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Witness: Amy Roschelle

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	**Rulemaking No. 04-04-003**

TESTIMONY OF AMY ROSCHELLE
ON BEHALF OF THE
UNION OF CONCERNED SCIENTISTS

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For
THE UNION OF CONCERNED SCIENTISTS

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TABLE OF CONTENTS

			Page
I.	INTRODUCTION AND SUMMARY		3
II.	WITNESS QUALIFICATIONS		8
III.	FORECASTING AND SCENARIO PLANNING FOR CARBON EMISSIONS AND GAS PRICES		8
	A.	Carbon Emissions	8
	B.	Gas Prices	16
IV.	RENEWABLES AND A MORE INTEGRATED PLANNING PROCESS		19
	A.	RSP Targets	19
	B.	Renewables Procurement Beyond the RPS Targets	26
	C.	Impact of Core/Non-Core Structure on Renewables	32
	D.	Analysis of Integration of Renewables in the Utility Plans	34
V.	DEBT EQUIVALENCY		35
VI.	SUMMARY AND CONCLUSIONS		41

I. INTRODUCTION AND SUMMARY

Q. Please state your name, business address, and occupation.

A. My name is Amy Roschelle. I am employed by Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139. Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Union of Concerned Scientists ("UCS").

Q. What is the purpose of your testimony?

A. My testimony addresses issues related to the long-term resource plans filed on July 9, 2004 by Pacific Gas and Electric Company ("PG&E"), San Diego Gas and electric Company ("SDG&E"), and Southern California Edison ("SCE".) UCS is particularly interested in the deployment of renewable resources through this planning process and strategies to reduce greenhouse gas emissions from electricity production.

Q. Please summarize the results of your review.

A. I believe that the Commission intended that each utility would submit a clear, comprehensive, forward-looking, and integrated long-term resource plan. In order to be comprehensive and forward looking, a resource plan must include scenario planning. The utility plans contain limited scenario analysis. One critical omission in the plans is with regard to carbon emissions. Scenario planning should include a look at each utility's entire portfolio with respect to carbon emission risks. Each utility should be required to provide its expectation of future carbon market risk – including the expected outcome when, not if, the carbon policy goes into effect.

Second, the planning should include more than one gas price forecast. There is a great deal of uncertainty around the long-term average gas price due to uncertainties related to carbon emissions and availability of Liquefied Natural Gas ("LNG") imports. Thus, high and low sensitivity analyses should be included for both gas price risk and carbon emission regulation risk. Such analyses will give a more true indication of each utility's portfolio and associated financial risks.

In terms of a more integrated plan, I am referring to the idea that the entirety of each portfolio should be evaluated in terms of overall costs and benefits of every supply and demand side option. For example, the utilities have not provided enough information to show specifically what kinds of additional resources they plan to deploy year-by-year over the next ten years through both internal generation resources and purchased power. This should be a fundamental part of the long-term plans.

In addition, SCE and PG&E have taken the 20% Renewables Portfolio Standard ("RPS") 2010 target as a limit on inclusion of renewables. As a result, the plans do not show the full extent of renewable potential that may be available and cost-effective. A far better approach is for the utilities to consider renewable generation options beyond the 20% RPS 2010 target along with all other resources, taking into account gas price and carbon emission risks associated with those resources. The 20% target should not be a limitation on the role of renewables for a utility; equal consideration of all supply and demand side resource options for the entire portfolio should be the cornerstone of an effective integrated plan.

I am also concerned about the utility proposals to include debt equivalency factors in evaluating the cost-effectiveness of long-term renewable contracts. Such contracts provide important financial hedging mechanisms including hedging against fossil fuel price risks and environmental regulation risk, as well as a hedge against wholesale price volatility risks. The utilities have not taken these factors into consideration in their evaluations. Such factors increase a company's credit rating and counterbalance debt equivalency factors.

Q. What specific actions do you recommend the Commission take?

A. The timing of this case is extremely problematic, given that the utilities seek approval of plans by the end of the year. If the Commission concurs with that schedule, it is not clear that there is a mechanism for changes to the plan, prior to their adoption. Given that, I recommend the following:

1) Each of the utilities should file a supplement to their plans, due by the end of January 2005 that addresses the concerns discussed above, namely:

- The Commission should require each utility to include a carbon cost in their evaluations of various resource options. The Commission should direct the utilities to model the impacts on their resource plans of carbon costs across the range currently used by other utilities.
- The utilities should weigh gas price risk as a major factor in determining their portfolios. Scenario analysis should be performed by the utilities to

determine the range of expected gas prices. The results of such analysis should be used to adjust the long-term plans to mitigate gas price risks, while adhering to the State's policy priorities for adding new resources.

- The Commission should refine its process for RPS solicitations, and establish a more detailed process for reviewing and approving renewables activities for 2005, including requiring updates to the renewables-specific procurement plans for 2005 and beyond.
- The Commission should direct the utilities, in creating comprehensive and integrated plans, to provide a year-by-year account detailing the specific types of resources that will be utilized in the next ten years – both through their owned generation resources as well as any purchased power. A utility should not be allowed to lock-up long-term capacity that would prevent it from continuing its purchase of additional renewable energy beyond the 20% RPS target and pursuing additional cost-effective energy efficiency.
- The Commission should adopt a debt equivalency factor for long-term renewable contracts that is lower than for non-renewable contracts.

The Commission should have an expedited review of those supplements in the first quarter of 2005, with a final decision on changes to the plans issued by May 1, 2005. In the meantime, the Commission should not approve any utility procurement activities for non-energy efficiency or non-renewable resources before first requiring the utility, at a minimum, to access the future value-at-risk due to carbon emissions for any proposed contract.

2) The Commission should issue clear direction for future long-term utility resource plans that address the issues I present in this testimony. These issues are summarized above. The Commission also should direct that future long-term plans include a more robust discussion of transmission planning, and proposed transmission projects that facilitate procurement of new renewable resources, with better integration of the results of RPS solicitations being considered in R.04-04-026 and the transmission planning issues being considered in I.00-11-001.

3) In addition to the general near-term and longer-term recommendations, I have one utility's specific recommendation that the Commission should address by January 2005:

- If the Commission approves the fall 2004 PG&E Request for Offers ("RFO"), it should first require PG&E to assess the future value-at-risk due to carbon emissions for each bid in that solicitation, and to compare its short-list bids with the cost of other resource alternatives, specifically energy efficiency and renewable energy

Q. Please describe how your testimony is organized.

A. My testimony is organized into 5 major topics. Section I, an introduction and summary, is found above. Section II describes my qualifications. Section III discusses some of the missing links in the utilities' long-term plans, including scenario planning for carbon emissions and gas price volatility. Section IV discusses factors the Commission should require in order to create truly integrated resource plans, including a discussion on RPS targets, energy efficiency, and resource mix. Finally, Section V discusses the debt equivalency issue, specifically with regard to long-term renewable contracts. Section VI summarizes my recommendations, both for supplements to these plans and for the next round of long-term resource plans.

II. WITNESS QUALIFICATIONS

Q. Please summarize your educational background and professional experience.

A. I hold an MBA from the MIT Sloan School of Management, a Master of Science in Engineering from UCLA, and a Bachelor of Science from the Massachusetts Institute of Technology.

Prior to completing business school in 2000, I worked for the Gillette Company for three years as a Process and Product Engineer. After completing business school, I worked briefly for a startup company called GreenFuel in an operations role. I then joined the technology transfer arm of the Massachusetts General Hospital, where I focused on technology strategy, grant writing, and product development initiatives. In May 2003, I joined Synapse Energy Economics. Since that date, I have worked on issues relating to economic analysis and environmental impact of technologies and polices, power plant valuation, utility resource planning and portfolio management, financial analysis, evaluation of water use and air emissions of electricity generation, and other topics including marketing/business development, project management, consumer advocacy, and technology strategy within the energy industry.

