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Decision 97-12-131 December 30, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	Rulemaking 94-04-031 (Filed April 20, 1994)
Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	Investigation 94-04-032 (Filed April 20, 1994)
Application of Pacific Gas and Electric Company to Identify and Separate Components of Electric Rates, Effective January 1, 1998. (U-39 E)	Application 96-12-009 (Filed December 6, 1996)
Application of San Diego Gas & Electric Company (U 902-M) for Authority to Unbundle Rates and Products.	Application 96-12-011 (Filed December 6, 1996)
In the Matter of the Application of Southern California Edison Company (U 388-E) Proposing the Functional Separation of Cost Components for Energy, Transmission, and Ancillary Services, Distribution, Public Benefit Programs and Nuclear Decommissioning To Be Effective January 1, 1998 in Conformance with D.95-12-036 as Modified By D.96-01-009, the June 21, 1996 Ruling of Assigned Commissioner Duque, D.96-10-074 and Assembly Bill 1890.	Application 96-12-019 (Filed December 6, 1996)
Application of PacifiCorp (U901E) for Approval of PacifiCorp's Transition Plan.	Application 97-05-011 (Filed May 5, 1997)
Application of Sierra Pacific Power Company for Approval of Its Transition Plan.	Application 97-06-046 (Filed June 27, 1997)

Application of Kirkwood Gas & Electric Company (U906E) for Compliance with the Requirements of AB 1890.	Application 97-07-005 (Filed July 3, 1997)
Southern California Water Company, for certain exemptions to California Public Utilities Commission Decisions 97-05-039, 97-05-040, and related Order Instituting Rulemaking (OIR) 94-04-031, and Order Instituting Investigation (OII) 94-04-032.	Application 97-08-064 (Filed August 22, 1997)

OPINION MODIFYING VARIOUS DECISIONS

Since the Commission announced its policy on restructuring the electric utility industry in Decision (D.) 95-12-063, as modified by D.96-01-009, the Commission, the Federal Energy Regulatory Commission (FERC), the Legislature, and the stakeholders in this effort have been working toward opening the electric generation and related markets to competition on January 1, 1998. As that date approaches, only a few steps remain to be taken to achieve that goal. The Legislature completed its work when it passed Assembly Bill (AB) 1890 and subsequent refinements. The Commission has to a large extent followed the schedule it set in the Roadmap decisions (D.96-03-022 and D.96-12-088). FERC has granted conditional authority for the Independent System Operator (ISO) to begin operations and for the Power Exchange (PX) to charge market-based rates (*Pacific Gas and Electric Co.*, 81 FERC ¶ 61,122 (1997) "FERC October 30 Order").

Electric restructuring, mandated by AB 1890, requires both state and federal regulatory action. All necessary FERC authorizations must be fulfilled prior to the commencement of ISO and PX operations. Although the necessary work is nearly done, on December 22, 1997, the ISO Board of Governors announced a delay of both its operations and its formal assumption of control of the transmission systems of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). The PX Board of Governors made a similar announcement. Specifically, the Chief Executive Officers (CEOs) of the ISO and the PX cannot make a certification required by FERC. The FERC October 30 Order requires that the CEOs of the ISO, the PX, PG&E, Edison, and SDG&E each certify that "all of the necessary features are in place to ensure reliable grid operations when the ISO and PX commence operations, and that sufficient pre-operational testing will be performed." (*Id.*, mimeo. at p. 2.) On December 23, FERC issued its "Order Establishing Comment Date and Directing Notification," which requires the ISO and the PX to provide FERC with at least 15 days' notice before the date that the ISO and the PX will commence operations. (*Pacific Gas and Electric Company*, 81 FERC ¶ 61,378 (1997) "FERC December 23 Order.") On December 29, the ISO and the PX announced that commencement of operations of each entity was expected to occur by March 31, 1998.

