Rulemaking No.: R.12-03-014
Exhibit No.: ____________
Witness: Robert Sparks

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

**TRACK 4 TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

TRACK 4 TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Please describe your educational and professional background.

A. I am a licensed Professional Electrical Engineer in the State of California. I hold a Master of Science degree in Electrical Engineering from Purdue University, and a Bachelor of Science degree in Electrical Engineering from California State University, Sacramento.

Q. What are your job responsibilities?

A. I manage a group of engineers responsible for planning the ISO controlled transmission system in southern California to ensure compliance with NERC, WECC, and ISO Transmission Planning Standards in the most cost effective manner. With the California transmission system undergoing a major transformation, there are significant uncertainties that must be considered. In particular, I have been involved in the studies conducted by the ISO to evaluate systems needs in the absence of the San Onofre Nuclear Generating Station (SONGS).

Q. What is the purpose of your testimony?

A. I will describe the results of the study conducted by the ISO as directed by the May21, 2013 Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge (hereinafter "the Revised Scoping Ruling"). I will also make some recommendations as to possible next steps in Track 4 of this LTPP proceeding.

Q. Have you provided testimony about local capacity needs previously in this proceeding and in other dockets?

A. Yes. I submitted opening and rebuttal testimony addressing the ISO's assessment of local area needs in the LA Basin and Big Creek/Ventura areas in this LTPP docket, Track 1. My recommendations in Track 1 were based on the ISO's once through cooling studies conducted as part of the 2011/2012 transmission planning process. I provided similar testimony about local area needs in the San Diego local area in Docket A.11-05-023 which was based on the same once through cooling studies for San Diego. My supplemental testimony in that proceeding can be found at http://www.caiso.com/Documents/2012-04-06_A11-05-023_Sparks_SuppTest.pdf. The Commission issued Decision 13-03-029 in A.11-05-023 on March 21, 2013 and Decision 13-02-015 in Track 1 on February 13, 2013.

Q. What was the ISO asked to do in Track 4?

A. The once through cooling study results for Los Angeles and San Diego local areas that I presented in prior testimony included the assumption that SONGS would be in operation through 2022. Although the SONGS units were out of service during the evidentiary hearings in both dockets, without additional analysis and record evidence, the Commission could not make a determination about procurement needs without SONGS. Track 4 was established to evaluate the impact of a long-term SONGS outage on mid-term and long-term local capacity needs, building on the modeling assumptions adopted by the Commission in the Track 1 and SDG&E PPTA decisions in A.11-05-023. The Commission requested that the ISO model three separate cases: 2022 without SONGS, 2022 with SONGS and 2018 without SONGS. Attachment A to the Revised Scoping Ruling contains the modeling assumptions to be used to study the three scenarios. It is my understanding that the purpose of the studies described in the Revised Scoping Ruling is to provide information about the "delta" (i.e., difference) between the resource needs determined by the Commission in the two previous decisions and resources needed to meet reliability requirements in the absence of SONGS.

Q. Please briefly describe the differences between the scenarios and modeling assumptions set forth in Attachment A and the ISO's once-through-cooling study scenarios.

A. Probably the biggest differences between the prior ISO studies and the Track 4 analysis are: (a) because the SONGS outage significantly impacts both San Diego and LA Basin, these local capacity areas have been studied together as one SONGS Study Area; (b) the inclusion of future preferred resource assumptions; and (c) non-once through cooling (OTC) generation retirement assumptions, based on facility age (more than 40 years old). The ISO utilized the commercial interest RPS portfolio from the 2012/2013 transmission planning cycle. This updated portfolio has some minor changes in the system-connected distributed generation (DG) compared to the same portfolio used in the 2011/2012 transmission planning cycle by having about 193 MW more of installed capacity assumptions for DG (or approximately 87 MW of net qualifying capacity). The local capacity area study methodology and 1-in-10 year load forecast all of which the ISO used in the OTC studies, were approved in the LTPP and SDG&E decisions and used for Track 4 purposes, so there are no differences with respect to these inputs.

Because the Commission decisions approved demand response and incremental energy efficiency assumptions that differed from those the ISO used in the OTC studies, Attachment A provided very specific modeling instructions with respect to these resources and load modifiers. The Commission also directed the ISO to make certain assumptions about generator retirements for both OTC and non-OTC generating units, and provided specific locational information for incremental energy efficiency and demand response. What follows is a description of how the ISO modeled the assumptions described in Attachment A:

1. <u>CEC's Load Forecast:</u>
   The ISO modeled the 2018 and 2022 1-in-10 peak load for the LA Basin and San Diego local capacity areas based on the CEC's mid-range economic and demographic assumptions. The most recently adopted forecasts are contained in the 2012 Integrated Energy Policy Report, August 2012 revision, form 1.5d.[1] The following provides summary of the CEC's 1-in-10 heat wave load forecast for the LA Basin and San Diego local capacity areas.

