33% RPS Reference Case Timeline Overview

CPUC 33% RPS Implementation Analysis

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Contents

1 Introduction to the Barrier Assessment and Timelines

This Barrier Assessment is part of the Phase II work plan for the CPUC 33% RPS Implementation Analysis. Phase I focused on identifying the new generating resources needed to fill the RPS need, which involved scoring projects according to their potential for siting risk or environmental permitting delays. Phase II focuses on the implementation of the 20% and 33% RPS "Reference Cases" developed by Energy and Environmental Economics, Inc. (E3), presented to the 33% RPS Implementation Analysis Working Group on January 15, 2009.

The 33% RPS portfolio selection and implementation modeling effort presented by E3 and Aspen Environmental Group (Aspen) improves upon previous RPS modeling efforts to produce portfolios of projects with much greater locational specificity. This improved detail allows implementation issues to be examined more realistically. In particular, timelines for implementing the portfolios can take into account location-specific environmental permitting issues that could affect online dates of specific resources and aggregations (portfolios) of those resources.

The implementation timeline analysis highlights potential interconnection, permitting, and construction bottlenecks that could delay achievement of the 20% and 33% RPS goals. Labor pool, equipment supply chain, generation procurement and contracting, and financial constraints are also potential sources of delay. To assess barriers and potential delays for developing renewable resource portfolios, the Phase II analysis considers important milestones and their associated timelines, as well as sensitivities for key factors affecting timelines.

Phase II final products include:

- Identification of the generic milestones, timelines and barriers (key sources of delay) associated with developing new transmission and generation projects.
- Projected implementation timelines for the overall 33% RPS Reference Case
- Case analysis of how overall implementation timelines would be impacted by administrative reforms and external risks
- Identification of potential critical path barriers

The Phase II products above are presented and discussed in Section 4 (33% RPS Reference Case Illustrative Timelines) and Appendix B (Methodology) of the 33% RPS Implementation Analysis Preliminary Results report. This white paper presents the empirical data used to construct the generic timelines presented in Appendix B, and provides additional discussion of the Phase II products.

2 Milestones and Timelines

2.1 Overview of Milestones and Factors[1]

Milestones are used in the Phase II assessment to represent discrete steps in the overall process of completing the development of the generation projects and transmission infrastructure required to develop the selected renewable energy zones. The generation and transmission milestones used to develop the generic timelines in Tables 21 and 22 of Appendix B, include:

1. **Generation Procurement Process**
   - Utility issues Request for Offers (RFO)
   - Generation developer secures a Power Purchase Agreement (PPA)
   - Phase I interconnection studies culminate in generator financial commitments for transmission
   - Phase II interconnection studies are integrated into overall transmission planning, culminating in interconnection agreements and specific transmission plans of service

2. **Transmission Planning process**
   - Generator submits transmission interconnection request to California Independent System Operator (CAISO) or publicly-owned utility (POU)
   - ISO interconnection studies/transmission planning and board approval
   - Investor-owned utility (IOU)/POU development of plan of service (may overlap with above)

3. **Preparation of Generation and Transmission Permit Applications**
   - Preparation of generation permit applications (Application for Certification [AFC] or other process, as applicable) and the transmission permit application Certificate of Public Convenience and Necessity (CPCN) and the required Proponent's Environmental Assessment (PEA), along with any applicable federal agency application

4. **Environmental Review Process and Need Determination (Transmission)**
   - Complete California Environmental Quality Act (CEQA)/National Environmental Protection Act (NEPA) process
   - Obtain CPCN from CPUC or Siting Certification from California Energy Commission (Energy Commission), or approval from applicable federal agency and/or local land use authority

[1] All milestones here represent processes associated with a CPUC-regulated utility and the transmission system planned and operated by the California Independent System Operator.

5. Final Design and Construction Process

- Final transmission design and construction
- Generator construction (including gen-tie to the transmission network)
- Project online

Several of these steps are described in more detail below.

2.2 Generation Development Milestones and Timelines

2.2.1 Renewable Resource Procurement

Implementation of a 33% RPS for IOUs includes a renewable resources selection (procurement and contracting) process. Aspen investigated whether the IOU resource selection process and the CAISO generator interconnection process could happen concurrently. If the two processes can occur concurrently, then the IOU resource selection process does not add time to the overall schedule for 33% RPS implementation.

The current resource selection process starts with the submittal by the IOU of its Annual Renewable Resource Procurement Plan to the CPUC for approval. Once this plan is approved, the IOU can initiate a bidding process for renewable resources. CPUC review of the Annual Renewable Resource Procurement Plan procurement plan has typically taken 5-9 months. This process is rolling, resulting in annual "requests for offers" (RFOs), but bilateral negotiations may also occur outside of this annual cycle. The IOUs issue RFOs shortly after the procurement plans are approved and allow three months for responses to the RFO to be returned. The next step is for the utilities to evaluate and select bids, notify the parties regarding results of this selection, negotiate PPAs with selected generation projects, and submit PPAs to the CPUC for approval. Timeframe estimates for the negotiation stage are variable; Aspen estimates a minimum of 5 months but this timeframe could be longer. The final step, review of the PPA by CPUC, takes between 3 and 6 months depending on the complexity of the PPA and staff resources. Summing the individual timeframes, and assuming 6 months for CPUC approval, the total expected time for CPUC-jurisdictional utilities to complete a renewable procurement process cycle is about 20 months. However, the minimum amount of time for the cycle is fourteen months, since the CPUC can approve a utility's PPA at any time (rather than taking six months). The nominal RFO process time frame shown on Figure 1 is thus 14 months.

Recent reforms in the CAISO's tariff provisions[2] regarding Large Generator Interconnection Procedures include requiring increased financial and other commitments from generators wishing to remain in the interconnection process. These changes, described in more detail in the section below, have caused less-viable (or less-prepared) projects to drop out of the interconnection queue, so that of the potential new generation in the queue as of mid-2008, somewhat less than half (40 GW) dropped out. However, CAISO personnel have indicated that

[2] CAISO Tariff and Protocols (http://www.caiso.com/pubinfo/tariffs/)

otherwise-viable generation projects larger than 20 MW (thus being subject to reformed Large Generator Interconnection Procedures) will not deem the increased study cost deposit requirements ($250,000 minus amounts already paid) as sufficient reason to drop out of the process. Since developers may recoup the majority of their deposit ($150,000) if they drop out after receiving results of the Phase I interconnection studies, the true cost of staying in the queue through the Phase 1 study period is only $100,000. Since the financial risk is modest, it is expected that prospective generators will enter the interconnection process concurrently with bidding into the RFO process. In fact, several tens of thousands of prospective renewable generation projects are currently in the interconnection process, with some being near the end of the process. B*ecause the time to complete the interconnection process is longer than the 14 to 20 months required to complete the procurement process, and because developers are entering the interconnection process concurrently with the RFO process, the IOU resource procurement process is not expected to add time to the overall 33% RPS implementation schedule.*