As a matter of prudence, the Commission has undertaken an effort to identify any actions it would have to take in the event that the operation of the ISO or PX, or both of them, were delayed past January 1. At the request of the Commission, conveyed at the meeting of November 5, members of the Commission staff have considered this issue, and have advised us that the primary action the Commission might have to take if the ISO or PX were delayed would be to preserve the regulatory status quo in certain respects. That preservation would be accomplished by modifying certain decisions and resolutions that require actions to be taken on January 1, 1998. This decision makes these modifications. A draft of this decision was issued for comment on December 23. We have received comments from PG&E, Edison, SDG&E, the Office of Ratepayer Advocates (ORA), San Francisco Bay Area Rapid Transit District (BART), and Enron. We have incorporated these comments, as appropriate.

It is important to stress that many of the restructuring initiatives that are scheduled for January 1, 1998, will go forward even though the ISO and PX have not commenced operations. The rate freeze required by Public Utilities Code § 368 and put in effect by D.96-12-077, the collection of "headroom" revenues to offset transition costs, the 10% rate reduction called for in § 368(a), the rate unbundling required by § 368(b),[1] the market valuation of utility-owned generation plants, and the education of consumers can and should continue regardless of the status of the ISO and PX. In addition, we expect the utilities to continue to comply with Commission orders to ensure that direct access can be implemented as soon as possible upon the commencement of ISO and PX operations, as discussed below. For example, we expect that the utilities will continue to process Direct Access Service Requests (DASRs) in a timely manner and will continue to provide metering and billing information to Energy Service Providers (ESPs) and other market participants.

The focus of the modifications ordered in this decision is on the requirements that are directly affected by the delay in operations of the ISO or PX. In particular, direct access is affected because of the statutory requirement for direct access to commence simultaneously with the ISO and PX. Section 365(b)(1) states, "Direct access transactions shall commence simultaneously with the start of an Independent System Operator and Power Exchange.... The simultaneous commencement shall occur as soon as practicable, but no later than January 1, 1998." The calculation of the nonbypassable Competition Transition Charge (CTC) and the direct access credit depends on the market price established in the PX. Since the ISO is the means to connect ESPs with their direct access customers by scheduling all direct access transactions on the transmission grid, a fundamental element of the direct access program is absent.

While the utilities obviously will not be able to buy and sell through a nonexistent PX, we recognize that the utilities' cost of procuring energy from the PX is zero for the interim period. This action accomplishes two important goals. First, consistent with our general approach to the delay of the operations of the ISO and the PX, we prefer to have as much of the structure of electric restructuring in place as possible as of January 1, 1998. Second, we are concerned that not eliminating the Energy Cost Adjustment Clause (ECAC) and Electric Revenue Adjustment Mechanism (ERAM)

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[1] While the unbundling of rates can go forward and the components of this service may be delineated in unbundled rate components, customers will continue to receive bundled service.

while proceeding with the establishment of the Transition Cost Balancing Account (TCBA) could lead to double recovery without detailed modifications. Therefore, we will proceed with the elimination of ECAC and ERAM and will not stay Resolution E-3514. Consistent with D.97-10-057, Resolution E-3514 approves the establishment of the Transition Revenue Account (TRA) for PG&E and Edison for the purpose of calculating headroom. By setting the utilities' cost of procuring energy from the PX equivalent to zero and transferring all nongeneration revenues to the TCBA, we can be sure that appropriate recovery takes place and that all generation-related costs and revenues will be appropriately recovered and monitored. All costs and revenues booked to the TCBA will be reviewed for reasonableness in either the annual Transition Cost Proceeding or the Revenue Adjustment Proceeding, as appropriate.

We do not establish a proxy PX price at this time, as ORA proposes, for purposes of later reasonableness review. We note that ORA has protested the advice letters filed to implement the requirements of D.97-11-074. We agree with ORA and the utilities that this protest should not preclude the implementation of the TCBA on January 1, 1998.

