Exhibit No. ISO-5

CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Grid Reliability/Operations Committee

From: Beth Emery, Vice President and General Counsel
Deborah Le Vine, Director of Contracts & Compliance

CC: ISO Board of Governors; ISO Executives

Date: October 19, 1999

Re: Access Charge - Proposed Methodology

EXECUTIVE SUMMARY

This memorandum requires Board action. Both AB 1890 and the November 1996 Federal Energy Regulatory Commission Order required the ISO to implement an Access Charge within two years of start-up. A Transmission Access Charge Working Group comprising Market Participants and ISO representatives has been meeting regularly with the goal of developing a consensus Access Charge methodology. Management is seeking Board action on the four key policy issues listed below in order to finalize a detailed proposal for Board approval in November.

- What is the appropriate design methodology for the Access Charge?
- Should the rate be implemented immediately or phased in, and if the latter, how?
- Should the rate be demand and volume-based, demand-based only, or solely volumetric?
- If there are rate increases from the new rate methodology, notwithstanding phase-in, should they be mitigated, and if so, how?

An overarching issue in devising an Access Charge is its relationship to the issues surrounding full participation by Governmental Entities[1] in the ISO. Because the Governmental Entities that will become the new Participating Transmission Owners ("New PTOs") generally have newer, higher-cost transmission facilities, most traditional transmission rate designs would result in substantial transmission rate reductions per kW or kWh for these New PTOs. Although customers of the three investor-owned utility ("IOU") PTOs would see a corresponding dollar-for-dollar increase in their transmission rates, the per kW or kWh effect would be much smaller given the relative sizes of the PTOs and New PTOs.

In considering options, Management has sought to balance the Board-set goal of expanding the ISO within California with the Board-approved strategic objective to "allocate cost fairly." It is important to note, however, that the Access Charge creates a one-time opportunity to "expand the pie" and then allocate costs and benefits of full ISO participation among a larger group of parties. That opportunity will be lost if the Access Charge is decided in isolation from the related issues of Grid Management Charge ("GMC"), Existing Contract conversion, Metered Subsystem ("MSS"), and the like. The current proposal is intended to link and resolve these issues. The proposed

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1 Governmental Entities means municipal utilities, state agencies and federal agencies that own or have contractual rights to transmission.

June 1, 2000 effective date recognizes the significant work required to integrate New PTOs, which is not practicable to complete by the target March 31, 2000 date set forth in AB 1890.

With respect to overall design methodology, the working group considered a variety of proposals including keeping the Access Charge utility-specific, going to a grid-wide Access Charge, dividing the rate into a "local" charge and a "regional" or grid-wide charge, and variations on each. Management proposes, as the ultimate design after a phase-in, a two-part Access Charge comprising utility-specific "local" rates for ISO Controlled Grid facilities below 200 kV and a grid-wide rate for ISO Controlled Grid facilities at 200 kV and above. There is no significant dispute over this concept of a "regional-local split" among any stakeholders.

The working group considered a variety of proposals to phase in the new Access Charge, including having continued utility-specific rates, two zones, and other variations. Management proposes a "TAC Area" rate, a compromise among the various proposals presented by stakeholders. Initially, there would be three "TAC Areas" (the former control areas of PG&E, SCE, and SDG&E) and, should it join, a fourth TAC Area for LADWP's control area for regional transmission. The regional "TAC Area" rate would transition to an ISO Grid-Wide rate over a five-year period that would start when a "critical mass"[2] of New PTOs join the ISO, bringing a defined amount of additional import capacity to constrained interfaces. The working group also considered whether to continue the traditional demand-based transmission rates (costs allocated based on peak demand or kW) or to move to a commodity-based rate (costs allocated based on throughput, or kWh). Management recommends charging the Access Charge (charged to Utility Distribution Companies ("UDCs") or MSSs) based on accumulated gross hourly Load, a $/MWh value. This commodity-based charge is consistent with how the ISO currently charges Scheduling Coordinators for Wheeling, as well as the entire energy-based market structure in California, including congestion pricing.

Finally, the working group has attempted to identify and quantify the types of cost increases and savings each party will experience under an Access Charge/New PTO scenario. Some values are more easily verified than others: for example, the rate increases and decreases from a rolled-in transmission rate *vs.* the expected savings from eliminating the Existing Contract "two pipe" model and its phantom congestion charges. In recognition of the differences in accuracy of the estimated costs and benefits, Management is seeking authority to develop a mitigation plan to be used during a transition period. Management believes key principles of such a plan would include that any PTO with a rate benefit on Transmission Revenue Requirements "share" a percentage of its incremental benefit, adjusted for increases in GMC, to reduce costs to other customers. Although Management's current straw proposal would take the "shared" amount and (1) prepay outstanding ISO tax-exempt bonds and then (2) prepay that PTO's transmission debt, the details are still being developed and discussed with Stakeholders.

Management proposes the following motion:

MOVED, that the Committee recommends that the Board:

- ***adopt the Access Charge methodology using Utility-Specific rates for ISO Controlled Grid Facilities below 200 kV and ultimately an ISO Grid-Wide rate for facilities at 200 kV and above, all based on $/MWh, to be filed and effective June 1, 2000;***

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[2] Management proposes to define "critical mass" as an increase in import transmission capacity of 3,500 MW of additional new firm use transmission participating from three or more New PTOs cumulatively on the following paths: California-Oregon Intertie, Nevada-Oregon Border, Palo Verde, and Path 15.

