Report of the Independent Advisory Panel Regarding the Five California Utilities' Study of Integration of Renewable Energy into California's Electric System

"Investigating a Higher Renewables Portfolio Standard in California"

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Executive Summary

The four-member independent Advisory Panel (AP) provides this report (AP Report) on the new Renewables Portfolio Standard study (RPS Study) sponsored by the five largest electric utilities in California. These five utilities, which we refer to collectively as the California Utilities in this report, include Los Angeles Department of Water and Power (LADWP), Pacific Gas & Electric Company (PG&E), Sacramento Municipal Utility District (SMUD), San Diego Gas & Electric Company (SDG&E), and Southern California Edison (SCE).

The RPS Study, "Investigating a Higher Renewables Portfolio Standard in California," dated January 2014, was conducted by a study team led by consultants from Energy and Environmental Economics, Inc. (E3), with support by DNV KEMA[5] (KEMA) and ECCO International and with input from the California Utilities and the state's independent grid operator (the California ISO (CAISO)). The RPS Study explores operational, economic and environmental issues affecting the state's electric system that might arise if California were to increase its RPS to require that power sold in those utilities' service territories include 40 percent or 50 percent renewables by the year 2030.

This AP Report reflects a consensus view of the four members of our diverse panel. Our report comments on the study process, technical and non-technical issues related to the study design and

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[5] During the course of the study process, representatives from KEMA provided the AP (and representatives of the California Utilities and E3) with information about KEMA's analysis of distribution system issues associated with renewable generation behind the customer meter. The AP only saw KEMA's report ("Qualitative Investigation of Distribution System Technical Issues and Solutions") for the first time on August 23, 2013, and therefore refrains from commenting on it, except to say that such issues will be important to understand over time. Additionally, we note that conclusions about reliability drawn from this study should reflect that there was not enough time for KEMA to complete an ambitious effort to analyze specific operational reliability issues (including topics known as frequency regulation and inertia). We strongly encourage that these issues be the subject of further analysis.

analysis, and potential implications of the RPS Study's results, for policy makers' consideration, regarding renewable and electric-industry policy issues in the near term in California.[6] Our AP Report also describes the premises of our involvement in the process, and broader thoughts about important policy-relevant issues that spring from the results and from important questions not answered by this analysis.[7]

As a starting point, the RPS Study is a very useful, timely and informative piece of work which advances the state of knowledge about the potential implications for grid operations, cost and carbon emissions of an increase in California's RPS to achieve higher levels of renewable energy in the future. Starting with a 2030 base case that examines electric industry issues assuming the current RPS requirement of 33 percent renewables is met by 2020, the RPS Study explores a number of possible scenarios under which California might meet a 40-percent or 50-percent RPS target by 2030.

The RPS Study examines a number of critically important "what if" questions. The RPS Study tends to frame the discussion in terms of what "will" happen; we hope that readers will interpret all uses of the word "will" to reflect what "could" happen, taking into account all of the assumptions embedded in the study. The RPS Study provides more insights than true answers to these questions, because, like all forecasts, this one's results are shaped inherently by its assumptions about things that can and will change in as-yet unknown ways in the future. Our pointing out that the RPS Study provides more insights than answers is not meant to be criticism, but rather to set the context for what readers of the report should – and should not – take away from it.

Importantly, the RPS Study suggests three general conclusions related to adoption of a renewables portfolio standard at the 40-percent or 50-percent level:

- Maintaining electric reliability is technically achievable, assuming a substantial set of assumptions are realized concurrent with the expanded use of renewable resources, given what was studied.[8]
- Higher RPS requirements at the 50-percent level would likely additionally increase electricity rates in 2030 by a wide range, compared to the expected rates based roughly on current policies and plans: the estimated increases were from 9 percent to 23 percent, depending upon the scenario under base case assumptions. The range was 3 percent to 36 percent under different sensitivity analyses, depending upon scenarios that changed combinations of variables. These estimated rate increases in 2030 were above and beyond the already-higher rates assumed to occur by then in the base case (which are estimated to be 47-percent higher than today's rates).
- Although less thoroughly evaluated than the two conclusions above, carbon-dioxide (CO_2) emissions would be substantially reduced in all scenarios (with the cost per unit of reduction being significant in each scenario) owing to the substantial reduction in fossil fuel consumption in power plants.

[6] It is important to note that we believe we have had unfettered access to the E3 analysis throughout the process. We have had extensive access to the California Utilities' executives and technical teams as well as the Consultants. Tremendous effort has gone into responding to all of our many questions and comments. We found the assumptions and methodologies used in the study that we reviewed were plausible and justified, especially for a complex study of events 17 years in the future.

[7] Our report was written in the Fall of 2013, at the end of the study period and after the Study draft was completed in 2013.

[8] See Footnote 5.

These conclusions come with very important caveats. Operating such a system reliably would likely require use of a variety of new techniques and new technologies, some of which remain relatively untested, expensive, and complex, and others of which may be counter-intuitive to consumers based on what they're experiencing today. Additionally, it will likely raise new financial, economic, regulatory, and consumer-behavior issues compared to the ways that consumers, utilities, investors, independent power producers, providers of advanced energy technologies, and other actors now tend to participate in California's electric system. There are also a set of trade-offs (such as potential direct and indirect rate impacts to various consumer classes) that policymakers will need to confront. The conclusion about technical achievability to maintain reliability assumes the ability to successfully address these challenges.

A foundational basis of this study is that high reliance on renewable resources, especially solar, will lead to large amounts of over-generation that must be managed to avoid threatening reliability. The RPS Study's presumptive method to resolve this issue is through reliance on a strategy of increasingly down-dispatch of fossil generation and heavy curtailment of potentially available generation, including renewable generation. This is a practice that is understood and physically possible to implement today, but may be extremely difficult to employ at the levels assumed here given the likely political reaction. Hence, it is imperative that cost-effective alternative strategies be further developed, such as those considered in the alternative scenarios, that would reduce future reliance on curtailment.

We also note that the choices about which renewable technologies are deployed appear to make a significant difference in terms of reliability, the need for curtailment and cost implications. This study has a heavy reliance on the current market trend toward solar without storage capability, and scenarios reflecting such combinations would have higher costs and more curtailment.

The AP reviewed the following key assumptions that are important to the report's conclusions:

- *Cost and performance attributes of renewable energy technologies and other technologies (e.g., such as storage systems and demand-shifting technologies) as of the year 2030;*
- *The mix of renewable energy (and non-renewable resources) in the different scenarios*;
- *The outlook for natural gas prices, for CO_2 emission-allowance prices in California's market, and the mix of power plants still in place in 2030;*
- *The cost of capital used for evaluating investment costs and for discounting future dollars occurring in different time periods into current dollars in order to compare different scenarios;*
- *The manner in which the study treats electricity flows and trades between California's power system and other parts of the Western (or "West-wide") electric grid;*
- *Potential changes in public policy affecting the electric industry in California relative to those now reflected in current law and regulatory policy;*
- *Reliability requirements for the bulk power system, as well as the types of tools available to grid operators to balance the system and ensure it does not violate operational reliability issues; and*
- *Extensive reliance on economic curtailment of renewable resources to maintain reliability*.

The electric system modeled in the RPS Study involves scenarios with different quantities of solar technologies, wind generation, fossil generation, storage and load-shifting technologies. In these scenarios, individual sources of generation may experience less utilization than they have in the past. The cost per unit of electrical output may rise as a result. For example, fossil generating capacity is assumed to be needed for balancing and system reliability in the context of intermittent renewables with output that varies seasonally, across each day, and potentially on a second-to-second basis. These fossil power plants would thus need to be in place to perform balancing and to provide power, but they would have much-lower levels of utilization. This implies that thermal units of the future would need to function differently and be optimized for different parameters, and receive compensation commensurate with their value contribution driven by a different business model.

In addition, output at renewable energy facilities might need to be curtailed at times when there is more power being produced than the load (i.e., the level of customer demand from the grid), although this insight reflects assumptions built into the RPS Study's methodology, which did not attempt to produce a least-cost portfolio of investments (with respect to either renewable resources or renewable integration solutions). Grid operators will need to use a variety of tools to assure system reliability. Such actions will be needed not only at the high-voltage level (as now) but also at the distribution-system level in cases where many decentralized sources of power (e.g., rooftop panels) are assumed to exist and to introduce changed patterns of power injection and withdrawal all around the system.

The RPS Study provides insights into these tradeoffs and challenges. Understanding what the results mean requires recognition that there is great uncertainty about technology innovation and about how the system develops between now and 2030. The challenges and trade-offs of a 50-percent RPS are significantly greater and perhaps even different in kind than the 33-percent RPS requirement that now exists in law in California. The 50-percent RPS has greater challenges than a 40-percent RPS. And the mix of resources in the portfolio affects the character and intensity of operational challenges. Addressing them will require substantial new attention and thinking, and consideration of "no regrets" actions.

The panel identified the following issues for further investigation, monitoring or policy attention:

- *Currently planned efforts to enhance system flexibility/reliability are essential.*
- *Reliability risks are varied, and need to be understood and addressed holistically.*
- *Substantially new and only lightly tested technologies and policies will need to be adopted to integrate renewables while maintaining reliability.*
- *Maintaining reliability will require policies addressing generating asset utilization, and associated business model and utility ratemaking issues.*
- *The California footprint of the analysis needs to be expanded to a West-wide consideration.*
- *Supply-side issues will interact with energy efficiency programs, demand response and load shifting.*
- *The impact of high-penetration distributed generation on distribution system costs and reliability needs further investigation*
- *Sustainable natural gas deliverability issues may become more important over time.*
- *An electrical future with higher capital costs and lower variable costs needs to be better understood, in terms of implications for planning and rate making.*
- *Planning with respect to all of these various issues should accelerate now.*

Addressing such operational, regulatory and technology-development issues will be essential for a system that aims to increase its reliance on renewable energy while also maintaining an affordable, reliable and safe electric system. Our intention in focusing attention on this array of issues is not to say “wait on making new renewables targets until these other technical questions are answered.” Nor are we saying that there is no risk in proceeding. Rather, we think that *as California decides whether and, if so, how to increase significantly its RPS requirements, policy makers in California should also be as committed to being cognizant of and addressing these operational, regulatory-policy and business-model issues affecting the electric system as those policy makers are to accomplishing their renewable energy goals*.

