UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NextEra Desert Center Blythe, LLC	**)**	
	)	
v.	**)**	**Docket No. EL15-47-000**
	)	
California Independent System	**)**	
Operator Corporation	**)**	

MOTION FOR LEAVE TO ANSWER AND LIMITED ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO ANSWER OF NEXTERA DESERT CENTER BLYTHE, LLC

The California Independent System Operator Corporation ("CAISO")[1] submits this answer to NextEra Desert Center Blythe, LLC's ("Desert Center") answer of March 26, 2015. This answer is limited to rebutting certain factual assertions and arguments that Desert Center raises for the first time in its March 26 pleading. Therein, Desert Center attempts to rehabilitate its position that, even though the interim West of Devers ("WOD") project was the product of a one-off negotiated agreement, the CAISO should nevertheless have treated the project as having been "proposed . . . in accordance with" the CAISO's transmission planning process, and therefore eligible to receive Merchant Transmission CRRs under the CAISO tariff. Desert Center's arguments are based on factually erroneous assumptions regarding references to the interim WOD upgrades in the CAISO's transmission planning process, a misplaced view of the applicability of Commission precedent, and an interpretation of the CAISO

[1] Capitalized terms not otherwise defined herein have the meanings set forth in the Master Definitions Supplement, appendix A to the CAISO tariff.

tariff that would require the CAISO to ignore the plain meaning of the relevant language.

The Commission should accept this answer because it will provide a more complete and accurate record and assist the Commission in its evaluation of Desert Center's complaint.

I. ANSWER

In its answer to Desert Center's complaint, the CAISO explained that the Interim WOD Project is not entitled to receive Merchant Transmission CRRs under the CAISO tariff because it only authorizes the CAISO to provide such CRRs under two general circumstances: (1) to projects proposed "in accordance with" the CAISO's transmission planning process, as set forth in Section 24 of the CAISO tariff;[2] and (2) for Network Upgrades identified in the CAISO's generator interconnection process and reflected in a Large Generator Interconnection Agreement, if a generator responsible for funding such upgrades elects to receive Merchant Transmission CRRs in lieu of direct cash reimbursement.[3]

The CAISO demonstrated that the interim WOD upgrades did not qualify under either provision. The interim WOD project was the outgrowth of extensive discussions among the CAISO, Southern California Edison ("SCE"), and Desert Center aimed at identifying whether a temporary solution could be implemented

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[2] *See* CAISO Tariff Section 36.11 (stating that a Project Sponsor that turns over a Merchant Transmission Facility to CAISO control and does not receive ratepayer reimbursement may elect to receive Merchant Transmission CRRs); definition of Project Sponsor (a developer "that proposes the construction of a transmission addition or upgrade in accordance with Section 24").

[3] The CAISO tariff also provides for the allocation of Merchant Transmission CRRs to two specific projects that had transmission usage rights recognized by the CAISO prior to the adoption of the CAISO's current market design and transmission planning process.

to allow Desert Center's Genesis McCoy Solar Project to receive full capacity deliverability status pending the completion of the permanent Network Upgrades identified in the CAISO's generator interconnection process. Because the interim WOD upgrades were never proposed or evaluated pursuant to the process set forth in Section 24 of the CAISO tariff, they do not meet the definition of a Merchant Transmission Facility. Also, the interim WOD upgrades are not Network Upgrades. Therefore, the CAISO had no authority under its tariff to allocate Merchant Transmission CRRs to Desert Center, and adopting Desert Center's argument would effectively nullify these provisions.

In its answer, Desert Center does not dispute the facts regarding the origins of the interim WOD upgrades, but nevertheless continues to assert that the CAISO should have treated the interim WOD upgrades as "proposed . . . in accordance with" Section 24. Desert Center suggests that this interpretation follows from references to the interim WOD project contained in CAISO transmission plans. The CAISO explained in its answer that the references to the interim WOD project in the CAISO's transmission plans cited by Desert Center in its complaint do not demonstrate that the interim WOD project was proposed in accordance with Section 24 because it was discussed as a pre-existing assumption, rather than the product of application and review under the Section 24 procedures. Desert Center now states that it has located two additional references to the interim WOD project in the CAISO's transmission plans that show it was "much more than an assumption in a model."[4] Desert Center misunderstands both of these additional references.

First, Desert Center, pointing to Table 5.9.2 in the CAISO's 2010-2011 transmission plan, erroneously asserts that the interim WOD project was included in a list of "category 1 projects which are identified as needed" in the CAISO's 2010-2011 transmission plan.[5] This is incorrect. The interim WOD project is not identified as a Category 1 project on such list or anywhere else in the 2010-2011 transmission plan. Desert Center may be confused by how the tables are numbered in this portion of the plan because they do not directly correspond to the numbering of the text sections. *Section* 5.9.2 of the report discusses the category 1 projects the CAISO selected as needed in the 2010-2011 planning cycle, but *Table* 5.9.2, which includes the interim WOD project, merely lists various projects that will facilitate California's ability to meet its 33% renewable portfolio standards. Table 5.9.2 does not list the Category 1 projects selected by the CAISO in the transmission planning process. Rather, Category 1 projects are identified in *Section* 5.9.2 of the transmission plan and the corresponding *Table* 5.9.3, which do include the interim WOD project.[6] Also,

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4 Desert Center Answer at 5.

5 *Id*.

