

MEMORANDUM

To: California ISO
From: UCAN
RE: ISO's analysis of the proposed Sunrise project
Date: April 11, 2006

I. Alternatives proposed by UCAN to be considered by the ISO

A. Transmission alternatives

1. "Mexico Light"

Currently, loss of the IV-Miguel segment of SWPL results in the cross-trip of Path 45 and the CAISO generation located in Mexico. This means that not only does SDG&E lose its largest single import path if SWPL trips, but the CAISO loses up to 1200 Mw of generation from the Sempra TDM facility and the Intergen La Rosita plant. SDG&E, in its Sunrise application, has rejected the idea of strengthening Path 45 enough to withstand the loss of SWPL without cross-tripping.

UCAN has a proposal, which we have dubbed "Mexico Light," which could avoid part of the loss of import capacity to SDG&E and part of the loss of generation to California which currently result from tripping of SWPL. This proposal, if technically feasible, should provide several hundred Mw of increased NSIL for SDG&E at a cost of \$10-20 million at most. This would provide only a partial alternative to the Sunrise project, but could dramatically improve SDG&E reliability in 2010 if, as is quite plausible, Sunrise is not operational by then. *As such, we request the ISO to give this idea a prompt and thorough vetting.*

The "Mexico light" alternative would consist of a very short segment of new 230 KV transmission from either the TDM and/or Intergen generators to the CFE grid. This new transmission would normally be operated open. The existing cross-trip for loss of SWPL would be amended so that, in the event of loss of the IV-Miguel segment of SWPL, the TDM and/or Intergen plants would no longer trip off completely, and the Tijuana-Otay Mesa circuit would no longer be opened. Instead, the TDM/Intergen to CFE circuit(s) would be closed, and the generators would continue to operate.

With "Mexico Light" in place, there would be several consequences. First, the CAISO's IV substation would continue to be completely cut off from Mexican generation and the CFE grid after a SWPL trip, just as it is today. Second, because CFE does not rely on exports from TDM and Intergen to the CAISO to balance its loads and resources, any post-trip generation delivered from those generators to the CFE grid would be in excess of CFE's loads. Third, because the Tijuana-Otay Mesa line would remain in service after a SWPL trip, excess generation on the CFE grid due to TDM and Intergen would be able to reach SDG&E's transmission system at Otay Mesa.

UCAN expects that this scheme would allow at most 800 Mw of TDM and Intergen generation to remain online after a SWPL trip, consistent with our understanding of the south-to-north limit on the Tijuana-Otay Mesa line. Possibly no more than 300-400 Mw would be able to stay on line in order to avoid overloading CFE's existing Mexicali-Tijuana 230 KV circuits. However, the costs of the Mexico Light proposal would be minimal – a very short bit of new transmission (possibly none in the case of Intergen, which already has a CFE interconnection), switching capability to allow TDM and Intergen to disconnect from the CAISO at IV and reconnect to CFE without going offline, and changes to the existing cross-tripping RAS for loss of IV-Miguel.

The benefits of Mexico Light for reliability would be substantial. The current NSIL for SDG&E is 2500 Mw, based on a first contingency of losing SWPL, a second contingency of losing a south-of-SONGS 230 KV line, and a 2500 Mw import rating for the remaining south-of-SONGS lines. Because Path 45 trips with SWPL, there is no Path 45 import as part of the NSIL. With Mexico Light in place, UCAN expects that the NSIL would be increased by about 300-350 Mw, depending on how much Intergen/TDM generation could be delivered San Diego via the CFE grid and Otay Mesa after tripping SWPL and the IV-Mexico lines. (350 Mw if the new 2nd-worst contingency after SWPL was loss of the Tijuana-Otay Mesa line, leaving 2850 Mw of NSIL via SONGS; 300 Mw if the 2nd worst contingency remained as it is today, but limits on the CFE system only allowed 300 Mw of post-contingency export generation from TDM and/or Intergen. In addition, Mexico Light could allow the SDG&E-area local RA requirement to be reduced, and might allow TDM and/or Intergen to be eligible to meet that requirement.

The ISO may note that the Mexico Light scheme is dependent on TDM and/or Intergen being on line. UCAN agrees that this is so, but since the scheme would only be necessary for reliability when SDG&E loads were high (at lower loads, the existing NSIL of 2500 Mw would be adequate for reliability), and since we would expect TDM and/or Intergen to be running for economic reasons under those conditions, we don't see this as a problem. In any case, the ISO has authority to compel participating generators to remain on line using its must-run authority. Alternatively, the CT portions of TDM or Intergen could be started during the 30-minute adjustment period after an N-1 loss of SWPL contingency, and would themselves generate over 300 Mw.

