FERC: REGULATORS IN DEREGULATED ELECTRICITY MARKETS

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY POLICY, NATURAL RESOURCES AND REGULATORY AFFAIRS

OF THE

COMMITTEE ON GOVERNMENT REFORM

HOUSE OF REPRESENTATIVES

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FERC: REGULATORS IN DEREGULATED ELECTRICITY MARKETS

THURSDAY, AUGUST 2, 2001

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY POLICY, NATURAL RESOURCES AND REGULATORY AFFAIRS,
COMMITTEE ON GOVERNMENT REFORM,
Washington, DC.

The subcommittee met, pursuant to notice, at 2:45 p.m., in room 2154, Rayburn House Office Building, Hon. Doug Ose (chairman of the subcommittee) presiding.

Present: Representatives Ose, Otter, Duncan, Tierney, Towns, Kucinich, and Waxman (ex officio).

Staff present: Dan Skopec, staff director; Barbara Kahlow, deputy staff director; Connie Lausten, professional staff member; Regina McAllister, clerk; Michelle Ash and Elizabeth Mundinger, minority counsels; Ellen Rayner, minority chief clerk; and Earley Green, minority assistant clerk.

Mr. OSE. The committee will come to order. I want to thank everybody for showing up today. Today's hearing is to discuss the prospective efforts of the Federal Energy Regulatory Commission—that I'm going to now refer to as FERC from hereafter—as they relate to energy markets and the effective functioning of them. We have a choice to make today. There are two paths that we could easily follow. Path A—sort of like Path 15. Path A is to engage in finger pointing and the like, and that is pretty pointless, however, I'm confident that some wish to pursue that path. Path B is to explore how to prevent a repeat of this debacle we've worked our way through over the past year. I am intent that today's hearing will pursue the second path.

FERC has been asked to do many things lately. Up until a year ago, this agency operated in the obscure back waters of the regulatory world. Over the past 12 months, though, circumstances have significantly changed. Today's challenge is that energy has become a commodity that is traded across electronic markets, traded across national borders and traded among market participants who, in some cases, have no generating capacity. If FERC is to meet its statutory obligations to ensure just and reasonable prices, then Congress must periodically examine the tools that are available to FERC to meet its responsibilities.

Now that FERC's role has evolved into one of market monitoring, as opposed to regulatory control, does the agency have the necessary tools to perform that function? As FERC tries to monitor the energy market, does it have the necessary staff to do its job? From a statutory standpoint, does current law constrain FERC in ways that are no longer useful? For instance, what was the original purpose of a 60-day lag between the time a pricing complaint was filed and the time when FERC could actually examine that complaint?

Given the possibility that egregious pricing behavior might occur, why were the remedies available to FERC restricted to ordering only the amount of an overcharge to be refunded as opposed to assessing fines or penalties?

I have introduced legislation, H.R. 1941, to address these two particular problems, and I look forward to the witnesses' comments on this piece of legislation. Members on both sides of the aisle and all of you in attendance are quite familiar with the facts in the energy crisis. The question remains, are we going to try and fix the problems, or are we going to engage in political sniping? I'm challenging every single member of this subcommittee to focus on the question that I just posed. Are we going to try and fix it or are we going to snipe?

The residents of my State of California need the Congress to examine this matter and provide direct concrete input as to how to avoid a repeat of this debacle elsewhere in the country. I look forward to the testimony of our witnesses today. I will submit the balance of my statement to the record. I recognize the gentleman from Cleveland for an opening statement.

[The prepared statement of Hon. Doug Ose follows:]

Chairman Doug Ose
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs
FERC: Regulators in Deregulated Energy Markets
August 2, 2001

In April 2001, this Subcommittee, and the full Government Reform Committee held three field hearings in California to investigate the causes and possible solutions of the California energy crisis. We learned that the crisis was caused by several factors. First and foremost was a terribly flawed market design. This design forced the utilities to sell much of their native generation, mandated that all power be bought and sold through the spot market, prevented the utilities from entering into long-term contracts, and froze retail rates, while wholesale rates were skyrocketing, which denied Californians the incentive to conserve. In addition, energy demand outstripped supply since very little new generation was built in California for over a decade, while demand in California and the rest of the West grew significantly. Low water levels in the Northwest and high natural gas prices also contributed to the crisis experienced in California.

However, the purpose of this hearing is not to rehash what we learned in our April hearings. Nor is it to review what the State of California has done to make the problem worse, which I think would take days of hearings. Instead, the purpose of this hearing is to look at the role of the Federal Energy Regulatory Commission (FERC) in regulating energy markets. Specifically, what does FERC need to ensure that the nation does not experience another situation like California?

The Federal Power Act gave FERC the responsibility to monitor energy markets and ensure that "just and reasonable" prices prevail. I think anyone who looked at California over the last 14 months will agree that prices were not always just and reasonable. While I congratulate the agency for its innovative market mitigation plan for California on April 26th and for the entire West on June 19th, I believe that FERC was slow to act. Having worked with and observed FERC over the last year, it is clear to me that the agency was unprepared to adequately monitor deregulated electricity markets. FERC lacks the tools and staff experience to properly regulate these markets.

We cannot deny that FERC needs to make some significant changes in order to protect consumers from future market meltdowns.

With regard to market monitoring, we are starting to see some significant changes at FERC. In Order 2000, FERC laid out a new paradigm by giving Regional Transmission Organizations (RTOs) a greater role in market monitoring. RTOs are to establish specific market monitoring plans, including fines and sanctions, that all market participants must follow. FERC has already approved the market monitoring plan of Pennsylvania-New Jersey-Maryland (PJM) and has indicated that it wants other RTOs to resemble PJM's. For that reason, I asked PJM to testify today. I am interested to hear about its market monitoring plan and determine what lessons the rest of the nation can learn from it.

Another step FERC has made to improve its market monitoring ability is the creation of the Market Observation Resource Center, which opened last month. I recently had the opportunity to visit the center and was quite impressed. FERC consulted with the Securities and Exchange Commission, the Federal Trade Commission, and the Commodity Futures Trading Commission and visited energy companies, such as Enron, Dynergy, and El Paso, to learn how and with what technology these agencies and companies monitored markets. The Center opened in July 2001 and is run by a former energy trader. The Center allows FERC to track energy markets in real time rather than read the trade press days later. Visiting the Center made me wonder how FERC could have properly monitored markets previously. Its creation is an acknowledgement that FERC needed to bring its monitoring capabilities into the 21st Century. I applaud this ongoing effort.

We are also interested to learn what additional tools FERC needs to continue to improve. Officially, FERC has 103 staff members who monitor markets. In reality, only a handful of people work in the Market Observation Resource Center actively monitoring energy markets. The rest are either lawyers or accountants who calculate cost-based rate tariffs rather than studying markets. There are only 11 economists. FERC needs more people who have private sector market experience as well as more economists that understand the nature of markets if it is to monitor the wily traders in the private sector.

I plan to ask FERC if Congress needs to give it more authority in regulating markets. I have introduced a bill, H.R. 1941, the "Electric Refund Fairness Act of 2001," which gives FERC more teeth to enforce just and reasonable prices. The bill repeals the 60-day delay from the time a pricing complaint is filed until the time refunds can be considered. The bill also allows FERC to issue penalties above and beyond the amount of overcharge if it finds unjust and unreasonable prices exist. Under current law, FERC can only order refunds equal to the amount overcharged, which essentially provides an incentive to gouge consumers.

The statutory restraints that I seek to address in H.R. 1941 are readily apparent as we consider refunds for California. On August 2, 2000, San Diego Gas and Electric filed a complaint with FERC alleging unjust and unreasonable rates. According to the Federal Power Act, FERC could not even consider refunds until October 2, 2000. Furthermore, FERC can only issue refunds equal to the amount of the overcharge. FERC reaffirmed this fact during the recent settlement talks on the California case. This provision needs to be changed to send a message to generators that if you gouge, you will pay a price.

The Subcommittee is also interested in FERC's approach to plant outages. The debate over plant outages has raged for months. Many people accuse the generators of withholding power to run up prices. The generators claim that their plants are old and were overworked last summer, leading to higher than normal outages. FERC attempted to review this issue in a February 2001 staff report. I was disappointed in this report. Approximately 60 percent of the outages investigated were done by telephone. FERC only made on-site investigations of two plants. I understand how difficult it is to determine whether a plant is truly down for maintenance or is being withheld to drive up prices. Many experts, including the General Accounting Office (GAO), have stated that it is impossible to know for sure whether an outage is legitimate or not. But, that does not mean that we should give up. As long as supply and demand are tight, withholding will be an issue. I call on FERC to devise a system that eliminates incentives to withhold power.

One issue of particular importance to me is how the California Independent System Operator (CAISO) will fit into FERC's vision for the nation, as outlined in Order 2000. It appears that FERC visualizes four RTOs operating throughout the country, including one for the entire West. The State of California has indicated that it wants to create its own RTO rather than join its Western neighbors. As FERC moves to create a national grid based on Order 2000, the issue of the independence of the CAISO will come into question.

In its December 15, 2000 Order, FERC took steps to address this issue by disbanding the CAISO's stakeholder board and laying out principles for a new board. The Governor of California ignored FERC's order and established a 5-member board of handpicked political cronies. Currently, three of the members are State employees and the Chairman is a political consultant to the Governor. The lack of independence has serious implications for Californians. The California Department of Water Resources (DWR) is the largest energy buyer in the State. As a result, the largest market participant and the supposedly "independent" system operator both answer to the Governor.

Many of you may think that this is just a political turf battle between FERC and the State of California, but it has serious implications for California's citizens and energy markets throughout the West. In the California settlement talks, FERC ruled that the California DWR was not eligible for refunds partly because of the preferences that the CAISO had given it. Apparently, CAISO allowed DWR employees exclusive access to its control room, allowing DWR to cherry-pick its power purchases. Also, some CAISO employees are actively working for DWR. It has been reported that CAISO's Chief Operating Officer is also serving as an energy advisor to the State and reports to Governor Davis's energy czar.

The State's interference into CAISO has possibly cost Californians billions of dollars in potential refunds. Moreover, it represents a serious violation of FERC's regulations. I call on FERC to address this issue immediately so that we can return integrity to the operators of California's energy markets.

I want to thank all the witnesses for coming today. I look forward to their testimony. Our witnesses include: Kevin Madden, General Counsel, FERC; Shelton Cannon, Deputy Director, Office of Markets, Tariffs and Rates, FERC; James E. Wells, Jr., Director, Natural Resources and Environment, GAO; Terry M. Winter, President and CEO, CAISO; Phillip Harris, President and CEO, PJM Interconnection, L.L.C; and William W. Hogan, Professor, John F. Kennedy School of Government, Harvard University.

Mr. KUCINICH. I thank the Chair, and I'm sure the Chair is aware that yesterday I had the opportunity to support California legislators who were looking for assistance in various amendments to the bill. So I have a great deal of sensitivity to the issues that were raised in the State of California. I've watched the troubles of deregulated energy markets brewing for several years now. I'm convinced that partially deregulated electricity market will do more harm to consumers than good.

California, while unique in some ways, is not the exception to the rule. Rising wholesale electricity costs can be found everywhere electricity has been deregulated. The most ridiculous free market argument is that California only partially deregulated and complete deregulation would have prevented the crisis. They are correct that complete deregulation would have prevented the bankruptcy, but only because of all of the excessive prices would have been passed on to the consumer.

Consumers would have shouldered the brunt of the failed market, and many more families and small businesses would be in bankruptcy. I have some serious concern with FERC's recent actions. For example, it took FERC a year to offer any real relief to California by applying the breaks to a dysfunctional market with their June 19th order. Yet FERC, in the same action, decided to illegally expand its jurisdiction to include public power agencies.

Where are FERC's priorities? FERC took a year to clamp down on the power producers who are reaping massive profits. In the same order, FERC illegally attacked the public power agencies who are nonprofit government agencies owned by the people. This contradiction amazes me. We all know that these public power agencies are not large enough to manipulate the market, and we all know that the large power producers consistently manipulate the market. Efforts to regulate the wrong party, I would suspectfully suggest, are misguided. The long-term action FERC should take is to significantly strengthen FERC Order 2000 to ensure regional transmission organizations are truly independent and shielded from market manipulation. Anything less, and greedy power producers will continually seek ways to manipulate the market for their profit.

If FERC and the free-marketeers want competition, at least it should be real competition. The average American cannot afford to pay electricity bills if large corporations are allowed to set excessive rates and eliminate competition. If FERC is to learn one thing today, their mandate is to protect people from monopolies, not monopolies from competition. I thank the gentleman.

[The prepared statement of Hon. Dennis J. Kucinich follows:]

Opening Statement for GROC Energy Subcommittee Hearing

I have watched the troubles of deregulated energy markets brewing for several years now. I am convinced that the partially deregulated electricity market will do much more harm to consumers than good. California, while unique in some ways, is not the exception to the rule. Rising wholesale electricity costs can be found everywhere the market has been deregulated. The most ridiculous "free market" argument is that California only partially deregulated, and a complete deregulation would have prevented the crisis. They are correct that complete deregulation would have prevented the bankruptcy, but only because all of the excessive prices would have been passed along to the consumer. Consumers would have shouldered the brunt of the failed market and many more families and small businesses would be in bankruptcy.

I have some serious concerns with FERC's recent actions. For example, it took FERC a year to offer any real relief to California by applying the breaks to a dysfunctional market with their June 19th order. Yet, FERC in the same action decided to illegally expand its jurisdiction to include public power agencies. Where are FERC's priorities? FERC took a year to clamp down on the power producers who are reaping massive profits. In the same order, FERC illegally attacked the public power agencies who are non-profit government agencies owned by the people. This contradiction amazes me. We all know the these public power agencies are not large enough to manipulate the market. And we also all know that the large power producers consistently manipulate this market. Your efforts to regulate the wrong party are misguided.

The long-term action FERC should take is to significantly strengthen FERC Order 2000 to ensure Regional Transmission Organizations that are truly independent and shielded from market manipulation. Anything less and greedy power producers will continuously seek ways to manipulate the market for their profit. If FERC and the "free marketers" want competition, it should at least be real competition. The average American cannot afford to pay electricity bills if large corporations are allowed to set excessive rates and eliminate competition. If FERC is to learn one thing today, their mandate is to protect people from monopolies, not monopolies from competition.

Mr. OSE. I thank the gentleman. The gentleman from Idaho, Mr. Otter, for an opening statement.

Mr. OTTER. Thank you, Mr. Chairman, and I take—I'm fully aware of the comments you made earlier about asking us all not to snipe, but it's hard not to do in this environment, and considering some of the comments from my good friend, Mr. Kucinich, I feel compelled to at least make a few statements out of the rest of my statement, which I will submit for the record. But I do want to commend you for your leadership in scheduling this very timely hearing, and I'm pleased that the House just last night, with bipartisan support, passed the most important energy legislation in generations, which, by the way, I might add, included a dimension of whether or not we ought to have price caps and they rejected that opportunity to introduce the idea of price capping themselves.

I do want to begin my remarks, though, by expressing particular outrage at the actions of Governor Gray Davis of California, who for months now has tried to place the blame of his State's energy woes at the feet of President Bush, who came into office long after California created the mess that they find themselves in. He tried to get away by explaining that what they had done in California was deregulate, when in fact they never did deregulate. It was a failure of restructuring.

He's also been quick to criticize other States and power companies, such as my own State of Idaho, that are outside of California, yet 2 days ago, the Los Angeles Times reported—and perhaps this is substance for another hearing of the Government Reform Committee—where his own consultants may have used inside information to trade the stock of power companies that were doing business with the State of California.

This hearing should not be focused on FERC's handling of the deregulation of electricity markets, but rather on whether or not Governor Davis himself profited from the power companies and sold power away from his own constituents.

Before the Governor or any of his fellow defenders here today try to blame this administration, they should look at the actual source of his decisions on California energy policy over the last few years and how he and his advisers made their money.

As I said, Mr. Chairman, I'm going to submit the balance of my statement for the record, but I would just conclude by saying that we've long tried caps. We long tried to manipulate the marketplace, and for the most part, what we've ended up doing is not creating any more, as in this case we didn't. We ended up dividing up scarcity, and we have to use the element of government, it seems, from time to time, to inflict the government on the free market, and we ended up dividing up the scarcity rather than dividing up the planning.

And I'm convinced that for as long as we want to try price caps, we're always going to end up dividing up scarcity and not the plenty.

Thank you, Mr. Chairman.

Mr. OSE. The gentleman's statement will be entered in the record.

[The prepared statement of Hon. C.L. "Butch" Otter follows:]

FOR THE RECORD

Statement of Congressman C.L. "Butch" Otter
House Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs
FERC: Regulators in Deregulated Energy Markets
August 2, 2001

Mr. Chairman, I want to commend you for your leadership in scheduling this very timely hearing. I'm pleased that the House just last night, with bipartisan support, passed the most important energy legislation in a generation. H.R. 4 is a giant step toward allowing America--through its own domestic resources--to meet its energy needs, decrease its dependence on foreign sources of energy, and increase our nation's security.

I want to begin my remarks by expressing particular outrage at the hypocrisy of Governor Gray Davis of California. For months now, he has tried to place the blame of his state's energy woes at the feet of President Bush, who came into office long after California created the mess that they find themselves in. He has also been quick to criticize other states and power companies outside of California. Yet, two days ago, the Los Angeles Times reported that the Governor of California's ***own energy consultants*** may have used inside information to trade the stock of power companies that were doing business with the State of California.

This hearing should not be focused on FERC's handling of deregulation of electricity markets, but rather whether the California Governor himself profited from power companies that sold power away from his own constituents. Before the Governor or any of his stalwart defenders here today try to blame this Administration, they should look at the actual source of his decisions on California energy policy over the last few years, and how he and his advisors made their money.

This hearing is a good opportunity to reiterate my strong opposition to federally-imposed price caps, and to point out that it hasn't worked in the past, it isn't working now, and it won't work in the future. The only reason that California isn't facing rolling blackouts right now is because of milder-than-usual weather patterns and effective conservation measures that other power suppliers in western states have undertaken to reduce demand. It doesn't take a rocket scientist to know that when you impose price controls on the power market, the end result is limits to available power generation, and ultimately, higher prices. Idaho and other Pacific Northwest states simply cannot support short-sighted policies that decrease our energy supply and/or increase California users' demand.

California has long tried price caps--and has failed miserably at it. The ceiling price for electricity sales in California ([redacted]) was steadily lowered in 2000 from $750 megawatt hour to $500 to $250 to finally $150. It failed, Mr. Chairman, because it only applied to a portion of the market--some power suppliers were subjected to the price cap, and others were exempt. Price caps in California actually ***reduced*** its own in-state power supply, because California power suppliers were given every incentive to sell their power out of state, while the state itself discouraged the new construction of power-generating plants.

Already, we are learning that power suppliers in the Pacific Northwest are being hurt by FERC's price mitigation order. The order does nothing to relax the price cap when California's power supply catches up with demand. In my opinion, this order should be rescinded immediately, and more market-based solutions should be instituted to protect western power supplies. A good subject for the General Accounting Office might be how this experiment has adversely impacted other western states such as Idaho, Washington, Oregon, and Montana. Moreover, the California Independent Service Operator's board should carefully review how critical power suppliers in the Pacific Northwest--

such as the Bonneville Power Administration--have benefited California during periods of peak demand and low supply to the detriment of other users in western states.

Finally, I am hopeful that today the Federal Energy Regulatory Commission (FERC) will act to uphold important provisions in H.R. 4 which directly affect millions of electricity consumers, families, small businesses, farmers and industries in Idaho and other western states.

One key concern of power users in the Pacific Northwest is that the federal government will not undermine the relicensing of hydroelectric dams--which generate thousands of megawatts of clean and renewable power. As you may know, Mr. Chairman, over 80 percent of Idaho's electricity comes form hydroelectric power, and a large share of that from the Hells Canyon Dam Complex operated by Idaho Power Company on the Upper Snake River.

We understand that the National Marine Fisheries Service recently sent a letter requesting FERC threatening to interrupt the relicensing of Idaho Power's dams--a move that would severely impact water and electricity users throughout Idaho. This is unacceptable, and I am calling on FERC to ensure that the relicensing process of the Hells Canyon Dams or any other dams in the Pacific Northwest are not interrupted and are processed in a timely manner.

Thank you, Mr. Chairman, and I look forward to hearing from the witnesses.

Mr. OSE. The gentleman from Tennessee, Mr. Duncan, for an opening statement.

Mr. DUNCAN. Well, thank you very much, Mr. Chairman. I'll be very brief. I thank you for calling this very important hearing and I agree with the statements by my good friend, Mr. Otter, who just referred to the landmark energy legislation which we passed last night. It's not been pointed out by many people, but that bill, 37 percent of that bill dealt with conservation and more funding for alternative and renewable energy sources, and frankly, that is far more than any President in history has ever done.

Yet some people don't want to give President Bush credit for that, because they want a political issue on certain other parts of the bill. But I'm interested in this hearing, and I've read that California built no new power plants for 10 years or so, and yet this was at a time when demand kept going up. It would be interesting to know how people expect you to meet increased demands with no increased production. As you know, Mr. Chairman, from the hearing we held 2 days ago, I just have completed 6 years as chairman of the House Aviation Subcommittee. We "deregulated" the airline industry many years ago. The airline industry remains, and it should remain, one of the most heavily regulated industries in the country.

I assume if we do get into utility deregulation, it will still be one of the most heavily regulated industries in the country, even after deregulation. So I'm very interested in this hearing, and I thank you very much for calling it.

Mr. OSE. Thank the gentleman. The gentleman from Massachusetts, for an opening statement.

Mr. TIERNEY. Thank you, Mr. Chairman. I want to thank you for holding this hearing and talk a little bit about those who advocated deregulation of the electricity markets. When they did that, they promised lower prices and workable markets. Twenty-four States and the District of Columbia adopted these State deregulation plans. However, as these States implement their plans, prices have been going up, not spiraling down as was promised to us. In California, one of the first States to implement deregulation, wholesale prices soared and the entire West has been thrown into an energy crisis.

The Federal Energy Regulatory Commission [FERC], is charged with monitoring the wholesale market and making sure that prices are just and reasonable. However, FERC's response, or you might say, the lack of response, to the energy crisis in the West has made me and others concerned that FERC may not be committed to actually doing its job. When FERC came to the obvious conclusion that wholesale prices in California were unjust and unreasonable and the market in the West was flawed, you would have expected FERC to immediately take action. You would have hoped that they would have rigorously enforced the law by ordering sufficient refunds and assessing penalties. You would have hoped that by imposing measures to prevent further abuse until a workable market was in place, they'd be doing their job. And, you would have hoped for monitoring of the market and you would have hoped they did that closely with respect to future problems.

Unfortunately, the reality is that FERC has ordered very few refunds and penalties. Its investigation of some of the overcharges has been, in the estimate of many, inadequate. In fact, when conducting an investigation of whether generators scheduled outages to influence prices, FERC ignored key evidence and vindicated industry on insufficient grounds. I look forward to hearing from the Government Accounting Office [GAO], on this important issue today.

In addition, FERC's attempts to prevent further market abuses were inadequate. FERC's orders were based on market principles when it was widely recognized that the market in the West was so deeply flawed that it was unworkable. Although the Governors of California, Oregon, and Washington and many others asked FERC to impose cost of service based rates until there was a workable market, FERC denied their request. In fact, FERC did not impose region-wide price caps of any kind until June of this year, over a year after the market flaws became apparent.

Moreover, FERC is apparently not gathering all the information needed to monitor the markets now. In June, after trying to review the status of California's electricity supplies this summer, the GAO released a report explaining that it did not have the information about outages that was necessary to complete its task. Because GAO can access information that FERC gathers, FERC was apparently not gathering the important outage information.

Some may argue that FERC simply does not have adequate staff and expertise to monitor deregulated markets. If this is the case, we ought to fix that situation. However, I don't think we should throw money at a problem unless we're confident that FERC is committed to doing its job. FERC needs to be committed to ensuring that wholesale prices are just and reasonable, even if this means abandoning market principles in the face of a broken market. It needs to be willing to hold industry's feet to the fire when there are abuses, even if that requires complicated market analysis. And it needs to monitor electricity markets carefully to prevent further abuses.

I'm looking forward to hearing about FERC's vision for the future, where regional transmission organizations are the first line of defense in market monitoring and how it should help FERC do its job.

I ask unanimous consent to include relevant materials in the record, Mr. Chairman. I thank you for the time.

Mr. OSE. Without objection. I thank the gentleman for his statement.

[The prepared statement of Hon. John F. Tierney follows:]

Statement of John Tierney (D-MA)
Subcommittee on Energy Policy
Hearing on FERC's Ability to Monitoring Markets
August 2, 2001

Mr. Chairman, thank you for holding this hearing.

Those who advocated deregulation of electricity markets promised lower prices and workable markets. Twenty-four states and the District of Columbia adopted deregulation plans. However, as these states implement their plans, prices have been going up -- not spiraling down as promised.

In California, one of the first states to implement deregulation, wholesale prices soared and the entire West has been thrown into an energy crisis.

The Federal Energy Regulatory Commission -- also known as FERC -- is charged with monitoring the wholesale market and making sure that prices are just and reasonable. However, FERC's response -- or lack of response -- to the energy crisis in the West has me concerned that FERC may not be committed to doing its job.
When FERC came to the obvious conclusion that wholesale prices in California were unjust and unreasonable and the market in the West was flawed, I expected FERC to immediately take action by:
1) vigorously enforcing the law by ordering sufficient refunds and assessing penalties;
2) imposing measures to prevent further abuse until a workable market was in place; and
3) monitoring the market closely for further problems.

Unfortunately, the reality is that FERC has ordered very few refunds and penalties and its investigation of some of the overcharges has been inadequate. In fact, when conducting an investigation of whether generators scheduled outages to influence prices, FERC ignored key evidence and vindicated industry on insufficient grounds. I look forward to hearing from the Government Accounting Office -- also known as the GAO -- on this important issue today.

In addition, FERC's attempts to prevent further market abuses were inadequate. FERC's orders were based on market principles when it was widely recognized that the market in the West was so deeply flawed that it was unworkable. Although the governors of California, Oregon, Washington, and many others asked FERC to impose cost-of-service based rates until there was a workable market, FERC denied their request. In fact, FERC did not impose regionwide price caps of any kind until June of this year -- over a year after the market flaws became apparent.

Moreover, FERC is apparently not gathering all of the information needed to monitor the markets. In June, after trying to review the status of California's electricity supplies this summer, GAO released a report explaining that it did not have the information about outages that was necessary to complete its task. Because GAO can access information that FERC gathers, FERC was apparently not gathering the important outage information.

Some may argue that FERC simply does not have adequate staff and expertise to monitor deregulated markets. If this is the case, we ought to fix the situation. However, I don't think we should throw money at the problem unless we are confident that FERC is committed to doing its job. FERC needs to be committed to ensuring that wholesale prices are just and reasonable, even if this means abandoning market principles in the face of a broken market. It needs to be willing to hold industry's feet to the fire when there are abuses, even if that requires complicated market analyses. And it needs to monitor electricity markets carefully to prevent further abuses.

I am looking forward to hearing about FERC's vision for the future -- where regional transition organizations are the first line of defense in market monitoring -- and how it will help FERC do its job.

I ask unanimous consent to include relevant materials in the record.

Mr. OSE. Now we're going to go ahead and swear our witnesses in. We do that for all of our panels. We're not just picking on you. So if you'd all rise.

[Witnesses sworn.]

Mr. OSE. Let the record show that the witnesses all answered in the affirmative.

Just as an introduction, I'm going to run through everybody who is here today, and then we're going to come back to Mr. Madden as our first witness.

Joining us today on your panel are Kevin Madden, who is the general counsel for the Federal Energy Regulatory Commission. And Shelton Cannon, also from the FERC. He's the Deputy Director of Office of Markets, Tariffs and Rates. Gentlemen, thank you for joining us.

Also we have the Director of the Natural Resources and Environment for the GAO, Mr. James Wells, Jr. Thank you.

Also joining us is the president and CEO, and if I'm correct from the testimony, the COO of the California ISO. The gentleman who has testified before this subcommittee before, Mr. Terry Winter.

Also joining us is the president and CEO of the PJM Interconnection Organization. That would be Mr. Phillip Harris. And also professor William Hogan from the John F. Kennedy School of Government, Harvard University.

Gentlemen, thank you all for coming. Now, we have your testimony. We've read it. You can summarize it. I have a strict 5-minute rule.

Mr. Madden, you're recognized for 5 minutes for the purpose of testimony.

STATEMENTS OF KEVIN MADDEN, GENERAL COUNSEL, FEDERAL ENERGY REGULATORY COMMISSION; SHELTON CANNON, DEPUTY DIRECTOR, OFFICE OF MARKETS, TARIFFS, AND RATES, FEDERAL ENERGY REGULATORY COMMISSION; JAMES E. WELLS, JR., DIRECTOR, NATURAL RESOURCES AND ENVIRONMENT, GENERAL ACCOUNTING OFFICE; TERRY M. WINTER, PRESIDENT AND CEO, CALIFORNIA INDEPENDENT SYSTEM OPERATOR; PHILLIP HARRIS, PRESIDENT AND CEO, PJM INTERCONNECTION, LLC; AND WILLIAM W. HOGAN, PROFESSOR, JOHN F. KENNEDY SCHOOL OF GOVERNMENT, HARVARD UNIVERSITY

Mr. MADDEN. Thank you, Mr. Chairman. I'm quite aware of your 5-minute rule, and I'll be very brief. I want to personally thank you and members of the committee for having what I consider a very, very important hearing. I learned a lot at the field hearings that this committee held in California in April, and we applied some of those thoughts to our program. I believe the time is right now to discuss key issues facing the electric industry, including how energy markets work, market monitoring and just how FERC operates in a new competitive environment.

Shelton and I share your views and want to hear a constructive dialog between and among the members of the committee and the panel members here. We may have been a backwater agency. I didn't think so. I've been there 20 years.

Mr. OSE. That was said with the greatest of respect, I want you to know that.

Mr. MADDEN. Well, now that we're not, I have, though, been hit a number of times by the sniping, and I believe a more constructive dialog occurs and a program can be improved substantially quicker, more efficiently than having political innuendos or the spin doctors in the press attack important programs.

My job as general counsel is to be the adviser, the chief legal adviser to the Commission, representing all interests of parties before us, and when we make the calls from a legal standpoint, not everyone likes our decisions. Contrary to some, I believe we've done a pretty damn good job. We may not have done the things in hindsight that we should have done, but we are, indeed, out to protect the interests of the consumer. We are indeed out there to promote a more competitive environment. We stand ready to improve our program so that the program is more viable, more competitive in this 21st century. Thank you, Mr. Chairman.

[The prepared statement of Mr. Madden follows:]

Summary of Testimony of
Kevin P. Madden, General Counsel
Shelton Cannon, Deputy Director, Office of Markets, Tariffs and Rates
Federal Energy Regulatory Commission
Before the Subcommittee on Energy Policy, Natural Resources
and Regulatory Affairs of the Committee on Government Reform
United States House of Representatives
August 2, 2001

The Commission's fundamental premise in regulating electric markets over the past decade has been that competitive bulk power markets – where such markets are possible – are the best means of assuring that consumers pay the lowest price possible for reliable electric service. For competition to flourish, however, we need adequate supply, enough sellers, the right organizational structures in the industry, and sound market rules. It is also critical that we have in place adequate market monitoring and the capability to promptly step in and take appropriate action if markets malfunction or sellers engage in market power abuse. The Commission has taken, and continues to take, steps to address these important issues.

If we are to achieve and maintain competitive bulk power markets in the electric industry, a key structural reform necessary to support such markets is the creation of regional transmission institutions, or RTOs. These institutions will: (1) operate the interstate transmission grid on a regional basis, independent of entities that are buying and selling electricity; and (2) recognize natural wholesale electricity trading patterns, which are increasingly regional and multi-state in character. The independence of RTOs from power market participants is essential to the success of competition. The Commission continues to take steps to encourage the formation of RTOs that provide one-stop shopping and fair and non-discriminatory pricing and terms and conditions for transmission service over large regions.

Competitive bulk power markets also must be supported by effective market monitoring. This is critical to ensure that wholesale electricity prices remain just and reasonable and that markets run efficiently. Effective market monitoring entails understanding energy markets, getting the market rules right, and making sure that market participants play by the rules. The Commission has made great strides in transforming our organization from a command and control cost-of-service regulator to a market monitor capable of not only detecting abuses, but also setting the rules of the market to establish price signals and incentives that make the most efficient use of existing resources and encourage investment in new generation and transmission facilities where they are most needed. Based on our experience with the severe market dysfunctions in California and the West over the past year, we are continuing to improve our processes and capabilities in this critical area to become a more proactive, rather than reactive, market monitor. RTOs can help us in this important function.

Testimony of
Kevin P. Madden, General Counsel
Shelton Cannon, Deputy Director, Office of Markets, Tariffs and Rates
Federal Energy Regulatory Commission
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I. Overview

Mr. Chairman and Members of the Subcommittee:

Thank you for the opportunity to appear here today. We are pleased to offer testimony on current issues affecting the Nation's bulk power markets for electricity. In particular, our testimony will focus on the development of regional transmission organizations (RTOs), the changing role of the Federal Energy Regulatory Commission (Commission), and the Commission's future plans for market oversight and enforcement. The views expressed in this testimony are our own, and do not necessarily reflect those of the Commission or any one Commissioner.

A competitive market–one with adequate supply, enough sellers, the right organizational structures, and sound market rules–is the best way to protect the public interest and ensure that consumers pay the lowest price possible for reliable electric service. For competition to flourish and bring benefits to wholesale as well as retail customers, it is critical that, RTOs, as described in the Commission's Order No. 2000, be formed. These new institutions will (1) operate the interstate transmission grid on a regional basis, independent of entities that are buying and selling electricity; and (2) recognize natural wholesale trading patterns, which are increasingly regional and multi-state in character. The independence of RTOs from market participants is critical for the success of competition.

Market monitoring is necessary to ensure that wholesale electricity prices remain just and reasonable. Effective market oversight entails understanding energy markets, getting the market rules right, and making sure that market participants play by the rules. Based on the Commission's experience in confronting the severe market dysfunction in California and the West over the past year, the Commission has continued the process of revamping its market oversight function. We have made great strides in transforming our organization from command and control cost-of-service regulation to the more difficult role of monitoring energy markets–not only of detecting abuses, but also proactively setting the rules of the market to establish price signals and incentives that make the most efficient use of existing resources and encourage investment in new generation and transmission facilities where they are most needed. We are continuing to improve our processes and capabilities in this critical area to become more proactive in anticipating and addressing market power issues before they create market distortions.

RTOs' market monitoring units can and should play a big role on the front lines by performing their own monitoring and analysis and reporting any suspect behavior to the Commission. These market monitoring units also could serve in an advisory role to the Commission, suggesting any market rule changes they believe necessary to improve the competitive conditions of their markets.

II. Order No. 2000 - A Vision for Regional Electricity Markets

In Order No. 2000, the Commission built upon the premise that competition in wholesale electricity markets is the best way to protect the public interest and ensure that consumers pay the lowest price possible for reliable electric service. Order No. 2000 also recognized that wholesale trading patterns have become increasingly regional and multi-state in character. In calling upon the industry to form RTOs, the Commission determined that utility-by-utility management of the interstate transmission grid was inadequate to support the efficient and reliable operation of the bulk power market and that vertically integrated utilities (those that control both generation and transmission facilities) continue to have the ability to discriminate in the provision of transmission service. The Commission found that the interstate transmission grid should be operated on a regional basis, in a manner which is independent of entities that are buying or selling electricity, if competitive wholesale markets are to flourish.

The objective of Order No. 2000 was for all transmission-owning entities, including non-public utility entities, to place their transmission facilities under the control of independent RTOs. Specifically, the Commission found that an appropriately sized and structured RTO could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) serve as a platform for much-needed transmission pricing reform.

An appropriately sized RTO should encompass existing natural markets, internalize constraints, and expand the number of economically viable competitors within each market by eliminating barriers to entry. Under the Commission's vision, wholesale electricity markets need to be governed by rules which ensure the independence of the transmission provider (the RTO), establish appropriate incentives to encourage competitive behavior by all market participants, and remove any incentive for transmission owners to favor their own generation over other competitive suppliers. This process is well under way. The Commission has issued numerous orders on applications submitted in compliance with Order No. 2000 from various regions in the country and continues to encourage these organizations to develop in ways that recognize regional trading patterns and minimize "seams" issues (i.e. reduce incompatibilities between neighboring RTOs).

We have learned a great deal about market design over the last several years based on our experience with bilateral electricity markets and our experience with the existing organized markets operated by the five independent system operators (ISOs): California ISO, PJM, New York ISO, ISO New England, and the Texas ISO. Experience has demonstrated the importance of designing markets correctly and shown us all too dramatically the consequences of poor market design. We continue to learn and will be working to develop market rules that incorporate the best features of our existing markets while discarding features that are flawed. But electricity markets will continue to evolve and RTOs will play a critical role in helping the Commission to fashion market rules that accommodate the changing needs of the marketplace.

III. Market Monitoring under Order No. 2000

RTOs can serve as a first line of defense in helping the Commission to oversee the proper functioning of certain energy markets and potential market power abuse. Order No. 2000 requires that RTOs monitor markets under their control. In placing this responsibility on RTOs, the Commission recognized the importance of independent market monitoring to understanding market operations in real-time, identifying and reacting swiftly to market problems, and maintaining credibility in the marketplace. The Commission has the responsibility to help protect against anticompetitive effects in electricity markets and RTOs can provide information to identify potential market power abuses. Further, market monitoring is an important tool for ensuring that regional bulk power electricity markets operate in a non-discriminatory, open, and transparent manner, and also will provide information regarding opportunities for efficiency improvements.

In Order No. 2000, the Commission granted RTO participants sufficient flexibility to tailor their own market monitoring plan to fit the corporate form of the proposed RTO as well as the types of markets the RTO will operate or administer. However, the RTO must propose a monitoring plan that contains certain standards:

- The monitoring plan must be designed to ensure that there is objective information about the markets that the RTO operates or administers and a vehicle to propose appropriate action regarding any opportunities for efficiency improvement, market design flaws, or market power identified by that information.

- The monitoring plan also must evaluate the behavior of market participants, including transmission owners in the region to determine whether their behavior adversely affects the ability of the RTO to provide reliable, efficient and nondiscriminatory transmission service.

- Because not all market operations in a region may be operated or administered by the RTO (e.g., there may be markets operated by unaffiliated power exchanges), the monitoring plan must periodically assess whether behavior in other markets in the RTO's region affect RTO operations and, conversely, how RTO operations affect the efficiency of markets operated by others.

- Independent reports on opportunities for efficiency improvement, market design flaws and market power abuses in the markets the RTO operates and administers also must be filed with the Commission and affected regulatory authorities.

In light of our requirements that the RTO have operational control over the transmission facilities transferred to it, the RTO will be in the best position to perform objective monitoring functions for the markets that the RTO operates or administers in the region. Performance of market monitoring by RTOs is not intended to supplant Commission authority. Rather it will provide the Commission with an additional means of detecting market power abuses, market design flaws and opportunities for improvements in market efficiency. Further, because market monitoring plans are required to be filed with and approved by the Commission, we will retain the ability to shape the market monitoring activities that will be performed by the RTO to ensure that they complement the Commission's ultimate responsibility to ensure just and reasonable rates in wholesale electricity markets. Moreover, as we have noted in our orders addressing various RTO applications, analysis and reports from an RTO's market monitoring unit are to be submitted to the Commission at the same time as they are submitted to the RTO. This will ensure that the analysis and reports are not subject to "pre-approval" by the RTO prior to Commission review.

IV. Adapting Regulation to Meet the Challenges of the Marketplace

As the Commission began to implement Order No. 2000, it saw the need to redeploy staff to be more responsive to the needs of the marketplace. This reorganization reflected not only the convergence of the natural gas and electricity markets, but also the fact that, if the Commission is to rely on competitive market forces to discipline the price of natural gas and electricity, it needs to ensure that competition is working. The Commission recognized the need to devote significant resources to monitoring energy markets. The Commission combined its gas and electric program offices, as well as its economic policy office, into a single Office of Markets, Tariffs, and Rates. Within that Office, a separate division was established to identify and bring to early resolution key issues in the marketplace and to ensure consistency of gas and electric policy decisions. In addition, a division was established to focus on understanding energy markets and developing a plan for overseeing and proactively shaping a competitive energy marketplace. Finally, within our Office of General Counsel, market oversight was added to the enforcement function within the Office, and we nearly doubled the number of staff devoted to these matters.

Beginning with the signs of serious market problems in California in the Summer of 2000, the Commission undertook a nationwide fact-finding analysis of bulk power markets. In the first Staff Report on Bulk Power Markets in November 2000, we identified that the primary problems in California and the West centered around a lack of available supply to meet demand which was caused by a variety of events and circumstances. In addition, in this report and in our second Staff Report on Bulk Power Markets, which covered the remainder of the country, we determined that some basic market rules needed to be changed. Soon after, we initiated a series of orders on California matters which responded either to emergency situations (high prices and supply shortages) or filings by California market participants or the California ISO. Through these orders we initiated a series of remedial steps which removed a variety of impediments to a competitive electric market and attempted to restore confidence and stability to the western marketplace (see attached Commission Staff Summary of Recent Commission Actions on California Electricity Markets). These measures included:

- removing the requirement to buy and sell all power in the spot market
- moving power purchases and sales into the long term and bilateral markets, thus removing restrictions on hedging
- requiring accurate scheduling of load
- ensuring independence of the regional transmission entity
- establishing mitigation measures West-wide during times of inadequate supply
- incenting the construction of needed generation and transmission investment as well as natural gas pipeline infrastructure in the short and long term
- increasing near-term supply to the maximum extent possible
- removing incentives for withholding through penalties and a must-sell requirement
- requiring ISO reporting on outages and bid data

Just last week, the Commission issued an order establishing a hearing to quantify refunds under a mitigation formula for sales in California for the period of October 2, 2000 through June 20, 2001. Throughout the West, spot market transactions after June 20, 2001 are subject to other mitigation rules including as an express condition on market-based authority, a prohibition on withholding or other forms of anti-competitive bidding behavior.

The Commission's experience with the severe market dysfunctions in California and the West magnified the need for the Commission to improve its processes and capabilities as an effective market monitor and to continue to become more proactive, rather than reactive, in this critical job. Our need to understand and react to the crisis required the Commission (and others) to conduct numerous studies (often put together very quickly) to examine market conditions -- including the status of existing and new supply sources, generator outage audits, transportation constraints, natural gas prices into California, and "gray market" issues. While we learned a great deal from these studies, the focus was backward-looking as the Commission tried to determine the causes of the dysfunction. In short, we were driven by the demands of the moment, rather than being able to rely upon a forward looking, comprehensive approach to monitoring wholesale markets.

V. Market Monitoring - Where We Are Going

A year later, a measure of stability has been restored to the western marketplace (please see the attached chart on spot market natural gas and electricity prices which have stabilized due to a number of factors, not the least of which has been favorable weather conditions) and we are continuing to develop and improve our market monitoring function based in large part on what we've learned from the California experience as well as experience in other regions of the country. The California experience has underscored the importance of market monitoring and oversight if we expect consumers to have confidence in the marketplace to protect them. As a result, we must address critical market design issues correctly, coherently, and before-the-fact if the promise of competitive wholesale electricity markets is to be fulfilled.

A. New Resources

First, we've recognized that market monitoring requires a substantial commitment of high quality resources, both in terms of information capability and human capability. To this end, we have recently unveiled our new Market Operations Resource Center, which is patterned after an energy trading floor and is designed to give the Commission near-instantaneous access to data on spot prices, projected and actual load curves, transmission constraints, market commentary, weather patterns, and other market developments. This resource allows the Commission to increase its understanding of the markets, while providing data to support our efforts to craft market rules and incentives to strengthen and further develop competitive market structures.

Second, we've increased our staffing levels and expertise devoted to the market monitoring function. We have increased staffing levels devoted to market oversight in the Office of Markets, Tariffs and Rates and the Office of the General Counsel from approximately 70 full time staffers to a current level of 103. Many of these additions came from our litigation staff and include several Ph.D. economists whose focus has been on market structures and market power. We also have the flexibility to further reallocate staff as the need arises. We have, however, not only added numbers to the function, but have also bolstered the market monitoring staff with some of our most experienced senior staff who are now devoted to market oversight on a permanent basis. Their charge is to continue the development of a comprehensive, proactive market monitoring and enforcement program based on the elements discussed below. In addition, we've added to this group several staffers who will focus on market issues that arise in the routine docketed rate and tariff filings which come before the Commission to ensure that our focus on markets at large does not cause us to miss incremental or isolated changes in the marketplace.

Third, we have diligently pursued training of our staff to increase our understanding of the intricacies of the markets, including, e.g. training on derivatives. Similarly, we are actively recruiting people with trading experience to help us gain additional perspective on this aspect of the markets.

B. Elements of Market Monitoring

As mentioned earlier, elements of a good market monitoring proposal are evident throughout the actions we have taken to date in California and throughout the West. A good market monitoring plan couples proactive market rule design and enforcement of those rules with a willingness to modify and adapt those rules to the changing needs of the marketplace. Specifically, we envision market monitoring as a continuous and on-going exercise in studying and understanding energy markets while ensuring that market participants follow the market rules, with the ultimate objective of ensuring the availability of ample supply coupled with the ability of customers to respond to changes in price. We want to facilitate the development of market rules that are known, transparent, and non-discriminatory. The aim should be to protect competition rather than competitors. Thus our investigations into the market will not be limited to finding someone who may have broken a rule, but will focus on finding rules that are broken and need to be fixed. The Market Observation Resource Center will be a useful tool to enable us to evaluate the competitiveness of markets and find the broken rules, i.e. those rules that permit (or may even incent) anti-competitive behavior.

When designed properly, market rules will establish price signals and incentives that make the most efficient use of existing resources and stimulate investment in new generation and transmission facilities where they are most needed. Good market rules will function as road signs, signaling appropriate speed limits, stopping and yield points, who has the right of way, and where it is acceptable to park. They rightly include such things as pricing and cost recovery mechanisms and should be developed to reward pro-competitive behavior while attacking the bottom line of market participants who choose to engage in anti-competitive behavior. Once the elements of a competitive market—an adequate amount of supply, enough sellers, and market rules that remove barriers to entry and protect competition—are in place, anti-competitive behavior such as physical or economic withholding of supply (in the hope of artificially driving up prices) largely becomes irrelevant, as other sellers will readily take the place of any one market participant opting not to sell.

Along with developing adequate market structures and rules, there remains a corollary enforcement or "cop on the beat" function within the realm of market monitoring. As market monitors, we need to be proactively working to develop markets rather than just looking to punish those who break the rules. Nevertheless, even carefully crafted market rules with incentives for good behavior will not be effective without a strong, highly visible, and vigilant enforcement program. Thus, our market monitoring function is backed up by an enforcement program where we, on our own motion or in response to complaints or requests of others, conduct investigations as needed to ensure that all market participants abide by established market rules. On an ongoing basis, the Commission undertakes investigations of allegations of market power abuse. We also need to ensure that market participants have sufficient, publicly available data to be able to detect and to file formal complaints when they suspect anti-competitive behavior, whether by electricity sellers or transmission providers. And we need to ensure that appropriate sanctions are in place when someone is found to be breaking the rules.

C. RTOs - Our First Line of Defense

As laid out in Order No. 2000, RTOs' market monitoring units can and should play a big role on the front lines both from a proactive market development perspective and from an enforcement perspective. To the extent it is fully independent from market participants, an RTO can form the first line of defense for any market monitoring proposal and would perform its own monitoring of the markets they administer, or the markets they affect or are affected by through the collection of data and reporting of any suspect behavior to the Commission for further review and possible enforcement action. While RTOs are not permitted to be in the power business, they do of necessity operate real-time balancing markets and ancillary service markets. The RTO would also serve in an advisory role to the Commission, conducting studies and suggesting any market rule changes it believes would be appropriate to improve the competitive condition of its markets. We've already seen examples of this kind of behavior in the context of the existing ISOs, as the ISOs have formally and informally proposed necessary rules changes to improve the market or eliminate potential for abuse. There is room for greater RTO involvement in this context, both in terms of greater coordination through prefiling discussions and formal rule change proposals. Further, where rules are broken, the objective and known criteria for penalties must be established and refined. Here again, RTOs can help. Since they are on the front lines, RTOs would be well positioned to build the case against the potentially offending market participant and file the charges, evidence, and any proposed penalty with the Commission for our review.

VI. Conclusion

The Commission has come a long way in trying to foster the development of a competitive marketplace for natural gas and electricity in this country. We know a lot more than we did even a year ago, but there is much more to learn and much that remains to be done. The role of the regulator has changed dramatically from the days of command and control cost-of-service regulation. But as we rely more and more on competition to discipline the price that consumers pay for electricity, we remain responsible for ensuring that wholesale electricity prices are just and reasonable. That means that we have to be just as good at monitoring energy markets as we were at auditing a utility's generation costs and awarding a fair rate of return on plant investment. Effective market oversight entails understanding energy markets, ensuring the right organizational structures are in place, getting the market rules right, and making sure that market participants play by the rules. RTOs, as envisioned in Order No. 2000, will play a critical role in helping the Commission to detect instances of market power abuse and proposing changes to market rules as they are needed. In the future, it will also require that we continue to work closely with our state counterparts to maintain confidence that the marketplace is working and that competition is a good deal for American consumers.

Thank you.

Commission Staff Summary of
Recent Commission Actions on California Electricity Markets

NOVEMBER 2000

- November 1: San Diego Gas & Elec. Co. (Complainant) v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, 93 FERC ¶ 61,121 (order proposing remedies for California crisis on complaint of SDG&E)("November 1 Order")

- November 6: CPUC asks FERC to assist CPUC in investigation (Docket EL00-95-000)

- November 9: Public Conference re FERC-proposed remedies held in Washington (see 93 FERC ¶ 61,122)

- November 22: California Power Exchange Corp., 93 FERC ¶ 61,199 (order accepting amendments to streamline and clarify several provisions of the PX tariff)

- November 22: Pacific Gas & Elec. Co., 93 FERC ¶ 61,207 (order suspending PG&E transmission rate increase proposal)

DECEMBER 2000

- December 7:

  SDG&E files request for emergency relief re natural gas prices (Docket RP01-180)

  SoCal Edison files motion seeking to subpoena ISO Market Surveillance Committee data (Docket EL00-95-000)

- December 8:

  San Diego Gas & Elec. Co., 93 FERC ¶ 61,238 (order waiving operating efficiency and other regulatory requirements governing "QFs" and other small power producers to boost power output in California)

December 8: California ISO Corp., 93 FERC ¶ 61,239 (order authorizing ISO tariff amendments to: (1) convert existing $250/MWh hard cap on bids in the real-time market into a $250/MWh breakpoint; (2) impose a penalty on generators who fail to comply with an ISO emergency order to provide power; and (3) assess costs against parties that underschedule demand or fail to deliver power.