6 This is unsurprising, given that Category 1 projects consist exclusively of policy-driven transmission projects which the CAISO has determined, in the transmission planning process, to be needed to meet state or federal policy requirements or directives "and are recommended for approval as part of the comprehensive Transmission Plan in the current cycle." These do not include Merchant Transmission Facilities. Table 5.9.3 does reference the interim WOD project in a note, pointing out that these upgrades will mitigate potential reliability concerns prior to the completion of the permanent WOD upgrades. However, Table 5.9.3 and the associated discussion in Section 5.9.2 make clear that the Mirage-Devers 230kV line reconductoring upgrades are the only Category 1 transmission projects identified in this section of the transmission plan.

both the heading and the text of Table 5.9.2 make clear that inclusion in this table does not mean that a project was processed and approved through the CAISO's transmission planning process or that the CAISO considered the project as having gone through that process. Not only does Table 5.9.2 include transmission projects outside of the CAISO's footprint,[7] it also includes *generation* projects, which, even under the broadest reading of Section 24, obviously do not qualify as transmission projects "proposed . . . in accordance with" the CAISO's transmission planning process.[8]

Desert Center's reliance on the reference to the interim WOD project on pages 211-12 of the 2011-2012 transmission plan fares no better.[9] The portion of that plan cited by Desert Center merely notes that in conducting its study of maximum import capability from Imperial Irrigation District, in accordance with its business practices, the CAISO assumed an increase in capability in 2014 based in part on the in-service date of the entire interim WOD project, as well as upgrades being planned and constructed by Imperial Irrigation District on its

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[7] *See* CAISO 2010-2011 Transmission Plan (relevant excerpts included with this filing as Attachment A) at pp 354-55, Table 5.9.2, entries 2 (referring to upgrades proposed by IID (*i.e*. the Imperial Irrigation District)) and 6 (assuming internal upgrades built by IID to accommodate IID generation).

[8] For example, the list includes the permanent West of Devers Upgrades, which the 2010-2011 transmission plan identifies as LGIA/LGIP upgrades that interconnection studies identified as needed, not transmission plan upgrades. *See* Attachment A at pp 15-16, 222, Tables E1 and 4.2.1. Not only does the transmission plan not identify the interim WOD upgrades as Category 1 facilities, it does not identify them as LGIP/LGIA upgrades identified in the interconnection study process, further confirming that they were approved outside of both the transmission planning and generator interconnection processes. As discussed in the CAISO's initial answer, treatment of the interim WOD facilities is governed by a separate, Commission-approved agreement -- the January 9, 2012 Letter Agreement between NextEra Desert Center Blythe, LLC and Southern California Edison Company.

[9] Desert Center Answer at 5.

system. Nothing in this discussion indicates or suggests that the interim WOD project was "proposed . . . in accordance with" the CAISO's transmission planning process, either as a Merchant Transmission Facility or other type of transmission project. The relevant provision of the version of the business practice manual in effect at the time the 2011-2012 plan was approved makes clear that this study is not limited to projects identified through the transmission planning process, but rather "will *assume* that *previously approved* transmission additions and upgrades are placed in service, and that new generating resources that were assumed in the base case . . . have achieved commercial operation."[10] Indeed, this same section of the 2011-2012 plan identifies upgrades being constructed on the Imperial Irrigation District System as a dependency for increased import capability. Obviously, the CAISO was not studying those upgrades as part of its planning process. Applying Desert Center's logic, however, the fact that the CAISO's transmission plans reference these facilities as necessary for increasing import capability means that they should be treated as having been proposed and approved under Section 24. This is, of course, inappropriate because the CAISO does not perform transmission planning for external systems, particularly those that are not even Commission-jurisdictional public utilities. In any event, revisions to the interim WOD upgrades before they were placed in-service -- namely forgoing a load shedding and generation dropping scheme that initially had been considered -- resulted in there being no

[10] CAISO Reliability Requirements Business Practice Manual, Version 11, Section 5.1.3.5.1 (emphases added), available at http://bpmcm.caiso.com/BPM%20Document%20Library/Reliability%20Requirements/Reliability_Requirements_BPM_V11.doc

increased import capability. Merely adding the series reactors paid for by Desert Center did not increase import capability.

In summary, these two references merely show that the CAISO included the interim WOD facilities in its transmission planning assumptions, just like it does for any facility or activity (*e.g.,* transmission, generation, demand response) that may impact the system once the CAISO has sufficient confidence that it will be developed and placed into service regardless of the origin. As such, these references not only do not support Desert Center's argument, they undercut it.

Desert Center also argues that the CAISO and SCE have failed to identify any requirements under Section 24 that Desert Center or the Interim WOD project "might have violated."[11] This argument ignores the fact that the CAISO explained in its answer that Section 24 contains a specific set of procedures for submitting and evaluating Merchant Transmission Facilities that must be followed, and none of these were actually followed with respect to the interim WOD upgrades.[12] The most basic of these is that an entity that wishes to propose a Merchant Transmission Facility must submit such proposal during the appropriate request window, using the appropriate forms, and satisfy the associated information and technical requirements.[13] Desert Center met none of

[11] Desert Center Answer at 3.

[12] *See* CAISO Tariff Section 24.1 ("The comprehensive Transmission Plan will identify Merchant Transmission Facilities meeting the requirements for inclusion in the Transmission Plan . . . ."); Section 24.4.3 (describing the timing windows during which the CAISO will accept "proposals for Merchant Transmission Facility projects"); Section 24.4.6.1 (setting forth the criteria by which the CAISO evaluates Merchant Transmission Facility proposals).

[13] *See* CAISO Tariff Section 24.4.3. For example, Section 24.4.3 (b) requires that "[a]ll solutions proposed during the Request Window must use the forms and satisfy the information and technical requirements set forth in the Business Practice Manual."

these requirements with respect to the interim WOD upgrades, for the simple reason that they were developed in order to provide Desert Center with interim deliverability for its generation facility pending the implementation of the permanent WOD facilities.

Desert Center ignores these requirements, suggesting that even if this process was not followed, the Interim WOD project should nevertheless be treated as a Merchant Transmission Facility because it meets the CAISO's "substantive planning standards."[14] This line of argument aptly illustrates the fundamental flaw in Desert Center's reasoning: the definition of Merchant Transmission Facility does not turn on whether an entity can make a *post hoc* demonstration that a facility meets some subset of requirements in the CAISO's transmission planning standards. The CAISO tariff is clear that a Merchant Transmission Facility is limited to facilities *proposed* in accordance with Section 24 of the CAISO tariff. Desert Center presents absolutely no evidence that the interim WOD upgrades were *proposed* according to the process set forth in Section 24. Desert Center would have the CAISO interpret this phrase in a way that would effectively render it a nullity and make compliance with the tariff optional. Such an approach would be incompatible with the statutory requirement that public utilities apply the terms of their tariffs as filed, and are not at liberty to modify such terms absent an appropriate Section 205 filing.