2.2.2 Generator Interconnection

In late 2007, the Federal Energy Regulatory Commission (FERC) initiated a process to address problems with the generator interconnection process established in Order 2003.[3] While the principal objective under Order 2003 was to achieve nondiscriminatory treatment of individual generators, an unintended by-product was a growing backlog in transmission providers' interconnection processes as generators were studied one by one on a first-in, first-out basis. Furthermore, the durations of studies were expanded when re-studies became necessary as generators dropped out or changed key project parameters. FERC asked transmission operators across the nation (including the CAISO) to identify issues with the current interconnection process and suggest possible reforms. In response, the CAISO initiated a stakeholder process to reform its large generator interconnection procedures (LGIP). The resulting reforms were designed to give interconnecting generators greater and earlier certainty regarding the costs and timelines for interconnection, reduce the need for re-studies (in part by studying generators in groups where possible), and discourage nonviable or premature generation projects from remaining in the interconnection queue, through increased study deposit and site control and information requirements. On September 26, 2008, FERC conditionally approved the CAISO's tariff amendments implementing the interconnection process reforms. These reforms are referred to as Generation Interconnection Process Reform (GIPR).

Under the reformed interconnection process, interconnecting generators are studied in groups based on timing and location of interconnection requests, and undergo a two-stage study process. To undergo Phase I studies, generators must make greater study deposits than previously and provide key information more quickly, as well as either demonstrating site control ("site exclusivity") or making additional deposits in lieu of site control. At the end of Phase I studies, generators are informed of their firm cost responsibilities for financing

[3] FERC conditionally approved the CAISO's proposed amendments to its interconnection queue process. Parties submitting interconnection requests must submit $250,000 for their request to be processed plus an additional $250,000 if they do not have site control.

transmission upgrades. At this point generators may drop out, in which case part of their study deposits and any "in lieu of site control" deposits are refunded. Those generators choosing to remain make an initial, partial payment of their firm cost responsibility for transmission financing and move into Phase II interconnection studies. Phase II studies are integrated into the broader transmission planning process and develop the actual plan of service for transmission upgrades needed to serve a group of one or more interconnecting generators being studied. This plan of service may reflect the fact that some generators dropped out after Phase I studies, and may also, under some circumstances, reflect the decision to size the new transmission larger than is needed for the present group of interconnecting generators in order to meet other system-wide transmission needs and/or to anticipate additional generators showing up later, such as within a high value renewable energy zone.

Under the reformed interconnection process, the standard timeframe from a generator's interconnection application to ultimate signing of an interconnection agreement and final design (not construction) of the transmission plan of service is as short as two years. It could be longer, depending on which of two cluster windows (application periods) per year the generator utilizes, and depending on where within that window the application is submitted. The reformed generator interconnection process is broken into the following six steps:

- Open queue cluster window (application period) to receive interconnection requests (4 months, two windows per year);
- Validate applications, conduct cluster scoping meetings and develop study base cases (3 months);
- Conduct Phase I interconnection studies for a cluster (temporal group of applicants) studied in groups based on electrical proximity (approximately 5 months, to be completed within 8 months of cluster window closing) - - twice per year;
- After Phase I studies, conduct Phase I "results" meetings and give generators time to decide whether to continue into Phase II studies and to make initial 20% payment of their transmission financing responsibilities established pursuant to Phase I studies (3 months);
- Conduct Phase II Interconnection Studies once per year, which are integrated with the overall transmission planning process and which identify actual transmission facilities that will be built (11 months); and
- Execute Large Generator Interconnection Agreements (LGIA) and obtain FERC approval of LGIA (3-5 months).

The above schedule gives a minimum timeline of about 2 years, and a maximum of roughly 6 months longer. The CAISO Board must approve all transmission projects is excess of $50 million, and this timeline assumes that CAISO Board approval occurs promptly at the end of this interconnection studies/planning process, so that the next step, preparing a PEA/CPCN application (which includes environmental studies) may begin immediately. If Board approval occurs later, then maintaining the standard timeframe would require that the PEA/CPCN step begins before Board approval. On the other hand, the interconnection timelines (e.g., for

conducting Phase I studies) generally are given in the CAISO tariff as maximum timelines, so that faster progress is possible.

Considering the various nuances regarding the generic interconnection timeline, a 24 month timeline for completing the generator interconnection and associated transmission planning process may be somewhat optimistic. If the PEA/CPCN preparation begins before Board approval or even before completion of CAISO studies for interconnection and associated transmission planning, then the 24 month generic timeline would not be a binding constraint, and IOUs could initiate the permitting process prior to the conclusion of the Phase II study period. In fact, such an expedited (overlapping) approach is being promoted by the CPUC and CAISO and is likely to occur if the transmission owner has some assurance of recovering pre-construction study costs, regardless of ultimate approval to construct. In fact, the CPUC's backstop cost recovery policy for transmission that supports renewable generation provides such a possibility for recovering pre-construction costs.

However, the basic interconnection studies cycle described above will not be fully in effect until 2010. Until then, transitional procedures will be used to process and clear the large backlog of generators in the interconnection queue. The interconnection applications in the queue as of June 2008 include renewable generation projects that were far along in their interconnection studies under the former (one generator at a time) interconnection process – these are called the "Serial Group" and are expected to have their interconnection studies completed in 2009, if not already completed in 2008 – and those generation projects that remained in the queue after the new study process were instituted – these are referred to as the "Transition Group" and are scheduled to complete their Phase I interconnection studies by the end of July 2009. Thus, while the generic timeline for interconnection and transmission planning may be somewhat optimistic, many generators do have a head start relative to that timeline. Whether timely processing of this large volume of interconnection applications will be affected by a potential limitation on availability of skilled professionals to perform the studies is unclear, although current indications are that interconnection studies are proceeding effectively.

2.2.3 Generation Permitting

Generation Subject to the Energy Commission Process

New large (>50 MW) thermal generators in California are subject to the Energy Commission permitting process. Major milestones are: filing the environmental applications (e.g., Application for Certification (AFC)), finalization of public environmental document (Final Environmental Impact Report [FEIR] or Final Staff Assessment [FSA]), permit approval (e.g., Energy Commission license), and achieving online status. Timelines for the Energy Commission process have not changed substantially in the past five years; a 2002 U.S. General Accounting Office (GAO) study noted that 90 percent of power plants in the Energy Commission process required less than 2 years for regulatory approval (GAO, 2002). Table 1 shows examples of the timelines for large thermal power plants, including eight that are now

online. The overall timeline for developing and constructing a large thermal power plant is about 5 years.

