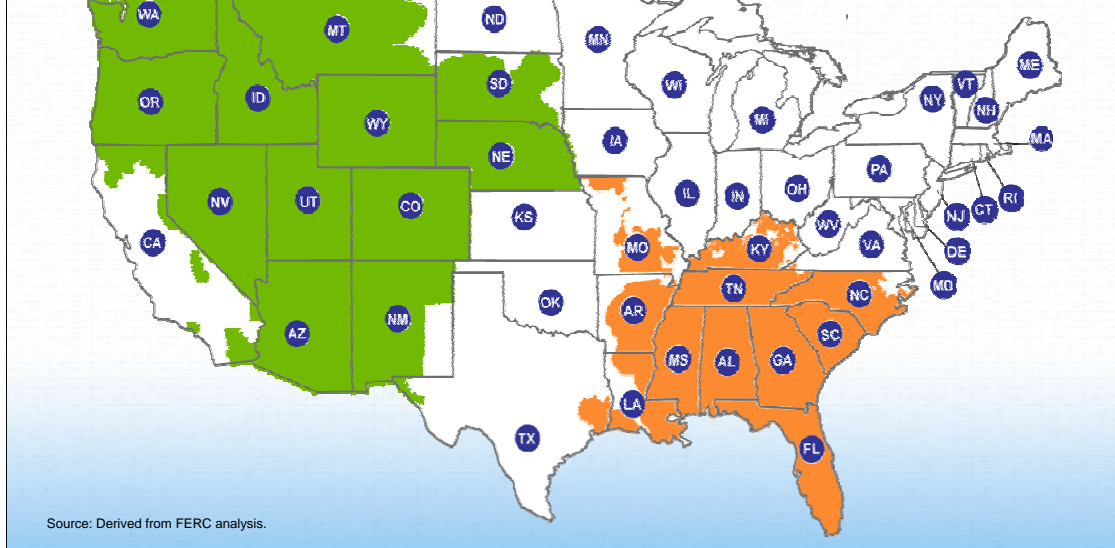


Mr. Chairman and Commissioners, good afternoon. I am here to present the Office of Enforcement's view into electric power markets outside the RTOs – that is, in the West and the Southeast. This presentation will be posted on the Commission's Web site today.

Non-RTO Areas in the West and Southeast



The slide highlights the Southeast and the West outside California. Together these regions account for about 40% of both total load and total generating capacity in the United States. The non-RTO West also accounts for a large proportion of the Nation's potential energy reserves. Both regions use bilateral electric power markets and depend on them for crucial aspects of their functioning. But the nature and role of the bilateral markets differs substantially between the two regions.

Forms of Bilateral Market Monitoring

- **Individual Company Reports**
- **Complaints**
- **Market Oversight at the Commission**

We have heard today from the market monitors for the RTOs. Outside RTOs, the challenges of monitoring markets are different and, in some ways, more difficult. In bilateral markets, participants can conclude deals on many different platforms. Much of the information in this presentation comes from the Intercontinental Exchange – ICE – because it is a major trading platform, and we have ready access to much of its information. But market participants can as easily use an array of voice brokers to make deals – or they can simply talk directly with possible counter-parties. In short, in non-RTO regions, there is no central market institution to serve as the primary focus for market monitoring. So the strategies for monitoring these markets must be different.

The Commission currently oversees the bilateral markets in three main ways: individual company reports, responses to complaints and internal oversight efforts. The first two approaches address possible abuse of transmission by individual companies. The third seeks to understand how the larger regional markets work.

We receive formal market reports from six individual companies. Five have individual company monitors – Potomac Economics in all five cases. Four of these are in the West or the Southeast: Arizona Public Service, PacifiCorp, Public Service Company of New Mexico and Duke Energy, Carolinas. Potomac Economics submits a report on each company quarterly, focusing especially on the company's use of transmission. This provides reasonable assurance of the good behavior of each company, but does relatively little to understand the larger regional market. Also in the Southeast, Entergy uses SPP as its ICT - Independent Coordinator of Transmission. The ICT is not a market monitor in the usual sense, but it does provide quarterly reports on the operation of Entergy's system and the development of its Weekly Procurement Process.

The Commission has an extensive system of accepting and responding to complaints. These can come from the Hot Line or from Section 206 complaints. We take care to respond to all of these complaints in an appropriate way. These mechanisms are effective at remedying specific problems that arise in both RTO and bilateral markets, but, by themselves, provide an incomplete picture of the overall performance of such markets.

The Division of Energy Market Oversight oversees the broader functioning of Western and Southeastern markets. Much of this oversight comes from examining a wide variety of data sources. Two of the most important are ICE and the Electric Quarterly Report – the EQR – you'll see examples of both today. We have also begun a pilot project with the Southern Company to help us understand better how the Southeastern market works. Southern volunteered to visit us periodically to provide its perspective on how Southeastern markets are working. The conversations so far have covered everything from showing us which hours Southern either bought or sold power during a recent period to describing the company's view of coal markets.

We understand that no single company provides a full view of the market, nor do we expect its view to be disinterested. We hope that other companies will join Southern in improving our understanding of how markets work in both the Southeast and the West. Let me quickly mention in this context that we also talk with State Commission staff in both regions in conference calls each month. Those calls have already provided us with an important additional point of view in both regions, and we are grateful to the participants on both calls.