III. FORECASTING AND SCENARIO PLANNING FOR CARBON EMISSIONS AND GAS PRICES

A. <u>Carbon Emissions</u>

Q. Please discuss scenario analysis and its importance to resource planning.

A. Scenario analysis focuses on understanding how well a forecast can be expected to fare under significant changes in the input variables. This is a model-driven form of stress testing and has long been used in integrated resource planning. In its longest standing form, scenario analysis begins by taking the forecaster's base case – the one that reflects the most likely versions of the future – and defining an uncertainty band around the most important input variables. For example, a utility might consider how its resource portfolio would perform if its largest plant were out twice the normal hours per year and gas prices were at the high end of the spectrum, while load was at the low end of its likely band. Overall, scenario analysis identifies the probability of a certain outcome and allows a company to plan strategically, financially, and operationally for such an outcome.

Q. What kinds of scenario analyses are important in terms of resource planning?

A. I am particularly concerned with scenario analyses dealing with variables that are especially uncertain over the next ten-year time frame. Carbon emission regulation and gas prices both fall under this category.

Q. Have the utilities addressed the questions about potential carbon regulations posed in the ALJ's supplemental requirements for long-term plan filings?

A. Yes. Each utility responded to those questions.

Q. Have the utilities effectively factored the cost of potential carbon regulations into the development of their resource plans?

A. No. None of the utilities factored the risk of carbon dioxide (“CO_2") regulations into the development of their resource plans in a methodical way. The utilities appear to have developed their resource plans first and then assessed the extent to which of the plans do or do not mitigate carbon risk, instead of factoring the risk of carbon regulation into the development of their plans. For SCE and SDG&E the risk of carbon regulation has been addressed as an afterthought. It appears that there would be little or no discussion of carbon regulation in these utilities' resource plans had they not been required by the ALJ to answer specific questions. The actions these utilities cite that reduce greenhouse gas emissions are either actions they have been required to take or part of meeting the “normal business objectives” of efficiency and cost reduction.

PG&E has gone further than SCE and SDG&E in evaluating its resource plan in the context of carbon regulations. Notably, PG&E states that it believes that carbon is likely to be regulated at some point during the planning horizon. In this proceeding, PG&E has calculated retrospectively the savings that certain portions of its plan would provide assuming an $8 per ton carbon cost. PG&E further states that “CO_2 was a consideration in several resource decisions,” but CO_2 risk clearly was not included in the planning process in a rigorous way.

Q. Do you believe it is important for the utilities to factor carbon risk into their resource planning in a rational and methodical way?

A. Absolutely. All energy companies will face real and substantial costs if carbon is regulated, and they have responsibilities to their customers and shareholders to hedge against the risk of these costs just as they hedge against financial and other risks. There is currently far too much evidence that carbon will be regulated in the U.S. for companies to adopt a "wait and see" attitude toward such regulations. This evidence includes the following initiatives.

- The Commission has had prepared in its Avoided Cost docket (R.04-04-025) a report that suggests a carbon cost of $12.50 per ton starting in 2008.[1]
- A number of bills that would regulate carbon have been introduced into the U.S. Congress, and one of them, the McCain/Lieberman bill (S.139), received 43 votes in the Senate in 2003.
- In July 2002, California Governor Gray Davis signed a first-of-a-kind law (AB 1493) to limit the emissions of CO_2 from new cars and trucks sold in the state. The law requires the California Air Resources Board to write regulations to achieve the maximum feasible reduction in CO_2 emissions from cars and trucks, beginning with the 2009 model year.
- In September 2003, the Governors of California, Washington, and Oregon established the West Coast Governor's Climate Change Initiative, stating that "global warming will have serious adverse consequences on the economy, health, and environment of the west coast states, and that the states must act individually and regionally to reduce greenhouse gas emissions and to achieve a variety of economic benefits from lower dependence on fossil fuels."[2]
- The Massachusetts Department of Environmental Protection issued "Emissions Standards for Power Plants" (310 CMR 7.29) in April 2001. This

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[1] Energy and Environmental Economics, Inc., "A Forecast of Cost Effectiveness: Avoided Costs and Externality Adders," prepared for the California Public Utilities Commission, January 8, 2004, p. 99

[2] See letter from the California Energy Commission and the California Environmental Protection Agency to interested parties, April 16, 2004, at: http://www.energy.ca.gov/global_climate_change/westcoastgov/.

multi-pollutant legislation requires emission reductions including CO_2 reductions from the six highest emitting power plants in the state.

- The state of Washington recently passed a law requiring that new power plants either mitigate or pay for a portion of their carbon emissions. Representative Jeff Morris, the bill's primary sponsor, said "Washington State is not going to solve global warming, but we are doing our part." [3]
- In 1997 Oregon established the first formal standard for CO_2 emissions from new electricity generating facilities in North America.[4]
- The New Hampshire "Clean Power Act" (HB 284), approved in May 2002, requires CO_2 reductions from the three existing fossil-fuel power plants in the state.
- In New Jersey, the Department of Environmental Protection released the New Jersey Sustainability Greenhouse Gas Action Plan in April 2000. The Plan provides a framework for reducing greenhouse gas emissions to 3.5% below their 1990 levels by 2005. Under the Plan, Public Service Enterprise Group, the state's largest utility, pledged to reduce total emissions from all of its fossil fuel-based plants by 15% below 1990 levels by 2005.
- The New York Greenhouse Gas Task Force was created by Governor Pataki in June 2001. The purpose of the Task Force is to develop recommendations for ways to significantly reduce the state's emissions of greenhouse gases, and New York is currently considering whether to adopt the recommendations of

[3] Washington House of Representatives Press Release, *Governor Signs Morris Bill to Clean Up Air Pollution*, March 31, 2004.

[4] Anne Egelston, *Oregon, Massachusetts Lead the Way in GHG Reductions*, Environmental Finance, July-August 2001.

the Greenhouse Gas Task Force. The 2002 State Energy Plan also recommends that the state commit to a goal of reducing greenhouse gas emissions by 5% below 1990 levels by 2010, and 10% below 1990 levels by 2020.[5]

- Nine Northeast and Mid-Atlantic states have formed "The Regional Greenhouse Gas Initiative" in a cooperative effort to discuss the design of a regional cap-and-trade program initially covering CO_2 emissions from power plants in the region.
- In addition to the regulations and programs described above, 25 states are working with the U.S. Environmental Protection Agency ("EPA") to develop climate action plans that identify cost-effective options for reducing greenhouse gas emissions at the state level. At least 19 states have completed an action plan to date.

PG&E, SCE, and SDG&E have been effectively put on notice that they should factor carbon risk into resource planning by (1) the discussion of a CO_2 adder in the CPUC's Avoided Cost Workshop (R.04-04-025) and (2) the paper attached as Appendix B to this proceeding's Order Instituting Rulemaking, which discusses a market-based system for regulating carbon emissions.[6] In light of all the initiatives cited above, a "wait and see" attitude toward carbon regulation is imprudent and the failure to take action to mitigate carbon risk should be found imprudent in the future by regulators and shareholders.

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5 New York State Energy Research and Development Authority, *2002 State Energy Plan and Final Environmental Impact Statement*, June 2002.

6 CPUC Order Instituting Rulemaking 04-04-003, Appendix B: "An Incentive Framework For Utility Procurement of Energy Resources Modeled After Cap-and-Trade Principles of the Sky Trust", April 6, 2004.