- ***provide that facilities at 200 kV and above be charged initially in three or four interim "TAC Areas" and transitioned 20% per year into a ISO Grid-Wide charge, commencing when a critical mass of New Firm Use import transmission capacity is obtained;***
- ***adopt a plan for mitigating the rate increases and decreases among New PTO and existing PTO customers; and***
- ***direct Management to provide Tariff language for Board approval in November.***

BACKGROUND

AB 1890 requires the ISO to recommend for approval to the Federal Energy Regulatory Commission ("FERC" or "Commission") no later than two years after the initial operation date, a rate methodology for the grid Access Charge which has been approved by the ISO Governing Board. The ISO Governing Board must adopt principles for the charge including, but not limited to, an equitable balance of costs and benefits; a definition for the transmission facility costs which shall be rolled in to the transmission service rate and spread equally among all ISO users; and which transmission facility costs should be assigned to a specific utility's service area.[3] If there is no ISO Governing Board decision, the rate methodology shall be determined following the Alternative Dispute Resolution ("ADR") process in Section 13 of the ISO Tariff.[4] If no ADR decision is rendered, the default rate methodology specified in AB 1890 is a uniform regional transmission Access Charge and a utility-specific local Access Charge. For the default methodology, regional transmission facilities are defined to be 230 kV or above plus an appropriate percentage of facilities operating below 230 kV; however, the default methodology may not be implemented until termination of the competitive transition costs (CTC) recovery or March 31, 2000, whichever is later.[5]

The Commission, in its Order of November 26, 1996, stated:

> Regardless of the procedural process, the ISO-recommended rate methodology is to be filed with the Commission at least sixty days before the end of the two-year period. If the ISO Governing Board recommended or the ADR-recommended rate methodology is accepted, the rates are proposed to go into effect when the two-year period ends. The default rate methodology is proposed to become effective on the latter of the end of the two-year period or the termination of the stranded cost recovery period.

The ISO has been working with stakeholders since December 1998 on this issue. The discussions in the working group meetings and data received in the working group are subject to confidentiality rules similar to those used in settlement discussions, although individual parties may chose to make their positions public.

We distributed a request for proposed methodologies in December 1998, with responses ultimately received in February 1999. Five main Access Charge methodologies were initially proposed and extensively discussed among the stakeholders: (1) utility-specific regional and local; (2) regional ISO Grid-Wide and local utility-specific; (3) ISO Grid-Wide regional and local; (4) power flow-based pricing; and (5) regional transmission Access Charge (TAC) Area and local utility-specific. The complete proposal provided to the working group by ISO Management is provided in ***Attachment A.*** More details on the confidential positions of parties and cost implications of the proposals (based on cost information provided confidentially) are contained in the separate Executive Session materials. We note that approval is not sought for all details in Attachment A; rather the attachment is provided for informational purposes.

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3 §9600(a)(2)(A)

4 §9600(a)(2)(B)

5 §9600(a)(2)(C)

ISSUE STATEMENT

Although AB 1890 set out three specific questions for the Board to answer (detailed above), we believe the policy issues that need to be addressed by the Board are better stated as four questions:

- What is the appropriate design methodology for the Access Charge?
- Should the rate be implemented immediately or phased in, and if the latter, how?
- Should the rate be demand and volume-based, demand-based only, or solely volumetric?
- If there are rate increases or decreases from the new rate methodology, notwithstanding phase-in, should they be mitigated, and if so, how?

The Access Charge is required by FERC and AB 1890 to be filed no later than 60 days before March 31, 2000, if it is to be effective within two years of start-up. Management believes the filing needs to be approved and completed by year-end (requiring Board action on actual Tariff changes in November) if we are to meet the filing timeline required by the FERC order addressed above. Although we will ask FERC to make the Access Charge effective June 1, 2000, we believe it is important to file on time and receive an early indication from FERC that the approach will be permitted to go into effect, given the substantial work that will be required for any New PTO, as well as by the PTOs, to support their inputs to the formula rate and file any necessary changes to their TO Tariffs. We also need time to change settlement and billing software and development and implement procedures to accommodate the new charge.

The proposed schedule for implementing the new Access Charge is as follows:

10/28/99	Board approves Policy Direction
11/18/99	Board approves Tariff language
12/15/99	ISO files Access Charge with FERC
1/1/00	Potential PTOs must declare intent to join the ISO
2/15/00	FERC issues an Order on the Access Charge filing
3/15/00	Agreements for New PTO must be negotiated and executed
4/1/00	Agreements for New PTO are filed with FERC along with new PTO's Transmission Revenue Requirements
4/1/00	Existing PTOs file updates to Transmission Revenue Requirements and Loads. If an update is not filed by this time then the existing FERC approved values will be used in the ISO's formula rate for the Access Charge
6/1/00	TAC Area/Utility-Specific Access Charge effective

Because the new Access Charge is equivalent to the current charges, until there is a New PTO, we believe this schedule meets the letter of FERC's Order and better achieves the policy behind it because the timing reflects stakeholder requests. Additionally, any delay in decisions by the Board would trigger the ADR process required in the legislation, in addition to violating FERC's Orders. This also results in taking the decision-making process out of the Board's hands and placing the decision in the hand of an arbitrator or eventually, FERC.

OPTIONS TO SOLVE PROBLEM OR DEAL WITH THE ISSUE

The four key policy issues and the options for each are described below.

What is the appropriate design methodology for the Access Charge?

Currently the Access Charge is based on a utility-specific rate for both regional and local transmission. Each existing PTO at FERC promulgates such utility-specific Access Charge. Regional transmission is generally defined as transmission at 200 kV and above and local transmission is below 200 kV. Today Load pays the Access Charge based on where the Load is served. Export pays wheeling rates based on the point at which the export exits the ISO Controlled Grid. The rates for ISO Controlled Grid regional transmission in 2000 will vary as follows:

- $1.93/MWh for PG&E,
- $2.40/MWh for SCE,
- $3.19 for SDG&E.

