PRESIDING OFFICER'S DECISION (Mailed March 24, 2004)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Universal Studios, Inc., Complainant, vs. Southern California Edison Company, Defendant.	Case 01-01-043 (Filed January 26, 2001)

Patrick J. Power, for Universal Studios, Inc., complainant.
Robert B. Keeler, for Southern California Edison Company, defendant.

DECISION DENYING COMPLAINT FOR REFUND OF EXCESS ENERGY CHARGES

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Summary

In this decision, we address a complaint filed by Universal Studios, Inc. (Universal) against Southern California Edison Company (Edison or SCE) in which Universal contends that Edison wrongly imposed penalties on it for refusing to interrupt its electric load on June 27, 2000. On this date, Universal was a sub-transmission customer served under SCE's I-6 schedule. Customers served under the I-6 schedule were subject to having their service interrupted down to the Firm Service Level (FSL) designated by the customer in the event that a Stage 2 alert was called by the California Independent System Operator (ISO). Since Universal had set its FSL at zero, it was required to shut down its entire load when asked to do so by Edison, or else incur excess energy charges for all of the energy it consumed while the curtailment request was in effect.

It is undisputed that on June 27, 2000, Universal did not shut down its load when the ISO declared a Stage 2 alert, and Edison thereafter asked customers on the I-6 schedule to curtail down to their respective FSLs. Owing to this refusal, Edison billed Universal for excess energy charges of $395,409.60. Instead of paying the charges, Universal filed this complaint and eventually deposited the disputed amount with the Commission.

Universal contends that it should be excused from having to pay the excess energy charges because Edison engaged in a "systematic practice" of not purchasing enough power to serve its forecasted load from the so-called "day-ahead" power market run by the California Power Exchange (PX). The motive for this underscheduling, Universal contends, was to avoid purchased power costs that Edison could not recover in rates. As a result of the underscheduling, Universal continues, the ISO was required to make very large purchases in the spot, or "real time," market run by the ISO, purchases that were much larger

than that market was designed to handle. Thus, Universal concludes, Edison's own actions were the proximate cause of the curtailment on June 27, 2000, because "Edison deliberately under-scheduled its generation capacity requirements in the day ahead market for June 27," which made it "almost certain" that the ISO would be forced to declare a Stage 2 alert, and that Edison would have to request load curtailments. (Complaint, ¶¶12-13.) Since Edison's own Electric Rule 14 requires SCE to "exercise reasonable diligence to furnish / deliver a continuous and sufficient supply of electricity to its customers and to avoid any shortage or interruption of delivery thereof," Universal contends that Edison's own scheduling practices brought about a breach of this rule, and that Universal should therefore be excused from having to pay the excess energy charges of $395,409.60.

It is well-established that in complaint cases like this one, the complainant has the burden of proving each essential element of its claim. We agree with Edison that in this case, Universal has failed to prove that SCE's scheduling practices in the day-ahead market for June 27, 2000 were unreasonable within the meaning of Rule 14, or that – in view of the supply withholding clearly engaged in by generators -- the purchases by the ISO in the real-time market can be considered the cause of the Stage 2 alert on June 27. Moreover, we agree that Edison has demonstrated that it could not have purchased enough power in the day-ahead market to serve its forecasted load for June 27 even if SCE had been willing to bid the maximum price allowable under the PX's rules. In view of these conclusions, it is clear that Universal has not met its burden of proof, that the complaint herein should be denied, and that the $395,409.60 on deposit with the Commission should be paid to Edison.

Procedural Background

The complaint was filed in late January 2001. On March 8, 2001, Edison filed a motion to dismiss, as well as an answer denying the material allegations of the complaint. In its motion, Edison argued that the complaint should be dismissed because Universal had failed to show any violation of law, as required by § 1702 of the Public Utilities Code. Noting that Electric Rule 14 requires Edison only to exercise "reasonable diligence" in delivering electricity to customers, that the rule expressly does not "guarantee a continuous or sufficient supply [of electricity] or freedom from interruption[s]," and that Rule 14 also exempts Edison from liability for interruptions or shortages "from any cause not within [Edison's] control," SCE argued that the curtailment request of June 27, 2000 resulted from weather conditions, transmission constraints, and actions by the ISO and generators, and not from any underscheduling by Edison. Moreover, SCE continued, neither Electric Rule 14, the I-6 tariff nor the tariffs of the ISO or the PX required Edison to take any actions that it had failed to take.[1]

Because some of the issues raised by the complaint were also being considered in Phase I of Rulemaking (R.) 00-10-002, our inquiry into the effect of interruptible programs on energy prices and the reliability of the electric system, the Commission decided not to act on Universal's complaint until it had had an opportunity to consider the history and application of the I-6 tariff in that proceeding.

In April 2001, the Commission issued Decision (D.) 01-04-006, its principal decision in Phase I of R.00-10-002. We concluded that customers under Edison's

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[1] On March 21, 2001, Universal filed a response to Edison's March 8 pleadings, arguing that the complaint did state a cause of action.

I-6 tariff should be able to opt out of interruptible service (and take firm service at higher rates) retroactive to November 1, 2000. (*Mimeo.* at 13-19.) In reaching this conclusion, we also noted that customers would be obligated to pay penalties for failure to comply with interruption requests "through the time the opt-out or adjustment in firm service level is effective." (*Id.* at 19.) In footnote 9 of D.01-04-006, we specifically pointed out that this meant "any penalties incurred up to and through November 2000." *(Id.)*

Edison filed an application for rehearing of D.01-04-006. Edison argued, among other things, that the decision to allow customers to opt out of the interruptible program retroactive to November 1, 2000 violated numerous statutory provisions. In November 2001, the Commission issued D.01-11-031, which denied Edison's rehearing application after an extensive discussion of the utility's grounds for challenging our decision to allow retroactive opting out of the interruptible program. (*Mimeo.* at 9-17.)

With Phase I of R.00-10-002 resolved, the Commission could begin to consider issues like those raised by Universal's complaint. The first step in this process occurred when we issued D.02-01-057, which extended until further order the one-year deadline set forth in Pub. Util. Code § 1701.2(d) for resolving this adjudicatory matter. After noting that the issues in Phase I of R.00-10-002 had finally been disposed of, D.02-01-057 stated:

> "Now that the Phase I issues concerning the I-6 tariff have been decided . . ., there is no reason not to proceed with the issues raised by Universal's complaint. Accordingly, we will direct the assigned Administrative Law Judge (ALJ) to hold a prehearing conference (PHC) within 90 days after the mailing date of this decision. With the benefit of the PHC, the ALJ will be able to decide whether this case can be decided on the pleadings, or whether an evidentiary

> hearing will be necessary. After the PHC, the ALJ should issue a schedule for resolving this proceeding promptly." (*Mimeo.* at 4.)

Pursuant to these instructions, a PHC was held on March 26, 2002. At the PHC, the ALJ first denied Edison's motion to dismiss, concluding that the case presented too many factual issues to permit a judgment based solely on the pleadings. (PHC Transcript, p. 8.) After a discussion with the parties, the ALJ ruled that Universal should immediately commence discovery, and that both parties should advise him by June 5, 2002 whether it would be possible to submit the case on a stipulated set of facts, or whether a hearing would be necessary. If a hearing was needed, the ALJ tentatively ruled that it would be held on September 9-10, 2002. He directed Universal to serve its direct testimony on July 8, 2002, and Edison to serve its responsive testimony on August 5, 2002. (*Id.* at 18-19.)

The parties advised the ALJ that submission on a stipulated set of facts did not appear feasible, and they submitted their prepared testimony in substantial accordance with the schedule worked out at the PHC. After a hearing was held on September 9 and 10, both parties submitted opening briefs on October 23 and reply briefs on November 22, 2002.

Background on the Relationships Among the Power Markets Run by the PX and the ISO in 2000

In order to comprehend the positions of the parties in this case, some understanding is necessary of the characteristics of the "day-ahead," "hour-ahead" and "real time" power markets that were being operated in 2000.

Under the electric restructuring regime established by AB 1890, the principal market for both buyers and sellers of power was envisioned as the day-ahead market, which was run by the PX. In its testimony, Edison gives the following description (which Universal does not dispute) of how the day-ahead market operated:

> "The PX operates a day-ahead market in which bids are submitted by 7:00 a.m. on Day One for the 24-hour delivery period from midnight to midnight on Day Two. Bids for buying the quantity one desires at a specified price are submitted in price pairs. At one extreme one defines a desired quantity for purchase at the PX's maximum price of $2,500/MWh (megawatt-hour). At the other extreme, one states a quantity to be purchased at a minimum price. Since there are other opportunities to purchase power after the PX day-ahead market is closed, the system is designed so that the demand bids, in conjunction with supply offers, establish a market clearing price and quantity for each hour. After all parties' supply and demand bids are submitted in the PX, an Unconstrained Market Clearing Price (UMCP)[[2]] is established by finding the price-quantity pair that occurs at the crossing of the supply and demand curves." (Exhibit 6, p. 7.)

In addition to the day-ahead market, the PX also ran the "hour-ahead" (or "day-of") market in June 2000.[3] Edison gives the following undisputed description of this market:

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[2] As Edison also explains, the UMCP does not, standing alone, take account of transmission constraints. The PX accounted for such constraints by running a "congestion management auction," which resulted in a Zonal Market Clearing Price (ZMCP) for each separate transmission zone. After describing this congestion management process, Edison concludes:

> "Transmission congestion will cause a utility that procures power in the congested zone to receive a lower final energy allocation from the PX at a higher price than it would have in the PX's original day-ahead UMCP market. Thus, utilities in transmission congested zones get less and pay more." (*Id.* at 8.)