Table 1 – CEC's 1-in-10 Heat Wave Load Forecast

	2018 Forecast	2022 Forecast
L.A. Basin	21,870 MW	22,917 MW
San Diego	5,652 MW	6,056 MW
Total SONGS Study Area	27,522 MW	28,973 MW

[1] http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Mid_Case_LSE_and_Balancing_Authority_Forecast.xls

2. <u>Incremental Uncommitted Energy Efficiency (i.e., Incremental EE):</u>
Per the CPUC's Revised Scoping Ruling, the low level of savings for incremental EE was modeled for the studies. The CEC provided specific locations (i.e., bus-bar data) for modeling incremental EE. The following table provides a summary of the incremental EE, which was further scaled up by 4.76% to account for the estimated resulting distribution system loss reduction due to the incremental EE. The CEC noted that the incremental EE was provided at the customer's meter level. To account for distribution losses when these values are modeled at the sub-transmission voltage level (i.e., 66kV or 69kV), between 4 – 5% losses need to be added. The 4.76% was provided by SCE and to account for distribution losses. The same factor was also utilized for factoring the distribution losses in San Diego as SDG&E was unable to provide an estimate at the time. This factor, however, is within the range which the CEC mentioned it would be for factoring in distribution losses for incremental EE.

Table 2 – Summary of Incremental EE Assumptions

	2018 Forecast/Modeled	**2022 Forecast/ Modeled**
L.A. Basin	427 / 448 MW	751 / 787 MW
San Diego	99 / 104 MW	187 / 196 MW
Total SONGS Study Area	526 / 552 MW	938 / 983 MW

The remainder of SCE service area (i.e., non-LA Basin) was also modeled with incremental EE as reflected in the following table. This value equals the difference of the total SCE area and the LA Basin values. A factor of 4.76% to account for distribution losses was also applied to the behind-the-meter incremental EE. There was no further additional incremental EE modeling for San Diego other than the above values.

Table 3 – Incremental EE Assumptions for the Remainder of SCE System

	2018 Forecast/Modeled	2022 Forecast/Modeled
Total SCE	556 / 582 MW	973 / 1019 MW
Non-LA Basin (SCE)	129 / 134 MW	222 / 232 MW

3. Demand Response (DR):

The Revised Scoping Ruling recommended a total of 189 MW of DR to be used for the SONGS Study Area under post first contingency, in preparation for the second contingency condition. This condition is sometimes referred to as an overlapping N-1-1 contingency condition, and is considered a Category C (C.3) contingency by both NERC and WECC reliability standards. The most critical N-1-1 contingency for the SONGS Study Area is the outage of the Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink. The ISO modeled this amount of DR for the SONGS Study Area based on the following most effective locations in the LA Basin (173 MW), after the occurrence of the first contingency, in preparation for the second contingency. Any location for DR (16 MW) in San Diego would be effective for this critical N-1-1 contingency. For the locations in the LA Basin, the ISO modeled the amount of DR based on recommendations from the CPUC Energy Division staff. For the locations in San Diego, the ISO selected the substations that serve the highest MWs of customer load. Similar to the EE modeling described above, the DR was scaled up by a factor 4.76% to account for distribution losses.

The DR available after occurrence of the first contingency in preparation for the next contingency was based on programs that respond to dispatch instructions within 30 minutes or less, including notification time to customers.

DR based on programs with slower response times would not be available within the required 30-minute time frame after the first contingency. The additional DR amount of 997 MW, based on the Revised Scoping Ruling, would be utilized to mitigate reliability concerns in the post second contingency condition. This would be applied to contingencies that are of Category D. An example is a major generating facility outage that occurs prior to or after the overlapping N-1-1 contingency. The amount of DR modeled for 2018 time frame is the same as modeled for year 2022.

Table 4 – DR Modeled at the Most Effective Locations in the LA Basin and San Diego Areas

Substation	2018 (MW)	2022 (MW)
Alamitos	6.75	Same amount as 2018
Barre	27.0	
Del Amo	25.3	
Ellis	42.4	
Johanna	16.2	
Santiago	28.8	
Viejo	9.9	
Villa Park	24.8	
Bernardo	8.4	
Margarita	8.4	
Total	197.95	

4. <u>Distributed Generation (DG):</u>

There were two types of DG modeled for the studies: one was system-connected DG (i.e., DG connected beyond the customer load meter) as part of the CPUC Commercial Interest RPS portfolio, and the other one was small photovoltaic (PV) to be connected behind the customer load meter. System-connected DG was modeled in the power flow study cases as part of the Commercial Interest RPS portfolio. Behind the meter DG (i.e., small PV), is largely embedded in the IEPR demand forecast, except for an approximate 1,300 MW of installed capacity in the ISO Balancing Authority Area. This amount is the net short of meeting the 3,000 MW CSI program target. As the Revised Scoping Ruling recommended, the location of the amount of 477 MW and 616 MW of net short installed capacity for behind the metered PV in the SONGS Study Area (or estimated 216 MW and 278 MW of production at peak load conditions) for 2018 and 2022, respectively, is difficult to determine and therefore should be considered located in the most effective locations , similar to the additional larger amount of DR, for mitigating reliability concerns associated with contingencies that are subsequent to second contingency condition (i.e., post second contingency) following an N-1-1 overlapping contingency. Because the Revised Scoping Ruling discusses the behind the customer load meter-connected DG (small PV) in detail, the ISO does not want to repeat the assumptions for that connected DG here, but rather provides information for the system-connected DG for the SONGS study area. The following table provides the assumptions of system-connected DG, as part of the Commercial Interest RPS portfolio that was modeled in the power flow study cases for 2018 and 2022 for the SONGS Study Area. The values are expressed in production (based on net qualifying capacity) and installed capacity. Net qualifying capacity was suggested by the CPUC at a factor of about 45% of its installed capacity at peak loads.

