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Hugh Wynne (Senior Analyst) • hugh.wynne@bernstein.com • +1-212-823-2692
Francois D. Broquin • francois.broquin@bernstein.com • +1-212-756-4051
Saurabh Singh • saurabh.singh@bernstein.com • +1-212-756-4113

U.S. Utilities: Manzana Wind Project Cancellation - End of the Road for Utility-Owned Renewable Generation in California?

Ticker	Rating	CUR	2/8/2011 Closing Price	Target Price	TTM Rel. Perf.	EPS 2009A	EPS 2010E	EPS 2011E	P/E 2009A	P/E 2010E	P/E 2011E	Yield
PCG	O	USD	46.54	54.00	-12.7%	3.21	3.43	3.67	14.5	13.6	12.7	3.9%
EIX	M	USD	36.95	40.00	-10.3%	3.25	3.61	3.06	11.4	10.2	12.1	3.4%
SPX			1324.57			61.70	85.34	97.17	21.5	15.5	13.6	1.8%

O – Outperform, M – Market-Perform, U – Underperform, N – Not Rated

Highlights

PG&E recently applied to withdraw its application for the 250 MW Manzana wind project, the first large-scale renewable utility-owned generation project in California, following an adverse ruling by an Administrative Law Judge (ALJ) at the California Public Utilities Commission (CPUC). Given this decision, will California's ambitious 33% Renewables Portfolio Standard (RPS) continue to play a role in the growth of the state's regulated utilities – or just create a risk of rate payer backlash?

- PG&E's decision to terminate its Manzana Wind Project calls into question the future of utility owned renewable generation (UOG) in California, and may limit utility participation in what is potentially an $80 billion capital investment opportunity over the next decade. Rather, the primary beneficiaries of this growth are likely to be renewable IPPs (independent power producers) and project developers.

- Rate payers would still bear the cost of renewable development, however, making it more difficult for utilities to secure rate increases related to utility investment, potentially limiting future rate base and earnings growth. A 2009 study by the CPUC estimates that, simply to maintain the current statutory requirement of 20% renewable generation through 2020, average electricity costs in California would rise by nearly 20% in real terms. To achieve 33% renewable generation by 2020, the study estimates, costs would rise by an additional 8%, for a total increase of 28% in real terms over 2008 levels.

- On December 21, 2010, ALJ Maryam Ebke issued a proposed decision (PD) rejecting PG&E's application seeking a permit for its 250 MW Manzana wind farm, to be developed and built by Iberdola Renewables on 7,000 acres in Southern California's wind-rich Tehachapi Pass region. On January 14, 2011, Iberdola Renewables terminated its agreement with PG&E, following which PG&E applied to the CPUC to withdraw its Manzana application on January 19, 2011. PG&E's action is presumably an attempt to pre-empt adoption of the PD by the CPUC, thereby limiting the establishment of an adverse precedent in a final CPUC-issued decision.

- In rejecting PG&E's Manzana application, ALJ Ebke agreed with objections raised by the intervenors in the proceeding, DRA (Division of Ratepayer Advocates) and TURN (The Utility Reform Network). DRA and TURN's objections were primarily centered on development risks that would result in cost over-runs and project delays, as well as operational and technological risks that would cause the project's generation output to be less than forecasted, thereby increasing the costs borne by ratepayers. DRA and TURN also disputed the cost-competitiveness of the $911 million project. These risks and costs could be better mitigated through competitively bid power purchase agreements (PPAs) with IPPs.

Hugh Wynne (Senior Analyst) • hugh.wynne@bernstein.com • +1-212-823-2692

Investment Conclusion

If adopted by the CPUC in a final decision, ALJ Ebke's ruling would set a precedent in favor of a PPA-driven approach where the utilities contract to purchase power from IPP-owned renewable projects, with project development, construction and performance risk being shifted from ratepayers to the IPPs. As such, we believe that utility investment in renewable generation, an important potential upside to rate base growth for California's utilities, may move increasingly out of reach. However, the state's utilities will continue to face the risk of rate payer opposition to the rate increases required to pay for renewable generation.

For California's utilities, investment in renewable-related transmission lines offers a clearer opportunity for rate base growth. There is a clear unmet need for new transmission lines, and upgrades to existing lines, to deliver power from remote renewable resource-rich areas to major load centers. SCE is the best positioned of the three major California investor-owned utilities (IOUs) with respect to new renewable transmission need, followed by SDG&E, while PG&E has relatively little exposure (**Exhibit 1**).