PG&E, Edison, and SDG&E have proposed to establish a new memorandum account, the ISO/PX Implementation Delay Memorandum Account, to record all ERAM-related costs, such as authorized Administrative and General (A&G) costs and Operation and Maintenance (O&M) costs that are not recorded in the TCBA, as well as all ECAC costs, such as fuel costs, that would otherwise have been recorded in other authorized memorandum accounts. Consistent with the recommendations of the utilities and ORA, we adopt this approach, with the requirement that these tracking mechanisms expire upon commencement of operations of the ISO and PX. In any filing requesting recovery of costs recorded in this tracking account, each utility shall include a showing that it undertook all practicable steps to minimize delay. We agree with both ORA and Enron that we prefer this delay to be as brief as possible.

The goal of this decision is to maintain the regulatory status quo for a short time until the ISO and PX are ready to commence operations, consistent with FERC authorizations. The following list identifies the significant passages of Commission decisions that must be modified to accomplish this goal. Incidental references to the

January 1, 1998 target date appear throughout many decisions, but these need not be changed now. The focus of this list is on ordering paragraphs, findings of fact, and conclusions of law where the Commission has required action by January 1 that may not be accomplished due to the delay of operation of the ISO or PX. This list is shorter than it otherwise would be because of the rate freeze. Until direct access is available, all customers will continue to receive utility service at frozen rates under the arrangements existing as of the date of this decision. Consistent with the mandates of AB 1890, the 10% rate reduction for residential and small commercial classes will go into effect beginning on January 1, 1998. All necessary tracking of costs and revenues will be accounted for in the TRA, the TCBA, and, if applicable, the rate reduction bond memorandum accounts.

While our focus is on those actions that cannot be implemented by January 1, 1998 because the ISO and PX will not commence operations, we make two additional changes. First, we will extend the September 30, 1998 date for use of 20 to 50 kW load profiles to allow such profiles to be used for at least the full nine months after the start date for direct access. This action is consistent with D.97-10-086, which provides that the Commission should weigh the costs and availability of hourly interval meters for customers with a maximum demand of 20 to 50 kW, and this extension allows those customers to examine the costs and benefits of moving toward an hourly interval meter. However, we reject the utilities' proposal to suspend the unbundling of revenue cycle services and metering and billing service activities other than meter installation. While we understand that the utilities need access to reliable data, we are confident that the procedures established in D.97-10-087 and D.97-12-048 will allow reliable data to be obtained by the utilities or Meter Data Management Agents.

Second, we will allow one additional request for customer usage data during this period of delay, at no cost to the requesting party. In D.97-05-040 and D.97-10-031, we required the utilities to provide customer usage data two times per year per customer account, at no cost to the requesting party. Because Enron intends to fulfill its marketing commitment to its customers for two free weeks of energy after one continuous year of service, Enron proposes that we allow for one additional request for customer consumption data for the period of the delay and that such a request will not count as one of the two free requests for customer data. We will adopt this approach and allow the additional request for all ESPs.

We also adopt Enron's recommendation that the utilities should be required to include a notice in all customers' bills, which provides the information that while direct access has been delayed, the utilities will continue to process direct access requests. We do not adopt Enron's proposed language, but direct our Public Advisor to prepare an appropriate notice to be included in utility customers' bills as soon as practicable.

In addition, we direct the utilities to have developed an additional direct mailing, as part of the Customer Education Program (CEP). This mailing should notify residential and small business consumers that direct access is delayed and that requests for new ESPs will continue to be processed. Review of the CEP notice shall be consistent with Ordering Paragraph 5 of D.97-08-064. This mailing should take place as soon as possible and must be completed within 45 days of the effective date of this decision. We will allow the utilities to record the costs of the bill insert and the additional mailing in the ISO/PX Implementation Delay Memorandum Account for later review and determination of cost responsibility.

