AGENDA ITEM K-2

CITY OF LODI
COUNCIL COMMUNICATION

TM

AGENDA TITLE: Discuss and Consider Several Items Related to Electric Utility Matters: (1) Adopt Resolution to Sell Surplus California Independent System Operator (CAISO) "Congestion Revenue Rights" for Lodi Electric Utility's Benefit and (2) Receive report Regarding Status of Market Redesign and Technology Upgrade (EUD)

MEETING DATE: March 18,2009

PREPARED BY: Electric Utility Director

RECOMMENDED ACTION: Discuss and consider several items related to Electric Utility matters: (1) Adopt Resolution to sell surplus California Independent System Operator (CAISO) "Congestion Revenue Rights" for Lodi Electric Utility's benefit and (2) Receive report regarding status of Market Redesign and Technology Upgrade

BACKGROUND INFORMATION: The CAISO is currently scheduled to begin operation under its Market Redesign and Technology Upgrade (MRTU) on March 31, 2009. The following is a discussion of several relevant items related to MRTU.

1. Conaestion Revenue Riahts

The Federal Energy Regulatory Commission in 2002 proposed new rules aimed at making the nation's electricity industry more efficient. One of those strategies included the creation of "Congestion Revenue Rights." CRRs are property rights that can be traded through an open market with the holders having the right to move electricity along a portion of the transmission system when demand for power is high, crowding available pathways.

In California, this market-based system of securing transmission rights goes into effect on March 31, 2009. Because the price of transmitting energy between designated points is determined through an Internet auction and uncertain, the CAISO is allocating Congestion Revenue Rights to utilities serving retail customers, such as the Lodi Electric Utility. For EUD's benefit, the Northern California Power Agency holds EUD's allocation of CRRs – some of which will be used to hedge physical transmission paths used by EUD to import power into Lodi and some of which are not needed for physical transmission of power but will have financial value instead. (This agency relationship between NCPA and EUD on CRR matters was approved City Council Resolution 2007-103 on June 6,2007.)

On behalf of EUD and other NCPA Pool members, NCPA will be strategically marketing surplus CRRs. They are expected to have significant value in the forward market. If held until "real time," however, there is a small risk these surplus CRRs can become a financial liability. To eliminate the risk of such a liability

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APPROVED:

or cost, NCPA plans to sell surplus CRRs in advance of real-time through an auction to be held by the CAISO.

As noted earlier, the City Council has previously approved NCPA as EUD's agent for CRR transactions with the CAISO. NCPA's General Counsel, however, has requested that this authority be explicitly extended to the marketing/sale of surplus CRRs in the forward market. Therefore it is recommended the Council approve the attached resolution to clearly authorize NCPA to offer and sell surplus CRRs on behalf of EUD.

2. Market Redesign and Technology Upgrade (MRTU):

As noted earlier, the CAISO is planning to "go live" with its new MRTU program on March 31, 2009, although some delay is possible.

Under MRTU, CAISO is creating and managing Day Ahead and Real-time "energy markets." The basic design of MRTU was approved in September 2006 by the Federal Energy Regulatory Commission, which has oversight responsibility for regional transmission organizations (RTOs) such as CAISO. For the CAISO, this has been a multi-year project to develop an extremely complex software model with the goal of efficiently managing limited transmission by using market forces to deal with congestion on the California transmission grid. During this time other market participants have also been required to develop software to interface with the planned MRTU market. NCPA manages the CAISO interface for NCPA Pool members such as Lodi.

There are a number of major issues with MRTU such as:

- Will the CAISO's software/hardware be ready for "go-live"?
- Will market participants, including NCPA and Lodi's energy suppliers, be ready to interface with CAISO?
- Will the overall MRTU program perform as advertised?
- Will there be significant economic/cost impacts of the new MRTU market system?
- Can CAISO handle the massive settlements process since all electricity transactions flow through them for settlement?

MRTU, and the so-called Standard Market Design it implements, is enormously complex and controversial. Public power electric utilities in California fought implementation of MRTU for many years in the legal and regulatory arenas until it was eventually approved by FERC. Since that time, public power agencies have worked hard to ensure that the details of MRTU were set up fairly for all market participants and for the consumers of the State. The American Public Power Association has been a significant ally for public utilities in questioning the value of MRTU and similar RTO markets (there are 5 other RTOs that operate markets in the United States).

We question the value, too, out of fear it may lead to significant unexpected costs that must be passed on to our ratepayers. California's previous experiment with open power markets had disastrous consequences because of illegal market manipulation and we have no assurances that will not be repeated.

Attached to this Council Communication are several documents to provide background on the implementation of MRTU specifically and RTO-run markets in general:

1. MRTU Update, written by NCPA, March 2,2009 (1 page)
2. MRTU FACT Sheet and timeline, prepared by CAISO (1 page)
3. Series of One Page MRTU-related Summaries, prepared by CAISO (8 pages)
4. Frequently Asked Questions about MRTU, prepared by CAISO (5 pages)
5. FERC Press Release (Fact Sheet) on MRTU Approval, September 21,2006 (5 pages)
6. Fact Sheet titled "Wholesale Electricity Markets, by APPA, February 2009 (4 pages)
7. Report titled "Consumers in Peril – Why RTO-Run Markets Fail to Produce Just and Reasonable Rates", prepared by APPA, February 2008 (35+ pages)

FISCAL IMPACT: Revenue from the sale of CRR's would accrue to EUD's benefit hence lowering net power costs. The impact of MRTU on Lodi Electric Utility is unknown.

FUNDING: Not applicable.

George F. Morrow
Electric Utility Director

MRTU Update

The California Independent System Operator (CASIO) has made a readiness certification filing with the Federal Energy Regulatory Commission (FERC) indicating that they will implement a new market design within California on March 31,2009. The CAISO is the organization that operates the vast majority of the electrical grid in California, and through its tariff, specifies the rules under which electricity will be purchased, sold and delivered for over 80% of the states residences and businesses, including NCPA members.

The new market design known as Market Redesign and Technology Upgrade or MRTU has been in development for approximately seven years and will dramatically change the way that utilities arrange to procure and pay for electricity that is ultimately delivered to their customers.

The CAISO has retained three independent experts to attest to CAISO's readiness to implement MRTU, and who either have, or will certify that:

- Market design software calculates Day Ahead and Real Time electricity prices accurately and consistent with the MRTU tariff
- Settlement software correctly calculates invoices in accordance with the MRTU tariff
- Applications and systems that constitute MRTU were developed, built and tested in accordance with the MRTU tariff

CAISO is also endeavoring to put in place mechanisms that will allow it to respond to unforeseen events such as unexpectedly high prices or defects in the overall design that might force either corrections to invoices or a complete rollback to the existing electric market design.

Despite all of the assurances of readiness offered by the CAISO and its experts, market participants such as NCPA, municipal utilities in southern California and large investor owned utilities such as Pacific Gas & Electric and Southern California Edison all remain concerned that critical MRTU systems are not performing as expected, and as a result, that the CAISO is not as ready to implement the new market design as claimed. Included in the concerns of these market participants are:

- The inability of the CAISO to produce one clean/accurate invoice during simulation exercises
- High unexplained prices occurring during simulation
- Inaccurate dispatch instructions to generators which could affect grid reliability
- Incomplete descriptions of safety net processes to protect against inordinately high electricity prices

To address these ongoing concerns, NCPA, on behalf of its member municipal utilities in northern California will continue to work with the CAISO and other market participants to attempt to resolve all remaining outstanding issues prior to the proposed "go live" date of March 31st. In the event remaining outstanding issues cannot be resolved, NCPA will also work with all appropriate regulatory and legislative bodies to defer or delay MRTU should further delays to implementation be warranted to protect the financial stability of NCPA members or the reliability of the electric grid.

March ***2,2009***

Northern California Power Agency

California ISO
Your Link to Power

Fact Sheet

Market Redesign and Technology Upgrade (MRTU)

MRTU esitsroots back to initiatives introduced in 1998. The current work began in earnest Sept. 21,2006, when the Federal Energy Regulatory Commission, the ISO lead regulator, accepted the most recent design proposal.

The new market further ensures power suppliers have fair and open access to the transmission system within the ISO control area, resulting in the delivery of the least cost electricity to consumers.

The redesign introduces a day-ahead market for energy (electricity produced for resale) that helps firm up next day production and delivery schedules as well as enable grid operators to manage transmission boitlenecks efficiently so that electricity flows without interruption.

MRTU is actually two projects. One creates the software needed to manage ail aspects of the market from power generators, to the transmission grid and eventually to the companies that deliver electricity. The other upgrades ISO computer hardware with technologies capable of running the sophisticated market software.

The several different elements of the new market redesign, working in concert, manage the state's electricity transmission system more efficiently and at less cost.

In addition, simultaneously managing of energy and transmission resources eases the time/price differential of today's market and reduces the opportunities for gaming the system.

New Features

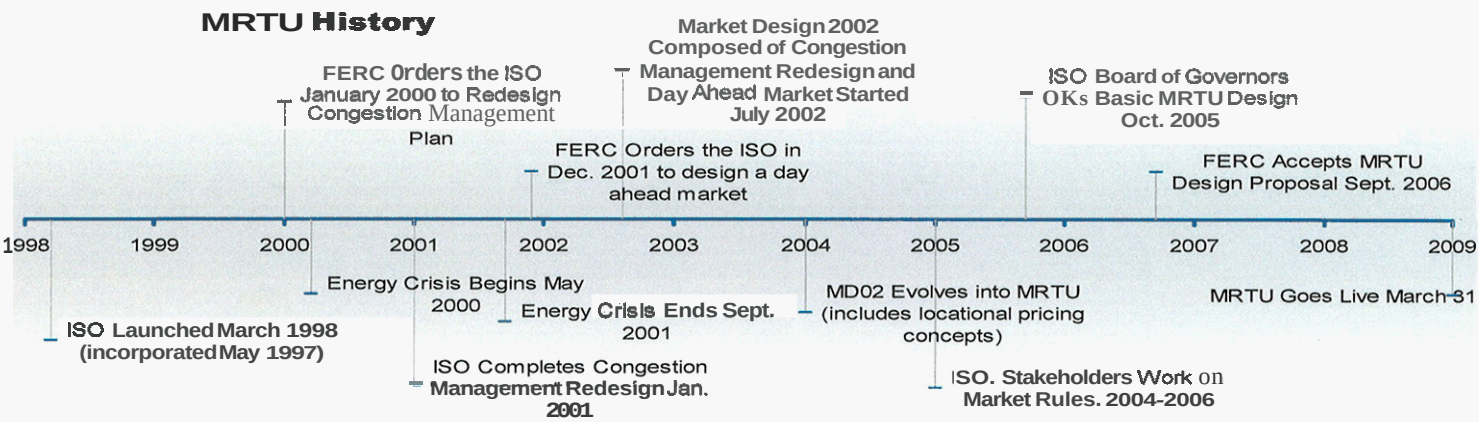
- Integrated Forward Market — is comprised of the day-ahead market, ancillary services (electricity reserves) and transimission management. Managing these resources at the same time is much more efficient and reduces the opportunity for market manipulation.
- Day ahead market — allows buyers and sellers to trade energy a day before it is needed.
- ILocational Marginal Pricing — when filly implemented sets wholesale electricity prices at 3,000 different system points (nodes) that reflect local generation and delivery costs. Grid users see higher costs nodes and avoid them, which also lowers costs.
- Full Network Model — this is a sophisticated computer model that enables the ISO to analyze the state transmission network to see how power is flowing and then to better manage energy schedules, thus avoiding bottlenecks and saves the expense of rerouting electricity.
- Congestion Revenue Rights — this is an auction system for reserving and allocating space on the transmission wires that helps power companies manage their delivery costs and avoiding surprise expenses to reroute electricity around bottlenecks.

Additional MRTU information is available on the California ISO website at www.caiso.com

Benefits

- The Integrated Forward Market links the day-ahead market for energy and ancillary services (electricity reserves) with the real-time market, which balances load on the grid on short notice. The software analyzes the best use of the grid and helps create pricing consistency between what generators have scheduled a day in advance and what the ISO needs in real-time to meet demand.
- Having a day-ahead market ensures generators deliver power in real-time as promised. This also helps grid operators avoid having to call upon standby generators at the last minute to fill supply gaps, which charge higher prices to respond quickly to ISO orders.
- Locational marginal pricing reflects the cost of generating electricity as well as the cost of transporting the power (currently only the cost of generating is transparent). LMP also provides a signal for where new wires or power plants will reduce consumer prices as well as assure developers a return on investment.
- The Full Network Model computer simulation saves money by enabling grid operators to see bottlenecks and then reroute power to avoid the congested higher-priced areas.
- Congestion revenue rights are like insurance that protects rights holders, often utilities, from the cost of untangling transmission bottlenecks. It also ensures price certainty for transmission customers, letting them avoid any surprise expenses to reroute electricity around bottlenecks.

MRTU History



California ISO Background

Clear, consistent market redesign is the sturdy framework for a fair and open power system. A healthy energy marketplace leads to innovation and impartiality. It is the heart of this hub for electricity — the California Independent System Operator (California ISO).

Who is the California ISO?

The California ISO is a not-for-profit public benefit corporation established in 1996. It began operating the bulk of high-voltage, long-distance transmission lines in California in March 1998. The ISO is dedicated to:

- Managing the safe and reliable flow of electricity on California's high-voltage power grid.
- Ensuring fair and open access to the transmission grid for all qualified users.
- Providing market and grid information with integrity and impartiality.

How Does the California ISO Do Its Job?

As guardian of open access to the grid, the California ISO acts as the impartial link between power plants and the utilities that provide electricity to customers. This provides a fair and level playing field for energy companies that want to use the 25,000-circuit mile wholesale transmission network. The California ISO is the gatekeeper to more than two-dozen pathways of power connecting California with neighboring states as well as Mexico and British Columbia. Charged with ensuring safe and reliable operation of the grid or "keeping the lights on," the California ISO is a traftic controller of sorts, managing bottlenecks that could overload key components and stop the flow of electricity.

The ISO also matches the demand for electricity the instant it is needed with just the right amount of megawatts. Because electricity cannot be stored, the ISO forecasts how much power customers will need at any given time and makes sure that standby power plants are available in case something goes awry.

What is more important; generation or transmission? Both are critical, as evidenced during the energy crisis of 2000/2001. Essentially, you can't have one without the other. More than 10,000 megawatts of new power plants were built in California between 2000-2003, but the power lines that make up the grid are often overcrowded, limiting where power generation can come from and where it can go. (For context, one megawatt is enough electricity to power approximately 750 homes).

Open Access

The ISO addresses crowded power lines via an electronic transmission market that allocates limited space for transmitting electricity. This market is conducted a day before and an hour before the electricity is due to be delivered. Energy suppliers participate in the transmission market by offering to reduce their usage of an overcrowded line or by offering to increase deliveries on another line that can feed the same zone without adding to the congestion. However, sometimes the financial solution of the auction doesn't completely meet the needs of the physical reality of grid reliability. The ISO provides the grease in the gearbox that safely and reliably smoothes over any discrepancies between the auction system that determines which entity gets access to an overbooked power line and the physical world of power-flow engineering.

Redesign for Reliability

Energizing the electricity market in California are two parallel programs: 1) Reliability and Market Improvements to assure grid reliability and 2) Technology and Infrastructure Upgrades to strengthen the computer systems that run the ISO power grid. These programs have been merged into one initiative called Market Redesign & Technology Upgrade (MRTU). The benefits of MRTU include:

- Reduced dependency on the ISO Real-Time Market; stabilizing costs and enhancing reliability.
- Elimination of certain opportunities for market manipulation and gaming.
- Updated control room computer systems that replace aging infrastructure and take advantage of technological advances made in past five years.
- Efficient and least-cost approaches in the operation of the transmission system.
- Wholesale price signals to help guide appropriate investment in California's electricity supply.

Why Does California Need a New Market Design?

The original ISO market design has been improved upon, but still contains inefficiencies that can make the electricity market vulnerable to manipulation. The energy crisis of 2000/2001 brought some of these flaws to the surface. The Market Redesign and Technology Upgrade (MRTU) is central to providing the framework for reliable operations of the grid in the long run. It provides ISO operators with the tools necessary to plan for known bottlenecks in the power grid in advance of real-time—allowing hours, rather than minutes, to consider options for scheduling electricity in a manner that will meet the needs of California consumers. It also replaces the "missing market" for electricity bought and sold a day ahead of time. That market disappeared when the California Power Exchange shut down operations in 2001. The new market design will also take into account long-term contracts for power signed during the energy crisis — pinpointing any delivery problems before the electricity actually flows on the system.

Nodal vs. Zonal: Key to Addressing Overcrowded Areas of the Grid

The original ISO market design was a "zonal" system, as opposed to a "nodal" one that allows a more detailed view of the transmission system. The zonal system divides California into three large zones that provide limited information about how day-ahead energy schedules will interact on the grid in real-time. It was assumed that transmission lines connecting one zone to another might become overcrowded, and the ISO developed a system to deal with that "inter-zonal congestion". It was also assumed that congestion within the same zone (intra-zonal) would be minimal in scope and cost. That turned out not to be the case. Dealing with intra-zonal congestion within the current market design can add $5-10 million a month to the cost of delivering electricity to California consumers. It is a significant problem with the addition of new power plants in the California ISO Control Area. The new generation is welcome, however some of the newly constructed power plants are connected to log-jammed sections of the power grid. As many as 1,700 megawatts of electricity *can* be "stranded" at the power plant due to inaccessibility to the grid.

The solution to intra-zonal congestion is a nodal system that divides the state into hundreds of separate "nodes" that represent generation and load points on the transmission grid. A nodal system, coupled with the use of a detailed computer model of the grid, will make it possible to determine if requests for transmission use can be accommodated as early as the day before electricity actually flows. Currently, scheduling conflicts within one of the three big zones are invisible until real-time, compromising the ISO's ability to operate the grid reliably. Our new market design will allow us to see all potential transmission line traffic jams a day ahead of time, instead of five minutes before the electron traffic has to be rerouted.

Missing Market

The only energy market that the ISO operates currently is the Real-Time Market for energy, which is needed to balance supply and demand. Under restructuring, most of the trading of electricity via a day-ahead wholesale energy market was performed at the California Power Exchange (PX), created at the same time as the ISO. The bulk of next day energy needs were traded at the PX, which submitted schedules from its day-ahead energy market to the ISO. As the independent transmission operator, the ISO determined whether the submitted schedules could be delivered as planned. However, in the wake of the energy crisis, the PX shut its doors and ultimately filed for bankruptcy.

Utilities now rely on long-term contracts and their own generating units to supply most of their customers' power needs, but there is no organized market held 24-hours ahead of time to meet the changing demand for energy. The hole left when the PX shut its doors can leave too much reliance on the ISO Real-Time Market. Just as buying an airline ticket at the last minute can be costly, so too can purchasing megawatts right before you need them in the Real-Time Market. That's why the California ISO market redesign includes a Day-Ahead Market for energy.

The Basics: MRTU Programs

On June 24,2004, the ISO Board of Governors approved two parallel programs, managed as one ISO initiative in order to gain economic and technical efficiencies:

- Market improvements to assure grid reliability and more efficient and cost effective use of resources.
- Technology upgrades to strengthen the entire ISO computer backbone.

Market Redesign

- Allows the ISO to conduct a Day-Ahead Market that combines three services; energy, ancillary services (operating reserves) and congestion management to better match what really happens when the electricity flows. The forward or Day-Ahead Market determines the best use of resources available, while finding the least cost method of procuring required components. With the bankruptcy of the Power Exchange in 2001, there is currently no centrally organized day-ahead energy market in California. By starting this process in the day-ahead time frame, there is less reliance on the more volatile Hour-Ahead and Real-Time Markets.

- Provides a more precise model of the grid using the latest computer technology to allow the ISO to better predict how energy scheduled a day ahead of time will flow in real-time. The ISO will be able to see ALL potential transmission line crowding a day ahead of time, rather than waiting until real-time. Once power is flowing, options for making adjustments are limited and potentially more expensive, and such adjustments present challenges to reliability.