We can’t expect to know everything today about 2030, but as more is learned about technology costs, system-control options, consumer behaviors, and so forth, the new lessons need to inform subsequent steps. Much more analysis is warranted along the way, and the RPS Study provides important insights for identifying additional analytic questions. We have attempted to provide a roadmap of what we need to learn more about and a list of some of the questions we find most important. Given the importance of storage, demand-shifting techniques, better monitoring and measurements, advanced analytics and two-way power flow electronics, for example, these should be at the top of the list for research and development support.

Interested readers who are seeking to divine a consensus AP view on whether to proceed with RPS expansion will be disappointed. We did not view that as our role and have avoided taking any position. Instead we have focused on the reasonableness and implications of assumptions and conclusions of this particular study, with a sprinkling of our lessons learned from participating in this exercise.

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I. Background: The Independent Advisory Panel and its Mandate

A. Overview

The Advisory Panel is composed of four members with extensive experience in renewable resources, electric markets and operations, and electric utility regulation and policy development at the federal, regional and state levels. The four members are:

- Dan Arvizu, Director and Chief Executive of the National Renewable Energy Laboratory (NREL) in Golden, Colorado.
- Severin Borenstein, Director of the University of California Energy Institute and Co-Director of the Energy Institute at the Haas School of Business, at the University of California, Berkeley.
- Susan Tierney, Managing Principal at Analysis Group, in Boston.
- Stephen Wright, General Manager Chelan County Public Utility District, retired Bonneville Power Administration.

Together, we have decades of relevant experience.[9] We represent diverse perspectives and skills, informed by deep knowledge of the theory and practice of electric markets, performance of electric systems, technology development, consumer behavior, and policy making.

B. The Mandate for the Advisory Panel

The California Utilities' original March 2013 Request for Proposals for the California RPS Study outlined their intention to establish a separate, independent advisory panel that would be "established from industry experts and academia to critique and provide feedback on the reasonableness of the policies and analyses developed by the successful bidder and The Utilities." That panel was established early in the process after the five California Utilities approached individual AP members to determine each person's interest in participating on a panel to be established as external advisors to the study group process. From the time those initial contacts began in March/April, 2013, the AP was actively engaged through the rest of the study period. The California Utilities compensated AP members[10] for their time and work over the six-month study period where such compensation was permitted by the employers of the individual

[9] Detailed bios for each of the four AP members are included in a final appendix to this Report.
[10] Compensation was to the AP member's employer for those not self-employed. No compensation was provided to Dr. Arvizu or NREL.

AP members. The work, including the drafting of our report, substantially concluded in last quarter of 2013.

The specific charge in the AP members' contract with the California Utilities reads as follows:

> *Advisor has been retained to provide advisory services to the Utilities regarding California RPS, and potential modifications or changes to the RPS requirements. Advisor is a member of the independent advisory panel, which the Utilities established from industry experts and academia to critique and provide feedback on the reasonableness of the policies and analyses developed by the Consultant selected to conduct the RPS study and the Utilities.*

Before starting their work, the AP members raised questions about the structure of the study and their role in it, including concerns about (a) having adequate access to information during the process to assure their ability to provide an independent judgment, (b) having sufficient involvement to be able to comment on (and potentially influence) the analysis during the process, and (c) ensuring that there would be no limitations on their ability to express an independent view during the process and after its completion, with the eventual ability to make their opinions public on an individual and/or group basis. Each of the members of the AP was satisfied with the California Utilities' commitment to engaging the AP during the analysis process and that their independence would not be compromised. At least one member of the AP also sought and received assurance from the California Utilities that AP members would eventually be able to provide policy recommendations, as appropriate, in public settings, based on the study results.

Prior to commencement of the Consultants' analysis, the AP received assurances from the California Utilities that their intention was to explore the implications for system operations and investment associated with alternative strategies for expanding California's Renewables Portfolio Standard to some target above the current 33-percent goal for 2020, and to develop unbiased estimates of the costs of such alternatives. The California Utilities also assured the AP prior to the study that the utilities would not attempt to exercise any editorial control over the AP's comments to the study's Consultants and the AP's eventual report on the study.

Each member of the AP also committed in the contract to keep all confidential information in confidence, including the fact of the RPS Study itself prior to its completion. The AP members respected the decision of the California Utilities to not release information about the study in advance of its completion to assure adequate time to prepare a thorough and thoughtful analysis.

The AP members expressed concerns, however, about whether they could reasonably be expected to identify and consider every potential issue that might arise with respect to the study assumptions and conclusions without external input or communications with other parties during the course of the study. Hence, with the AP's encouragement, the California Utilities agreed to solicit and consider public comment on the study and the AP report after their completion.

C. The Advisory Panel's Role in the Study Process

Starting with the first in-person meeting of the California Utilities, the Consultants and the AP in late April 2013, the AP members were provided with information about the study's methods, data and assumptions, and had unrestricted ability to ask questions, make comments, and raise concerns about any and all issues of interest or concern to the AP members individually and as a group. The AP met with the California Utilities and the Consultants on numerous occasions between late April and August 2013, participated in many conference calls and other communications. As individuals and as a group, the AP members actively reviewed and commented directly to the Consultants and the California Utilities throughout.

Specific AP involvement included:

- Participation in discussions relating to the initial study design with the Consultant and the California Utilities, and with the opportunity to comment and provide unfettered input.
- Raising several topics of concern regarding methodology, data and assumptions. The AP was included in discussions on the rationale, potential constraints, and other factors that have driven the Consultants' choice of methods and assumptions.
- Developing a set of points for discussion and clarification to be addressed as the study progressed. The study team showed openness and receptivity to address the issues raised in the AP input.
- Consultation on what assumptions to use in the future (i.e., 2030) regarding certain regulatory policies (e.g., net energy metering, retail rate design), and technology cost and performance characteristics (e.g., for storage, demand-shifting, wind and renewables technology). The AP members had extensive technical discussions and questions/answers with Consultants on these and related topics.
- Drafting this report. The AP members have drafted this Report as a collaborative effort and on their own behalf. It reflects their views, and not the views of any of their employer organizations or any other parties. Before finalizing this report, the AP shared drafts of it with the California Utilities and the Consultants, and provided them with an opportunity to comment on it. The AP alone, however, has made the final decisions on all topics, positions and statements expressed in this review.

Our report is organized as follows: Section II summarizes our comments on the overall study process and on key analytic and technical issues. We aim to provide sufficient grounding in our reactions to the study approach and on the Consultants' choice of assumptions and methods so as to help readers of our report understand the context of our subsequent discussion related to the more policy-relevant implications of the study presented in Section III. We provide much more detailed and specific comments in the Technical Appendix with respect to our review of technical issues in the study approach, assumptions and data. Our bios are in a final appendix.

II. Summary Comments on the Overall Study Process and Key Analytic Issues in the RPS Study

A. Overview

This ambitious study by the California Utilities and the Consultants significantly advances our understanding of some of the alternatives available for and implications of moving California towards a greater reliance on renewable energy. The RPS Study focuses narrowly on the costs and benefits of different approaches to increasing the share of California electricity coming from renewable generation from 33 percent (the current goal for 2020 and thereafter) to 40 percent or 50 percent by 2030.

By design, however, the RPS Study does not address a number of larger questions in California energy policy, including:

- What are the ultimate environmental, economic and technological goals of a higher RPS?
- Is raising the RPS the most effective way to meet those goals?
- What role should an increased RPS play in meeting those goals versus changes in some combination of other electricity policies (such as use of other low-carbon sources or reduced consumption), transportation fuels or policy, or R&D policy.

The AP understands that these questions are outside the scope of the study, but believes it is important to view the results of this study in the larger context.

The RPS Study does not find any technological or technical barriers to expanding the RPS to a 40-percent or 50-percent level. Its results do suggest that the expansion is likely to increase the total cost of generating and delivering the electricity Californians consume in 2030, relative to the estimated costs of a system with a 33-percent RPS requirement. The range of cost estimates is large, however, and reflects the tremendous uncertainty that remains in the costs of renewable generation, the cost of conventional fossil fuel alternatives, and the adjustments that will be required in management of generation, transmission and distribution.

While to some it may be disappointing that the RPS Study does not come to more definitive conclusions on the costs of alternative strategies for RPS expansion by 2030, we think that it would be unrealistic to expect more from a study done in 2013, even if the study had not been carried out in the compressed timeframe in which this one was prepared. Rather, the AP views this RPS Study as providing valuable insights on the challenges that expansion of the RPS is likely to bring, and pointing to some ways to address those challenges. The RPS Study helps to clarify the state of technology, costs and knowledge today, while acknowledging the considerable range of uncertainty in how these critical factors will evolve over the coming decades.

In light of that uncertainty, the AP believes that the path to RPS expansion will require frequent attention to learning by doing and to re-evaluation as technologies evolve and we learn more about the barriers to integrating higher levels of non-dispatchable resources. Should California decide to expand the RPS, we think that policy makers must be as committed to overcoming the technical and institutional barriers raised by increased renewables integration as they are to RPS expansion itself.

From the RPS Study and our own understandings of the technology, business and policy environments, we conclude that it would not make sense to greatly narrow the options while the landscape is changing so rapidly. The results suggest some relative advantages of a diverse portfolio of approaches to renewable development, rather than committing to a single path.