Consistent with the FERC December 23 Order, the ISO and the PX must provide notification to FERC at least 15 days prior to the date the ISO and PX will commence operations. Once that notice is provided and the ISO and the PX are ready to commence operations and all five CEOs provide their certifications before FERC, direct access should begin within a specified number of business days. We delegate to the Coordinating Commissioner the task of issuing a ruling which will order when direct access should commence. Consistent with AB 1890, once such CEO certifications take place, direct access shall begin simultaneous with the commencement of ISO and PX operations, per the Coordinating Commissioner's ruling.

Findings of Fact

1. The CEOs of the ISO, the PX, PG&E, Edison, and SDG&E have not yet certified that they have met all the conditions of the FERC authorization.

2. On December 22, 1997, the governing boards of the ISO and PX informed us of a delay in commencement of operations.

3. The calculation of the nonbypassable CTC and the direct access credit depends on the market price established in the PX.

4. The ISO is the means to connect ESPs with their direct access customers by scheduling all direct access transactions on the transmission grid.

Conclusions of Law

1. The Commission should act to allow as many of the restructuring initiatives as possible to go forward during the delay in the start of operations of the ISO and the PX.

2. Public Utilities Code § 365(b)(1) requires direct access to commence simultaneously with the ISO and PX, no later than January 1, 1998.

3. The commencement of direct access is affected by the delay in the start of operations of the ISO and PX, because of the lack of necessary FERC authorizations.

4. The utilities' cost of procuring energy from the PX should be set at zero. The utilities should be authorized to establish ISO/PX Implementation Delay Memorandum Accounts to record (a) ERAM-related costs, such as authorized A&G and O&M costs that are not recorded in the TCBA and (b) ECAC costs, such as fuel costs, that would otherwise have been recorded in other authorized memorandum accounts. These memorandum accounts will sunset with the commencement of ISO and PX operations.

5. In any filing requesting recovery of costs in this tracking account, each utility shall be required to include a showing that it undertook all practicable steps to minimize delay.

6. The ISO and PX must provide notice to FERC at least 15 days prior to the commencement of operations.

7. When the ISO and the PX are ready to commence operations and all five CEOs provide their certifications before FERC, direct access should begin within a specified number of business days, simultaneously with the commencement of ISO and PX operations.

8. It is reasonable to delegate to the Coordinating Commissioner the task of issuing a ruling which will order when direct access should commence.

9. Direct access tariffs and other tariffs should be modified only as necessary to comply with the change of start date of direct access and the ISO and PX.

10. Notice of this matter was not provided with the agenda of the Commission meeting on December 30, 1997. This matter is being taken up on less than 10 days notice pursuant to Government Code Section 11125.3(a)(2), in that there is a need for immediate action and events leading to this action did not become known until subsequent to the posting of the agenda for the December 30 meeting.

11. This decision should be made effective immediately because of the importance to the public interest of opening the electric generation market to competition as soon as possible.

ORDER

IT IS ORDERED that:

1. Ordering Paragraph 11 of Decision (D.) 95-12-063 as modified by D.96-01-009 (the Policy Decision) is modified to read:

> "As of the date the Commission or its delegate declares to be the start date for direct access, the distribution utilities shall offer tariffed electric service which references the real-time market-clearing price as published by the Power Exchange."

2. Conclusion of Law 7 of D.96-04-054 (PG&E's Interim CTC) is modified to read:

> "Interim CTC should be collected from any customers who leave the system after December 20, 1995 and before the date the Commission or its delegate declares to be the start date for direct access."