- Introduces new market rules and penalties that prevent Enron-like gaming and manipulation. The ISO is charged with keeping the grid reliable. It does so by issuing dispatch orders to energy suppliers to increase or decrease the amount of energy they have successfully bid into the market. But the ISO had limited authority to compel suppliers to respond to dispatch instructions. The ISO has been granted new authority by the Federal Energy Regulatory Commission (FERC) to assess financial penalties on market participants that do not comply with instructions from the ISO control room. The new market design also determines the deliverability of all schedules, rejecting requests that are physically impossible.

- Produces local prices that eliminate the distinction between inter- and intra-zonal congestion. Locational Marginal Pricing (LMP) essentially shows the cost of producing power as well as the cost of delivery. This gives the ISO and market participants a clearer picture of the true cost of getting power to areas that may not have enough local generation or where transmission capacity is lacking. It will find and block infeasible day-ahead schedules—those that cannot fit on the grid.

Technology Upgrade

- Prior to the market redesign effort in 2001, the ISO began assessing its future systems and infrastructure needs as the computers originally installed at start-up began to approach the end of their useful lives. A "fence and reinvest" strategy was initiated, with the ISO seeking to minimize maintenance costs and further investment in outdated systems while developing new systems based on a more open architecture that offers greater flexibility and allows for more cost-effective changes down the line.

- Because power grids depend on the latest computer technology to help manage loads and resources, their reliability drives the reliability of the grid. New computer systems are designed to minimize downtime and the possibility for interruption, enabling grid operators to manage the transmission system more effectively and giving them a better forecasting tool to spot potential bottlenecks on power lines before electricity actually flows in real-time.

Just as home computers become outdated over time, the ISO computers are in need of updating after seven years of operation. New computer systems will replace the existing systems that have been "patched" more than 400 times over the years. Replacing the aging infrastructure also takes advantage of technological advancements in the past five years.

Scheduling Energy Under a New Paradigm

Utilities or energy service providers cannot always cover 100 percent of their customers' electricity needs. Even those that can always look for opportunities to meet the requirements as cheaply as possible, and they will skip using one of their power plants if they *can* buy reliably on the open market for less. In part, facilitating purchases and sales is one element of the market redesign. Even if utilities line up all their customers' power needs ahead of time, the ISO must match supply and demand to assure that power flows on the grid reliably in real-time.

To make that assessment, every day and every hour, wholesale energy suppliers and the utilities that serve end users submit schedules to the ISO that detail which power plants will supply power at what level, at what time, and at which point on the grid. These schedules are analogous to "flight plans" for electrons. The ISO makes sure that thousands of day-ah4 and hour-ahead schedules, and any adjustments made to them, will all "fit" on the grid without overloading sensitive equipment or exceeding reliability rules. Sometimes that means adjusting schedules to avoid overloads that can be predicted ahead of time. However, current systems cannot "see" all the potential overloads from the day-ahead scheduling process. It's like an air-traffic controller who cannot tell ahead of time if a pilot's flight plan will conflict with other pilots' flight plans. Under its new market design, through the use of the Full Network Model and the Integrated Forward Market system, the ISO, which acts like a traffic controller for electricity, will have the ability to electronically evaluate the routes chosen before clearing energy schedules for "takeoff.

The ISO can operate the grid more reliably when it can "see" all the congestion from the day-ahead schedules in advance, allowing it to make other arrangements. That's why, as part of its market redesign, the California ISO is developing a Full ***Network Model*** of the grid and a computerized simulator that can analyze the schedules submitted today to make sure the energy can actually flow safely and reliably tomorrow. If the system detects bottlenecks, the ***Integrated Forward Market,*** also part of the redesign, will allow the ISO to adjust day-ahead schedules to address the bottlenecks. ***Locational Marginal Pricing,*** another part of the new market design, makes it easier for the ISO and others to see the least-cost option for adjusting those schedules.

The market redesign is a complex set of changes, but it can be boiled down to three main elements:

- ***The Integraled Forward Market (a Day-Ahead Market)***
- ***The Full Network Model***
- ***Locational Marginal Pricing***

The Integrated Forward Market (IFM) is a one-stop shop for all three of the main services the ISO uses to operate the grid; Energy, Ancillary Services (operating reserves) and Transmission Management. Beginning in the day-ahead time frame, the IFM will determine the best use of the resources (mostly generation and imports) made available to meet the scheduled energy requirement and provide necessary reserves. This will be done in a manner that *can* be transmitted on the grid without creating bottlenecks based on the expected grid conditions. Currently, the ISO does not have the tools or procedures in place to operate an organized day-ahead energy market, making this kind of one-stop shopping impossible. Furthermore, if the scheduled energy requirement is less than the ISO next day load forecast, any leftover resources can he made available in the Real-Time Market. Finally, the ISO will continue to fine-tune the grid, using the IFM system to make adjustments in real-time based on changing conditions. Making those adjustments with IFM builds on the forward market schedules and provides pricing consistency between the two time frames, something lacking in the original design.

The Full Network Model (FNM) refers to a new computer program that "models" the entire ISO-operated grid, taking into account all known limitations and predicting how power will actually flow. It's like a simulator for pilot training. The ISO will use this accurate and detailed computer simulation of the grid to determine if the energy schedules submitted hy various entities will actually be able to flow on the grid. The less sophisticated model currently used by the ISO to analyze schedules is not programmed to recognize all the possible problems. In simpler terms, the ISO will be trading up from a magnifying glass to a microscope to preview the grid. The Full Network Model will allow the ISO to analyze forward schedules and "see" all the potential power line crowding before it actually occurs, allowing ISO operators to plan accordingly.

Read About **LMP** >>>>

Congestion Management: Inter-Zonal vs. Intra-Zonal

One of the biggest flaws in the ISO market structure is the difference in the way two types of gridlock are currently handled:

- **Inter-Zonal Congestion:** The ISO-controlled grid is divided into three main "zones" that roughly correlate to northern, southern and central California. Overcrowding on power lines that connect one zone to another is called "inter-zonal congestion." When this type of bottleneck occurs, the ISO computer systems currently can rearrange the schedules automatically in the day-ahead time frame to prevent an overload in real-time, provided that the rearranged schedules operate as planned and that grid conditions don't change significantly.

- **Intra-Zonal Congestion:** Many high-voltage power lines are fully contained within one of the current zones. These lines can be overbooked, too, creating "intra-zonal congestion." The ISO computer systems were not designed to look at intra-zonal congestion from the day-ahead schedules, so any overbooking is allowed to stand until real-time. This is an inherent flaw that continues to create operational difficulty and add to costs. ISO control room staff are forced to rearrange schedules in real-time to compensate for the day-ahead schedules that can't all actually tit on the grid. It can be more costly and creates unnecessary reliability risks.

A Simple Example of How Congestion Management Works Now

Imagine a straight line marked with points A, B, C and D. There are generators at points A, B, and D and "load" or an energy consumer at point C. Generator A has a contract to send 100 megawatts of power to the load at point C.

But on summer afternoons, the demand for energy at point C rises to 150 megawatts. The generator at point B submits a day-ahead schedule to the ISO, indicating it wants to send **50** megawatts to point C. But, the line between A and C is limited to 100 megawatts. This overbooked line, or "intra-zonal congestion", is invisible to the ISO until real-time.

The ISO cannot arbitrarily decide which generator should get access to the overloaded line and which one should reduce its schedule, but one or both generators at A and B must decrease or (DEC) their output by a total of **50** megawatts to keep the A-to-C line from overloading. The consumer at C still needs **50** megawatts of power to make up for that which can't be delivered by A or B. The ISO calls on the generator at point D to increase or (INC) its output by 50 megawatts. Because of its location, it is not affected by the 100-megawatt limitation at what would be the inter-zonal boundary. But the current system doesn't check for any lower level bottleneck between D and C, or at the intra-zonal level. So even if the inter-zonal bottleneck is resolved, it is possible to create another intra-zonal bottleneck with the solution, something that the new system will take into consideration.

That is "congestion management" in its most simplistic form. Multiply this by thousands of miles of transmission lines, hundreds of generators, and an ever-fluctuating demand for power, and yon will see that managing congestion can quickly become a very complex endeavor.

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(Gen)                (Gen)        (100 MW limit)   (Demand)                (Gen)
A———————————————B———————————///———————C———————————————D
Power flow from A and B to C >>>>>>>>>>>>>>>>><<<<<<<<<<<<<<< Power flow from D
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California ISO
Your Link to Power

Congestion Revenue Rights

Insurance Against Variable Congestion Costs

Congestion on the grid occurs when the total desired energy flows scheduled by buyers and sellers of power cannot fit on the power lines. This is when the ISO steps in and reschedules the electricity deliveries. Buyers and sellers whose power is reshuffled will be assessed congestion charges that reflect the cost of rearranging the desired schedules to fit the grid. These congestion charges will vary from season to season, from day to day, and from hour to hour within the day, and they can he very hard to predict. The ISO offers a kind of insurance against these unpredictable charges. Called Congestion Revenue Rights (CRRs), these insurance "coupons" entitle the holder to a payback of hourly congestion charges to offset a major portion, perhaps even the full amount, of the congestion charges they have to pay for using the grid.

Under the new market design, the ISO will allocate CRRs, free of charge, to end-use customers located within the ISO transmission grid. The objective is to provide, as accurately as possible, the correct quantity of CRR coupons to offset fully the annual congestion charges the customers will be assessed. In practice, the CRRs will actually he allocated to the utilities or retail energy service providers responsible for serving the customers, not directly to the customers.

The ISO will also allocate CRRs to companies that invest in building new transmission facilities (that do not get paid back for this investment through any kind of customer surcharge). The objective in this second type of allocation is to enable the investor to earn the congestion charges that are paid by other parties who use the new facilities added by the investor. After conducting these allocations on an annual and monthly basis, the ISO will hold annual and monthly auctions for CRRs in which any qualified parties may bid to buy and sell CRRs. This will enable parties that are not eligible for free allocations of CRRs to invest in CRRs as a way of smoothing out or "hedging" the unpredictable hourly congestion charges they will he exposed to under the new market design.

Locational Marginal Pricing (LMP) divides California into thousands of points or "nodes" on the transmission grid instead of three main "zones". Distinct prices at the different nodes axe used to determine the most cost-effective use of resources to resolve transmission bottlenecks. Locational Marginal Pricing (LMP) will provide more information about the real cost of delivering power to customers. Buyers and sellers can make informed decisions about energy pricing based on the ability to produce and deliver power to where it's needed and, over time, help to determine the best locations for new generation. Wholesale prices for energy will vary, depending on the ability to produce or contract for power that can be easily delivered to where it is needed. LMP will not affect retail rates, so residential and business customers should not see any changes in their utility bills. The new pricing system simply provides market participants the correct signals, so they can make wise choices at the wholesale level.

The LMP pricing method is working well elsewhere. LMP is the preferred method for dealing with transmission traffic jams and determining the least cost method for meeting electricity demand It is used by all of the ISOs in the eastern and central United States, where it is successfully reducing costs and increasing reliability.

California ISO
Your Link to Power

Putting a new market design in place while the ISO continues to operate on a daily basis has been compared to doing a major engine overhaul on your car and changing all four tires, while you're traveling down the highway at 60 miles per hour. So, the ISO is implementing the plan in phases.

Phase 1A—October, 2002

Phase 1A gave the ISO a new tool, the Automatic Mitigation Procedure (AMP), to combat "market power." Market power is the ability of a buyer or seller to significantly change the price of electricity through its behavior. The new automatic process compares previous offers to sell energy to current market conditions and to each generator's recent bidding history. If the price of those offers is found to be too high, *AMP* automatically lowers the bids to a preset "reference level" based on the cost of producing power from that generator. Phase 1A also continues the "must offer" rule, which requires generators to offer their capacity into the real-time market. It also establishes a **$250** damage control price cap that acts as a backstop to AMP. Together, these rules and systems are designed to reduce, if not eliminate, the opportunity and incentive to exercise market power.

Phase 1B—Fall 2004

Phase 1B of the Market Redesign &Technology Upgrade (MRTU) program is a new set of rules and tools developed for control room operators and market participants to automate the routine activities of the Real-Time Market. The program helps generators respond to ISO dispatches more quickly and accurately. The result is greater consistency and efficiency in grid operations as well as the least expensive power to meet customers' needs. Phase 1B is a key step toward a more reliable and least-cost electricity system for California. There are **two** main components of Phase 1B:

- **Economic Dispatch** ensures the best resources are selected to meet the demand for electricity. In this case, "best" means most reliable and cost effective, which is good for California consumen who want dependable and affordable electricity.

- **Uninstructed Deviation Penalties (UDPs)** ensure that once a generator's bid is accepted and dispatched, the generator delivers the megawatts when and where they **are** needed. If they fail to do so, the Federal Energy Regulatory Commission (FERC) has authorized the ISO to levy tines in order to ensure markets are fair.

What are the benefits for California? Phase 1B and the MRTU program together are key to the state's electricity future. It's a win-win for everyone:

- California's utilities and consumers get what they are seeking — reliable and cost-effective electric service.

- Generation owners are better able to manage their units because they are clear about how the ISO system is operating and what is expected from them.

Market Redesign and Technology Upgrade (MRTU)

Frequently Asked Questions

1. How will **MRTU** improve grid operations in California?

Most importantly, MRTU improves reliable management of California's transmission grid by using an accurate model of the transmission system. Today's rules permit a serious disconnect between expected power flows and the real time impact on the transmission network, thus requiring ISO operators to manage congestion and avoid overloads in real time. MRTU fixes these flaws by creating rules for a "day ahead" market and scheduling process where:

a) power flows over the next **24** hours are scheduled and modeled according to actual grid conditions and the laws of physics;
b) the risk of shortages is assessed and minimized in advance; and
c) the power flows in real time as grid operators expect from the network models.

In addition, MRTU will provide clear, stable rules for buyers and sellers in California's wholesale electricity markets as well as useful information for investors in transmission lines and power plants. The transparent MRTU rules will allow market prices to reflect actual costs based on the way electrons physically flow on transmission lines.

2. Will **MRTU** encourage new investment in generation and transmission and provide efficient use of resources in California and the West?

The primary drivers for investment, like today, will continue to be the State's resource adequacy requirements and long-term procurement rules, as they apply to load-serving entities. In addition, the CAISO will continue to proactively identify and pursue needed transmission projects. MRTU will complement and enhance these features of the California landscape by providing transparent locational marginal prices (LMPs) that reflect the true costs of energy and transmission.

Locational prices reveal how new power plants will impact the grid, which greatly helps investors to estimate the revenue streams they can expect to earn by siting at potential locations. High prices will more easily identify areas with congested transmission lines, so that profit-minded companies and regulated utilities can build new lines, with the CAISO's coordination, to improve efficiency and reliability.

3. What measures is the CAISO taking to ensure that locational prices will not spike, thereby harming consumers?

First, it is important to clarify that under MRTU only suppliers will see locational prices, not consumers. For consumers, their prices will continue to be averaged over larger geographical areas representing their utility's service area. MRTU rules include appropriate local market power mitigation measures as well as "price caps" that limit how much generators can get paid. Perhaps most importantly, as a result of requirements and incentives that promote forward contracting, generators will no longer have an incentive to raise spot market prices. Under this new framework, if load-serving entities have forward contracts, it is the suppliers that have an incentive to keep prices low, since it they who will have to buy out of the spot market if they are unable to keep their contractual commitments to deliver power. However, if price spikes are caused by supply shortages, especially during extreme weather conditions, then the price signal will ultimately attract more generation to the area and will reduce the risk of high wholesale prices.

By aligning reliability requirements with market rules, MRTU should create more incentives for power plant developers to site in areas needed to best serve consumers and promote grid reliability.

4. Because Locational Marginal Pricing calculates prices based on the highest accepted bid (i.e., the bid of the "marginal" generating unit), will all generating units in the control area be compensated at the highest price?

No. Under LMP the prices are calculated at each of about 3000 locations within the control area, and the highest accepted bid at each generator location sets the price for that location but not for the entire control area or large load (consumer) pricing zone. As noted above, prices charged to load-serving entities are averaged over large load aggregation areas, so the impact on consumers of a few high locational prices will be muted.

5. How does MRTU protect load-serving entities from excessive congestion costs?

The CAISO's new market design will give load-serving entities a hedging instrument called Congestion Revenue Rights or CRRs. These rights give the ability to load to largely hedge the risk of congestion costs, thus providing certainty in the costs of transmission service.

6. Will load serving entities have an opportunity to evaluate in a concrete way the likely impact **of** the MRTU market design on their procurement plans and costs?

The CAISO has performed several LMP studies to provide insights on the impact on the market of moving to an LMP-based congestion management system. Additional monthly studies will be posted until MRTU start-up.

Details of these studies and reports on the outcome can be found at: http://www.caiso.com/docs/2O04/01/29/20040129103614281D6.html

In addition, the CAISO has conducted mock allocations and auctions of CRRs, which give parties practical insights on the tools they can use to manage risk associated with the congestion component of LMPs. Currently, the CAISO is conducting its CRR Dry Run based on the allocation and auction rules that were approved by FERC.

To provide parties with a full bid-to-bill knowledge and experience prior to start-up, the CAISO has developed a series of market simulation activities that allow participants to evaluate and learn to use the scheduling and market systems. The CAISO has also worked with its stakeholders to release details of the full network model that will allow participants to evaluate the impact of the market rules using their own tools.

7. Given all the complexities and uncertainties associated with Locational Marginal Prices, is it worth it? Why not stick with the current market?

First, the "simplicity" of the current market design is illusory and, as explained above, is based on an inaccurate representation of the power system. This forced simplicity creates reliability problems for our operators and results in huge uplift costs to all customers as a result of the need to make last minute adjustments to the power system. Moreover, this disconnect between the market design and reality can allow others to manipulate the system. The current market design is a belt and suspenders system sustained by burdensome regulatory requirements on generators, heavy dependence on State contracts, extensive manual operational procedures in real-time and high uplift costs (costs not reflected in the market transaction price) that are being spread to all consumers rather than allocated on cost causation principles. LMPs replace this current system of unpredictable and sometimes substantial uplift costs with prices that are based directly on cost-causation principles.

Moreover, congestion management based on LMPs using a full network model provides a tried and tested structure to aid grid operators. LMP provides more transparent processes for determining dispatch levels, enabling all parties to observe and track the cost of redispatch due to congestion.

8. How does MRTU affect on-going concerns with "seams" between the CAISO markets and other markets in the Western region?

Seams issues between control areas have long existed. The CAISO believes that MRTU will help alleviate some seams issues and is neutral on the rest. For example, the start of a Day Ahead market will help resolve congestion earlier and the improve flows that need to be managed in real-time between control areas.

Additionally, MRTU diminishes current differences between CAISO and the rest of the west, by moving the intra-day scheduling deadline from 2.25 hours before each operating hour (T-135) up to 1.25 hours (T-75). This change has been widely sought by parties scheduling interchange transactions, and will facilitate increased intra-day trading of power for import and export to and from the CAISO control area.

The most beneficial aspect of MRTU with respect to seams is the fact that LMPs will provide more transparent and predictable pricing. One existing problem at the seams, and one that MRTU alone will not be able to resolve, is the chronic problem of unscheduled loop flows in real time, which is a challenge to reliable operations as well as yet another non-transparent cost that is spread to all grid users.

Pursuant to a FERC's directive, the CAISO will be participating in a technical conference and is working on further initiatives to address seams issues under MRTU. The CAISO looks forward to working with its neighbors to address unscheduled flows and other seams issues that are problematic features in the industry throughout the West.

9. The Energy Policy Act of **2005** afforded the Pacific Northwest protection of transmission contracts, preventing FERC from requiring the conversion of physical transmission rights financial rights. Will MRTU impact transmission rights outside of California?