Overall, the AP applauds the California Utilities for sponsoring this analysis. We also applaud the Consultants for producing a detailed and insightful study in such a short time, while at the same time interacting frequently with the California Utilities, the CAISO and the AP to vet assumptions and modeling approaches. As the RPS Study makes clear, many modeling choices and assumptions were required in order to make progress on this daunting task. The RPS Study describes those choices and assumptions,[11] how they were made, and the degree of certainty of how well they reflect reality today and going forward. We highlight here some of the key analytic issues that the study has raised (and in the Technical Appendix we discuss each of them in more detail for those with an appetite to understand our perspectives on these technical issues).

The more important assumptions in the RPS Study are those relating to the following variables, all of which the AP spent considerable time reviewing:

- *Cost and performance attributes of renewable energy technologies such as solar and wind, and other technologies (such as storage systems and demand-shifting technologies) as of the year 2030:* These assumptions relate to not only the absolute cost levels but also the relative costs of different technologies (especially in light of their ability to experience cost improvements due to "learning curves" for less mature technologies). The study focuses with more detail on the scale-up of solar technologies (i.e., utility-scale, or "large," solar systems; smaller-scale ground-mounted solar systems; and rooftop photovoltaic [PV). The study assumes less reliance on wind power with modest additional wind in each of the scenarios and no additions of geothermal, biomass and biogas beyond the amount included in the 33-percent best case and no contribution from less mature renewable sources such as enhanced geothermal, offshore wind, or hydrokinetic power.

- *The mix of renewable energy (and non-renewable resources) in the different scenarios*: The RPS Study does not attempt to find an optimum resource mix, but rather develops scenarios that emphasize one type of renewable over another, as well as a scenario that reflects greater diversity of renewable supply. In the main cases, renewables are assumed to be physically located in California, which affects the types of renewables assumed in each mix. Also the report assumes that California would not satisfy its RPS requirement through renewable-energy credits produced by renewable projects in other states or by rooftop solar built under the current net-metering mandate.

- *The outlook for natural gas prices, for CO_2 emission allowance prices in California's market, and the mix of power plants still in place in 2030:* The study assumes a large range for natural gas prices, increased prices for CO_2 allowances, and a mix of non-renewable power plants dominated by plants that burn natural gas.

- *The cost of capital to be used for investment analysis and for discounting future dollars occurring in different time periods into current dollars when comparing different scenarios:* The study calculates the cost of renewable technologies using a nominal after-tax weighted average cost of capital of 7.1 to 8.4 percent, assuming that inflation averages 2 percent. This implies a 5-to-6 percent real cost of capital. While this may be a reasonable figure in this analysis, there is a still great deal of uncertainty in the future cost of capital and this has significant impact on the relative cost effectiveness of different technologies

- *The manner in which the study treats electricity flows and trades between California's power system and other parts of the West-wide electric grid:* The analysis models California as a single electric system in great detail, and with exports to / imports from rest of the Western grid in much less detail.

[11] For example, we understand that the study's assumptions regarding the demand (load) forecast and the deployment of energy efficiency are generally consistent with recent analysis performed by the California Energy Commission. This provided us comfort that the analysis is based on best available data and consistent with the view of regulators about such issues.

Given the importance of interstate electricity flows in the West, the study's results appear sensitive to this treatment.

- *The future of public policies affecting the electric industry in California relative to those now reflected in current law and regulatory policy:* The study assumes that current policies are extended, except for those with known dates for expiration. This affects certain underlying assumptions in the report, for example, with respect to such things as continuation of current net-metering policies and retail rate designs, expiration of certain tax incentives for renewables; continuation of energy efficiency programs administered by the electric utilities.

- *The reliability requirements for the bulk power system, as well as the types of tools available to grid operators to balance the system and to ensure it does not violate operational reliability issues* (leading to involuntary disruption of electric service to customers): The study assumes that the principal tools include: security-constrained economic dispatch of those power plants capable of such control by the grid-operator; the use of such facilities to balance supply from non-dispatchable renewable resources, and physical operational constraints on those facilities to ramp up and down fast enough to balance solar and wind supply; the curtailment of supply from renewable energy in situations where there is still too much generation relative to demand and where load-shifting resources are not assumed available to shift demand to other periods. The results appear quite sensitive to the mix of tools and their costs.

- *The study's extensive reliance on economic curtailment of renewable resources to maintain reliability:* The study estimates that electricity costs will rise in the future even in the base case of 33-percent renewables, due to net cost increases reflecting the all-in costs of generation, transmission and distribution in the year 2030. The scenarios differ with respect to their estimate of costs relative to that base case. One of the biggest influences on cost estimates is the study's default strategy (for maintaining operational reliability) to rely on large amounts of renewable energy that must be curtailed, because curtailment means that renewable facilities (like non-renewable facilities that have lower capacity factors due to their role in balancing renewables) end up with lower generation than they might otherwise provide in the absence of curtailment. This, in turn, leads in the study's analysis to need to add even more renewable capacity to make up for the generation that's otherwise curtailed and thus not able to contribute to meeting the RPS requirement.

In the end and in light of these various technical modeling issues, we think that the value of this study is in helping to define directional results rather than specific answers. There are many places in the study where a more precise input would have reduced uncertainty of the results, but the AP concluded that the increase in precision would have added little value to the conclusions and insights that could be derived from the study.

III. Implications of the RPS Study Results for Policy Issues and for a Research/Analysis Agenda

The core issues, described in Section III.A below, include implications of the RPS Study's results due to: (1) the features of the study's "base case" outlook (i.e., the state's electric system in 2030 assuming a 33-

percent RPS and others changes), even in the absence of increases in the California RPS; (2) several aspects of electric system reliability which must be addressed in the base case and with even more attention in cases with a higher RPS; (3) reliance on various solutions (including curtailment) as means to integrate renewables while maintaining reliability; (4) various ratemaking policy and business/investment model issues for utilities and for owners of, and investors in, critical electricity infrastructure; (5) California's imports/exports from other parts of the Western grid; (6) the value of CO_2 reductions from renewables; (7) implications of the increased RPS for energy efficiency; (8) the need for sustainable natural gas delivery; (9) the implications of a higher RPS goal on the fixed-cost share of total costs and implications for capital requirements, financing and rate stability; and (10) the value of incorporating integration issues at the time of interconnecting renewables. In Section III.B, we identify areas where our reading of the RPS Study suggests topics in need of further research or analysis. In Section III.C, we discuss the value in opening a larger conversation among stakeholders with regard to these various policy-relevant issues.

We intend this section to be a sort of road map for what the RPS Study's results might mean, what questions the RPS Study did or did not answer (or even attempt to answer), and what questions stakeholders may want to explore more deeply in in the future. After we describe these issues in Section III.A, we also point to a number of "next steps" in the policy and technical conversations that will inevitably (and appropriately) occur after the publication of the RPS Study.

A. Core issues relevant for public policymaking

1. Currently planned efforts to enhance system flexibility/reliability are essential

The RPS Study compares deeper reliance on renewables to a base case designed to depict the future electric system in California in 2030 which includes, among many other things, a 33-percent RPS requirement. The study assumes many future changes will take place between 2013 and 2030. Some of these changes may create more flexibility in generating resources added in the future compared to what now exists to handle the challenges associated with increased penetration of renewable resources. Some of these represent policy decisions and actions of investors that are yet to be made.

For example, the study assumes that over 14,000 MW of the existing fleet of power plants now using "once through cooling" systems will be retired by 2030 and that new capacity additions by then will include 11,200 MW of natural-gas generating capacity (using a combination of combined-cycle and combustion-turbine technologies). That new generation is assumed to be more flexible than today's power plants, with increased ability to ramp their output quickly up or down at the request of the grid operator. Such capability of the replacement gas-fired units is a critical component of improving the system's ability to integrate high levels of non-dispatchable renewable resources.[12] Should the replacement investment not occur as forecasted in the base case, it could make a substantial difference in the results as reported in the RPS Study. It will be important for California to monitor actual capacity additions to keep apprised of changing attributes of the overall fleet and to take steps as necessary to

[12] Additionally, the characteristics of such replacement plants (in combination with renewable technologies) reflects reduced mass in the overall power-generating fleet, thus raising challenges for the overall "inertia" in the system to enable it withstand perturbations.

ensure it has the requisite flexibility for reliability grid operations. California should also track and assess the year-by-year ramifications of incremental renewable and non-renewable capacity additions; the RPS Study only looks at a 2030 snapshot in time, and there are likely to be different types and levels operational issues that must be addressed before then.

Similarly there are assumptions about the implementation of substantial cost-effective energy efficiency measures between now and 2030 that affect how consumers use electricity. The assumed energy efficiency investments affect the average, seasonal and time-of-use demand (or “load”) in 2030. This load level and shape is a basis of the RPS Study’s assessment as to operating issues relating to reliability, as well as cost and CO_2 impacts. If consumers’ use of energy ends up shifting in different patterns than assumed, then it could change the results in significant ways. To illustrate the point, today’s demand-reduction and demand-response programs tend to seek to shift power away from the peak electricity use in the middle of the day, when power is currently expensive to supply. Should power from solar energy peak in the middle of the day with the potential for surplus power in those hours, one could imagine different demand-side programs (some enabled by new technologies) that would shift air-conditioning and refrigeration use and charging of electric vehicle batteries *into* the middle of the day. This could lead to very different cost results than those depicted in the RPS Study’s base case, because much less renewable generation would need to be curtailed and much less renewable capacity would have to be paid for to meet the deeper RPS targets.

This RPS Study also suggests that the type of renewable resources relied upon for meeting RPS standards makes an important difference in terms of the ultimate cost and reliability challenges. This could inform public decisions about any statutory or regulatory changes that could influence the mix of renewables in which California’s customers and suppliers invest. Additionally, the RPS Study provides insights into the value of different technologies to assist in reliable integration of renewables, which also could inform policy. For example, the base case in the RPS Study assumes the current practice in California that smart inverters with communications and voltage control are mandatory for all new utility-scale solar PV installations. This allows for better control of curtailment and stability features. Although not an issue explored in this study, the inclusion of smart inverters technology at the distributed generation level (which is currently not mandatory) could provide additional capabilities to control curtailment and voltage support to provide benefits useful for overall system flexibility and reliability.