3. D.97-05-040 (Direct Access Threshold Issues) is modified as follows:

   a. Conclusion of Law 13 is modified to read:

   > "Direct access should be made available to all California electricity consumers on the date the Commission or its delegate declares to be the start date for direct access, regardless of customer class or size of load."

   b. Ordering Paragraph 5.a is modified to read:

   > "Direct access should be made available to all California electricity consumers on the date the Commission or its delegate declares to be the start date for direct access, regardless of customer class or size of load."

c. Ordering Paragraph 5.e(4) is modified to read:

"Each UDC shall begin accepting direct access requests on November 1, 1997, which shall become effective on or after the date the Commission or its delegate declares to be the start date for direct access."

d. Ordering Paragraph 5.l is modified to read:

"Upon written authorization by a customer, every UDC shall be required to disclose to the designated electric service provider the customer's basic information. Access to this type of information shall be provided up to two times per year free of charge to the customer or the recipient of such information. During the time period when the Independent System Operator and the Power Exchange commencement of operations are delayed, this type of information shall be provided an additional time free of charge to the customer or the recipient of such information."

4. D.97-08-056 (Unbundling), as modified by D.97-11-073, is modified as follows:

a. Finding of Fact 10 is modified to read:

"The utilities will discontinue their role in electric dispatch and system control beginning the date the Commission or its delegate declares to be the start date for direct access. Nevertheless, the utilities seek to recover revenue requirements previously authorized to conduct generation dispatch and control activities."

b. Finding of Fact 11 is modified to read:

"The utilities have not demonstrated that the revenue requirements for dispatch and control will be required beginning the date the Commission or its delegate declares to be the start date for direct access."

c. Conclusion of Law 9 is modified to read:

"The utilities should be prohibited from entering into their CEMA accounts any generation-related costs caused by events that occurred after the date the Commission or its delegate declares to be the start date for direct access."

d. Conclusion of Law 10 is modified to read:

"The utilities should be prohibited from entering into their HSCLS accounts any generation-related costs caused by events that occurred after the date the Commission or its delegate declares to be the start date for direct access."

e. Ordering Paragraph 9 is modified to read:

"PG&E, Edison, and SDG&E shall not enter into their respective Catastrophic Events Memorandum Accounts any generation-related costs caused by events that occurred after the date the Commission or its delegate declares to be the start date for direct access."

f. Ordering Paragraph 10 is modified to read:

"PG&E, Edison, and SDG&E shall not enter into their respective Hazardous Substance Clean-up and Litigation Cost Accounts any generation-related costs caused by events that occurred after the date the Commission or its delegate declares to be the start date for direct access."

g. Ordering Paragraph 12(g) is modified to read:

"Provide that customer bills will include rates, charges and other information consistent with this decision no later than June 1, 1998. After the date the Commission or its delegate declares to be the start date for direct access and prior to the time the utilities unbundle rates, the utilities shall specify PX prices as set forth in this decision."

5. Finding of Fact 14 of D.97-08-064 (Customer Education Program) is modified to read:

"Direct access is to be made available to all on the date the Commission or its delegate declares to be the start date for direct access."

6. D.97-09-048 (Capital Additions) is modified as follows:

a. The first sentence of Finding of Fact 4 is modified to read:

"As of the date the Commission or its delegate declares to be the start date for direct access, the ISO assumes responsibility for operating the state's transmission system in the restructured industry environment."

b. Finding of Fact 6 is modified to read:

"As of the date the Commission or its delegate declares to be the start date for direct access,, the ISO will be responsible for evaluating the relative costs and reliability benefits of all must-run units and for negotiating appropriate reliability contracts with the owners of those facilities."

7. D.97-10-086 (Load Profiling) is modified as follows:

   a. Conclusion of Law 3 is modified to read:

      "The UDCs' proposal to use static load profiles on an interim basis for the majority of the customer classes, and Edison's use of dynamic load profiles for its residential and small commercial and industrial customers, should be adopted and made effective the date the Commission or its delegate declares to be the start date for direct access."

   b. The first sentence of Ordering Paragraph 2 is modified to read:

      "The interim load profile approach that was proposed by Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E), and as discussed in this decision, is approved and made effective the date the Commission or its delegate declares to be the start date for direct access."

   c. Ordering Paragraph 4.b is modified to read:

      "The 20 to 50 kW load profiles shall be made available for use no later than the date the Commission or its delegate declares to be the start date for direct access, and shall remain in effect until nine months after the date the Commission or its delegate declares to be the start date of direct access, unless extended by the Commission."