[3] Edison's testimony notes that "at times [the hour-ahead] market is run for blocks of hours rather than individual hours." When that occurred, the market was referred to as the "day-of" market rather than as the hour-ahead market. (*Id.* at 8, n. 3.)

> "To the extent a buyer has been unable to procure its forecasted demand from the PX day-ahead market, the PX runs an hour-ahead market. There are at least four reasons why a buyer may wish to purchase additional power (or alternatively, sell excess power) in the hour-ahead market. First, based on more current information, its forecast of demand may have changed. Second, it may not have been able to purchase its full day ahead forecast based on the prices in the day-ahead market. Third, congestion may have made the delivery of the power it intended to purchase in the day-ahead market infeasible, resulting in a schedule cut. Fourth, a supply resource scheduled to provide power in the day-ahead market may have become incapable of meeting its schedule (e.g., a forced outage of a generating unit), requiring an additional purchase from the market to make up the schedule shortfall. For each of these four cases the converse is possible, resulting in the need to sell excess power after the PX day-ahead market." (*Id.* at 8-9; footnote omitted.)

However, because the hour-ahead or day-of market was "typically illiquid" and insufficient to meet the utilities' shortfall in the day-ahead market, (*id.* at 10), Edison was frequently obliged to turn to the final power market involved in this case, the so-called "real time" market run by the ISO. Edison's testimony notes that "the use of this market is particularly risky for a buyer," because "some costs in addition to energy are allocated to purchases in the real-time market." (*Id.* at 9.)

Because the day-ahead market had a price cap of $2500 per MWh, whereas the real-time market was subject to a price cap of $750 per MWh, Edison acknowledges that it devised a bidding strategy under which it did not always seek to meet its total forecast demand in the day-ahead market, and would instead satisfy some of its demand in the hour-ahead and real-time markets. In its testimony, Edison gives the following general description of this bidding strategy:

> "SCE's objective was to purchase energy for its customers at the lowest possible cost. Accordingly, as long as no transmission congestion was anticipated, SCE submitted bids into the PX day-ahead market which would result in a purchase of 95 to 100 percent of its customers' expected energy needs in each hour through the day-ahead market, depending on SCE's forecast for the next day's PX prices and the prices SCE expected in later markets – particularly in the real-time market which was subject to a Commission [FERC]-ordered price cap. SCE would also reduce its demand bids to reflect its expectations about transmission congestion. For example, SCE would bid in a way so as to purchase as much of its needed supply as it expected to be available after the ISO completed its congestion management process. The ISO and PX Tariffs permitted demand bidders to submit to the PX demand/price curves that, under certain circumstances, would result in only a portion of a load-serving entity's forecasted demand being met ahead of real time. Where the price sellers demanded in the PX day-ahead market exceeded the price SCE was willing to pay, SCE's demand bid would result in less than 100% of its forecast load being purchased in the day-ahead market.
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> "In such circumstances, SCE would purchase some of its customers' electricity demand in the later markets. In general, SCE would bid to buy its shortfall in the PX's day-of market, though this market was typically illiquid and insufficient to meet the shortfall. In this case, some of SCE's load would ultimately be met in the ISO's real-time market. Some of SCE's load would also be met in the ISO's real-time market because of (1) transmission congestion or (2) actual load exceeding forecast load (forecast error)." (*Id.* at 10.)

Universal's Position

In its Opening Brief, Universal summarizes its position in this case as follows:

> "Universal believes that Edison's own actions were a proximate cause of the June 27 curtailment. Edison deliberately underscheduled its load requirements in the (PX) day ahead market for June 27. Edison's practice of deliberately underscheduling its

> purchases in the Power Exchange day ahead market forced the ISO to have to make up for Edison's underscheduling by purchasing more generation on the spot market. Faced with the large gap between scheduled supply and actual demand, there was a much higher and more substantial probability that the ISO would not be able to maintain the minimum five percent reserve capacity needed to avoid a Stage 2 alert, thus causing Edison's curtailment of Universal." (Universal Opening Brief, p. 4.)

Universal begins by addressing the argument that as an interruptible customer, it had no cause to complain when it was asked to curtail its service down to zero on June 27, 2000. Universal's response is that it agreed to become an interruptible customer in the mid-1990s after concluding that historically, Edison had imposed very few curtailments, and also after taking into account Edison's obligation under Rule 14 to "exercise reasonable diligence to furnish / deliver a continuous and sufficient supply of electricity to its custom-mers . . ." Universal states that like Edison's 1500 other interruptible customers, it "had no intention that it would curtail its full requirements, and the I-6 Tariff did not require such a response." Moreover, once scheduling and system reliability became the responsibility of the ISO in 1998, "Universal reasonably anticipated that interruptible status would remain secure and that [Edison] would continue to operate in accord with prudent utility practices and ISO guidelines intended to maintain system reliability." (*Id.* at 6.) However, Universal continues, that is not what happened:

> "Instead, Edison embarked on a procurement strategy that sacrificed reliability for lower prices. In effect, Edison introduced the greatly increased risk of economic curtailment into the interruptible customer relationship. Economic curtailment as practiced by Edison does not meet the 'reasonable diligence' standard required by Rule 14." (*Id.* at 6-7.)

Universal also argues that in view of the bidding strategy Edison admits it was using at the time in question here, the risk of a curtailment for economic reasons was greatly increased on June 27, 2000. Universal gives the following description of what Edison did on that day, as opposed to what Universal believes SCE should have done under a proper interpretation of Rule 14:

> "Edison's best forecast of its load for Hour 16, the peak hour, on June 27, 2000 was 13,938 MWh. Edison submitted a bid curve based on a market clearing price of $556.00 per MWh. As a result of its bidding strategy, Edison's final schedule awarded in the PX day ahead market for Hour 16 was 12,026 MWh.
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> "If Edison had submitted bids for its entire forecasted load at prices of at least $730.56 per MWh, Edison would have been able to purchase its full forecast hour 16 load. However, Edison 'would have had to pay more than $1.1 million of additional cost for hour 16 alone.' . . . It is clear that Edison was seeking to avoid the additional cost, as stated in its procurement strategy.
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> "After being awarded only 12,026 MWh in the PX's day ahead market, Edison next tried to gain additional energy in the PX day of market. Edison received only about 10% of the quantity that it required. The remaining energy would have to be purchased in the ISO real-time market, or curtailments would be necessary.
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> "Edison's lack of success in the day of market on June 27 was consistent with Edison's overall results. According to Edison's data request responses, Edison's typical success rate in the day of market was only about 46%, compared to about 97% in the day-ahead market.
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> "As stated by Stern, Edison purchased 16% of its peak hour requirements from the ISO real-time market on June 27, 2000 . . . That volume of purchases from the ISO real-time market far

> exceeded the design volume intended for that market, and contributed directly to the resulting curtailment. As the ISO [had] pleaded, Edison's actions were 'entirely unacceptable, from a reliability . . . standpoint.' (*Id.* at 9-10; citations omitted.)

Universal also points out that, as the last sentence in the preceding quotation suggests, the ISO had been very critical of the practice (used by the other California utilities as well as Edison) of capping bids in the PX day-ahead market and purchasing the balance of the energy needed to serve load in the ISO's real-time market. As evidence of the ISO's dissatisfaction with this practice – which the ISO saw as compromising reliability -- Universal points to the following cross-examination of Edison's principal witness, Gary Stern:

> "Q. Did the ISO ever express to Edison any concerns that the ISO had with Edison's scheduling practices?
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> "A. The ISO expressed concerns with the fact that the real-time market was large, and there certainly were times when the ISO blamed the load for those real-time problems.
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> "Edison and I in particular on many occasions tried to convince the ISO that they needed to look at what was happening in the PX to understand that we had no choice but to use the real-time market. Eventually the PX gave this demonstration to the Oversight Board to make that very point.
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> "So the fact that the ISO, other than the division of market analysis, was slow to pick up on this point doesn't belie the fact that supply withholding, as has been identified since 1998, was the cause of this so-called 'underscheduling of load.' One cannot purchase what is not offered for sale.
>
> "Q. So the answer to my question is 'Yes'?
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> "A. Yes." (Transcript, pp. 155-56, *quoted in* Universal's Opening Brief, p. 11.)

As the final leg in its argument, Universal points to criticism by the Federal Energy Regulatory Commission (FERC) of load underscheduling by the California utilities, and to the fact that in a December 15, 2000 order, FERC prospectively imposed a penalty on the California utilities to the extent they continued to underschedule load in the PX's day-ahead market.

Universal notes that one of the bases for FERC's conclusion that load underscheduling had contributed to the California electricity crisis was a report submitted by the ISO on September 6, 2000. This report asserted that excessive underscheduling created a reliability threat, and concluded that the volume of recent purchases in the ISO's real-time market "far exceeded" the original market design, often equaling 20-30% of total market demand rather than the 5% of total demand that the market's designers had envisioned. (Exhibit 2, p. 4; Universal Opening Brief, pp. 14-15.)