Q. How should the utilities be required to factor the cost of potential carbon regulations into their resource plans?

A. The utilities should be required to include a carbon cost in their evaluation of various resource options in the January 2005 supplement. For example, in evaluating the economics of a natural gas-fired plant versus investments in conservation and other zero-carbon resources, a utility should add a specified dollar amount to each MWh of generation from the gas-fired plant. This dollar amount should be calculated using an imputed cost of carbon ($/ton) and the carbon emission rate of the plant (ton/MWh). This method should factor the risk of carbon regulations into the plan in an unbiased and methodical way. This method results in an expenditure for lower carbon resources quite similar to an expenditure for a financial hedging instrument. However, in this case, the computed value of carbon risk does not reflect an actual payment to the generator; rather, it forms a quantitative tool to be used in fairly evaluating resource bids.

Q. Do the utilities have all of the information they need to evaluate carbon regulation risk?

A. Yes. To perform this evaluation, the utilities will need to know the carbon emissions rate of each plant, a value that they may know, or that they may have to calculate. The utilities may be able to use plant heat rates to estimate the emissions or use available data, as suggested by PG&E and SDG&E. PG&E notes that while the California Climate Action Registry does not require reporting of the emissions from its purchased power contracts, it will do so as part of its environmental management strategy. PG&E states it may use "publicly reported data and federal emissions databases"[7]. PG&E suggests it could require reporting by the generator of greenhouse gas emissions in long-term procurement contracts.[8] SDG&E states it will quantify emissions from purchased power contracts "to the extent that the source and its emissions are known," and otherwise use an emissions rate from a federal emissions database.[9] [10] Thus, all the necessary information to perform a risk analysis of carbon emission is known.

Q. Do you have an opinion on the specific cost of carbon that the utilities should use?

A. In its Avoided Cost Docket (R.04-04-025), the Commission had a report prepared that suggests a carbon cost of $12.50 per ton starting in 2008.[11] I find the figures suggested in the report to be conservative assessments of the cost of carbon mitigation and appropriate for use in utility planning.

I have seen a number of estimates of carbon compliance costs in the range of $8 to $60 per ton. Numbers at the higher end of this range tend to come from studies that model electric-sector carbon regulations or otherwise estimate the cost of reducing carbon. One such study is the EIA's analysis of the McCain/Lieberman bill (S.139), which estimates the cost of carbon allowances in the range of $22 to $60.[12] The low end of this range is the $8 per ton figure used by PacifiCorp in the base case for its 2003 Integrated Resource Plan. PacificCorp

[7] See PG&E, p. 7-5
[8] *Ibid.* p. 7-6
[9] Specifically, the "Emissions & Generation Resource Integrated Database."
[10] See SDG&E, witness Gaines, p. 3
[11] Energy and Environmental Economics, Inc., "A Forecast of Cost Effectiveness: Avoided Costs and Externality Adders," prepared for the California Public Utilities Commission, January 8, 2004, p. 99
[12] US Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003*, EIA Report: SR/OIAF/2003-02, June 2003.

also evaluated scenarios with carbon priced at $2, $25, and $40 per ton.[13] Another utility, Idaho Power Company, recently evaluated its Integrated Resource Plan in the context of carbon at $12.30 per ton and $49.21 per ton. I recommend the Commission direct the utilities to model the impacts of carbon costs on their resource plans across a range starting at no less then $8/ton.

B. <u>Gas Prices</u>

Q. Please summarize the utilities' analysis of future natural gas prices and the impact of those prices on their resource plans.

A. A June 4, 2004 Assigned Commissioner's Ruling ("ACR") by President Michael Peevey required that the utilities perform certain scenarios within their long-term resource filings. Among those requirements, the utilities had to "consider gas prices and market prices for electricity at the 95th % of expected future prices." The utilities responded to this request by performing Monte Carlo or other simulations for monthly gas prices through 2014.

Q. Please explain the concept of simulation.

Computer simulation or modeling allows one to run hundreds or thousands of trial events for each uncertain variable affecting an outcome. To do this, one inputs all of the variables that affect an outcome into a computer model. To get a meaningful result, one must choose reasonable end point ranges for each variable. The model is then run many times and the results are recorded. One can then chart the distribution of outcomes and determine the probability of a particular event.

[13] See: PacificCorp, *Integrated Resource Plan 2003*, p. 45-46.

Q. How do the *a priori* assumptions in the utilities' gas price simulations affect the results?

A. None of the utilities provided enough information in their filings and/or confidential work papers to determine exactly what their *a priori* assumptions were. Specifically, it was not possible to determine which of the variables affecting gas prices were assumed to be uncertain or what the range of each variable was for purposes of running the simulations. The utilities provided the end results of the simulations, but did not include a description of the inputs or their relationship to the end results.

Q. Why is this important?

A. Not only are gas prices extremely volatile, but there is a great deal of uncertainty around the long-term average gas price. A variety of factors such as the extent of future carbon emissions restrictions or projected LNG capacity could have a significant impact on gas prices. National regulation of CO_2 would almost certainly cause a shift from coal-fired generation to natural gas-fired generation, and this shift would increase the demand for and the price of natural gas. Because of this, it is critical to know which variables were allowed to fluctuate in the simulations and within what range. Without such information the value of the utilities' simulations is unclear.

Q. How were the results of gas price simulations or other gas price risk information incorporated into the utilities' long-term filings?

A. While the simulations that were performed may be an indication of how the various portfolio options perform in the face of higher gas prices it is also important to consider portfolio options that minimize the utilities' exposure to that risk. PG&E discussed how gas price risk associated with DWR and QF contracts would be managed and mentioned that it "used several criteria to test candidate portfolios to ensure they met requirements and were sufficiently robust and adaptable under a range of potential conditions, including…gas price volatility."[14] PG&E did not, however, discuss how it would manage gas price risk associated with gas-fired resources apart from its DWR and QF contracts in its preferred portfolio. While SCE used stochastic analysis to evaluate how various portfolios perform under gas price uncertainty, the Company did not clarify its underlying assumptions behind the gas price uncertainly. SDG&E, whether intentionally or unintentionally, minimized its gas price risk through 2010 by choosing a portfolio that would not require it to procure conventional resources before then. Beyond that year, there is no indication that gas price risk will be a consideration in procuring power.

Q. What are some of the challenges in incorporating gas price risk into utility forecasting?

A. Designing well-thought out and robust scenarios is critical to reaching meaningful conclusions in any analysis, including that of power procurement plans. Considering just one gas price forecast is inappropriate.

Q. What is your recommendation?

A. The Commission should mandate that the utilities explicitly account for gas price risk when determining how they plan to procure power. The utilities should perform simulations or other types of analyses and clearly detail all variables and

[14] Prepared Testimony of Pacific Gas and Electric Company, p. 5-3.

ranges used in the simulations. The results of the simulations should then be used to create a portfolio that is least susceptible to future expected gas price risks.

IV. RENEWABLES AND A MORE INTEGRATED PLANNING PROCESS

A. RPS Targets

Q: Do the utilities' plans sufficiently demonstrate that they will meet the goals of the California Renewables Portfolio Standard?

A: I commend each of the utilities for their commitment to meeting a 20% RPS target by 2010, consistent with the accelerated goal of the Energy Action Plan ("EAP").[15] SDG&E, in particular, deserves recognition for stating that it plans to achieve a 24% renewables portfolio by 2014. In following the EAP "loading order" of resources, all of the utilities have assumed they will meet this goal in each of their supply scenarios, without any discussion of contingencies.

Despite good intentions, none of the plans sufficiently demonstrates that the RPS goals will be met. The plans do not include contingencies for problems such as insufficient transmission capacity in the timeframe required to access new renewable resources, a possible depletion of funds in the Supplemental Energy Payment account for any above-market costs, or solicitations failing to produce bids sufficient to meet the RPS target. The RPS statute exempts the utilities from procuring any further renewable energy to meet RPS targets if Supplemental Energy Payment funds are unavailable.[16] Decision 03-06-071 allows the utilities to exercise flexible compliance mechanisms, without penalty, if a utility receives

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[15] California Power Authority, California Energy Commission, California Public Utilities Commission, "State of California Energy Action Plan," May 8, 2003.
[16] *See* Pub. Util. Code §399.15(b)(4).

insufficient bids in an RPS solicitation. SDG&E witness Bartolomucci identifies additional factors that may "significantly affect SDG&E's ability to procure renewable resources in the future," such as upward pricing pressures due to supply limitations, the ability to own renewable resources as well as purchase energy from renewable resources, and the ability to procure and trade renewable energy credits.[17] I discuss potential problems related to the development of sufficient transmission capacity to access renewable resources below.