Desert Center also argues that the interim WOD project should be treated as having been proposed in accordance with the CAISO's transmission planning process because section 24.2(e) "expressly incorporates the generator

[14] Desert Center Answer at 3, 5.

interconnection process (and assessments of generator deliverability) within . . . Section 24."[15] Even, assuming, *arguendo*, that this language means that all upgrades identified through the CAISO's generator interconnection process should be treated as "proposed . . . in accordance with" Section 24, it still does not support Desert Center's argument with respect to the characterization of the interim WOD project. As explained in the CAISO's answer to the complaint, the interim WOD project was not identified in the CAISO's generator interconnection studies and was not the product of the CAISO's interconnection process. The CAISO's interconnection studies identified deliverability network upgrades, and those upgrades were incorporated into Desert Center's interconnection agreement. The interim WOD project came about separately as a stop-gap solution pending the in-service date for the permanent deliverability upgrades identified in the CAISO's interconnection process. The interim WOD upgrades allowed Desert Center to meet its commercial needs for achieving full capacity deliverability status prior to completion of the permanent delivery Network Upgrades.[16]

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15 *Id*. at 5-6.

16 This also undercuts Desert Center's argument regarding the 2008 Commission order, in which the Commission accepted the CAISO's proposal to add to its tariff a new section (found at Section 24.14.3.2 of the current tariff) to permit the allocation of Merchant Transmission CRRs to FPL Energy, LLC ("FPL") for an existing transmission upgrade in order to replace the outdated firm transmission rights that FPL already held. 125 FERC ¶ 61,328 (2008). Desert Center points out that the only reason this amendment was needed was because the FPL upgrade was an existing merchant upgrade rather than a new upgrade. Even if this is correct, the CAISO's current tariff only provides for Merchant Transmission CRRs for network upgrades funded by generation developers as an alternative to direct reimbursement. However, the January 9, 2012 Letter Agreement approved by the Commission expressly states that the interim WOD upgrades are not Network Upgrades, and they were not identified through the CAISO's generator interconnection studies and process.

Desert Center attempts to analogize the CAISO's position regarding the eligibility of the interim WOD project for Merchant Transmission CRRs to *Southwest Power Pool*, 149 FERC ¶ 61,076 (2014), in which the Commission rejected SPP's attempt to limit long-term firm transmission rights to entities that actually take transmission service from SPP. Desert Center suggests that if the CAISO tariff is interpreted to limit the availability of Merchant Transmission CRRs to projects that are proposed through the CAISO's transmission planning process, then the Commission would likely not find the CAISO to be compliant with Guideline 3 of Order No. 681.[17] This argument is flawed. First, there is a significant difference between conditioning the availability of firm transmission rights based on whether a customer agrees to take some other service under a transmission provider's tariff, and requiring that, in order to receive CRRs, potential merchant developers follow a set of transparent and non-discriminatory tariff procedures that the Commission has determined to be just and reasonable *as written*. Accepting Desert Center's argument would not only negate these procedures, it would basically say that merchant developers do not have to follow the rules in the tariff in order to receive CRRs. This would raise the question as to whether market participant compliance with other tariff provisions, timelines, and processes is likewise optional. Adopting Desert Center's position would affirmatively require transmission providers to include in their tariffs language broad enough to ensure that they guarantee firm transmission rights to any project that might be able to demonstrate, even well after the project is planned

[17] Desert Center Answer at 8.

and implemented, some incidental congestion benefit, regardless of its origins or whether the applicable tariff process was followed or not.

II. CONCLUSION

For the reasons explained in this pleading, and in the CAISO's original answer to Desert Center's complaint, the CAISO respectfully requests that the Commission deny Desert Center's request to find that the CAISO tariff provides for the allocation of Merchant Transmission CRRs relating to the Interim WOD project, or that the CAISO tariff is unjust and unreasonable as a result of not providing for such allocation.

Respectfully submitted,

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Attachment A

California ISO
Shaping a Renewed Future

2010-2011 Transmission Plan

May 18, 2011
Approved by ISO Board of Governors

4) 33% RPS Generation Portfolios and Transmission Assessment

The transition to greater reliance on renewable generation creates significant transmission challenges because renewable resource areas tend to be located in places distant from population centers. As a result, development in these areas often requires new transmission lines. The ISO is keenly aware that without transmission in place, developers are extremely reluctant to invest in generation. At the same time, an entirely reactive transmission planning process creates its own problems — most significantly, the time required to develop generation is typically much shorter than the time required to develop a new transmission line. In other words, a transmission process that relies on generators making investments first can leave generation without the necessary transmission for a significant period of time.

The RTPP addresses this challenge and uncertainty by creating a structure for considering a range of plausible generation development scenarios and identifying transmission elements needed to meet the state's 2020 RPS goals. Commonly known as a least regrets methodology, the portfolio approach allows the ISO to consider resource areas (both in-state and out-of-state) where generation build-out is most likely to occur; evaluate the need for transmission to deliver energy to the grid from these areas; and identify any additional transmission upgrades that are needed under one or more portfolios. The ISO 33% RPS assessment is described in detail in chapters 4 and 5 of this plan.

The scenario development methodology is straightforward and begins with evaluating the probability of renewable resource build-out using criteria set forth in the tariff[4]:

Commercial interest in geographic locations evidence by signed purchase power and interconnection agreements;

The results of the CPUC procurement proceedings, as well as similar proceedings sponsored by other regulatory agencies;

Planning level cost estimates of transmission required for alternative resource locations;

Potential energy and capacity values of resources located in various zones;

Publicly available environmental information about the resource locations as well as potential environmental, economic and reliability impacts of additional transmission elements needed to access such resources;

Potential future connections to alternative resource locations;

Potential resource integration requirements;

[4] Section 24.4.6.6

The effect of other transmission upgrades and additions being considered for approval during the planning process; and

The effects of uncertainty on any of the other criteria that could increase the risk of stranded investment.