If a New PTO joined the ISO under the existing methodology, its Access Charge would also be utility-specific if it is "Self Sufficient" as defined in Section 7.1.2 of the ISO Tariff. A "Dependent Participating TO" would pay pancaked charges specified in Section 7.1.3. The Governmental Entities view the current methodology as a significant barrier to joining the ISO. Moreover, tracking and administering 31 Access Charges within the State of California, which would occur if all Governmental Entities joined the ISO, is not practical.

Five Access Charge methodologies were discussed at length during the stakeholder process: (1) utility-specific regional and local; (2) regional ISO Grid-Wide and local utility-specific; (3) ISO Grid-Wide regional and local; (4) a power flow model; and (5) regional TAC Area and local utility-specific. Of the proposals presented in the working group, not surprisingly, each proposal would most benefit its proponent and was unacceptable to one or more of the other stakeholder representatives.

Management considered proposing an ISO Grid-Wide rate because there is a single California market, but concluded that the initial cost shifts were unacceptably large. To advance the ball, Management put forth a compromise using "TAC Areas" based on the four principal control areas that existed prior to the ISO – PG&E, SCE, SDG&E, and LADWP, which are the same areas used today as the basis of the present utility-specific rates.[6]

Grouping transmission charges by the old control areas recognizes the manner in which the transmission system was built in California. Generally, the IOU facilities were the backbone of a majority of the municipal and governmental systems, except for the LADWP system, and supported many of the facilities built by the Governmental Entities. The municipal and governmental systems depended upon the IOUs for interconnection to what is now the ISO Controlled Grid. Only in recent years did municipal utilities built their own major transmission systems. Eventually, the TAC Area rates would transition into a single ISO Grid-Wide rate for facilities at or above 200 kV.

There are two important and beneficial elements of this methodology. First, the method dispenses with the "self sufficiency" test. Second, the New PTO must immediately convert its Existing Transmission Contract rights ("ETCs") and its own transmission to ISO scheduling rules, and thus facilitating the elimination of the "two pipe" model for congestion management, which produces phantom congestion, and higher energy prices. New PTOs will accept FTRs, in place of their ETCs and for owned transmission lines. The ISO will issue the appropriate number of FTRs to each New PTO, who may hold them for its own use or sell them in the primary FTR auction.

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6 Imperial Irrigation District has not participated in the Access Charge development process.

Each TAC Area would include as the basis of the regional TAC Area rate the Transmission Revenue Requirement of all participating IOUs and Governmental Entities within that area. Specifically, the TAC Area Access Charge would be based on the sum of the Transmission Revenue Requirements of all PTOs in that area for facilities at or above 200 kV, divided by the sum of each utility's gross hourly Load. As the Access Charge transitions to an ISO Grid-Wide rate, the Transmission Revenue Requirements for all PTOs Grid-Wide would be combined and all UDCs and MSSs in the ISO Control Area would pay a single regional ISO Grid-Wide rate.

Under either the TAC Area or the ultimate Grid-Wide rate, the ISO would bill and collect the Access Charge from the UDCs and MSSs and forward the applicable Transmission Revenue Requirement to the applicable PTOs. (If the UDC and PTO were the same entity, the Access Charge payment and allocation would be netted.) Transmission Revenue Requirements for facilities under 200 kV would be recovered by a utility-specific local Access Charge developed and billed directly by the PTO to the UDCs or MSSs. The rate design to the end-user would be subject to state or local regulation, but subject to applicable FERC preemption principles.

Should the rate be implemented immediately or phased in, and if the latter, how?

Management proposes ultimately to merge the regional TAC Areas into an ISO Grid-Wide rate; such transition will commence when "critical mass" has been attained. This transition recognizes that if a New PTO joins, it will in most circumstances enjoy a significant savings immediately by rolling its Transmission Revenue Requirements into those of the applicable TAC Area, which is likely to reflect lower average costs for its end-users. The benefits that customers of the IOUs get from New PTOs' participation come from reductions in the GMC and savings from increased market efficiencies. Those efficiencies are gained by elimination of the "two pipe" model for Congestion management needed to honor Existing Contracts and are realized in large measure when sufficient new transmission is available to the entire market structure. For that reason, Management proposes starting the transition to an ISO Grid-Wide regional rate when "critical mass" is reached -- a minimum amount of additional new firm use import transmission capacity on the existing congested paths in the ISO Controlled Grid.

The definition of "critical mass" is still being finalized, but Management has proposed to use the following definition: when three or more New PTOs provide 3,500 MW of additional new firm use import capacity cumulatively on the California-Oregon Intertie, the Nevada-Oregon Border, Palo Verde, and/or Path 15, critical mass is attained. These paths were chosen because they are the four paths most frequently congested based on total quantity congested in MW. When critical mass is reached, the TAC Area-based Access Charge will begin a five-year transition (20% per year) to ISO Grid-Wide pricing. The trigger of 3,500 MW represents greater than 50% of the Existing Contract transmission capacity on the cited paths.

Should the rate be demand and volume-based, demand-based only, or solely volumetric?

Although it was not the subject of extensive debate in the working group meetings, another fundamental policy issue for the Board is whether the Access Charge should be demand-based ($/MW), commodity based ($/MWh), or some combination. Typically, transmission was built based on the need for additional transfer capability, and consequently the rate was demand based. However, the new market structure (including congestion pricing) is entirely commodity based and all wheeling is also commodity based. Moreover, there was little stakeholder support for anything other than volumetric charges. Management therefore proposes a commodity rate, based on gross hourly Loads in the UDC or MSS and Exports.