Mexico Light would have little effect on annual dispatch, since it would only come into operation during SWPL outages. However, because it is likely to be so inexpensive to implement, its reliability benefits could make it very cost effective whether or not Sunrise is built. It could also be valuable insurance against delays in bringing Sunrise online. *For these reasons we urge the ISO to promptly examine the practicability and cost of Mexico Light.*

A further potential benefit of the Mexico Light alternative, and a reason to consider it for accelerated development with or without Sunrise, can be found in SDG&E's March 3, 2006 Grid Assessment Study and Transmission Expansion Plan. SDG&E reports on pp. 28 reports that its power flow test failed to converge for the "forced outage of TL50001 (IV-ML), followed immediately by tripping of

the IBGens generation." This is precisely the situation that Mexico Light is intended to ameliorate, by allowing TDM and/or Intergen to both remain on line after tripping of IV-ML and providing a path for delivery of energy from them to SDG&E.

2. "SONGS Light"

The current NSIL for SDG&E is 2500 Mw, based on a first contingency of losing SWPL, a second contingency of losing a south-of-SONGS 230 KV line, and a 2500 Mw import rating for the remaining four south-of-SONGS lines. The SIL is 2850 Mw, based on operating the system in anticipation of loss of SWPL (and the associated cross-trip of Path 45) and the 2850 Mw import limit for the south-of-SONGS lines with all five lines in service. This suggests that adding a 6th south-of-SONGS line could increase NSIL by 350 Mw, as well as increasing the SIL.

As the ISO is no doubt aware, the existing SCE-SONGS lines that form the north-of-SONGS transmission path pass right by SDG&E's Talega substation. Looping one of those lines into Talega would require no more than one mile of new transmission line, plus two new termination positions at Talega, and would create a 6th south-of-SONGS line. *UCAN urges the ISO to examine the feasibility of doing so.*

UCAN does not expect that increasing the NSIL for SDG&E to 2850 Mw would require more than just looping an existing SCE-SONGS line into Talega. The existing SCE system north of SONGS can already handle flows of up to 2850 Mw into the SDG&E system, because that is the SIL today. Similarly, a six-line south-of-SONGS path should be able to handle 2850 Mw after losing one of the six lines, because a five-line south-of-SONGS path can handle 2850 Mw today under N-0 conditions. The real question with regard to NSIL is what it would cost to loop in a line to Talega, and how the costs of doing so would be allocated between SDG&E and SCE. Such questions may have been an obstacle in the past, but with the ISO operating both the SCE and SDG&E transmission systems, and both SCE and SDG&E transmission expansion costs reflected in a statewide TAC rate, they should no longer be implementation barriers.

UCAN does not have an opinion as to how much a 6th south-of-SONGS line would increase SDG&E's SIL. That may be driven by constraints farther north in the SCE system, such as Barre-Lewis line constraints, or constraints farther south in the SDG&E system (see discussion of "SONGS Medium" below). We look forward to the ISO's analysis of the SIL issue, which goes directly to the economic (as opposed to reliability) benefits of the SONGS Light option. But even if SONGS Light provided **no** economic dispatch benefits, its reliability benefits would be substantial if it truly provided 350 Mw of increased NSIL. *Because SONGS Light should be inexpensive and quick to implement, particularly compared to Sunrise, it should be considered as both an alternative*

to Sunrise for provision of reliability and as a backup to Sunrise in the event that Sunrise cannot be online by 2010.

3. “SONGS Medium”

In its Valley-Rainbow application to the CPUC, SDG&E indicated that accommodating increased imports into its grid from the north would require a second Talega-Escondido 230 KV line to be added. The existing Talega-Escondido line is strung on double-circuit towers, so adding a second line would not require any new right of way or towers. Increasing SDG&E’s import capability at SONGS might also require either a second Talega-Escondido line or a 4th SONGS-San Luis Rey line. The SONGS Medium alternative would consist of SONGS light (looping an SCE-SONGS line into Talega) plus a new 230 KV line, either Talega-Escondido #2 or SONGS-San Luis Rey #4. *UCAN suggests that the ISO make a determination as to whether would make more sense from a powerflow and/or economic cost basis.*

SONGS Medium should provide greater reliability benefits than SONGS Light, because it would add yet another line over which to deliver generation south from the SONGS/Talega area.