FERC's response to the ISO report came in its December 15, 2000 Order,[4] from which Universal quotes in its testimony and briefs. In particular, FERC expressed concern that "the ISO was being forced to supply a large portion of California's load at the last minute as the supplier of last resort. System operations were jeopardized as the ISO was effectively transformed from providing the imbalance services needed for reliable transmission to the supplier of last resort." (93 FERC at p. 61, 993.) To address what it saw as the problem of chronic underscheduling, FERC decided to impose a penalty on utilities that

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[4] *San Diego Gas and Electric Company (Complainant)*, Docket No. EL00-95-000 et al., Order Directing Remedies for California Wholesale Electric Markets (issued December 15, 2000), 93 FERC ¶61, 294. This order is hereinafter referred to as the "December 15, 2000 Order."

failed to purchase at least 95% of their forecast demand in the PX's day-ahead market. FERC said:

> "Market participants will be required to schedule 95 percent of their loads prior to real-time and will be subject to a penalty for deviations in scheduling in excess of five percent of an entity's hourly load requirements, with disbursement of revenues to all loads that scheduled accurately." (*Id.* at p. 61, 982.)

Although Universal acknowledges that FERC rescinded this penalty in its December 19, 2001 Order reconsidering the December 15, 2000 Order,[5] Universal emphasizes that in the December 19, 2001 Order, FERC (1) reserved the right to re-impose the penalty under appropriate circumstances, and (2) continued to assert that underscheduling in the day-ahead market had created a serious reliability problem. (Universal Opening Brief, pp. 17-18, *quoting* 97 FERC at p. 62,227.)

Universal concludes by asserting that under the relevant statutory schemes, this Commission is not free to ignore the findings of FERC or the ISO on the underscheduling issue. Universal states:

> "Regulatory jurisdiction over electricity is divided by federal law into two spheres of authority: states have regulatory authority over retail sales of electricity and the federal government has authority over interstate, i.e. wholesale sales. This scheme for dual authority is codified in the Federal Power Act, 16 USC Sec. 824-824m.
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> * * *

[5] *San Diego Gas and Electric Company (Complainant)*, Docket No. EL00-95-000 et al., Order on Clarification and Rehearing (issued December 19, 2001), 97 FERC ¶61, 275. This order is hereinafter referred to as the "December 19, 2001 Order."

> "Under this scheme, individual states are empowered to regulate retail sales as well as local distribution services involving electric power, but may not intrude on the federal government's plenary power to regulate interstate transmission and wholesale sales of electricity in interstate commerce. The federal government exercises its jurisdiction by delegating authority to the FERC, which has exclusive jurisdiction over all facilities for interstate transmission and sale of electric energy. Pursuant to this grant of jurisdiction, FERC has authority to regulate the rates, terms and conditions of interstate transmission, transportation and wholesale rates by nongovernmental entities.
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> "All of the transactions relating to the June 27 curtailment were FERC jurisdictional: i.e., the underscheduling of purchases in the PX day-ahead market, the bidding strategy in the PX day of market, the over-reliance on the ISO real-time market. The ISO found that these practices unreasonably impaired the reliability of its operations, and the FERC concurred. This Commission is bound by those findings by the ISO and the FERC and does not have the jurisdiction to overrule their findings." (Universal Opening Brief, pp. 18-19.)

Edison's Position

Although Edison takes issue with many of complainant's contentions, it particularly disputes Universal's claims that SCE had a systematic policy of underscheduling load in the day-ahead market, or that if SCE had only been willing to bid somewhat more, it could have met all of its forecast demand for June 27, 2000 in the day-ahead market. To the contrary, Edison argues, it is now clear from documents recently produced by Enron that in the summer of 2000, generators were offering to sell significantly less energy in the PX's day-ahead market than they did in 1999 and 1998. Not only could it not purchase what was not offered for sale, Edison continues, but even if there had been no price cap on SCE's bid in the day-ahead market for June 27, only an additional 65 MWh of total supply would have been forthcoming. Thus, Edison concludes, its bidding practices in the day-ahead market cannot be considered the cause of the Stage 2 alert that was called by the ISO on June 27, the event that led to the curtailment request to Universal.

In his testimony on behalf of Edison, Stern notes that the PX's Market Monitoring Committee (MMC) had begun to observe supply withholding not long after the PX was established. The MMC's March 1999 report to FERC,[6] portions of which are attached to Stern's testimony as Attachment 2, described the effects of such withholding as follows:

> "Consider, in more detail, what happens during the hours when end-use demand exceeds offered supply in the PX market . . . At such times, the supply side has substantial market power . . . [B]ecause of the shortfall of supply, buyers (principally IOUs) are forced to buy in the real-time market. This has given rise to a controversy about so-called 'load underscheduling' in the PX market; the claim is made that load servers are shifting their demand to the real-time market. But as Figure 14 shows, it would be more accurate to say that supply had been 'underoffered' in such hours. No matter what price buyers offered in the PX market, they could not have met all their needs; not enough supply was offered. Increasing their demand bid prices would serve only to increase the PX market-clearing price, with negligible effect on quantity." (Exhibit 6, Attachment 2, p. 47; *quoted in* Ex. 6, p. 11.)

Stern also discusses a study that the PX prepared and shared with the Electricity Oversight Board (EOB) in June 2000. This study compared the amount of supply available in the day-ahead market at the peak hour (*i.e.*, 4 p.m., or "hour 16") on three specific dates: August 25, 1999, June 15, 2000, and the same day at issue in this case, June 27, 2000. In Stern's view, the study

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6 *Second Report on Market Issues in the California Power Exchange Energy Markets*, filed in FERC Docket Nos. ER98-2843-006, et al., dated March 9, 1999.

demonstrates "the fact that although demand was willing to buy more, and at higher prices in 2000 . . ., there was as much as 10,000 MW less supply offered . . . This demonstrates beyond any doubt that the cause of increased real time volumes was the lack of supply offered in advance of real time, and not the bidding behavior of buyers." (Ex. 6, p. 12.)

Stern also notes that the under-supply problem was made worse by a variety of trading strategies employed by various power suppliers, strategies that came to light in 2002 when FERC released a memorandum from one of Enron's outside law firms. One of the strategies extensively employed in the California market was known as "Fat Boy." Under this strategy, Enron

> ". . . uses a phony load schedule matched against a quantity of power that it has acquired through a contract, to effectively sell that power into the real-time market of the ISO. By submitting a phony load that does not materialize, Enron has a supply that exceeds its demand, and is viewed as having a positive imbalance in the ISO's real-time market. Enron will thus be paid for effectively selling its excess power in the real-time market. But when Enron engaged in this strategy[,] it also withheld the sale of its contract power from the PX day-ahead market, making it unavailable for SCE or other buyers to purchase in advance of real time. This helped create an artificial supply shortage in the day-ahead market, thus requiring buyers like SCE to increase their purchases in the real-time market. Enron would then 'solve' the problem it created by making extra supply available at high prices at the last minute in the real-time market." (*Id.* at 14.)

Another strategy Enron used in the California market involved making out-of-state sales of power that Enron had purchased from the PX. According to Stern, "Enron would buy power out of the PX market at effectively capped prices, and sell that power out of state at higher prices, once again taking power away from the California IOU buyers in the day-ahead market, and leaving them with no choice but to meet some of their load in the real-time market." (*Id.*)

A third strategy used by Enron in California was known as "Load Shift." Stern gives the following description of it:

> "This strategy involved bidding load so as to create transmission congestion in the day ahead schedule on a path where Enron owned the transmission rights, and would thus receive payments – both for transmitting the power and for relieving the congestion they had created. The impact of this strategy on SCE's buying was that when SCE tried to buy in the day-ahead market to meet its demand in SP15 (California's southern transmission zone), congestion from Northern California to Southern California would appear to the ISO to be significant, making SCE's schedule infeasible and requiring the ISO to cut some of SCE's day ahead purchases. Since the congestion was created by phony Enron load bids, SCE's schedule would ultimately have to be met in the ISO's real-time market, where it could be characterized by naïve or sinister parties as load underscheduling." (*Id.* at 14-15.)

A final strategy used by Enron and other traders was known as "Ricochet." Stern states that "in this strategy, the sellers would schedule their California power for export outside of the ISO area in the day ahead scheduling. This would once again reduce the supply available for purchase in the PX day-ahead market, making it impossible for buyers to meet their demand without using the ISO's real-time market. The power scheduled out of the ISO area would then be 'parked' there until it could be 'imported' and sold to the ISO's real-time market." (*Id.* at 15.)