- December 11 and 12: Motions for clarification, modification, and rehearing of December 8 ISO order

- December 13: SoCal Edison files motion for immediate modification of December 8 QF order

- December 13: California Power Exchange Corp., 93 FERC ¶ 61,260 (order accepting settlement re PX dispute resolution procedures)

- December 15: San Diego Gas & Elec. Co. (Complainant) v. Sellers of Energy and Ancillary Services into Markets Operated by CalSO and CalPX, 93 FERC ¶ 61,294 (Order adopting remedial measures to reduce reliance on volatile spot markets, including: (1) eliminating requirement that investor-owned utilities sell all their generation into the PX markets; (2) requiring 95 percent of demand to be scheduled in advance and establishing a benchmark for long-term contracts; and (3) imposing an interim $150/MWh soft cap or "breakpoint" on spot markets pending development of longer term price mitigation plan)("December 15 Order")

- December 18 and 20: SoCal Edison and PG&E file emergency requests for rehearing of December 15 Order

- December 20: Marketers file emergency motion for order requiring ISO and PX not to disclose confidential information (Docket EC96-1663-000)

- December 22:

  Dynegy files complaint alleging that rates paid for energy supplied in response to an ISO emergency order are confiscatory (Docket EL01-23-000)

  Dynegy files emergency motion for clarifications of December 15 order to ensure payment to suppliers (Docket EL00-95-006)

Commission issues data request in response to December 7 SDG & E complaint re natural gas prices

- December 26: PX files request for rehearing and stay of December 15 order (Docket EL00-95-005)

- December 29:

  Southern California Edison Co., 93 FERC ¶ 61,320 (order analyzing and accepting SoCal Edison rates for scheduling and dispatching)

  Pacific Gas & Elec. Co., 93 FERC ¶ 61,322 (order rejecting PG&E filing regarding its scheduling on the ISO)

  San Diego Gas & Elec. Co., 93 FERC ¶ 61,333 (order accepting SDG&E rate filing re so-called "RMR" generating units–units that must run to assure system reliability)

  Southern California Edison Co., 93 FERC ¶ 61,334 (order accepting RMR tariff for SoCal Edison)

  California ISO Corp., 93 FERC ¶ 61,337 (order accepting ISO grid management charges)

JANUARY 2001

- January 4: ISO files tariff amendment to relax its creditworthiness standards to allow PG&E and SoCal Edison to continue conducting transactions on ISO-controlled grid, notwithstanding downgrades in their credit ratings (Docket No. ER01-889-000)

- January 5: PX files tariff amendment to relax its creditworthiness standards to allow PG&E and SoCal Edison to continue trading in the PX markets, notwithstanding downgrades in their credit ratings (Docket No. ER01-902-000)

- January 8: San Diego Gas & Elec. Co., 94 FERC ¶ 61,005 (order clarifying that December 15 Order was not intended to bar the PX from engaging in bilateral forward contracting)

- January 12:

  Pacific Gas & Elec Co., 94 FERC ¶ 61,025 (order authorizing intra-corporate reorganization of PG&E Corporation)

  Sierra Pacific Power Co., 94 FERC ¶ 61,033 (order denying rehearing re priority use of certain California grid interties)

- January 16: California Power Exchange Corp., 94 FERC ¶ 61,042 (order authorizing PX to implement emergency tariff changes to allow SoCal Edison two additional days to make its payment)

- January 18: ISO files tariff amendment to conform to December 15 order re payment procedures for RMR operations (Docket ER01-991-000)

- January 19 through February 12: Various persons, including State of California and CPUC, file requests for late intervention and rehearing of January 12 order authorizing intra-corporate reorganization of PG&E Corporation (Docket Nos. EC01-41-000 and EC01-49-000)

- January 23: PG&E files motion for immediate order to stop PX from liquidating PG&E's long-term or "block forward" contracts after PG&E refuses PX demand for payment to cover a portion of SoCal Edison's nonpayment for transactions in the PX spot markets (Docket No. EL01-29-000)

- January 23: FERC staff conducts technical conference with industry representatives re prospective spot market monitoring and mitigation plan

- January 25: Pacific Gas & Elec. Co., 94 FERC ¶ 61,082 (order denying rehearing request re PG&E transmission rates)

- January 29: San Diego Gas & Elec. Co., 94 FERC ¶ 61,085 (order finding PX in violation of December 15 order for failing to implement $150/MWh breakpoint)

FEBRUARY 2001

- February 1: Los Angeles Dep't Water & Power files emergency petition for reimposition of price cap on natural gas pipeline capacity (Docket RP01-222-000)

- February 2:

  SoCal Edison files emergency motion for cease and desist order preventing PX from liquidating SoCal Edison's long-term "block forward" contracts to cover SoCal Edison's nonpayment for transactions in the PX spot markets (Docket EL01-33-000)

  SoCal Edison and PG&E file for immediate suspension of underscheduling penalties imposed by December 15 order (Docket EL01-34-000)

- February 6: Mirant Delta files complaint with request for fast track processing that: (1) seeks enforcement of the creditworthiness standards for PG&E and SoCal Edison in the ISO tariff; and (2) alleges ISO violation of December 15 order for failure to replace governing board (Docket EL01-35-000)

- February 7: Pacific Gas & Elec. Co., 94 FERC ¶ 61,093 (order accepting settlement re PG&E transmission rates)

- February 8 and 12, and March 2: Various parties, including Coral Power, Enron, SDG&E, Salt River Project Agricultural Improvement and Power District, Sacramento Municipal Utility District, and Public Service Company of New Mexico file three complaints requesting that the PX be barred from further implementing tariff "charge back" provision that allows the PX to recover uncollected amounts owed by PG&E and SoCal Edison from other market participants (Docket EL01-36-000, EL01-37-000, and EL01-43-000)

- February 14: California ISO Corp., 94 FERC ¶ 61,132 (order rejecting ISO and PX tariff amendments relaxing creditworthiness standards for PG&E and SoCal Edison as applied to transactions affecting third-party suppliers)

- February 15: FERC staff meets with PX regarding requirements for implementing $150/MWh breakpoint

- February 21:

California ISO Corp., 94 FERC ¶ 61,141 (order accepting amended Transmission Control Agreement among ISO and transmission owners and addressing complaints by City of Vernon regarding conditions of becoming participating transmission owner)

California ISO Corp., 94 FERC ¶ 61,148 (order denying rehearing of October 2000 order relating to ISO's Transmission Access Charge)

Pacific Gas & Elec. Co., 94 FERC ¶ 61,154 (order denying intervention and rehearing of January 12 order authorizing PG&E Corporation intra-corporate reorganization)

- February 22: generators request order compelling ISO to comply with February 14 order re creditworthiness (ER01-889-002)

- February 23: San Diego Gas & Elec. Co., 94 FERC ¶ 61,200 (order on rehearing of December 29 order re reassignment of RMR costs)

- February 26: PX files request for clarification/rehearing of February 14 creditworthiness order

- February 28:

  PX makes compliance filing proposing implementation of $150 MWh breakpoint requirement; seeks rehearing of January 29 order (EL00-95-016; EL00-98-015);

  Tucson Electric files complaint against the Governor of California challenging California's "commandeering" of PG&E and SoCal Edison's long-term contracts from the PX (EL00-95; EL01-40-000)

  Complaint filed by Strategic Energy L.L.C. versus ISO concerning out-of-market costs (EL01-41-000)

MARCH 2001

- March 1:

ISO files revised tariff amendment on creditworthiness in compliance with February 14 order rejecting earlier proposed amendment

California Electricity Oversight Board files motion for clarification of December 15 order

ISO and Electricity Oversight Board file motion for issuance of refund notice to sellers, request for data, and request for hearing

- March 2: Universal Studios files complaint against SoCal Edison challenging penalties Universal was charged for failing to interrupt its service under its interruptible service contract with SoCal Edison (Docket No. EL01-42-000)

- March 7 through 23: Various persons file second round of requests for intervention and rehearing of January 12 order authorizing PG&E Corporation intra-corporate reorganization

- March 8: Ridgewood Power requests emergency relief and extension of waiver of "QF" regulations applicable to small generators (Docket No. EL00-95-020)

- March 9:

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalSO and CalPX, 94 FERC ¶ 61,245 (Order directing refunds or further justification for charges)

  "Staff Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market" (Docket Nos. EL 00-95-012, *et al.*)

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalSO and CalPX, 94 FERC ¶ 61,243 (Order dismissing rehearing request of 1/8/01 order)

- March 14:

  "Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States and Requesting Comments on Further Actions to Increase Energy Supply and Decrease Energy

Consumption (Docket No. EL 01-47-000) (order includes: (1) requirement that ISO and western transmission owners file list of grid enhancements that can be implemented in short term; (2) extension of waiver of QF regulations through December 31, 2001; (3) authorization for western businesses with back-up generators and customers who reduce their consumption to sell wholesale power at market-based rates; and (4) solicitation of comment on additional proposals)

Cities of Anaheim, et al. v. ISO, 94 FERC ¶ 61,268 (order dismissing in part and granting in part complaint alleging that certain cities are being charged inappropriate costs when ISO allocates the cost of power obtained through emergency orders to generators).

AES Southland, Inc., Williams Energy Trading & Marketing Co., 94 FERC ¶ 61, 248 (order directing parties to explain why they should not be found in violation of the Federal Power Act for engaging in actions that inflated electric power prices)

- March 15: Chairman testifies before the Senate Committee on Energy and Natural Resources

- March 16: San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalSO and CalPX, 94 FERC ¶ 62,245 (notice re proxy market clearing price and refunds for February transactions)

- March 20: The Commissioners testify before the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality

- March 21: Reliant files fast-track complaint against the ISO challenging the ISO's issuance of emergency orders requiring generators to supply power (Docket No. EL01-57-000)

- March 22 through April 9: Parties file requests for rehearing of 3/9 order directing refunds (Docket No. EL00-95-019, et al.)

- March 28: CPUC v. El Paso Natural Gas Co., et al., 94 FERC ¶ 61,338 (order dismissing portion of complaint alleging affiliate abuse but ordering public hearing on whether El Paso exercised market power to drive up natural gas prices)

- March 29: ISO files motion for order directing Reliant to keep generating unit in service (Docket No. EL01-57-000)

APRIL 2001

- April 2 through 4: Proposed generation interconnection procedures filed by California ISO, PG&E, SDG&E, and SoCal Edison in compliance with 12/15 order (Docket Nos. EL00-95-022, -023, -024, -025)

- April 5: Complaint by California Cogeneration Council, et al., alleging that a CPUC decision affecting QF rates violates PURPA (Docket No. EL01-64-000)

- April 6:

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, 95 FERC ¶ 61,021 (Order dismissing rehearing, accepting compliance filing, and directing the recalculation of lower wholesale rates)

  Pacific Gas and Electric Co., et al., 95 FERC ¶ 61,020 (Order on complaints concerning use of chargebacks and liquidation of collateral)

  Kern River Gas Transmission Co., 95 FERC ¶ 61,022 (Order issuing certificate for facilities to transport natural gas from Wyoming to California)

  California Independent System Operator Corporation, 95 FERC ¶ 61,024 (Order granting motion of generators to compel ISO to comply with creditworthiness requirements)

  California Independent System Operator Corporation, 95 FERC ¶ 61,026 (Order granting clarification in part and denying rehearing of order on PX tariff creditworthiness amendment)

  Southern California Edison Co and Pacific Gas and Electric Co, 95 FERC ¶ 61,025 (Order deferring action on request for suspension of underscheduling penalty and issuing request for information)

- April 9: Ridgewood Power files an updated request for emergency relief re QF regulations in light of PG&E's bankruptcy filing

- April 10: Commission convenes Western Energy Issues Conference in Boise, Idaho

- April 10-12: The Chairman and General Counsel testify before the House Committee on Government Reform regarding wholesale electricity prices in California and the West

- April 16:

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX (unpublished notice of proxy price for March wholesale transactions in Docket No. EL00-95-028, et al.)

  CAlifornians for Renewable Energy files complaint against BC Hydro and other generators alleging withholding (Docket No. EL01-65-000)

- April 18: Public Utilities Commission of the State of California v. El Paso Natural Gas Co., et al., 95 FERC ¶ 61,089 (Order on rehearing regarding allegations of affiliate abuse and market power by gas pipeline)

- April 25: Tractabel Power Inc files a petition for enforcement action alleging that a CPUC decision affecting QF rates violates PURPA (Docket No. EL01-67-000)

- April 26:

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, 95 FERC ¶ 61,115 (Order establishing prospective mitigation and monitoring plan for the California wholesale electric markets and establishing an investigation of public utility rates in wholesale Western energy markets)

  Avista Corporation, et al., 95 FERC ¶ 61,114 (Order granting, with modification, RTO west petition for declaratory order and granting Transconnect petition for declaratory order)

  CalISO files bylaw amendments incorporating changes in governance (Docket No. EL00-95-030, et al.)

- April 27:

Calpine Corp. files a petition for enforcement action and/or a declaratory order alleging that a CPUC decision affecting QF rates violates PURPA (Docket No. EL01-71-000)

Commission notices initiation of investigation of rates in the WSCC (Docket No. EL01-68-000)

- April 30:

  Edison Mission Energy files an application for approval of corporate reorganization (Docket No. EC01-93-000)

  AES Southland, Inc. and Williams Energy Marketing & Trading Co., 95 FERC ¶ 61,167 (Order approving stipulation and consent agreement with respect to issues raised in the 3/14 show cause order)

MAY 2001

- May 1:

  The Commissioners testify before the House Subcommittee on Energy and Air Quality to discuss the proposed Electricity Emergency Relief Act

  The Director of Markets, Tariffs and Rates issues a letter to the ISO, PG&E, SDG&E, and SoCal Edison offering staff's assistance to complete RTO filings

- May 2: The Commission instituted a proceeding under FPA § 210(d) in Docket No. EL01-72-000 to consider whether it may need to order interconnection or transmission services to alleviate generation capacity shortages in California

- May 3: Western Systems Coordinating Council and two regional transmission groups file a petition for a declaratory order disclaiming jurisdiction or for an order approving the transfer of functions to a new Western Electricity Coordinating Council.(Docket Nos. EL01-74-000/EL99-23, et al.)

- May 7:

Requests for rehearing of the Commission's 4/26/01 market mitigation order filed (Docket No. EL00-95-031, et al.)

Request for rehearing of the 4/6/01 order granting motion filed (Docket No. ER01-889-004, et al.)

El Paso Natural Gas Co., 95 FERC ¶ 61,176 (Order issuing a certificate permitting increased pipeline capacity to California by converting an oil pipeline to gas service)

City of Vernon files a complaint asking FERC to prevent the ISO from subjecting Vernon's customers to rolling blackouts (Docket No. EL01-75-000)

- May 9: Director of OMTR issues a letter to Southern California Air Quality Management District requesting information on its NOx Emission Program

- May 10: Cogeneration Ass'n of California files a petition for enforcement action and/or a declaratory order alleging that a CPUC decision affecting QF rates violates PURPA (Docket No. EL01-77-000)

- May 11: CalISO files a compliance filing in Docket No. ER01-889-005, as directed in the 4/6/01 order granting motion

- May 14:

  Cities of Anaheim, et al. v. CalISO, 95 FERC ¶ 61,197 (Order on rehearing concerning complaint about OOM costs)

  Edison Mission Energy, 95 FERC ¶ 61,198 (Order approving corporate reorganization)

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, 95 FERC ¶ 62,125 (notice of proxy price for April wholesale transactions in Docket No. EL00-95-033, et al.)

- May 16:

Removing Obstacles To Increased Electric Generation And Natural Gas Supply In The Western United States, 95 FERC ¶ 61,225 (Further order on removing obstacles to increased energy supply and reduced demand in the Western United States and dismissing petition for rehearing)

San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, 95 FERC ¶ 61,226 (Order granting motions for emergency relief by QFs in part and establishing further procedures)

California Independent System Operator Corporation, 95 FERC ¶ 61,199 (Order accepting in part and rejecting in part ISO Tariff Amendment No. 38)

- May 18: Reporting of Natural Gas Sales to the California Market, 95 FERC ¶ 61,262 (Order proposing reporting requirements on natural gas sales to California markets and requesting comments)

- May 22: San Diego Gas & Electric Co., et al., 95 FERC ¶ 61,264 (Order requesting comments on whether the Commission should reimpose the maximum rate ceiling on short-term capacity release transactions into California)

- May 24: Commission convenes a technical conference regarding pipeline capacity into and adequacy within California (Docket No. PL01-4-000)

- May 25:

  San Diego Gas & Electric Co., et al., 95 FERC ¶ 61,275 (Order providing clarification and preliminary guidance on implementation of mitigation and monitoring plan)

  CE Generation files a petition for enforcement action alleging that a CPUC decision affecting QF rates violates PURPA (Docket No. EL01-83-000)

- May 31: Strategic Energy LLC v. CalISO, 95 FERC ¶ 61,312 (Order rejecting as premature complaint that ISO overcharged for power being bought out-of-market)

JUNE 2001

- June 1:

  California ISO, SDG&E, SoCal Edison, and PG&E submit RTO compliance filings in RT01-85, et al.

  Salt River Project Agricultural Improvement and Power District files a complaint alleging the ISO overcharged Neutrality Adjustment Charges during CY 2000 (Docket No. EL01-84-000)

- June 4: Cogeneration Council of California, et al: (Notice of intent not to act re two petitions for enforcement filed pursuant to PURPA § 210(h) in Docket Nos. EL01-64-000 and EL01-67-000)

- June 11: CPUC v. El Paso Natural Gas Co., et al., 95 FERC ¶ 61,368 (Order granting in part rehearing of 3/28/01 order and setting for hearing the allegations of affiliate abuse raised by complainants)

- June 13:

  California Independent System Operator Corporation, 95 FERC ¶ 61,391 (Order denying rehearing of order granting motion of generators to compel ISO to comply with creditworthiness requirements)

  California Independent System Operator Corporation, 95 FERC ¶ 61,390 (Order accepting ISO tariff amendments to conform with FERC formatting requirements)

- June 14: Morgan Stanley Capital Group Inc. files a complaint against the ISO concerning the ongoing problem of phantom congestion (Docket No. EL01-89-000)

- June 15:

  Consumers Union of U.S. Inc. tenders a filing requesting the Commission to immediately protect consumers against unjust and unreasonable charges in the Western United States under FPA sections 205 and 206 (Docket No. EL01-90-000)

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al. (unpublished notice of proxy price for May wholesale transactions in Docket No. EL00-95-037, et al.)

- June 19: San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al., 95 FERC ¶ 61,418 (Order on rehearing of monitoring and mitigation plan for the California wholesale electric markets, establishing West-wide mitigation, and establishing a settlement conference)

- June 22: San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al., 95 FERC ¶ 61,425 (Order clarifying settlement conference procedures established in June 19 order)

- June 25: Parties file requests for rehearing of 5/25/01 order clarifying monitoring and mitigation plan (Docket No. EL00-95-038)

- June 25 - July 9: Settlement conference convened regarding refunds/offsets of past accounts, etc.

- June 26: Calpine Corporation, et al., 95 FERC ¶ 61,430 (notice of intent not to act re two petitions for enforcement filed pursuant to PURPA § 210(h) in Docket Nos. EL01-71-000 and EL01-77-000)

- June 29: ISO files to update its High Voltage Access Charges (Docket No. ER01-2457-000)

JULY 2001

- July 3 through July 19: Numerous parties file requests for rehearing of 6/19/01 order (Docket No. EL00-95-039)

- July 6: Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California v. California ISO, et al., 96 FERC ¶ 61,024 (order establishing settlement proceedings in Docket Nos. EL00-111-000 and EL01-84-000)

- July 10: CalISO submits compliance filing in response to 6/19/01 order (Docket No. EL00-95-040)

- July 11: Universal Studios, Inc. v. Southern California Edison, 96 FERC ¶ 61,043 (order dismissing complaint re penalties Universal was charged for failing to interrupt its service under its interruptible service contract)

- July 12:

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al., 96 FERC ¶ 63,007 (Report and Recommendation of Chief ALJ and Certification of the Record following settlement proceeding)

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al., 96 FERC ¶ 61,051 (order denying rehearing of 5/25/01 order which clarified 4/26/01 price mitigation order)

- July 13: Dynegy files request for rehearing of 6/13/01 order re creditworthiness (Docket No. EL00-95-041)

- July 16: San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al., 96 FERC ¶ 61,088 (order deferring action on rehearing requests of the 5/16/01 order concerning QF issues and on the issues that arise under FPA § 210)

- July 25:

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al., 96 FERC ¶ 61,120 (order establishing the scope of and methodology for calculating refunds for past periods in California spot markets, initiating evidentiary hearing, and instituting preliminary evidentiary hearing for Pacific Northwest)

  San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services into Markets Operated by CalISO and CalPX, et al., 96 FERC ¶ 61,117 (order granting Mirant's emergency motion for clarification of the must-offer requirement in the 4/26 and 6/19 price mitigation orders)

  Reporting of Natural Gas Sales to the California Market, 96 FERC ¶ 61,119 (Order imposing reporting requirements on natural gas sales to California markets)

COURT CASES

- In re: Southern California Edison Co., No. 00-1543 (D.C. Circuit Jan. 5, 2001) (petition for writ of mandamus to order FERC to set cost-based rates denied)

- City of San Diego v. FERC, No. 00-71701 (9th Cir.)(petition for writ of mandamus regarding Dec. 15 order; petition denied on April 11, 2001)

- In re: California Power Exchange Corp., No. 01-70031 (9th Cir.)(petition for writ of mandamus to stay Dec. 15 order; petition denied on April 11)

- California Municipal Utilities Association v. FERC, et al., No. 01-1156 (D.C. Cir.)(four petitions for review of Dec. 15 order)

- City of San Diego v. FERC, No. 01-70609 (9th Cir.)(petition for review of Dec. 15 order)

- Western Power Trading Forum and Coalition of New Market Participants v. FERC, No. 99-1532 (D.C. Cir.)(petition for review challenging the Commission's approval of governance for the California ISO dismissed on 4/10/01)

- In re: John L. Burton, et al. v. FERC, No. 01-70812 (9th Cir.) (Court denied petition for writ of mandamus on 5/29/01) (petition for rehearing pending)

- Turlock Irrigation District v. FERC, No. 01-1289 (D.C. Cir.) (petition for review challenging application of mitigation plan (April 26 and June 19 orders) to non-public utilities)

- Public Utilities Commission of the State of California v. FERC, No. 011-71051 (9th Cir.) (petition for review of November 1, December 15, March 9, and June 19 orders in EL00-95 et al.)

STAFF INVESTIGATIONS

The Commission's staff has completed or initiated a number of public investigations, audits, and studies of matters relating to events in California, including:

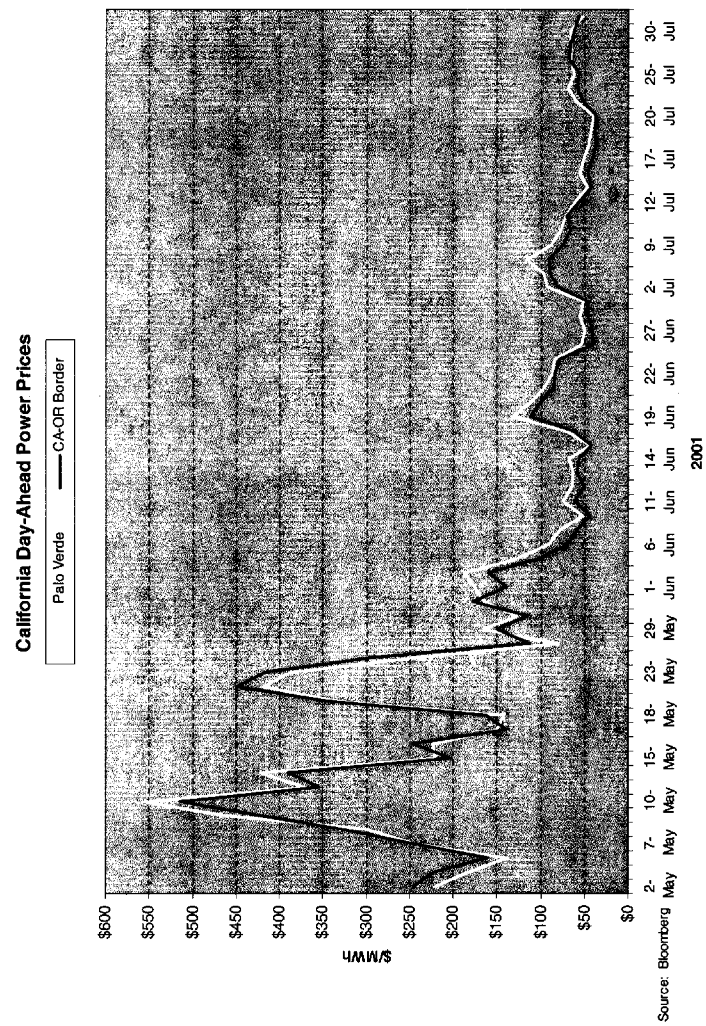
- An audit of generation outages (report issued February 2, 2001)

- An analysis of the effect of a western region-wide price cap (released in early February)

- An analysis of causes of high prices in Pacific Northwest and California (released in early February)

As of 7/31/01

FERC Chart


California Day-Ahead Power Prices
Palo Verde
CA-OR Border
$/MWh
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$550
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
2- May
7- May
10- May
15- May
18- May
23- May
29- May
1- Jun
6- Jun
11- Jun
14- Jun
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22- Jun
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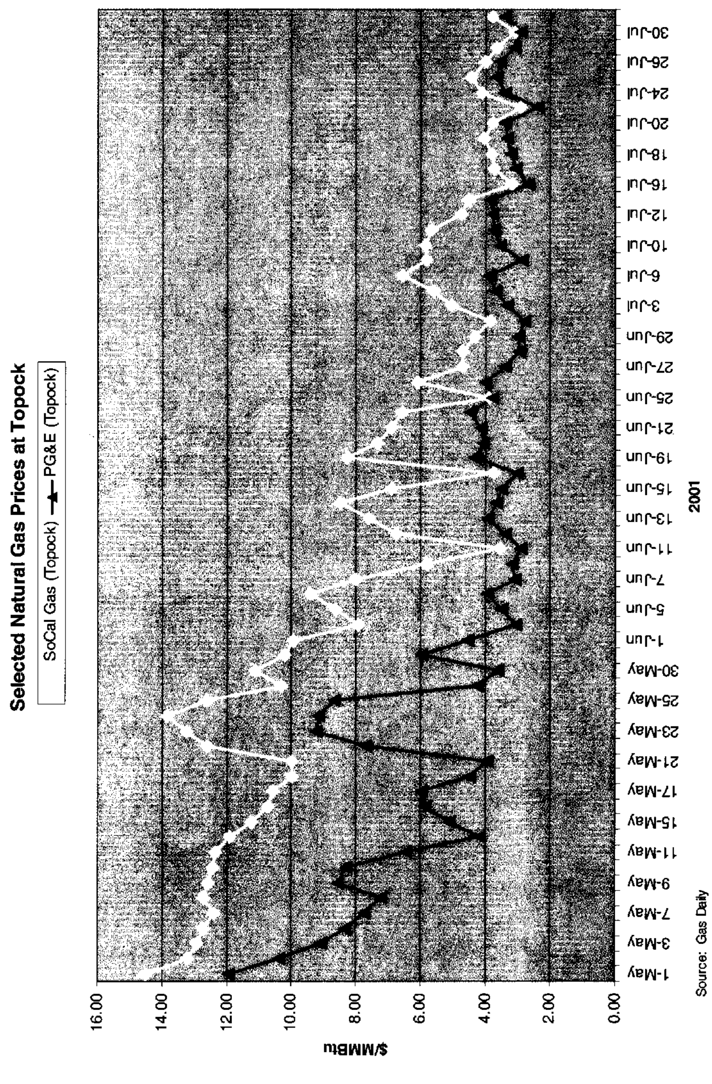
2- Jul
9- Jul
12- Jul
17- Jul
20- Jul
25- Jul
30- Jul
2001
Source: Bloomberg

FERC Chart


Selected Natural Gas Prices at Topock
SoCal Gas (Topock)
PG&E (Topock)
$/MMBtu
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
1-May
3-May
7-May
9-May
11-May
15-May
17-May
21-May
23-May
25-May
30-May
1-Jun
5-Jun
7-Jun
11-Jun
13-Jun
15-Jun
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21-Jun
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27-Jun
29-Jun
3-Jul
6-Jul
10-Jul
12-Jul
16-Jul
18-Jul
20-Jul
24-Jul
26-Jul
30-Jul
2001
Source: Gas Daily

Mr. OSE. Thank you, Mr. Madden. I just want to make sure, when I said an obscure backwater agency, my measure of success is how quietly you do your job, not how loudly. So it was meant as a measure of respect.

Mr. MADDEN. Thank you, Mr. Chairman.

Mr. OSE. Mr. Cannon.

Mr. CANNON. I would echo that. I'd like to get back to being an obscure backwater agency where things are taken care of.

Good afternoon, Mr. Chairman, members of the subcommittee. We appreciate the opportunity to be here today. We're pleased to offer testimony on some of the current challenges that confront regulators in restructured electricity markets. I have to add the standard caveat that as staff members, the views we're going to express today are our own and don't necessarily reflect the view of any particular Commissioner.

At the Commission, though, we start from the simple premise that a competitive market—that is, one with adequate supply, enough sellers, the right organizational structures and sound market rules—is the best way to protect the public interest and to ensure that consumers pay the lowest price possible for reliable electric service. However, for competition to flourish, it is critical that we have in place adequate market monitoring and the capability to promptly step in and take appropriate action if markets malfunction or sellers engage in market power abuse. The Commission has taken and continues to take actions to address these important issues.

If we are to achieve and maintain competitive power markets in the electric industry, a key structural reform necessary to support such markets is the creation of regional transmission organizations [RTOs]. We expect a great deal from these new organizations. But fundamentally—I'm not going to give you the 12 characteristics and functions—but we expect they will operate the interstate transmission grid on a regional basis, independent of entities that are buying and selling electricity. And we expect them to recognize and to facilitate natural wholesale electricity trading patterns, which are increasingly regional and multistate in character.

The independence of RTOs from power market participants is essential to the success of competition. The Commission is stepping up its efforts to encourage the formation of RTOs that provide one-stop shopping and fair and nondiscriminatory pricing and terms and conditions for transmission service over very large regions.

Now, competitive power markets also must be supported by effective market monitoring. This is critical to ensure that wholesale electricity prices remain just and reasonable and markets run efficiently. Effective market monitoring entails understanding energy markets, getting the market rules right and making sure that market participants play by those rules. The role of the Commission has changed dramatically from the days of command and control cost of service relation, but as we rely more and more on competition to discipline the price that consumers pay for electricity, we remain responsible for ensuring that wholesale electricity prices are just and reasonable. This means that we have to be just as good at monitoring energy markets as we were at auditing a utility's generation costs and awarding a fair return on plant investment.

The Commission has made great strides in transforming our organization into the new role of market monitor, not only seeking to detect instances of market abuse, but also working to improve and standardize market trading rules. Thus, our investigation and oversight of the market we regulate will not be limited to finding—simply finding someone who is breaking the rules, but we're also going to be focusing on trying to find rules that are broken and need to be fixed.

At the same time, we want to establish price signals and incentives that make the most efficient use of existing resources and encourage investment in new generation and transmission facilities where they are most needed.

Based on our experience with the severe market dysfunctions in California and the west over the past year, we are continuing to learn and we're working to improve our processes and capabilities in this critical area and trying to become more proactive in anticipating and addressing market power issues before they result in market distortions.

RTOs can help us in this important function of monitoring electricity markets, and they allow us to limit—excuse me. They allow us to leverage our limited resources.

But market monitoring by RTOs is not intended to supplant Commission authority. Rather, we envision them as a first line of defense that will provide the Commission with an additional means of detecting market power abuses, identifying market design flaws, and looking for opportunities for improvements in market efficiency.

Thank you again for the opportunity to appear before you today and we look forward to addressing your questions.

Mr. OSE. Thank you, Mr. Cannon.

Mr. Wells for 5 minutes.

Mr. WELLS. Thank you, Mr. Chairman. It's true. FERC is many things to many people. While it's true in the past, it was a backwater agency, it's certainly not true today. To some it's almost a household word recently, and to others it may be a four-letter word. But let me just be brief. The importance of FERC's monitoring role is illustrated by the situation in California. In response to concerns about high prices and short supplies, FERC did undertake a study—it was released in February 2001—to determine whether generators were, in fact, using plant outages to physically withhold power and drive up prices of electricity. FERC's overall conclusion was that the generators it audited had not physically withheld electricity supplies. Within days of the release of that study, the press started with generating companies saying that they had been vindicated. The officials of the State of California and other parties insisted that market power had indeed been used to drive up electricity prices.

The State went into other studies. They claimed to have found market power and demanded that FERC require generators to pay refunds. It's at this point the GAO was called in to review the thoroughness of what that FERC February study said.

In that context, let me say that the FERC study was quick. It was a few months, and it had a specific scope, and a limited timeframe. We found that the FERC study was not thorough enough to support its overall conclusion that the audited generators were not physically withholding electricity supply to, in fact, influence prices. They did state that they found no evidence of withholding power, but went into great detail defining their findings and that each specific outage that they saw was examined and had a reasonable cause. The two academic studies that we looked at and studied did, in fact, use broader evidence of exercise of market power in the entire market by comparing wholesale electricity prices to the estimated cost of producing that electricity. They found in their conclusion that prices were, in fact, higher than would be expected if the generators were acting competitively.

The bottom line was that none of the studies that was presented to the press or to the public was thorough enough to truly determine the precise extent to which power market was either used or not used versus other factors that cause the high electricity prices in California since May 2000.

Let me conclude here and just say that we believe that as the Federal Government's marketing entity, FERC does have a very important responsibility to fully investigate the potential exercise of market power and clearly report its results of its investigations. Perhaps the point is not that the FERC study was incomplete or complete, but that it's really how the market—how the press, and even the Congress reacts. Anything FERC does in terms of publishing information sends a message that future studies need to be sharp and clear, and they need to be issued quickly.

Market monitoring capabilities, the subject of today's hearing, is critical to the future credibility of FERC. In this area, we've begun work to review FERC's monitoring and oversight roles and responsibilities with respect to the energy market. We hope that this work will include a broad-based review of FERC's management, existing practices, staffing and their internal organization. We hope to have this report ready for the Congress and the result of this study shortly after the first of the year.

Mr. Chairman, you asked what should FERC do. Let me just quickly say, my short answer would be they need to have a goal. What is market success? I think it's unknown today.

Second, they need to know how to monitor a market. I think that's unknown today.

Third, I think they need to communicate, communicate to the American people and to the industry clearly and quickly, and I don't think the past has been great.

Mr. Chairman that, concludes my remarks.

Mr. OSE. Thank you, Mr. Wells.

[The prepared statement of Mr. Wells follows:]

United States General Accounting Office

GAO

Testimony

Before the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs, Committee on Government Reform, House of Representatives

For Release on Delivery
Expected at 2:00 p.m.
Thursday, August 2, 2001

ENERGY MARKETS

Results of FERC Outage Study and Other Market Power Studies

Statement of Jim Wells, Director
Natural Resources and Environment

GAO
Accountability * Integrity * Reliability

GAO-01-1019T

Mr. Chairman and Members of the Subcommittee:

We are pleased to be here today to discuss the role of the Federal Energy Regulatory Commission (FERC) in monitoring electricity and other markets. As you know, the electricity industry is in transition, from cost-of-service regulation to a less regulated market in which competition plays a greater role in determining the price of electricity. In FERC's March 2000 report entitled "State of the Markets 2000," FERC acknowledged that the rapid change in energy markets has caused the commission to fundamentally alter its activities. Among its evolving duties, FERC seeks to protect consumers from the exercise of market power by individual energy suppliers seeking to affect the price of electricity or natural gas. To protect consumers from the effects of market power, FERC recognizes that it must continue to develop better tools and procedures to understand markets and identify and address market power issues.

The importance of FERC's monitoring role is illustrated by the situation in California. Wholesale electricity prices in California rose sharply in May 2000 and have remained high. In addition, there were disruptions in service—blackouts—this winter and spring. A number of factors have likely contributed to these high prices and service disruptions, including rapid demand growth since 1995 accompanied by slow growth in supply, higher-than-normal natural gas prices, and flaws in the design and structure of California's electricity market. In addition to these factors, state officials and others have attributed the problems, at least in part, to market power exercised by individual electricity-generating companies. In response to concerns about high prices and short supplies of electricity in California, FERC undertook a study, released in February 2001, to determine whether generators were using plant outages to physically withhold power and drive up prices of electricity in California. FERC's overall conclusion to this study was that the generators it audited had not physically withheld electricity supplies to influence prices. One generating company concluded that FERC's study affirmed the company's operating procedures in the face of "incorrect and inflammatory allegations that we have somehow been withholding power from our four plants in California." Notwithstanding this interpretation, officials of the state of California and other parties insist that market power has indeed been used to drive up electricity prices and have demanded that FERC require generators to pay refunds to the state.

In the context of these high electricity prices and the surrounding controversy, Congressmen Jay Inslee and Peter DeFazio asked us to review FERC's outage study and two other studies that examined possible exercise of market power in California's electricity industry.[1] Our testimony is based largely on the results of our review of these studies.[2]

In summary, we found the following:

- FERC's study was not thorough enough to support its overall conclusion that audited generators were not physically withholding electricity supply to influence prices. FERC's study was largely focussed on determining whether or not the outages that occurred were caused by actual physical problems—such as leaks in cooling tubes—requiring maintenance or repairs. However, it is practically impossible to accurately determine whether such outages are orchestrated or not because plants frequently run with physical problems and the timing of repairs and maintenance is often a judgment call on the part of plant owners or operators.
- FERC's overall conclusion differs from that of the other two studies we examined, which found evidence that electricity generators exercised market power to increase electricity prices in California. These studies looked for broader evidence of the exercise of market power in the entire market by comparing wholesale electricity prices to the estimated costs of producing electricity. In doing so, they found that prices were higher than would be expected if the generators were acting competitively.
- None of the studies was thorough enough to determine the precise extent to which market power versus other factors caused the high electricity prices in California since May 2000. A thorough study of market power would combine the market-wide approach of the other two studies with a quantification of the extent to which outages, or other supply disruptions, were caused by factors other than generators' attempts to drive up prices. Such factors may include the operating and

[1] *Report on Plant Outages in the State of California* prepared by the Office of the General Counsel, Market Oversight & Enforcement and the Office of Markets, Tariffs and Rates, Division of Energy Markets, Federal Energy Regulatory Commission, February 1, 2001; *Diagnosing Market Power in California's Restructured Wholesale Electricity Market*, Severin Borenstein, James Bushnell, and Frank Wolak, August 2000 [unpublished]; and *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000*, Paul Joskow and Edward Kahn, January 2001 [unpublished].

[2] See *Energy Markets: Results of Studies Assessing High Electricity Prices in California*, (GAO-01-857, June 29, 2001).

maintenance history of existing power plants; constraints on the number of hours certain plants can be run; and financial problems of utilities, which led to suspension of payments to some generators.

FERC's Study Not Thorough Enough to Support Its Conclusion

While FERC's study was an initial step to more closely monitor generators' activities, it was not thorough enough to support its overall conclusion that the audited companies did not physically withhold electricity supplies to influence prices. This study largely focused on determining whether or not there were actual physical problems—such as leaks in cooling tubes—in generating units experiencing outages. Under this approach, if FERC found that there were physical problems with downed generating plants and that repairs or maintenance was performed, it concluded that the outages were legitimate and not orchestrated to reduce supply and push up prices. In this context, FERC determined that most of one company's generating plants were old and suffered from mechanical problems. In addition, FERC found that many of these plants had run at higher-than-usual rates in the summer and fall of 2000, prior to their shutting down for repairs or maintenance.

These facts could certainly offer a rationale for higher-than-normal levels of outages later in the year. However, the industry experts we spoke with generally agreed that it is practically impossible to accurately determine whether outages are legitimate or not, because plants frequently run with physical problems, and the timing of maintenance or repairs is often a judgment call on the part of plant owners or operators. Another weakness in the FERC study—or any study that seeks to determine whether specific outages are legitimate—is the lack of data for past outages to use as a benchmark with which to compare the number, type, and duration of outages during the study period. In discussions with FERC, officials told us that accurate outage data do not exist for the years prior to their study. Without a baseline comparison, it is not possible to conclude that observed outages are above normal in number, type, and duration. Finally, strategic use of plant outages is not the only way that a generating company could exercise market power, and FERC's methodology did not look at other ways. As FERC acknowledged in its report, the agency did not analyze whether companies were using other techniques to influence prices, such as not offering bids to sell some capacity, or bidding at prices high enough to practically ensure exclusion from the market.

FERC officials acknowledge that simply looking at outages and maintenance records of generators is not sufficient to determine whether generating companies are exercising market power. Accordingly, they told us that FERC has recently implemented a more comprehensive plan for monitoring the exercise of market power. Under this plan, FERC will continue to look at outages to determine if the number, type, and duration are warranted. In addition, FERC will monitor generators' bids and try to detect bidding behavior that is designed to exclude generating capacity from the market. FERC officials also said they have notified electricity generators that their ability to earn unregulated market prices for electricity will be in jeopardy if they are found to be withholding power in order to drive up prices.

Two Other Studies Reached Different Conclusions From FERC's

In contrast to FERC's study, the other two studies found evidence that market power had been used to raise prices. The authors reached this conclusion after looking for evidence of the existence and exercise of market power in the entire market, rather than focusing on particular instances of generator outages. The first of these two studies, dated August 2000, concluded that from June 1998 to September 1999, prices were 16 percent higher than they would have been had generators behaved competitively. One of the study's authors told us that while their study provides strong evidence of market power, it does not necessarily suggest any illegal activity on the part of electricity-generating companies. He believes that individual companies are sometimes able to exercise unilateral market power to raise prices without violating antitrust laws.

The second study, dated January 2001, also concluded that there was strong evidence that market power was exercised to raise prices in summer 2000. While the authors found that higher electricity prices were caused in part by higher natural gas prices and other factors, they also found that prices in summer 2000 were greater than they would have been had the market behaved competitively. In addition, they concluded that the level of outages experienced during June 2000 cannot be explained by reasonable expectations about repairs or maintenance requirements, or by the need to hold power in reserve to ensure the reliability of the power system.

A More Thorough Study Still Needed

Niether FERC's study nor the other two studies covered the entire period of high prices, nor did they evaluate all the factors that could have led to greater-than-normal levels of generator outages. Therefore, their results are inconclusive about the precise extent to which market power versus these other factors explains high electricity prices in California since May 2000. We believe that a thorough and conclusive study of market power in California since May 2000 must combine the market-wide approach of the two market-power studies, with a quantification of the extent to which outages or other supply disruptions were caused by factors other than companies' attempts to drive up prices. In its study, FERC pointed out two such factors that could lead to higher-than-normal levels of outages: (1) some plants had been run at above-normal rates prior to being shut down for repairs or maintenance, and (2) many plants that were shut down were older. A third factor, suggested by other industry sources, is that a number of companies were simply refusing to operate their generators at various times during 2000 because they had not been paid for electricity they had previously sold to California's utilities. While the precise extent to which high prices were the result of market power has not been conclusively determined, the authors of the August 2000 and January 2001 studies believe that there is enough evidence that market power exists to warrant a policy response from FERC and the state of California.

In conclusion, we believe that, as the federal government's market-monitoring entity, FERC has an important responsibility to fully investigate the potential exercise of market power and clearly report the results of its investigations. In light of changes in the electricity industry, we recognize that FERC's role in overseeing this industry is evolving and that FERC's outage report was simply one part of its ongoing effort. We encourage FERC to continue to improve its market-monitoring capabilities. In this regard, we are currently conducting an analysis of the electricity market in California to determine whether the design of the market has facilitated the exercise of market power. In addition, we have begun work on a review of FERC's monitoring and oversight roles and responsibilities with respect to energy markets. This work will include a broad-based review of FERC's management practices and internal organization. We will report to Congress with the results of these studies in early 2002.

I would be happy to respond to any questions that you or other Members of the Subcommittee may have at this time.

Contact and Acknowledgements

For further information, please contact Jim Wells on (202) 512-3841. Individuals making key contributions to this testimony were Dan Haas and Frank Rusco.

Mr. OSE. Mr. Winter for 5 minutes. And before you start, welcome back.

Mr. WINTER. I will try not to point fingers. I think a couple of things historically we ought to remember, and that is that I don't think we can go back, and I think we need to understand there was a reason why we went to competitive markets, why the Congress itself opened up the generation of electricity to independent power producers, why FERC had its open access rules of 888 and 889, and I think they play a lot on what we are doing today.

But what is necessary? I totally agree that regulatory oversight is probably more demanding in the electric industry than others. I agree with the gentlemen that spoke on the aviation area. And why is that? One, it is a very competitive, capital-intensive market with a lot of barriers to entry, and when you can't come in and out of the market easily, you have to have regulatory oversight.

Second, there is no substitutability. If I don't have enough wheat, I can buy oat bread. It is pretty hard to substitute electricity, and therefore it does need to be regulated.

I think State and Federal coordination is extremely important in this area because markets are not made up of only the wholesale, but the retail side.

Second, I think that the monitoring of the responsibility of how the markets work has got to be pushed down to the lowest level possible. If I have learned one thing from watching those markets operate for the last 3 years, No. 1, for the first 2 years they operated quite well with prices in the $30 range. Then I watched the thing become completely disconnected. And the analysis of that has to take into account generation outages, which is happening in real-time; how the market is responding to the rules. And you cannot get that from Washington, DC, you have got to be there where the operator is making a decision on a day—minute-by-minute basis.

Second, what is Congress' role? To me, the FPA or the Federal Power Act, was, in fact, a consumer protection act. I'm somewhat dismayed when people tell me that they can't go back and look at the—the activity that occurred that may not be appropriate or that people got windfall profits and can't go back. So I think that is something we clearly will try and need to correct.

Second, I do believe that you cannot have a market with one set of players playing with one group of rules and another playing with another. So I would encourage that FERC's authority over those, and specifically what they do in a market, be governed by FERC or some common entity so that you don't have two sets of rules.

OK. What are the effective elements of a market monitoring program? First, I think one of the things that we all desperately need is a real-time benchmark so that we can say, what is the level of pricing that, in fact, is inappropriate. Do we use market clearing price? Against what benchmark? Do we allow a percentage of the market to go above what we consider competitive prices? For how long? To send encouragement, all of these need to be studied, but above all, we have to have a safety valve, some way to avoid the runaway markets that we saw. And I think those only come through a very strong and dedicated market monitoring element.

And with that, I will conclude my comments.

[The prepared statement of Mr. Winter follows:]

**Testimony of Terry Winter,
President and Chief Executive Officer,
California Independent System Operator Corporation
Before the
Subcommittee on Energy Policy, Natural Resources and
Regulatory Affairs
House Committee on Government Reform
August 2, 2001**

Mr. Chairman and Members of the Committee:

I thank you for allowing me the opportunity to share with you my views on the role of and responsibility for market power monitoring in a deregulated electricity economy. While the views that I will offer are mine alone, they are the product of my experience with the operation of California's electricity markets over the past three-plus years. From the inception of the restructuring debate in California, I have been concerned with the efficient functioning of those markets in my roles as Chief Operating Officer and now Chief Executive Officer of the California Independent System Operator Corporation ("CA ISO").

I am particularly pleased with what I understand to be the Committee's intent in holding these hearings: not to assign blame, but to reassess what needs to be in place, particularly in the area of market power monitoring, to assure that the problems which, in recent months, have proven catastrophic in California are neither continued there nor replicated elsewhere. The issues presented warrant dispassionate analysis and bipartisan support for constructive solutions.

I recognize that there is a division of opinion about the merits of restructuring and deregulation, and it is not my intent to debate further those issues. Suffice it to say, the electric power industry was not without problems even when power supply was tightly regulated. There were reasons why Congress felt it necessary to open entry to independent power producers, including cogenerators. There were reasons why the Federal Energy Regulatory Commission

("FERC") felt it necessary to require comparable access to essential transmission facilities and to insist upon the prescription of Standards of Conduct. There were reasons why ISOs were established and why Regional Transmission Organizations ("RTOs") are being encouraged. And, there were reasons why California embraced competition as early as 1996.

It is now tempting to ignore this history and to focus instead on the problems that have emerged. I do not come here as an apologist for those problems. To the contrary, as one who has been on the front lines, often struggling hour-by-hour to keep the lights on while simultaneously struggling desperately to keep some check on prices, I surely am mindful of the prejudice that flows when reliance is placed on markets that are inherently non-competitive.

But it is well to remember that this was not the case when California opened its doors to competition in the Spring of 1998. For the remainder of that year and the next, prices were favorable, to the point of allowing the investor-owned utilities to lower retail rates and still recoup stranded investments.

What then happened? What changed so dramatically to cause such financial distress to be imposed on the State, on its investor-owned utilities, and, most importantly, on its consumers? And what can we learn from that experience that is of relevance to the work in which this Committee is now engaged?

The answer is that we can learn a great deal. We can learn that competition cannot work when supply becomes constrained and consumers lack the information and the ability with which to say "no" to purchases at prices they find unacceptable. We can learn that competition cannot work when, in a resource-constrained marketplace, demand is forced to satisfy needs in spot markets. We can learn of the absolute essentiality of market monitoring in real-time, by persons close to the operating scene and mindful of its complexities and idiosyncrasies. And we can learn of the critical need for an expeditious responsive enforcement mechanism, one capable of dispensing relief long before the pain becomes intolerable.

The challenge is to draw from these experiences the principles that must be embraced. In my judgment, as I presently will develop more fully, they distill into the following:

First and foremost, it must be clear that load-serving entities ("LSE"), be they traditional utilities or newly-emerging energy service providers, shoulder the responsibility to acquire sufficient resources to be able to serve load reliably. The operator of the transmission grid, be it an ISO or an RTO, cannot be put to the task of scurrying for supply in real-time. The operating challenges are daunting enough without adding that layer of complexity. Instead, that operator should be provided, on a periodic basis, with information about the LSE-anticipated load and supply portfolio and, if the latter is inadequate, the grid operator should competitively acquire the deficiency assigning the costs to the particular LSE. Ultimately, this should encourage the LSE itself to arrange for an appropriate portfolio of resources. Coupled with this, consumers must be given the option to say "no." We have done far too little to make price responsive demand a reality and, without it, competition can never realize its full potential.

Second, while FERC unquestionably must monitor markets and enforce compliance with competitive principles, the first line of defense must be where the action itself is taking place. Recognizing its overriding responsibility to ensure that all rates, whether set by traditional cost-of-service models or by the market, must be just and reasonable, FERC should define clearly what that means under a competitive paradigm. Does it mean that on average, recognizing that temporal scarcity will justify price fluctuations, prices should be within a certain percentage of a competitive benchmark, and that failing that, a safeguard should be triggered? These are fertile questions for Congress and FERC to ponder and to resolve. The answers would not seem dependent on the idiosyncratic nature of individual market structure, nor is it necessary, at this very early stage in our competitive evolution, to straightjacket market design. What is important is that overarching measures of success and failure be developed and, in the case of the latter, responsive corrective responses that can be implemented before the damage to consumers is profound.

Armed with this overarching guidance, monitoring and enforcement should be delegated down, to the grid operator. These markets are characterized by hundreds of actions occurring at a rapid-fire pace over exceedingly short time intervals. Monitoring must be in real-time, and where abuses are spotted, they must be rectified with equal dispatch. Apart from the intolerable damage to consumers of delay, the difficulties of unwinding the consequences of abusive conduct in a market are formidable to say the very least.

Therefore, the local grid operator should itself be able to step in, under an enforcement structure previously sanctioned by FERC, with appeal to that body should any market participant feel aggrieved. And all who participate in the competitive markets, be they entities that traditionally have been FERC-jurisdictional or not, must be subject to the same market rules and to the same penalties in the case of abuse.

With these conclusions, offered by way of introduction to place what follows in context, let me begin anew by describing the functions and operational responsibilities of the CA ISO. It is a non-profit public benefit corporation established pursuant to State legislation that required the three California investor-owned utilities to transfer operational control over their backbone transmission facilities to an independent system operator. That transfer was approved by the FERC, and the CA ISO became operational on April 1, 1998. Since that time, and because it has been blessed with supremely competent and dedicated professional and support personnel, the

CA ISO has succeeded in merging, for the mutual benefit of all participating systems, what theretofore were discrete systems operated largely in isolation, and it has succeeded in maintaining regional reliability to the greatest extent possible notwithstanding the emergence of issues of supply availability and technical difficulties of unprecedented proportion. I am unabashedly proud of that staff, and of what it has accomplished.

Under the former command and control regulatory paradigm, responsibilities were more clearly defined and accountability could be assigned. There was no confusion about the obligation to serve; it remained with the local utility, the so-called load-serving entity. It was its responsibility to assure the adequacy of supply. Restructuring, at a minimum, resulted in a decoupling. Even where the obligation to serve remains the responsibility of the local utility, it is to obtain needed supplies from the market, not from investments in bricks and mortar. And, apart from contractual commitments, independent power suppliers have not accepted an obligation to serve. Instead, they are permitted to operate their facilities with the freedom to profit maximize. In California, this introduced an immediate problem (although its prejudicial ramifications were not evident during the first year following restructuring): because new utility capacity had not been added to the State's power supply inventory over the preceding decade, and because the existing, utility-owned thermal capacity was divested to independent owners who were not obliged to meet the needs of the former owners, from almost the outset, constrained supplies were under the control of profit-maximizing entrepreneurs.