Spot Markets: West and Southeast

Spot Electric Power Trading on ICE by Region, 2007, '000 GW Hours

Region	Physical Trading	Financial Trading	Load in 2006
West	67.8	<0.1	709.8
Southeast	1.5	0.0	802.3

Source: ICE and Form 714. (Note that ICE has no contracts within SPP.)

Bilateral markets have a mix of both long-term and spot transactions. Today, I am going to focus mainly on spot transactions, both to make the focus consistent with most of the reports from RTO market monitors, and because the strongest differences among regional markets show up in the way spot markets operate. As we shall see, however, spot markets are a relatively small part of the overall wholesale market in the Southeast, so a major focus for us going forward will probably be on longer-term transactions, at least in that region.

This year's State of the Markets presentation provided the highest level description of the differences for the west and southeast spot electric market regimes in the United States. This slide shows transaction volumes from ICE, which provides the clearest view we have into day-ahead and intra-day bilateral trading. The slide shows only spot transactions, though ICE accommodates longer-term transactions also.

To review: In regions where RTOs have day-ahead markets, bilateral spot markets act primarily as intraday financial derivatives of the prices RTOs produce. The RTO prices are the standard benchmark for day-ahead value, and the bilateral spot market becomes a way for market participants to tweak their positions during the day.

In the West, bilateral spot markets are far more important. Spot physical transactions account for more volume in the West than in any other region of the country. In fact, the bilateral spot market appears to be playing some of the same role in day-ahead price discovery in the West that RTO markets do in the Northeast and Midwest. Of course, the RTO day-ahead markets are much more complex and differentiate much more strongly among locations and timing during the day. But for basic daily valuations, the two systems seem to fill similar niches. For Western Spot markets, financial instruments are unimportant.

In the Southeast, bilateral spot markets are much smaller, at least according to ICE data. They are entirely physical, but less than one fortieth the size of their counterparts in the West. The Southeastern spot markets appear to be a residual market for small amounts of power traded after the integrated utilities have handled most of their own loads. It is unlikely that they serve a major price discovery role – the spot markets are simply too small overall. Nonetheless, bilateral spot markets are important at the margin, and can become quite important during periods of system stress.

Roots of Western Power Markets

◆ **Bonneville Dam (1937)**

◆ **Grand Coulee Dam (1942)**

◆ **Hoover Dam (1935)**

◆ **Glen Canyon Dam (1960)**

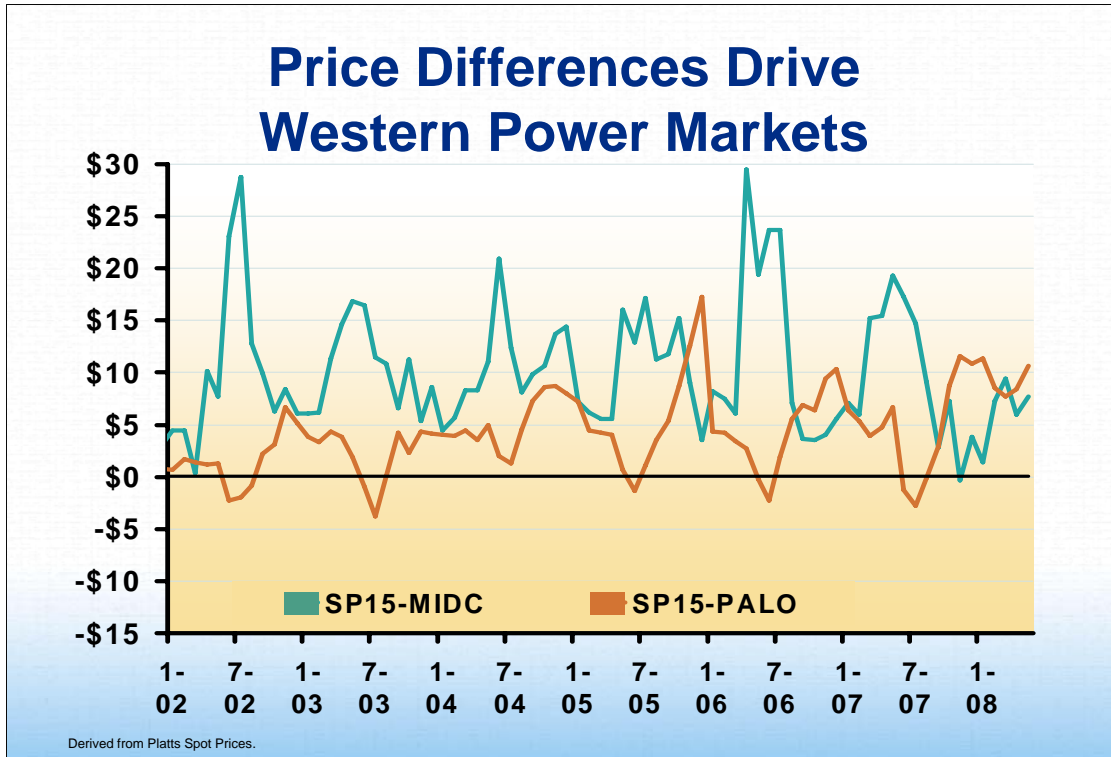
**California Oregon
AC Intertie
(1970s)**

**Pacific DC Intertie
(1971)**

Source: Derived from Energy Velocity data.