Exhibit 1
Major Renewable Transmission Projects In Progress

Transmission Project	Miles	Project Cost ($ MM)	Status	In-Construction Date	In-Service Date
SCE Techachapi Renewable Transmission Project (TRTP) Segments 4-11 (500 kV)	128	$1,742	Approved	Mar-10	2015
SCE Devers-Colorado River (500 kV)	153	$658	Approved	Q2 2011	2013
SCE Eldorado-Ivanpah (220 kV)	35	$469	Licensing (BLM, PUCN)	Q3 2011	2013
SDG&E Sunrise Powerlink (500 kV)	117	$1,883	Approved	Dec-10	2012

Source: Company Reports, Bernstein Analysis

Details

On December 21, 2010, ALJ Maryam Ebke issued a proposed decision (PD) rejecting PG&E's application seeking a permit for its 250 MW Manzana wind farm, to be developed and built by Iberdola Renewables on 7,000 acres in Southern California's wind-rich Tehachapi Pass region. On January 14, 2011, Iberdola Renewables terminated its agreement with PG&E, following which PG&E applied to the CPUC to withdraw its Manzana application on January 19, 2011. PG&E's action is presumably an attempt to pre-empt adoption of the PD by the CPUC, thereby limiting the establishment of an adverse precedent in a final CPUC-issued decision.

Manzana Decision

Rationale

In rejecting the Manzana application, ALJ Ebke agreed with objections raised by the intervenors in the proceeding, DRA (Division of Ratepayer Advocates) and TURN (The Utility Reform Network). DRA and TURN's objections were primarily centered on development risks that would result in cost over-runs and project delays, as well as operational and technological risks that would cause the actual generation output to be less than forecasted, thereby increasing the costs borne by ratepayers. DRA and TURN also disputed the cost-competitiveness of the $911 million project.

Some of the intervenors' key objections are summarized below:

- *Lack of cost competitiveness:* DRA disputed the "net market value" approach used by PG&E and recommended a time-of-day adjusted levelized cost of energy approach as a more transparent benchmark for cost comparison.
- *Project development delays:* PG&E's commercial operations date (COD) for the project December 2011 was unrealistic considering the need for a six-mile tie line to a new substation that would have to be constructed by Southern California Edison (SCE) and connect with segment 4 of SCE's Tehachapi renewable transmission line, which is still under construction.
- *Failure to develop to full capacity:* Iberdola Renewables had only secured local permits and land leases for 189 MW of the 246 MW project.
- *Optimistic capacity factor:* PG&E's assumed lifetime capacity factor of 31% was considered overly optimistic, especially given the potential for decline over the 30-year projected useful life.
- *Risk of project curtailment due to condor collisions:* The Manzana site is in close proximity to the habitat of an endangered species, the California condor, and the California Department of Fish & Game has the authority to order a full or partial shutdown even if there is a loss of a single condor.
- *Other Risks to project life:* The intervenors questioned the sufficiency of technical data to back up PG&E's predicted a 30-year project life assumption, and noted that some of the land leases were scheduled to expire before the end of this period and would need renewal.

Comparing the Economic Attractiveness of Renewable Generation Projects

Since the question of whether the proposed project was cost competitive with other renewable projects was a heavily contested issue in the proceeding, it is instructive to examine the methodological differences in the two approaches used to evaluate its cost: the "net market value" approach used by PG&E and the time-of-day adjusted levelized cost of energy approach recommended by the DRA.

The net market value of a project is the difference between the market value of energy and capacity expected to be produced by the project, expressed in $/MWh, and the per MWh levelized cost of the project. The lower the per MWh levelized cost of the project, or the higher the market value of its energy and capacity, the higher the net market value of the project. In calculating the market value of energy, PG&E used its proprietary forward power price curve for the region of the project.

PG&E claims that the net market value approach is a better measure of economic competitiveness as it takes into account both the production profile of a project (when generation takes place, i.e. during peak or off-peak periods) and the location of a project (where generation takes place). PG&E compared the net market value of 20 RPS contracts it had executed over the past year (mostly from its 2008 and 2009 RPS solicitations) with the net market value of the Manzana project and concluded that the project ranked high among this set of comparables, thereby demonstrating its economic attractiveness.