By weighing the LTPP discounted core[5] procurement information, as well as previously identified transmission projects in various stages of approval, permitting and construction against the tariff criteria, the ISO developed four resource portfolios and populated each one with sufficient generation to meet the 33% RPS goals. Additional transmission was then added to each portfolio as needed to deliver the generation to the ISO grid.

The ISO portfolios cover a broad range of plausible generation possibilities including relatively high levels of internal resources, out-of-state generation and distributed smaller generation, as well as a hybrid portfolio that reflects a balance of potential sources of traditional and renewable energy. The generation resources comprising these four portfolios reflect the latest and best available information on the commercial interests of transmission customers, as measured by interconnection queue positions and whether the resources have signed power purchase agreements with California load-serving entities. Other factors such as cost, procurement policies, permitting, environmental assessments conducted by RETI, and resource financing capabilities were part of the metrics used to evaluate each portfolio. The hybrid portfolio represents an amount of out-of-state renewable procurement that tends to maximize the use of existing import transmission; an amount of distributed generation that exceeds the amount in the CPUC's discounted core, but is plausible, especially given emerging state policies; and a moderate build-out of large in-state renewable generation areas that are already farthest along in development. Given these attributes, the hybrid portfolio was designated as our base case because it is considered the more likely scenario to occur.

According to the tariff and the least regrets methodology, the additional transmission elements added to each portfolio to support the 33% RPS goals were considered to be policy-driven and were placed into category 1 or category 2.

In addition to transmission already approved by the ISO through the transmission planning process, the ISO considered Large Generator Interconnection Procedures (LGIP) network upgrades required to serve renewable resources that either have or were expected to have signed generator interconnection agreements. As such, these transmission upgrades and additions form a core part of the ISO analysis methodology.

The ISO assessment of the transmission projects identified above indicate that those projects with some additional minor system upgrades are sufficient to meet the 33% RPS target by 2020. These transmission

[5] The CPUC chose projects for the discounted core based on two publicly available criteria that adequately demonstrate developer interest: projects must have a signed power purchase agreement (PPA), and a permitting application submitted to the responsible permitting entity (CEC, BLM) must be judged data adequate.

upgrades were tested under the four ISO generation portfolios and all of the projects identified above were determined to be needed.

For this transmission plan, the ISO has concluded that some upgrades to WECC Path 42 are also needed to deliver renewable resources under development in Imperial County that are modeled in the base case portfolio.

The ISO also identified other upgrades that are potentially needed but require further analysis in the next transmission planning cycle as more information becomes available regarding renewable generation development and integration requirements. For example, environmental concerns are growing over the level of development occurring in the California desert. Some of the facilities below would allow development to increase in areas where already disturbed land is available for possible renewable resource development.

Table E1 provides a summary of the various transmission elements of the 2010/11 transmission plan for supporting California's RPS goals. These elements are composed of the following categories:

- Major transmission projects that have been previously approved by the ISO and are fully permitted by the CPUC for construction;
- Additional transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the approval process;
- One policy-related transmission project; and
- Policy-related projects that are potentially needed but will be carried forward for evaluation in the next transmission planning cycle.

Table E1: Elements of the 2010/11 ISO Transmission Plan Supporting Renewable Energy Goals

Transmission Facility	Potential Renewable energy Delivery	Renewable Deliverability potential with upgrade
	(TWh)	(MW)
Transmission Facilities Approved and Permitted For Construction		
Sunrise Powerlink	4.1	1,700
Tehachapi Transmission Project	18.2	5,500
Colorado River - Valley 500 kV line	2.9	1,600
Eldorado – Ivanpah 230 kV line	3.6	1,400

Additional LGIP Network Transmission not Permitted		
Borden Gregg Reconductoring	2	800
South of Contra Costa Reconductoring	0.8	300
Pisgah - Lugo	4.1	1,750
West of Devers Reconductoring	5.7	3,100
Carrizo Midway Reconductoring	2.1	900
Coolwater - Lugo 230 kV line	1.4	600
Needed Policy-Driven Transmission Elements		
Mirage-Devers 230 kV reconductoring (Path 42)	3.6	1,400
Potentially Needed Policy-Driven Transmission Elements		
Midway-Gregg 500 kV line		
Gregg - Herndon 230 kV line Reconductoring		
Warnerville - Wilson 230 kV line Reconductoring		
Barton - Herndon 115 kV line Reconductoring		
Manchester - Herndon 115 kV line Reconductoring		
Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)		
400 MVAr reactive power support at Sycamore, Mission, and Talega 230 kV substations		
The third Miguel 500 kV transformer		
Total	48.5	19,050

5) Reliability Assessment

The reliability studies necessary to ensure compliance with North American Electric Reliability Corporation (NERC) and ISO planning standards are a foundational element of the transmission plan. During the 2010/2011 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure

Policy-driven facilities are identified through a scenario based study approach involving several steps.[27] These are summarized as follows:

1. Develop RPS portfolios as described in greater detail later in this chapter.
2. Verify the need under each scenario for transmission under development through the LGIP process but not permitted for construction yet.
3. Use production simulation, power flow and transient stability analysis to identify additional transmission facility needs in each of the scenarios.

4.1.2 Planning Paradigm

The lead times from transmission project inception to planning, permitting and construction can extend to as much as 10 years, which can potentially hinder an aggressive renewable energy development schedule. The planning period can be particularly long when the generation sources are located relatively far from load, as is the case with many renewable resources. One potential remedy is to make transmission planning less reactive and more anticipatory of future renewable generation needs. While this solution has the benefit of facilitating development and potentially reducing development costs, it also has the potential to lead to building more transmission than might be necessary.