Table 5 – System-Connected Distributed Generation Assumptions

	2018 NQC / Installed Capacity (MW)	**2022 NQC / Installed Capacity (MW)**
LA Basin	95 / 211 MW	247 / 549 MW
San Diego Area	186 / 413 MW	210 / 467 MW

5. Transmission Projects:

Per the Revised Scoping Ruling, transmission projects that received the ISO Board and Management's approval as of March 2013 should be modeled in the study cases; specifically the projects that would affect the local capacity requirements in the SONGS Study Area. The following table includes the latest projects in the SONGS Study Area that were approved by the ISO Board of Governors in the 2012/2013 Transmission Plan.[2]

Table 6 – List of the latest ISO Board and Management Approved Transmission Projects in the SONGS Study Area

ISO Board Approved Transmission Projects in the SONGS Study Area (2012/2013 Transmission Plan)	**LA Basin**	**San Diego Area**
Barre – Ellis Reconfiguration Project	√	
Install one 80 MVAR (each) at Johanna and Santiago and two 80 MVAR shunt capacitors at Viejo Substation	√	
Convert Huntington Beach Units 3 & 4 to Synchronous Condensers	√ (Modeled for 2018 Study Case)	

[2] (http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf), as well as from the Addendum to the Final 2013 Local Capacity Technical Analysis (http://www.caiso.com/Documents/Addendum-Final2013LocalCapacityTechnicalStudyReportAug20_2012.pdf).

ISO Board Approved Transmission Projects in the SONGS Study Area (2012/2013 Transmission Plan)	LA Basin	San Diego Area
South Orange County Dynamic Reactive Support (aka 480 MVAR SVC Near SONGS)		√
Talega Area Dynamic Reactive Support (240 MVAR synchronous condenser at Talega 230 kV bus)		√
Sycamore – Penasquitos 230kV Line		√

6. <u>New Generation Project Assumptions:</u>

The following generation projects in the SONGS Study Area were modeled in the power flow study cases. The first three are completed projects in 2013, and the fourth is an approved repowering project in San Diego that was included in the SDG&E PPTA decision.

- Walnut Creek Energy Center (500 MW)
- NRG El Segundo Repowering Project (570 MW)
- Sentinel Peaker Project (850 MW)
- Escondido Repowering Project (45 MW)

7. <u>Generation Retirement Assumptions:</u>

The Revised Scoping Ruling included specified retirement assumptions about once-through cooled (OTC) generation and also aging or refurbished non-OTC plants. The following table includes the OTC units and non-OTC units in the SONGS Study Area. The Track 4 study assumed that OTC units would meet the compliance dates of the State Water Resource Control Board (SWRCB) by either retiring or repowering. Specific repowering assumptions assumed in the study were described above in the new generation project assumptions.

Table 7: Generation Retirement Assumptions in the Starting Study Cases

Generating Plant	Total Plant Capacity (MW)	Individual Unit Capacity (MW)	LCR Area	SWRCB Compliance Date	Scheduled Retirement Date*
Alamitos (OTC)	2011	Unit 1 (175) Unit 2 (175) Unit 3 (332) Unit 4 (336) Unit 5 (498) Unit 6 (495)	LA Basin	12/31/2020	
El Segundo (OTC)	670	Unit 3 (335)^ Unit 4 (335)	LA Basin	12/31/2015	Unit 3 (6/2013)^
Huntington Beach (OTC)	904	Unit 1 (226) Unit 2 (226) Unit 3 (225) Unit 4 (227)	LA Basin	12/31/2020	Unit 3 (11/2012)** Unit 4 (11/2012)**
Redondo Beach (OTC)	1343	Unit 5 (179) Unit 6 (175) Unit 7 (493) Unit 8 (496)	LA Basin	12/31/2020	

Generating Plant	Total Plant Capacity (MW)	Individual Unit Capacity (MW)	LCR Area	SWRCB Compliance Date	Scheduled Retirement Date*
Encina (OTC)	946 (OTC) 15 (non-OTC)	Unit 1 (106) Unit 2 (103) Unit 3 (109) Unit 4 (299) Unit 5 (329)	San Diego	12/31/2017	
Etiwanda (Non OTC)	640	Unit 3 (320) Unit 4 (320)	LA Basin	N/A	
Long Beach (Non-OTC Refurbished Plant)	260	Unit 1 (65) Unit 2 (65) Unit 3 (65) Unit 4 (65)	LA Basin	N/A	
Broadway Unit 3 (Non-OTC)	65	Unit 3 (65)	LA Basin	N/A	Repowered as Glenarm Unit 5 at 71 MW)
Cabrillo II (Non-OTC)	188	El Cajon (16) 9 Kearny Mesa Units (Total 136) 2 Mira Mar Units (Total 36)	San Diego	N/A	