If there are rate increases or decreases from the new rate methodology notwithstanding phase-in, should they be mitigated, and if so, how?

Using a utility-specific access charge as the starting point, any other Access Charge methodology adopted will by definition appear to shift costs between PTOs. As more fully discussed in the Executive Session materials, the potential annual rate decrease to some New PTOs is substantial and other PTOs, including the three IOUs, will see corresponding increases in their customers' rates.

The issue is whether the ISO should establish a formula to mitigate rate increases and decreases among the various parties by having the New PTO "share" some of the benefits of lower transmission rates achieved by ISO participation over some transition period. Absent such a provision, the New PTO would presumably use its transmission cost savings either to reduce rates or, to the extent permitted by local law, to offset costs in other areas.

The working group has attempted to identify and quantify the types of cost increases and savings each existing and New PTO will experience under the proposed TAC Area Access Charge. Some values are more easily verified than others; for example, the cost-shift from a rolled-in transmission rate (a benefit to the New PTO) is easily forecasted. The increase or the decrease in GMC is also easily calculated. What is more difficult to calculate is "hard dollars" associated with increased market efficiencies due to increased ISO participation. These entail decreases in PX energy prices, decreases in Ancillary Service costs if sources increase with additional participation, and congestion cost decreases. Management has estimated that the ratepayers of California could benefit by more than $200 million annually,[7] the IOU customers by $135 million, if all Transmission Owners join the ISO and convert their Existing Contracts.

We must, however, take account of the difference in accuracy of the estimated costs and benefits. The key is a "bigger pie" and the promise of savings in market efficiencies. Though difficult to quantify precisely, they are the foundation for reaching a settlement all concerned can live with. To "allocate costs fairly", Management believes that a mitigation proposal can assist, during a transition period, in balancing the "hard" and "soft" dollars. The key principal would be that a portion of the revenues reflecting substantial opportunity for transmission rate reductions (net of increased GMC) should be used to reduce costs for all ISO customers as a further way to enhance the "soft" dollar potential benefits. This is particularly so since all customers benefit from the "soft" dollar market efficiencies.

Management has provided a potential mitigation plan in its latest straw proposal, detailed in ***Attachment A.*** A key portion of the proposal is the plan to use funds to prepay ISO infrastructure financing. This approach arguably offers the biggest "bang for the buck" for two reasons. First, prepayment would further decrease the GMC for all customers. Second, we believe it offers the opportunity to further decrease costs by facilitating expansion of the ISO regionally by mitigating the "too costly" arguments. We estimate that the period for repayment of debt would be 2-3 years if this portion of the mitigation straw proposal were in place.

This proposal is still being refined. Management proposes to bring the specifics to the Board in November, based on further Stakeholder discussions.

PROS AND CONS OF EACH OPTION

What is the appropriate design methodology for the Access Charge?

Management proposes an ISO Grid-Wide rate for facilities at or above 200 kV.

Pros: Remaining with a utility-specific Access Charge, coupled with the self-sufficiency test, is seen as a barrier to entry by other Transmission Owners in California and administering 31 utility-specific Access Charges (if

7 This calculation assumes changes in GMC due to increased participation; a $0.25/MWH decline in PX energy costs; a 15% decrease in Ancillary Service Costs due to increased supply; increased Ancillary Service sales opportunities for New PTOs; and decreased congestion costs.

all potential Transmission Owners joined the ISO) for the State is impractical. Additionally, Management believes that all users eventually should pay the same for the grid service on the high voltage system. Maintaining utility-specific rates is not consistent with our vision of a regional grid and does not obtain the efficiencies possible with an ISO Grid-Wide rate.

Cons: Any shift from a utility-specific Access Charge would initially shift costs to Edison and PG&E end-users. However, the TAC Area proposal mitigates those shifts. Other benefits of increased participation (reduced GMC costs, increased market participation which should decrease Ancillary Service prices and PX energy prices, and reduced administrative burden of Existing Contracts), provide the basis for an equitable balance of costs and benefits.

Should the rate be implemented immediately or phased in, and if the latter, how?

Management proposes immediate implementation of a TAC Area rate initially, with a phase-in to a ISO Grid-Wide rate over five years once critical mass is obtained.

Pros: The creation of TAC Areas is a compromise proposal that should increase participation in the ISO by utilities with transmission facilities and Existing Contracts. The primary benefits of creating TAC Areas is that it mitigates the increases in rates to IOU customers that would occur with other methodologies. It also simplifies the Access Charge ratemaking associated with the addition of large New PTOs to the ISO, by permitting the creation of a new TAC Area for any New PTOs with substantial control areas. This approach thus is consistent with FERC's policy in favor of expanded regional transmission organizations.

The benefits to the ISO Controlled Grid and the market structure include: additional New Firm Use transmission due to conversion of Existing Contracts and New PTOs joining the ISO; increased market efficiencies; decreased congestion; and decreased GMC. With one ISO Controlled Grid, Management believes that ultimately there should be one Access Charge.

Cons: An ISO Grid-Wide Access Charge results in further rate increases to IOU and other Transmission Owner's customers. These incremental shifts are mitigated, however, by the benefits associated with the availability of additional capacity for New Firm Uses and are likely to be reduced by future transmission expansion costs.

Should the rate be demand and volume-based, demand-based only, or solely volumetric?

Management is proposing a commodity-based charge.