DRA, on the other hand, criticized the net market value approach because it uses a proprietary forward curve that is both uncertain and volatile. The forward price curve varies over time, leading DRA to claim that it is not appropriate to compute net market values using a different set of forward curves for each project and then compare them. DRA instead supports using time-of-day adjusted levelized cost of energy as the primary benchmark for cost comparisons of renewable projects.

Hugh Wynne (Senior Analyst) • hugh.wynne@bernstein.com • +1-212-823-2692

While we are sympathetic to PG&E's argument that the economic value of a project reflects the market price of power in the region of the project and at the time the project is generating power, we share DRA's concerns about other aspects of PG&E's cost comparison ranking. In particular, PG&E's set of comparables is skewed toward more expensive solar thermal and solar photovoltaic (PV) projects: only 2 of the 20 projects were wind projects, 2 were biomass projects and the remaining were all solar projects. PG&E's analysis thus fails to establish whether it proposed Manzana project is competitive with other potential wind projects in the same region.

Utility Owned Renewable Generation

The question that emerges from ALJ Ebke's decision is whether this decision is project specific or has broader applicability to renewable generation owned by California's utilities. The CPUC in the past has publicly spoken out on its desire to see more initiatives by the utilities to developrenewable utility owned generation (UOG). In its annual decisions approving the RPS solicitations of the utilities over the past three years (the 2010 RPS decision is not yet available) the CPUC not only stated its support for UOG explicitly (**Exhibit 2**) but also criticized the utilities for their limited plans to pursue such opportunities in the future.

Exhibit 2
Selected Comments from CPUC's RPS Solicitation Approval Decisions

- *"CalWEA says IOUs should not be encouraged to pursue direct ownership until completion of a public comment process. We disagree." -- 2007 RPS Solicitation Decision*

- *"We do not here require utilities to build resources. Nonetheless, we encourage IOUs to actively assess the feasibility of utility ownership, and pursue such ownership when and where it makes sense." -- 2007 RPS Solicitation Decision*

- *"There may be a unique and important role for utility owned RPS generation. Utility-owned generation from renewable energy resources, for example, can put downward pressure on what are otherwise increasing renewable energy prices." -- 2008 RPS Solicitiation Decision*

- *"We commend utilities for innovative work (e.g., PG&E proposal to include joint development and ownership; SCE RPS Standard Contract Program) and continue to encourage utility-owned RPS generation as necessary to meet RPS goals" -- 2009 RPS Solicitation Decision*

Source: CPUC

The utilities have historically been hesitant to take on renewable UOG projects for two reasons: (i) a CPUC requirement to competitively bid utility-built projects and (ii) an asymmetric risk sharing arrangement, where allowable capital costs were subject to a cap, but cost savings under the cap were shared on a 50/50 basis with ratepayers. This put UOG and IPP projects on an unequal footing from the perspective of the utilities. Utilities also felt that the authorized ROE might be inadequate for certain projects which have higher development, operational, or technological risk than ordinary utility investments, the bulk of which relate to lower risk distribution and transmission assets. This obstacle was removed by the CPUC in a

Hugh Wynne (Senior Analyst) • hugh.wynne@bernstein.com • +1-212-823-2692

decision issued in December 2007 as part of the utilities' biennial Long-Term Procurement Plan (LTPP) proceeding for 2006, which allowed utilities propose returns on equity for UOG on a project-specific basis. Subsequent to this rule change, there has been some interest shown by the utilities in pursuing UOG, but it has been restricted to lower-risk, smaller-scale distributed generation projects that avoid permitting and transmission interconnection issues (**Exhibit 3**).