There may also be opportunity in adding transmission to avoid curtailment of renewable resources and this is worthy of further investigation. There is also a need for better understanding the physical impacts of distributed generation on the system particularly in terms of what is needed to maintain reliability.

2. Reliability risks are varied. They need to be understood and addressed holistically

One of the most important sets of insights provided by the RPS Study results from its exploration of the grid-integration issues associated with high levels of renewable energy (and solar energy, in particular). Based on the results of the study, we do not see any technically unsolvable long-term reliability problems associated with going to a higher RPS, but we note that such a conclusion assumes that there will be a similar level of commitment to addressing reliability issues associated with RPS implementation as there is to acquiring renewable resources to meet the RPS. There are cost and aggressive schedule management issues associated with various options for addressing reliability concerns. In other words, these appear to be challenges that money can probably solve, but it will be important to understand the cost and resource commitment that will be necessary. This RPS Study did not attempt to produce a least-cost portfolio of investments (with respect to either renewable resources or renewable integration solutions).

In the context of an expanded RPS that is measured by kilowatt-hour (kWh) produced, not all kWh of electricity generated are created equal from either a financial or a reliability perspective. (This is true of both fossil-fired and renewable generating resources.) There is a substantial difference in value between one more kWh produced when the system is in need versus when it is in surplus. There are also substantial differences from a voltage stability (reliability) standpoint as to whether generating resources forestall versus accelerate perturbations on the system. An RPS (or for that matter the federal production tax credit) based on energy (kWh, rather than kW of capacity or kWh of ancillary services) rewards all kWh as if they are created equal. Rewarding all kWh equally can lead to the potential for over or undersupply of electricity and a lack of consideration for maintaining voltage stability necessary to maintain reliability. As this study suggests, there are many potentially viable mitigation strategies, but they add costs.

Utility systems in California are large and can absorb modest variations in the supply of generating resources. The adoption of a 40-percent or 50-percent RPS however could require the system to absorb much more than modest variations in generating supply. As such, they would require the adoption of specific policies and programs that are implemented in a timely way in order to keep pace with the renewable generation expansion and in order to avoid unacceptable reliability risks. Operational challenges are substantially more complex at higher levels of RPS requirements.

We think that the high penetration of non-dispatchable renewable resources unaccompanied by much greater storage or demand-shifting capability could result in five significant risks to reliability. We think these are important to address, and we point out both the type and level of each type of reliability risk, as well as our thoughts on potential risk mitigation strategies:

- *The need to reduce the output of generating resources due to electricity over-supply conditions* (e.g., more generating output than there is load): Over-supply of electricity has already begun to occur in the West, most often during Spring hours where total generation exceeds load. The RPS Study suggests that this problem would be greatly exacerbated by increasing the RPS to 40 percent or 50 percent by 2030, relative to the current 33-percent RPS requirement. This particular reliability issue may be one of the easiest problems to solve physically, because it merely requires turning generation off. The difficulty resides in determining the absolute costs and allocation of costs associated with turning generating resources off. The fundamental problem is who should pay? Present amounts of over-supply are being managed, but there is already substantial dispute over issues such as the use of curtailment rights to firm transmission for delivery and the priority order of resource curtailments. The lack of clear policy resolution on this matter creates a significant risk that operators in real time will face uncertainty about the options available to them. Ultimately, the sensitivity analysis suggests that the use of curtailment could be reduced through the use of cost-effective load shifting, demand response, use of renewable energy credits, or market expansion. As discussed elsewhere in our AP Report, these options are unlikely to eliminate the value of all economic curtailment.

- *The need for very significant flexible capability (beyond what exists today) to increase or decrease the output of generating resources to respond to fluctuations in the output of non-dispatchable* *resources* (e.g. the ability to increase electricity production to offset reductions in solar output in the evenings): The RPS Study suggests that the level of need for flexible capacity is significant, important, new, and will require a dedicated effort to develop cost-effective compensation strategies. The electric power system serving California, like those nearly anywhere else, was not developed in a world where there were frequent periods of day-time over-supply conditions followed immediately by a reduction in generation output during what are still considered peak hours. This is the world one would expect with significant solar resources on the system. The potential for other power plants to have to ramp up (as solar power diminishes at the end of a day) or down (as solar power comes on line) to levels exceeding 10,000 MW over two to three hours is far beyond historical system design. The RPS Study suggests a technically plausible strategy of aggressive use of curtailing non-dispatchable resources in advance of the ramp in order to assure adequate flexible capacity is available to maintain reliability consistent with operating criteria. From the perspective of RPS compliance, however, this strategy would result in the need to develop even more renewable capacity in order to compensate for the lost renewable kWh that were curtailed. Because the RPS Study did not attempt to evaluate the economic optimization of alternatives (such as storage or demand shifting), it remains unclear whether there are superior alternatives to curtailment. But the RPS Study does indicate that there is at least one strategy available – aggressive curtailment – that will maintain reliability and against which other alternatives can be tested for cost and other performance metrics.

While this study suggests that reliability could be maintained in 2030 through the availability of adequate flexible capacity on the system, reliability challenges could arise if such flexible capacity were not added in parallel with an expanded fleet of non-dispatchable resources. It will be necessary to monitor the planned construction of more flexible capacity that is currently embedded in California planning forecasts. It will also be necessary to go beyond this study to investigate the year-by-year ramifications of extensive use of RPS as this study only looks at a 2030 shot in time.

- *The need for adequate generating resource capacity to be available to meet the needs of the system at peak load*: The RPS Study results indicate that while the output of renewable resources often is significantly reduced during the high and low temperature events that result in high peak loads, the system should have enough capability to withstand these challenges. In fact, the RPS Study suggests that, among other things, higher requirements for renewables would likely lead to a temporary surplus of capacity needed to meet peak loads in 2030. We understand that this result is likely due largely to the study's finding that large amounts of generating capacity investment takes place in order to meet RPS requirements during a time of low load growth. While we did not review these study results, the consultants informed us that the study finds that the capacity surplus is likely short term in nature and additional capacity would be necessary within a few years. These conclusions are worthy of monitoring and additional review particularly if strategies are adopted to reduce renewable resource curtailment. There is also a need to explore a deeper understanding of the potential for simultaneous shortfalls of renewable resource output.

- *The need for voltage stability in light of the amount of distance between sources of generation and location of loads*: The RPS Study was built around critical assumptions that included the requirement to maintain operation of critical resources within large load pockets, such as Los Angeles and San Diego. Should these needed generating resources become unavailable for whatever reason in the future, the RPS Study's results would no longer be valid.

We note that this study was originally conceived to address the very important issues of short-term fluctuations on the system that can create cascading large-scale outages. There have been concerns that these minute-by-minute and even second-by-second variations (referred to as "regulation" in the industry) may be significantly impacted by deep reliance on non-dispatchable renewable resources. In particular there have been concerns about solar resources without storage because of the potential increase or decrease of output due to cloud cover. But this remains an area that is not well understood. The regulation study that was originally intended to be part of this RPS Study was not completed soon enough for the AP to review it. We continue to believe this is very important analysis that needs to be performed.

- *The need for adequate "inertia" (mass) on the system*. The study does not address a potentially significant reliability issue: the implications of changing resources on California's system for inertia requirements going forward.[13] Electric power systems have historically relied on "inertia" created by rotational mass (very large generating units that are in motion) to withstand the inevitable perturbations caused by events such as lightning strikes, or the sudden unexpected loss of large generating units. As large central-station power generation begins to play a less dominant role in the overall system, the loss of inertia will be important, and we suspect that reliability risk is increased. We do not know, however, how much the risk rises in particular regions or situations. Historically, our power systems have had more than enough inertia, by virtue of the types of power plants that were conventionally added to the system. As a result, the importance of inertial power has not been the subject of study and there is little guidance as to where the break point is between enough and not enough. While it is difficult to assess, we heard from experts on this issue that California is already likely leaning on other parts of the Western interconnection to assure adequate inertia to maintain reliability and that adoption of additional renewables without mitigation could only make this problem worse. (Inertia analysis was conducted as part of this study but, like the analysis of frequency regulation, was not able to be concluded during the study period.) To the extent mitigation will be necessary to increase inertia on the system, such costs were not included in this study.

  Inertial response should be better forecasted and monitored at the system level (West-wide and specific to California) and at the "load pocket" level to better understand this issue. Modeling tools should be developed to analyze how much inertia is necessary to maintain system reliability. Testing of new power electronics that offer "synthetic inertia" services must also be conducted to ensure their effectiveness and to better understand their characteristics. When large scale use of wind and solar are planned, consideration needs to be given as to whether wind and solar resources can be utilized to provide support for inertial response. This may mean partially unloading turbines and/or implementing control mechanisms to respond to system perturbations. Future contracts should include options for gaining inertial response from non-dispatchable resources. Technology development for "synthetic inertia" power electronics needs further testing and validation.

The bottom line is that reliability can be maintained with high RPS if: (1) curtailment of surplus generation including renewables is used extensively and/or cost-effective load-shifting, storage or market expansion is utilized; (2) flexible generation is available in the future ; (3) reliability must-run units

[13] Inertia requirements were originally intended to be studied by KEMA as part of the overall RPS Study. We understand that KEMA's analysis was not ready by the time of the release of the RPS Study.

remain on-line even if they ramp down to minimum operating levels and end up increasing curtailment of renewable resources; (4) measures that enhance inertia response from renewable and distributed resources are adopted; and (5) there is better tracking of, and operational management of, system-wide and load-pocket inertia and capacity to meet peak loads. We think it is particularly important to complete the frequency regulation and inertia studies originally contemplated to be part of this effort.