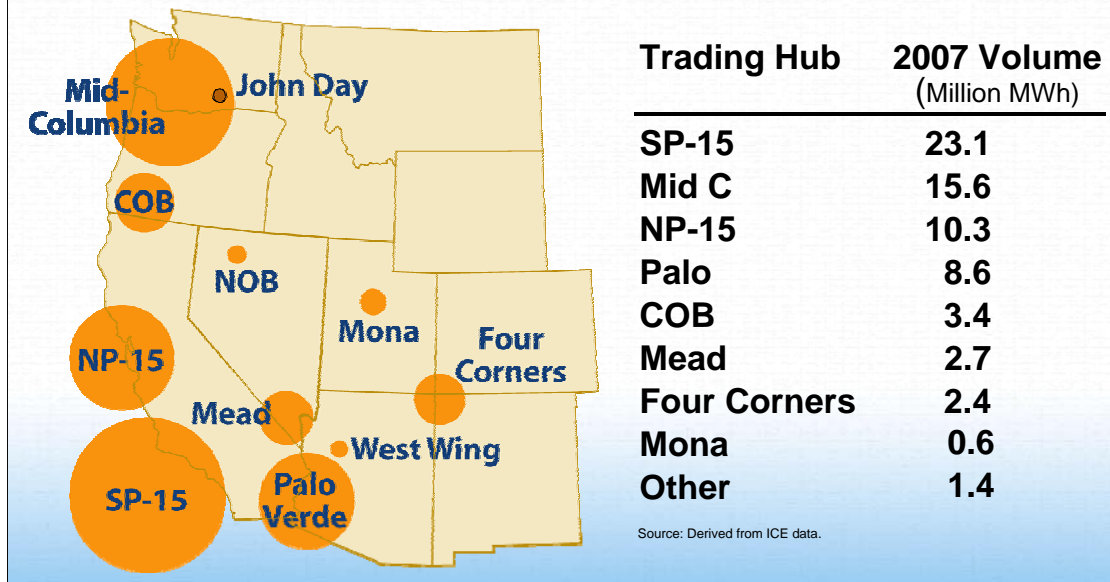
The roots of Western power markets reach back into the 1930s, with the development of very large hydropower reserves in both the Pacific Northwest and the Colorado River Basin. As demand in California grew, the need for long-distance transmission became clearer and clearer. As the slide shows, the first major intertie from the Pacific Northwest to California dates to the 1970s. Thereafter, the West became an increasingly integrated electric system, dependent on moving large quantities of bulk power over large distances.

As a result, when electric markets became possible toward the end of the century, the West had a very large commercial need to develop ways to trade power over long distances. At heart, that remains the basis of today's Western power markets.



Western power markets still display considerably different valuations for power in different sub-regions. The slide shows the difference in valuation by month between the Northwest and southern California (the blue line) and the Southwest and Southern California (the orange line). The difference of values are especially important for the Pacific Northwest, where the availability of hydropower is not entirely predictable over the long run, and where hydropower plays a major role in determining what power is available for trade and at what prices. There are also significant differences between California and the Southwest. Market participants need ready access to markets where they can arbitrage the differences and make power move from areas with plentiful cheap supplies to areas where it is more valuable.

Relative Volumes of ICE Spot Physical Trades at Western Hubs in 2007



The trade press began to report prices for Western electric spot markets in the 1990s. By that time, there was a compelling commercial need to create such markets and report on them. In this respect, they resemble natural gas markets that emerged slightly earlier for similar reasons. As with natural gas markets, Western spot electric markets differentiate the most commercially important price differences. This slide shows that the largest spot trading occurs in four places: mid-Columbia in the Northwest, NP-15 and SP-15 in California and Palo Verde in Arizona. Several other points – the California-Oregon Border (COB), Lake Mead in Nevada, and Four Corners in the Southwest are also significant spot trading points. Each trades peak and off-peak power.

Those who are used to RTOs will find these distinctions rudimentary, compared with the hourly prices that are available for thousands of nodes in RTO markets. Western bilateral markets simply do not reflect the detailed differences in valuation that are the hallmark of RTO markets. Nonetheless, the Western markets do reflect the **most** important differences in commercial value for both location and timing. They also provide simplicity and convenience at relatively low cost. The point is not that one model is inherently better or worse than the other. Each grew up in a different historical context, and each serves different functions.

As we have heard today, CAISO expects to implement MRTU in the fairly near future. If the Western experience follows precedents from the East, the existence of an ISO day-ahead market will change the nature of the bilateral market. In particular, CAISO's day-ahead market is likely to become the primary pricing vehicle for spot power transactions within California, replacing that function for the current bilateral market at SP-15 and NP-15. It is less likely to displace the price discovery function for points that often show quite different prices from California – for example, Mid-Columbia.