Let me be clear, I do not refer to profit maximization pejoratively. It is the expected – indeed the desired – behavior of market participants, and it will result in the maximization of efficiency and of consumer welfare, but only if the market is workably competitive.

Unfortunately, for much of the past two years, electricity markets have not been workably competitive either in California or throughout the western interconnected grid. Instead, as FERC has found, the markets have been dysfunctional, resulting in prices and profit margins that defy justification. As a committed believer in competitive markets, I have been sadly disappointed by the actions of many participants in California's electricity markets over the past two years. Not only have those actions precipitated financial distress and dislocations and the need for unprecedented State intervention, they have threatened to undermine the very case for restructuring, perhaps setting progress back for a significant period.

If we are to preserve the benefits of restructuring and of the efficiencies and innovation that it best can offer, the public's faith in our collective ability to safeguard against monopolistic abuses must be restored. That is why the subject of the Committee's inquiry today is so very important.

At the outset, we must be mindful that we are dealing with a unique commodity – electricity cannot be stored, and consumer demand for it is highly inelastic. This places a high premium on the avoidance of over-reliance on spot markets. No rational supplier, bearing an obligation to serve, would fail to invest in a balanced supply portfolio. Where that supply obligation is clear, the market will be encouraged to bring forth the array of resources that enables the LSE to meet its obligations on a least-cost basis. That requirement, until recently, was missing in California; it is not that there was ambiguity about the obligation to serve, it is that the IOUs, at least, lacked the ability to accumulate balanced supply portfolios, having been forced to deal exclusively in spot markets. The incentives were wrong, for both LSEs and suppliers.

We also failed to arm consumers with the ability to shop intelligently and with the ability simply to say "no" when the price proved unacceptable. Price responsive demand is a critical precondition of competitive markets. It is distressing that we long have recognized the importance of time-of-use pricing yet so little has been done to facilitate the availability of cost-effective metering technology.

Supply sufficiency, supply portfolios that are balanced and adequate to meet the extent and the shape of an LSE's obligation to serve demand, and consumer choice are critically important preconditions to an effective competitive market, but they alone will neither obviate the need to monitor for market power abuse nor to take corrective action.

Effective market power monitoring is essential for two principal reasons: (1) to ferret out abusive behavior at the earliest possible time (the ability to do so itself serving an important deterrent function) so that there never again is replicated the extreme injustice that has been suffered in California because of the entirely unacceptable lag between the destructive behavior and the conferral of relief; and (2) to be in a position to introduce timely modifications to market rules where it is apparent that efficiencies are being sacrificed.

Since the very formation of the CA ISO, it has been the intent that it be able to contribute effectively to the realization of each of those objectives. Toward this end, two organizations were established, one internal to the CA ISO, one external. The former, originally the Market Surveillance Unit, now the Department of Market Analysis ("DMA"), is the CA ISO's principal market "watchdog." The expert economists that we are fortunate to have in DMA constantly monitor market performance with a view to identifying abusive individual behavior, as well as inefficiencies (from a competitive benchmark standpoint) in market rules. It was the work of DMA that ultimately resulted in a FERC enforcement order against a generator (with associated refunds), and it was its work that educated the CA ISO and the market on how the rules governing the acquisition of Ancillary Services could be reformed, resulting in hundreds of millions of dollars in first-year savings. These are but two of many, many comparable examples. Most recently, it is the work of DMA that has been of central, singular importance in the refund debate now before FERC for adjudication.

DMA provides the CA ISO Board with assessments of market performance on a regular basis, with alerts as appropriate. And it regularly provides to the CA ISO Management and Board its views on the desirability of modifications to market rules. Quite candidly, it is input that we cannot be without. Additionally, at least annually and whenever on a more frequent basis the circumstances require, DMA provides its assessment of market performance directly to the FERC, and remains in continued dialogue with the FERC staff about these important issues.

Complementing the work of the internal DMA group, the CA ISO is fortunate to have available to it an external, independent, Market Surveillance Committee ("MSC"), chaired by Dr. Frank Wolak of Stanford. With the freedom to request the data it desires from DMA, the MSC is able to analyze the market issues it determines worthy of consideration, and freely shares its conclusions with ISO Management, the ISO Board, FERC and other policy leaders at both the federal and State levels. In my judgment, it is critically important to have available this independent source of judgment from persons who are well versed in operational realities, but not consumed by the daily difficulties of implementation.

What has this experience taught us that might be of use to this Committee? Quite a lot, I believe.

First, however regional integration is to proceed, there must be an internal watchdog that is both familiar with the rules governing and with the operation of local markets. Wholesale electricity markets are very complex and involve millions of transactions in a single day. Effectively monitoring these markets requires the development of a sophisticated data base and monitoring system and requires intimate familiarity with how the markets operate and how transactions get recorded in the data systems. These functions must be maintained at the operational level if there is to be the requisite understanding of what really is going on and of the technical and economic implications of current practices and of possible modifications. In short, every entity that is responsible for actual market operation, that is for acquiring Ancillary Services and for keeping supply and demand in balance in real time, must have onsite experts who monitor the pulse of those market operations and stay ever vigilant for abnormalities. Distance from actual market operations not only complicates the ability to recognize problems, it prejudices timely corrective action. A DMA capability is a necessity for any such operating entity. And, that entity must have available to it not only information that can be provided by the system operator (e.g., the CA ISO) but, as well, information that can only be provided by market participants. FERC, in consultation with entities who have had responsibility for the operation of these markets, should immediately promulgate a delineation of the information that must regularly be provided by all market participants, whether or not traditionally subject to FERC jurisdiction, to the local grid operator for the benefit of its "DMA" so that it, in turn, is capable of monitoring for abuse. And where a respondent is recalcitrant, the local entity, by delegation, should be empowered to seek enforcement.

This suggests an area where legislative action may be warranted. Recently, when seeking judicial intervention to preclude the ability of a market participant to disregard obligations under its FERC-approved tariff (a refusal which threatened the ISO's ability to maintain system reliability), the ISO was met with the contention – advanced by FERC itself – that only FERC could bring an enforcement action. Assuming this to be a correct statement of the law, and the decided authorities suggest that might well be the case, this must be changed. In the old regulated world, where a snail's pace was the norm, this may have been understandable. Today, it is entirely unacceptable. In a competitive market, characterized by transactions that occur in seconds but with implications that are long-lived, the luxury that the market operator first direct its grievance to FERC urging it to take enforcement action and then, if successful, waiting until FERC is able to 'do so, cannot be accommodated. Operators of grids used for competitive commerce must themselves have direct, immediate access to FERC and the Courts where they seek to enforce tariff obligations, and any ambiguity as to the availability of this remedy should be resolved.

In a workably competitive market, a profit-maximizing supplier should be desirous of making its capacity available to the market whenever it can realize at least its short-run marginal costs of operation, that is, the costs that it would save by not operating. This is because at worst its costs will be covered, and it stands to earn far more if the capacity that sets the market clearing price is higher cost. (There is an exception to this rule for units, such as hydro facilities with water limitations, that have limited run-times.) A "red flag" therefore appropriately is raised whenever a unit that should have cleared the market, and was not previously scheduled as unavailable, fails to bid. Similarly, it would be of concern if the unit failed to clear because the bid submitted for it was at a level far in excess of marginal or avoidable cost. The former may be an example of physical withholding, the latter of economic withholding. In either case, it could be suggestive of anticompetitive behavior, and the local market monitoring unit must have the capability of analyzing the facts, which at times will necessitate timely access to the unit. To assure proper discharge of this essential monitoring function, the investigative time interval must be kept to the absolute minimum. To the extent, therefore, that market monitoring units of ISOs (or of RTOs) do not otherwise have this authority, it must be conferred. FERC should be encouraged to do so.

Second, the entity responsible for local grid and associated market operations must coordinate the scheduling of planned outages of both generation and transmission facilities. It is not that the system operator should be able to override the owner's judgment about the maintenance that is required. But there typically is scheduling flexibility, and the coordination of outages is absolutely essential to minimize avoidable scarcity and the creation, thereby, of opportunities for the exercise of market power. The CA ISO's ability to discharge this function recently has been expanded. All operators of transmission grids that are operated for the benefit of competitive commerce absolutely must have this authority, extensive enough to cover all units so benefited. As operations become more regional in scope, it may be important to move these coordination activities higher up on the regional ladder to maximize the efficiencies of integrated operations across the region.

Third, there should be an independent entity similar to the MSC that has both the expertise and the resources to enable it to monitor and evaluate operations across the entire interconnected regional grid. At a minimum, this capability should exist wherever multi-state RTOs are in place. But short of that, and even where system operation is discharged on a local or single-state basis, there is no justification for the sacrifice of a competitive regional marketplace. Even if a multi-state RTO is not the path chosen by some or all of the states that make up the western interconnected grid, avoidable "seams" issues must not be allowed to interfere with the realization, to the maximum extent feasible, of mutual benefits. On an operational level, neighboring system operators will continue, as they always have, to work together to maximize the technical capabilities of their respective systems, but economic benefits necessarily will be lost if those with expertise in the design and functioning of competitive markets fail to discharge a companion monitoring and oversight responsibility.

Fourth, there must be a responsive enforcement mechanism in place. I know that this Committee has under consideration whether FERC appropriately has shouldered this responsibility. Let me suggest a more preliminary question: should principal enforcement responsibility lie with FERC? I am not yet certain of the answer. Unquestionably, FERC must play a supervisory role, defining rules of the road and imposing standards of conduct. But I really doubt that enforcement can be effective – and effectiveness in this context means expeditious – if it is removed from the action. A better course of action, therefore, might be for FERC to delegate enforcement to the grid operator while retaining appellate and oversight responsibilities. I do not believe that this delegation would require a legislative change. I believe that it can be handled as a tariff matter, and as a condition that market participants would accept as a precondition to utilization of the grid.

If, instead, FERC is to shoulder first-line responsibility, then I suggest that it must be prepared to do so by establishing a greater local presence. The question then becomes one of resources and their best utilization. Rather than replicate the required resources on a region-by-region basis, concentrating expertise in Washington and focusing its responsibilities on the development of overall guidance and on matters of appellate review might prove more efficient – but only if the delegation described above is embraced. To the extent that FERC's role is one of appellate review, it must still be under a mandate to act expeditiously. It truly is the case that when dealing with market power abuse, relief delayed often effectively equates to relief denied.

This brings to mind one final grievance that I must bring to your attention. It may require a legislative initiative, although I hope not. It has to do with the refund issue that currently is pending before FERC, not with the merits, but with the extent of FERC's ability to reach back to recoup for consumers the ill-gotten fruits of market power abuse. FERC's statutory obligation is to assure that rates are just and reasonable. Historically, it assured this result by scrutinizing costs and determining precisely the rates that could be charged.

In California, FERC replaced the traditional cost-based approach with rates to be set by market forces. It is free to do so if it reasonably can conclude that the market itself will produce rates that are just and reasonable. That conclusion presumes a market that is workably competitive.

We know, from analyses undertaken by DMA and others, that the electricity markets in California have not been workably competitive at least since May of 2000, and we have asked that FERC exercise its refund authority back to that date. FERC has declined, not because it has concluded that the rates then charged were just and reasonable, but because of a retroactivity bar that it reads into the Federal Power Act.

We disagree with that reading. We believe that it applies only to "filed" or "stated" rates that once were the subject of FERC scrutiny and approval, not to rates that suppliers are free to adjust on their own, without the need to submit changes to FERC or to seek its approval. FERC has long applied this more "relaxed" rule to formula rates, for example to fuel charges that utilities are able to change on their own without FERC intervention. The parallel is precise and if FERC, or a reviewing court is not so persuaded, legislative intervention will be necessary.

The public cannot be expected to embrace competition if abusive behavior is allowed to escape detection and abusers, when finally unmasked, are given dispensation. The work of this

Committee will make an important contribution to the debate now underway, and I thank the Committee for allowing me this opportunity to offer my views.

Mr. OSE. Mr. Harris for 5 minutes.

Mr. HARRIS. Thank you, Mr. Chairman. PJM is the only fully functioning, FERC-approved regional transmission organization in the country. We operate the largest competitive wholesale electric marketplace in the world, and we are the second largest centrally dispatched entity in the world. We serve within five States and the District of Columbia, and will soon include portions of Ohio and West Virginia. We have 12 transmission owners and over 200 traders involved in our marketplace. Those five States plus the District of Columbia are involved in retail choice programs.

The critical test of any economic theory or new business practice is the test of use, and what we have discovered over 4½ years of use is that competition has worked in the Mid-Atlantic region. We have discovered that reliability has increased, and we have discovered that value has been provided to customers over the past 4½ years.

Last year, for example, our wholesale prices were below $100 over 95 percent of the time. Over 70 percent of the time, our wholesale prices were below $40 dollars.

So I come to you today to talk to you not as an economic expert, but simply as someone who has had his shirtsleeves rolled up trying to do the job over the past 4½ years in a system where some things have worked out quite well.

We have certain recommendations that would help FERC's role as we move forward in electric competition. One, FERC should have full authority and flexibility to adopt and enforce reliability standards to integrate market-based solutions for maintaining and improving the wholesale electricity system. What we have found is that there are no clear distinctions between reliability and economics. With the power of technology today, it is very difficult to say this is a reliability issue or that is an economic issue. There needs to be clear and unambiguous authority for the Federal Energy Regulatory Commission to deal with those issues.

Second, we believe that FERC should ensure that there is a strong market monitoring function within the regional transmission organization. Our market monitoring function has been hailed as one that works quite well, and yet we have no sanction authority. What our market monitoring unit has is data. We have over 30 terabytes of real-time data. The amount of information that is necessary to ensure the robustness of a market that is trading with hundreds of customers every hour is massive. We are using new tools. We have research and artificial intelligence so that our market monitoring unit can see what is happening, make appropriate analyses of that information, and then report appropriately to the respective authorities as necessary. It is the ability to access information, and it is the ability to have the sophisticated tools of the 21st century that can convert that data into information responsibly.

We have been directed by the Federal Energy Regulatory Commission to be responsive to each of the States, and we are responsive to our States in order to meet their needs and information requirements, so that they can understand what is going on in the market.

Third, we believe that the FERC could take a leadership role in determining what the RTO Board's responsibility is as far as market monitoring. Much like the Security and Exchange Commission has determined what an audit committee of the board of directors responsibilities are, the FERC should determine what the Board's responsibilities are for market monitoring along the same way that the SEC does for internal auditing.

We also believe that there is a clear role for FERC to adopt some of these newer technologies and these new authorities. It is through these information technologies that we find that the State and Federal jurisdictional issues should not be as contentious. We work very carefully with the States to ensure that the wholesaler and the retailer are adequately bonded. And indeed, from a reliability standpoint, 99 percent of the outages that occur, occur on the distribution level, which is clearly State jurisdictional.

Electricity is the ultimate e-commerce. It travels at the speed of light. Electricity doesn't know from the time it passes wholesale to retail. It is the power of information, information availability, and the understanding of that dynamic that enables the public, enables the States and enables this Congress and the FERC to ensure that competition is working fairly. And with these improvements, Mr. Chairman, we think that we can do go ahead and continue to improve in the Mid-Atlantic region. Thank you.

Mr. OSE. Thank you, Mr. Harris.

[The prepared statement of Mr. Harris follows:]

TESTIMONY OF
PHILLIP G. HARRIS, PRESIDENT AND CEO,
PJM INTERCONNECTION, L.L.C. HEARING ON
FERC: REGULATORS IN DEREGULATED
ELECTRICITY MARKETS BEFORE THE
UNITED STATES HOUSE OF REPRESENTATIVES
SUBCOMMITTEE ON ENERGY POLICY, NATURAL RESOURCES
AND REGULATORY AFFAIRS
AUGUST 2, 2001

Mr. Chairman, members of the Subcommittee, I thank you for the opportunity to speak to you today. We find ourselves at a key decision point in the history of the electric industry. Our institutions can function only if they earn the trust of the public. And, more than ever, the public is demanding affordability, reliability and environmental sensitivity. If the public is to have trust in the marketplace, the public demands that the marketplace produce real fair and just results. It is up to all of us to take immediate steps to regain that public trust. We must roll up our sleeves and reaffirm our commitment to finding the best market-based solutions that deliver real value to the customer. And we need 21st century tools to do the job.

Mr. Chairman, the critical test remains the test of use. I am here to indicate to you that in our region of the country, that trust is there. Competition in the supply of this vital product in the mid-Atlantic region IS working and IS producing significant benefits to the

consumer. I also am here to indicate that with strong and visionary leadership from the Federal Energy Regulatory Commission ("FERC"), with its having adequate resources to do its job and with its willingness to take bold action to get critical market structures in place, it can, and most recently has, taken on a vital and appropriate role as a regulator to protect the public interest. Its for this reason that our story in the mid-Atlantic is one of success—not as a result of any special magic but rather as a result of our commitment to reliability "AND" market-place solutions driven by a clear commitment from the regulators, both state and federal, to take the critical steps needed to make the markets work.

My name is Phillip Harris. I am the President and CEO of PJM Interconnection, the country's only fully functioning FERC-approved regional transmission organization. We operate the largest centrally dispatched electricity market in the country and, with the recent addition of Allegheny Power, the second largest in the world. We manage the reliability of the high voltage electric power grid and operate the world's most successful market for electricity. We serve approximately 8.7% of the U.S. population in a five—soon to be seven-- state region stretching from Washington D.C. to the northern border of New Jersey and west into Ohio.

We were recently designated by Business Week as one of the top 50 businesses in the United States successfully integrating Internet technologies in to our business---the only utility to receive such designation. In the PJM region, the restructuring experience has worked. Customers have saved money and enjoy more choices and improved service. Investors are flocking to our region and have announced more than 140 new generating projects, which would add over 40,000 MW of new generation to our region as well as over $700 million in new and upgraded transmission investment.

We are governed by an independent Board which is guided by three unique fiduciary duties:

1. **To create and operate robust competitive bulk power markets;**
2. **To maintain the reliability of the network; and**
3. **To avoid undue influence by any one sector of the marketplace.**

Each of these responsibilities is co-dependent on each other and each work to make the markets work. Our history is one of complete openness and transparency---openness of our actions and openness of the markets. We post our prices every five minutes on our website. We have an open, transparent process to maintain reliability and to

undertake regional planning. And it works. In the year 2000, our spot market prices cleared below $100/mwh 99% of the time and more than 70% of the time those prices were less than $30/mwh.

What is the role of the FERC in all this? We need a strong regulator with adequate resources—funding, advanced technology and skilled personnel---to work with the RTOs to monitor these markets and make critical design corrections. We have made over 140 such design changes to our markets and have sought and received the FERC's support when our Board and the Members found changes needed.

We need a regulator willing and able to speak clearly on its vision for the country and then look to the institutions it has helped to foster to carry out that vision. We applaud the FERC's recent actions to create four large RTOs in the country as setting forth an important vision. We think we are well poised, working with our colleagues and market participants in the northeast, to take the critical and bold steps needed to make that vision a reality. We are well aware of the difficulties which lie ahead. We've been through many of these issues before. But PJM as we know it today was born out of a vision to create a robust competitive

wholesale market. We believe we've delivered on that vision and the American consumer in our region is better off as a result.

I did want to touch on some specific ways we have delivered on the vision and comment on issues we believe are important for this Congress' consideration:

Reliability---We take our fiduciary obligation to maintain reliability as job one. Restructuring cannot and need not mean any compromise to the reliability we have come to enjoy be it for Philadelphia and Washington, D.C. or for the rural communities of West Virginia and Ohio. But we also understand that, unlike the old paradigm, we can develop market solutions that both ensure reliability and enhance the marketplace. Our reliability is stronger now than it has ever been. That has only occurred because we have integrated the workings of the market and the maintenance of reliability. You cannot separate out the two any more than you can separate out the function and design of a pen from a pen cap. They need to work together as a common tool.

It's for this reason, we have proposed before this Congress that FERC be granted the authority and flexibility to adopt and enforce solutions that balance the needs of the marketplace and reliability. We

share the concern raised by the Electricity Consumers Resource Council with the present proposals before the Congress that "It is becoming increasingly clear that the 'consensus' language approved in February 1999 is too complicated, too prescriptive and too long." (Testimony of James B. Rouse before the Senate Energy and Natural Resources Committee, July 25, 2001). We remain concerned that this three-year old proposal submitted by the North American Electric Reliability Council seeks to codify outdated tools and cumbersome structures when nimbleness and agility are needed to meet the speed and integrated nature of the 21st century marketplace. We don't think we should lock into stone yesterday's solution which only address one half of the equation and therefore urge the Congress' consideration of a more simplified and balanced approach.

Market Monitoring---The market monitoring function of the RTO is critical to maintaining the robustness of our marketplace. Our market-monitoring unit has authority to review the marketplace, to issue cease and desist letters and to go to the FERC to seek enforcement actions. We believe that a market monitor that works alongside the system operator provides the needed daily interaction that is critical to understanding the workings of the market rules and ensures that the

market remains competitive. We see a strong market monitor working with the RTO Board and with the Commission as key to this vital task. This function is very much akin to the role of an auditor acting under SEC guidelines and advising a corporate board of directors. We envision Board guidelines, approved by the FERC and carried out in accordance with FERC directives to guide this important task.

A good example of the market monitor, our independent Board and the FERC working together can be seen in our recent action, approved by the FERC, to make modifications to the workings of our installed capacity market. Earlier this year, the PJM market monitor had detected problems with the potential economic withholding of generation in a manner that caused prices to rise. The market monitor and our Board moved quickly but we were unable to achieve consensus from the market participants. With the critical support of our state commissions, our Board exercised its independent judgment and filed changes under Section 206 of the Federal Power Act, which the FERC subsequently approved. It was an example of the market monitor, the independent Board and the regulator working together to craft timely solutions that maintain the competitiveness of the marketplace;

Operation of the Market---There are two models that are emerging for the RTO. In one model, the RTO operates the spot market and ensures its transparency. In the other model, the RTO is merely a grid operator with no role in operating the marketplace.

We certainly don't want or expect all purchases to be made in the volatile spot market. In fact, within PJM only 18% of all transactions went through the spot market in the year 2000. But that market represents a critical benchmark for the larger market, including bilateral arrangements. And it is for that reason that the spot market needs to be both liquid and transparent.

The New York Stock Exchange would not work very well without the publishing of prices. By the same token, a transparent spot market operated by the RTO provides the needed price transparency that can make a bilateral market work and ensure fair prices for consumers.

We are concerned that some of the proposed RTOs being formed around the country are simply grid operators with little responsibility for operating critical markets. We think this lack of a neutral transparent spot market will cause significant problems in those regions in the future. In order to jump-start such markets, our members have authorized us to make our market rules available at nominal cost to

newly developing RTOs around the country. We are undertaking this effort because we firmly believe that we should all learn from our past experiences rather than reinvent the wheel on costly untested systems that have not withstood the test of use.

We also need to ensure that FERC's regulatory toolbox is filled appropriately to oversee the workings of the marketplace. To that end, we recommend the following:

1. **FERC should employ tools to work with the states to ensure the smooth operation of the marketplace. Through joint boards and deference to regional solutions, an appropriate balance can be reached that respects the rights of the states while also recognizing the interstate nature of the grid;**
2. **FERC should be able to ensure that cooperatives, municipals and federal power marketing agencies provide comparable access to their transmission grids that they provide to themselves;**
3. **FERC should be empowered to require all transmission entities to participate in RTOs to ensure a synchronous market and wholistic regional planning;**

4. **Legislation should require the FERC to promote competitive markets, including the deployment of demand response tools;**
5. **FERC should have the authority to encourage and defer to regional siting decisions made by states through an open transparent siting process;**
6. **Mandatory and enforceable reliability rules, established by FERC with input and advise from the industry, should be applied to all system operators and subsequently enforced through RTOs. FERC should have the unfettered ability, in the first instance, to balance competing market and reliability issues.**

Mr. Chairman, in short, we believe that we can and have made robust competitive markets a reality in our region. I look forward to working with this Committee and the Congress as it works through the variety of legislative issues in implementing a national energy policy. I welcome your questions and comments.

Mr. OSE. Dr. Hogan for 5 minutes.

Mr. HOGAN. Thank you, Mr. Chairman. I too appreciate the invitation, and I have remarks that I submitted for the record. Let me summarize them.

Your interest in market monitoring raises an important question, which is prior to the evaluation of the success or failures in market monitoring, and that has to do with the question of how we design these markets to support competition.

There has been a debate in this country and other countries, but especially here, for the last few years. One end of spectrum is an argument that markets more or less take care of themselves. So if we set a few broad principles, the institutional structure will evolve naturally through the interplay of the participants. The FERC doesn't have to do that much other than announce those broad principles, 1,000 flowers will bloom to provide different ways to approach the market.

The other approach says that electricity markets are special because of the technical characteristics of these markets and that certain functions, the types of things that are the responsibility of the ISOs that have to be performed, that have to be performed in a certain way in order to be consistent with the operation of the market. And this view dictates that FERC has to get much more into the business of deciding in the public interest what is the structure of the institutional design and how are the details going to work, how are the rules going to operate. And that debate has been going back and forth in the United States.

I would say that the—the position of the Commission so far has reflected the debate and the positions that they have received, and they have been relatively deferential to the regions in allowing 1,000 flowers to bloom and experiment and so forth. But I think what we have from the experience in California, and the experience elsewhere, is plenty of evidence now to conclude, as I have concluded, that, in fact, we know that we have to take the view that FERC has to be much more prescriptive about standard market design in order to make sure that these markets work.

That makes a big difference if you are thinking about market monitoring, because if you have a badly designed market in the first place, it is going to be extremely difficult to monitor it. And, in fact, I would argue that if it is badly designed, it may even be impossible to find out exactly what is going on. And I think much of the experience in California fits that case, that the—the situation there is so murky, because the market design is so convoluted, that you have a hard time actually untangling actually what happened.

So before you can get into the question of how to monitor these markets you have to address the question of what should be the design, And I think the evidence points to the fact that the Commission should be much more aggressive about this.

The good experience in the United States is concentrated in the Northeast, particularly in New York and PJM where Phil Harris is. We do have a standard market design that has been working. It has been working as long or longer than the failures that you saw in California. And New England recently decided to embrace this standard market design. The common elements include bid-based, security-constrained, economic dispatch with locational prices, bilateral schedules, financial transmission rights, license-plate access charges, and a broad scope for market-driven investment.

The details of this I have discussed in my papers, but I wanted to recite them both to get them on the record here, and also to indicate that they are at a level of detail which is quite a bit below the broad principles announced in Order 2000. So it requires FERC to actually do more and to get more active in specifying the standard market design.

If FERC were to do so, then that would be—adopt a standard market design—and recommended it for the other RTOs, it would be a major step forward. It would make clear that FERC accepts responsibility for doing what needs to be done to create effective institutions in support of a competitive market. It would make clear that FERC recognizes that defining the essentials of a standard market design is a task that only government can perform in its role of setting the rules under which markets can do their magic, and it would set limits on the scope of government action to supporting the market rather than dictating the outcomes.

And if we had a sensible standard market design modeled after this experience in the Northeast, we also would then have a sensible structure for market monitoring, which is the question that is before this committee today. That monitoring structure would be dictated by the design and would follow some of the principles that have already been developed, for example, in PJM and New York.

This is a very important question, but—market monitoring, but I think you can't deal with it until you deal with the standard market design question that is also before FERC, and I hope you can encourage them to be more aggressive in this area. Thank you.

Mr. OSE. Thank you, Dr. Hogan.

[The prepared statement of Mr. Hogan follows:]

STATEMENT OF PROFESSOR WILLIAM W. HOGAN[1]

BEFORE THE SUBCOMMITTEE ON ENERGY POLICY, NATURAL RESOURCES AND REGULATORY AFFAIRS

UNITED STATES HOUSE OF REPRESENTATIVES

August 2, 2001

Thank you for the opportunity to participate in these hearings today. The Federal Energy Regulatory Commission (FERC) faces significant challenges in developing and monitoring restructured energy markets. This committee is to determine if FERC is able to meet the challenge and, where necessary, help craft new tools and authorities to address identified problems.

The Commission has related responsibilities for natural gas and electricity regulation. However, in these summary remarks, I will focus on restructured electricity markets. The case of electricity is important on its own, the issues are complicated, and a great deal is still unsettled. Furthermore, the unhappy experience with the California electricity market has raised many new questions and doubts that extend to the consideration of present efforts to restructure electricity markets in other parts of the country, and the rest of the world.

A competitive electricity market can be a vehicle for pursuing the public interest, but only if the market structure addresses the particular characteristics of the electricity system with its complex mix of essential facilities and large network externalities. The changes required are not well described as "deregulation." For electricity markets, "restructuring" is the better term where

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[1] Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University, a Director of the LECG, LLC., Research Director of the Harvard Electricity Policy Group and participant in the Harvard-Japan Project on Energy and the Environment. I am or have been a consultant on electric market reform and transmission issues for American National Power, Brazil Power Exchange Administrator (ASMAE), Comision Reguladora de Energia (CRE, Mexico), British National Grid Company, Calpine Corporation, Commonwealth Edison Company, Detroit Edison Company, Duquesne Light Company, Electricity Corporation of New Zealand, Entergy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., Mirant Corp., National Independent Energy Producers, New England Independent System Operator, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, PJM Office of Interconnection, San Diego Gas & Electric Corporation, Sempra Energy, Southern Company, Southwest Power Pool (SPP), TransÉnergie, Transpower of New Zealand, Westbrook Power, Williams Energy Group, and Wisconsin Electric Power Company. I am speaking on my own behalf, and the views presented here are not necessarily attributable to any of those mentioned. (Related papers can be found on the web at http://www.ksg.harvard.edu/whogan).

introducing competition leads not to less regulation, only different regulation.

Any evaluation of FERC's ability to monitor the performance of restructured electricity markets must begin with a view of the nature of the market and the extent of FERC's responsibilities. One view might be that the market can essentially create itself, such that FERC's role in establishing market design and rules should be relatively limited. A few basic principles of open access and non-discrimination would be enough. Within this framework, through the give and take among market participants, new market structures would evolve as needed. Different regions would pursue different designs, and any of a number of market models might suit. By this view, the broad principles and functions defined by FERC in Order 2000 should be enough, a thousand flowers should bloom, and the principal task remaining would be to make a few policy calls to preclude egregious deviations from the basic principles.

An alternative view would be that the special characteristics of electricity, with its complex networks and limited storage, require a more deliberate approach to market design to have an effective competitive electricity market. The existing technology for production and delivery of electricity operates under conditions that dictate the need for close coordination by a system operator. A fully decentralized electricity market is not possible. Evolutionary development through give and take among market participants can only take us so far, because in the end an electricity system must be coordinated to keep the lights on, and that reality requires that market actions and incentives be consistent with this necessary coordination function. As counterintuitive as it may seem, an electricity market requires central coordination and consistent market pricing in order to support decentralized competition. By this view, Order 2000 was only the beginning of a far-reaching set of policy decisions working towards a standard market design.

The choice matters for the issues being considered by this committee. As I have described at length in supporting papers, the logic of the case and the evidence of both successful and failed experiments indicate the need for a standard market design that provides certain essential ingredients for the competitive market. It is not possible to avoid the requirements for central coordination. Hence, the principal matter at issue is whether or not the rules for the coordinated market support efficient and effective competition.

The most fundamental assumption of electricity restructuring has been validated beyond dispute. Market participants respond to incentives. Electricity markets with poorly designed institutions have provided the wrong incentives, and market participants have responded. The mistakes, once made, have been costly and difficult to fix. However, the mistakes have revealed what doesn't work, and the successes have reinforced the analysis of what should appear in a standard market design.

From this perspective, failure to adopt a standard market design founded on the need for a consistent market and system coordination would greatly complicate the task of monitoring market performance. With flawed designs, perverse incentives and a lack of transparency, it is very difficult to monitor market performance or analyze the behavior of market participants. The case of California illustrates the point. There is little doubt that the flowers that bloomed in California produced what FERC has repeatedly described as "seriously flawed" structure and design. High prices and other evidence suggested a pattern of market manipulation, but FERC has said that it has not had a record to "support findings of specific exercise of market power." My colleagues and I have argued that FERC's caution is justified because the California market design is so convoluted that it is difficult to tell what is an exercise of market power and what is simply a competitive response to bad market signals. There is little doubt that FERC is not up to the task of monitoring a market so badly designed.

The priority, therefore, should be to get a good market design in place and then consider the means and mechanism for market monitoring. Where is FERC in this debate?

Based on their orders and other public statements, it would be fair to say that FERC reflects the diverse positions presented to it. These different positions arise from competing interests as well as parties at different stages along the learning curve. However, FERC has a broad mandate to pursue the public interest, and it should be further along the learning curve. It appears that FERC is rethinking its approach. It is clear that FERC recognizes now that some flowers that sprouted were actually weeds choking off an effective competitive market. Further, its recent orders regarding the size and scope of regional transmission organizations (RTO) were a major break with FERC's past pattern of exceptional deference to regional preferences. But FERC has not yet taken the next step of defining in more detail how market institutions should work within and among these RTOs. This may be coming, but further delay only complicates the transition and increases costs.

The experience is now sufficient for FERC to go beyond its previous deferential approach to markets created by stakeholders without regard to a set of detailed standard design principles. The good experience is concentrated in New York and in PJM, which serves the Mid-Atlantic region. These two markets now function under independent system operators (ISO) who employ a standardized spot market design for system coordination. New England recently decided to embrace this standard market design. The common elements of this standard design include a bid-based, security-constrained, economic dispatch with locational prices, bilateral schedules, financial transmission rights, license-plate access charges and a broad scope for market-driven investment. Efficient pricing consistent with the ISO coordination functions then permits maximum commercial freedom without undermining reliability. The market monitoring and market power mitigation rules follow from the design. The details of this approach are readily available, theoretically sound, well understood, and bolstered by successful experience covering the same period of operation as the California failure. The precise implementation may differ slightly to recognize best practices or local reliability requirements, but the principles go further in the direction established by Order 2000.

These principles would include:

1. The ISO must operate, and provide open access to, short-run markets to maintain short-run reliability and to provide a foundation for a workable market.
2. An ISO should be allowed to operate integrated short-run forward markets for energy and transmission.
3. An ISO should use locational marginal pricing to price and settle all purchases and sales of

energy in its forward and real-time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.

4. An ISO should offer tradable point-to-point financial transmission rights that allow market participants to hedge the locational differences in energy prices.

5. An ISO should simultaneously optimize its ancillary service markets and energy markets.

6. The ISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.

I would be happy to discuss these principles further.

Adopting and articulating these principles would be a major step forward. It would make clear that FERC accepts responsibility for doing what needs to be done to create effective institutions in support of a competitive market. It would make clear that FERC recognizes that defining the essentials of a standard market design is a task that only government can perform in its role of setting the rules under which markets can do their magic. And it would set limits on the scope of government action to supporting the market rather than dictating the outcomes.

Given this major step in establishing a presumption of a standard market design, it would be possible to consider further the requirements of market monitoring. The emphasis on market design and institutions would place a great premium on developing people and procedures that focussed on market analysis and the special complexities of the case of electricity. There are economists at the ISOs who have been developing the tools and data systems to do analysis and report to FERC. There are economists at FERC who have the skills and understanding that would be needed to monitor markets designed along the lines of those in New York and PJM. However, at FERC these economists are too few, and the commitment to the standard market design too tentative, to yet be effective in managing the task.

But this is not an insurmountable problem. The requirement for market monitoring can be met. The means are available through the FERC's powers to create regional transmission organizations. Through the creation of effective RTOs with a standard market design, the FERC has the opportunity and the responsibility to act. If competitive electricity markets are to work, FERC must act soon. Time is running out on further experimentation.

Supporting papers attached or available at:

www.whogan.com or http://www.ksg.harvard.edu/whogan

William W. Hogan, "Electricity Market Restructuring: Reforms of Reforms," May 2001.

Scott M. Harvey and William W. Hogan, "On the Exercise of Market Power Through Strategic Withholding in California." April 2001.

John Chandley, Scott M. Harvey, and William W. Hogan, "Electricity Market Reform in California," November 2000.

Mr. OSE. I want to thank all of the witnesses for their summaries, and I'm going to recognize the gentleman from Idaho for 5 minutes.

Mr. OTTER. Thank you, Mr. Chairman.

Dr. Hogan, in the purest sense, and I wasn't here, so I don't know what, nor was I in California when they thought to call what they did as "deregulation" in 1995, but in the purest sense in your—from your understanding of deregulation, I assume that meant we should create a free market, we should let the marketplace discipline and marketplace controls decide what happens to price, what happens to quantity, what happens to need.

Would you agree with that idea of what maybe the Congress meant by deregulation?

Mr. HOGAN. Well, I think you have to be careful about the terminology. I wouldn't call it "deregulation" myself, I would call it "restructuring," which I tried to use in the formal remarks that I submitted, because you are changing the rules, not eliminating the rules, and that is important.

And, second, there are many functions, maybe the most important functions that make the biggest difference, that can be left to the market: investment decisions and all of the kinds of choices that you have described. On the other hand, there are other characteristics of these markets over a very short period of time, like a day, hours or minutes, where very careful coordination of the market is necessary. This is a little counterintuitive because we are not used to thinking about it that way, but in order to have the kind of market that you are talking about, which I think can be done and works well in many places and can be successful, it is critical that the functions that the ISOs performed are done and done in a way that is consistent with the market. The coordination functin is not something that can be just left to the marketplace to decide for itself.

Mr. OTTER. I guess what I am trying to get back to, Doctor, is I am trying to get a sense of what the Congress had on its mind when the Congress said, "let's let these folks deregulate if they want to." And California was one, and Oregon was another that said, "OK, we are going to deregulate." And what they did—I agree with you. In fact, if you recall in my formal opening statement, I used the term it was a "failure of restructuring," it wasn't a failure of deregulation. But I believe what Congress conceived was the academic theory, the academic idea of what deregulation meant, and I think the end result was that there would be freedom in the marketplace, freedom of entry, which California did not allow, freedom of price control for the market to control the price, which California did not allow, and freedom to withhold product, which California says that they didn't allow.

Yet the only thing we really have is we have—under this restructuring—and the press continues to call it "deregulation," which would suggest that the free market disciplines were actually in control, and they were not, because the only freedom that anybody had was in the middle. The retail price was held at a certain level. They were free to sell—buy and sell—pardon me. Even the wholesale market wasn't free to buy and sell, because they were not allowed to buy except, as I recall, on the spot market. And so when they were offered long-term contracts—in fact, I have one right here. When San Diego requested—Duke Energy offered to meet the supply needs of San Diego Electric and Gas Co. for 5 years at a price of $55 per megawatt hour, and of course this is a—this is 55 times what we are—California and Gray Davis is now selling power for, I'm told, at $1 a megawatt. But this is also a fraction of the price of $376 paid on the spot market in December and $314 in January, and that was because they refused to permit its utilities to buy except on the spot market.

And so where is the marketplace discipline there if you still have these controls that say, no, you can't go take advantage of a long-term contract, 5 years at $55? I would almost guarantee you that in December and January, we in Idaho, who were forced to run water through our pen stocks and our dams in order to wheel power down the Pacific grid into California and displace it, would have loved to have had $55 megawatt power.

My point is, I hope you agree with me, and you can just say yes or no to this, but did we or did we not have deregulation in California?

Mr. HOGAN. Well, that is an easy statement. The answer is no.

Mr. OTTER. Thank you.

Mr. OSE. Your time has expired.

Mr. OTTER. I'm still on yellow, Mr. Chairman.

Mr. OSE. The gentleman's time has expired. The gentleman from Tennessee. We will have multiple rounds.

Mr. DUNCAN. Thank you, Mr. Chairman.

You know, the title of this hearing is "FERC Regulators in Deregulated Electricity Markets." This is my 13th year in the Congress, and every year I have been visited by companies and groups that want to talk about utility deregulation, some for it, some against it. And for several years I told them that I felt it was such a complicated, difficult problem that I didn't think we were going to do it that year.

I still wonder, but sometimes I think we may be getting a little closer to doing something. I do remember, though, when Congressman Dan Schaefer of Colorado chaired the Appropriations Subcommittee for the Energy and Commerce Committee as it was then called, I think, and he is a very good man, but I think he thought that was going to be his legacy in Congress, and he retired a few years ago. So it is a complicated, difficult problem.

But I wonder, and I direct this to any of you who wish to comment, do you think that we are getting closer to real deregulation in this industry or now, because of the problems in California, further away from it? And whatever you think, if we went to, if we somehow could get to what we would call a deregulated electricity or power market, do you think it would end up—there has been so much consolidation and concentration in almost every industry with most industries going toward the big giants—would the electricity market in this country end up being controlled by two or three or four big giants?

Mr. HARRIS. Yes. I would be pleased to address at least portions of that.

What we have found out in the Mid-Atlantic is that restructuring, changing the rules, as Bill said, really has increased the reliability. We have factual data that shows the reliability of our power grid has increased because of introducing competition. We have factual data that shows that the prices have decreased, as we have seen. We have data that shows that the customers have benefited.

The Energy Policy Act of 1992, or the amendments to the Federal Power Act, had as a goal their intention to ensure that customers have the benefit of competitive price generation. We have seen that with properly structured markets, customers have the benefit of competitive price generation.

We are also discovering, and this is almost an epiphany, that because electricity really is the ultimate e-commerce and is the only thing that is consumed the very instant it is produced, that network information technologies are the very tool that are there to enable electricity to be competitive. We could not have done this 10 years ago or really even 5 years ago. It is the ability to take information and make it ubiquitously available that has enabled competition to work. That moves us forward. That creates jobs. That creates business. That creates a new way of dealing with this thing called electricity.

The sad thing about California, is that it has masked the value of moving to competition. We have seen it work in the Mid-Atlantic. We have others that are endorsing and moving ahead.

I would agree with you, it is extraordinarily complicated, but one of the things that the power of information does, is it enables us to make life more simple for the customer and even more convenient. So it is a challenge worth taking. We have seen the measurable benefits, and it can work, but it must be done incrementally. We believe it must be done regionally. It must be done with appropriate FERC oversight in the monitoring functions, because if you lose the trust of the public, if you lose the confidence of business, then you are dead in the water. And we spent a lot of time ensuring that the trust of the public and the confidence of the business is maintained as we proceed and move down this path of restructuring.

Mr. DUNCAN. Let me ask Mr. Winter a question somewhat related to the question that I just asked, particularly as to the consolidation within the industry.

You mentioned barriers to entry, and I have dealt with that in the aviation area. It is very difficult. But I know almost nothing about the electricity industry, and it would seem to me that the barriers to entry here would be even greater.

Is there anything on the horizon, or do any of you envision a time in the future where it might be possible for even a small business or a medium-sized business to get into the business of generating electricity, or is this something that is going to always have to be dominated by monopoly type giants?

Mr. WINTER. No, I don't think it has to be dominated by giants at all. Quite honestly, in California we have many independent power producers called QFs, or qualifying facilities, with 50-megawatt units. They make up almost 10,000 megawatts in our system. All of these are owned by various owners, some small, some large. I think that the open markets are a way to get those people in.

Now, the question is on the huge units that make up the gas-fired units and some of the efficiencies that we see, they are very clearly—they are gravitating to probably four, five, six large entities.

But, no, there is clearly a spot for wind, clearly a spot for renewables, a spot for the qualifying facilities, and we see tremendous numbers of those coming into the market.

Mr. OSE. The gentleman's time has expired. We will have multiple rounds.

Dr. Hogan, in your testimony, if I understand, what you are saying is you think FERC, from a national standpoint, needs to define the template that the market works under, and then as it approves that basic template, perhaps the regional markets that would work under—submarkets that would work under the national market template can apply to FERC for the little permutations that they need to reflect their respective regions.

Is that your basic message on the market structure?

Mr. HOGAN. That is right, Mr. Chairman. The first part of the story is that there is a template. For a long time I have been arguing that the model that is embraced, for example, by PJM and New York is a way to approach a competitive market, that it was internally consistent, it made sense, and it worked. I think the evidence is accumulating that it is the way to approach the market, and that anything that is dramatically different from that is going to be very problematic and will create enormous costs during the transition.

That doesn't mean that everything has to be precisely identical, because there are different requirements in different places for reliability. For example, New York City is not the same thing as the rest of the Northeast. It has special reliability requirements and the like. So you have to deal with those, and those would be somewhat different in every place.

But for the basic structure, I think there is a template.

Mr. OSE. If I understand your testimony further, it is that having arrived at a template that works, that the market monitoring function thereby is significantly easier, not simple, but easier than it otherwise might be?

Mr. HOGAN. That is correct.

Mr. OSE. All right.

Mr. Madden, as far as FERC's obvious interest in this subject, has FERC given any thought to a template, per se, for market structure?

Mr. MADDEN. Mr. Chairman, in Order 2000 the Commission gave its vision in terms of the functions and characteristics of what our regional transmission organization should look like.

Dr. Hogan, of course, wants to drill down another hundred feet to get into all of the details, but more recently the Commission in a number of orders said that it would like to see in general four regional transmission organizations, one in the Northeast, one in the Southeast, one in the Midwest, and one in the West.

PJM, I must say from a personal standpoint, has worked very well. The Commission recognized in its order about 2 weeks ago that it should serve as the platform upon which a regional transmission organization is based.

At the same time there are good things about what is currently existing in New York as well as in New England, and we shouldn't necessarily throw out those good things when we try to establish a regional transmission organization.

What we are doing right now is having settlement agreements, or mediation agreements, rather, at the Commission with all of the parties associated with those regional organizations in the Northeast as well as in the Southeast. But as to the Northeast, what we are trying to do is to develop a plan to have one Northeast RTO that has the principles meeting Order 2000, that is the first thing, and then we will drill down and get into issues as to license-plate rates, and I don't want to dwell on that stuff today.

Mr. OSE. Actually, if I understood Order 2000, it is FERC's desire that the RTO would then get into the regional details, if you will, that you want to shift that burden to the RTO.

Mr. MADDEN. We set out general principles initially, and under those general principles, of course, you have issues raised in terms of what type of rates, congestion management, etc. We try to have the parties work together on those particular issues to reach consensus.

The Commission will ultimately serve as the umpire, calling the balls and strikes, as to how those details should look. We set out the parameters. We have addressed some of the details in individual RTO filings to date, but we have more work to do.

Mr. OSE. I suspect you are going to get more work to do.

Mr. CANNON. I think the Commission is recognizing that there is going to be a need to start standardizing certain aspects of market design, things like interconnection policy, the market rules, particularly where one regional transmission organization butts up against another. If you have got inconsistent rules on either side of that seam, then that becomes an impediment to the efficient operation of the market.

So I think the whole movement that Mr. Madden just alluded to, the Commission pushing toward even larger regional transmission organizations, is an effort to reconcile those rules and to try to standardize them over a much larger area.

Mr. OSE. Thank you.

Mr. Otter for 5 minutes.

Mr. OTTER. Let me begin, Mr. Chairman and members of the panel, by making a disclaimer, which I guess I should have. As Lieutenant Governor of Idaho the last 14 years, when deregulation was offered to the States, I was adamantly against it for the State of Idaho. And the State of Oregon and the State of California went ahead and did what they thought was deregulation. But, just for the record, I want you to know that I didn't think the structure was ready to handle the free market that was going to be required to set the price either.

And I would just say one thing to a comment by you, Mr. Harris, that energy is one of these things that is consumed or used the minute that it is delivered. That may be the case; however, the effects of that are ongoing. And for a long period of time, because in Idaho we have got a $32 billion economy that is reliant almost 90 percent on value-added products, one of the key elements in that in this day and age happens to be the energy element. It didn't used to be many years ago. But it takes 27,000 BTUs to make 1 pound of french fries, and those french fries won't be consumed for a long time, because they need to continue to consume energy because they need to be put in a freezer, and they need to be held until the marketplace is ready for them.

So I just wanted you to know that in our case we see the long-term energy use as a long time between the time that we might pay for it and actually get our money back. So we have got that in it.

I want to ask either Mr. Madden or Mr. Cannon a question about your June 18th price mitigation order for California so far, and whether or not you think that is a success.

Mr. MADDEN. Mr. Otter, looking at the prices today in California, as compared to some of the prior mitigation orders, and recognizing the fact, though, that the weather in California has been pretty good this year, and that—as compared to last year, and that Californians did their part and reduced a substantial amount of consumption, and that the Governor has added generation, I think our mitigation order, if you look at all of those factors, has added stability and lower prices to California.

Mr. OTTER. Has it added additional supplies?

Mr. MADDEN. Our order recognized the importance that we not have a price cap per se, or hard price cap, to affect the development of supply.

I understand that the Governor of California has specified that approximately 5,000 megawatts will be built by October. I think they are a little bit behind schedule in terms of the amount, but there has been additional supply added to California.

Mr. OTTER. But, Mr. Madden, I know that part of the action was to kind of free the market up. Part of the action that was taken was allowing the market to sort of set the price to the user, and I don't think it was any regulatory action that caused the great wave of conservation that suddenly took place. It was a higher price. It was a price that was starting to reflect really what the cost of production was.

And so, you know, up in Idaho we started conserving right away, because our we didn't have a cap on our price. And when we started exporting that power to California, along with our water rights, I was concerned about that. Immediately we started conserving electricity. We started shutting down areas that weren't necessary to be operating that time of year.

So I think perhaps I would agree with you that the price and conservation was working, but I think that is a result of the price going up to the end user. But as far as any additional supplies, in fact, it has been reported that the power suppliers are beginning to leave the Northwest. Isn't that true?

Mr. MADDEN. There—I don't—I may have to ask Shelton Cannon if that is true relative to the Northwest, but before I do, let me make one particular statement. My personal belief is this, Congressman Otter, that what the market needs today is certainty in the rules and the structure, and that the consumers indeed feel comfortable in terms of protection. Those, to me, are critical things that must happen.

Now, I recognize when we did the mitigation order, we had to do a balancing, and we had to balance the question of does this affect supply against how are market rules working? How are the consumers affected? And the Commission believed for an interim period, and through September 2002, that mitigation was the best approach.

Mr. CANNON. I would just echo that with any form of mitigation you are, by definition, interfering in the workings of the market, and that can be dangerous, because it can have impact on entrepreneurial decisions of do I invest or do I not? Is this a good place to go put money into a new generator? There certainly have been allegations of—that people are going to not build generation, or they are going to pull out.

What we have built into that order was an occasion in October of this year to go back and take another hard look at the mitigation and see if we have struck this balance correctly.

Mr. OTTER. Does that provide certainty? You are going to go back and relook at it and maybe change the rules in October?

Mr. CANNON. No, it doesn't. But——

Mr. OTTER. Wasn't I just told that certainty was one of the most important things here?

Mr. CANNON. Certainty is indeed very, very important, but I guess it does reflect the fact——

Mr. OSE. The gentleman's time has expired. Butch, we'll come back, if you'd like, on this question.

Mr. OTTER. Thank you, Mr. Chairman. Thank you, members of the committee.

Mr. OSE. Mr. Waxman for 5 minutes.

Mr. WAXMAN. Thank you, Mr. Chairman. I want to thank you for holding this hearing, and I will pick up where the gentleman left off, because I think certainty is an important ingredient in decisions that will be made.

I think that a lot of the decisions by the industry not to produce more power plants in California was based on the uncertainty after the law was passed, unanimously by the legislature, Democratic legislature, signed by a Republican Governor. Am I accurate in that, Mr. Cannon? Is that your view?

Mr. CANNON. Yes. I think any time you have that kind of uncertainty in terms of legislative proposals or regulatory uncertainty, that is something that very much weighs on the minds of someone considering that kind of investment.

Mr. WAXMAN. So we had this law, which I think everyone now will acknowledge was a serious mistake, on the books. Business people were trying to make a decision about their investments, and they didn't see it made sense with all of the uncertainty to make investments in new power plants.