No. MRTU does not require utilities in neighboring control areas to convert their firm transmission rights to financial rights.

The CAISO does not anticipate that MRTU will alter transactions between the CAISO control area and the rest of the West. Nevertheless, the CAISO recognizes that there are differences in market rules that will require solutions to ensure that barriers to trade between the control areas are minimized or eliminated. The CAISO has launched a coordinated effort to consult with its neighboring control areas to identify and address any seams issues that may exist.

10. How will capacity markets in California affect the Pacific Northwest?

At the start of MRTU, the CAISO will not have a centralized capacity market in place. The State's current "Resource Adequacy" and "Long-Term Procurement" rules should lead to more contracts with generating plants in California. The CPUC is now starting a process to evaluate the need for capacity markets in California, which could lead to further incentives for generation investment both within and outside of California.

11. Does a municipal electric system or other entities have to buy or sell in the CAISO's markets?

No. Parties in California must submit hourly energy schedules so the CAISO can safely manage the grid, but there is no requirement to participate in CAISO markets. Any entity can buy or sell directly with any other entity, with no CAISO knowledge or involvement other than scheduling the transmission.

12. Will the ISO offer long-term firm transmission rights as directed by FERC?

Yes. The CAISO is currently developing these long-term rights under MRTU, with significant input from stakeholders.

13. How does the CAISO accommodate the business needs of municipal electric systems?

Over the years, the CAISO has worked closely with the municipal community to develop specific features that substantially enhances the functioning of municipal utilities in the CAISO Control Area. One of these important features is the ability for a municipal utility to be a metered subsystem (MSS) entity. Under today's market, an MSS entity can choose to follow their load with their resources, schedule resources within their MSS to serve their own load, and be exempt from uplift charges. Under MRTU, MSSs can continue to function the same way.

In addition, MRTU guarantees that contracts for transmission service remain effective, even if signed before the CAISO's creation. Finally, MRTU preserves the primary jurisdictional roles by which municipalities are regulated and meet necessary reserve margins.

14. Will the **MRTU** rules change if there is more competition for retail electricity customers?

No, not necessarily. If California policy makers decide *to* change State law and revive and promote "Direct Access" among electricity consumers, the MRTU design structure is already set up to be compatible with retail choice.

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

FACT SHEET

SEPTEMBER 21, 2006

CALIFORNIA INDEPENDENT SYSTEM OPERATOR MARKET REDESIGN AND TECHNOLOGY UPGRADE (MRTU)

The following relevant facts provide a broad overview of the Federal Energy Regulatory Commission's action today on the California independent System Operator's (CAISO) proposed MRTU tariff:

- The changes represent important, hut incremental improvements to the existing market design. MRTU does not create organized markets in California. They already exist, and MRTU actually makes reforms to ensure that they function properly. Moreover, these reforms are based on an extensive record reflecting input from numerous parties inside and outside of California.

- MRTU does not create seams with the bilateral markets in the West; those seams already exist due to the differing market structures within the Western Interconnection. Instead, MRTU is designed, in many ways, to mitigate the seams and enhance trade between the differing regions within the West.

- The day-ahead energy market will allow more opportunities for imports and exports to be scheduled ahead of real-time. Transparent locational marginal prices in the day-ahead market will make it easier for suppliers located outside of California to sell their excess power into California at a competitive price.

- MRTU adopts oiily limited, but crucial, changes in the area of congestion management. MRTU adopts improved price signals for generators to allow for more efficient generation dispatch, hut it does so in a way that protects customers. MRTU will offer monthly and annual transmission rights to protect customers against a much larger portion of congestion charges than is currently possible.

- These reforms should lower costs by increasing the efficiency of the CAISO's transmission grid operations, and offer customers important protections from congestion charges that do not exist today.

The following are the most important elements of MRTIJ that fix market design flaws, enhance reliability, better protect wholesale customers from price volatility and gaining, incorporate price-responsive demand in the markets, and encourage construction of new resources:

- Eliminates infeasible schedules. Market participants currently submit infeasible schedules for energy because there are no negative financial consequences to their doing so. Also, under the current tariff, the CAISO must accept infeasible day-ahead schedules that do not reflect actual transmission bottlenecks and operating limitations of generators because its computer software ignores these limitations. This is a serious problem that forces the CAISO's transmission grid operators to scramble in real-time to correct infeasible day-ahead schedules. MRIU will ensure that day-ahead schedules are physically feasible because its new computer software will fully consider all transmission bottlenecks and generator operating limitations. This will make the CAISO's system more reliable.

- Uses a more comprehensive model of the transmission grid. The CAISO currently decides which resources will be used for reserves (ancillary services) in a manner that is independent from its energy dispatch decisions. This results in less efficient use of generation capacity. Under MRTU, the CAISO will consider at the same time which resources to use for energy and which resources to use for reserves. This will create more efficient dispatch. Meeting demand and reserve requirements from the lowest cost set of generators will benefit customers by keeping prices down.

- Adds a financially binding day-ahead market. Existing market rules require each Scheduling Coordinator to anticipate customer demand and to match that demand with an equal amount of generation supply. This can create inefficiencies because there is no systematic way to ensure selection of the least cost set of generators to meet customers' needs. Under MRTU, this problem is solved by the creation of the day-ahead energy and ancillary services market, which is open to all creditworthy market participants on a non-discriminatory basis. The day-ahead market will enable all suppliers and customers to submit offers to buy and/or sell electricity in advance of real time. The CAISO will consider the bids of all suppliers in the day-ahead market and select the lowest cost mix of suppliers to serve customers' needs. The creation of a financially-binding day-ahead market will make it easier for all market participants, particularly smaller entities, to participate in the California market. A transparent day-ahead price signal can also be useful in demand response programs. The day-ahead market will provide market efficiencies that will help keep wholesale electricity prices down and make it easier for the CAISO to maintain reliability.

- Adopts locational marginal pricing for suppliers and for improved congestion management: Under locational marginal pricing, or LMP, prices in wholesale markets vary by location and time, based on the physical limitations of the transmission grid, and reflect the incremental cost of meeting customer demand at each location. Locational marginal pricing will communicate the true market value of electricity at each location, as well as the cost of alleviating congestion between any two locations. This will create financial incentives to dispatch the lowest cost energy, when considering all transmission bottlenecks. In the long-term, by making energy and congestion prices more transparent, locational marginal pricing will help encourage transmission and generation investment at appropriate locations, as well as demand response. It hears emphasis that the CAISO's version of locational marginal pricing is aimed primarily at suppliers who will be paid their location-specific price. Wholesale customers will be insulated from the location-specific prices because they will continue to pay an aggregated zonal price.

- Improves transmission rights: The CAISO already incorporates financial transmission rights, but these are limited to rights to congestion revenues associated with transmission service between adjacent zones and external interconnection points. The existing financial transmission rights allow customers to protect themselves from congestion charges occurring between zones. Currently, however, most congestion occurs inside the existing zones and there is no way for customers taking transmission service within each of the CAISO's three zones to protect themselves from these costs, which again means that some customers are forced to significantly subsidize the cost of serving other customers. Wholesale customers must pay for the costs of congestion within zones in the form of "uplift" payments, or billing surcharges, which can he highly volatile and unpredictable. MRTU largely alleviates this problem by ensuring that all congestion costs are reflected in market prices, and by issuing a better form of financial transmission rights, called congestion revenue rights, or CRRs. Congestion revenue rights will enable load serving entities and others to protect themselves against the costs of congestion. Also, customers under contracts that pre-date the existence of the CAISO will continue to receive protection against congestion costs consistent with the requirements of their contracts.

- Requires compliance with the Long-Term Firm Transmission Rights Final Rule: Currently, the CAISO offers no financial transmission rights with a duration of longer than one year. This has often been cited as an impediment to the construction of new facilities necessary to serve the California market, and a harrier for customers trying to access needed resources on a long-term basis. This order addresses that problem by directing the CAISO to comply with the

Long-Term Firm Transmission Rights Final Rule. This should hasten the creation and availability of long-term firm transmission rights, directly addressing concerns raised by customers in California.

- Increases bid caps incrementally: Currently, suppliers' bids into the CAISO's real-time markets are capped at $400/MWh. It has long been recognized that, if price caps are set too low, they can result in a reduction in needed supply that will usually not be in the public interest. Therefore, in markets where bid caps are used to help protect against the exercise of market power, it is imperative to set the bid cap at an appropriate level in order to stimulate demand response, provide incentives to enter into long-term contracts, and foster investment in new infrastructure. If a bid cap is set too low, this could adversely affect reliability by artificially suppressing resource prices when resources are scarce. MRTU is slated to go into effect November 2007. At that time, the bid cap will be increased first to $500/MWh, and thereafter incrementally increased over the next two years until it reaches $1,000/MWh. This gradual increase will give market participants time to adjust to both the new cap levels and other mitigation features, while helping to ensure that needed supply is not driven from the market by overly restrictive price caps.

- Improves local market power mitigation: Currently the CAISO's market power mitigation lacks adequate measures to address the potential for generators located in load pockets (areas surrounded by transmission bottlenecks) to exercise market power. MRTU adopts local market power mitigation techniques that identify generators with the potential to exercise local market power, and limits those generators' bids to pre-established default levels. These default energy bids are tailored to contribute to the recovery of the generator's fixed costs, so the generator can afford to continue producing energy. These local market power mitigation rules will help prevent market manipulation and price volatility, while maintaining adequate generation supply and reliability.

- Demand Response: MRTIJ provides loads with demand response capability – the opportunity to participate in the CAISO day-ahead, real-time, and ancillary services markets under comparable requirements as supply, and receive the corresponding market value. Price-responsive demand moderates price increases and price volatility for all customers (because some demand is willing to be reduced rather than pay higher prices for energy from more expensive units) and it also helps to check potential market power because it provides a countervailing willingness to reduce demand in the face of high prices. Further, demand response contributes to reliability by shaving peak demand and providing reserves. We believe the continuing development of demand response is an effective route to produce CAISO markets that are competitive

and that can be relied upon to produce rates that are just and reasonable for customers. We therefore direct parties interested in further developing demand response in the CAISO markets to provide proposals to the Commission that detail new avenues for incorporating price-responsive demand within 60 days of the date of this order.

- Builds upon resource adequacy: Resource adequacy is the availability of an adequate supply of generation or demand responsive resources to support safe and reliable operation of the transmission grid. Until June 2006, the CAISO market did not require load-serving entities to procure sufficient generation capacity to serve their customers. The lack of this requirement jeopardized reliability and made it difficult to ensure that wholesale prices would remain just and reasonable. Under MRTIJ, load-serving entities under the authority of the California Public Utilities Commission will be required to obey its requirement to maintain a level of capacity above load serving entities' forecasted customer needs (currently 15-17 percent). They will also have to demonstrate a year in advance that they have procured resources to cover 90 percent of their summer (May through September) peak period needs. Other load-serving entities that are CAISO members and serve customers in the CAISO control are required to comply with the planning reserve margin for capacity that is set by their Local Regulatory Authority. If the Local Regulatory Authority does not establish such a margin, the default margin will be 15 percent. These resource adequacy requirements will help ensure sufficient supply, enhance reliability, protect against price volatility, and reduce the opportunities to game the market that exist when electricity supplies are insufficient to meet customers' needs.

In order to further address commenter concerns and to build on further market improvements, the Commission's order on MRTU directed that future technical conferences be held on various aspects of MRTU. One of the technical conferences the Commission directed will address commenter concerns about operational rules that differ between the CAISO and other providers of transmission service in the West (so-called "seams" issues). The Commission order also directed the CAISO and neighboring transmission providers to meet to resolve these seams issues, and to jointly inform the Commission on the progress of these efforts through the filing of quarterly status reports.

American Public Power Association
FACT SHEET February 2009

Wholesale Electricity Markets

Summary

In response to continuing problems facing members of the American Public Power Association (APPA) in regional wholesale power markets, primarily in regions with Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs) that are under federal jurisdiction, APPA instituted the Electric Market Reform Initiative (EMRI) in March of 2006. EMRI was established to first assess and then address the market failures and other serious challenges facing public power systems across the country.

The migration to RTOs in certain regions of the country coincided with a push in the 1990s to deregulate state retail electricity markets. This push was coupled with assertions by state policymakers and federal regulators that lower prices and increased infrastructure investments would be the result. It has become increasingly clear to APPA, however, that RTO-operated markets are not benefiting electricity consumers, and that prices have increased disproportionately to inflation and other factors like rising fuel costs. In our view, these markets are not competitive; and we believe consumers are exposed to prices for electricity that fly in the face of the standard of "just and reasonable" rates required by the Federal Power Act.

This issue is important to APPA because almost all public power utilities rely to some extent on purchases from the wholesale markets for the energy they supply to their customers, and many rely almost exclusively on such purchases. APPA, and many other organizations, asked the Federal Energy Regulatory Commission (FERC) to investigate the problems in these markets identified through the EMRI studies and to take corrective action, but FERC denied that request. Thus, APPA believes that Congress should exercise its oversight and other authorities to ensure that FERC addresses the problems in these markets, and adheres to its statutory obligation under federal law to protect electricity consumers.

Background

Often termed "restructuring" or "deregulation," a major transition has taken place in some of both the retail and wholesale electricity markets over the past 15 years. These changes were based in part on the belief that electric utilities should no longer be regulated monopolies and instead should be deregulated and face competition, just as trucks, railroads and airlines did during the 1980s. In the retail markets, which are under state control, policy changes in the 1990s encouraged or required abandonment of the traditional vertically-integrated utility company model in order to disperse ownership of generation facilities and thus spur competition. In most states that made such changes, public power utilities were allowed to "opt out" of the retail access programs, and almost all of them did so. That means that public power utilities retained their legal obligation to serve all customers in their service territory and to plan for and acquire the necessary resources, either through ownership or contract.

In the states that "deregulated," retail customers of private utilities were given the right to purchase power from non-utility providers. As mentioned above, the private utilities were required to sell their generation facilities, but in many cases those power plants were simply sold to an unregulated affiliate of the same holding company that also owns the distribution utility that sold them. As a result, the private utilities were also

forced to purchase their power on the wholesale market, often generated from tlic same plants they used to own, but at much higher prices. Two agreements were generally reached between utilities and customer representatives as part of the new retail market regime. First, consumers were often required to finance the unpaid debt on the existing generating Facilities, known as "stranded costs." Second, retail rates for residential customers were frozen during what was thought to be a "transition" period until all customers could participate in the markets by choosing alternative suppliers.

Meanwhile, the federal agency that regulates wholesale power sales, the Federal Energy Regulatory Commission (FERC), began to push for restructuring of the wliolesale **markets** and tlic creation of RTOs/ISOs to oversee these markets. FERC abandoned the requirement that. electricity sold in the wliolesale market should reflect tlie cost of producing the power (plus a reasonable profit) – the traditional approach to meeting the just and reasonable standard in federal law mentioned above. Instead, they nsed certain economic tests to analyze various market conditions and determine whether they were sufficiently "competitive" to set prices, subject only to reporting and limited oversight requirements. These changes in the wholesale and retail markets were predicated on assertions by federal and state officials and other RTO proponents that they would promote competition, spur efficiencies and innovation, and lower rates for consumers – assertions that, for the most part, have not come to fruition.

In response to FERC's encouragement, wholesale markets in the Northeast, Mid-Atlantic, Midwest regions and California are **now** operated by RTOs/ISOs. These organizations administer niarkcts where electricity is bought and **sold** under highly complex arrange**ments.** RTO-run markets generally cover the same regions in which the majority of tlic retail access states are located. As a result, these states are home to a large pool of generation with prices that arc unregulated at both the state and federal levels.

In most retail access states, competitive suppliers at tlic retail level have not materialized for most residential and small business customers, and thus these customers still purchase power from heir local utilities. But because these utilities no longer own generation (as discussed above), they must procure such power on tlie wholesale markets run by RTOs/ISOs through various "auctions" and other procedures nsed to select tlic suppliers of the power. Again, as discussed above, often tlic suppliers winning these auctions arc tlic unregulated owners of the generating plants formerly owned by affiliated utilities, and largely paid for by customers. Yet, because tlic prices for electricity are no longer cost-based, these new owners arc able to charge much more than they were paid prior to deregulation.

One core function of an RTO is to provide non-discriminatory open access transmission service for electricity transactions. This requires that owners of transniission lines do not give any preference or deny the use of their transmission lines to other sellers ***and*** purchasers of electricity. To carry out this responsibility, RTOs have functional control, but not ownership, of tlie transmission system. RTOs also coordinate regional planning for **new** transmission lines and eliminate rate "pancaking" (charging multiple transmission ices for one transaction). Most RTOs handle these functions well and provide benefits to consumers.

A second core function of RTOs is to administer markets for various electricity services in their regions including energy, capacity and ancillary services . RTO-administered markets are intended to provide a centralized marketplace in which electricity can be bought and **sold** at. pi-ices established by "competitive" forces. RTOs do not own the power plants that generate the power bought ***and*** sold in the market, but rather develop the rules to administer tlic niarkcts, decide which generators will run and at what levels, grant (or deny) the transmission services needed for transactions to occur, and run the billing systems for payments for power. The problems that have developed stem from this second core function—the energy-related markets operated by the RTOs—and are attributable to certain fundamental features of the market design, tlic exercise of market power by some generators, and **lack** of sufficient FERC oversight.

Congressional Action

The Energy Policy Act of 1992 opened wholesale markets to independent power producers, which in turn underscored the need for open access by these new market participants to the bulk transmission lines largely owned by vertically-integrated investor owned utilities. In April of 1996, FERC issued its landmark Order Nos. 888 and 889. In Order No. 888, FERC directed the electric utilities under its jurisdiction (primarily investor-owned utilities) to provide open and nondiscriminatory access to their transmission lines in order to help bring down the cost **of** electricity through increased wholesale competition. FERC also encouraged the formation of RTOs/ISOs, and set out certain functions they should perform. In Order No. 889, FERC required jurisdictional utilities to establish electronic bulletin boards, called "Open Access Same Time Information Systems," to help manage the nondiscriminatory flow of electrons across transmission systems.

As regional power markets began to develop, it became clear that new transmission facilities were not being built at the same rate as new generation (and almost all of that generation was non-utility owned and natural gas-fired).Therefore, in December of 1999, FERC encouraged all transmission owners to voluntarily develop and join RTOs. Order No. 2000 was then issued and required FERC-jurisdictional transmission owners to submit an RTO plan by October of 2000, and targeted December of 2001, as the date by which all RTOs would be operational. However, since Order No. 2000 did not contain a mandated obligation to join an RTO, they did not form in a number of regions of the country. In response to this situation, in 2002 FERC pushed to standardize RTO functions and markets across the nation and to require jurisdictional utilities to participate in them. This FERC initiative, called "Standard Market Design" (or SMD) spawned significant opposition in Congress and further stalled RTO development in regions of the country that did not yet have them – primarily the Pacific Northwest, the South and the desert Southwest.

In early 2008, companion Senate and House legislation to provide cost accountability to Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs) was introduced. The Consumer Protection and Cost Accountability Act (S. 2660 and H.R. **5547,** respectively) was sponsored in the Senate by Senators Sanders (I-VT) and Snowe (R-ME), and cosponsored by Senators Kerry (D-MA), Kennedy (D-MA), Leahy (D-VT), Collins (R-ME) and Mikulski (D-MD); while in the House it was sponsored by former Representative Allen (D-ME) and cosponsored by Representatives Delahunt (D-MA), McGovern (D-MA), Michaud (D-ME), Welch (D-VT), and Tierney (D-MA). It is unclear as of this writing if this legislation will be reintroduced during the 111th Congress.

Also in 2008, the Government Accountability Office issued a report on wholesale electricity markets as requested by Senators Lieberman (I-CT) and Collins (R-ME) which urged FERC to investigate these markets to ensure that rates are just and reasonable.

APPA and other like-minded organizations continue to encourage leadership in both the Senate Energy and Natural Resources Committee and the House Energy and Commerce Committee to hold investigative hearings into the functionality of these RTO/ISO-run electricity markets and to urge FERC to undertake an investigation of these markets as recommended by the GAO.

