recreational facilities are one measure of the project’s public use.

The number of licenses the Commission issued with license requirements addressing recreational facilities appears in the table below:

License Requirements	Number of Projects	
	FY 1999	FY 2000
Required new or upgraded recreational facilities	14	5
Existing recreational facilities adequate following review	5	5

The Commission often requires a licensee to submit a plan showing how it intends to implement recreational license requirements. These plans typically require the licensee to construct or improve facilities available to the public for their benefit. The benefits include fishing access, boat ramps, fishing platforms, canoe portages, parking areas, campgrounds, and picnic areas. In addition, during the license term, facilities may be added or modified if needs change. In FY 2000, the Commission approved or amended 26 recreational plans.

Besides license requirements, the Commission works with concerned parties to ensure the water resource value of its jurisdictional projects. In FY 2000, as a member of the National Recreational Fisheries Coordination Council, the Commission implemented a plan for enhancing recreational fishing opportunities at its licensed projects. Also in FY 2000, the Commission continued to promote recreational fishing at licensed projects through a brochure and an Internet “Fishing Net” page.

Dam Safety

The Commission has statutory responsibility for the safety of more than 2,600 nonfederal hydropower projects. Inspections verify the structural integrity of dams and compliance with engineering, environmental, and public safety conditions and regulations. They also identify necessary maintenance and remedial modifications. Inspections safeguard the continued operation of projects, as well as downstream lives, property, and environment. As a second line of defense, emergency action plans make sure that the dam owner and community know how to deal with potential emergencies.

Performance Indicator: *The percentage of high- and significant-hazard dams meeting all current structural safety standards will remain uniformly high.*

Significant-hazard dams are those dams where failure could cause economic loss or environmental damage, disrupt lifeline facilities, or impact other concerns but would result in no probable loss of human life. High-hazard dams are those dams where failure could result in the same events as significant-hazard dam failure and would probably cause loss of human life. During FY 2000, the Commission identified 989 high- and significant-hazard dams. At the end of FY 2000, 92.8 percent of these dams met all current structural safety standards. The remaining 7.2 percent or 71 dams were in remediation, undergoing dam safety modifications. The percentages are determined as follows:

$$\frac{989 \text{ qualifying dams} - 71 \text{ dams undergoing safety modification}}{989 \text{ qualifying dams}} = 92.8 \% \text{ of high- and significant-hazard dams meeting all current structural safety standards}$$

The remaining 7.2 percent of high- and significant-hazard dams are in remediation, and the Commission is deeply involved in the pre-construction and construction phases of this work.

Performance Indicator: *One hundred percent of high- and significant-hazard dams will be inspected annually.*

To ensure a successful dam safety program, it is critical that the Commission inspects high- and significant-hazard dams regularly. Inspections verify structural integrity, determine compliance with engineering and safety guidelines and regulations, and identify necessary maintenance and remedial actions. In FY 2000, the Commission inspected 100 percent of the 989 dams it identified as having high- or significant-hazard potential.

Performance Indicator: *One hundred percent of high- and significant-hazard dams will comply with emergency action plan requirements.*

Inspections, evaluations, remediation, and monitoring cannot guarantee that emergencies will not occur. High- and significant-hazard dam failures, most often, cause large quantities of water to flow into nearby river basins. Downstream communities are susceptible to the consequences of such failures, including damage to property and the environment, and loss of life. Emergency action plans, which require development, maintenance, and periodic testing, are a second line of defense to protect life, property, and the environment. The plans specify actions that owners must take in coordination with federal, state and local preparedness agencies, in case of flood, earthquake, or project facility failure. Of the 989 high- and significant-hazard potential dams the Commission identified in FY 2000, 99.7 percent – all but 3 dams – complied with emergency action plan requirements. The Commission’s jurisdiction over the three dams is in dispute.