8. D.97-12-093 (Small and Multijurisdictional Utilities) is modified as follows:

   a. Finding of Fact 33 is modified to read:

      "It is necessary to make a clear distinction between possible transition cost recovery as of December 31, 1997 and what should be recovered as a going-forward cost in the marketplace as of the date the Commission or its delegate declares to be the start date for direct access."

   b. Ordering Paragraph 1 is modified to read:

      "As of the date the Commission or its delegate declares to be the start date for direct access, Southern California Water Company's Bear Valley Electric (Bear Valley), Kirkwood Gas and Electric Company (Kirkwood), PacifiCorp and Sierra Pacific Power Company (Sierra) (collectively, the applicants) shall provide their electric customers with direct access to competitive energy services in a manner consistent with this order and Decision (D.) 97-10-087."

   c. The first sentence of Ordering Paragraph 3 is modified to read:

      "From the date the Commission or its delegate declares to be the start date for direct access through no later than May 31, 1998, PacifiCorp

> and Sierra Pacific shall provide energy credits on the bills of direct access customers as proposed in their transition plans."

9. Ordering Paragraph 4 of D.97-12-090 (Retail Settlements and Information Flow) is modified to read as follows:

> "The distribution loss factor methodologies of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison company, as described in this decision, are adopted for use beginning on the date the Commission or its delegate declares to be the start date for direct access, in their respective service territories."

10. Until direct access is available, all customers shall continue to receive utility service at frozen rates under the arrangements existing as of the date of this decision, except that the 10% rate reduction mandated by Assembly Bill 1890 for residential and small commercial customers shall be implemented beginning January 1, 1998.

11. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (Edison), PacifiCorp, Sierra Pacific Power Company (Sierra), Southern California Water Company, and Kirkwood Gas & Electric Company (Kirkwood) are authorized to file advice letters if appropriate, to establish Independent System Operator and Power Exchange Implementation Delay Memorandum Accounts to record (a) Electric Revenue Adjustment Mechanism-related costs, such as authorized Administrative and General and Operation and Maintenance costs that are not recorded in the Transition Cost Balancing Account and (b) Energy Cost Adjustment Clause costs, such as fuel costs, that would otherwise have been recorded in other authorized memorandum accounts. These memorandum accounts will sunset with the commencement of Independent System Operator (ISO) and Power Exchange (PX) operations. PG&E, SDG&E, Edison, PacifiCorp, Sierra, Southern California Water Company, and Kirkwood shall file advice letters, if appropriate, by January 28, 1998 to implement the requirements of this decision. Upon staff review and approval, these advice letters shall be effective January 1, 1998.

12. The Public Advisor is ordered to prepare an appropriate notice to be included in utility customers' bills as soon as practicable.

13. The Coordinating Commissioner is delegated the task of issuing a ruling which will order when direct access should commence simultaneous with the commencement of operations of the ISO and the PX.

14. All of the investor-owned electrical corporations that are authorized to participate in the joint Customer Education Program (CEP), or are authorized to design and implement their own utility-specific CEPs shall have developed an additional direct mailing consistent with the requirements of this decision. Review of the CEP notice shall be consistent with Ordering Paragraph 5 of Decision 97-08-064. This mailing shall take place as soon as possible and shall be completed no later than 45 days from the effective date of this decision. The utilities are authorized to record costs of the bill insert and the additional mailing in the ISO/PX Implementation Delay Memorandum Account for later review and determination of cost responsibility.

This order is effective today.