Q: Describe how the utilities have incorporated RPS procurement into their long-term plans.

A: Generally, the utilities assume they will achieve a 20% renewables portfolio by 2010, without discussing the process by which they will arrive at that amount. This is particularly problematic, as the process to procure renewable resources to meet each utility's annual procurement target for 2005 needs to commence expeditiously once the long-term plans are approved. There is an unfortunate incongruity, however, between an intention stated in Decision 04-07-029 regarding renewables procurement plan filings, and the long-term plans under consideration. D.04-07-029 established parameters for RPS least-cost and best-fit evaluation of renewables bids, correctly directing renewables procurement plans to be evaluated as part of the overall procurement planning process: "We intend to coordinate future renewable procurement plan filings with the Commission's schedule for overall procurement plan review."[18] Indeed, coordination is required, to the extent possible, by the RPS statute:

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[17] SDG&E testimony, witness Bartolomucci at p. 6.
[18] D.04-07-029, p. 7.

> The commission shall direct each electrical corporation to prepare renewable energy procurement plans as described in paragraph (3) to satisfy its obligations under the renewables portfolio standard. To the extent feasible, this procurement plan shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process. The commission shall require each electrical corporation to review and update its renewable energy procurement plan as it determines to be necessary. (Pub. Util. Code §399.14(a))

That coordination, however, particularly related to 2005 renewables procurement, is absent from all three utilities' long-term plans. The utilities merely state that they will comply with the RPS and achieve a 20% renewables portfolio by 2010 without incorporating a more thorough analysis – indeed, a renewables procurement plan as required by the RPS – of how to meet their 2005 procurement targets.

Additionally, the 2004 renewables procurement plans filed by the utilities and approved by the Commission do not address renewables procurement in 2005 and beyond.[19] Therefore, those plans need to be updated and coordinated with the long-term plans. That process should commence promptly so that the utilities will be ready to conduct solicitations as necessary in 2005 to meet their procurement targets for that year, and renewable energy providers can plan how to best meet the needs to be identified by the utilities.

SCE does not identify specific resource types and estimated quantities for new renewables, but does provide the information for existing renewables. PG&E identifies wind repowering as a potential source of new energy deliveries, and states it considered geothermal, biomass, new wind, solar thermal, and biodiesel generating

[19] SCE and SDG&E filed plans on June 14, 2004, and PG&E filed its plan on June 24, 2004. Energy Division approved SCE's plan on June 25, SDG&E's plan on June 28, and PG&E's plan on June 30.

facilities in developing its portfolio development.[20] PG&E only provides rough estimates of new renewables capacity for these technologies in its confidential work papers. SDG&E provides thorough estimates of renewables capacity and energy for both existing and new resources in its confidential work papers. PG&E and SCE should have provided this same level of detail.

I commend PG&E for pursuing contracts with repowered facilities, and concur with the potential benefits conveyed by these contracts as discussed in PG&E's testimony.[21] SCE and SDG&E should follow PG&E's lead and encourage bids from repowered facilities to the full extent such opportunities exist. PG&E claims that 9 million tons of CO_2 emissions reductions result from "discretionary decisions to significantly exceed customer energy efficiency and renewable portfolio standard requirements."[22] PG&E has not demonstrated anywhere in its plan that it will exceed its RPS requirements. While PG&E projects it will reach 20% by 2010 under its medium-load scenario,[23] my analysis of PG&E's confidential workpapers indicates PG&E may exceed 20% under its low- and medium-load scenarios by 2014, though not I do not believe its projections "significantly exceed" 20% as indicated in its plan. PG&E also states that it will need an additional 175 MW of baseload renewables if its load does not decrease due to a core/non-core split or community choice aggregation..[24]

[20] *Ibid.* PG&E testimony p. 4-61.
[21] *Ibid.* p. 5-12 and 5-13
[22] *Ibid.* PG&E, p. 7-11 at lines 10-12.
[23] *Ibid.* PG&E , p. ES-1
[24] *Ibid.* PG&E, p. 5-13 at lines 7-10.

It is not clear why PG&E uses the same level of new renewables procurement for the medium- and high-load scenarios.[25] A high-load case would require a higher percentage of renewable energy to achieve the same goal (i.e. 20% by 2010). It is distressing to find that PG&E does not anticipate reaching 20% until 2014 in the high-load scenario.

Q: What is your recommendation?

A: I recommend that the Commission refine its process for RPS solicitations. The 2004 renewables procurement plans were necessarily abbreviated, sparsely detailed, and approved under a shortened public review schedule, in order to allow first-round RPS solicitations to be issued in July. The Commission has not yet established a schedule or process by which the utilities will update those plans for renewables procurement in 2005 and beyond. As discussed above, the Commission expressed a preference for integrating future renewables procurement plans into the general procurement plan review process.

The Commission should issue a ruling in November 2004 jointly in this proceeding and in R.04-04-026 inviting comment on the content of the updated renewables procurement plans. That ruling should discuss the process for incorporating more detailed renewables plans into the broader resource plans for 2005 and beyond. The Commission should refer to the level of detail provided in SDG&E's long-term plan as a model for the data to be provided. The ruling also should contain an order for the utilities to file updated renewables procurement plans.[26] This allows the utilities sufficient time to undertake procurement

[25] *Ibid.* PG&E , p. 4-61 at lines 29-30 and p. 4-62 at lines 1-2.
[26] This recommendation is consistent with the August 4, 2004, Draft Decision in R.01-08-028, which

activities necessary to meet their 2005 RPS requirements. The timing and process for issuance of requests for offers pursuant to those plans should be addressed in R.04-04-026.

Q: **Describe how the utilities have incorporated transmission planning with respect to renewable resources into their long-term plans**.

A: It is crucial that renewables procurement planning be fully integrated into the broader resource planning to conduct proper transmission planning. SDG&E witness Brown identifies a key long-term transmission goal:

> Expand transmission infrastructure to provide access to proposed renewable resources to meet SDG&E's commitment to 20% of energy from renewable sources by 2010.[27]

Brown also identifies two possible 500 kV transmission projects, and states that those lines may be used to access out-of-area renewable resources.[28] SCE identifies two 500 kV transmission projects that may "increase access to economic resources located in the southwest by about 1,700 MW,[29] although it does not specifically identify any of this capacity as renewable. SCE also references the transmission upgrades under consideration to access renewable resources in Tehachapi. PG&E states that it "believes that transmission must be considered as part of effective integrated resource planning and that coordination with the [California Independent System Operator] transmission planning process

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orders: Within 20 days form the effective date of this decision, PG&E, SCE and SDG&E shall revise their long-term electric procurement plans submitted in R.04-04-003 to fully reflect the energy efficiency savings goals adopted in today's decision," Ordering Paragraph 5).

[27] SDG&E, Chapter C at 2.

[28] *Ibid*., pp. 13-14.

[29] SCE, Minick, p. 123

is essential".[30] However, PG&E does not provide detail on specific transmission proposals, stating that "it would not be fruitful to attempt to duplicate that process here." PG&E does reference potential projects it "may propose" as part of its 2005 Electric Transmission Grid Expansion Plan and 2006 long-term resource plan that would access additional renewable generation in northern California and in SCE's service area.