Long-Term Financial Trading Dominate Western Power Markets

Total Volume of Trades in 2007

Millions of MWhs	Physical		Financial	
Trading Hub	Spot	Long-term	Spot	Long-term
SP-15	23.1	1.8	—	480.5
Mid C	15.6	2.6	—	128.5
NP-15	10.3	0.2	—	23.1
Palo	8.6	0.2	—	16.9

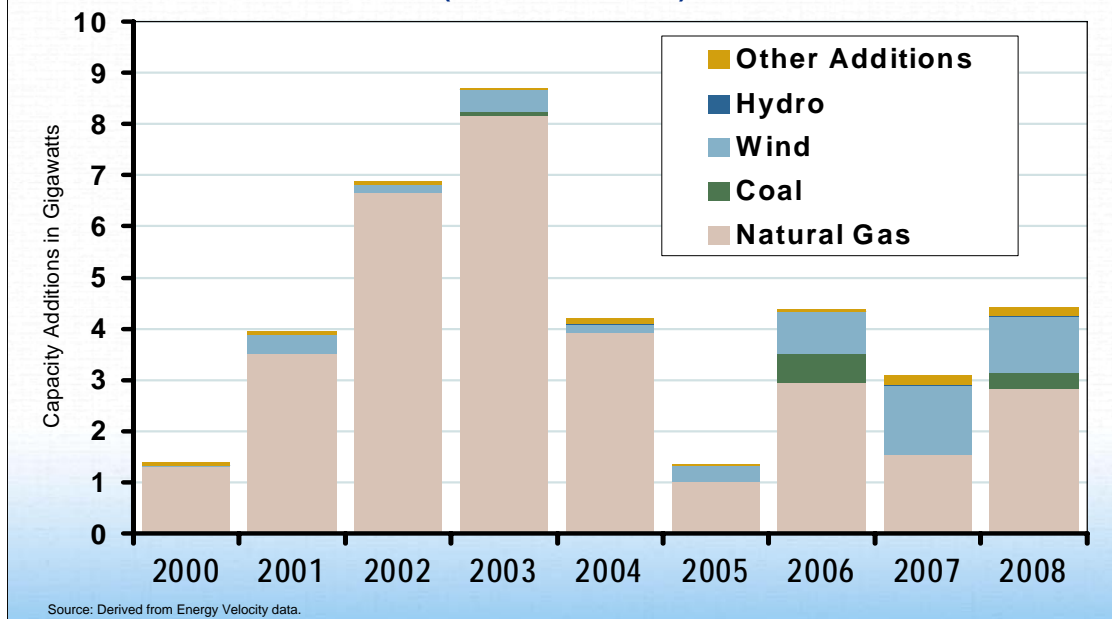
Source: Derived from ICE data. Spot includes daily and hourly deals. Long-term includes quarterly and longer deals.

Market participants also trade long-term power in the West. At least on ICE, the physical side of the longer term market is relatively small, compared both to the physical spot market and to longer-term financial markets. Long-term physical ICE deals are most prevalent in the Northwest. Of course, there are also many company to company long-term contracts that do not use ICE.

The bulk of long-term Western trade on ICE occurs financially. As is true in many commodity markets, this financial trading dwarfs the related physical trading. And it is very heavily concentrated at SP-15 and, to a lesser extent, at Mid-Columbia. This also is consistent with many financial commodity markets that tend to concentrate on a small number of delivery points. Cinergy Hub, NEPool and PJM West play a similar role in long-term Eastern financial power markets. In the case of the West, it makes sense to concentrate at SP-15 – that is the largest consuming area in the region, and over the long term, prices are fairly similar between Southern California and the desert Southwest. That is, it makes sense to arbitrage the California-Southwest price differences in daily markets, but not in long term markets. It also makes sense that there is considerable long-term activity in the Northwest. There prices can be quite different over the long term from the prices in California.

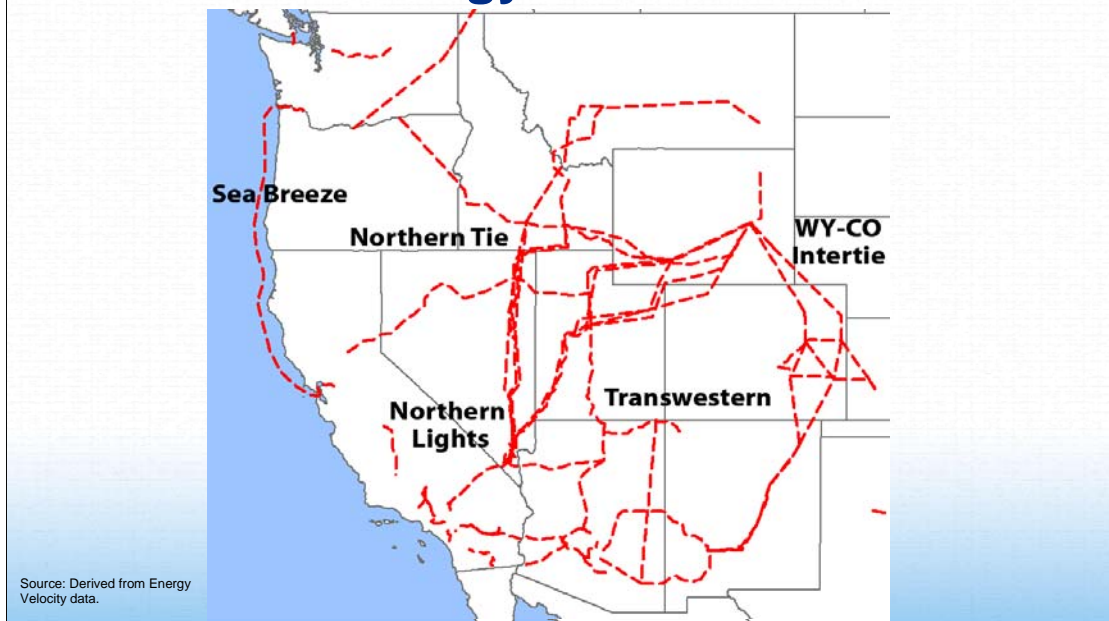
Western Generation Additions

(Outside California)



