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Attachment 2

Standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans

Summary of Updates

This brief document summarizes the most significant changes in the attached Standardized Planning Assumptions (Part 2 – Renewables), as compared to the draft Long-Term Renewable Resource Planning Standards released on June 22, 2010.

For ease of comparison, throughout the attached Planning Assumptions, all changes to the *inputs* or *methodology* presented in the June 22 draft Planning Standards are also highlighted in red, with the titles to tables highlighted in red if there are changes to any of that table's content. The one exception is that, given the substantial changes to Appendix E, that Appendix has been replaced in its entirety. Language changes in the report that simply clarify or provide more detail about the methodology that was presented in the June draft is not highlighted.

Significant changes and updates include:

Resource and Cost Assumptions

- Small solar PV availability is updated as described in Table 6, fixing discrepancies between potential identified by E3/B&V and the amounts included in the June 18th Calculator.
- Biomass potential in the Northwest and California has been reduced, as discussed in Section II.5.1.
- Tables B2 and B3 are updated as described in Appendix B, to reflect updated assumptions about resource RPS eligibility, and to correct for discrepancies between the Energy Division database and modeled commercial resources.
- NOx permit costs are now considered for biomass resources in sensitive Air Quality Basins; this applies only to the Fairmont and Palm Springs zones.
- The displayed costs in the Pro Forma tab are updated to consistently calculate California (rather than U.S. averages), and the error in the June 18th Calculator with double application of regional multipliers has been resolved, resulting in changes to the costs shown in Table 1. Also, Table 1 now reflects only California-average costs, rather than the WECC-wide averages shown previously. This also resulted in changes to the capacity values shown in Table 3, as the Gas CT cost used to calculate the capacity value was subject to the same double application of regional multipliers.
- The transmission cost assumption was reduced from \$68/kW-yr. to \$54/kW-yr. The average annual cost of new transmission lines in California is used as a proxy for network upgrades that may be required for NonCREZ resources.

Energy and Capacity Valuation

- NQC values for in-state resources are updated:
    - Biogas, small solar PV, and small hydro no longer receive a capacity credit. These resources are assumed to connect via the Small Generator Interconnection Process or Wholesale Distribution Access Tariffs available to generators < 20

MW, and those study processes do not currently include the deliverability study that is necessary for capacity to be counted towards California's Resource Adequacy program.

    - Biomass reduced from 100% to 66%
    - Wind NQC increased from 11% to 16%
    - Geothermal reduced from 100% to 72%

- Energy Value calculation for small hydro resources is updated, as reflected in Table 2.
- Costs and losses associated with delivering Idaho REC resources to the local market are updated, resulting in changed energy values in Table 3.

Timing Assumptions

- Generation timing assumptions in Table 5 and Appendix F1 are updated; Table 5 now includes detail about the timing of different development steps that was previously only contained in Appendix F1, identifies timing assumptions unique to biogas facilities, clarifies that the 33% RPS Calculator only considers a resource for inclusion in a scenario as of its first <u>full year</u> of commercial operation, and reflects adjustments to general project development timing made in response to party comment. With few exceptions, the updated assumptions reflect longer development timeframes.
- Transmission timing assumptions in Table 7 and Appendix F2 have been lengthened slightly to reflect party comment.
- A lag of 18 months is assumed between the completion of any transmission line and the availability in the Calculator of all the generation in that line's zone, as discussed in Section II.7.2, below.

Ranking and Scenario Creation Methodology

- The environmental scoring methodology is updated significantly, in response to party comment, as detailed in Appendix E.
- The Net Short Calculation has been updated to reflect the demand levels adopted in the Scoping Memo and presented in the Standardized Planning Assumptions (Part 1).
- Three new scenarios have been added, pursuant to the direction in the Scoping Memo: a 20% by 2020 Trajectory Scenario, and high and low load sensitivities around the 33% Trajectory Scenario.
- The weighting of scores used to create the Time-Constrained Scenario has been adjusted slightly as shown in Table 9 and described in that section.
- Model has been adjusted to ensure that *local, non-California* RPS builds are always based on cost, not the criteria that a user has selected to sort resources for delivery *to California.*

Updates to 33% RPS Calculator Functionality

- The updated calculator will be available on the 2010 LTPP History webpage: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.
- The Solar Pro Forma Tool is now integrated into the 33% RPS Calculator. Previously, solar costs had to be brought in from an external pro forma model to ensure adequate debt-service coverage ratios.
- The user can now select thin-film or crystalline tracking as the default technology for large-scale solar PV resources. In the June 18^{th} version of the model, all large-scale solar PV resources were assumed to use crystalline tracking technology. While that remains the default, the user now has the option to select thin-film as the default large-scale solar PV technology.
- The user can now run sensitivities assuming that Wyoming and Montana resources are delivered by DC lines; default assumption continues to be AC lines

Other

- The Results section is updated to reflect the new scenarios resulting from the revised inputs and methodology, and to allow for easier comparison across scenarios.
- The Out-of-State REC Supply Table in Appendix B6 has been added, as it was inadvertently omitted from the June 22 draft.
- The formatting problems with Appendix D that had made it difficult to read and understand the source of the information in that Appendix.
- Language throughout is updated to reflect the change from a draft staff proposal to a final adopted document.

Table of Contents

Standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans

I Introduction

I.1 2010 Long-Term Procurement Plan Proceeding

The Commission opened the 2010 Long-Term Procurement Plan (LTPP) proceeding with an Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans (OIR) on May 6, 2010. In that OIR, the Commission stated its intent "to continue our efforts to ensure a reliable and cost-effective electricity supply in California through integration and refinement of a comprehensive set of procurement policies, practices and procedures underlying long-term procurement plans. This is the forum in which we shall consider the Commission's electric resource procurement policies and programs and how to implement them."[1]

The 2010 LTPP is expected to consider new generation needs within the 2010-2020 planning term. The OIR laid out three tracks for the proceeding:

> "(1) **Track I** will identify California Public Utilities Commission (CPUC)-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of IOU procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through- cooling (OTC).
>
> "(2) **Track II** will address the development and approval of individual IOU "bundled" procurement plans consistent with §454.5.
>
> "(3) **Track III** will consider rule and policy changes related to the procurement process which were not resolved in R.08-02-007…"[2]

As noted in the OIR, the need to integrate renewables is anticipated to be one of the "primary drivers for any need for new resources identified in this proceeding."[3] These standardized planning assumptions present the set of inputs, assumptions, methodologies, and resulting scenarios that will guide long-term renewables planning within the 2010 LTPP.

I.2 Background

Since Decision (D.) 05-07-039, the Commission has stated its intent to integrate long-term planning for renewables into the LTPP proceeding. D.05-07-039 states: "We will address the long-term plans filed in this proceeding in a subsequent decision. After that decision, we intend to return long-term RPS planning to the long term procurement planning component of R.04-04-003 or its successor, as contemplated by [Pub. Util. Code] § 399.14(a)."[4] In the Scoping

[1] Rulemaking (R.) 10-05-006, at p. 2.
[2] *Id*., at p. 9.
[3] *Id*., at p. 12.
[4] D.05-07-039, at p. 29.

Memo for the 2006 LTPP, the Commission stated that "The 2006 LTPPs will identify the key planning decisions that the utilities need to make in the next few years in order to ensure the Commission's energy policy objectives are maintained and pursued in the future, including moving on a path to achieve the EAP [Energy Action Plan] II goal of 33% renewables by 2020".[5] The utilities were specifically directed to include in their plans "information about the extent to which the IOUs [Investor Owned Utilities] will exceed the existing legislative mandate of 20% renewables by 2010 and work towards the EAP policy goal of 33% by 2020."[6]

In response to the 2006 Long-Term Procurement Plans filed by the IOUs, and recognizing the growing support for increasing the existing 20% by 2010 Renewables Portfolio Standard (RPS) to a standard of 33% by 2020, the Commission directed "parties to work with ED staff to refine a methodology for resource planning and analysis that will allow [the IOUs] to adequately address the issue of a 33% renewables target by 2020 in subsequent LTPPs ….We expect these sections to be much more robust in subsequent LTPPs and expect that parties will work to make RETI [Renewable Energy Transmission Initiative] useful in this regard."[7] In response to this direction, Energy Division staff worked with parties to the 2008 LTPP proceeding, R.08-02-007, and other stakeholders to assess implementation of a 33% RPS, considering various resource portfolios with which the state might achieve such a target, as well as the associated timing, costs, and risks.

In June 2009, Energy Division staff released its *33% RPS Implementation Analysis Preliminary Results*[8] report. A December 9, 2009 ACR in the 2008 LTPP confirmed that the study had responded to the Commission's direction to develop a methodology for considering a 33% renewables target within long-term procurement planning; stated that it exemplified the sort of system-wide "Renewables and Transmission Study" that parties had generally supported in the 2008 LTPP proceeding; and anticipated that staff would "refine the 33% RPS Implementation Analysis assumptions and methodology in an updated study, as a direct input to the 2010 system planning proceeding."[9] On December 9-10, 2009, Energy Division staff held a workshop to review party comments on the *33% RPS Implementation Analysis Preliminary Results* report and to consider the refinements that should be incorporated into an updated analysis for the 2010 LTPP.

I.3 Preliminary Process and Relationship to other Considerations in LTPP

On May 28, 2010, a Ruling in R.10-05-006 transmitted two Energy Division staff proposals related to the Track I system plans – *Standardized Load and Resources Tables for System Resource Plans*, and *Planning Standards for System Resource Plans* (similar documents for the Track II bundled plans were also released). The scenarios presented in this report are discussed in the May 28 Planning Standards proposal:

[5] September 25, 2006 ACR/Scoping Memo, at p. 18
[6] *Id*., at p. 20
[7] D. 07-12-052, at p. 256.
[8] Available here: http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf
[9] Assigned Commissioner's Ruling in R.08-02-007, December 3, 2009, p. 3

"The Energy Division shall propose a minimum set of renewable generation scenarios in its draft report due in June 2010. In addition to comments on staff's proposed renewable scenarios, the IOUs or any other party may propose other scenarios the Commission should consider to achieve the goals of this proceeding. The Assigned Commissioner will determine a reasonable minimum set of resource planning scenarios in the Scoping Memo, based on initial proposals and parties' comments. The required scenarios shall be consistent with the guiding principles set forth in Section II."[10]

This attachment presents seven "RPS scenarios", containing specific portfolios of generation and transmission resources with which the state might achieve a 33% RPS in 2020, as well as sensitivities around the Trajectory Scenario for high and low load levels, and a 20% by 2020 scenario. These RPS scenarios, however, are only one set of many inputs and assumptions discussed in the Standardized Planning Assumptions as critical to the LTPP's determination of need for new system resources.

Some of the "non-RPS" inputs to the LTPP, such as assumptions about the retirement of once-through-cooled plants, have little or no impact on the makeup of the RPS scenarios. Others, however, including forecasts of load and of "load modifiers" such as customer-side distributed generation (DG) and combined heat and power (CHP), affect the amount of renewable generation assumed necessary under a 33% RPS, by affecting retail sales. The May 28, 2010 Planning Standards document proposed and solicited party comment on these inputs, and a separate, more detailed report specifically on energy efficiency assumptions was released on June 22, 2010 as "Resource Planning Assumptions – Part 3" and discussed at a workshop on June 25.

The scenarios selected for further analysis have been updated to be consistent with the demand-side assumptions presented in the Standardized Planning Assumptions (Part I), as discussed in the "Resource Gap Calculation" section below.

II Methodology

II.1 Terminology – Scenarios, Sensitivities, Cases, Portfolios

These planning assumptions rely on the terminology for scenarios, cases, etc. presented in the Standardized Planning Assumptions Part I – with the important exception noted in the next section. Specifically, for the terms relevant to this report:

Scenario - A possible future state of the world encompassing assumptions about policy requirements, market realities and resource development choices. *Required scenarios* are those specified in the Scoping Memo. *Supplemental scenarios* are any additional scenarios provided by parties, and evaluated in addition to those required in the Scoping Memo.

Portfolio - A set of electric resources, both supply-side and demand-side, that provides electric service to all system ratepayers, under a given scenario. *Utility-Preferred*

[10] *Administrative Law Judge's Initial Ruling on Procurement Planning Standards and Setting Schedule for Comments and Workshops*, May 28, 2010, Attachment 2, at p. 6.

Portfolio is a resource portfolio identified by the IOU as a preferred resource portfolio and submitted to the Commission for consideration and possible adoption.

Resource Plan – A filing before the Commission containing information and analysis on all portfolios developed and evaluated, including complete documentation of each portfolio's performance under required evaluation criteria.

Case – A set of input assumptions and parameters (e.g., gas price, or electricity demand) under a given scenario that drives the selection of a given portfolio of resources.

Common Values – A set of input assumptions and parameters that represent the expected or most likely values for each scenario. All required scenarios shall have the same common value assumptions, whereas supplemental scenarios may consider alternative assumptions.

Sensitivity Analysis - A test to measure the change in output variable (e.g., cost, resource need) due to a change in input assumptions and parameters. Sensitivity analysis is conducted by changing one or more input assumptions from the common value to an alternative value.

II.2 Statewide Approach

The one exception to these planning assumptions' consistent use of these terms is that the "portfolios" presented here contain resources providing electric service to all ratepayers statewide, rather than to just the "system" ratepayers of one or all of the three large IOUs.

The need for a statewide approach to the development of the 33% RPS scenarios is due to the nature of renewable resources. The highest-quality renewable resources are clustered in distinct geographic areas, and they are often transmission-constrained. In order to assure that multiple utilities – whether investor-owned or publicly-owned – do not count on the same transmission-constrained resource to meet their long-term RPS targets, a statewide approach is warranted. Such an approach can also serve to identify priority resource areas to which utilities might consider developing transmission lines that would benefit ratepayers both inside and outside the system operated by the California Independent System Operator (ISO).

In order to be useful for the IOUs' system plans, the statewide scenarios presented in this report have also been disaggregated, with resources "allocated" to each IOU for system planning purposes, based on physical location. These allocations are presented in the Loads and Resources (L&R) Tables attached to the Scoping Memo.

II.3 33% Resource Gap Calculation

These planning standards estimate the level of statewide renewable generation in every year between 2010 and 2020, the end of the 2020 LTPP planning horizon, under seven different scenarios: four 33% by 2020 scenarios, two load sensitivities around the 33% Trajectory Scenario, and one 20% by 2020 scenario. In order to calculate the need, or "RPS resource gap" in each year, assumptions must first be made about three inputs: existing/baseline generation, load, and load-modifying demand-side resources.

II.3.1 Baseline generation

Energy Division's consultant, Energy and Environmental Economics, Inc. (E3) relied on the California Energy Commission's 2008 Net System Power Report[11] for California utilities' claims of renewable energy deliveries in 2008. Because the 2009 Net System Power Report for 2009 is not yet available, E3 added to the 2008 list those renewable resources that came online in 2009 according the CPUC's records, yielding a figure that represent the total existing renewable generation contracted to or located in California as of 2009.

In order to project the RPS need in 2020, E3 also had to make assumptions about the RPS generation facilities that would either retire or roll off their contracts over the next several years. A number of the projects now under contract to California utilities have short-term contracts that expire before 2020. In the case that these are in-state resources, E3 has assumed that the contracts would be renewed such that those resources would continue to contribute to the target through 2020; for out-of-state resources, E3 has assumed that no re-contracting occurs and that the local jurisdiction repossesses the RECs associated with these resources before 2020. E3 has assumed no renewable generation facility retirements over the course of the study period.

II.3.2 Load forecast

These standardized planning assumptions rely on the forecast developed by the California Energy Commission as part of the 2009 Integrated Energy Policy Report process[12] for estimates of statewide retail energy demand 2010-2020. See Appendix A for more detail.

II.3.3 Load-modifying demand-side assumptions

These standardized planning assumptions use a common set of demand-side assumptions to create four 33% by 2020 scenarios (described in more detail in Section II.4.4, below), and one 20% by 2020 scenario. These demand-side values assume statewide achievement of:

1.) The mid-case incremental energy efficiency forecasts[13] presented by the Energy Commission in its *Incremental Impacts of Energy Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast.*[14] The Energy Commission's estimates for IOU savings have been scaled up in order to estimate statewide – not only IOU – savings, by applying an assumed IOU:non-IOU ratio of 75:25. This scaling was performed only on the savings estimated from "2020 Incremental Uncommitted Impacts", and not on the "IOU Program Decay Replacement" savings.

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[11] Nyberg, Michael, 2009. *2008 Net System Power Report*. California Energy Commission. CEC-200-2009-010.

[12] Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF.

[13] See discussion in the Scoping Memo on Energy Efficiency and decrements to Big Bold Energy Efficiency Strategies, for more detail.

[14] Electricity and Natural Gas Committee. *Incremental Impacts of Energy Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast*. CEC-200-2009-001-CTF.

2.) The customer-side DG assumptions embedded in the 2009 IEPR forecast. Because the load forecast already assumes a large amount of customer-side DG, no additional installments of customer-side DG are assumed within the planning horizon.

3.) Increases in CHP in IOU service territories at the midpoint between no incremental CHP and the IOUs' portion of the nearly 4,000 MW of incremental state-wide CHP that ARB targets in its AB 32 Scoping Plan. Additional assumptions include: existing CHP capacity is maintained through 2020; incremental CHP growth is split evenly between on-site use and exports to the grid; the ratio of capacity between the IOUs' territories remains constant at the 2010 percentages for supply-side and demand-side CHP; and the 2020 values are evenly distributed back to 2010.

These standardized planning assumptions also test the sensitivity of one of the four 33% RPS scenarios – the Trajectory Scenario – to changes in load levels, presenting a Trajectory Scenario – Low Load and a Trajectory Scenario – High Load. The "Low Load" sensitivity assumes total RPS eligible retail sales of 10% *below* the standard demand assumption, and the "High Load" sensitivity assumes total eligible RPS sales of 10% *above* the standard demand assumption.

More detail on the assumptions and their values are provided in the Scoping Memo, in Attachment 1 and its appendices, and in Appendix A to this report.

II.4 Portfolio Development Approach and Required Scenarios

II.4.1 Guiding Principles for RPS Scenario Development

At the December 10-11, 2009 workshop, staff proposed that the following principles should guide development of new 33% RPS scenarios. These principles are reflected in the adopted methodology and scenarios:

<u>Guiding Principles for development of Inputs, Assumptions and Methodologies:</u>

1.) Assumptions should reflect the behavior of market participants, to the extent possible

2.) Methodology should be consistent with previous regulatory decisions, to the extent applicable

3.) Any proposal should explain the policy basis for the proposal

4.) Any proposal must include supporting documentation

<u>Guiding Principles for development of RPS Scenarios:</u>

5.) RPS scenarios should be reasonably feasible and reflect plausible procurement strategies with associated (conceptual) transmission.

6.) RPS scenarios should represent substantially unique procurement strategies resulting in material changes to corresponding (fossil) procurement needs and/or required (conceptual) transmission.

7.) The number of RPS scenarios should be limited to 3-5

Although not explicitly listed in the guiding principles, transparency was also a primary goal for staff, and the attempt to bring transparency to the planning process drove key decisions related to methodology, as described below.

II.4.2 Inclusion of a "Discounted Core" of Contracted Projects

One weakness of the June 2009 *33% RPS Implementation Analysis* was that, for all scenarios except the "33% Reference Case", insufficient consideration was given to the thousands of MW of projects with which California's utilities have signed contracts since the beginning of the RPS program, but which are not yet delivering energy. In effect, the "High Wind", "High DG" and "High Out-of-State" cases in that analysis were built on the assumption that utilities could either step out of many of the contracts they had signed to pursue a different procurement strategy, or that those resources would fail to develop in accordance with the contract specifications. While it is not realistic to assume that all of the projects contracted to utilities will deliver as contracted, the IOU contracts nevertheless represent the best information available about the state's potential renewable resource portfolios over the next 10 years.

The adopted methodology addresses this issue via the identification of a "discounted core" of resources intended to represent the most viable of the projects with which IOUs have signed contracts. These projects are held constant across all scenarios, assuming that these projects are reliable under several different futures. The exception, however, is that a project that meets the criteria described below for inclusion in the discounted core is not "forced" into a scenario if that project would prompt the need in the model for new transmission. New transmission is only added to accommodate *discounted core* projects – and thus included in all of the scenarios – if discounted core projects would provide at least 67% of the energy that could be accommodated over the added transmission line. If the discounted core projects in a zone don't meet that threshold, then they enter the larger pool of "commercial interest" projects and compete for inclusion in each scenario as per the methodology described in Section II.8. Users can adjust and test the sensitivity of results to this assumption by changing cell D16 on the Control Tab sheet of the 33% RPS Calculator.

The intent of this approach is to ensure, given the model's limited choice of sizes for new transmission lines, that discounted core resources do not "force" the inclusion in every scenario of major new transmission lines that would serve only a small amount of RPS generation that met the policy goal of that scenario. Historical experience suggests that major transmission projects must provide access to a significant amount of renewable generation in order to be successfully permitted and financed.

The adopted methodology uses entirely public information as criteria for choosing the discounted core. Although the Commission has access to confidential information about project development and viability, use of such information – or of subjective judgments about project viability that could harm an individual project's ability to secure financing – in order to determine inclusion in the discounted core would preclude the public release of the specific portfolios of resources in each scenario. Given the widespread interest in long-term planning for renewables and the desire that the scenarios be fully vetted by

parties, the benefits of transparency in this case outweighed the potentially small gains in accuracy that might be gained by using confidential information.

To be included in the discounted core, the project must be a new, repowered, or restarted RPS-eligible generation project with:

1.) a **signed power purchase agreement** (PPA) either under review or already approved by the Commission as of June 1, 2010; and

2.) its **major permit** (Application for Certification if under the jurisdiction of the Energy Commission; Conditional Use Permit in most other cases) filed with and deemed data adequate by the appropriate agency, as of March 1, 2010.

Staff also considered the use of other public, objective information about developers' project development and ownership experience, and past demonstration of a technology at the scale proposed. Although these criteria are not adopted, the functionality to test the use of these criteria on the makeup of the discounted core remains in the tool developed by E3, for parties to consider.

The discounted core also includes the full MW potential that would be developed under the wholesale solar PV programs proposed and approved by the Commission for Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), and the program proposed and under review by the Commission for San Diego Gas & Electric (SDG&E).[15] If successful, these programs would lead to the development of 1,052 MW of rooftop and ground-mounted PV programs under 20 MW, over the next 5 years. Although the programs are relatively un-tested, it is reasonable to assume the goals will be met, given the large solar PV potential identified for this analysis, and the increasing number of bids in RPS solicitations from projects less than 20 MW, and the high level of commercial interest in the utility programs.

