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MEMORANDUM

Date: September 16, 2002

To: McCullough Research Clients

From: Robert McCullough

Subject: Three Crisis Days At The California ISO

Gradually, analysts are beginning to understand the structure of the California market failure that began on May 22, 2000 and whose final emergency took place on July 3, 2001. The slow pace of analysis is due in no part to the ISO's stubborn allegiance to the secrecy standards that they adopted in response to the lobbying of the very parties now under investigation. Even the current report, summarizing events that occurred several years ago, required the energetic efforts of Senator Dunn's staff to get the ISO to release materials that should have been public under their tariff.[1] As of this date, the ISO's willingness to divulge

[1]Charles Robinson, the ISO's General Counsel, responded to the California Senate Committee's request for information on January 2001 with the following closing comment:

> As a final matter, should the committee consider releasing the information sought by the June 6 letter, the ISO notes that the more information competitors can obtain in the public domain, even if that information is historical, the greater the opportunity there is to exercise market power.
>
> June 14, 2002 letter to Senator Joseph Dunn.

The irony in these admonitions to secrecy is that virtually all trading data is now available to the competitors themselves in a host of FERC cases, civil trials, and investigations. The only parties without access are the press, policy makers, and the public.

basic operating data has been grudging and contentious.[2]

All the information in this report, both data and textual materials, has come from the discovery work of the California Senate Select Committee. Enron documents, where used, have been provided directly from the Committee discovery. No materials from other sources has been used.

Overview

The California crisis represented over one hundred days of Stage 1, Stage 2, and Stage 3 Emergency declarations by the California ISO – fifty-five in 2000 and seventy in 2001. It is yet to be widely understood that these emergencies represented an application of the ISO's rules to its forecasts – these were not emergencies in the sense of a major disaster that had direct physical impacts on the electric system. During most of the crisis, the ISO was extremely secretive about the causes of the emergency declarations. While ISO press releases would cite low hydro in the Pacific Northwest and heat waves in California, the direct cause of the emergency declaration was a forecast of available reserves that fell below the ISO's reliability standards – 7% for Stage 1, 5% for Stage 2, and 1.5% for Stage 3.[3]

In spite of frequent statements from the beneficiaries of the crisis, it is likely that none of the conditions faced by the ISO from May 22, 2000 through July 3, 2001 would have led to an emergency declaration by a traditional utility. Traditional utility reserves are provided by ownership and long term contract. The ISO had chosen a vastly less reliable course – their reserves were the product of a daily bid. When reserve bids did not materialize, the ISO could be forced into an emergency. As we now understand, market participants like Enron, understood this very well and could arrange stratagems designed to cause emergency declarations – not just profit through the ISO's easily manipulated rules. Moreover, until we understand the California crisis, it is very unlikely that FERC's Standard Market Design can be judged immune from these same schemes.

In a sense, this was an application of chaos theory. The stable region of ISO operations was small. With appropriate planning, a major market participant – or a consortia of them – was able to shift the ISO outside of the area of stability. At this point, market conditions became chaotic and highly profitable.

We have selected three dates from the history of the ISO. The first, May 25, 1999 is the date of the infamous Silver Peak incident.

On May 24, 1999, Enron Power Marketing Incorporated (EPMI) submitted four bids into the California Power Exchange (PX) for 2,900 megawatts during on-peak hours. The path identified for the power to be sold was the Silver Peak line from Nevada. Ratings for Silver Peak vary, but the consensus appears to be

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[2]When asked why previously public data had been removed from the ISO's web site, one ISO middle manager told McCullough Research staff that the data was available if the request was made by someone sufficiently important – apparently meaning that it would be available to a marketer, but not a researcher.

[3]The ISO actually plans to meet "MORC" – minimum operating reserve criteria. This is roughly equivalent to 7%.

that the line had a capacity of 15 megawatts. This impossible schedule went largely unnoticed by the California Independent System Operator (ISO), but two complaints spurred an investigation by the PX compliance unit.[4] The investigation dragged on for twelve months, and, in spite of a finding that Enron had cost consumers $4.6 million to $7 million, was settled for a fine of $25,000 and a commitment by Greg Whalley to not "substantially repeat" the behavior.[5] We now know that Enron had taken a financial reserve of $10 million dollars for a scheme they convinced the California PX brought Enron no profits.

The second date is the start of the California crisis, May 22, 2000. On this date the California ISO called both a Stage 1 and a Stage 2 emergency. The results of this declaration on the industry were electric. May is generally regarded as the least risky moth of the year, representing relatively low loads, high water from the Columbia run-off, and favorable operating conditions. It is clear from the Enron materials gathered in the course of the California Senate Select Committee's investigation, that Enron had positioned itself to take advantage of the first emergency declaration. Since May 22, 2000 has fallen into the California ISO's retroactive secrecy rules, more discovery will be required until we understood which market participants were prepared to profit from this declaration.[6] It is a comment on Enron's aggressive behavior during the California market failure, that Enron's chief west coast trader sent an email to Terry Winter, the ISO's Chief Executive Officer, detailing his mechanics and complaining that the prices they were paid during the first emergency of the California crisis were not high enough.

The third date is January 17, 2001. This is the date of the ISO's first rolling blackout in Northern California. This date is important in that it represents an emergency caused, in part, by the ISO's inability to transfer electricity into Northern California. ISO data does not support this hypothesis. We have been unable to verify whether the inability to serve Northern California loads was due to management failure or to a deliberate effort to fool the ISO into believing it did not have access. A careful review of ISO data and corresponding data from outside the ISO reveals dramatic inconsistencies. The ISO has been unable, or possibly unwilling, to clear up these inconsistencies over the past three months.

