California Electricity Policies – Today & Tomorrow

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Key CA state policies driving decarbonization of the electric sector

I was asked to address several different aspects of California's climate policies, specifically those related to the electric sector. I'll start by addressing a few of the more critical state policies that account for the bulk of GHG emission reductions that have occurred and are likely to occur. To date, the primary drivers of GHG reductions have been our energy efficiency programs and the renewable portfolio standard. These programs are currently saving millions of tons of GHG each year. The RPS program has resulted in over 6000 MW of new renewable resources coming on line to serve the investor-owned utilities' customers since the program's inception, with over 80% of that capacity coming online since the start of 2010. In addition to these operational MWs, the Commission has approved another 6500 MW of resources that are in various stages of development. Our utilities are substantially overprocured for the 2014 to 2016 compliance period, and there is little doubt that they will reach the 33% target by 2020. Clearly this program has impacted the electricity sector more than any other single program during the last decade.

Going forward, it's unclear to me how much RPS per se will continue to drive further adoption of renewable energy in California. Many of you may be familiar with Assembly Bill 327 that the California legislature passed last year. It is mostly know for the sections of the bill pertaining to the reform of residential electric rates, but another provision could also have profound implications for

California's IOUs. This provision simply changed the words "shall not" to "may" in one sentence of the Public Utilities Code. The thing that the Commission may now do that it could not do before is require the load serving entities under our jurisdiction to exceed 33% RPS. I'd like to assure you that neither I nor the other commissioners have hatched a plan to use this newly-delegated authority to begin ordering massive increases in the RPS requirements. For the time being, we are still focused on developing the cost-containment provisions of the program and ensuring that the utilities are on target to meet the 33% goal.

I'd like to talk for a couple of minutes about what is referred to in California as the "loading order" and how it might begin to usurp RPS as the dominant policy shaping renewable procurement in the future. The loading order is quite simply a broad policy statement that was originally included in the Energy Action Plan adopted by the CPUC and the Energy Commission in 2003 as a roadmap for ensuring reliability in the aftermath of the electricity crisis. The loading order set out a ranking of preferences to guide the acquisition of resources: first, energy efficiency and conservation; second, renewable energy and distributed generation; and third, efficient central gas-fired generation. The Plan was extensively revised in 2005, and among other revisions, demand response was added to efficiency and conservation among the highest priority resources. Until recently, the loading order served primarily as a guiding principle for the Commission, but it was not implemented in a concrete manner. Commission policy and state law required the utilities to strive for all cost-effective energy efficiency and the utilities were frantically soliciting bids and executing contracts with new renewable energy projects to meet first the 20%, and then the 33% RPS targets. Essentially, the preferred resources of efficiency, demand response and renewables were developed under their own separate, and ambitious, programs with gas-fired resources approved as needed.

I suggested that the loading order rather than RPS targets per se may begin to serve as the primary driver of new renewable energy going forward, but that historically it has been implemented haphazardly. So how might that be improved? The recent trend has been to use our bi-annual Long-Term Procurement Plan proceedings to implement the loading order in a more integrated and tangible fashion. In both the general local capacity authorization issued last year and a recent decision authorizing additional procurement for SCE and SDG&E as a result of the closure of San Onofre, the Commission has begun to require the procurement of a minimum amount of preferred resources and storage to meet local capacity requirements. Those decisions also set the stage for allowing preferred resources and storage to compete for a large share of the capacity authorized beyond the required minimums for those categories.

Besides these more tailored policies, California's cap and trade program is of course, an important policy tool. In light of the fact that allowance prices have been hovering near the floor price, I would not say at this point that cap and trade has been a significant driver of GHG reductions. It appears that all of the state's complementary policies, combined with the lingering effects of the recession, are expected to suffice to keep the state on track to meet the 2020 target. I am curious to see how the expansion of the program to transportation fuels and natural gas utilities in 2015 will play out. You would expect that any expected deficits in allowances to cover emissions from these sources would have been factored into recent allowance prices so I don't expect to see major changes. The greatest hope for relying on a carbon price to play a more significant role in driving emission reductions is for the Air Resources Board to set new long-term target for 2030 or beyond. A bill introduced in the Senate this year by Fran Pavley [SB 1125], who was one of the lead authors of AB 32, would direct the Board to do just that. I believe an ambitious target for 2030 would cause allowance prices to rise substantially, in which case cap and trade could become an important driver of GHG reductions rather than serving primarily as a backstop to other policies.