Exhibit 3
California Investor Owned Utilities' Solar PV Programs

Program	CPUC Approval	Program Size (MW)	Ownership Split	Project Size	Project Siting	Utility Capex
SCE Solar PV Program (SPVP)	Jun-09	500 MW	250 MW UOG / 250 MW IPP	1 - 2 MW	Primarily rooftop	$1.45 billion
PG&E PV Program	Apr-10	500 MW	250 MW UOG / 250 MW IPP	1 - 20 MW	Primarily ground-mount	$1 billion
SDG&E PV Program	Sep-10	100 MW	26 MW UOG / 74 MW IPP	1 - 5 MW	Primarily ground-mount	$100 million

Source: CPUC, Company Reports

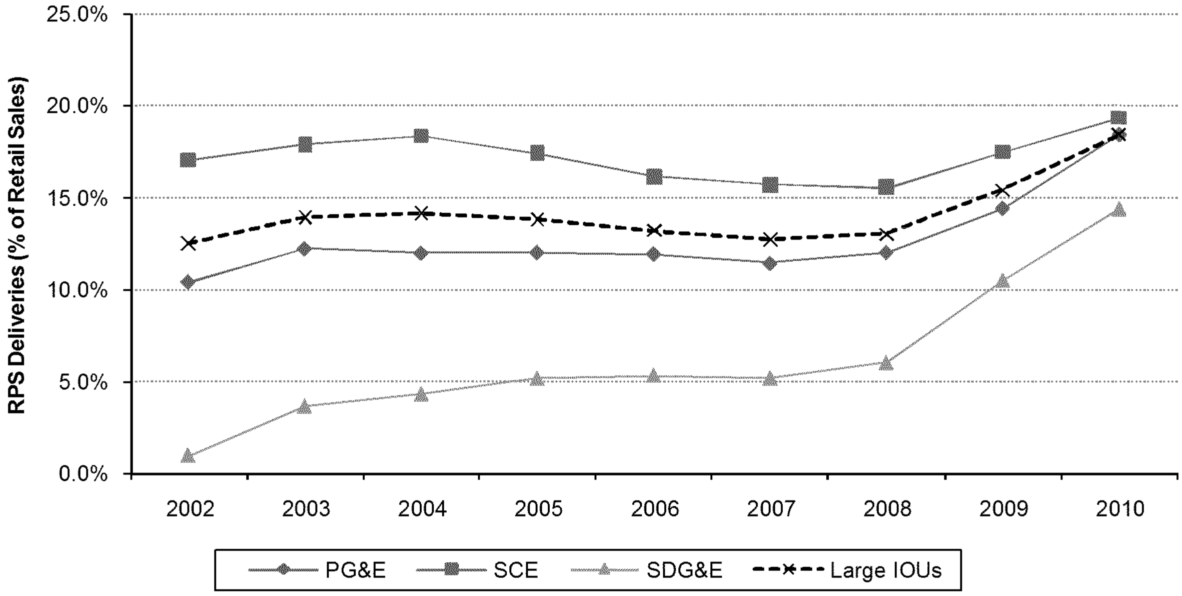
There is also a possibility that the CPUC's past stance supporting UOG might have been motivated by concerns over the financing difficulties faced by IPPs in the wake of the credit crisis, and the slow pace of RPS capacity additions, rather than a consistent embrace of UOG. Certainly, the rationale for the Manzana rejection, which ultimately is a discussion of pros and cons of different asset ownership models, seems to suggest that IPP ownership of renewable generation is viewed as being more beneficial to ratepayers from a risk perspective than UOG. With recent changes in the composition of the CPUC it would appear only more likely that this tilt towards IPP ownership of renewable generation will be strengthened.

Progress towards the RPS Goal

Challenges to Achieving 20% RPS

Progress by California's investor owned utilities (IOUs) in meeting RPS targets has been slow, with the large IOUs not expected to achieve the 20% by 2010 target for renewable generation until 2011 at the earliest and possibly 2012. (Such delays are permitted under the 3-year window provided by the flexible compliance mechanism of the RPS.) In fact at the end of 2008, six years after the effective date of the first RPS obligation, the percentage of retail electricity sold by California's IOUs that came from renewable resources was 13.0%, virtually indistinguishable from the 12.5% share in 2002 (**Exhibit 4**).

Exhibit 4
Renewable Energy Deliveries for Major IOUs by % of Retail Sales, 2002 – 2010



Note: 2010 based on Bernstein estimates

Source: CPUC RPS Compliance Reports, August 2010; Bernstein Analysis

The regulatory implementation framework for California's RPS has proven to be complex, due to (i) the high degree of detailed regulatory oversight over the renewable energy procurement process, and (ii) the split of administrative responsibilities across two different agencies, the CPUC and CEC (California Energy Commission). Certain elements of the RPS statute, most notably the cost containment provisions designed to limit the total amount spent by utilities procuring renewable energy at above-market prices, and the evaluation criteria to rank bids, have required the CPUC to devise detailed regulatory frameworks. The CPUC's regulatory decisions, moreover, have been spread across disparate proceedings instead of being consolidated into a single proceeding (or at least a narrower set of proceedings). As a result, the CPUC had to instruct the IOUs to issue interim solicitations on a voluntary basis in 2002 and 2003, while it worked on its decisions relating to the structure and mechanisms underlying the implementation of the RPS. It took almost two years for the CPUC to issue all the required decisions, and the first formal RFO solicitations did not launch till July 2004.