Overall, these three dates focus on a single overriding question:

> To what degree was the crisis in California staged by a deliberate plan to destabilize the ISO?

Evidence abounds that the crisis was unnecessary. New evidence is available that the crisis itself may well have been managed as well. A careful review of these three dates makes this a very believable hypothesis, although analysis of January 17, 2001 is still preliminary.

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[4]While the ISO did not undertake a formal investigation, we have now received files summarizing their review. It is clear they understood some of the mechanics, but not the overall goals of this scheme.

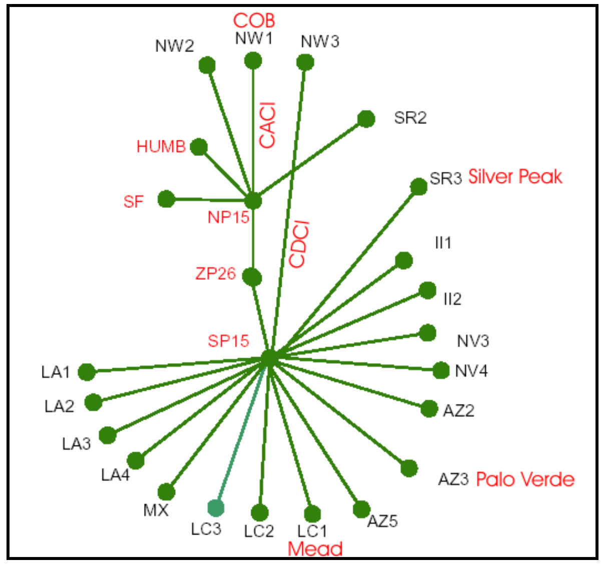
[5]Greg Whalley was president of Enron's trading unit at the time. Today, he is the Director of UBS Warburg's trading unit, purchased from Enron this spring.

[6]ISO staff indicated that older data was also secret under an unspecified FERC order.

May 25, 1999 – Silver Peak

The Silver Peak incident was tightly planned and carried out. The scheme appears to have been a "proof of concept" where a single fraudulent schedule destabilized the entire California market for the day.

The Silver Peak line is not a central part of the regional power market landscape. The connection, two 55 kV lines that stretch from the town of Silver Peak into California, was built to facilitate generation at the Beowawe Geothermal unit. While the theoretical landscape of the California ISO allows it to be treated as an intertie, its actual operation is closely tied to this one power project. Not only is the line not capable of carrying more power than the project's generation, but the interconnections in Nevada are also very weak. In actual practice, Silver Peak is simply used to carry the geothermal unit's output to Southern California Edison. While Tim Belden argued that a counterschedule could have made the schedule feasible, it is highly unlikely that a vast power schedule could have simultaneously appeared flowing east.



The Incident

On May 24, 1999, at 6:10 A.M., Enron submitted four bids of 725 megawatts for the heavy load hours of May 25th at prices from $18 to $29 per MWh. An hour later, the California PX notified Enron that it was the successful bidder.

At 7:29 A.M. Enron identified Silver Peak as the delivery point for the energy. At 11:17 A.M. the California ISO called Enron to ask if the bid (and delivery point) were in error. Tim Belden was clearly waiting for the call from the ISO, since it was immediately transferred to him. The conversation makes it clear that the ISO's reaction had been expected:

> TIM : Um, there's a -- there -- we. just, um -- we did it because we wanted to do it. And I don't -- I don't mean to be coy.
> KAREN: 'Cause, I mean, it's -- it's -- it's a -- I mean --
> TIM: It's probably --
> KAREN; -- it's a pretty interesting schedule.
> TIM : It -- it's how we -- it makes the eyes pop, doesn't it?
> KAREN: Um, yeah. I'll probably have to turn it in 'cause it's so odd .
> TIM : Right.[7]

[7]ISO Transcript of ISO/Enron call on May 24, 1999.

The ISO triggered CONG, their congestion model, which, in turn, accepted the adjustment bids filed by Enron. The Power Exchange had provided a balanced schedule to the ISO. Once the congestion on Silver Peak was taken into account, the PX schedule was 2,885 megawatts below projected loads. The ISO balanced the loads by increasing imports, using reserves, and providing considerably higher prices back to the PX. The higher PX prices reduced day-ahead loads.

Since actual loads did not change, the primary impact of the Silver Peak incident was to increase imports and to move loads from the day-ahead market to hour ahead markets and the ISO. The ISO's estimates of the market adjustments were:

Source	MW
Needed Adjustment to Silver Peak	(2,897)
Increased Import from other Branch Groups	1,038
Internal Production Increases	182
Internal Load Decreases	1,676[8]

The line entitled, "Internal Load Decreases," is a misnomer. The increased price at the PX from the distortion caused the supply curve to meet the demand curve at a lower level – 1,676 MW lower. While this has been labeled as "underscheduling" by the California utilities, the situation is a bit more complex. The California utilities priced their bids into the PX based on the opportunity cost of ISO real time replacement costs. If the costs were too high, as was the case here, the nature of the PX bid left it for the ISO to make up the differential from reserves and real time purchases.