II.4.3 Zone-based Approach

The approach to portfolio development used in these standardized planning assumptions is an updated version of that used in the 2009 33% Implementation Analysis. The approach draws heavily on the resource identification, cost assessment, environmental ratings and Competitive Renewable Energy Zone (CREZ) identification done by the Renewable Energy Transmission Initiative (RETI).[16] Using an updated version of the 33% RPS Calculator developed for last year's analysis, E3 builds 33% RPS portfolios in three main steps:

Step 1: Identify resources geographically as located in one of 41 CREZs; as a "non-CREZ" resource that will deliver energy to California; or as an out-of-state

[15] On September 2, 2010, the Commission issued Decision (D.)10-09-016, approving SDG&E's proposed Solar Energy Project. Rather than the 52 MW total proposed in SDG&E's application, the Decision authorized a program total of 100 MW of primarily 1-2 MW projects. The assumptions for this analysis were already finalized by the time of the Decision's release, however, with 52 MW in the discounted core, rather than 100. Given the relatively small impact that a change from 52 to 100 MW in the discounted core would have on the overall results, the analysis was not updated.

[16] Information about RETI is available on the RETI website, http://www.energy.ca.gov/reti/.

"REC" resource assumed to deliver energy into the local out-of-state market (detail in Section II.6);

Step 2: Rank resources based on cost, timing, environmental concern, and commercial interest (detail in Section II.8);

Step 3: For each CREZ, select resources into bundles according to transmission constraints:

Increment 1: Generation that can fit on the existing transmission system;
Increment 2: Generation that can be accommodated by minor upgrades;
Increments 3-6: Generation that can be accommodated by the addition of new generic transmission lines of various sizes;

Step 4: Select from among non-CREZ resources, CREZ "bundles", and RECs enough resources to meet the 33% target (Section II.6)

One major change to last year's approach is in the treatment of transmission, as described in Step 2. This approach is explained in more detail in Section II.6.3, below.

II.4.4 Proposed Scenario Definitions

A key finding of last year's *Implementation Analysis* was that the scenarios developed for that study – High Wind, High DG, High Out-of-State Delivered and a Reference Case weighted towards contracts signed and under negotiation –varied in their achievement of policy goals often attributed to the RPS program.[17] From a high-level, for example, the High DG scenario may perform better on market transformation, while the High Wind case performs better on cost, but no one scenario performed well across all policy objectives.

For this updated analysis, the 33% scenarios are in fact defined by the policy objectives against which they are expected to perform best:

1.) Cost-constrained Scenario;
2.) Time-constrained Scenario;
3.) Environmentally-constrained Scenario; and
4.) a Trajectory Scenario weighted heavily towards commercial contracts, thus representing the IOUs' current contracting/procurement trajectory

In order to develop these scenarios, staff and its consultants developed metrics for zones and distributed projects related to that project or zone's estimated cost, estimated online date, estimated high-level environmental concern, and commercial interest/contracting status. The development of each of these metrics is discussed in more detail in the following sections.

[17] California Public Utilities Commission, *33% RPS Implementation Analysis: Preliminary Results*, June 2009, at p. 10.

II.5 Resource Potential, Cost, and Performance

II.5.1 Overview of Resource Potential

The RPS model includes estimates of resource potential for renewables throughout the WECC based on four sources:

1.) **Commercial Projects Database:** The Commercial Projects Database includes data on potential projects currently under some phase of development by California utilities and draws from two sources: the CPUC Energy Division (ED) Database for IOU solicitations and resource plans for POUs in California. The ED Database includes all of the renewable resources with pending or approved contracts as well as projects that have been shortlisted by the IOUs. Details on the projects with pending or approved contracts are available to the public through the CPUC and are included explicitly in the RPS model. A subset of these projects is distinguished as the "Discounted Core," as described above.

The database also includes IOU shortlisted projects, which are confidential and cannot be included in the public model individually; therefore, the RPS model includes aggregate info on these contracts when there are at least 3 projects of the same technology type in a single CREZ. This process is necessary in order to preserve the confidentiality of projects that have not yet begun the permitting process. The RPS model has also incorporated information on planned Publicly-Owned Utility (POU) procurement based on data gathered from the Energy Commission. This data is similar in format and treatment in the model to the non-Discounted Core ED Database projects. Most of the projects included in this set of data are small and are unlikely to require major transmission upgrades, but several POUs have expressed interest in the development of resources in CREZ that might require new transmission.

2.) **RETI Phase 2B Database**: This database includes assessments of renewable resources in California within CREZ as well as estimates of out-of-state potential developed as part of the Western Renewable Energy Zone (WREZ) Transmission Model. The resource potential quantified in the WREZ model is based on an assessment of high-quality remote resources that could be developed with new transmission and is not a comprehensive assessment of out-of-state potential. In addition to resource potential, RETI provides cost and performance metrics for each of the sites considered in its analysis.

E3 made adjustments to the resource availability where appropriate. Specifically, while RETI and other sources report substantial potential for biomass generation, many questions remain about the extent to which this potential can ultimately be realized. Air quality concerns, fuel transport costs, and competing uses for the feedstock are just some of the hurdles that may prevent large-scale development of biomass generation in the near term. As a result of these hurdles, and party comments received in response to the 2009 *Implementation Analysis*, E3 reduced

the RETI biomass potential estimates for California from 1,421 MW to 474 MW, and for the Northwest from 883 MW to 514 MW.

3.) **<u>E3 Greenhouse Gas (GHG) Calculator:</u>** E3 has used data that it developed on renewable resource potential throughout the Western Electricity Coordinating Council (WECC) as part of the GHG Calculator, to supplement the RETI Phase 2B data on out-of-state resources. The resource potential estimates in the GHG Calculator were developed using a wide range of sources including National Renewable Energy Laboratory, the US Energy Information Administration, the Alberta Electric System Operator and the British Columbia Hydro and Power Authority. E3 data were used to develop "local" renewable resource builds for each zone (resources were selected assuming that the most cost-effective resources in each zone were selected to meet local RPS targets), and to develop resource bundles available for export to California from Colorado, Montana, and the Canadian provinces of British Columbia and Alberta.

4.) **<u>E3/Black & Veatch Estimates of Statewide DG Potential:</u>** As part of the 2010 LTPP, E3 and another CPUC consultant, Black & Veatch, have worked together to assess the resource potential, performance, and cost of distributed solar photovoltaic (PV) resources in the state of California. These latest estimates are included as candidate resources to meet California's RPS target.

    The solar resources were divided into two bins. The first bin (500 MW each from PG&E and SCE, 52 MW from SDG&E – see footnote 15) reflects the IOUs' recently approved plans for procurement of wholesale distributed solar procurement efforts. All of these resources are considered a part of the Discounted Core, i.e. they are included in all of the required RPS scenarios. The second bin represents the remaining DG potential statewide, and is treated as a generic (i.e. non-Commercial) project.

Resources in the model are divided into two categories: those available for delivery to California, which include all in-state resources and out-of-state resources that would require new transmission; and those only available as unbundled Renewable Energy Credit (REC) purchases, which include all out-of-state resources that could be developed without major new transmission investments. The model thus incorporates the functionality to build up a renewable portfolio with a combination of delivered resources and REC-only transactions.

II.5.2 Resource Cost and Performance

The RPS model assumes that new renewable resources are developed under PPAs between an independent power producer (IPP) and a credit-worthy utility. The utility's cost of developing a resource is the PPA price, which is a function of three types of assumptions: resource costs, resource performance, and financing characteristics. Using a detailed pro-forma model, the RPS model calculates a levelized cost of energy (LCOE) for each resource, which is used as the PPA price in the model.

For each resource type, cost assumptions are derived based on an average of the site-specific costs included in the RETI Phase 2B Database, supplemented with data from the E3 Capital Cost Tool for resource types not included in RETI. These costs, which include capital costs, fixed and variable operations and maintenance (O&M), and fuel, serve as a generic set of assumptions for the costs of renewable resources in California. Site-specific information is preserved for the RETI and WREZ resources, while average costs are applied to the in-state resources from the ED and POU databases. For out-of-state resources, the model includes regional cost multipliers that are used to adjust resource costs appropriately based on local costs of labor, construction, and materials.

A similar methodology is applied to determine the capacity factor for each resource: site-specific information is used where available (RETI and WREZ resources), while a generic average of the RETI projects is used for projects that do not have specific performance characteristics (ED and POU databases). The capacity factors for wind resources from the GHG Calculator are based on the resource class, which is used to make adjustments from the generic capacity factor for those resources.

Table 1.

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Capacity Factor	LCOE ($/MWh)
Biogas - Landfill	$ 2,750	$ 130	$ -	12,070	80%	$ 96
Biogas - Other	$ 5,500	$ 165	$ -	13,200	80%	$ 121
Biomass	$ 4,529	$ 93	$ 13	14,749	85%	$ 128
Geothermal	$ 5,155	$ -	$ 35	-	83%	$ 115
Hydro - Small	$ 3,960	$ 30	$ -	-	35%	$ 196
Solar Thermal	$ 5,300	$ 66	$ -	-	27%	$ 202
Wind	$ 2,399	$ 60	$ -	-	32%	$ 99

Based on these cost and performance assumptions, the RPS model calculates a levelized cost of electricity using a pro-forma tool included with the model. In addition to cost and performance, the levelized cost depends upon the tax credits available to and financing assumptions used for a specific resource, both of which vary by resource type. In order to capture real-world financing activity in new renewable development, E3 has adjusted the fractions of debt and equity in each project so that the debt-service coverage ratio of the project is at least 1.4. Subject to this constraint, the levelized cost of energy is calculated for each renewable technology considered in the model and is used as the representative generic PPA price for that technology.

II.6 Transmission and Geographic Classification

II.6.1 Overview

As described above, the RPS model selects from among hundreds of candidate resources to meet the 33% target. Resources are first identified geographically as being located either in one of the 41 CREZs, as a "non-CREZ" resource that will deliver energy to California, or as an out-of-state "REC" resource that is assumed to deliver energy into the local out-of-state market.

II.6.2 Geographic Classification

Resources are classified into three geographic categories:

1.) CREZ resources;

2.) non-CREZ resources; and

3.) out-of-state RECs.

Non-CREZ resources are resources that are not in an identified CREZ, but are located in California or directly across the border and assumed to deliver energy directly to California. These resources generally require transmission upgrades. Where there is specific information regarding the transmission upgrade costs, this information is included in the total delivered cost. Non-CREZ resources for which no specific information is available are assigned a "neutral" transmission upgrade cost calculated as an average of the upgrade costs for CREZ resources.

REC resources are resources that are located distant from California and would be scheduled over the western transmission grid. These resources may or may not schedule their energy to California. For pricing purposes, the resources are assumed to sell energy and capacity services into the wholesale energy market closest to the project location (e.g., the Mid-Columbia or Palo Verde markets). RECs are priced at the "Net Cost" or "Green Premium" discussed below in Section II.8.1: the resource's LCOE plus transmission and integration services minus the revenues earned through sale of energy and capacity services into the local market. E3 has assumed that the costs of integration will be captured in any REC contract and uses a flat adder of $7.50 per MWh[18] for intermittent resources. The following tables show the energy and capacity revenues for each REC resource type in each state in the WECC. These values include the cost of firm, point-to-point service from the resource location to the nearest market hub. More detail about REC resource assumptions is available in Appendix B.

Table 2.

REC Resource Energy Value by State and Resource Type ($/MWh)							
	Biogas	Biomass	Geothermal	Hydro - Small	Large Scale Solar PV	Solar Thermal	Wind
Alberta	$ 59	$ 59	$ 59	$ 53	n/a	n/a	$ 60
Arizona	$ 55	$ 55	$ 55	$ 56	$ 60	$ 62	$ 52
British Columbia	$ 47	$ 47	$ 47	$ 42	n/a	n/a	$ 49
Colorado	$ 51	$ 51	$ 51	$ 52	$ 57	$ 58	$ 49
Idaho	$ 47	$ 47	$ 47	$ 39	n/a	n/a	$ 45
Montana	$ 49	$ 49	$ 49	$ 44	n/a	n/a	$ 50
New Mexico	$ 50	$ 50	$ 50	$ 51	$ 55	$ 56	$ 48
Nevada	$ 53	$ 53	$ 53	$ 44	$ 56	$ 56	$ 52
Oregon	$ 55	$ 55	$ 55	$ 50	n/a	n/a	$ 55
Utah	$ 47	$ 47	$ 47	$ 39	$ 49	$ 49	$ 45
Washington	$ 55	$ 55	$ 55	$ 50	n/a	n/a	$ 55
Wyoming	$ 47	$ 47	$ 47	$ 42	n/a	n/a	$ 48

[18] This value was developed during E3's Greenhouse Gas modeling for the Commission in Rulemaking (R).06-04-009. It is used here in the absence of more rigorous analysis of California-specific integration costs.

Table 3.

REC Resource Capacity Value by State and Resource Type ($/MWh)	Biogas	Biomass	Geothermal	Hydro - Small	Large Scale Solar PV	Solar Thermal	Wind
Alberta	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Arizona	$ 20	$ 19	$ 19	$ 29	$ 39	$ 30	$ -
British Columbia	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Colorado	$ 25	$ 23	$ 24	$ 37	$ 49	$ 38	$ -
Idaho	$ 19	$ 18	$ 19	$ 29	n/a	n/a	$ -
Montana	$ 24	$ 23	$ 24	$ 36	n/a	n/a	$ -
New Mexico	$ 24	$ 22	$ 23	$ 35	$ 46	$ 36	$ -
Nevada	$ 28	$ 27	$ 27	$ 42	$ 55	$ 43	$ -
Oregon	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Utah	$ 19	$ 18	$ 19	$ 29	$ 38	$ 30	$ -
Washington	$ 21	$ 20	$ 20	$ 31	n/a	n/a	$ -
Wyoming	$ 19	$ 18	$ 18	$ 28	n/a	n/a	$ -

We understand that REC-only transactions are not currently compliant with RPS rules. Utilities' RPS transactions must be bundled (energy plus RECs) and if the facility is not interconnected within California, then the energy must be delivered to California pursuant to the provisions in the CEC's RPS Eligibility Guidebook.[19] However, since the current Guidebook allows the energy from the RPS-eligible facility to be remarketed in an out-of-state market before it is delivered to California, the assumptions used in this analysis are not inconsistent with current RPS rules. These assumptions may not reflect what would be allowed under future RPS policies and law, as the Commission is currently considering petitions for modification of a stayed Decision that would authorize REC-only transactions, define bundled versus REC-only transactions, and set limits on the amount and the cost of REC-only transactions that could be used for RPS compliance. In addition, the delivery requirements at the Energy Commission are subject to change and the California Legislature is considering eligibility and delivery rules for RPS resources in a 33% RPS bill. The Commission may revisit the assumptions adopted here if the Commission adopts a Decision on tradable RECs.

CREZ resources were identified principally through the RETI process; however, the commercial projects represented in the ED database have also been assigned to CREZs or identified as a non-CREZ resource by the contracting IOU and CPUC staff, based on stated project location. Resources that are located in CREZs are first assessed based on transmission availability.

The model uses the following CREZs:

[19] http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

Table 4.

Resource Zone Name	Description or Source
Alberta	GHG Calculator Zone
Arizona	RETI Competitive Renewable Energy Zone (CREZ)*
Baja	RETI CREZ
Barstow	RETI CREZ
British Columbia	RETI CREZ*
Carrizo North	RETI CREZ
Carrizo South	RETI CREZ
Colorado	GHG Calculator Zone
Cuyama	RETI CREZ
Fairmont	RETI CREZ
Imperial East	RETI CREZ
Imperial North	RETI CREZ
Imperial South	RETI CREZ
Inyokern	RETI CREZ
Iron Mountain	RETI CREZ
Kramer	RETI CREZ
Lassen North	RETI CREZ
Lassen South	RETI CREZ
Montana	GHG Calculator Zone
Mountain Pass	RETI CREZ
Nevada C	RETI CREZ*
Nevada N	RETI CREZ*
New Mexico	RETI CREZ*
NonCREZ	Resources of all types in the CPUC ED Database or POU Database that are assumed to come online without substantial transmission upgrades, though generic transmission costs are assigned as discussed in Section D.3
Northwest	RETI CREZ*
Owens Valley	RETI CREZ
Palm Springs	RETI CREZ
Pisgah	RETI CREZ
Riverside East	RETI CREZ
Round Mountain	RETI CREZ
San Bernardino - Baker	RETI CREZ
San Bernardino - Lucerne	RETI CREZ
San Diego North Central	RETI CREZ
San Diego South	RETI CREZ
Santa Barbara	RETI CREZ
Solano	RETI CREZ
Tehachapi	RETI CREZ
Twentynine Palms	RETI CREZ
Utah-Southern Idaho	RETI CREZ*
Victorville	RETI CREZ
Westlands	RETI CREZ
Wyoming	RETI CREZ*

* - RETI did not look at Small Hydro or Biogas options in the Out-of-State zones, so these zones are supplemented with E3 GHG Calculator data for those resource types.

II.6.3 Transmission sizing for CREZ resources

Resources from any one CREZ compete to fill transmission bundles from that zone, in the following increments:

Increment 1: Generation that can fit on the existing transmission system;

Increment 2: Generation that can be accommodated by minor upgrades;

Increments 3-4: Generation that can be accommodated by the addition of new generic transmission lines of various sizes[20];

Estimates of capacity on existing transmission system, and with minor upgrades

The previous 33% RPS Implementation Analysis assumed that the existing transmission system could not accommodate any new generation, and that new major new transmission lines would be needed to access any CREZs. While staff and parties agreed that this was a weakness, staff did not have the expertise to make any other informed assumption.

For purpose of this new analysis, the ISO has provided high-level estimates, based on the results of interconnection studies, of the amount of new renewable generation from certain CREZ that could be accommodated on the existing transmission system, as well as the amount of incremental generation that could be accommodated by new, relatively minor and inexpensive upgrades.

The ISO numbers are high-level estimates, they are not available for CREZ in which there are not a number of interconnection requests, and they are not in any way a guarantee. Nonetheless, this addition is a significant improvement – the estimates are based on the ISO's recent experience with interconnection studies for the extraordinarily large amount of generation now moving through the ISO's interconnection process, and they may allow for a more realistic assessment of the cost as well as the timing of generation from several CREZ.

The model selects resources delivered over existing transmission and minor upgrades in different fashions. Resources delivered over existing transmission are selected on a resource-by-resource basis, reflecting the fact that the cost of delivering these resources to load is not a function of the other resources selected to fill the remaining existing transmission. In contrast, minor upgrades are selected as bundles. This ensures that the costs of the minor upgrade are properly allocated across the resources on that minor upgrade, and that the minor upgrade as a whole is competitive (by whatever ranking metric the user chooses).

The assessment from the ISO is available in Appendix D.

[20] For our analysis, the maximum total capacity added by new transmission from any CREZ to or within California is 3,000 MW. The Excel 2007 Version of the RPS Calculator allows the user to allow up to four lines (maximum of 12,000 MW).

Addition of new generic transmission lines

The size and cost of new generic transmission lines depends on the CREZ. Transmission lines from CREZs are sized on a case-by-case basis based on the total potential for resources within the zone and the distance between the CREZ and load centers. Generally, high voltage (500kV) lines are used to link zones that have large resource potential or that are very far from California loads (e.g. out-of-state lines), while lower voltage lines are assumed for smaller CREZs close to loads. The cost of each line is a function primarily of its length and capacity; the main components are the cost of the line itself, new substation costs, and right-of-way costs. E3 uses generic estimates of each of these types of cost to assign a total capital cost to each potential transmission line considered in the model.

II.6.4 Consideration of RETI Conceptual Transmission Plan

Another source of information that has become available since the release of the June 2009 *Implementation Analysis* is the RETI Phase 2A Conceptual Statewide Plan,[21] finalized in September 2009 with the active participation and support of dozens of stakeholders, including the Commission. The Phase 2A plan represents an important contribution to statewide planning, particularly in its introduction of an objective methodology for considering the value of particular groups of transmission lines for accessing renewable energy, and a process and methodology for considering environmental concerns early in the process of transmission planning.

Energy Division's consultant, Zaininger Engineering Company, Inc. (ZECO), estimated the amount of new capacity that could be accommodated by the transmission segments identified by RETI. This assessment is included in Appendix D to this report. To date, the RETI assessment has not been directly incorporated into the 33% modeling effort. Because the RETI line segments are tied to more than one CREZ, and vice versa – each CREZ is potentially dependent on several line segments – direct consideration of these lines in the 33% model is challenging. However, direct incorporation of the RETI information and attention to specific line segments would allow for more detail on the cost, timing, and environmental aspects of this assessment.

II.7 Zone Timing Assessment

The 2009 *Implementation Analysis* presented a first-of-its-kind attempt to estimate whether the state could actually develop the generation and transmission infrastructure estimated as necessary under the 33% Reference Case, under 3 different "states of the world". The analysis found that it would be very difficult to build 24,000 MW of new generation and 11 major new transmission lines by 2020, given existing permitting and planning processes, risks around deployment of new technology, concerns about environmental impacts, and other factors. That report stated that this finding might be justification for considering procurement strategies that offered less timing risk, due to a decreased dependence on new transmission or other factors.

[21] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F-REV2.PDF

Because the ARB has identified a 33% renewable energy target as a key strategy for reducing GHG emissions, timing is a critical consideration. For this updated analysis, generation and transmission development timing is an explicit input into scenario development, and the "Time-Constrained Scenario" is weighted towards those resources estimated to be available earliest.

II.7.1 Timeline Tool

The Commission's consultant, Black & Veatch, developed an Excel-based timeline tool to automate the timing considerations and methodology developed by Aspen Environmental Group (Aspen) and CPUC staff for the *Implementation Analysis*.

The assumptions populating the tool – estimates about the time required to develop various types of generation and transmission resources – have changed very little since last year's analysis, given their basis in historical experience and general party support for last year's assumptions. Based on party comments on the June 22 draft planning standards, we have not updated these assumptions to reflect recent efforts by the Energy Commission, the Bureau of Land Management, and others to streamline generation permitting, and by the ISO to reform its annual Transmission Planning Process to more explicitly account for transmission needed for renewables. Because many of these new efforts are in their early stages, it is difficult as of this writing to estimate their effect.

The timeline tool has not yet been released to parties, as it is still being updated to reflect the new scenarios. Staff anticipates release of the tool later in 2010, so that parties can use it to test assumptions and assist in the potential construction of alternative scenarios.

II.7.2 Incorporating "Timing" into Scenario Development

The process for incorporating timing into scenario development involved three steps: estimating the availability of individual *generation* projects, combining those generation timelines with transmission timing to create *zone* timelines, and creating timelines for entire *scenarios*, once the zones for each scenario had been chosen.

<u>Generation Timing</u>

Each candidate generation project or resource, whether a non-CREZ or CREZ resource, was assigned an online date, based on expected commercial online date (COD) per a contract, or an estimate based on project size and type, assuming that development started on 7/1/2010, and that *transmission was available*. Those assumptions are detailed in Table 5 below, and details about permitting jurisdiction assumptions are in Appendix F1:

Table 5. Generation Development Timing Assumptions

Project Type		Project Development (months)	Permitting (months)	Construction (months)	**Total** (months) *excluding transmission*	**Estimated Online Date** (first **full** year of commercial operation)
Biogas	< 50 MW > 50 MW	12 12	12 24	10 12	34 48	2014 2015
Biomass	< 50 MW > 50 MW	12 18	14 24	24 26	50 68	2015 2017
Geothermal	< 50 MW > 50 MW	12 18	14 24	20 28	46 70	2015 2017
Small Hydro		12	14	20	46	2015
Solar Thermal	< 50 MW > 50 MW	12 18	14 24	24 32	50 74	2015 2017
Solar PV	20 - 50 MW > 50 MW	12 18	10 18	12 18	34 54	2014 2015
Wind	< 50 MW > 50 MW	12 18	10 18	12 18	34 54	2014 2015
ED Database projects 1. Filed/approved by CPUC (public) 2. Under negotiation (confidential)						1. Per public contract information 2. Per generic estimates above
*Timelines assume that the contracting process proceeds in parallel to project development.						