Dated December 30, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

I will file a concurring opinion.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

Commissioner Jessie J. Knight, Jr., Concurring:

As anyone can guess who is familiar with my ardent support for direct access since my arrival at this Commission in 1993, I am deeply disappointed with the announcement of a three month delay to the start up of the California Independent System Operator (ISO) and Power Exchange (PX). Every person involved with electric restructuring at this Commission has worked valiantly to meet the 1/1/98 deadline for direct access and a new world order in the electric industry and it is discouraging that despite all of the efforts by this Commission, a delay by the ISO and PX -- two agencies beyond our direct control -- has brought our march toward competition to a screeching halt.

It is natural to search for someone to blame at this juncture. But blame is not the issue – accountability is the issue. Unfortunately, assigning accountability to any one individual or entity is not possible today. In my mind, the deadline of 1/1/98 was not unrealistic and the resources had been provided to make it happen.[1] But while the Commission cannot identify a culpable person or entity at this time, the events of the past week surrounding the announcement of delay raise some significant questions in my own mind that I will endeavor to have this Commission address should the delay extend beyond March 31, 1998. Two immediate questions that I raise for my colleagues to reflect upon in the near future are:

1) What are the negative impacts and actual dollar costs to California consumers and the competitive market players of each day of delay?

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[1] The Commission voted out $250 million in support of the ISO and PX in D.96-08-038, as modified by D.96-10-044, plus an additional $50 million in D.97-11-077.

2) Who is ultimately responsible for this delay, and can this Commission ensure they bear the costs of some appropriate penalty?

With regard to the first question, each day of delay beyond 1/1/98 brings costs to new entrants such as additional financing burdens, higher capital costs, new marketing costs, and the loss of opportunity for new providers to garner revenues from the marketplace. The potential for a spillover delay of divestiture raises costs to the utilities selling their plants, and perhaps ultimately to utility ratepayers. Depending on its duration, the ISO/PX delay could result in a reduced market value for the plants because of more plants coming on the market across the nation. Delay also raises market power concerns in the fledgling electric market since each day that a customer <u>must</u> stay with his or her incumbent utility beyond 1/1/98 is that much more of a hurdle to getting that customer to ultimately change providers out of potential fears raised by this <u>new</u> uncertainty. A delay might also raise transition costs because the absence of a PX price for three months decreases headroom and potentially restricts the early pay-off of transition costs.

Most importantly, a delay costs those consumers who were prepared to begin new contractual relationships with their chosen new providers the day after tomorrow. Consumers who had already exercised their choice could have realized immediate savings through these new commercial arrangements, but now they only get delay and the status quo. What about them? Finally, there are potential additional costs to ratepayers for the start up expenses of the ISO and PX which must be considered – one of the few levers left for this Commission to influence and motivate a speedy end to the delay.

My concern with who is to blame in the second question centers around who will ultimately pay for the costs of this delay? Who is accountable? Why did it take the ISO and PX until barely 7 days before 1/1/98 to announce the need for 90 more days of testing? Even a purely technical glitch has a source, and that source could likely have been overcome given enough resources and motivation. I do not mean to imply that the reliability of the electric system does not warrant extra attention and time to ensure all systems are "GO." Prudency requires diligent testing. But I do question, given the current circumstances, who is motivated to get the ISO and PX up and running fast? How can the parties bearing the costs of this delay exact any retribution for non-performance? Non-performance clauses are typical in projects like this. I would like to understand whether contractual protections or penalties for occurrences such as this had been considered. A competitive market would provide accountability and accounting for these costs, and a means for recovery. Perhaps this Commission should consider methods to mirror those market forces and the incentives they provide. If the Commission cannot accomplish this through its own jurisdiction, it should undertake appropriate discussions with and intervention at FERC to provide accountability for the costs of unreasonable delays, if in fact these are unreasonable delays.

Dated December 30, 1997 in San Francisco, California.

/s/ Jessie J. Knight, Jr.