Another key aspect of longer-term markets is the amount of new investment taking place. The slide shows the amount of new generation coming on line in the West outside of California since 2000. As with other regions, there was a large burst of new capacity early in the decade, almost all of it fired by natural gas. Since then, the region has continued to build a significant amount of new capacity, but with a greater diversity of energy sources. Although the majority of capacity additions are still gas-fired, wind has become much more important, and there are also some coal additions. In any case, NERC reports that reserves are adequate now and projects that they will remain so.

Delivering the Northern Rockies Energy Reserves



The largest strategic challenge facing the West is how to make use of the energy reserves in the Rockies. The states of the northern Rockies – Wyoming, Montana, Colorado and Utah have vast stores of potential energy:

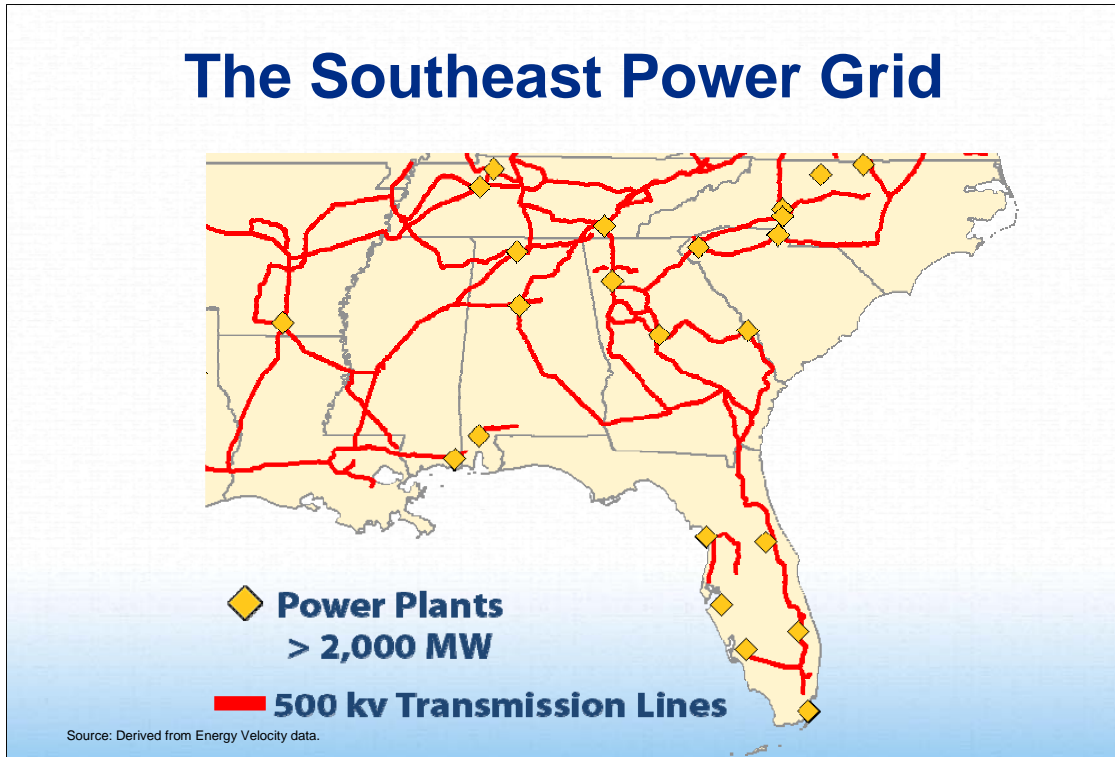
- Coal from the Powder River Basin and other deposits;
- Natural gas, especially from Wyoming and Colorado; and
- Wind that blows in abundance – as anyone who has spent time in Cheyenne can attest.

If the hallmark of Western electric markets so far has been the ability to support commerce over wide distances on the West Coast and the Southwest, the next challenge will be whether the markets can support the development of the infrastructure needed to get Rockies energy to market.

Market participants are working hard to create the infrastructure that will be needed to bring Rockies energy to market. In the case of natural gas, they have recently completed building Rockies Express into the Midwest, and have a variety of projects to build more pipeline capacity in the next few years. For electric power, there has been little expansion of the transmission grid so far, but there are many proposals at various stages of development.

So far, there has been little spot trading at points in the Rockies. If the West succeeds at connecting electric power resources in the Rockies with consuming markets, that is likely to change. In the absence of an RTO in the region, Western bilateral spot markets would then be likely to provide price discovery for that sub-region as well.