3. Substantially new and only lightly tested technologies and policies will need to be adopted to integrate renewables while maintaining reliability

The RPS Study focuses on a primary case in which economic curtailment of renewable energy, combined with redispatch of fossil generation, will be needed to address potential over generation. The RPS Study assumes that both are realistic means to maintain reliability in a cost-effective manner.

Such a situation does, however, raise a host of issues that should be understood by policymakers prior to extensive use of both such strategies. Curtailment as assumed in this RPS Study would mean that there would be frequent times during which fossil fuel resources will stay on line while renewable resources are being curtailed (in order to ensure that fossil-units' start times, ramping times and other operational requirements are respected). It also means that additional renewable capacity will need to be developed and paid for and then used only during non-curtailment hours in order to meet the renewables production goals under the RPS.

We imagine that there could be questions raised by stakeholders about the reasonableness of such a strategy. A reasonable question is why we cannot adopt alternatives that would allow the available renewable kWh to be utilized fully, such as through such things as load shifting, storage or exports to other markets. In fact, some of such options may well make economic sense. Economically optimal adoption of these alternatives, however, went beyond the scope of this RPS Study. In the end, though, it is unlikely that optimal adoption of these alternatives will eliminate all curtailment of renewable resources.

This study focuses on aggressive use of curtailment to avoid over-supply condition and to assure adequate flexible generating capacity to address severe ramping needs. Whether it is cost-effective compared against storage, load shifting, smart grid, or other options remains unanswered. Future analysis should examine whether and how much such options are needed. In the meantime, curtailment options should be explored and further developed from a policy perspective. An important topic of analysis is whether modifications for current or future power-supply contracts are warranted. Policymakers need to be fully informed that the RPS Study's default strategy for maintaining reliability during conditions of over-supply in deep RPS scenarios is to rely on curtailment, and to examine cost-effective alternatives going forward.

4. Maintaining reliability will require policies addressing generating-unit asset utilization, and associated business model/ratemaking issues

The 2030 system modeled in the RPS Study is very different from today's, not just in terms of the sources of energy, but also in the complexities of grid operations, and the other topics mentioned above. It is also one in which many of the key pieces of the electric infrastructure (e.g., renewable facilitates, fossil-fueled power plants, even transmission and distribution wires) will likely perform in different ways than they do today.

Given the various assumptions about the future – for example, with regard to how consumers would use electricity over the course of days and seasons (i.e., the "shape" and level of their demand), about the continued penetration of ever-more efficient consumer devices and building energy use, about wind and solar patterns, about the types of storage technologies available, and so forth – the RPS Study suggests that virtually all power production facilities will end up being able to produce less power than they are capable of producing. This appears to be true for PV on rooftops, hydropower resources, natural-gas fired power plants, and most everything else.

To meet a 40-percent or 50-percent renewable target reliably appears to require power production capacity that is used less on average (e.g., lower capacity factors) than would seem intuitively sensible. This occurs, apparently, as some available plants (e.g., gas-fired generating capacity) are not dispatched or as other available plants (e.g., wind or solar facilities) have output that must be curtailed because there's literally more overall supply than demand.

The extent to which the system in 2030 actually resembles the ones depicted in the RPS Study will depend on many factors, including the development of technologies (such as different types of storage systems, demand-shifting technologies, electric-vehicle charging/discharging profiles) with lower cost and/or improved performance. The RPS Study provides insights into technologies where great improvements could make a significant difference in system operations, costs and rates.

Adjustments in financial, market-design and ratemaking practices and policies will also be important: For example, owners of power plants and renewable facilities that run less often but are needed to keep the system reliable will only stay in the market if it is financially worth it for them to do so. If a building owner considers installing a PV system, or if a power plant owner considers whether to continue to operate his power plant, or if the distribution utility needs to keep operating the local wires so that the building owner can sell its surplus power to the grid or draw power from it when needed, then the investments need to make sense commercially for these individual actors.

This raises important questions about the ultimate evolution not only of the technologies, but of the business models, financial incentives, regulatory frameworks, and other features of the electric system existing in California today.

One example may illustrate the ratemaking and business-model issues we think are raised by the RPS Study results. Assume, for example, that in the high-rooftop solar scenario, current net-metering policies (with payments for surplus power set to reflect the full retail rate otherwise charged to the customer when he/she uses electricity) remain in place. Assume further that such solar power is not counted for RPS compliance purposes (as is the case today), that retail utility rates for households includes a steep increasing-block rate design, and that usage-based charges are the means through which the local utility recovers a considerable portion of the cost of the wires. Assume also that the fossil power plants' costs to standby, ready to produce power, need to be picked up not only by the customers using that power around the clock, but also by those whose use is substantially met by on-site power and by the option to draw from the grid on an as-needed basis. Such a situation raises a host of questions for the residential customers with rooftop PV who feel they shouldn't have to pay for fossil plants or for a grid they don't believe that they use very much, and with other questions for the residential customers who would otherwise have to pick up the full tab for the conventional system. Yet it seems implausible to us that there would be no grid or distribution system any time soon, and hence public policy needs to support a business model that will maintain the reliable operation of these systems.

Similar or parallel questions arise in all of the 2030 scenarios (including the base case assuming a 33-percent RPS). We encourage policy makers to confront openly and soon the complex set of incentives built into today's electric power rates and products that will need to be tweaked or changed in more fundamental ways if the numbers are expected to add up. Regulatory and business model issues are ripe not only for local utility distribution companies and grid operators, but also for wholesale power market products and pricing.

5. The California footprint of the analysis needs to be expanded to a West-wide consideration

The RPS Study focused primarily on developments within California and performed only a cursory review of West-wide implications. The Western electric power system (i.e., the Western interconnection) operates as one big interconnected machine, spanning a region that includes the Rockies and Western states to the Pacific Ocean. What happens in one section of the Western grid reverberates in others, as has been clearly displayed by power outages affecting wide geographic areas and the 2001 West-Coast electricity crisis (that resulted in outages and extraordinary unanticipated costs) that have occurred over the last two decades.

The physical power flows on the Western interconnection are likely to change substantially over the next 15 years as renewable resources are added, as some existing generation is retired, as transmission lines are added, and as load growth in different areas also affects the flows on the system. The reality of this dynamic situation is that the large diversity of the Western region could shape power flows and electric realities in ways not modeled in the RPS Study's scenarios. The RPS Study provides more questions than answers about the West-wide implications for reliability, cost and CO_2 impacts, and the impacts on California of such West-wide dynamics.

California and the rest of the Western U.S. have a long and productive relationship engaging in electricity trade resulting in literally billions of dollars of benefits that has flowed to electric consumers across the West. It has also produced substantially lower air emissions and enhanced reliability. And yet, like any economic trading activity where there is so much at stake, there has also been friction along the way. There have been disputes about how benefits are shared, what actions individual entities should take to protect the reliability of the entire Western interconnected system and the impacts of environmental protections. We expect tension on these topics to continue and perhaps increase. Still, history has shown that the Western power system has been largely driven to greater interconnectedness because it has created large societal benefits of value to all stakeholders. History has also shown that it has been more productive to expand the size of the economic/environmental pie and argue about benefit allocation, rather than argue about how to allocate a shrinking pie.

The profound reshaping of the electric power system of the West that is currently underway creates a new set of threats and opportunities to regional collaboration. It seems likely there will be substantial benefits from sharing diversity across the West, although in radically different ways than has been experienced historically. For example, California has generally been a net importer of electricity. Yet this study suggests that California could become a net exporter of electricity particularly during what have been historically viewed as peak periods.

This study suggests that greater interregional coordination has the potential to result in reduced system costs in California. This seems logical and it seems reasonable to expect there could be benefit for other parts of the West as well. The substantial introduction of solar and wind resources on the system, however, will require a rethinking of trading relationships and institutional roles.[14] In order to move toward optimally capturing the benefits of Western regional diversity, it will take leadership from a cadre of individuals from government, industry and other stakeholders who see the value of increased interconnectedness and are willing to strive to achieve it. It will take an effort to seek to resolve existing disputes in an equitable manner with an eye toward the larger picture of the potential for greater benefits through long-term partnership. It will take a willingness to exchange information about policy development that seeks to raise the vision toward seeking regional solutions. It will take formal and informal venues where the primary purpose is seeking to build stronger regional collaboration.

We strongly encourage accelerated West-wide planning scenarios that seek to better understand risks and opportunities from changing the generation fleet in the West. The estimates of CO_2 reductions, costs and reliability will be heavily influenced by whether system costs can be reduced through the synergies of operation of generating resources across the West.

6. The amount and cost of CO_2 reductions compared against other policy alternatives

As a result of the study design and methodology, the RPS Study provides an incomplete window into the effect of a greater RPS requirement on expected actual power-sector CO_2 emissions as of 2030. The analysis, for example, was not conducted at a level assessing the West-wide impacts on CO_2 emissions, even though the Western electric power system is operated as a single integrated whole, and changed operation of generating resources in California impact the operation of resources elsewhere in the West.[15] This study was intended primarily to provide a sense of direction on CO_2 impacts.

The RPS Study suggests that an increased RPS would reduce CO_2 emissions by between 6 to 15 million metric tons, or roughly 10 percent to 25 percent of the total emissions from the entire electric power

[14] This reshaping is taking place against a backdrop of substantial hangovers of disputes dating back more than a decade. Not the least of these results from the 2000-2001 West Coast energy crisis. It is important for California electricity policymakers to be aware that there remains a residual belief that a flawed California market design was one of the significant underpinnings of the energy crisis. Hence there is some hesitancy to merely follow California's lead on policy. There are also concerns across the west on issues such as: who bears the costs of integrating variable energy resources that are currently operating on the system, geographic limitations placed on where renewable resources can be located to comply with renewable portfolio standards and the extent to rely on markets. All of these are hurdles to greater regional collaboration.