The plans do not provide assurance that adequate transmission will be identified, permitted, and constructed in the time necessary for the utilities to reach 20% by 2010 as stated. SDG&E witness Brown estimates "a minimum of five years is required from the filing of a CPCN until the commercial in-service date" of its proposed transmission projects. SDG&E responded to UCS' July 29, 2004 data request, in which UCS asked:

> "Are the additional transmission resources that SG&E has proposed in its resource plan sufficient to meet its 24% renewable goal by 2014? If not, what additional renewable resources are needed?"

SDG&E responded to this question on August 5, 2004 as follows:

> "No. SDG&E may need to build additional transmission lines to reach the renewable power goal. SDG&E anticipates that additional transmission lines and/or upgrades to existing lines will be needed to get renewable power from the generation site to SDG&E's load. The specific lines and timing will not be known until the specific renewable projects are selected."

[30] PG&E, p. 4-52

This is troubling, because even the specific lines proposed by SDG&E may not be sufficient to achieve its renewables targets, and additional needs will not be identified until RPS solicitations are conducted. The latter problem also applies to PG&E and SCE.

Q: What is your recommendation?

A: To ensure that adequate transmission upgrades and expansions are available to meet the goals of the RPS, I recommend the Commission guide the utilities to better integrate the results of RPS solicitations considered in R.04-04-026 and the transmission planning issues considered in I.00-11-001 into this proceeding and into subsequent filings of long-term resource plans. The utilities should include a more robust discussion of transmission planning, including proposed transmission projects that facilitate procurement of new renewable resources. The Commission, in collaboration with the CEC, should carefully evaluate location-specific transmission needs to access new renewables, and expedite the CPCN process for construction of these new facilities and upgrades.

B. Renewables Procurement Beyond the RPS Targets

Q: Does the RPS establish a cap on a utility's procurement of renewable energy?

A: No. Public Utilities Code Section 399.15(b)(1) requires each electrical corporation to increase its procurement of renewable energy to fulfill 20% of its retail sales no later than December 31, 2017. One goal of the Joint Agency Energy Action Plan is to accelerate this goal to 2010, and Senate Bill 1478, if passed, would establish a new target date of December 31, 2010. The law establishes a *minimum* target for renewable energy purchases, but does not *require* the utilities "to increase its procurement of such resources" if the 20% target is reached in a given year (§399.15(b)(1)).

SCE ensures that its portfolio will stabilize at 20% beyond 2010 under all three load scenarios,[31] and identifies 20% at a limit to its renewable procurement.[32] PG&E projects it will reach 20% by 2010 under its medium-load scenario.[33] Based on my analysis of PG&E's confidential workpapers, PG&E may exceed 20% by 2014, but may not achieve 20% in 2010 under its high-load scenario. SDG&E projects it will achieve 24% renewables in 2014.

Q: Are there any problems associated with the utilities' approach to the procurement of renewable energy beyond the 20% targets identified by the utilities in their plans?

A: Yes, I identify five problems: 1) Unless the utilities continue to conduct renewables-only solicitations pursuant to established RPS rules, once they reach a 20% renewables portfolio, the structure of an all-source or other style solicitation would discourage renewables; 2) The utilities' proposed treatment of debt equivalency discourages long-term renewables contracts; 3) PG&E proposes to issue an RFO in 2004 that could largely fill capacity needs in 2008 and 2010; 4) The utilities express a preference for short-term contracts due to uncertainties in future market structure; 5) The lack of consideration of carbon emissions risks does not fully capture the value of renewables, as discussed above, and thus does not afford fair evaluation of renewables against other resource types.

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[31] SCE plan, p. 148 at Table VI-31
[32] SCE, p. 119 at lines 22-23
[33] *Ibid*. PG&E p. ES-1

Q. Please describe problems with including renewables in all-source solicitations.

A. Any renewable energy purchases made above the 20% volume would likely result from all-source solicitations, not from renewables-only solicitations following RPS rules. SDG&E indicated at the long-term plan workshop on July 16, 2004 that it is not sure how it will conduct solicitations to achieve a 24% renewables goal by 2014. All-source solicitations may subject renewables bids to different rules and contract terms than were designed for the RPS. For example, the utilities would not be required to follow the specific least-cost and best-fit parameters set forth by the Commission in D.04-07-029. Also, it is unlikely that such bids would be eligible for Supplemental Energy Payments ("SEPs") to offset any above-market costs for renewables as allowed in the RPS, to the extent other utilities have not yet fulfilled their 20% targets. Additionally, it is unlikely a Market Price Referent would be established in an all-source solicitation for any renewables bids received, thus SEPs would not be awarded pursuant to the RPS rules that have been established by the CPUC and CEC.[34]

Q. Please describe how proposed debt equivalence measures disadvantage renewables.

A. Renewables projects would also be placed at a disadvantage in all-source solicitations under the utilities' proposed application of debt equivalence measures. (Debt equivalence is discussed in greater detail in Section V of my testimony.) PG&E and SCE have expressed how the application of such

[34] RPS rules were established in CPUC decisions D.03-06-071, D.04-06-014, D.04-06-015, and D.04-07-029; see also CEC RPS program and New Renewable Facilities Program guidebooks in CEC Docket 03-RPS-1078.

measures favor contracts with short terms, because the credit rating agencies exclude contracts with terms three years or less in their evaluation. California's RPS law requires renewables contracts to be long-term, "no less than 10 years in duration, unless the [CPUC] approves of a contract of shorter duration." (Pub. Util. Code §399.14(a)(4)) The purpose of such long-term contracts is to create a financeable and stable market for renewables projects. These two needs – the utilities' claimed need for short-term contracts to minimize debt equivalency impacts and the need for renewables contract to have minimum term lengths of 10 years – are incompatible. Thus, there is no incentive for the utilities to procure renewable energy beyond the 20% RPS requirement.

Q. Why is the utilities' preference for short-term contracts a problem for renewables?

A. All three utilities indicate a preference for short-term contracts in the near term due to uncertainties in future market structure, and are concerned that departing load due to competitive markets and Community Choice Aggregation will leave them long (i.e., "over-procured" resources).[35] This practice disfavors renewables contracts, which are generally for longer terms.

A utility should not lock up long-term capacity that would prevent it from continuing its purchase of renewable energy once the 20% target is met. Once that capacity is filled, it becomes increasingly difficult to justify an increase in renewable energy procurement, because such procurement could create a long position resulting in market sales of excess energy at a loss to the utility. This

[35] See: PG&E, p. 1-9 at lines 6-15, 2-9 at lines 22-29, 2-27 at line 21; SCE presentation at July 16, 2004 workshop, "Overview of '04 Long Term Procurement Plan," Slide 2; SDG&E, McClenahan, p. 7)

position would allow the utilities to argue against any new future legislative proposals to increase RPS targets (such as the 33% by 2020 expressed by Governor Schwarzenegger in his campaign agenda).[36]

Q: What is your recommendation?

A: My recommendation is that the Commission direct the utilities on a going-forward basis to consider renewable energy products (either representative or actual bids) alongside other resource options when identifying and going to bid to fill any procurement need. While the utilities have followed the resource "loading order" preference expressed by the Energy Action Plan, they do not fully consider the ability of resources such as renewables, energy efficiency, demand response, and distributed generation to fill any remaining open positions. The forecast quantities of those resources currently contained in the utilities' plans should not represent a *cap* but rather the anticipated amounts to meet established program and policy goals. The process to fill the remaining open positions should explicitly consider the resource types I just named. That process is closer to integrated resource planning than the process proposed by the utilities.[37] The 20% target should establish a floor for utility purchases from renewable energy, not a cap. The Commission should direct that the evaluation process the utilities

[36] "Action Plan for California's Environment," available from http://www.joinarnold.com/en/agenda

[37] On August 4, 2004, the Commission issued a draft decision in the energy efficiency docket, R.01-08-028, which reaches similar conclusions about how utilities should be including energy efficiency (in this case) in their procurement plans: "We disagree with the underlying premise reflected in this statement; namely, that the reasonableness of energy efficiency savings goals must be considered in the context of the IOUs' plans to dispatch existing or procure additional supply-side resources. Rather, the converse is the case, based on the policies clearly articulated in the Energy Action Plan and by this Commission. Those policies dictate that cost-effective conservation and energy efficiency are *first* in the IOUs resource loading order – energy efficiency is evaluated for cost-effectiveness and procured *before* supply side resources are to be factored into the procurement plan." (8/4/04 Draft Decision, p. 25) The same would apply for renewable resources, which are next in the loading order.

use for filling procurement needs, whether by competitive solicitation or bilateral agreement, fully consider the risk of carbon emissions, and the benefits renewables provide in mitigating fuel price risks and reducing the potential impact of debt equivalence, both issues discussed in more detail elsewhere in my testimony.