Table 1. Project Examples and Overall Timeframes – Large Thermal Power Plants

Project Name (Energy Commission Cases)	Technology/ Capacity (MW)	Duration of Pre-Permitting Development Process (months)*	Duration of Environmental Review Process (months)	Duration of Construction to Online (months)	Total Duration of Project Development to Online (months)
AVERAGE TIME REQUIRED to Online (for Large-State > 50 MW)					60
Median Energy Commission Timeline to Online (for Large-State > 50 MW)					63.5
Magnolia Power Plant	Natural Gas Combined Cycle/ 328 MW	12	21.5	30.5	64
Palomar Energy	Natural Gas Combined Cycle/ 546 MW	12	19.5	32	63.5
SMUD Cosumnes Power Plant	Natural Gas Combined Cycle/ 1000 MW	12	23.5	29.5	65
City of Vernon Combined Cycle Power Plant Project	Natural Gas Combined Cycle/ 134 MW	12	17	29	58
Elk Hills Power Plant	Natural Gas Combined Cycle/ 500 MW	12	22	31.5	65.5
Walnut Energy Center Turlock Irrigation District	Natural Gas Combined Cycle/ 250 MW	12	15	24	51
Sutter Power Plant	Natural Gas Combined Cycle/ 540 MW	12	15.5	26.5	54
Inland Empire Energy Center	Natural Gas Combined Cycle/ 670 MW	12	28	60 (Ongoing)	Ongoing
Gateway Generating Station	Natural Gas Combined Cycle/ 530 MW	12	16	92	120
Otay Mesa Power Plant	Natural Gas Combined Cycle/ 510 MW	12	20	90 (Expected online in 2009)	Expected 122
Salton Sea Geothermal Power Plant	Geothermal/ 185 MW	12	16	Unknown	Unknown

* Duration of Development Process is assumed to be 12 months. Information for actual duration of development process is unknown.

Note: Average and Median times are for completed power plant cases only; does not include estimates or Gateway or Otay Mesa, which were the subject of settlements with regulated utilities.

Source: Energy Commission, 2009. Alphabetical List of Power Plants Filed Since 1996; Energy Commission, 2009a. Energy Facility Status

The Energy Commission typically processes and approves power plant cases at a rate of approximately eight cases per year, reflecting about 2,000 MW per year. This includes all natural gas and any other fossil fuel-fired thermal generators in the Energy Commission jurisdiction, with other thermal generators above 50 MW, such as geothermal and solar thermal, also being subject to certification by the Energy Commission. The 33% RPS Reference Case would add 1,497 MW of geothermal and 7,298 MW of solar thermal projects; this represents about 37 new projects. If Energy Commission staff could be devoted to an annual project review rate of about eight renewable energy projects or 2,000 MW per year of exclusively geothermal and solar thermal capacity, about five years would be needed to process the 37 new projects in the 33% RPS Reference Case. In reality, the Energy Commission would also need to concurrently process fossil fuel-fired thermal power plant applications.

Table 2 shows the filing and approval rates for applications subject to the Energy Commission process over the past eight years. Note that in 2001 substantially more applications were processed due to the emergency permitting process implemented as a result of the energy crisis.

Table 2. Energy Commission Process Filing and Approval Rates Over 8 Years

Year	AFCs Filed	Capacity Filed (MW)	Power Plants Approved	Capacity Approved (MW)	Power Plants Online	Capacity Online (MW)
Average Year	**9**	**2,826**	**8**	**2,423**	**5**	**1,648**
2001	27*	7,824	27*	6,270	10	1,914
2002	4	1,132	3	445	7	2,504
2003	5	492	8	3,770	10	3,893
2004	2	241	7	3,945	0	0
2005	3	1,160	4	1,310	7	2,584
2006	9	2,880	7	555	6	2,015
2007	9	4,069	3	1,085	2	177
2008	11	4,813	5	2,006	1	93

Source: http://www.energy.ca.gov/sitingcases/all_projects.html.

* In 2001, Governor Davis directed the Energy Commission to implement its emergency permitting authority for many of these projects.

Solar Generators Subject to Local or Energy Commission Processes

Table 3 summarizes some examples of utility-scale solar technology projects and the timeframes for development, permitting, and construction. Average timelines for solar generators were not calculated because of the wide range of sizes, site-specific characteristics, and lack of historical data.

Table 3. Project Examples and Overall Timeframes – Solar Energy Power Plants

Project Name	Technology/ Capacity (MW)	Duration of Development Process (months)*	Duration of Environmental Review Process (months)	Duration of Construction to Online (months)	Total Duration of Project Development to Online (months)
Ivanpah Solar Electric Generating Station (ISEGS)	Solar Thermal – Power Tower/ 400 MW	12	Estimated BLM ROD 5/2010 (33 months)	Estimated 48	Estimated 93
Ausra Solar Bakersfield	Solar Thermal – Linear Fresnel/ 5 MW	12	8**	7	27
GreenVolts Solar Photovoltaic Field	Solar Photovoltaic/ 2 MW	12	7	Estimated end of 2009 (16 months)	Estimated 35
Carrizo Energy Solar Farm	Solar Thermal – Linear Fresnel/ 177 MW	12	Estimated 9/2009 (23 months)	Estimated to take 35 months	Estimated 70
Victorville 2 Hybrid Power Project	Up to 50 MW Solar thermal (parabolic trough)	12	17.5	Expected online early 2011 (27 months)	Expected 56.5

* Duration of Development Process is assumed to be 12 months. Information for actual duration of development process is unknown.

** Site was an existing power plant so no new environmental review was required, just updates to permits.

Source: Energy Commission, 2009. Alphabetical List of Power Plants Filed Since 1996; Ausra; 2008.

Executive Order S-14-08

The issue of biological mitigation is of state-wide importance, because it is an essential step in the environmental review and permitting of all major projects, and its development can delay project approval. This issue has been especially challenging with large-scale solar projects because of the extent of project disturbance (thousands of acres per project), driving the need for mitigation on an unprecedented scale. In response to this challenge, Governor Schwarzenegger issued Executive Order S-14-08 on November 17, 2008, directing the Energy Commission and California Department of Fish and Game (CDFG) to facilitate renewable energy siting by identifying areas where permitting can be expedited; to develop a Best Management Practices manual for protecting biological resources; to identify areas in California where a renewable energy-focused Natural Communities Conservation Plan (NCCP) would be beneficial; and to ensure close coordination among regulatory agencies. The implementation of the Executive Order is now underway. Because its results and implications for project development timing have yet to be seen, however, the generic timelines presented here do not consider possible streamlining effects of this work.