Generating Plant	Total Plant Capacity (MW)	Individual Unit Capacity (MW)	LCR Area	SWRCB Compliance Date	Scheduled Retirement Date*
San Onofre Generating Station (SONGS)	2,246	Unit 1 (1,122) Unit 2 (1,124)	SONGS Study Area (LA Basin and San Diego)	12/31/2022	6/7/2013
Total	**9,288 MW #**				

Notes:

^ El Segundo Unit 3 was retired in June 2013 upon completion of El Segundo Energy Center

* Only publicly announced retirement is indicated in the table

** Huntington Beach Units 3 and 4 were retired in January 2012 to provide offsets for emission credits required by the new Walnut Creek Energy Center (500 MW), scheduled to be on-line in June 2013. However, these two units temporarily were brought back to service for the summer 2012 due to extended outage of SONGS.

Assuming Broadway Unit 3 is repowered with 71 MW, the net total retirement would be 9,217 MW.

8. RPS Portfolio:

The Commercial Interest RPS portfolio, utilized for the 2012/2013 transmission planning process, was used for Track 4 studies. The CPUC Energy Division staff also provided the listing of RPS projects for respective years 2018 and 2022 in Chart 2 in the Revised Scoping Ruling.

Q. Did the ISO study the SONGS outage in the 2012/2013 transmission planning cycle?

A. Yes. The ISO examined the long-term grid reliability impact in the absence of the two nuclear generating stations, Diablo Canyon Power Plant (DCPP) and SONGS. As part of the 2012-2013 transmission planning cycle, two studies related to the nuclear generation backup plan were performed. One addressed the extended outage scenario at DCPP or SONGS for an intermediate time frame (2017-2018). The other considered the reliability concerns and potential mitigation options in the long term (i.e., 2022 time frame). The study related to DCPP absence focuses on grid reliability implications for northern California and the ISO overall. The study related to SONGS absence focuses on grid reliability implications for southern California, specifically the local capacity areas in southern California, and the ISO overall. In addition, the ISO also performed the combined DCPP and SONGS absence studies, which focused on the grid reliability assessment for the ISO bulk transmission system.

Q. Besides the assumption that DCPP was offline, in addition to the SONGS outage, how does the study conducted in the 2012/2013 transmission planning cycle differ from the Track 4 analysis?

A. The following are the major differences between the studies conducted in the 2012/2013 transmission planning cycle and the Track 4 analyses:

- The Track 4 study includes the ISO-approved transmission projects from the 2012/2013 Transmission Plan in the SONGS Study Area, as discussed above;
- The Track 4 study includes the preferred resources described in the Revised Scoping Ruling and discussed above;
- For the Track 4 study the ISO prepared a 2018 Commercial Interest RPS case with the projects projected to be in service by that year. Previously in the 2012/2013 transmission planning cycle, the ISO utilized the CPUC RPS Calculator to prepare the 2018 study case. However, the 2018 study case in

the 2012/2013 transmission planning cycle assumed the same amount of system-connected DG in the SONGS Study Area as in the 2022 Commercial Interest RPS case. The 2018 study case prepared for the Track 4 studies has different level of system-connected DG for 2018 and 2022 as described on page 8 above. This difference in system-connected DG model has a marginal effect on the local capacity study results.

- The Track 4 study included the additional non-OTC generation retirement assumptions described above. This results in an increase of an additional 1,088 MW of non-OTC generation retirement in the SONGS Study Area for Track 4 analyses as discussed above.

Q. For purposes of the two no-SONGS Track 4 scenarios, what assumptions were made about reactive support in the ISO's power flow studies?

A. Consistent with the Revised Scoping Ruling, the ISO modeled the following reactive support projects:

- A total of 320 MVAR of shunt capacitors in the Southern Orange County at Johanna, Santiago and Viejo Substations;
- A total of 480 MVAR Static VAR Compensator (SVC) near San Onofre 230kV switchyard;
- A total of 240 MVAR of synchronous condensers at Talega 230kV Substation; and
- An additional total of 150 MVAR of shunt capacitors at Penasquitos 230kV Substation currently under development by SDG&E.

In the 2012/2013 transmission planning cycle, the ISO evaluated, in an exploratory assessment, additional dynamic reactive support located at other substations in San Diego area (i.e., San Luis Rey, Penasquitos and Mission).

Q. Please describe how reactive support in specific locations can be used to address reliability impacts created by the absence of SONGS.

A. SONGS provided a base load generation of 2,246 MW of real power and 1,100 MVAR of dynamic reactive support to both SCE and San Diego local capacity areas. Its location, electrically, is ideal because it provided both real power and reactive power to meet electric demand as well as voltage support needs, particularly under a forced outage condition when SDG&E's electric system is disconnected from the Arizona, IID and CFE systems and would have to rely on the support from the SDG&E northern system that is connected to SCE. SONGS not only provided a strong source of real power for meeting demand, it also provided dynamic reactive output for voltage support for purposes of mitigating a potential voltage collapse due to instantaneous reactive power losses caused by massive and sudden increased power flow on SCE's and SDG&E's systems to meet SDG&E's entire imported power need under an overlapping outage condition. With the SONGS closure, there is an absence of 2,246 MW of real power to meet electric demand, as well as the loss of 1,100 MVAR of dynamic reactive output for voltage support under contingency conditions.