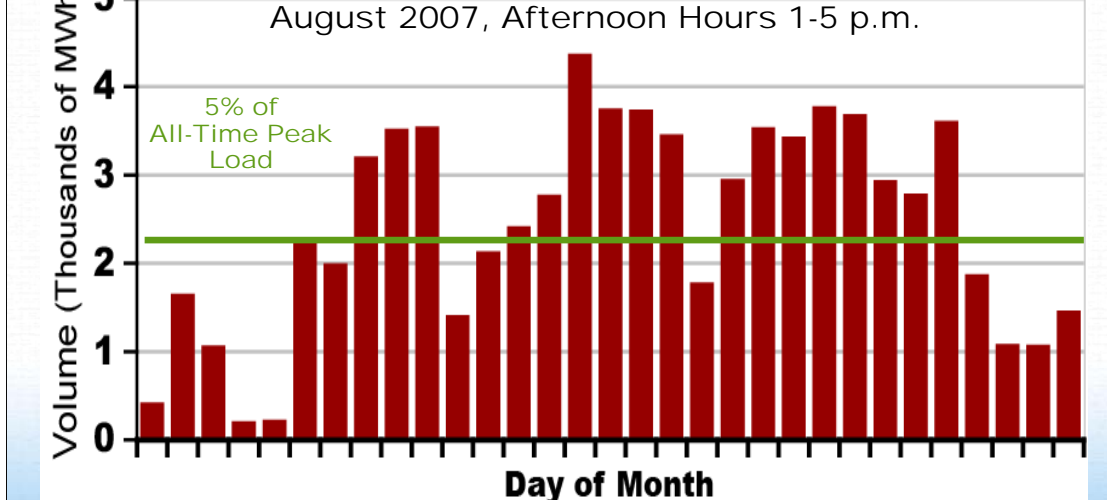
The Southeast Power Grid



Let me turn to the Southeast. Southeastern power markets also have their roots in earlier times. Beginning in the 1960s, and especially in the wake of the New York blackout of 1967, the Southeast began to build out its electric transmission grid. The slide shows that many of the transmission lines connected large generating plants. This was primarily to ensure reliability, but it also had economic consequences. One key is that it allowed companies to share reserves better. If a company was building a nuclear plant, for example, it was much cheaper to rely on a neighbor's nuclear plant for reliability, rather than having the company build a second plant by itself. The result was a gradually more integrated transmission grid that enabled reserve sharing. It also made possible more economy transactions – that is, small trades of power at the margin that could cut costs for both sides.

The second impetus for markets in the Southeast was the need to meet Florida's demand for power. Through the 1970s and 1980s, the region built transmission lines to deliver coal by wire into Florida – essentially the same logic that propelled the long line transmission lines in the West. This included smaller lines not shown on this map. However, the electric links between Florida and the Southeast remain relatively small, and have not provided the same basis for a large bilateral spot market that one finds in the West.

Southern Company's Afternoon Spot Purchases



Source: Derived from FERC's Electric Quarterly Report data.

The state of the Markets presentation reported EQR data for the Southern Company. During normal times EQR reports confirmed what Southern had told us, that they normally bought or sold less than 1% of their overall supply on spot markets. EQR also confirmed that spot markets were more important during stressful periods. During last August's heat wave Southern's spot purchases rose above 5% for the afternoon peak loads on most days. This highlights the importance of the spot market to meet unusual peaks, at least for Southern.

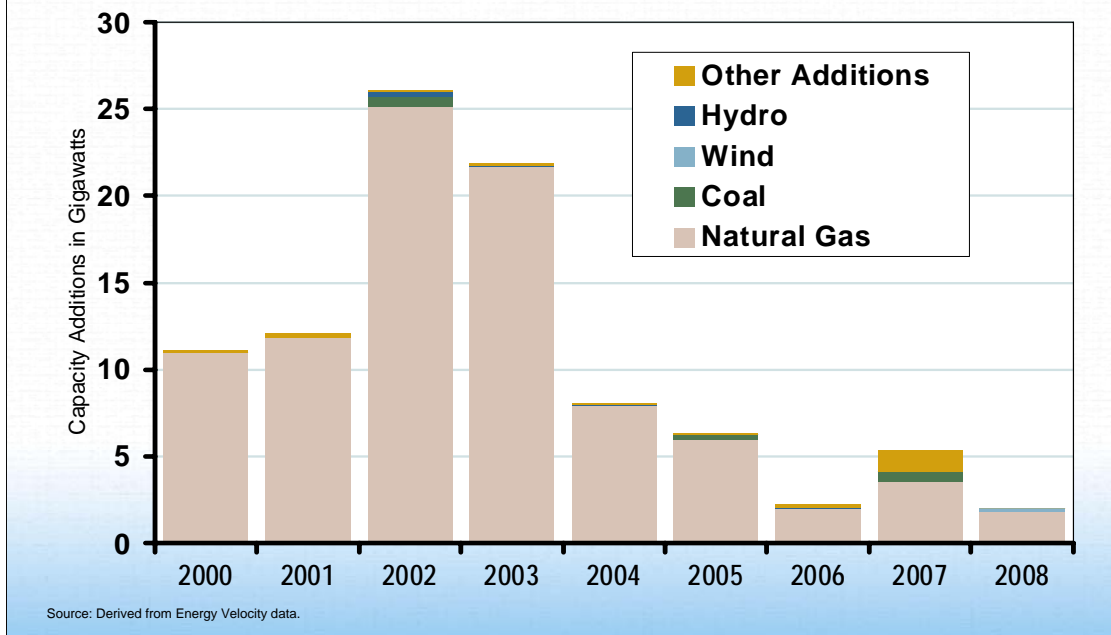
Southeast Power Markets Long-term & Financial