[15] The Consultants have indicated that their analysis relies on assumptions about CO_2 emissions attributable to California electricity consumers that are consistent with the current accounting policies of the California Air Resources Board (CARB). We note two issues related to this assumption, and the extent to which the RPS Study's results reflect likely CO_2 emissions in 2030. First, we understand that CARB's accounting rules necessarily make some simplifying assumptions about the relationship between changes in California's electricity consumption and actual changes in greenhouse gas emissions. Second, there may be changes in dispatch, power flows and CO_2 emissions that occur outside of California as a result of policy and actions in California. CARB's accounting may not reflect such impacts. In the end, because the analysis did not conduct a West-wide dispatch of all power plants inside and outside of California, the report's estimate of total CO_2 emissions from the power sector would diverge from reality to the extent that CARB's rules diverge from actual changes in dispatch.

system. Such an outcome would make a significant contribution toward meeting California's target of 80-percent reduction in CO_2 emissions by 2050. However, the additional cost associated with the various scenarios for accomplishing renewable resource increases range from roughly $250 per ton to over $600 per ton of CO_2, though we recognize that these calculations account only for the CO_2-reduction benefits of RPS expansion.

In contract, the current cost per ton of CO_2 emissions (offsets) in California's cap and trade market is roughly $10 to $15 per ton of CO_2. The RPS Study assumes that the cost per ton may rise to a level of $50 per ton by 2030 in today's dollars. At a minimum analysis of the cost of achieving environmental goals through the RPS deserves further investigation. The conclusions may help set policy priorities.

There are multiple public policy initiatives affecting the electricity sector in California. It is difficult to discern the impact of a single initiative, as was attempted in this analysis, without also considering the overlapping impacts of other initiatives. It seems worthwhile for California policy makers to consider harmonizing the goals of the variety of public policy initiatives. If such an effort is undertaken it may be worthwhile to address current policies that appear to be leading to an over-supply of electric energy at times when renewables may be most prevalent in California. Alternative policy structures could be considered that would reduce the challenges of addressing over-supply conditions.

7. The potential impacts on energy efficiency programs/demand response and load shifting

Starting from a premise that energy efficiency typically represents the least cost electric resource alternative by a substantial margin, we note that the RPS Study suggests that there is a high likelihood in future years that there will be a combination of substantial rate increases and large periods of over-supply of energy. In that situation it is not hard to envision that there would be pressure to reduce spending on incremental additions to the power supply system, including those tied to energy efficiency. This would certainly be an unfortunate outcome as a lower cost resource would be deferred in favor of prior-year decisions. We note, though, that as the needs of the power system evolve in California, there will also be a need for investment in energy efficiency to evolve as well. Energy efficiency program planners should be seeking energy-efficient investments that will provide the greatest value to ratepayers, including programs that dovetail with the upcoming shape of load and power-supply requirements in the future under different outlooks for renewable energy.

Of the available options for addressing under- or over-supply of generation relative to load, it is likely that load-shifting options will be quite economically attractive. Yet we know from our experience with energy efficiency that it will take a sustained institutional effort to capture the resource potential primarily because of the numbers of homes and businesses that must participate in order to produce an aggregate response of sufficient magnitude to meaningfully address the challenges identified in this study. Moreover the technological infrastructure to assure interoperability between grid control systems and retail loads needs further development. We encourage much greater analytic attention to these issues.

There are also significant challenges associated with communicating with consumers about the new trends in the electric system under high-penetration RPS scenarios. Consumers may be disconcerted by changing the pricing structures associated with electricity use, particularly with respect to time of use (reflecting the potential surplus of electricity during the day rather than the night-time as now) and marginal cost (reflecting the potential for many day-time hours when the use of *additional* kwh would actually reduce costs on the system, contrary to the traditional utility model of today in which each added kwh increases costs). A concerted effort will need to be made to tap into demand response and incentives for efficient load-shifting policies, such that it will make a significant impact within the timeframes of accelerated renewable development in California. The preliminary investigation of load shifting in this study suggests though that substantial further study is warranted as an economically attractive alternative to curtailment.

8. The need for sustainable natural gas deliverability

While it was outside of scope for the RPS Study, its conclusions are premised on substantial availability of on-demand natural gas into the California power market to address the electric system ramping needs. There is a need for assessing whether in fact the infrastructure, regulatory structure and contractual relationships are adequate to support what is likely to be dramatic changes in the use of natural gas by electric generators as of 2030 (and before then).

9. Some implications of higher-capital-cost and lower-variable-cost strategies embodied by scenarios of higher reliance on renewables

The RPS Study concludes that strategies relying on renewable resources have substantially higher capital costs (ranging from an incremental investment of $25 to over $100 billion). This reflects the fact that with renewable generation technologies, users are, in essence, paying for the fuel savings up front in the form of higher capital costs. Therefore, this cost increase must be weighed against future fuel-cost savings. Although not highlighted in the RPS Study, fuel costs will be substantially lower in a high renewables scenario. There are implications associated higher fixed-cost and lower variable-cost strategies. First, because there are no or limited fuel costs for renewable generation resources, there is less variability over time on rate impacts compared with strategies that rely more on resources paying for fuel. Second, there is greater rate risk associated with plant maintenance or even failure because the debt service costs will be paid no matter how well the plant operates. This may not be relevant to California ratepayers if this risk is assumed by merchant project developers.

10. The value of greater near-term reliability planning

This study creates an important opportunity to identify likely challenges to maintaining reliability early on, and then to take steps to mitigate them in advance of problems arising. It also suggests greater attention to proposing solutions that could become part of the interconnection agreements, while not introducing barriers to entry for new renewables. Addressing some of these issues during the interconnection phase may avoid later high-cost retrofits, although care should be taken to do this in ways that align with competitive considerations and without increasing barriers to entry of worthwhile projects. Addressing these problems early could help reduce countless years and dollars associated with after-the-fact litigation over problems that could be resolved earlier. It would be preferable to identify and implement mitigation up front so that assignment of costs and risks is reflected in investment and contract decisions.

From a resource planning point of view, we observe that the extensive use of variable energy resources contemplated in the RPS Study raises a number of new issues in long-term planning. That is not necessarily bad, but it does mean that planning studies that we rely on for maintaining reliability have to be rethought from the ground up. For example, electric systems with substantial under-utilization of capacity and with a set of resources with very low capital costs may raise fixed costs while lowering risk of fuel price increases. (We note that the RPS Study's presentation of investment costs displays figures showing only aggregate capital costs without commensurate presentations of total fuel costs of the different scenarios.) There is risk in making this transition that the change moves faster than utility planners can keep up. While this should not be viewed as a show-stopper, there is still need for adequate investment in planning and modeling to attempt to keep pace with rate of proposed policy change.

B. The need for additional research and analysis

The RPS Study raises many issues for further investigation, as suggested above. We found the following issues, however, to be the most compelling from a public policy perspective:

Analyzing business model and economic frameworks for asset investment (for generation, transmission, distribution, and system operations): The RPS Study did not address whether the operations of flexible capacity (either generation or demand response) might end up being uneconomic under current market rules and policies. If so, this could create risk that needed capacity will not be available for peak hours. It will be important to assure that plants that run few hours but provide critical flexibility value are able to cover their costs through fixed or other payments. If the business model produces insufficient revenue, generator owners are unlikely to be willing to take financial losses to maintain plant availability. The same could be true for investment recovery in transmission and distribution systems. California has begun to confront this problem, but it appears that sustainable solutions have yet to be achieved. Policy and financial analysis must address the need to assure that adequate capacity with appropriate operating characteristics can come forward to meet planning standards in conjunction with an RPS requirement. It is possible that properly structured markets and regulatory/ratemaking approaches will create incentives for assuring adequate flexible capacity to maintain reliability, but this is not assured. Regulatory action to assure generating resource adequacy may be necessary. System planning "with teeth" is needed because the need must be identified along with mechanisms to assure resource development and importantly adequate assurance for cost recovery in the context of California's market.

C. Opening a larger conversation about these issues

We were pleased to see the RPS Report address the three key issues that are critical to defining a future electric power system that is responsive to the public interest. These issues are: electric system reliability; the level of system costs and electricity rates; and CO_2 emissions. Although the RPS Study focused most deeply on the first of these potential outcomes, the fact that it attempted to inform policy makers about all three of them is important, because all are relevant for policy.

The reliability analysis frames important high-level issues associated with introducing substantial amounts of renewable energy generation into California, and substantially advances our understanding of the technical issues that would need to be addressed. The cost-impact analyses appear reasonable from a high-level point of view, without yielding granular information about rate impacts likely in particular utility services territories for particular types of customers. The analysis of CO_2 impacts receive less focus than the cost and reliability impacts, yet it still provides some directional insights about how the electric power system would be operated with high use of renewable resources and the impacts on air emissions from such operations.

This RPS Study provides some important insights regarding a system that includes high penetration of renewable resources. It investigates in substantial detail issues that have previously been areas of interest or concern but not rigorous study. The RPS Study's conclusion that it is technically feasible to integrate 40-percent to 50-percent renewables (as such are currently defined in California law) is, in and of itself remarkable, even with the caveats noted herein. This is especially so because this outcome does not count some of the renewable resources that are being produced in California (e.g., net-energy-metered solar power). If these resources were included in the 50-percent renewable scenario (which is tied to a share of total retail *sales* rather than actual renewable generation), the amount of energy actually produced from renewable resources would represent approximately 54 percent of electricity production by 2030.

The RPS Study also raises important public policy questions about cost, rate, reliability and environmental protection that are worthy of further review by California policymakers. These are just as important to address as the question of whether to increase the RPS percentage requirement. We think it is critical for policymakers to understand that the determination of technical achievability is only possible with concerted policy and technical efforts such as those (or other ones) embedded in the assumptions that led to this conclusion. Dealing with these other critical enabling technologies, operational issues, and public policies is essential to any hoped-for deeper reliance on renewable energy. We urge policymakers to consider these issues as part of any decision about expansion of the renewables portfolio requirement.