A SONGS Medium alternative should also have economic benefits over and above SONGS Light. It would allow for a greater SIL, and thus allow economic dispatch benefits as well as reliability benefits. Since SDG&E has recently received CPUC approval for a 200 Mw wind project in the Tehachapis, it might also allow for increased imports of renewables. Finally, by beefing up the northern portion of SDG&E’s 230 KV system, SONGS Medium might facilitate future expansion of generation at Encina, such as SDG&E has assumed in its Sunrise “case 3” analysis in the Sunrise proceeding.

4. “SONGS Heavy”

It is unclear to UCAN at what point adding more lines south of SONGS no longer provides import benefits to SDG&E because of constraints on the SCE side of SONGS. If that point is not yet reached with SONGS Medium, or if SCE-side constraints could be resolved at low cost, then a “SONGS Heavy” alternative should also be considered.

SONGS Heavy would consist of SONGS Light (loop an SCE-SONGS line into Talega) plus **both** Talega-Escondido #2 and SONGS-San Luis Rey #4. This alternative would result in a total of 8 230 KV lines capable of delivering energy to SDG&E from SCE (SCE-Talega-Escondido, three SONGS-Talega lines, and four SONGS-San Luis Rey lines). UCAN expects that if the south-of-SONGS path can currently handle 2500 Mw with one line out, then SONGS Heavy should be able to carry 3500 Mw with one line out, and would thus provide reliability benefits at least as large as those expected by SDG&E from Sunrise.

SONGS Heavy should also increase SDG&E’s SIL by at least 1000 Mw, and thus could provide renewable import capability and economic dispatch benefits comparable to those from Sunrise, particularly if LADWP’s planned 500

KV conversion of a 287 KV line south from Victorville goes forward as planned and creates a new 500 KV path into the LA Basin. *UCAN looks forward to seeing the ISO's estimates of the cost to construct SONGS Heavy and how it compares as a full-fledged alternative to Sunrise.*

B. Demand-side alternatives

1. AMI

On March 28, 2006, SDG&E submitted its updated AMI application to the CPUC. In that application, SDG&E provides year-by-year estimates of the peak load reductions that will result from AMI. SDG&E also provides confidence intervals around its demand reduction estimates. For 2011, for example, SDG&E forecasts a 90% chance of obtaining a demand reduction of 160 Mw or more, with an expected demand reduction of 203 Mw (both numbers are at the end-user level, before adding associated loss reductions).

The ISO's analysis should include AMI impacts, since it is on a track to be developed prior to Sunrise. Given that the ISO has a variety of conservatisms built into its reliability criteria (1-in-10 weather, G-1/N-1-1 contingency planning, peak day loads), it would be appropriate to include the full forecasted levels of AMI as load adjustments. At a minimum, the ISO should include the level of AMI demand reduction which SDG&E testifies has a 90% probability of occurring, which is some 80% of the expected level.

We ask that the ISO note SDG&E's AMI-based load reductions occur not just on CPP days (7 hours per day, 13 days per year) but (to a lesser extent) in non-CPP peak hours. *Thus, the ISO should not only incorporate AMI into its reliability analyses but also into its economic analyses.* The production cost savings due to reduced on-peak loads will more than offset the production costs due to increased off-peak loads caused by AMI, and this will affect the economic value of Sunrise and any other alternative whose use is not flat in all hours of the year.

2. Other DSM programs

SDG&E justifies the reliability value of Sunrise in part by its ability to facilitate SDG&E responses to N-1-1 transmission events. Under the N-1-1 criteria, SDG&E has 20-30 minutes after an N-1 transmission contingency to prepare its system to withstand a subsequent second transmission contingency. *The ISO should include in its evaluation of Sunrise and alternatives any and all SDG&E DSM programs that would be available to provide load reductions after an N-1 transmission contingency, with response times of **under** 30 minutes.*

C. Generation alternatives

1. In-basin CTs

SDG&E's reliability analysis shows a shortfall, absent Sunrise, of 737 Mw by 2015 before accounting for AMI. With AMI, UCAN estimates the shortfall would be only 500 Mw by 2015, having increased about 90-100 Mw per year in the preceding years. *This shortfall is just the right size to be met by adding a pair of 46 Mw CTs in each year from 2010-2015 (except 2011, when the completion of AMI installation would obviate the need for one of the CTs). The ISO should examine the consequences of adding CTs in 2010-2015 as needed to meet SDG&E's post-AMI reliability needs.* UCAN expects that the economic part of the analysis of such an alternative would show much lower capital costs than Sunrise, and also lower dispatch benefits. We look forward to the ISO's views on which of these offsetting effects would be larger.