Finally, another policy that is having an impact on California's GHG emissions is the Emission Performance Standard. This law, which was passed contemporaneously with AB 32, prohibits California's load-serving entities from constructing, or entering into long-term contracts with, baseload power plants having a GHG emission rate greater than a gas-fired combined cycle plant, which we defined as 1100 lbs CO_2 per MWh. This law mostly affects the publicly-owned utilities, which we do not regulate because at the time the law was enacted, there were only two coal-fired power plants owned by or under contract to the state's investor-owned utilities: the Boardman plant in Oregon, delivering power to SDG&E under a PPA, and Four Corners in New Mexico, which was partially owned by SCE. The Boardman contract expired in 2013 and SCE's operating contract with Four Corners was scheduled to expire in 2016. However, SCE sold its share of the plant to the operator, Arizona Public Service at the end of last year. With that transaction, California's investor-owned utilities are coal-free. The Emission Performance Standard, in conjunction with stricter EPA criteria emission limits, is now beginning to have an impact on the publicly-owned utilities' assets as well, with LADWP announcing that it will divest itself from the Navajo generating station ahead of schedule.

Addressing Key Issues Associated with Implementation

Transforming the electric grid to date has not been without its challenges. The years immediately following the passage of Senate Bill 107 from 2006, which accelerated the 20% RPS target from 2017 to 2010, were hectic for all entities in the electric sector. Four years was damn little time for all of the solicitations, negotiations, permitting, contract approvals and, fundamentally, the construction that needed to occur for the utilities to hit the 20% target. In hindsight, that was too drastic a change with too little time to react. The utilities began negotiating and executing contracts with the zeal of the newly converted, the California ISO was still conducting interconnection requests on a first-come/first-served basis, which was not well-suited to interconnecting a multitude of small and medium-sized projects over the span of just a few years. Our Energy Division was also struggling to keep pace with reviewing all of the contracts the utilities were submitting for approval. Although I can't say with certainty, it's possible that the haste with which we were all trying to comply with SB 107 created a sellers' market that drove up costs for California ratepayers. Things have settled down to a steadier and more manageable pace, but I think one lesson to draw from this is that the enactment of major new policies must provide a realistic amount of time for necessary systems to be put in place and actions undertaken in order to comply.

Looking ahead, we have a couple of major issues that will need to be resolved over the next 5 to 10 years. These are the buzzwords that have generated a lot of hype in the electric industry lately: renewable integration and the evolving utility business model. First, on the subject of integration we will face challenges at various levels of the grid. At the system level, although our resources are currently sufficient to handle the integration of the renewable resources that are coming online, the ISO's analysis indicates that thousands of MW of ramping capacity will be needed by 2018 in order to complement the drop in solar production that will occur in the evening. At lower levels of the distribution system, the utilities have been voicing concerns about large fluctuations in solar output leading to voltage swings that exceed the utilities' specifications. The CPUC and the ISO have begun to proactively address some of these concerns with measures such as creating a market for flexible capacity, funding R&D in technology that will help improve cloud cover forecasting and tracking, and soon we will launch a process to holistically evaluate distribution planning and optimization.

In addition to these concerns regarding the impact of renewables on operational requirements, we must be mindful of the costs of complying with these policies. A recent study completed by E3 on behalf of California's five largest electric utilities examined the operational challenges and costs associated with RPS targets of 33%, 40% and 50% by 2030. According to their estimates, compliance with the 33% RPS will raise average rates of the investor-owned utilities by 6 to 8% in real dollars from 2012 to 2030. I believe this is an acceptable cost for adding another 13% share of renewable energy to the utilities' portfolios. However, E3's analysis indicates that increasing the RPS share to 40% by 2030 would increase average rates by 12% compared to 2012. They also examined a few different portfolios that could be used to meet a 50% RPS target. Although E3 includes several caveats to their analysis, they estimate that average rates would rise by anywhere from 13% to 39% relative to 2012 rates, depending on the scenario and assumption about gas and CO_2 prices. To put that into perspective as a strategy for reducing GHGs, E3 calculates the estimated cost per ton of CO2 avoided by moving from 33% to 50% RPS as a little over $400 per metric ton. Clearly, the state is going to need to think carefully about the suite of policies that we use going forward to reduce emissions beyond 2020. It seems certain that a greater reliance on a carbon price is likely to be much more cost-effective than merely mandating ever higher shares of renewable energy in our utilities' portfolios.

Another topic that I'd like to touch on is the utility business model. At the present, with all behind-the-meter solar accounting for a little over 1% of load served I don't believe that the California's utilities are facing an imminent existential threat. For all of the hype about the utility death spiral and grid defection, it's important to maintain some perspective. I do not yet believe there is a need to radically overhaul the utility business. There are several reasons I believe this is the case. First, there is a substantial number of accounts where customers will never be able to serve all, or even most of their own loads with solar. Multistory office or residential buildings simply do not have enough roof space relative to their loads. Over 40 percent of California's population lives in rental housing and about 30 percent lives in multifamily housing. Moreover, a significant number of occupant-owned single family residences are shaded or are otherwise not suited for solar. I see little threat of grid defection for the vast majority of California's load. However, over the next several years, we must address mechanisms to ensure that utilities receive fair compensation for the use of their distribution and back-up services and that costs are fairly allocated among customers with and without on-site generation.