Commission Administration

The changing nature of regulation requires changes not only to the Commission's policies, but also to *how* it does its work. Many key initiatives in the Commission's reengineering effort addressed human resources issues – how to develop and retain the right workforce – and information technology. The Commission has also undertaken several other changes to ensure that its management and administrative efforts will fully support its core programs. The following are highlights of the Commission's efforts to improve its administrative work:

- C **Electronic Filing.** Through better management of information technology, the Commission will set up a largely paper-free environment with electronic filing and posting of documents and automated work flow management.
- C **Strategic Workforce Planning.** As the Commission faces the challenges of the future, its overall success will depend on workforce planning that aligns strategic goals with people planning. The Commission is reexamining human resources programs to ensure that they support changing resources and work requirements.
- C **Diversity.** Employees must have appropriate experience and education. They also should come from all walks of life and be optimistic, versatile, energetic, and creative. A rich mix of talents and skills requires people with novel ideas and differing perspectives.
- C **Leadership.** The Commission has begun an intensive effort to improve the quality of its leadership. Every manager now has performance standards based on how well they provide direction, achieve results, support teamwork, build trust and commitment, and communicate. This program, coupled with a reduction in the number of managers, will help the Commission make the best use of its entire workforce.
- C **Annual Charges.** The Commission will continue to collect annual charges and provide timely payment of contractors' invoices using electronic funds transfer (EFT).
- C **Independent Auditing.** To ensure that all financial requirements comply with applicable laws, statutes and regulations, the Commission will continue to have external and independent audits conducted where appropriate.
- C **New Procurement Systems.** Implementation of acquisition reform initiatives will continue to speed procurement of goods and services. These initiatives

include using the government-wide credit card, contractors' past performance, and Interagency Agreements, which will streamline the procurement process.

- C **Outreach.** The Commission has undertaken a systematic effort to enhance relationships with Congress, federal and state agencies, and other stakeholders, to improve overall coordination and communication. The Commission is hosting more public conferences and information exchange opportunities so that industry and other interested parties can meet and exchange information with the Congress and its staff.

Because of its strategic realignment, the Commission's administrative support activities have become a separate program. This transition took place during FY 2000. The FY 2001 budget and performance plan reflect this change. Besides the administrative performance indicators published in the FY 2000 annual performance plan, the Commission has included financial measurements previously developed for its annual financial statements. The Commission has included the financial measurements for two reasons. First, the financial measurements present an alternative view of administrative activity by displaying performance based on the principles of good business practices. Second, they represent the more substantive measurements the Commission will use in FY 2001.

Reducing Administrative Burden

The results for the three indicators in this category display some distinct similarities. The cause lies in the interconnectedness of the indicators themselves. For example, reducing processing times for workload, minimizing filing burdens, and generating better information for use by the industries have roots in the Commission's ability to develop and maximize a robust information technology infrastructure. While this may lead to some repetition in the results, it also demonstrates the Commission's commitment to reducing the administrative burden placed on the industries it regulates.

Performance Indicator: *Reduce the processing time for docketed workload and for resolving disputes.*

Two accomplishments in reducing processing time for docketed workload center on technology initiatives:

- C **Electronic Filing Pilots.** In FY 2000, electronic filing pilots began testing the interface between the Commission's Internet site and the FERC Automated Management and Information System. Pilots include comments, protests and interventions, which collectively account for 35 percent of filings with the Commission. The Commission received its first completely paperless filing in FY 2000. The Commission automated and is testing Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants. The Commission can

apply the e-form software to all 14 of its forms, accounting for nearly half a million pages filed annually. Further, the software is flexible enough to adapt to changes to data to be collected in the future.

- C **The FERC Automated Management and Information System.** The Commission developed this system to track workload, automate processes where possible, and create an electronic work space for staff to collaborate on projects requiring input by multiple staff. The system permits managers to assign work to specific staff and to track the progress of each assignment.