While the ISO market surveillance unit apparently did not notice the excursion, the market immediately observed what had happened.[9] The Energy Market report for the 25th noted:

> Speaking of the PX, much of the hubbub on Tuesday surrounded the 44$/MWh congestion adjusted prices. Rumors circulated that an unnamed party had manipulated the PX on Monday by bidding 3000 MW of power on a 20 MW line between Nevada and California. Someone played a game yesterday which caused everyone's adjustment bid schedules to come into play, and that resulted in the higher prices throughout the system," said one market pundit. Other players did not believe that someone could consciously manipulate PX prices from a UMCP of 27.25$/MWh to an adjusted price of 44.31$/MWh, and blamed human error for the high price. Nonetheless, sources indicated that the PX was going to look into the matter to determine if "market manipulation" had actually taken place.[10]

In the course of the investigation, the Power Exchange staff estimated that the Silver Peak incidents cost

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[8]Analysis of Possible Day-Ahead Congestion Gaming, ISO Market Analysis Department, June 1999, page 3.

[9]The ISO Weekly Market Watch's only mention of the Silver Peak incident was a statement that "Price spikes of $177/MW and $162/MW occurred on May 25 at hours ending 1600 & 1700 due to significant incremental energy requirements that exceeded 2400 MW."

[10]Energy Market Report, May 25, 1999, page 1.

consumers $4.6 million to $7.0 million. Amazingly, they also estimated that Enron lost $102,000 in the day-ahead market as a result of the imaginary resource bid.[11]

This calculation is surprising, to say the least. We now have evidence that Enron had engineered a considerable profit from this one scheme. Tim Belden's financial reserves for west coast trading are contained in a form called "Schedule C." Schedule C contains reserves for a number of different schemes including selling non-firm as firm. It also contains two entries on Silver Peak:

> Cover potential liability associated with scheduling at Silver Peak on May 24, 1999. $4,000,000
> Increase reserve associated with PX schedule at Silver Peak. Reserve for total potential in Day Ahead & Real Time markets, includes actual damages & opportunity cost. $6,000,000[12]

The implication is that Enron cleared $10 million from the scheme, not losing a small amount as they had argued during the PX investigation.

The real question on Silver Peak is why the ISO did not call an emergency on that day. The shortfall coming into the ISO was equal to the "Internal Load Decreases." If Enron had managed to toggle the ISO into an emergency, the situation would have more closely resembled May 22, 2000.

May 22, 2000 – The Start of the California Market Failure

The first day of the California crisis was completely unheralded. May generally has low loads and hydroelectric generation reflecting the impact of the runoff as snows in the Rockies melt and swell the Columbia River. The forecasted reserve margin for California was 39.1% for May.[13] The actual reserve margin for May turned out to be 14.2%.[14] While loads were higher than expected for May, they were considerably below the peak loads that had been forecasted for in the summer of 2000.

The problem from the beginning was not actual physical generating capacity, it was the availability of promises of that capacity to the ISO. Unlike a traditional utility, the ISO did not arrange for reserves in advance. Their approach was to stage a daily auction for tomorrow's reserves. If the auction was not successful, the ISO was forced to call an emergency.

The situation was accentuated by a number of other flaws in the tangled collection of rules and markets that were administered by the California Power Exchange and the California ISO. Power Exchange schedules into the ISO might or might not reflect the full requirements of the California investor owned utilities.

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[11]Report on the Compliance Unit Investigation of Market Events for May 25, 1999, page 5. The PX investigative staff also "accepts Enron's statements that it had no other arrangements outside of the Ca1PX markets from which it profited financially as a result of its actions."

[12]Schedule C Summary as of 3/14/0.

[13]January 1, 2000, WSCC Summary of Estimated Loads and resources, page 112.

[14]January 1, 2001, WSCC Summary of Estimated Loads and resources, page 111.

When the PX prices were above the opportunity cost for power from the ISO, the requirements provided by the PX fell below actual loads. While the generators point at the utilities for causing this, their control over the supply curve was able to affect the amount of underscheduling at the PX. A high set of bids meant high underscheduling at the PX and a call on reserves and real time purchases at the ISO.

The question concerning May 22, 2000 and its following emergencies is "where did the capacity go?" In May, California had 5, 930 megawatts of surplus unused capacity. The WSCC as a whole had 24,211 MW – approximately 100 GE Frame 7F combined cycle units. By any normal standards, these reserve margins – after loads and outages – were very healthy. In fact, the margins were higher than those planned for the investor owned utilities in planning studies before California restructuring.

Enron clearly had an idea that summer of 2000 was going to be interesting. While the analytics at Enron were no more prescient than the research undertaken at the WSCC, the ISO, or the region's utilities, Tim Belden's email tells a different story. Less than two weeks before the crisis, Tim Belden wrote to his Houston colleague, Greg Piper:

> We long. Pricing keep going up. So far so good.[15]

On May 23, 2000, the day after the start of the California crisis, Tim Belden writes an email directly to Terry Winter and Kellan Fluckiger at the California ISO. The full text of the email is:

> I just finished talking with Zora about the Out of Market activities yesterday and thought that it would be a good idea to put my thoughts into an e-mail. It appears as though the MW that you procure out of market end up suppressing the ex post price . For example, Enron sold the ISO 100 MW for $750/MWh during hours 17, 18, and 19 . It was our impression that the ISO was procuring large volumes of energy out of market during these hours . Yet the ex post price for these hours settled at $379.29, $300.00, and $119.77 respectively. Every MW that you purchase out of market reduces the number of MW that must be procured through the BEEP stack. Reducing the number of MW procured through the BEEP stack naturally puts downward pressure on the ten-minute and ex post price. Yesterday's prices support this theory . We saw this happen in the summer of 1998 as well.
>
> The result is that you harm providers of energy in-state. This could be instructed or un-instructed deviations . Yesterday we had nearly 800 MW of uninstructed generation in the state (in the form of over-scheduled load). Your out of market calls, coupled with the way that you perform ex post pricing, hurt us and everyone else who provided energy within the state to you in real time.
>
> If you value power at $750/MWh in the bilateral market, then your BEEP price should be $750 as well. This is the proper price signal as the marginal resource in the state is $750. Because of timing issues and software inflexibility I understand that your BEEP stack can't reflect this. In essence, you are taking $750/MWh power and pricing it into the BEEP stack at $0. There is a simple fix here. You could simply set the Target Price to $750/MWh in any hour that you procure energy out of market for reliability reasons. You have proven before that the Target Price can be changed quickly and unilaterally.
>
> We know that you have to place reliability first on critical days. I have no problem with the ISO procuring MW's out of market when the need is there. There is a simple way to send the proper price