After describing Fat Boy, Load Shift, Ricochet and the other strategies that Enron officials have admitted to using in the California market,[7] Stern concludes:

> "[A]s a result of these and other withholding strategies, SCE could not have purchased its entire forecast demand through its bids in the

[7] In its Opening Brief, Edison notes that on October 17, 2002, Timothy N. Belden, former Vice President and Managing Director of Enron's West Power Trading Division, pleaded guilty in U.S. District Court in San Francisco (in Action No. CR 02-0313 MJJ) to an Information charging him with participating in a conspiracy to manipulate California energy prices by using the strategies described by Stern. In addition to pleading guilty, Belden agreed to forfeit $2.1 million, the proportional share of his compensation from Enron attributable to the scheme to defraud. As part of his plea, Belden agreed that the following facts were true:

> "Beginning in approximately 1998, and ending in approximately 2001, I and other individuals at Enron agreed to devise and implement a series of fraudulent schemes through these markets. We designed the schemes to obtain increased revenue for Enron from wholesale electricity customers and other market participants in the State of California. The schemes required us to submit false information to the PX and ISO in the electricity and ancillary services markets described above. Among other things, we knowingly and intentionally filed energy schedules that misrepresented the nature of electricity we proposed to supply, as well as the load we intended to serve. We intentionally filed schedules designed to artificially increase congestion on California transmission lines. We were paid to 'relieve' congestion when, in fact, we did not relieve it. We exported and then imported amounts of electricity generated within California in order to receive higher, out-of-state prices from the ISO when it purchased 'out-of-market.' We scheduled energy that we did not have, or did not intend to supply.
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> "As a result of these false schedules, we were able to manipulate prices in certain markets, arbitrage price differences between the markets, obtain 'congestion management' payments in excess of what we would have received with accurate schedules, and receive prices for electricity above price caps set by the ISO and the [FERC]." (Attachment 1 to Edison's Opening Brief, Plea Agreement, ¶ 2.)

Pursuant to Edison's request, we take official notice of Belden's plea and the related Information in accordance with Rule 73 of our Rules of Practice and Procedure.

> day-ahead market on June 26, 2002, and could not have avoided the use of the ISO's real-time market on June 27, regardless of any action SCE could have taken in the day-ahead market." (*Id.* at 16.)

To support this conclusion, Stern provides a quantitative analysis based on available bidding data for hour 16 in the day-ahead market for June 27. Stern asserts that his analysis demonstrates that even if Edison had been willing to bid a "vertical demand curve" -- which he defines as a bid curve that is "vertical and price-inelastic, *i.e.*, [one that tries] to purchase the full forecasted load at all price levels up to the highest limit of $2,500.00" -- Edison would not have elicited enough additional supply to avert the Stage 2 alert that was called. (*Id.* at 22.)

Stern also examined the ISO real-time market for each of the other hours on June 27, 2000. From this examination, he concluded that the imbalances between PX purchases and forecasted load from entities other than Edison were considerably larger than the imbalance shown by SCE. Thus, even if one "accept[s] the premise (which SCE asserts is false)[8] that Stage 2 conditions are

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8 Elsewhere in his testimony, Stern emphasizes that whether the ISO has the 5% operating reserve necessary to avert a Stage 2 alert is a function of the total demand on the system, not just the size of the real-time market:

> "The demand that the ISO must meet is the total demand on the system, of which the real-time market is just [a] component. While it is true that when more demand and supply are scheduled in advance of real time, less demand and supply must be scheduled in real time, it is also true that the total market determines the reserve requirement, not just the subset that is the real-time market. On June 27, 2000, there was a Stage 2 alert in California because total market demand was high (due to hot weather, limited conservation, and virtually no effective price responsive demand) and total supply was short (due to low hydro, a low level of imports because of regional needs outside California, and strategic withholding of power in California). In fact, total ISO demand reached 42,693 MW at hour 15 on June 27, 2000." (*Id.* at 29.)

the result of a large ISO real-time market, this [analysis] demonstrates that other entities were responsible for a much larger portion of the ISO imbalance than was SCE." (*Id.* at 24.)

Stern precedes his detailed analysis of June 27 with two important qualifications. First, he notes that although Universal clearly seems to be arguing that Edison should have submitted bids with a vertical demand curve, "such a curve is, in fact, unacceptable" under Rule 2.4.1.e of the PX Bidding and Bid Evaluation Protocol, because the rule provides that "for Demand Bids, the piece-wise linear curve . . . must have a *downward* slope." (*Id.* at 22; emphasis added.)

Second,

> ". . . all other day-ahead bids submitted for June 27, 2000, both supply and demand, by other UDCs [*i.e.*, utility distribution companies] and market participants are assumed unchanged because SCE had no way to know, and certainly no way to change, their bids. This assumption, in fact, is necessary to show the impact that SCE's action alone would have had on the interruption." (*Id.*)

After reconstructing the aggregate demand and supply curves for hour 16 in the day-ahead market for June 27, and replacing Edison's original demand bid curve with a vertical bid curve, Stern concludes:

> "If SCE had offered to pay any price to purchase its full forecast hour 16 load, *i.e.*, if it had submitted a vertical demand bid curve, the PX DA market for hour 16 would have increased by only 65 MWh due to limited supply offers. This implies that the ISO real-time market for that hour would have been reduced by a mere 65 MWh. This would definitely not have reduced the risk of I-6 [tariff] interruption, even if one accepts the premise that I-6 interruptions were due to a large ISO real-time market, since the statewide 'underscheduled' amount for hour 16, *i.e.*, the size of the ISO real-time market, was more than 8,000 MWh. In other words, if SCE had submitted a bid with a vertical demand curve, as suggested by Universal, the size of the ISO real-time market would have been reduced by less than one percent. This would have had no impact at all on the risk of an I-6 interruption. While such a bid would have allocated more supply to SCE,[9] it would have resulted in less

9 During cross-examination, Stern estimated that if Edison had been allowed to submit a vertical bid demand curve, it would have obtained about 250 additional MWh, while other purchasers' allocations would have been reduced by the PX:

> "My understanding is that Edison would have acquired perhaps an additional 250 megawatt-hours, but other participants would have had their purchases reduced by some 175 or 180 megawatt-hours, such that the resulting total, the clearing price in the . . . PX's market for that hour would have only changed by 65 megawatt-hours." (Tr. 172-73.)

> supply to other participants, with only a new 65 MWh (approximately 0.2%) increase in total PX supply." (*Id.* at 22-23.)[10]

Stern also concludes that if one compares Edison's PX imbalances with total PX imbalances for all of the hours during June 27, 2000, it is clear that Edison played only a small role in bringing about the Stage 2 alert on that day:

> "[T]he imbalances from entities other than SCE are considerably larger than the imbalance from SCE. If one were to accept the premise (which SCE asserts is false) that Stage 2 conditions are the result of a large ISO real-time market, this graph demonstrates that other entities were responsible for a much larger portion of the ISO imbalance than was SCE. As noted previously, no bidding strategy by SCE could have reduced the ISO's imbalance appreciably on that day . . . Moreover, SCE's imbalance made up only a fraction of the total PX (or ISO) imbalance. Universal has not demonstrated how it is that SCE was the entity responsible for the large ISO imbalance that Universal asserts precipitated the Stage 2 condition on June 27." (*Id.* at 24.)

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[10] Like the MMC report cited in footnote 6 and discussed in the accompanying text, Stern also concludes that even if the PX's rules had allowed Edison to bid a vertical demand curve in the day-ahead market, such a bid would only have increased the price Edison had to pay:

> "Assuming SCE had been successful in its vertical demand bid, and assuming there had been no congestion management, SCE would then have been able to purchase its full forecast hour 16 load of 13,938 MWh at the [market clearing price] of $730.56 . . . However, this would have meant an increase in price of $80.56 per MWh from the original price of $650.00. Thus, SCE would have had to pay more than $1.1 million of additional cost for hour 16 alone. Compared to the penalty of $395,409.60 that Universal Studios refused to pay for continuing to operate during an interruption that lasted almost 3½ hours, the additional cost that SCE would have had to pay for hour 16 alone was almost three times as much." (*Id.* at 23.)

Stern closes by pointing out that at least three independent reports have concluded that Stage 2 alerts like the one experienced on June 27 were principally the result of the tight statewide electric supplies that had been evident since the spring:

> "The ISO declares a Stage 2 condition whenever it has insufficient resources to maintain 5% operating reserves. In order to find the cause of the June 27, 2000 Stage 2 declaration, one must examine the demand and supply conditions on that date.
>
> "Among other studies, the GAO report issued in June 2002 describes the supply demand balance as so tight as to reach scarcity beginning in May of 2000. This GAO report, the PX report of September, 2000, and the FERC Staff Report issued November 2, 2000 all agree that this tightness of available supply to meet an increasing demand beginning in May of 2000 contributed to the price spikes and reliability problems faced by the ISO, as well as the necessity for the ISO to declare Stage 2 emergencies. According to these varied sources, these conditions clearly existed in June of 2000. It is these conditions, not any bidding approaches employed by SCE, that caused the Stage 2 condition leading to the call for Universal to interrupt its load on June 27, 2000." (*Id.* at 28-29.)

Discussion

We begin by pointing out that, contrary to some suggestions in Universal's briefs, this proceeding is not a tort case, but a tariff interpretation case in which two potentially conflicting provisions in an Edison tariff rule must be reconciled. SCE Rule 14 requires Edison to "exercise reasonable diligence to furnish / deliver a continuous and sufficient supply of electricity to its customers and to avoid any shortage or interruption of delivery thereof." However, the very next sentence of the rule states:

> "[Edison] cannot, however, guarantee a continuous or sufficient supply [of electricity] or freedom from interruption. SCE will not be

> liable for interruption or shortage of supply, nor for any loss or damage occasioned thereby, if such interruption or shortage results from any cause not within its control."

Although Universal acknowledges that there is an inherent tension between reliability and price, it argues that Edison's power purchasing practices in the day-ahead market for June 27 did not meet the test for "reasonable diligence," and were the proximate cause of the Stage 2 alert called by the ISO on that day. After noting on page 6 of its Reply Brief that "over 2000 MWh were available at a market clearing price of $1,500 per MWh and additional supplies would have been available at prices above $1,500 per MWh" in the day-ahead market for the peak hour on June 27,[11] Universal concludes:

> "In the abstract, it may be debatable where to find the balance between reliability and price, but this proceeding is not about where that balance might be. In the real world that issue has been resolved by Edison's Tariff Rule 14.