Q. Would additional reactive support at the SONGS location, in addition to some of the other locations that the ISO considered in the 2012/2013 planning cycle, be sufficient to offset the permanent SONGS outage?

A. No. As I described above, the ISO evaluated various locations for installing dynamic reactive support devices such as static VAR compensators (SVC), or synchronous condensers to make up for the loss of dynamic reactive support that SONGS provided. It is not surprising that the optimal locations for these dynamic reactive support devices are at or near SONGS, because the voltage needs to be supported to enable increased power transfer from SCE to SDG&E system under the critical contingency condition (overlapping loss of SWPL and Sunrise). However, there is a limit on where dynamic reactive support can be provided because its primary function is to provide voltage support to mitigate potential voltage collapse. The power still needs to be generated elsewhere to provide real power to meet electric demand. Furthermore, there may be environmental or permitting limits associated with locating dynamic reactive support facilities in the best electrical locations, and sites that are far from heavily populated areas may be much less effective.

Q. Did the ISO evaluate any transmission mitigation solutions - including additional reactive support- as part of the Track 4 analysis?

A. No. The ISO strictly followed the Revised Scoping Ruling. As I described above, the ISO's understanding is that the purpose of the Track 4 studies is to update the decisions in Track 1 and the SDG&E PPTA proceeding to account for the difference in resource needs in the absence of SONGS. In light of SCE's June 7, 2013, announcement that SONGS will be permanently shut down, a timely evaluation of additional resource needs certainly makes sense.

Q. **What were the ISO's objectives for determining resource needs in the LA Basin/San Diego study area?**

A. The ISO's study objectives included: (a) minimizing the OTC generation repowering or replacement need; and (b) minimizing residual new resource needs. To meet these objectives, the ISO used an iterative process to determine the general vicinity of optimal resource locations to mitigate reliability concerns. In doing so, the ISO relied on a number of factors: (i) power flow studies; (ii) inputs from the state energy agencies regarding forecasted preferred resources at specific load substations; (iii) inputs from the utilities regarding potential sites for resource development (i.e., small peaking units), and (iv) known generation development in the area. In addition, ISO Board approved transmission projects, as listed in Table 6, were incorporated in the starting study cases. The ISO views the study results described below as a benchmark from which consideration of potential alternatives to conventional generation (e.g., additional preferred resources, new transmission) can be evaluated to determine the extent to which they would reduce the need for conventional generation.

Q. Please describe the ISO's study process and the study results for the 2018 Without SONGS scenario.

A. Table 9 provides a summary of the study results for year 2018 without SONGS. Please note that the study results are based on the preferred resource assumptions listed on Tables 2 – 5. OTC generation with compliance dates up to December 31, 2017 was assumed to be off-line as listed in Table 7. In addition, the non-OTC generation in the SONGS study area, as discussed above and listed in the same table, was assumed to be off-line in the starting 2018 study cases. The primary reliability constraint that drives resource needs is the post-transient voltage instability concern under the most critical Category C overlapping outage (N-1-1) of the Sunrise Powerlink, system readjusted, and then followed by the outage of the Southwest Powerlink line. The studies were performed and identified based on applicable WECC voltage stability criteria. The following explanation is provided for better understanding of the individual column heading of the following table.

- OTC Replacement Assumptions: OTC generation repowering or replacement in compliance with the SWRCB's Policy on OTC plants.
- Additional resource needs: these could be from additional conventional resources, or preferred resources. If new conventional generation, it is referred to generating units that are typical 100 MW in size. The locations are approximately based on their electrical effectiveness to

provide mitigation to reliability concerns as well as informal inputs from the utility staff to the ISO in previous planning cycles. Only general location information is provided here in the summary table.

- Extension of Non-OTC Aging Generation Assumptions: potential interim extension power purchasing contract to keep aging non-OTC generation in operation until long-term mitigation (i.e., generation repowering or replacement, etc.) can be implemented.
- Repowering of Non-OTC Generation Assumptions: if these generating units are needed for the long term (i.e., 2022 or beyond) because of being located in effective locations, the ISO assumes that these units would be replaced by repowering.

Table 9 – Summary of the 2018 Without SONGS Study Results

Area	OTC Replacement Assumptions (MW)	Additional Resource Assumptions (MW)	Extension of Non-OTC Aging Generation Assumptions (MW)	Repowering of Non-OTC Generation Assumptions (MW)
Southwestern LA Basin	0	0	0	260
Northwestern LA Basin	0	0	0	0
Eastern LA Basin	0	0	640	0
Subtotal LA Basin	***900***			
Northwest San Diego	520		0	0
Southwest San Diego	0	100	0	0
Southeast San Diego	0	300	0	0
Subtotal San Diego	***920***			
Total SONGS Study Area	***1820***			

Based on the study results in the table above, there is a need to extend the operation of 640 MW of non-OTC generation in the eastern LA Basin as well as the repowering or replacement of 260 MW of non-OTC generation in the southwestern LA Basin. For San Diego sub-area, the ISO identified the need for repowering or replacement of 520 MW of OTC generation in the northwest area, adding 100 MW of resources in the southwest area, and constructing 300 MW of new generation in the southeastern San Diego area. These locations are based on known resource development in the San Diego area.