APPA Position

APPA members in RTO regions report substantial problems that impair their ability to provide reasonably priced and reliable long-term service to their own electric customers because of RTO-run markets. Studies undertaken by APPA's Electric Market Reform Initiative have shown that there is substantial evidence that prices in these regions are "unjust and unreasonable." FERC has the ability to use its existing and new authorities (provided in the Energy Policy Act **of** 2005) to remedy this situation.

In December of 2007, APPA joined 40 other consumer, business and public interest groups in asking FERC to conduct a broad investigation of fundamental RTO-run market problems and to take the necessary steps to protect consumers as required by law. In a final rulemaking issued by FERC in late 2008, this request was denied. APPA has also spearheaded a new coalition of industry and consumer groups called the Campaign **for** Fair Electric Rates. This group is asking Congress to

put pressure on FERC, either through oversight hearings or legislation, to fulfill its obligation of ensuring just and reasonable rates Tor electric consumers.

In addition, APPA has developed detailed proposals for both short- and long-term solutions to the problems in RTO markets. The most recent of these is APPA's Competitive Market Plan released in February of 2009, and available on APPA's website at www.appanet.org. In summary, the plan proposes to retain the RTO functions that are working well—principally those associated with planning for and operating the regional transmission grid—and replacing those functions that are not benefiting consumers, mainly the design and operation of the energy and capacity markets. The Competitive Market Plan focuses on moving market participants away from short-term, high-priced spot. markets, and into long-term bilateral contractual arrangements that will stabilize electricity prices and provide tlie financial certainty necessary for investments in new generation and transmission infrastructure necessary to meet future reliability requirements.

American Public Power Association

Consumers in Peril

Why RTO-Run Electricity Markets Fail to Produce Just and Reasonable Electric Rates

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February 2008

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Executive Summary

This white paper, prepared by the American Public Power Association, comes at a time of increasing peril for electricity consumers – both in present costs and future reliable service. Over the past 15 years, federal and state policymakers have fundamentally restructured wholesale electricity markets and retail electric service in many parts of the country. These changes were predicated on the promise that increased "competition" would spur efficiencies, promote innovation, ensure an adequate infrastructure and, most importantly, result in lower rates for consumers. But the opposite has occurred — restructured markets are producing higher prices (and higher profits) than one would expect in a competitive market. Nor is new infrastructure being constructed. And the only "innovation" many consumers have seen is in the new and complex market mechanisms developed to extract more dollars from them for the same basic product — retail electric service.

During this time, the Federal Energy Regulatory Commission changed its policy emphasis from ensuring non-discriminatory open access transmission service to implementing centralized wholesale electric markets run by regional transmission organizations (RTOs). The commission has limited its regulation of electric markets and allowed electricity generators to charge market-based rates. Many states in regions with RTOs implemented some form of retail electric utility restructuring, to allow retail consumers to choose their own power supplier. As part of the transition to these new retail restructuring regimes, many state-regulated incumbent electric utilities sold off their existing generation assets to unregulated third parties, including their own unregulated affiliates. All of these policy changes were made on the assumption that competition in wholesale and retail electric markets would develop, But, as this white paper explains, the structural features of the electric utility industry (high capital costs, high barriers to entry, control by incumbents of generation sites, etc.) make it difficult for true competition to develop or flourish.

RTO Market Failures

The centerpiece of FERC's new wholesale electric regulatory policy — development of RTOs and their operation of centralized markets for wholesale power supply, capacity, and ancillary services — has been especially problematic. RTOs do provide services that have substantial value, which should not be overlooked. These services include administration of regional open access transmission tariffs (OATTs) on a non-discriminatory basis, elimination of "pancaked (utility-by-utility) transmission rates and development of more coordinated regional transmission planning processes. But these substantial accomplishments have been overshadowed by the high costs and dysfunctional nature of RTO-run centralized markets. Dysfunctional features of these markets include:

- Offers to sell power are not connected to the sellers' actual costs of generating power (average, marginal or otherwise), as FERC would have required under a traditional cost-of-service ratemaking regime and as a more competitive market would have produced. Lower-cost generators are paid the same price as those with higher operating costs, but these additional dollars have not spurred the

entry of new competitors or induced substantial investment in new generation facilities.

- Prices for power sold under bilateral contracts (individual contracts between a buyer and a seller) have been substantially influenced by the high prices sellers can obtain in the RTOs' centralized markets. It is uncommon to see bilateral power supply contracts in RTO regions for terms longer than one to five years, or that are backed by specific electric generation units. Long-term bilateral contracts are increasingly difficult for purchasers to obtain under reasonable terms and conditions.
- RTO-run bid-based markets create incentives for generators to withhold capacity (to create artificial shortages that increase prices) and to refrain from building otherwise-needed new generation capacity (which could reduce prevailing market prices, thus reducing profits).
- In contrast to its theoretical basis, there is no evidence of any relationship between locational marginal pricing (LMP) signals and the construction of new generation and transmission facilities.
- Electric consumers are paying billions in additional charges required by new RTO-run locational capacity markets, but it is highly uncertain, at best, whether these markets will support future development of enough new generation facilities to meet demand.
- Regional high-voltage transmission facilities are essential to support wholesale power supply transactions. However, transmission capacity is often insufficient to meet demand and the associated transmission rates are therefore uncertain, due to substantial congestion charges imposed by the RTO.
- In RTOs, new markets are continually developed to price previously cost-regulated products, e.g., ancillary services, without any rigorous cost-benefit analysis. The administrative and software costs associated with these new markets are very high, with little evident benefit to consumers.

Fundamental Market Reform is Necessary to Protect Consumers

It is time to acknowledge that market forces alone are not sufficient to discipline prices and ensure adequate service in the electric utility industry. There is a significant amount of evidence of problems in RTO-run markets presented in the studies that APPA sponsored during the initial phase of its Electric Market Reform Initiative. APPA summarizes that evidence in this white paper. The EMRI studies—along with the multitude of materials filed by other load-side interests, in FERC's Advanced Notice of Proposed Rulemaking (ANOPR) in Docket Nos. RM07-19-000 and AD07-7-000, Wholesale Competition in Regions with Organized Electric Markets—strongly suggest that RTO-run centralized wholesale electricity markets are not producing just and reasonable rates. In the face of this evidence, FERC has an affirmative obligation—expressly set forth in the Federal Power Act—to investigate whether rates subject to its jurisdiction are unjust and unreasonable and to take remedial steps if it finds they are.

To avoid further harm to consumers while FERC is carrying out this investigation, APPA recommends that FERC quickly place a moratorium on both the establishment of new RTO-run centralized markets, as well as the implementation of new markets for additional products and services in existing RTOs, unless such markets are supported by all classes of stakeholders and accompanied by a valid cost/benefit analysis.

APPA Recommends Restructuring RTOs as Day 1 RTOs

Based on recent indications, APPA is concerned that FERC will not initiate an investigation into the justness and reasonableness of rates in RTO-run centralized markets without first having received specific proposals for RTO market reforms. While a number of RTO market reform proposals have been offered, APPA in this white paper offers its own suggested reform proposal—to restructure full "Day 2" RTOs (RTOs with full centralized power supply markets) into more streamlined "Day 1" RTOs. This proposal is designed to keep what is working relatively well in RTOs, namely the "Day 1" transmission-related functions, but to streamline and ultimately replace those functions and features—mostly associated with RTO-run centralized power supply, ancillary service and locational capacity markets—that have failed to produce sufficient benefits for consumers. Such a regime would de-emphasize participation in RTO-run centralized power supply markets by both buyers and sellers, and foster longer-term bilateral power supply contracting.

The functions that such a Day 1 RTO would carry out are as follows:

- Ensure non-discriminatory access to the grid through independent administration of a regional OATT and provision of transmission service, including needed ancillary services.
- Develop and administer a regional transmission rate design that eliminates rate pancaking and assures the recovery of the cost of transmission facilities for all transmission facility owners that wish to participate in the RTO, regardless of their form of ownership.
- Operate a single regional open access same-time information system (OASIS) and independently calculate available transmission capacity (ATC).
- Conduct independent and collaborative regional transmission and generation interconnection facilities planning, with the full inclusion of affected stakeholders.
- Carry out wide-area system security and reliability-related activities, ensuring that transmission facilities are operated in compliance with relevant North American Electric Reliability Corp. and regional reliability entity criteria.
- Operate an energy imbalance market to enable transmission customers to manage their imbalances and to allow generators (including intermittent renewable generators) to sell excess generation not committed under bilateral contract arrangements.
- Ensure adequate generation reserves through implementation of appropriate regional resource adequacy requirements.

APPA intends to produce a more detailed description of this proposal in a separate

document, which will be published later in 2008.

Until this proposal or similar fundamental RTO market reforms are implemented, there are a number of discrete RTO-related problems that could be addressed more quickly, to provide electric consumers with some interim relief:

- Require cost-benefit studies and proof of broad stakeholder support to accompany any RTO filings to implement new markets and programs or changes to existing markets or programs;
- Revise RTO mission statements and strategic plans to include an explicit goal of reducing electric power costs to customers;
- Improve RTO governance to be more responsive to stakeholders;
- Ensure that market monitors are truly independent and have all of the resources necessary to perform their functions; and
- Improve data transparency by providing public access to generator bid data on a next-day basis, with open identification of generators, as well as generator cost and operating data.

Conclusion

APPA wants this white paper and the proposals it contains to contribute to a constructive dialogue to develop sorely needed reforms to RTO-run centralized wholesale electricity markets. The debate should no longer be about who can best massage the statistics on prices or whether it is more virtuous to support "competition" or "regulation." Instead, all industry participants need to work together to design a regulatory system for electricity markets that truly benefits consumers, businesses and the environment.

I Introduction

Wholesale electricity markets have changed fundamentally over the past 15 years. The Federal Energy Regulatory Commission changed its policy emphasis from ensuring nondiscriminatory open access transmission service to implementing centralized wholesale electricity markets run by regional transmission organizations (RTOs), with limited regulation. Meanwhile, many states implemented programs to provide retail consumers with a choice of electricity providers. In many of these states, shareholder-owned electric utilities sold off their generating plants to third parties (in many cases, unregulated affiliates), who can sell their power at prices that are no longer tied to the cost of production and arc subject only to limited RTO "market mitigation" rules.

These changes were predicated on the premise that the combination of open access transmission service and these new centralized wholesale markets would promote "competition" that would spur efficiencies and innovation, ensure adequate supplies and, most importantly, lower rates for consumen. But evidence gathered in investigations of the RTO-run wholesale markets and the real-world experience of consumers shows that the opposite has occurred. These deregulated markets are producing both higher prices and higher profits than one would expect in a competitive market. Prices exceed those prevailing in the remaining regions that have not restructured and have retained cost-of-service regulation.

This is not to say that RTOs provide no benefits. Properly structured, RTOs can provide independent and nondiscriminatory transmission service under open access transmission tariffs (OATTs), charge regional, non-pancaked transmission rates, and lead regional collaborative transmission planning and construction processes. Such RTO functions benefit consume —yet FERC's policies in promoting centralized RTO-run markets have increasingly lost sight of these RTO functions, as market implementation has taken center stage. It is the RTO-run centralized wholesale markets that are the primary focus of this white paper.

On December 17,2007, a diverse group of 41 consumer advocacy, business and public power organizations came together to ask the FERC to investigate whether restructured wholesale electricity markets are producing unjust and unreasonable wholesale power prices—prices that are then passed along to retail customers in their monthly bills. Among the serious problems flagged in that filing are the increasingly high electricity prices consumers are paying, while certain sellers of electric generation are earning excessive profits. Worse yet, these higher profits are not invested in new electric generation and transmission facilities and, therefore, will not reduce prices over the longer term.

A large body of evidence gained through various studies that the American Public Power Association and others have commissioned supports these conclusions.[1] These studies contain substantial evidence of market dysfunction, demonstrating that the portion of the electricity industry operating under FERC-jurisdictional RTOs resembles more of a

[1] A summary of the initial studies that APPA commissioned can be found at: http://www.appanet.org/files/PDFs/EMRISummarybooklet.pdf. For the full studies, go to http://www.appanet.org/emri.cfm.

Supporters of restructuring continue to promote market-based rates, highly restricted access to relevant price and *cost* data and other policies that could work only in markets with robust competition.

concentrated oligopoly than a competitive market. (For example, financial analyst Edward Bodmer found that shareholders of five owners of unregulated generation assets have earned as much as $70 billion more than investors in regulated electric utilities over the past few years.)[2] Analyses by London Economics and Synapse Energy Economics suggest behaviors inconsistent with a competitive market and consistent with the exercise of market power: large and fluctuating disparities between costs and prices, aberrational patterns of offers to sell power, and the absence of effective price signaling for the construction of sorely needed new generation and transmission facilities?

These non-competitive outcomes are the result of specific policies applicable to centralized RTO-run wholesale markets. For example, FERC allows generators to charge "market-based rates," relying on a supposedly competitive market to discipline prices to the "just and reasonable" levels required by the Federal Power Act. Such a policy fails to recognize that these markets are fundamentally different from markets for other goods and services. As the December 17 filing notes, '"the commission's ratemaking methodology in RTO-run organized markets is based on presumed conditions that are at variance with reality."[4] These presumed conditions include: the absence of significant market power; free entry and exit of competitors; an optimized generation resource mix; the absence of significant structural and behavioral impediments to long-term contracting; the presence of price-responsive demand; and the availability of short-term substitution alternatives.

Despite the large body of evidence that these markets do not meet the preconditions for effective competition and in fact demonstrate outcomes indicative of the exercise of market power, supporters of restructuring continue to call these markets "competitive." They continue to promote market-based rates, highly restricted access to relevant price and cost data and other policies that could work only in markets with robust competition. Many of these restructuring supporters are entities with large portfolios of generation facilities in RTO regions; they are the primary beneficiaries of the current dysfiinction in centralized RTO-run wholesale electric markets.

Supporters of these markets try to frame the debate by characterizing critics as opposing "markets" and "competition" and instead supporting "regulation." But it is becoming increasingly apparent that leaving electricity pricing and supply up to these "markets" is an invitation to exercise market power. Because current wholesale regulatory policies

[2] Affidavit of Edward Bodmer, Comments of the American Public Power Association, FERC Dockets RM07-19-000 and AD07-7-000, Wholesale Competition in Regions with Organized Electric Markets, September 14, 2007.

[3] *A Comparative Analysis of Actual Locational Marginal Prices in the PJM Market and Estimated Short-Run Marginal Costs: 2003-2006*, prepared by Serkan Bahceci, Julia Frayer, Amr Ibrahim and Sanela Pecenkovic, London Economics International, February 2007, and *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers*, prepared by Ezra Hausman, Robert Fagan, David white, Kenji Takahashi and Alice Napoleon, Synapse Energy Economics, at http://mwappanet.org/emri.dm.

[4] Request to Expand the Scope of the 206 Proceeding, Docket Nos. RM07-19-000 and AD07-7-000, December 17, 2007.

ignore these problems, they are detrimental to consumers. Moreover, the problems arc growing worse. These policies are harming not just public power utilities and the consumers they serve, but also consumers and businesses throughout the country.

Because many states that implemented retail access programs required their investor-owned utilities to sell off their generation facilities to unregulated entities, these generation facilities are now largely concentrated in the hands of owners that can charge "market rates" for this power (often unregulated affiliates of the traditional utility supplier). Most consumers in these states arc still purchasing retail electric service from their traditional electric utility under "default" or "provider of last resort" service. As a result, most residential customers are receiving power from the same utility as before, but that utility must now procure electricity on the wholesale market, at substantially higher "market" rates, in many cases from the same generation facilities that the utilities themselves used to own. With retail rate caps now expiring in many states, consumers arc finding themselves exposed to the lull brunt of the resulting higher wholesale power prices for the first time.

In restructured states where customers arc now fully exposed to market prices, electricity rates increased almost 40 percent since 2002, compared to 19 percent for states that remain regulated.[5] In July 2007, the average electricity price in states located within RTOs was almost 11 cents per kilowatt-hour, about 2.4 cents greater than tlic rates paid outside of RTO markets (about a 30 percent difference). This differential was significantly greater than the 1 cent difference in January 2003, when non-RTO states had an average rate of about 6 cents.[6]

Not only are prices increasing at a faster rate in RTO-run markets, but also wholesale customers in these regions (load-serving electric utilities that procure power to serve their end-use customers and large industrial customers that can purchase directly in wholesale markets) are finding it difficult to obtain reasonably priced longer-term power supply contracts.[7] The lack of such long-term contracting makes it more difficult to

[5] *The Impact of Competition on Electricity Prices: Can We Discern a Pattern?*, Kenneth Rose, Ph. D., Consultant and Senior Fellow, Institute of Public Utilities, presentation to the Harvard Electricity Policy Group, December 6, 2007, available at http://www.appanet.org/emri.cfm.

[6] *The Missing Benchmark in Electricity Deregulation*, by Robert McCullough, Managing Partner, and Ann Stewart, Research Analyst, McCullough Research, December 2007, available at http://www.appanet.org/emri.cfm.

[7] See for example the following testimony provided to FERC in Conferences on Competition in Wholesale Power Markets, Docket No. AD07-7-000: Prepared Statement of Roy Thilly, President and CEO of Wisconsin Public Power Inc., February 27, 2007, http://www.ferc.gov/EventCalendar/Files/20070301133025-Thilly,%20Wisconsin%20Public%20Power.pdf; Testimony of Walter Brockway – Manager of Regulatory Affairs – Energy for Alcoa, May 8, 2007, http://www.ferc.gov/EventCalendar/Files/20070508083948-Brockway,%20Alcoa.pdf Statement of Duane S. Dahlquist On Behalf of Blue Ridge Power Agency, May 8, 2007, http://www.ferc.gov/EventCalendar/Files/20070509151931-Dahlquist,%20Blue%20Ridge%20Power.pdf

finance needed new electric generation projects, including clean and innovative sources of power. Moreover, in the absence of regulatory measures to assure adequate supplies of electricity *to* enforce a traditional service obligation by electric utilities to their retail customers, generation owners and incumbent utilities have little incentive to invest in new generation and transmission infrastructure.

It is time to acknowlcdgc that "market forces" alone are not sufficient to discipline prices and ensure adequate service in the electric utility industry. The market failures described above must be addressed before the lack of affordable electricity becomes even more of a threat to the quality of life and the economy of much of the nation. As the clcctric utility industry implements carbon-reduction measures lo address climate change, and as needed new transmission and generation infrastructure addiiions come on line to meet increasing demand, the financial burden on retail electric customers will increase. State and federal policymakers owe it to these customers to make sure that rate increases are not layered on top of already unjust and unreasonable rates engendered by dysfunctional RTO markets.

The purpose of this white paper is to present an overview of the problems in today's restructured wholesale electric markets and to identify the steps needed to address these problems. Section II provides a brief discussion of the public power business model and our perspective on the industry. Section III then addresses the unique characteristics of the wholesale electricity market that make competition difficult to achieve and the statutory responsibility of FERC to ensure that rates arcjust and reasonable. Section IV details the specific problems that have arisen in the RTO-run wholesale markets. Section V introduces APPA recommendations for longer-term reforms, and is followed by a listing in Section VI of proposed interim remedial actions that FERC should take in the near-term lo protect consumers until more fundamental changes call bc agreed upon and implemented.

II Public Power's Perspective

Public power utilities were created by state or local governments to serve the public interest. They are not-for-protit entities controlled locally by the customers they serve. Their purpose is to provide reliable and low-cost electric power to their retail and wholesale customers, consistent with good environmental stewardship, and to do so consistently year after year. They have retained their traditional utility obligation to serve all customers in their service areas; indeed, they see this as their mission.