Wind Generators Subject to Local Agency Approval Process

Up to 5 years are needed to bring large wind projects through the development, local agency approval, and construction processes. Additionally, federal environmental review requirements are

becoming increasingly time-consuming. Discussion with a contact at San Bernardino County indicated (email: 1/20/09) that one project currently under review is now subject to an "extended" environmental review period. A major source of extended federal review is that the Bureau of Land Management (BLM) is requiring 2 years of avian and bat monitoring before release of the Draft Environmental Impact Statement (EIS), which increases the timelines for projects on federal land.

Table 4 summarizes the timeframes for recent new wind energy power plants.

Table 4. Project Examples and Overall Timeframes – Wind Energy Power Plants

Project Name (Lead Agency)	Wind Energy Capacity (MW)	Duration of Pre-Permitting Development Process (months)*	Duration of Environmental Review Process (months)	Duration of Construction to Online (months)	Total Duration of Project Development to Online (months)
AVERAGE TIME REQUIRED to Online (for Small-Local, <50 MW)**					40
AVERAGE TIME REQUIRED to Online (for Large-Local, >50 MW)**					59
Granite Wind Energy (BLM)	62.1 – 81 MW	12	42	9	63
Edom Hills Repower (BLM)	20 MW	12	7	12	31
Mountain View IV (BLM)	49 MW	12	30	14	56
Kumeyaay Wind (Bureau of Indian Affairs)	50 MW	12	8	8	28
Montezuma Wind (Solano County)	37 MW	12	15	33 (expected online 2010)	Expected 60
Shiloh II (Solano County)	176 MW	12	29	9	50
Buena Vista (Contra Costa County)	38 MW	12	17	21	50
Dillon Wind (Riverside County)	45 MW	12	12	11	35
Shiloh I (Solano County)	75 MW	12	9	43	64

* Duration of Development Process is assumed to be 12 months. Information for actual duration of development process is unknown.

** Does not include Montezuma Wind Project.

Source: BLM, 2008. Wind Energy Projects; Energy Commission, 2009b. IOU Contract Database; CPUC, 2009. RPS Project Status Table 1st Quarter 2009.

2.2.4 Case Study: Ivanpah Solar Electric Generating Station, BrightSource Energy, Inc.

Ivanpah Solar Electric Generating Station (ISEGS) is a 400 MW power tower solar plant proposed to be located adjacent to Interstate 15 just west of the Nevada state line (Primm, Nevada). It is proposed to be constructed in three phases (100 MW, 100 MW, 200 MW). The first phase would use an existing Southern California Edison (SCE) transmission line (Eldorado), but the second and third phases require that the line be upgraded. SCE has been participating in pre-filing activities with the CPUC since early 2008 and is submitting a CPCN application to the CPUC in early 2009 to re-build the transmission line between Eldorado Substation (Nevada) and a new Ivanpah Substation (that would be in the ISEGS project area). It is not known when ISEGS may have filed for the large generator interconnection request with CAISO (CAISO queue position-holders' identity is confidential), but it is reasonable to expect that it was in 2007, 24 months before SCE applied to the CPUC for the line. Concurrent with the transmission review process is the Energy Commission engineering and environmental evaluation (Energy Commission Docket: 07-AFC-5) and the BLM review process.[4] Table 5 illustrates the schedule for this project that appears most likely as of July 2009.

Table 5. Case Study: Expected Schedule for Energy Commission Process (ISEGS 400 MW Solar Thermal Plant)

Task	Current\Energy Commission/BLM Schedule
AFC submittal	August 2007
AFC considered "data adequate"	October 2007
Preliminary Staff Assessment published	December 2008
FSA/Draft EIS to be published	September 2009
Final EIS to be published	March 2010
Energy Commission approval	February/March 2010
BLM approval	April/May 2010
Begin construction	**Second Quarter 2010**
Commercial operation (Phase 1)	**First Quarter 2012**
All Phases operational	**Fourth Quarter 2013**

ISEGS is a good example for study since it requires both Energy Commission and BLM approval, and was the first large-scale solar thermal project to enter the joint permitting process. Because no large solar project has yet been approved (whether in the Energy Commission/BLM joint process or in the Energy Commission process alone), it is difficult to anticipate all the barriers that might arise prior to construction of these large renewable projects. Regardless, based on issues addressed in the Revised Committee Scheduling Order of July 15, 2009, the following are major anticipated barriers to the implementation of this project and their current status:

- **Biological Resources Mitigation.** Definition of mitigation requirements for biological resources. Acquisition of mitigation lands for biological resources. The Victorville hybrid gas-solar project would have permanent disturbance to 338 acres (250 acres for the solar portion), and the Energy Commission and CDFG biologists required 3-to-1 mitigation (three acres mitigation land per one acre project land). With temporary disturbance of

[4] California Energy Commission ISEGS Proceeding (http://www.energy.ca.gov/sitingcases/ivanpah/index.html).

construction areas, the applicant is required to guarantee the perpetual care of 1,315.5 acres of off-site habitat that would be suitable for Mohave ground squirrel, desert tortoise, burrowing owl, and creosote rings. It would be difficult or impossible to obtain and preserve the amount of land that would be required by the application of this 3:1 mitigation ratio to ISEGS, a large project with an area of over 4,000 acres. BLM normally requires 1:1 mitigation for that portion of a project's area representing desert tortoise impacts, and even this would be very difficult to implement. The negotiation of mitigation requirements with CDFG and U.S. Fish and Wildlife Service (USFWS) has been time-consuming and challenging. The implementation of the Governor's Executive Order S-14-08, discussed above, is occurring concurrently with the processing of this application. As a result, the agency negotiations required for ISEGS may not be as time-consuming for subsequent large renewable projects. This process has extended the time required to prepare the Preliminary Staff Assessment (PSA)/Draft EIS, as illustrated in Table 5.