I also recommend that the Commission on a going-forward basis evaluate any long-term contracts proposed by a utility to ensure that non-renewable resources do not completely fill the utility's identified capacity need. I am not recommending that the remaining open position be met with any particular resource type, and the utility could opt to leave the position open if it has not identified specific cost-effective renewable or energy efficiency resources. This particularly applies to PG&E's request to issue an RFO in 2004 for long-term capacity needs in 2008 and 2010. As I also recommend below, PG&E should not completely fill capacity without expressed consideration of renewable energy and energy efficiency to meet those needs.

Q: Should the Commission approve PG&E's requested long-term Request for Offers?

A: As I have stated, I do not believe the Commission should approve any utility procurement activities for non-energy efficiency or non-renewable resources before first requiring the utility, at a minimum, to assess the future value-at-risk due to carbon emissions for any proposed contract. PG&E requests that it be allowed to issue a long-term RFO in 2004 to fill capacity needs of 1,200 MW by

2008, and an additional 1,000 MW by 2010.[38] Under PG&E's proposed timeline, PG&E would submit contracts for approval in February or March 2005 with a Commission decision in June 2005.[39] I am concerned that PG&E has not fully explained what products it anticipates will meet the identified need. If the Commission approves the RFO, it should first require PG&E to assess the future value-at-risk due to carbon emissions for each bid in that solicitation and to compare its short-list bids with the cost of other resource alternatives, specifically energy efficiency and renewable energy. PG&E already has cost information for a variety of energy efficiency programs. It will also have cost information for a range of renewable technologies resulting from its current RPS solicitation, as well as easily accessible market intelligence on renewable energy prices. PG&E should also model renewable energy technologies that could meet its anticipated long-term needs to determine the comparable cost and portfolio fit of those resource options. While PG&E should allow renewables to bid into the RFO, it should also consider how products bid into its currently open RPS solicitation, issued on July 15, may fit the identified long-term need and reduce PG&E's reliance on and risk associated with non-renewable resources.

C. Impact of Core/Non-Core Structure on Renewables

Q: What effect might the utilities' core/non-core load scenarios have on their renewable energy purchases?

A: The multitude of core/non-core load scenarios in the long-term plans illustrates the planning uncertainties the utilities will face in the coming years. Particularly

[38] *Ibid.* PG&E, p. 5-17 and 6-1 et seq
[39] *Ibid.* PG&E p. 6-6.

striking in SCE's plan is the "overshoot" of its 20% RPS target under the low-load scenario, whereby load migration causes SCE's renewable portfolio to reach 27.3% as early as 2006. Given that the utilities have little incentive to exceed the percentage of renewables purchases mandated by the RPS, as I discussed above, I am concerned that the uncertainties surrounding load migration under the core/non-core scenarios may forestall further development of new renewables under the low-load scenarios outlined in the utilities' plans.

For this reason, the Commission needs to promptly address the RPS rules for energy service providers (ESPs) and Community Choice Aggregators (CCAs), who are required by law to meet RPS targets.[40] If the Commission adopts rules that allow ESPs and CCAs to count tradable renewable energy credits ("RECs") toward meeting their requirements, then the investor-owned utilities may have an incentive to procure beyond 20%, whether due to load migration or additional contracting for renewables (e.g. a product that is a best-fit to fill an open position), and sell RECs. However, this incentive may be diminished or eliminated by the utilities' expressed preference for shorter-term contracts, due in part to proposed treatment of debt equivalency, as I discuss in Section V.

Q. What is your recommendation?

A. I recommend that the Commission move forward with establishing RPS rules for ESPs and CCAs and establish a schedule and process for adopting those rules, in the RPS proceeding (R.04-04-026) to further remove uncertainties surrounding how load migration affects utility resource planning, particularly as it concerns renewable resources. The Commission identified this issue when it opened R.04-

[40] See Public Utilities Code §399.13(b)(2) and (3)

04-026, but has not addressed the process for resolving the matter. While resolution prior to the adoption of the plans may better inform the utilities' planned renewables purchases, the Commission's higher priority is undoubtedly approval of the long-term plans. The process to resolve this issue should commence once the long-term plan decision is issued.

D. Analysis of Integration of Renewables in the Utility Plans

Q. What concerns do you have with regard to the utilities' long-term resource mixes?

A. The utilities have failed to provide detailed information in their resource plans regarding all of the resource types that will be employed during the next ten years. For example, SCE states that its resources are generic in design and not tied to any specific resource type or fuel. The resources do not represent any specific technology, existing product, or specific defined contract type. Similarly, SDG&E expresses that there is a potential that off-system purchases will come from coal and nuclear plants outside of its service territory. Yet, SDG&E does not give any indication of the probability of such an event or how much coal or nuclear power might be required and whether or not it is possible to purchase non-traditional generation outside of its service territory. PG&E discusses its preferred long-term strategy of 50% purchased power and 50% generation ownership over the 10-year planning horizon.[41] PG&E identifies specific renewable resource types that will meets its RPS needs[42] and contract types for combined cycle and

[41] See PG&E, p. 6-2
[42] *Ibid.* p. 4-61

combustion turbine plants.[43] Beyond rough estimates of new renewables capacity, as I discuss above in relation to the integration of RPS procurement, none of the utilities specify the anticipated resource mix (e.g. percentage contribution of a resource type to need), that it will use to fill its purchased power needs.

With respect to the above, I am concerned that the utilities will employ traditional resources (gas, coal and nuclear generation) without regard to the Energy Action Plan's required loading order and without consideration of additional cost-effective renewable resources.

Q. What is your recommendation?

A. In creating comprehensive and integrated plans, the utilities should provide a year-by-year account detailing the specific types of resources that will be utilized in the next ten years – both through their owned resources and external as well as their purchased power. These will necessarily be rough estimates, as the utilities' needs will fluctuate, as will the market for various supply resources. The utilities should also be required to show that the overall resource mix satisfies the EAP's required loading order.

V. DEBT EQUIVALENCY

Q. Please describe the factors involved in determining a utility's credit rating.

A. Rating agencies take both business factors and financial factors into account when they assign a credit rating to a company. Business factors for a utility include

[43] *Ibid*.p. 4-64

industry characteristics, the company's competitive position (its ability to market, adopt new technologies, incorporate efficiencies, and respond to new regulation) as well as the company's overall management capabilities. Financial factors for a utility include the company's overall financial characteristics, its financial policy profitability, capital structure, cash flow protection, and financial flexibility.[44] Thus, there are many inputs that go into determining a utility's credit rating. Some are quantitative and some are more qualitative evaluations.

Q. How does debt equivalency factor into a utility's credit rating?

At least one ratings agency (Standard and Poors) calculates the present value of all future fixed power payments and adds a percentage of these payments to the company's long- and short-term debt prior to calculating the company's debt-to-equity ratio. When a rating agency uses such a formulation with regard to long-term power contracts, the company being evaluated will appear to have additional debt on its balance sheet. This additional debt is referred to as debt equivalence and it may have a negative impact on a company's rating.