And then we were caught off guard when the deregulation went awry, and the way the deregulation went awry is that the generators saw that they could increase the supply by withholding electricity, increasing the price by withholding electricity, and driving up the demand without having enough supply to meet it. Through this contrivance, they were able to make a windfall because that law required that the electricity be purchased at the spot market price.

Is that an accurate evaluation of what went on in California, Dr. Hogan? You are an academic. Did you come to that conclusion?

Mr. HOGAN. I would certainly agree with parts of that. The requirement, for example, that utilities had to buy through the power exchange, the spot market, I think everyone recognized was a mistake, and it contributed to the financial impact of the higher prices.

The question as to whether or not generators withheld supply in order to increase prices and profit from it, I would echo the comments that Mr. Wells from the GAO made here earlier today. The bottom line, when you look at all of the studies that have been done so far, you can't tell.

Mr. WAXMAN. I suppose that is true. You can't tell for sure, but it seems like a strange coincidence. It seems to me also that in this kind of new world that we are living in with deregulation, some of which is not thought through, the way that California's was not thought through, there is an even more important role for FERC.

Under the law FERC is to make sure that wholesale prices are just and reasonable. The problem we had is that FERC basically did nothing for a very long time. For months it ignored repeated pleas from California for assistance. Most of its orders, such as those in December 2000, April 2001, June 2001, were completely ineffective or even made the problem worse.

And since FERC's latest order in June, electricity prices have eased, but we are not so sure whether that is not due to milder weather and conservation.

Do you have any views of that?

Well, before I ask that question to get your views on it, let me state that GAO's investigation seems to confirm the inadequacy of FERC's oversight. In the report released last month, the General Accounting Office found that, "FERC's study of electricity generator outages was not thorough enough to support its overall conclusion that audited companies were not physically withholding electricity supply to influence prices." And, furthermore, GAO explained that FERC officials verbally acknowledged that FERC could not determine whether generating companies were exercising market power to increase prices, because FERC only looked at outages and maintenance records of generators.

The FERC report came at a time when people in this country, and particularly in California, were paying colossal electricity prices. Consumers, State officials and industry experts were looking for answers from FERC about whether electricity-generating companies had been charging unfair prices, and unfortunately we did not get such answers from the FERC report. We are only left with more questions.

So some of us still have a question, now that FERC finally took action, whether that action is going to be sufficient should the weather get warm again in California, and we see no greater conservation than we already have, which is pretty impressive to this point.

Mr. Madden, do you want to comment on this?

Mr. MADDEN. Yes, I would, Congressman Waxman. Let me first say, we at the staff level have been involved in this for the past year. And, contrary to statements made by many people here on the Hill or elsewhere, we have taken a lot of actions.

Now, I believe if we looked at our orders, we look at whether or not the market was dysfunctional first, and we try to fix those dysfunctions. In that regard——

Mr. WAXMAN. The market was dysfunctional?

Mr. MADDEN. Clearly there were market flaws. I'm not disagreeing with you. Everyone here agrees with that.

The question arises, do you cure the market flaws or the dysfunctions, or do you go after the refunds from a remedy type of standpoint? That issue was squarely before the Ninth Circuit Court of Appeals——

Mr. WAXMAN. Was it one or the other?

Mr. MADDEN. Yes. Here is what the court said in its order mandamus from San Diego: That the Commission was correct in correcting the market dysfunctions in setting the market rules first, and that is the appropriate approach, and then look at what refunds or remedies lie with respect to refunds.

So that issue has already been before the court, and we have granted refund authority back to October 2nd. So I think, and you can ask the panelists, the important thing is to get the rules right, set the structure, and we will have remedial authority on that.

As to the outages and GAO, I believe GAO in its opening statement recognized that it wasn't the best study, it was a quick study, and they recognized that. It was more of an engineering-related type of study, and it is very difficult to find physical withholding relative to outages.

As to the other economists' report, they also found faults with that. There was—we are trying to do a better job. For example, we have gotten authority from OMB to collect outage data from all the generators, even nonjurisdictionals. We work daily now with the ISO on the outages. We are still looking at the historical patterns of outages. There is not a lot of history on outages, as the ISO will admit, in terms of a historical standpoint. We are trying to do a better job.

Mr. WAXMAN. Thank you.

Thank you, Mr. Chairman.

Mr. OSE. I want to followup on the legislation that I have introduced, that being H.R. 1941.

If I understand the current statute that FERC operates under, there is a statutory requirement that FERC allow 60 days to pass from the date on which a pricing complaint is filed before any action can be taken. Am I correct on that?

Mr. MADDEN. It is 60 days from the filing of any type of complaint, or 60 days after the Commission on its own initiates the investigation and is placed in the Federal Register. That is correct.

Mr. OSE. All right. Am I also correct that the remedies that can be determined by FERC are restricted to mandating refund of the amount determined to be overcharges above just and reasonable prices?

Mr. MADDEN. We—from a refund standpoint, we only have the authority back to, in this particular case, October 2nd to those prices above the J&R.

Mr. OSE. Separate and apart from the August 3rd filing.

Mr. MADDEN. That is J&R level plus any interest owed during that period. In this particular case, we also got to consider the offsets, offsets meaning how much do California parties owe the generators for not being paid.

Mr. OSE. I understand. I am just trying to make sure that I have got the understanding of the statute.

So it is refund of overcharges plus interest, and that is the sole financial remedy available to FERC when they find overcharges?

Mr. MADDEN. Under 206 of the act. We also have authority to go after anyone who has violated a particular tariff or condition and can ask for a disgorgement of profits.

Mr. OSE. Now, the question that I have is whether or not the proposal to eliminate that 60-day delay has merit, and whether or not giving the Commission the ability to assess fines and penalties over and above the overcharges they might order refunded has merit. I'm particularly interested in Mr. Harris's response as operator of PJM, and Mr. Winter's response as the CEO/COO of the Cal ISO.

So, Mr. Harris.

Mr. HARRIS. Well, Mr. Chairman, we think as we administer the tariff that certainly you have to have prompt response—capabilities to respond when a complaint has been filed, and to be able to be addressed. So we would support such amendments.

As we were discussing earlier, there is just so much money on the table in administering competitive electricity markets. Delays do and can create dysfunctions over time. So more prompt response is always helpful, assuming that the facts and the merits are available so that FERC can make an informed decision.

Mr. OSE. Mr. Winter.

Mr. WINTER. I think clearly timeliness is of major importance. Again, I don't want to play attorney, because I am not one, but I think the 60-day rules were in there to allow people to comment on it. I think a better approach is rather than change those that we put in play, the tariffs that allow for immediate action by FERC, once we as a, quote, ISO or an RTO bring forward a complaint or something in the market that we don't think is working right, then if it is clearly a violation, and we set the rules up right, we ought to be able to act on that immediately and not go through any 160 days, 60 days, a year, whatever.

So, while I think people need the ability to have their day before FERC and discuss what they have been accused of; if we have the documentation, I don't think you can go for a year on the prices we have been seeing without taking some type of action immediately to at least forestall it until you can make your decisions.

Mr. OSE. There was a discussion over in the Senate last week about conditioning the operating certificates that are issued to the generators in just such a manner. In other words, you attach a condition to the certificate that gives the generators the ability to sell power at market rates, and then if they violate that provision, you basically pull their certificate.

Do you have any feedback on how this works?

Mr. Madden, I am going come to you, don't worry.

Mr. WINTERS. Yeah. I have some immediate feedback, and that is, if you are sitting in a situation where you don't have enough generation to serve your load, and I go to a generator and say, you have been bad, I am going to take your 1,000 megawatts offline, I find myself in a real operating dilemma in that I am now unable to serve the load that I need to serve. So I think there has got to be some kind of—rather than just, quote, yank their license—there has got to be some mechanism that I can force them to provide that power at the same time penalizing them. Did I make that clear?

Mr. OSE. I think you are arguing in favor of fines and penalties as opposed to pulling their certificate.

Mr. WINTER. Only because I am in a situation where there is insufficient supply. To take them out of the market would really hurt me from a reliability standpoint.

Mr. OSE. Mr. Harris, do you agree with that?

Mr. HARRIS. Mr. Chairman, I am not directly familiar with the discussion on the proposal for the licensing conditions for generating units. I would like to say, though, that what we have found in operating the market over the past 4½ years, that the real secret is spot price transparency of information, and if you have information, then you have the information to determine if it was or was not a problem.

One of the discussions that we have is in the approval of the RTOs, that FERC has approved some RTOs that have spot price administration capabilities and some that do not. We think this can create a problem.

If the RTO is administering the spot market, we publish prices every 5 minutes. They are universally available. If you want, we will publish the price every 3 to 5 seconds for you. Having spot price information then allows the market monitoring units to be able to determine what was going on, and appropriate information then would lead to appropriate remedy.

So I think my gut sense is I would rather see a system that would ensure that you had spot price information uniformly distributed throughout the United States. Then you could take appropriate remedial action, whatever that may be.

Mr. OSE. We are going to come back and finish this question.

Mr. Towns for 5 minutes.

Mr. TOWNS. Mr. Chairman, I would like to ask unanimous consent to submit some questions and to have them answered. I have a conflict, and I won't be able to stay throughout, but I would like to just read the questions and then have them answer them in writing.

Mr. OSE. We will be happy to submit the questions to record. The record will be left open for 10 days for such a purpose. If you would like to read them, that is fine, but we will be happy to submit them in writing, too.

Mr. TOWNS. On that note, then, I would just read them real fast, and then, of course—what studies, economic analysis or cost-benefit analyses have been done to justify the regional transmission organization ordered by FERC?

No. 2. What basis is there for setting up this market in such an expedited fashion? What is the hurry? What is the rush?

What impact will this RTO arrangement have on a State like New York that has a more sophisticated market?

And then I guess I probably picked this one up out of Professor Hogan's testimony. In your testimony you set criteria for RTOs.

Which current independent system operator best fulfills this criteria?

So I would like to have those questions answered. Thank you very much, Mr. Chairman. I yield back.

Mr. OSE. If I understand, you want the fourth question directed to Dr. Hogan, the first three questions were directed to Mr. Madden——

Mr. TOWNS. For—yes.

Mr. OSE [continuing]. And FERC. Well, we've got the general counsel and Mr. Cannon. Neither of them are Commissioners here.

Mr. TOWNS. Either one of them.

Mr. OSE. OK. So we've got three for the FERC folks and one for Dr. Hogan?

Mr. TOWNS. That's correct.

Mr. OSE. Any for any of the other witnesses?

Mr. TOWNS. No. That's it.

Mr. OSE. All right. So ordered.

Mr. TOWNS. Thank you very much. And I yield back, Mr. Chairman.

Mr. OSE. Mr. Otter for 5 minutes.

Mr. OTTER. Thank you, Mr. Chairman.

Mr. Wells, in GAO's review of the FERC's actions and the FERC study and the other two studies referenced in your testimony here, was there any analysis that the GAO did outside of that, for instance, many of the actions that were taken by Governor Davis and his representatives during that same time period? Was there any analysis of what kind of disruption and what kind of uncertainty that those actions taken by Governor Davis made in the marketplace?

Mr. WELLS. We did not do our own analysis in the outage work that we did, as well as some other work that we were asked to do in terms of commenting on whether there was going to be a surplus or shortage, and it came down to the thorny issue for us of access to the data. We were not given access to outage information or information on outages wasn't available. So, we only relied on the critiquing and looking at what efforts had been made by others to write their studies.

Mr. OTTER. I see. OK. Mr. Madden, in an answer to a question from the gentleman from California, Mr. Waxman, his question to you about supply and about suppliers was prefaced with the fact that there hadn't been any building, nobody had rushed to build a lot of capacity in California since 1995. But in fact, did your report discover that there were a lot of megawatts in the permitting process and in the request for construction process?

Mr. MADDEN. Congressman Otter, I believe there hasn't been any, really, construction at all since 1990, at least a good decade. I don't know what report you're referring to. Is this the GAO outage report, or is this our December order?

Mr. OTTER. This is the analysis by the GAO of your report on whether or not there was market manipulation by withholding supplies from the market.

Mr. MADDEN. Well, I think we have somewhat of a disagreement between GAO, although I think they did a very good report. But the report that staff tried to do was to focus more on engineering in terms of whether or not the plants went down for any physical reasons. It didn't focus on—and even though there's a disagreement between our two agencies, it didn't focus on whether or not there was influencing of prices, per se, etc. And maybe—I mean, that is something we've got to look at.

Mr. OTTER. Before we get too involved in that, I'm just concerned that we're only looking at a very, very small part of what could have been the reason for some of these things, and I am told, either by direct reports or by other investigations, that there were some 14,000 megawatts of new generation capacity waiting to be permitted and waiting to startup. And if I'm a supplier and I see a whole bunch of new products coming some way, I'm going to make sure that my price is going to be competitive so that there's not a whole lot more enthusiasm for getting into my market and driving the price even lower.

So it goes to that, in part, but I'm also told there was a terrific curtailment in some of these plants, which was legitimized by the fact that they didn't have pollution permits to a certain level, and so that they could run at 60 percent capacity or 50 percent capacity, because that's all of the "pollution" permits that they had, because they didn't get the bag houses on or for whatever purpose.

But I think to look at this thing, to go in and look and see whether or not they were soldering up cooling tubes in one of the production facilities, and that's why they were shut down, and if they weren't carrying on some kind of maintenance, then they were artificially withholding product, curtailing their production. I think there were a lot of reasons. What I'm saying is that there was a curtailing of production, and it wasn't all simply for market manipulation. That's just my statement. I just want to ask you one question.

We were told last night in the debate on the energy bill that a public facility, a municipal electric facility, the Los Angeles Department of Water and Power, was charging during this time period $285 a megawatt. At the same time period, which they said was market manipulation by the private sector, they were charging $245. Have you any information about that?

Mr. MADDEN. Well, I don't have the figures before me, but I do have some information, since I usually deal in information at the Commission. The system was set up in California to have one clearinghouse with a single price auction, where you buy and sell into the PX and the ISO. And you had as part of that framework both public utility sellers, sellers over which we have direct jurisdiction over, and nonpublic utility sellers, LADWP for example, over which we do not have direct jurisdiction, selling in, buying out and getting the same price. All right? And that, in many cases, it may have sold at higher rates than what the sellers, the jurisdictional sellers, may have sold on a bilateral basis or whatever the case may be.

The issue before the Commission is the amount of refunds now that LADWP and other nonjurisdictional entities may owe, along with the jurisdictional entities, as a result of them using that single price clearinghouse and agreeing to be subject to those rules during the time period.

So the bottom line is this: those nonjurisdictional entities received the same price through the single price auction as did the jurisdictional sellers.

Mr. OSE. The gentleman's time has expired. I want to come back to the question on the 60-day window and the fines and penalties, and ask Mr. Madden for his input on that particular proposal.

Mr. MADDEN. If I may, let me just step back and address the license certificates for market-based rates. Let me just tell you that with respect to sellers in the West who have market-based rates, the Commission has conditioned those market-based rates now from a prospective basis when it issued its, I believe, April order, that they're subject to anti-bidding behavior, and they have retroactive refund conditions attached to those market-based rates that will give us flexibility to go after them. We have not done that yet for the rest of the country, but we're looking at our market-based rate program in general.

Mr. OSE. Those conditions last until when?

Mr. MADDEN. We've never set a date.

Mr. OSE. OK.

Mr. MADDEN. A term date. They're conditional with the market-based rate.

As to your request for 60 days as to whether or not Congress would be, or the consumer would be better off in having a refund effective date from the date of complaint or when the Commission took action, 60-day action, on its own. I have a couple thoughts. One, I think it's hard to apply that to the spot market type of transactions, because they move so quickly. What I think Mr. Harris said, and I agree with him, is that what is important on the spot market is the information, the transparency, etc. In terms of the bilateral market, I think it could be done, but the problem, from my own personal view, again, is that you create more certainty as to whether or not bilateral deals, which were mutually agreed upon by the parties, get reopened. But should the Congress want to modify that, I would recommend at the max to only go back to the date that the complaint was filed.

Mr. OSE. My question is a little more subtle than that. Even with the 60-day window on a bilateral contract, if there is a pricing complaint and FERC takes action ordering a refund and overcharge, you're still voiding a bilateral contract.

All I'm saying is, should the calculation be from the date of the complaint regarding the pricing, or from 60 days after that date?

Mr. MADDEN. It's a policy call, Mr. Chairman. I could go either way on it. This issue was addressed with the Regulatory Fairness Act that Congress dealt with in the early 1990's when it modified the act itself, and what it did before that was it was prospective from the date of the final order of the Commission. I could see benefits going back from the date of the complaint in order to have more certainty and get the Commission to act very quickly and get the refunds moving.

On the other hand, the question is, is it really a viable complaint unless you hear from all the parties and the Commission makes its decision? But I think it has some merit, but there are pros and cons associated with doing something like that.

Mr. OSE. How about the issue of assessing fines and penalties as opposed to just refund of the overcharge plus interest?

Mr. MADDEN. Here's my personal opinion, and again I don't want to speak for the chairman or the commissioners. I personally believe in penalty authority. The Commission could have a good stick, to go against those—we may not have remedial authority with respect to a complaint or a 206, but it's something that the Commission can use against it. We do have penalty authority under the Natural Gas Policy Act. We do have some remedial penalty authority in the Federal Power Act, but in my opinion, as we move forward and try to monitor these type of markets and make sure that players play by the rules, I don't think it's a bad idea to have penalty authority.

Mr. OSE. Mr. Cannon.

Mr. CANNON. I would echo that, again as a personal opinion, because if you look at how these markets are starting to form with some sort of single market clearing price auction, the Commission right now is involved in a very tedious and horrible exercise of trying to figure out who owes money to whom for the last several months in California. Trying to go back and reconstruct what might or might not have happened in a market is almost impossible.

It's just a very, very difficult task, and going forward, it seems that refunds don't make as much sense anymore. I mean, it was a nice paradigm in the days of bilateral cost of service regulation. You know, I was dealing with you. We could go back, and if I overcharged you, you could bring a complaint to the FERC, and we could make sure I gave you back money with interest. But going back and trying to reconstruct what might have happened in a market, had certain entities done things differently, and putting everybody back to where they would have been under those different actions is very, very hard. So I'm drawn to some sort of penalty that can be assessed against the entity that is breaking the rules.

Mr. OSE. Thank you.

Mr. Otter for 5 minutes.

Mr. OTTER. Thank you, Mr. Chairman. I recently received from Mr. Curt a letter stating that the State of Idaho, Idaho Power, the National Marines Fishery, and FERC had reached an agreement, and let me refresh you if you're not familiar with this. I guess you are familiar with it. I can tell by the look on your face.

Mr. MADDEN. I'm somewhat familiar with hydro, but my focus hasn't been on hydro the past couple of——

Mr. OTTER. Well, if you don't feel——

Mr. MADDEN. No, I'll——

Mr. OTTER [continuing]. That this is in your area, just tell me you can't answer this. But what the agreement came down to, National Marines Fishery came along and they said, "Idaho Power, we want you to release 350,000 acre-feet of water out of Idaho and behind your empowerments, and we're not going to give you compensation for it, and we need this 350,000 acre-feet of water for salmon recovery and the continuum under their scientific study," which I might add has not been, as far as there are many circumstances under which many people are saying that this is not working. The flush is not working, but we do know what is working.

But anyway, in an agreement with FERC and NMFS, NMFS backed off and said, "OK, we're going to continue the regular flows through the summer months," and you know, I appreciate the wisdom and not only that, but the logic that NMFS—or that FERC obviously used to suggest to NMFS that this was not a good idea. Where I want to go with this is the scarce electricity months are coming up. Are we going to have that same kind of consideration in the months to come? Will we continue that, whether we continue the approach that FERC took for the summer months into the winter months when the electricity is going to be a lot more scarce?

Mr. MADDEN. Commissioner—excuse me, Congressman Otter—I get used to answering commissioners these days. I'm aware of the Hells Canyon Project, and I think it was crucial that we brought all the parties in and we discussed it instead of having paper flying back and forth, and I think I had to give NMFS ultimately credit for, you know, pulling back on their proposal and recognizing the importance of generating energy and recognizing there is a need to balance environment against supply.

As to your ultimate question, we are working with other licensees in order to modify their particular projects to generate more electricity, both during the summer and for the next year or so, and working with the environmental agencies, many of whom support us, by the way, so that more generation will be able to occur with less environmental constraints, but yet within the environmental law. So we are pulling together a dialog with numerous agencies on a number of hydroprojects in the west.

Mr. OTTER. Just to make you aware, I have introduced, along with several of my colleagues, legislation to actually put the U.S. Fish and Wildlife back in charge of the Endangered Species until it hits the ocean, and put NMFS back out in the ocean. Not only in these circumstances, but we have many, many circumstances over the Pacific northwest where it's tough to find a place to go to to surrender, because just about the time you get permission from U.S. Fish and Wildlife to go ahead with a problem on the Endangered Species Act, then you have to go get permission also from NMFS, and NMFS doesn't want to dot the Is; they don't want to cross the Ts, and so what should take maybe 60 days working with one agency, you end up spending years, in fact, running back and forth between the agencies.

So I would be interested some time in a conversation that we might have in less formal circumstances how you as a government agency, who has to deal with all of these other government agencies and the dictates that Congress puts on them, like the Endangered Species Act, would feel in being able to go to a one-stop shop when it comes to those kinds of things.

Mr. MADDEN. I can give you my opinion now.

Mr. OTTER. In public?

Mr. MADDEN. In public.

Mr. OTTER. On the record?

Mr. MADDEN. On the record.

Mr. OTTER. I want to hear it.

Mr. MADDEN. Under oath. I believe in one-stop shopping. I am firmly a believer of some agency having the ultimate call on balls and strikes, working in a collegial fashion with the other agencies, recognizing the statutory restrictions that have been imposed on other agencies or the authorities as well. But I've worked on the pipeline side of the business. I've worked on the electric side of the business. I used to run the hydro program in my younger days, and I think it's about time to cut through the chase and cut through the paperwork and timing and have a more collegial framework and one-stop shopping.

Mr. OTTER. Thank you. Thank you, Mr. Chairman.

Mr. OSE. I want to return to something having to do with the RTOs and the manner in which they're operated. FERC put out an order last week, July 25th, and the order said that while DWR is a market participant that competes with other suppliers and purchasers of energy in the ISO markets, unlike other participants, DWR has had access to the ISO's control room and associated written materials, visual observations and oral statements regarding ISO's markets, systems, operations and activities. This has provided DWR a competitive advantage.

Now, that is a direct quote from an order dated July 25th from FERC. And Dr. Hogan, I'm trying to figure out, DWR is the big buyer in California. I mean, in my neighborhood, they're the big dog, so to speak. How do you run a market if the major participant is in the same room as the operator of the system?

Mr. HOGAN. Well, I think the answer is obvious, and it's obvious in your question. We do have a short-run problem which was created by a whole series of mistakes, which led to DWR buying all this power in the emergency mind-set that appeared last spring. But going forward, it simply would not pass muster by any objective analysis that you should have one big buyer, and you would have one big buyer sitting in the control room with special access to all the information.

No one would call that a market or a sensible market design going forward, and I don't think California could call that a sensible market design going forward.

Mr. OSE. It may well just be a happenstance. And Terry, I'm going to let you comment. I'm just trying to figure out how we fix that. Mr. Madden, Mr. Cannon, do the FERC regulations allow this to occur, or is this happening, again, by happenstance?

Mr. MADDEN. This is my personal opinion. The DWR buying on behalf of the State and utilities in the State is a market participant, and as a market participant, it should not be in the ISO control room, and it should not have the ability to cherry-pick the contracts that come in—the lower price contracts, pull them out of the ISO market and enter into bilateral sales with them. It gets into the cornerstone question underlying the RTOs in a lot of things going forward, and that is independence.

Mr. OSE. You brought this up about 12 or 15 minutes ago. It was your comment.

Mr. MADDEN. I don't recall that, but I don't recall a lot of things these days.

Mr. OSE. FERC has a desire for independence on behalf of the RTO. How do you go about establishing that?

Mr. MADDEN. Well, in the RTO, we establish the parameters upon which we would see an independent RTO, an independent board. Mr. Harris is operating the PJM, and they have met our established criteria for independence, and we view their board as an independent board.

Now, as to looking at a particular California——

Mr. OSE. You have criteria that you've applied?

Mr. MADDEN. We look at individual cases in the RTOs and determine whether or not they've met the independence standard that we specified in Order 2000.

Mr. OSE. Why does it make any difference? Why have you done it? Why do you want an independent RTO board?

Mr. MADDEN. I'll pass this to Shelton.

Mr. CANNON. The primary objective is to totally separate transmission decisionmaking—how this interstate grid is operated—from decisions of market participants, where any particular entity that may have a generator and has an interest in trying to influence decisions about how that transmission system is operated in its favor. What we want the RTO to do is administer the interstate transmission system in a totally unbiased manner so that it's fair to any and all market participants.

Mr. OSE. Well, I have to admit to some concern, and maybe, Mr. Winter, you can speak to this. DWR is buying a lot of power in the State. It's not going to successfully function, at least on appearance's sake, without them buying the power. I mean, how do we reconcile this?

Mr. WINTER. I guess I have somewhat felt like a patient laying on the table with everybody dissecting me and wondering how I'm going to respond. But I would like to comment on several things, this being certainly one of them.

Just for the record, I am not for standardization. To me, that's like taking a race car that is running well but it doesn't have good brakes, so it crashed on the corner. Therefore, we throw the race car and everything else away.

Mr. OSE. Going back to the question I asked Dr. Hogan.

Mr. WINTER. Right. And so I want it on the record that I am not for standardization. I think innovation will occur, because we all look at things differently. That does not mean we don't take the best of what Dr. Hogan has proposed, the best that other people have proposed, and take our experience and put it together. But just to do standardization for standardization's sake, in my opinion, retards innovation and the things that Phil was talking about that we really need to go forward with.

The supply issue, there were several questions asked about supply. I made the decision in 1994, along with some other people, not to build a 500-megawatt power plant in San Diego, and the sole reason for that was because deregulation was on the horizon, and we could—we did not know what our responsibility as a utility would be under that, and we did not know who was going to pay for it. Without those two things, we were not going to go forward with generation. That does not mean that we did not have over 14,000 megawatts of generation in the queue looking to build in the State.

Where we failed miserably was that we estimated up until the year 2004 we would have sufficient supply in California. We made two very critical errors. One, we did not see the increased growth in the surrounding States, and since we're an importer of about 30 percent of our power, we got caught when the other States grew, and they used the resource and we had not contracted forward for it.

The second mistake that we clearly made was that we didn't recognize the State was going to grow, and so our demand grew much more rapidly.

Having said that, the market failure, in my opinion, was the lack of supply. We had two very good years when we had more supply. We also got caught with the drought in the year, which advanced things.

So I think, again, we've got to look at the reason, and I'm not pointing fingers or looking back. I think we have to learn from history before we go forward. The whole power plant outage issue, extremely hard. I have run power plants. At any time, I could shut the power plant down and have a very good justification for doing it, because tubes leak. What acceptable leak rates are there?

I think there you have to go to performance-based criteria and say give me availability of 92 percent or something that motivates the people to do it, because they can always find something that is wrong with it. You asked about DWR on the floor. That occurred because, No. 1, the market was not functional. It was not working. And it added an element that we haven't talked about here and that's bankrupt or creditworthy entities on the other end.

So, as on the floor when we tried to ask a generator to supply energy, his first question was, "Who is the backer of this purchase?" And the only way we could get that information in immediate real-time was to have a DWR operator who could commit for DWR that they would back those transactions.

We advised FERC of that, and we're working very hard to get them moved out. Now that the crisis has moved along. I think the last thing that I would like to say—and I know I'm over my 5 minutes, but we've asked whether the FERC mitigation has, in fact, worked. I firmly believe it's too early to tell, because I didn't get in the situation where I don't have enough power to meet my load, we don't know what the impact is going to be and whether the market is going to take off. I have high hopes for it, and I think it's well laid out and will help us, but until we get to that point, I don't think we're going to know.

Now, on the point of independence, which you asked me——

Mr. OSE. Let me come back. Mr. Otter has been very patient here. I'm way over my time. We'll come back to that. OK? Mr. Otter for 10 minutes if he so chooses.

Mr. OTTER. Thank you, Mr. Chairman. I would direct my first question to Mr. Madden and Mr. Cannon, and let's go back and start in December 2000 when as part of your FERC order you requested a restructuring of the board. Then, again, certain times it was mentioned that it was going to be up until, in fact, a couple of weeks ago or a week ago, that it was part of the agenda as to when they were going to get the restructuring, even after the Governor had gone forward and restructured the board himself.

But yet you continued to put it on the schedule for addressing what you felt was a problem or at least a concern that you had. And yet you've continued to drop it off the schedule as you did this last meeting just before this last meeting. When does FERC plan on taking action on what they have since for the last 7 months indicated was a problem?

Mr. MADDEN. I'm precluded, Congressman Otter, from giving you a certain date when the Commission would act on the question of whether or not the board is independent or not under my regulations. It was on the Commission's agenda last week, and it was taken off. It was not on any other agenda prior to that time, at least as I recall. The Commission recognizes that they have to act swiftly one way or another on this issue, and there are different positions of the parties, of course.

California, the ISO believes that they're in compliance with our December 15th order and that they file bylaws to implement the new changes that the Governor signed in January. It's clear from our November order and our December order, which essentially required that the old stakeholder board remove itself from service and advisory board, and that the ISO management under Terry Winter and others serve until such time as the consultant selected or gave a list of candidates——

Mr. OTTER. Why do you feel that was necessary?

Mr. MADDEN. Because we thought the whole question of independence was not occurring with respect to the stakeholder board. Under the order that we authorized back in 1998 that we allow the State to pick 50 percent of the stakeholders because the retail—we recognized that there were major problems with the stakeholder boards where the Commission, in its draft order in December, recognized the importance of independence and wanted things to be changed.

Mr. OTTER. And why didn't you feel that they were independent?

Mr. MADDEN. There were questions as to whether or not they were—the stakeholder board was representing the particular interest of their group and not the interests of the ISO, among other things.

There are a number of party—or pleadings before the Commission which were scheduled last week which raised concerns about the independence of the board right now. Like I said, the Commission had that matter taken off, and it will be before the Commission quickly, but I can't tell you when.

Mr. OTTER. Mr. Winter, how would you characterize the relationship with the State agencies with the DWR?

Mr. WINTER. I guess I don't understand. The relationship with State agencies and DWR?

Mr. OTTER. Your relationship.

Mr. WINTER. Oh, our relationship with DWR. Clearly, they are our biggest purchaser of power, although I should clearly state that the IOUs self-provide about 48 percent of the power. DWR buys another 20 and some small real-time, and then the municipalities provide their own. So they're not in the sense of being a 60 or 70 percent buyer of power. That is not the case. They're buying the shortfall, but the investor-owned utilities cannot purchase with their folks.

Clearly, we have tried to work with them and are working with them to set up procedures so that they can get the information they need. When you have utilities with insufficient credit ratings, they're the only creditworthy person that is purchasing power, and therefore we work with them to make sure that we've got the available resources to meet the load.

Mr. OTTER. Do you believe that the CAISO board now meets the requirements that were laid out for independence?

Mr. WINTER. Let's see. I want to be sure I understand your question. Do I believe that the current board meets the independent requirements that are laid out in the FERC rules for independence? I think that we have a concern that as long as the State has a buyer, that there is an issue in having the State and the buyer with the board. Beyond that, who a board is appointed by, just like regulatory agents are appointed by the President, I think they still function very independently.

So just the fact that the Governor—you say the Governor, but in fact, legislation was passed that gave him the authority to appoint the current board. I clearly think that from that standpoint, they're independent from the market.

Mr. OTTER. Thank you, Mr. Chairman.

Mr. OSE. If I might followup. As I understand the legislation, was it AB 5X?

Mr. WINTER. I believe so. I get 5X and 1X confused.

Mr. OSE. That's the problem I have, too. Well, one of them actually made the pleasure appointments of the Governor? Is that not correct? They're not subject to Senate confirmation.

Mr. WINTER. That is correct.

Mr. OSE. Or anything? And I think that's different. I want to be sure I understand that difference between, say, a FERC appointee who is confirmed by the Senate or any of the others.

Mr. WINTER. That is correct. That is different.

Mr. OSE. One case here at the Federal level, we have a Senate confirmation process, but under AB 1X or 5X, whatever it is, these are pleasure appointments who can be terminated on no notice, if I understand it correctly, by the Governor.

Mr. WINTER. That is my understanding also.

Mr. OSE. OK. I'm trying to figure out what happens if we cannot satisfy FERC as to the independence of the ISO board. What transpires? Mr. Madden, maybe I should ask you that.

Mr. WINTER. Yeah. Please ask FERC, because I don't know.

Mr. MADDEN. Mr. Chairman, the matter is pending before the Commission, but let me give you a scenario. Should the Commission find that the board is not independent, does not meet our independence as defined in Order 2000, the Commission could require—it does have the authority of pre-emption. The whole Cal ISO is wholesale, is subject to the Federal Power Act, subject to rates, terms and conditions. The authority under that and the conditions established there are therefore under the Federal Power Act.

So what it could do is clearly enforce our rules and require what we did in December 15th if we wanted to do that, and that is to establish an advisory board, pending an independent consultant being given a slate of candidates, etc.

Mr. OSE. Did FERC sign off on having the DWR employee or the DWR buyers on the floor of the ISO?

Mr. MADDEN. There has, to my knowledge, never been Commission action on that matter.

Mr. OSE. Mr. Winter, did somebody request—I'm seriously concerned about this independence issue, because if we can't solve it, I mean, it almost seems like everything just gets gridlocked, and then we're potentially back at square one. Somebody must have asked whether or not the DWR employees could come on the floor, or there's got to be some understanding. Is that accurate?

Mr. WINTER. Yeah. Let me give you the scenario of what transpired. Clearly, the generators were refusing to supply power based on the fact that, "the backers of our market were uncreditworthy."

Mr. OSE. So they were concerned about getting paid?

Mr. WINTER. Correct. DWR, on the other hand, felt that it had a very strong fiduciary responsibility to be current on what the prices were for their purchases and also have—give us immediate response, because I'm buying in 10-minute intervals here, so it was not a case where we could, in fact, wait around till people approved a purchase. So DWR said that well, to meet their requirements, they wished to be on the floor. To meet my requirements, I had to have a creditworthy entity approving the contract.

So I made the decision that we would allow them on the floor during the emergency crisis here and notified FERC with a letter that they were on the floor and that we were doing this under the emergency situation that we found ourself.

Mr. OSE. And the concern had to do with the ability of the alternative buyer, if you will, or the first line of buyers to be able to pay for the power that they purchased from the generators?

Mr. WINTER. That's correct. DWR was backing all the purchases that we were making in real-time.

Mr. OSE. Why not extend the same offer to someone other than DWR, who had the significant liquidity, to stand behind their purchases?

Mr. WINTER. If someone would have stepped up and said they were willing to back the purchases, I'm sure we would have.

Mr. OSE. Mr. Madden, I don't know how to evaluate this issue of independence of the board as it relates to the apparent conflict between DWR's purchasers having access to the floor and the interests of the consumer in getting the best price at the end of the day. Is this one of the criteria that FERC is going to use, or is this one of the things that we need to fix in California to satisfy FERC about the independence issue?

Mr. MADDEN. Mr. Chairman, I think the issue of whether or not DWR has been the ISO can be easily remedied by Commission action. So I don't think you need any type of congressional action on to that particular matter. And as I mentioned to Congressman Otter, the question of the independence in general of the board will be before the Commission soon. In Order 888 and Order 2000, independence is the linchpin. You've got to have independence in order for the market to work. People have to trust the market. You can't have—you know, we try to separate out the generators from the transmission. You can't have them working together. You have to have the confidence, I believe.

I think the Commission will answer that question very, very soon.

Mr. OSE. Mr. Otter for 5 minutes.

Mr. OTTER. Mr. Winter, how many—how many employees, if any number, work or consult with both CAISO and the State of California?

Mr. WINTER. I'm sorry. How many employees do what?

Mr. OTTER. How many State employees wear two hats, so to speak? In other words, how many or do you know if there are employees of the State of California that also consult or work with CAISO?

Mr. WINTER. I'm sorry. People in the—an employee of the State of California?

Mr. OTTER. Yes.

Mr. WINTER [continuing]. That works——

Mr. OTTER. That also consult with California ISO.

Mr. WINTER. Well, when you say "consult," I mean, if a person from the Electric Oversight Board or the Energy Commission calls us and asks us about how we came up with our projection for outages or how we came up with our projection of loads this summer, is that—I mean, there's many, many of them, because we're constantly sharing information with all kinds of people.

So if that's the tenor, then, you know, high numbers within the company are actually sharing those kind of information with State employees, as we do with FERC and we do with every other group that asks us questions.

Mr. OTTER. And also with the CW—or CDWR?

Mr. WINTER. Correct.

Mr. OTTER. Do you have a—when you say high numbers, it sounds like—could that be——

Mr. WINTER. Yeah. That could be 40, 50 people. I mean, we have Enron call us. We have Reliant call us and ask us questions. We talk to those folks all the time.

Mr. OTTER. Would you have a list of those? Could you make a list available of those folks?

Mr. WINTER. I would have to qualify it by saying, until I go back and ask if they ever had a phone call from a generator, I'm not sure how productive that would be, because I'm not understanding what it is you're really after.

Mr. OSE. If I might interject here.

Mr. OTTER. I yield.

Mr. OSE. Is it the gentleman's objective to find out who has had access to the ISO floor while they are employees of DWR charged with providing the power to the State? Is that what you're trying to get at? The name of the people who have been on the floor?

Mr. OTTER. As usual, the chairman has asked the question much better than I could.

Mr. OSE. OK. Could we get that?

Mr. WINTER. Yes. We can give you the names of the DWR employees who have been on the floor. That is no problem.

Mr. OSE. He's—OK. And you'll be able to tell which of those have been trading and which of them have not?

Mr. WINTER. Yes.

Mr. OSE. I think that's what Congressman Otter's interest is in.

Mr. WINTER. Yes. All right.

Mr. OTTER. All right.

Mr. OSE. Mr. Winter, you mentioned that DWR first came on the floor under an emergency provision. I mean, obviously we did have a problem.

Mr. WINTER. Yes, we did.

Mr. OSE. I live in the State, so I'm familiar with it. They came on the floor under an emergency provision. Circumstances at least from a supply or pricing standpoint have changed significantly from, say, January or February. Does that emergency order still stand?

Mr. WINTER. Yes.

Mr. OSE. DWR employees are still coming on the floor.

Mr. WINTER. That is correct under the emergency order of the Governor.

Mr. OSE. OK. At this point, can you tell me whether any of those people who—I don't remember if it's the Times or the Bee or somebody reported they'd been let go. Are any of those people part of the group of the DWR employees?

Mr. WINTER. I do not know. I have not gone back, mainly because I don't know the list of the—I assume the folks you're talking about are the ones that were doing something, and I don't have the list of those names of those people, so I don't know whether they were ones that were on the floor or not. We certainly can give you the list of the people that were on the floor and we——

Mr. OSE. OK. Mr. Harris, at PJM, how do you balance the independence of the ISO or the RTO with the need to provide power? I mean, out in California, obviously, we've got some concerns here. Any suggestions?

Mr. HARRIS. A few things, yes, sir. I think, first of all, it begins with the fiduciary duties of the board. The board's fiduciary duties were very, very important to us when we were forming our market in the 1995, 1996 timeframe. We had a lot of discussion with our States. The States did not want a self-perpetuating board. They wanted a board that was accountable to the stakeholders. So we set up a board that the articles that are filed to incorporate the board state that the board has three fiduciary duties, and upon these three fiduciary duties, they are subject to all corporate law, practices and so forth.

The first fiduciary duty of our board is to ensure we operate a safe and reliable interaction. That's very important, because we want it safe largely because of the nuclear concerns. We operate more nuclear capacity in our area than any other area. The second fiduciary duty of our board is to ensure that we create and operate robust nondiscriminatory electric power markets.

The third fiduciary duty of our board is to ensure that no member or group of members has an undue influence over the interaction.

Additionally to that, our board has adopted a very strict code of conduct, which we have filed with the Federal Energy Regulatory Commission. In that code of conduct, no employee, nor any member of the board, can have any financial interest in any market participant. That means zero. And with over 200 members in all their subsidiaries, you can imagine the list is getting quite long.

As far as daily operations, we do not allow any market participant to even enter the control room building. On certain occasions for a tour, for example, a company wants to bring some employees just for information, we will allow them under escort to the overhead viewer gallery, and then escort them off so they can at least see the floor, but that's the only time they have access. Outside of that, they're totally barred from the control room.

Mr. OSE. In terms of your daily obligations to provide power, does your operating team meet once a day to talk about what might be the unique challenges of that day?

Mr. HARRIS. Yes, sir, we do. We have a schedule of events. We also have what we call a performance group that actually oversees and monitors—we log every telephone call that comes in and out. We have videotape that we have. We have a performance function that looks at all the operations previously, and we go over that.

Mr. OSE. I didn't ask my question very well. I'm thinking more in terms of, say, a management team that meets before the market opens, so to speak, and says, all right, it's hot over here. There's low water over there. We've got a bottleneck here on transmission. Do you meet regularly in a conference setting where the different teams of the management—different members of the management team can provide input and you can work out a lot of these problems?

Mr. HARRIS. Yes, sir, in short we do. It's a continual theme, since electricity is 24 by 7, and we have a mobilization plan, depending on the severity of the events in front of us, that we mobilize different levels of management to deal with the situation that is in front of us. And we rehearse and train on that several times a year on the mobilization plan.

Mr. OSE. Members of this team are all subject to these parameters that you defined here?

Mr. HARRIS. Yes, sir, every employee is subject to that. We audit that, and they also have to fill out certificates periodically that they've met all the concerns. Every employee has.

Mr. OSE. OK. Mr. Otter for 5 minutes.

Mr. OTTER. Mr. Harris, if I might continue, I appreciate your reiteration of your three standards of conduct. I don't know how much information that you have available—I mean, you were knowledgeable of before this panel and before today, but recognizing the lack of independence or the apparent lack of independence, recognizing FERC's early on concern, clear back in December and their continuing concern for the appearance of a lack of independence, does the board meet your standard of conduct for independence?

Mr. HARRIS. Are you talking about the California board?

Mr. OTTER. Yes.

Mr. HARRIS. No, sir, it would not.

Mr. OTTER. Would—I mean, would that——

Mr. OSE. Would the gentleman yield?

Mr. OTTER. Yes.

Mr. OSE. I want to be very clear. Mr. Winter did not appoint the board. All right? I don't want to hang this around his neck.

Mr. OTTER. No.

Mr. OSE. And I yield back.

Mr. OTTER. I wasn't suggesting who did. I think I know who did appoint the board. But let me be clear on this. No. 1—your No. 1 covenant was you've got to operate a safe operation.

Mr. HARRIS. Yes, sir.

Mr. OTTER. Your operations, you're going to ensure that the operations that you operate are safe, and I'll assume that's for the employees but also for the customer base.

Mr. HARRIS. Yes, sir.

Mr. OTTER. So that there's no damage there. Do you feel that the lack of independence or the apparent lack of independence of the California board makes the potential for what they do operate unsafe?

Mr. HARRIS. I can't opine on that, because I'm just not that close to the way that California operates.

Mr. OTTER. The second principle, ensure that we create an operation with nondiscriminatory groups. Does the California board meet that test?

Mr. HARRIS. Well, from what I've heard today, there certainly are questions, you know, when you have people that are bidding and trading there, that makes it questionable. Our goal is to create and operate robust, nondiscriminatory electric power markets, and it's very clear and that's what we have to manage to do.

Mr. OTTER. And of course, the No. 3, no undue——

Mr. HARRIS. Yes, sir. Our board is accountable to the membership. We're a limited liability company, so they're elected by the members under staggered terms, and the members have insisted that they have to ensure that no group or single group has an undue influence over the operations of the PJM interconnection.

Mr. OTTER. Mr. Hogan, from your perspective, do those seem to be reasonable covenants that Mr. Harris enumerated?

Mr. HOGAN. Yes, I think they're very reasonable, and I would emphasize particularly the first one, safe and reliable, is not controversial. The controversial one is the part about operating robust nondiscriminatory markets with no undo influence by any participants. And the pressure is always on the ISO, the pressure has certainly been on the California ISO. When you get into these tight situations the pressure is to essentially take sides, to line up with the buyers against the sellers or the sellers against the buyers or something like that.

And the trick is to have a set of rules and procedures that the ISO could administer without taking sides in that matter, and to try to do so in and even-handed way. That's an extremely difficult task. It's especially difficult if you have a very badly designed market, and so I don't envy Terry Winter his job at all. He didn't design the market. He didn't create this mess, and he's had to live with it. I have thought for a long time the California design was simply unworkable, but that's the task that he has to get back to, which is to meet that second fiduciary responsibility, which circumstances have made impossible.

Mr. OTTER. Mr. Madden and Mr. Cannon, would FERC agree that those are good standards of integrity that should be adopted by most boards to operate with that level of independence that you obviously suggested in your December 15th report?

Mr. MADDEN. Congressman Otter, PJM filed those with the Commission, and the Commission approved those standards as to PJM. So the Commission has spoken on that. I cannot speak because of the pending matter on the California independence, though.

Mr. OTTER. I see. And let me not speak—let me not ask you specifically, then, as it applies to California, but for a board that needed independence, wouldn't those be three good pillars of——

Mr. MADDEN. We approved them, so I assume the Commission thought they were good.

Mr. OTTER. Do you agree with that, Mr. Cannon?

Mr. CANNON. Yes.

Mr. OTTER. Let me just ask one other question. And maybe I have to ask it across the board, and I know I'm over my time, Mr. Chairman. But when the Governor appointed the board, is this correct now that there was no requirement for Senate confirmation, Mr. Winter?

Mr. WINTER. That is correct.

Mr. OTTER. Was there an investigation of any potential conflicts of interest of the board members for the board that they were going on?

Mr. WINTER. Clearly, each of the board members had to sign a certificate saying that they did not hold market positions, etc., in other corporations.

Mr. OTTER. At that time?

Mr. WINTER. Market participants.

Mr. OTTER. At that time?

Mr. WINTER. That's correct.

Mr. OTTER. Would they be required to not acquire a stock which could be considered a conflict of interest during their time that they were served on the board?

Mr. WINTER. Yes. I'm almost positive—I haven't read it in the last day or two, but that does prohibit them from investing in stocks that are in the market.

Mr. OTTER. Do you know if anybody on the board has invested in any stock?

Mr. WINTER. No, I do not know.

Mr. OTTER. Thank you, Mr. Chairman.

Mr. OSE. I might followup. It's my understanding that the members of the ISO board have to file financial disclosure statements with FERC. Am I correct?

Mr. MADDEN. I don't know. I'd have to get back to the committee on that. They currently have filed their bylaws to implement—I think it's AX 1, and the Governor's selection of the boards, and that's pending—as part of an independence filing. But I don't think they have to file the financial, per se. I have to get back with you, sir.

Mr. OSE. How about senior staff members such as might exist at Cal ISO, such as Mr. Winter, or over at PJM, Mr. Harris. Do they file such statements with FERC?

Mr. MADDEN. We have general standards of conduct that the employees of the ISOs are to abide by. I do not think—and, again, I have to get back to the committee on whether we also review their financial records.

Mr. OSE. OK. I've always found it helpful, as Mr. Harris and I discussed, to talk about a challenge amongst the people that work with me.

Mr. Winter, does that same kind of activity take place at Cal ISO on any given day? I mean, do you have a regular gathering or a conference call? And I'll tell you why I asked that question. We've had some interviews, and it has been suggested to us that there are daily meetings where spot market prices and conditions are talked about in advance, potential this, potential that. I'm just trying to clarify.

Mr. WINTER. I don't know specifically that prices are discussed in those meetings. We have an operational meeting and during the crises times, those would last 24 hours a day. We have always been open line with the operators talking. We have a 9 a.m. meeting that we talk to all the operators. We tell them what we see as the load. If it looks like we're going to have a bad day the next day, there's a 7:30 a.m. meeting, as well as a 2:30 p.m. meeting where they talk about where the load is going and what kind of demand responsiveness we've got and whether a rain cloud is coming in, all those kind of things are discussed.

The actual discussion of prices, I do not believe take part in those meetings, but I've not sat in all of them, so I can't tell you that a price wasn't mentioned in some meeting.

Mr. OSE. But you are in those meetings, or some of them at least?

Mr. WINTER. No. My vice president of operations and the director of operations sit in on those meetings.

Mr. OSE. Help me out here in terms of who might sit in on those meetings. You have the vice president of operations.

Mr. WINTER. The director, the person who is over all the dispatchers on the floor, the emergency notification people, because they're impacted if we have to declare an emergency. We have the investor-owned utilities calling in, who are the operators who have to implement any load shedding.

Mr. OSE. Of the native generation, such as it still exists?

Mr. WINTER. Correct.

Mr. OSE. OK.

Mr. WINTER. We have members of the Electric Oversight Board, the Energy Commission. Matter of fact, just about everybody sits in on those to hear what the status is during the day. Then we also—we've recently started publishing our load information, etc.

Mr. OSE. I have a couple questions. I just need to understand whether or not the following people are participating in this. Is Vikram Budhraha?

Mr. WINTER. Vikram Budhraha, no, he is not.

Mr. OSE. How about Mark Skowronski?

Mr. WINTER. I am not aware that he is.

Mr. OSE. Bruce Willison?

Mr. WINTER. No. He's on the EOB board, but he is not in those calls.

Mr. OSE. How about Richard Ferreiro?

Mr. WINTER. No, I do not believe he is. He is a DWR employee. He may have, but I do not know for a fact that he did.

Mr. OSE. Is David Freeman in on those meetings?

Mr. WINTER. No, he is not.
Mr. OSE. Or Scott Maviglio?
Mr. WINTER. No. On Scott or—is it Scott or Steve?
Mr. OSE. Steve Maviglio. You're right.
Mr. WINTER. I don't know whether he's ever listened in on those or not.
Mr. OSE. Are any of the people who are actually making the decisions as to which power to take or not take involved in those meetings?
Mr. WINTER. There could be, because the people from DWR who also are the operating people who approve the transactions occasionally have sat in those, but, again, remember we're talking about supply and demand, not the prices in those meetings.
Mr. OSE. Has William Mead ever sat in those meetings?
Mr. WINTER. I'm not aware—I'm not even sure I know who he is.
Mr. OSE. How about Herman Leung?
Mr. WINTER. I don't know who he is.
Mr. OSE. Constantine Louie?
Mr. WINTER. No. I'm not saying no he didn't sit in. I'm saying I don't know him.
Mr. OSE. Peggy Cheng.
Mr. WINTER. I don't know.
Mr. OSE. Elaine Griffin.
Mr. WINTER. I don't know.
Mr. OSE. Bernard Barretto.
Mr. WINTER. Again, I do not know.
Mr. OSE. OK. All right. I want to shift back to something, if Mr. Otter will allow me to, that Mr. Madden brought up some minutes ago. You had said that FERC and everybody in the room knows it, FERC's working through a process by which it can determine what, if any, refunds may or may not be due as a result of alleged overcharges, they are by the jurisdictional or nonjurisdictional entities in California, and that's something that is in process right now.
Mr. MADDEN. That is in hearing right now.
Mr. OSE. OK. Do you have a list of the—I think the number that comes to my mind that I'm familiar with is $8.9 billion. Do you have a breakdown of the $8.9 billion number by—item by item by company or by entity, the amount of the alleged overcharge?
Mr. MADDEN. I do not have that. If the Commission would have it, it would come at the hearing, because the judge would require the Cal ISO to specify under its methodology that the Commission—who owes what.
Terry may be in a better position to——
Mr. OSE. Yeah, but I'm asking the questions here. So——
Mr. MADDEN. Well, I don't have—I don't have——
Mr. OSE. You don't have it?
Mr. MADDEN. I don't have it.
Mr. OSE. Terry—or Mr. Winter, do you have it?
Mr. WINTER. We clearly have an indication of how we arrived at those dollars, and I would have to check to be sure, but I'm quite certain we gave those to the settlement folks.
Mr. OSE. Can we get a copy of it? It's going to be a public record here soon anyway.