The plan identifies the transmission needs for each of the four scenarios described in detail in the following section. Each scenario represents a generation development path toward meeting the 33% RPS goals. The process of developing plausible generation portfolios relies to a large degree on the following three main data sources: the CPUC list of discounted core projects, the ISO queue and interconnection processes, and environmental scoring provided by RETI. The likelihood of development in different regions will change as these scenarios are updated in future planning cycles. For example, detailed environmental studies for generation permitting applications will provide new data on regional development, which will be reflected in future transmission plans.

4.2 Base Input Assumptions for Comprehensive Transmission Planning to Meet 33% RPS

To meet the 33% RPS portfolio standard by 2020, the grid must have sufficient transmission capacity to interconnect renewable generation, as well as to transport the renewable energy to load. Some transmission upgrades have been identified or approved in earlier transmission planning processes prior to this comprehensive transmission planning study or as network upgrades in large generator interconnection agreements and LGIP studies. Table 4.2.1 summarizes these transmission projects.

[27] Section 24.4.6.6 of the approved tariff for the RTPP lists detailed criteria that the ISO uses in its analysis to identify need policy-driven transmission elements.

The additional transmission capacity provided by the upgrades listed in Table 4.2.1 were considered in the developing the 33% RPS portfolios.

Table 4.2.1 — Transmission projects considered in the 33% RPS portfolio development

Transmission Upgrade	Approval Status		Renewable Deliverability Potential with upgrade
	ISO	CPUC	MW
Carrizo - Midway	Transition Cluster	Pending PTC approval	900
Sunrise Powerlink	Approved	Approved	1700
Eldorado - Ivanpah	LGIA	Approved	1400
Pisgah - Lugo	LGIA	Need to file CPCN	1750
Valley - Colorado River	Approved	Approved	
West of Devers Upgrade	LGIA	Need to file CPCN	4700
Tehachapi	Approved	Approved	4500
Wind and Solar diversity in Tehachapi	Transition Cluster		1000
Coolwater - Lugo 230 kV line	LGIA	Need to file CPCN	600
South of Contra Costa reconductoring	Transition Cluster		300
Borden - Gregg 230 kV line reconductoring	Transition Cluster		800
Llano - Kramer 500 kV line, Kramer - Inyokern 230 kV, Bishop - Inyokern 230 kV lines	Transition Cluster		800

Some new substations are needed for the transmission projects listed in Table 4.2.1 and for interconnecting new generation projects. These substations are listed in Table 4.2.2.

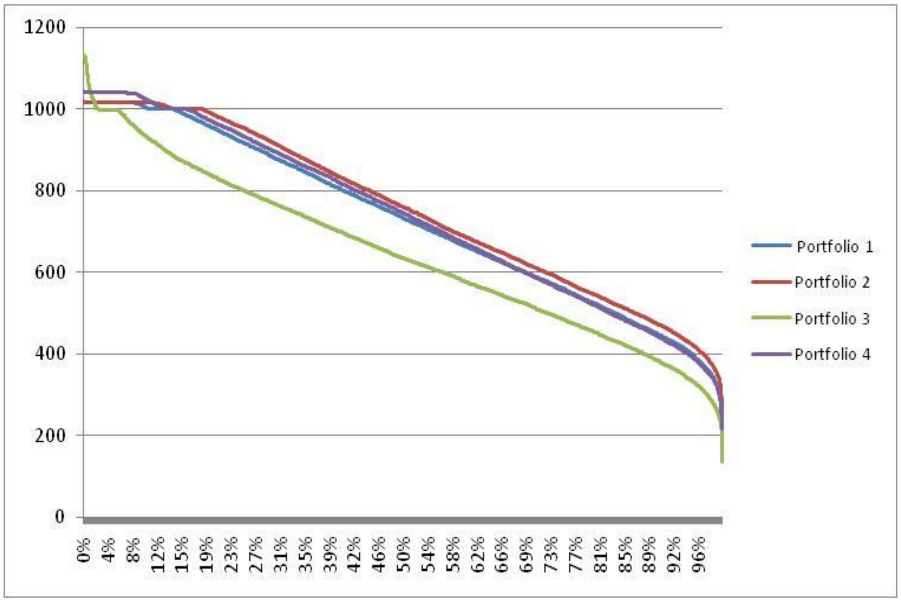
Table 4.2.2 — New substations associated with the transmission projects considered in the 33% RPS portfolio development

Substation	Associated transmission lines	Served CREZs
New ECO 500 kV	Imperial Valley – Miguel 500 kV loop-in	San Diego South
New RedBluff 500 kV	Colorado River – Dever 500 kV lines loop-in	Riverside East
Conversion of Pisgah	Pisgah – Lugo 500 kV line; El	Pisgah, Mountain Pass

230 kV to 500 kV	Dorado – Lugo 500 kV loop-in	
New Jasper 230 kV	Coolwater – Lugo 230 kV loop-in	Kramer, San Bernardino Lucerne
Conversion of Ivanpah 115 kV to Ivanpah 230 kV	El Dorado – Ivanpah 230 kV	Mountain Pass
New Llano 500 kV	Vincent – Lugo 500 kV line loop-in; Kramer – Llano 500 kV line	Kramer, Owens Valley
New Carrizo 230 kV	Morro Bay – Midway 230 kV loop-in	Carrizo South and North, Santa Barbara

The new transmission facilities listed in Table 4.2.1 are shown on the map of California as in Fig. 4.2.1.

Fig. 5.8-11 Sunrise Power Link Flow Duration Curves



5.9 Conclusions from Comprehensive Planning Assessment to Meet 33% RPS

Comprehensive assessments have been performed on all four 33% renewable portfolios, including power flow and stability assessments, a deliverability assessment and a production cost simulation.

On top of the transmission upgrades that are listed in Table 4.1.1, which have been modeled in the starting power flow base cases and the production model, both generation and transmission needs to accommodate 33% renewable portfolios have been identified in the 33% RPS comprehensive transmission

Section 5.9.1 summarizes the study results.

Section 5.9.2 identifies the projects that have been selected as category 1 projects which are identified as needed in this planning cycle.

Section 5.9.2 identifies the projects that have been selected as category 2 projects which could be needed and which will be carried forward into future planning cycles.