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[11] As support for this assertion, Universal cites Exhibit 10, which is the actual bid curve (showing both demand and supply bids) for Hour 16 in the day-ahead market for June 27. During cross-examination, Stern testified that he had reached the conclusion that a vertical demand bid curve would have elicited only 65 MWh of additional supply by substituting a vertical demand bid curve for the actual Edison bid curve reflected in Exhibit 10. (Tr. 175.)

As noted in the text, we accept Edison's analysis that during Hour 16, even if a vertical demand bid curve from SCE had been acceptable under the PX's rules, it would have elicited only 65 MWh of additional supply. It should also be noted that our own examination of the actual bid curve shown in Exhibit 10 indicates that at $1500 per MWh, the amount of additional supply that would have been offered was about 900 MWh, rather than the 2000 MWh claimed by Universal. Moreover, the actual supply bid curve is nearly vertical between $1500 / MWh and $2500 / MWh; *i.e.*, a willingness to pay $1000 per MWh more would have elicited only tiny increments of supply.

> "Edison's Rule 14 obligates Edison to exercise reasonable diligence to furnish a continuous supply of power. That obligation is not couched in terms of price. Additional supplies were available to Edison in the PX's day ahead market. Economic curtailment was not an acceptable utility procurement practice under Rule 14." (Universal Reply Brief, p. 9.)

Thus, Universal's position seems to be that if energy was available in the day-ahead market, Edison was obliged to purchase it, no matter what the price, in order to meet its obligation to exercise reasonable diligence in delivering power to customers.

Universal's interpretation of Rule 14 is at odds with the evolution of interruptible rate programs that we described in D.01-04-006, our order in Phase I of R.00-10-002. In D.01-04-066, we decided to lift the suspension we had imposed in D.00-10-066 on the right of Edison's interruptible customers to make an annual election whether to opt out of SCE's I-6 tariff (or to adjust Firm Service Levels) partly because, owing to the dramatic increase in curtailments in 2000 and 2001, "the electricity system is operating outside any reasonable bounds, or any realistic assumption customers could have been expected to use" in making their opt-out decisions. (*Id.* at 14.)

In restoring opt-out rights, we noted that Commission expectations about the role of interruptible programs had changed in the late 1990s with the advent of electric restructuring. We pointed out that in 1998, because of the "transformation of the electricity market (e.g., deregulation, creation of ISO and Power Exchange)," we reduced from five years to one year the amount of notice that customers who wished to leave Edison's interruptible program were required to give. We also noted that after this change (and the curtailment requests I-6 customers experienced during the summer of 1998), SCE's interruptible customers "began to rely on the ability to reassess their situation annually." (*Id.* at 13-14.)

In the light of this history, we find no merit in Universal's argument that because there had been few curtailments prior to electric restructuring, "Universal reasonably anticipated that [its] interruptible status would remain secure." (Universal Opening Brief at 6.) Moreover, in view of the 1998 changes in the I-6 program, Universal is clearly exaggerating when it says that it "and other [I-6] customers could not know that their service reliability expectations had been severely compromised" by the changes in how Edison operated after the ISO assumed responsibility for what had been SCE's control area. (Universal Reply Brief at 2.)

Although it stops just short of saying so, Universal's position boils down to an assertion that by virtue of Rule 14, it became the beneficiary of a contract under which Edison guaranteed that, no matter what might happen, the frequency of curtailments would be no greater than when Universal first entered the interruptible program. In light of the language of Rule 14 itself and the above-noted changes to SCE's interruptible program, this is not a reasonable position. And as a corollary of this conclusion, the fact that a small additional amount of energy may have been available on June 27, 2000 does not mean that under Rule 14, Edison was obliged to purchase it regardless of price.

In any case, we do not think Universal has met its burden of proving that Edison could have purchased enough additional energy in the day-ahead market for June 27 to avert a Stage 2 alert. In order to prevail on its claim that Edison has not complied with Rule 14, Universal must show that (1) Edison could have met its forecast demand in the day-ahead market for June 27 by submitting a higher bid that would have been acceptable under the PX's rules, (2) Edison's meeting its forecast demand in the day-ahead market would have obviated the need for a curtailment request to I-6 customers, and (3) in view of all the circumstances, Edison acted unreasonably by failing to submit a higher bid.

Universal has not made that showing here. Edison's testimony clearly establishes that (1) based on the information available to it on June 26, SCE would have had to submit a vertical demand bid curve in the day-ahead market to have any assurance of obtaining enough energy to meet all of its forecast load for June 27, (2) the PX's rules did not allow Edison to submit a vertical demand bid curve, (3) even if the rules had allowed a vertical demand bid curve, the supply curve that has subsequently become available indicates that such a bid by Edison would have induced only an additional 65 MWh of total supply during the peak hour, (4) if Edison had submitted a vertical demand bid curve, the 250 MWh of additional supply it might have obtained would have been offset by a reduction of 175-185 MWh in the amounts awarded to other bidders, and (5) the Stage 2 alert called on June 27 came about as the result of a statewide energy shortage of at least 8,000 MWh. Since the most aggressive bidding by SCE that was theoretically possible would have increased total supply in the day-ahead market's peak hour by only 65 MWh, Edison's failure to submit a higher bid curve in that market cannot be considered the cause of the Stage 2 alert.

In its briefs and during the cross-examination of Gary Stern, Universal made several attempts to undermine his testimony on these points. For example, Universal did elicit an admission that the testimony of its witness did not specifically advocate the use of a vertical demand bid curve. (Tr. 171.) However, as Stern testified, that was the logical implication of Universal's testimony, and if it was advocating something less, then even less than 65 additional MWh would have become available:

> "What [Universal] does is provide the implication that Edison was somehow unreasonable and in violation of Tariff 14 because of underscheduling. Thus, the logical inference is that Universal believes Edison should have been willing to pay any price in order to minimize underscheduling. The only way to pay . . . any price to minimize underscheduling would have been to bid a vertical demand curve at $2,500.
>
> * * *
>
> "And if Universal [meant] something less than this, then the resulting change would have been something less than 65 megawatt-hours. So what I intend to prove here is that there is nothing that was within Edison's capability to acquire sufficient power to avoid the underscheduling or purchases from the real-time market to any significant degree. And therefore, what it appears that Universal is implying that Edison should have done[,] was not possible." (Tr. 171-172.)

On page 9 of its Opening Brief, Universal asserts that "if Edison had submitted bids for its entire forecasted load at prices of at least $730.56 per MWh, Edison would have been able to purchase its full forecast hour 16 [*i.e.*, peak] load." This assertion is based upon a statement in Stern's testimony that "assuming Edison had been successful in its vertical demand bid, and assuming there had been no congestion management, SCE would then have been able to purchase its full forecast hour 16 load of 13,938 MWh at the [market-clearing price] of $730.56, in the PX day-ahead market." (Ex. 6, p.23, lines 12-15.)

However, it is obvious from examining the section of his testimony in which this statement appears that Stern did not consider such a purchase a realistic possibility. First, as he had previously testified, the PX's rules did not allow Edison to submit a vertical demand bid curve. Second, Stern made clear that the amount of energy available to bidders at particular times in particular market zones was often reduced due to transmission constraints.[12] (*Id.* at p. 8, lines 1-17; p. 22, lines 9-13.) Thus, for Universal to suggest that Edison could have purchased enough energy to meet its forecast demand during the peak hour if only SCE had submitted a bid of at least $730.56 per MWh is a serious mischaracterization of Stern's testimony.

Universal's third line of attack is to argue that, since Edison assumed all of the other buyers' bids in the day-ahead market remained constant, Edison's analysis is unsound. The reason the analysis is unsound, Universal asserts, is because it assumes that Pacific Gas and Electric Company (PG&E) would also continue its underscheduling practices:

> "[E]ven taken at face value[,] Edison's claims do not exonerate Edison. Edison's calculations assume that PG&E would continue to underschedule, which only confirms [Edison's and PG&E's] respective roles as concurrent tortfeasors . . . It is no defense for Edison that PG&E's actions also contributed to the putative supply failure." (Universal Reply Brief, p. 8.)

As stated below, we agree with Edison that during 2000, its difficulty in purchasing enough energy in the day-ahead market to meet forecasted load was a function of under-supply (*i.e.*, sellers withholding from the PX energy they had offered in the past) rather than of underscheduling (*i.e.*, utilities purchasing from the PX significantly less than their forecasted load in the hope of obtaining a

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[12] Indeed, in his description of what actually occurred in the day-ahead market for June 27, Stern notes that because of transmission constraints in the SP15 Zone, Edison's initial award of 12,690 MWh at an unconstrained price of $650.00 was reduced to 12,026 MWh at a constrained price of $653.00, and that "no additional supply was available to SP15 due to these transmission constraints." (Ex. 6, pp. 20-21.)

better price in the ISO's real-time market). In any case, we agree with Stern that one cannot undertake the type of hypothetical analysis he conducted without keeping some factors constant, and that in this case one of the factors that needs to remain constant is the demand bid curves submitted by the other utilities:

> "In this analysis, all other day-ahead bids submitted for June 27, 2000, both supply and demand, by other UDCs and market participants are assumed unchanged because SCE had no way to know, and certainly no way to change, their bids. This assumption, in fact, is necessary to show the impact that SCE's action ALONE would have had on the interruption." (Ex. 6, p. 22, lines 14-19.)