- **Long-term contracts predominate**
- **Many full requirements or purchased power contracts**
- **No financial investments on ICE**

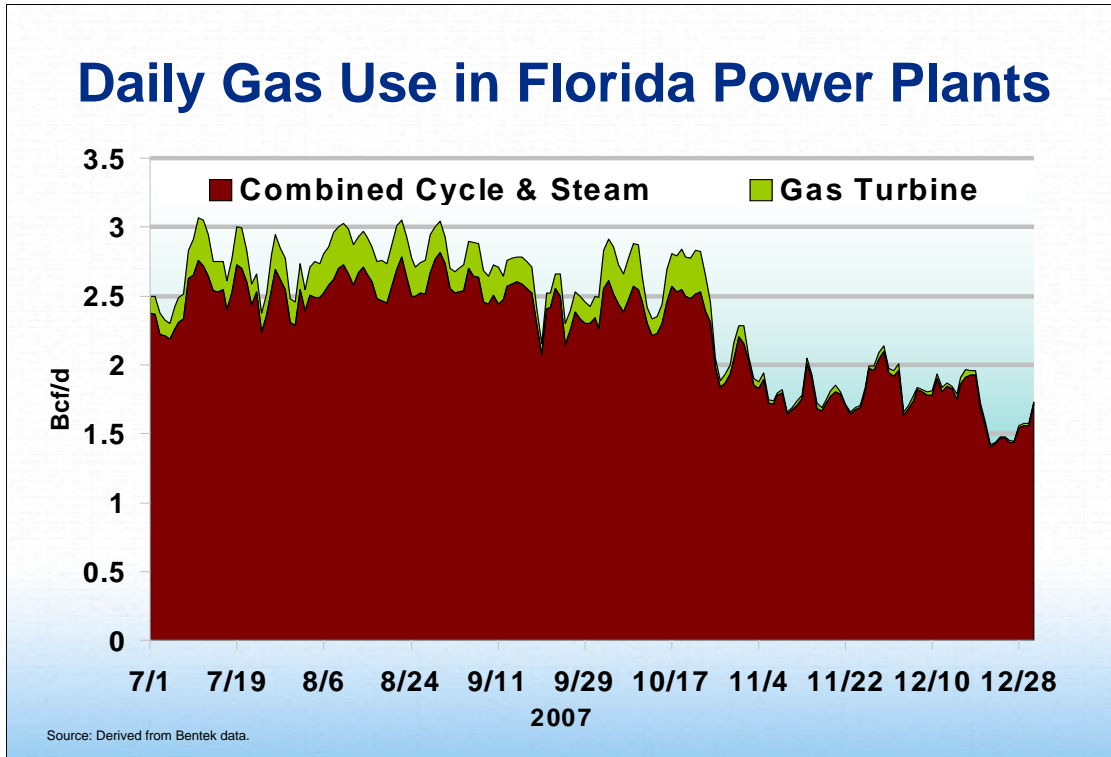
Long-term energy transactions are a hallmark of the Southeast. Preliminary analysis of EQR data suggests that jurisdictional sellers in the Southeast sell far more power under contracts of a year or more than they do through spot transactions.

Many – certainly not all - of the long-term sales agreements in the Southeast take place under either full requirements contracts (typically between large utilities and smaller publicly owned utilities) or long-term purchased power agreements (typically between independent power generators and utilities). In both cases, the contracts are usually isolated from long-term price risks – except for fuel costs. That is the likely explanation of the fact that there is no financial trading of power on ICE for the Southeast. If market participants want to hedge their fuel price risk, they can do so directly in natural gas or coal markets, and there is relatively little reason for a separate hedge for power. To the extent that requirements and purchased power contracts are prevalent in the Southeast, it would suggest that the most important point for potential competition in the Southeast would be at the stage when a plant is being planned, not after it is built. I'll mention an example of such competition in a moment.

Southeast Generation Additions



In the early part of this decade, the Southeast invested heavily in natural gas plants. Indeed, most observers would probably say the region over-invested. In any case, the region has been growing into that capacity in recent years and has added relatively little new generation since 2003. Going forward there seems to be increased emphasis in the region on building new baseload capacity, including Plant Vogtle, a nuclear plant proposal in Georgia and the Summer Plant, also a nuclear plant in South Carolina. In any case, NERC reports that there are adequate reserves today and projects that the reserves will remain adequate in the future.



Probably the greatest challenge in understanding power markets in the Southeast is a lack of visibility into how the systems are operating. Please note that I did not refer to transparency. As we learned in talking with the Southern Company, there simply is not much of a spot market to see. For example, Southern is active – either buying or selling – in the hourly spot market in only about 30 percent of all hours. In effect, there just aren't very many spot market transactions to see, at least judging by Southern's experience and ICE data.

Florida provides a particular challenge for market oversight. ICE reports no electric power prices for Florida. The trade press reports one spot electric power price for Florida – but on most days, those prices rest on no reported volumes.

In practice, Florida is far more completely integrated into the Nation's natural gas grid than into its electric grid. Our best indication of the marginal cost of power in Florida may well come from natural gas reports. Bentek Energy monitors deliveries of natural gas to many electric plants around the country, including Florida. This slide shows how much gas was scheduled to natural gas plants in Florida and how often gas was scheduled to more costly gas turbine units during the second half of last year. This shows at least when gas peaking plants were probably running and when they were not and provides the first step in understanding the marginal cost of power each day in Florida.