5.9.1 Summary of 33% RPS comprehensive transmission planning assessment

Comprehensive assessments have been performed on all four 33% renewable portfolios, including power flow and stability assessments, a deliverability assessment and a production cost simulation.

On top of the transmission upgrades that are listed in Table 4.1-1, which have been modeled in the starting power flow base cases and the production model, both generation and transmission needs to accommodate 33% renewable portfolios have been identified in the 33% RPS comprehensive transmission planning studies. The study results are summarized in Table 5.9-1.

Table 5.9-1 Summary of 33% RPS Planning Study Results

	Mitigation for Portfolio 4	Mitigations for other portfolios	Alternative
1	1) Maintain 2000 MW generation inside San Diego, meanwhile assuming Western LA Basin available capacity is not less than 6200 MW (see SCE-1) 2) The third Miguel 500 kV transformer 3) Revise the existing Border SPS to trip Border and Otay generation for outage of Silvergate-South Bay 230 kV N-1 4) 400 MVAr reactive power support at Sycamore and Mission230 kV substations	Portfolio 1: 1) Maintain 2550 MW generation inside San Diego and 6700 MW in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer Portfolio 2: 1) Maintain 2350 MW generation inside San Diego and 6550 MW generation in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer	Portfolios 1, 2 and 4: 1) 1400 MW SDGE generation 2) IV ROA phase shifter to limit CFE loop flow to no higher than 550 MW under N-0 condition 3) Revise Border SPS to trip Border and Otay gens (N-1 South Bay-Silvergate 230 kV to relieve overload on Sweetwater-Sweetwater Tap 69 kV and Division-Sampson 69 kV). 4) 1100 MVAr reactive support at Sycamore, Mission, Talega, and Otay Mesa 230kV (need 700 MVAr reactive support if Western LA Basin is assumed repowered, see SCE-1) 5) Third Miguel 500 kV transformer 6)IV ROA series reactor (20 ohms) for N-1 and N-2 contingencies, reactor less than 20 ohms overloads Otay Mesa-Tij following N-2 (need 30 ohms for Portfolio 1) (the need of the series reactor can be eliminated if SDGE internal generation is 1500 MW, 1600 MW and 1700 MW for Portfolio 4, 2 and 1, respectively, and Western LA Basin is assumed repowered, see SCE-1)
2	IID proposed upgrades in the IV 230 kV area	Portfolio 1: same as Portfolio 4.	N/A
3	N/A	Portfolio 1: N.Gila - Imperial Valley 500 kV Series Cap upgrade and install SPS to bypass the series cap once the flow exceeds the emergency rating.	N/A
4	1) Maintain generation capacity in Western LA Basin at about 6200 MW level for the 1-in-5 load assumption 2) San Diego available capacity not less than 2000 MW, otherwise, 400 MVar reactive Var support at SDGE is needed (See SDGE-1)	Portfolio 1: 1) Maintain generation capacity in Western LA Basin at about 6700 MW level for the 1-in-5 load assumption, 2) San Diego available capacity not less than 2550 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1) Portfolio 2: 1) Maintain generation capacity in Western LA Basin at about 6550 MW level for the 1-in-5 load assumption 2) San Diego available capacity not less than 2350 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1)	1)Build the new Mira Loma - Lighthipe 500 kV line and upgrade the existing Lighthipe 230 kV substation to 500 kV. 2) Install dynamic reactive power support at Santiago, Eagle Rock, Encina and South Bay (500 MVAr at each) 3) SPS of load tripping at Lewis following Serrano-Lewis 230 kV N-2. This alternative may minimize the requirement of OTC repower
5	Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)	Portfolio 1: same as Portfolio 4	Bypass the series cap following the contingency overload

6	Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) and Devers-Mirage 230 kV lines Assume IID internal upgrades to accommodate IID's new generation	All portfolios: Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42).	
7	WOD interim solution prior to WOD 230kV upgrades: Install serial reactors on Devers – San Bernardino 230 kV line and Devers – Elcasco 230kV line; Install SPS to trip generation and load under contingency conditions	All portfolios: same as Portfolio 4	N/A
8	1) Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line	Portfolio 1: same as Portfolio 4 Portfolio 2: 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line	1) Build the new McCall - Gregg 230 kV line 2) Reconductor Borden - Gregg 230 kV line 3) ReconductorMidway - Gates 230 kV #1 and #2 lines 4) Replace terminal equipment on Gates - Henrietta Tap 230 kV line 5) Develop the emergency rating for the Gates 500/230 kV transformer 6) Revise the existing SPS for Los Banos South N-2 contingency to increase generation tripping in South of Los Banos 7)Reconductor 20 miles of the Warnerville – Wilson 230 kV line;upgrade terminal equipment 8) Reconductor 9.2 miles of the Sanger – Mc Call 115 kV line; upgrade terminal equipment. 9) Oro Loma 70 kV Area Reinforcement proposed in annual NERC compliance reliability assessment
9	N/A	Portfolio 2: Re-rate Malin – Round Mt. 500 kV #2 line	Revise the existing SPS with additional generation tripping in NW for CapJack - Olinda 500 kV lines N-2, or reduce the NW HVDC schedule that modeled in Portfolio 2
10	N/A	Portfolio 1: Reconductor Los Banos - Westley 230 kV line	Revise LosBanos North SPS to increase generation tripping
11	N/A	Portfolio 2: Reconductor Temblor - San Luis Obispo 115 kV line and 50 MVAr reactive power support at San Luis Obispo 115 kV bus	Add a new 115 kV line between Temblor - San Luis Obispo
12	N/A	Portfolio 1: SPS to trip generation at Morro Bay area	Reconductorithe Morro Bay - Templeton 230 kV #1 and #2 lines
13	SPS to trip generation at Contra Coasta area	Portfolio 1 & 2: N/A	Reconductoring the Contra Coasta Sub - Contra Coast 230 kV line
14	SPS to trip generation at Colusa and revise the existing SPS for Round Mountain - Table Mountain N-2 and Table Mountain South N-2	Portfolio 1&2: N/A	Reconductoring Deleven - Cortina
15	SPS to bypass series cap on the remaining Round Mt. - Table Mt. 500 kV line p after the Round Mt. - Table Mt. 500 kV line N-1	Portfolio 1&2: N/A	SPS to trip more NW generation