It is our hope that this RPS Study will lead to a richer and better informed dialogue about the consequences of expanding the commitment to further use of renewable resources in California. In this regard we have urged the California Utilities to take public comment on this study and it is our understanding they have embraced this recommendation. We welcome comments on our report as well.

Technical Appendix:
Regarding Assumptions and Methodological Issues in the RPS Study
"Investigating a Higher Renewables Portfolio Standard in California"

A. Future renewable and other technology cost and performance

The assumptions in the RPS Study reflect current market and public policy conditions and expectations. The study assumes that in the context of present economic constraints and public policy discussions, when current policy mechanisms expire, there will be no renewal of these measures. These assumptions are reasonable for the purposes of this study, but by no means certain.

Additionally, the analysis reflects today's estimates of the true costs of renewables in the future, without policy measures, and with continued technical improvement along standard learning-curve trajectories. The study is primarily focused on strong solar PV scale up, with some modest additions of wind. One large uncertainty that exists today pertains to the cost of future renewable technologies. National and international research efforts continue to make progress and with continued or accelerated research investment, there is considerable potential for costs to decrease and performance to increase beyond the assumed values of this study in 2030. The assumed cost of central station PV in 2030 is $1.70/watt. Although the sensitivity analysis assessed the impact of lower-cost PV that is more consistent with achieving the DOE's SunShot goal of $1/watt, DOE intends to achieve that goal by 2020. Also, the RPS Study only increased the amount of wind-generated MWh by 20 percent above the amounts in the 33-percent RPS base case, leaving the remaining incremental amount (i.e., the other 80 percent) in the scale-up to a 50-percent RPS to come from MWh generated by solar PV for three of the four scenarios presented. Increases in geothermal, biomass, and biogas power, with additional wind additions in the Study's Diverse Scenario case (for a 50-Percent RPS) together represented 52 percent of the additional MWh in that scenario. The Diverse Scenario also included a significant increase in concentrating solar power generation, so the Solar PV scale up was reduced from 80-percent of the new generation in the other scenarios to 33 percent of the additional generation in the Diverse Scenario. The study did not consider any contribution from other renewable sources that are currently less mature such as enhanced geothermal, offshore wind, or hydrokinetic power. Where the study results suggest significant improvements with greater diversity of resources, it was assumed that current market information does not support including these technologies as major contributors in this study. The validity of this assumption will need to be assessed periodically and, of course, be reexamined for regions different than California.

It should be noted that this analysis assumes a societal cost approach in that solar is assumed to be acquired through PPAs by utilities. If consumers end up picking up a portion of the cost, then societal cost would not change but the utilities' revenue requirement (and therefore retail rates) would be reduced.

B. Technical system operation challenges/integration/grid security issues

The RPS Study suggests that at high penetration of renewable energy generation, the electric system must operate very differently than under present conditions. While the study assumes that infrastructure investments will continue to be made and that new thermal units will have additional flexibility, there is still considerable uncertainty about the amount and types of investments that are required to maintain system regulation and stability.

While we recognize it is beyond the scope of this study to attempt to investigate the effects of how new technologies can mitigate operational challenges as these new technologies come on line, we think it is also important to acknowledge that some technologies are already being introduced, such as smart meters and synchophasers. These promise to be a part of a smart grid technology suite that will mitigate many of the grid integration and operational challenges associated with high renewable generation scenarios. Further, it is expected that as this smart grid technology suite – which will include smart inverters, new measuring and monitoring instruments, data analytic processing and intelligence, and two way flow power electronics – comes on line, more grid flexibility will be available that will lessen the burden on thermal units to provide reserve margins and to perform ramping functions. This study reviewed these technologies only on a qualitative basis, suggesting a need for more research and analysis.

Finally, as we move to an electric grid with higher renewable generation and integration of distributed resources, the system's operations will necessarily depend upon more-intensive information technology and real-time data. Such improvements in data collection and information analytics are widely expected to provide enhanced opportunity to optimize the operations of the grid. However, at the same time this dependency on real time information gathering and processing will also greatly increase the vulnerability to cyber security type threats. It was beyond the scope of this study to investigate the effects of these important elements of a future more sophisticated grid, but these must be borne in mind as we interpret the results of this investigation.

C. Over-generation and power (or demand) curtailment

The RPS Study confronts directly the possibility of curtailing renewables to balance the grid in response to over-generation and extreme ramping situations. It is possible that curtailing renewable generation will be the cheapest way to balance the system at some times. But it is difficult to consider curtailing renewables without raising the question of the purpose of the RPS. Taking 50-percent of generation as a hard target, curtailing renewable generation may very well be the cheapest way to meet it at some times. However, throwing away significant quantities of free power – or *negative* priced power – is an indication of how expensive all other forms of integration are implicitly assumed to be.

Curtailment also increases the effective levelized cost of the renewable generation because the total cost is then levelized over fewer MWhs of power. It is clear to the AP that some renewable generation curtailment is likely to be necessary to integrate a high share of renewables, but alternate solutions that harvest some value from that power must be pursued aggressively in order to improve the economics of increasing renewable shares. Conventional generation can also be curtailed, but that may not help the problem of ramping and could actually make it worse. On the other hand, curtailing conventional generation saves fuel costs.

We note that the curtailment issues raised in the RPS Study are influenced, in part at least, by certain assumptions in the study. For example:

- The assumed 1500-MW limitation on exports (from California to other states) substantially increases the amount of curtailment. It is hard to judge the merits of this assumption. The substitution of greater gas-fired for coal-fired generation that is likely to take place outside California (due to fundamental economics regarding natural gas prices relative to coal prices) may increase the size of the export market for California power. On the other hand, other states may also develop aggressive RPS requirements which could increase over-generation across the West, not just in California.

- There may be greater opportunities to limit must-run generation within California, thereby being able to better utilize over-generation. On the other hand, issues with maintaining adequate inertia (described above) may increase the need for must-run generation. In addition, this study assumes, perhaps mistakenly, that there are no must-run units in the LADWP service territory.
- This analysis assumes a $1000/MWh displacement price for over-generation, which seems extraordinarily high relative to the cost of shutting down renewables (even including the cost of replacing the renewables MWh for the purpose of meeting the RPS). We recognize that the Consultants assumed a high price for curtailment in order to attempt to minimize the curtailment of renewables even though a much lower, more realistic price was used for calculating the revenue requirement impact. We recognize that a more realistic price would have led to even more renewables curtailment than results in this study.
- The cost of curtailment should decrease through time as a portion of the cost is compensating project developers for lost incentive credits based on kWh production. The renewables cost analysis assumes these incentives will be phased out but that was not translated into the curtailment analysis.

On balance, we believe that the amount of curtailment presented in the RPS Study is not necessarily an accurate forecast. Rather, we think that curtailment will have to be addressed – just as lower utilization of fossil units will have to be addressed – as potentially effective tools for assuring system reliability. Further studies will determine the economically optimal amount of curtailment.

D. Solution set: demand response, storage, and other approaches

The RPS Study takes as the default that the solution to over-generation and ramping constraints – after accounting for the operation constraints of thermal generation – would be curtailment of renewable resources. It then presents three additional approaches that could mitigate the need to curtail renewable generation. These are: load shifting (sometimes referred to as “advanced demand response” in the study); storage technologies (e.g., those that allow storage of power generated during the middle of the day to dispatch of that stored power during the night); and export/import of electricity between California and the adjoining electricity-control areas.

The treatment of load shifting in mitigating the need to curtail renewable generation is worthy of substantial additional examination. The year 2030 is 17 years away. Technologies for synchronizing load with available generation already exist and will likely be much improved by then. The barriers are likely to be institutional (e.g., how to value flexibility of load) as much as, if not more than, technical (sending price or other signals and automated response). With moderate institutional and technical advances, load shifting may be able to take up a lot of the ramp smoothing and possibly substantial load shifting into the afternoon net demand trough that results from high solar penetration. This is one of the areas where the limits to our understanding of 2030 from the 2013 vantage point are very real, but the potential for large changes that reduce the cost of renewables integration is great.

Regarding storage, it has been recognized for some time that a robust MW scale storage capability with 6-to-10-hour residence time would be a game changer for a high variable renewable energy penetration scenario. Unfortunately, the state of the art for cost-effective utility-scale storage options is limited. Where the conditions are right, pumped hydro storage or compressed air energy storage (CAES) could be quite effective. Some other technologies such as thermal storage or electrochemical batteries are still expensive and research and development continues to explore the opportunities associated with scaling-up such storage technologies. Progress in this area continues, albeit at a slow pace (in part due to underinvestment at the Federal level). Other energy storage technologies to address shorter time scale generation intermittency or grid instabilities issues are also in various stages of development and deployment. Technologies include advanced batteries, kinetic energy devices such as flywheels, super capacitors, and more sophisticated devices like superconducting magnetic energy storage (SMES). The value of storage in this study was handled via sensitivity analysis.

Another potential solution is broader exchange of power between California and neighboring electrical markets. Such interstate power trade is discussed further below.

E. Natural gas prices

In light of the RPS Study's assumption that the RPS is a firm target under the scenarios analyzed, the assumed price for natural gas in the future has a fairly small impact on the relative costs of the four scenarios. The fuel burn at power plants providing energy and balancing services around the renewables will depend somewhat on ramping and effective heat rates, but that is likely to be second order compared to the overall cost of the residual amount of power generation from non-renewables.

Natural gas price will be a large factor in the cost impact of increasing renewables at all from the baseline 33-percent level in 2020 (and 2030). The study could be interpreted as saying the cost of going from 33 percent to 50 percent could be large, but that conclusion is very sensitive to all assumptions including the assumed natural gas price.