Projects from the ED Database that are still under development, but for which the public expected commercial online dates have already passed, were all assigned an online date of 6/1/2013. This rough date, which is earlier than the dates assigned to most generic projects above, is meant to reflect the uncertainty associated with projects that have already missed expected deadlines, but also the assumption that such projects have already undertaken significant development activities.[22]

The 0.5-20 MW solar PV resources identified by E3 and B&V were assigned a different development schedule than other PV resources. Because this market segment is relatively new and very few of these wholesale distributed generation (WDG) projects have been developed, it is difficult to estimate how many MW could be available in each year before 2020. However, for purposes of this analysis, staff assume that the utility PV programs approved by the Commission for Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), and San Diego Gas & Electric (SDG&E), each meet their program targets of 500, 500, and 52 MW, respectively, within 5 years (see footnote 15). For the other generic resources identified by E3 and B&V, staff assumed that the full potential identified by E3 and B&V could be available by 2020. For the 0.5-20 MW

[22] The timing assessment is another area in which, when dealing with ED Database projects, staff faced a tradeoff between the use of transparent, public information and confidential information or subjective assessments that might present more realistic estimates of individual projects' online dates. Section II.4.2 discusses this tradeoff. The adopted methodology relies on objective, public information.

"easier to interconnect" projects, staff assumed a smooth build-out 2014-2020 that would allow the realization of the full identified potential by 2020. For the remote, "harder to interconnect" projects that might require more upgrades to the transmission or distribution system, staff assumed a build-out that begins in 2015 and then accelerates until that potential is fully built-out in 2020. The resulting timing assumptions are detailed in Table 6 below:

Table 6. Assumed Availability of Wholesale Distributed Generation, by Year

Year	0.5-2 MW Roof available/year		0.5-2 MW Ground		2-5 MW Ground		5-20 MW Ground		20 MW Remote		CUMULATIVE TOTAL		
	IOU Programs* (MW)	Generic** (MW)	IOU Prog. (MW)	Generic (MW)	IOU Prog. (MW)	Generic (MW)	IOU Prog. (MW)	Generic MW)	IOU Prog. (MW)	Generic (MW)	**IOU Prog. (MW)**	**Generic (MW)**	**TOTAL (MW)**
2011	86		5				68				**159**	**0**	**159**
2012	86						96				**340**	**0**	**340**
2013	86						128				**554**	**0**	**554**
2014	86	377	2	6		28	222	141			**863**	**552**	**1,415**
2015	86	377		6		28	103	141		500	**1,052**	**1,604**	**2,656**
2016		497		6		28		242		750	**1,052**	**3,127**	**4,057**
2017		497		6		28		242		1,000	**1,052**	**4,900**	**5,952**
2018		497		6		28		242		1,500	**1,052**	**7,173**	**8,225**
2019		497		6		28		242		2,000	**1,052**	**9,946**	**10,998**
2020		497		6		28		242		3,417	**1,052**	**14,136**	**15,188**
TOTAL	**430**	**3,241**	**7**	**43**	**0**	**194**	**615**	**1,492**	**0**	**9,167**			

* IOU program assumptions, based on program specifics approved or under review by the Commission (see footnote 15)

SCE: 10% is 10 MW ground; 90% is 1-2 MW rooftop

PG&E: 5% is .5-2 MW rooftop; 95% is 1-20 MW ground

SDG&E: all 1-2 MW roof

The timing above allocates the potential remaining evenly over the five years from 2011 – 2015 after netting out projects identified in the ED Database

** Generic numbers assume that all of the MW potential identified by E3 and B&V is available by 2020, less the MW already counted under IOU programs or in the ED database (2 projects subtracted from the 0.5-2 MW Ground category; 23 projects subtracted from the 5-20 MW Ground category)

Numbers may not sum correctly due to rounding.

<u>Transmission and Zone Timing</u>

Following the generation timing assessment, each CREZ "transmission bundle"– incremental MW accommodated by the existing system; MW accommodated by minor upgrades; and MW accommodated by major new transmission lines – was assigned an online date, based on the expected development horizon of the required transmission.

The timeline tool allows users to assign to each CREZ transmission increment one of 9 different transmission schedules, and to choose a development start date:

Table 7. Transmission Development Timing Assumptions, by Schedule Type

Transmission Schedule Type	**Transmission Planning by CAISO/ POU/ WECC** (months)	**Project Description Prep by Utility** (months)	**CEQA/ NEPA Review by CPUC/POU / Feds** (months)	**Final Review and Approval by CPUC/ POU/Feds** (months)	**Final Design and Construction by Utilities** (months)	**Total** (months)
Existing / Distributed	0	0	0	0	0	**0**
Typical	18	12	24	6	24	**84**
Typical - Short	12	12	12	3	18	**57**
Typical - Long	24	18	24	6	30	**102**
Long-Distance	24	18	24	6	30	**102**
Tehachapi	0	0	0	6	48	**54**
Sunrise	0	0	0	0	24	**24**
Devers - CO River	0	0	0	0	30	**30**

CREZs and transmission increments were assigned schedules and start dates as detailed in Table 8 below, with few exceptions as justified by public details about specific projects such as the Tehachapi Renewable Transmission Project. A detailed list of the schedule type and development start date assigned to each CREZ and its transmission increments is provided in Appendix F2.

Table 8. Transmission Schedule Type Assignments for Transmission Increments

CREZ and Transmission Increment	**Transmission Schedule Type**	**Development Start Date**
Non-CREZ	Existing/Distributed	6/1/2010
CREZ – accommodated by existing system	Existing/Distributed	"
CREZ – accommodated by minor upgrades	Typical-Short	"
CREZ – 230 kV line, in-state	Typical-Short	"
CREZ – 500 kV line, in-state	Typical or Typical-Long, depending on location	6/1/2010 for up to 4500 MW of capacity; every 2 years thereafter
Out-of-state Resource	Long-Distance	"

The output of the timeline tool for each transmission increment within each CREZ – a single date for each – becomes an input to the 33% Calculator. In the calculator, then, CREZ projects and non-CREZ projects can be compared to each other according to their expected online dates, allowing the creation of a "Time-Constrained Scenario" that chooses resources based on their expected availability by year.

Lag of Eighteen Months assumed between Transmission Completion and Generation Availability

In the June 22, 2010 draft of these planning standards, staff proposed that generation be assumed to develop concurrent with required transmission, such that an entire zone of

generation would be available to the market upon completion of an enabling transmission line. This differed from the 2009 *Implementation Analysis*, but was proposed as perhaps justified, given the long time horizon associated with much of the candidate transmission development and increased state efforts to signal the market as to the location of priority resource areas.

No parties offered support for this new assumption, and several parties commented that it was likely too optimistic. Thus, these standardized planning assumptions adopt the addition of an 18-month lag between transmission and the availability of all (if any, given the modeling approach that adds zones in "chunks") of the dependent generation in that zone. This assumption remains overly simplistic, as some generation will likely be available immediately after transmission completion, and some not available for potentially several years. It is sufficient for modeling purposes, however. It is a significantly shorter lag than the 30-month delay found in the 2009 *Implementation Analysis*, but reflects current activity in the market, where many renewable energy developers are investing millions of dollars prior to final assurance from transmission permitting agencies.

II.8 Resource Ranking and Selection Methodology

II.8.1 Resource Scoring Metrics

The model's resource ranking algorithm uses four scoring metrics to compare resources, including cost, environmental, commercial, and timing scores. Each score represents a characteristic of a candidate resource that may be used to better understand that project's likelihood of development. These four scores serve as the basis for the ranking process used to select resources and build scenarios.

<u>Cost Score</u>

The cost score is based on the Modified RETI Economic Ranking cost, which captures the "Green Premium" associated with a specific renewable resource: the net cost to California ratepayers of procuring an additional MWh of that resource. This ranking cost is based on the levelized cost of energy; transmission, interconnection, and integration costs; and the market value of energy and capacity associated with that resource:

+ Levelized Cost of Energy (PPA Price)
+ Interconnection Cost
+ Integration Cost
+ Transmission Cost
- T&D Avoided Costs
- Energy Value
- <u>Capacity Value</u>

= Modified Economic Ranking Cost

Each component of the Modified Economic Ranking Cost captures a part of the cost (or benefit) to California ratepayers to develop a specific resource:

1.) **Levelized Cost of Energy** is the sum of all direct costs (capital, fixed and variable O&M, fuel, and NOx permits for biomass resources) required to construct and operate a plant of the specified type. All costs are amortized over the plant's lifetime, resulting in an average cost of generating electricity from that particular plant.

2.) **Interconnection Costs** are any costs associated with interconnecting into the grid; these costs were obtained directly from RETI where available. For resources from the E3 GHG Calculator, these costs are based on the assumed length of the interconnection.

3.) **Integration Costs** apply only to intermittent resources (wind and solar) and capture the increased costs of dispatching conventional generators and procuring sufficient ancillary services in order to integrate these renewable resources into the grid. E3 assumed a flat integration cost adder of $7.50/MWh (see footnote 18), which is adopted here.

4.) **Transmission Costs** capture the cost of any transmission developments required to deliver energy from the point of generation to load. For resources delivered over existing transmission, this cost is zero; if resources are developed along with a transmission upgrade or a new line, the cost of that new line is allocated to each unit of generation to reflect cost of developing transmission along with the resources. The cost of each potential transmission line is calculated using E3's Transmission Cost Calculator, which includes costs of the line itself ($/mile), the right-of-way cost ($/mile), and substation costs.

5.) **T&D Avoided Costs** apply to a small set of resources, most often distributed renewables. The development of distributed renewable resources can result in the deferral of transmission and distribution network upgrades, which results in a net benefit to ratepayers.

6.) **Energy Value** is the average value in wholesale markets that a specific resource would receive for its generation over the course of the year. This adjustment captures the varying value of generation at different points of the day; resources that produce a large fraction of energy during peak periods (e.g. solar) have a higher energy value than resources that produce energy during off-peak periods (e.g. wind). Energy value is calculated for each resource based on the resource's production profile and wholesale market prices in California over the course of the year. The energy values assigned to categories of resources, expressed in heat rates, can be found in rows 174 to 244 of the "ProForma" tab of the 33% RPS Calculator.

7.) **Capacity Value** is the value to ratepayers of avoided investments in conventional capacity resources in order to maintain resource adequacy. Each renewable resource provides a certain amount of capacity in peak periods (dependent on the type of generation); this capacity results in avoided construction of new conventional units to meet peak loads. The capacity value of a resource is a function of its availability during peak load hours and the carrying cost of a combustion turbine, which E3 uses as a proxy for the cost of capacity. The capacity values assigned to categories of resources can be found in rows 103 to

173 of the "ProForma" tab of the 33% RPS Calculator. The capacity values assigned to CA resources are intended to be as consistent as possible with California's adopted Net Qualifying Capacity methodology,

The ranking cost for each resource is translated to a cost score by assigning a score of 0 to a resource with a $0 (or less) green premium, and a score of 100 to the LCOE of the most expensive solar PV resource (representing a backstop technology). The cost score for each resource is a linear interpolation between these two endpoints.

Environmental Score

As with the Implementation Analysis, this update attempts to take into account environmental concerns with an infrastructure development as potentially massive as that required to achieve a 33% RPS. Ongoing efforts, including the Desert Renewable Energy Conservation Plan (DRECP) and the Bureau of Land Management's Solar Programmatic Environmental Impact Statement (PEIS) are examining these factors in a scientific and rigorous way, and will provide direction to developers in coming months and years. In the absence of results from those efforts, however, Aspen and staff have updated the 2009 methodology as described in detail in Appendix E, relying in part on information gleaned from the environmental review of several renewable generation facilities now requesting certification by the Energy Commission.

The adopted methodology continues to rely heavily on RETI's environmental ratings. Among the most significant changes, however, is that environmental scores are now specific to each pairing of location and resource type, so that a project-specific score can be created. This was necessary given the project-specific ranking methodology used in the analysis, and also reflects the fact that environmental concerns and potential impacts on factors such as sensitive species will vary with both the choice of technology and the site of development. While not in any way intended or adequate to reflect project-specific environmental assessments, this methodology attempts to capture some of the risk and uncertainty that environmental concerns introduce into the project development process.

Commercial Score

The commercial score is used to distinguish those projects currently under contract, negotiation or development by IOUs and POUs, from the generic resources included in the model: the former is assigned a commercial score of 0 (a "better" score, for purposes of ranking), while the latter is assigned a commercial score of 100. This scoring distinction is included to allow for scenario analysis of compliance portfolios that rely to differing extents upon the resources already in the permitting process.

Timing Score (Online Date)

As described in Section II.7, timing scores were developed by the Commission to distinguish between projects that can be brought online within a relatively short timeframe from those that are unlikely to be developed soon due to expected delays or extensions in the generation and transmission development process. Distributed

resources and resources that can be delivered over existing transmission perform better on the timing assessment, relative to resources requiring major new transmission lines.

II.8.2 Resource Ranking and Selection Methodology

Resource ranking and selection is carried out differently for each scenario. The model first calculates the cost, commercial, environmental and timing scores as discussed above based on user-defined inputs. It then calculates a weighted-average project score for each resource based on user-defined weights that sum to 100%. For example, if the user selects 25% for each of the four metrics, the model will score resources evenly across the four metrics. If the user selects 85% for cost and 5% for commercial, environmental and timing, the model will select a resource mix based heavily on the cost metric. The following table lists the weights used for each required Scenario:

Table 9. Score Weights, by Scenario

Scenario	Cost Weight	Commercial Weight	Environmental Weight	Timing Weight
Trajectory	20%	60%	20%	0%
Cost-Constrained	100%	0%	0%	0%
Environmentally-Constrained	0%	0%	100%	0%
Time-Constrained	0%	0%	5%	95%

The Trajectory Scenario gives some weight to cost and environmental concern to account for the impact these factors may have on the viability of those commercial projects that are very early in the development process and may not yet even have contracts. The Time-Constrained Scenario includes environmental score essentially as a tie-breaker, given the limited differentiation that exists among the timing scores, which depend only upon first full expected year of operation. The environmental criterion was chosen as the tiebreaker given the impact that environmental concerns could have on a project's permitting and construction timelines.

As discussed above, CREZ resources are ranked and selected first to make use of any existing available transmission capacity from a zone. Remaining resources in the zone are selected in increments to fill transmission bundles.

In the ranking, projects from the Discounted Core are always ranked higher than all other commercial and theoretical projects. Once capacity has been allocated (either on existing or new transmission) to all of the Discounted Core projects in a zone, capacity is allocated to commercial and generic projects. On existing transmission and minor upgrades, the remaining commercial projects compete with theoretical projects based on their score; on potential new lines, the remaining commercial projects are ranked above all the theoretical projects. Thus, commercial projects (particularly Discounted Core projects that didn't meet the threshold for forcing in new transmission, as described in Section II.4.2) are much more likely to be assigned to lower-cost transmission bundles than are generic projects.

After all of the commercial projects have been included, generic projects are selected to fill any remaining capacity created by the assumed transmission upgrades. Aggregate

scores for each of the 4 metrics are then calculated for each CREZ bundle, and the bundles then compete against non-CREZ resources and RECs for inclusion in each 33% scenario.

III Results

This section presents the portfolio of resources selected for each of 7 scenarios, along with the scenario ranking metrics resulting from the modeling process described above. The tables summarize the resources selected in various ways, and allow for easy comparison across scenarios.

The results show that each scenario scores best on the criterion that defines the policy goal for that scenario, e.g., the cost-constrained case has the lowest cost, the environmentally-constrained case the lowest environmental impact, the time-constrained case has the lowest time score, and the trajectory case has the most commercial interest. Accordingly, there is significant variety across the scenarios as to the types of resources selected by the model to meet the policy goal of each scenario.

Table 10. Comparison of Scenario Scores

Scenario	Scenario Score, by Ranking Metric			
	Cost	Environmental Concern	Commercial Interest	Timing
33% Trajectory	20.3	29.2	6.3	50.7
33% Environmentally-Constrained	28.6	14.3	47.9	53.0
33% Cost-Constrained	15.4	20.9	37.8	47.5
33% Time-Constrained	19.0	23.2	36.9	42.3
33% Trajectory - Low Load	17.9	25.9	0.5	45.8
33% Trajectory - High Load	19.5	27.6	17.0	55.6
20% Trajectory	20.5	28.8	0.4	37.6

Table 11. Scenario Composition, by Generation Project Status

Scenario	Scenario Composition by Generation Project Status (MW)				Scenario Composition by Generation Project Status (GWh/yr)			
	Discounted Core	Commercial Non-Core	Generic	Total	Discounted Core	Commercial Non-Core	Generic	Total
33% Trajectory	8,966	9,239	1,061	19,266	23,376	27,484	3,409	54,269
33% Environmentally-Constrained	8,062	2,038	10,429	20,530	21,121	7,143	26,005	54,269
33% Cost-Constrained	8,331	3,911	5,251	17,493	21,892	11,880	20,497	54,269
33% Time-Constrained	7,904	4,794	7,104	19,802	20,669	13,548	20,052	54,269
33% Trajectory - Low Load	8,337	7,570	102	16,009	21,905	23,426	249	45,581
33% Trajectory - High Load	8,978	9,742	2,044	20,763	23,405	28,868	10,684	62,957
20% Trajectory	7,580	0	35	7,615	19,957	0	86	20,042

Table 12. Scenario Composition, by Transmission Delivery Type

Scenario	Scenario Composition by Transmission Delivery Type (MW)					Scenario Composition by Transmission Delivery Type (GWh/yr)				
	Accomodated on Existing System	Minor Upgrades	New Lines	Out-of-State Undelivered RECs	Total	Accomodated on Existing System	Minor Upgrades	New Lines	Out-of-State Undelivered RECs	Total
33% Trajectory	8,517	2,362	3,295	5,093	19,266	22,398	8,722	8,777	14,372	54,269
33% Environmentally-Constrained	15,327	2,384	-	2,818	20,530	37,606	6,852	-	9,811	54,269
33% Cost-Constrained	8,034	2,661	-	6,798	17,493	23,424	10,682	-	20,163	54,269
33% Time-Constrained	10,291	937	-	8,574	19,802	27,547	2,095	-	24,627	54,269
33% Trajectory - Low Load	8,517	2,362	38	5,093	16,009	22,398	8,722	88	14,372	45,581
33% Trajectory - High Load	8,517	2,362	4,791	5,093	20,763	22,398	8,722	17,465	14,372	62,957
20% Trajectory	4,841	548	-	2,226	7,615	12,723	1,259	-	6,060	20,042

Tables 13 and 14. Scenario Composition, by Technology and Location

	Scenario Composition by Technology and Location (MW)													
	33% Trajectory		33% Environmentally-Constrained		33% Cost-Constrained		33% Time-Constrained		33% Trajectory - Low Load		33% Trajectory - High Load		20% Trajectory	
	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State
Biogas	178	-	178	66	168	73	172	73	178	-	178	-	12	-
Biomass	126	34	404	156	291	129	212	103	126	34	126	34	126	32
Geothermal	667	154	240	270	797	202	-	158	617	154	1,591	154	-	-
Hydro	-	16	-	132	-	14	-	223	-	16	-	16	-	-
Large Scale Solar PV	3,527	340	2,315	340	1,549	340	2,543	340	3,147	340	3,684	340	1,111	340
Small Solar PV	1,052	-	9,077	-	1,052	-	2,322	-	1,052	-	1,052	-	1,052	-
Solar Thermal	3,589	400	1,072	400	1,279	400	1,084	400	1,790	400	3,589	400	979	400
Wind	5,034	4,149	4,426	1,454	5,559	5,639	4,895	7,276	4,006	4,149	5,450	4,149	2,109	1,454
Total	***14,173***	***5,093***	***17,711***	***2,818***	***10,696***	***6,798***	***11,228***	***8,574***	***10,916***	***5,093***	***15,670***	***5,093***	***5,389***	***2,226***

	Scenario Composition by Technology and Location (GWh/yr)													
	33% Trajectory		33% Environmentally-Constrained		33% Cost-Constrained		33% Time-Constrained		33% Trajectory - Low Load		33% Trajectory - High Load		20% Trajectory	
	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State
Biogas	1,248	-	1,248	489	1,178	546	1,206	546	1,248	-	1,248	-	84	-
Biomass	938	250	3,007	1,152	2,167	961	1,577	757	938	250	938	250	938	238
Geothermal	4,843	1,116	1,837	1,945	6,066	1,463	-	1,135	4,458	1,116	11,951	1,116	-	-
Hydro	-	48	-	404	-	65	-	737	-	48	-	48	-	-
Large Scale Solar PV	7,808	864	5,179	864	3,485	864	5,719	864	6,839	864	8,210	864	2,489	864
Small Solar PV	2,105	-	18,050	-	2,105	-	4,565	-	2,105	-	2,105	-	2,105	-
Solar Thermal	8,512	935	2,627	935	3,112	935	2,656	935	4,306	935	8,512	935	2,411	935
Wind	14,442	11,159	12,509	4,023	15,993	15,330	13,919	19,653	11,313	11,159	15,619	11,159	5,956	4,023
Total	***39,896***	***14,372***	***44,458***	***9,811***	***34,106***	***20,163***	***29,642***	***24,627***	***31,208***	***14,372***	***48,585***	***14,372***	***13,983***	***6,060***