The first phase focused on replacing several workload tracking systems and service list systems that resided on the non-Y2K compliant mainframe computer. The new system went into production in October 1999, with initial access limited to users of the systems migrated from the mainframe. This allowed the Commission to retire its mainframe computer.

During FY 2000, access to the new system became agency-wide. Agency staff have begun to work in collaborative work spaces, and managers are beginning to use system features to assign workload to staff automatically. The Commission established high-level workflow processes to move work products through reviews needed for document issuance. The Commission posts issuances on its Internet site, where they are available to the public.

System implementation includes establishing an infrastructure to support e-filing in a variety of formats, developing interfaces with the workflow and tracking components, and routing the e-filing to the Commission's electronic library (RIMS) where it is available to the public via the FERC Internet site. When the Commission fully enables e-filing processes and develops core program processes, the system will route documents to the appropriate group or individual automatically, and to RIMS.

Other accomplishments in reducing processing times and resolving disputes were initiated within the energy markets and energy projects programs:

- C **New Time Lines Expedite Hearings.** On October 27, 1999, the Commission implemented new time lines to reach faster decisions on proceedings set for hearing before the Commission's Administrative Law Judges (ALJs). The expectation is that on average, litigation times for many cases would reduce by as much as one-quarter.

The new procedural time standards differ based on the complexity of the proceeding and include a separate schedule of time frames for complaints:

Case Type	Hearing Begins	Reply Briefs Due	Initial Decision Due
Track I: Simple Proceedings	19.5 weeks	25.5 weeks	29.5 weeks
Track II: Complex Proceedings	32 weeks	40 weeks	47 weeks
Track III: Exceptionally Complex Proceedings	42 weeks	53 weeks	63 weeks
"Fast-track" Complaints	3 days	5 days (oral arguments)	8 days
Complaints Before an ALJ	30 days	45 days	60 days

Merger cases set for hearing will be processed within these time lines consistent with the Commission’s merger policy, which calls for the ability to issue a final order within 12 to 15 months from the date the Commission receives most complete applications.

The new time standards have worked well during the short period that they have been in effect. During this period three proceedings were completed under the Track I schedule. Two were completed within the 29.5 weeks, and one was granted a two-week extension due to extenuating circumstances. Nine proceedings were completed under the Track II schedule and all were completed within the established time lines. One proceeding was designated as Track III and it was completed much before the 63-week deadline. Two regular complaint proceedings were completed during this period. Both complaints involved complex issues requiring extensive discovery. These complaints were completed within 13 and 14.3 weeks.

The Commission is also placing more emphasis on alternative dispute resolution. For example, during this fiscal year, 73 new cases were set for hearing. The Commission instituted mediation or Settlement Judge procedures in 38 of these cases. This represents 52 percent of all cases set for hearing.

The Commission has also made great strides in speeding the approval of uncontested settlements. In December 1999, the Commission instituted new procedures where the Judge drafts the Commission’s letter order and the uncontested settlement is scheduled for consideration in the next Commission agenda after the certification of the settlement. Since the new procedures began the average time for approval of uncontested settlements has been 47 days. This is a dramatic improvement from the prior average approval rate of more than 100 days. The Commission expects that the process will result in even quicker approval as the new procedures are perfected.

- C **Promoted ADR.** The Commission participated in multiple efforts within and outside the Commission to communicate alternative dispute resolution (ADR) values and practices. These efforts included:

- < development of an advanced negotiation course in effective, assisted negotiations for the Commission as a whole;
 - < revising the Commission's procedures to include the option of using ADR for Equal Employment Opportunity and non-EEO employee disputes, labor/management disputes, and contractor disputes;
 - < participation in a panel discussion at the American Bar Association's annual meeting on the ADR services the Commission can provide, and at the New York Financial Times on the development of an electricity market using ADR;
 - < participation in three outreach sessions to groups in the Midwest, the Southeast, and the Northwest on ADR initiatives in the Alternative Licensing process for hydroelectric facilities;
 - < initiation of ADR training programs within the electric and the hydroelectric industries; and
 - < continuation and creation of partnerships with external organizations such as the Interagency ADR Working Group Civil Enforcement Section, the Environmental Center for Conflict Resolution, the Bureau of Indian Affairs, the National Park Service, Native American Rights Fund, Indian Dispute Resolution Service, leaders of the Federal Bar Association's Indian Law Section, and the Great Lakes Tribal Council.
- C **The Federal Preservation Officer (FPO) now resides in the Commission's Dispute Resolution Service.** The FPO coordinates the Commission's historic preservation activities and assists the Commission and outside parties resolve disputes involving historic properties and properties to which Indian tribes attach religious and cultural significance. The FPO coordinates with several offices within the Commission and with outside entities such as the Advisory Council on Historic Preservation, State/Tribal Historic Preservation Officers, and other organizations and persons having an interest in cultural resources and the effects of projects on those resources.
- C **Streamlined Rate Schedule Sheet Designation Procedures for the Electric Industry.** On March 31, 2000, the Commission issued a final rule (Order No. 614), amending its regulations to require the inclusion of proposed designation for all rate schedule sheets filed with the Commission by public utilities. The rule streamlines rate schedule sheet designation procedures for the Commission and the electric industry. The rule will also conform public utility tariff filing procedures with those for interstate natural gas and oil pipelines. This revision to the regulations accommodates the movement

toward an integrated energy industry and facilitates the development of common standards for the electronic filing of all electric, gas, and oil rate schedule sheets.

- C **Landowner Notification Rule.** This rule, issued in October 1999, prescribes methods for early notification by applicants of landowners whom natural gas pipeline construction may affect. The goal of the rule is to ensure that landowners have sufficient opportunity to participate in the Commission's certificate process. The timely participation of landowners will result in earlier resolution of issues, allowing faster Commission decisions.

- C **Processing Times for Natural Gas Certificates.** While adhering to its statutory requirements, the Commission strives to process natural gas pipeline applications as expeditiously as possible. The Commission's target is to process 82 percent of all cases in four categories within an established target time. In FY 2000, the Commission's processing times in all four categories were less than the target time. This successful performance reflects the Commission's willingness to work with all interested parties.

- C **Natural Gas Outreach Program.** In FY 2000, the Commission designed an outreach program to develop a toolbox of options applicants could use to gain faster Commission approval of their applications for natural gas facilities. The Commission held the first outreach seminar in Albany, New York on September 26, 2000. More than 125 people from the industry, federal, state, and local agencies, and the public participated, giving presentations and participating in interactive discussions. The Commission will continue similar seminars through FY 2001.

- C **Reducing Processing Time Through Collaborative Procedures.** In FY 2000, the Commission's collaborative efforts resulted in several accomplishments related to hydropower licensing.
 - < *Interagency Task Force (ITF).* The Commission finds that using a collaborative process generally speeds the license processing time. To promote the collaborative process with federal and state agencies, the Commission participated in the ITF along with the Departments of Commerce, Interior, and Agriculture. In early FY 2000, the ITF recommended reforms to improve the hydropower licensing process. In May 2000, the ITF participants signed a Joint Statement of Commitment for An Improved Hydropower Licensing Process, obligating the parties to implement the ITF recommendations. Carrying out the recommendations will encourage collaborative efforts and settlements, improve communication among all participants in the licensing process, and coordinate and streamline processes at the various agencies, making the hydropower licensing process more timely and less costly.