Q. What are the primary credit rating agencies in the U.S.?

A. The three primary ratings agencies are Fitch, Moody's, and Standard and Poors ("S&P").

Q. How does S&P treat debt equivalency in its ratings?

A. The utilities state that S&P uses a straight formulation to determine the effect of long-term purchased power contracts on a company's financial health. S&P uses a risk factor (30% for SCE, SDG&E, and PG&E) based on its assessment of the

[44] Standard & Poor's 2003 Corporate Ratings Criteria, Nov 13, 2003, p. 21.

long-term risks of recovery of power procurement costs in rates. Thus, S&P calculates total debt equivalence as the net present value of all future contract capacity payments times 30%.

Q. Are there agencies that consider the debt equivalency of purchased power contracts differently?

A. Yes. Both Fitch and Moody's believe that the debt equivalency of long-term purchased power contracts should be thought of more qualitatively in determining an electric company's credit rating.

Q. What are some of the types of qualitative issues that Moody's considers with regard to debt equivalency?

A. Moody's considers variables around the types of contracts that a utility enters into as well as the degree to which there are benefits to the long-term contracts that might partially mitigate any associated financial risks. In attempting to evaluate such benefits, Moody's considers such issues as "the terms of the contracts, the viability and reliability of the power providers, the diversity of power sources, the regulatory environment in which the utility operates, potential prudency review of power contracts, a company's declining rate base in the absence of new plant, supply availability, and fuel diversity."[45]

Q. Why are these qualitative issues important to the company's resource plans?

A. In their resource plans, the utilities are trying to minimize their use of long-term power contracts in order to protect or advance their credit ratings. However, the utilities neglect to discuss the qualitative benefits that certain long-term contracts

[45] "Moody's Continues to Weigh the Credit Risks of Purchased Power on Electric Utility Credit Quality, " Moody's Special Comment, September 1992, p.13.

provide. In fact, in response to UCS' first data request (question 2), SCE says, "[It] does not make a distinction between renewable and non-renewable resources when determining debt equivalence costs."

Q. Can you be more specific with regard to the qualitative benefits that long-term renewables contracts offer?

A. Yes. Long-term renewable contracts in particular have a positive effect on a company's generating portfolio. Specifically, with respect to Moody's qualitative considerations, renewables lower risk in the following ways: 1) Renewables provide a diversity of suppliers to buyers. Renewable generation often consists of many smaller contracts instead of one large contract. In Moody's analysis, this reduces risk to the buyer, in this case, the utility. 2) Renewables promote fuel diversity. In fact, renewables provide a hedge against fossil fuel price risks. This hedge value can be substantial. Moody's rates power contracts that promote fuel diversity in a positive light.[46]

Q. How does Fitch think about debt equivalency issues for utilities?

A. On August 2, 2004, I spoke with Fitch analyst Donna DiDonato, who specializes in utility credit ratings. She explained that Fitch's primary concern in evaluating debt equivalency for long-term power contracts is determining the likelihood that the utility will be able to recover its generating costs. She stated, "[Our] view of California has been very positive." She went on to explain that QF contracts are the most likely to be recovered, but that even non-QF contracts in California

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[46] "Moody's Continues to Weigh the Credit Risks of Purchased Power on Electric Utility Credit Quality, " Moody's Special Comment, September 1992, p.14.

would likely have a very small debt equivalency factor of around 10% (as opposed to S&P's 30% figure).

Overall, it is clear that neither Fitch nor Moody's uses a straight quantitative methodology in determining the effect of debt equivalency to a company's credit rating. Each rating agency evaluates a utility's debt equivalency on an individual basis.

Q. Are there other benefits that long-term renewable contracts can provide?

A. Yes. Long-term renewable purchased power contracts not only provide a diversity of suppliers and fuel types, but they also provide protection against future environmental regulation risk. In addition, as with any long-term contract, renewable contracts act as a hedge against the highly fluctuating wholesale electric market.

Q. So is S&P wrong in the way it evaluates long-term contracts?

A. No. However, when the utilities describe the S&P methodology, they present an incomplete picture of how S&P performs its evaluations. To state that S&P looks only at the quantitative effects in making its credit recommendation is incorrect. S&P states very clearly that,

> "There are no formulae for combining scores to arrive at a rating conclusion. Bear in mind that ratings represent an art as much as a science. A rating is, in the end, an opinion. Indeed it is critical to understand that the rating process is not limited to the examination of various financial measures. Proper assessment of debt protection levels requires a broader framework, involving a thorough review of business fundamentals, including judgments about the company's competitive position and evaluation of management and its strategies. Clearly, such judgments are highly subjective; indeed, subjectivity is at the heart of every rating."[47]

Q. What is your recommendation?

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[47] Standard & Poor's 2003 Corporate Ratings Criteria, Nov 13, 2003, p. 17.

A. The utilities have given too much weight to S&P's quantitative methodology, which adds 30% debt equivalency to the present value of a utility's long-term capacity payment obligations. Two analysts at Fitch each indicated in separate conversations that the 30% figure sounded quite high, given California's regulatory environment, wherein utilities are assured to a relatively high degree that they will be able to recover their generating costs from customers.[48] [49]

In addition, Moody's makes it very clear that its credit rating evaluation and particularly its purchased power risk evaluation has a qualitative aspect to it. S&P also indicates that its credit rating analysis has a qualitative component.

Given these factors, I believe that the Commission should consider a lower risk factor in looking at the debt equivalency issue for long-term contracts, perhaps somewhere in the 10% range.

I also feel that lumping renewable and non-renewable long-term contracts into the same risk group is wrong. By doing so, utilities, in an effort to sustain or enhance their credit ratings, try to avoid entering all long-term contracts – non-renewable and renewable contracts alike. The result is that the positive hedge factors that long-term renewable contracts present are going to be lost to the utilities, their shareholders, and their customers. The Commission should adopt a debt equivalency factor for long-term renewable contracts in California

[48] Conversation with Donna DiDnato of Fitch, dated 8/2/2004.

[49] Conversation with analyst Rob Hornick of Fitch, dated 7/29/04, "We evaluate each utility on an individual basis." He went on to say that for regulated entities, the debt equivalency of long-term purchased power contracts is minimal in figuring into a company's credit rating. He stated that at Fitch, it might account for up to 10-20% of the net present value of all future contract capacity payments contracts (as opposed to S&P's 30% added risk figure.)

that is lower than for non-renewable contracts – perhaps 5% of the net present value of capacity payment obligations.

VI. SUMMARY AND CONCLUSIONS

Q. Please provide a summary of your conclusions regarding the utilities' resource plans.

A. The goal of the utilities' 10-year resource plans is to ensure the provision of reliable and cost-effective electricity generation over a longer-term planning horizon. The plans should be clear, comprehensive, forward-looking, and include the full potential of every supply and demand-side option. With this in mind, I recommend the Commission require each of the utilities to supplement their current resource plans and make modifications to future plans in the following ways:

1) Each of the utilities should file a supplement to their plans, due by the end of January 2005 that addresses the concerns discussed above, namely:

- The Commission should require each utility to include a carbon cost in their evaluations of various resource options. The Commission should direct the utilities to model the impacts on their resource plans of carbon costs across the range currently used by other utilities.
- The utilities should weigh gas price risk as a major factor in determining their portfolios. Scenario analysis should be performed by the utilities to determine the range of expected gas prices. The results of such analysis should be used to adjust the long-term plans to mitigate gas price risks, while adhering to the State's policy priorities for adding new resources.

- The Commission should refine its process for RPS solicitations and establish a more detailed process for reviewing and approving renewables activities for 2005, including requiring updates to the renewables-specific procurement plans for 2005 and beyond.
- The Commission should direct the utilities, in creating comprehensive and integrated plans, to provide a year-by-year account detailing the specific types of resources that will be utilized in the next ten years – both through their owned generation resources as well as any purchased power. In examining the plans, the Commission should not allow utilities to currently fill all of their future needs with long-term traditional generation resources that leave no room for the future use of renewables.
- The Commission should adopt a debt equivalency factor for long-term renewable contracts that is lower than for non-renewable contracts.