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[15] Belden email to Greg Piper, May 12, 2000.

> signal to the entire market through the Target Price. I recognize that this is politically challenging. But these prices are real and are driven by scarcity. Your reliability problems over the next couple of years will be a direct result of too little investment in new generation. Prices need to reflect market conditions in order to incent new generation. I encourage you to stand up to your slogan "Reliability through markets" and adjust your target price methodology or your ex post pricing so that in the hours of the greatest scarcity the ISO pays generators the proper marginal price.
>
> Thanks for your consideration of this matter. Call me at 503-464-3820 if you would like to discuss.[16]

This was a very strange communication in any number of ways. First, Belden is complaining that prices paid to this fraudulent load were not high enough. Enron, as well as a number of other market participants, have taken the position that the possession of a load in California allows the marketer to schedule any amount of power to meet that load. In this case, Tim Belden has scheduled 800 MW above the requirements of their California loads. In effect, Belden has proposed increasing shipment to the University of California by a factor of ten.

Second, Belden has taken the side of the in-state generators. While this might simply have been a kindly act to benefit the interest of his competitors, the fact is that Enron did not own in-state generation.

Third, Belden has already started using the speech he makes throughout the crisis of scarcity and "the next couple of years." Enron's own fundamentals analysis does not show scarcity.[17]

The most important question is why Tim Belden would overschedule 800 MW to a much smaller load. We know from a review of the affidavits filed by marketers in PA02-2-000, that Enron was not unique in this practice. Within the context of the Yoder/Hall memos, this is called "Fat Boy" – also known as the "Big Picture."

> The answer is to artificially increase ("inc") the load on the schedule submitted to the ISO. Then, in real-time, Enron sends the generation it scheduled, but does not take as much load as scheduled . The ISO's meters record that Enron did not draw as much load, leaving it with an excess amount of generation . The ISO gives Enron credit for the excess generation and pays Enron the dec price multiplied by the number of excess megawatts . An example will demonstrate this, Enron will submit a day-ahead schedule showing 1000 MW of generation scheduled for delivery to Enron Energy Services ("EES"), The ISO receives the schedule, which says "1000 MW of generation" and "1000 MW of load. The ISO sees that the schedule balances and, assuming there is no congestion, schedules transmission for this transaction. In real-time, Enron sends 1000 MW of generation, but Enron Energy Services only draws 500 MW. The ISO's meters show that Enron made a net contribution to the grid of 500 MW, and so the ISO pays Enron 300 times the dec price.
>
> The traders are able to anticipate when the dec price will be favorable by comparing the ISO's forecasts with their own. When the traders believe that the ISO's forecast underestimates the expected load, they will inc load into the real time market because they know that the market will be short, causing a

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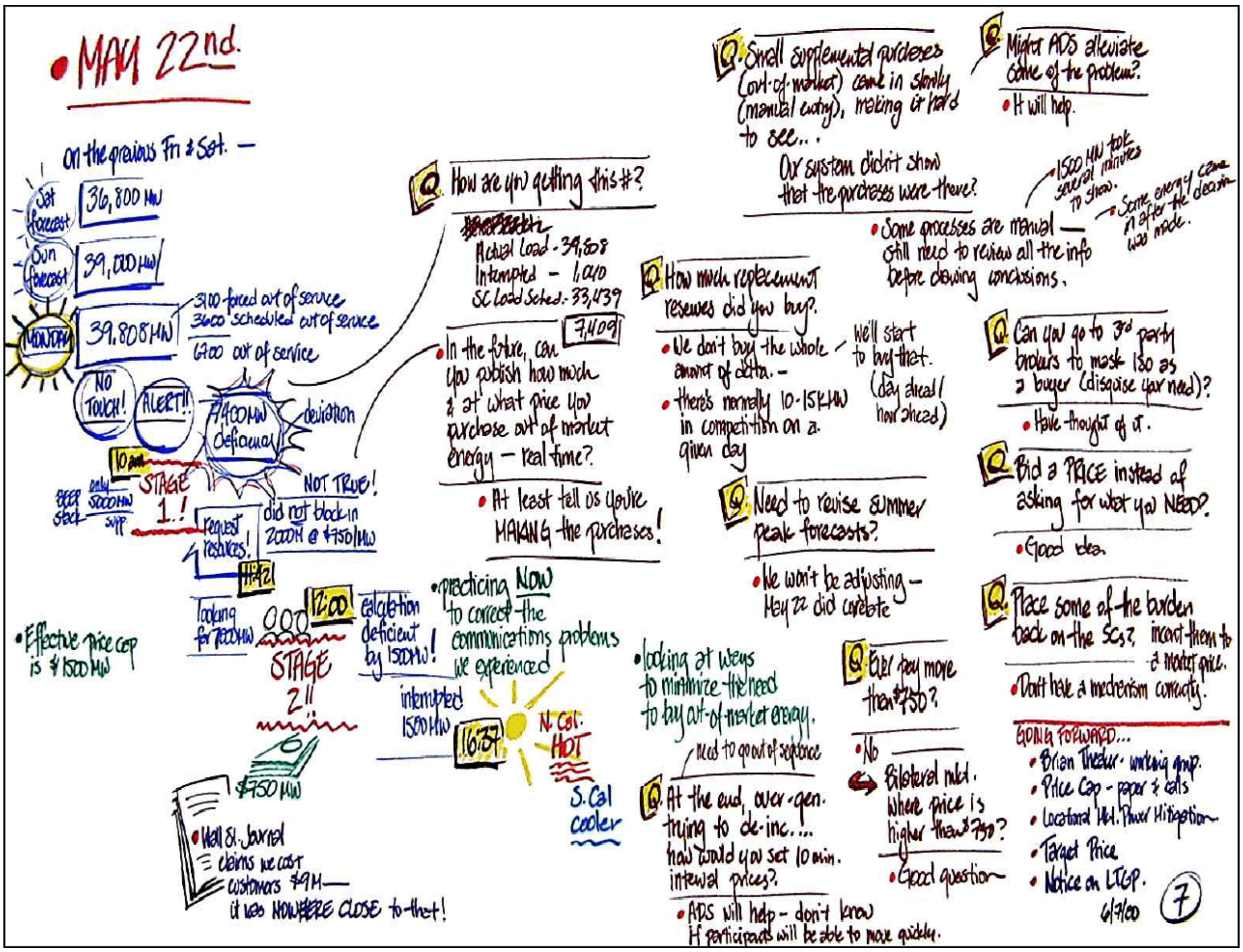
[16]Belden email to Kellan Fluckiger, Zora Lazic, and Terry Winter, May 23, 2000.