Mr. WINTER. Again, I can't answer, because of the FERC tariffs and the settlement kind of restricted what I could give out. But clearly I'll check on it and give you an answer based on what information is available and who it was given to.

Mr. MADDEN. Mr. Chairman, if it's filed with the judge, I think there's an August 9th or 10th date for the filing of information. That is a public hearing, and I will see that if it's filed, I will provide the committee with a copy of it.

Mr. OSE. The gentleman from Idaho.

Mr. OTTER. I have nothing more, Mr. Chairman.

Mr. OSE. All right. Let me work through the rest of my questions, then. Mr. Winter, do Cal ISO employees have to submit financial disclosure forms?

Mr. WINTER. Yes. I wouldn't characterize it as a disclosure form. In other words, they don't have to tell us all their investments and give us criteria. What they have to sign is a disclosure that they have not traded any stocks that are controlled by the people whom they are doing the business with, that they don't have employment with folks and so——

Mr. OSE. It's a code of conduct.

Mr. WINTER. Yes, it is.

Mr. OSE. Much like what Mr. Harris has.

Mr. WINTER. Yes, it is.

Mr. OSE. Now, are these statements of economic interest or affidavits saying they will not and they have not?

Mr. WINTER. I think they are statements saying they will not and they have not. I'm familiar with the ones as officers we sign, which is we divest ourselves of all stocks that are in the market and don't deal with those. I haven't looked at the employees signs.

Mr. OSE. Now, those are the Cal ISO employees?

Mr. WINTER. Correct.

Mr. OSE. Do you know what conditions apply to the DWR employees who might be on the floor?

Mr. WINTER. No, not at all.

Mr. OSE. OK. I need a moment here.

Mr. Madden, or the balance of the witnesses, I don't have any more questions, but you can tell from my questions and my curiosity the degree to which I'm concerned about this issue of independence of the Cal ISO board. I don't have a solution for you. I worked a month to make some suggestions to Mr. Madden and his colleagues over at FERC, and they were kind enough to take them under advisement, but at some point or another, this issue of independence has to be resolved, and it has to be resolved positively so that FERC, No. 1, can be satisfied. And as important, it has to be resolved positively because of the difficulty California Members are having here in Congress in working in the best interests of California.

We get, if you will, blindsided regularly, and it undermines our credibility here, and it compounds the difficulty that we have in being representatives for the State of California. I don't know about this stuff that I've read in the paper lately, I don't know who's right or who's wrong, but it's a serious issue for us here to try and resolve this positively. Think on that.

If any of you have any comments about or suggestions as to how we could expedite that, I'd certainly appreciate them.

Mr. Harris.

Mr. HARRIS. Mr. Chairman, I just want to echo the fact of how extremely important independence is. What we have found is that because we have the central planning function, we do all the planning. We operate the market. We have all the functions. It's the largest wholesale competitive marketplace in the world. There were only about 300 employees. Without the bedrock of independence, we wouldn't have the trust of the public or the customers. It is absolutely crucial for the functioning of our marketplace.

The other thing that applies to market monitoring, when we talked earlier about the meetings that we have as we plan the days and the weeks, our market monitoring function that reports to our board is integral to that. They have to be coupled with what is going on. We have some sophisticated tools that can provide check points and highlight things, and the market monitoring then can talk freely and understand what is going on in the system with many different players. And you wouldn't have that freedom if you didn't have the independence.

So independence is the bedrock upon which the other layers are built to enable you to have a competitive effective marketplace.

Mr. MADDEN. Mr. Chairman, let me just add a couple things. As I mentioned to you earlier, it is squarely before the Commission and I will let the Commission know the urgency of acting quickly, at least based on what I'm hearing today. Terry Winter is not part of the building. Terry Winter is the CEO, CEO of the ISO. In my personal opinion, he has done a great job under very difficult situations. I trust him. He's honest. And I value his advice.

Mr. OSE. I share your analysis and evaluation.

Anybody else? Dr. Hogan.

Mr. HOGAN. I certainly agree with everything about independence, and I think it's independence on both sides. You don't want the ISO owning shares and the generators, and you don't want the ISO representing the State at refund hearings. The ISO should be providing information for all of those purposes, but you don't want to get into this taking sides.

Furthermore, you could have the most independent board in the world, and if you don't have a well designed market, it isn't going to help. So I think that independence is just the tip of the iceberg, and it's to easy to think that if I could just appoint an independent board, that FERC could go home early and this committee wouldn't have any more work to do. I just don't think that's right. Independence is just the beginning, not the end, and you've got to get into these details, as much as people hate to do it. But we have the benefit of things that work, and we know that they work, and we should be using them. If people could innovate and provide something that is better, I'm all in favor of it. But when they come forward and they give you something that doesn't work in theory, that's never been tried any place else, and the only reason they do it is they say markets are so powerful, markets can overcome anything—the evidence is, you shouldn't give that credence. It just isn't that way. This market is too complicated. We should do what we have experienced actually works.

Mr. OSE. Mr. Otter.

Mr. OTTER. I have nothing.

I want to thank the panel. Thank you very much for being here.

Mr. OSE. I do want to close. I had the opportunity to go over to FERC's new market monitoring room the other day, and it was very interesting. It's probably very much like Mr. Winter's office, where it's got all the different markets and the transmission lines and the generation facilities and what have you. I think that's a great step in the right direction, to bring the tools that are available to FERC staff into the 21st century. I know that they exist or similar equipment, similar technology exists at the Commodity Futures Trading Corp., and the SEC and similar regulatory bodies, in terms of monitoring markets, and I know that Enron online has it. I haven't been to see it, but I know they have it.

What you do in Pennsylvania or PJM in putting your 5-minute prices on your Web site, it's a great idea. Transparency galore. Here it is. Love it or leave it kind of thing. I'm hopeful that we can refine what FERC has from a transparency standpoint. I haven't figured out the licensing thing with the provider of the service in terms of aggregating and dissemination, but I hope we can provide through FERC some similar vehicle for the RTOs to use to monitor their respective or regional markets. I think that would be a great step forward.

I want to thank the witnesses today. This has been very educational for me, very informative. I know some of you have travelled a long way to come today. We appreciate that. Thank you again. This hearing is adjourned.

[Whereupon, at 5:20 p.m., the subcommittee was adjourned.]

[Additional information submitted for the hearing record follows:]

13 April 2001 CONFIDENTIAL

To: Mike Florio, ISO Board Governor

From: Eric Woychik

Re: Impacts on Costs and Reliability of DWR/SERS Scheduling Practices

Current DWR/SERS practices cause very large additional costs for purchases on behalf of UDC customers and this also compromises reliability. The situation is worse than alarming, it's a potential bombshell of negative publicity waiting to go off. Further, what does this suggest for the Governor's plan to have the State take a larger role -- "don't go there." If the press, Legislature, or FERC get wind of this, I think we are toast!!!

The situation, as you may know, is exemplified by scenarios such as these three:

- SCENARIO 1: DWR/SERS has required ISO to schedule short-term bilateral contracts which caused ISO to back-down (dec) much less expensive available generation, including Mojave's cheap coal units. A specific example is where DWR/SERS required that ISO take a bilateral contract at $400/Mwh and ISO was forced to turn down Mojave at $60/Mwh, for a $360 INCREASE IN CONSUMER COSTS for that period.
- SCENARIO 2: DWR/SERS over-scheduled cheap power available from the south and under-scheduled necessary power in the north, which CAUSED ISO TO VIOLATE PATH-15 TRANSMISSION CONSTRAINTS FOR AN EXTENDED PERIOD (in grid operation terms). This results in fines for WSCC violations but, more importantly, required ISO to scramble to back-down (dec) everything it could control at the time (hydro, thermal, geothermal) in order to avoid burning-down high-voltage transmission lines in the middle of the State. Thus, you have an emergency condition of large proportions on the ISO grid operating floor, which can be resolved only be operator experience, caused by DWR/SERS.
- SCENARIO 3: DWR/SERS is repeatedly scheduling multiple blocks of bilateral contracts, without sufficient amounts of flexible plant, into ISO, which causes ISO to go into contortions to redispatch to accommodate the bilateral blocks of power AT SUBSTANTIAL COST TO RATEPAYERS. At the same time, DWR/SERS does not act responsibly for these costs.

The Board needs to obtain (1) a rough quantification of the dollar impacts of DWR/SERS scheduling practices and (2) an estimate of the occasions and the extent to which grid reliability has been compromised by DWR/SERS scheduling and operating practices. Then, procedures must be defined to control DWR/SERS scheduling practices, possibly through a memorandum of understanding (MOU) or other form of agreement. For the Board to do otherwise would be a serious abrogation of responsibility, with huge potential consequences in terms of political fall-out, costs, and power reliability.

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August 13, 2001

BY FACSIMILE
Mr. Terry Winter
President & Chief Executive Officer
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630-9014

Dear Mr. Winter:

This letter follows up on your testimony at the August 2, 2001, hearing of the House Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs, which focused on the Federal Energy Regulatory Commission (FERC). Thank you for your participation in this hearing. As was evident in the hearing, I am very concerned with the relationship between the California Department of Water Resources (DWR) and the California Independent System Operator (CAISO). To help the Subcommittee better understand this relationship, I would appreciate your responding to the following questions and requests for information.

During the hearing, you promised to provide the Subcommittee with a list of all California DWR employees who had access to the CAISO control room or privileged information (i.e., information not given to other market participants). You also agreed to designate which of these employees were traders and which were not. Please also include in this list any other State employees or consultants who had access to the CAISO control room, had access to privileged information, or participated in meetings in which market activities or prices were discussed.

During the hearing, I asked you about the possibility of CAISO employees working or consulting for the State. Please provide the Subcommittee with a list of all current or former CAISO employees who now work or consult for the State on energy-related matters.

During the hearing, you explained the basic tenets of a code-of-conduct for CAISO employees as it relates to their personal financial portfolios. Please provide the Subcommittee with a copy of the conflict-of-interest rules that govern CAISO employees. In the wake of the recent scandal involving the stock holdings of influential State energy advisors, do you have any plans to require CAISO employees to file more detailed financial disclosure forms, such as requiring a list of individual stocks owned? Have any CAISO employees violated the code-of-conduct? If so, what were the repercussions? Did any of the employees who were fired by the Governor's office or resigned for violating conflict-of-interest clauses have access to CAISO's control room or other privileged information? These employees include: Richard Ferreiro, William Mead, Herman Leung, Constantine Louie, Peggy Cheng, and Elaine Griffin. What about current State employee Bernard Barretto?

The hearing also examined FERC's Order 2000, especially as it relates to market monitoring. Professor William Hogan testified that the best way to monitor markets is to create market structures that prevent adverse outcomes. I am concerned that DWR's close involvement in CAISO operations undermines the independence of the California market and threatens reliability and efficiency of the system. FERC testified that independence is the lynchpin of a properly functioning market. During questioning, you acknowledged that DWR's presence in the CAISO control room was problematic and you were "working very hard to get them out." Does CAISO have a plan to halt the preferential treatment given to DWR? Could you provide the Subcommittee with details of that plan, including specific milestones and deadlines?

If you have any questions about this request, please contact Staff Director Dan Skopec at 225-4407. Please provide the requested information by September 4, 2001, to the Subcommittee majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building.

Thank you in advance for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable John Tierney

CALIFORNIA ISO

California Independent
System Operator

Charles F. Robinson
Vice President and General Counsel

September 4, 2001

Subcommittee on Energy Policy
Natural Resources and Regulatory Affairs
Subcommittee Majority Staff
B-377 Rayburn House Office Building
Washington, DC 20515

Subcommittee on Energy Policy
Natural Resources and Regulatory Affairs
Subcommittee Minority Staff
B-350A Rayburn House Office Building
Washington, DC 20515

Ladies and Gentlemen,

Terry Winter forwarded to me for response the letter by Congressman Doug Ose dated August 13, 2001, requesting further information regarding Mr. Winter's testimony before the Subcommittee on August 2, 2001.

Your first, second and third requests each seek information regarding the identity and role of employees or consultants of the State of California or the California Department of Water Resources (CDWR) who may have had access to information related to the California ISO markets not generally available to all participants in those markets. Please find attached as Exhibit A a list that, to the best of our knowledge, identifies all CDWR employees or consultants who had access to our facilities at some point during the past year and, therefore, may have had access to nonpublic information. In addition, Exhibit A sets forth an additional list of employees or consultants of the State or CDWR who identified themselves as participants during conference calls regarding real time operation issues and, therefore, may have had access to nonpublic information.

The fourth request concerns current or former California ISO employees who now work or consult for the State on energy-related matters. Only one employee, whose employment with the ISO is scheduled to end on September 7, currently is on loan to the State for purposes of providing advice on energy-related matters. One additional employee previously was on loan to the State to assist with energy-related matters for approximately two months. These individuals are identified in Exhibit B. With regard to former employees, although it is generally not our policy to track where individuals go after leaving our employ, we have tried in Exhibit B to identify as many individuals as we can who meet the criteria set out in the Congressman's letter.

The fifth item requests information regarding the California ISO's Code of Conduct for employees and asks a series of related questions. Please see the following attachments in response: (a) Exhibit C, Employees Code of Conduct; (b) Exhibit D, Governors Code of Conduct; (c) Exhibit E, an exemplar of an annual certification of compliance with Code of Conduct; (d) Exhibit F, PriceWaterhouseCoopers audit of compliance with Code of Conduct for FY2000 (the compliance process for FY2001, which routinely occurs during this time of year, currently is underway); and (e) Exhibit G, a response to those questions related to this request.

The final inquiry relates to the California ISO's action plan to resolve issues related to CDWR's presence in our control room. As of September1, no CDWR personnel remain present in the ISO control room, and it is the parties' intent that no further (nonpublic) access will be given to such personnel in the future.

Please feel free to contact me if you have any questions regarding the foregoing responses.

Very truly yours,

Charles F. Robinson

Charles F. Robinson
Vice President and General Counsel

Cc: The Honorable Doug Ose
The Honorable Dan Burton
The Honorable John Tierney

EXHIBIT A

CDWR personnel who have had access to ISO Facilities are listed below. We do not have sufficient information to respond whether the CDWR personnel listed below, if any, may have been engaged in trading related activities in addition to those required to facilitate the real time obligations of CDWR.

- Bernard Barretto
- Terry Dennis
- Douglas DuRose
- James Dyer
- Linus Galang
- Howard Mellow
- Linda Ng
- Arthur Primm
- Tom Uechi
- Pete Garris
- John Amyx
- Mike Brown
- Peggy Cheng
- Kevin Healy
- Robert Huss
- Robert Lanini
- Herman Leung
- Constantine Louie
- Bill Mead
- Henry Munoz
- An Nguyen
- Daryl Pegues
- Terry Sack
- Glenn Solberg

CDWR or other State employees that have participated in conference calls include the following individuals (in addition to individuals identified above, some of whom may also have participated in such calls):

Conference Call Participation Only

- B.B. Blevins, B.B. (CDWR)
- Dave Cleveland, Dave (CDWR)
- Bill Green (CDWR)
- Ray Hart (CDWR)
- Susan Lee (CDWR)
- Tom Flynn (Energy Oversight Board)
- Gary Heath (Energy Oversight Board)

EXHIBIT B

Employees Currently Working or Consulting for the State

- Kellan Fluckiger

Employees Previously Working or Consulting for the State

- David Hawkins

Former Employees Working or Consulting for the State

- Pete Garris
- Bill Green
- Terry Dennis
- Chris Smith
- Hamid Dayani

EXHIBIT C

EMPLOYEES CODE OF CONDUCT

The Code of Conduct for officers, employees and substantially full-time consultants and contractors of the California Independent System Operator Corporation (the "Corporation") shall be as follows:

(a) STANDARDS

Non-Participation in Energy Transactions

(1) Neither the Corporation, its officers, its employees or its substantially full-time consultants or contractors will act as a broker in connection with any power or energy sale or purchase.

(2) Neither the Corporation, its officers, its employees or its substantially full-time consultants or contractors will purchase electricity, except for ordinary personal uses, or sell electricity except to the extent necessary to carry out the Corporation's functions.

(3) Unless a request has been made in writing, supported by specific reasons, and unless prior written approval has been granted by the Governing Board, no officer or employee of the Corporation, and no substantially full-time consultant or contractor to the Corporation, may be an employee, director or attorney for, or a substantially full-time consultant or contractor to, any entity engaged in the generation, transmission, marketing or distribution of electricity (a "Market Entity"). Any such request shall be noticed on the agenda of the meeting of the Governing Board at which action on the request is scheduled to be taken and shall be deemed approved by the Governing Board if at least a majority of the Governors then in office vote in favor of granting such request.

(4) No person shall become an officer or full-time or part-time employee of the Corporation, and no person shall be hired as a substantially full-time consultant or contractor to the Corporation, unless such person has agreed in writing to dispose of securities owned by such person which were issued by a Market Entity or any affiliate thereof within six (6) months

after the time such person is to commence providing services to the Corporation (no later than April 30, 1998, for persons employed by the Corporation on October 30, 1997) in order to assure that such person will not directly or indirectly (e.g., through a family trust, self directed pension or profit sharing plan, or employee benefit plan) own securities issued by a Market Entity or any affiliate thereof. Any question regarding whether particular securities are subject to this divestiture requirement, including shares of mutual funds or other collective investment vehicles owning securities issued by a Market Entity or any affiliate thereof, should be directed to the Corporation's Legal Department.

(5) No officer or employee of the Corporation, and no substantially full-time consultant or contractor to the Corporation, shall acquire, directly or indirectly (e.g., through a family trust, self directed pension or profit sharing plan, or employee benefit plan) securities issued by a Market Entity or any affiliate thereof. Any questions regarding whether particular securities are subject to this limitation, including shares of mutual funds or other collective investment vehicles owning securities issued by Market Entity or any affiliate thereof, should be directed to the Corporation's Legal Department.

Administration of Tariffs

(6) It is the policy of the Corporation to offer open-access transmission service on a non-discriminatory basis.

(7) If there is discretion in the application of any tariff provision relating to the transmission of electricity, including, but not limited to, cost, available transmission capacity, scheduling, dispatching, ancillary services or transmission curtailment priority, the Corporation, its officers, employees and substantially full-time consultants and contractors will apply the tariff provision in substantially the same manner to the same or similarly situated persons.

(8) The Corporation, its officers, employees and substantially full-time consultants and contractors will strictly enforce any tariff provision relating to transmission service which does not, by its

terms, provide for the exercise of discretion.

(9) The Corporation, its officers, employees and substantially full-time consultants and contractors will process all similar requests for transmission in a non-discriminatory manner and without undue delay. The Corporation will maintain for public inspection records of all requests for transmission, when each request was received, and the determination of each request.

(10) To the extent that the Corporation may grant a waiver of a non-material rule which provides for discretionary waiver, the Corporation will maintain a written log of each waiver of a rule, the circumstances involved, the person authorizing such waiver and the source of authority for such waiver and provide the log for review and copying at the request of any interested person at such person's expense during regular business hours at the Corporation's offices.

Non-disclosure of Transactional Information

(11) The Corporation, its employees, and its substantially full-time consultants and contractors will abide by the Standards of Conduct for Public Utilities set forth in FERC Order 889 and 889A, as those standards are codified in 18 C.F.R. Section 37.1-37.4, as amended, or any successor law.

Use of Information

(12) No employee shall use any non-public information obtained in his or her capacity as an employee for his or her own personal gain or to the detriment of the Corporation except to the extent authorized by the Corporation's bylaws, any law or any court order.

General

(13) Corporation officers, employees and substantially full-time consultants and contractors shall comply with all laws and regulations applicable to the conduct of the business of the Corporation and this Code of Conduct. Officers, employees or substantially full-time consultants or contractors who become

aware of any illegal or improper conduct on the part of another officer, employee or substantially full-time consultant or contractor, or conduct inconsistent with this Code of Conduct, shall promptly report such conduct to their supervisor or the General Counsel of the Corporation.

(14) Corporation officers, employees and substantially full-time consultants and contractors shall not put themselves in a position in which their personal interests and those of the Corporation might be in conflict or which might interfere with the officer's, employee's, consultant's or contractor's ability to perform his or her job as well as possible.

(15) Corporation officers, employees and substantially full-time consultants and contractors shall not use any Corporation property or services for personal gain and shall not remove or dispose of the materials, supplies or equipment of the Corporation without proper authority.

(16) Corporation officers, employees and substantially full-time consultants and contractors shall not accept any form of gratuity which would tend to affect, or give the appearance of affecting, their judgment in the performance of their duties. Food, refreshments and entertainment in the course of a luncheon, dinner, other meeting or corporate event, and non-cash gifts, such as pens, pencils, note pads, calendars, clothing or gifts received as a promotional matter or for a special occasion, are examples of acceptable gratuities. Cash in any form or amount is not considered an acceptable gift and is explicitly forbidden. Such individuals shall keep a personal written record of all forms of gratuities with an individual value of $50 or more ("Recordable Gratuities") they do accept. In no event may an officer, employee or substantially full-time consultant or contractor accept Recordable Gratuities with an aggregate value in excess of $250 per source per year.

(17) Corporation officers, employees and substantially full-time consultants and contractors shall not give or offer to give gratuities in any form to anyone for the purpose of influencing their judgment in the performance of their duties.

(18) Corporation officers, employees and substantially full-time consultants and contractors shall not use funds or resources of the Corporation in support of any political party or candidate for elected office. A Corporation officer, employee or substantially full-time consultant or contractor may not use his or her position, authority, or influence with the Corporation for the purpose of affecting the result of an election or a nomination or a party or public office. An officer, employee or substantially full-time consultant or contractor shall not directly or indirectly coerce, attempt to coerce, command or advise another officer, employee or substantially full-time consultant or contractor, to pay, lend, or contribute anything of value or to contribute personal services to a party, committee, organization, agency or person for political purposes.

(19) Corporation officers, employees and substantially full-time consultants and contractors with responsibility to initiate or modify entries in the Corporation's accounting records shall perform such duties in accordance with management's directions and in conformance with the Corporation's accounting policies and procedures.

(20) Corporation officers, employees and substantially full-time consultants and contractors shall not, except as may be allowed by a recognized legal privilege or appropriate assertion of confidentiality, withhold information from or give false or misleading information to anyone conducting duly authorized investigations or audits of or relating to the Corporation or its business.

(21) Corporation officers, employees and substantially full-time consultants and contractors shall not discriminate against anyone on any unlawful basis, including sex, race, religion, color, national origin, sexual orientation, age, medical condition, physical or mental disability, HIV or AIDS condition, marital status, veteran status, or family leave status.

(22) Corporation officers, employees and substantially full-time consultants and contractors shall not be under the influence of alcohol, or possess, use or be under the influence of illegal drugs while on the job or during work hours, including meal breaks.

(b) IMPLEMENTATION

(1) The Corporation will inform and train its officers, employees and substantially full-time consultants and contractors in appropriate provisions of federal and state law. The Corporation will direct all of its officers, employees, and substantially full-time consultants and contractors to comply with appropriate provisions of federal and state law. The Corporation will monitor its officers, employees and substantially full-time consultants and contractors, and will conduct periodic reviews to ensure continued compliance. The Corporation will instruct its officers, employees and substantially full-time consultants and contractors to contact their supervisors or the General Counsel of the Corporation if they have any questions regarding applicable federal or state law or this Code of Conduct.

(2) The Corporation will distribute copies of this Code of Conduct to all of its officers, employees and substantially full-time consultants and contractors. Copies of this Code of Conduct will be provided to any new officer, employee and substantially full-time consultant and contractor as part of an orientation process. The Corporation will direct all of its officers, employees and substantially full-time consultants and contractors to comply with this Code of Conduct. All officers, employees and substantially full-time consultants and contractors shall be required to complete an annual disclosure questionnaire regarding compliance with this Code of Conduct and investments in Market Entities; provided, however, that the Governing Board may determine that certain categories of non-management employees, consultants and contractors of the Corporation shall not be required to complete such questionnaire or may complete an abbreviated questionnaire.

(3) The Governing Board of the Corporation will evaluate the Corporation's experience and refine these procedures, if necessary, to ensure continued compliance with this Code of Conduct.

(4) The Audit Committee shall monitor compliance with this Code of Conduct and shall make a compliance report to the full

Governing Board at least annually.

(5) Any officer, employee or substantially full-time contractor or consultant of the Corporation shall be subject to discipline for failure to comply with all applicable federal and state laws or for failure to comply with this Code of Conduct. Discipline may take the form of reprimand, suspension without pay, limitation in the scope of responsibilities, monetary fines, or termination, in accordance with policies approved by the Governing Board.

(6) The Governing Board shall adopt guidelines and policies for granting waivers of compliance with paragraph (a)(3) of this Code of Conduct.

EXHIBIT D

GOVERNORS CODE OF CONDUCT

The Code of Conduct for Governors of the California Independent System Operator Corporation (the "Corporation") shall be as follows:

(a) STANDARDS

Administration of Tariffs

(1) Governors shall act in accordance with the policy of the Corporation to offer open-access transmission service on a non-discriminatory basis.

(2) Governors shall act in accordance with the policy of the Corporation to apply each tariff provision in substantially the same manner to the same or similarly situated persons.

Non-disclosure of Transactional Information

(3) The Governors will abide by the Standards of Conduct for Public Utilities set forth in FERC Order 889 and 889A, as those standards are codified in 18 C.F.R. Section 37.1-37.4, as amended, or any successor law.

Use of Information

(4) No Governor shall use any non-public information obtained in his or her capacity as a Governor for his or her personal gain, for the gain or an affiliate or to the detriment of the Corporation, any competitors of any entity with which the Governor is affiliated or any suppliers to such competitors or customers of such competitors, except to the extent authorized by the Corporation's bylaws, any law or court order.

General

(5) Governors shall comply with all laws and regulations

applicable to the conduct of the business of the Corporation and this Governors Code of Conduct. Governors who become aware of any illegal or improper conduct on the part of another Governor, or conduct inconsistent with this Governors Code of Conduct, shall promptly report such conduct to the General Counsel of the Corporation.

(6) Governors shall not use any Corporation property or services for personal gain and shall not remove or dispose of the materials, supplies or equipment of the Corporation without proper authority.

(7) Governors shall not accept any form of gratuity which would tend to affect, or give the appearance of affecting, their judgment in the performance of their duties. Food, refreshments and entertainment in the course of a luncheon, dinner, other meeting or corporate event, and non-cash gifts, such as pens, pencils, note pads, calendars, clothing or gifts received as a promotional matter or for a special occasion, are examples of acceptable gratuities. Cash in any form or amount is not considered an acceptable gift and is explicitly forbidden. Governors shall keep a personal written record of all forms of gratuities with an individual value of $50 or more ("Recordable Gratuities") they do accept. In no event may a Governor accept Recordable Gratuities with an aggregate value in excess of $250 per source per year. This paragraph (7) shall not apply to compensation, benefits or bonuses paid to a Governor by his or her primary employer.

(8) Governors shall not give or offer to give gratuities in any form to anyone for the purpose of influencing their judgment in the performance of their duties.

(9) Governors shall not use funds or resources of the Corporation in support of any political party or candidate for elected office. A Governor may not use his or her position, authority, or influence with the Corporation for the purpose of affecting the

result of an election or a nomination or a party or public office. A Governor shall not directly or indirectly coerce, attempt to coerce, command or advise another Governor, officer, employee or substantially full-time consultant or contractor to pay, lend, or contribute anything of value or to contribute personal services to a party, committee, organization, agency or person for political purposes.

(10) Governors shall not give false or misleading information to, and, except as may be allowed by a recognized legal privilege or appropriate assertion of confidentiality, Governors shall not withhold information from anyone conducting duly authorized investigations or audits of or relating to the Corporation or its business.

(11) Governors shall not discriminate against anyone on any unlawful basis, including sex, race, religion, color, national origin, sexual orientation, age, medical condition, physical or mental disability, HIV or AIDS condition, marital status, veteran status, or family leave status.

(12) Governors shall advise the Corporation on an annual basis of any investment in the securities of any entity engaged in the generation, transmission, marketing or distribution of electricity (a "Market Entity"). To the extent that any such securities are issued by an entity which has registered with the Corporation to participate in the election of Governors of any class specified in the Corporation's bylaws, such class affiliation shall be noted in the Governor's report concerning the ownership of such securities. Each Governor's report regarding ownership of securities of Market Entities shall be made available to the public upon request.

(b) IMPLEMENTATION

(1) The Corporation will inform its Governors in appropriate

provisions of federal and state law. Governors shall comply with all applicable provisions of federal and state law. The Audit Committee will monitor the Governors, and will conduct periodic reviews to ensure continued compliance. Governors shall contact the President or General Counsel of the Corporation if they have any questions regarding applicable federal or state law or this Code of Conduct.

(2) The Corporation will distribute copies of this Governors Code of Conduct to its Governors and to any new Governors. All Governors shall be required to complete an annual disclosure questionnaire regarding compliance with this Governors Code of Conduct.

(3) The Governing Board of the Corporation will evaluate the Corporation's experience and refine these procedures, if necessary, to ensure continued compliance with this Governors Code of Conduct.

(4) Governors shall be subject to discipline for failure to comply with all applicable federal and state laws or for failure to comply with this Governors Code of Conduct. Discipline may take the form of reprimand, monetary fines, or termination, as the other Governors shall determine.

CALIFORNIA ISO

California Independent
System Operator

EXHIBIT E

2001 Employee Acknowledgment Form

The Employee Handbook describes important information about my employment with California ISO, and I understand that it is my responsibility to consult the Human Resources Department regarding any questions not answered in the handbook.

I have entered into my employment relationship with California ISO voluntarily and acknowledge that there is no specified length of employment. Accordingly, I understand and agree that my relationship with California ISO is "at-will," which means that either I or California ISO can terminate the relationship at will, with or without cause, at any time and without notice, so long as there is no violation of any applicable federal or state law. Nothing in this handbook shall limit the right of California ISO to terminate my employment at will.

Since the information, policies, and benefits described in the handbook are necessarily subject to change, I acknowledge that revisions to the handbook may occur. Only the Chief Executive Officer of California ISO has the ability to adopt any revisions to the policies in this handbook. Any such changes will be communicated in writing through official notices, which may be delivered by e-mail or via the California ISO's intranet site *(http://home.caiso.ecn)*. Revised information may supersede, modify or eliminate existing policies.

I have been advised that a copy of the handbook is available for review and printing on the California ISO intranet site in the Human Resources area. I understand it is my responsibility to read and comply with the policies contained in this handbook and any revisions made to it.

I understand that if my employment with California ISO is terminated or I terminate my employment with California ISO and I have used more vacation than I have accrued, the balance will be deducted from my final paycheck. _______ ***(initial)***

I hereby acknowledge that I have received copies of and have read the following materials, and agree to comply in full with all of the requirements set forth therein:

- California ISO Employees Code of Conduct;
- California ISO Information Security Policy; and
- California ISO Fitness for Duty Policy.

It is California ISO's policy to require all employees to execute and return this acknowledgement not less than once each year. Please sign and return this form to the Human Resources Department no later than August 8, 2001.

EMPLOYEE'S NAME (printed): ______________________________

EMPLOYEE'S SIGNATURE: ______________________________

DATE: ______________________________

POLICY AGREEMENT AND ACKNOWLEDGEMENT

I, ________________, hereby acknowledge that I have received copies of and have read the following materials:

- California Independent System Operator Corporation ("ISO") Employees Code of Conduct ("Code of Conduct")
- California ISO Information Security Policy ("Security Policy")
- California ISO Fitness for Duty Policy ("Fitness for Duty Policy")

I hereby agree to comply in full with all requirements of the Code of Conduct, the Security Policy, and Fitness for Duty Policy.

______________________________ ____________

Signature Date

EXHIBIT F

California Independent System Operator Corporation

Code of Conduct Certification Process

Report of Independent Accountants on Applying Agreed-Upon Procedures

November 15, 2000

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Suite 1200
555 Capital Mall
Sacramento, CA 95814
Telephone (916) 930 8100
Facsimile (916) 930 8450

Report of Independent Accountants on Applying Agreed-Upon Procedures

November 15, 2000

To the Board of Governors of the
California Independent System Operator Corporation

We have performed the procedures described in this report with respect to your process of obtaining certification by employees, contractors and your Board of Governors that they are complying with the California Independent System Operator Corporation (the "CAISO") Code of Conduct. The scope of these procedures were agreed to by you. This engagement to apply agreed-upon procedures was performed in accordance with standards established by the American Institute of Certified Public Accountants. The sufficiency of the procedures is solely the responsibility of the specified users of the report. Consequently, we make no representation regarding the sufficiency of these procedures.

The procedures we performed and our findings are described at Exhibit I. Such procedures principally consist of our comparison of signed certifications obtained by CAISO management to listings of three classes of CAISO constituents as of the following dates:

- employees as of August 31, 2000
- selected contractors (see description in Exhibit I) as of August 31, 2000
- Board of Governors as of December 31, 1999

These dates were selected, based on the timing of the CAISO's processes of obtaining such certifications.

Sample copies of the certification forms completed by these constituents are included at Exhibits II and III.

We were not engaged to, and did not, perform an audit or examination, the objective of which would be the expression of an opinion on the level of CAISO's compliance with its code of conduct. Accordingly, we do not express such an opinion. Had we performed additional procedures or if we were to perform an audit or more extensive procedures, other matters might have come to our attention that would have been reported to you. This report relates only to these specified items and does not extend to the CAISO Code of Conduct taken as a whole.

PRICEWATERHOUSECOOPERS

This report is intended solely for the use of the Board of Governors and management, and should not be used by those who have not agreed to the procedures and taken responsibility for the sufficiency of the procedures for their purposes. However, this report is a matter of public record and its distribution is not limited.

PricewaterhouseCoopers LLP

California Independent System Operator Corporation
Agreed-Upon Procedures and Findings — Exhibit I

The procedures we performed, and our findings, are described below.

1.) For employees

Procedures performed:

a.) We obtained a list of all employees of the CAISO as of August 31, 2000.

b.) We obtained the CAISO payroll register ("Employee Net to Gross Report") which covered the period including August 31, 2000.

c.) We compared the employee list and the payroll register to determine if there were any differences between the employees listed in each.

d.) For all employees included on the employee list obtained above we obtained their certifications to determine if they were signed and whether they contained any written indication of exception to CAISO requirements.

e.) For a selection of 43 randomly selected employees (approximately 10 percent of total employees), we compared the signature included on their certifications to signatures in their personnel file.

Findings – We performed the above procedures without exception.

2.) For contractors

Procedures performed:

a.) We obtained a list of all contractors that are considered by CAISO management (provided to us through the Human Resources Department) to be substantially full time contractors as of August 31, 2000.

b.) For all contractors included in this contractor list, we obtained their certifications and determined if they were signed and whether they contained any written indication of exception to CAISO requirements.

c.) For a selection of 18 randomly selected contractors (approximately 10 percent of all contractors on the list), we compared the signature included on their certifications to signatures in files maintained by Human Resource or in other CAISO files.

Findings – We performed the above procedures without exception.

3.) For Board members

Procedures performed:

a.) We obtained a list of all members of the Board of Governors of the CAISO as of December 31, 1999 – this list was taken from the Board of Governors Meeting Minutes as of December 22, 1999.

b.) We obtained certifications for all members on the list and determined if they were signed and whether they contained any written indication of exception to CAISO requirements.

c.) For a selection of 3 randomly selected board members (approximately 10 percent of Board members on the list) – we compared the signature included on their certifications to signatures on file with the CAISO.

Findings – We performed the above procedures without exception.

California Independent System Operator Corporation
Sample Form Used By Employees and Contractors **Exhibit II**

POLICY AGREEMENT AND ACKNOWLEDGEMENT FORM

I, ________________, hereby acknowledge that I have received copies of and have read the following materials:

- California Independent System Operator Corporation ("ISO") Employees Code of Conduct ("Code of Conduct")
- California ISO Information Security Policy ("Security Policy")
- California ISO Fitness for Duty Policy ("Fitness for Duty Policy")

I hereby agree to comply in full with all requirements of the Code of Conduct, the Security Policy, and Fitness for Duty Policy.

______________________________ ____________

Signature Date

California Independent System Operator Corporation
Sample Form Used By Members of the Board of Governors **Exhibit III**

Governor Acknowledgement Form

I, ________________________, a Governor of California Independent System Operator Corporation, hereby acknowledge that I have received a copy of the Governors Code of Conduct, as amended through February 25, 1999, and do hereby agree to abide by its terms.

GOVERNOR NAME: ____________________________

SIGNATURE: ____________________________

DATE: ____________________________

EXHIBIT G

- Does the California ISO have any plans to require its employees to file more detailed financial disclosure forms, such as requiring a list of individual stocks owned? No.

- Have any California ISO employees violated the code-of-conduct and, if so, what were the repercussions? See PriceWaterhouseCoopers audit attached as Exhibit F.

- Did any of the employees who were fired by the Governor's office or resigned for violating conflict-of-interest clauses have access to the California ISO's control room or other privileged information? See list of individuals set forth in Exhibit A.

EXHIBIT H

CALIFORNIA ISO

California Independent
System Operator

Charles F. Robinson
Vice President and General Counsel

Via Facsimile and U. S. Mail

August 29, 2001

Mr. Thomas M. Hannigan
Director
California Department of Water Resources
1416 9th Street
Sacramento, California 95814

Dear Mr. Hannigan:

The California Independent System Operator (ISO) hereby confirms its understanding that no California Energy Resource Scheduler (CERS) personnel will be present in the ISO Control Room as of September 1, 2001. Based on discussions with your staff, the ISO understands that only a major catastrophic system event could delay this plan. It is imperative that this transition be completed as seamlessly as possible. To that end, I understand that our staffs are working together to develop whatever procedures will be necessary and are trying to set-up additional meetings this week. Please let me know if you have any questions or concerns.

Sincerely,

Charles F. Robinson

Charles F. Robinson

Cc: Peter Garris, CERS - Acting Deputy Director
Gary Heath, EOB - Executive Director
Michael Kahn, Chairman – California ISO Board of Governors

ONE HUNDRED SEVENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON GOVERNMENT REFORM

2157 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515–6143

MAJORITY (202) 225–5074
FACSIMILE (202) 225–3974
MINORITY (202) 225–5051
TTY (202) 225–6852

www.house.gov/reform

August 13, 2001

BY FACSIMILE
The Honorable Linda Key Breathitt
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dear Commissioner Breathitt:

On Thursday August 2, 2001, the House Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs held a hearing titled, "FERC: Regulators in Deregulated Energy Markets." I want to thank you for the testimony of General Counsel Kevin Madden and Deputy Director of the Office of Markets, Tariffs, and Rates Shelton Cannon.

During the hearing, the issue of the independence of the California Independent System Operator (CAISO) Board was discussed. The Subcommittee is very concerned that the CAISO Board does not meet the standards set forth in the Federal Energy Regulatory Commission's (FERC's) December 15, 2001 Order. Members of the Subcommittee and several of the witnesses, including both FERC witnesses, expressed the need for Independent System Operators (ISOs) to be truly independent.

At the hearing we also discussed the relationship between CAISO and the California Department of Water Resources (DWR). It became apparent that CAISO affords DWR employees preferential treatment, in terms of access to the CAISO control room and critical information on power prices. I asked FERC whether the access provided to DWR by the CAISO is in accordance with FERC's regulations. Further, I asked FERC to explain the adverse consequences of providing DWR preferential access and having a non-independent CAISO Board.

Finally, in the hearing, I asked the witnesses what additional statutory authority FERC needed to improve its ability to monitor markets and ensure just and reasonable electric power prices. In that context, we discussed H.R. 1941, the "Electric Refund Fairness Act of 2001," which I introduced to provide FERC with additional powers to prevent the exercise of market power. Please provide me with your comments on H.R.

1941 and any other suggestions you have as to how Congress can improve FERC's ability to regulate energy markets under the Federal Power Act.

Once again, thank you for the testimony of your staff. I urge FERC to take immediate steps to restore independence to the CAISO Board. Please provide the requested information by September 4, 2001, to the Subcommittee majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building. If you have any questions about this request, please contact Subcommittee Staff Director Dan Skopec at 225-4407.

Thank you in advance to your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable John Tierney

ONE HUNDRED SEVENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON GOVERNMENT REFORM

2157 RAYBURN HOUSE OFFICE BUILDING

WASHINGTON, DC 20515–6143

MAJORITY (202) 225-5074
FACSIMILE (202) 225-3974
MINORITY (202) 225-5051
TTY (202) 225-6852

www.house.gov/reform

August 13, 2001

BY FACSIMILE
The Honorable Nora Mead Brownell
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dear Commissioner Brownell:

On Thursday August 2, 2001, the House Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs held a hearing titled, "FERC: Regulators in Deregulated Energy Markets." I want to thank you for the testimony of General Counsel Kevin Madden and Deputy Director of the Office of Markets, Tariffs, and Rates Shelton Cannon.

During the hearing, the issue of the independence of the California Independent System Operator (CAISO) Board was discussed. The Subcommittee is very concerned that the CAISO Board does not meet the standards set forth in the Federal Energy Regulatory Commission's (FERC's) December 15, 2001 Order. Members of the Subcommittee and several of the witnesses, including both FERC witnesses, expressed the need for Independent System Operators (ISOs) to be truly independent.

At the hearing we also discussed the relationship between CAISO and the California Department of Water Resources (DWR). It became apparent that CAISO affords DWR employees preferential treatment, in terms of access to the CAISO control room and critical information on power prices. I asked FERC whether the access provided to DWR by the CAISO is in accordance with FERC's regulations. Further, I asked FERC to explain the adverse consequences of providing DWR preferential access and having a non-independent CAISO Board.

Finally, in the hearing, I asked the witnesses what additional statutory authority FERC needed to improve its ability to monitor markets and ensure just and reasonable electric power prices. In that context, we discussed H.R. 1941, the "Electric Refund Fairness Act of 2001," which I introduced to provide FERC with additional powers to prevent the exercise of market power. Please provide me with your comments on H.R.

1941 and any other suggestions you have as to how Congress can improve FERC's ability to regulate energy markets under the Federal Power Act.

Once again, thank you for the testimony of your staff. I urge FERC to take immediate steps to restore independence to the CAISO Board. Please provide the requested information by September 4, 2001, to the Subcommittee majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building. If you have any questions about this request, please contact Subcommittee Staff Director Dan Skopec at 225-4407.

Thank you in advance to your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable John Tierney

ONE HUNDRED SEVENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON GOVERNMENT REFORM

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FACSIMILE (202) 225–3974
MINORITY (202) 225–5051
TTY (202) 225–6852

www.house.gov/reform

August 13, 2001

BY FACSIMILE
The Honorable William L. Massey
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dear Commissioner Massey:

On Thursday August 2, 2001, the House Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs held a hearing titled, "FERC: Regulators in Deregulated Energy Markets." I want to thank you for the testimony of General Counsel Kevin Madden and Deputy Director of the Office of Markets, Tariffs, and Rates Shelton Cannon.

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Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable John Tierney

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FACSIMILE (202) 225–3974
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August 13, 2001

BY FACSIMILE
The Honorable Pat Wood, III
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dear Commissioner Wood:

On Thursday August 2, 2001, the House Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs held a hearing titled, "FERC: Regulators in Deregulated Energy Markets." I want to thank you for the testimony of General Counsel Kevin Madden and Deputy Director of the Office of Markets, Tariffs, and Rates Shelton Cannon.

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Thank you in advance to your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable John Tierney

ONE HUNDRED SEVENTH CONGRESS

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MAJORITY (202) 225–5074
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August 7, 2001

BY FACSIMILE
Professor William W. Hogan
John F. Kennedy School of Government
Harvard University
79 John F. Kennedy Street
Cambridge, MA 02138

Dear Professor Hogan:

On August 2, 2001, the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs held a hearing on the Federal Energy Regulatory Commission (FERC) at which you testified. During the course of this hearing, Congressman Edolphus Towns posed a question to you for the record.

On behalf of Congressman Towns and pursuant to the Constitution and Rules X XI of the United States House of Representatives, I ask that you respond to the question in the enclosure. Please forward your responses by August 28, 2001 to the majority and minority staffs of the Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs. The offices are located in B-377 and B-350A, respectively, in the Rayburn House Office Building.

If you have any questions about this request, please contact Staff Director Dan Skopec at 225-4407. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable John Tierney
The Honorable Edolphus Towns

Question on behalf of Congressman Edolphus Towns

Q. In your testimony, you set criteria for Regional Transmission Organizations (RTOs). Which current Independent System Operator (ISO) best fulfills this criteria?

HARVARD UNIVERSITY
JOHN F. KENNEDY SCHOOL OF GOVERNMENT

WILLIAM W. HOGAN
Lucius N. Littauer Professor
of Public Policy and Administration

79 JOHN F. KENNEDY STREET
CAMBRIDGE, MASSACHUSETTS 02138
Phone: (617) 495-1317
Fax: (617) 495-1635
E-Mail: William_Hogan@harvard.edu
http://ksgwww.harvard.edu/people/whogan

August 9, 2001

The Honorable Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources, and Government Regulation
US House of Representatives
Washington, DC 20515-6143

Dear Chairman Ose:

I write in response to the question that Representative Edolphus Towns directed to me at the hearing before the Subcommittee on Energy Policy, Natural Resources, and Government Regulation on Thursday August 2. Representative Towns asked which current ISO best fulfills the criteria that I outlined in my prepared remarks.

In response, I considered the independent system operators currently operational, including those in California, Texas, New England, New York, and PJM.

- The problems of market design in the California system are well documented. I discussed those at length in the papers that supported my written remarks.

- There are similar problems in the design of the Texas market, and, therefore, the Texas system operator will face difficulties similar to those that have occurred in California. I also provided, on February 15, 2001 a presentation on this subject in Texas before the Public Utilities Commission, including the report "Coordination for Competition: Electricity Market Design Principles." This report is available on my web site *www.whogan.com*.

- The market design flaws in New England have already been recognized by the participants and the system operator, and they have gone through a lengthy process to review and revise the design. New England has now decided to adopt the essence of the standard market design that is employed in PJM and New York.

- The best market design is found in the features that exist in New York and PJM. There are differences between these two designs, but they are small compared to the differences with ISOs in other regions of the country, which have incomplete or inadequate market designs. The principal differences between New York and PJM reflect differences in the conditions of their markets, such as the responsibility of the New York ISO for the special reliability conditions in New York City.

My advice is to develop a generic market design based on best practices in New York and PJM. This could be the foundation of a template that could serve as the presumptive standard market design that would be the starting point for discussion in other parts of the country. Further innovations would be appropriate only if they could be clearly established as offering benefits or dealing with unique problems in ways that cannot be addressed with the successful market model in New York and PJM. Any proposed innovations which are shown at least in theory to be problematic would not be accepted on the simple grounds that "any innovation must be worth trying." The cost of making further mistakes is too great to reject a model that works. The burden of proof for any alternative model should rest with those who propose it.

Yours truly,

cc:

The Honorable Edolphus Towns, Subcommittee on Energy Policy, Natural Resources, and Government Regulation

Ms. Elizabeth Mundinger, Minority Counsel, Subcommittee on Energy Policy, Natural Resources, and Government Regulation

ONE HUNDRED SEVENTH CONGRESS

Congress of the United States

House of Representatives

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WASHINGTON, DC 20515–6143

MAJORITY (202) 225–5074
MINORITY (202) 225–5051
TTY (202) 225–6852

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August 7, 2001

BY FACSIMILE
Mr. Kevin Madden
General Counsel
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dear Mr. Madden:

On August 2, 2001, the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs held a hearing on the Federal Energy Regulatory Commission (FERC) at which you testified. During the course of this hearing, Congressman Edolphus Towns provided questions for the Federal Energy Regulatory Commission (FERC) for the record.

On behalf of Congressman Towns and pursuant to the Constitution and Rules X XI of the United States House of Representatives, I ask that you respond to the questions in the enclosure. Please forward your responses by August 28, 2001 to the majority and minority staffs of the Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs. The offices are located in B-377 and B-350A, respectively, in the Rayburn House Office Building.

If you have any questions about this request, please contact Staff Director Dan Skopec at 225-4407. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable John Tierney
The Honorable Edolphus Towns

Questions for FERC on behalf of Congressman Edolphus Towns

Q1. What studies, economic analyses, or cost-benefit analyses have been done to justify the Regional Transmission Organization (RTO) ordered by FERC?

Q2. What basis is there for setting up this market in such an expedited fashion?

Q3. What impact will this RTO arrangement have on a state like New York that has a more sophisticated market?

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

OFFICE OF THE GENERAL COUNSEL

August 15, 2001

The Honorable Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources
and Regulatory Affairs
Committee on Government Reform
House of Representatives
Washington, D.C. 20515

Re: Responses to questions from Rep. Edolphus Towns

Dear Mr. Chairman:

Thank you for your letter of August 7, 2001 enclosing questions from Representative Edolphus Towns for the record of your Subcommittee's August 2, 2001 hearing on "Regulators in Deregulated Electricity Markets." My responses are enclosed.

If you need additional information, please do not hesitate to let me know.

Sincerely,

Mark Frame for

Kevin P. Madden
General Counsel

Enclosure

cc: The Honorable John Tierney
The Honorable Edolphus Towns

Response to Questions from Congressman Edolphus Towns

__Question 1:__

What studies, economic analyses or cost benefit analyses have been done to justify the RTO ordered by FERC?

__Answer:__

Numerous studies have been prepared showing the benefits of having a single Northeast market operating under consistent market rules. Commission Staff prepared a report entitled, "Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States" dated November 1, 2000, that highlighted numerous differences between the three Northeastern ISOs and facts indicating that a single Northeast market exists that is served piecemeal by the existing three ISOs. The Staff report found that three different sets of rules and structures inhibit trade across the region. Enron Power Marketing, Inc.and Mirant Companies also have prepared studies showing the benefits of a single Northeast market. Additionally, the state commissions, market participants, and ISOs recognized the problems relating to transmission ties (seams issues) between the three ISOs. In August 1999, the three ISOs along with the Ontario Independent Electicity Market Operator entered into a Memorandum of Understanding (MOU) to address various issues including seams issues. The MOU process, however, has resulted in missed deadlines and few significant solutions that address the seams issues and market design differences between the ISOs.

__Question 2:__

What basis is there for setting up this market in such an expedited fashion?

__Answer:__

The Commission did not specify in its orders when the single Northeast RTO must be operational. Rather, the Commission directed the three ISOs and interested parties to participate in mediation for 45 days under the direction of an Administrative Law Judge to develop a plan and timeline for the establishment of a single Northeastern RTO. The Administrative Law Judge was instructed to file a report within 10 days after the 45-day period, which will include an outline of the proposal to create a single Northeastern RTO, milestones for completion of the intermediate steps, and a deadline for submitting a joint proposal. The Commission will review the report and may issue further orders as needed.

Question 3:

What impact will this RTO arrangement have on a state like New York that has a more sophisticated market?

Answer:

Each of the three Northeastern ISOs currently operate sophisticated energy markets, albeit with differences in market design and market rules. The Commission stated that the parties should determine the "best practices" among the three Northeastern ISOs in developing the market design and market rules for a single Northeastern RTO.

ONE HUNDRED SEVENTH CONGRESS

Congress of the United States

House of Representatives

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2157 RAYBURN HOUSE OFFICE BUILDING
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FACSIMILE (202) 225–3974
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www.house.gov/reform

August 7, 2001

Via Facsimile and First Class Mail
Kevin Madden
General Counsel
Office of General Counsel
Federal Energy Regulatory Commission
888 First Street NE
Washington, D.C. 20426
FAX: (202) 208-2115

Dear Mr. Madden:

Thank you for testifying at the August 2, 2001 hearing in front of the House Government Reform Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs. Your testimony was very informative.

Unfortunately, floor speeches and votes dominated much of my schedule that day and I was, therefore, unable to ask you some questions. As a result, I am writing to request that you answer the attached questions regarding FERC's assessment of the Northeast Pipeline proposal. I have also included the questions that Congressman Towns asked at the hearing.

As FERC and Subcommittee staff have discussed, my office will need your response to these questions by August 15, 2001, in order to include them in the hearing record. If you have any questions regarding this matter, please contact Elizabeth Mundinger at (202) 225-5051.