PROS: A commodity-based charge ($/MWh) is consistent with the ISO's market structure and the data is easily attainable for billing purposes. Gross Loads should pay for the Access Charge because all Loads are supported by the regional grid system. Some Stakeholders favor a peak/off peak structure. Given current congestion patterns, this is not appropriate. Management does believe the peak/off-peak question should be revisited until after we have data for some period after Critical Mass is obtained, when congestion patterns could change.

Cons: Typically transmission has been priced based on demand ($/MW) and rates for End-Users is both demand and commodity based. The concern that has been raised is that if the ISO establishes a commodity-based charge, then the UDCs and MSSs would be required to revise their rate structure to only commodity charges.

<u>If there are rate increases and decreases from the new rate methodology, notwithstanding phase-in, should they be mitigated, and if so, how?</u>

Management proposes a mitigation plan that allows a PTO to keep percentage of the incremental benefits resulting from the rate change and assigns a percentage to reduce (1) ISO infrastructure financing to in turn reduce the GMC; and (2) the transmission costs of that PTO by prepayment of debt.

Pros: Cost shifts should be mitigated to allow fair treatment of end-users. Ideally, the total costs and benefits can be "win-win". A mitigation plan to direct where some or most of the savings a PTO gets from a rolled-in rate can help balance the costs and benefits. Moreover, it would facilitate getting savings to end-users by limiting the ability of Governmental Entities (who are not regulated by FERC or the CPUC) from using the savings for non-transmission expenses.

Cons: This approach mandates what the Governmental Entities must spend their transmission revenue on, a directive that is not palatable to them. They also contend that, unless they continue to charge their customers based on stand-alone transmission costs, rather than the lower TAC Area Access Charge, there will be no excess revenues that can be used for mitigation.

PROJECTED COST OF PERSONNEL AND IMPLEMENTATION

The ISO was aware of implementation of the Access Charge for regional transmission, and monthly billing of such charge to the Scheduling Coordinators representing UDCs or MSSs and monthly distribution of revenues to PTOs at the time that the budget for FY 2000 was developed. Consequently, such software and labor costs have already been included in the FY 2000 budget. It should be noted that the Board has not approved the budget at this time.

POSITIONS OF THE PARTIES

The Access Charge stakeholder process used a parallel path method with both public and confidential meetings and discussions. The Market Issues Forum participants have been briefed monthly as to the status of the Access Charge development. Market Participants in that process took no positions.

A Transmission Access Charge Work Group met to discuss the various proposals and implementation details of the Access Charge under a confidentiality agreement that is akin to the privilege afforded settlement negotiations. If the Access Charge discussions were held in public session, any information, position or discussion could be used against anyone of the parties in the FERC litigation. Management believed that frank discussion needed to take place if there was any hope for a consensus on the Access Charge. Additionally, without the ability for parties to provide data on a confidential basis, responses to the ISO's data requests for specific breakdowns of information might not be forthcoming. This stakeholder process depends on the submission of data by Market Participants, some of which have indicated their reluctance to submit data except on a confidential basis.

A description of the parties' confidential positions is included in the Executive Session documents.

MARKET ANALYSIS OPINION

The Brattle Group has had the lead for the ISO on the economic and financial analysis in support of the Access Charge project, and on the development of many of the details of the present proposal. The scope of the DMA's comment is therefore limited to the larger structural principles and design features of Management's Access Charge proposal.

The DMA supports Management's vision of the ultimate Access Charge structure – a single ISO Grid-Wide charge to cover all transmission facilities at or above 200 kV, and utility-specific charges to cover facilities below 200 kV, applied to gross Loads and Exports on a $/MWh basis. We also support a gradual transition to this structure from the present utility-specific structure, during which a mitigation plan could be used to balance the relative costs and benefits.

Several of the more detailed elements of the Access Charge proposal remain to be fully worked out, including the conversion of Existing Contract capacity to FTRs, an issue we believe merits careful attention to ensure the internal consistency required for a highly liquid market for FTRs. The DMA will continue to participate in the working group as this process continues and to provide input on this and other details of the proposal.

MANAGEMENT RECOMMENDATION

Management recommends that the Board approve in concept an initial TAC Area Access Charge to be filed in December with the following components:

- a requested June 1, 2000 effective date;
- initial use of a TAC Areas Access Charge for regional ISO Controlled Grid Facilities, 200 kV and above;
- transition to an ISO Grid-Wide Access Charge, triggered when critical mass in the form of additional import transmission capacity from New PTOs is attained;
- maintain utility-specific charges for ISO Controlled Grid facilities below 200 kV;
- rate to be commodity-based and paid based on gross Load and Exports; and
- requiring mitigation criteria for those PTOs who benefit the most from the change in rates.

This approach is a compromise between the various proposals. It mitigates the rate changes better than any other proposal, while setting the stage for an increased number of Participating Transmission Owners and a more efficient and reliable California electric system.

Additional information regarding cost impacts will be provided to the Board in Executive Session.

ATTACHMENT A
PROPOSED ACCESS CHARGE METHODOLOGY DETAILS

Background

The ISO is required to have an ISO grid Access Charge in place within two years of ISO startup (by April 1, 2000) and, based on Federal Energy Regulatory Commission ("FERC" or "Commission") orders, filed with the Commission by December 31, 1999. The ISO's internal Transmission Access Charge ("TAC") team has been working with stakeholders since December 1998 to consider options for an overall methodology to use in developing the proposed Access Charge. As a result of these meetings and discussions, we have narrowed the options to four:

- Utility Specific (the current system used by the investor-owned utilities ("IOUs"));
- Regional/Local split (the default methodology proposed in AB 1890);
- ISO Grid-Wide; and
- TAC Areas.