[17]Belden email to John J. Lavorata, May 1, 2000.

favorable movement in real-time ex past prices.[18]

Fat Boy answers the question raised above concerning where the generation went. Enron could have bid 900 MW – 800 MW of overscheduled load and 100 MW of emergency sales into the normal PX markets. If they had, they would have received $40 to $50 per megawatt-hour. Parking the energy at the ISO allowed them to profit from the Stage 1 and Stage 2 declarations without preventing the emergency entirely. Moreover, the overscheduled energy is automatically sold to the ISO during the emergency without the necessity of bidding against other competitors.

Total required reserves for the ISO on this date were 2,800 MW. On June 7, 2000, the ISO provided this colorful description of the emergency:



Enron's overschedule was 2% of total loads – all by itself – which normally is the full step between a Stage 1 Emergency and a Stage 2 Emergency for this level of loads.

[18]Christian Yoder and Stephen Hall Memo To Richard Sanders, December 6, 2000, page 2.

Taken in context, May 22, 2000 was the success that eluded Enron at Silver Peak. Where as May 25, 1999, stressed the system, it did not plunge the ISO into the declaration of an emergency. It also proved to "make the eye's pop," as Tim Belden puts it. An unsuitable strategy to cause the ISO to feel that it was reacting to a real shortage.

January 17, 2001 – California's First Rolling Blackouts

Our analysis of January 17, 2001 is a work in progress. As noted above, three months has not been sufficient time to get clear answers from the California ISO.

By January 17, 2001, California suffered from a full set of afflictions. Approximately half of the divested base load units were offline. Suppliers were citing credit issues in negotiations with the ISO and the PX. FERC had cancelled the PX, leaving confusion in the market. Also, the ISO found it was unable to successfully integrate the two halves of California into one electric system.

Given the discussions above, it is clear that the inability to integrate these two halves is a logical area to seek destabilizing behavior.

As with the start of the California market failure on May 22, 2000, the fundamentals on January 17, 2001 were not nearly as bad as they appeared. California's reserve margin was 3,865 MW – 10.8%.[19] Total WSCC reserves were 19,648 MW – 17.5%, even after the massive outages on California's steam units.

As always, ISO operations were largely secret during this period. The ISO's Stage 3 Emergency filing with the North American Electric Reliability Council (NERC) described the situation as:

> 1/17/01:
> Prescheduled interchange imports are much less on the 17th than the 16th.
> From approximately 0515 until 2200, all non firm loads were requested to be interrupted. The estimated total of these non firm loads is 1500 MW.
> Pump load is curtailed as available. CDWRs water operations have been severely impacted as a result of the many requests for curtailment.
> Generation outages (forced and planned) are approximately 10,000 MW.
> From 1140 until 1345, the ISO requested PG&E interrupt 500 MW of firm load. Path 15 limits were being exceeded due to hydro generation in northern California that must be backed due to low water levels. During the reduction of those hydro facilities, a thermal plant in central California tripped which in turn created an overload on Path 15.[20]

The stress on Path 15 has caused puzzlement in the utility community for the past eighteen months. The following map shows the California ISO in the context of the neighboring states:

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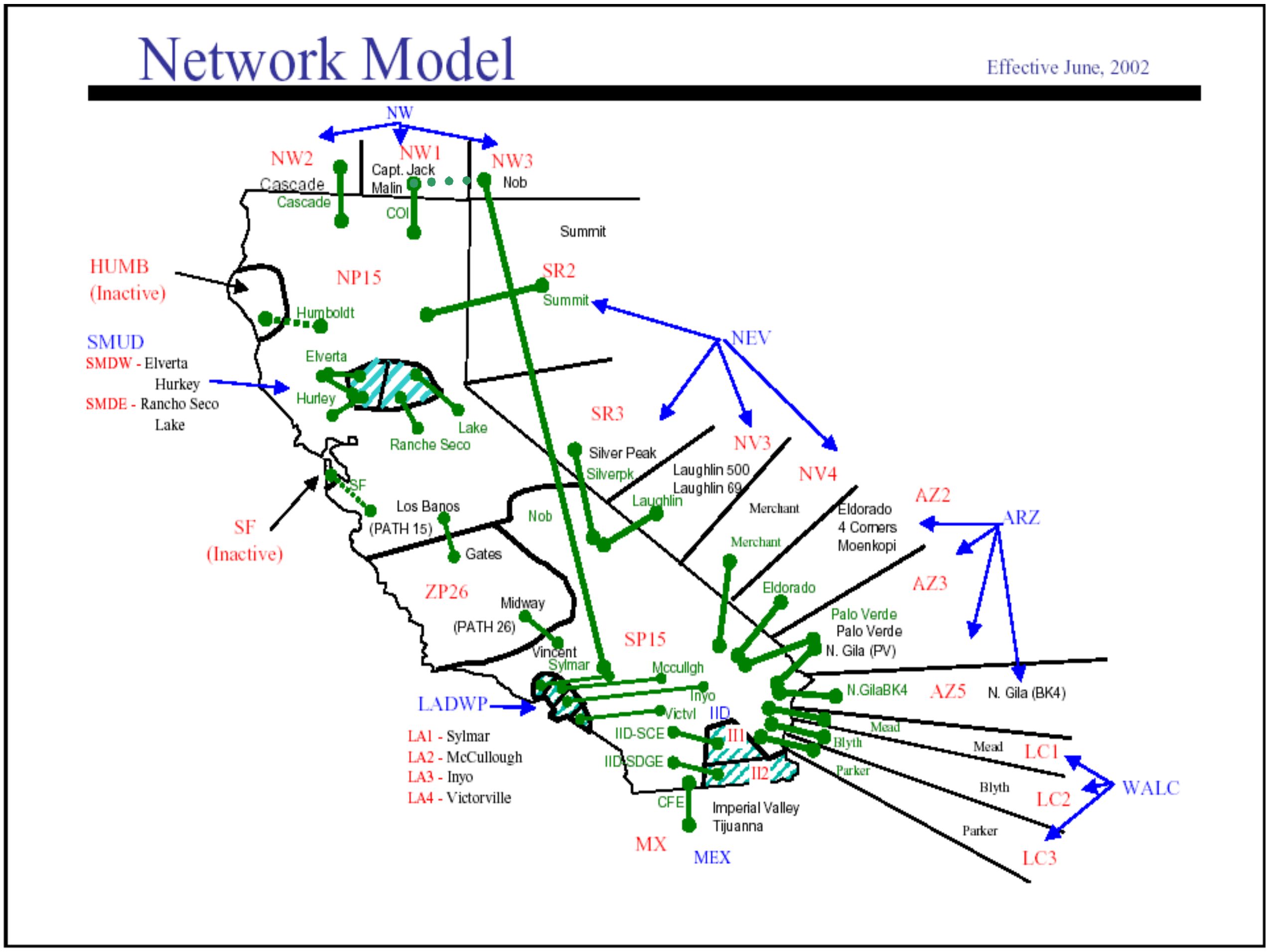
[19]January 1, 2002, WSCC Summary of Estimated Loads and resources, page 111.

[20]NERC Energy Emergency Alert 3 Report, January 17,2001 through January 20,2001, Tamara Elliott



Only one change has been made to this chart. The top of the NOB (Nevada Oregon Border) has been connected by a dotted line to COB (California Oregon Border.) As an operational matter, there are two parallel paths from Southern California to Northern California. The first, Path 15, runs through Central California. The second, runs through Nevada to Northern Oregon and back from Northern Oregon to Northern California. As a general rule, any effective congestion management system should consider both alternatives. In theory, congestion costs should be similar if not identical on the two paths.[21]

Scheduling at the ISO has three different stages. On a day ahead basis, initial schedules are compared with transmission constraints and required adjustments are calculated.

The adjustments from the Initial Day Ahead calculations were:

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[21]The path through Oregon is less efficient in that it has higher losses and wheeling costs. In the absence of congestion on Path 15, the path through Oregon would not normally be used. Once Path 15 has become congested, market theory would argue that schedules would shift to the uncongested path until both paths were used. Before firm loads were interrupted in Northern California, both paths should have had similar congestion costs.

	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
COB	16	16	17	16	15	11	162	151	126	62	23	23	23	24	25	24	39	60	57	8	10	20	4	10
NOB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Path 15	-971	-784	-775	-777	-895	-913	-1329	-1286	-1098	-839	-1045	-935	-963	-1014	-1050	-1138	-914	-577	-655	-805	-1063	-1045	-1049	-1067

The adjustments are of interest because CONG, has calculated energy "escaping" from Northern California and paying congestion fees to do so. Rationally, schedules flowing into Northern California and then into Oregon could be more efficiently served by taking the path through NOB which has no CONG adjustments and no adjustment fees. Path 15's adjustments are negative, reflecting the opposite direction of flow and very large adjustments.

The next stage is the Final Day Ahead calculations:

	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
COB	16	16	17	16	15	11	162	151	126	62	23	23	23	24	25	24	39	60	57	8	10	20	4	10
NOB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Path 15	-971	-784	-775	-777	-895	-913	-1329	-1286	-1098	-839	-1045	-935	-963	-1014	-1050	-1138	-914	-577	-655	-805	-1063	-1045	-1049	-1067

No changes took place between the initial and final day ahead calculations. This is surprising since a simple inspection of the initial calculations makes it clear that they are counterproductive.