F. Carbon prices

The CO_2 price impact is qualitatively the same as the impact of natural gas. For California, the carbon price impact results primary from raising the cost of burning natural gas at power plants because the only carbon that will affect utility cost is from in-state gas-fired plants and from out-of-state plants for which the carbon cost is based on the emissions from a combined-cycle generating technology (CCGT). As with natural gas, the impact is minor for the relative costs of different scenarios that get to 40-percent or 50-percent RPS, but is potentially large for evaluating the cost of getting to a 40-percent or 50-percent RPS from the current 33-percent RPS.

As a point of comparison, the study evaluates gas from \$3/MMBTU to \$10/MMBTU and GHG costs from \$10/CO_2e to \$100/CO_2e. At an average heat rate of 8 MMBTU/MWh (approximately the current CA weighted average heat rate), the \$3-\$10 per MMBTU spread in gas translates to a \$54/MWh spread in production cost, while the \$10-\$100 per CO_2e translates to a spread of about \$38/MWh.

G. Cost of capital

The RPS Study calculates the costs of renewable technologies using a nominal after-tax weighted average cost of capital of 7.1 percent to 8.4 percent, while maintaining the assumption that inflation averages 2 percent. This implies a 5-to-6 percent real cost of capital. The discount rate used may accurately reflect the risk associated with these technologies today, but it may be higher than the capital costs that a more mature renewables industry would face. A lower cost of capital would make renewables, with a very high share of costs sunk before the first MWh is generated, more economical. In any case, there is significant uncertainty about the real cost of capital renewables companies will face 5 or 10 years from now and a change of one or two percentage points has very substantial impacts on the costs of renewables. In one study of solar PV,[16] a two percentage point change in the real cost of capital changed the levelized cost by about 16 percent. This will affect both the cost of renewables compared to conventional generation and the relative costs of different renewable technologies to the extent that they face different capital costs.

H. Transmission and distribution system requirements and impacts

Regarding transmission costs, it is well established in various other studies that optimized use of renewable resources nationally, and specifically in the Western U.S., depends on connecting energy from the high renewable resource areas to the load centers. Rich resource areas are typically sparsely populated, and distant to the load centers where most of the population lives. Since this study is primarily focused on the California market, the transmission costs and issues were handled by assuming historical values for transmission, and assigning those to the new generation sources inside and external to California. Of note in the RPS Study methodology is that it did not investigate the impact or uncertainties of handling many of the difficult issues around siting, permitting and other logistics of building new transmission. These have been difficult issues in the past.

It is our understanding that the base case assumes all existing transmission is retained and transmission projects that are projected as needed to meet the 33-percent renewables standard will be put in service and rolled into rates. The RPS Study considers the potential new transmission cost implications of a strategy of relying on new renewable resources. The estimates of the costs of new transmission from outside of California appear to be in line with recent estimates of costs of new transmission from Wyoming and British Columbia. It is important to recognize that these projects still require substantial effort to bring them to fruition and it is difficult to conclude whether the projects could overcome expected opposition and still stay within the price ranges estimated. The study does not effectively consider the impacts of additional transmission on renewables curtailment to protect reliability.

Regarding distribution costs, the impact of renewables on local distribution is primarily an issue for distributed generation. Many parties have opined on the incremental cost saving from behind-the-meter solar PV. The RPS Study delves into these issues, but the findings are very preliminary. This is one of the areas in which further study is clearly warranted.

I. Overall changes in power cost and rate impacts (base case and incremental)

[16] Severin Borenstein, "The Market Value and Cost of Solar Photovoltaic Electricity Production," Center for the Study of Energy Markets Working Paper #176, January 2008. Available at http://www.ucei.berkeley.edu/PDF/csemwp176.pdf

The RPS Study focuses on the production cost impact of increasing the RPS, but does not address the question of how those costs would be recovered through rate design in the future. The AP understands that rate design issues were not in the scope of this study. Nonetheless, it will be important to consider how rates should be structured to recover any additional costs, and the incentives those rates create. Among residential rates, for example, there will be important questions of fixed versus variable charges, and allocation of variable charges across the different rate tiers. There will also be issues of how to allocate costs between residential and commercial/industrial customers, particularly given the state's comparatively high existing commercial and industrial rates. And all rate setting will have to incorporate greater roles for demand response through time-varying energy prices and, potentially, willingness to change loads rapidly and/or at the control of the system operator.

The scenarios analyzed in this study, with their attendant assumptions, all result in higher rates with an expanded RPS relative to the base case of leaving the RPS at the current 33-percent level beyond 2020. The study's sensitivity analyses – with high natural gas and high CO_2 prices, and low renewable energy capital costs, when treated individually – also produced higher rates in the expanded RPS scenarios. However, the AP believes there is a possibility of future rates being lower as a result of expanded use of RPS when combinations of the solution scenarios (or other solution sets) are considered. It does appear, however, that the likelihood of rates being higher as a result of RPS expansion is greater than without the expansion. The scenarios studied herein represent what the AP believes are a reasonable range of assumptions that are likely to be the biggest drivers of future rate impacts. A primary driver of increased costs, however, is amount of curtailment of renewable resources. As the sensitivity analysis suggests there may be alternatives to reduce these costs. It is also worth noting that integration services in this study are priced at their cost. If markets are used to provide these services, the market price could be higher or lower than the costs estimated here.

J. Treatment of imports and interstate trade of electricity

A significant limitation of this RPS Study is that from the beginning it was not intended to be a West-wide analysis using broad regional models of interstate electrical flows. Exports and imports are simply limits established in the models rather than attempts to understand the economic dispatch of West-wide generation. E3 did review historical data and found no hours in which California was a net exporter. While there may have been market barriers that limited exports, it is difficult to know what, if any, technical barriers, might constrain California's ability to export power during over-generation periods. For sensitivity analysis purposes, the Consultants created a scenario that would allow up to 6,500 MW of exports. This is still less than the 6,500 MW the Consultants concluded California could potentially have available for export. The AP did not review this analysis. Our conclusion was that for this kind of study that was generally not intended to model economic optimization of generation dispatch across the West, the potential for significant changes to the generating fleet across the West due to public policy initiatives, or the seasonal or diurnal shape of a potential export market, the limitations developed by the Consultants are not unreasonable. But as we stated above, this is an area where further analysis could significantly improve the understanding of reliability, cost and environmental impacts. It is not surprising that the sensitivity analysis increasing the export limits does substantially reduce costs reinforcing the notion that further more detailed study of this issue is warranted.

Bios of the Members of the Independent Advisory Panel

Dr. Dan Arvizu:

Dr. Arvizu has headed NREL, the Department of Energy's primary national lab focused on renewable energy and energy efficiency research and development, since 2005. NREL works in partnership with industry and related stakeholders to accelerate the nation's transformation to a clean energy future. Dr. Arvizu's 40-year professional career has included 4 years at Bell Telephone Laboratories, 20 years at Sandia National Laboratories, and 7 years at CH2M Hill, Ltd. Most of his career has focused on clean energy R&D and he has become one of the world's leading experts on renewable and sustainable energy science and technology and the conditions necessary for commercialization and widespread adoption of renewable energy and energy efficiency technologies into the global and domestic marketplace. He has served on numerous boards, commissions, and advisory panels and frequently testifies before Congress. He presently serves as Chairman of the National Science Board, which oversees the National science Foundation, and serves on the Executive Committee of the National Laboratory Director's Council. He is a fellow of the National Academy of Public Administration. He has a BSME from New Mexico State University and a Masters and Ph.D. in Mechanical Engineering from Stanford University.

Dr. Severin Borenstein:

Dr. Borenstein has served as Director of the University of California Energy Institute and Co-Director of the Energy Institute at the Haas School of Business, U.C., Berkeley. He is also E.T. Grether Professor of Business and Public Policy at the Haas School, and an affiliated professor in the Department of Agricultural and Resource Economics and the Energy and Resources Group. He has done research and teaching on the economics of energy markets for nearly 30 years, focusing most recently on retail tariff design and the economics of renewable energy. From 1997-2003, he served on the Board of Governors of the California Power Exchange. Since 2012, Borenstein has served on the Emissions Market Assessment Committee that advises the California Air Resources Board on the operation of the state's cap and trade market in greenhouse gases.

Dr. Susan Tierney:

A Managing Principal at Analysis Group, Dr. Tierney is an expert on energy economics, regulation and policy, particularly in the electric and gas industries. Her career includes consulting, senior government service, academic positions, and involvement in numerous groups involved in energy and environmental policy. She served as the Assistant Secretary for Policy at the U.S. Department of Energy, and in senior positions in Massachusetts state government (Secretary of Environmental Affairs, Chair of the Massachusetts Water Resources Authority, Commissioner of the Department of Public Utilities, and executive director of the Energy Facilities Siting Council). She chairs the External Advisory Council of NREL and ClimateWorks Foundation, and is a director of the World Resources Institute, the Alliance to Save Energy, and other environmental organizations. She served on the U.S. Secretary of Energy Advisory Board (and its Shale Gas Subcommittee), led the policy group of the National Petroleum Council study on North American natural gas, and served on several electric reliability committees. She has taught at MIT and at the University of California at Irvine.

Mr. Stephen Wright:

Having recently joined the Chelan County Public Utility District as General Manager, Mr. Wright has over 30 years of experience in the electric power industry and was for 12 years the Administrator/CEO of the Bonneville Power Administration. BPA is a federal power marketing agency with costs and revenues of approximately $3.5 billion annually through managing roughly 75 percent of the high voltage transmission grid and marketing roughly 30 percent of the electricity produced in the Pacific Northwest. BPA is effectively a government-sponsored not for profit enterprise operating a wholesale electric utility. It is expected to operate in the public interest while also assuring all its costs are covered with revenue from the sale of power and transmission services. Under his leadership BPA went from having approximately 200 MW of wind interconnected to its system to over 4500 MW in less than a decade. At the time of his retirement from the agency BPA had the highest peak-wind-to-peak-load ratio for any balancing authority in the country and among the highest in the world. He had accountability for among other matters, reliability, cost recovery, rate-setting and compliance with environmental laws