2. In-basin CCs

a. South Bay

The owners of the existing South Bay powerplant have indicated to both the CEC and CPUC their intention to replace that facility with a new 600+ Mw combined cycle plant in the 2010 timeframe. Their proposed plant is in the ISO interconnection queue, and a system impact study (SIS) has already been completed. SDG&E's Sunrise application assumes the existing South Bay generation will be retired, but not replaced. A new South Bay combined cycle, together with AMI, would more than meet the 737 Mw reliability need SDG&E projects for the year 2015. *The ISO should analyze both the reliability consequences and the economic impacts of a new South Bay generator as an alternative to Sunrise.*

b. Encina/Sycamore (SDG&E's alternative)

SDG&E's Sunrise application to the CPUC examines the economic impacts of adding 1650 Mw of new combined cycle generation at Encina and Sycamore Canyon in the 2010-2015 period. *To the extent that location matters, the ISO should look at how combined cycle additions at Encina and/or Sycamore Canyon would impact SDG&E costs and reliability.* UCAN is particularly interested in the CAISO's view of SDG&E's contention that it needs 1650 Mw of new combined cycles in lieu of adding 1000 Mw of import capacity with Sunrise, and of SDG&E's contention that interconnecting new combined cycle generation at Encina and Sycamore would cost hundreds of millions of dollars for transmission upgrades. We assume that your studies of in-basin combined cycle alternatives to Sunrise will identify any associated transmission upgrades that would be required.

Additionally, we understand that NRG is planning to file an application to fully repower Encina/Cabrillo by 2011. *It will be necessary for the ISO to factor that expected repower application into its analysis.*

II. Questions to be addressed for all alternatives

The following are a list of questions that UCAN believes the ISO needs to address for all of the alternatives it studies, including both Sunrise and any no-action alternative, in order to be able to present defensible conclusions to both the CPUC and the ISO Board regarding the cost-effectiveness of Sunrise or any other alternative. Some of the questions are self-explanatory. For others, UCAN has added explanatory text.

A. Time frame of analysis

1. *What years need to be addressed directly?*

SDG&E's CPUC filing has direct analyses of only the years 2010 and 2015. *At a minimum the ISO should analyze the same years to allow a comparison between its results and those of SDG&E.*

2. *What years need to be addressed indirectly through interpolation or extrapolation?*

B. Reliability issues

1. *What will SDG&E's SIL and NSIL be with this alternative?*

SDG&E asserts that Sunrise will increase the SDG&E-area NSIL to 3500 Mw, based on the import capacity under G-1/N-1-1 conditions, where the largest single generator is 561 Mw at Otay Mesa, the first transmission contingency is the IV-Miguel segment of SWPL, and the second transmission contingency is the North Gila-IV segment of SWPL. UCAN requests that the ISO also study the Sunrise NSIL in the case where the second transmission contingency is loss of Sunrise itself, which we presume would also trigger cross-tripping of path 45. We believe this case is more restrictive than the case studied by SDG&E. In general, if the ISO wants to use a G-1/N-1-1 planning criteria to determine the NSIL for SDG&E, the two transmission contingencies should include both 500 KV lines into SDG&E for any scenario which has two 500 KV lines to SDG&E, and should account for cross-tripping of Path 45 where applicable.

2. *What will SDG&E's future local area RA needs be with this alternative?*

Currently, SDG&E pays twice for capacity when it is charged for RMR costs for units that are not part of its RA portfolio. It pays once for the units it needs to meet its own RA obligations, and a second time for non-RA units that are under RMR contracts. UCAN believes that with the implementation of a local RA obligation in 2007, it will become cost-effective for SDG&E to meet its local RA obligations with a subset of the generators used to meet its system RA

obligations. Doing so would change the economic impacts of adding Sunrise (or any other alternative) from those calculated by SDG&E to date. We encourage the ISO to provide a credible analysis of how local RA obligations will interact with resource additions such as Sunrise.