Q. What was the ISO's study process and the study results for 2022 Without SONGS scenario?

A. The *incremental* resource needs (beyond year 2018) are summarized in Table 10. Just as with the 2018 Without SONGS scenario, these study results are based on the incremental energy efficiency, demand response and system connected PV assumptions listed in Tables 2 – 5 above. The columns and headings for this table are the same as Table 9 except for the Non-OTC Retirement column, which reflects the non-OTC generating unit retirements as suggested in the Revised Scoping Ruling that were not assumed retired in the 2018 study.

Table 10 – Summary of the 2022 Without SONGS Study Results

(Incremental Resource Need)			
Area	**OTC Replacement Assumptions (MW)**	**Retirement of Non-OTC Aging Generation Assumptions (MW)**	**Additional Resource Assumptions (MW)**
- Southwestern LA Basin	2912	0	550
Northwestern LA Basin	0	0	0
Eastern LA Basin	0	-640	0
Subtotal LA Basin	***2822***		
Northwest San Diego	0	0	0
Southwest San Diego	0	0	0
Southeast San Diego	0	0	0
Subtotal San Diego	***0***		
Total SONGS Study Area	***2822***		

Similar to the year 2018 Without SONGS study results, the primary reliability concern that drives the resource needs in the SONGS Study Area is the post-transient voltage instability concern due to overlapping Category C outage of the Sunrise Powerlink, system readjusted, then followed by the Southwest Powerlink line. This is the most critical outage that affects reliability of the SONGS Study Area. The ISO identified the need to repower or replace 2,912 MW of OTC generation in the southwestern LA Basin that is subject to OTC compliance by the end of 2020 time frame. In addition, to be able to retire 640 MW of non-OTC generation the eastern LA Basin, instead of replacing it in kind at its existing location, the ISO evaluated other effective locations to see if there could be lower generation needs. Approximately 550 MW of new resources at various locations in the southwestern LA Basin could facilitate the retirement of the 640 MW of the non-OTC generation in the eastern LA Basin. I also note that even if the 640 MW of this non-OTC generation remains in operation, approximately 400 MW of generation still is needed at various locations in the southwestern LA Basin to mitigate the reliability concern. Therefore, with resources at the more effective locations, we would be able to reduce the generation need in the LA Basin, as a whole, by 490 MW (640 + 400 – 550 = 490 MW). The following table provides a consolidated summary of the years 2018 and 2022 generation need, and the total for the two timelines.

Q. Can you provide a comparison of the 2018 and 2022 Without SONGS scenarios?

A. Yes. Table 11 contains a comparison of the total resource needs in the SONGS study area, given the generation retirements discussed earlier in my testimony and the additional resource locations I described in the preceding answer.

Table 11 – Summary of the Without SONGS Study Scenarios for 2018 and 2022

	2018 - WithoutSONGS				2022 - WithoutSONGS (IncrementalNeed)			Total Resource Needs (MW)
Area	OTC Replacement Assumptions (MW)	Additional Resource Assumptions (MW)	Extension of Non-OTC Aging Generation Assumptions (MW)	Repowering of Non-OTC Generation Assumptions (MW)	OTC Replacement Assumptions (MW)	Retirement of Non-OTC Aging Generation Assumptions (MW)	Additional Resource Assumptions (MW)	
Southwestern LA Basin	0	0	0	260	2912	0	550	3722
Northwestern LA Basin	0	0	0	0	0	0	0	0
Eastern LA Basin	0	0	640	0	0	-640	0	0
Subtotal LA Basin	*900*				*2822*			*3722*
NorthwestSan Diego	520	0	0	0	0	0	0	520
Southwest San Diego	0	100	0	0	0	0	0	100
Southeast San Diego	0	300	0	0	0	0	0	300
Subtotal San Diego	*920*				*0*			*920*
Total SONGS Study Area	***1820***				***2822***			***4642***

Q. Did the ISO consider other locations in the SONGS study area for resources to replace the generation assumed to be retiring?

A. Yes. The ISO performed an additional power flow analyses for a scenario where further resources were added in the San Diego area. The purpose of this analysis was to demonstrate the interaction between the LA Basin and San Diego local capacity areas, and to a certain extent, how much LA Basin resource needs would be reduced when resources are added in San Diego. The analysis also provides information suggesting the range of flexibility associated with where replacement resources can be electrically located and still effectively meet the local need. Although the feasibility of constructing new generation in this vicinity is unknown, for this analysis, the ISO assumed 565 MW of conventional gas-fired resources connected to San

Onofre 230kV switchyard. The following table provides a summary of the study results, indicating a1.24 MW reduction in the LA Basin for every 1 MW of generation that is added to San Onofre switchyard. The study results further illustrate how resource development location affects the total resource needs in local capacity areas.