Table 5.9.2 Summary of Estimated Costs and Schedules for 33% RPS Comprehensive Transmission Planning Upgrades

	Mitigation for portfolio 4	Cost	Schedule of upgrades for portfolio 4	Mitigations for other portfolios	Cost	Schedule of upgrades for portfolios 1 & 2	Alternative	Cost	Schedule of alternative upgrades
1	1) Maintain 2000 MW inside San Diego, meanwhile assuming Western LA Basin available capacity is not less than 6200 MW (see SCE-1) 2) The third Miguel 500 kV transformer 3) Revise the existing Border SPS to trip Border and Otay generation for outage of Silvergate-South Bay 230 kV N-1 4) 400 MVAr reactive power support at Sycamore and Mission230 kV substations	1) Depends on generation development 2) $75M 3) $0.1 4) $164M ($82M at each substation)	1) Depends on generation development 2) 60 months 3) 12 months 4) 36 months at each substation	Portfolio 1: 1) Maintain 2550 MW generation inside San Diego and 6700 MW in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer Portfolio 2: 1) Maintain 2350 MW generation inside San Diego and 6550 MW generation in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer	1) Depends on generation development 2) additional $82M 3) $100,000 1) depends on generation development 2) additional %82M 3) $100,000	1) Depends on generation development 2) 36 months 3) 12 months 1) depends on generation development 2) 36 months 3) 12 months	1) 1400 MW SDGE generation 2) IV ROA phase shifter to limit CFE loop flow to no higher than 550 MW under N-0 condition 3) revise Border SPS to trip Border and Otay gens (N-1 South Bay-Silvergate 230 kV to relieve overload on Sweetwater-Sweetwater Tap 69 kV and Division-Sampson 69 kV). 4) 1100 MVAr reactive support at Sycamore, Mission, Talega, and Otay Mesa 230kV (need 700 MVAr reactive support if Western LA Basin is assumed repowered, see SCE-1) 5) Third Miguel 500 kV transformer 6)IV ROA series reactor (20 ohms) for N-1 and N-2 contingencies, reactor less than 20 ohms overloads Otay Mesa-Tij following N-2 (need 30 ohms for Portfolio 1) (the need of the series reactor can be eliminated if SDGE internal generation is 1500 MW, 1600 MW and 1700 MW for Portfolio 4, 2 and 1, respectively,	1) N/A 2) $100M 3) $100,000 4) $328M ($82M at each substation) 5) $75M 6) $10M	1) N/A 2) 36 months 3) 12 months 4) 36 months each substation 5) 60 months 6)36 months

							and Western LA Basin is assumed repowered, see SCE-1)		
2	IID proposed upgrades in the IV 230 kV area	N/A	36 months		N/A	N/A	N/A		
3	N/A	N/A	N/A	N.Gila - Imperial Valley 500 kV Series Cap upgrade and install SPS to bypass the series cap once the flow exceeds the emergency rating.	$25M	24 months	N/A		
4	1) Maintain generation capacity in Western LA Basin at about 6200 MW level for the 1-in-5 load assumption, 2) San Diego available capacity not less than 2000 MW, otherwise, 400 MVar reactive Var support at SDGE is needed (See SDGE-1)	N/A	N/A	Portfolio 1: 1) Maintain generation capacity in Western LA Basin at about 6700 MW level for the 1-in-5 load assumption. 2) San Diego available capacity not less than 2550 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1) Portfolio 2: 1) Maintain generation capacity in Western LA Basin at about 6550 MW level for the 1-in-5 load assumption. 2) San Diego available capacity not less than 2350 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1)	N/A	N/A	1)Build the new Mira Loma - Lighthipe 500 kV line and upgrade the existing Lighthipe 230 kV substation to 500 kV. 2) Install dynamic reactive power support at Santiago, Eagle Rock, Encina and South Bay (500 MVAr at each) 3) SPS of load tripping at Lewis following Serrano-Lewis 230 kV N-2. This alternative may minimize the requirement of OTC repower	$500M	84 months
5	Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)	$25M	24 months	Same as Portfolio 4	$25M	24 months	Bypass the series cap following the contingency overload	$1M	24 months

6	Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) and Devers – Mirage No. 1 and No. 2 230 kV lines. Assume IID internal upgrades to accommodate IID's new generation	$80M	36 months	All portfolios: Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42). Assume IID internal upgrades to accommodate IID's new generation	$40M	36 months	Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) and SPS to trip IID generation under outage of one Devers – Mirage 230kV line.	$40M	36 months
7	WOD interim solution prior to WOD 230kV upgrades: Install serial reactors on Devers – San Bernardino 230 kV line and Devers – Elcasco 230kV line; Install SPS to trip generation and load under contingency conditions	$20M	24 months	Same as Portfolio 4	$20M	24 months	N/A	N/A	N/A
8	1)Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line	1) $1,000M-$1,100M 2) $1.5M-$2M 3) $38M-$44M 4) $15M-$22M 5) $12M-$15M	1)72 Months 2)24 Months 3)36 Months 4)36 Months 5)36 Months	Portfolio 1: Same as Portfolio 4 Portfolio 2: needs item 4) and 5)	Portfolio 1: Same as Portfolio 4 Portfolio 2: needs itiem 4) and 5)	Portfolio 1: Same as Portfolio 4 Portfolio 2: needs itiem 4) and 5)	1) Build the new McCall - Gregg 230 kV line 2) Reconductor Midway - Gates 230 kV #1 and #2 lines 3) Replace terminal equipment on Gates - Henrietta Tap 230 kV line 4) Develop the emergency rating for the Gates 500/230 kV transformer 5) Revise the existing SPS for Los Banos South N-2 contingency to increase generation tripping in South of Los Banos 6)Reconductor 20 miles of the Warnerville – Wilson 230 kV line; upgrade terminal equipment 7) Reconductor 9.2 miles of the Sanger – Mc Call 115 kV line; upgrade terminal equipment. 8) Oro Loma 70 kV Area Reinforcement proposed in annual NERC compliance reliability assessment	1) $55M-$65M 2) $120 M- $130 M 3) $1M 4) $1M-$5M 5) $1M - $2M 6)$38M-$44M 7) $12M - $15M 8)$0.2M - $0.5 M	1) 60 Months 2) 48 Months 3) 12 Months 4) 6 Months 5) 12 Months 6) 36 Months 7) 36 Months 8) 12 Months