The Commission should have an expedited review of those supplements in the first quarter of 2005, with a final decision on changes to the plans issued by May 1, 2005. In the meantime, the Commission should not approve any utility procurement activities for non-energy efficiency or non-renewable resources before first requiring the utility, at a minimum, to assess the future value-at-risk due to carbon emissions for any proposed contract.

2) The Commission should also issue clear direction for future long-term utility resource plans that address the issues I present in this testimony. These issues are summarized above. The Commission should also direct that future long-term plans include a more robust discussion of transmission planning and proposed

transmission projects that facilitate procurement of new renewable resources, with better integration of the results of RPS solicitations being considered in R.04-04-026 and the transmission planning issues being considered in I.00-11-001.

3) In addition to the general near-term and longer-term recommendations, I have one utility-specific recommendation that the Commission should address by January 2005:

- If the Commission approves the fall 2004 PG&E RFO, it should first require PG&E to assess the future value-at-risk due to carbon emissions for each bid in that solicitation, and to compare its short-list bids with the cost of other resource alternatives, specifically energy efficiency and renewable energy.

Q. Does this conclude your testimony.

A. Yes, it does.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. Business Consultant. May 2003 - Present.

Consulting on economic analysis and environmental impact of technologies and polices, power plant valuation, resource planning and portfolio management, financial analysis, evaluation of water use and air emissions of electricity generation, and other topics including marketing/business development, project management, consumer advocacy, and technology strategy within the energy industry.

- **Project Topics:**
  - Best practices in procurement of default electric service
  - Portfolio management practices
  - Laddering theory and practice
  - Generating options and financial instruments
  - Relationship between contract duration and contract price
  - Regulated return on equity
  - Stranded costs and control premiums
  - Stranded costs and capital structure
  - Underground transmission lines
  - Resource planning
  - End-user electricity options
  - Electricity rate trends
  - Natural gas supply and LNG terminals
  - Wind financing
  - Health effects of diesel generators
- **Papers:**
  - "Best Practices in Procurement of Default Electric Service," Electricity Journal, August/September 2004.
  - "Portfolio Management and the Use of Generation Options and Financial Instruments," NRRI Journal of Applied Regulation, Summer 2004.
  - "Long-term Power Contracts: The Art of the Deal," Public Utilities Fortnightly, August 2004.
  - "Energy Efficiency: Still a Cost-Effective Resource Option," prepared for the USAEE/IAEE Conference, Washington, DC July 2004.
  - "Strategies for Procuring Residential and Small Commercial Standard Offer Supply in Maine," April 2004

- “The 2003 Blackout: Solutions That Won't Cost a Fortune,” Electricity Journal, November 2003.
- “FERC's Transmission Pricing Policy: New England Cost Impacts,” October 2003
- “Portfolio Mangement: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers,” September, 2003

- **Testimony:**
  - Prepared testimony for Neil Talbot regarding Texas Centerpoint Stranded Cost True-up Filing, May 2004.
  - Prespared testimony for Neil Talbot regarding Ohio Market Based Standard Service Offer, April 2004.
  - Prepared comments for David Schlissel on the California Natural Gas Utilities’ Phase 1 Proposals regarding natural gas supply, March 2004.
  - Prepared testimony for Neil Talbot regarding return on equity in regard to Central Vermont Public Service Memorandum of Understanding, November 2003.
- **Meetings/Conferences:**
  - NEPOOL Reliability Committee Meetings, monthly 2003.
  - USAEE: Energy (In)Security in the US, December 2003
  - Edison Energy Institute: Emerging Issues in New England, November 2003.
  - New York State Energy Research and Development Authority: PM2.5 Conference, October 2003.
  - Renewable Modeling Conference, April 2004.
  - Restructuring Roundtable.
- **Clients:** Massachusetts Office of Attorney General, Connecticut Office of Consumer Counsel, Maine Office of the Public Advocate, New Hampshire Office of Consumer Advocate, Regulatory Assistance Project, Union of Concerned Scientists, AARP, Connecticut towns, PJM Independent System Operator, Massachusetts Audubon Society, Arkansas Public Service Commission, Natural Resources Defense Counsel, CHOKE, Illinois CUB, US Public Interest Research Group, Gulf Coast Coalition of Cities, Ohio Office of Consumer Counsel, Ratepayers for Affordable Clean Energy.

Center for Integration of Medicine and Innovative Technologies, Cambridge, MA. Project Specialist. February – May 2003. Experience with technology strategy, grant writing, and product development. Led effort to raise $2.5M to fund the tissue engineering initiative at MIT, Draper, and MGH Evaluated proposals for new medical technologies in terms of potential for long-term patient impact Coordinated technology implementation plans and progress of currently funded research initiatives

Greenfuel Corporation, Cambridge, MA. Director of Operations. Summer 2002
Experience raising capital and preparing/implementing business plans. Developed and implemented strategies for venture capital funding and market share growth. Led $3 million project proposal initiative to fund initial product development. Negotiated all legal and employee issues including incorporation and stock plan incentives. Managed investor/board relationships and coordinated corporate decision-making process.

National Park Service, Washington, DC. Business Plan Initiative Consultant. Summer 2001
Financial analysis, marketing, operations experience. Produced a 40-page business plan detailing funding needs and shortfalls for the most visited park in the National Park Service. Prepared park-wide operational standards to be used as performance management tools. Analyzed $25 million budget and recommended strategies for efficient resource allocation and alternative funding-source identification. Developed and re-branded park literature for distribution to congressional representatives, outside agencies, the National Park Foundation, and the 20 million annual visitors to the National Mall.

The Gillette Company, Boston, MA
Process Engineer. 1997-2000
Project management and consumer product experience. Managed overall operations of the corporate measurement laboratory to ensure worldwide product standardization. Streamlined product flow by implementing information management system to automatically prioritize, monitor, and analyze test results. Reduced overtime substantially by creating metrics to understand personnel efficiency and machine utilization. Led multidisciplinary Safety, Health, and Environment Team to international standards (ISO) approval.

Product Engineer. Cross-functional team and new product experience. Organized product for distribution to critical marketing consumer-use tests. Insured that product specifications conformed to overall product definition. Partnered with operations team to schedule prototype builds and analyses. Linked Mach3 blade and cartridge engineering teams by attaining hands-on technical expertise in each area.

Siemens AG, KWU, Erlangan, Germany. Researcher, MIT Coop Program. Summer 1992.
Nuclear Power Generation Division. Worked in multidisciplinary team to design, test and enhance performance of novel high temperature superconducting materials.

Mobil Solar Energy Corporation, Billerica, MA. Researcher, MIT Coop Program. Summer 1991. Evaluated the process of manufacturing solar cells in an effort to boost process yields. Performed edge strain/strength tests on laser cut cells to determine fracture pattern and process handling sensitivities.

EDUCATION
MIT Sloan School of Management, MBA, Cambridge, MA, 2002.
University of California, Los Angeles, MS, Los Angeles, CA, 1995
Massachusetts Institute of Technology, BS, Cambridge, MA, 1993

CERTIFICATE OF SERVICE

I, Jack McGowan, certify that I have, on this date, caused the foregoing TESTIMONY OF AMY ROSCHELLE ON BEHALF OF THE UNION OF CONCERNED SCIENTISTS to be served by electronic mail, or for any party for which an electronic mail address has not been provided, by U.S. Mail on the parties listed on the Service List for the proceeding in California Public Utilities Commission Docket No. R.04-04-003

I declare under penalty of perjury, pursuant to the laws of the State of California, that the foregoing is true and correct.

Executed on August 6, 2004, at San Francisco, California.

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Jack McGowan