- **Lengthy CEQA/NEPA permitting processes.** Normally, time can be saved by combining state and federal permitting processes, but due to BLM public noticing requirements, the Energy Commission and BLM decided to separate the federal NEPA process from the state-level environmental document. This separation has added about 6 months to the ISEGS schedule, and the schedule is contingent on BLM producing a Final EIS on its own, after Energy Commission's FSA/Draft EIS is completed. In addition, changes made to the Final EIS may require subsequent modification of the FSA. Based on BLM workload and depending on the process and staff used to prepare the Final EIS after completion of the Energy Commission's FSA, the Final EIS could be delayed an additional 3 to 6 months, beyond the expected schedule.
- **Applicant inexperience with technologies and permitting processes.** The initial applications to Energy Commission and BLM contained inadequate engineering detail of proposed project design, so impact analysis, especially for ground disturbance and hydrologic impacts, could not be completed. BrightSource had to hire a civil engineering firm to design its project in greater detail after the application was submitted (and found to be complete per the Energy Commission's requirements, but not adequate for BLM's evaluation). This added 6 months to the PSA/Draft EIS preparation process because inadequate data was provided to the agencies to use for PSA preparation. This time is reflected in the schedule. Similar delay occurred on the Energy Commission-permitted Carrizo Solar Farm Project (developed by Ausra) because inadequate design had been done for the large scale project and re-design had to occur during the PSA preparation phase. If the applicant makes any changes to the original application, the Energy Commission will evaluate the changes and determine if the original application must be amended or a new application submitted to the Energy Commission.
- **Legal Challenges – cumulative impacts and mitigation options.** While the environmental community was initially generally supportive of renewable projects and the efforts to reduce greenhouse gas (GHG) emissions, these projects have become more controversial as the extent of their impacts is being defined. As a result, it would be surprising if at least one

group did not challenge these agency approvals for inadequate consideration of impacts and mitigation of both project and cumulative impacts. If not resolved, legal challenges could delay implementation of all large renewable projects by a year or more.

Timing of Permits

In its AFC, BrightSource considered that all Energy Commission permits, BLM rights of way (ROW), and other environmental requirements could be completed between 8/31/07 and the first quarter of 2009 (presumably 3/31/2009, when construction of Ivanpah 1 was expected to begin), for a total of 20 months. Interagency discussions on biological mitigation issues have added time to that process, but as described above, these issues appear to be close to resolution.

The following are some of the main permits and timeframes identified in the AFC:

- **Biological resources permits – expected to take 6 – 9 months:**
  - USFWS Endangered Species Act, Section 7 compliance (Biological Opinion)
  - CDFG 2081 Permit
  - CDFG Streambed Alteration Agreement
  - U.S. Army Corps of Engineers, Clean Water Act Section 404 Permit
  - Lahontan Regional Water Quality Control Board, Section 401 Permit
- **Cultural Resources:** Section 106 compliance determination – 60 to 90 days or more.
- **Soils Permits:** County Grading Permit (if required) – estimated 6 months from submittal of complete application, construction requirements relating to soil – estimated 6 months from approval of ROW.
- **Land use permits:** BLM ROW for project, transmission lines, and access roads, BLM Encroachment – No effect on schedule.
- **Water permits:** Statewide General Permit for Construction Activities, Statewide General Permit for Industrial Activities, Domestic Water Supply Permit, County Groundwater Well Permit – prior to construction.

ISEGS Case Study: Summary of Timelines and Hurdles

Pacific Gas and Electric (PG&E) requested approval of the ISEGS power purchase agreement by the CPUC on April 1, 2008 (in PG&E Advice Letter 3243-E). The request urged the CPUC to approve the contract by October 16, 2008. According to the Advice Letter, BrightSource entered bilateral negotiation with PG&E for the power purchase agreement in 2006.

The ISEGS case study reveals that at least 24 months were needed for negotiating the power purchase agreement, and an additional 12 months were needed after the power purchase agreement for the interconnecting utility to file an application to CPUC for the necessary transmission upgrades.

Transmission upgrades identified in the Energy Commission AFC process would need to be built by SCE, and the utility filed an application for the CPCN in May 2009. The Energy Commission process is expected to be complete in early 2010, about 48 months after the applicant entered negotiation for the power purchase agreement. If Energy Commission and BLM approval of the solar facility occur in early 2010, and construction requires 24 to 48 months, *the total timeline for development would be a minimum of 66 months, but probably closer to 84 months*.

The timeline has encountered and may continue to encounter delays due to the ongoing development of an effective inter-agency process, and developer inexperience with large-scale design and environmental processes.

2.3 Transmission Development

To develop the generic timeline assumptions presented in Table 21 of Appendix B, Aspen conducted a review of recent transmission projects. The results of this review are presented in Table 6, below. In response to utility comments, this table assumes that 24 months is needed for the RFO and CAISO phase of transmission development.

Table 6. CPUC CPCN Transmission Permitting Timelines

Type of Timeline *Generic, or for Actual Recent Projects*	**CAISO Planning and Intercon-nection Studies** *(Approved project plan of service)*	**Prepare Environ-mental Applications** *(Submit CPCN App.& PEA to CPUC, ROW App to BLM)*[5]	**Project Review** *(Publish Final EIR/EIS)*	**CPUC & BLM Approval, (***Final Decision)*	**Construction (***Project In-Service Date)*	**TOTAL** *Estimated to In-Service Date*
Generic Timeline range	24 mo	12-24 mo to prepare	24-30 mo environ. review	3-5 mo for decision	24-42 mo to build	**87-125 mo total**
Average Generic Timeline for Major Transmission Project *Includes average times for CPUC steps; assumes 48 months for CAISO planning process plus CPCN/PEA preparation prior to submittal to CPUC*			20 mo	4 mo	24 mo	**48 mo from CPCN submittal;** **96 mo total**
Typical Timelines for Generator Interconnection Transmission (Gen-ties) when CPUC is the Responsible Agency)			N/A	6 mo for CPUC	Unknown	**appx 24 to 36 mo**
High Voltage Transmission						
SCE DPV2 (500 kV)	7/2004	CPCN submitted: 4/11/2005	CPUC: 10/24/2006 BLM NOI of FEIR/EIS: 3/15/2007	CPUC: 1/25/2007 BLM ROD: Pending; (AZ approval: Pending) Note: SCE now proposes to construct the California segment only.	Est. 24-36 mo	**Est. 57 mo from CPCN submittal** Ignoring need for BLM approval
SDG&E Sunrise Powerlink (500/230 kV)	10/2004	CPCN submitted: 12/14/2005 PEA: 8/4/2006 BLM ROW: 11/02/2005	10/13/2008	CPUC: 12/18/2008 BLM ROD: 1/20/09; NFS: Pending	Est. 24 mo	**Est. 53 mo from CPCN submittal** Ignoring need for NFS approval
SCE TRTP Segment 1, Antelope-Pardee (500 kV)	2002	CPCN submitted: 12/9/2004 NFS Special Use Appl: 1/11/2005	12/26/2006	CPUC: 3/1/2007 NFS: 8/23/2007	Est. 13 mo (Ph 1 & 2 under construction; online 2009)	**Est. 46 mo from CPCN submittal**

[5] Date reflects submittal of application; agency determination that the application was complete may have come some time later, if there were deficiencies in the application. The CEQA process begins once a permit application has been deemed complete.