Table 15. Scenario Composition, by Resource Location

	Resources Selected by Scenario (MW)							Resources Selected by Scenario (GWh/yr)						
	33% Trajectory	33% Environ-mentally-Constrained	33% Cost-Constrained	33% Time-Constrained	33% Trajectory - Low Load	33% Trajectory - High Load	20% Trajectory	33% Trajectory	33% Environ-mentally-Constrained	33% Cost-Constrained	33% Time-Constrained	33% Trajectory - Low Load	33% Trajectory - High Load	20% Trajectory
Tehachapi	4,445	3,491	3,491	4,150	4,445	4,445	1,912	11,465	10,019	10,019	11,437	11,465	11,465	5,399
Imperial	1,202	347	1,125	-	1,125	2,625	-	6,193	2,092	6,740	-	5,733	14,677	-
Northwest	2,359	838	2,359	2,359	2,359	2,359	614	6,044	2,676	6,510	6,308	6,044	6,044	1,571
Pisgah	1,775	275	275	275	313	1,775	275	4,169	643	643	643	731	4,169	643
NonCREZ	1,074	599	1,211	1,080	1,074	1,074	317	3,944	3,489	5,316	4,342	3,944	3,944	1,456
Solano	1,129	300	300	-	300	1,129	-	3,473	860	992	-	860	3,473	-
Riverside East	1,042	1,042	1,042	1,500	1,042	1,042	1,042	2,433	2,433	2,433	3,542	2,433	2,433	2,433
Alberta	886	450	450	886	886	886	450	2,422	1,230	1,230	2,422	2,422	2,422	1,230
Mountain Pass	888	-	-	-	-	888	-	2,178	-	-	-	-	2,178	-
Carrizo South	900	900	900	900	900	900	511	1,960	1,959	1,960	1,959	1,960	1,960	1,089
Utah-Southern Idaho	258	258	258	258	258	258	90	1,379	1,446	1,417	1,060	1,379	1,379	229
San Diego South	400	400	699	400	400	400	21	1,227	1,227	2,096	1,227	1,227	1,227	156
Colorado	420	-	600	1,371	420	420	-	1,169	-	1,679	3,767	1,169	1,169	-
Nevada C	450	549	500	549	450	450	450	1,062	1,745	1,403	1,745	1,062	1,062	1,062
Distributed Solar - PG&E	500	1,757	500	790	500	500	500	1,015	3,313	1,015	1,546	1,015	1,015	1,015
Montana	300	300	300	300	300	300	300	994	994	994	994	994	994	994
Distributed Solar - SCE	500	2,345	500	895	500	500	500	991	4,658	991	1,771	991	991	991
Arizona	290	290	872	1,390	290	290	290	737	737	2,171	3,448	737	737	737
Wyoming	96	4	461	461	96	96	-	317	27	1,460	1,465	317	317	-
New Mexico	32	78	947	947	32	32	32	238	573	2,927	3,034	238	238	238
Round Mountain	78	100	100	100	78	78	78	221	383	374	383	221	221	221
Palm Springs	77	178	178	178	77	77	77	217	532	532	532	217	217	217
San Bernardino - Lucerne	49	140	261	261	49	49	42	168	845	753	868	168	168	119
Kramer	62	62	62	62	62	62	62	145	145	145	145	145	145	145
Distributed Solar - SDGE	52	397	52	127	52	52	52	99	798	99	249	99	99	99
British Columbia	2	52	50	52	2	2	-	12	384	372	384	12	12	-
Remote DG (Brownfield) - SDGE	-	78	-	4	-	-	-	-	171	-	9	-	-	-
Remote DG (Brownfield) - PG&E	-	1,842	-	100	-	-	-	-	3,740	-	204	-	-	-
Remote DG (Brownfield) - SCE	-	564	-	31	-	-	-	-	1,258	-	69	-	-	-
Distributed Solar - Other	-	1,522	-	344	-	-	-	-	2,890	-	650	-	-	-
Westlands	-	800	-	-	-	-	-	-	1,781	-	-	-	-	-
Remote DG (Brownfield) - Other	-	571	-	31	-	-	-	-	1,222	-	67	-	-	-
Fairmont	-	-	-	-	-	74	-	-	-	-	-	-	204	-
Total In-State	14,173	17,711	10,696	11,228	10,916	15,670	5,389	39,896	44,458	34,106	29,642	31,208	48,585	13,983
Total Out-of-State	5,093	2,818	6,798	8,574	5,093	5,093	2,226	14,372	9,811	20,163	24,627	14,372	14,372	6,060
Total	***19,266***	***20,530***	***17,493***	***19,802***	***16,009***	***20,763***	***7,615***	***54,269***	***54,269***	***54,269***	***54,269***	***45,581***	***62,957***	***20,042***

IV Next Steps ***(removed)***

Appendix A

Load Forecast and Demand-Side Assumptions

A1: 2009 Integrated Energy Policy Report Demand Forecast

A2: Assumptions about Load-Modifying Demand-Side Resources

A1: 2009 Integrated Energy Policy Report Demand Forecast

The demand forecast used for this analysis can be found in Table 1.1c of the Energy Commission's California energy Demand 2010-2020, available here: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF. To calculate RSP-obligated sales, E3 used "Total Statewide Retail Deliveries excluding pumping load", minus forecasted sales from small load-serving entities. Any load-serving entity with 2020 retail sales less than 200 GWh/yr qualifies as a small LSE and is exempt from compliance with the RES; the LSEs that E3 included in that category are shown below:

Load Serving Entity	2020 Retail Sales (GWh)
City of Shasta Lake	193
City of Banning	184
Bear Valley Electric Service	176
Plumas-Sierra Rural Electric Cooperation	172
Truckee-Donner Public Utility District	163
Lassen Municipal Utility District	153
City of Lompoc	151
Boulder City/Parker Davis	137
City of Ukiah	133
Trinity Public Utility District	99
Surprise Valley Electrification Corporation	92
City of Healdsburg	76
City of Rancho Cucamonga	67
Moreno Valley Utilities	65
Anza Electric Cooperative, Inc.	62
City of Needles	58
Port of Oakland	54
City of Cerritos	48
City of Gridley	42
Victorville Municipal	32
Calaveras Public Power Agency	30
Tuolumne County Public Power Agency	29
City of Biggs	20
Port of Stockton	14
Valley Electric Association, Inc.	7
Mountain Utilities	4
Total	**2,260**

A2: Assumptions about Load-Modifying Demand-Side Resources

The assumptions described in Section II.3.3 result in the following reductions to the demand forecast referenced above, to create the load forecast used for the four "standard" 33% by 2020 RPS Scenarios and the one 20% by 2020 Scenario.

Load Decrement (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EE Decay replacement	169	313	488	693	913	1,093	1,254	1,391	1,504	1,598	1,684	1,769	1,861
EE Uncommitted - IOU	0	0	0	0	0	1,613	2,823	3,983	5,490	7,294	9,101	10,607	11,867
EE Uncommitted - Non-IOU	0	0	0	0	0	403	706	996	1,373	1,824	2,275	2,652	2,967
Incremental DG	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP	0	0	0	756	1,511	2,267	3,022	3,778	4,533	5,289	6,045	6,800	7,556
Total	**169**	**313**	**488**	**1,449**	**2,424**	**5,376**	**7,805**	**10,148**	**12,900**	**16,005**	**19,105**	**21,828**	**24,251**

As described in Section II.3.3, for the low and high load sensitivities performed around the 33% Trajectory Scenario, total RPS-eligible demand was assumed to be 10% lower and 10% higher, respectively, than the standard demand level that results from the retail sales and load decrements referenced above.

Appendix B

RPS Generation Resource Assumptions

B1: RPS Baseline: Existing Generation and Retirement Assumptions
B2: Planned Procurement by Publicly-Owned Utilities
B3: Energy Division Database
B4: Statewide Solar PV Resource Assessment
B5: Renewable Energy Transmission Initiative Phase 2B List of Resources
B6: Out-of-State Renewable Energy Credit Supply Estimates

B1: RPS Baseline – Existing Generation and Retirement Assumptions

	Energy (GWh)	Source
Total In-State Renewable Generation, 2008	28,804	*2008 Net System Power Report* (p.5)
Utilities Claims for Out-of-State Renewable Generation, 2008 (Northwest)	1,728	*2008 Net System Power Report* (p.A-2)
Utilities Claims for Out-of-State Renewable Generation, 2008 (Southwest)	740	*2008 Net System Power Report* (p.A-2)
Total Existing Renewable Generation, 2008	***31,272***	
New In-State Resources Online in 2009	992	ED Database
New Out-of-State Resources Online in 2009 with Long-Term Contracts	350	ED Database
Total Existing Renewable Generation, 2009	***32,613***	

B2: POU Data

Data on planned procurement of renewables has been gathered for a number of the larger POUs in California. This data was obtained from the California Energy Commission and gives POU renewable resource plans for 2010 and 2018; the data has been adjusted in order to incorporate it in to the RPS model, which uses 2008 and 2020 as its starting and ending points. The table below shows an overview of the distribution of POU planned procurement incremental to 2008 levels by resource type. There are 140 MW of small hydro included in the POUs's plans that are excluded from this table and the model, due to uncertainty about the current RPS eligibility of those resources, given their location in British Columbia.

	In-State		Out-of-State	
	MW	GWh	MW	GWh
Biogas	145	1,013	-	-
Biomass	-	-	2	12
Geothermal	550	3,884	42	299
Hydro - Small	-	-	16	48
Solar Thermal	358	836	-	-
Solar PV	-	-	-	-
Wind	504	1,455	648	1,871
Total	***1,557***	***7,188***	***708***	***2,230***

B3: Energy Division Database

The Energy Division (ED) Database tracks the IOU solicitations for renewables and includes both CREZ and non-CREZ resources. The database includes both public projects that are in advanced stages of permitting and confidential shortlisted projects. A public list of the RPS contracts approved and under review by the Commission is available here: http://www.cpuc.ca.gov/PUC/energy/Renewables. The tables below show an overview of the distribution of the resources included in the RPS model from the ED Database.

CREZ	MW	GWh
Alberta	1,018	2,782
Arizona	290	737
British Columbia	114	290
Carrizo South	849	1,830
Colorado	420	1,169
Distributed Solar - PG&E	244	503
Distributed Solar - SCE	140	323
Fairmont	296	752
Imperial	1,213	4,019
Inyokern	242	566
Kramer	250	584
Montana	300	994
Mountain Pass	710	1,720
Nevada C	450	1,062
New Mexico	32	238
NonCREZ	573	2,166
Northwest	3,162	8,089
Palm Springs	182	514
Pisgah	1,700	3,974
Riverside East	1,042	2,433
Round Mountain	78	221
San Bernardino - Lucerne	49	168
San Diego South	415	1,269
Santa Barbara	83	233
Solano	240	690
Tehachapi	4,173	10,697
Utah-Southern Idaho	90	229
Total	**18,354**	**48,251**

	Signed - Approved		Signed - Pending Approval		In Negotiations		*Total Projects Included in RPS Calculator*	
	MW	GWh	MW	GWh	MW	GWh	*MW*	*GWh*
Biogas	21	144	13	91	-	-	**34**	**235**
Biomass	81	603	90	673	-	-	**171**	**1,276**
Geothermal	139	1,005	40	289	-	-	**179**	**1,294**
Hydro	-	-	-	-	-	-	**-**	**-**
Large Scale Solar PV	1,138	2,574	1,421	3,477	1,596	3,350	**4,155**	**9,400**
Small Solar PV	7	14	268	587	109	225	**384**	**826**
Solar Thermal	1,615	3,775	2,434	5,812	-	-	**4,049**	**9,587**
Wind	2,950	8,313	2,521	6,650	3,910	10,668	**9,382**	**25,632**
Total	**5,951**	**16,428**	**6,788**	**17,580**	**5,615**	**14,243**	***18,354***	***48,251***

B4: Statewide Solar PV Resource Assessment

The assessment of the solar PV resource potential was adjusted from the original 33% RPS Implementation Analysis approach. PV potential estimates were identified as 'Easy-to-connect' and 'Harder-to-connect' and were further broken down into 4 size categories (0.5 – 2 MW rooftop, 0.5 – 2 MW ground-mounted, 2 – 5 MW ground mounted, and 5 – 20 MW ground mounted) and 4 locations across California (Desert, Central Valley, North Coast, South Coast). The proprietary utility substation data and the large rooftop potential data from satellite imagery were screened for 'easy' interconnection, participation, and penetration. Existing PV programs including the California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP) and other utility PV programs were accounted for. The table below shows the results of the solar PV resource assessment:

Easy to Interconnect						Harder to Interconnect	
Ground Mounted (5-20MW)	Ground Mounted (2-5MW)	Ground Mounted (0.5-2MW)	Large Rooftop	Small Rooftop	Easy to Interconnect Total	RETI projects (>30%)	TOTAL
2,107	200	43	3,671	977	6,999	9,167	16,165

The solar PV assessment performed by E3 and Black & Veatch is available here, in PowerPoint form: http://www.cpuc.ca.gov/NR/rdonlyres/A0CBE958-E2C4-4AC7-9D56-3AB4D14D723D/0/BVE3PVAssessment.ppt.

B5: RETI Phase 2B list of resources

The list of RETI resources, costs, and other detail is available on the RETI website, http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls.

B6: Out-of-State REC Supply

The RPS model assumes that a subset of the out-of-state candidate resources is available to California for use as REC-only transactions. The potential out-of-state supply of RECs is constrained by several criteria. It is unlikely that any resource that would require significant new transmission would be developed for RECs alone. For this reason, the highest quality wind resources in each zone—which are generally also the most remote—are excluded from

the potential supply of RECs. These remote, high-quality wind resources are available for development for delivery to California if a new transmission line from that zone to California is selected in the ranking process.

The supply of potential REC resources—especially wind—is further limited by the physical operating constraints of the grid. There is a limit to the amount of wind that an area can easily integrate before it begins to have major effects on market operations and integration costs increase substantially. As that limit is approached, it would become increasingly difficult to find a buyer for the energy produced, and the economics of a REC deal based on the "green premium" that is calculated in the model (described in Sections II.6.2 and II.8.1) would no longer apply. E3 has roughly estimated this limit in each out-of-state resource zone by analyzing 2020 production simulations to determine the point at which REC resources would begin to displace baseload generators instead of intermediate gas generators; this gives a good approximation of the point at which market operations would shift dramatically. The capacity of REC resources that can be developed for REC-only deals for California is then capped in each zone at the greater of (1) half of the zone's REC limit reduced by existing installed renewable capacity and (2) existing ED database contracts; these limits are shown in the table below. With these two constraints on supply, the final set of resources that is available as RECs for California is scored using the same methodology as candidate delivered resources. The REC resources then compete against transmission bundles and non-CREZ resources for selection in California's renewable portfolio.[23]

	ED Database RECs	Estimated Near-Term Physical Limits on RPS Supply (MW)	Existing and Near-Term RPS Resources (MW)	RECs assumed available to CA (MW)	Modeled Cap on RECs available to CA (MW)
AB	886	2,211	595	808	886
AZ	740	3,968	90	1,939	1,939
BC	2	1,700	0	850	850
CFE	0	0	0	0	0
CO	420	3,665	922	1,371	1,371
MT	300	738	189	275	300
NM	32	2,135	240	947	947
NV	0	0	50	0	0
NW	2,359	6,461	1,948	2,257	2,359
UT	258	229	135	47	258
WY	96	1,231	308	461	461
Total	**5,093**	**22,337**	**4,477**	**8,955**	**9,372**

[23] See the discussion in Section II.6.2 on the relationship of these assumptions to current policy.

Appendix C

RPS Generation Cost Assumptions

C1: Project Characteristics and Cost Calculator spreadsheet
C2: E3 Capital Cost Tool
C3: PV Cost Calculator

For each renewable resource type included in the RPS model, E3 has developed cost and performance assumptions using data from several sources. E3's general approach in modeling is to use any site-specific public cost and performance information where it is available and to apply generic estimates to resources without site-specific data. The table below shows the source of the generic assumptions for each resource in the model.

Resource Type	Description or Source
Biogas	E3 Capital Cost Tool
Biomass	RETI Project Characteristics and Cost Calculator
Geothermal	RETI Project Characteristics and Cost Calculator
Hydro	E3 Capital Cost Tool
Large Scale Solar PV - Thin Film	PV Cost Calculator
Large Scale Solar PV - Tracking	PV Cost Calculator
Small Scale Solar PV	PV Cost Calculator
Solar Thermal	RETI Project Characteristics and Cost Calculator
Wind	RETI Project Characteristics and Cost Calculator

C1: Project Characteristics and Cost Calculator spreadsheet

RETI maintains the Project Characteristics and Cost Calculator spreadsheet[24], a detailed database with site-specific data on resource potential, cost, and performance in California and similar data for the out-of-state zones in the WECC based on data developed as part of the WREZ transmission modeling efforts. E3 has incorporated each of these individual resources, along with site-specific information on costs (capital, fixed and variable O&M, gen-tie, fuel) and performance (heat rate, capacity factor, on-peak availability) into the RPS model. In addition, E3 uses the Project Characteristics and Cost Calculator to develop generic assumptions for the renewable technologies included in the RPS model that do not have site-specific information from RETI. E3's generic cost and performance assumptions, below, are based on averages of the data in the RETI spreadsheet (table is identical to the updated Table 1, earlier in the report).

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Capacity Factor	LCOE ($/MWh)
Biogas - Landfill	$ 2,750	$ 130	$ -	12,070	80%	$ 96
Biogas - Other	$ 5,500	$ 165	$ -	13,200	80%	$ 121
Biomass	$ 4,529	$ 93	$ 13	14,749	85%	$ 128
Geothermal	$ 5,155	$ -	$ 35	-	83%	$ 115
Hydro - Small	$ 3,960	$ 30	$ -	-	35%	$ 196
Solar Thermal	$ 5,300	$ 66	$ -	-	27%	$ 202
Wind	$ 2,399	$ 60	$ -	-	32%	$ 99

[24] The RETI Project Characteristics and Cost Calculator can be found here: http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls

C2: E3 Capital Cost Tool

The E3 Capital Cost Tool was developed in collaboration with WECC's Transmission Expansion Planning Policy Committee (TEPPC) in order to facilitate further analysis of TEPPC's studies of WECC-wide transmission development. The tool contains generic assumptions for a wide range of resources; E3 consulted a large number of sources in the development of these estimates. The tool is used to inform the RPS model's assumptions for resources that are not included in the scope of the RETI analysis; for these resource types, cost and performance information was taken directly from the E3 Capital Cost Tool. The RPS Model also uses the regional multipliers developed in the tool in order to translate generic costs for the WECC into region-specific costs, which vary based on local costs of labor, materials, and construction.

The E3 Capital Cost Tool is available for public download via TEPPC: http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/E3%20Capital%20Cost%20Tool/E3_TEPPC_ProForma_2010-01-17.xls.

C3: PV Cost Calculator

The PV cost calculator tool was developed to accurately calculate the levelized cost of solar PV projects, given user-defined inputs. The financial modeling behind the tool includes features to balance complexity with applicability for a broad range of projects. The PV cost and performance assumptions were developed as a joint effort by E3 and Black and Veatch.

The adopted assumptions and key results of the cost calculator are detailed here: http://www.cpuc.ca.gov/NR/rdonlyres/A0CBE958-E2C4-4AC7-9D56-3AB4D14D723D/0/BVE3PVAssessment.ppt.

The cost calculator is available here: http://www.cpuc.ca.gov/NR/rdonlyres/A52A5A3E-F737-49E1-A4D5-E81ED68F3E41/0/FinalPVProForma.xls.

Appendix D

Transmission Assumptions

D1: California ISO assessment of capacity on existing transmission system, and with minor upgrades

D2: ZECO assessment of capacity over segments of RETI Phase 2A conceptual plan

D3: E3 additions of generic 500kV transmission lines and project-specific cost assumptions

D4: Avoided T&D costs for PV

D1: California ISO assessment of capacity on existing transmission system, and with minor upgrades

In May 2010, the CAISO provided the CPUC with assumptions about the existing capacity on the transmission system that could be used to deliver renewable resources from the various CREZs. The data provided included estimates of the existing capacity without any incremental upgrades and identified those areas in which relatively minor transmission upgrades could provide spare capacity on the system. For those projects, CAISO provided a rough estimate of the total cost of the upgrade. The table provided by the CAISO, which includes the assumptions underlying the numbers, is below.

A rough estimate of available transmission by CREZ, assuming that transmission that has been approved by the ISO Board and the CPUC (if required) is built. So, the full Tehachapi Renewable Transmision Project, Sunrise, and Devers-Midpoint (we'll assume that it meets the ISO's LGIA test) are all assumed built, as well as perhaps some smaller upgrades, to the extent that they've met the approval threshold.

CREZ #	CREZ Name	MW of existing transmission capability with no upgrades	MW of existing transmission capability with minor upgrades not approved by ISO	Description of minor transmission upgrades	Cost of minor upgrade ($)	Comments
14	Carrizo North					No interconnection requests in this area
18	Carrizo South	300	900	reconductoring from Carrizo interconnection Points to Midway and possibly from Morro Bay to Templeton	$100 M	
17	Cuyama					No interconnection requests in this area
2	Lassen North					No interconnection requests in this area
1	Lassen South					No interconnection requests in this area
3	Round Mountain	100	100			
8	Solano	0	300	various reconductorings South of Contra Costa	$100 M	
	Westlands	0	800	reconductor Borden-Gregg 230 kV line	$50 M	
45	Barstow					No interconnection requests in this area
47	Fairmont					No interconnection requests in this area
29	Imperial East					No interconnection requests in this area
31	Imperial North					No interconnection requests in this area
51	Inyokern	0	62	Inyo 115 kV phase shifter replacement and revised existing SPS in North of Lugo	$20 M	
50	Kramer					

37	Iron Mountain					No interconnection requests in this area
25	Owens Valley					No interconnection requests in this area
30	Imperial South	0	1125	install third Imperial Valley 500/230kV bank	$50 M	
34	Needles					No interconnection requests in this area
27	San Diego South	400	761	connect Boulevard substation to new 500/230 kV substation between Imperial Valley and Miguel substations	$60 M	
40	Mountain Pass	0	0			
43	Pisgah	0	275	SPS	$40 M	
44	San Bernardino - Lucerne	261	261			
41	San Bernardino - Baker					No interconnection requests in this area
52	Tehachapi	4500	5825	2nd and 3rd AA banks at Whirlwind	$100 M	
26	San Diego North Central					No interconnection requests in this area
32	Palm Springs	1000	1000			
16	Santa Barbara					No interconnection requests in this area
36	Riverside East	1500	1500			West of Dever reconductoring is needed to go beyond these levels
38	Twentynine Palms					No interconnection requests in this area
46	Victorville					No interconnection requests in this area

Column Heading	**Explanation of information in this column**
MW of existing transmission capability with no upgrades	ISO engineers reviewed previously completed interconnection studies and applied judgement to determine these MW amounts. Total MWs of interconnection requests as well as intermediate amounts of interconnection requests and necessary transmission upgrades associated with these amounts were reviewed to make this determination. If no delivery transmission upgrades were necessary for a particular amount of interconnection requests then this amount was entered into this cell. Generation already in-service was not included in the amount. There may be higher queued non-renewable generation included in this amount.
MW of existing transmission capability with minor upgrades not approved by ISO	These numbers were developed following the same process as above, but if only minor transmission upgrades were necessary for a particular amount of interconnection requests then these upgrades were assumed to be built and the corresponding amount of generation was entered into this cell.
Description of minor transmission upgrades	A description of the minor upgrades assumed to be built, if any, is included here. These minor upgrades have not been approved by the ISO.
Cost of minor upgrade ($)	A very rough cost estimate of the minor upgrades assumed to be built, if any, is included here. These minor upgrades have not been approved by the ISO.

D2: ZECO assessment of capacity over segments of RETI Phase 2A conceptual plan

General Assumptions

The potential MW capacity of each CREZ is listed in Table 2-2 on Page 2-36 of the RETI 2A report. Looking at Table 2-2, the potential 2A CREZ MW capacity totals more than 77,000 MW. Note, only a fraction of this CREZ capacity will be required to deliver the renewable energy requirement for 2020.