I appreciate your assistance in this matter.

Sincerely,

John F. Tierney
Ranking Minority Member
Subcommittee on Energy Policy, Natural Resources
and Regulatory Affairs

attachments

Congressman John F. Tierney

Proposed Questions for the FERC Hearing, Regarding the Northeast Pipeline:

As you know, in my home district a proposed North Shore gas pipeline has been under discussion for some time. The initial proposal was put forward by Maritimes and Northeast Pipleline and Algonquin Gas Transmission Company. But last month, the Tennessee Gas Pipeline Company wrote FERC and proposed a less costly system that would rely on existing pipeline facilities in the area.

I am extremely concerned that the energy needs of the Northeast be met with the least disruption and adverse environment impact possible.

1) Is Tennco's proposal independent of the Maritime's proposal currently considered for the 6th district or is it intended to join with the Maritime's proposal?

2) Does Tennco have, if it intends to loop the western part of the city from Dracut to Southern Massachusetts and Connecticut, the existing capacity in the system to accommodate those customers and the capacity from Canada? Or, will they have to file for new pipelines to be installed?

3) With Pan-Canadian's recent announcement that they intend to bring on-line additional volumes of gas from the Sable Islands gas fields, will Tennco have the capacity to accommodate additional volume?

Congressman Towns (NY-10)
Questions for FERC Commissioners:

What studies, economic analyses or cost benefit analyses have been done to justify the Regional Transmission Organization (RTO)ordered by FERC ?

What basis is there for setting up this market in such an expedited fashion ?

What impact will this RTO arrangement have on a state like New York that has a more sophisticated market ?

AUG 14 2001 15:39 FR FERC TO 92258185 P.02/04

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

OFFICE OF THE GENERAL COUNSEL

August 14, 2001

The Honorable John F. Tierney
Ranking Minority Member
Subcommittee on Energy Policy, Natural Resources
and Regulatory Affairs
Committee on Government Reform
House of Representatives
Washington, D.C. 20515

Re: Responses to questions from Representative John Tierney

Dear Congressman Tierney:

Thank you for your letter of August 7, 2001 enclosing questions pursuant to the Energy Policy, Natural Resources and Regulatory Affairs Subcommittee's August 2, 2001 hearing on "Regulators in Deregulated Electricity Markets." My responses to your questions are enclosed.

If you need additional information, please do not hesitate to let me know.

Sincerely,

Kevin P. Madden
General Counsel

Enclosure

Response to Questions from Congressman John Tierney's related to Maritimes & Northeast Phase III and HubLine:

Question 1:

Is Tennco's proposal independent of the Maritime's proposal currently considered for the 6th district or is it intended to join with the Maritime's proposal?

Answer:

Tennessee Gas Pipeline Company (Tennco) has two filings before the Commission. They are both independent of Maritimes & Northeast Pipeline's (Maritimes) proposed project.

On May 7, 2001, Tennco filed an application in Docket No. CP01-360-000 to replace 11.92 miles of 16-inch diameter pipeline with 11.50 miles of 24-inch diameter pipeline and 0.42 miles of 16-inch diameter pipeline between Dracut and Burlington, MA. As stated in Tennco's application the purpose of that project is to "provide additional firm transportation capacity and flexibility within Tennco's pipeline system in New England". The Commission is in the process of evaluating that application.

Subsequently, on July 11, 2001, Tennco identified a potential alternative that would replace the Maritimes Phase III Project, Docket No. CP01-4-000 and Algonquin Gas Transmission Company's (Algonquin) HubLine application in Docket No. CP01-5-000 (Phase III/HubLine Project). The alternative is described in answer 2. The Commission staff is in the process of evaluating Tennco's proposed alternative in the context of a environmental system alternative to the Maritimes/Algonquin proposal.

Question 2:

Does Tennco have, if it intends to loop the western part of the city from Dracut to Southern Massachusetts and Connecticut, the existing capacity in the system to accommodate those customers and the capacity from Canada? Or, will they have to file for new pipelines to be installed?

Answer:

The design of Tennco's facilities as stated in its application in Docket No. CP01-360-000 involves the replacement of pipeline facilities and does not incorporate any pipeline looping. Tennco states in its application that these proposed facility modifications are designed to increase its take-away capacity from the pipeline systems of Portland Natural Gas Transmission (Portland) and Maritimes at Dracut from 300 MMcf per day to 500 MMcf per day on a firm year round basis.

Now, for its potential alternative as stated above, Tennco indicates that it would only need compression at its existing compressor station in Mendon in addition to the facilities proposed in its application in Docket No. CP01-360-000 to accommodate the proposed Maritimes/Algonquin volumes (300.5 MMcf per day). In addition to Tennco's compression, Tennco states that Algonquin would need to install additional compression at its existing Burrillville compressor station and construct a 10-mile, 16-inch diameter lateral from Algonquin's existing system at the Fore River to the Deer Island Massachusetts Water Resources Authority (MWRA) facility. This lateral would be in place of the Deer Island Lateral and the southern end of the HubLine Project proposed by Algonquin. Tennco and Algonquin would have to file for the additional facilities. The staff is presently in the process of evaluating the engineering behind these statements and the reasonableness of this as an alternative.

Question 3:

With Pan-Canadian's recent announcement that they intend to bring on-line additional volumes of gas from the Sable Islands gas fields, will Tennco have the capacity to accommodate additional volume?

Answer:

In Tennco's July 11, 2001 filing in the Phase III/HubLine Project it says that it could provide up to 1 Bcf per day (300 MMcf per day currently subscribed on its system, 300.5 MMcf per day for the system alternative to the Phase III/HubLine Project and an additional 400 MMcf per day from Canada via Maritimes over that proposed in the Phase III/HubLine Project) with an additional 36 miles of pipeline looping along Tennco's existing right-of-way. However, Maritimes indicates that the additional volumes from the Sable Island gas fields could be accommodated on its system with "primarily" only additional compression.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

OFFICE OF THE GENERAL COUNSEL

August 15, 2001

The Honorable John F. Tierney
Ranking Minority Member
Subcommittee on Energy Policy, Natural Resources
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Committee on Government Reform
House of Representatives
Washington, D.C. 20515

Re: Responses to questions from Representative Edolphus Towns

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Kevin P. Madden
General Counsel

Enclosure

cc: The Honorable Doug Ose
The Honorable Edolphus Towns

Response to Questions from Congressman Edolphus Towns

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ELECTRICITY MARKET RESTRUCTURING: REFORMS OF REFORMS

William W. Hogan

May 25, 2001

20th Annual Conference
Center for Research in Regulated Industries
Rutgers University
May 23-25, 2001

Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138

CONTENTS

ELECTRICITY MARKET RESTRUCTURING: REFORMS OF REFORMS

William W. Hogan[1]
May 25, 2001

Electricity systems present complicated challenges for public policy. In many respects these challenges are similar to those in other network industries in providing a balance between regulation and markets, public investment and private risk taking, coordination and competition. As with other such industries, natural monopoly elements interact with potentially competitive services, but electricity has some unusual features that defy simple analogy to other network industries. Following a reversal of a long-term decline in real electricity prices, the last two decades of the twentieth century were for the United States a time of reform, reaction, and reforms of reforms in electricity systems, moving slowly towards greater reliance on competition and markets. Changing technology, new entrants in the generation market, and a legislative mandate to provide access to the essential transmission facility accelerated a process that required major innovations in institutions and operations. Complete laissez-faire competition is not possible, and the details of an efficient competitive electricity market are neither obvious nor easy to put in place. The benefits of reform may be substantial, but they require careful attention to market design. A review of the past identifies some choices on the road ahead.

INTRODUCTION

The international experience in restructuring electricity market institutions has been reflected in the many debates and experiments in the United States. The details matter, as is illustrated by examples of both success and failure. A competitive electricity market can be a vehicle for pursuing the public interest, but only if the market structure addresses the particular characteristics of the electricity system with its complex mix of essential facilities and large network externalities. Restructuring is the better term, not deregulation. Electricity is an example of the phenomenon where introducing competition leads not to less regulation, only different regulation.[2]

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[1] William W. Hogan is the Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University and a Director of the LECG, LLC. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for American National Power, Brazil Power Exchange Administrator (ASMAE), Comision Reguladora de Energia (CRE, Mexico), British National Grid Company, Calpine Corporation, Commonwealth Edison Company, Detroit Edison Company, Duquesne Light Company, Electricity Corporation of New Zealand, Enetergy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., Mirant Corp., National Independent Energy Producers, New England Independent System Operator, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, PJM Office of Interconnection, San Diego Gas & Electric Corporation, Sempra Energy, Southern Company, Southwest Power Pool (SPP), TransÉnergie, Transpower of New Zealand, Westbrook Power, Williams Energy Group, and Wisconsin Electric Power Company. Helpful comments received from Richard Green, Scott Harvey and Larry Ruff. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at http://www.ksg.harvard.edu/whogan).

[2] Steven K. Vogel, Freer Markets, More Rules: Regulatory Reform in Advanced Industrial Countries,

Hence, power markets are made, they don't just happen. Importantly, the rules for access to essential facilities and pricing, to provide consistent and efficient incentives, are not mere technical details that can be deferred or left alone to be discovered through the magic of the market.

The move to greater reliance on markets rests on a belief that the market participants will respond to incentives. Markets with poorly designed institutions have provided the wrong incentives, and market participants have responded. The mistakes, once made, have been costly and difficult to fix. However, the mistakes have revealed what doesn't work. The electricity market reform process in the United States and many other countries may have reached the end of the beginning. By the turn of the millennium, efforts were well underway to move from the initial reforms of regulated markets by introducing competition, to reforms of the reforms to improve the workings of partly competitive and partly regulated markets. In at least one prominent case, California, policy was turning away from market-oriented reforms.

The complete story of electricity restructuring is a complicated matter that covers transition costs and contracts, rent seeking behavior, jurisdictional disputes, market power, and much more.[3] To focus the present discussion, the effort is not to describe the full tapestry but rather to identify the threads that relate to the matter of competitive wholesale market design. This design question centers on the complications of transmission and the implications for efficient markets. This design question is important for at least two reasons. First, it makes a big difference:

> "The practice of ignoring the critical functions played by the transmission system in many discussions of deregulation almost certainly leads to incorrect conclusions about the optimal structure of an electric power system."[4]

Second, the design challenges that arise from the special nature of electricity transmission are surprising and somewhat counterintuitive. Other problems such as cost recovery, non-discrimination, and retail competition are important, but they lend themselves to more straightforward analysis and have familiar analogues in other industries. By contrast, the special nature of electricity systems leads to the need for a seeming contradiction in terms: coordination for competition. The roots of the electricity market reform policy grow into a discussion of the essential ingredients for competition and the implications for further reforms.

THE ROOTS OF ELECTRICITY RESTRUCTURING

The motivation for electricity restructuring has been slightly different in different countries. In the United Kingdom, for example, privatization of a state owned enterprise reinforced the ideology of the Thatcher government and its interest in reducing the costs of domestic coal subsidies.[5] Similar ideological and political explanations can be found from Norway to New

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Cornell University Press, 1996, p. 3. Willis Emmons, The Evolving Bargain: Strategic Implications of Deregulation and Privatization, Harvard Business School Press, 2000, p. 6.

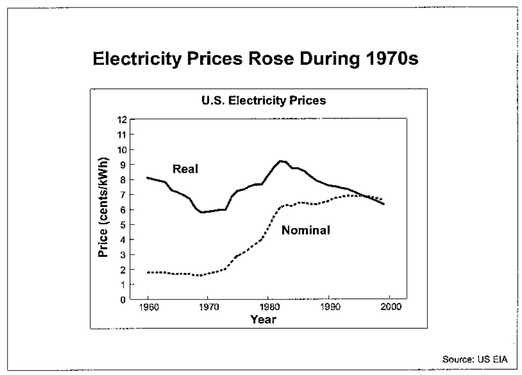
3 Paul L. Joskow, "Deregulation and Regulatory Reform in the U.S. Electric Power Sector," in Deregulation of Network Industries: The Next Steps (S. Peltzman and Clifford Winston, eds.), Brookings Press, 2000.

4 Paul L. Joskow and Richard Schmalensee, Markets for Power: An Analysis of Electric Utility Deregulation, MIT Press, 1983, p. 63.

5 Willis Emmons, The Evolving Bargain: Strategic Implications of Deregulation and Privatization, Harvard Business School Press, 2000, p. 109.

Zealand. However, there has been a common theme of growing disaffection with the electricity market model of the past and a belief or hope that the success found in "deregulation" of other industries, such as airlines or telephones, could be repeated in the case of electricity production and delivery.

In the United States, the push for restructuring electricity markets accumulated from a number of related factors. The old model, stylized as a vertically integrated monopoly with a regulated franchise, had served the country well for many years. But by the end of the 1960s, the story started to change. Until then, improved technology and further exploitation of economies of scale and scope had meant that electricity could be provided with constant or declining prices, in real and nominal terms. Meanwhile the regulated utilities enjoyed high returns and the quiet life that Hicks described as the best of all monopoly profits. All that changed in the 1970s. The oil crisis and resulting higher fuel prices, combined with higher inflation, meant that electricity prices would have to be increased to cover costs. With the apparent exhaustion of economies of scale and scope, and greater attention to environmental impacts, new investments, especially in nuclear power, were suddenly more expensive than the existing stock of generating plants. As shown in the figure, the trend in electricity prices reversed in a dramatic way, and prices were up sharply in both real and nominal terms.



The nuclear accident at Three Mile Island punctuated the transition.[6] By the beginning of the 1980s, disaffection had grown with the electric utility industry and the traditional model of the vertically integrated monopoly. The wheels were in motion for dramatic changes in the industry. The scope and surprise of the problems were captured in the massive 1983 bond default of the Washington Public Power Supply System, WPPSS, ironically know as "Whoops."[7] Previously unthinkable, these events foreshadowed other financial crises and bankruptcies in the previously stable electric utility industry.

In that same year, Joskow and Schmalensee described both the accumulating disaffection

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[6] On March 28, 1979, the Three Mile Island Unit 2 (TMI-2) nuclear power plant near Middletown, Pennsylvania suffered a partial core melt. Nuclear Regulatory Commission, Annual Report - 1979, NUREG-0690, Washington DC.

[7] In 1983 Washington Public Power Supply System defaulted on $2.25 billion of bonds due to inability to complete five nuclear reactors. "It was the largest municipal bond default in U.S. history." David Mhyra, Whoops!/WPPSS: Washington Public Power Supply System Nuclear Plants, McFarland, 1984, p. 1-2.

with the old utility industry model and the challenges then ahead for "utility deregulation."[8] Their analysis holds up well in retrospect. While recognizing the failings of traditional regulation, Joskow and Schmalensee analyzed the difficulties of using markets given the complex technology of the electricity system. "The close physical linkages of the components of a modern power system raise serious externality problems."[9] The authors laid out a series of scenarios, intended to span the range of plausible deregulation scenarios. In the event, their most radical alternative was more conservative than the patterns that emerged in the complicated policy dance as the electricity industry moved towards greater reliance on markets and competition.

A major factor that reinforced the interest in markets grew from an initially obscure element of the Public Utilities Regulatory Policies Act of 1978 (PURPA).[10] As part of a comprehensive effort to address an "energy crisis," PURPA included many elements dealing with conservation and natural gas. Little noticed was the creation of a special class of non-utility generators who could build small power plants and co-generation facilities, known as "qualifying facilities" (QF). Section 210 of PURPA required that traditional utilities purchase electricity from QF facilities at prices set at administrative estimates of the utilities' avoided costs. For many reasons, these estimates of the avoided cost, some set in legislation such as New York's infamous "six cent law," were high enough to produce a market reaction that surprised and almost overwhelmed the regulatory process.[11] The original expectation was that QF supplies would be atypical and represent a small fraction of the market. In practice, in the most aggressive states the high administrative prices coupled with the ingenuity of new entrepreneurs who stormed into the market were enough to create a massive problem of excess capacity.

The fallout from PURPA produced may things. Regulators in states as different as California and Maine scrambled to change the rules and lower estimates of avoided costs in order to avoid the new costs they were creating. However, more importantly for the larger restructuring effort in the United States and elsewhere, the unexpected success of PURPA in stimulating new supplies put a stake through the heart of the old view that independent power producers could not provide cost-effective and reliable supplies. Furthermore, the new generating companies became effective at lobbying to put pressure on the system to relax the QF rules and, eventually, to allow independent generators to build power plants without any special restrictions. A new industry emerged.

The opportunities that could be seen in the success of the QFs created a new vision for the electricity market. The idea blossomed that a fully competitive electricity generation industry could

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8 Paul L. Joskow and Richard Schmalensee, Markets for Power: An Analysis of Electric Utility Deregulation, MIT Press, 1983.

9 Paul L. Joskow and Richard Schmalensee, Markets for Power: An Analysis of Electric Utility Deregulation, MIT Press, 1983, p. 41

10 Public Utilities Regulatory Policies Act of 1978, 16 U.S.C. § 2601 et seq.

11 In 1981, New York law required payment of six cents per kilowatt-hour ($60/MWh) for QF power; N.Y. Pub. Serv. Law Section 66-c.1. In California, the QF "standard offer" solicitations at avoided costs were so oversubscribed that the California regulators sought coordinated procurement through the "Biennial Resource Plan Update" (BRPU) which required utilities to put their planned new generation out to bid. In the end, the regulators never approved new plant construction in the BRPU proceeding; Southern California Edison Company, et al., (1995) 70 FERC ¶ 61, 215, at p. 61,677. The collapse of the BRPU process played a prominent role in the move to reform regulation in California.

set the framework for the future. Given access to the transmission grid and other essential facilities, these generators could move their power to utilities that would buy in a competitive wholesale market. The term of art for such movement of wholesale power across the territories of multiple utilities was "wheeling." The spirit of the time supporting the introduction of competition was captured in the main title of an important study of the Congressional Office of Technology Assessment (OTA), "Electric Power Wheeling and Dealing."[12] Like with the earlier scenarios of Joskow and Schmalensee, the OTA anticipated competition limited to the wholesale purchases by existing utilities. However, the debate raged on with a great deal of attention as to whether the open competitive market would extend to final customers through "retail wheeling" or be limited to wholesale transactions. The proposal to include retail transactions was opposed by most electric utilities, who lobbied to "just-say-no" to retail wheeling.[13] The attendant debate diverted attention from more fundamental market design issues.

The reforms in the United States accelerated given the observation of the advance of electricity restructuring in England and Wales. In 1989, the British government launched the restructuring and privatization of the state owned Central Electricity Generating Board to include separation of the ownership and operation of generation, transmission and distribution.[14] The British policy also included eventual extension of competition and choice for retail customers. Similar innovations followed in Norway in 1991.[15] Chile had been the first to launch a major effort to reorganize electricity markets in 1982, but the Chilean model had more influence in Latin America than in England and the United States.[16] There were many sources of reform proposals, and the ideas were in the air.

At the next major transition in the United States, the "just-say-no" utilities appeared to win the battle. The breakthrough legislation in the Energy Policy Act of 1992 (EPAct) explicitly disavowed any extension of open competitive markets to retail customers.[17] However, EPAct included a number of other provisions that ultimately had profound effects. The law expanded the scope of QFs by creating a new class of exempt wholesale generators (EWG), essentially power producers that could be either independent or affiliated with traditional utilities, but would be spared the usual restrictions under the regulations for holding companies.[18] Furthermore, EPAct required utilities to give third parties access to their transmission systems in order to facilitate wholesale

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12 Office of Technology Assessment, United States Congress, Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition, Washington DC, May 1989.

13 The distinctive phrase achieved its original popularity in a campaign against the use of illegal drugs.

14 The Electricity Act of 1989 set the stage for privatization and launch of the new market and the attendant electricity "Pool" in 1990. David M. Newbery, Privatization, Restructuring, and Regulation of Network Utilities, MIT Press, 1999, p. 202.

15 David M. Newbery, Privatization, Restructuring, and Regulation of Network Utilities, MIT Press, 1999, p. 246.

16 Hugh Rudnick, Ruy Varela, and William W. Hogan, "Evaluations of Alternatives for Power System Coordination and Pooling in a Competitive Environment," IEEE Transactions on Power Systems, 1996.

17 Energy Policy Act of 1992, Public Law 102-486.

18 Public Utility Holding Company Act of 1935, Public Law 74-333 (PUHCA). The law provides for regulation under the Securities and Exchange Commission, and was an earlier reform designed to restrict the activities of utility holding companies.

trading and competition. Transmission open access, largely still undefined, had become the law of the land.

Eventually, EPAct came to be seen as "...one of the most significant pieces of legislation in the history of the industry."[19] But the initial expectations of the framers of the law were more modest. At the time, non-utilities provided less than 10% of the total production volume, with the vast bulk of electricity production occurring through integrated utilities that sold to their own customers or other utilities.[20] The assumption was that this arrangement would more or less continue, allowing for a modest amount of competition at the margin.[21] The assumption was wrong. The camel's nose was in the tent, and soon the whole camel followed. The introduction of a little competition created pressure for more, and the process moved aggressively to expand the opening that had been created by the small volumes from non-utilities and the requirements of open access to the transmission wires.

The expansion beyond marginal competition flowed from two parallel streams, one in the state efforts to open up retail competition and the other in the implementation of EPAct by the Federal Energy Regulatory Commission (FERC). At the state level, the most prominent initiative was in California, where the California Public Utility Commission (CPUC) responded to a perception of a growing crisis in traditional regulation and sought an alternative in greater reliance on the new EWGs and the forces of competition. The CPUC organized an extensive and extended effort to fashion a restructured industry. The CPUC staff report, known from its cover as the "Yellow Book," concluded that California should reform its regulatory program and offered alternative strategies.[22] After further public discussion, the CPUC issued its "Blue Book" plan to substantially reorganize the structure of the industry and its regulation.[23] The subsequent implementing order by the CPUC laid out detailed prescriptions for a new market design.[24] The new design borrowed much from the experience with the reforms in England and Wales. The effect of the decisions by the CPUC was to radically alter the nature of the market in California, soon separating generation, transmission and distribution and creating new institutions to coordinate the market. Further, going well beyond the EPAct, California set in motion a plan to open its retail

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19 Energy Information Administration, The Changing Structure of the Electric Power Industry 2000: An Update, DOE/EIA-0562(00), Washington DC, October 2000, p. 33.

20 Energy Information Administration, The Changing Structure of the Electric Power Industry 2000: An Update, DOE/EIA-0562(00), Washington DC, October 2000, p. 117.

21 An observation from Congressman Philip Sharp, Chair of the Energy and Power Subcommittee of the House Committee on Energy and Commerce from 1981-95, and a principal author of EPAct.

22 California Public Utility Commission, Decision 92-09-088, W4, 43, "Order Instituting Investigation on the Commission's Own Motion to Implement the Biennial Resource Plan Update Following the California Energy Commission's Seventh Electricity Report," September 16, 1992. California Public Utility Commission, Division of Strategic Planning (DSP), "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future," February 3, 1993

23 California Public Utility Commission, "Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation and Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring of California's Electric Services Industry and Reforming Regulation," Docket Nos. R.94-04-031 and I.94-04-032, April 20, 1994.

24 California Public Utility Commission, Decision 95-12-063 December 20, 1995, as amended y D.96-01-009, January 10, 1996.

markets to competition.

These innovations in California went beyond the scenarios of Joskow and Schmalensee, the scenarios of the OTA, or the expectations of the framers at the time of the passage of the EPAct. Although the story is more complicated than this cursory summary, and the results had different effects in different states, there is little doubt that the California example had a profound impact. It changed the national perception of electricity market reform from one of limited competition at the edges of the wholesale market to full blown separation of the functions of utilities into many independent pieces with unbundled supply and pricing.[25]

While California was pushing forward its radical proposals, the parallel activities of the FERC expanded the scope and conditions of what would prove to be a critical element of the evolving wholesale market, namely access to the transmission grid. Following an extensive series of paper filings and technical conferences, the FERC issued its transmission open access provisions in Order 888 with its companion information systems mandate.[26] The FERC advertised the importance of this landmark order by assigning the identifying number that coincided with the address of its new headquarters in Washington.[27] The intent in implementing the principle of open access was to give everyone equal rights to use the transmission grid. The regulatory device would be to require comparability of service. The basic structure of the industry would remain, with vertically integrated utilities, but each utility would be required to provide transmission service in a manner that was "comparable" to the transmission service it provided to itself. In effect, this would separate the transmission function from the rest of the utility. The hope was that non-discrimination would be the key to ensuring the necessary support for the competitive market.

The decisions under Order 888 coupled with the unfolding reforms in California and other states, reinforced by the examples in other countries, soon swept away the more limited scope for competition as anticipated by the framers of EPAct in 1992. By 1996 in the United States, it was clear that to some degree and in some regions, a restructured industry would include retail competition, unbundled services, and complete unpacking of the generation, transmission and distribution activities through either separation of the functions or separation of the companies. The generation and retail supply sectors would be treated as competitive industries. Distribution wires would continue under traditional monopoly franchise regulation. And somehow the essential facility in between – transmission – would be available on an open access basis.

Even if never fully achieved, this more radical scenario presented a problem for the development of electricity markets. The electric system is complex and there are many functions that must be performed but that are unlike the requirements of other industries. Most prominent is the necessity to maintain system balance of supply and demand, moment to moment, given the

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25 For a further elaboration of state case studies, see Energy Information Administration, The Changing Structure of the Electric Power Industry 2000: An Update, DOE/EIA-0562(00), Washington DC, October 2000, pp. 82-90.

26 Federal Energy Regulatory Commission, Order No. 888, Docket Nos. RM95-8-000 and RM94-7-001 "Promoting Wholesale competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Final Rule issued on April 24, 1996. " Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct," FERC Order 889, Final Rule, Washington, DC, April 24, 1996.

27 888 First Street N.E., Washington DC, 20426. The zip code is still available for a future reform.

inability to store electricity at a reasonable cost. Second, understood by electrical engineers but unfamiliar to most others, is the requirement to manage the complex externalities associated with the flow of power across constrained transmission systems. It has long been recognized that some "...pooling and coordination entity will have to be created to serve as an intermediary (both physical and financial) between individual producers of electric power and wholesale consumers (primarily distribution companies)."[28] "With large amounts of competitive or unbundled generation ... explicit arrangements for coordinated dispatch and scheduling will be required."[29] As unbundling proceeded and competition expanded, the need for some entity performing these functions became ever more obvious.

This necessity was not lost on the FERC. As is its custom, the FERC included in Order 888 a review of the public comments and problem diagnoses. A close reading finds an extensive discussion of the obstacles to electricity markets created by the need for instantaneous balancing and managing the externalities of transmission usage. In particular, the FERC recognized that the traditional power "wheeling" model was built on the fiction of the "contract path."[30] In other words, the trading arrangements were based on the assumption that the power could be directed to follow a particular path in the network, in contravention of the accepted physical reality that the power would flow over every parallel path. In the old world of vertically integrated utilities, with small volumes of non-utility production, the contract path was a workable fiction for commercial purposes, and the engineers could deal separately with the physical reality. But in the new unbundled world with a growing volume of third party transactions, the traditional wheeling model would break down. A simple reading of Order 888 shows plainly that the FERC knew all this, but in the end FERC embraced the wheeling model for the expedient reason that it could not reach agreement on an alternative approach for coordinating transmission service.

The evidence of the immediate seriousness of the problems thus created was readily at hand. For example, shortly after the adoption of Order 888, the North American Electric Reliability Council (NERC), the organization responsible for system reliability, recognized that contract-path scheduling created incentives to overload the electric network system. The NERC immediately adopted transmission loading relief protocols to undo the damage whenever the system became constrained.[31] In essence, NERC created an administrative un-scheduling system to counteract the effects of the FERC-mandated scheduling system.[32] The NERC system did not work well.[33] However, something was necessary in order to keep the lights on.

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28 Paul L. Joskow and Richard Schmalensee, Markets for Power: An Analysis of Electric Utility Deregulation, MIT Press, 1983, p. 114.

29 Office of Technology Assessment, United States Congress, Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition, Washington DC, May 1989, p. 133.

30 The contract paths are redefined as "posted paths" in Federal Energy Regulatory Commission, "Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct," Order No. 889, Final Rule, Washington, DC, April 24, 1996, p. 66.

31 Rajesh Rajaraman and Fernando L. Alvarado, "Inefficiencies of NERC's Transmission Loading Relief Procedures," Electricity Journal, October 1998, pp. 47-54.

32 Michael Cadwalader, Scott Harvey, William Hogan, and Susan Pope, "Market Coordination of Transmission Loading Relief Across Multiple Regions," Center for Business and Government, Harvard University, December 1, 1998.

33 Congestion Management Working Group of the NERC Market Interface Committee, "Comparison of

Perhaps the most striking evidence that the problems created by the contract-path approach were both serious and immediate appeared in the words of the FERC itself. Remarkably, on the very day the FERC issued its landmark open access tariff in Order 888, the FERC issued a companion notice of proposed rulemaking for a new transmission capacity reservation tariff (CRT). The notice included the stunning preamble:

> "The proposed capacity reservation open access transmission tariff, if adopted, would replace the open access transmission tariff required by the Commission ..."[34]

Apparently after years of deliberation and mountains of paper, the FERC knew that what it had just wrought would fail, and something else would be required. The proposed capacity reservation tariff would create completely new arrangements for coordinated dispatch and scheduling.[35] The CRT proposal received a generally negative review from the industry. It soon disappeared from the FERC agenda. However, as we shall see below, the CRT later reappeared in another guise.

The discussion of the CRT was overtaken by events. Most prominent was the parallel rise of the independent system operator (ISO). The prescient predictions of the earlier analyses of electricity market restructuring were born out by the arrival of new institutions for coordinating system dispatch and use of the transmission grid. Given current electric technology, some such entity is necessary. The question is not whether there should be a system operator, the only meaningful question is what should be rules and protocols that the system operator should follow in support of a competitive market.

The market structures of England and Wales, Norway and many other countries depend on coordination through system operators.[36] Following their lead and encouraged by the FERC, new ISOs appeared in California (CAISO), the Pennsylvania-New Jersey-Maryland Interconnection (PJM), New York (NYISO), New England (ISONE), Texas (Electric Reliability Council of Texas-ERCOT), and the Midwest (MISO). More were in the planning stages. The recognition of the limitations of the landmark Order 888, the evident necessity of such coordinating organizations, and the pressing requirements for specifying the rules, transformed slowly into another extended set of hearings and filings at the FERC under the rubric of a new name, the Regional Transmission Organization (RTO). The FERC was asking: what were these ISOs, or RTOs, or Poolcos, or similar entities under a myriad of new names, supposed to do exactly? The FERC then issued a new order with another signature numbering, Order 2000, referred to here as the Millennium Order.[37] This order was the CRT born again in greatly expanded form. To develop the implications of these reforms, it is necessary to consider further the requirements for supporting a competitive electricity

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System Redispatch Methods for Congestion Management," September 1999.

[34] Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996, p. 1.

[35] Scott M. Harvey, William W. Hogan, and Susan L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," Center for Business and Government, Harvard University, June 6, 1996, (Revised March 8, 1997).

[36] For a thorough discussion of the early designs and roles of contracting, see Sally Hunt and Graham Shuttleworth, Competition and Choice in Electricity, John Wiley and Sons, 1996.

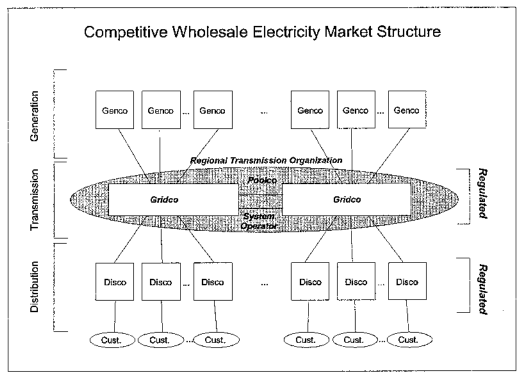
[37] Federal Energy Regulatory Commission, "Regional Transmission Organizations," Order No. 2000, Docket No. RM99-2-000, Washington DC, December 20, 1999.

market.

THE ESSENTIAL MARKET INGREDIENTS

Real markets are complicated by imperfections with information asymmetries, transaction costs and market power. The best we can hope for is workable competition. However, even if we assume that buyers and sellers in the wholesale electricity generation market act as pure price takers, the competitive case, the task of market design confronts special difficulties in the circumstances of electricity markets.

The central problem in the development of competitive electricity markets arises from the need for a system operator who can manage the complex short-term interactions in the network and maintain system reliability.[38] There must be a system operator. The only open questions are about the rules the system operator will apply and the governance of its activities. Given that the subject is internalizing externalities, there are winners and losers. Given that the subject is complex, it confronts conflicting ideologies. The topic has proven to be highly controversial. Nevertheless, the development of Independent System Operators has proceeded steadily in the worldwide restructuring of electricity markets. There are significant advantages in this approach. Control of the use of the transmission grid means control of the dispatch, at least at the margin, because adjusting the dispatch is the principal (or, in some cases, only) means of affecting the flow of power on the grid. That this system operator should also be independent of the existing electric utilities and other market participants is attractive in its simplicity in achieving equal treatment of all market participants. The ISO provides an essential service, but does not compete in the energy market.



Competitive Wholesale Electricity Market Structure

The process of restructuring wholesale electricity markets in the United States has added to the extensive worldwide debate about the range of possible and preferred alternatives for organizing regional electricity markets. Most importantly, the FERC addressed a wide range of issues in its analysis of and orders for the design of Regional Transmission Organizations. The Millennium RTO Order covers a great deal in fashioning well-designed market institutions to serve the public

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[38] For expanded version of the argument here, see William W. Hogan, "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems," Center for Business and Government, Harvard University, May 2000.

interest.

Surprisingly for an industry as capital intensive as electricity production and distribution, the essential elements are found in a consistent organization of short-run operations and the associated pricing. Difficult or otherwise intractable problems that arise in electricity markets, in both the long run and the short run, disappear or are simplified when the pieces fit together for efficient short-term operations in the context of flexible choices for market participants.

In the short run, there are critical functions that must be performed by someone. The complex network interactions in an electric grid require that there be an entity that can provide certain critical coordinating services.[39] But the implications that follow from this fact are so contentious that the discussion often becomes confused and the language strained. Here we focus on the activities of this entity as the system operator, no matter what final name we may give it.

The most obvious example of the essential services is in energy balancing. The electric system must maintain continuous aggregate balance of production and consumption. This same balance of inputs and outputs must be coordinated in a way that respects the many limits in the transmission system. Hence, not only must the aggregate inputs and outputs conform to the electrical laws that govern the interconnected grid, but the locational pattern of power production and use must honor these same laws in order to manage the flow of power within the limits of the transmission system.[40] Simultaneously, in order to maintain reliability within the security limits of the grid, various ancillary services such as spinning reserve and reactive support need close coordination and monitoring.

This coordination function is not optional. It appears in every electric system. It must be provided. And the services must be integrated with each other. The needs for reactive power and spinning reserve depend importantly on the overall pattern of power production and use. Individual market participants can produce individual elements of these services, but the fundamental coordination function requires a single entity. This is the responsibility of the system operator. And there is always a system operator.

Since the functions of the system operator are not optional, the only open question for market design is how these functions will be performed. The system operator could do a good job, meaning operating efficiently to support a competitive market. Or the system operator could do a bad job, providing the services in a way that increases costs and undermines the competitive market. The central effect of policy should be to require good design for the functions of the system operator.

A central problem appears in designing the design process. Experience indicates that reliance on voluntary agreements among market participants is not likely to be successful. Some problems, like dividing the pie, are largely political and voluntary agreement would be natural. But other problems, like designing bridges, dictate a need for careful consideration of how the pieces fit together and what is in the public interest. Electricity market design is more like the latter than the former. The Millennium Order responds to the need for coherent design that recognizes the complexity of electricity markets.

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39 RTO Order, p. 270. See also, William W. Hogan, "Independent System Operator: Pricing and Flexibility in a Competitive Electricity Market," Center for Business and Government, Harvard University, February 1998.

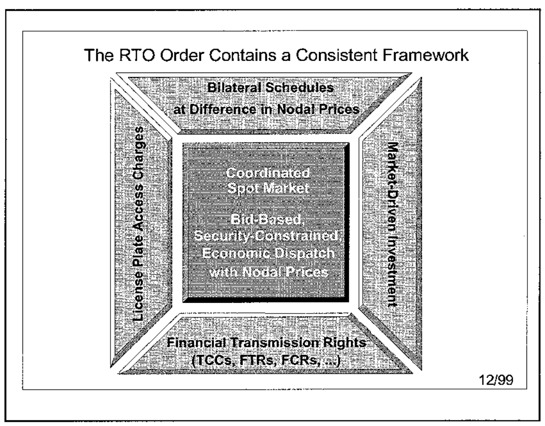
40 RTO Order, pp. 423-424.

The example of energy balancing illustrates the point. Energy balancing and congestion management are inextricably intertwined. The best approach is to run the balancing and congestion management market as a bid-based, security-constrained economic dispatch with voluntary participation by generators and loads. The corresponding prices would be consistent with the competitive outcome and would reflect the marginal cost of meeting load at each location.

To do anything else would be to decide on providing the essential coordination services in a way that would be inconsistent with the fundamental goals of electricity restructuring and inconsistent with the basic principle of designing market institutions to support the public interest. As a matter of good public policy, we should not have an interest in market designs that raise costs and decrease the real flexibility of market participants.[41]

These same essential ingredients would provide many other benefits. Bilateral transmission schedules of great flexibility and market-responsiveness could be accommodated with the transmission usage price set consistently at the difference in the locational energy prices. There would be no bias between bilateral schedules and the coordinated spot market. The market for ancillary service acquisition and pricing could be integrated simultaneously in the economic dispatch.

From the perspective of design of institutions, the most important theme running through the Millennium Order's discussion of these characteristics and functions is the prominence of markets as the means for achieving the many goals of electricity restructuring. The key element is in the recognition of the importance of a coordinated spot market. In the Millennium Order this appears principally in the discussion of the balancing market. In particular, "[r]eal-time balancing is usually achieved through the direct control of select generators (and, in some cases, loads) who increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator."[42] To be consistent with the competitive market, it is essential that this be through a bid-based, security-constrained economic dispatch: "Proposals should ... ensure that (1) the



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[41] Larry Ruff, "Competitive Electricity Markets: One Size Should Fit All," The Electricity Journal, November 1999, pp. 20-35.

[42] RTO Order, p. 635.

generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and (2) limited transmission capacity should be used by market participants that value that use most highly."[43]

Further, the FERC requires that everyone be able to participate in this coordinated spot market, at the efficient, and necessarily locational or nodal, prices: "The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions."[44] In addition, "[t]he Regional Transmission Organization must ensure that its transmission customers have access to a real-time balancing market. The Regional Transmission Organization must either develop and operate this market itself or ensure that this task is performed by another entity that is not affiliated with any market participant."[45]

Efficient Pricing

Efficient pricing is a central feature of a competitive electricity market. It is essential if the benefits of a competitive market are to flow through to customers and other market participants. Pricing that is inefficient, on the other hand, will fail to signal and encourage appropriate levels of consumption and supply or the appropriate levels and locations of new generation and transmission investment.

The standard determinant of competitive market pricing is system marginal cost. This is the simple definition of the market-clearing price where supply equals demand. This production level just balances the marginal benefit of additional consumption with the marginal cost of production. Under the usual competitive assumptions, this textbook market equilibrium condition also provides the welfare maximizing economic outcome, which is the definition of economic efficiency.

The basic textbook model extends to the definition of competitive equilibrium for products across multiple locations. The same criterion applies in finding the economic, or least-cost, dispatch of the power grid given the benefits of consumption or the costs of production at each location.[46] Using the bids as the representation of these benefits and costs, the corresponding economic dispatch produces the same outcome as a competitive equilibrium. The economic dispatch accounts for system congestion and transmission losses, and thus inherently produces prices that can vary at each location by the combined effect of generation, losses and congestion. These locational prices provide proper signals for the quantity and location of new investment.

As a matter of principle, these locational prices are simply the market-clearing prices based on all the bids and the details of the requirements of network operations. Furthermore, for any given economic dispatch, it is an easy matter to determine these prices based on the bids and

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43 RTO Order, pp. 332-333. See also p. 382.

44 RTO Order, p. 332. See also p. 743.

45 RTO Order, p. 423. See also p. 715.

46 F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R.E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988.

the system conditions. These locational prices are in use today as an integral part of the market design in many regions.

In addition to defining the market-clearing price at each location, these locational prices provide an immediate and simple answer to the otherwise intractable question as to the appropriate marginal cost or market-clearing price of transmission use. The electric network is complicated, with the power flow dictated by the laws of physics and many system constraints. Tracing the details of transmission flow has proven to be a blind alley that has frustrated attempts to define workable methods of transmission pricing.[47] But the locational pricing approach that accompanies the coordinated spot market provides an immediate simplification of this difficult problem. In particular, transmission of a megawatt between two locations is physically equivalent to sale at the source and purchase at the destination. In equilibrium, therefore, the market-clearing price determined by the marginal cost of transmission must be the same as the net price for the combined purchase and sale transaction. In other words, the price of transmission between two locations must be just the difference in the locational prices of energy.

Since these pricing conditions are derived from first principles for a competitive equilibrium, any efficient mechanism must produce the same pricing result. It follows, therefore, that the market design requirement for a system operator with a balancing and congestion management system provides an easy solution for the efficient support of a competitive market. Economic dispatch with its locational prices defines the efficient outcome.

This is not a new idea. "Spot pricing (or real-time pricing) is another approach that has been considered for coordinating the output of generators to follow loads. ... However, a lack of experience with spot pricing leaves significant uncertainties about its practical application."[48] What is new is the practical experience obtained in many countries that shows such efficient pricing to be at least practical, and perhaps essential.

When the system is constrained, the spot prices create congestion rents reflecting the opportunity cost of the constraints. Similarly, rents arise in pricing transmission losses. An issue then arises as to the best use of these transmission rentals. The basic logic is that the payment should be divorced from the marginal usage decisions, in order to preserve the incentives of efficient pricing. Further, it is intuitive that the proper recipients of the rentals should be those who are paying the transmission access charges to cover the fixed costs of the grid. This logic is consistent as far as it goes. However, as we shall see, a superior use of these rentals is in funding long-term transmission rights.

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[47] William W. Hogan, "Flowgate Rights and Wrongs," Center for Business and Government, Harvard University, August 2000. Larry E. Ruff, "Flowgates, Contingency-Constrained Dispatch, and Transmission Rights," Electricity Journal, Vol. 14, No. 1, January/February 2001, pp. 34-55.

[48] Office of Technology Assessment, United States Congress, Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition, Washington DC, May 1989, p. 133.

Long-Term Transmission Rights

With changing supply and demand conditions, generators and customers will see fluctuations in short-run prices. Changing flows will produce changes in losses. When demand is high, more expensive generation will be employed, raising the equilibrium market prices. When transmission constraints bind, congestion costs will change prices at different locations.

Even without transmission congestion constraints or significant changes in losses, the spot market price can be volatile. This volatility in prices presents its own risks for both generators and customers, and there will be a natural interest in long-term mechanisms to mitigate or share this risk. The choice in a market is for long-term contracts.

Traditionally, and as is seen in many other markets, the notion of a long-term contract carries with it the assumption that customers and generators can make an agreement to trade a certain amount of power at a certain price. The implicit assumption is that a specific generator will run to satisfy the demand of a specific customer. To the extent that the customer's needs change, the customer might sell the contract in a secondary market, and so too for the generator. Efficient trading in a secondary market would guarantee equilibrium and everyone would face the true opportunity cost at the margin.

However, this notion of specific performance stands at odds with the operation of the short-run market for electricity. To achieve an efficient economic dispatch in the short-run, the dispatcher must have freedom in responding to the bids to decide which plants run and which are idle, independent of the provisions of long-term contracts. And with the complex network interactions, it is impossible to identify which generator is serving which customer. All generation is providing power into the grid, and all customers are taking power out of the grid. It is not even in the interest of the generators or the customers to restrict their dispatch and forego the benefits of the most economic use of the available generation. The short-term dispatch decisions by the system operator are made independent of and without any recognition of any long-term contracts. In this way, where the disconnect between operations and contracts is not only feasible but necessary, electricity is not like other commodities.

This dictate of the physical laws governing power flow on the transmission grid does not preclude long-term contracts, but it does change the essential character of the contracts. Rather than controlling the dispatch and the short-run market, long-term contracts focus on the problem of price volatility and provide a price hedge not by managing the flow of power but by managing the flow of money. The short-run prices provide the right incentives for generation and consumption, but create a need to hedge the price changes. Recognizing the operation of the short-run market, there is an economic equivalent of the long-run contract for power that does not require any specific plant to run for any specific customer.

Consider the case first of no transmission congestion and no losses. In this circumstance, it is possible to treat all production and consumption as at the same location. Here the natural arrangement is to contract for differences against the equilibrium price in the market. A customer and a generator agree on an average price for a fixed quantity, say 100 MW at $50 per megawatt-hour (MWh). On the hour, if the spot price is $60, the customer buys power from the spot market at $60 and the generators sells power for $60. Under the contract, the generator owes the customer $10 for each of the 100 MW over the hour. In the reverse case, with the spot price at $30, the customer pays $30 to the system operator, which in turn pays $30 to the generator, but now the customer owes the generator $20 for each of the 100 MW over the hour.

This then is the familiar "contract for differences (CFD)."[49] It is a forward contract like those found for other traded commodities but discovered anew for electricity as an innovation in the market in England and Wales. The CFD allows for long-term contracts without direct contract administration by the system operator.

In effect, the generator and the customer have a long-term contract for 100 MW at $50. The contract requires no direct interaction with system operator other than for the continuing short-run market transactions. But through the interaction with system operator and the coordinated spot market, the situation is even better than with a long-run contract between a specific generator and a specific customer. For now if the customer demand is above or below 100 MW, there is a ready and an automatic spot market where extra power is purchased or sold at the spot price. Similarly for the generator, there is an automatic spot market for surplus power or backup supplies without the cost and problems of a large number of repeated short-run bilateral negotiations with other generators. And if the customer really consumes 100 MW, and the generator really produces the 100 MW, the economics guarantee that the average price is still $50. Furthermore, with the contract fixed at 100 MW, rather than the amount actually produced or consumed, the long-run average price can be guaranteed without disturbing any of the short-run incentives at the margin. Hence the long-run contract is compatible with the short-run market.

In the presence of transmission congestion and losses, the generation contract is necessary but not sufficient to provide the necessary long-term price hedge. A bilateral arrangement between a customer and a generator can capture the effect of aggregate movements in the market, when the single market price is up or the single market price is down. However, transmission congestion and losses can produce significant movements in price that are different depending on location. If the customer is located far from the generator, transmission congestion might confront the customer with a high locational price and leave the generator with a low locational price. Now the generator alone cannot provide the natural back-to-back hedge on fluctuations of the short-run market price. Something more is needed.

Transmission congestion and losses in the short-run market raise another related and significant matter for the system operator. For example, in the presence of congestion, revenues collected from customers will substantially exceed the payments to generators. The difference is the congestion rent that accrues because of constraints in the transmission grid. At a minimum, this congestion rent revenue itself will be a highly volatile source of payment to the system operator. At worse, if the system operator keeps the congestion revenue, incentives arise to manipulate dispatch and prevent grid expansion in order to generate even greater congestion rentals. System operation is a natural monopoly and the operator could distort both dispatch and expansion. The same would apply to rents on losses. If the system operator retains the benefits from transmission rentals, this incentive would work contrary to the goal of an efficient, competitive electricity market.

The convenient solution to both problems – providing a price hedge against locational congestion differentials and removing the adverse incentive for the system operator – is to re-distribute the congestion and net loss revenue through a system of long-run financial

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[49] Sally Hunt and Graham Shuttleworth, Competition and Choice in Electricity, John Wiley and Sons, 1996, pp. 119-132.

transmission rights (FTR) operating in parallel with the long-run generation contracts.[50] Just as with generation, it is not possible to operate an efficient short-run market that includes transmission of specific power to specific customers. However, just as with generation, it is possible to arrange an FTR that provides compensation for differences in prices, in this case for differences in the congestion and marginal loss costs between different locations across the network.

The FTR for compensation would exist for a particular quantity between two locations. The generator in the example above might obtain an FTR for 100 MW between the generator's location and the customer's location. The right provided by the contract would not be for specific movement of power but rather for payment of the price difference. Hence, if a transmission constraint caused the price to rise to $60 at the customer's location, but remain at $50 at the generator's location, the $10 difference would be the congestion rental. The customer would pay the $60 for the power. The settlement system would in turn pay the generator $50 for the power supplied in the short-run market. As the holder of the FTR, the generator would receive $10 for each of the 100 MW covered under the FTR. This revenue would allow the generator to pay the difference under the generation contract so that the net cost to the customer is $50 as agreed in the bilateral CFD power contract. Without the FTR, the generator would have no revenue to compensate the customer for the difference in the prices at their two locations. The FTR completes the package.

As with the familiar generation contract-for-differences, the FTR leaves undisturbed the marginal incentives for efficient operations. The FTR is defined for a fixed quantity. If actual usage exactly matches this quantity, the FTR provides a perfect transmission price hedge. But if usage exceeds this FTR quantity, there is no hedge for the incremental volume and the full incentive effect of efficient pricing applies. Likewise, if usage should be below the FTR volume, the payment would apply to the full FTR quantity, so the owner would see the proper marginal incentive to reduce transmission use.

These FTRs are equivalent to perfectly tradable physical transmission rights in a system that has parallel flows. Parallel connections increase system reliability, but create otherwise difficult problems in defining and using transmission rights.

If a simple feasibility test is imposed on the FTRs awarded to customers, the aggregate congestion payments received through the spot market will fund the payment obligations under the FTRs. Still, the transmission prices paid and received will be highly variable and load dependent. Only the system operator will have the necessary information to determine these changing prices, but the information will be readily available embedded in all the spot market locational prices. The FTRs define payment obligations that guarantee protection from changes in the transmission rentals.[51]

Given the availability of this coordinated spot market and these efficient locational prices,

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50 All current implementations of FTRs use congestion but not loss rentals. They are also known as Transmission Congestion Contracts (TCC), as in New York, and Financial Congestion Rights (FCR), in New England.

51 Scott M. Harvey, William W. Hogan, and Susan L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," Center for Business and Government, Harvard University, June 6, 1996, (Revised March 8, 1997).

market participants could schedule bilateral transactions or rely on trade through the spot market. The differences in locational prices would define the opportunity costs of transmission, giving rise to the creation of financial transmission rights.[52] Payment for the existing grid would appear in part as access charges, including the use of the "license plate" approach with region-specific access charges.[53]

These are the most important elements. These define the functions of the essential system operator. These are not mere technical details, and they have far-reaching implications for how, and how well, the market works. The rules for access to the limited capacity of the transmission system stand at the core of all other issues.

Market Power

The problem of market power remains as an important policy issue in electricity markets. The discussion here about the essential ingredients for market design addresses the institutions needed to support a competitive generation market. The full treatment of market power is a complex issue. Furthermore, the argument would be that market design is not the best tool for mitigating market power. An examination of the implications of market power would take us too far afield. For the present purposes, recognize that the coordinated spot market design itself will not eliminate market power. Substantial market power would call into question any proposal to rely on markets for generation.

If there is significant exercise of traditional market power through withholding of generation, this has important policy implications. The preferred response would be bid caps targeted at those exercising market power in the short-run and divestiture in the long-run, and this action alone might be sufficient to moderate the average price impacts. However, if the explanation for market problems lies elsewhere, the policy implications would be different. If scarcity and higher costs are the dominant forces, bid caps on large suppliers and divestiture would have little, maybe no, impact on the outcome of prices and production. Most importantly, price caps that appear more justifiable in the presence of traditional market power become exactly the wrong approach in dealing with scarcity.[54]

REFORMS OF REFORMS

The theory of the case for the market design with an efficient coordinated spot market run by the system operator is by now well supported by practical experience. The main ingredients of the coordinated spot market with locational pricing exist in many parts of the world as diverse as Chile and New Zealand, and the combined package with FTRs has been operating successfully in PJM since 1998. The same general design has been adopted in New York,[55] and embraced as a

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52 RTO Order, pp. 382-383.