Jessie J. Knight, Jr.
Commissioner

R. 94-04-031 / I. 94-04-032
D. 97-12-131

Commissioner Jessie J. Knight, Jr., Concurring:

As anyone can guess who is familiar with my ardent support for direct access since my arrival at this Commission in 1993, I am deeply disappointed with the announcement of a three month delay to the start up of the California Independent System Operator (ISO) and Power Exchange (PX). Every person involved with electric restructuring at this Commission has worked valiantly to meet the 1/1/98 deadline for direct access and a new world order in the electric industry and it is discouraging that despite all of the efforts by this Commission, a delay by the ISO and PX -- two agencies beyond our direct control -- has brought our march toward competition to a screeching halt.

It is natural to search for someone to blame at this juncture. But blame is not the issue – accountability is the issue. Unfortunately, assigning accountability to any one individual or entity is not possible today. In my mind, the deadline of 1/1/98 was not unrealistic and the resources had been provided to make it happen.[1] But while the Commission cannot identify a culpable person or entity at this time, the events of the past week surrounding the announcement of delay raise some significant questions in my own mind that I will endeavor to have this Commission address should the delay extend beyond March 31, 1998. Two immediate questions that I raise for my colleagues to reflect upon in the near future are:

1) What are the negative impacts and actual dollar costs to California consumers and the competitive market players of each day of delay?

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[1] The Commission voted out $250 million in support of the ISO and PX in D.96-08-038, as modified by D.96-10-044, plus an additional $50 million in D.97-11-077.

2) Who is ultimately responsible for this delay, and can this Commission ensure they bear the costs of some appropriate penalty?

With regard to the first question, each day of delay beyond 1/1/98 brings costs to new entrants such as additional financing burdens, higher capital costs, new marketing costs, and the loss of opportunity for new providers to garner revenues from the marketplace. The potential for a spillover delay of divestiture raises costs to the utilities selling their plants, and perhaps ultimately to utility ratepayers. Depending on its duration, the ISO/PX delay could result in a reduced market value for the plants because of more plants coming on the market across the nation. Delay also raises market power concerns in the fledgling electric market since each day that a customer <u>must</u> stay with his or her incumbent utility beyond 1/1/98 is that much more of a hurdle to getting that customer to ultimately change providers out of potential fears raised by this <u>new</u> uncertainty. A delay might also raise transition costs because the absence of a PX price for three months decreases headroom and potentially restricts the early pay-off of transition costs.

Most importantly, a delay costs those consumers who were prepared to begin new contractual relationships with their chosen new providers the day after tomorrow. Consumers who had already exercised their choice could have realized immediate savings through these new commercial arrangements, but now they only get delay and the status quo. What about them? Finally, there are potential additional costs to ratepayers for the start up expenses of the ISO and PX which must be considered – one of the few levers left for this Commission to influence and motivate a speedy end to the delay.

My concern with who is to blame in the second question centers around who will ultimately pay for the costs of this delay? Who is accountable? Why did it take the ISO and PX until barely 7 days before 1/1/98 to announce the need for 90 more days of testing? Even a purely technical glitch has a source, and that source could likely have been overcome given enough resources and motivation. I do not mean to imply that the reliability of the electric system does not warrant extra attention and time to ensure all systems are "GO." Prudency requires diligent testing. But I do question, given the current circumstances, who is motivated to get the ISO and PX up and running fast? How can the parties bearing the costs of this delay exact any retribution for non-performance? Non-performance clauses are typical in projects like this. I would like to understand whether contractual protections or penalties for occurrences such as this had been considered. A competitive market would provide accountability and accounting for these costs, and a means for recovery. Perhaps this Commission should consider methods to mirror those market forces and the incentives they provide. If the Commission cannot accomplish this through its own jurisdiction, it should undertake appropriate discussions with and intervention at FERC to provide accountability for the costs of unreasonable delays, if in fact these are unreasonable delays.

Dated December 30, 1997 in San Francisco, California.

Jessie J. Knight, Jr.
Commissioner