Some public power utilities, particularly the largest ones, are fully vertically integrated. They own and operate all of the facilities-generation, transmission and distribution—necessary to provide electric service to their retail customers. Large public power utilities also provide transmission services to other eligible customers and partner with their neighboring utilities tojointly plan transmission to meet regional needs. Other public power utilities are "virtually" vertically integrated—they have contract and tariff arrangements under which they buy wholesale transmission and power supply services from others. Many havejoined together to form municipaljoint action agencies to own or procure wholesale generation and transmission services. Nearly 1,000 public power utilities belong to joint action agencies.

Still other public power utilities are distribution-only utilities that purchase the energy and transmission services they need from larger utilities, including the Tennessee Valley Authority, the Bonneville Power Administration or neighboring investor-owned or cooperatively owned utilities. A significant number of public power utilities are located in or near RTO regions and thus rely on RTO markets to meet a major portion of their wholesale power supply and transmission needs.

III Competition and Wholesale Electric Power Markets

What is Competition?

Supporters of RTO-run centralized wholesale electricity markets and state retail restructuring regimes commonly use the term "competitive" to describe these markets and programs. Of course, calling a market "competitive" does not make it so, particularly when there is no basis to believe these markets meet the basic criteria for effective competition, Notwithstanding this lack of analysis, RTO-run centralized wholesale markets assume that competitive forces would somehow keep prices at reasonable levels.

Advocates of these markets argue that wholesale electric power is essentially no different from other industries and all that needs to be done is to improve market rules and market oversight. But the threshold question—whether the economic and technical characteristics of electric power production and transmission are compatible with truly competitive markets—has never been thoroughly addressed. Even the economist Alfred Kahn, a proponent of deregulating electricity markets, recognized that a deteimination of whether market forces could sufficiently discipline prices and guide investment decisions "would have to take into account the extraordinary and in some respects literally unique characteristics of the industry."[8]

Addressing the question of whether true competition is achievable in elecuicity markets first requires a common understanding of the term "competition." As simple as the concept may seem, it is a major source of misunderstanding in the restructuring policy debate. Economists disagree on a practical definition of competition, and many policymakers apparently have not understood the implications and importance of this disagreement.

The conventional textbook definition of competition requires numerous buyers and sellers, no barrieis to entry, price flexibility in response to underlying cost changes, perfect infoimation, and foresight by buyers and sellers. While the textbook definition of competition might be too stiingent as a practical matter, the listed characteristics still serve as a useful guide and, if too many of them *are* not present, policymakers should he concerned. Columbia University economist Joseph Stiglitz, a Nobel laureate, provides what he calls a simple "old-fashioned definition of competition: It is a "rivalry among firms to supply the needs of consumers and producers at the lowest price with the highest qualities."[9] If such rivalry is present, then sellers will be "price takers," not "pricc setters," and consumers will benefit.

[8] Kahn, Alfred. "The Deregulatory Tar Baby: The Precarious Balance Between Regulation and Deregulation, 1970–2000 and Henceforward." *Journal of Regulatory Economics*. Vol. 21. Issue 1 (2002), 46.

[9] Stiglitz, Joseph. *Whither Socialism?* Cambridge (MA): The MIT Press, 1994, 255.

Structural Characteristics of Electricity Markets

Price competition is especially important in electric power markets. In other industries, lack of vigorous price competition may not be a major problem because firms can compete by improving existing products or introducing new ones. But this is not so for electricity Price is essentially the only dimension over which suppliers can compete and if suppliers are not vigorously competing on the basis of price, then consumers will not be better off. (One exception is the offering of "green power" whereby consumers can purchase electricity generated by renewable energy facilities. But the "product" that is consumed is still the same.)

A number of very important structural characteristics of the electric power industry raise substantial barriers to entry and thus severely limit competition. Most obvious, perhaps, is the size of the capital investment needed to enter the industry.[10] Other threshold questions confronting a potential competitor are how much lead time it takes to enter the market, where to build a new generation plant and, most importantly, whether there will still be the same level of demand for electricity once the new plant is built and what impact the addition of its new supply will have on prices.

A new competitor might see a market opportunity where prices have been high for a significant period of time and so might believe this would be the case for the next year or two. But it takes a minimum of five years to build a large fossil fuel-fired plant and even longer for a nuclear plant. Price forecasts become less reliable that far out and risks increase correspondingly Without a long-term commitment by one or more buyers to purchase the plant's output, financing becomes very problematic. Hence, the longer it takes to enter the market, the less certain the amount of future revenues becomes. This factor poses a significant barrier to entry, especially in the electric power indusy, where the incumbents generally already control many of the best generation sites.

The control of most of the best locations for new generation sites provides a significant absolute cost advantage to incumbent utility generators, These generators can add capacity at existing sites by increasing the size of existing units, building new units in their place or by adding new units to old ones at existing sites. In contrast, new entrants face the challenge of finding sites not too far from high-population areas, transmission lines, sources of water, rail lines, etc., depending on the type of unit they wish to build. Consequently, new entrants often have to build plants at less desirable locations where they may not have convenient access to other necessary infrastructure. If they do locate plants closer to end users, land values are likely to be high, and siting and environmental requirements more stringent and costly.

The control of most of the best locations for new generation sites provides a significant absolute *cost* advantage to incumbent utility generators.

[10] A new 500-600-megawatt, base-load coal plant costs about $800 million and a new comparably sized nuclear facility cost? more than a billion dollars. Energy Information Administration, Table 39. Cast and Performance Characteristics of New Central Station Electricity Generating Technologies, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3.

Many of the generation units in their portfolios are the same units that the vertically integrated utility built prior to restructuring to serve their retail customers. Thus, the generation portion of their business went from being a regulated monopoly to part of an unregulated oligopoly.

Advocates of RTO-run centralized markets have touted the entrance of "merchant generators" into the marketplace as a sign that these markets are competitive. But many of these companies are the deregulated generation affiliates of former vertically integrated electric utility companies. Many of the generation units in their portfolios are the same units that the vertically integrated utility built prior to restructuring to serve their retail customers. Thus, the generation portion of their business went from being a regulated monopoly to part of an unregulated oligopoly.''

For example, the 6,000 megawatts of electric generation capacity that Baltimore Gas and Electric Co., a stateregulated transmission and distribution utility, once owned is now owned hy the company's unregulated affiliateswithin the Constellation Energy holding company.[12] Constellation's "merchant" affiliates therefore do not face many of the high barriers to entry-such as financing the plant and locating a site—that a true new entrant would. This head start enhances the market power of these merchant affiliates of traditional utilities. They can charge prices substantially above their own economic costs of producing power (reaping very handsome profits as they do so) and have little to fear from new entrants. As a result, there are only a limited number of generation competitors in RTO markets, further undermining the ability of "competition" to bring prices to reasonable levels.[13]

Despite these and other impediments, advocates of RTO markets believe competition can he "made to work," "designed" or "created." This belief assumes that the basic physical characteristics of the production and delivery of electric energy and the economic characteristics of the industry matter little and that legal, structural and institutional changes can make the industry competitive, in the process rendering price regulation unnecessary, But this view is inconsistent with one of the cardinal elements of competition: Competition itself restrains the behavior of market participants so there is little or no need for government involvement. If wholesale electric power markets were truly competitive, then the market itself would produce the correct levels of investment in reliable and environmentally responsible electric service and assure that electricity is produced and priced efficiently. Were the markets truly competitive, there would not be a constant need for patchwork solutions to address concerns about reliability, excessive prices and the adequacy of future generation capacity, as there are today

[11] A market characterized by such a small number of sellers such that each one can take actions that affect the prices in the market.

[12] Constellation Energy Group, 2006 Form 10-K p. 6.

[13] For example, in peak hours in PJM in 2006, the Herfindahl-Hirschman Index (HHI), a measure of market concentration, averaged 4,157, well above the cutoff of 1,800 for a "highly concentrated market." The average for intermediate houn was similarly high, at 2,664. (An HHI of 1,800 represents about five or six firms with equal market shares.) 2006 *State of the Market*, PJM Interconnection, LLC.

Are Restructured Markets Synonymous with Competition?

It is time to ask: Are continuing concerns about adequate capacity reliability arid generation market power simply due to the fact that we haven't yet been able to come up with tlie correct "market design" or is it because the basic characteristics of electric power markets ensure a large and unacceptable level of market power that cannot simply be "designed away!" Arc the disconnects between how competitive markets should theoretically perform and what is actually happening in RTO wholesale power markeu due to faulty market design or, alternatively, do they reflcct faulty assumptions regarding what can realistically be done about the inherent lack of competitiveness of electric power markcw?

APPA believes a detailed, unbiased study of tlic inherent economic conditions of the electric power industry would raise serious questions about the competitiveness of RTO-rim centralized markcw **and** their ability to discipline wholesale pi-ices Io just and reasonable levels. This does not mean that prices should not vary by time of use to reflect varying costs of production in different hours al different levels of customer demand. But variability in prices docs not mcan, and should not serve as a pretext for, setting prices far above costs, resulting in excessive returns to a limited set of oligopolistic generators. Nor should extreme price spikes bc justified as promoting demand response, when tlie actual result is "demand destruction" that can greatly harm consumers and businesses.

There are significant natural and artificial impediments to competitive RTO-run centralized wholesale markcw that policymaken cannot simply assume away. The views of RTO-market proponents about the real or alleged failures of traditional regulation need to bc balanced with other views about the failures of electricity deregulation and RTO markcw in particular. It is precisely those who must deal with these RTO market realities — consumers and the load-serving entities[14] responsible for meeting their needs—who have expressed tlie most concerns, while it is tlie RTOs themselves and tlic generators who participate in these markets who claim consumers are benefiting from them. This disconnect in itself should prompt policymakers to question whether these markets benefit consumers or oligopoly generators.

How the Federal Power Act Addresses the Potential for Anti-Competitive Behavior Through the Just and Reasonable Rate Standard

During tlie early years of tlic electric utility industry, concerns about utilities exercising market power to exploit consumers led Io enactment of federal and state statutes requiring that wholesale rates meet a "just and reasonable" standard. This standard still

[14] A load-serving entity is a utility that has a responsibility to provide electricity to retail customers and purchases or generates electricity in order to satisfy that responsibility.

exists in the Federal Power Act (FPA), which Congress has entrusted the FERC to enforce.

The FERC's core responsibility under the FPA is to "guard the consumer from *exploitation by non-competitive electric power companies.*"[15] Its primary (but not its only) statutory tools to protect consumers are FPA Sections 205 and 206.[16] These sections require commission-regulated "public utilities" to charge rates that are "just and reasonable." In reviewing public utilities' rates under this standard, the commission must balance competing interests: it must ensure that investors in the public utility receive a fair return on their investment while, at the same time, protecting consumers from excessive rates.[17]

Although the statute does not stipulate what method should be used to achieve just and reasonable rates, the commission has until relatively recently used cost-of-service regulation to make sure that rates were just and reasonable. The recent shift toward the use of markets and supposed competitive forces to ensure just and reasonable rates, while not prohibited by the FPA as a method, is clearly not working to achieve the required result.

Because the commission has decided to allow alleged competitive forces to discipline wholesale power rates, it takes on the heavy burden of ensuring that public utility sellers in fact still charge only just and reasonable rates.[18] The U.S. Court of Appeals for the District of Columbia Circuit has found that while "contrasting or changing characteristics" within the industry may justify "taking a new approach to the determination of just and reasonable rates," FERC may not abdicate "its statutory responsibilities in favor of a method that guards against only grossly exploitative pricing practices."[19] Evidence from the restructured markets clearly shows that market-based rates and unregulated prices do not equate to just and reasonable rates.

In an effectively competitive market, where neither buyers nor sellers have significant market power, the commission can rationally assume that the terms of their voluntary exchanges are reasonable, and specifically infer that the sales prices are close to marginal cost, so that a seller makes only a normal return on its investment.[20] (A normal return is that which is sufficient to attract adequate levels of capital financing and not a level that earns supra-normal profits.) But, as explained above, **the** structural features of the

[15] *NAACP v. FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662 (1976).

[16] 16 U.S.C. §§ 824d and 824e.

[17] *Public Utility District No. 1 of Snohomish County, Wash. v. FERC*, 471 F.3d 1053, 1058 (9th Cir. 2006).

[18] *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004).

[19] *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1503-04 (D.C. Cir. 1984) ("*Farmers Union*").

20 *Tejas Power v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990).

wholesale electric power industry, and the resultant marker power of generators, make it very difficult for competitive forces actually to discipline prices to just and reasonable levels. Moreover, research conducted for APPA in the first phase of its Electric Marker Reform Initiative (undertaken in 2006) shows that wholesale power prices in RTO markets bear no relationship to sellers' marginal costs of production; " " to the contrary, certain owners of generation are "earning supra-competitive returns that are not commensurate with returns on investments in other enterprises having corresponding risks." " "

These facts, taken together, lead APPA to conclude that wholesale rates in RTO-run centralized markets are not just and reasonable. APPA believes the commission has the statutory responsibility to investigate this situation, and to remedy it if it finds rates to be unjust and unreasonable. As FERC Chairman Joseph Kelliher himself has pointed out, "[t]he legal duty of the commission to prevent unjust and unreasonable rates and undue discrimination or preference in the sale of wholesale power or interstate transmission by jurisdictional sellers is absolute: the commission does not have the discretion to ignore them."[23]

[21] "A Comparative Analysis of Actual Locational Marginal Prices in the PJM Market and Estimated Short-Run Marginal Costs," prepared by London Economics International, LLC (February 5, 2007) (LEI's analysis of bidding in PJM markets based on short-run marginal costs showed that offers to sell electricity into PJM's organized markets are often not tied to the seller's marginal cost of producing that electricity; for example, in PJM Interconnection, during peak periods in recent years, as much as 10 to 25 percent of the price appears to be attributable to the difference between that price and the short-run marginal costs of the generator whose bid cleared the market.).

[22] Request to Expand the Scope of the Section 206 Proceeding, Docket Nos. RM07-19-000 and AD07-7-000, December 17, 2007 at 4.

[23] Joseph T. Kelliher, *Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission*, 26 Energy L.J. 1, 3–4 (2005).

IV. Failures of Centralized RTO-Run Wholesale Electricity Markets

Central to FERC's policies encouraging competition in the wholesale electricity markets has been the promotion of RTOs and their operation of centralized markets for wholesale electricity and ancillary services. These markets, while operated without traditional cost-of-service regulation, are very complex, entailing numerous market rules, large bureaucracies and expensive software packages. The history of these RTO markets has been characterized by continued attempts to address various issues through a series of market "fixes." However, because these centralized markets were assumed to be competitive, the fact that continual "fixes" have been required calls into serious question the underlying assumption of competition.

Features of RTO Markets[24]

There are currently six FERC-regulated ISOs: ISO New England (ISO NE); the New York ISO (NY ISO); the PJM Interconnection (PJM, which covers the Mid-Atlantic states and some parts of the Midwest); the Midwest ISO (MISO, which covers other parts of the Midwest); the California ISO (CAISO); and the Southwest Power Pool (SPP), which covers parts of Texas, Louisiana, Arkansas, Missouri, Kansas and Oklahoma.[25] The concerns expressed in this paper focus specifically on the centralized RTO-run markets that have come to dominate RTO operations. RTOs do provide services that have substantial value and should not be eliminated. RTOs have implemented regional OATTs, administered on a non-discriminatory basis, eliminated pancaked transmission rates (allowing transactions to take place over a broader geographic area, provided that the necessaiy transmission infrastructure is available) and attempted to strengthen regional transmission planning. Yet these substantial accomplishments have been overshadowed by the costs and dysfunctional nature of RTO-run centralized markets. RTOs generally opeiate centralized day-ahead and real-time spot markets for electricity, as well as markets for ancillary services needed to use open access transmission service. The prices for electric power in these markets are set at certain intervals (often every hour) hased on the offers to sell power submitted hy generation owners to the RTO. These offers need not reflect the sellers' actual costs of geneiating power (average, marginal or otherwise), as FERC would have required under a traditional cost-of-service ratemaking regime. Rather, the sellers set their own price offers, unless the prices they propose trigger preset "market mitigation" thresholds set hy the RTO.[26]

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24 For a more detailed description, see *Understanding Electricity Markets An examination of how electricity markets work—and how they don't*, by Gary Newell and Ransom E. (Ted) Davis, Thompson Coburn, for APPA, November 2006, at http://nww.appanet.org/aboutpublic/index.cfm?ItemNumber=17766.

25 The Electric Reliability Council of Texas ("ERCOT") is also an ISO, but since ERCOT does not operate in interstate commerce, it is regulated by the Texas Public Utility Commission.

26 For example, there are exemptions from mitigation granted to generators in PJM. The Maryland Public Service Commission asserts in a complaint filed with FERC against PJM in January 2008 that "a significant share of generation resources in the PJM footprint avoids mitigation even though they exercise market power," and that these exemptions "added $87.5 million to Maryland's 2006 real-time energy related charges."

The RTO takes all offers for a particular upcoming time interval in ascending price order, stopping with the last offer needed to meet the power needs of loads during that time interval. All sellers in that time interval, regardless of the amount of their own price offers, are paid the price based on the last and highest offer the RTO accepts to supply power to meet its regional demand—known as the bid that "clears the market." This market design is known as a "single clearing price" market, and such markets are called "Day 2" markets.[27]

Bid-based markets create well-known incentives for generators to withhold capacity (to create artificial shortages that increase prices) and to refrain from building otherwise-needed new generation capacity (which could reduce prevailing market prices, thus reducing profits). This combination of complex market rules, incentives for short-term withholding, and depending on the "market" to assure adequate generation and transmission infrastructure can ultimately jeopardize reliable service to retail customers, as witnessed by the load shedding that customers experienced in California during the 2000-2001 energy crisis. The complexity of the transition to using RTO markets to operate a large multi-state power system may also have contributed to the August 14, 2003 Midwest/Northeast blackout, by distracting bulk power system facility operators at the Midwest Independent Transmission System Operator and First Energy from their respective obligations to comply with the North American Electric Reliability Corp. reliability standards. Price volatility in RTO energy markets has also resulted in irrational generating unit commitment and dispatch directives, as transitory RTO market price spikes cause market participants to chase prices up and down in search of profit.

Price volatility in RTO energy markets has also resulted in irrational generating unit commitment and dispatch directives, as transitory RTO market price spikes cause market participants to chase prices up and down in search of profit.

Another central element of RTO-operated energy markets is "locational marginal pricing" (LMP) in which electricity is bought and sold at prices that vary by location within the RTO area. LMP reflects the differences in the costs of delivering electric power to different parts of the transmission grid due to transmission constraints (often called "congestion"). Prices for power wry within the RTO's region during hours in which transmission congestion (demand for use of specific transmission facilities that exceeds those facilities' capacity to move power) makes it impossible for electricity to reach every part of the RTO's system at the lowest overall economically efficient cost. If a customer happens to be located in a portion of the transmission system affected by such a limitation (a "constrained zone"), the price the customer pays reflects the offer submitted by the generator that is actually able to deliver electricity to the customer, even if there are generators offering lower prices elsewhere in the RTO. The difference between the lowest price and that charged in the constrained zone is referred to as the "congestion charge."

Advocates of locational marginal pricing argue that the higher costs charged when congestion occurs on the transmission system will give market participants an incentive

[27] The California ISO does not yet use a full-fledged "Day 2" marker, bur intends to implement one in April 2008 (according to the California ISO Web sire). SPP has not to date proposed a "Day 2" market, but does run an energy imbalance market

Hedge funds, investment banks and other financial entities have begun purchasing FTRs through the auctions, further exposing transmission customers to undue risks. These entities often have no stake in the market except a financial one and are therefore bidding on these FTRs purely for speculative purposes.

to pay for construction of new generation and transmission facilities. Alternatively, the higher costs might prompt electricity customers to reduce consumption or to use power during periods of lower overall demand. However, there is no evidence that such pricing signals have led to construction of generation or transmission.[28] RTOs offer their transmission customers an opportunity to limit the adverse impact of these congestion charges by issuing financial transmission rights (FTRs), which generally give their holders a right to receive a share of the congestion charges. Typically, RTOs allocate some portion of these FTRs based on the amount and location of the generating resources that each transmission customer has declared it will use to serve its retail loads. Some RTOs also operate auctions and facilitate the secondary purchase and sale of FTRs among customers.