Transmission expansion requirements to deliver the CREZ energy to the California utility customers in the RETI 2A report are broken into three groups - several local transmission collector line segment groups to reliably inject the power from the associated local CREZs into the transmission foundation group, transmission foundation group line segment additions to reliably deliver the renewable power between northern and southern California load centers, and delivery group line segment additions to deliver the power within the northern and southern California load centers. Table 3-5 in the RETI 2A report presents the transmission collector line segment groups developed as part of the RETI 2A study and associated CREZ accessed by the transmission collector groups. Line segments developed for each transmission collector group as well as the foundation and delivery groups are listed on Page F-55 in Appendix F, the line segments are described in Appendix G, the line segment costs and mileage are listed in Appendix H, new substations and network upgrades are listed in Appendix I and CREZ injection points and new substations used for the RETI 2A study are listed in Appendix J.

Transmission cost assumptions used in the RETI 2A study for the line segment costs in Appendix H were obtained from Jan Strack of San Diego Gas & Electric Co. Some of these assumptions listed in Table 1 have been used to develop the incremental transmission line segment cost estimates in this work. All new 230 kV line segments are assumed to be double circuit construction as in the RETI 2A study. Line termination costs are assumed to be an adder of 25% to the line segment cost as assumed in the RETI 2A study.

Table 1 - Transmission cost assumptions from RETI 2A Study

Line Segment Description	Line Cost $1000/mi
Cost of 230 kV double circuit towers with one circuit	2000
Cost of second 230 kV circuit on double circuit 230 kV towers	500
Cost of 230 kV double circuit towers with two circuits	2500
Cost of 500 kV single circuit construction	2600
Cost of 500 kV double circuit towers with one circuit	4500
Cost of second 500 kV circuit on double circuit 500 kV towers	500
Cost of 500 kV double circuit towers with two circuits	5000
Adder for "Line Termination" costs	25%

The MW capacity of the transmission line segments employed in the RETI 2A study was not included in the RETI 2A report. The typical range of existing 230 kV transmission line ratings is from 200 - 800 MW[25]. For this high level estimate, existing 230 kV lines will be assumed to have a 500 MW rating per circuit. New and uprated 230 kV lines will be assumed to have a higher line rating of 1000 MW per circuit, which is compatible with the capacity assigned for a potential new 230 kV line included for the Carrizo area upgrades described in Appendix G of the RETI 2A report. The typical range of existing 500 kV transmission line ratings in the above referenced EPRI synthetic utility system report is from 1200 - 2500 MW. Both new and existing 500 kV line capacity is assumed to be 2000 MW per circuit, which is compatible with the ratings of existing 500 kV lines.

The philosophy of this high level, first cut allowable local CREZ estimate is to consider the above assumed transmission ratings for the new transmission collector line segment additions for each line segment along with the assumed ratings of other existing local transmission facilities in the vicinity, when estimating how much power can reliably be injected into the foundation transmission facilities. The simplified transmission reliability considerations are that there must be enough transmission capacity remaining to transmit the power from the local CREZ to the foundation transmission lines with any one of the new or existing single circuit lines out of service. For double circuit lines on the same structures, there must be enough transmission capacity remaining to transmit the power from the local CREZ to the foundation lines with both circuits out of service. Foundation and delivery line segments are assumed to be adequate to deliver the power from the transmission lines to the California load centers in this task. These transmission reliability assumptions used for this simplified high level estimate of allowable local CREZ are compatible with the category B single contingency (N-1) criteria and category C credible double contingency (N-2) criteria presented in the NERC/WECC Planning Standards26 commonly used in WECC detailed bulk power system planning assessments.

The following caveats should be considered when interpreting the accuracy level of the results of this work. The high level estimates of allowable CREZ are based on inspection of the RETI 2A report and maps showing collector line segments added for each of the collector groups along with other existing local transmission corridors. This high level inspection also included review of associated existing transmission facilities shown on a pre 9/11 WSCC one line diagram27 to identify characteristics of existing transmission facilities in the transmission corridors. No power flow, transient or post transient analyses commonly employed in transmission planning assessments have been performed for this high level estimates.

[25] Table 4-19, page 4-44, *Synthetic Electric utility Systems for Evaluating Advanced Technologies*, EPRI EM-285, Final Report, February 1977.

[26] Table 1, page 24, *Western Electricity Coordinating Council NERC/WECC Planning Standards*, Revised April 10, 2003.

[27] *Western Systems Coordinating Council Map of Principal Transmission Lines*, January 1, 2000.

Carrizo

Table 2 presents the resulting high level estimates of allowable local CREZ MW capacity for the Carrizo Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. Reconductoring the Midway - Carrizo 230 kV lines will provide the first 1100 MW as described in Appendix G of the RETI 2A report. Reconductoring the Morro Bay - Gates 230 kV lines will provide the next 1000 MW resulting in a total local allowable local CREZ of about 2100 MW, as also described in Appendix G of the RETI 2A report. Mileage and cost assumptions for these line segment upgrades from the RETI 2A report are also included.

Adding a new 230 kV line from Carrizo to Gates is expected to increase the allowable local CREZ MW capacity another 1000 MW, resulting in a total local allowable local CREZ of about 3100 MW. This line segment addition is also described in Appendix G of the RETI 2A report. Note adding this new approximately 70 mi. line segment to allow the next 1000 MW of local CREZ is expected to cost significantly more than the reconductoring of the existing line segments.

Individual CREZ and transmission considerations

Reconductoring the Midway - Carrizo 230 kV lines is expected to provide adequate transmission capacity for a total of 1100 MW local CREZ installed at Carrizo South and Cuyama . Adding a new 230 kV line from Carrizo to Gates is expected to increase the allowable local CREZ MW capacity another 1000 MW to 2100 MW.

Reconductoring the Morro Bay - Gates 230 kV lines is expected to provide adequate transmission capacity for 1000 MW local CREZ installed at Carrizo North.

Table 2 – Carrizo Collector Group

CREZ Accessed: Carrizo North, Carrizo South, Cuyama

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
MIDW_CARZ_1	46	31.05	1100
GATE_MBAY_1	70	47.25	1000
Totals RETI 2A	116	78.30	2100
Incremental mi Cost and CREZ	70	175.00	1000
New Totals	186	253.30	3100

North

Table 3 presents the resulting high level estimates of allowable local CREZ MW capacity for the North Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. Building a 500 kV line from Collinsville – Tracy, a +/- 500 kV HVDC line from NE Oregon – Collinsville, and a Selkirk, BC - NE Oregon double circuit 500 kV line kV line will provide a total local allowable local CREZ of about 3000 MW. This assumes that there are adequate transmission facilities in the Northern portion of WECC to supply the 3000 MW for a credible N-2 outage in the DC or double circuit portion of the RETI 2A line segments. Mileage and cost assumptions for these line segments show that delivering these CREZ more than 1200 mi. will be costly. If there is serious consideration about delivering a significant amount of these Northern CREZ to California, a detailed transmission study will be required to determine how much the other existing northern WECC transmission facilities can transmit for a credible N-2 outage of these proposed RETI line segments.

Building a second set of line segments, another 500 kV line from Collinsville – Tracy, another +/- 500 kV HVDC line from NE Oregon – Collinsville, and a second Selkirk, BC - NE Oregon double circuit 500 kV line kV line will increase total local allowable local CREZ to about 6000 MW, assuming existing northern WECC transmission facilities can supply 3000 MW for a credible N-2 outage. If northern WECC transmission facilities cannot supply 3000 MW for a credible N-2 outage of the RETI 2A lines, the second set of transmission line segments will firm up the Northern collector lines and allow about 3000 MW of local CREZ during a credible N-2 event on one of the sets of line segments.

Individual CREZ and transmission considerations

Building a 500 kV line from Collinsville – Tracy, a +/- 500 kV HVDC line from NE Oregon – Collinsville, and a Selkirk, BC - NE Oregon double circuit 500 kV line kV line is expected to provide for a total allowable local CREZ of about 3000 MW for CREZ installed in British Columbia and Oregon assuming there are adequate transmission facilities in Northwest WECC. If all the 3000 MW of CREZ are located in Oregon, the Selkirk, BC - NE Oregon double circuit 500 kV line kV line is not required.

The +/- 500 kV HVDC line from NE Oregon – Collinsville is shown going right by the Round Mountain A and B CREZ. Thus, the Round Mountain A and B CREZ are included in both the North and Northeast transmission collector groups. However, my cursory investigation indicates that the Round Mountain A and B CREZ should not be included in the North collector group, because of expected high costs to connect the CREZ in the middle of the DC line.

Instead the Round Mountain A and B CREZ can be connected to the Northeast transmission collector group or be connected to existing transmission facilities without adding any of the North collector group transmission lines. There are two existing 500 kV lines and the Round Mountain substation in the vicinity of the Round Mountain CREZ which could be used to interconnect these CREZ. For example, the Round Mountain A and B CREZ could be connected to the Round Mountain substation. See the Northeast collector group discussion for potential mileage and cost estimates for the Round Mountain trunk-lines.

These assumptions would be similar to connect to the ZETA1 subatation, which is about a mile away from the Round Mountain substation .

Table 3 – North Collector Group

CREZ Accessed: British Columbia, Oregon, Round Mountain

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
COLL_TRCY2_1	40	130.00	
NEO_COLL_1	640	2080.00	
SELK_NEO_1	270	843.75	
SELK_NEO_2	270	843.75	
Totals RETI 2A	1220	3897.50	3000
Incremental mi Cost and CREZ	1220	3897.50	3000
New Totals	2440	7795.00	6000

Northeast

Table 4 presents the resulting high level estimates of allowable local CREZ MW capacity for the Northeast Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a single circuit 500 kV line from Olinda - Dillard Rd, a single circuit 500 kV line from Zeta1 – Olinda, a short 500 kV connection from Zeta1 - Round Mountain. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW. These lines are part of the TANC project, which is no longer actively being pursued I believe.

Adding a second set of these line segments, another single circuit 500 kV line from Olinda - Dillard Rd, another single circuit 500 kV line from Zeta1 – Olinda, and another short 500 kV connection from Zeta1 - Round Mountain Sub is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

Individual CREZ and transmission considerations

The key issue for this transmission collector group is how to transmit the power from the local CREZ to the ZETA1 substation.

Round Mountain A CREZ could be connected to the ZETA1 substation with a single circuit 230 kV approximately 50 mi. long trunk-line costing about $125 million.

Round Mountain B CREZ could be connected to the ZETA1 substation with a single circuit 230 kV approximately 10 mi. long trunk-line costing about $25 million.

On Page G-75 of the RETI 2A report, Lassen North and South CREZ are shown connected to the ZETA1 substation with two 80-100 mi. 500 kV collector lines costing up to about $650 million to maintain N-1 reliability. This transmission would also apply to other CREZ in northern Nevada.

Table 4 – Northeast Collector Group

CREZ Accessed: Round Mountain A&B, Lassen N&S, N Nevada

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
OLND_DILL_1	183	594.75	
ZETA1_OLND_1	42	136.50	
ZETA1_RDMT_1	1	3.25	
Totals RETI 2A	226	734.50	2000
Incremental mi Cost and CREZ	226	734.50	2000
New Totals	452	1469.00	4000

Inyo

Table 5 presents the resulting high level estimates of allowable local CREZ MW capacity for the Inyo Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a building a 230 kV line using 500 kV construction from Control - Lone Pine, building a 230 kV line using 500 kV construction from Inyokern – Kramer, and building a 230 kV line using 500 kV construction from Lone Pine - Inyokern. Adding these 230 kV lines is expected to result in a total local allowable local CREZ of about 500 MW, assuming that the parallel existing 230 kV is limiting with an outage of these new lines.

Adding a second set of single circuit 500 kV line segments from Control - Lone Pine, Inyokern - Kramer, Lone Pine - Inyokern, and operating both sets of lines at 500 kV is expected to increase the allowable local CREZ MW capacity to 2000 MW, an incremental increase of 1500 MW.

Individual CREZ and transmission considerations

The transmission collector line segments proceed in series southward from Control to Lone Pine to Inyokern to Kramer. Although the new 230 kV line segments will have a rating of about 1000 MW when operated at 230 kV, total local CREZ is limited to 500 MW due to the line capacity of an existing parallel 230 kV line. Since the collector line segments are constructed using 500 kV construction, the plan should be to construct additional 500 kV transmission collector segments to access more than 500 MW of local CREZ. If a second set of 500 kV line segments are built and the two sets of line segments are operated at 500 kV in parallel, the above local CREZ totals will increase to about 2000 MW.

Kramer is near the foundation transmission system and Kramer CREZ can be accessed through the foundation system as well as the Inyo collector group. Several thousand MW of Kramer CREZ can be connected directly to the foundation transmission system without connecting to the transmission collector system.

Accessing Inyokern CREZ requires building the Inyokern – Kramer line segment. Assuming only the Inyokern – Kramer line segment is built as described in the RETI 2A report, the collector system can reliably inject a total of about 500 MW of Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern will increase to about 2000 MW, or 1500 MW, with an additional 500 MW total CREZ at Owens Valley and Central Nevada.

Accessing the Owens Valley CREZ requires building the Inyokern – Kramer line segment and the Lone Pine – Inyokern line segment. Assuming the Inyokern – Kramer line segment and the Lone Pine – Inyokern line segment are built, the collector system can reliably inject a total of about 500 MW of Owens Valley CREZ, Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Lone Pine - Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern and

Owens Valley will increase to about 2000 MW, or 1500 MW, with an additional 500 MW total CREZ in Central Nevada.

Accessing the Central Nevada CREZ requires building the Inyokern – Kramer line segment, the Lone Pine – Inyokern line segment, and the Control – Lone Pine line segment. Assuming the Inyokern – Kramer line segment, the Lone Pine – Inyokern line segment, and the Control – Lone Pine line segment are built, the collector system can reliably inject a total of about 500 MW of Central Nevada CREZ, Owens Valley CREZ, Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Control - Lone Pine - Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern, Owens Valley and Central Nevada will increase to about 2000 MW.

Note this transmission expansion from Control – Lone Pine – Inyokern – Kramer could temporarily transmit approximately 1000 MW of CREZ while operating at 230 kV. However, it would not maintain N-1 transmission system reliability.

Table 5 – Inyo Collector Group

CREZ Accessed: Central Nevada, Inyokern, Owens Valley, Kramer

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
CONT_LPIN_1	45	202.50	
INYK_KRAM_1	66	214.50	
LPIN_INYK_1	53	238.50	
Totals RETI 2A	164	655.50	500
Incremental mi Cost and CREZ	164	533.00	1500
New Totals	328	1188.50	2000

MtPass

Table 6 presents the resulting high level estimates of allowable local CREZ MW capacity for the MtPass Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a building a 500 kV line from Baker - Barstow, building a 500 kV line from Barstow - Lugo, building a 500 kV line from Mountain Pass – Baker and building a 500 kV line from Mountain Pass - Eldorado. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding a second set of single circuit 500 kV line segments from Baker - Barstow, Barstow - Lugo, Baker - Mountain Pass and Mountain Pass – Eldorado is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

Individual CREZ and transmission considerations

The 500 kV line segments result in a 500 kV path from Eldorado – Mt. Pass – Baker – Barstow – Lugo. Eldorado is a large substation with two existing 500 kV lines heading to the LA area and two other 500 kV lines heading elsewhere in WECC. Lugo is part of the foundation group. With any collector line segment out of service it is expected that 2000 MW can be delivered into the foundation system either through Lugo or via the 500 kV lines out of Eldorado.

The Victorville CREZ is located near the foundation transmission system and is its power expected to be injected directly into the foundation network rather than through the collector lines.

Mt. Pass, Baker and Barstow CREZ are expected to be accessed by the Mt. Pass collector group transmission lines. This high level assessment indicates that a total of about 2000 MW at these three CREZ locations can be reliably injected into the foundation lines. If a second set of collector lines is installed, the total allowable CREZ can be increased to about 4000 MW.

Considering the CREZ individually, Mt. Pass is about 150 mi. from Lugo. 2000 MW of Mt. Pass CREZ could be probably be reliably injected into Eldorado substation with two 32 mi. 500 kV line segments costing about $248 Million, and delivered to the foundation system via the existing 500 kV transmission system.

Barstow is about 50 mi. from Lugo. 2000 MW of Barstow CREZ could be reliably delivered to Lugo with two 51 mi. 500 kV line segments from Lugo – Barstow costing about $574 million.

Baker is about 100 mi. from Lugo. 2000 MW of Barstow plus Baker CREZ could be reliably delivered to Lugo with two 51 mi. 500 kV line segments from Lugo – Barstow and two 50 mi. 500 kV line segments from Barstow – Baker costing about $962 million. Note this alternative is more expensive than building the transmission line segments from Lugo – Barstow – Baker – Mt. pass – Eldorado in shown in Table 6.

Table 6 – MtPass Collector Group

CREZ Accessed: Mountain Pass, Baker, Barstow, Victorville

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
BAKR1_BARS1_1	50	193.75	
BARS1_LUGO_1	51	286.88	
MTPS1_BAKR1_1	50	193.75	
MTPS1_ELDO_1	32	124.00	
Totals RETI 2A	183	798.38	2000
Incremental mi Cost and CREZ	183	594.75	2000
New Totals	366	1393.13	4000

BarrenRidge

Table 7 presents the resulting high level estimates of allowable local CREZ MW capacity for the BarrenRidge Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of upgrading the existing Owens Gorge - Rindaldi 230 kV line from Barren Ridge switching station to Haskel Canyon switching station, building double circuit 230 kV line #2 from Barren Ridge switching station to Haskel Canyon switching station, adding 230 kV #2 line from Castaic power plant - Haskel Canyon on open side of towers, and upgrading the existing Owens Gorge - Rindaldi 230 kV line from Haskel Canyon switching station to Rinaldi. Upgrading and adding these 230 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding additional single circuit 230 kV lines from Barren Ridge switching station to Haskel Canyon switching station, from Castaic power plant - Haskel Canyon, and from Haskel Canyon to Rindaldi is expected to increase the allowable local CREZ MW capacity another 1000 MW, resulting in a total local allowable local CREZ of about 3000 MW.

Individual CREZ and transmission considerations

First further review of the RETI 2A report, Page G-61 indicates that the allowable CREZ in Table 7 should be increased from 2000 MW to 2200 MW.

This transmission collector group provides a path to deliver approximately 2200 MW of Tehachapi and Kramer CREZ to the LADWP system as described in the RETI 2A report. The additional transmission expansion is expected to increase the allowable CREZ another 1000 MW to 3200 MW.

Table 7 – BarrenRidge Collector Group

CREZ Accessed: Kramer, Tehachapi

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
BRNR_HASC_1	60	40.50	
BRNR_HASC_2	60	150.00	
CAST_HASC_2	12	7.50	
HASC_RNLD_1	15	10.13	
Totals RETI 2A	147	208.13	2200
Incremental mi Cost and CREZ	87	217.50	1000
New Totals	234	425.63	3200

IronMt

Table 8 presents the resulting high level estimates of allowable local CREZ MW capacity for the IronMt Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of rebuilding double circuit 500 kV line circuits #1 and #2 from Iron Mountain - Junction over existing 230 kV to assess Iron Mountain CREZ, rebuilding a 500 kV line from Junction - Camino over existing 230 kV to access Needles CREZ, and building a double circuit 500 kV line circuit #1 and #2 from Jontry Junction – Pisgah. Unfortunately uprating and adding all these 500 kV lines is expected to only result in a total allowable local CREZ of about 500 MW at Iron Mountain and possibly 1000 MW at Needles, while meeting transmission reliability criteria discussed above. Problems associated with reliably delivering larger amounts of power from potential Iron Mountain CREZ are discussed in the RETI 2A report on page 3-71. Note, there is enough capacity in the double circuit 500 kV line to deliver about 4000 MW of CREZ into the foundation transmission system with both circuits in service, without meeting the credible N-2 outage criteria.

If the current problems can be resolved, Adding another double circuit 500 kV line from Iron Mountain – Jontry Junction - Pisgah, could deliver up to 4000 MW from Iron Mountain or 1000 MW at Needles with 3000 MW at Iron Mountain, while maintaining a credible N-2 reliability criteria.

Individual CREZ and transmission considerations

The individual CREZ and transmission considerations associated with Iron Mountain and Needles CREZ are discussed above.

Table 8 – IronMt Collector Group

CREZ Accessed: Iron Mountain, Pisgah, Needles

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
IRMT_SCEJ_1	39	134.06	
IRMT_SCEJ_2	39	134.06	
SCEJ_CAMI_1	10	38.75	
SCEJ_PISG_1	84	262.50	
SCEJ_PISG_2	84	262.50	
Totals RETI 2A	256	831.88	500
Incremental mi Cost and CREZ	123	768.75	3500
New Totals	379	1600.63	4000

Riverside

Table 9 presents the resulting high level estimates of allowable local CREZ MW capacity for the Riverside Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of building two 500 kV lines from Desert Center - Devers, and building a 500 kV line from Midpoint – Desert Center. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 4000 MW.

Adding another single circuit 500 kV line from Midpoint – Desert Center, and from Desert Center - Devers is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 6000 MW, with up to 4000 MW of the CREZ connected at Midpoint.

Individual CREZ and transmission considerations

The above allowable CREZ limits apply to Riverside East CREZ.

The Palm Springs CREZ appears to be located near Devers substation, and the CREZ power should be able to be injected directly into the foundation transmission system using a 10 mi. 230 kV trunk-line costing about $25 million.

Table 9 – Riverside Collector Group

CREZ Accessed: Riverside East, Palm Springs

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
DESC_DEVR_1	40	125.00	
DESC_DEVR_2	40	125.00	
MIDP_DESC_1	70	227.50	
Totals RETI 2A	150	477.50	4000
Incremental mi Cost and CREZ	110	357.50	2000
New Totals	260	835.00	6000

LEAPS

Table 10 presents the resulting high level estimates of allowable local CREZ MW capacity for the LEAPS Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of reconductoring the double circuit Talega - Escondido 230 kV #1 line from Escondido - Camp Pendleton, adding a second #2 circuit to the towers, reconductoring the double circuit Talega - Escondido 230 kV #1 line from Talega - Camp Pendleton, and adding a second #2 circuit to the towers, and building a 500 kV Talega to Escondido to the Valley - Serrano line. Reconductoring the 230 kV lines and adding the 500 kV line is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding another single circuit 500 kV line from Talega to Escondido to the Valley - Serrano line is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

Individual CREZ and transmission considerations

Table B-1 in the RETI 2A report indicates that the total local developable North Central San Diego CREZ is 281 MW. The above cursory examination of the transmission segments proposed in the RETI 2A report indicates that the proposed collector segments provide for about 2000 MW of allowable local CREZ. In my opinion the existing 230 kV transmission may be adequate to inject a large portion of the developable North Central San Diego CREZ power directly into the San Diego transmission system.