Table 6. CPUC CPCN Transmission Permitting Timelines

Type of Timeline *Generic, or for Actual Recent Projects*	**CAISO Planning and Intercon-nection Studies** *(Approved project plan of service)*	**Prepare Environ-mental Applications** *(Submit CPCN App.& PEA to CPUC, ROW App to BLM)*[5]	**Project Review** *(Publish Final EIR/EIS)*	**CPUC & BLM Approval, (***Final Decision)*	**Construction (***Project In-Service Date)*	**TOTAL** *Estimated to In-Service Date*
SCE TRTP Segments 2&3, Antelope Trans. Project (500 kV)	2002	CPCN submitted: 12/9/2004	12/26/2006	CPUC: 3/15/2007	Est. 16 mo (Online 2009)	**Est. 43 mo from CPCN submittal**
SCE TRTP (500 kV)	2005	CPCN submitted: June 2007	Est. 8/28/2009	Est. 10/09	Est. 2013	**Est. 52 mo from CPCN submittal**
PG&E Tri Valley (230 kV)	1997	CPCN submitted: 11/22/1999	4/18/2001	CPUC: 10/10/2001	12/2003 (Ph. 1-2) 9/29/2006 (Ph. 3)	49 mo (Ph. 1-2) from CPCN submittal 82 mo (Ph. 3) from CPCN submittal
PG&E Jefferson-Martin (230 kV)	4/1999	CPCN submitted: 9/30/2002	11/13/2003	CPUC: 8/19/2004	8/2006	47 mo from CPCN submittal
SDG&E Otay Mesa PPA (230 kV)	10/2003	CPCN submitted: 3/8/2004	5/2005	CPUC: 6/30/2005	7/20/2007	41 mo from CPCN submittal
Generator Interconnections						
SCE Inland Empire Energy Center 500 kV Gen-tie	CPUC as Responsible Agency *	CPCN submitted: March 2006 AFC: 8/2001	CEQA completed by Energy Commission 12/2003	CPUC: 10/19/06	10/2007	19 mo from CPCN submittal (7 mo for CPUC approval)
PG&E Colusa Gen-tie	CPUC as Responsible Agency *	CPCN submitted: Nov 2007 AFC: 11/2006	CEQA completed by Energy Commission, 4/2008	CPUC: 2/28/08		(4 mo for CPUC approval)
PG&E Shiloh II Wind Farm Gen-tie	CPUC as Responsible Agency *	CPCN submitted: May 2008	CEQA completed by Solano County, Federal EIR: 9/2002	CPUC: 8/21/08		(4 mo for CPUC approval)

Table 6. CPUC CPCN Transmission Permitting Timelines

Type of Timeline *Generic, or for Actual Recent Projects*	**CAISO Planning and Interconnection Studies** *(Approved project plan of service)*	**Prepare Environmental Applications** *(Submit CPCN App.& PEA to CPUC, ROW App to BLM)*[5]	**Project Review** *(Publish Final EIR/EIS)*	**CPUC & BLM Approval, (***Final Decision)*	**Construction (***Project In-Service Date)*	**TOTAL** *Estimated to In-Service Date*
PG&E Camanche, Freeport Regional Water Authority	CPUC as Responsible Agency *	April 2008	CEQA completed by FRWA, Federal EIR: 4/2006	CPUC: 10/1/08		(7 mo for CPUC approval)

Source: Prepared by Aspen from data in the CPUC Transmission Project Tracking Spreadsheet
* Generator interconnections required an unknown duration for CAISO system impact studies.
(http://www.cpuc.ca.gov/puc/energy/transmission.htm).

For the generic timeline presented in Table 21 of Appendix B, we assume a 100-mile line partly on federal land (requiring both BLM and CPUC approval), and entirely within the boundaries of California. Many major resource areas would involve transmission of this length or shorter (e.g., Solano, Tehachapi, San Bernardino–Lucerne, Palm Springs).

2.3.1 Transmission Planning

The generic timeline developed for this analysis assumes that the transmission line is within the CAISO system. For more discussion of the transmission planning process and its timing, see Appendix B and pages 44-47 of the Report.

2.3.2 Transmission Permitting, Final Design, and Construction

In the environmental review associated with the CPCN process, the CPUC reviews the transmission project as proposed by the sponsoring entity, as well as routing alternatives developed by CPUC staff or suggested by the public. The CPUC thus has the option of approving of the proposed project, the environmentally superior alternative, or another alternative.

Final design of transmission occurs after the completion of the environmental process, and construction durations are highly case-specific. For this analysis, the generic line is estimated to take 3 to 4 years to design and construct. Major transmission projects recently reviewed by CPUC are forecast to require at least 2 years for construction alone (as shown in Table 3). The design and construction process schedule components include:

- Final design (where some modifications to the preliminary design are typically required as a result of the CEQA/NEPA process);

- Equipment procurement (e.g., transformers);
- Transmission line construction and commissioning;
- Substation construction (e.g., substation receiving generator output) ; and
- Feeder lines to the renewable resources (gen-ties).

Numerous siting, permitting, legal, labor, and supply chain factors could affect the timing of transmission line design and construction. Uncertainty in the siting and permitting process arising from legal appeals of permit decisions may introduce delays in the design and construction part of the timeline. Appeals of CPUC or BLM permitting decisions could also delay design and construction progress; however, no CPUC project has yet been appealed at the Supreme Court. The final design of a proposed transmission line is dependent upon establishing the center line of the route to be used by the proposed facilities. If changes in the route occur in the permitting process then final design work, including design for the towers along the affected portion of the route cannot be completed until the center line is known with certainty.

Labor and equipment supply chain issues could pose a serious problem to design and construction execution. Transmission planners have indicated there is currently a shortage of technical personnel to plan transmission projects and prepare permit applications. In addition, there is a shortage of linemen that would be needed to construct the transmission projects. Potential manufacturing bottlenecks for transmission equipment could affect the schedule depending on whether aggressive transmission construction simultaneously occurs in California and the rest of the nation. There are currently a relatively small number of firms producing major transmission equipment, such as transformers, and the lead times on these components are currently as long as three years. In addition, while the manufacturing capacity for transmission towers and other equipment can meet current demand, demand for transmission equipment has been low for the last two decades, and manufacturing capacity likely will have to expand to meet new requirements.

3 The Effect of Market Constraints on Development Timelines

3.1 Supply chain constraints

Supply chain constraints in the renewable resource and transmission development process may be encountered at each step in the overall implementation schedule. The constraints become more severe as demand for renewable generation increases statewide, nationally and internationally in response to state, national and international climate change policies; renewable portfolio standards; favorable tax credit policies for renewables; and most recently, the American Recovery and Reinvestment Act of 2009.