For all of these reasons, we conclude that none of Universal's criticisms undermine the validity of Stern's testimony. Even if the rules had allowed Edison to submit a vertical demand bid curve, the supply curves made available after-the-fact demonstrate that SCE could not have purchased enough energy in the June 27 day-ahead market to meet its forecasted load. Further, since the 5% reserve margin necessary to avoid a Stage 2 alert is computed on the basis of the ISO's system-wide demand rather than on the size of the real-time market alone, and the hypothetical use of a vertical demand bid curve would have elicited only an additional 65 MWh of supply, we find that SCE's scheduling practices in the June 27 day-ahead market did not cause or significantly contribute to the Stage 2 alert called on June 27.[13] Thus, Edison has established that its power shortage on that day was due, in Rule 14's words, to a cause "not within [SCE's] control."

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[13] In its opening brief, Universal argues that we cannot rule in Edison's favor here without also considering trading activity in the PX's day-of or hour-ahead market, and that when we do so, it will be clear SCE has not met its burden of proof:

> "Edison's attempted proof of futility [in the day-ahead market] is deficient regardless of the legal standard applied. Edison presented no evidence

Footnote continued on next page

Perhaps sensing the weakness of its case about what was really possible in the day-ahead market for June 27, Universal has placed great emphasis on (1) the FERC's December 15, 2000 Order that prospectively imposed penalties on PG&E, Edison and San Diego Gas & Electric Company (SDG&E) if they did not schedule 95% of their forecasted load in the day-ahead market, and (2) statements made

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> regarding what might have been the result in the PX day[-]of market if it had been willing to pay a higher price. Without that additional evidence it is not possible for this Commission to find that Edison would not have been able to purchase its full requirements from the PX." (Universal Opening Brief, p. 22.)

This argument misstates who has the burden of going forward. In his prepared testimony, Stern quoted an SCE data response to FERC pointing out that when Edison could not meet its forecasted load in the day-ahead market, it sought to purchase in the day-of or hour-ahead market. However, the data response continued, "this market was typically illiquid and insufficient to meet the shortfall." (Ex. 6, p. 10, lines 32-33.) Stern also testified that on June 27, 2000, Edison was able to obtain only 214 MWh of the 2037 MWh it had sought in the day-of market at a market-clearing price of $750 / MWh. (*Id.* at p.21, lines 3-9.)

Even though Universal was aware of Edison's position about the limited usefulness of the day-of market, Universal did not provide rebuttal testimony on the issue, nor did its counsel conduct any cross-examination on the matter. Accordingly, Universal has not met its burden of going forward on this issue. If Universal was dissatisfied with Stern's testimony that the day-of market was not a useful resource, then in view of Stern's extensive analysis, the burden was on Universal to demonstrate, either through rebuttal testimony or cross-examination, that Edison might have been able to purchase enough additional power at a higher price in the day-of market on June 27 to have made a difference. *See*, *Coachella Valley Communications v. U S Sprint*, D.92-08-018, 45 CPUC2d 258, 261 (complainant that failed to furnish call detail could not rely on general claims of overbilling in its complaint to meet its burden of proof once the defendant had offered rebuttal evidence); *Re Pacific Bell*, D.87-12-067, 27 CPUC2d 1, 22 (in a rate case, "where other parties propose a result different from that asserted by the utility, they have the burden of going forward to produce evidence, distinct from the ultimate burden of proof.") Universal's failure to offer any evidence to rebut Stern on the day-of market means that we may accept his testimony about its illiquidity, including on June 27.

by the ISO and FERC during 2000 and 2001 that these three utilities were all guilty of underscheduling, and that this practice had created a reliability threat. Based on the December 15, 2000 FERC order and these statements (which complainant claims we cannot question due to principles of federal jurisdiction), Universal argues that it is clear Edison's own conduct was a proximate cause of the conditions leading to the June 27 Stage 2 alert, that the role played by other factors (such as market manipulation by Enron) does not absolve Edison of liability for its conduct, and therefore that Edison did not meet its obligations under Rule 14.

In our view, none of these arguments overcome the evidence Edison has presented. Universal's argument with respect to FERC's December 15, 2000 Order is particularly weak. As Stern noted in his testimony, the penalty that FERC prospectively imposed for "underscheduling" had precisely the opposite effect of what FERC had intended:

> "By penalizing load [i.e., utilities] up to $100 / MWh in the real-time market, the FERC was providing sellers the opportunity to raise their prices in the day-ahead market even more, since they now knew that utilities who refused their offers would be subject to this penalty. As SCE had warned in its pleadings to FERC, the penalty, along with the soft cap 'price mitigation,' backfired, and the reliability problems and skyrocketing prices reached new heights during January and February 2001." (Ex. 6, p. 18.)

The nature of these reliability problems are set forth in Exhibit 5, which Universal sponsored. Edison vividly summarizes the data in Exhibit 5 as follows:

> "Between the time the [FERC] order was issued in December 2000 until it was significantly modified in June 2001, California suffered some 85 Stage 1 alerts, 78 Stage 2 alerts, and 39 Stage 3 alerts, as well as 6 days of rolling blackouts. This level of alerts and blackouts had

> never been experienced in the entire history of the state, and reflects the degree of chaos that was unleashed on California by FERC's order." (Edison Reply Brief, p. 14; footnotes omitted.)

As Edison has emphasized (and Universal acknowledges), the resultant chaos caused FERC to make substantial modifications to the December 15, 2000 Order in June 2001, and then to eliminate the underscheduling penalty altogether in the December 19, 2001 Order. In light of this history, we agree with Stern that "the fact FERC made a serious error in December 2000, which it later rectified, does not support a conclusion that SCE acted inappropriately in its scheduling practices in June 2000." (Ex. 6, p. 18.)

We also find unpersuasive Universal's argument that, as a memo on trading strategies by Enron's counsel contended,[14] supply withholding by generators was merely a response to utility underscheduling. (Universal Opening Brief, p. 12.) As Stern noted, an hour-by-hour comparison of the amounts of energy offered to the PX on August 25, 1999 with those offered on June 15 and June 27, 2000 shows that on average, about 10,000 MWh less was offered for the days in 2000, even though purchasers were willing to pay significantly more in 2000. (Ex. 6, p. 15.) Further, as Stern also points out, generators such as Enron had an incentive to mislead regulators into believing that highly-profitable trading strategies such as Fat Boy, Load Shift and Ricochet were merely defensive responses to utility underscheduling. (*Id.* at 15-16.) We also note that the guilty plea by former Enron vice president Timothy Belden

[14] The Enron counsel's memo is included as Attachment 5 to Stern's testimony (Ex. 6), and the assertion that strategies such as Fat Boy were a response to utility underscheduling appears at pages 2-3 thereof.

(which is quoted in footnote 7) significantly undercuts the argument that Enron's trading strategies were merely responses to underscheduling.

Belden's guilty plea is not the only admission by an energy trader that supply withholding was happening in the day-ahead market during 2000. In January 2003, FERC approved a settlement between its staff and various companies in the Reliant Energy Wholesale Group (Reliant) in which the latter admitted that on June 20 and 21, 2000 -- *i.e.*, within a week before the date at issue here -- two Reliant affiliates purposefully withheld available capacity from the PX day-ahead market for the express purpose of driving up the prices paid in that market.

In approving the staff settlement, FERC noted both the circumstances that had motivated such behavior and the evidence indicating it had occurred:

> "The amounts bid into the CalPX day-ahead market reveal the extent of Reliant's withholding. For the weekdays of the prior two-week period, Reliant bid an average of approximately 1130 MW in the CalPX day-ahead market with a high of 1800 MW and a low of 950 MW. On June 21 and 22, 2000, Reliant sold an average of approximately 130 MW in the CalPX day-ahead market with a high of 550 MW and a low of zero in 25 of the hours.
>
> "Statements made by some of Reliant's traders demonstrate that the reason for reducing capacity bids was to increase CalPX day-ahead prices in order to mitigate losses in Reliant's existing forward positions. The transcripts clearly state the market manipulation strategy and goal, including the use of such terms as: (1) 'market manipulation attempts on our part,' (2) 'we decided that the prices were too low on the daily market so we shut down . . .;' and (3) 'everybody thought it was really exciting that we were gonna play some market power.' Thus, Reliant employees intentionally withheld capacity from the day-ahead market to manipulate prices. Reliant has agreed to pay the CalPX customers who suffered financially as a result of the Reliant traders' actions and to ensure

> that similar trading activities will not recur." (Order Approving Stipulation and Consent Agreement, Docket No. PA02-2-001, 102 FERC ¶ 61, 108 at p. 61,287; footnote omitted.)

In evaluating what happened on June 27, 2000, Universal would have us give conclusive weight to statements made several years ago by FERC and the ISO that were critical of utility underscheduling, even though these statements were made well before the evidence about Reliant's and Enron's trading practices came to light. Such a result would make no sense, and the principles of federal jurisdiction cited by Universal do not require it.