General Proposal:

Effective June 1, 2000, the ISO proposes to have a two-part Access Charge: a "regional" component to recover costs of ISO Controlled Grid facilities 200 kV and above and a "local" component to recover costs of ISO Controlled Grid facilities below 200 kV. The regional Access Charge would initially be based on "TAC Areas" and, if a "critical mass" of new Participating Transmission Owners ("New PTOs") join the ISO, transition to an ISO Grid-Wide charge in equal percentages over a five-year transition period.[1] Revenue Requirements for the local component (facilities below 200 kV) would continue to be recovered through a utility-specific Access Charge. The TAC Areas would be based on the previous WSCC Control Areas (except for the City of Pasadena, which would be part of the former Southern California Edison ("Edison") Control Area).

Each TAC Area would include all IOUs and Governmental Entities[2] within that area. The regional Access Charge within that area would be based on the sum of the net Transmission Revenue Requirements for facilities over 200 kV of PTOs within that area and would be billed by the ISO. Transmission Revenue Requirements for facilities under 200 kV would be recovered by a utility-specific local Access Charge billed by Utility Distribution Companies ("UDCs") or Metered Subsystems ("MSS") that enter into an MSS agreement with the ISO in lieu of a UDC agreement.

The longer-term goal of the proposed Access Charge design would be ultimately to merge the TAC Areas into an ISO Grid-Wide regional rate; such transition will commence when "critical mass"[3] has been attained. The primary benefit of creating temporary TAC Areas is to provide immediate incentives for ISO participation of Governmental Entities, eliminate currently-existing "barriers to increased ISO participation (e.g., the self-sufficiency test and disputes over facilities crediting), and mitigate rate increases during the transition period. An additional benefit of the TAC Area approach is that it simplifies the Access Charge ratemaking associated with the addition of large PTOs from outside of California to the ISO by permitting the creation of a new TAC Area for any such New PTOs. In this respect, the approach maybe characterized as consistent with FERC's policy in favor of expanded regional transmission organizations. The transition to the ISO Grid-

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1 Joining the ISO means that a transmission owner executes the Transmission Control Agreement, turns over operational control of its transmission to the ISO and therefore becomes a Participating Transmission Owner in accordance with the ISO Tariff.

2 Governmental Entities mean municipal utilities, state agencies and federal agencies.

3 Defined below.

Wide Access Charge is only beneficial if sufficient new transmission is available to the entire market structure. Once critical mass is attained, the benefits to the ISO Controlled Grid and the market structure consist of: additional new firm use transmission due to conversion of Existing Contracts and New PTOs joining the ISO; increased market efficiencies; decreased congestion; and decreased Grid Management Charge ("GMC").

Rate Structure:

The regional Access Charge would be calculated for each TAC Area based on the following formula:

$$\text{Access Charge} = \frac{\sum \text{Each PTO's Net Transmission Revenue Requirement}^{4}}{\sum \text{Each PTO's Gross Load}}$$

For the TAC Area regional Access Charge, the cost of all grid facilities operated at 200 kV and above within that TAC Area will be included in the Transmission Revenue Requirement and the gross Load will be based on the total of all Loads in the TAC Area, including MSS. The use of gross Load is required because all end-use Loads benefit from the regional transmission grid and therefore should pay for such transmission. For the utility-specific local Access Charge, each Transmission Owner shall calculate its own local Access Charge, based on the revenue requirements of its own local facilities and its own load served by those local facilities, and obtain approval from the applicable regulatory authority.

The Access Charge proposal would initially be based on three TAC Areas: "Northern", "East Central" and "Southern". If no New PTO(s) join, the TAC Area rate would consist of Pacific Gas and Electric Company's ("PG&E") rate in the Northern area, Edison's rate in the East Central area and San Diego Gas & Electric Company's ("SDG&E") rate in the Southern area. If the Los Angeles Department of Water and Power becomes a PTO, a fourth area, "West Central", will be added. At full participation, the four TAC Areas and their members would be as follows:

- Northern Area: PG&E, SMUD, WAPA, NCPA, Redding, SVP, Palo Alto, CCSF, CDWR North[5], Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, MID, TID, Plumas, Roseville, City of Shasta Lake and Ukiah
- East Central Area: Edison, Anaheim, Riverside, Azusa, Banning, Colton, Pasadena, CDWR South, MWD and Vernon
- West Central Area: Los Angeles, Burbank, Glendale[6]
- Southern Area: SDG&E

Imperial Irrigation District ("IID") has not been involved in the working group until very recently. Should IID decide to join the ISO, Management would review their transmission rates to determine whether it would be best to incorporate IID into the Southern Area or to create a separate East Southern TAC Area for the transition period.

Load taking service off the ISO Controlled Grid above 200 kV will pay only the regional Access Charge. Load taking service off the ISO Controlled Grid below 200 kV will pay the utility-specific local Access Charge component

[4] Net Transmission Revenue Requirement deducts wheeling revenues related to exports.

[5] CDWR North consists of the portions of the State Water Project physically located in the Northern TAC Area; CDWR South consists of the remainder of the State Water Project.

[6] If Burbank and/or Glendale join but Los Angeles does not, Burbank and Glendale will be incorporated in the East Central Area.

in addition to the applicable regional Access Charge. Therefore, regional Transmission Revenue Requirements will be recovered from all Load and exports, while local revenue requirements will be recovered only from local Load.