Supply chain constraints in the renewable and transmission equipment industries are dependent upon the level and timing of demand. If demand is high in the short-term, manufacturing supply constraints may be unable to match increased demand. However,

depending on the magnitude and timing of the renewable demand shift, a critical mass of demand could spur manufacturing capacity expansion to overcome potential short-run supply chain constraints. Manufacturing constraints for renewable generation equipment vary by technology and arise from capacity limitations and technical uncertainty. The wind industry is mature and has a developed manufacturing base, whereas other renewable resource types such as solar photovoltaics (PV) and concentrating solar power (CSP) have developing manufacturing bases

3.2 Effects of the Financial Crisis

Investment in the renewable industry has increased dramatically in recent years. One source, reports that worldwide investment in renewable technologies has grown from $33.2 billion in 2004 to $148.4 billion in 2007.[6] However, a deterioration in economic conditions and crises in financial markets stemming from global credit market failures in 2008 present barriers to successful development of renewable resources to meet a 33% RPS by 2020. Funding from traditional sources is currently limited. Further, extensions of investment and production tax credit (PTC) programs in 2008 for solar and wind resources initially appeared to be just what these industries needed. However, tax-equity investors that normally buy tax benefits from renewable projects have become scarce since the financial crisis and bankruptcies have impacted major financing institutions like Lehman Brothers that facilitated these types of investments.

Under any successful implementation timeline, it is imperative to note that many of the renewable resources needed to meet the 33% RPS implementation schedule must be selected within the next few years so that the long development process for the supporting transmission projects can begin. If the development schedule for a renewable energy zone requires the construction of new transmission projects, the renewable resources from the zone will be selected during the beginning and conceptualization of a multi-year transmission development schedule and built towards the end of that schedule. For this situation, decisions to commit to various stages of transmission development may depend on increasing progress in generation procurement and development. The financial crisis is likely to have the biggest affect on development of these resources. In other words, even if the resources will not be constructed for some time, the 33% RPS target makes their selection presently more urgent. Given that a large number of projects must be selected prior to 2012 in order to demonstrate progress toward achieving the 33% RPS implementation targets, it is likely that the current economic conditions and the financial crisis will affect utility-developer contract negotiations and could impact the implementation schedule.

To make matters worse, it is likely that contract negotiation between the developer and utility or load serving entity will factor in the projected availability of investment and production tax credits at the time of construction. Given the current expected termination date of the investment and production tax credits and the expected schedule for development to achieve a

[6] See SEFI Global Trends in Sustainable Energy Investment 2008. http://sefi.unep.org/english/globaltrends.html

33% RPS, any timeline for development is subject to uncertainty over whether these credits will be available when the resources are constructed. This circumstance might affect financing of the renewable projects and consequently affect purchase power agreement negotiations between the developers and the IOUs. Uncertainty in contracts for generation in turn creates uncertainty in the demand for labor, materials, components, and generation technologies which makes it more difficult for manufacturing companies to obtain financing for their expansion plans. Portfolio selection for this analysis assumes that credits remain available. With timelines for transmission and generation construction extending well beyond 2016, the current duration of tax credits is too short to apply to later projects.

It is clear the ongoing financial crises will have an impact on transmission project timelines, as well as generation timelines. However, the magnitude of this impact is highly uncertain and will be affected by federal and state policies and recent changes introduced by the Obama administration which has made announcements to upgrade domestic transmission. In the short-term, major transmission projects may be put "on hold" pending financing constraints. Financing for facility upgrades may be difficult amid uncertainties about future demand. Delays in federal GHG regulation and limitations in the volume of financing could limit the number of new projects that can be initiated in time to meet the expected transmission date of commercial operation.

3.3 Consideration of Market Constraints in Timeline Analysis

It is difficult to predict the overall impact of supply chain constraints on the timing of the build-out of the 33% RPS Reference Case, given the many factors at play. The implementation timelines presented in the report are thus driven predominantly by factors such as human resource constraints and anticipated process improvements, the effects of which are considered more predictable. However, general market constraints are among the factors that contribute to the "external risk" applied to Timeline 2B – see pages 48-53 (Figure 9) of the report for discussion.

4 Development of Overall 33% RPS Implementation Timelines

4.1 Introduction to Approach

As described in Section 4 and Appendix B of the 33% RPS Implementation Analysis Preliminary Results report, following the development of the generic generation and transmission timelines, Aspen and CPUC staff constructed development timelines for each of the six "transmission zones" – those zones for which major new transmission was needed – that were included in the 33% RPS Reference Case. The team then combined these six zone timelines into timelines for the overall development of the 33% Reference Case portfolio. Appendix B and Section 4 of the report describe the construction of these timelines. This section provides more background

information and specifics on the differences between zone timelines between zones and between timeliness 1, 2A and 2B.

Table 7, on the next page, identifies the generation included in the 33% RPS Reference Case, by zone and resource type.

As described in detail in the report, transmission development generally takes longer than generation development. Thus, although generation developers' need for some level of certainty of transmission access before fully engaging in development activities often leads to a time-lag between completion of transmission lines and their full subscription by generators, this analysis assumes that *the steps involved in developing a major new transmission project constitute the critical path for the development of each of the zones contributing to the 33% RPS Reference Case*.

Table 7. Generation Projects in 33% RPS Reference Case, by CREZ and Resource Type

New Generation included in 20% RPS Reference Case, by Zone	Available Capacity, by Resource Type (MW)	Available Energy (GWh)
Solano	Wind: 1,000 MW	3,197 GWh
Tehachapi	Solar: 180 MW Wind: 2,820 MW	8,862 GWh
Imperial North	Solar: 170 MW Wind: 195 MW Geothermal: 1,120 MW Biomass: 15 MW	9,634 GWh
Riverside East	Solar: 1,349 MW (for 20%)	3,153 GWh (for 20%)
NEW RENEWABLE MW in 20% REFERENCE CASE	**6,849 MW (In-State) 525 MW (Distributed, not shown) 2,062 MW (Out-of-State, not shown)**	
Additional new generation included in 33% RPS Reference Case, by Zone		
Mountain Pass	Solar: 1,480 MW Wind: 170 MW	4,041 GWh
San Bernardino – Lucerne	Solar: 1068 MW Wind: 641 MW Biomass: 91 MW	5,020 GWh
Riverside East (in addition to CREZ needed for 20%, above)	Solar: 1,651 MW	3,869 GWh
Palm Springs	Wind: 806 MW	2,711 GWh
Carrizo North	Solar: 1,500 MW	3,306 GWh
Fairmont	Solar: 309 MW Wind: 1,282 MW Biomass: 59 MW	5,003 GWh
Kramer	Solar: 1,423 MW Wind: 203 MW Geothermal: 24 MW	4,226 GWh
Needles	Solar: 745 MW Wind: 455 MW	3,078 GWh
Baja	Wind: 100 MW	321 GWh
TOTAL NEW RENEWABLE MW in 33% REFERENCE CASE (including 20% Case)	**18,760 MW (In-State) 949 MW (Distributed, not shown) 4,093 MW (Out-of-State, not shown)**	

4.2 Development of Transmission Zone Timelines

In order to develop the overall 33% RPS Reference Case timeline, the study team developed development timelines for the zones included in the 20% RPS Reference Case. These timelines reflect actual expected timelines for transmission currently under development (in the cases of the Tehachapi, Imperial North, and Riverside East zones), or that could be planned and developed relatively quickly, due to proximity to major load centers (Solano).