Table 10 – LEAPS Collector Group

CREZ Accessed: San Diego North Central

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
CMPL_ECND_1	37	24.98	
CMPL_ECND_2	37	23.13	
CMPL_TALG_1	10	6.75	
CMPL_TALG_2	10	6.25	
LELK_CMPL_1	31	100.75	
Totals RETI 2A	125	161.85	2000
Incremental mi Cost and CREZ	31	100.75	2000
New Totals	156	262.60	4000

Tehachapi

Table 11 presents the resulting high level estimates of allowable local CREZ MW capacity for the Tehachapi Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of upgrading the existing line #1 from Antelope - Vincent from 220 kV to 500 kV, upgrading the existing line #2 from Antelope - Vincent from 220 kV to 500 kV on separate right of way, upgrading existing 220 kV line from Chino – Mira Loma to double circuit 220 kV lines #1 and #2, adding 220 kV circuit to the open side of existing 500 kV creating Chino - Mira Loma 220 kV line #3 (using 500 kV construction), adding 220 kV Gould – Eagle Rock 220 kV line using existing towers, rebuilding a portion of the Eagle Rock - Pardee 220 kV line creating the Mesa - Vincent #2 220 kV line, building the Rio Hondo - Vincent #2 220 kV line, changing the Windhub - Antelope line operating voltage from 220 kV to 500 kV, building the Whirlwind - Windhub 500 kV line, and building the Whirlwind - Antelope 500 kV line. Upgrading the above 220 kV lines and adding the 500 kV lines creates a lot of transmission capacity. The total local allowable CREZ capacity is difficult to estimate without performing load flow analysis. However, all these upgrades and additions are expected to result in a total local allowable local CREZ of at least 4000 MW.

Adding another single circuit 500 kV line, say from Windhub – Whirlwind - Vincent is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 6000 MW.

Individual CREZ and transmission considerations

Table B-1 in the RETI 2A report indicates that the total local developable Tehachapi CREZ is more than 10,000 MW and Fairmont CREZ is more than 3500 MW. It appears that the following list of Tehachapi collector group transmission line segments in Table 11 were developed based on a relatively extensive transmission assessment by the RETI group. If more than 6000 MW local CREZ is planned, I suggest we contact the appropriate transmission planners to develop a more accurate estimate of the allowable local CREZ associated with the transmission facilities added in the RETI report.

Table 11 – Tehachapi Collector Group

CREZ Accessed: Tehachapi, Fairmont

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
ANTE_VINC_1	21	16.28	
ANTE_VINC_2	18	68.20	
CHNO_MIRA_1	7	24.06	
CHNO_MIRA_2	7	15.31	
CHNO_MIRA_3	7	15.31	
GULD_EGLR_1	9	3.53	
MESA_VINC_2	36	126.00	
RIOH_VINC_2	32	124.39	
WHUB_ANTE_1	26	16.64	
WHUB_WRLW_1	17	54.60	
WRLW_ANTE_1	16	50.70	
WRLW_VINC_1	33	10.79	
Totals RETI 2A	228	525.81	4000
Incremental mi Cost and CREZ	50	162.50	2000
New Totals	278	688.31	6000

Imperial

Table 12 presents the resulting high level estimates of allowable local CREZ MW capacity for the Imperial Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of rebuilding the existing 161 kV Line to double circuit 230 kV line #1 from Avenue 58 - Coachella Valley, rebuilding the existing 161 kV line to double circuit 230 kV line #1 from Avenue 58 – Bannister, adding a second circuit to double circuit 230 kV line creating Bannister - Coachella Valley line #1, building the 500 kV Bannister - Devers #1 line, adding the second circuit to double circuit 230 kV creating the Bannister - El Centro line #1, building 230 kV Bannister - Geo #1 line, building 230 kV Bannister - Geo #2 line, building 230 kV Coachella Valley - Devers II line #1, building 230 kV Coachella Valley - Devers II line #2 , upgrading 230 kV Coachella Valley - Mirage line #1, upgrading 230 kV Coachella Valley - Mirage line #2, adding a short 500 kV line connection between Devers – Devers II, rebuilding existing 161 kV to double circuit 230 kV line #1 from Dixieland – Bannister, rebuilding existing 161 kV to double circuit 230 kV line #1 from El Centro – Highline, adding second circuit to double circuit 230 kV creating El Centro - Highline line #2, building El Centro - Imperial ValleyII 230 kV line #2, building the 500 kV Bannister - Imperial Valley line#1, replacing the existing 500/230 kV 600 MVA Imperial Valley transformer with a new 1120 MVA transformer, adding a third 500/230 kV 1120 MVA Imperial Valley transformer, building Midway - Geo double circuit 230 kV lines #1 and #2, upgrading existing Mirage - Devers 230 kV line #1, and upgrading existing Mirage - Devers 230 kV line #2. I believe the transmission capability of all these upgrades and additions has been studied pretty thoroughly, as can be seen in the RETI 2A report. As stated in Appendix G, page G-57 of the RETI 2A report, 3200 MW of local CREZ capacity can be delivered at to LADWP and SCE at Devers/Mirage and 1800 MW of local CREZ can be delivered to SDGE at Imperial Valley, resulting in a total allowable local CREZ of 5000 MW.

Adding another single circuit 500 kV line 500 kV line from Imperial Valley - Bannister – Devers is expected to increase the allowable local CREZ MW capacity delivered to LADWP and SCE at Devers/Mirage another 2000 MW, to about 5200 MW, and increasing the total allowable local CREZ to 7000 MW.

Individual CREZ and transmission considerations

This collector group has been thoroughly studied in determining the allowable local CREZ. If more than 7000 MW local CREZ is planned, I suggest we contact the appropriate transmission planners to discuss additional transmission facilities to add.

Table 12 – Imperial Collector Group

CREZ Accessed: Imperial North A&B, Imperial South, Imperial East, Baha

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
AV58_CHCV_1	18	32.81	
BANN_AV58_1	61	107.41	
BANN_CHCV_1	56	140.22	
BANN_DEVR_1	91	296.40	
BANN_ELCN_1	28	51.56	
BANN_GEO_1	16	25.00	
BANN_GEO_2	16	25.00	
CHCV_DVR2_1	35	54.69	
CHCV_DVR2_2	35	54.69	
CHCV_MIRG_1	20	13.50	
CHCV_MIRG_2	20	13.50	
DEVR_DVR2_1	0	0.98	
DIXL_BANN_1	43	51.56	
ELCN_HILN_1	19	35.63	
ELCN_HILN_2	19	35.63	
ELCN_IMPV2_2	18	33.75	
IMPV_BANN_1	51	165.75	
IMPV_XFMR_2	0	51.25	
IMPV_XFMR_3	0	51.25	
MIDW_GEO_1	16	25.00	
MIDW_GEO_2	16	25.00	
MIRG_DEVR_1	15	10.13	
MIRG_DEVR_2	15	10.13	
Totals RETI 2A	608	1310.81	5000
Incremental mi Cost and CREZ	142	462.15	2000
New Totals	750	1772.96	7000

D3: E3 additions of generic 500kV transmission lines and project-specific cost assumptions

E3's analysis includes a look at the relative values of fixed capacity transmission lines from the various zones. The size of the transmission lines from each zone are chosen to reflect the total resource availability in that zone, up to a maximum of 3,000 MW consisting of two single-circuit 500 kV lines or one dual-circuit 500 kV line. The lines are assumed to originate at the center of the resource clusters in each zone[28] and terminate at the closer of the Tesla (near Tracy, CA) or Victorville substations, whichever. These two substations were chosen because they represent transmission hubs in close proximity to major California load centers.

With the exception of the line from British Columbia, which E3 models as a hybrid alternating current (AC) and direct current (DC) line, E3 assumes all lines to be AC lines. The cost of these lines is estimated using a generic line costing model that accounts for both equipment (substations, towers, conductors, etc.) and right-of-way acquisition.[29] The following table details the cost and size of the transmission line that E3 assumes from each zone, as well as the losses associated with those lines.

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[28] For example, the Wyoming line originates in eastern rather than central Wyoming due to the fact that most wind resources are located in the eastern part of the state.

[29] This transmission costing model was the same as that used for the GHG Calculator. It can be found at http://www.ethree.com/GHG/Transmission_Line_Cost_2007-11-16.xls

CREZ Name	Assumed Line Capacity	Transmission Line Distance (Miles)	Transmission Configuration	Segment Capital Cost (2008$ millions)	Segment Losses	Levelized Cost (2008$ Millions)
Alberta	3,000	1498	500 kV Double Circuit AC Line	$7,998	17.20%	$1,160
Arizona	1,500	403	500 kV Single Circuit AC Line	$2,044	4.63%	$296
Baja	1,500	211	500 kV Single Circuit AC Line	$1,425	2.42%	$207
Barstow	1,500	48	500 kV Single Circuit AC Line	$889	1.11%	$129
British Columbia	3,000	1045	500 kV Double Circuit AC Line and 3,000 MW DC Line	$5,100	13.39%	$740
Carrizo North	1,500	87	500 kV Single Circuit AC Line	$1,127	2.00%	$163
Carrizo South	1,500	119	500 kV Single Circuit AC Line	$1,478	2.72%	$214
Colorado	3,000	936	500 kV Double Circuit AC Line	$5,250	10.75%	$761
Cuyama	500	124	500 kV Single Circuit AC Line	$1,094	0.54%	$159
Distributed Solar - PG&E	All Distributed Solar Resources are assumed to utilize existing transmission					
Distributed Solar - SCE						
Distributed Solar - SDGE						
Distributed Solar - Other						
Fairmont	1,500	7	500 kV Single Circuit AC Line	$549	0.15%	$80
Imperial	1,500	93	500 kV Single Circuit AC Line	$1,252	2.13%	$182
Inyokern	1,500	59	500 kV Single Circuit AC Line	$948	1.35%	$138
Iron Mountain	1,500	85	500 kV Single Circuit AC Line	$1,120	1.96%	$162
Kramer	1,500	41	500 kV Single Circuit AC Line	$823	0.94%	$119
Lassen North	1,500	133	500 kV Single Circuit AC Line	$1,642	3.06%	$238
Lassen South	1,500	172	500 kV Single Circuit AC Line	$1,940	3.95%	$281
Montana	3,000	1105	500 kV Double Circuit AC Line	$6,090	12.69%	$883
Mountain Pass	1,500	97	500 kV Single Circuit AC Line	$1,287	2.23%	$187
Nevada C	1,500	215	500 kV Single Circuit AC Line	$1,345	2.46%	$195
Nevada N	500	476	230 kV Single Circuit AC Line	$1,232	0.86%	$179
New Mexico	3,000	790	500 kV Double Circuit AC Line	$4,522	9.08%	$656
NonCREZ	All NonCREZ Resources are assigned a transmission cost of $54/kW-yr.					
Northwest	1,500	611	500 kV Single Circuit AC Line	$3,270	8.48%	$474
Owens Valley	1,500	94	500 kV Single Circuit AC Line	$1,211	2.16%	$176
Palm Springs	1,000	36	500 kV Single Circuit AC Line	$668	0.32%	$97
Pisgah	1,500	56	500 kV Single Circuit AC Line	$908	1.28%	$132
Remote DG (Brownfield) - PG&E	All Remote DG Resources are assumed to utilize existing transmission					
Remote DG (Brownfield) - SCE						
Remote DG (Brownfield) - SDGE						
Remote DG (Brownfield) - Other						
Remote DG (Greenfield) - PG&E						
Remote DG (Greenfield) - SCE						
Remote DG (Greenfield) - SDGE						
Remote DG (Greenfield) - Other						
Riverside East	1,500	85	500 kV Single Circuit AC Line	$1,143	1.94%	$166
Round Mountain	500	96	500 kV Single Circuit AC Line	$879	0.42%	$128
San Bernardino - Baker	1,500	63	500 kV Single Circuit AC Line	$1,002	1.44%	$145
San Bernardino - Lucerne	1,500	32	500 kV Single Circuit AC Line	$732	0.74%	$106
San Diego North Central	500	23	500 kV Single Circuit AC Line	$585	0.10%	$85
San Diego South	1,000	102	230 kV Double Circuit AC Line	$1,118	0.89%	$162
Santa Barbara	500	140	230 kV Single Circuit AC Line	$1,153	0.61%	$167
Solano	1,000	10	230 kV Double Circuit AC Line	$538	0.09%	$78
Tehachapi	3,000	40	500 kV Double Circuit AC Line	$1,252	0.92%	$182
Twentynine Palms	1,000	56	230 kV Double Circuit AC Line	$766	0.49%	$111
Utah-Southern Idaho	1,500	676	500 kV Single Circuit AC Line	$2,925	7.76%	$424
Victorville	1,500	21	500 kV Single Circuit AC Line	$674	0.49%	$98
Westlands	1,500	75	500 kV Single Circuit AC Line	$1,058	1.71%	$153
Wyoming	3,000	1030	500 kV Double Circuit AC Line	$5,796	11.83%	$840

D4: Distribution System Benefits/Upgrade Penalties for Wholesale Distributed Solar Resources

E3 has modeled four different types of wholesale distributed solar PV generation for this effort. These different types of solar resource are either given a credit for the benefits that they provide to the distribution system (small installations serving load downstream of the substation) or assessed a penalty for system upgrades that they might trigger (larger installations that violate Rule 21[30]).

The size of the benefit for the smaller installations was determined by where they interconnect to the system. Remote DG installations that are not compliant with Rule 21 are assessed a generic $68/kW-yr system upgrade penalty. The following table shows the different benefits/penalties by interconnection point and the types of distributed resources to which they correspond.

Interconnection Point	Upgrade Penalty (Distribution System Benefit), $/kW-yr.	Applicable Solar PV Technologies
Meter	($45)	Large Rooftop (0-2 MW)
Feeder	($45)	Small Ground (0-2 MW)
Dist. Bank	($45)	
Transmission Substation	($10)	Mid Ground (2-5 MW), Large Ground (5-20 MW)
Remote DG	$68	Large Ground (5-20 MW), Not Rule 21 Compliant

[30] Rule 21 governs the amount of downstream distributed generation that can be connected to a given substation. More information on Rule 21 can be found at the California Energy Commission website: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html.

Appendix E

Environmental Scoring

Note: Due to the number of changes to the environmental scoring methodology since the June 22 draft, the Appendix has been replaced in its entirety, and individual changes are not highlighted.

Environmental Scoring for 33% RPS Scenarios

This white paper describes work conducted by Aspen Environmental Group (Aspen) in consultation with Energy and Environmental Economics, Inc. (E3) to support the ongoing effort by CPUC to identify various 33% RPS Scenarios. Aspen's tasks were to help CPUC update the methodology for environmental ranking of renewable resources and to assign scores to generation resources so environmentally-ranked scenarios (portfolios) could be developed. A preliminary methodology was identified in our June 9, 2010 paper (as Staff's proposal for Resource Planning Assumptions, in Appendix E of Attachment 1 of the June 22, 2010 filing [R. 10-05-006, Long Term Renewable Resource Planning Standards]). This white paper substantially updates the approach to improve transparency and reflect public comments.

Aspen is under contract to provide RPS Technical Support to the California Institute for Energy and Environment (CIEE) through direction from the CPUC Energy Division. The CPUC 33% RPS Implementation Analysis team will use the scores to create environmentally-constrained scenarios of new renewable generating resources to fill the RPS need and for use in the Long-Term Procurement Planning (LTPP) process.

Revisions from Proposal Released June 22, 2010

This white paper reflects the following revisions from Aspen's previous scoring methodology:

- Remove the "weighting" approach of how each environmental criterion may or may not be relevant to the successful development of a given renewable technology. The new methodology avoids using a relative weight of the environmental criteria for the potential level of concern by technology. In eliminating weighing of the environmental criteria for each renewable technology, the present methodology instead relies on published data from the RETI process to first quantify the environmental concerns over each geographic area then factor the "area needs" (or footprint per energy output) of each technology. The "area needs" are weighted by the percentage of land found not to be 'mechanically disturbed' in that zone. Weighting by the percentage of Undisturbed Land in a given zone results in favorable scores (lower "area needs") for resource development that may occur where there is abundant Mechanically Disturbed Land. This penalizes a resource for its area needs if in a zone with a high fraction of Undisturbed Land. The product of the environmental ranking and the area need (multiplied by the Undisturbed Land fraction) equals the score.
- Restore the RETI EWG criteria for "Sensitive Areas in CREZs" and "Sensitive Areas in CREZ Buffer Areas" that were initially not used in the scores to improve consistency with RETI efforts. These criteria originally from the RETI EWG are now included in the present scoring, although Aspen's experience indicates that these criteria are not highly relevant to specific projects. Projects can be directed by agencies to avoid sensitive areas, and the presence of an adjacent sensitive area does not necessarily increase environmental concern.
- Remove "high desert ecosystems" and "regional air quality" as environmental indicators because no consensus could be found in the public comments on how to treat these issues methodologically. The "high desert ecosystems" indicator of our original scoring methodology reflected Aspen's experience that valuable biological resources correlate especially well with portions of the desert at higher elevations. Aspen recommended this indicator as a proxy for information not yet reflected in statewide databases and to reflect our review of various proposals for renewable projects located in the California Mojave and Sonoran Deserts. "Regional air quality" conditions were originally considered as a partial proxy for environmental justice and public health concerns because most of

California's population resides in polluted air basins. Public comments suggested more work would be needed before including these two indicators in scoring.

- Include an environmental score for minor transmission upgrades and new transmission from a given zone. Transmission scores were based on the length of the line, and weighted according to whether they were minor upgrades (x1) or new transmission corridors (x4).

1. Introduction

1.1 Purpose

Aspen Environmental Group shows a way of scoring individual renewable energy projects based on the relative environmental ranking of its location [using the Renewable Energy Transmission Initiative (RETI) Competitive Renewable Energy Zone (CREZ)] and the technology of the resource. Aspen also provides comparable scores for projects that are out-of-state or do not fall within a CREZ.

The CPUC Energy Division is forecasting scenarios of new renewable generation development to comply with the mandate for 33% renewable electricity by 2020. In separate work for the LTPP, a range of development scenarios for 2020, including those that are environmentally-constrained, will be made up of specific selected projects. This white paper describes how each project can be given an environmental score. Each environmental score is a composite of the environmental ranking of the applicable CREZ, which characterizes location, and the relative area needs of each technology per unit of energy production.

1.2 Reliance on Renewable Energy Transmission Initiative

RETI EWG Environmental Criteria. The Renewable Energy Transmission Initiative includes an Environmental Working Group (EWG) that developed eight environmental criteria for measuring the level of environmental concern associated with developing renewable generation in various Competitive Renewable Energy Zones (CREZs). The eight criteria originally defined as part of RETI Phase 1B are documented in the RETI Phase 1B report of January 2009.

Identification of Resources. New generating resources to fill the RPS need come from the RETI Phase 2B Supporting Documents and the confidential CPUC Energy Division database. Given the variety of resources and the different levels of available information on possible projects, this white paper identifies a way of discerning which projects would have the least environmental concern based solely on the ranking of each project's CREZ and the technology proposed.

- **Projects Identified by RETI:** Scores are assigned to projects identified by RETI Phase 2B Supporting Documents (1,222 projects),[31] which do not include distributed solar photovoltaic (PV) projects.
- **Photovoltaic Distributed Generation (DG):** Separate scores were derived for rural small-scale PV systems considering that only a portion of the environmental score would be relevant when

[31] The RETI Phase 2B Supporting documents include the list of 1,222 projects with the following description (available at: http://www.energy.ca.gov/reti/documents/index.html, accessed June 2, 2010): "Hypothetical proxy projects have been located based on relative resource potential and other constraints in a general area; pre-identified projects have been located based on known commercial interest in a general area. Locations of actual projects may vary significantly from locations shown in the [RETI] GIS files."

compared to utility-scale projects. Urban DG PV projects are given low scores to ensure priority in selecting these resources.

Revisiting RETI Environmental Criteria. This white paper shows how our environmental scoring departs from CREZ Environmental Ranking of the RETI process in several ways. Our work:

1) revises the two RETI environmental criteria regarding development footprint and land degradation;

2) identifies the fraction of mechanically disturbed farmland as an environmental indicator within each CREZ;

3) includes new publicly-available data for degraded land;

4) divides each environmental indicator by the area of the CREZ (acres or ac), rather than the anticipated energy produced by each CREZ (gigawatt-hours or GWh);

5) applies data from the RETI process on the "area needs" of each technology and weights it by the fraction of undisturbed land with the zone to arrive at a the level of environmental concern for each renewable technology; and

6) results in scores for each technology in each CREZ, rather than area rankings, in a range of 0 to over 100, with 0 representing the projects with the lowest level of environmental concern and scores over 100 indicating the highest level of environmental concern.

The formulas developed and documented in the RETI Phase 1B report determined the relative levels of concern for the environmental criteria as follows:

$$\frac{\textit{Environmental Indicator for CREZ}}{\textit{Annual Energy Produced by CREZ}}$$

This white paper uses a two-step set of formulas instead of the RETI formula. Environmental scoring in this white paper uses the RETI data on environmental indicators divided by the CREZ area, rather than energy output. This "normalizes" the relative level of environmental concern so that it does not depend on the renewable technology mix or presumed energy output of the CREZ. Our formula first uses the environmental concern per unit of area to derive a ranking, then applies a separate factor depending on the "undisturbed area needs" of the major renewable technologies per unit of energy production, as follows:

$$\left[\frac{\textit{Environmental Indicator for CREZ}}{\textit{Total CREZ Area}}\right] \times$$

$$\left[\frac{\textit{Footprint Area of Technology in CREZ} \times \left(\frac{\textit{CREZ Area} - \textit{Mechanically Disturbed Area}}{\textit{CREZ Area}}\right)}{\textit{Annual Energy Produced by Technolgy in CREZ}}\right]$$

This results in a table of environmental scores that are factors of the environmental ranking of the applicable zone and the relative area needs of each technology. The results of scoring resources in California are then extrapolated to score renewable projects outside of California, where data on project

location and environmental attributes are scarce. Projects are drawn from the RETI list and projects within the Energy Division database.

The remainder of this paper explains the goals and methodology used to arrive at the environmental scores in more detail and the scoring results.

2. Goals in Deriving an Environmental Score

Aspen's primary goal is to score resources on a clear range for side-by-side comparison. A total of seven environmental criteria (or environmental concerns) were considered for each location and each major renewable technology, using a mix of existing RETI data and additional publicly-available data. For each geographic location, each criterion was given a score of between 0 and 10, 0 representing the least environmental concern and 10 the greatest. The seven environmental criteria were then totaled and multiplied by the undisturbed area needs for each renewable technology based on the premise that greater area needs are directly related to greater environmental concerns, and that development in an area with less Mechanically Disturbed land is associated with greater environmental concern. Projects in geographic areas with the greatest combined potential environmental concern across the seven criteria and the greatest undisturbed area needs result in total environmental scores over 100, where scores closer to 0 indicate the least environmental concern.

Another goal was to arrange the scoring system so projects from the RETI and CPUC Energy Division (ED) project databases could be treated with the same methodology. The location of each project determines whether it is within or near a ranked CREZ. If it is within or near a ranked CREZ, the project is given a score appropriate for that technology in that CREZ. When a project falls far beyond a CREZ boundary or out-of-state, then it is treated as a Non-CREZ or out-of-state resource, as needed. The environmental score is only a function of the project's location relative to a CREZ and the project's technology.

3. Environmental Criteria

This section details the eight environmental criteria representing the level of environmental concern for each renewable resource. The environmental criteria originate from RETI EWG scores and are modified by Aspen to normalize the environmental concerns by CREZ area, rather than energy output.

3.1 RETI EWG Environmental Assessment of CREZs

The RETI EWG determined how environmental considerations should be factored into CREZ development and ranking. The EWG's work was finalized in the January 2009 Phase 1B report as a 46-page appendix addressing "Environmental Assessment of CREZs."