Despite the launch of the formal annual RFO solicitation process in 2004, 2008 was the first year in which renewable energy deliveries rose faster than overall load growth after three years of back-to-back declines over 2005-2007 (**Exhibit 5**). In fact, one reason for the rapid gain in the percentage share for renewables in retail MWh sales has been the decline in load as a result of the recession, while the renewable pipeline has continued to be built out. Had load in 2010 simply stayed steady with 2008 levels, the RPS percentage would currently be at 17%, up only 3% over the seven years since 2003 for a growth rate of ~0.5% per year -- about half of the 1% per year share gain the RPS legislation had hoped to achieve.

Hugh Wynne (Senior Analyst) • hugh.wynne@bernstein.com • +1-212-823-2692

Exhibit 5

Renewable Energy Deliveries by Major IOUs, 2002 – 2010

		2002	2003	2004	2005	2006	2007	2008	2009	2010E
PG&E	**Total Retail Sales (GWh)**	70,797	71,099	72,114	72,372	76,356	79,078	81,524	79,624	76,128
	RPS Eligible Deliveries	7,392	8,686	8,660	8,707	9,118	9,044	9,798	11,493	14,031
	% of Retail Sales	*10.4%*	*12.2%*	*12.0%*	*12.0%*	*11.9%*	*11.4%*	*12.0%*	*14.4%*	*18.4%*
SCE	**Total Retail Sales (GWh)**	68,462	70,617	72,964	74,994	78,863	79,505	80,956	78,048	74,655
	RPS Eligible Deliveries	11,658	12,615	13,375	13,042	12,708	12,467	12,574	13,619	14,416
	% of Retail Sales	*17.0%*	*17.9%*	*18.3%*	*17.4%*	*16.1%*	*15.7%*	*15.5%*	*17.4%*	*19.3%*
SDG&E	**Total Retail Sales (GWh)**	14,301	15,044	15,812	16,002	16,847	17,056	17,410	16,995	16,222
	RPS Eligible Deliveries	141	550	678	825	900	881	1,047	1,784	2,335
	% of Retail Sales	*1.0%*	*3.7%*	*4.3%*	*5.2%*	*5.3%*	*5.2%*	*6.0%*	*10.5%*	*14.4%*
Large IOUs	**Total Retail Sales (GWh)**	153,560	156,760	160,889	163,368	172,066	175,639	179,890	174,667	167,006
	RPS Eligible Deliveries	19,191	21,851	22,713	22,574	22,725	22,392	23,420	26,897	30,782
	% of Retail Sales	*12.5%*	*13.9%*	*14.1%*	*13.8%* ↓	*13.2%* ↓	*12.7%* ↓	*13.0%* ↑	*15.4%* ↑	*18.4%* ↑

Note: 2010 based on Bernstein estimates

Source: CPUC RPS Compliance Reports, August 2010

Challenges with Achieving 33% RPS

Given the difficult progress towards achieving the 20% RPS by 2010 goal, it is worth examining the challenges in accomplishing the broader 33% RPS by 2020 goal. The CPUC conducted a preliminary study of this topic in a report published in June 2009 (*"33% Renewables Portfolio Standard Implementation Analysis Preliminary Results Report"*). This analysis was conducted as part of the biennial Long-Term Procurement Plan (LTPP) proceeding for 2008 and a revised report will be published as part of the currently ongoing 2010 Long-Term Procurement Plan proceeding . The report was intended not to prescribe a particular implementation roadmap or composition of resource portfolios, but to illustrate high-level planning tradeoffs in an in-depth fashion. A 20% RPS Reference Case was analyzed to reflect the scale of resource additions required simply to maintain the current statutory requirement of 20% renewable generation through the end of 2020. In addition, four different 33% scenarios were analyzed:

- 33% Reference Case: Prioritizes RPS projects already contracted or short-listed by the IOUs
- 33% High Wind Case: Deemphasized solar thermal projects in favour of wind projects
- 33% High Out-of-State Case: Assumes construction of a new interstate transmission system to allow IOUs to procure low-cost renewable energy from other Western states
- 33% High Distributed Generation (DG) Case: Assumes limited new transmission development and assumes more extensive use of smaller-scale projects that connect directly to the distribution grid

We caution readers that a few underlying assumptions should be kept in mind while interpreting the results of this study:

(i) The report uses a load forecast prepared at the end of 2007 by the California Energy Commission (CEC) that is now out-of-date given the severity of the subsequent recession and its impact on load growth. As a result, the required scale of capacity additions is likely overstated.

(ii) The costs for new renewable generation projects that are not captured in the existing CPUC Energy Division renewable generation project database ("ED Database") are estimated through "proxy" power plants that reflect the levelized cost of energy to build and operate a project at a "reasonable profit." These estimates do not capture changing market conditions, such as the demand and supply for renewable projects, and changes in market prices for electricity that might affect competitive solicitations.

Hugh Wynne (Senior Analyst) • hugh.wynne@bernstein.com • +1-212-823-2692

(iii) The cost for existing and new conventional generation assumed a 2020 Henry Hub gas price of \$8.46/MMBtu (\$6.57/MMBtu in 2008 dollars delivered to California generators), while the current 2020 average NYMEX forward price for 2020 is about 20% lower at \$6.65/MMBtu.

(iv) The analysis assumes that GHG regulations will be in place and estimates 2020 CO2 allowance prices of \$42.46/tonne (\$31.58 in 2008 dollars), with revenues from the auction of 108 million tonnes of CO2 allowances being used to reduce utility rates so as to higher market prices for power due to CO2 allowance purchase costs.

Within the framework of the above assumptions, the analysis shows that, simply to maintain the current statutory requirement of 20% renewable generation through the end of 2020, average electricity costs would rise by nearly 20% in real terms to 16 cents/kWh relative to 2008 costs of 13 cents/kWh (**Exhibit 6**). To achieve 33% renewable generation by 2020 (33% Reference Case), costs per kWh would rise by an additional 8% to 17 cents/kWh for a total increase of 28% in real terms over 2008 levels. Costs for the High Wind Case and Out-of-State Case are comparable at a 24-25% increase, and costs for the High Distributed Generation case are significantly higher at 18 cents/kWh, a 37% increase from 2008 levels.

Exhibit 6
impact to Retail Electricity Costs Under Various RPS Scenarios

	2008 Actual	20% RPS Reference Case	33% RPS Reference Case	33% High Wind Case	33% High Out-of-State Case	33% High DG Case
Total Statewide Electricity Expenditures	\$36.8 BN	\$50.6 BN	\$54.2 BN	\$52.7 BN	\$52.5 BN	\$58.0 BN
Average Statewide Electricity Cost	\$0.132 / kWh	\$0.158 / kWh	\$0.169 / kWh	\$0.165 / kWh	\$0.164 / kWh	\$0.181 / kWh
% Incr. Relative to 2008A		19.7%	28.2%	24.7%	24.2%	37.1%
% Incr. Relative to 20% RPS			7.1%	4.2%	3.8%	14.6%

Source: CPUC, "33% RPS Implementation Analysis Preliminary Results", June 2009

The CPUC staff concluded in its preliminary report that it would be challenging for California to meet the 33% by 2020 RPS goal given its current focus on large-scale renewable projects requiring new transmission links to load centers. Based on these considerations, it seems that the CPUC is now eager to push forward a more diverse RPS procurement strategy by encouraging the development of small to medium scale (< 20 MW) system-side distributed generation projects, as witnessed by its December 16th, 2010 decision approving the Renewable Auction Mechanism (RAM) for projects of this size. This framework would also seem to align with Governor Brown's campaign pledges in which he articulated an ambitious goal of developing 12,000 MW through new distributed energy projects of up to 2 MW in size for rooftop solar, and up to 20 MW in size for ground-mount solar. Without arguing the merits of this policy option, it is clear that it will increase ratepayer costs more than other alternative RPS compliance scenarios would. Both PG&E and SCE have filed motions for reconsideration with the CPUC contesting various aspects of the RAM program that would strike at its very core. This suggests that despite publicly articulated support for a 33% RPS standard, there is still a latent fear among California's utilities of a potential rate payer backlash as consumers face rising utility bills due to the procurement of expensive renewable energy.