But load-serving entities and large customers have faced difficulty obtaining sufficient FTRs to hedge deliveries of power from their own electric generation sources.[29] The number of financial rights an RTO issues is limited by the physical capability of the network, which varies from time to time, depending on forecasted operating conditions. Some load-serving entities have suffered sharp cuts in their financial rights allocations when forecasted changes in operating conditions caused the RTO to impose reductions. In addition, the amount of revenue FTRs provide is not guaranteed at any particular level and can fluctuate due to a number of factors.

In another development, hedge funds, investment banks and other financial entities have begun purchasing FTRs through the auctions, further exposing transmission customers to undue risks. These entities often have no stake in the market except a financial one and are therefore bidding on these FTRs purely for speculative purposes. Loadsewing entities, industrial customers and other wholesale power buyers must purchase FTRs as a hedge against real congestion costs,

In December 2007, two hedge funds defaulted on $85 million in payments to PJM after they suffered financial losses associated with FTRs they had purchased for speculative purposes. The two funds had purchased "counterflowpositions" that historically would have earned them money. When PJM-controlled transmission lines were shut down for routine maintenance in New Jersey, the power flows on the system changed and these FTRs lost money Both funds then defaulted on their financial obligations associated with these FTRs. It appears that the remaining participants in PJM (and ultimately, retail

[28] In *LMP Electricity Markets: Market Operations, Market Power,* and *Value for Consumers,* by Synapse Energy Economics, February 2007, the authors found that "[t]here is simply no evidence that the price signaling associated with LMP has been an effective spur to investment in generation, transmission or demand response initiatives, and some evidence to the contrary"

[29] In response to new legal requirements included in the Energy Policy Act of 2005 (incorporated in new Section 217 of the FPA), the commission has required RTOs to develop long term (e.g., 10-year) financial transmission rights. These rights, however, are not yet fully available due to the time required for the commission to develop the relevant generic guidelines for these rights and to approve the subsequent compliance filings the various RTOs have made to implement the guidelines.

customers in the PJM region) will he hilled for these losses.[30]

RTOs also administer markets for the sale and purchase of generation capacity, or the ability to produce electric energy on an instantaneous basis as and when needed. Load-serving entities with traditional service obligations have historically maintained an adequate amount of capacity to meet their respective contributions to the region's projected peak loads plus a reserve margin.

Because of concerns regarding the future adequacy of generation resources to meet demand in RTO regions, three RTOs (ISO NE, PJM and the NYISO) have implemented locational capacity markets, under which existing and new generators bid to receive additional revenues (in addition to the centralized spot energy markets) from the RTO and its load-serving customers in exchange for assuring the RTO that their generation facilities can be called on in future periods to supply power. These markets have proven to he very controversial, due to their high prices and questionable efficacy in supporting the development of substantial new generation resources.

Buyers and sellers in Day 2 markets can attempt to avoid purchasing power in the RTO-run spot markets hy entering into individual contracts with generators (called "bilateral" contracw). But the prices for power sold under those contracts are substantially influenced by the prices the sellers can obtain in the RTOs' centralized markets. Very substantial volumes of power are sold through the centralized markets. It is uncommon to see bilateral contracts in RTO regions for terms longer than five years and most such contracts are only to supply electric power; they are not tied to specific electric generating resources and therefore cannot be used to meet the buyer's locational capacity market obligations. These contracts are often called "seller's choice agreements," meaning the seller will determine exactly what generation sources the power sold will come from at the time it is actually supplied. Moreover, bilateral contracts do not insulate the customer from the payment of RTO congestion charges, which are collected through an additional charge on top of the RTOs "base" transmission rate.

The generators' preference for selling into RTO-run centralized power markets rather than under bilateral contracw is illustrated by a presentation made by Public Service Enterprise Group (PSEG) to the Edison Electric Institute in November 2007.[31] One of the slides in the presentation shows a decline in the percentage of coal and nuclear output sold under bilateral contracw from 80 to 20 percent from 2008 to 2010. Generation capacity under bilateral contracw is projected to decline from about 90 to 50 percent in the same time period.

It is uncommon to see bilateral contracts in RTO regions for terms longer than five years.

[30] "PJM Completes Analysis of Recent Market Payment Default and Announces Steps to Mitigate Future Risk Exposure," PJM Press Release, December 26, 2007, http://www.pjm.com/contributions/news-releases/2007/20071226-credit-default-news-release.pdf; Two companies default on payment of $85M in financial transmission rights, says PJM, *Public Power Daily*, January 4, 2008.

[31] Presentation by the Public Service Enterprise Group at the 42nd EEI Financial Conference, Lake Buena Vista, Fla., November 6, 2007, http://library.corporate ir.net/library/99/998/99807/items/268128/PSEG_EEI.pdf

Bilateral markets in certain parts of the country (for example, the Desert Southwest and Pacific Northwest) are very active, with many wholesale sellers offering power on a short- and long-term basis, and many buyers seeking to purchase such supplies.

APPA members in (or even near) RTO regions cannot avoid dealing with their RTOs simply by consuucting their own generation resources or contracting with third-party suppliers. Under either arrangement, the APPA members would still be required to take wholesale transmission service from their RTOs under FERC-regulated rates and tariffs. Hence, they must obtain FTRs to hedge the transmission congestion costs associated with their power supply transactions. And they must still participate in their RTOs centralized day-ahead and real-time power supply markets, if only to resolve their hourly energy imbalances. They are increasingly required to participate in RTO locational capacity markets and ancillary services markets as well.

Features of Bilateral Markets without RTOs

The absence of centralized RTO-run markets in some regions of the country does not necessarily equate to thin wholesale power markets in those regions. Bilateral markets in certain parts of the country (for example, the Desert Southwest and Pacific Northwest) are very active, with many wholesale sellers offering power on a short- and long-term basis, and many buyers seeking to purchase such supplies. As would be expected, the strength of the wholesale electric power supply market in any particular region depends on the same basic factors: the number of wholesale power buyers and sellers (and whether they have significant market power); the level of access to transmission service needed to support transactions; long-term sufficiency of the underlying transmission and generation infrastructure; and adequacy of information about different power supply and transmission service options. This holds true in both RTO and non-RTO regions.

In regions without RTOs, bilateral contracts between power sellers and buyers are the norm. They can be for very short terms (e.g., one hour to 30 days) or very long terms (e.g., 20 years). They are more often tied to sales of power (with or without associated capacity) from specific generation resources or fleets of such resources, although seller's choice-type energy-nnly agreements not tied to specific plants are also used in bilateral regions. Because there is no centralized spot market run by one regional institution, there are no regional "clearing prices" for any time interval. However, trade press periodicals collect information on specific bilateral transactions and publish "index prices" at certain key points on regional transmission systems.[32]

In bilateral regions, individual transmission owners provide the associated transmission services needed to support bilateral wholesale power supply deals under their own open access transmission tariffs (OATTs), which establish standard rates for the provision of transmission service. Transmission providers generally offer transmission service under a "physical rights" model, where they will only sign "firm" transmission service agreements (under which transmission service is guaranteed unless curtailments are required to maintain system reliability). The provider will offer these physical rights only if it has sufficient available transfer capability (ATC) to support the specified transaction over the

[32] For example, trade publications publish market index prices far the Southeast (into TVA, into Entergy, into Southern, etc.) and the West (California-Oregon Border, Palo Verde, Mead, etc.)

proposed contract term. Hence, they do not ration access to their transmission systems through the use of congestion pricing. While customers must obtain transmission service from individual transmission providers instead of over a single RTO-managed grid, some tools have been developed to support easier procurement of transmission, such as the joint WesTTrans computer site, where market participants can obtain transmission service from 24 Western transmission providers (both FERC-regulated and non-jurisdictional) using a common computer interface.[33]

One example of a non-RTO-based approach to transmission system management and planning is the ColumbiaGrid in the Northwestern United States.[34] This is a nonprofit membership corporation formed in 2006. ColumbiaGrid does not own transmission; its members and the parties to its agreements own and operate an extensive network of transmission facilities. While different models may he appropriate for different regions. the ColumbiaGrid demonstrates that there are effective and consumer-friendly alternatives to the use of pricing incentives to manage the power grid.

ColumbiaGrid does not *own* transmission; its members and the parties to its agreements *own* and operate an extensive network of transmission facilities.

Public Power's Concerns with RTO-Run Wholesale Markets

AFPA was an early and strong supporter of ISO development. Many APPA members hoped ISOs would eliminate "pancaked" [individual system-hy-system) transmission rates, bring a more coordinated regional approach to planning and constructing transmission facilities, and ensure nondiscriminatory transmission access. But as the commission moved from encouraging initial ISO development to full-fledged RTOs, its policies underwent a fundamental shift. The FERC's RTO policies morphed from promoting open access to the transmission grid and a more coordinated approach to transmission planning and construction into advancing centralized, RTO-run markets for day-ahead and real-time energy capacity and ancillary services, and the use of LMP to price transmission congestion. The use of market-based rates, combined with the single-price auctions in these markets, often allowed generators to collect the higher of their own units' specific costs (if they had higher cost units needed for reliability purposes, regardless of costs) or the RTO-determined market price (if they had lower cost units).

Further, centralized bid-based auction markets have changed the incentive structures faced by deregulated generators: measures that would reduce congestion or prevailing market prices will reduce the profits of incumbent companies with large deregulated generation portfolios. Incumbent generators have clear disincentives to make investments that might reduce prevailing prices (and benefit consumers); new competitors often find asset-based e n y difficultto impossible, unless such e n y is supported by factors such as long-term contracts with load-serving entities (often public

[33] www.wesnrans.net.

[34] http://www.columbiagrid.org. The corporation, with the participation and agreement of its members, conduce transmission planning, including determination of cost allocation methodologies, analyzes long-term reliability projects, and administers an Open-Access Same-Time Information System (OASIS).

Incumbent generators have clear disincentives to make investments that might reduce prevailing prices (and benefit consumers).

power utilities rather than investor-owned utilities which, in many cases, no longer have an obligation to serve) or regulatory and tax policies (principally state renewable portfolio standards and federal production tax credits).

APPA first made its concerns about these RTO-run markets public in December 2004, when it issued a white paper entitled *Restructuring at the Crossroads; FERC Electric Policy Reconsidered.*[35] APPA there noted (at page 6): "APPA members located in RTO regions report substantial, across-the-board problems with spiraling RTO costs, unaccountable governance, lack of understanding of transmission customer and end-user needs and less-than-satisfactory service options. They see more and more RTO services being provided through questionable market mechanisms, and RTO resistance to any questioning of the economic theories underpinning these actions." APPA discussed the problems its members were encountering in some detail, and suggested a number of proposed "midcourse corrections," including development of long-term FTRs, meaningful mechanisms to get additional transmission facilities constructed, encouragement of joint ownership of transmission, more scrutiny of RTO administrative costs, and more accountability of RTO managements to stakeholders. As APPA stated in the conclusion of its white paper (at page 26), it sought to "reform the existing RTOs, so that they operate to benefit electric consumers (rather than particular industry participants), and employ market mechanisms only as a means to an end (serving electric customers), and not an end in themselves."

There have been some improvements in the commission's RTO policies in the three years since APPA issued that white paper. In part as a result of changes in the membership of the commission, in 2005, the commission abandoned its insistence on RTO formation in all regions, permitting more regional diversity. The commission also revised its public utility accounting rules and reporting requirements to better accommodate RTOs' administrative and operating cost categories. This will bring much-needed cost accounting standardization, so the costs billed to market participants for the administration and operation of each RTO can be better compared across RTOs. Finally, the commission conducted the rulemaking required by EPAct 2005 to set guidelines for long-term FTRs in RTO regions, which RTOs are now implementing.

Despite these improvements, the fundamental problem of an absence of effective regulation and oversight in these wholesale markets has not been addressed. The problems have indeed worsened since the release of *Restructuring at the Crossroads.* As a result, the gap between regulated and unregulated prices has widened and profits of owners of unregulated generation facilities have increased, while projected reserve margins continue to shrink and many portions of the transmission system remain congested. Because of the failure of RTO-run centralized spot markets and LMP-based congestion pricing to support the construction of new generation and transmission facilities, three RTOs have implemented separate locational capacity markets to try to fill

[35] The paper is available at: http://www.appanet.org/files/PDFs/APPAWhitePaperRestructuringatCrossroads1204.pdf.

the void. It is unclear whether such markets are now, or will in the future, support development of substantial new generation,[36] hut it is abundantly clear that electric consumers in these three RTO regions are paying billions of dollars in additional locational capacity charges?'

Prices in RTO-run centralized spot markets continue at very high levels, while certain utility-affiliated merchant generators holding fully depreciated, formerly utility-owned generation assets are reaping extraordinary profits. The price expectations that sellers have formed from the high RTO spot market prices have bled over into bilateral markets in RTO regions. In the experience of most APPA memhen, nearly all medium and long-term contracts are indexed to natural gas prices and tend to pass through RTO administrative costs, congestion charges and the exorbitant costs of RTO generation capacity markets. Power marketers generally demand a substantial price/risk premium above their costs, perhaps reflecting uncertainty about their own costs as well as the foregone profits that might otherwise be made from sales into RTO spot, capacity and ancillary services markets.

RTO "markets" are continually applied to previously cost-regulated products, e.g., ancillary services, without any rigorous cost-benefit analysis to ensure that end-use customers are well served hy such markets. Administrative costs associated with these new markets are also very high, adding to the RTO costs that are passed directly on to the customers who purchase power through these markets.

APPA filed comments on September 14, 2007, with FERC on its "Advance Notice of Proposed Rulemaking" (ANOPR) in Wholesale Competition in Regions with Organized Wholesale Markets, FERC Docket Nos. AD07-7-000 and RM07-19-000.[38] In those comments, APPA delineated in great detail load-serving entities' substantial concerns with RTO markets, casting significant doubt on the commission's statement that RTO markets "benefit consumers." APPA also filed sworn affidavits providing additional evidence about the complex relationship between higher fuel prices and high RTO spot-market prices, and the extremely high profits enjoyed by certain merchant generaton in RTO regions. Based on this evidence, together with the findings of its Electric Market Reform Initiative studies, which were filed with the commission, APPA asked FERC to investigate the prices charged in RTO markets, asserting that they are not just and reasonable, as Sections 205 and 206 of the Federal Power Act require. As of this writing,

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[36] At least one study. prepared for APPA. conclude, they will not. "*Investment Performance in Deregulated Markets for Electricity A Case Study of New York State,*" prepared by Dr. Timothy Mount of Cornell University. September 2007.

[37] James F. Wilson, a principal at LECG LLC, found that although it is too soon to conclude that RPM is working...the evidence to date suggests the contrary; that it is not attracting new capacity where needed, and the bidding and price formation in the auctions are not as mended and expected ..capacity prices for the first three RPM delivery years reflect an approximately $15 billion increase in capacity value relative to the highest rapacity price from the prior four years, adjusted fur Inflation. "Too Soon to Determine Success of PJM s Reliability Pricing Model, *Power Market Today*, October 29. 2007.

[38] There comments are available at http://www.appanet.org/files/PDFs/APPA_Cmts_AD07-7_9-14-07%20%5Bas%20filed%5D.pdf.

tlic commission has not acted **on** APPA's request

The remainder of this section describes the growing body of evidence on tlic consumer harms and absence of benefits from tlic current market structure and the importance of *FERC action* in *response*.

Findings of EMRI Studies of Wholesale Markets

During the initial phase of its Electric Market Reform Initiative in 2006, APPA commissioned a series of studies to gather more information about wholesale RTO market operations and the associated impacts on consumers. APPA in these studies attempted to delve more deeply into assumptions and assertions often made in support of the current markets.

The findings of these studies paint a very disturbing picture of RTO-run centralized markets and the state of "competition" in them. There is real evidence of RTO market failures that are harming consumers, and strong indications that the wholesale rates these markets produce are not just and reasonable. The findings in these studies stand in stark contrast to the contrary claims of the RTOs and tlic owners of unregulated generation selling into those markets.

To begin to evaluate tlic results of restructnring, APPA decided to examine a group of studies often cited by RTO market proponents, concerning the impacts of restructuring on consumers. Dr. John Kwoka, an economist at Northeastern University, reviewed these studies and found that tlic methodologies used in them fell short of the standards necessary for reliable economic research. As a result there "[i]s no reliable and convincing cvidencc that consumers are better off as a result of the restructuring of the U.S. electric power industry," Dr. Kwoka said.

Given this dearth of reliable data and analyses, APPA decided to undertake a more careful examination of the impacts of restructuring. One important indicator of whether "competition" is disciplining prices to just and reasonable levels is the profitability of tlic generators making sales into these markets. APPA therefore asked independent consultant and financial analyst **Ed** Bodmer to look at the current ***and*** future profitability of the five largest sellers of unregulated wholesale power in PJM. Using publicly available data, Mr. Bodmer calculated the earnings by shareholders iii these PJM companies to he **$32** billion and $40 billion greater than those for cost-regulated utility companies, for a three- and 10-year time period, respectively.[39] Information these companies themselves have prepared for investors and analysts contains predictions of additional substantial profits upon expiration of state retail rate caps and full implementation of PJM's locational capacity market, known as the "reliability pricing model," or RPM. Indeed, in a

[39] *The Electric Honeypot: The Profitability of Deregulated Electric Generation Companies*, by Edward Bodmer, February 2007.

[40] Affidavit of Edward Bodmer, Comments of the American Public Power Association, FERC Dockets RM07-19-000 and AD07-7-000, September 14, 2007.

September 2007 update of his study using 2006 data, Mr. Bodmer found that these extra investor earnings have now grown to between $44 billion and $67 billion.[40]

Such excessive profit levels indicate that sellers with lower costs do not face substantial competitive pressures to pass on such savings to consumers. Another key question is the extent to which there is a relationship in a deregulated market between power supply prices and the costs of production. If a generator can successfully offer to sell power at a price significantly above its actual cost to run its generation unit, then it is unlikely that such a generator is facing any meaningful competition.

London Economics International, LLC (LEI) conducted a computer simulation for APPA that asked what clearing prices would result if generator offers to sell power into PJM's spot markets were actually based on their short-run marginal costs. LEI then calculated the difference between this simulated clearing price and the actual clearing price and found that offers to sell electricity are often not tied to the marginal cost of producing that electricity. For example, during peak periods in PJM in recent years, as much as 10 to 25 percent of the price is attributable to a markup above the short-run marginal costs of the generator whose bid cleared the market. The LEI study also showed a high degree of variation in the markup, raising questions about PJMs publication of only an average measure of the markup in its "State of the Market" reports. LEI also noted that PJMs markup index results are based on the production costs generators report to the market monitor, rather than independently verified cost data, and also noted that much of the data that LEI needed to conduct its study was unavailable from PJM.[41]

A study for APPA by Synapse Energy Economics provides further evidence of the gap between generators' offers and their actual production costs. Synapse examined offer data from generators in both PJM and ISO New England and found that offers from the same generating unit fluctuated by over $100 per megawatt-hour within one month. Yet, generating units typically have only minimal day-today changes in their production costs. These data indicate that these sellers of electric power may have sufficient market power to manipulate prices, or at a minimum are pursuing a strategy of attempted manipulation.

As data raising questions about the supposed price benefits from restructuring became increasingly prevalent, supporten of RTO markets have employed a new rhetorical strategy They now acknowledge price increases, but claim such increases have been driven by rising fuel costs, principally natural gas. Yet, Dr. Ken Rose, a consultant and senior fellow with the Institute of Public Utilities at Michigan State University, found in a study APPA commissioned that fuel costs cannot fully explain the increase in wholesale electricity prices. According to Dr. Rose, "attributing electricity price increases to only the cost of fuels used to generate electricity is overly simplistic at best." In fact, recent trends in PJM prices show that, rather than moving in lockstep, electricity prices and fuel costs

Synapse examined offer data from generators in both PJM and ISO New England and found that offers from the same generating unit fluctuated by over $100 per megawatt-hour within one month. These data indicate *that* these sellers of electric power may have sufficient market power to manipulate prices.