- < *Applicant-Prepared Environmental Assessment (APEA)*. Under the Commission's alternative licensing program (ALP), licensees and applicants can choose to submit an APEA or third-party contract environmental impact statement (EIS) as part of their application. Through the APEA process, the Commission anticipates that the participants can resolve all issues with a substantial reduction in the time required for environmental review after filing with the Commission. During FY2000, the Commission continued fostering APEAs for 49 projects and issued three licenses using the APEA process.
- < *Interagency Training*. The U.S. Forest Service, the U.S. Fish and Wildlife Service, and the Commission developed an interagency hydropower workshop to train those participating in the licensing process. Workshop participants include federal and state resource agency personnel and others involved with the licensing process. During FY 2000, the Commission held one major workshop.
- < *Project-Specific Public Information Meetings*. The Commission holds public information meetings near specific projects that will undergo relicensing in the future to give the public accurate information about the Commission's relicensing processes. Commission staff gives an overview of the Commission, what it regulates, its make-up, how it operates, and the traditional and alternative licensing processes, encouraging the use of the collaborative alternative licensing process, which is better for effective public involvement than the traditional process. Since August 1999, Commission staff has made presentations and answered questions at ten such public meetings.

Performance Indicator: *Minimize filing burden.*

Revised Reporting Requirements. In July 2000, the Commission issued a notice of proposed rulemaking (NOPR) as part of its ongoing effort to update accounting and reporting requirements and eliminate any that are burdensome or unnecessary. The NOPR proposes to: (1) revise Annual Report of Oil Pipeline Companies (Form 6) schedules and instructions to meet current and future regulatory requirements and industry needs better; (2) update Uniform Systems of Accounts requirements to be more consistent with current Generally Accepted Accounting Principles, and (3) amend its regulations to provide for the electronic filing of Form 6. The Commission also proposes to mechanize the Form 6 to allow for electronic filing. If adopted, these changes would reduce nearly 24.7 percent the burden on regulated companies for maintaining and reporting information under the Commission's regulations.

Records Retention. In July 2000, the Commission issued Order No. 617 to update, clarify, and reduce records retention requirements. This was part of the Commission's efforts to update regulations and reduce industry burden, and was in response to requests from the industry and the Office of Management and Budget. The order, affecting public utilities, hydropower licensees, natural gas companies, and oil pipeline companies, modifies records retention regulations by shortening various records retention periods, increasing retention periods in a few categories, and removing all but one retention reserve item.

Electronic Filing Pilots. In FY 2000, electronic filing pilots began testing the interface between the Commission's Internet site and the FERC Automated Management and Information System for 35 percent of filings with the Commission. As it becomes operational, electronic filing will reduce expenses to industry related to paper filings, such as copying, mailing, and messenger costs.

Performance Indicator: *Generate better information for use by the industries.*

The Commission is continuously upgrading and updating its hardware and software to ensure the reliability and stability of its IT systems, and give its staff the latest versions of the tools that they need to accomplish their work. The Commission's IT systems also support the Commission's Internet site, which provides a means for the public to access information from the agency, 24 hours per day, 7 days per week. One example of success in this area in FY 2000 was the increased use of the Internet to disseminate dam safety information, making the Dam Safety and Inspections Operating Manual, Engineering Guidelines for the Evaluation of Hydropower Projects (Engineering Guidelines), Public Safety Guidelines, and other information available.

The Commission has increased efforts to improve the security of its Internet site, Internet e-mail, local and wide area networks, and individual personal workstations. New software has been added to filter viruses and remove them before they can reach the network or individual personal computers. The Office of the Chief Information Officer also established a full-time computer security officer, and ongoing consultation with Department of Energy security specialists.

Registering an average of more than 4,000 user sessions daily, the Commission's Internet site provides a portal for e-filing and making information available to industry and the public. Current Internet site development efforts focus on improving server reliability, providing a more powerful search engine, making it easier to navigate the site and find information, providing the ability to view large maps and drawings, and making Commission notices and orders available to the public within minutes or hours after issuance. As the Commission implements e-

filing initiatives, systems will route electronic submissions automatically to RIMS, where they will be available to the public more quickly via the Commission's Internet site.

The Commission Issuance and Posting System (CIPS) also is available through the Commission's Internet site. Timely and accurate Commission issuances, such as notices, orders, and major rules, continue to promote the flow of information throughout the agency and to all interested parties and the public.