In Florida, and to a lesser extent for the whole Southeast, spot power markets are simply not active enough to be a primary indication of how the broader wholesale market is working or is likely to work. We need instead to work creatively with other data sources to gain the kind of understanding that spot markets convey elsewhere.

Competition and Markets in the Southeastern Model

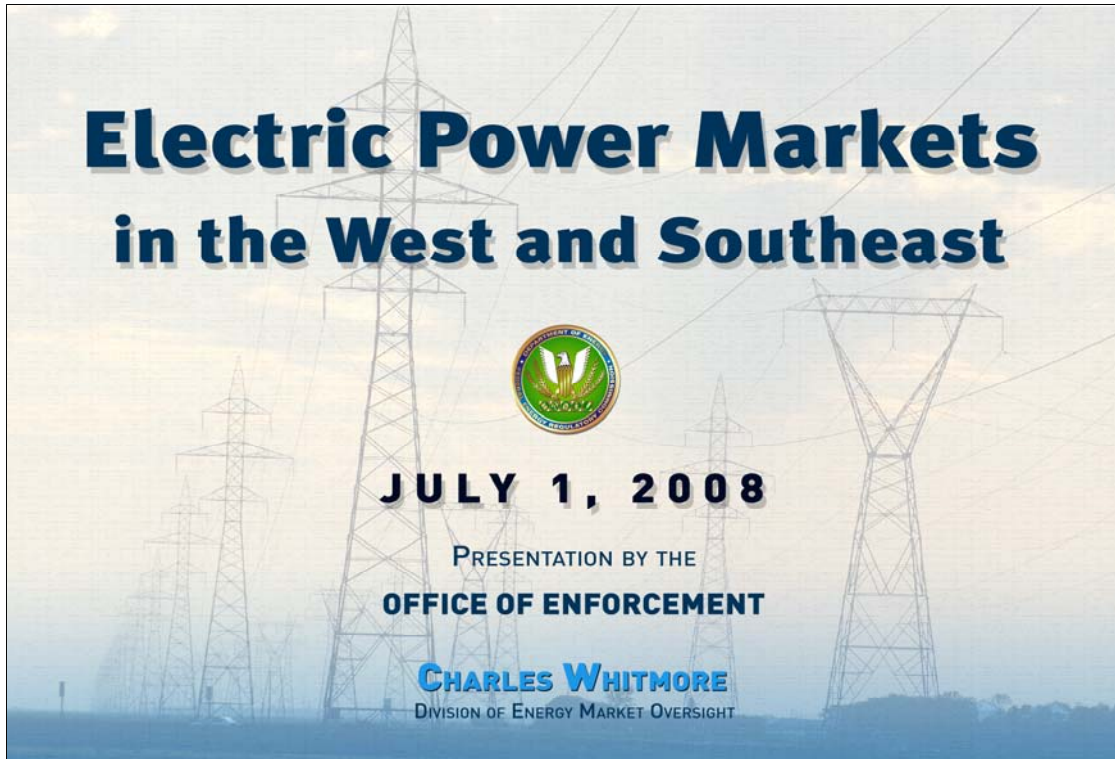
- **The Case of Georgia**
 - Competitive Procurement
 - Real-time Pricing

The Southeast is not generally known as a hotbed of competition for the electric power industry. But States have taken opportunities to use competitive forces to the advantage of their rate payers, especially for long-term decisions. Georgia may provide the two best examples in this regard.

First, Georgia requires Georgia Power to make almost all of its capacity additions through a competitive procurement process. This process begins with a transparent stakeholder process to determine an Integrated Resource Plan. It includes an open process to design the requests for proposals. Once competitors submit their bids, an independent assessor judges the proposals. The Georgia Public Service Commission supervises the overall process and makes final decisions. The Southern Company says that non-affiliated companies have become more competitive with time and that it expects about half of all capacity additions in Georgia between 2007 and 2015 to come from non-affiliates. If realized, this would still result in a quite concentrated outcome – but it is also a far cry from a traditional monopoly.

Second, Georgia allowed many of its publicly-owned utilities to compete with Georgia Power to supply large industrial users in the state. Partly in response, Georgia Power developed the real-time pricing program that I mentioned earlier this year in our State of the Markets Report – one of the most successful real-time pricing programs in the country. This kept many industrial customers on Southern's system, but it also provided real price signals to real customers – arguably the heart of a market outcome.

I do not wish to overstate the case for competition in the Southeast. The Georgia examples are not unique, but they are also not common. Still, there is nothing in the wholesale model that prevents the growth of such programs.



To conclude: both the Western and Southeastern bilateral markets are important, but they work quite differently from each other, and both differ deeply from RTO markets.

In the West, we see a market that used existing transmission resources to develop markets without central direction, roughly along the lines of the natural gas markets. The biggest challenge to this market going forward may be whether it can integrate new resources that will require substantial new infrastructure.

In the Southeast, we see an electric industry that focused primarily on long-term investment decisions, mostly within a traditional integrated utility framework. Spot electric markets developed as small add-ons to that basic structure, and appear to be particularly useful at peak periods.

That concludes the presentation. I welcome any comments and questions.