The final stage is the hourly calculations:

	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
COB	19	66	17	16	15	4	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Path 15	-36	-83	-34	-33	-32	-4	-58	-68	-67	-27	0	0	0	0	0	-44	-58	-79	-76	-27	-29	-39	0	0

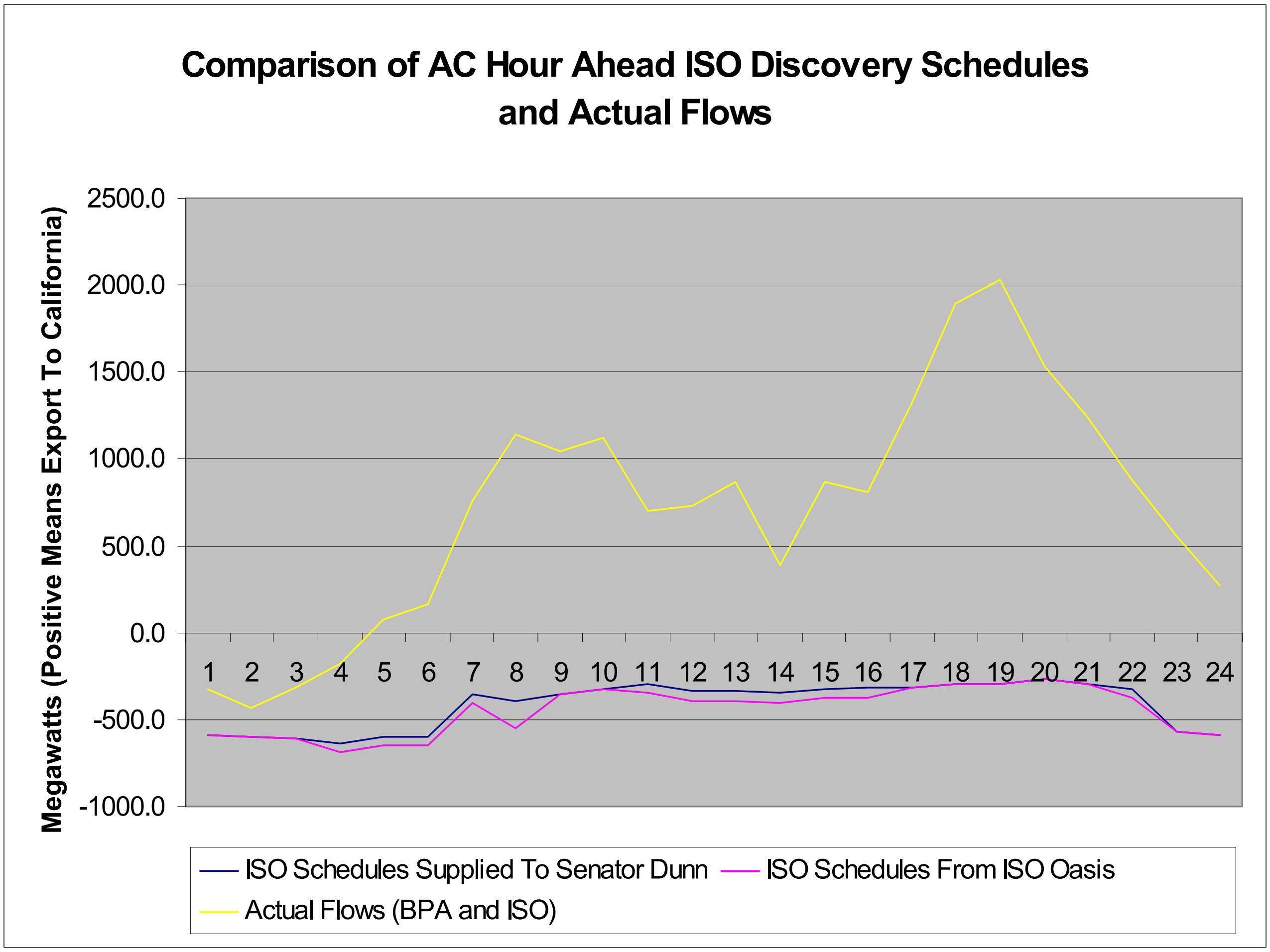
This is continuing to show congestion leaving Northern California for Oregon and congestion entering Northern California from Southern California.

Any market participant facing congestion should have rescheduled its generation from Path 15 and taken the uncongested path to NOB and then received congestion payments for relieving congestion on the lines leaving Northern California. The ISO's tables show that when the blackouts were ordered – 11:40 until 13:45 none of these lines was congested in the hour ahead market.

In trying to make sense of the schedules received from the ISO, the contrast between the detailed, but illogical, schedules and reality was pronounced.

On the BPA side, the interties are metered and information is freely available. Normal checks and balances are allowed to operate, so it is easier to believe BPA developed information than the ISO's.