53 RTO Order, p. 524.

54 For a further discussion of market power issues, see Scott M. Harvey and William W. Hogan, "On The Exercise Of Market Power Through Strategic Withholding In California," Center for Business and Government, Harvard University, April 24, 2001.

55 New York began operation under this market design in November 1999.

reform in New England.

Efficient pricing, in particular, is especially important in markets that allow participant choices. Almost by definition, any approach other than economic dispatch with nodal pricing will produce prices that are not consistent with market equilibrium. Inevitably, this inconsistency will drive the monopoly system operator or grid owner to intervene in the market. The problems that arise when we do anything else are apparent in various experiments where supposed simplifications produced predictable problems. The successes did not come immediately or easily, and success is not found everywhere. There have already been reforms of reforms, and more will follow. However, the outcome is uncertain. The delay in implementing good RTO designs throughout the United States leaves the restructuring process vulnerable. Other countries are still struggling with the core issues. Review of a few prominent cases that go beyond the initial reforms illustrates the general argument.

PJM Interconnection

The debate over transmission usage and transmission pricing in PJM provides a stark illustration of the difficulty and the challenge of market design.[56] In March of 1997, the FERC approved an interim transmission access and pricing system to operate in conjunction with a real-time spot market coordinated through the PJM ISO. Faced with opposition to a full locational pricing and congestion charging mechanism for actual use of the system, the FERC endorsed the locational approach in principle but adopted temporarily an alternative model based on a single market clearing price (MCP). The MCP approach minimized the importance of transmission congestion and rejected the locational pricing model as too complicated and unnecessary. Instead, the MCP model would treat the entire PJM system as a single zone.

In essence, much like the approach in England and Wales, the MCP model priced all transactions through the spot-market at the "unconstrained" price, based on a hypothetical dispatch. To the extent that the actual dispatch encountered transmission constraints, the MCP model would pay the more expensive generators to run and average these congestion costs over all users.

The model included two other notable features. First, in the face of transmission congestion, the generators that were constrained not to run would be paid nothing, even though they had bids below the "unconstrained" price. Unlike in the case of England and Wales, there was objection to adopting any system that depended on paying generators not to generate power, with the attendant discrimination and perverse incentive effects. Second, market participants had the option to schedule bilateral transactions separately from the bid-based economic dispatch of the ISO, with a separate payment for their share of the total congestion cost. This flexibility to use bilateral transactions or to participate in the coordinated spot market was a major design objective not to be abandoned.

This pricing system is representative of a zonal approach, and has much in common with zonal systems adopted elsewhere in the world.[57] However, should the system become

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[56] For details, see William W. Hogan, "FERC Policy on Independent System Operators: Supplemental Comments," Federal Energy Regulatory Commission, Docket No. PL98-5-000, Washington DC, May 1, 1998.

[57] Here the issue is pricing for transmission congestion. The recovery of embedded costs of transmission

constrained, the two exceptional features noted above would create a powerful and perverse incentive. If there were no transmission constraints, there would be no transmission congestion and everything would work as with the locational pricing system. But when congestion appeared, everything would be different. The supporters of the zonal approach argued that the total cost of congestion would be small, summed over the year, and therefore any inefficiencies could be safely ignored.

Ignoring a difference between prices and marginal costs is a safe practice in a regulated world without flexibility and choice. The incentives don't matter and the small costs get lost in the larger system. Inconsistent pricing can work inside the closed black box of the vertically integrated system. But the cost of ignoring a gap between prices and marginal costs in the world of choice can be large indeed. Witness the events when the PJM system became constrained, starting in June of 1997.

The data for a representative constrained dispatch found the marginal cost in eastern PJM at about $89 per MWh, when at the same time the marginal cost in the west was $12 per MWh and the "unconstrained" price was approximately $29 per MWh. The incentives were clear. A customer could buy from the spot-market dispatch at $29, or it could arrange a bilateral transaction with a constrained-off generator in the west at a price closer to $12.[58] The small average congestion cost would be the same either way, and would not affect the choice. The choice, therefore, presented a test for generators.

Faced with these incentives, constrained-off generators passed the test. They quickly arranged bilateral transactions and scheduled their power for delivery, thereby exceeding the transmission limits. This, in turn, required the ISO to constrain the output from some other generator, who would then follow the same direct path to a bilateral schedule rather than sit idle and collect nothing. Soon the ISO had no more controllable generating units with which to manage the transmission constraints. Unable to fix the perverse pricing incentives, the ISO resorted to administrative mechanisms to prohibit bilateral transactions or declare a "minimum" generation emergency during the peak generation period. In effect, while restructuring to facilitate a market, the unintended consequences of superficially simple pricing spawned administrative rules to prohibit the market from responding to the price incentives when they mattered most. Shackled with inconsistent pricing rules, the ISO had to resort to direct preemption of market choices.

The point was made in a dramatic way. The important issue is not the total cost of congestion, which may be small on average. The point is the incentives at the margin when the system is constrained. In designing the rules for transmission pricing and access for a competitive market, it matters little what the rules are for periods when the system is unconstrained. The important question is how the rules deal with the market when the system is constrained. Even if the total cost of congestion might be modest over the year, the gap between $29 and $12, or $89 and $12, is more than sufficient to get the attention of market participants. Given the margins in this business, they will change their behavior for $1. And the changes in behavior can substantially affect system operations; in fact, the whole point of electricity

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investment through access charges is a separate matter that is amenable to zonal approach.

[58] Power Markets Week, September 1, 1997, p. 13.

restructuring is that changes in behavior can affect system operations and lead to different patterns of electricity use and investment.

In the locational pricing system, the perverse incentives would not arise. Given the same facts as above, the locational prices would equal the marginal costs. Those customers purchasing power from the spot market in the east would have seen $89 as the price. True, they could have arranged a bilateral transaction with a generator in the west, paying $12 for the energy. But they would then face a transmission charge of $77 ($89-$12), making them indifferent at the margin, just as intended. Likewise, customers in the west would pay $12 and have no incentive to change. Every generator would be producing at its short-run profit maximizing output, given the prices. The market equilibrium would support the necessary dispatch in the presence of the transmission constraints. Spot-market transactions and bilateral schedules would be compatible. Flexibility would be allowed and reliability maintained consistent with the choices of the market participants.

The PJM ISO was fully aware of the perverse incentives of zonal congestion pricing and the problems they created, but without the authority to change the pricing rules it had no alternative but to restrict the market. Faced with this reality, the FERC acted to approve the locational pricing system that became operational in PJM at the beginning of April of 1998. The developing experience should be better understood to avoid the pitfalls of the complicated zonal "simplification." The subsequent successful experience in PJM has demonstrated the practical importance of locational pricing.[59] The PJM ISO determines locational prices for over two thousand locations every five minutes. Trading hubs are included and the western hub has become a major market center. FTR auctions occur ever month. Congestion is common. generators are building where generation is valuable. The PJM system works with both a real-time and a day-ahead market.[60]

New England

There are many ways that things can go wrong. The PJM 1997 experiment with a zonal pricing system collapsed as soon as the system became constrained. Subsequently, New England adopted a similar MCP approach but without the flexibility for participants to self-schedule to counteract dispatch instructions. However, New England found that the one-zone congestion pricing system created inefficient incentives for locating new generation.[61] Faced with uniform pricing, generators preferred to build where costs were low rather than where value was high. To counter these price incentives, New England proposed a number of limitations and conditions on new generation construction. Following the FERC's rejection of the resulting barriers to entry for new generation in New England, there developed a debate over the preferred model for managing

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[59] Two of the original sponsors of the MCP plan, Philadelphia Electric Company and Enron, subsequently became active supporters of the PJM locational pricing market model.

[60] PJM Interconnection. L.L.C. For further details on the experience in PJM, see William W. Hogan, "GETTING THE PRICES RIGHT IN PJM. Analysis and Summary: April 1998 through March 1999, The First Anniversary of Full Locational Pricing," April 2, 1999, available through the author's web page; and the earlier discussion in the Electricity Journal, September 1998, pp. 61-67.

[61] New England Power Pool, 85 FERC Para 61,141 (1998). For a critique of the previously proposed one-zone congestion pricing system, see Peter Cramton and Robert Wilson, "A Review of ISO New England's Proposed Market Rules," Market Design, Inc., September 9, 1998.

and pricing transmission congestion.[62] One zone was not enough, but perhaps a few would do?

The extended conversation amounted to a complete replay of all the market design issues, going well beyond the issue of congestion alone. In the end, New England proposed to go all the way to a locational pricing system. The revised model included a new coordinated spot market, locational pricing, and financial transmission rights.[63] Hence, the ISONE reforms of reforms would produce a market design that is similar to that operating in New York and PJM. The three ISOs then joined with the Ontario market operator in a memorandum of understanding to coordinate the operation of their markets and resolve seams issues.[64] Subsequently, ISONE and PJM announced an agreement for ISONE to adopt the PJM market design, protocols, and certain software.[65]

New Zealand

In many ways, the New Zealand market design has been at the forefront of best practice. Furthermore, the electricity reform process in New Zealand involved extensive consideration of the essential ingredients of market design and the experience in other countries. The New Zealand electricity market provides fundamental design elements needed to support competition in generation and supply. A key feature of any such market is the use of a coordinated spot market to handle balancing, transmission usage and security requirements. The New Zealand spot market includes a bid-based, security-constrained, economic dispatch with fully locational prices for real-time decisions. The bids summarize the preferences of the market participants and ensure that the final dispatch choices respect those preferences. The security constraints preserve the conditions needed to ensure reliable operations. The principles of economic dispatch define both the traditional engineering practice and the results of a competitive equilibrium. In this regard, the New Zealand model for real-time operations is aligned with the best international practice for a competitive electricity market.[66]

Nevertheless, motivated in large part with concerns over the results of retail competition, New Zealand has reconsidered its reforms and revisited the issues of electricity market design.[67] There are special issues in New Zealand, particularly its distinctive attempt to create regulation

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62 Federal Energy Regulatory Commission, New England Power Pool Ruling, Docket No. ER98-3853-000, October 29, 1998.

63 ISO New England, "Congestion Management System and a Multi-Settlement System for the New England Power Pool," FERC Docket EL00-62-000, ER00-2052-000, Washington DC, March 31, 2000. The proposal includes full nodal pricing for generation and, for a transition period, zonal aggregation for loads. Federal Energy Regulatory Commission, "Order Conditionally Approving Congestion Management and Multi-Settlement Systems," Docket No. EL00-62-000, June 28, 2000.

64 PJM, NYISO, ISONE, IMO Press Release, "Ontario's IMO and U.S. Independent System Operators Sign Agreement To Coordinate Inter-Regional Power System Operations," December 21, 1999.

65 PJM, ISONE Press Release, "ISO New England and PJM Interconnection Propose a Standard Market Design for Wholesale Electricity Markets," March 29, 2001.

66 For a further discussion, see William W. Hogan, "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems," Center for Business and Government, Harvard University, May 2000.

67 Ministry of Economic Development of New Zealand, "Inquiry into the Electricity Industry," Report to the Minister of New Zealand, Wellington, New Zealand, June 2000.

without regulators. The latest reform of the reforms was not complete at the end of 2000, but it did give evidence of continuing the process of careful examination of all the pieces and their interdependence. The Government of New Zealand set down principles for reform of the electricity market and development of new regulatory arrangements.[68] These principles could serve as a model for other countries.

The foremost missing ingredient in the New Zealand wholesale market design is a system of long-term transmission rights. A further extension of the New Zealand design would allow for a connection between short-term operations and long-term contracting by providing FTRs. It is straightforward that the monopoly transmission provider must be the first source of transmission rights. These rights might be tradable in a secondary market, but the fundamental definition, initial award, and ongoing provision of the transmission rights must be handled through the transmission provider. Furthermore, the transmission rights must be made compatible with the operation of the coordinated spot market. The special characteristics of the electricity network complicate the definition and provision of long-term transmission rights. The use of FTRs provides a consistent solution that is both theoretically sound and demonstrated in successful applications.

At the end of 2000, there was common agreement that preserving the best features of the existing New Zealand wholesale market design should be a high priority. Furthermore, there was agreement that extending the model to include FTRs would provide an added tool that would provide mechanisms for hedging transmission congestion costs and incentives for long-term investment.[69]

England and Wales

The case of England and Wales presents an exception and a challenge to the argument developed in this paper. The initial reforms in England and Wales in 1990 were highly influential in subsequent developments in electricity restructuring around the world. The signature element of the model was the introduction of the "Pool" by which the system operator managed a coordinated spot market. The principal difference from the British design and the essential ingredients described above was the reliance on a single zone in place of locational pricing to recognize the effects of transmission congestion. The problems created by this exception were managed through a combination of socialization of the congestion costs and a policy of guaranteeing full access to the grid for all generators. In practice, this meant that generators in certain regions would be paid not to generate power when the system was constrained.

The perverse incentives that flowed from this pricing system created a predictable market response that led to a rapid increase in the cost of managing congestion. This could not be sustained, and the policy response was to provide incentives for the National Grid Company to manage the transmission grid, set locational connection charges, and absorb a fraction of the congestion costs. In effect, this approach reverted to the use of a monopoly with price cap

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68 Pete Hodgson, Minister of Energy, "Government Policy Statement: Further Development of New Zealand's Electricity Industry," Wellington, New Zealand, December 2000.

69 Ministry of Economic Development of New Zealand, "Inquiry into the Electricity Industry," Report to the Minister of New Zealand, Wellington, New Zealand, June 2000, p. 61.

regulation in order to provide incentives to counteract the effects of inefficient pricing presented to the market participants. This left problematic incentives for the location of new generating plant, much as in New England, but on balance the system seemed to be working reasonably well.[70] This particular solution would be difficult to transport to another country where multiple interconnected system operators would be found with parallel flows, not just one system operator with a few controllable interconnections. In any event, the locational incentive problems remain and "...the costs of inefficient location can be large compared to the benefits of competition."[71]

The more persistent problem in England and Wales was the concern over the ability of the relatively few large generating companies to manipulate the pool price.[72] Although there were some divestitures of existing generating plants and a substantial volume of new construction, the concern remained that the exercise of market power was a problem. Of course, no market is perfect, and different observers might come to different conclusions about the seriousness of the market power problem in England and Wales. However, this is a value judgment, and the British regulator came to the view that something needed to be done about market power and other features of the market design.

The subsequent argument and analysis took an unusual turn, however, when the conclusion emerged that the very design of the British pool and its coordinated spot market facilitated, even caused, the exercise of market power. The argument arose that somehow the formal application of the economic law of one price made it easier to manipulate the market, and the transparency of the pool reinforced this ability.

Thus arrived the New Electricity Trading Arrangements (NETA) for the market in England and Wales.[73] The new system is complicated, but the essence is simple. Market participants would be required to arrange bilateral transactions at confidential prices. As always, the desire to rely completely on decentralized trading could not be realized. There is still a need for a system operator providing coordination services. Hence, in the NETA design the old day-ahead pool based on a coordinated spot market with a market-clearing price was replaced by a three-and-a-half-hour ahead balancing system with a complex pricing scheme that features a pay-as-bid mechanism with rules intended to penalize imbalances. In effect, the old coordinated spot market with relatively efficient pricing was replaced with a new coordinated spot market with inefficient and obscure pricing.

A complete analysis of the features of this reform of the reform in England and Wales is beyond the scope of the present paper. However, there is substantial support for the view that the NETA reform premise was misplaced:

> "The government believes that the Pool has been biased against coal-fired generators, and that its price-setting rule (all generators are paid the bid of the

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70 David M. Newbery, Privatization, Restructuring, and Regulation of Network Utilities, MIT Press, 1999, pp. 210.

71 David M. Newbery, Privatization, Restructuring, and Regulation of Network Utilities, MIT Press, 1999, pp. 269.

72 Catherine Wolfram, "Measuring Duopoly Power in the British Electricity Spot Market," American Economic Review, Vol. 89, No. 4, September 1999, pp. 805-826.

73 For details on NETA see the UK regulator: Office of Gas and Electricity Markets, "Balancing and Settlement Code," March 1, 2001.

marginal unit) has inflated the level of prices. In practice, many of the perceived problems in the Pool are the result of market power, not the basic design of the Pool, which is capable of sending the right price signals to generators."[74]

Other economic analyses come to even stronger conclusions that the policy does not hold up under logical scrutiny,[75] will increase costs,[76] and should not be followed by the rest of the world.[77]

In any event, this particular reform of reforms is fully supported by the British regulator and was launched in March 2001 after a great deal of preparation and expense. The early days included the expected startup problems. The lights have stayed on, but it is too early to tell much. It will be of great interest to follow the progress of NETA. It is a test of the main argument here. By the analysis above, we would expect the use of inefficient pricing in the spot market to result in greater costs for market participants and substantial unanticipated market behavior. This in turn will produce more, not less, intervention by both the regulator and the monopoly system operator as they then seek to undo what the market has done.

California

The most prominent early death of an electricity reform appears to be a suicide by reckless behavior. At the turn of the millennium, the early promise of the California electricity market reforms unraveled in the cascading collapse of a major market and the worst electricity restructuring policy failure ever seen or even previously imagined. By the end of 2000, a power crisis in California laid bare the dangers of designing a market while ignoring the fundamentals of how power systems operate. A flawed wholesale market and a caricature of a retail electricity market arose in California as the product of a volatile combination of bad economic theory and worse political economy practice.

Bad design outcomes were compounded by bad luck. There had been little addition to generating capacity for more than a decade. Low water reservoirs behind power dams combined with higher natural gas prices and tighter environmental conditions. An unexpected surge in demand from economic growth hit the inefficient market and produced unprecedented price increases. In the event, starting in June 2000 wholesale prices surged and stayed above $150 per MWh while retail prices for the same energy were limited to approximately $65. The system soon fell apart, the lights literally began to go out, and "deregulation" was pronounced dead.[78]

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74 Richard Green's "Draining the Pool: The Reform of Electricity Trading in England and Wales", Energy Policy, Vol. 27, No. 9, 1999, p. 515.

75 Alex Henney, "The Illusory Politics and Imaginary Economics of NETA," Power UK, 85, March 2001, pp. 16-26.

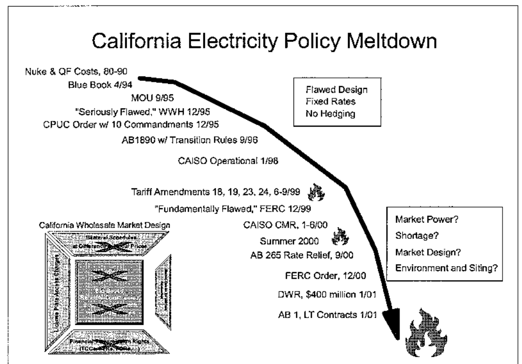
76 Bower, John and Derek W. Bunn, "Model-Based Comparisons of Pool and Bilateral Markets for Electricity," Energy Journal, Vol. 21, November 3, 2000, pp. 1-29.

77 Catherine D. Wolfram, "Electricity Markets: Should the Rest of the World Adopt the UK Reforms?", Regulation, The Cato Institute, Vol. 22, No. 4, 1999, pp. pp. 48-53.

78 For a polished review of the elements of the unhappy combination of events, see Bay Area Economic Forum, "The Bay Area - A Knowledge Economy Needs Power: A Report on California's Energy Crisis and its Impact on the Bay Area Economy," April 2001. (www.bayeconfor.org)

A full investigation of this subject would take us far from the main topic.[79] However, for the subject at hand, California is important because the market was in trouble well before it spun out of control in the summer of 2000. Even without its run of substantial bad luck and exploding prices, the California reform needed reforming, almost immediately.

As the political process took over in 1995, California turned away from the regulator's "Blue Book." Instead, California built its market design on a flawed premise that the inescapable reality of coordination requirements could be ignored or minimized in an effort to honor a boundless faith in the ability of markets to solve all problems. Worse yet, the design of the California market embraced the notion that what little the system operator would do should be done inefficiently in order to leave even more coordination problems for the market to solve.[80] This was an unprecedented experiment with a "seriously flawed" market design that did not work in theory.[81] We now know that it did not work in practice either.



The bad economic theory was a full embrace of the objective of creating a market for middlemen, no matter what the cost. In California, the approach of a coordinated spot market was explicitly rejected in preference to a complicated trading regime as embodied in the Memorandum of Understanding of 1995.[82] The subsequent 'ten commandments' from the CPUC

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79 For an expanded version of this discussion and further references on the California market design failure, see John D. Chandley, Scott M. Harvey, William W. Hogan, "Electricity Market Reform in California," Comments in FERC Docket EL00-95-000, Center for Business and Government, Harvard University, November 22, 2000.

80 Steven Stoft, "What Should a Power Marketer Want?", The Electricity Journal, 1997, pp. 34-45.

81 William W. Hogan, "A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy," Electricity Journal, December 1995, pp. 26-37.

82 "Professor Hogan can also be read to suggest that the ISO should become the 'pool' by taking schedules which include not just quantity information, but also include price information so that the ISO can select 'the most economically efficient' requests from among the schedules, as if the schedules were bids into the pool. This proposal would essentially re-create the pool in the guise of the ISO. Again, there can be no doubt that the parties intended to foreclose this situation. Indeed, the parties went to great lengths in the MOU to allow buyers and sellers to purchase unbundled transmission rights, to make quantity-only schedules, and not to disclose pricing information to the ISO or subject their transactions to 'economic dispatch.'" Enron et al., "Comments of Enron Capital & Trade Resources, Wickland Power Services, Destec Power Services, inc., Illinova Power Marketing, Inc., Coastal Electric Services, and Electric Clearinghouse, Inc., on the Memorandum of Understanding filed September 11, 1995," dated

attempted to undue these errors,[83] but these commandments were ignored in the resulting enabling law AB1890 and the implementation of the market design with the CAISO and a separate Power Exchange (PX). Given the inevitable requirements for coordination, this produced an expanding collection of arcane rules to prevent what was natural by making the coordination process ever harder to use, all in the interest of supporting separate exchanges and marketers. For example, the CAISO was explicitly precluded from providing a least-cost combination of balancing services.[84] Since the operator still had to provide balancing services, these were required to be inefficient and expensive, in order to create more business for the middlemen. Eventually the CAISO and the PX were operating so many un-coordinated and inconsistent markets for energy and various ancillary services that it was amazing it worked at all.

The compounding failures in the market design accumulated from the market's inception in 1998. Many of the problems that confronted the California ISO and market participants had a common origin in the limitations of the congestion pricing system. California has had essentially a two zone congestion pricing system that was characterized by the existence of considerable intra-zonal congestion, the prospect of additional intra-zonal congestion in the future, and load regions in which high cost generation and transmission investments would be required to meet future load growth. This system has not worked and cannot work in the long-run, because it does not provide generators with the right incentives either with respect to short-run operating decisions or long-run investment decisions.

For example, the constrained-off payment mechanism for managing intra-zonal congestion did not provide generators the right incentives in either the short- or long-run. Generators that were backed down in real time due to intra-zonal congestion received constrained-off payments based on the zonal price. Hence, inefficiently high cost generators would remain in operation, and there was a potential incentive for inefficient entry of new generators requiring additional constrained-off payments. Moreover, there were short-run circumstances in which intra-zonal transmission constraints would create gaming opportunities for individual generators that could schedule transactions in the day-ahead market for which very high constrained-off payments could be extracted in the real-time market.

Amendments 19[85] and 23[86] to the CAISO tariff attempted to reduce the potential for inefficient outcomes under the constrained-off payment mechanism by placing a variety of restrictions on generator choices. Rather than correcting the market design flaws, these amendments addressed market imperfections by adding command and control mechanisms that would likely serve as barriers to efficient generation entry in the case of Amendment 19 and

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October 2, 1995, and filed with the CPUC, p. 13.

83 California Public Utility Commission, Decision 95-12-063 December 20, 1995, as amended by D.96-01-009, January 10, 1996, Section III, Part 2. See the ten "Principles for Operation of the ISO."

84 William W. Hogan, "WEPEX: What's Wrong With Least Cost?" Public Utilities Fortnightly, January 1, 1998, pp. 46-49.

85 CASIO tariff proposed Amendment 19 Docket No. ER99-3339-000 (New Generator Interconnection Policy), June 23, 1999.

86 CAISO tariff proposed Amendment 23 Docket No. ER00-555-002 (Hourly Ex-Post Price), November 10, 1999.

would lead to an inefficient non-market based intra-zonal redispatch in the case of Amendment 23.

The Amendment 19 policy was not new. Essentially the same type of proposal was in place in New England until October 1998.[87] The policy was defined for similar reasons; namely, to offset the perverse incentives of zonal price aggregation and had the same effect of protecting the incumbent generators. The New England policy was abandoned as inefficient, unfair, and unworkable. As a result, New England revisited the market design issues which created the problem the policy was trying to solve.

At the same time, the CAISO recognized that the pricing system had not drawn forth the necessary level of generation and transmission investment within the transmission constrained areas that include most of the load in California. Hemmed in by its basic design principles, the CAISO sought to remedy the inadequate returns and lack of investment within transmission constrained regions by proposing a process that would govern the distribution of additional extra-market payments to generators within constrained regions (Amendment 24[88]).

Finally, in December 1999, the FERC rejected the ad hoc market adjustments and call for fundamental reform of the zonal congestion management system. "The problem facing the [California] ISO is that the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced."[89] By the usual standards of dry FERC prose, this was strong language. There then began an intense process to rethink congestion management, and soon the full market design, from first principles.

It was a race against time. Time ran out. When the bad luck arrived in the summer of 2000, California's Comprehensive Market Redesign (CMR) effort was blown back as the explosive combination of variable wholesale prices and fixed retail prices confronted the spark of a suddenly tight market. Bad luck collided with bad policy. The California government intervened with AB265 to impose retail price caps in San Diego, the one region that had moved to a retail market. The FERC issued a series of orders that reflected a view that the problems must largely be solved in California. The state Department of Water Resources jumped in to buy power for the near or soon to be bankrupt utilities who stopped paying their bills. The state then launched a long-term program, beginning with law AB1, to take over or at least play a prominent role in the electricity market. Even those who predicted problems were surprised at the scope and speed of the policy disaster.

The tragic case of California reinforces the basic argument of the present paper. The magic of the market is no sure thing. The details matter. However, the conditions were so extreme in California that even a good market design may not have survived the summer of 2000 and its aftermath. The outcome of all this was unknowable as the summer of 2001 was about to

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87 See New England Power Pool, 85 FERC Para 61,141 (1998).

88 CAISO tariff proposed Amendment 24 Docket No. ER00-866-000 (Revised Long Term Grid Planning), December 21, 1999.

89 Federal Energy Regulatory Commission, "Order Accepting for Filing in Part and Rejecting in Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion," Docket ER00-555-000, 90 FERC 61, 000, Washington DC, January 7, 2000, p. 9. See also Federal Energy Regulatory Commission, "Order Denying Requests for Clarifications and Rehearing," 91 FERC 61, 026, Docket ER00-555-001, Washington DC, April 12, 2000, p. 4.

begin. But everything would be different after the experience of such a major failure of market restructuring.

CONCLUSION

The developing experience around the world provides insight into the options and implications of alternative models of access to transmission grids in support of an efficient competitive electricity markets. It is argued from this experience that the central wholesale market design requirement is easy access to a coordinated spot market. There are certain critical functions that must be provided by the system operator. When these functions are organized within the framework of a bid-based, security-constrained economic dispatch with locational pricing, the market has the tools available to deal with the most important network complexities that otherwise confound electricity markets. Furthermore, there must be a close connection between the design of options for market flexibility and the pricing principles for actual use of the transmission grid. If prices closely reflect operating conditions and marginal costs, then market participants can have numerous choices in the way they use the transmission system. However, if pricing does not conform to the operating conditions, then substantial operating restrictions must be imposed to preserve system reliability. Customer flexibility and choice require efficient pricing; inefficient pricing necessarily limits market flexibility. As experience develops, the reforms of reforms reveal just how critical are the details of electricity market design, and how they constrain what can be done.

ELECTRICITY MARKET REFORM IN CALIFORNIA

JOHN D. CHANDLEY*
SCOTT M. HARVEY*
WILLIAM W. HOGAN**

*LECG, LLC, Cambridge, MA 02139

**Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138

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ELECTRICITY MARKET REFORM IN CALIFORNIA

John D. Chandley, Scott M. Harvey and William W. Hogan [1]

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> "...the Commission's goal has been to balance, on the one hand, holding overall rates to levels that approximate competitive market levels for the benefit of consumers, with, on the other hand, inducing sufficient investment in capacity to ensure adequate service for the benefit of consumers. We believe that a well functioning competitive wholesale power market in California, which includes a well functioning regional transmission grid, is a fundamental part of the solution to the supply problems and price volatility in California....
>
> ... It is important to get the fundamentals right and to devise a roadmap that takes into account the needs of the market and the regional implications of electricity trade." [2]

INTRODUCTION

The Federal Energy Regulatory Commission has proposed remedies for the problems observed in the California wholesale markets during the summer of 2000.[3] The Commission findings properly emphasize the importance of defects in the California market, which by now has a history of largely unsuccessful reforms. Furthermore, the Commission highlights the need both to address the immediate problems in the market as

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1 John Chandley is a Principal with LECG, LLC., an economic and management consulting company. Scott Harvey is a Director with LECG, LLC. William Hogan is the Lucius N. Littauer Professor of Public Policy and Administration at the John F. Kennedy School of Government, Harvard University, and a Director of LECG, LLC.. The authors are or have been consultants on electricity market design and transmission pricing, market power or generation valuation issues for American National Power, British National Grid Company, Calpine Corporation, Commonwealth Edison, Constellation Power Source, Detroit Edison, General Electric Capital, GPU, Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., Duquesne Light Company, Electricity Corporation of New Zealand, ISO New England, Midwest ISO, National Independent Energy Producers, New England Power, New York Energy Association, New York ISO, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, Ontario IMO, PJM Office of the Interconnection, Putnam, Hayes & Bartlett, Reliant Energy, San Diego Gas & Electric, Sempra Energy, Southern Energy, Southwest Power Pool, TransÉnergie, Transpower of New Zealand Ltd., Westbrook Power, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any errors are solely the responsibility of the authors.

2 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, pp. 4, 18.

3 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000.

well as to initiate a successful redesign process that will lead to a workably competitive regional wholesale market.

The present paper examines the direction laid out by the Commission in light of the available analyses of the problems and the record of the market design process in California.[4] We submit that the Commission's proposals need substantial clarification, revision and extension. The clarifications should eliminate certain ambiguities in the Commission's guidance, ambiguities that could complicate or completely undermine the Commission's intent. The revisions point to modifications of the short-term transition that would be more consistent with the goal of reforming the basic flaws in the California market design. The extensions focus primarily on the immediate need to embrace the fundamental reforms that are sure to be required and for which further delay could threaten the success of the entire endeavor.

The issues are important for California, but the implications extend well beyond the boundaries of this particular market. The example of the California market is cited in virtually every restructuring policy discussion, and the California market interacts directly with the rest of the electricity market in the Western system. The events have started a process that has produced many attempts to sort out the complicated issues. However, the debate is not likely to be settled through the by now familiar process of the Commission responding to stakeholder initiatives. The current institutions are unlikely to produce workable reforms in California, so the Commission must provide the necessary guidance and direction. Importantly, the Commission has a great deal of evidence and experience to define reforms that would be likely to work.

THE FATAL FLAW

California built its market design on a flawed premise. It is a commonplace that electric systems are both complicated and highly interdependent. Over short horizons of a day or less, generating facilities must work through the transmission network to provide the multiple products of energy, reserves and ancillary services. The same generating facilities must provide all of these products, in the right amounts, and with very limited tolerances. The simple physical reality dictates that these services must, in the end, be coordinated by a system operator. There is no other choice available with our current technology, and every electric system has such a system operator.

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[4] Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000. California ISO (CAISO), Department of Market Analysis, "Report on California Energy Market Issues and Performance: May-June, 2000," August 10, 2000. Severin Borenstein, James Bushnell and Frank Wolak, "Diagnosing Market Power in California's Restructured Wholesale Electricity Market," August 2000. Frank A. Wolak, Robert Nordhaus, and Carl Shapiro, "An analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," September 6, 2000. Northwest Power Planning Council, Study of Western Power Market Prices Summer 2000, October 11, 2000. California Power Exchange Corp., Compliance Unit, Price Movements in California Electricity Markets, September 29, 2000.

The flawed premise of the California market design was that this inescapable reality could be ignored or minimized in an effort to honor a faith in the ability of markets to solve the problems of coordination. Worse yet, the design of the California market embraced the notion that what little the system operator would do should be done inefficiently in order to leave even more coordination problems for the market to solve. This was an unprecedented experiment in markets that did not work in theory.[5] We now know that it did not work in practice either.

The failed experiment is at the root of many of the market defects. And the root is deep. The principles have been embodied as part of the so-called "four pillars" of the California market design.[6] Throughout the review of the market design in the intensive process that began when the Commission identified the "fundamentally flawed" congestion management system, the California Independent System Operator (CAISO) has reflected the will of some stakeholders that above all else the four pillars must be preserved.[7]

These four pillars include:

- The design should "separate the forward energy markets from the ISO forward transmission market."
- The design should "use second-price auction and marginal cost pricing for transmission."
- The design should "utilize the principle of market separation," such as requiring the ISO to preserve balanced schedules for each scheduling coordinator, notwithstanding the ISO's need to adjust these schedules to manage congestion and balance the system.
- The design should "use zonal congestion design where prices within a zone are close enough to use one price for the whole zone."

Only the second principle, to use marginal cost pricing, has a basis in theory or been shown to be workable in practice. Unfortunately, many of the perverse incentives in the California market arise precisely because the ISO is not allowed to apply even this principle consistently. At the same time, the remaining three pillars stand in opposition to the reality of how electric systems must work.

Separating forward energy markets from the ISO's forward transmission markets is a mistake. Over short horizons, there is no distinction between energy dispatch and transmission use. Once we know the dispatch of plants needed to produce energy to meet load, the use of the transmission system is determined. It is a fallacy that these can be determined separately, or that these functions do not have to be carefully integrated to achieve both economic efficiency and reliable operation. Furthermore, this same flawed

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[5] William W. Hogan, "A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy," Electricity Journal, December 1995.

[6] "Congestion Management Reform," presentation by the California ISO, March 17, 2000.

[7] See, for example, California ISO, Congestion Management Reform Recommendations, Appendix E, July 28, 2000.

market separation principle leads to explicit prohibitions of economic dispatch. The separation of day-ahead transmission and energy markets creates problems that could be and have been avoided elsewhere.

Similarly, the principle of market separation that gives rise to the requirement for individually balanced schedules imposes constraints on operations that are designed solely to create opportunities for otherwise unnecessary transactions for the California Power Exchange (PX) and other scheduling coordinators. Aggregate balancing is required by the physics. But individual balancing is not required, often not efficient, and sometimes not even possible. The restriction is entirely artificial and makes it harder for the ISO to coordinate the market. Moreover, the restriction appears likely to increase the capacity shortage in the California market by increasing the CAISO's demand for capacity (to provide regulation) and requiring market participants to withhold capacity from the energy markets in order to provide adjustment bids.

Likewise, the zonal pricing system defines a requirement that should not be a requirement at all given the conditions in its definition. If the (true) prices in a zone were "close enough," there would be no need to convert them to one price. Furthermore, we know by now that the implied simplification of the zonal system was a mirage, and its implementation requires more and more complex contortions to counteract its perverse incentives. The real impact of zonal aggregation is to convert (true) prices that are not close into a single price that gives the wrong incentives just when incentives matter most.

These ill-advised pillars have trapped California in a box that excludes meaningful market reform. The Commission has recognized some, if not all, of the pathologies that fester inside this box. As the Commission has noted, the separation of the roles of the ISO and the PX in dealing with short-term coordination is a source of continuing trouble. The requirement for individually balanced schedules, rather than a collectively balanced system, serves no good public policy purpose. The prohibition against economic dispatch in real time necessarily reduces efficiency and forecloses a market-based option that is fundamental to workable markets in other systems. The continued pursuit of "simplified" zonal designs, that are truly complicated in practice, reflects the perverse philosophical commitment to preventing the CAISO from doing well what it must do of necessity. The initial complete and still partial separation of markets for energy, reserves and other ancillary services imposes demands on market participants, and on the supply of generating capacity, that could be alleviated easily in the use of a combined optimization that only the CAISO could perform.

The recitation of design defects attributable to the flawed pillars could be extended.[8] But even this short summary of the experience in the reform process, and the continued adherence to the fatally flawed premise of the California market design, presents the Commission with an unhappy combination of circumstances. First, the California market will not be amenable to reform without stepping outside the constraints imposed by the flawed pillars. Second, the California participants have demonstrated

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[8] See, for example, Scott Harvey and William W. Hogan, "Comments on the Congestion Management Proposals of the California ISO," August 31, 2000.

repeatedly that they cannot take this step on their own, and will not allow the ISO management to take it for them.

The Commission, therefore, will have to take the initiative to drive the process in the right direction. This is essential for several reasons. The obvious importance of the California market should be enough to declare an end to the failed experiment and turn to a superior market design in place elsewhere that has proven itself in both theory and practice. Furthermore, the example of California is unavoidable in establishing precedents or creating obstacles for the development of Regional Transmission Organizations (RTOs) in other regions. Without a fundamental correction in California, the Commission will face serious complications in the development of workable regional markets well beyond the borders of California.

There is an understandable focus on high prices and efforts to mitigate the impact on California consumers. Near-term efforts to define just and reasonable prices receive immediate attention, often at the expense of efforts to correct the underlying flaws in the market. But even here the design flaws intrude. They confound diagnosis and treatment of the market ills in California. Initially, high prices in California were seen as *prima facie* evidence of the exercise of market power. However, closer examination of the structure of the market and its rules reveals a more complicated story that implicates the interaction of bad market design and shortage as at least a prominent feature of the California experience.[9] Without the fundamental reforms in market design, it may be impossible to separate the effects of market power from these other elements. And without a better diagnosis, it is hard to know what treatments to prescribe to mitigate market power, or even if market power is a part of the problem. Furthermore, if the real problems have been a combination of a shortage of capacity and high cost energy, market reform may be essential to achieving just and reasonable prices.

Direction from the Commission should be specific and comprehensive, both as to the final destination and the path for transition. The Commission's recognition that it must confront the difficulties of market design is a promising start, but more is required. It must now get the market design right and ensure that the flawed market design elements now evident in the California structure are not allowed to take root in the emerging RTOs elsewhere.

THE COMMISSION'S PROPOSALS

The Commission has reviewed the accumulated experience in California and produced a series of proposed actions for the immediate future and for more fundamental reform. The initial actions include: [10]

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9 Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000. Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000.

10 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 5.

- the elimination of the requirement that the three investor-owned utilities (IOUs) -- Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SoCal Edison), and San Diego Gas & Electric Company (SDG&E) -- must sell into and buy from the PX;
- the addition of a penalty charge for deviations in scheduling in excess of five percent of an entity's hourly load requirements and the disbursement of penalty revenues to the loads that scheduled accurately;
- the establishment of independent, non-stakeholder Governing Boards for the PX and the ISO;
- the establishment of generation interconnection procedures; and
- a new form of "soft" price cap at $150.

Further, the Commission identified a number of structural reforms that must be addressed, including: [11]

- the submission of a congestion management redesign proposal;
- possible changes to the auction mechanisms;
- improved market monitoring and market mitigation strategies;
- demand response programs by the ISO and Scheduling Coordinators;
- elimination of the requirement for balanced schedules; and
- new approach to reserve requirements.

This is an ambitious agenda, pointing towards undertaking a comprehensive redesign of the entire California market structure. It raises many questions that could lead to extensive discussion and debate. However, in making the case that the agenda is not prescriptive enough, it is better to concentrate on the main points. These observations will serve as a backdrop for the clarifications, revisions and extensions that we see as dictated by the Commission's analysis and the serious problems that remain.

Governance

The California governance arrangements have failed to meet the basic test of operating success. The governance mechanism that produced the flawed initial market design evolved into the stakeholder boards of the CAISO and the PX. As is now clear, this governance mechanism has been unable to correct, or even acknowledge, its initial mistakes. The Commission has concluded that California needs a new, more independent, governance mechanism. This is an important step that will have major impacts both inside and outside California.

Whatever the necessity of improving the governance of market institutions in California, there is little reason to hope that this alone will be sufficient to ensure timely

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[11] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 5.

or sensible reforms. Responsibility for the existing problems in California rests not just with its governing bodies. Regulators in Washington and California accepted and approved the defective market design, albeit at a time when there was little experience with operating electricity markets in the United States. The most important guidance regarding improvements of these market designs is not likely to come from the as yet unnamed new boards, especially given the delay in their arrival on the scene and the natural requirement that they will spend time understanding the current market institutions and problems, and making their own mistakes. In the meantime, the Commission must do the hard work of sorting through market design issues and weeding out designs that have failed from those that have proven to be workable.

Sole reliance on the new boards to do the hard work for the Commission could be further complicated by the guidance the Commission has given as to the composition of these Boards: "[t]he Boards should include members with experience in corporate leadership (at the director or board level) or professional expertise in either finance, accounting, engineering or utility law and regulation. The PX board should include members with expertise in areas of commercial markets and trading. The ISO board should include members with experience in the operation and planning of transmission systems." [12] This could be interpreted as direction for the expertise sought separately for the CAISO and PX boards to preserve a distinction in their functions that would codify the fatal flaw of market separation. This would be a mistake. In particular, the CAISO functions should include the necessary understanding of what needs to be done in the management of short-term operations to support both reliability and markets.

The change in governance may help, but it is not likely to be decisive in the near term. Explicit guidance from the Commission regarding the nature and trajectory of reforms will be essential if market reform is to be accomplished within an acceptable time frame.

Market Separation

The flaw of market separation receives attention from the Commission in its direction regarding the functions of the CAISO and the PX. The Commission proposes with one hand to abolish the requirement for utilities to purchase solely from the PX, and it asserts that it wants to eliminate the balanced schedule requirement. But with the other hand the Commission reinforces the artificial distinction between the energy market and transmission management: "We propose to temporarily correct the current situation by limiting the ISO to only the functions needed to reliably operate the transmission system, i.e., provide a balancing service rather than running an energy market."[13] In addition, as discussed above, the Commission may be construed to having directed the new independent Boards to have correspondingly different expertise. Further, in its detailed discussion, the Commission requires not the elimination of balanced schedules but no

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12 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, pp. 28-29.

13 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 24.

more than that the PX and the CAISO discuss in the future how to better integrate the day-ahead markets.[14] The Commission is silent on the contradictions of these ambiguous instructions and fails to address the impact of the market separation requirement on the capacity shortages in California.

Further, in its discussion of the use of spot markets the Commission wrongly focuses on the symptoms rather than the disease. The symptom is the so-called underscheduling in the day-ahead market and greater reliance on the spot market. The pathology is the market structure that gives the wrong price signals to the participants and forces inefficiency that contributes to a capacity shortage. If the prices were right, there should be no need for penalties or special rules to force market participants to act in ways that go against the market incentives. As we have seen in other markets, it is possible for day-ahead and real-time markets to work without special penalties or rules and without the pathologies present in California.

The ambiguity in the guidance and the confusion it will create are a recipe for delay and further *ad hoc* reforms. The Commission should face the reality of electricity systems and the extensive analysis that supported its directions in Order 2000.[15] The CAISO should be given the clear responsibility to run an efficient day-ahead and real-time market, in support of an efficient competitive market. Pricing rules in each market should be based on standard marginal cost principles and be consistent across markets. Any attempt to straddle the four pillars and maintain market separation is bound to fail. There should be an unambiguous decision and direction to give the CAISO the responsibility to operate an integrated system for day-ahead and real-time scheduling, balancing, congestion management, ancillary services, reserves, and so on, recognizing that these and their associated pricing must be parts of an integrated whole.

Forward Contracting

Freeing utilities from restrictions on forward contracting is a move in the right direction. In a real market, there would be no such restrictions. The arguments for the restrictions in the first place were at best problematic. Whatever the original merits, the arguments depended in part upon other market reforms that would allow for vigorous competition to serve retail loads. These other reforms were not put in place. In addition, the well documented effect of the rate freeze and stranded asset recovery mechanism created the worst possible combination of small customers left *de facto* without access to retail suppliers who could provide price stability, and utilities precluded from providing any hedging services.

Removing the restrictions on forward contracting is one thing. Putting formal requirements or informal pressure on buyers to sign long-term forward contracts would be quite something else. The expectation that merely allowing utilities to participate in

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[14] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 30.

[15] William W. Hogan, "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems," May 2000. (available at ksgwww.harvard.edu/people/whogan).

forward contracting necessarily would be the solution to high prices is problematic and not supported by the Commission's staff report. "[H]olding forward contracts does not guarantee that consumers will incur lower total energy costs. These costs ultimately depend on the relative level of prices in the forward and spot energy markets."[16] To the contrary, putting pressure on buyers to sign contracts in the present environment may make things worse. It is doubtful that requiring buyers to sign forward contracts would improve matters if the high prices are largely due to the exercise of market power,[17] and if the high prices are largely due to high costs and capacity shortages, requiring California buyers to sign forward contracts could make things worse not only in California, but in a broad part of the Western system (WSCC).

Forward contract prices after Summer 2000 were much higher than for the Summer 1999, and a regulatory requirement that buyers increase their demand for such contracts can only be expected to make the contract price increase. Furthermore, the complications of getting the utilities back in the long-term supply business have been ignored. A rush to extensive long-term forward contracting now may be closing the barn door too late. A return to new but strangely familiar stranded cost hearings may not be far in the future. One of the purposes of electricity market reform was to provide customer choice. It would be inconsistent with this purpose if the distribution utilities were to be required to enter into forward contracts to buy electricity at prices that may turn out to be much higher than what customers are actually willing to pay for that power. Recall the natural gas markets in the 1980s with high contract prices that precipitated the restructuring of the gas industry.

It is not clear that the Commission's proposal would require long-term forward contracting. The language about forward contracting and the emphasis on real-time penalties could be interpreted as applying only to day-ahead scheduling.[18] If this is the Commission's intent, it should be clarified. If not, then the role of long-term forward contracting deserves much more examination before committing to a new round of sunk costs.

The Commission should on the other hand take steps to eliminate artificial barriers to forward contracting and ensure that competitive electricity providers are able to participate in the market and offer load management services to end users.

Soft Price Cap

The soft price cap proposal is novel and raises many new issues. It does not appear in the staff report and there is little critical analysis of the implications, other than

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16 Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 5-9. See also, Scott M. Harvey and William W. Hogan, "California Electricity Prices and Forward Market Hedging," October 17, 2000.

17 Scott M. Harvey and William W. Hogan, "California Electricity Prices and Forward Market Hedging," October 17, 2000. (available at ksgwww.harvard.edu/people/whogan).

18 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, pp. 24, 41.

the discussion of Commissioner Hébert. Essentially the soft price cap appears to be an attempt to straddle two auction price regimes, with market-clearing prices applying below $150 and pay-as-bid systems applying above $150. Below $150 it would seem that any price would be acceptable. Above $150, there would at least be requirements for further review by the Commission and possible refunds.

It is uncertain what is intended. One possibility is that the Commission intends to require and enforce cost justification for all bids in excess of $150. If this is the intent, the proposal in effect lowers the existing price cap and formalizes the CAISO practice of making out-of-market purchases in order to obtain supplies available only at prices above the price cap. [19] In this case, the Commission should recognize that requiring cost justification of generator bids, particularly under a pay-as-bid system, will impose substantial burdens on the Commission that would rival those under wellhead price controls in the natural gas industry. Some of the issues the Commission and its staff would have to address include:

- Would fuels be priced based on their acquisition price or their current market price?
- Would emission allowances be priced based on their acquisition cost or their current market price, and how would market prices be determined?
- Would firm transportation charges be included in costs, and if so how, or only interruptible (and thus avoidable) gas transportation charges?
- How would the cost justification account for start-up and no-load costs?
- How would the opportunity costs of limited energy resources such as pondage hydro be measured?
- How would expected ancillary services prices be evaluated in measuring opportunity costs?
- How would imports and exports be priced?

Moreover, even if this regime were successfully applied the price discrimination and price averaging implicit in the pay-as-bid market structure would likely deter, rather than promote, forward contracting. Finally, such a cost based approach would appear to deter investments in new capacity, improved heat-rate performance, and reduced emissions, all of which will not be made unless they earn more than their short-run costs and all of which are necessary if California is to address the three problems of capacity shortage, high gas costs and high emissions.

Alternatively, the soft price cap might be truly soft and not require cost justification. Hence, there would be no price cap for any entity that is willing to file a report to FERC and face the possibility of a refund. If this is the Commission's intent,

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[19] Commissioner Hébert for one is concerned that this requirement would act as a *de facto* price cap at $150. See Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Concurring Opinion of Commissioner Hébert, Docket No. EL00-95-000, Washington, DC, November 1, 2000.

there might be little impact on consumer prices (particularly if the principal sources of those high prices are high costs and regional capacity shortages rather than the exercise of market power). Even so, the proposal might serve to deter entry and new investments, thus combining the worst of both worlds, high consumer prices and little or no new investment.

As with any price cap, the incentives run against the operation of markets and make the mechanism a source of complication in achieving a transition to a more market-like mechanism. It would be especially problematic for prospective new entrants. Consider a competitive existing generator with production costs below but opportunity costs above $150. The opportunity costs should set a floor on its bid in a competitive market. Under a truly "soft" price cap, the risk for such an entity of bidding above $150 would be limited to the cost of filing and review by the Commission, plus the possibility that a refund may be required to return its short-run operating profits in excess of $150. There would be no rational reason not to bid the supplier's opportunity costs, as the worst case outcome would be no worse than if it did not try to capture its opportunity costs in its bid. By contrast, consider the new generator that needs a significant number of hours with revenue above $150 to justify the fixed costs of building a plant and entering the market. No matter what the Commission says now, the new generator (or the generator contemplating closing a plant, or a generator contemplating an investment to improve generating performance or reduce NOx emissions) would face a larger maximum risk and would have to evaluate the chance that it would make a cash investment and then not recover its required return. In this case, it is not simply a matter of failing to capture its opportunity costs and being no worse off than if it had not tried, because the ability to capture opportunity costs may have provided the basis for an investment that would be sunk and would fail to recover its cost of capital. It is easy to imagine that this soft price cap would have almost the same effect as a hard price cap for such entrants, namely discouraging new entry. Given the short supply situation, this would be just the wrong incentive.

In addition, a soft price cap would face the same problems of any pay-as-bid market. To the extent that shortage is driving the high prices in California, this rule would indirectly reinforce the problematic features of bidding and scheduling.

Auction Mechanisms

The Commission expressed an interest in the possible benefits of switching to a pay-as-bid auction format rather than the originally intended design of a uniform price auction. Electricity markets that rely on uniform price auctions to clear markets exploit a simple argument based on the law of one price. The law of one price says that in a decentralized market for a homogeneous commodity, trade will tend to converge towards a common market-clearing price. In the case of electricity, where decentralized trading is foreclosed in the final day-ahead and real-time markets, this convergence is not possible and the simple approach is to use what the market would produce if only there were enough time and no transaction costs.

Whenever these uniform price electricity markets encounter trouble for any reason, someone notices that market participants are responding to the incentives of the uniform price auction by bidding something below the market-clearing price. They then leap to the *non sequitur* that paying the bid rather than the market-clearing price would somehow reduce average prices. A moment's reflection would suggest that the same market participants who respond to the incentives of the uniform price auction would also respond to the incentives of the pay-as-bid auction. Now the incentive would be to bid the market-clearing price.