[41] London Economics International. February 2007, p. 77.

Areas where LMP prices are the highest, and thus transmission facilities are the most congested, do not correspond with the areas where the greatest investments in new generation and transmission have been made.

can sometimes even move in opposite directions?* Dr. Rose's conclusions were recently confirmed by an analysis hy Dr. Robert McCullough showing that when fuel costs are removed from prices, the differential between retail rates in RTO and non-RTO states was 2.8 cents in July 2007, compared to 1.1 cents in January 2003. [43]

Another critical measure of the success of a market structure is its ability to support reliable electricity service, hy ensuring that sufficient generation and transmission facilities are in place to meet projected future consumer needs. RTO-run centralized markets attempt to ensure future facilities adequacy largely through pricing incentives. Synapse found, however, that the areas where LMP prices are the highest, and thus transmission facilities are the most congested, do not correspond with the areas where the greatest investments in new generation and transmission have been made.[44]

Alarmed by the continuing lack of adequate investment, some RTOs are increasingly relying on locational capacity payments to generators to encourage the needed infrastructure investments. At APPA's request, Dr. Timothy Mount of Cornell University examined the effectiveness of the locational capacity market the New York ISO administers. Dr. Mount found that the main accomplishment of the hundreds of millions of dollars consumers have paid to generators through the New York capacity markets has been to increase the market value of generators' existing capacity. He concluded "the evidence from New York shows that paying a large amount of additional money to generaton in the [New York locational capacity] market does not guarantee that investment in new generating capacity will he made in a timely way."[45]

The findings from these various studies and the increased questions they raise about the results from "competitive" RTO-run markets have led both the generation owners and the RTOs themselves to step up their defense of the status quo. Yet additional claims of benefits are now emerging. One of the most prominent is the claim that RTOs have promoted the development of renewable generation resources. To fully investigate this claim, Dr. Lester Lave and Kathleen Spees of the Carnegie Mellon Electricity Industry Center conducted a rigorous statistical analysis and found "no indication that RTOs have facilitated the development of renewable resources." Rather, it appears that state policies fostering renewahles are most effective, such as rebate programs, loan programs, net metering, required green power offerings and renewable portfolio standards.

Supporters of restructured RTO markets also contend that restructuring promotes improvements in operational efficiencies in generating plants. At the request of APPA

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[42] *The Impact of Fuel Costs on Electric Power Prices,* by Kenneth Rose, June **2007.**

[43] *The Missing Benchmark in Electricity Deregulation,* by Robert McCullough, Managing Partner, and Ann Stewart, Research Analyst, McCullough Research, December **2007.**

[44] *LMP Electricity Markets: Market Operations, Market Power,* and *Value for Consumers,* by Ezra Hausman, Robert Fagan, David White, Kenji Takahashi and Alice Napoleon, Synapse Energy Economics, February **2007.**

[45] *Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State,* by Timothy Mount, PhD, Professor of Applied Economics and Management, Cornell University, September **2007.**

and the National Rural Electric Cooperative Association, Laurence D. Kirsch and Matthew J. Morey of Christensen Associates Energy Consulting reviewed a study by Kira Fabrizio, Nancy Rose and Catherine Wolfram on this topic. They also reviewed the COMPETE Coalition's press release publicizing this study. Kirsch and Morey found that in addition to several flaws in the study's methodology, the COMPETE Coalition's public statement that the study provides "further evidence that competitive forces in restructured electricity markets drive efficiencies that benefit consumers by helping to drive down costs and reduce adverse environmental impacts" is misleading. They found that the study itself provides no evidence of how competitive forces work in restructured environment., or whether any cost reductions resulting from increased operational efficiencies were passed on to consumers. Nor does the study attempt to measure any environmental impacts associated with this market model.[46]

Evaluations of RTO-run centralized markets are hampered by the dearth of adequate data to explain the extent to which the RTO-operated markets diverge from the competitive model. Moreover, it is impossible to identify the degree to which participants exert market power. At the request of APPA, William Dunn, a consultant with Sunset Point LLC, analyzed available RTO electricity market data to determine what information would be needed to allow adequate oversight of RTO markets. Mr. Dunn recommends that generator offer data in RTO markets be made publicly available on the next day with the specific generation owners identified, as is common practice in the markets in England, Wales and Australia. He also recommends providing the operating characteristics of the generation plants.[47] The issue of data transparency is discussed further in Section V of this white paper.

Not only are consumers in RTO regions bearing the brunt of power prices higher than those in non-RTO regions, but their electricity bills also include the costs RTOs charge simply to run their centralized markets. In an analysis for APPA, the consulting firm GDS Associates found that RTO participants in 2005 paid more than $1 billion in total administrative and operational costs to RTOs.[48] This figure did not include the RTO customers' own increased internal administrative and other costs incurred to participate in RTOs. These high costs, taken together with the highly problematic power prices in RTO-run markets, point up the need for an unbiased analysis of the costs and benefits of

Not only am consumers in RTO regions bearing the brunt of power prices higher than those in non-RTO regions, but *their electricity* bills also include the coots RTOs charge simply to run their centralized markets.

[46] *The Compete Coalition Oversells Independent Study Findings,* by Laurence D. Kirsch and Mathew J. Morey of Christensen Energy Associates Energy Consulting, December 2007.

[47] Concept Paper by William H. Dunn Jr.: *Data Required for Market Oversight,* December 2007.

[48] *Analysis of Operational and Administrative Cost of RTOs* prepared by William M. Bateman and Robert C. Smith, CDS Associates, February 2007.

These "markets" are essentially administratively developed constructs featuring centralized repeated auctions, in which oligopoly sellers *can* quickly learn the strategies of other bidders and adjust their own bids accordingly.

these markets.

Regulators And Other Policymakers Must Take Action

Given the results of these studies, and the increasing turmoil in states with retail restructuring regimes,[49] federal and state energy regulators and legislators cannot allow the current problems with RTO-run centralized wholesale markets to continue unexamined or unaddressed. The RTOs themselves and the "merchant" generators reaping extraordinary profits in RTO-run markets have bombarded the public with a steady stream of public announcements asserting that electric consumers benefit from "competition" and "free markets." But RTO-run markets are neither competitive nor free. These '"markets" are essentially administratively developed constructs featuring centralized repeated auctions, in which oligopoly sellers can quickly learn the strategies of other bidders and adjust their own bids accordingly According to the generators, their offers are extensively mitigated, preventing full recovery of their costs, yet some generators are clearly making profits far in excess of the "cost plus a reasonable return" that they would earn in a regulated market. Moreover, few of these dollars are reinvested in new generation and transmission facilities. Access to regional transmission facilities is essential to support wholesale transactions, but capacity is often insufficient and the associated transmission rates are uncertain, due to LMP congestion fees and limited FTRs.

No amount of free market rhetoric or touting of environmental benefits can cover up the increasing shortfall of new generation capacity required to ensure adequate electricity supplies in future years, at the same time that billions of dollars are simply leaving the market in the form of profits to shareholders of unregulated generators. Failure to take appropriate corrective actions to fix these systemic problems will not only leave consumers prey to unjust and unreasonable rates, hut could also lead to inadequate transmission and generation capacity that undermines the electrical reliability of entire regions of the country.

The next two sections discuss steps that should he taken to address these market problems, including both fundamental reforms and more discrete steps to deal with immediate problems with RTO-run markets.

[49] Examples include recent actions taken against Constellation by the Maryland Public Service Commission, the current debate over Governor Strickland's legislation in the Ohio House of Representatives, and recent attempts in Pennsylvania by the state legislature to extend the rate caps.

V. Fundamental Market Reform is Necessary to Protect Consumers

Consumer, Business, Public Interest and Other Groups Agree on the Need for Reform

A broad range of load-side interest and advocacy groups share APPA's concerns about problems in the RTO-run markets and agree that fundamental market reforms are needed.[50] For example, in their September 2007 comments on the FERC's advanced notice of proposed rulemaking, the Electricity Consumers Resource Council (ELCON), American Iron and Steel Institute (AISI) and American Chemistry Council (ACC) (collectively Industrial Consumers) said the "Industrial Customers believe that, as currently designed, the organized (e.g., RTO) markets are permanently structured as sellers' markets." They further said "...fundamental changes in the Day 2 market paradigm will be necessary to establish a robust forward market capable of delivering net benefits to consumers."

In that same proceeding, the Portland Cement Association (PCA) said "It is the hope of PCA that the commission will seriously consider the impacts of prior commission decisions on electricity consumers and address some of the basic market design deficiencies that currently exist and cause the current system to effectively impose a tax on electricity consumers for the benefit of the shareholders and management of electricity generating companies."

As a first step toward such reforms, APPA joined with these organizations and a wide range of other groups representing consumers, large industrial users, businesses and the public interest to file a petition in this proceeding requesting the FERC to "expand the scope of the Section 206 proceeding beyond the four issues discussed in the ANOPR to comprehensively investigate the justness and reasonableness of wholesale power supply prices in the centralized markets administered by regional transmission organizations."[51]

[50] Among the market participants filing comments or making presentations in Docket No. AD07-7-000 expressing strong concerns about the impacts of RTO-run centralized markets were the following: the National Rural Electric Cooperative Association; Golden Spread Electric Cooperative; the Electricity Consumers Resource Council: the Steel Manufacturers Association; the PJM Industrial Customer Coalition; Industrial Energy Users-Ohio; West Virginia Energy Users Group; NEPOOL Industrial Customer Coalition; Southwest Industrial Customer Coalition; Coalition of Midwest Transmission Customers; American Transmission Co., LLC; Alcoa, Inc.; Office of the Ohio Consumers' Counsel; and Eastman Chemical Co.

[51] Request of AARP, American Antitrust Institute, American Chemistry Council, American Forest & Paper Association, American Iron and Steel Institute, American Municipal Power–Ohio, American Public Power Association, Association of Businesses Advocating Tariff Equity, Citizen Power, Citizens Utility Board of Illinois, Coalition of Midwest Transmission Customers, Colorado Office of Consumer Counsel, Consumer Federation of America, Council of Industrial Boiler Owners, Democracy and Regulation, Electricity Consumers Resource Council, Florida Industrial Power Users Group, Illinois Industrial Energy Consumers, Illinois Public Interest Research Group, Industrial Energy Consumers of America, Industrial Energy Consumers of Pennsylvania, Industrial Energy Users–Ohio, Louisiana Energy Users Group, Maryland Office of the People's Counsel, Maryland Public Interest Research Group, Missouri Industrial Energy Consumers, National Association of State Utility Consumer Advocates, NEPOOL Industrial Customer Coalition, Office of the People's Counsel of the District of Columbia, Ohio Hospital Association, Ohio Manufacturers' Association, Ohio Partners for Affordable Energy, PJM Industrial Customer Coalition, Portland Cement Association, Power in the Public Interest, Public Citizen, Inc., Public Utility Law Project of New York, Inc., Steel Manufacturers Association, West Virginia Energy Users Group, Wisconsin Industrial Energy Group, Inc., and Wisconsin Paper Council to Expand the Scope of the 206 Proceeding, Docket Nos. RM07-19-000 and AD07-7-000, December 17, 2007.

APPA suggests the commission consider restructuring full "Day 2" RTOs as more streamlined "Day 1" RTOs. Such an approach would maintain most of the demonstrated consumer and economic benefii of RTOs, which are in the Day-1 transmission-related functions.

FERC Must Lead the Effort to Protect Consumers

Neither APPA nor other interest groups, no matter how well-informed, have the means, the legal authority, or the access to pertinent data necessary to investigate fully and adequately the causes of dysfunction in RTO-run wholesale markets. However, based on its research, APPA believes such a thorough examination would likely reveal a mélange of administratively determined market rules, algorithms understandable only to a few, ad hoc patches, makeshift and incomplete mitigation, perverse incentives, and profit-taking at the expense of consumers.

Even with limited access to data, APPA's Electric Market Reform Initiative studies have presented a significant amount of evidence of market problems. Moreover, the multitude of materials filed in the ANOPR proceeding by other load-side interests provide ample evidence that RTO-run centralized wholesale electricity markets are not producing just and reasonable rates and do not, in fact, meet many of the basic criteria for competitive markets. In the face of this evidence, FERC cannot simply claim that it has found the "right mix" of competition and regulation for RTO markets52 and decline to examine the situation. FERC has an affirmative obligation-expressly set forth in the FPA—to investigate whether rates subject to its jurisdiction are unjust and unreasonable, and to take appropriate remedial steps.

APPA Recommends Restructuring RTOs as "Day 1" RTOs

APPA does not believe that RTO-run centralized markets produce just and reasonable rates. APPA believes a thorough investigation by FERC, subject to appropriate congressional oversight, would confirm this. FERC, however, has indicated that it would not initiate such an investigation without first having received specific proposals for RTO market reforms to assist it in that effort. While some affirmative RTO market reform proposals have been offered,[53] APPA has borne the brunt of considerable criticism from regulators, generators and the RTOs themselves for not providing any affirmative reform proposal.

To contribute another policy option to the ongoing debate about possible "solutions" for RTO market problems, APPA suggests the commission consider restructuring full '"Day 2" RTOs as more streamlined "Day 1" RTOs. Such an approach would maintain most of the demonstrated consumer and economic benefio of RTOs, which are in the Day 1 transmission-related functions. Thus, this proposal is designed to keep what is working relatively well in RTOs and replace those functions and features, mostly associated with

[52] **ANOPR** at Paragraph *6*.

[53] *Deregulation/Restructuring – Where Should We Go From Here?*, Carnegie Mellon Electricity Industry Center Working Paper **07-07** http://wpweb2.tepper.cmu.edu/ceic/papers/ceic-07-07.asp; Comment of American Forest & Paper Association under RM07-19 and AD07-7, September **14,2007,** http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13538931, Comments of Portland Cement Association, Multiple Intervenors, PJM Industrial Customer Coalition, et al under RM07-19-000, January 11,2008.

RTO-run centralized energy and rapacity markets, that have failed to produce sufficient benefits to consumers. The functions that such a Day 1 KTO would carry out are described in general terms below Seven I questions and concerns that APPA is exploring arc listed next to these functions.

- Ensure non-discriminatory access to the grid through independent administration of an open access transmission tariff and provision of transmission service, including needed ancillary services. For services that require generation, an appropriate pricing method would need to be developed (e.g., cost-based, price-capped, market-based, etc.) If the RTO were to provide ancillary services using market-based rates, strong market power monitoring and mitigation tools would bc necessary.
- Develop and administer a regional transmission rate design that eliminates rate pancaking and assures the recovery of the cost of transmission facilities owned by all transmission owners and providers tliat wish to participate in the RTO, regardless of their form of ownership.
- Operate a single regional open access same-time information system (OASIS) and independently calculate available transmission capacity (ATC). A crucial question here is whether implementation of a Day 1 RTO would require a return to a physical transniission rights regime and, if so, how such a transition would be accomplished. It may be difficult to provide non-pancaked non-discriminatory transmission service under a physical transmission rights regime (at least without a substantial transition period) given that Day 2 RTOs superseded such rights with financially based rights. I'hysical rights may also bc more difficult to administer, given the size of some existing RTOs.
- Conduct independent and collaborative regional transmission and gcncration interconnection facilities planning, with the inclusion of affected stakcholdcn, including state authorities, thus building t... regional support required to get siting authority for needed new transmission facilities and upgrades.
- Carry out wide-area system security and reliability-related activities, ensuring that transmission facilities are operated in compliance with relevant North American Electric Reliability Corp. (NERC) and regional reliability entity criteria. A minimalist congestion regime is likely to be required, but would need to be designed to avoid the substantial problems that have developed under LMP-based congestion regimes.
- Operate an energy imbalance market to enable transmission customers to manage their imbalances and to allow generators (including *intermittent renewable* generators) to sell e ccess generation not committed under bilateral contract arrangements. As with the ancillary services market, the pricing system used in the imbalance market would have to hc carefully considcrcd. A market-based system should only be considcrcd if the imbalance market. is limited to no more than 5 percent of the load and accompanied by strong market power monitoring and mitigation tools.
- Carry out additional functions (e.g., operation of a power pool) if all classes of stakeholders in the region agree on the need for snch functions and the RTO can *justify them* as beneficial to *ultimate consumers through thorough cost-benefit* analyses.
- Ensure adequate generation reserves through implementation of resource adequacy

Supporting a more robust bilateral market and reducing reliance on a bid-based spot market would come at a time when several retail choice states are already reevaluating their retail access regimes and are considering regimes that provide a greater role for their incumbent utilities in the construction or procurement of generation.

requirements. Individual load-serving entities would meet these requirements through development of appropriate power supply and capacity porifolios.

Such a Day 1 RTO would provide substantial consumer benefits from regional transmission open access, elimination of rate-pancaking and capturing of short-term operational efficiencies in the imbalance market. Equally important, it would minimize the market dysfunction problems that have plagued Day 2 RTOs. The RTO would operate an energy market only to balance loads. Thus the bulk of the energy would be sold under regulated retail rates, wholesale bilateral contracts (which would be at market-based rates if the seller held the appropriate market-based rate authority), or retail supplier pass-through of wholesale power purchases.

Such a regime would de-emphasize spot market participation by both buyers and sellers. APPA believes this is important to foster long-term power supply contracting, thus providing the certainty needed for construction of new generation facilities. It would also reduce the complexity and costs imposed on end-use consumers by Day 2 RTOs, both directly through their tariffs and administrative fees and indirectly through load-serving entities' increased costs of internal operations. It would eliminate the mandatory RTO hid-based energy and capacity markets that magnify both the effects of generator market power and the design flaws in RTO-administered markets.

Supporting a more robust bilateral market and reducing reliance on a bid-based spot market would come at a time when several retail choice states are already reevaluating their retail access regimes and are considering regimes that provide a greater role for their incumbent utilities in the construction or procurement of generation. Examples include steps to allow incumbent utilities to build generation facilities (as in Connecticut) or to procure power through long-term contracts (as in Maryland.) [54] Power supply choices should he determined under rigorous review procedures to ensure that retail customers are served by the most economic set of generation resources.

APPA presents its Day 1 recommendation here in broad outline to introduce it and allow policymakers to consider it in the context of the issues discussed in this paper. APPA intends to produce a more detailed version of this proposal in a separate document, which will be published later in 2008.

APPA recognizes that implementation of such a Day 1 RTO regime would take time. Many thorny transition issues would have to be resolved. Substantial institutional and political obstacles exist as well. Moreover, differences among RTOs and the retail regimes in the states they serve, as well as their different stages of development, likely requires

[54] *Interim Report of the Public Service Commission of Maryland to the Maryland General Assembly, Part 2 Options For Re-Regulation and New Generation,* December 3, 2007, p. 34. Connecticut enacted a law in July 2005 that allows the state's regulated utilities to build up to 250 megawatts of peaking capacity. See "What Is Happening In State Retail Choice Programs? August Update: A Focus on Obtaining Power Supply," APPA, http://www.appanet.org/files/pdfs/stateupdateaugust2006.pdf.

customized application of this proposal in each RTO in a manner that recognizes and accommodates these differences. Hence, APPA proffers this solution as a long-term one. but one tlic industry should begin to move toward now. In tlic interim, there are several more discrete RTO-related problems that FERC should address, which arc discussed in the final section of this report.

FERC Should Do No Harm in the Interim

In APPA's view, returning to just and reasonable rates requires FERC first to ensure that there is no further development of RTO-run centralized wholesale markets. As discussed above, one of tlic difficulties in addressing tlic failure of these markets is the extent *and* level of complexity to which they have already evolved and the continuing series of patches that have been applied in attempts to remedy shortcomings in market design. Adding further levels of complexity will only make the eventual return to just and reasonable rates more difficult. Thus, APPA recommends that FERC quickly place:

- A *moratorium on the establishment of any* new Day 2 RTOs; and
- A moratorium on the establishment of new RTO-run markets for additional products and services within existing RTOs, unless accompanied by the type of cost/benefit analysis discussed later in this paper.