9	N/A			Portfolio 2: Re-rate Malin – Round Mt. 500 kV #2 line	<$1M	6 Months	Revise the existing SPS with additional generation tripping in NW for CapJack -Olinda 500 kV lines N-2, or reduce the NW HVDC schedule that modeled in Portfolio 2	$1M- $2M	12 Months
10	N/A			Portfolio 1: Reconductor Los Banos - Westley 230 kV line	$12M-$15M	24 Months	Revise LosBanos North SPS to increase generation tripping	$1M- $2M	12 Months
11	N/A			Portfolio 2: Reconductor Temblor - San Luis Obispo 115 kV line and 50 MVAr reactive power support at San Luis Obispo 115 kV bus	$65M - $75M	36 Months	Add a new 115 kV line between Temblor - San Luis Obispo	$70M - $100M	60 Months
12	N/A			Portfolio 1: SPS to trip generation at Morro Bay area	$1M- $2M	12 Months	Reconductor the Morro Bay - Templeton 230 kV #1 and #2 lines	$25M-$30M	24 Months
13	SPS to trip generation at Contra Coasta area	$1M- $2M	12 Months	Portfolio 1&2: N/A			Reconductor the Contra Coasta Sub - Contra Coast 230 kV line	$2M- $3M	24 Months
14	SPS to trip generation at Colusa and revise the existing SPS for Round Mountain - Table Mountain N-2 and Table Mountain South N-2	$1M- $2M	12 Months	Portfolio 1&2: N/A	N/A	N/A	Reconductor Deleven - Cortina	$6M-$10M	24 Months
15	SPS to bypass series cap on the remaining Round Mt. - Table Mt. 500 kV line p after the Round Mt. - Table Mt. 500 kV line N-1	$1M-$2M	12 Months	Portfolio 1&2: N/A	N/A	N/A	SPS to trip more NW generation	$1M-$2M	12 Months

5.9.2 List of Category 1 Upgrades

Table 5.9.3 Category 1 upgrades

Category 1 Transmission projects for Portfolio 4	Lead Time for Implementation	Note
Path 42 and Mirage-Devers upgrades	36 months for Path 42/Mirage-Devers upgrades.	1) Need West of Devers (WOD) interim solution that will use SPS of generation and load tripping and series reactors to mitigate the potential reliability concerns prior to the in-service date of the permanent WOD upgrade of reconductoring the 230 kV lines. It is estimated that the implementation of the WOD interim solution needs 36 months.

In the 2010/2011 cycle of the Comprehensive Transmission Plan, the Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) owned by IID and Devers-Mirage 230 kV lines owned by SCE were identified as constraints on the delivery of renewable generation in the base line scenario (Hybrid, Portfolio 4). Through CTPG the ISO has worked with IID on the coordination of these two upgrades. IID has over 1000 MW of renewable generation in their interconnection and transmission service queues that are in the late stages of negotiation contractual agreements to construct the Path 42 upgrades along with other upgrades required on the IID system. The Mirage – Devers 230 kV line reconductoring upgrades have been categorized as category 1 upgrade for the following reasons:

- Mirage – Devers 230 kV line reconductoring upgrade has been identified as needed for Portfolio 4 (the most likely portfolio).
- Path 42 upgrade has been identified as needed in the generation interconnection process by IID to deliver renewable generation in the IID system into the CAISO balancing authority area. The generation developers of the renewable generation in the IID system have publicy communicated their plans to fund the necessary upgrades identified as needed by IID, including Path 42 upgrade.
- Mirage – Devers 230 kV line reconductoring and the Path 42 (Coachella – Mirage and Ramon – Mirage) upgrades are both needed in order to allow delivery of renewable generation in the baseline portfolio. A commitment to fund the Path 42 upgrades provides assurance that the Mirage-Devers upgrades will not become stranded assets.
- The difference on the Mirage – Devers flow among Portfolio 4 and other portfolios is mainly because the renewable generation modeled in Portfolios 1 and 2 is less than Portfolio 4 (detail can be found in Section 5.1). The development of Portfolio 1 and Portfolio 2 was prior to Portfolio 4. During the development of Portfolio 4 the ISO learned about the substantial progress that had been made in the interconnection of generation in the IID and the related Path 42 upgrades through discussions with CTPG and incorporated that information. Had the ISO revisited the already-completed Portfolios 1 and 2 with the same information, it is expected that the Mirage – Devers upgrades would also have been determined to be needed in Portfolio 1 and Portfolio 2.
- Mirage – Devers 230 kV double circuit tower line is only about 20 miles long and the cost of the upgrade is estimated to be only about $40 million.

In summary, Mirage – Devers upgrades has been recommended as category 1 upgrade that in conjunction with IID's planned Path 42 upgrades will deliver the renewable generation in the Imperial County area to meet the State's 33% RPS. Although the Mirage-Devers upgrades have been identified as category 1 elements, these elements consist of reconductoring existing 230 kV lines owned by SCE. According to ISO tariff Section 24.5.2, if the selected elements involve upgrades on an existing PTO facility, the PTO will construct and own such facilities. Thus, SCE is the project sponsor for the Mirage-Devers upgrade and there will be no competitive solicitation.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the parties listed on the official service list for the above-referenced proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C this 10th day of April, 2015.

/s/ Michael Kunselman
Michael Kunselman
Alston & Bird LLP