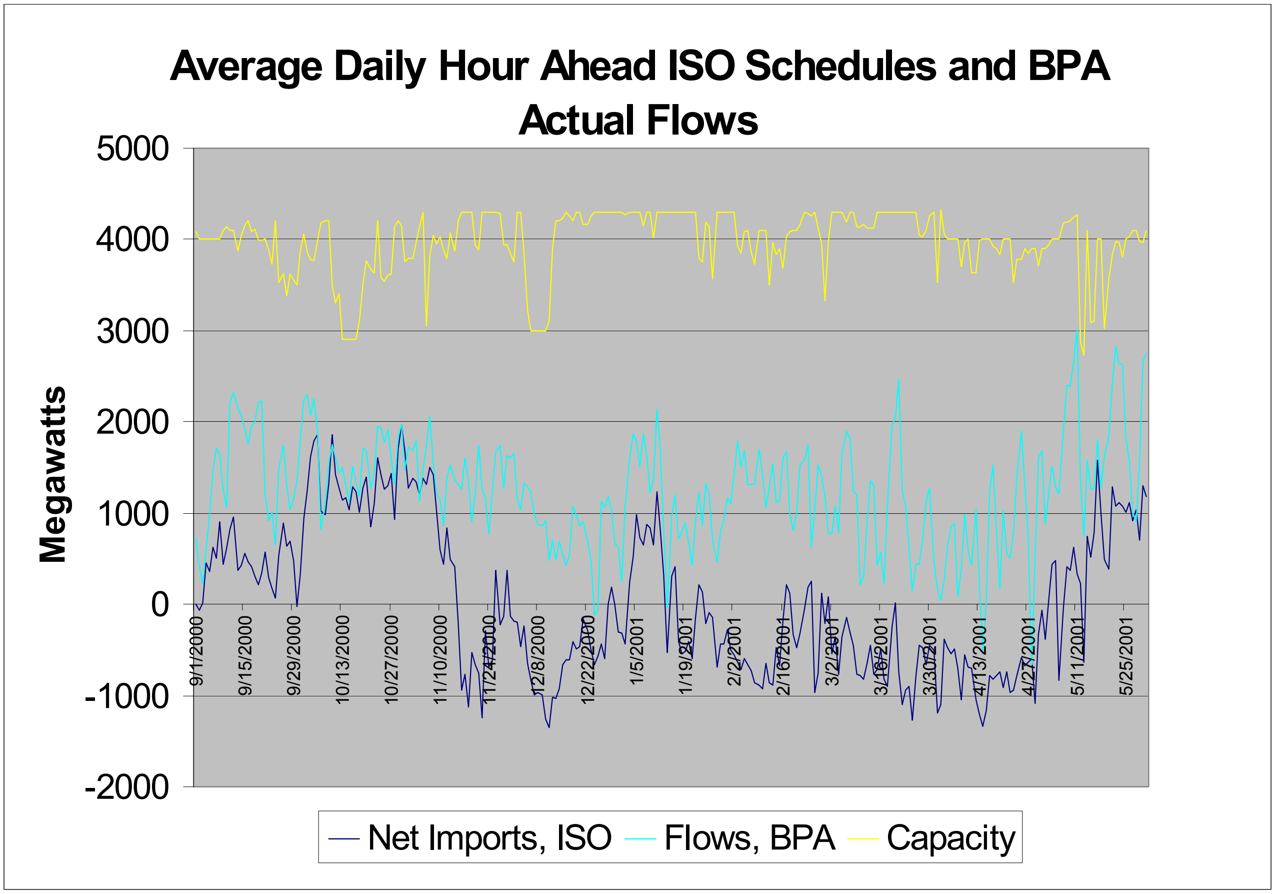
In checking actual flows, we found that the ISO and BPA report similar flows on the AC line to COB. January 17, 2001 shows almost no similarity between schedules and flows. On a net basis, all ISO supplied schedules are exports – energy leaving Northern California for Oregon. Actual flows are negative at night and strongly positive during the day. This is logical, since the proper use of the hydroelectric resources in the Pacific Northwest is to store thermal generation from California when it is not needed at night and return it to California during the day.



Repeated attempts to get the ISO to clarify the contradiction between its data and actual flows proved hopeless.[22] The contradictions are even more puzzling when BPA's scheduling policies are taken into account. BPA requires hourly schedules for the use of the intertie. Although exceptions are granted, the exceptions are just that – exceptions. Clearly, exceptions alone would not explain a pervasive long term difference between flows and schedules on the AC intertie to Oregon.

We conducted a similar comparison on a daily average basis from September 2000 through May 2001. The following chart shows that the deviations remain large throughout much of the period.

[22]One admittedly recent hire in DMA even expressed some uncertainty about the transmission lines comprising the California Oregon AC Intertie – one of the largest transmission projects in the world.



The lack of comparability between actual metered flows and the ISOs total schedules over the crisis is very troubling. BPA requires hourly schedules on the California Oregon intertie. While it is true that exceptions – major outages – are made to this rule, the match between BPA and the California ISO is simply too great and too pervasive to be a set of hourly rule exceptions.

The data in hand gives little credence to a fundamental explanation of the outages in Northern California. Mapping schedules to outages is simply not a credible exercise until the schedules themselves make more sense.

It is possible to see whether the actual capacity on the lines to NOB and from COB back to Northern California would have been able to avert the outages if the system had been operated according to traditional utility methods. It is clear that real, unused transmission capacity was available during all hours on January 17, 2001.

Unused capacity ranges from 124 MW to 284 MW through the period of the blackouts. If within day factoring was allowed, the entire blackouts could have been averted by the use of the DC line.

At this point, it is not clear whether this is an indictment of ISO management or market manipulation by a third party. Either answer seems equally likely. If the ISO believes in the data it has provided and has been unable (or unwilling) to justify, the entire operation of the ISO's administered markets would seem in severe doubt. If the ISO also sees possible contradictions between their market data and actual operations, the presence of Yoder/Hall manipulations would seems likely.