VI: Recommended Solutions to Specific, More Discrete Market Problems

Protection of consumers' interests requires a return to just and reasonable rates as mandated by federal law. While the fundamental long-term changes necessary to protect consumers are implemented, other discrete market problems could be addressed more quickly These, especially in the aggregate, could provide substantial consumer benefits. Following are some examples.

RTO Costs and Services

RTOs have unbundled their services into many separate markets, including day-ahead and real-time energy, locational capacity and ancillary services. Since most of these products are provided by the same generdtion base, pricing such services separately makes it difficult to determine whether the generation owner is receiving revenue more than once to cover the same claimed costs. As a result, such separation can result in costs higher than what would be charged for an integrated product.

In addition, the proliferation of RTO-operated markets has resulted in more complexity, requiring that participants, including load-serving entities, conduct detailed monitoring of billing procedures and extensive training of employees to learn the technical aspects of market participation. Stakeholders also incur administrative and legal costs to participate in RTO system planning, stakeholder governance and other RTO processes.

Whether the benefits derived from participation in RTO markets outweigh the sum of these costs remains an open question—but APPA's Electric Market Refoim Initiative studies imply this is unlikely To begin to provide a definitive answer, FERC should require RTOs to obtain unbiased cost-benefit studies to accompany any filing of any new markets and programs, as well as changes in existing markets and programs. No new program or change should be put in place unless it is affirmatively shown to provide true net benefits to end-use consumers in the form of lower costs and more reliable service. Such assessments should be performed by neutral third parties (such as an independent policy analysis group, academic department, outside market review committee or a consulting firm engaged on a one-time basis) rather than for-profit consulting firms beholden to the RTOs for continuing future business.

FERC should also develop clear criteria to measure the perfoimance of RTOs. Measures could include: differentials between generator costs and prices charged in RTO-run power markets; success in meeting RTO transmission expansion plans; responsiveness in dealing with transmission service and interconnection requests; reductions or increases in the level of transmission congestion costs over time; and benchmarking of administrative and operating costs among RTOs.

RTO Mission Statements and Objectives

Judging by their mission statements, RTOs believe their core objective is to ensure reliability and the effective operation of wholesale electricity markets. While some RTO mission statements include references to customers and to the public interest, the focus on the end-use customer must be stronger, more explicit and in fact central to an RTO's purpose. The justification for introducing competition into electricity markets was to

increase economic efficiency and thereby provide lower prices and greater reliability to electricity consumers. RTOs grew out of the competition experiment. Ultimately, to be costeffective and efficient, an RTO must make end-use customers better off than they would be without the RTO.

RTOs must be accountable for the cost impacts of their decisions. Their mission statements should include an explicit goal of reducing electric power costs to customers. This entails keeping costs—both from RTO operations and from the design of wholesale markets—as low as reasonably possible. In addition, RTOs' strategic plans should he developed in view of the central goal of providing tangible benefits to consumers.

RTO Governance

RTO boards must reflect a balance between independence from indusy stakeholders and accountability to the industry as a whole. Board decisions affect all aspects of RTO market design and costs. It is therefore crucial that stakeholders have direct and effective access to RTO hoards.

Current RTO governance structures include independent boards as well as processes for developing stakeholder input. However, these processes do not always function well. In particular, smaller load-serving entities, which include many public power utilities and theirjoint action agencies, do not have the resources to participate in the numerous RTO committees and working group. In addition, RTO boards often are not responsive to stakeholder input even when it is provided. They have implemented significant changes in spite of strong opposition from a large number of stakeholders.[55]

Hybrid RTO boards, composed of a majority of independent directors and a minority of stakeholder directors, would ensure that stakeholder input is heard as part of all board discussions. Since they have experience operating in an RTO, stakeholder board members could provide practical advice on how RTO markets work and how potential changes could affectvarious market participants. Stakeholder hoard members should he elected by a supermajorityof the stakeholder sectors. This approach would ensure that the stakeholder directors are well-respected and have the broad support of the stakeholder community.

Governance would also improve through better use of stakeholder advisory committees to provide a broader range of input to RTO boards. An advisory committee's interaction

Governance would also improve through better use of stakeholder advisory committees to provide a broader range of input to RTO boards.

[55] A recent example is the January 30, 2008 filing made by PJM in FERC Docket No. ER08-516-000, in which PJM proposes to increase the "Cost of New Entry" component of its RPM framework (see http://www.pjm.com/documents/ferc/documents/2008/20080130-er08-xxx-000.pdf). PJM notes in that filing (at 5) that it was unable to obtain the support of the PJM Members Committee to proceed with the filing, since the sector vote held in the Members Committee was split between supply and load interests (93% of generation owners voted in favor of the proposal, while only 9% of electric distributors and 0% of end-use customers voted in favor of it.) The PJM Board subsequently voted to proceed with the filing, notwithstanding the outcome of the vote in the Members' Committee.

RTO management should not be allowed to direct market monitor activities, change market monitor reports or otherwise interfere with a market monitor's activities.

with the board should not be limited to making formal presentations prior to the board's vote on a topic. Rather, the process should allow the advisory committee to have early and unfiltered access to the board. This could occur through monthly teleconferences or quarterly meetings, with agendas set through nominations by the stakeholders.

Market Monitoring

Given the important role that has fallen to market monitors, FERC must ensure that market monitors are truly independent and have all of the resources necessary to perform their functions. The structure of the market monitoring unit (MMU)—internal vs. external—and the specific tariff provisions regarding the MMU are less important than what happens in practice. In particular, RTO management should not be allowed to direct market monitor activities, change market monitor reports or otherwise interfere with a market monitor's activities. FERC should require the market monitor to report directly to the RTO board or a board committee and FERC itself should be active in enforcing the MMU tariff provisions.

The MMU should also have the full cooperation of market participants in data gathering, including access to companyspecific financial information and generating unit cost and operating data. The market monitor must have sufficient resources to carry out its duties. This includes unrestricted access to RTO data and a budget that provides for the necessary personnel, computer systems and training. If possible, the market monitor should have an office and staff on site at the RTO, along with complete access to RTO staff and RTO computer information systems.

A central part of the market monitor's mission is to protect wholesale and retail customers from the exercise of market power and the payment of unjust and unreasonable rates. Thus, the MMU must have the right to review bids submitted into RTO markets and to take actions to prevent the exercise of market power or the manipulation of RTO markets. As part of this mission, the MMU must also be responsible for identifying adverse competitive consequences of RTO market rules. The MMU should not participate in the initial development of rules, but should be allowed to express in public forums its news on proposed rules. The RTO should also ask the MMU for an independent assessment of the efficacyof a proposed rule, including the effect of the rule on consumers and suppliers. Finally, the market monitor should have the right to file in FERC dockets to make clear any concerns it bas with RTO proposals.

Information Transparency

RTOs publish a large volume of data on market operations, but currently keep the most crucial information–generator bid data-confidential, releasing it only in masked form after a delay of several months. Providing the public with access to this data on a nextday basis and with open identification of generators would allow third parties to conduct their own analysis of bidding behavior and price formation in RTO markets. (Note that the release of bid data on a nextday basis is standard practice in international electricity markets such as Australia, England and Wales.) This added transparency would discipline market behavior because bidders would know that they were operating in full view of the

public. It would also raise confidence in market operations because all market participants and the public could independently validate how well markets were working. They would be able to analyze bidding patterns, compare bids with cost factors, search for indications of market power and, ultimately, advocate for better RTO market rules.

According to Frank Wolak, professor of economics at Stanford University, regulators must have sufficient information to thoroughly analyze market operations and public release of data is crucial:

> The second crucial aspect of "smart sunshine regulation" is public data release. Specifically, all data submitted to a real-time market and produced by the system operator should be released to the public immediately. The public data release should identify the market participant and specific generation unit associated with each bid, generation schedule or output level. Masking the identity of the market participants, as is done in all U.S. wholesale markets, limits the disciplining value of public data release on market participant

The FERC should also consider requiring RTOs to report their "system lambdas"—the variable cost of the last kilowatt produced over a set time period (e.g., each hour) from the dispatchable generation units participating in each RTOs power supply markets. This would allow observers to compare the prices set by these markets with the underlying generation costs.[57] Similarly, non-utility generators should be required to report annual cost and operating data to FERC and this information should be made publicly available, as is currently the case with the generator cost data reported to FERC by regulated public utilities. This information would allow FERC and the public to determine whether rates in RTO-operated markets are just and reasonable.

Generators cite *two* basic arguments against making their cost and bid information publicly available. First, they claim that revealing cost information would harm their competitive position. Second, they assert that revealing bid data could facilitate collusion among bidden. But, in fact, large generators already have substantial market information because of their active roles—often with multiple plants—in both electricity and fuel markets. In addition, generators can learn the bidding strategies of their competitors through repeated interaction in an RTOs auction-based markets. large generators also have access to more information resources, such as subscriptions to proprietary databases of generation units and fuel market information that allow them to model market behavior and analyze their competitors' costs and bidding patterns. Making cost and bid data public would put the same information in the hands of smaller market players,

The FERC should also consider requiring RTOs to report their "system lambdad'—the variable cost of the last kilowatt produced *over* a set time period (e.g., each hour) from the dispatchable generation units participating in each RTO's power supply markets.

[56] Frank **A. Wolak,** "Unilateral Market Power in Wholesale Electricity Markets," published in *CESifo Dice Report, Journal for Institutional Comparisons,* Ifo Institute for Economic Research, **Vol. 4, No. 2,** Summer **2006,** p. **12.**

[57] This recommendation is contained in "The Missing Benchmark in Electricity Deregulation," McCullough and Stewart.

regulators, academics and the public, so it would not be available only to those with superior market positions or the financial resources to purchase it.

Finally, FERC and the public should have greater access to financial information on unregulated generating companies. Some generating companies arc privately held and thus report little information. Others arc units of larger holding companics, so the publicly available statistics arc on a holding coinpang-wide basis and provide few specific details on particular unregulated affiliates' generation operations. Electric generation companies should be required to file with FEKC basic financial information at the individual company level, similar to the information regulated investor-owned public utilities file in their FERC Form Is, including balance sheets, operating income and expenses, retained earnings and cash flows. FERC should require annual reporting of data specific to generation operations in detail sufficient to allow FERC to develop basic profit statistics. Data on prices, costs and profits are essential to determine whether rates are just and reasonable, whether they arc set using cost-of-service regulation or a market-based regime.

VII. *Conclusion*

The electricity markets are in a time of crisis, with dire implications for the economy, reliability and the general well-being of the population. It is our intention that this white paper and the proposals contained herein will open a constructive dialogue to develop sorely needed reforms to the wholesale electricity markets. The first step in achieving such a solution, however, will be for FERC and other RTO market supporters to cease the rhetoric and acknowledge that these markets are not competitive.

The debate should no longer be about who can best massage the statistics on prices or whether it is more virtuous to speak of competition or regulation. But instead, we all must work together to design a regulatory system for electricity markets that is truly in the best interest of consumers, businesses and the cnvironment

RESOLUTION NO. 2009-33

A RESOLUTION OF THE LODI CITY COUNCIL
AUTHORIZING NORTHERN CALIFORNIA POWER AGENCY
TO SELL SURPLUS CALIFORNIA INDEPENDENT SYSTEM
OPERATOR "CONGESTION REVENUE RIGHTS" ON
BEHALF OF THE CITY OF LODI

WHEREAS, by Resolution 2007-103 the City Council authorized the Northern California Power Agency (NCPA) to participate on behalf of the City of Lodi Electric Utility (EUD) in the California independent System Operator (CAISO) Congestion Revenue Rights (CRRs) allocation process in order to stabilize and/or reduce the costs of transmission in delivering energy from Lodi's power resources to load; and

WHEREAS, the CAISO has allocated CRRs to NCPA on behalf of EUD and may do so again from time to time; and

WHEREAS, certain CRRs may be surplus to EUD's need to hedge transmission costs; and

WHEREAS, NCPA's General Counsel believes it is unclear whether NCPA has been granted the authority under Resolution 2007-103 to market and sell surplus CRRs for the City of Lodi's account; and

WHEREAS, EUD staff, the NCPA Risk Oversight Committee, and the NCPA Commission (NCPA Commission Resolution 09-08) have reviewed and approved limited participation in CAISO auctions to reduce risk.

NOW, THEREFORE, BE IT RESOLVED that the Lodi City Council does hereby authorize NCPA to offer and sell surplus CRRs in CAISO auctions on behalf of the City of Lodi Electric Utility until such time that NCPA is notified otherwise in writing by the City Manager or Electric Utility Director.

Dated: March 18, *2009*

I hereby certify that Resolution No. 2009-33 was passed and adopted by the Lodi City Council in a regular meeting held March 18, 2009, by the following vote:

AYES: COUNCIL MEMBERS – Hitchcock, Katzakian, Mounce, and Mayor Hansen

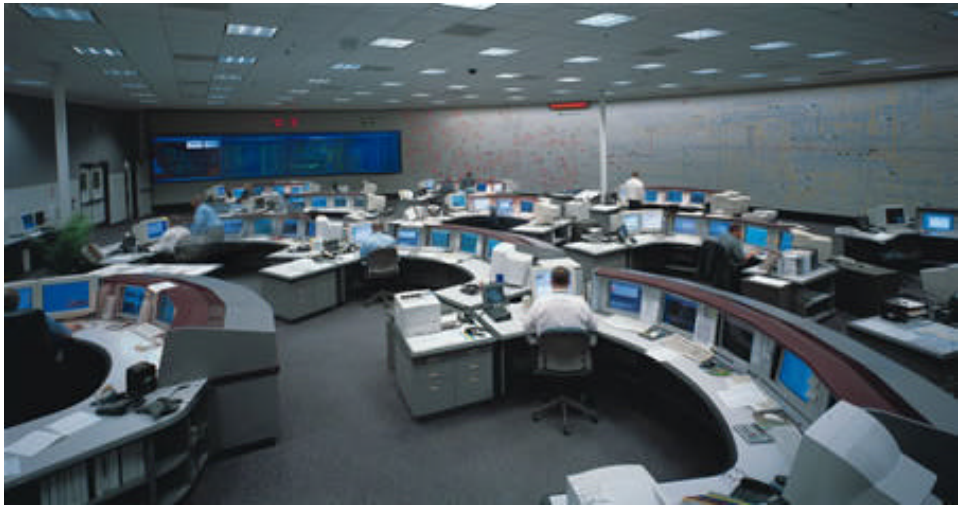
NOES: COUNCIL MEMBERS – Johnson

ABSENT: COUNCIL MEMBERS – None

ABSTAIN: COUNCIL MEMBERS – None

RANDI JOHL
City Clerk

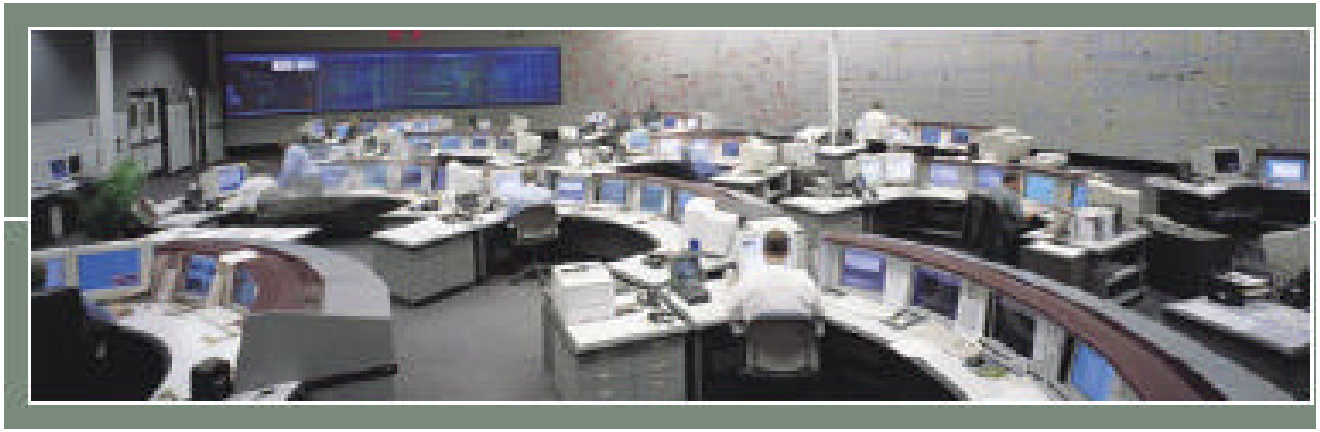
Market Redesign & Technology Upgrade 101
(MRTU)



City Council
March 18, 2009

CAISO

- California Independent System Operator
- Established by AB1890 (Deregulation Bill) in 1996
- Began operation in 1998 as operator of much of California's transmission network
- 500+ employees, $150M annual expenses



CAISO Operations Today

- Uses a simplified 3 “Zonal” transmission model of electric network
- CAISO tasks:
  - Preventing network overloads by adjusting power schedules in real time
  - Procuring “ancillary” services (reserves)
  - Day ahead generating unit commitment
- Limitations
  - May accept infeasible day-ahead schedules
  - Difficult to handle “intra-zonal” problems
  - Lack of a forward or “day ahead” market

MRTU

- Approved by FERC in September 2006
- Planned "Go Live" date is March 31
- For CAISO, resolves limitations of current management of grid by:
  - Use of a Full Network Model
  - Establishment of an Integrated Forward Market
  - Use of Locational Marginal Prices (LMP's)

LMP's

- "Locational Marginal Price"
- Difference between energy prices for any 2 network nodes
- Composed of marginal prices for:
  - energy
  - congestion
  - transmission losses

Value of RTO/ISO's

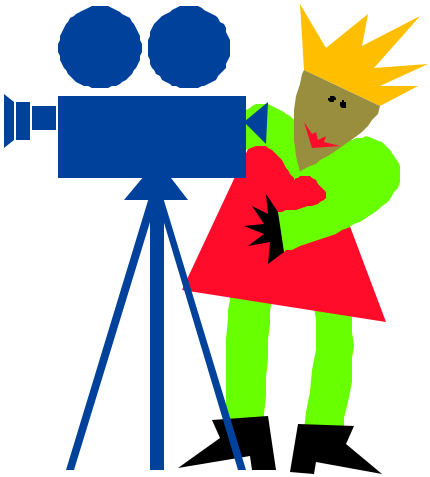
- "Regional Transmission Organizations"
- Transmission access is non-discriminatory
- Administer "open access" tariffs
- Elimination of "pancaked" transmission charges
- Regional transmission planning coordination

MRTU Risks

- Software/hardware doesn't perform as designed (CAISO and/or NCPA)
- New "Market" isn't competitive
  - Seller's have market power
- "LMP's" are high and/or create major winners & losers
- CRR's don't perform as expected
- Creates centralized market similar to AB1890 (California deregulation law)

Video

CAISO Video on MRTU:



- The MRTU Program (10 minutes)
- The Heart of Market Redesign (15 minutes)

ISO Market "Problems"

- All seller's receive "market clearing price"
- Sellers become shorter term on pricing of power
- Incentives for generators to withhold capacity from market
- No evidence that high LMP's promote new transmission and/or power plants
- New costs to consumers for "capacity" and CRR's
- High ISO administrative costs

CRR's

- "Congestion Revenue Rights"
- Financial instrument to insure against Congestion costs under MRTU
- Lodi granted authority to NCPA to procure CRR's for Lodi (June 6, 2007)
- NCPA desires members to clarify that NCPA has authority to market and sell surplus CRR's also.

Action

- Approve Resolution to clarify that NCPA has the authority to market/sell CRR's for the benefit of Lodi Electric Utility

Questions/comments?