California's Plans for Decarbonization through 2050

So far I've been discussing the California policies and programs that have driven GHG reductions over the past decade and will continue to do so in the near term. Now I'd like to address another point that Tom and I were asked to cover: the longer-term vision for drastically reducing GHG emissions out to 2050. Before delving much into California's options, I'll just say that well before 2050, we must hope that the federal government will have finally set the entire country on a path of major reductions in GHGs, whether by establishing a meaningful price on GHGs through cap and trade or a GHG tax, or some other combination of policies. If not, it's difficult to imagine California continuing to require any measures that impose substantial costs without the rest of the nation committed to comparable targets. As I discuss my ideas for California's GHG mitigation options, this can in fact be extrapolated to cover the US.

So to continue – all options for reductions beyond 2020 are very preliminary. The California Council on Science and Technology and the consulting firm E3 have each conducted scenario analyses of pathways to meet former Gov. Schwarzenegger's 2050 goal of reducing emissions by 80% relative to 1990 levels. These analyses can be distilled into the following three points:

1) make all end-uses of energy incredibly efficient 2) generate virtually all electricity with emission-free resources (which may include nuclear and carbon capture and sequestration), and 3) electrify all end-uses that can be electrified. That may sound daunting, but we've got 36 years to get there. Given the timeframe that we're talking about, we shouldn't expect to have an overly detailed plan. Between now and 2050, I think the best we can plan on is to continue ratcheting down the cap in the cap and trade program, continue investing in R&D in clean energy technologies, continue to expand the use of EV's and other low carbon vehicles, fostering the entrepreneurial climate in California that will deliver the next generation of GHG mitigating technologies, and monitor our progress along the way. At various points we may need course corrections to overcome barriers affecting certain technologies. For example, the Commission recently issued a decision that establishes an energy storage procurement mandate for our electric utilities. We hope that this mandate will help transform the market to bring down the cost of storage while also giving our utilities substantial real world

experience using storage to integrate renewable energy and improve grid performance. In the future, we may find for example that Californians are not adopting electric vehicles as rapidly as we had hoped. This may lead us to encourage the utilities to play a more active role in promoting the technology and helping customers with installation of charging equipment.

Views on the Prospects for AB 32 Programs to be Considered "Equivalent" under 111(d)

Now, I'd like to move on the final topic: how US EPA regulation of greenhouse gases from existing sources – the Section 111(d) regulations – may interact with California's AB 32 programs. In December, I joined California Air Resources Board Chairman Mary Nichols, California Energy Commission Chairman Bob Weisenmiller, and 12 other energy, utility, and air regulators from other states to send a letter to US EPA advocating our position on this very point.

We had extensive comments, most of which can be boiled down to the fact that our states have demonstrated successful models of reducing GHG emissions, and so EPA should recognize those programs and policies in its 111(d) standards. More specifically, we made three recommendations:

1. Establish the performance level of the standard based on a "best system of emission reduction" that reflects the full range of approaches that states have successfully used to cost-effectively reduce carbon pollution from the electricity system as a whole;

2. Establish the form of the emission guideline in a way that equitably recognizes the different starting points and circumstances of different states, including the pollution reductions already achieved by states like California through climate and clean energy programs; and

3. Allow for a variety of rigorous state compliance options, including options for compliance through participation in regional emission budget trading programs and state portfolio programs.

Let me expand on a couple of these points.

On the first point, under the Clean Air Act, the EPA is required to set the national GHG standard for the electric sector based on the "Best System of Emission Reductions" that has been demonstrated somewhere in the country. We would argue that California has demonstrated a very effective, and cost-effective, system for reducing emissions. With nearly 40 years of energy efficiency programs, twelve years of RPS, and two years of cap-and-trade under our belt before these standards are finalized, we think California and like-minded states have more than adequately demonstrated that reducing GHG pollution from electricity is not only feasible, it is affordable.

On the third point, flexibility in compliance is key. Because emissions from the delivery and use of electricity can be reduced in numerous ways, and because global warming is, well, global, all actions that reduce the overall level of emissions need to be accepted as part of a 111(d) compliant plan. Thus, changes in dispatch to use cleaner and more efficient units, fuel-switching, greater use of renewables, and energy efficiency, could all be accepted as part of a plan to reduce GHGs. In California, this means that the full gamut of AB 32 programs should be more than enough to comply with EPA's requirements.

There are some complications raised by the fact that California's AB 32 program covers more than just the electricity sector, that we trade carbon allowances with Quebec, and that we use carbon offsets. But none of these are insurmountable barriers. It's our expectation that as long as we can show the EPA that there is enough reduction in GHG pollution from electricity generation units in California, those broader program complexities will not be deal-breakers.

California's policies are effectively setting the state toward a clean energy future. We are pleased, and we think it about time that the federal government leads such a transformation across the country. California and other states have shown it can be done. The feds should set ambitious standards based on those demonstrated successes.