The public, regulated industries, and agency staff all benefit from having a stable, secure, reliable IT environment that supports access to agency information 24 hours per day, 7 days per week. Maintaining a stable and reliable IT environment requires the Commission to invest in powerful new hardware and software to enable those needing access to the Commission's information to have it while protecting that data from unauthorized intrusion.

**Continue to Improve
and Enhance the
Commission's
Fiscal and
Budgetary Position**

These performance indicators involve some of an agency's most fundamental activities. They represent the agency's financial standing, its ability to plan for successfully and manage its resources, its ability to meet its financial obligations, and its ability to maintain internal controls. The Commission has measured these activities since it began compliance with the Chief Financial Officers Act in the early 1990s, and is committed to continued success in this area.

The Commission will ensure effective management of its budgetary resources by instituting a decentralized budget structure called Manage to Budget. Manage to Budget is a major cost-containment measure that places more resource accountability at the office level. In keeping with increased fiscal responsibility and accountability, the Commission will require all managers to operate within their designated budget allocations. This initiative will allow Commission offices direct control of their spending levels in all funding areas, with particular emphasis on salaries, which represent more than 65 percent of total budgetary resources. Ultimately, each office's performance will rely on sound fiscal management of salary dollars and awareness of the impact personnel actions have on their budgets. The Commission will begin implementation of Manage-to-Budget in the third quarter of FY 2000.

Performance Indicator: *Continue to receive an unqualified audit opinion on the Annual Financial Statements.*

As interpreted by KPMG LLP, the Commission continues to receive an unqualified opinion on its financial statements along with no material weaknesses, reportable problems, or instances of noncompliance. This measurement is critical

to the Commission in presenting our financial stability to our customers and regulated entities, and ensuring our financial statements reflect true and accurate balances.

Performance Indicator: *Formulate the budget so that current year costs are within 5 percent of the total budgetary resources for the fiscal year.*

The Commission's current year costs were within 5 percent of total budgetary resources for FY 2000. The total cost entries recorded against current year obligations amounted to \$166,908,025. Compared with total budget authority less funds allotted to outside entities, \$176,407,533, we found that the Commission had costed 95 percent or 5 percent of budgetary resources were left uncOSTed at the end of FY 2000.

Reaching this performance goal shows the Commission's dedication to reduce uncOSTed and unobligated balances. As the Commission continues to develop sound budget requests during times of increased fiscal constraints, we anticipate that we will continue to meet this goal in future years.

Performance Indicator: *Pay 95 percent of all payments accurately and on time: vendors within the time required by the Prompt Payment Act; internal customers in 10 days or less.*

In FY 2000 the Commission implemented a new financial accounting system approved by the Joint Financial Managers Improvement Plan. To close out all accounting information before converting to the new financial system, the Commission made early payments of invoices to external customers in the old financial system. Taking this necessary measure affected the Commission's Prompt Payment Act percentage. Due to this action, the on-time invoice payments to vendors for FY 2000 are 85 percent, below the target of 95 percent. The Commission anticipates recovering its former performance of more than 95 percent on-time payments in FY 2001.

The conversion to the new system did not impact the Commission's payments to internal customers. The average processing time for payments to internal customers in FY 2000 is 2.6 days, well within the target of 10 days or less. Performance measurement results are based on the Commission's Performance Measurement Report transmitted to DOE for the fiscal year ending September 30, 2000.

Performance Indicator: *Meet or exceed planned due dates 90 percent of the time for performing and completing Federal Managers' Financial Integrity Act requirements and internal financial and performance reviews.*

In FY 2000, the Commission met 100 percent of the planned due dates for conducting and completing the requirements of the Federal Managers' Fiscal Integrity Act. All of the previous year's reportable problems were closed, and the Commission resolved one potential reportable problem this year. Management continues to be alerted to lower level reportable problems, resolving them at the organizational level necessary to take corrective action.