3. *What will SDG&E's future overall RA needs be?*

4. *What will SDG&E's largest single generator contingency be with this alternative?*

SDG&E assumes that its largest single generator for G-1 reliability analysis purposes will be the 541 Mw Palomar Project in 2006-07, and the 561 Mw Otay Mesa project in 2008 and thereafter. Both Palomar and Otay Mesa are combined cycle projects with two CTs and a steam turbine (ST). Each of them is designed such that the CTs can continue operating after tripping of the ST. It is thus not clear why an outage of the entire facility should be considered a single contingency.

UCAN understands that the ISO is, understandably, reluctant to consider a 100% outage of a new combined cycle plant as anything other than a single contingency without operating evidence to the contrary. However, by the year 2010 (and certainly by the year 2015), SDG&E will have multiple years of operating experience at Palomar and Otay Mesa. *The ISO should clarify what operating experience would be necessary to allow it to change its definition of a single contingency for Palomar and/or Otay Mesa to an outage of a single CT (and associated reduction in ST output) rather than an outage of both CTs and the ST. The ISO should also indicate when, if ever, it expects SDG&E to be able to make the required showing to reduce the size of its largest single contingency below 561 Mw.*

5. *Will this alternative allow the cross-trip of Path 45 after loss of SWPL to be removed as a RAS? Both if the SWPL outage is the only transmission outage (N-1) as well as if SWPL and another line (e.g. Sunrise) are both out (N-1-1)?*

6. *What level of resources does the ISO expect to count towards SDG&E-area RA in the future?*

This question requires the ISO to consider DSM with <30 minute response time and AMI impacts on peak loads in 91 CPP hours per year. SDG&E has justified the economics of installing AMI by claiming that AMI will reduce its need to procure generation capacity. If the ISO determines that AMI does not save money by reducing generation requirements, then it must reconcile this determination with SDG&E's March 28, 2006 contention. Thus the ISO needs to clarify that it will indeed allow SDG&E to count AMI-caused reductions in demand as reducing SDG&E's reliability needs, and indicate the data and timing

associated with such capacity credits. Similarly, the ISO should consider the implications AMI impacts on peak hours outside CPP hours

Also, the ISO must consider Intermittent resources (e.g., wind) SDG&E currently has at least 50 Mw of in-basin wind generation. It has indicated in its Sunrise filings that it could install as much as 500 Mw of wind capacity in the next decade. The ISO needs to determine what data is needed to allow some fraction of this capacity to be counted as firm capacity for reliability purposes and when such data will be available (e.g., 2 years after facility operation). It must also consider the resultant fraction of installed capacity which would be countable by SDG&E as capacity for reliability purposes?

Finally, the ISO analysis should analyze imported resources (e.g., resources delivered to SDG&E via south-of-SONGS, Path 45, SWPL, or a future 500 KV line such as Sunrise or LEAPS).

7. How many Mw of RMR or equivalent generation does the ISO expect SDG&E to need in the future under this alternative?

The biggest single economic benefit claimed by SDG&E for Sunrise is a reduction in future RMR costs. To verify SDG&E's claims, the ISO needs to identify the RMR (or equivalent, post-MRTU, if any) Mw that will be required under each alternative it studies, including any no-action alternative.

C. Renewable energy deliverability

1. How many Mw of renewable energy will be deliverable to SDG&E from outside its service area under this alternative?

2. How many Mwh of renewable energy will be actually delivered to SDG&E under this alternative?

D. Economic impacts

The ISO surely understands that it cannot evaluate economic impacts in a vacuum. It will need to define a "No-Action" case to compare Sunrise and any other alternatives to. However, a No Action case cannot literally be a no-action case. It cannot assume the world of the future looks exactly like the present except for having higher loads. Thus some care must be taken in defining the No Action case. UCAN urges the ISO to look at the following six issues:

1. Quantifying capacity costs

SDG&E's Sunrise application calculates the impacts of Sunrise compared to a no-action case in which SDG&E is required to pay for about 1000 Mw more RMR generation than with Sunrise, but does not include capital costs for the

imported resources which displace RMR. *The ISO needs to include capacity costs in its economic analysis, and it needs to make sure those costs occur in all alternatives.* Thus, under the CPUC's newly implemented RA regime, SDG&E will need to pay for capacity to meet its RA obligations. Sunrise (and other transmission alternatives) may allow more RA capacity to be imported rather than obtained locally at RMR-type prices, but they will not make it free. Imported capacity and local capacity will both need to have RA costs assigned to them.