Table 12 – Summary of Additional Resource Additions in San Diego (in the – Without SONGS Scenarios)

	2018 - Without SONGS				2022 - Without SONGS (Incremental Need)			Total Resource Needs (MW)
Area	OTC Replacement Assumptions (MW)	Additional Resource Assumptions (MW)	Extension of Non-OTC Aging Generation Assumptions (MW)	Repowering of Non-OTC Generation Assumptions (MW)	OTC Replacement Assumptions (MW)	Retirement of Non-OTC Aging Generation Assumptions (MW)	Additional Resource Assumptions (MW)	
Southwestern LA Basin	0	0	0	260	2462	0	300	3022
NorthwesternLA Basin	0	0	0	0	0	0	0	0
Eastern LA Basin	0	0	640	0	0	-640	0	0
Subtotal LA Basin	*900*				*2122*			*3022*
NorthwestSan Diego	520	0	0	0	0	0	565	1085
Southwest San Diego	0	100	0	0	0	0	0	100
Southeast San Diego	0	300	0	0	0	0	0	300
Subtotal San Diego	*920*				*565*			*1485*
Total SONGS Study Area	***1820***				***2687***			***4507***

Q. **What are the residual resource needs for the SONGS study area, based on the ISO Track 4 study results compared to the Track 1 SDG&E A.11-05-023 procurement decisions?**

A. As I discussed above, the ISO evaluated two different total resource development scenarios, illustrated in Tables 11 and 12 above. In Table 11, the ISO assumed that about 80% of the replacement resource development would be in the LA Basin, and 20% would be located in San Diego. For the scenario depicted in Table 12, the ISO assumed about two-thirds of the replacement resource development would be in the LA Basin, and one-third would be in San Diego. Because these two scenarios produced different total resource needs for the SONGS study area, identifying residual resource needs requires two calculations. Table 13 sets forth the total resource needs for both scenarios in 2022 based on the study results from Track 4 (total need by 2022 without SONGS) and then identifies the residual needs by subtracting the maximum procurement authorizations from Track 1 and D. 13-03-029 in A.11-05-023 from the total need study result. As depicted in the last column, the calculated residual resource needs for the study area are 2,534 MW, or 2,399 MW, depending on resource development scenario each of the two local capacity areas. The preferred resource and DG modeling assumptions that I described earlier in this testimony have been included for informational purposes.

Table 13 – Residual Resource Needs in 2022 Without SONGS

Scenario	Track 1 Decisions (MW)		Track 4 Studies (2022) (SONGS Study Area = LA Basin + San Diego) (MW)				Residual Resource Needs (Total Track 4 – Maximum Track 1) for SONGS Study Area (MW)
	LA Basin	San Diego	DR Assumptions Modeled for Studies***	Inc. EE Assumptions Modeled for the Studies	System-Connected DGs (Commercial Interest)	Identified Resource Needs Without SONGS	
80%/20% (LA/SD) Total Resource Development Scenario	1,800*	308**	198	983	1,016 (Installed) 457 (NQC)	4,642	4,642 – 1,800 - 308 = 2,534 Breakdown: LA Basin (1,922) San Diego (612)
Two-thirds/One-Thirds(LA/SD) Total Resource Development Scenario	1,800*	308**	198	983	1,016 (Installed) 457 (NQC)	4,507	4,507 – 1,800 – 308 = 2,399 Breakdown: LA Basin (1,222) San Diego (1,177)

Notes:

*Maximum authorized procurement resources in the LA Basin, including preferred resources

**Includes 10 MW of net increase for Escondido

*** Post first contingency values (for use in preparation for second contingency)

Q. Please describe the 2022 With SONGS study process and study results.

A. For this request, the ISO performed two study scenarios: one without the SONGS separation and the other with the SONGS separation scheme in service. In brief, the

SONGS separation scheme can be described as a relay protection system that was designed to automatically separate the SCE and SDG&E electric system during times of system trouble. Specifically, the scheme would open the circuit breakers between the SCE and SDG&E systems at the SONGS 230kV switchyard when the SONGS interconnection overload relay exceeds 8,000 Amps. This action would electrically separate the SCE and SDG&E systems. The ISO consulted with SCE and was advised that the SONGS separation scheme likely would have been put back in service had SONGS returned to service although, the scheme would have been evaluated for a potential higher setpoint. Therefore, because there was uncertainty about the form of the SONGS separation scheme had SONGS returned to service, the ISO performed two studies for the 2022 With SONGS scenario: with and without the SONGS separation scheme as it existed at the time SONGS was taken offline. The following table includes a summary for both scenarios for the 2022 With SONGS studies. These are mutually exclusive values and are not additive.