We close with the observation that because of the complex events that occurred in the markets run by the PX and the ISO during 2000, we think that the formulation of proximate cause on which Universal ultimately relies in this case cuts much too broadly. Universal argues that the test for proximate cause is whether the conduct at issue can be considered a "substantial factor" in bringing about the harm complained of, and relies on the statement in *Osborn v. Irwin Memorial Blood Bank* (1992) 5 Cal.App.4th 234, 253, that "[c]onduct can be considered a substantial factor in bringing about harm if it 'has created a force or series of forces which are in continuous and active operation up to the time of the harm' (Rest. 2d Torts, § 433, subd. (b)), or stated another way, 'the effects of the actor's negligent conduct actively and continuously operate to bring about harm to another,' (Rest.2d Torts, § 439, 433, com. e.)." Universal argues that because "Edison's actions [since 1998] had contributed to a series of forces that were in continuous and active operation up to" June 27, 2000, SCE should be held responsible for the fact it could not obtain enough energy to serve forecasted load in the day-ahead market for June 27, even though other factors may also have contributed to its difficulties in this regard. (Universal Opening Brief, pp. 21-22.)

Proximate cause is predominantly a tort concept, and has rarely if ever been applied by the Commission in tariff interpretation cases, which more nearly resemble contract disputes. Even in proceedings with a tort-like flavor (such as reasonableness reviews), the Commission has made it clear that we are not automatically bound to apply the same tort concepts that a civil court would employ. *See, e.g., Re Southern California Edison Company*, D.94-03-048, 53 CPUC2d 452, 466-67, 479. In any event, however, Universal's formulation of the proximate cause standard is too amorphous to apply to the complex events that took place in the power markets in 1998 and 1999. As Professors Prosser and Keeton have stated:

> "'Proximate cause' – in itself an unfortunate term – is merely the limitation which the courts have placed upon the actor's responsibility for the consequences of the actor's conduct. In a philosophical sense, the consequences of an act go forward to eternity, and the causes of an event go back to the dawn of human events, and beyond. But any attempt to impose responsibility upon such a basis would result in infinite liability for all wrongful acts, and would 'set society on edge and fill the courts with endless litigation.' As a practical matter, legal responsibility must be limited to those causes which are so closely connected with the result and of such significance that the law is justified in imposing liability." (Prosser and Keeton, THE LAW OF TORTS (5th ed. 1984), § 41, p. 264; footnote omitted.)

The issue we are required to decide in this case is what obligations Rule 14 imposed on Edison on June 27, 2000, not during the two-year period leading up to that date. For example, while Edison may have had an incentive in 1998 and 1999 to minimize its purchased power costs to accelerate the recovery of Competitive Transition Charges -- as Universal alleged and Stern admitted (Universal Opening Brief, pp. 19-20; Tr. 127-128) -- that incentive had vanished by May 2000, when power costs in the PX market consistently began to exceed

Edison's frozen retail rates. By November 2000, Edison's solvency was at stake. Stern is correct that if, in connection with June 27, 2000, Rule 14 were to be interpreted to impose on Edison the obligations that Universal claims, then the implication would be that Edison should have reached insolvency sooner than it did. (Ex. 6, pp. 27-28.)

Universal's proximate cause argument also ignores the changes that had come about in the demand-supply balance in the markets by June 2000. Stern's evidence is compelling that by that time, significantly less energy was being offered during the peak hour in the day-ahead market than had been offered the year before. (*Id.* at 15-16.) The guilty plea by Timothy Belden of Enron and the Reliant settlement with the FERC staff confirm this. Universal did not rebut Stern's evidence that even if SCE had been allowed to submit a vertical demand bid curve for the peak hour in the June 27 day-ahead market, the most it could have obtained would have been about 250 additional MWh, with other bidders' allocations being reduced by about 185 MWh. This clearly would not have been enough to avert the Stage 2 alert.[15]

Thus, we conclude that Universal has not proven that Edison breached its duties under Rule 14 in connection with the PX's day-ahead power market for June 27, 2000. Accordingly, the $395,409.60 excess energy charge that Edison imposed on Universal is valid, and this penalty must now be paid to Edison.

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[15] We also reject Universal's argument that Edison had a systematic policy of reducing purchased power costs by relying on curtailment requests to I-6 customers. (Ex. 1, pp. 12-14; Universal Opening Brief, pp. 19-20, 23-24.) As Stern noted during cross-examination, a Stage 2 curtailment imposes significant additional costs on Edison, costs that dwarf the savings achievable through reduced purchased power costs. (Tr. 133-134.)

Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and A. Kirk McKenzie is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. In D.02-01-057, the Commission extended the one-year deadline applicable to this proceeding pursuant to Pub. Util. Code § 1701.2(d).

2. On June 27, 2000, Universal was a sub-transmission customer of Edison taking service pursuant to SCE's Tariff Schedule I-6, which provides for interruptible service to large customers.

3. A customer taking service under Schedule I-6 is obliged to reduce its energy use down to the customer's Firm Service Level (FSL) when requested to do so by Edison, or else pay excess energy charges as set forth in the schedule.

4. Edison's Tariff Rule 14 requires SCE to use reasonable diligence in delivering a continuous and sufficient supply of electricity to its customers and to avoid any shortage or interruption of delivery of such electricity, but also states that Edison does not guarantee a sufficient or continuous supply, and is not liable for any interruption or supply shortage (or for loss or damage occasioned thereby) if the interruption or shortage results from a cause not within Edison's control.

5. SCE's Tariff Rule 14 was applicable to customers taking service under the I-6 schedule.

6. On June 27, 2000, the ISO declared a Stage 2 alert, pursuant to which Edison asked customers taking service under the I-6 schedule to reduce their respective energy usages down to the applicable FSLs.

7. Prior to June 27, 2000, Universal had set its FSL at zero.

8. On June 27, 2000, Universal did not curtail its energy usage down to zero when asked to do so by Edison.

9. Pursuant to the I-6 schedule, Edison billed Universal for an excess energy charge of $395,409.60.

10. Universal refused to pay Edison the aforesaid excess energy charge and instead filed the instant complaint.

11. On September 12, 2002, Universal deposited the sum representing the disputed excess energy charge, $395,409.60, with the Commission's Fiscal Office.

12. In 1998, the Commission reduced from five years to one year the amount of notice that an Edison customer taking service under the I-6 schedule was required to give either to leave the interruptible program, or to reduce the customer's FSL.

13. In D.00-10-066, the Commission suspended the right of Edison customers taking service under Schedule I-6 to make an annual election about whether to continue taking interruptible service, or to adjust the customer's FSL.

14. In D.01-04-006, the Commission concluded that customers taking service under Schedule I-6 should once again have the right to make an annual election about whether to continue taking interruptible service or to adjust FSLs, and made this right retroactive to November 1, 2000. The Commission also decided that I-6 customers would remain liable for any excess energy charges that Edison had imposed through November 1, 2000.

15. Under the electric restructuring regime established by AB 1890, the principal market for both sellers of power and utilities seeking to serve load was envisioned to be the day-ahead market, which was run by the PX. In the day-ahead market, both buyers and sellers submitted bids on Day One for the 24-hour delivery period commencing at midnight on Day Two. Based on the

matching of buyer and seller bids, the PX would then establish an Unconstrained Market Clearing Price (UMCP) for each hour in Day Two.

16. To account for transmission constraints in the applicable transmission zones, the PX would also run a congestion management auction when necessary, which resulted in a Zonal Market Clearing Price (ZMCP) for each transmission zone. In general, transmission congestion caused utilities procuring power in a congested zone to receive a lower final energy allocation from the PX, and at a higher price, than would have been the case without the congestion.

17. To the extent a buyer was unable to procure its forecasted demand from the day-ahead market, the buyer could turn to the hour-ahead market, which was also run by the PX. When the hour-ahead market was run for blocks of hours rather than individual hours, it was referred to as the day-of market. Use of this market allowed both buyers and sellers to adjust for late-breaking developments such as updated demand forecasts, reductions in PX power allocations due to congestion management, and the sudden unavailability of supply resources that had been scheduled in the day-ahead market. In general, the day-of market was illiquid and insufficient to meet the utilities' shortfall from the day-ahead market.

18. To the extent utilities could not meet their demand for power in either the day-ahead or the day-of market, they were obliged to turn to the real time market, which was run by the ISO.

19. Because the day-ahead market had a price cap of $2500 per MWh, whereas the real-time market was subject to a price cap of $750 per MWh, Edison devised a bidding strategy in 1998 under which it did not always seek to meet its total forecast demand in the day-ahead market, but instead satisfied a portion of this demand in the day-of market or, more often, in the real-time market. Under

this bidding strategy, Edison sought to purchase 95% to 100% of its forecast demand in the day-ahead market (depending on expected prices and transmission constraints), with the rest being purchased in the day-of and real-time markets.

20. From the early 1990s until the summer of 1998, Edison made no curtailment requests to its I-6 customers. In the summer of 1998, Edison interruptible customers were asked to curtail on four occasions.

21. When the ISO calls a Stage 2 alert and Edison's I-6 customers are asked to curtail, the additional costs that the Stage 2 alert imposes on Edison exceed the savings that SCE realizes as a result of having to purchase less power to serve the I-6 customers.

22. On several occasions in 1999 and 2000, the ISO conveyed its concerns to Edison that the volume of SCE's power purchases in the real-time market was exceeding the design parameters for that market, a situation that ISO management thought might lead to reliability problems. The ISO's Division of Market Analysis did not concur with this viewpoint.