The New PTOs will be required to turn over operational control to the ISO of all regional transmission facilities that meet the FERC seven point test and criteria adopted by the ISO Governing Board, both owned facilities and Existing Contracts.

Self-Sufficiency

For the regional component (for both the TAC Area and ISO Grid-Wide proposals), a Self-Sufficiency test would not be required because all Load and exports in an area will be paying the same Access Charge. Additionally, a credit for facilities at the regional level will not be needed because the Access Charge will include the cost of all facilities.

For the local component, the charge and any customer credit will be based on the utility-specific Access Charge and will be approved by the appropriate local regulatory authority.

ISO Participation

When a New PTO joins the ISO, they will be required to execute the Transmission Control Agreement. Owned transmission facilities will be operationally controlled by the ISO and the New PTO will receive an FTR for its owned transmission capacity during the Existing Contract conversion period (until March 31, 2003). Existing Contracts will be converted as discussed above. If the underlying Existing Contract has not been terminated, financial payments are still made by the New PTO to the original transmission service provider. After the conversion period, owned capacity and Existing Contract transmission capacity will be treated as new firm use transmission capacity available to the market. The New PTO will be required to sell their FTRs and receive the auction revenue or the New PTO has the opportunity to buy back their FTRs in the ISO's primary auction or any secondary auction. However, if the Existing Contract has not been terminated, the financial obligations will still exist.

Existing Contracts

Existing Contracts for New PTOs would be converted in accordance with section 2.4.4 of the ISO Tariff, except as provided below. Conversion of Existing Contracts will:

- require the New PTO to turn over Operational Control of its transmission Entitlement to the ISO immediately and immediately require the SC scheduling the transmission to comply with the ISO's scheduling and operational procedures and protocols.
- require the New PTO to obtain future transmission services within, out of, or through the ISO Controlled Grid using the ISO's scheduling and operational procedures and protocols.
- entitle the New PTO to receive FTRs for 100% of its Existing Contract transmission capacity, adjusted in real-time for transmission line derates, for the Existing Contract conversion period. If the PTO does not want to retain the FTRs, the PTO is entitled to sell the FTRs in the ISO's primary auction and to receive the auction revenues. However, such auction revenues must be deducted from the New PTOs' Transmission Revenue Requirement.
- entitle the New PTO to receive the Usage Charge revenues for transmission capacity that is unscheduled through the Hour-Ahead Market and all Wheeling revenue credits throughout the term that the capacity is

available under Existing Contracts. Usage Charge revenues do not have to be deducted from the New PTO's Transmission Revenue Requirement.

- continue to obligate the New PTO to pay the provider of the service for its transmission service at rates provided in the Existing Contract, including changes pursuant to Federal Power Act Section 205 or 206 rights. The cost of transmission service associated with the Existing Contract will be part of the New PTO's Transmission Revenue Requirement that is recovered through the transmission Access Charge.

Congestion Revenue and FTR

New PTOs that join the ISO with their own transmission are eligible to auction their ownership rights in the FTR auction or retain them. If the New PTO chooses to sell the FTR, they are obligated to deduct the auction revenue from their Transmission Revenue Requirement.

Converted Existing Contracts would be eligible for the ISO's primary FTR auction. The amount of FTRs from the Existing Contract would be 100% of its Existing Contract transmission capacity, adjusted in real-time for transmission line derates, for the duration of the Existing Contract conversion period which is until March 31, 2003. Revenue from the FTR primary auction would be the entitlement of the New PTO but are obligated to be credited against the New PTO's Transmission Revenue Requirement.

Critical Mass and Transition

Critical mass is defined as a minimum amount of additional new firm use transmission capacity on the ISO's existing congested paths or paths that relieve existing congestion within the ISO Controlled Grid. Once 3,500 MW of additional new firm use import capacity participates from three or more New PTOs cumulatively in COI, NOB, Palo Verde, and/or Path 15, then all existing TAC Area-based Access Charges will begin their five-year transition to ISO Grid-Wide.[7] Following the initial phase-in triggered by the achievement of "critical mass", if a New PTO joins in subsequent years it will be integrated in the appropriate TAC Area and start the five-year phase-in process to a ISO Grid-Wide charge starting in its first year of membership. Id a New PTO located outside of California joins the ISO, it will be established as a new TAC Area.

In all cases, the transition would be based on percent of net Transmission Revenue Requirement ("TRR") and gross Load as follows:

	% of TRR and gross Load included in the TAC Area Regional Charge	% of TRR and gross Load included in the ISO Grid-Wide Regional Charge
Year 1	80%	20%
Year 2	60%	40%
Year 3	40%	60%
Year 4	20%	80%
Year 5	0%	100%

7 The trigger of 3,500 MW represents greater than 50% of the Existing Contract transmission capacity on the cited paths.

Mitigation of Rate Increases

Rate increases or rate decreases occur when the Access Charge, under either the TAC Area approach or the ISO Grid-Wide approach, is different than what the PTO would have paid if the Access Charge were utility-specific. In some instances, the rate decrease is a benefit, by decreasing the cost the PTO would have paid as compared to its utility-specific rate. In other instances, the rate increase is a burden because the Access Charge is greater than what the PTO would have paid under its utility-specific rate. Consequently, in addition to the market efficiencies and decreases in GMC costs that are of benefit to the existing PTOs, Management believes the rate increases should be mitigated.