Hugh Wynne (Senior Analyst) • hugh.wynne@bernstein.com • +1-212-823-2692

Disclosure Appendix

Valuation Methodology

Our target price for PG&E reflects the results of a combination of valuation methodologies including: (1) a discounted cash flow model over the forecast period of 2012-16, and a terminal value in 2017, discounted back to present value using estimated weighted average cost of capital at 6.4%; (2) a discounted dividend model over the forecast period of 2012-16, and a terminal value in 2017, discounted back to present value using estimated cost of equity at 8.5%; and (3) a relative valuation technique that applies a set of key valuation metrics derived from comparable groups of regulated power utilities, to our estimates of a utility's future earnings, dividends, EBITDA and book value.

Risks

EIX:

There are several possible risks to our price target. EMG's large portfolio of coal-fired plants is exposed to gas price volatility. Our estimate of EMG's value is based on current forward power prices, which in turn reflect the prevailing forward curve for natural gas. For 2010, the forward gas price averages $4.51/MMBtu, rising to $5.15 in 2011, $5.58 in 2012, and approximately $5.85 in 2013. Given EMG's forecast coal fired generation in 2012, and in the absence of any power price hedges, we estimate that a $1.00/MMBtu increase in gas prices would add some $169 million in after-tax earnings at EMG's coal-fired fleet, or $0.51 per EIX share. Thus a $1.00/MMBtu increase in the gas price, if perceived by the market to be sustainable and capitalized at an 8x P/E multiple, could add $4.00 to the value of EIX stock.

Another significant risk to our earnings forecast is the prospect that federal or state government may impose a cap-and-trade scheme to limit power plant emissions of CO2. Coal-fired power plants in the United States emit, on average, twice as much CO2 per MWh (1.1 tons) as do their gas-fired competitors (0.6 tons). The impact on generation costs of a mandatory program of allowance purchases for CO2 emissions will thus be far greater for coal-fired plants than gas-fired generators. In the event CO2 emissions limits are imposed by the federal government, and allowances are sold by the government rather than allocated to generators for free, we estimate that an allowance price of $10/Mt would reduce EMG's earnings by $105 million, or $0.32 per share.

Risks at EIX's regulated utility, Southern California Edison for the next five years are primarily associated with the investment programs that are subject to various regulatory proceedings. Although SCE has received its 2009 GRC decision, it only determined rates for 2009 through 2011. Some 78% of the 2009-13 capital investment program is to be determined by proceedings beyond 2009 GRC, including 41% under upcoming 2012 GRC, 11% under other CPUC proceedings, and 26% under FERC rate cases. Therefore the projected rate base growth from 2010 through 2014 would be affected by the outcomes of these various regulatory proceedings, posing risk for SCE's earnings.

PCG:

PG&E's valuation remains highly uncertain until the cost of its liability for the accident, the cost to survey its transmission grid, and the scale of any potential penalties imposed by the CPUC are known. Longer-term risks include a reduction by the CPUC of PG&E's allowed ROE and equity ratio. The eventual resolution of the liabilities arising from the San Bruno explosion, and the extent to which these liabilities are covered under PG&E's liability insurance policy, could have a material impact on our forecasts and target price.

SRO REQUIRED DISCLOSURES

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- Bernstein rates stocks based on forecasts of relative per formance for the next 6-12 months versus the S&P 500 for stocks listed on the U.S. and Canadian exchanges, versus the MSCI Pan Europe Index for stocks listed on the European exchanges (except for Russian companies), versus the MSCI Emerging Markets Index for Russian companies and stocks listed on emerging markets exchanges outside of the Asia Pacific region, and versus the MSCI Asia Pacific ex-Japan Index for stocks listed on the Asian (ex-Japan) exchanges - unless otherwise specified. We have three categories of ratings:

  Outperform: Stock will outpace the market index by more than 15 pp in the year ahead.

  Market-Perform: Stock will perform in line with the market index to within +/-15 pp in the year ahead.

  Underperform: Stock will trail the performance of the market index by more than 15 pp in the year ahead.