23. Beginning in May 2000, Edison's purchased power costs regularly began to exceed the generation component of its I-6 rate and other rates.

24. The PX's Market Monitoring Committee began to observe supply withholding in the day-ahead market shortly after the PX was established in 1998.

25. A study that the PX prepared for the EOB indicates that the amount of supply offered during the peak hours on June 15 and June 27, 2000 was approximately 10,000 MWh less than the amount of supply offered during the peak hour about ten months earlier, on August 25, 1999.

26. A memorandum prepared by Enron's outside counsel and released by FERC staff in May 2002 indicates that between 1998 and 2000, Enron's energy trading company engaged in a variety of trading strategies that were designed to reduce the amount of power Enron would have to offer in the PX's day-ahead market, and to shift that power to the real-time market, where it would fetch higher prices. These strategies included Fat Boy, Load Shift and Ricochet.

27. On October 17, 2002, Timothy N. Belden, former Vice President and Managing Director of Enron's West Power Trading Division, pleaded guilty in U.S. District Court in San Francisco to an Information charging him with participation in a conspiracy designed to manipulate California energy prices by using strategies including Fat Boy, Load Shift and Ricochet. Belden admitted that this conspiracy had lasted from 1998 to 2001.

28. On June 26, 2000, Edison forecasted that its load during the peak hour on June 27, 2000 would be 13,938 MWh. Edison submitted a bid curve that included a bid for this amount at a UMCP of $556/MWh, and lesser amounts at higher prices. The initial preferred schedule in the day-ahead market awarded Edison 12,690 MWh at a UMCP of $650, but owing to congestion management, the final schedule reduced Edison's allocation to 12,026 MWh at a ZMCP of $653. Edison sought to obtain 2037 MWh, the balance of its revised forecast of peak hour demand for June 27, in the PX's day-of market, but was awarded only 214 MWh at a price of $750/MWh.

29. Metered demand for the peak hour on June 27 was 14,576 MWh, which indicates that for that hour, Edison had to purchase 2,336 MWh in the ISO's real-time market.

30. The PX's rules did not allow Edison to submit a vertical demand bid curve in the day-ahead market, *i.e.*, a bid curve that is vertical and price-inelastic,

such that the bidder is willing to purchase its full forecasted load up to the PX's limit of $2500 per MWh.

31. Even if the PX's rules had allowed Edison to submit a vertical demand bid curve in the day-ahead market for June 27, 2000, Edison's unrefuted analysis indicates that total supply during the peak hour would have increased by only about 65 MWh, with Edison being awarded about 250 MWh more and other bidders about 175-185 MWh less.

32. In conducting its analysis of the June 27 peak hour, it was reasonable for Edison to assume that bids by other suppliers and purchasers would remain the same, since Edison had no way to change these bids, or to know how different conditions might have led to different bids.

33. Universal's Opening Brief mischaracterizes Edison's testimony when it states that if Edison had submitted a bid of at least $730.56 per MWh for SCE's entire forecast load for the June 27, 2000 peak hour, Edison would have been able to purchase its entire forecast load for that hour.

34. Edison could not have purchased its full forecast demand for the peak hour in the day-ahead market for June 27, 2000, even if it had submitted a bid for the entire load at a price of $730.56 per MWh.

35. The day-of market for June 27, 2000 was illiquid and insufficient to meet Edison's shortfall in the day-ahead market.

36. Based on the consensus regarding market conditions reflected in a June 2002 GAO report, a PX report prepared in September 2000, and a FERC staff report issued on November 2, 2000, it is reasonable to conclude that the supply-demand balance in California beginning in May 2000 was so tight as to amount to a condition of scarcity.

37. In its December 15, 2000 Order, FERC prospectively imposed a penalty of up to $100 per MWh on California utilities that failed to schedule at least 95% of their forecasted load in the day-ahead market.

38. The penalty provision in FERC's December 15, 2000 Order gave sellers in the day-ahead market an incentive to demand even higher prices for their power. In the months immediately after that order, prices in both the day-ahead market and the real-time market increased dramatically, as did the number of Stage 2 and Stage 3 alerts the ISO was forced to call.

39. FERC made substantial modifications to the December 15, 2000 Order in June 2001, and formally rescinded the underscheduling penalty (which had never been collected) in the December 19, 2001 Order.

40. In January 2003, FERC approved a settlement between the FERC staff and certain Reliant companies pursuant to which the latter admitted that on June 20 and 21, 2000, they had purposefully withheld supply from the PX's day-ahead market for the purpose of increasing the prices paid by buyers in that market.

41. As shown by the guilty plea of Timothy Belden and the FERC staff's settlement with Reliant, Edison's difficulties during the second quarter of 2000 in purchasing enough energy in the day-ahead market to meet forecasted load was a function of under-supply (*i.e.*, sellers withholding from the PX energy they had offered in the past) rather than of underscheduling (*i.e.*, utilities purchasing from the PX significantly less than their forecasted load in the hope of obtaining a better price in the ISO's real-time market).

42. Since Edison's imbalances were not large in relation to total PX imbalances for all hours on June 27, 2000, these imbalances played only a small role in bringing about the Stage 2 alert on June 27, 2000.

Conclusions of Law

1. This proceeding is a tariff interpretation case, and as such, it more nearly resembles a contract dispute than a tort case.

2. Proximate cause is a legal concept that has been applied in some types of Commission proceedings with a tort-like character, such as reasonableness reviews.

3. Universal's proximate cause test, under which Edison would be liable for the Stage 2 alert called on June 27, 2000 because SCE's conduct in 1998 and 1999 supposedly contributed to market forces that were in continuous and active operation up to June 27, 2000, should not be applied here.

4. The issue in this case is the extent of Edison's duty under Rule 14 to furnish its customers with electric energy in light of all the applicable circumstances on June 27, 2000, not during some earlier period.

5. On June 27, 2000, Edison was not obliged to purchase additional power at an exorbitant price in order to satisfy its obligation under Rule 14 of using reasonable diligence to deliver power to its customers.

6. In view of the language in Rule 14 that Edison is not liable for interruptions or shortages of electricity caused by circumstances beyond its control, Universal's interpretation of Rule 14 is not reasonable.

7. In order to determine whether Edison satisfied its obligation to use reasonable diligence in delivering power to its customers on June 27, 2000, the Commission must consider all the circumstances, including the existence of market forces beyond Edison's control.

8. In view of the modifications to Edison's interruptible program that occurred in 1998 and the interruption requests that began at the same time, it is not reasonable to conclude that Edison guaranteed that the frequency of

interruptions in 2000 would be no greater than when Universal first entered the I-6 program.

9. In order to meet its burden of proof in this case, Universal must prove that (a) Edison could have met its forecast demand in the June 27 day-ahead market by submitting a higher bid that would have been acceptable under the PX's rules, (b) Edison's meeting its forecast demand in the day-ahead market would have obviated the need for a Stage 2 alert, and (c) in view of all the circumstances, Edison acted unreasonably by failing to submit such a higher bid.

10. Because the PX's rules in 2000 did not allow Edison to submit a vertical demand bid curve in the day-ahead market, and because Edison's analysis of the peak hour for June 27, 2000 shows that even if such a bid curve had been allowed, it would have elicited no more than 250 MWh of additional supply for Edison, Universal has not proven that Edison could have met its forecast demand in the June 27 day-ahead market by submitting a vertical demand bid curve.

11. Even if Edison had been able to obtain an additional 250 MWh of supply during the peak hour in the June 27, 2000 day-ahead market, such an increase would not have been enough to avert the Stage 2 alert called by the ISO on June 27, since the decision to call a Stage 2 alert is based on the reserves needed to support the ISO's system-wide demand, rather than on the reserves needed to support merely Edison's demand or the real-time market. Accordingly, Edison's scheduling practices in the day-ahead market did not bring about the Stage 2 alert on June 27, 2000.

12. The Commission should take official notice of the guilty plea by former Enron executive Timothy Belden and the FERC decision approving a stipulation between its staff and Reliant, as described in the foregoing findings.

13. The Stage 2 alert called by the ISO on June 27, 2000 was due to market circumstances not within Edison's control, including supply withholding.

14. In view of all the circumstances that prevailed on June 27, 2000, Edison exercised reasonable diligence in connection with its power purchases for that day, as required by Rule 14.

15. Universal has failed to meet its burden of proving that Edison has violated any law, rule or order of the Commission, as required by Pub. Util. Code § 1702.

16. Owing to its failure to meet the burden of proof imposed by Pub. Util. Code § 1702, Universal is not entitled to be relieved of the excess energy charge that Edison imposed on Universal due to the latter's failure to curtail down to its FSL when such curtailment was requested on June 27, 2000.

17. The Commission's Fiscal Office should be instructed to pay to Edison the $395,410.60 that Universal has deposited with the Commission, plus accrued interest.

18. Today's order should be made effective immediately.

O R D E R

IT IS ORDERED that:

1. Official notice is taken of the matter specified in Conclusion of Law 12.
2. The complaint filed herein by Universal Studios, Inc. (Universal) is denied.
3. Within 60 days after the effective date of this decision, the Commission's Fiscal Office shall pay to defendant Southern California Edison Company the sum of $395,409.60 that Universal deposited with the Commission in connection with this case, plus any accrued interest.
4. This proceeding is closed.

This order is effective today.

Dated ___________________________, at San Francisco, California.