2. *Calculating energy costs*

SDG&E's Gridview modeling is based on a least-cost dispatch of the Western Grid. This kind of modeling needs to be done very carefully to avoid overcounting the prospective benefits of increased trade. In particular, must-run generation needs to be modeled carefully and accurately, or else the computer may end up claiming that new transmission lines will allow local generation in some areas to be reduced to zero. The ISO has identified thousands of Mw of local generation needs throughout California. *UCAN requests that you reflect those local generation requirements as constraints on any economic modeling you do.*

3. *Identifying transmission facilities to be built by others*

There are currently pending proposals to build at least five new 500 KV transmission lines in Southern California: DPV2 (SCE), LEAPS (Nevada Hydro), IID-Upland (LADWP), Victorville-Upland-Los Angeles (LADWP; conversion of existing 287 KV line), and Sunrise (SDG&E). A new Vincent-Mira Loma 500 KV line has also been proposed, and there are multiple 500 KV proposals farther east in Arizona and beyond. It is entirely possible that there are diminishing returns, such that it makes sense to build some but not all of these lines. If so, the order in which lines are added will determine which ones are economically desirable and which are not.

UCAN proposes that all the ISO's analyses in this case should include the DPV2 and LADWP proposals. DPV2 is almost fully permitted, and has not been opposed at the CPUC. The LADWP projects are part of the joint IID-LADWP Green Path transmission proposal and are integral to LADWP's planned renewable resource development in the Imperial Valley. It would be inconsistent to assume that IID will scrap its pre-existing Green path partnership with LADWP in order to build Sunrise with SDG&E.

On the other hand, UCAN does not propose that the ISO include LEAPS as part of its base case analyses. LEAPS is more clearly a competitor to Sunrise than a precursor to it.

4. *Identifying generation to be built by others.*

In its Sunrise filings, SDG&E has assumed that there will be 2200 Mw of geothermal generation in the Imperial Valley by 2015. UCAN believes this is both unrealistic and inconsistent with even optimistic Imperial Valley generator plans. In another place where large-scale development of new generation is expected, the wind resource area in the Tehachapis, transmission development is being done incrementally based on incremental generation development. *The ISO should also assume only incremental development of geothermal generation in the Imperial Valley. If the ISO wishes to assume full build out of Imperial County geothermal, it should assume that buildup is priced to fully recover its total costs (not priced at incremental operating costs with no capital recovery), and it should assume the LADWP-IID 500 KV line is in place prior to full build out.*

Similarly, there is currently a surplus of generation east of California, which makes it possible to import coal-based and gas-based generation from Arizona and other states at prices that would not cover the capital plus fuel plus O&M costs of a new combined cycle plant. Because of the large difference between summer and winter peak demand in Arizona, some of that surplus will persist (particularly in winter months and off-peak hours) indefinitely. However, to the extent the surplus is due to the boom in merchant generation in Arizona and Nevada in the last few years it will shrink over the next few years. The undeliverable portion of the surplus will also shrink due to various upgrades to import capacity into California, notably DPV2. *UCAN urges the ISO to be judicious in its modeling of future generation additions in Arizona and Nevada, and not implicitly assume that the current surplus will persist, let alone grow.*

5. Determining the impacts on congestion.

In its Sunrise filings, SDG&E has concluded that Sunrise can substantially reduce congestion between Imperial and San Diego Counties. This is the functional equivalent to claiming that Sunrise will substantially reduce the difference in locational marginal prices (LMPs) between Imperial and San Diego Counties. UCAN is dubious that there will be much of an LMP difference between Imperial and San Diego Counties in the future, since recent upgrades have increased SWPL capacity and north-of-Miguel 230 KV capacity to over 1900 Mw. *In conducting its analysis, ISO must be particularly careful in its analyses so as to review the LMPs associated with its modeling results.*

6. Quantifying the consumer impacts.

In its Sunrise analyses, SDG&E has pointed out that gains to generators that are under cost-of-service pricing (either contractually or by virtue of utility ownership) are actually gains to consumers, and the same for losses. SDG&E's point is well taken. However, if the ISO uses an economic evaluation method which calculates consumer and producer surpluses, it will have to very careful to identify which generators are actually owned or controlled by consumers so that changes in their costs flow to consumers and not to producers. Because the

implementation of RA is causing a substantial increase in bilateral contracting by utilities, future transmission projects that reduce producer surpluses may have unexpectedly negative impacts on consumers as well. *The ISO's economic analyses will have to take these issues into consideration.*