For the incremental zones included in the 33% RPS Reference Case, the study team made rough assumptions about which of the resource zones could, for purposes of planning, permitting, and construction, share one single major transmission project. The zones were combined, based on geography and relation to the existing transmission system, as below:

Table 8. Assignment of Resource Zones to Transmission Zones for Overall Timeline Analysis

Resource Zones included in 33% Reference Case	Assigned "Transmission Zone"
Fairmont	* Assumed to be accommodated by Tehachapi transmission upgrades accessing the "Tehachapi" zone in 20% Reference Case
Mountain Pass + San Bernardino-Lucerne	Transmission Zone 1
Carrizo North	Transmission Zone 2
Riverside East + Palm Springs	Transmission Zone 3
Kramer	Transmission Zone 4
Needles	Transmission Zone 5
Baja	Transmission Zone 6

As described in the report, the order in which the transmission zones were assumed to be developed was random. Further, the "external risks" applied to certain zones in Timeline 2B, which result in delays to the development of those zones, were applied randomly, and are not meant to indicate a real likelihood that any one zone is more than another to face delays.

The study team did, however, attempt to capture in the timelines some differences in the expected complexity and thus the development timing of transmission projects to specific "transmission zones". Given the very schematic nature of the transmission identified in this analysis, these expected timing differences were based almost exclusively on differences in the distances associated with the schematic transmission links and the amount of generation the projects were assumed to access. For example, the study team assumed that it would take twice as long (36 months) to construct a transmission project that would fully access Transmission Zone 1 (Mountain Pass and San Bernardino-Lucerne zones; 3,450 MW), as it would to construct a transmission project accommodating Transmission Zone 2 (Carrizo North, 1,500 MW; 18 months to construct).

Table 9, below, details the time assumed for each step of the development of a major new transmission project to each transmission zone, for each of the three timelines presented in the report. The table illustrates the differences in timing assumptions across zones based on expected project complexity, as described above; changes between Timeline 1 and Timeline 2A to reflect the reforms detailed on pages 44-47 of the report, e.g. a reduction in CEQA/NEPA review time from 24 to 18 months for most 33% zones; and changes between Timeline 2A and Timeline 2B to reflect the external risks detailed in pages 48-55 of the report, e.g. a doubling of the construction time for Transmission Zone 5 to reflect human resource or financial constraints. Aside from these considerations, the timing assumptions in Table 9 reflect the generic timelines described in Section 2 of this white paper, and in Appendix B of the report.

Table 9. Timing assumptions for development of 20% and 33% Reference Case Transmission Zones (months)

	Zone	CAISO Development of 33% "Conceptual Master Plan"	Transmission Planning	CPCN/ Project Description Preparation	CEQA/ NEPA Review	Final Project Review	Final Design, Construction
20% Reference Case Zones	Solano		24	6	24	3	24
	Tehachapi + Fairmont				6	4	52
	Imperial North						48
	Riverside East				3	6	30
Timeline 1: Historical Experience without Process Reform	33% Transmission Zone 1		24	18	24	4	36
	33% Transmission Zone 2		24	12	24	4	18
	33% Transmission Zone 3		24	18	24	4	30
	33% Transmission Zone 4		24	18	24	4	24
	33% Transmission Zone 5		24	18	24	4	24
	33% Transmission Zone 6		8	6	12	5	18
	Path 15 upgrade		18	12	18	3	24
Timeline 2A: Current Practice with Process Reform and no External Risks	33% Transmission Zone 1	(complete in Q1 2010)	24	0 (concurrent w/ transmission planning)	18	3	36
	33% Transmission Zone 2	"	24	0	18	3	18
	33% Transmission Zone 3	"	24	0	18	3	30

Table 9. Timing assumptions for development of 20% and 33% Reference Case Transmission Zones (months)

	Zone	CAISO Development of 33% "Conceptual Master Plan"	Transmission Planning	CPCN/ Project Description Preparation	CEQA/ NEPA Review	Final Project Review	Final Design, Construction
	33% Transmission Zone 4	"	24	0	18	3	24
	33% Transmission Zone 5	"	24	0	18	3	24
	33% Transmission Zone 6 (no change: Baja assumed minimally impacted by California reforms)	N/A	8	6	12	5	18
	Path 15 upgrade	N/A	17	0	18	3	24
Timeline 2B: Current Practice with Process Reform and External Risks	33% Transmission Zone 1	(complete in Q1 2010)	24	0 (concurrent w/ transmission planning)	18	3	36
	33% Transmission Zone 2	"	24	0	18	3	18
	33% Transmission Zone 3	"	24	0	18	3	0
	33% Transmission Zone 4	"	24	0	18	3	24
	33% Transmission Zone 5	"	24	0	18	3	48
	33% Transmission Zone 6	N/A	8	6	12	5	18
	Path 15 upgrade	N/A	17	0	18	3	24

The overall 33% RPS Reference Case timelines resulting from the assumptions above are presented graphically as Figures 7, 8, and 9 of the 33% RPS Implementation Analysis Preliminary Results.

Acronyms & Abbreviations

AFC: Application for Certification (Energy Commission)	IOU: Investor Owned Utility
BLM: Bureau of Land Management	MW: megawatts
CAISO: California Independent System Operator	MND: Mitigated Negative Declaration (CEQA)
Energy Commission: California Energy Commission	ND: Negative Declaration (CEQA)
CEQA: California Environmental Quality Act	NEPA: National Environmental Policy Act
CPCN: Certificate of Public Convenience & Necessity (CPUC)	RETI: Renewable Energy Transmission Initiative
CPUC : California Public Utilities Commission	
CREZ: Competitive Renewable Energy Zone	RETI EWG: The RETI Environmental Working Group
EA: Environmental Assessment (NEPA)	RFO: Request for Offers
ED: Energy Division of CPUC	RFP: Request for Proposals
EIR: Environmental Impact Report (CEQA)	ROW: Right-of-way
EIS: Environmental Impact Statement (NEPA)	RPS: Renewables Portfolio Standard
GHG: Greenhouse Gas	SB-L: San Bernardino–Lucerne CREZ
GW: gigawatts; GWh: gigawatt-hours	Utilities: Investor Owned Utilities and Publicly Owned Utilities

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