The RETI EWG assessment illustrated the relative merits of each zone. The RETI EWG scores are not intended for use in evaluating individual projects, and the EWG makes no recommendations for the level of environmental concern for resources outside of defined CREZs (Non-CREZ), outside a scored sub-CREZ (portions of CREZs with differing economic profiles), or areas outside of California (out-of-state). RETI EWG Phase 2B results included updates limited to environmental ranking of certain CREZs, rather than all CREZs, and Phase 2B also provided one alternate set of CREZ rankings to address a lack of consensus on how the footprint of wind projects should be defined (May, 2010). RETI identified alternative CREZ rankings under the assumption that typical wind projects have a disturbed footprint of 3.5% of the lease area.

The RETI EWG scores apply uniformly across each CREZ and do not discern which types of projects within a ranked CREZ might have a lower or higher level of environmental concern. The occurrence of an environmental concern within each CREZ is normalized by RETI by assuming a given annual energy output of each CREZ. This means that the RETI scores originally introduced in Phase 1B embody certain fixed assumptions of the technology mix. Because our environmental scoring aims to show the environmental concern for various types of renewable projects in each CREZ, with a variable mix of renewable technologies, our approach normalizes the environmental concerns across the total land in the CREZ rather than assuming the CREZ energy production.

Table 1. RETI Phase 2B Annual Energy Mix

CREZ Name	Biomass/ Biogas (GWh/yr)	Wind (GWh/yr)	Solar (GWh/yr)	Geothermal (GWh/yr)	Total Annual Energy (GWh/yr)	CREZ Area (acres)
Barstow	---	2,363	3,000	---	5,362	98,687
Carrizo North	---	---	3,053	---	3,053	45,868
Carrizo South	---	---	5,823	---	5,823	47,181
Cuyama	---	---	801	---	801	6,150
Fairmont	976	1,992	4,032	---	7,000	95,391
Imperial East	---	200	3,216	---	3,416	66,724
Imperial North-A	---	---		10,095	10,095	52,073
Imperial North-B	212	---	3,753	---	3,965	67,901
Imperial South	253	113	7,405	426	8,197	77,172
Inyokern	---	678	4,911	---	5,589	71,605
Iron Mountain	---	143	10,145	---	10,288	96,149
Kramer	---	448	14,176	160	14,784	127,328
Lassen North	---	3,595	---	---	3,595	185,291
Lassen South	---	1,051	---	---	1,051	32,393
Mountain Pass	---	445	1,667	---	2,111	78,790
Owens Valley	---	---	10,651	---	10,651	67,370
Palm Springs	---	1,047	---	---	1,047	17,170
Pisgah	---	---	4,706	---	4,706	12,360
Riverside East	---	---	22,525	---	22,525	181,834
Round Mountain-A	---	---	---	2,557	2,557	9,363
Round Mountain-B	---	339	---	---	339	19,236
San Bernardino - Baker	---	---	7,064	---	7,064	67,694
San Bernardino - Lucerne	644	1,586	3,427	---	5,656	167,805
San Diego North Central	---	502	---	---	502	37,608
San Diego South	---	1,829	---	---	1,829	31,844
Santa Barbara	---	1,121	---	---	1,121	37,461
Solano	---	2,721	---	---	2,721	34,744
Tehachapi	262	9,075	16,095	---	25,432	317,323
Twentynine Palms	---	---	3,959	---	3,959	36,172
Victorville	---	1,161	2,737	---	3,899	88,896

Table 1. RETI Phase 2B Annual Energy Mix

CREZ Name	Biomass/ Biogas (GWh/yr)	Wind (GWh/yr)	Solar (GWh/yr)	Geothermal (GWh/yr)	Total Annual Energy (GWh/yr)	CREZ Area (acres)
Westlands	---	---	8,317	---	8,317	35,413

Source: RETI Phase 2B, May 2010 and supporting spreadsheets (Black & Veatch).

3.2 Environmental Criteria Retained

The ranking criteria originally developed as part of RETI EWG Phase 1B address important environmental concerns, some of which were used directly in our environmental scoring. The following criteria were carried forward as part of our environmental scoring, modified to remove the CREZ energy production assumptions and to reflect a 0 to 10 scale instead of 0 to 5 as used by RETI:

- **Transmission Footprint:** This criterion includes the amount of land needed for new transmission rights-of-way (ROW) as a useful measure of the expected impact on the environment.
- **Sensitive Areas in CREZs:** Each CREZ may include sensitive areas in which development is restricted or prohibited (mapped by RETI as Category 1 or Category 2 areas), such as: National Wildlife Refuges, Areas of Critical Environmental Concern (ACEC), and proposed and potential conservation reserves.
- **Sensitive Areas in CREZ Buffer Areas:** The RETI EWG agreed that lands within 2 miles of a CREZ boundary may be affected by development in the CREZ. This criterion therefore is scored on the amount of sensitive lands within 2 miles of a CREZ boundary.
- **Significant Species:** State and federal policies identify species of wildlife that are of significant concern. This criterion gives preference to CREZs in which fewer significant species are known to occur. Sensitive species data collected during recent environmental reviews for major California renewable projects is not yet entered into the California Natural Diversity Database. Because this data has yet to be published in the database, it was not included in our environmental scores, which are based on database searches originally conducted by the RETI EWG. This criterion in particular should continue to be updated based on new information that is continuously uploaded in the California Natural Diversity Database.
- **Wildlife Corridors:** Biologists have recognized the importance of the integrity of wildlife corridors that enable animals to move as needed from one habitat to another. Although corridors are not well understood and existing data is preliminary, the EWG included corridor data to give preference to those CREZs that minimize conflicts with wildlife corridors. As with the significant species data, this criterion does not reflect the most recent data on wildlife corridors found during environmental review of major renewable projects in the California Mojave and Sonoran Deserts and potentially elsewhere, like the Carrizo Plain. This criterion should also continue to be updated based on ongoing environmental studies.
- **Important Bird Areas:** Potential impacts of energy development on avian species are of significant environmental concern. Areas designated as Important Bird Areas (IBA) by the National Audubon Society are areas designated as vital to bird species, including common and game species as well as rare species.

The January 2009 RETI Phase 1B report includes more information on the economic and environmental rankings of the CREZs and the data sources for quantifying these environmental concerns in each CREZ.

Additional environmental concerns, including aesthetics (visual impact), Native American concerns (cultural resources), and some land use conflicts (regarding forest use), are neither represented in the existing RETI data nor the criteria in this white paper. Identifying potential conflicts with agricultural use is beyond the scope of this analysis, as is a consideration of air quality or environmental justice. However, these concerns could be addressed by the environmental scores in future updates of this work as criteria and data become available.

Disclaimers within the RETI Phase 1B report remain applicable to this environmental scoring methodology. Namely, that the: "*. . . ranking process is not intended in any way to prejudge or substitute for a thorough environmental review of proposed projects as required by the California Environmental Quality Act (CEQA) or the National Environmental Policy Act (NEPA)*."

3.3 Environmental Criteria Updated or Added

Our environmental scoring takes into account two additional and updated environmental factors, building on the criteria of the RETI EWG rankings. In addition to the six RETI EWG criteria that were incorporated (see Section 3.2), we revised the criterion for development opportunities on degraded lands, including brown-field and other EPA-tracked sites.

EPA Tracked Degraded Lands

We sought to capture the results of work completed in February 2010 by U.S. EPA and the National Renewable Energy Laboratory (NREL) regarding renewable energy development opportunities on "degraded" lands. The U.S. EPA and NREL published a tool that tracks certain EPA and state-tracked degraded sites and maps these based on their appropriateness for renewable development.[32] We identified the acreage of tracked degraded land considered appropriate for renewable development inside of each CREZ and within 10 miles of each CREZ boundary. A 10-mile buffer from each CREZ edge was used because the boundaries of the opportunity sites are not mapped in the U.S.EPA and NREL data and because many large-scale renewable energy proposals currently under review in California specify a distance of 10 miles or less from transmission as one of the project objectives.

We calculated the area of degraded land inside or within 10 miles of each CREZ and divided that by the total CREZ area. For degraded lands known to be currently in use, such as is the case for active military lands, ten percent of these degraded lands were included for the calculation. CREZs with excess or the most degraded land available received the lowest (best) scores, and CREZs with little or no degraded land available were assigned higher (worse) scores.

Table 2 shows the data for each of the RETI CREZs supporting the eight environmental criteria.

[32] See http://www.epa.gov/renewableenergyland/ for further tools compiled by the EPA for siting renewable energy on potentially contaminated land and mine sites.

Table 2. Data Used for Environmental Criteria

CREZ Name	Mechanically Disturbed (ac)	ROW Transmission Footprint (ac)	CREZ Yellow & Black Area (ac)	Buffer Yellow & Black Area (ac)	Significant Species (# species)	Wildlife Corridors (meters)	Important Bird Area (ac)	EPA Tracked Degraded (ac)
Barstow	582	42,538	55,489	127,499	73	16,704	3,795	215
Carrizo North	10,587	35,633	3,784	17,540	111	3,693	0	54
Carrizo South	0	28,003	0	4,788	109	7,886	6,695	0
Cuyama	0	3,923	94	6,005	65	0	0	0
Fairmont	8,630	46,827	0	29,894	130	10,463	8,936	480
Imperial East	0	26,758	11,496	59,721	116	4,662	720	156
Imperial North-A	23,281	50,526	16,673	57,133	114	7,803	31,489	0
Imperial North-B	15,985	44,203	15,012	72,973	126	4,245	25,523	796
Imperial South	23,047	48,826	13,055	64,123	111	13,007	30,770	170
Inyokern	996	29,972	34,441	88,859	82	5,320	0	21
Iron Mountain	0	54,315	5,079	31,729	52	0	0	5
Kramer	0	68,610	61,291	186,399	65	16,202	7,964	30,302
Lassen North	0	84,206	2,222	37,419	110	7,928	0	2
Lassen South	0	12,411	5,027	87,065	112	18,917	10,159	3,792
Mountain Pass	0	23,479	23,150	118,089	108	0	5,420	371
Owens Valley	0	35,452	69	14,764	92	51,665	3,335	65
Palm Springs	1,210	9,801	11,182	42,434	133	28	2,422	148
Pisgah	0	875	153	14,202	50	0	0	5
Riverside East	6,770	46,792	22,265	137,212	107	0	0	426
Round Mountain-A	0	9,363	7,684	43,929	74	0	0	1
Round Mountain-B	96	9,078	754	9,942	82	4,371	0	0
San Bernardino - Baker	0	27,808	15,855	107,660	56	16,802	31	17
San Bernardino - Lucerne	1,096	95,717	25,083	122,518	201	15,984	252	650
San Diego North Central	1,490	19,129	10,498	54,304	169	3,105	9,058	40
San Diego South	67	7,255	3,757	38,021	129	8,349	96	9
Santa Barbara	738	7,129	5,121	24,074	119	7,965	0	9,947
Solano	0	6,654	137	3,783	120	6,280	30,012	5,502
Tehachapi	13,520	103,466	35,819	35,819	143	44,810	18,948	690
Twentynine Palms	0	16,519	39	13,729	66	5,692	0	113
Victorville	254	29,341	28,756	67,335	66	2,560	463	1,120
Westlands	34,784	4,791	0	0	77	7,987	0	3,637

Sources: RETI Phase 2B, May 2010 and supporting spreadsheets (Black & Veatch), except for “Mechanically Disturbed” and “EPA Tracked Degraded,” as described in text.

3.4 Relative Ranking Results

Table 3 shows how each of the environmental criteria occur over the total CREZ area using the formula established in this white paper. This shows the environmental concern per unit of total CREZ area.

Table 3. Environmental Concern per CREZ acre

CREZ Name	ROW Transmission (ac/CREZ ac)	Yellow & Black Area (ac/CREZ ac)	Buffer Yellow & Black Area (ac/CREZ ac)	Signif. Species (# species/CREZ ac)	Wildlife Corridors (meters/CREZ ac)	Important Bird Area (ac/CREZ ac)	EPA Tracked Degraded (ac/CREZ ac)
Barstow	0.43	0.56	1.29	0.0007	0.17	0.038	1.00
Carrizo North	0.78	0.08	0.38	0.0024	0.08	0.000	1.00
Carrizo South	0.59	0.00	0.10	0.0023	0.17	0.142	1.00
Cuyama	0.64	0.02	0.98	0.0106	0.00	0.000	1.00
Fairmont	0.49	0.00	0.31	0.0014	0.11	0.094	0.99
Imperial East	0.40	0.17	0.90	0.0017	0.07	0.011	1.00
Imperial North-A	0.97	0.32	1.10	0.0022	0.15	0.605	1.00
Imperial North-B	0.65	0.22	1.07	0.0019	0.06	0.376	0.99
Imperial South	0.63	0.17	0.83	0.0014	0.17	0.399	1.00
Inyokern	0.42	0.48	1.24	0.0011	0.07	0.000	1.00
Iron Mountain	0.56	0.05	0.33	0.0005	0.00	0.000	1.00
Kramer	0.54	0.48	1.46	0.0005	0.13	0.063	0.76
Lassen North	0.45	0.01	0.20	0.0006	0.04	0.000	1.00
Lassen South	0.38	0.16	2.69	0.0035	0.58	0.314	0.88
Mountain Pass	0.30	0.29	1.50	0.0014	0.00	0.069	1.00
Owens Valley	0.53	0.00	0.22	0.0014	0.77	0.050	1.00
Palm Springs	0.57	0.65	2.47	0.0077	0.00	0.141	0.99
Pisgah	0.07	0.01	1.15	0.0040	0.00	0.000	1.00
Riverside East	0.26	0.12	0.75	0.0006	0.00	0.000	1.00
Round Mountain-A	1.00	0.82	4.69	0.0079	0.00	0.000	1.00
Round Mountain-B	0.47	0.04	0.52	0.0043	0.23	0.000	1.00
San Bernardino - Baker	0.41	0.23	1.59	0.0008	0.25	0.000	1.00
San Bernardino - Lucerne	0.57	0.15	0.73	0.0012	0.10	0.002	1.00
San Diego North Central	0.51	0.28	1.44	0.0045	0.08	0.241	1.00
San Diego South	0.23	0.12	1.19	0.0041	0.26	0.003	1.00
Santa Barbara	0.19	0.14	0.64	0.0032	0.21	0.000	0.73
Solano	0.19	0.00	0.11	0.0035	0.18	0.864	0.84
Tehachapi	0.33	0.11	0.11	0.0005	0.14	0.060	1.00
Twentynine Palms	0.46	0.00	0.38	0.0018	0.16	0.000	1.00
Victorville	0.33	0.32	0.76	0.0007	0.03	0.005	0.99
Westlands	0.14	0.00	0.00	0.0022	0.23	0.000	0.90

Table 4 shows the relative ranking according to the seven criteria used in this white paper. These ranking results differ substantially from those of the RETI process due this paper's use of the RETI data on environmental indicators divided by the CREZ area, rather than the presumed energy output of the CREZ (as explained in Section 1.2).

Table 4. Environmental Criteria and Ranking Results

CREZ Name	ROW Transmission	Yellow & Black Area	Buffer Yellow & Black Area	Signif. Species	Wildlife Corridors	Important Bird Area	EPA Tracked Degraded	Total Rankings (per CREZ ac)
Barstow	4.3	6.9	2.8	0.7	2.2	0.4	10.0	27.2
Carrizo North	7.8	1.0	0.8	2.3	1.0	0.0	10.0	22.9
Carrizo South	5.9	0.0	0.2	2.2	2.2	1.6	10.0	22.2
Cuyama	6.4	0.2	2.1	10.0	0.0	0.0	10.0	28.6
Fairmont	4.9	0.0	0.7	1.3	1.4	1.1	9.9	19.3
Imperial East	4.0	2.1	1.9	1.6	0.9	0.1	10.0	20.7
Imperial North-A	9.7	3.9	2.3	2.1	2.0	7.0	10.0	37.0
Imperial North-B	6.5	2.7	2.3	1.8	0.8	4.4	9.9	28.3
Imperial South	6.3	2.1	1.8	1.4	2.2	4.6	10.0	28.3
Inyokern	4.2	5.9	2.6	1.1	1.0	0.0	10.0	24.7
Iron Mountain	5.6	0.6	0.7	0.5	0.0	0.0	10.0	17.5
Kramer	5.4	5.9	3.1	0.5	1.7	0.7	7.6	24.9
Lassen North	4.5	0.1	0.4	0.6	0.6	0.0	10.0	16.2
Lassen South	3.8	1.9	5.7	3.3	7.6	3.6	8.8	34.8
Mountain Pass	3.0	3.6	3.2	1.3	0.0	0.8	10.0	21.8
Owens Valley	5.3	0.0	0.5	1.3	10.0	0.6	10.0	27.6
Palm Springs	5.7	7.9	5.3	7.3	0.0	1.6	9.9	37.8
Pisgah	0.7	0.2	2.4	3.8	0.0	0.0	10.0	17.1
Riverside East	2.6	1.5	1.6	0.6	0.0	0.0	10.0	16.2
Round Mountain-A	10.0	10.0	10.0	7.5	0.0	0.0	10.0	47.5
Round Mountain-B	4.7	0.5	1.1	4.0	3.0	0.0	10.0	23.3
San Bernardino - Baker	4.1	2.9	3.4	0.8	3.2	0.0	10.0	24.4
San Bernardino - Lucerne	5.7	1.8	1.6	1.1	1.2	0.0	10.0	21.4
San Diego North Central	5.1	3.4	3.1	4.3	1.1	2.8	10.0	29.7
San Diego South	2.3	1.4	2.5	3.8	3.4	0.0	10.0	23.5
Santa Barbara	1.9	1.7	1.4	3.0	2.8	0.0	7.3	18.1
Solano	1.9	0.0	0.2	3.3	2.4	10.0	8.4	26.2
Tehachapi	3.3	1.4	0.2	0.4	1.8	0.7	10.0	17.8
Twentynine Palms	4.6	0.0	0.8	1.7	2.1	0.0	10.0	19.1
Victorville	3.3	3.9	1.6	0.7	0.4	0.1	9.9	19.9
Westlands	1.4	0.0	0.0	2.1	2.9	0.0	9.0	15.3

3.5 Scoring Out of State Resources

Out of state resources that are adjacent to the California border and have similar environmental characteristics as their neighboring CREZs were given a score that reflects the average score of the neighboring California CREZs. This groups the out of state resources with those that would have similar ecology as neighboring California.

For instance, the Baja California CREZ falls within the La Rumorosa mountain chain which is an extension of the Peninsular Ranges of eastern San Diego. As such it has a similar habitat and similar special status species as one would find in eastern San Diego. Efforts such as the *Las Californias Binational Conservation Initiative* recognize the shared landscape between these two border regions and the many shared resources. Likewise, the CREZs located in the Sonoran Desert of eastern Imperial County share numerous ecological characteristics with the adjacent Sonoran Desert in western Arizona. For these reasons, the Baja California, Arizona, and Nevada zones were given the average of the neighboring California CREZ scores.

Oregon and other out of state renewable resources were given a median environmental score reflecting the median of all CREZs. This was done in an attempt to retain a relatively neutral ranking for renewable resources outside California.

4. Applying the Environmental Criteria to Technologies

This section outlines our approach for considering how the environmental criteria apply to each major given renewable technology. Because the environmental ranking of each CREZ is given here per acre of the total area of the zone, the area needed by each renewable technology must be considered before completing the score. Technologies with greater land use and "undisturbed area needs" per unit of energy production result in higher (worse) scores, where lower scores indicate less environmental concern.

4.1 Indentifying Area Needs by Technology

The RETI process provides the availability of energy production for biomass/biogas, wind, solar, and geothermal technologies for each CREZ as well as the expected energy development footprints for each of these resources except biomass/biogas. Footprints vary by geographic region, energy output, and the relative area needs of each technology.

Table 5 shows the development footprints expected by RETI within each CREZ and the area needs, which are simply the footprint divided by energy output expected by RETI for each technology and CREZ (in Table 1).

Table 5. RETI Phase 2B Development Footprints and Area Needs by Technology

CREZ Name	Total Annual Energy (GWh/yr)	Wind (ac)	Solar (ac)	Geothermal (ac)	Wind (ac per GWh/year)	Solar (ac per GWh/year)	Geothermal (ac per GWh/year)	Undisturbed Land (ac/CREZ ac)
Barstow	5,362	49,930	8,960	0	21.13	2.99	---	0.99
Carrizo North	3,053	0	10,240	0	---	3.35	---	0.77
Carrizo South	5,823	0	19,200	0	---	3.30	---	1.00
Cuyama	801	0	2,560	0	---	3.19	---	1.00
Fairmont	7,000	32,365	12,800	0	16.25	3.17	---	0.91
Imperial East	3,416	11,852	9,600	0	59.26	2.98	---	1.00
Imperial North-A	10,095	0	0	1,370	---	---	0.14	0.55
Imperial North-B	3,965	0	11,520	0	---	3.07	---	0.76
Imperial South	8,197	2,710	22,848	64	23.90	3.09	0.15	0.70
Inyokern	5,589	22,936	13,728	0	33.85	2.80	---	0.99
Iron Mountain	10,288	6,089	35,840	0	42.47	3.53	---	1.00
Kramer	14,784	16,545	39,584	24	36.95	2.79	0.15	1.00
Lassen North	3,595	100,968	0	0	28.09	---	---	1.00
Lassen South	1,051	19,954	0	0	18.99	---	---	1.00
Mountain Pass	2,111	44,295	4,992	0	99.64	2.99	---	1.00
Owens Valley	10,651	0	32,000	0	---	3.00	---	1.00
Palm Springs	1,047	7,376	0	0	7.05	---	---	0.93
Pisgah	4,706	0	11,520	0	---	2.45	---	1.00
Riverside East	22,525	0	67,520	0	---	3.00	---	0.96
Round Mountain-A	2,557	0	0	384	---	---	0.15	1.00
Round Mountain-B	339	10,125	0	0	29.87	---	---	1.00
San Bernardino - Baker	7,064	0	23,488	0	---	3.33	---	1.00
San Bernardino - Lucerne	5,656	47,313	14,976	0	29.84	4.37	---	0.99
San Diego North Central	502	18,631	0	0	37.13	---	---	0.96
San Diego South	1,829	24,607	0	0	13.45	---	---	1.00
Santa Barbara	1,121	30,285	0	0	27.01	---	---	0.98
Solano	2,721	27,990	0	0	10.29	---	---	1.00
Tehachapi	25,432	168,513	46,048	0	18.57	2.86	---	0.96
Twentynine Palms	3,959	0	11,552	0	---	2.92	---	1.00
Victorville	3,899	51,463	7,680	0	44.31	2.81	---	1.00
Westlands	8,317	0	32,000	0	---	3.85	---	0.02
Median Footprint per Output	---	---	---	---	28.09	3.00	0.15	
Lowest Footprint per Output	---	---	---	---	7.05	2.45	0.14	

Source: RETI Phase 2B, May 2010 and supporting spreadsheets (Black & Veatch); wind area is shown without adjusting by 0.035. Development footprint divided by energy output (Table 1) equals the area need (ac per GWh/yr).