Table 14 – Summary of 2022 Studies (With SONGS Scenario)

	2022 - With SONGS SONGS separation scheme disabled		2022 - With SONGS SONGS separation scheme maintained	
Area	OTC Replacement Assumptions (MW)	New Generation Assumptions (MW)	OTC Replacement Assumptions (MW)	New Generation Assumptions (MW)
Southwestern LA Basin	1588	0	1438	0
Northwestern LA Basin	0	0	0	0
Eastern LA Basin	0	0	0	0
Subtotal LA Basin	*1588*		*1438*	
Northwest San Diego	0	0	0	0
Southwest San Diego	0	0	0	140
Southeast San Diego	0	90	0	300
Subtotal San Diego	*90*		*440*	
Total SONGS Study Area	***1678***		***1878***	

For the 2022 With SONGS and with SONGS separation scheme maintained, the constraints are related to transmission facility loading concerns for the LA Basin and San Diego local capacity areas. Specifically, the need for generation resources (OTC generation repowering or replacement need in the amount of 1,438 MW) in the Western LA Basin is triggered by the thermal loading concern on the Serrano – Villa Park No. 1 230kV line due to an overlapping Category C N-1-1 contingency of the Serrano – Lewis No. 1, system readjusted, followed by the Serrano – Villa Park No. 2 230kV line. For the San Diego local capacity area, the new generation need (440 MW) is caused by the need to maintain flow within 8,000 Amps going south at the SONGS switchyard between SCE and SDG&E under an N-1-1 contingency of the Sunrise Powerlink, system readjusted, followed by the Southwest Powerlink line outage.

For the 2022 With SONGS and the SONGS separation scheme disabled, the primary need for generation resources (via 1588 MW of OTC generation repowering or replacement) in the Western LA Basin is caused by the same overloading concern on the Serrano – Villa No. 1 230kV line under the same N-1-1 contingency as described above. For San Diego local capacity area, the need for new generation (90 MW) is caused by overloading concern on the San Onofre – San Luis Rey No. 1 230kV line under the same N-1-1 contingency in San Diego.

Q. Has the ISO considered the impact of the higher amount of demand response and additional small PV suggested in the Revised Scoping Ruling as being available under post second contingency conditions?

A. Yes, to a certain extent. In a 2022 without SONGS scenario, the post second contingency includes a major combined cycle generating facility outage that occurs after an N-1-1 overlapping contingency of the Sunrise Powerlink and Southwest Powerlink lines. According to NERC reliability standards, this is a Category D contingency (extreme event resulting in two or more (multiple) elements removed or cascading out of service). Under these circumstances, the additional 997 MW of DR and approximately 796 MW (installed capacity) of customer-connected small PV identified in the Revised Scoping Ruling for post-second contingency could help to avoid a certain amount of load shedding. SDG&E has installed an involuntary load dropping scheme that would automatically drop approximately up to two blocks of 400 MW of involuntary load in this scenario to avoid a widespread uncontrolled power system outage in the WECC system. Implementation and utilization of this demand response and small PV could reduce the reliance on this involuntary load shedding under the condition described above.

Q. Is the ISO recommending that the Commission make a procurement decision based on these study results?

A. Not at this time. As I mentioned previously, the ISO views these study results as a benchmark from which consideration of potential alternatives to conventional generation (e.g., additional preferred resources, new transmission) can be evaluated to determine the extent to which they would reduce the need for conventional generation. The ISO will continue its studies to evaluate potential transmission mitigation solutions-including additional reactive support- that might address a portion of these needs. These studies are being conducted as part of the 2013/2014 transmission planning cycle that is currently underway. The ISO is also willing to evaluate any additional preferred resources that are determined through this proceeding to be viable from a development standpoint to determine the extent to which they may reduce the needs for conventional generation. The ISO also wants to consider incorporating the 2013 IEPR demand forecast which is anticipated to be completed and adopted by the CEC Commission by the end of this year.

Q. Are there differences between the assumptions in the 2013/2014 cycle studies and the Track 4 studies?

A. The ISO 2013/2014 transmission planning cycle utilizes the same load forecast and incremental uncommitted energy efficiency as the Track 4 studies. In addition, the Track 4 analysis includes the DR assumptions described in the Revised Scoping Ruling recommended, whereas the 2013/2014 TPP study base assumptions do not yet include these amounts (but can be considered as a mitigation option). Additional non-OTC generation retirements in the SONGS Study Area are incorporated for Track 4 studies, whereas the starting 2013/2014 TPP base cases do not include these assumptions for the LA Basin area.

Q. Does the ISO recommend that the transmission planning study results be presented to the Commission in Track 4 to inform the procurement decision?

A. Yes. The ISO recommends that the Commission wait to make a decision about the need for additional resources until the ISO has completed its studies of potential transmission mitigation solutions (including the need for additional reactive support). With that information, the Commission can then consider the appropriate resource "mix" that can meet the local reliability needs arising from the SONGS retirement. Such a mix can include additional preferred resources and other alternatives to conventional resources, depending on location and effectiveness.

Q. Can you suggest a possible procedural timetable for presentation of the ISO's additional study results and a Commission decision?

A. Yes. The ISO's draft study results will be presented in the draft 2013/2014 Transmission Plan which is usually presented at the end of January. The ISO will be able to present testimony on transmission mitigation solutions by the end of March, 2014 This will allow for a Commission decision on additional resource needs related to the SONGS outage by July, 2014.

Q. Does this conclude your testimony?

A. Yes, it does.