Management proposes that any PTO that has a rate increase will contribute a percentage of this incremental benefit, net of the incremental GMC paid above the GMC amount paid in 1999, to first pre-pay the ISO's infrastructure cost, thereby accelerating the repayment of the ISO's debt and decreasing the GMC for all Market Participants. Once the infrastructure cost is repaid, the amounts will be used to accelerate repayment of their transmission debt. The reason for netting the GMC is to avoid a concern raised by potential New PTOs that it is costly to participate in the ISO and that part of the benefits received through the Access Charge methodology is needed to off-set the burdens associated with the additional GMC payments on gross Load. The calculation would be based on estimates at the beginning of the year and trued-up in the first quarter of the following year. The 1999 GMC amount would remain constant. As an example, if the contribution were 75% of the incremental benefit:

> If the annual rate decrease is $9 million, the 1999 GMC paid is $1 million and the annual GMC cost based on gross Load is $6 million, then the incremental amount is $3 million ($9 - ($6 - $1)). Consequently, $3 million (75% of $4 million) would be used first to pay the ISO's infrastructure and then retire the PTO's transmission debt.

Participation

For implementation and ratemaking purposes, it is advisable to establish an enrollment schedule for New PTOs to join the ISO. If, in any year, a potential PTO declares its intent to join the ISO by January 1, all agreements must be negotiated and executed by March 15 and filed with the FERC on April 1, along with the New PTO's Access Charge. This would allow for a June 1 effective date for the Access Charge including the New PTO. The same process could be available for the second half of the year (i.e. July 1 declaration; October 15 execute agreements; November 1 FERC filing; and January 1 effective date).

Transmission Expansion

Transmission expansion costs will be included in the Transmission Revenue Requirement of the PTO if the transmission expansion project is a local reliability project. If the transmission expansion project is an economic project, then the sponsor of the project will identify the beneficiaries of the project and such beneficiaries will be required to pay the costs associated with the project in accordance with the existing ISO Tariff. In the context of long-term grid planning, the ISO does not intend to change this payment mechanism.

Billing

The ISO will bill UDCs and MSS for the regional component of the TAC and continue to bill SCs for Wheeling charges. After collecting the funds from the UDCs and MSS, the ISO would pay the amounts due to the PTOs, based on their filed net Transmission Revenue Requirement. The monthly payment made by the ISO to each PTO would be that PTO's pro rata share of the revenue collected.[8] If the UDC or MSS is also a PTO, then the ISO will net bill the UDC or MSS. The ISO will need software changes in settlements to implement this billing requirement and funds have been budgeted for 2000 to enable such software changes.

Each Transmission Owner will be responsible for billing its own customers to recover the net Transmission Revenue Requirement associated with its own local transmission facilities.

Wheeling

The Access Charge rate schedules also apply to Wheeling. During the transition to an ISO Grid-Wide Access Charge, the location of Scheduling Points will determine which TAC Area charge is applied. The Wheeling rate will equal the TAC Area rate at the Scheduling Point, provided the Scheduling Point is not a jointly owner facility. Each TAC Area may have a different Wheeling rate, depending upon the applicable net Transmission Revenue Requirement. For Scheduling Points that are shared among TAC Areas and Scheduling Points that are joint facilities, a blended rate (as used today) will be applicable. Once TAC Areas transitions to the ISO Grid-Wide Access Charge, the ISO will use a single wheeling rate applicable to all Export Scheduling Points

If the exit Scheduling Point is below 200 kV and therefore utility-specific, the Wheeling Charge will equal the summation of the regional Access Charge and the local Access Charge at that point. Shared and joint facilities will be the weighted average rate based on firm capacity at the exit point, as is the Wheeling Charge today.

Time-of-Use Rates

Time-of-use and seasonal rates often are meant to provide market incentives to levelize Demand over time. With respect to transmission, however, the appropriateness and effectiveness of time-of-use pricing is questionable given that 1) a significant portion of the experienced congestion occurs during off-peak hours and off-peak months; and 2) congestion charges already provides market incentives for transmission demand. While a time-of-use Access Charge may provide additional price signals to further reduce transmission congestion, we believe that any such benefit does not justify the additional administrative burden at this time. The ISO is willing to re-evaluate implementing time-of-use pricing two-years after the Access Charge has transitioned to ISO Grid-Wide. The ISO believes that at that time it will have sufficient data to do an analysis to justify time-of-use rates.

Reliability Must-Run Charges

Reliability Must-Run ("RMR") is a Service Area issue and the Service Area benefiting from the RMR Unit should pay the revenue required for RMR, in accordance with the ISO Tariff. RMR costs at this time should be allocated using the existing ISO Tariff mechanisms and not included in the ISO's Access Charge.

FERC Filing

The ISO would file the Access Charge methodology as a formula rate by December 31, 1999. The filing will consist of an ISO Tariff revision addressing the proposal, the timeline, the definition of the TAC Areas, the trigger mechanisms, the formula for cost allocation, and the billing and payment methodology.

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8 E.g., assuming that the ISO consists of Systems A and B, if System A has an annual TRR of $200 and System B has an annual TRR of $100, and $6 is collected in total in one month by the ISO, Systems A and B will receive $4 and $2, respectively, from the ISO.

Separate Federal Power Act Section 205 filings would be made by FERC jurisdictional PTOs. Non-FERC jurisdictional PTOs would file their Transmission Revenue Requirements with the FERC as "NJ" (or in the case of certain Federal entities "EF") filings. These Non-Jurisdictional filings will be subject to the standard of review established by FERC for that type of submission. Such 205, NJ, or EF filings would supply the supporting documentation for each respective PTOs Transmission Revenue Requirement. Each PTO is responsible for defending and modifying its filings. Additionally, the PTO would be free to file revisions to its Transmission Revenue Requirements as needed. The final Access Charge as implemented would be updated based on the FERC Order(s).