As the staff report summarizes, the results would be the same price and revenue flows as under the uniform price auction.[20] This assumes, however, that there would be no uncertainty and no transaction costs. In the presence of uncertainty and transaction costs, there will be errors in the bids. The one sure thing that these errors will produce will be higher true costs through inefficient choices in the ultimate dispatch. There is no available evidence that the result would be lower prices. There are studies that suggest that both costs and prices would be higher.[21]

This general observation applied to any commodity auction applies with special force to something as complicated as the bids for a security-constrained economic dispatch. We saw what could happen in such a market when California operated fully separate energy, reserve and ancillary services markets.[22] In effect, this was an approximate prototype of a full pay-as-bid market. It was a stunning failure, the first in a line of special California problems. To cite another complication, consider the problems of transmission congestion management if everyone is bidding to make sure that the bid is close to the market-clearing price. For example, in PJM the presence of transmission congestion can change the market value of generation by an order of magnitude. Every generator would be compelled to consider the likelihood of transmission congestion in each interval, and change its bids accordingly. This embrace of a pay-as-bid rule would be a nightmare for the system operator and the competitive bidder, but a godsend for any generator who wished to cloak the exercise of market power.

Market Power and Shortages

High prices in the summer of 2000 arose because of a combination of factors. Faulty market rules created both inefficient dispatch and incentives for behavior that complicated market operations. Costs were up due to higher natural gas prices and tightening markets for emission allowances. Capacity was reduced because of the low availability of hydro power, a failure to invest in generating capacity in California, and increased congestion in the transmission system. Demand in areas not exposed to market prices grew at a rate that surprised most observers. On these points there is no dispute. In addition, there are those who argue that the high prices were exacerbated by the exercise of market power.

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20 Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 5-15.

21 John Bower and Derek W. Bunn, "Model-Based Comparisons of Pool and Bilateral Markets for Electricity," Energy Journal, Vol. 21, No. 3, pp. 1-29.

22 Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000. (available at ksgwww.harvard.edu/people/whogan).

The need to fix badly flawed markets should be beyond dispute after the evidence of the failed experiment in California. The impacts of increased production costs and shortages are easy to understand, if not pleasant to endure. Markets respond to scarcity by increasing prices, and the increase in price creates the incentives for adjustments in supply and demand. Were it not for the large wealth transfer, the analysis of the proper response to scarcity would lead to the uncontroversial conclusion to let the market work.

The controversy in California centers more on the role of market power, and separating how much of the increase in prices is the result of the exercise of market power versus how much is from the more conventional explanation of scarcity, albeit scarcity created in part by the market design. In this regard, the debate is confused because we are dancing around the words where the truth may be hard to face. The confusion is evident in the Commission's summary of its findings and conclusions: "[w]hile this record does not support findings of specific exercises of market power, and while we are not able to reach definite conclusions about the actions of individual sellers, there is clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA." [23]

The traditional definition of the exercise of market power would apply to circumstances when generators withhold some capacity and leave it idle in order to raise the market price. The withholding suppliers are presumed to make more money through the increased price on what they do supply than they lose on the supply they withhold.[24] There is an unambiguous policy conclusion regarding this exercise of traditional market power. If it is occurring on any significant scale, it is a problem and regulatory intervention is indicated. The preferred mechanisms would be through bids caps, or divestiture, applied to the offending suppliers, as discussed below.

The difficulty in the present case is that there has been no direct showing that such traditional market power has been exercised at all, much less that it has been exercised on a widespread and significant basis. [25] The often mentioned tendency of generators and loads to avoid the day-ahead market in preference to the real-time market is a response to bad market design and pricing incentives (including price caps), but does not demonstrate the exercise of market power. If these participants ultimately transact through the real-time market (for either energy or reserves), there is no final withholding of capacity. Even a 1 MW generator would have an incentive to follow these incentives. This is not the traditional exercise of market power.

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23 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 3.

24 In the presence of transmission bottlenecks, it is possible to exercise market power by increasing some supply in order to force reductions elsewhere, but this does not change the thrust of the present argument.

25 Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000, pp. 2-4. Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 5-16.

In contrast, sometimes the term "market power" is applied to something else in analyses of the California experience. This is clearest in the discussion of market power with the occasional cryptic reference to the definition: "[t]he data also indicate some attempted exercise of market power, if the standard of bidding above marginal cost is used,..."[26] This definition flows from a view that the California market is a pure uniform price auction and that bidders without market power should bid their own opportunity cost. However, there are several translation steps that are implicit and problematic in this definition.

The distinction between direct marginal cost and opportunity cost is sometimes lost in the discussion. Hence, a competitive bidder whose direct cost of generation is $40 but who could sell the same energy outside California for $100 should bid no less than $100. This would not be an exercise of market power. Furthermore, the California market is not a true uniform price market. In fact, the many peculiar design features in the California market mean that the market-clearing price in related markets, such as ancillary services, should determine the opportunity cost in others. Hence, even a small 1 MW generator should be anticipating the willingness to pay of the market and try to bid so as to ensure that it is paid the market-clearing price. Under the California rules, the rational bid of the competitive generator can easily be to pick the largest price at which it will still be called into use. This is not withholding, it is a rational response to market incentives. To the extent that this is caused by market design problems, fixing the design should change the bidding behavior. To the extent that the market-clearing price is due to scarcity, however, the resulting price impacts and behavior of the bidders is consistent with what we would expect in a competitive market and cannot be avoided without eliminating the market.[27]

Dispelling the semantic fog should be a high priority for the Commission. If there is significant exercise of traditional market power through withholding, this has important policy implications. The preferred response would be bid caps targeted at those exercising market power in the short-run and divestiture in the long-run, and this action alone might be sufficient to moderate the average price impacts. However, if the explanation lies elsewhere, the policy implications would be different. If scarcity and higher costs are the dominant forces, bid caps on large suppliers and divestiture would have little, maybe no, impact on the outcome of prices and production. Most importantly, price caps that appear more justifiable in the presence of traditional market power become exactly the wrong approach in dealing with scarcity.

Other Proposals

The Commission identifies a number of other initiatives that seem important, uncontroversial, and overdue. These would include the promotion of greater demand-side response, improved congestion management, establishment of non-discriminatory

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[26] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, Appendix D.

[27] Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000. (available at ksgwww.harvard.edu/people/whogan).

interconnection procedures, enhanced market monitoring, and full implementation of an effective RTO that complies with the spirit of Order 2000.

MARKET REFORMS

The list of necessary reforms for the California market is long, and the difficulty of identifying and fixing all of the problems has been exacerbated by repeated *ad hoc* reforms that have dismissed theoretically sound and proven design principles. A transition will be necessary, but it must be guided by a set of principles that are consistent with a workable, efficient, and sustainable market. The necessary principles have been articulated in a number of different forms and forums.[28] Here we restate and summarize the key principles and their rationale before addressing the transitional steps that will be needed in the near term.

1. *The ISO must operate, and provide open access to, short-run markets to maintain short-run reliability and to provide a foundation for a workable market.*

These short-run markets include, at a minimum, the real-time balancing market associated with the real-time dispatch, along with associated ancillary service markets – for regulation and operating reserves -- necessary to maintain reliability. A bid-based real-time dispatch is the means by which the ISO provides a real-time balancing and spot market, maintains system balance, and provides economic redispatch to manage congestion. We restate this principle first because it has been only weakly embraced in California and is now further threatened by misguided attempts to solve the problem of "underscheduling," a phenomenon whose causes lie elsewhere and whose solution does not require limiting access to an essential market.

While the ISO's real-time dispatch provides the most essential of all short-run reliability functions – it is the true "provider of last resort" in all electricity markets -- the real-time spot market that flows from this dispatch provides the cornerstone for an effective, workable market. Real-time spot prices provide a reference for writing forward contracts and effectively eliminate the problem of liquidated damages when either party fails to perform (i.e., to generate or consume) as expected. Access to this market allows contracting parties to avoid the burden and expense of precise or even approximate load following. Imbalances are simply supplied or absorbed by the ISO's real-time dispatch and the parties are simply settled at the market-clearing spot prices that flow from that dispatch. With an open spot market, moreover, generators have a ready market for their uncontracted output, and loads have a dependable market to obtain energy to meet their uncontracted demand. Hence, the ISO's real-time market is not just a "balancing market," it is an open spot market that provides important options for all market participants and a standard reference and backup for forward contracting.

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[28] For example, see the 17 design recommendations submitted to the Commission by San Diego Gas and Electric Company. "Comments of San Diego Gas and Electric Company on Order Proposing Remedies for California Wholesale Electric Markets, Attachment A," filed November 22, 2000.

In California, this necessary cornerstone of an effective market has been undermined by rules that prevent the ISO from performing an efficient economic dispatch. An efficient dispatch would follow from the voluntary submission of bids from generators and dispatchable loads and the logical, efficient use of those bids by the ISO to arrange a security-constrained, economic dispatch. Such a dispatch would simultaneously balance the system, clear the market and redispatch generators to relieve all congestion, and do so at the lowest as-bid cost, given the bids and the constraints that had to be honored. Security-constrained economic dispatch is the bedrock principle of efficient electricity operations, and it should be the foundation for an efficient real-time market. Yet current market rules in California prevent the ISO from attempting an economic dispatch when the system is congested, instead forcing the ISO to deviate from an unconstrained merit-order dispatch only enough to relieve the constraint but no further, even if a more efficient –i.e., lower-cost – dispatch is possible given the bids. The Commission should direct the ISO to remove this "minimum shift" restriction on economic dispatch immediately.

Once the Commission removes the restrictions on an economic dispatch, it should also ensure that all parties have open, unlimited access to the associated spot market. Unfortunately, the Commission proposes to embrace one of the fundamental design flaws of the California market by imposing penalties and other measures to discourage parties from using the ISO's real-time spot market. Rather than seeing the real-time spot market and open access to that market as the cornerstone for a much broader market, the California philosophy has mistakenly regarded the real-time spot market as a "residual" market necessary only for maintaining real-time reliability. Any use of that market beyond some arbitrarily low level is deemed to be a problem. This is a mistaken view, incompatible with the important role played by the spot market.

The Commission now proposes to approve this flawed, narrow view and to enforce it by penalizing parties that deviate from their forward market schedules by more than five percent. Indeed, the Commission seems dismayed that the market's voluntary use of the ISO's real-time market has "forced the ISO to operate a market," as though the operation of real-time spot markets by ISOs were a novel approach and incompatible with Commission policy and sound market design. This is dangerous view that will only foster restricted, inefficient markets in every RTO.

The Commission should recall that until June of this year, the PJM market, to which the Commission has repeatedly pointed as a model for emulation, consisted of a real-time spot market based on voluntary bids submitted to the ISO in conjunction with arranging a security-constrained economic dispatch. All "forward" markets were entirely bilateral and voluntary, as there was no bid-based forward energy market operated by PJM until June 1, 2000. The key features of the PJM spot market were (and continue to be) open, unlimited access, without penalties. Parties are free to use this spot market to any degree consistent with their commercial interests, and they are entitled (obligated) to receive (pay) the spot market prices for the quantities they sell (purchase) in that market. The success of this open spot market and the important role it plays in supporting the overall PJM market structure were surely understood by the Commission when it declared in Order 2000 that open, non-discriminatory access to a real-time balancing market is necessary to achieve non-discriminatory access to transmission. And this is clearly why a real-time balancing market is a required function of every RTO.

Since June, PJM has also operated a day-ahead market in which parties can bid to buy and sell energy and transmission in an integrated market with consistent pricing. Any yet parties are free to use the forward market or not, and rely on the real-time spot market or not, as best suits their commercial interests. The parties are not penalized for their choices, beyond the requirement that they be settled at the market-clearing prices in whatever market they use.

Both the California ISO and the Commission now seem preoccupied by the fact that substantial percentages of load (and generation) often "underschedule" in the ISO forward markets and show up only in the real-time market, forcing the ISO to scramble to arrange sufficient resources to meet the real-time demand when real-time prices are soaring. The Commission should recognize that it is not "underscheduling" that caused real-time prices to soar or the ISO to have to scramble to meet real-time demand but the high energy prices and capacity shortage. Neither of these problems is solved merely by scheduling resources day-ahead. Indeed, there has been no demonstration that the external resources that were actually made available in real-time to allow the California ISO to meet real-time load would or even could have been offered in the day-ahead markets in which it would be mandated that loads cover their demands.

The reality is that markets do not work well in shortage conditions, particularly when price controls are in place. Underscheduling is merely a symptom of the other more fundamental problems, high energy prices, capacity shortages, and binding price controls. Treating the symptom of underscheduling is in practice a decision to do nothing and to hope for falling gas prices, high hydro-conditions, or a recession to solve the problem.

As the Commission recognizes, this problem of "underscheduling" is in part peculiar to the California market design and pricing rules and is not a serious problem in PJM. Curing the problem of "underscheduling" is thus a matter of fixing the California rules, not restricting access to an essential market. California artificially separates its forward markets for transmission (ISO) and energy (PX), and hence artificially separates its forward energy market from its real-time market. The ISO and PX then use different pricing rules – including different price caps – in their respective markets. For example, a higher price cap in the PX forward markets than the ISO uses in real time provides a strong incentive for load-serving entities to "underschedule" loads in the PX market so that they can gain the protection of the lower price cap in the ISO real-time market during high-price hours. From the loads' perspective, this is not "underscheduling;" it is rational scheduling in the market expected to have lower prices.

In PJM, or the similar market in New York, the incentives tend to be the reverse. While there are no explicit penalties for using the real-time spot market, there are reasons why the real-time prices may be higher if substantial quantities of loads bypass the day-ahead market and show up in real time. Moreover, the PJM and New York ISOs has an important tool -- a tool that the California market designers deliberately forbade the ISO to use -- that it can use to ensure reliability, even if substantial loads show up in real time.

For example, the PJM ISO offers a voluntary unit commitment service based on three part bids. Generators that wish to self schedule their units may do so, but those who wish to have their unit commitment optimized by PJM may submit bids that indicate not only their incremental energy prices but also their start-up costs and minimum generation costs. PJM then optimizes the unit commitment and ensures that enough units are committed to meet the ISO's independent forecast of total loads for the following day. Units that are committed must start up and/or be available on short notice, even if the load does not materialize and the units are not run. If they are not dispatched, or are not dispatched long enough to receive enough revenues at the market-clearing prices to recover their start-up and minimum generating costs, they are made whole. Hence, generators have an incentive to be available if needed.

In arranging the next-day's dispatch, PJM will optimize for all bid-in costs to meet the bid-in load. However, to meet the additional load that it forecasts but that did not bid in or schedule in the day-ahead market, the ISO will commit additional resources but optimize only to minimize start-up and minimum generation costs (but not incremental running costs). Thus, if the additional load shows up in real time, the PJM ISO will have committed enough resources to meet the total load reliably, but the market price may well be higher in real time. The reason is that the additional committed resources will tend to have low start-up costs but higher running costs, thus tending to drive the real-time price higher for loads that did not lock in prices day ahead.

The total effect of the PJM or New York approach is to encourage, but not force, parties to bid in or schedule in the day-ahead market, and to allow parties to use the real-time market as much as their commercial needs dictate. There are no penalties, but the ISO has the resources it needs to maintain reliability. In other words, maintaining reliability does not have to come at the expense of restricting access to the ISO's real-time spot market.

The key to avoiding artificial penalties is consistent pricing. If prices in each market reflect the true system marginal costs, then the incentives to use one over the other would reflect the true cost. There would be no need to be concerned about over or under using any market option.

Moreover, the Commission should recognize that artificial penalties on "underscheduling" can give rise to other bidding strategies by market participants that could make the situation much worse, not better, next summer. In particular, market participants with large FTR positions on transmission interfaces that are unconstrained in real-time could use such penalties to extract congestion charges from loads forced to schedule imports in the day-ahead market. Such cornering in the day-ahead market would be possible with mandatory scheduling requirements, but unsuccessful if customers could just turn to the real-time market as an alternative.

In sum, the Commission should reject the California restrictions on economic, least-cost dispatch for energy and ancillary services and refrain from imposing further restrictions or penalties on those who use the ISO's real-time market. The real-time market should be allowed to become an open, efficient spot market available to all market participants. To the extent that the ISO tends to have insufficient resources available to meet real-time loads, it should offer a unit commitment service to obtain those resources without restricting market choice.

2. *An ISO should be allowed to operate integrated short-run forward markets for energy and transmission.*

Currently, the ISO is prohibited from operating integrated day-ahead forward markets for energy, even though it is charged with operating forward markets for transmission. However, the markets for energy and transmission cannot be separated without creating serious coordination problems that lead to inconsistent pricing and gaming between the markets. These inconsistencies can also lead to infeasible schedules that are accepted in the forward market but which force the ISO to redispatch in real time.

ISO-operated day-ahead and hour-ahead markets can provide useful options to market participants, allowing them to lock in energy and transmission (congestion) prices in advance of real-time. They also provide a mechanism for parties to exchange their transmission rights; that is, to settle their existing transmissions rights and gain new entitlements that match their scheduled transactions.

The Commission should direct the ISO to operate open, bid-based integrated forward markets. These markets would allow parties to buy and sell energy, ancillary services and transmission. The integrated markets could come about by consolidating the ISO and PX or by allowing the ISO to acquire and/or operate the related day-ahead and hour-ahead functions of the PX and to integrate these energy markets with the ISO's transmission markets. The combined markets could then be fully coordinated under a consistent set of bidding, market-clearing and pricing rules.

Just as rules preventing the ISO from achieving an economic (least-cost) dispatch should be removed from the real-time market, so too should rules preventing the ISO from clearing the forward markets and relieving congestion at the lowest cost be removed. Currently, the ISO is prevented by the so-called "market separation rule" from relieving congestion at the lowest cost in its day-ahead and real-time markets. These rules should be eliminated.

The premise of these rules is flawed. The rules state that participants should be required to balance their schedules to match generation and loads rather than providing open access to the balancing service. With an open balancing market provided by an ISO or RTO, these impediments to trading are not justified. There is sometimes an argument that the ISO should not be allowed to effect "trades" between unwilling participants, but the argument has always been backwards. This California rule has historically prevented the ISO from effecting "trades" between parties who would be willing to have the ISO coordinate such trades. Hence, rather than forcing parties to accept an ISO result, the rule prevents parties from getting access to the ISO's market coordination. The "trades" referred to would occur if the ISO used the most cost-effective incremental bid from one party and the most cost-effective decremental bid from another party in order to relieve a transmission constraint in the most cost-effective manner. Thus, the market separation rule as applied to the ISO's forward markets is just another example of preventing least-cost dispatch, or in this case, least-cost redispatch to relieve congestion.

Importantly in the current context, by making market participants balance their schedules and manage congestion using only congestion adjustment bids, the market separation principle is likely to require both more capacity for use by the ISO, in the form of regulation, and more capacity to be held back by market participants to manage congestion (to support adjustment bids). The market separation doctrine may therefore have been an important contributor to the capacity shortages that have periodically affected the California and West Coast markets during the past year. The market separation doctrine and the other inefficiencies built into the California market design were built on an implicit premise that there would always be lots of excess capacity to accommodate that inefficiency. It should be clear after last summer that neither California nor the WSCC can afford that level of market inefficiency.

Moreover, in the long run, the market separation rule may intensify market concentration and facilitate the ability of dominant scheduling coordinators to exercise market power. By forcing the ISO to deal with each scheduling coordinator individually, rather than pooling the adjustment bids submitted by all scheduling coordinators, the rule favors the largest schedule coordinators with the largest and most diverse portfolio of adjustment bids. Over time, the natural advantages will concentrate the market, forcing the ISO to deal with the most dominant schedule coordinator(s) while leaving smaller entities at their mercy. Given its concerns about market power, the Commission should direct the ISO to eliminate the market separation rule and its companion requirement that parties submit only balanced schedules. [29]

Once the ISO is free to use all the bids to achieve a least-cost redispatch to relieve congestion, it can then use that redispatch to deal with all of the congestion in each market. Currently, the California ISO does not solve all congestion in its forward markets, because the market separation rules make it very difficult to do so. Thus, in its forward markets, the ISO uses adjustment bids to relieve only the congestion between existing zones (inter-zonal congestion) but does not attempt to resolve congestion within each zone (intra-zonal congestion). The result is that the ISO is forced to approve schedules in the forward market that it knows are infeasible and that will require it to solve through redispatch in the real-time market. (Note that balanced schedule requirements and restrictions on access to the real-time market would only exacerbate the ISO's real-time redispatch problem.) Further, the ISO's inability to address intra-zonal congestion in the forward markets means that the prices in those forwards markets do not reflect the marginal cost of all of the congestion. The price signals are misleading. At best, they tend to encourage scheduling parties to overschedule the grid in the forward market, causing further intra-zonal congestion that cannot be solved until real time. At worst, they create opportunities for artificially creating congestion that the scheduling parties must be paid to relieve. The Commission should therefore direct the ISO to use the voluntary bids submitted in each market to relieve all congestion in each market, and to do so at the lowest as-bid cost.

If the ISO is to be successful in dealing with congestion in the day-ahead forward market, the model it uses for evaluating congestion must reflect the full complexity of the

[29] If our understanding of the CAISO software is correct, the elimination of this restriction would be easy to implement, as the software relaxes the balanced schedule constraints in the solution process.

grid. Recent "reform" proposals from the ISO and urged by some stakeholders would make this impossible. Instead, they would require the ISO to create and use a simplified "commercial" model of the grid that ignores important constraints. If the ISO used this unrealistic model in the real-time market it could endanger reliability; if it used the model in the forward market, it would guarantee that schedules approved in the forward market could still be infeasible because important constraints had been ignored. There is no escaping the realities of the grid. The ISO should be allowed (required) to use realistic models of the grid when evaluating congestion. Whatever level of modeling accuracy is required to maintain reliability in real time should be applied in the forward markets to ensure feasible schedules and consistent pricing.

3. *An ISO should use locational marginal pricing to price and settle all purchases and sales of energy in its forward and real-time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.*

The Commission will recall that several months before the California ISO and the Commission became preoccupied with the high prices produced by the California market, the Commission had already found the ISO's congestion management system to be "fundamentally flawed" and in need of comprehensive reform. Because the congestion management system implicates many other aspects of the overall market design, the ISO management's process for congestion management reform eventually grew into a comprehensive market redesign process. However, the most fundamental reform needed by the market design and the congestion management process is to get the prices right. The California zonal system is fundamental flawed because it cannot get the prices right. It is time for the California market to solve this fundamental problem by moving to nodal locational marginal pricing.

The Commission appears to have concluded that the ISO can satisfy the need for comprehensive reform of its congestion management system by simply creating a few more zones. The ISO Staff has so far steadfastly maintained that with these new zones, all will be well. It promises to model the system periodically to make sure that its zones remain sufficient and to revise its zones in the future when and if needed. This is the same argument used since the beginning of restructuring in California. It has been an illusion and a license to maintain a fundamentally flawed concept.

The zonal experiment has failed and it must be replaced. It is the source of persistent gaming, infeasible schedules, and poor locational signals. It encourages overscheduling of constrained transmission, fosters market power and muffles the price signals that loads need to respond to high prices. It requires side payments to provide an economic incentive for generators to follow redispatch instructions, but the requirement to make these payments creates gaming opportunities that have been exploited by some generators. It requires constant ISO intervention to offset the poor price signals while forcing the ISO to become increasingly entrenched in centralized resource planning and acquisition schemes. Even when it is not struggling with inadequate supplies, the ISO must still struggle with operating the system, because getting the prices wrong ensures that generators have incentives that will be inconsistent with what the ISO needs them to do to maintain reliability. The experiment has failed, and it is time to end it.

The ISO's most recent congestion management reform proposals anticipate that there might be at least eight new zones (now called "local pricing areas" or "local reliability areas"). The creation of these eight new zones is a positive step, but it should be understood that it will only mitigate, not eliminate, California's recurrent problems with infeasible schedules and intra-zonal congestion. It is important to recognize, moreover, that the creation of eight new zones will likely greatly exacerbate the problems associated with the current form of the adjustment bid based congestion management system. As a result, the ISO Staff has maintained throughout the congestion reform process that it must have additional mechanisms to relieve the new "inter-zonal" congestion between these new zones and the existing zones.

To address this need, the ISO Staff proposed (but the ISO Board rejected) a new two-day-ahead process to select resources in each new LRA. These resources would be required to schedule in the day-ahead market enough energy to ensure that all expected intra-zonal congestion within, and any inter-zonal congestion into each LRA would be relieved. Apparently, the Staff had concluded that reliance on the adjustment bids in the day-ahead market would not be sufficient to relieve all of the congestion, because the market separation rule would effectively limit the number of bids that the ISO could use to relieve constraints at each inter-zonal interface. Thus, an accumulation of flawed rules and their perverse interactions have made the market virtually unmanageable using market processes, forcing the ISO to rely increasingly on command and control measures. More seriously for consumers in the short-run, the combination of eight additional zones and the current adjustment bid congestion management system could pull additional capacity out of the day-ahead markets, increasing the capacity shortage, at a time when there is no excess capacity to subsidize this inefficiency. Retention of the adjustment bid congestion management system and balanced schedule requirements across additional zonal interfaces could give rise to market conditions that would make the outcomes in the California electricity market during the summer of 2000 look good in comparison.

The Commission should not rely on the ISO's assurances that just a few more zones will capture all of the commercially significant congestion within and into California. Such claims have been made before and been proven incorrect. Experience everywhere is that congestion patterns are not stable, and new constraints will arise frequently. Studies of PJM are particularly instructive about the general phenomenon. Last year's constraints are poor indicators of the constraints that are binding this year.[30] And this year's constraints will prove equally poor indicators of the constraints that will be binding next year. As new generation is added at various locations, the congestion patterns will change, and when fuel prices and hydro conditions change, the pattern will change yet again. Trying to predict and lock in the commercially significant constraints, and to define pricing zones around these predictions, is a recipe for getting the prices wrong.

[30] See, Andy Ott, "Can Flowgates Really Work? An Analysis of Transmission Congestion in the PJM Market from April 1, 1998 to April 30, 2000," September, 15, 2000. A soon to be published extension of the Ott study of the PJM market shows that during 2000, there have been over 130 new binding constraints that have not been binding in previous years.

At a minimum, the Commission should direct the ISO to determine and post nodal prices using locational marginal pricing and to use those LMP prices to settle with all generators. The LMP prices should be used in both the forward and real-time markets operated by the ISO. This will eliminate the need for constrained-on and constrained-off payments for redispatched generations, thus eliminating the "constrained-on gaming" and "constrained-off gaming" that have plagued the ISO congestion management markets. LMP pricing will ensure that generators are paid the market-clearing price at their location without having to withhold capacity or guess the market-clearing price. The strategy of drawing the generators into accepting less than the market-clearing price has not worked, and California can't afford the inefficiency any longer. Efficient nodal pricing will send the right price signals for short-run operations and will reinforce what the ISO is trying to do to manage congestion and maintain reliability. The efficient prices will also provide the right signals for long-run investments, obviating the need for ISO restrictions on new generator interconnections. Getting these prices right is the foundation for relying on market-based decisions.

Appropriately metered loads should also have access to the nodal prices at their locations. Giving the right price signals to these loads will enhance the effectiveness of demand response programs, which in turn will provide more efficient prices and help mitigate market power.

For loads without appropriate interval meters, monthly averaging will still be a necessity, and the value of mapping individual loads to individual pricing buses may be limited. However, the prices charged to these loads should be determined as the weighted average of the nodal prices in their pricing area. The choice of each "pricing area" is a matter of retail rate design. At the highest level of aggregation, the area may be the traditional utility service area. Alternatively, the State can be guided by the ISO's studies, such as those used recently to define new local pricing areas. How these areas are defined, and how often, can be determined by the respective state rate-making authorities working with the ISO.

4. *An ISO should offer tradable point-to-point financial transmission rights that allow market participants to hedge the locational differences in energy prices.*

Once market participants are exposed to locational price differences and point-to-point congestion charges, they will need tradable transmission rights that allow them to hedge these locational differences and congestion charges in order to obtain *ex ante* price certainty for their transactions. Point-to-point FTRs will be necessary to support a nodal LMP system.

The current FTRs are not point-to-point but are rather defined across specific inter-zonal interfaces. With the addition of at least eight more zones (LRAs) within California, the existing FTRs would have become increasingly unworkable. The existing FTRs are essentially a form of financial flowgate rights, and the addition of new zones would force market participants to struggle with the need to obtain multiple flowgate rights for each transaction, given the loops within and around the California grid. The ISO and stakeholders were only beginning to recognize the problems of changing distribution factors last Spring when they were overwhelmed by responding to the high price conditions. No clear solution to this problem has been proposed.

The basic problem is that market participants will not be able to predict the power transfer distribution factors that will apply when the ISO solves congestion in real time. This means that participants will not know in advance how the flows of their planned transactions will disperse across each flowgate (inter-zonal interface) and hence will not know how many flowgate rights to acquire at each flowgate to hedge any given transaction. Essentially, this means that there can be no complete long-term transmission rights in the California market. If the ISO continues its current course, flowgate rights will become, at best, illiquid partial hedges, unless the stakeholders convince the ISO to pretend the rights are full hedges and agree to subsidize the difference. If this happens, the price signals will continue to be wrong, as scheduling parties are encouraged to schedule transactions that are infeasible, because their "full" hedges will have been subsidized against the redispatch costs that their transactions impose on the ISO and other market participants.

The Commission should direct the ISO to redefine its FTRs as point-to-point financial transmission rights. Point-to-point FTRs would remain viable no matter where or how many constraints occur and whether or not "new" constraints arise between the points. They would remain viable no matter how the PTDFs changed.[31] Hence, participants could obtain effective hedges on a long-term basis, without fear that their FTRs would leave them unhedged when grid conditions changed.

Moreover, the Commission should direct the ISO to define FTRs in the form of obligations as well as options and to formulate an auction format in which generators can offer such counter-flow FTR obligations, creating a forward counter-flow market for congestion management such as that currently found in PJM (through its monthly auction) and New York (through both its monthly reconfiguration auction and longer-term auctions). This would be consistent with the Commission's goal of eliminating barriers to efficient forward contracting.

5. *An ISO should simultaneously optimize its ancillary service markets and energy markets.*

Experience in New England and California have now amply demonstrated that the short-run markets for regulation and operating reserves must be fully coordinated with the short-run markets for energy. Ideally, these markets should be simultaneously optimized and their pricing rules made consistent. This will ensure that generators receive efficient market-clearing prices in each market and are neither forced nor

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[31] Maintaining each FTR's full hedging ability may require that when there are transmission outages, full FTR funding be maintained even if congestion rentals for a given settlement period fall short. In such cases, the rules could require that FTR funding be reduced *pro rata*, or they could require that surplus rentals from other settlement periods be carried over to fund deficit rentals in other periods. Ideally, transmission owners could be provided a performance incentive for efficient maintenance, while holding them financially responsible for making up any revenue shortfalls in funding the FTRs when lines are down.

encouraged to guess at which market would be the more profitable venue. By optimizing these markets simultaneously, the ISO will ensure that the mix of resources chosen for energy and ancillary services will be the lowest overall cost, given the available bids. By using consistent pricing, generators will be assured that their cost recovery and potential for profits will not be adversely affected whether they are chosen to provide energy, provide regulation or spin, or withheld to provide reserves. If generators are paid consistent market-clearing prices in each market, they will not have to guess the market price or risk bidding mistakes. Instead, generators will have an incentive to bid their marginal costs.

Simultaneous optimization and the associated price cascading are not complicated in principle and can be made to work reasonably well in practice to eliminate perverse bidding and scheduling incentives. Simultaneous optimization and price cascading (and the rational prices they would give rise to) would also permit the CAISO to implement a two settlement system for ancillary services that would avoid paying generators once for reserves in forward markets and again for energy in real-time markets.

6. *The ISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.*

The least controversial reform of market design would be to implement all the changes needed to allow for demand side response in the face of higher prices. This should include changes both in the wholesale market mechanisms to allow for demand side bids in the day-ahead markets and, for properly metered and controllable loads, in the real-time market. In addition, retail rate designs under the control of the California Public Utilities Commission (CPUC) should be such that customers who choose can see the wholesale price and respond to higher prices by reducing their demands. Prices for usage should be based on the market-clearing level. Retail prices in California that are below the cost of fuel, subsidize electricity consumption in California and raise both electricity and gas prices throughout the WSCC. Any rebates should be in terms of reduced connection costs or in some other manner to break the link between average and marginal rates.

Slightly more controversial, but equally important, would be to introduce the same type of demand response for reserves and ancillary services. Not all reserves are equally valuable, and there has always been some tradeoff between reliability and cost. The traditional procedures that embodied this fact have been replaced by rigid requirements in the new market that have the effect of forcing prices to very high levels, much higher than the reserves or the energy are really worth. The Commission has already addressed this issue in principle in the context of recent proceedings regarding the Northeast ISOs.[32] The same arguments apply to California. The reality is that on its worst high load day, the CAISO is purchasing enough capacity to meet load, provide a large amount of regulating capacity, maintain sufficient 10-minute reserves to cover the

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[32] For ISO New England, see for example, Federal Energy Regulatory Commission, "Order Conditionally Approving Congestion Management and Multi-Settlement Systems," Docket No. EL00-62-000, June 28, 2000.

largest single generator outage contingency, and maintain what appears to be another couple thousand mega-watts of extra reserves. The couple of thousand mega-watts of extra reserves have value and contribute to reliability, but they may not have sufficient value to treat their acquisition as a requirement at any cost in potential shortage situations. The CAISO should eliminate absolute reserve requirements in excess of the largest contingency and implement a demand curve, reflecting reserve shortages in day-ahead and real-time prices.

TRANSITION RULES

Pointing to the preferred market design is necessary. A Commission direction to the CAISO to produce a filing that filled in the details would be essential if such a design is to be embraced before events force the road to reform to reverse the course towards greater reliance on markets in a return to cost-of-service regulation, or worse. Furthermore, it is essential to have some framework to evaluate any transition steps, if nothing else to make sure that the transition is headed somewhere that we want to go.

However, knowing the eventual market design goal is not enough. As the Commission has recognized, there is an immediate need for action now to mitigate the most serious impacts in the California market.

Furthermore, it is no longer possible to work with a clean slate. The experience of the California Summer of 2000 was too searing. The political process is now well engaged and there are many proposals for reform that work in opposition to each other or move away from the long-term goal. Faced with this reality, the transition must be considered in terms of the degree to which it meets various objectives.

One proffered objective is ensuring the "protection of consumers." Average prices have been judged to be "too high." The immediate steps going forward seek to guarantee reliable service at an average price to the final consumer that is deemed to be low enough, as well as "just and reasonable." Any transition proposal must address the degree to which it envisions, or even seriously risks, a repeat of Summer 2000.

However, more is required if there is any hope of making the immediate steps a real transition, rather than an *ad hoc* implementation of endless experimental regulation. The transition rules must incorporate as much of the critical market design features as possible along with an internally consistent method of moving from the old to the new. Hence, any transition framework should include explicit consideration of how well it is likely to work in a market setting and how it will ensure a transition to an efficient, workable market.

Consistent with the Commission's policy orientation towards a market approach, transition rules should be biased towards reliance on voluntary commercial transactions. The Commission can mandate market rules, structure and incentives. But it must rely on the incentives for performance. This creates problems given the evolution of the California market. The initial decisions peculiar to the California restructuring have produced new ownership patterns and contractual obligations. These embody public policy commitments made in restructuring that may have been ill conceived, but nonetheless have created obligations in place.

Immediate consumer protection is a debate about how to ensure just and reasonable average prices. When prices are high, there are typically two competing explanations. One is the exercise of traditional market power, the other is shortage that produces high prices through simple competition when demand exceeds supply at lower prices. Untangling the mess in California to distinguish the market power effects from the scarcity effects is difficult. Whatever the source of the high prices, there is the same general flow of the money away from customers and towards suppliers. At the margin, we can have different views about the true opportunity cost, but on average some part of the high prices is a rent transfer from customers to suppliers of electricity, suppliers of natural gas, holders of environmental permits, and so on.

By contrast, markets and their magic are all about what happens on the margin. Transition to a market requires that the market design allow for proper signals for marginal decisions and investments. The desired remedies of greater demand responsiveness, new generation entry and greater operational efficiency all build on the idea that the market participants face incentives that reflect the true opportunity costs at the margin.

Immediate adoption of a number of the key elements of the long-term market design would help in the transition. For example, consolidation of the responsibility for short-term market coordination and reliability management under the CAISO would allow other reforms to proceed. Introduction of better mechanisms for demand side bidding on the energy market would incorporate a reform that all agree is necessary to operate a market and moderate price spikes. Introduction of a demand curve for reserves would better reflect the reality of how electric systems have always been operated but translating that into the context of market bidding and pricing. Allowing the CAISO to perform an economic dispatch that simultaneously optimizes the energy and ancillary reserve markets would remove some of the perverse incentives that lead to pricing anomalies and probably reduce the need for capacity devoted to regulation and supporting adjustment bids. All this could and should be done expeditiously, and need not take a long time.

These changes could only help, would not cost much, and would work both in the short run and the long run. The Commission should not hesitate to direct these changes. However, it is uncertain what their short-term and long-term impacts on the wholesale price level would be, particularly given the additional uncertainties involving gas prices, demand and hydro energy supply. Other remedies are targeted directly at lower prices. These other remedies that might be part of a transition are much more problematic. Here we consider the impacts of taxation, price caps, bid caps, and forward contracts.

Taxation

To the extent that the problem in California is perceived to be that small customers are paying market prices, and market prices are too high, any source of money could be used to reduce the financial impact of the customers' bills even though the customers continue to consume the electricity. An emphasis on taxation to ease the transition would put the focus on the money and not on distortions of the market rules. Hence, the use of tax dollars to reduce the impact of higher market prices could have a significant impact.

Paying taxes is not voluntary, but the burden of the increased taxation would be relatively less when viewed as a part of total income rather than of electricity consumption. Other things being equal, the distorting effects of broadly based taxes are generally viewed as less than those that are more concentrated. Hence, taxing everyone is better than taxing only one sector of the industry. Furthermore, the transfer from taxpayers to electricity consumers would probably not be neutral. The incidence of taxes is not likely to be the same as the incidence of electricity consumption. The payments to consumers might be further limited to only those small residential customers and on a basis that is not related too closely to individual electricity consumption decisions.

There is some precedent in California for considering use of general tax revenues to support the transition in electricity restructuring. At a minimum, this would be a way for the state legislature to address directly some of the problems created by the defects in the original restructuring law and policy. Furthermore, to the extent that such revenues are available, this would be an approach to addressing the overhang of costs from high prices seen in the summer of 2000.

On the other hand, if the source of the problem is high costs for gas and emission allowances and capacity shortages, subsidizing electricity consumption in California could largely serve to further elevate gas and allowance prices, while elevating electricity prices throughout the WSCC.

Price Caps

The transition remedy of price caps does not meet the second objective because it does not allow for this operation of the market at the margin. Setting aside the many difficulties of defining, implementing and enforcing price caps, if a price cap can be enforced and is low enough, it will mitigate the average payments by consumers and reduce the flow of money to the suppliers. But the price cap will exacerbate all the other problems that require incentives at the margin. In the end, either this is a policy that requires load curtailment and reduced reliability or, as we have seen, this will drive the CAISO to find mechanisms where it enters the market to make arrangements for supplies that cannot be obtained under the incentives of the price cap. At best, this will put the CAISO in the role of being the vertically integrated supplier of more and more services. At worst, it will undermine the intent and effect of the price cap.

Price caps might be useful as temporary circuit breaker protection to keep peak prices from reaching very high levels, but not as a way of keeping average prices low. Witness the experience of Summer 2000 with falling price caps accompanying rising average prices. In effect a price cap attempts to reduce the flow of money from consumers to suppliers. It seems simple, but this is deceptive. Price caps have a long and unhappy history. The history says that either of two things can happen. One, we eventually abandon the price cap, but only after enduring substantial costs that defeat its main purpose and make the eventual transition to the market even more expensive and more difficult. Or, the regulatory system accommodates more and more ways to work around the price cap to create all the worst features of cost-of-service regulation going forward. The U. S. experience with the former path is best illustrated by oil and natural gas markets in the 1970-1980s. The unhappy experience with the latter path can be seen in electricity markets in the 1980-1990s, which prompted electricity restructuring in the first place. Going back is not the way forward.

Bid Caps

A bid cap is not the same thing as a price cap. If the cause of market turmoil and high prices is the exercise of traditional market power, then it must be that capacity is being withheld from actual use to supply energy or reserves in the final dispatch. Note that this is not the same as asking for and receiving a high price for capacity that is eventually made available in the final dispatch, i.e. being paid the market-clearing price. If the generation capacity is actually used, high prices must be driven by shortage. Traditional market power entails ultimate withholding.

The bid cap approach would be to identify those suppliers that are withholding in this way and impose on these suppliers an obligation to offer most or all of their capacity into the market at no more than a bid cap.[33] This is intended to remove the ability to withhold, but not require any other changes in the market. In particular, if the true market-clearing price is above the bid cap, then the supplier would receive the market price. If the market-clearing price were below the bid, then the supply would not be called because it would not be needed.

By design, a bid cap differs from a price cap in order to make it compatible with a market and market-clearing price. Hence, when traditional market power can be identified, the bid cap provides a targeted means for mitigating market power. And this mitigation procedure would be compatible with the rest of the market design during the transition. Even bid caps can require difficult evaluations of why generation is not available in the market, was a particular outage avoidable, was the unit brought back as quickly as possible, and so on. Hence if the market power were likely to persist in the long-run divestiture might be preferable to continued reliance on bids caps.

Of course, compliance with the bid cap is not voluntary. The justification for the deviation from the principle of voluntary participation would be a finding of market power. Presumably the restructuring rules were never intended nor could be construed as providing a foundation for protecting the exercise of market power. Furthermore, to the extent that the bid cap is not set too low, the bid cap compels no more than that the existing generator surrender its market power, not that it surrender the normal profits it would earn under the competitive market assumption. The bid cap is selective, and does not apply to new entrants or those who do not have market power.

Bid caps could be an important part of the transition rules. They would not be easy to administer, but they would be much easier to administer than would price caps. However, the very attraction of bid caps means that the effect is limited to mitigating traditional market power. By contrast, if the real cause of high prices is high costs and capacity shortage, where demand outruns supply, then bid caps would not significantly reduce the market-clearing price. The market price would still be set at a high level by some entity lacking market power and not subject to the bid caps. Bid caps would be

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[33] The design of a bid cap is easiest in the case of thermal plants. The question of hydro suppliers that exercise market power might require some other mechanism.

effective in mitigating traditional market power; they would not be effective in lowering prices in a shortage condition.

Forward Contracts

An alternative transition tool that has been prominent in other electricity restructuring efforts has been the vesting contract. The basic idea would have been simple had it been applied in the divestiture process. If utilities sold generating plants, the sale would include a contract for the output of the plant at a price deemed "just and reasonable" over the life of the contract, a period set to cover the transition to the full market operation. These long-term forward contracts would a provide dual beneficial effect. First, they would help reduce or remove incentives to exercise market power in spot markets. Second, they would provide an effective hedge for customers to protect them from higher spot market prices.

The impact on market power would arise because the forward contract transfers the economic interest in the output of a generating facility from the generator to the customers. The generator continues to control production, but now the principal incentive would be to maximize the production from the plant whenever the market-clearing price exceeded costs, just the right incentive to support the competitive market. [34]

The impact on customers' average prices through such forward contracts is obvious. The effect would be to recycle the money on average but not on the margin. Market-clearing prices at the margin might be high, but long-term forward contracts for a significant fraction of total load could serve the purpose of mitigating the financial impact of price increases (and decreases) without giving rise to the perverse incentives of price caps. If such contracts were in place, at least for customers deemed small enough to need protection from the transition market, it could be possible to allow for a market design that provides the right incentives at the margin and allows for a self-enforcing exit from the transition stage. This would still not be trivial, however, for if the problem is in part high costs and capacity shortages it would be important to encourage consumers to reduce consumption, and thus important that consumers see the full marginal price for incremental consumption, rather than some average price that would subsidize continued consumption.

The Commission has recommended encouraging (perhaps requiring) utilities to enter into long-term forward contracts. These forward contracts would be quite different from the vesting contracts described above. In particular, the vesting contracts would have been set at the time of sale of the generation with an energy price then determined to be reasonable. The energy pricing would have been mandatory and the implicit value of the vesting contracts would have been reflected in the sale price of the generating facilities. By contrast, entering into forward contracts after the sale of the facilities is a different matter.

[34] Frank A. Wolak, "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market." International Economic Journal, 14(2), pp. 1-40. (available from http://www.stanford.edu/~wolak) See also, Richard Green, "Britain's Unregulated Electricity Pool," in M. Einhorn (ed.) From Regulation to Competition: New Frontiers in Electricity Markets, Kluwer, Boston, 1994, pp. 73-95.

One proposal suggests emulating a vesting contract by having a contract form, duration and price set in advance and approved in advance by regulators.[35] This suggestion would address the concern of utilities that such long-term contracts be deemed prudent so that the ultimate costs can be recovered in regulated rates charged to customers. While the prudence issue is important, it does not speak to the more difficult question of why suppliers would be prepared to sign such contracts. If the price is set low, it might appeal to regulators, but there is no reason that suppliers should agree to sign such contracts.

If generators did sign such contracts, that might be helpful. However, this could be viewed simply as evidence that the price was high enough to capture by contract the high prices that otherwise would be expected in the spot market. As a means of lowering costs to customers, this would not seem to accomplish the stated objective. It might make prices lower than Summer 2000, but it could also make them higher, even much higher, than the prices of Summer 1999, and it could make them higher than spot prices turn out to be for Summer 2001. On balance, customers might not be better off, and the utilities may be justified in their worries about the *ex post* prudence review.

If the regulatory pre-approved price is set low enough, suppliers may not sign voluntarily. What then? Inevitably there would be calls for using the power of regulation to force generators to sign the contracts. This will present many difficulties. On its face, this approach would abandon the notion of voluntary participation in economic choices. What would be the justification for such compulsion? The justification could not be traditional market power, which could be handled through bid caps. If the problem of high prices arises from high costs and capacity shortage, then use of such mandatory forward contracts would be a rejection of a market approach. In effect, we would be reversing the decisions of restructuring to date and abrogating the deals that had been made in good faith.

At a minimum, it should be recognized that tracking down the deals that have been made would involve a complicated contract chain. Many of the owners of generating plants have already sold some or all of their power forward. Presumably a new mandated obligation to sell it forward again would not be applied to these generators. Would this then mean we would have to trace the ultimate beneficiaries of the forward contracts? The contract chain of further transfers of rights to the hedges could lead to customers already hedged, so we would have to separate these from others. This would require distinctions among the beneficiaries of forward contracts. How would these judgments be made? Without voluntary participation of the parties, how could we untangle the complex contracts and ownership provisions that have evolved? Simply making the pre-approved forward contracts mandatory would not be easy or quick.

One alternative to preserve voluntary participation might be to combine the taxation and forward contract approaches. Suppose there were a class of customers, such as residential and small commercial customers, deemed to be the responsibility of the

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[35] Remarks of Commissioner William Massey (attributed to Professor Frank Wolak of the California Market Surveillance Committee) Energy Bar Association Meeting, Washington, DC, November 17, 2000.

utilities to arrange low cost supplies. The pre-approved forward contract would be defined. This would be defined as a "contract for difference" relative to the locational market-clearing price at the point of load defined by the utility. The utility would decide on the amount of energy to hedge under such contracts. Given the amount, the utility would conduct an auction for the payment that would be required for suppliers to sign the contract.[36] The source of funds for the signing bonus would be from general taxation revenues. Given a decision to have such forward contracts, this would be a means that would allow low direct average prices, market-clearing prices for incremental energy, voluntary participation by the suppliers, and a transition that would be both market oriented and consistent with the move to a more normal market operation. If tax revenues were to be employed, this should minimize the immediate payments required.

This is a way to have forward contracts. But the merits of any forward contracting at this time are far from obvious.[37] Simply put, in a seller's market, pushing buyers to sign long-term contracts runs a greater risk of paying too much than paying to little and is as likely to create new stranded costs as it is to benefit consumers. California missed the window of opportunity of having vesting contracts.[38] The appeal of that foregone opportunity should not cloud our judgment about the realistic opportunities before us.

A Comprehensive Package

Whatever approach is taken to the transition rules, the Commission should continue in the spirit set out in its proposals to provide a comprehensive package for reform. Some of the initiatives, such as improved demand side response, might be desirable no matter what happens. But much of what needs to be done is interdependent.

For example, the beneficial effect of bid caps in mitigating the price impacts of traditional market power might be small if there is still a shortage situation, and a material price impact would depend in large part on the success in developing a demand curve for energy and reserves. In the extreme, without any demand response, bid caps would do little to lower prices in shortage situations.

Similarly, the ability to get a response from suppliers in signing long-term forward contracts will depend in part on how the other parts of the reform package may work. The alternative to some form of negotiated settlement on contracts might be worse for everyone if the effect is simply to ensure the reintroduction of cost of service regulation. At the same time, many or most suppliers might be more willing to enter into reasonable contracts if the rest of the market reforms are included in the package. But

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36 The echoes of the Biennial Resource Plan Update (BRPU) process are noted. Presumably we could benefit from that unhappy experience with complicated bidding schemes by keeping the form of the forward contracts as simple as possible and reducing the bids to the single dimension of the amount required to sign the contract.

37 Scott M. Harvey and William W. Hogan, "California Electricity Prices and Forward Market Hedging," October 17, 2000. (available at ksgwww.harvard.edu/people/whogan).

38 Of course, even if we had replayed history, acquiring vesting contracts at fix low prices might have reduced generator proceeds materially and raised stranded cost recovery requirements.

these suppliers may be unwilling to cooperate if the worst aspects of the market design remain in place and long-term contracts are seen only as a confiscation of assets.

The approval of long-term contracts to preempt *ex post* prudence exposure for what might be relatively high prices would seem to be essential, else the utilities would face the prospect of bankruptcy later to provide others with relief now. Ultimately, there would have to be some resolution that included both the existing overhang of the high costs from the summer of 2000 as well as the high cost that we see going forward.

The sharp change in market conditions presents a major policy dilemma. Looking ahead, the utilities have an interest in advance guarantees of prudence for forward contracts. Otherwise they would face the risk of *ex post* prudence reviews that would apply perfect hindsight to set prices at the "lower of cost or market," reflecting a counterproductive asymmetry in regulation that produced large stranded asset accounts. At the same time, we look today at the existing electricity suppliers who purchased generating assets at costs once seen as high but that now seem low relative to the market. The political pressure is to apply a similarly faulty asymmetric regulation to these suppliers. The dilemma is in finding a rationale for these conflicting tendencies. Any principled argument that applies to one case should apply to other.

Whatever the merits of the argument, the legal situation may be controlling. If the Commission finds that there has been an exercise of traditional market power, then it would be appropriate to determine that the current prices are not just and reasonable. By contrast, if the high prices reflect only scarcity and higher real costs, current prices could be determined to be just and reasonable. Furthermore, if scarcity is the principal explanation of high prices, it would be especially important that the high prices be seen and passed through at the margin in order to provide the right signals for the market. Any reductions in average costs in California should be restricted to infra-marginal transfers that would avoid exacerbating problems throughout the WSCC.

If the legal finding comes down to a conclusion that prices are not just and reasonable, then the Commission may be constrained to a return to cost-of-service regulation if some better solution cannot be fashioned. This finding would change expectations from a continuation of the *status quo* to an anticipation of a prospective regime that would be worse than a comprehensive settlement at this stage. In this environment, a comprehensive package of market reforms, expanded use of bid caps, and negotiated forward contracts might be in the interest of everyone, both customers and suppliers, as preferred to a return to cost of service regulation.

SUMMARY

The Commission has taken a major step in its proposals for California. Its own analysis points in the direction of fundamental reforms in market design. However, this same analysis and the experience of the failed process in California dictate that the Commission travel much further, much faster. The Commission should clarify the responsibility of the CAISO in operating the integrated reliability rules and short-term markets that will be essential for successful operation of an electricity market. The Commission should give quite specific guidance about the design of the future California market along the lines that have worked elsewhere and that reinforce the requirements of Order 2000. At the same time, the Commission should reconsider its use of the soft price cap or any movement to pay-as-bid auctions. The better policy mix for mitigating traditional market power would be a combination of bid caps and forward contracts, but only under conditions where these are part of a comprehensive reform and not simply another short-term fix that creates long-term costs. None of this will be easy, but procrastination or another round of failed reforms in California would be worse.