4.2 Discussion of Area Needs by Technology

Biomass and Biogas. The primary environmental concern for most biomass and biogas generation is air quality, because biomass and biogas projects do not require large land resources as compared to other renewable technologies. However, biomass and biogas projects can serve a role in air quality management if the fuel would otherwise be burned in an uncontrolled manner. The RETI Phase 1B report noted: "*Environmental concerns associated with biomass projects are primarily associated with production, collection and transportation of fuels for which no acceptable data exist. Biomass CREZs are therefore not included in the EWG ranking process.*" For the present environmental scores, a single factor of 0.15 acres per GWh/yr is assumed (equal to geothermal median area need that is from RETI Phase 1B), although this is only an approximation for ranking purposes because the area needs for biomass and biogas vary widely depending on the fuel type and the distance fuel must travel to the biomass or biogas power plant.

Geothermal. Geothermal generation has the lowest footprint per output and results in relatively low area needs due to the high capacity factor. Environmental concerns can be avoided by strategic placement of geothermal project elements like wells and piping. RETI Phase 1B specifies one acre per megawatt of capacity (or a median of 0.15 acres per GWh/yr).

Solar Photovoltaic (PV) and Solar Thermal. RETI data merges the energy development footprint for these two technologies. As a result, the methodology in this white paper does not distinguish the differences or comparative advantages of these two technologies for environmental scoring. Relatively high levels of environmental concern occur for utility-scale solar PV development, especially due to large project footprints and likely impacts to significant species and habitat corridors. Solar PV projects are generally more configurable than solar thermal projects, meaning that significant species and habitat corridors may be less of a concern for PV than they are for solar thermal. However, utility-scale solar thermal projects generally have an advantage with higher energy conversion efficiency of the solar resource, which compensates for the comparative inflexibility in siting that this technology seems to have.

Wind. Wind generation has the highest footprint per output in terms of project lease area. RETI data presents the development footprint for wind in terms of both expected lease area for project development (shown here in Table 5) and the development footprint or fraction of ground disturbance caused by turbines and roads (given as 3.5% of the lease area, presented in RETI Phase 1B and Phase 2B). Adjusted for expected ground disturbance, wind has a median area need of about 28 acres per GWh/yr times 3.5%, or 1 acre per GWh/yr. The primary environmental concern for developing wind resources is typically avian mortality.

Photovoltaic Distributed Generation (DG). Rural solar photovoltaic (PV) that would occur at the scale of distributed generation (DG) (on the order of 20 MW or less) has similar environmental concerns as utility-scale solar PV. Because there is a greater flexibility and ability to avoid major wildlife corridors when locating a rural DG PV project compared to a larger utility scale project, the environmental criterion for wildlife corridors is not included in this score.

Urban PV Distributed Generation. Urban solar PV developed on a DG scale would be likely to avoid most of the environmental concerns discussed in this report. Rooftop PV could essentially avoid all of the environmental concerns identified here. To reflect this and to ensure priority in selecting these resources, where available, urban PV DG are assigned scores matching the lowest score of any resource in the CREZ.

4.3 Weighting "Area Needs" by Percentage of Undisturbed Land

In order to reflect the differences in Undisturbed vs. Mechanically Disturbed land between zone, the area needs above were weighted by the percentage of Undisturbed Land in each zone (shown in the rightmost column of Table 5, above). This weighting results in favorable scores (lower "area needs") for resource development that may occur where Mechanically Disturbed Land is abundant. Resources would be penalized for higher area needs if in a zone with a high fraction of undisturbed land.

5. Transmission Scores

Each RETI CREZ was assigned a transmission score for both minor upgrades (where available) and new transmission from that CREZ to a load center. Scores were assigned based on the distance from the CREZ to a major delivery point in California, and weighted by the type of transmission. The scores and weightings used are shown in the table below. Minor upgrades were given a much smaller weight than new transmission because, although associated in the scoring methodology with the mileage between the relevant CREZ and the major load center, the minor upgrades were in some cases only additions to a substation that would not result in any expansion of the substation footprint. The nature of the minor upgrades is detailed in the CAISO's assessment, in Appendix D1, above.

Table 6. Transmission Line Scoring

Length of Line	Minor Upgrades	New Transmission
<25 miles	1.0	4.0
25 – 50 miles	2.0	8.0
50 – 100 miles	3.0	12.0
100 - 200 miles	4.0	16.0
>200 miles	5.0	20.0

6. Results

6.1 Environmental Rankings and Scores

Each RETI CREZ was analyzed according to the seven environmental criteria (Section 3). The results for each area were then multiplied by the undisturbed area needs of each technology (Section 4) to arrive at an individual score for each technology in each CREZ, as shown in Table 7.

Table 7. Environmental Scores by Technology and CREZ

CREZ Name	Biomass / Biogas	Geothermal	Large Scale Solar PV and Solar Thermal	Wind	Minor Upgrades	New Transmission
Barstow	4.1	4.1	80.9	20.0	2.0	8.0
Carrizo North	1.5	1.5	33.4	9.8	3.0	12.0
Carrizo South	3.3	3.3	73.1	21.8	4.0	16.0
Cuyama	4.3	4.3	91.5	28.2	4.0	16.0
Fairmont	2.6	2.6	55.8	10.0	1.0	4.0
Imperial East	3.1	3.1	61.7	42.9	3.0	12.0
Imperial North-A	3.1	3.1	61.4	20.1	3.0	12.0
Imperial North-B	3.3	3.3	66.4	21.3	3.0	12.0
Imperial South	3.0	3.0	61.3	16.6	3.0	12.0
Inyokern	3.7	3.7	68.2	28.9	3.0	12.0
Iron Mountain	2.6	2.6	61.8	26.0	3.0	12.0
Kramer	3.7	3.7	69.4	32.2	2.0	8.0
Lassen North	2.4	2.4	48.8	16.0	4.0	16.0
Lassen South	5.2	5.2	104.5	23.1	4.0	16.0
Mountain Pass	3.3	3.3	65.3	76.0	3.0	12.0
Owens Valley	4.1	4.1	82.9	27.1	3.0	12.0
Palm Springs	5.3	5.3	105.6	8.7	2.0	8.0
Pisgah	2.6	2.6	41.9	16.8	3.0	12.0
Riverside East	2.3	2.3	46.8	15.3	3.0	12.0
Round Mountain-A	7.1	7.1	142.6	46.7	3.0	12.0
Round Mountain-B	3.5	3.5	69.6	24.2	3.0	12.0
San Bernardino - Baker	3.7	3.7	81.0	24.0	3.0	12.0
San Bernardino - Lucerne	3.2	3.2	93.1	22.2	2.0	8.0
San Diego North Central	4.3	4.3	85.6	37.0	1.0	4.0
San Diego South	3.5	3.5	70.6	11.1	4.0	16.0
Santa Barbara	2.7	2.7	53.2	16.7	4.0	16.0
Solano	3.9	3.9	78.8	9.4	1.0	4.0
Tehachapi	2.6	2.6	48.8	11.1	2.0	8.0
Twentynine Palms	2.9	2.9	55.8	18.8	3.0	12.0
Victorville	3.0	3.0	55.6	30.7	1.0	4.0
Westlands	0.0	0.0	1.0	0.3	3.0	12.0
Arizona	2.7	2.7	56.8	28.1	5.0	20.0
Nevada	3.6	3.6	72.9	38.4	5.0	20.0
Northwest	3.3	3.3	66.4	21.3	5.0	20.0
Baja	3.9	3.9	78.1	24.0	5.0	20.0
Out-of-State (Other)	3.3	3.3	66.4	21.3	5.0	20.0
NonCREZ	3.3	3.3	66.4	21.3		

The area need (acres per GWh/yr, Table 5) multiplied by the percentage of Undisturbed land (Table 5) multiplied by the ranking results (Table 4) equals the environmental score.

6.2 Environmental Scores for Small Scale PV

Small scale PV was separated into three categories for environmental scoring: Distributed Solar, Remote DG (Brownfield), and Remote DG (Greenfield). Distributed Solar was assumed to be easy to connect and sited on rooftops or mechanically disturbed land, and was assigned an environmental score of 0. Remote DG (Brownfield) was assumed to be hard to connect (requiring gen-tie construction) and sited on mechanically disturbed land. It was assigned an environmental score of 2.0 to reflect an average 45-mile gen-tie rated as a minor upgrade. Remote DG (Greenfield) was assumed to be hard to connect (requiring gen-tie construction) and sited on undisturbed land with the average solar acres/GWh score across all zones (3.1). This resulted in an environmental score of 75.8 with a transmission adder of 2.0 (for a 45-mile gen-tie) for a total of 77.8.

Solar Resource	Environmental Score
Distributed Solar	0.0
Remote DG (Brownfield)	2.0
Remote DG (Greenfield)	77.8

6.3 Environmental Supply Curve

The "environmental supply curve" shows the cumulative annual energy in gigawatt-hours per year (GWh/yr) that could be provided by renewable projects in relation to the environmental scores.

The environmental scores from this white paper (Table 6) can be assigned to each of the projects in the RPS calculator that is not reserved for local use, representing ~900,000 GWh/yr potential generation, and the results are shown in Figure 1.

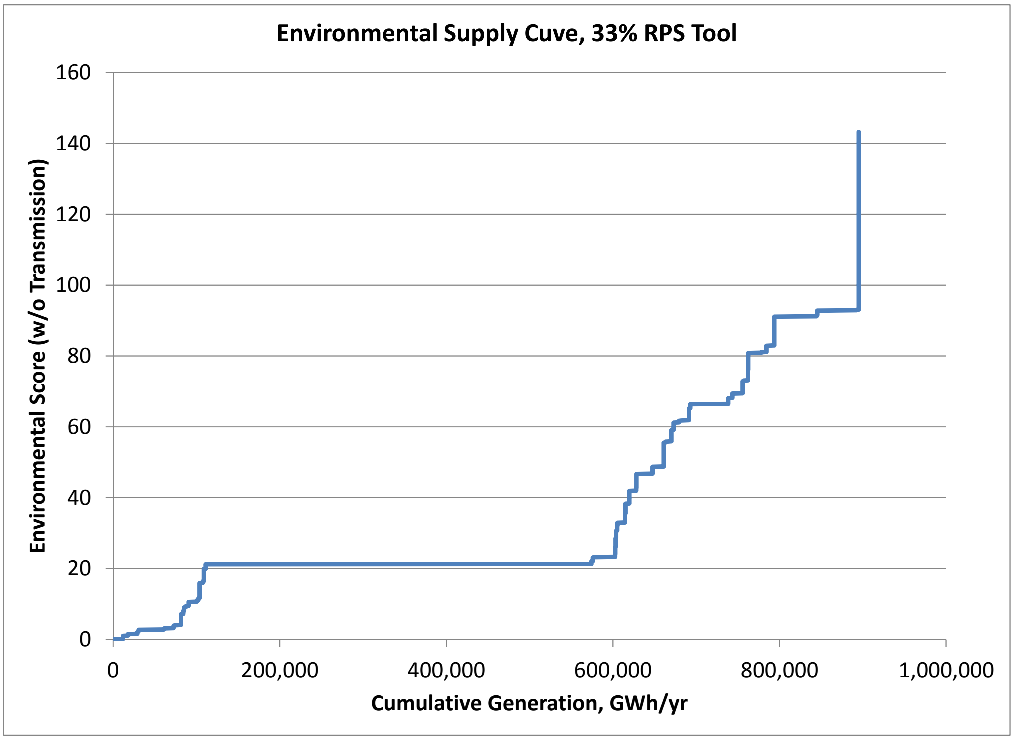

Figure 1. Environmental Scoring Results for 33% RPS Tool Projects

References

Renewable Energy Transmission Initiative (RETI). 2008. RETI Phase 1B – Environmental Assessment of Competitive Renewable Energy Zones. Prepared by the RETI Environmental Working Group. Final Report. December.

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Appendix F

Timing Assessment

F1: Generation timing assumptions

F2: Transmission timing assumptions

F1: Generation Timing Assumptions

The table below summarizes the timing assumptions used to develop the summary development timelines presented in Section II.7 of this report.

Technology	Size	Permitting Jurisdiction	Development Duration (months)			
			Preparation	Permitting / Environmental Review	Construction	Total
Biogas						
	<50 MW	City/County/Federal	12	12	10	**34**
	≥ 50 MW	State/Federal	12	24	12	**48**
Biomass						
	<50 MW	City/County/Federal	12	14	24	**50**
	≥ 50 MW	State/Federal	18	24	26	**68**
Geothermal						
	<50 MW	City/County/Federal	12	14	20	**46**
	≥ 50 MW	State/Federal	18	24	28	**70**
Small Hydro						
		City/County/Federal	12	14	20	**46**
Solar Thermal						
	<50 MW	City/County/Federal	12	14	24	**50**
	≥ 50 MW	State/Federal	18	24	32	**74**
Solar PV - ground mounted, ≥ 20 MW						
	20-50 MW	City/County/Federal	12	10	12	**34**
	≥ 50 MW	City/County/Federal	18	18	18	**54**
Wind						
	<50 MW	City/County/Federal	12	10	12	**34**
	≥ 50 MW	City/County/Federal	18	18	18	**54**

F2: Transmission Timing Assumptions

As described in Section II.7, each transmission "bundle" from each CREZ was assigned to one of the following transmission schedules:

Transmission Schedule Type	**Transmission Planning by CAISO/ POU/ WECC** (months)	**Project Description Prep by Utility**	**CEQA/ NEPA Review by CPUC/POU / Feds**	**Final Review and Approval by CPUC/ POU/Feds**	**Final Design and Construction by Utilities**	**Total**
Existing / Distributed	0	0	0	0	0	**0**
Typical	18	12	24	6	24	**84**
Typical - Short	12	12	12	3	18	**57**
Typical - Long	24	18	24	6	30	**102**
Long-Distance	24	18	24	6	30	**102**
Tehachapi	0	0	0	6	48	**54**
Sunrise	0	0	0	0	24	**24**
Devers - CO River	0	0	0	0	30	**30**

In general, zones were assigned to schedules as follows:

CREZ and Transmission Increment	Transmission Schedule Type	Development Start Date
Non-CREZ	Existing/Distributed	6/1/2010
CREZ – accommodated by existing system	Existing/Distributed	"
CREZ – accommodated by minor upgrades	Typical-Short	"
CREZ – 230 kV line, in-state	Typical-Short	"
CREZ – 500 kV line, in-state	Typical or Typical-Long, depending on location	6/1/2010 for up to 4500 MW of capacity; every 2 years thereafter
Out-of-state Resource	Long-Distance	"

The table below lists CREZ transmission bundles more specifically, by the size of the incremental bundle, the assumed transmission schedule, and the assumed development start time.

For the modeling effort, E3 assumed that each zone was available at the beginning of the year following whatever date resulted from the combination of the assigned start date and transmission schedule.

Transmission Zone	Line Capacity (MW)	Schedule Type	Start Date
Existing		Existing	1-Jun-2010
Alberta		Long-Distance	1-Jun-2010
Arizona-Southern Nevada			
Arizona-Southern Nevada - 1	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 2	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 3	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 4	1500	Long-Distance	1-Jun-2010
Baja			
Baja - 1	1500	Typical - Short	1-Jun-2009
Baja - 2	1500	Typical - Short	1-Jun-2010
Baja - 3	1500	Typical - Short	1-Jun-2010
Baja - 4	1500	Typical - Short	1-Jun-2010
Barstow			
Barstow - 1	1500	Typical	1-Jun-2010
Barstow - 2	1500	Typical	1-Jun-2010
British Columbia			
British Columbia - 1	3000	Long-Distance	1-Jun-2009
British Columbia - 2	3000	Long-Distance	1-Jun-2012
British Columbia - 3	3000	Long-Distance	1-Jun-2014
British Columbia - 4	3000	Long-Distance	1-Jun-2016
Carrizo North			
Carrizo North - 1	1500	Typical	1-Jun-2010
Carrizo South			
Carrizo South - existing/approved	300	Existing	1-Jun-2010

Carrizo South - minor new	600	Typical - Short	1-Jun-2009
Carrizo South - 1	1500	Typical	1-Jun-2010
Colorado			
Colorado - 1	3000	Long-Distance	1-Jun-2010
Colorado - 2	3000	Long-Distance	1-Jun-2012
Colorado - 3	3000	Long-Distance	1-Jun-2014
Colorado - 4	3000	Long-Distance	1-Jun-2016
Cuyama			
Cuyama - 1	500	Typical - Short	1-Jun-2010
Distributed Biogas		Distributed	1-Jun-2010
Distributed Biomass		Distributed	1-Jun-2010
Distributed CPUC Database		Distributed	1-Jun-2010
Distributed Geothermal		Distributed	1-Jun-2010
Distributed Solar		Distributed	1-Jun-2010
Distributed Wind		Distributed	1-Jun-2010
Fairmont			
Fairmont - 1	1500	Typical	1-Jun-2010
Fairmont - 2	1500	Typical	1-Jun-2010
Imperial East			
Imperial East - 1	1500	Typical	1-Jun-2010
Imperial North			
Imperial North - 1	1500	Typical	1-Jun-2010
Imperial North - 2	1500	Typical	1-Jun-2010
Imperial South			
Imperial South - minor new	1125	Sunrise	1-Jun-2010
Imperial South - 1	1500	Typical	1-Jun-2010
Imperial South - 2	1500	Typical	1-Jun-2010
Inyokern			
Inyokern - 1	1500	Typical - Long	1-Jun-2010
Inyokern - 2	1500	Typical - Long	1-Jun-2010
Iron Mountain			
Iron Mountain - 1	1500	Typical - Long	1-Jun-2010
Iron Mountain - 2	1500	Typical - Long	1-Jun-2010
Iron Mountain - 3	1500	Typical - Long	1-Jun-2010
Kramer			
Kramer - minor new	62	Existing	1-Jun-2010
Kramer - 1	1500	Typical - Long	1-Jun-2010
Kramer - 2	1500	Typical - Long	1-Jun-2010
Kramer - 3	1500	Typical - Long	1-Jun-2010
Kramer - 4	1500	Typical - Long	1-Jun-2012
Lassen North			
Lassen North - 1	1500	Typical - Long	1-Jun-2010
Lassen South			
Lassen South - 1	1500	Typical - Long	1-Jun-2010
Montana			
Montana - 1	3000	Long-Distance	1-Jun-2010
Montana - 2	3000	Long-Distance	1-Jun-2012
Montana - 3	3000	Long-Distance	1-Jun-2014
Montana - 4	3000	Long-Distance	1-Jun-2016
Mountain Pass			
Mountain Pass - 1	1500	Typical - Short	1-Jun-2010
Nevada N			
Nevada N - 1	500	Typical - Long	1-Jun-2010

Nevada N - 2	500	Typical - Long	1-Jun-2010
Nevada N - 3	500	Typical - Long	1-Jun-2010
Nevada N - 4	500	Typical - Long	1-Jun-2010
Nevada C			
Nevada C - 1	1500	Typical - Long	1-Jun-2010
Nevada C - 2	1500	Typical - Long	1-Jun-2010
Nevada C - 3	1500	Typical - Long	1-Jun-2010
Nevada C - 4	1500	Typical - Long	1-Jun-2012
New Mexico			
New Mexico - 1	3000	Long-Distance	1-Jun-2010
New Mexico - 2	3000	Long-Distance	1-Jun-2012
New Mexico - 3	3000	Long-Distance	1-Jun-2014
New Mexico - 4	3000	Long-Distance	1-Jun-2016
NonCREZ		Distributed	1-Jun-2010
Northwest			
Northwest - 1	1500	Long-Distance	1-Jun-2010
Northwest - 2	1500	Long-Distance	1-Jun-2010
Northwest - 3	1500	Long-Distance	1-Jun-2010
Northwest - 4	1500	Long-Distance	1-Jun-2012
Owens Valley			
Owens Valley - 1	1500	Typical - Long	1-Jun-2010
Owens Valley - 2	1500	Typical - Long	1-Jun-2010
Owens Valley - 3	1500	Typical - Long	1-Jun-2010
Palm Springs			
Palm Springs - existing/approved	1000	Existing	1-Jun-2010
Pisgah			
Pisgah - minor new	275	Typical - Short	1-Jun-2010
Pisgah - 1	1500	Typical	1-Jun-2010
Pisgah - 2	1500	Typical	1-Jun-2010
Pisgah - 3	1500	Typical	1-Jun-2010
Remote DG		Distributed	1-Jun-2010
Reno Area/Dixie Valley			
Reno Area/Dixie Valley - 1		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 2		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 3		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 4		Typical - Long	1-Jun-2010
Riverside East			
Riverside East - existing/approved	1500	Devers - Colorado River	1-Jun-2010
Riverside East - 1	3000	Typical	1-Jun-2010
Riverside East - 2	3000	Typical	1-Jun-2012
Riverside East - 3	3000	Typical	1-Jun-2014
Round Mountain			
Round Mountain - existing/approved	100	Existing	1-Jun-2010
Round Mountain - 1	500	Typical - Short	1-Jun-2010
San Bernardino - Baker			
San Bernardino - Baker - 1	1500	Typical	1-Jun-2010
San Bernardino - Baker - 2	1500	Typical	1-Jun-2010
San Bernardino - Lucerne			
San Bernardino - Lucerne - existing/approved	261	Existing	1-Jun-2010
San Bernardino - Lucerne - 1	1500	Typical	1-Jun-2010
San Diego North Central			
San Diego North Central - 1	500	Typical - Short	1-Jun-2010
San Diego South			

San Diego South - existing/approved	400	Existing	1-Jun-2010
San Diego South - minor new	361	Typical - Short	1-Jun-2010
Santa Barbara			
Santa Barbara - 1	500	Typical - Short	1-Jun-2010
Solano			
Solano - minor new	300	Typical - Short	1-Jun-2010
Solano - 1	1000	Typical - Short	1-Jun-2010
Tehachapi			
Tehachapi - existing/approved	4500	Tehachapi	1-Jun-2010
Tehachapi - existing/approved	3400	Tehachapi 4-11	1-Jun-2010
Tehachapi - minor new	1325	Typical - Short	1-Jun-2010
Tehachapi - 1	3000	Typical	1-Jun-2012
Tehachapi - 2	3000	Typical	1-Jun-2014
Twentynine Palms			
Twentynine Palms - 1	1000	Typical	1-Jun-2010
Twentynine Palms - 2	1000	Typical	1-Jun-2010
Utah-Southern Idaho			
Utah-Southern Idaho - 1	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 2	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 3	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 4	1500	Long-Distance	1-Jun-2012
Victorville			
Victorville - 1	1500	Typical	1-Jun-2010
Westlands			
Westlands - minor new	800	Typical - Short	1-Jun-2010
Westlands - 1	1500	Typical	1-Jun-2010
Westlands - 2	1500	Typical	1-Jun-2010
Wyoming			
Wyoming - 1	3000	Long-Distance	1-Jun-2010
Wyoming - 2	3000	Long-Distance	1-Jun-2012
Wyoming - 3	3000	Long-Distance	1-Jun-2014
Wyoming - 4	3000	Long-Distance	1-Jun-2016