  Not Rated: The stock Rating, Target Price and estimates (if any) have been suspended temporarily.
- As of 02/03/2011, Bernstein's ratings were distributed as follows: Outperform - 42.9% (1.6% banking clients) ; Market-Perform - 49.4% (1.4% banking clients); Underperform - 7.7% (0.0% banking clients); Not Rated - 0.0% (0.0% banking clients). The numbers in parentheses represent the percentage of companies in each category to whom Bernstein provided investme nt banking services within the last twelve (12) months.
- Mr. Wynne maintains a long position in Duke Energy Corp. (DUK).
- Accounts over which Bernstein and/or their affiliates exercise investment discretion own more than 1% of the outstanding comm on stock of the following companies EIX / Edison International.
- The following companies are or during the past twelve (12) months were clients of Bernstein, which provided non -investment banking-securities related services and received compensation for such services PCG / PG&E Corp.
- An affiliate of Bernstein received compensation for non -investment banking-securities related services from the following companies PCG / PG&E Corp, EIX / Edison International.
- In the next three (3) months, Bernstein or an affiliate expect s to receive or intends to seek compensation for investment banking services from PCG / PG&E Corp, EIX / Edison International.

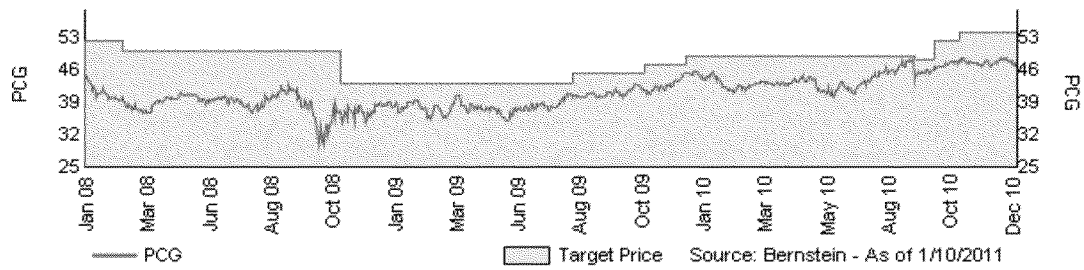
12-Month Rating History as of 02/08/2011

Ticker	Rating Changes
EIX	M (RC) 10/08/09
PCG	O (RC) 03/22/07

Rating Guide: O - Outperform, M - Market-Perform, U - Underperform, N - Not Rated
Rating Actions: IC - Initiated Coverage, DC - Dropped Coverage, RC - Rating Change

PCG / PG&E Corp

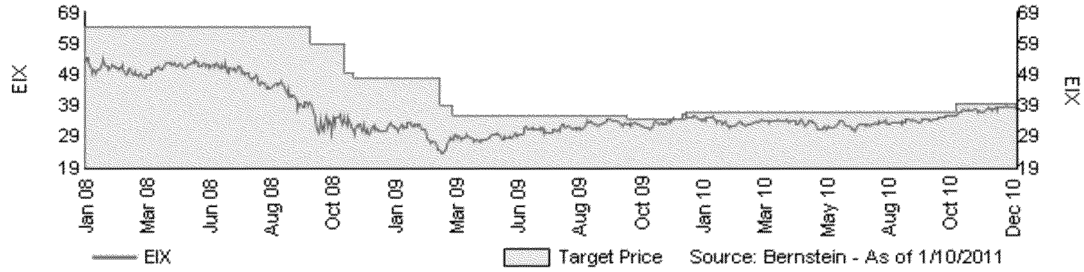
Date	Rating	Target(USD)
12/11/07	O	52.00
02/25/08	O	50.00
11/07/08	O	43.00
08/06/09	O	45.00
10/30/09	O	47.00
12/18/09	O	49.00
09/13/10	O	48.00
10/06/10	O	52.00
11/05/10	O	54.00



O - Outperform M - Market-Perform U - Underperform N - Not Rated

EIX / Edison International

Date	Rating	Target(USD)
01/02/08	O	65.00
10/02/08	O	59.00
11/10/08	O	50.00
11/21/08	O	48.00
03/03/09	O	39.00
03/18/09	O	36.00
10/08/09	M	35.00
12/18/09	M	37.00
11/01/10	M	40.00



O - Outperform M - Market-Perform U - Underperform N - Not Rated

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