MEMORANDUM

To: Alameda County Community Choice Aggregation (CCA) Steering Committee

From: Mark Fulmer

Subject: Responses to Comments on the Feasibility Study

Date: June 29, 3016

MRW & Associates (MRW) released its CCA Feasibility Study report to the Steering Committee at its June 1, 2016 meeting. A number of Steering Committee members provided written comments and questions on the report (which are attached to this memo). The following are MRW's responses to those questions and comments.

Pleasanton

1. ***Key risks:*** The ranges of risks we used we think were appropriate. In any given year, the variable might be outside the range assumed, but on average we think the range is reasonable based on historical experience. Trying to predict opt-outs as a function of rate differentials is beyond the scope of the study. That said, there have been times in the past when MCE Clean Energy had rates that were higher than PG&E but there was no discernable change in the opt-out rates.
2. ***A high local renewables case:*** A high local renewables case, which assumes that 50% of the renewables requirement of the CCA would be developed in Alameda County, is currently under development and will be included as an addendum to the report.
3. ***PCIA risk.*** MRW agrees with the recommended strategy for dealing with the PCIA (collaborating with the other CCAs) and will include it in the risk assessment section.
4. ***Forecast:*** The forecast is from the California Energy Commission and is consistent with other long-run forecasts.
5. ***Rate analysis from a customer perspective:*** The analysis compares customers' rates with the Alameda CCA versus PG&E. It is not clear what additional analyses is desired.
6. ***Renewable premiums:*** MRW endeavored to be realistic yet conservative in its renewable cost estimates and based much of its analysis on renewable energy costs on actual contract prices that have been made available in the market. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low. By being conservative, the CCA has a higher likelihood of obtaining renewable contracts at a lower-than-anticipated pricing.
7. ***Balance sheet modeling of the sensitivity cases:*** The impacts on the balance sheet and reserves of the sensitivity cases were calculated in all of the sensitivity cases, but for the sake of length not included in the report. In no case but the "stress" were there any cash flow problems from the CCA point of view.

MRW generally concurs with the recommendations for further investigation, but note that they are beyond the scope of the feasibility study.

Hayward

Please add to Chapter 3 information about anticipated rates for large and small commercial customers. Anticipated rates for all classes are included in Appendix A.

Berkeley Climate Action Committee

1. ***Overstates costs of small solar*:** MRW endeavored to be realistic yet conservative in its renewable cost estimates and based much of its analysis on renewable energy costs on actual contract prices that have been made available in the market. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low. By being conservative, the CCA has a likelihood of obtaining renewable contracts at a lower-than-anticipated pricing.
2. ***Include a case with Community Solar:*** Modeling an explicit Community Solar program is outside the scope of the feasibility study. This of course does not mean that one is infeasible or should not be pursued; only that it was outside of the major variables needed to demonstrate the feasibility (or infeasibly) of community choice energy in Alameda County. It can be assumed, however, that any Community Solar program pricing would be similar to any other type of solar contract of similar size. It would seem, therefore, that in the study we could include a descriptive paragraph on Community Solar programs and say that the programmatic details would be developed by the CCA program after launch.
3. ***Energy efficiency estimate is too low***: The analysis was based on current funding limitations from the CPUC. Additional amounts can be achieved if the CCA chooses to using any incremental revenues for energy efficiency rather than bill savings or renewables.

Charles Rosselle

1. ***Competition among CCAs for limited carbon-free resources***. We agree that this could become an issue, and will add some discussion in the risks section.
2. ***Upward pressure on the PCIA form many CCAs:*** This issue is discussed on page 49 of the report.

The remaining points are thoughtful and should be kept in mind by the JPA and CCA planners if the EBCE moves forward.

Albany Sustainability Committee

1. ***Compare historic PG&E Rates to existing CCAs***. A comparison will be provided if historic CCA rates prove readily available.
2. ***Address potential curtailment of CCA solar PV projects by the CAISO***. The impacts of potential curtailment are acknowledged in Study. See the discussion starting at the bottom of page 15 and page 48.

3. ***Replace Diablo Canyon with energy efficiency, storage and renewables***. First, the base case assumes that Diablo Canyon (DC) would be shut, but replaced with gas-fired resources. While PG&E recently announced it would close DC and replace it with non-fossil resources, there are no details available (including what the rate implications of that path might be). A detailed plan will be decided at the CPUC in the Long Term Procurement Plan dockets. For a press release, there is no way they can say what they'll actually do, so they might as well put the best spin on is as they can—more renewables/EE. Second. Given that DC is a 2,000 MW baseload plant, simply replacing it with just (intermittent) solar and wind and EE can't be done without a great deal of storage. The feasibility of such an approach will depend on how much storage costs come down in the next several years. Certainly as of today, having 2,000 MW of renewables combined with large amounts of storage would cause rates to increase dramatically – thus, it's reasonable to assume that a large portion of that 2,000 MW would be replaced with fossil resources.

   Qualitatively, if we replaced DC with storage, energy efficiency and renewables, the net result would be PG&E costs that are between the base PG&E cost and the Diablo Canyon Relicense cost *(really? I would think costs would be higher if you have all that storage)*, but with PG&E GHG emissions that would be significantly lower than the PG&E base case (i.e., the big jump up on PG&E GHG emissions in 2025 would not occur).

IBEW (June 18)
General problem with approach: A stochastic (probabilistic) approach preferred over the scenario (snapshot) approach taken.

A stochastic approach requires one to identify the key inputs to an analysis, assign a probabilistic distribution to each of the values, and then run numerous scenarios to get the "average" outcome as well as the distribution of outcomes. This allows one to identify not only the average expected outcome but the probability of a negative outcome (i.e., the CCA not achieving rates lower than PG&E).

While there is an appeal to this method, it requires significantly more resources that were provided for in this study. Furthermore, it requires analysts to make critical assumptions concerning the probabilistic distribution of the values. This makes the analysis significantly more opaque and difficult to verify (was the distribution function reasonable?) without necessarily adding accuracy.

The snapshot approach allows the study to select outlying values for key variables and see if they cause undue burdens on the program. This allows the JPA or other planners to take into account these variables and implement actions to contain them. Thus, overall, we think that a probabilistic approach would yield a significant increase in cost without adding any greater level of accuracy in the forecasts. It should also be noted that no other CCA technical studies have undertaken such analyses.

1. ***A&G assumptions*****:** The values used from Sonoma Clean Power were consistent with other CCA feasibility studies. The fact that Sonoma has (nor has not) achieved their goals

in the relatively short time they have been in existence does not mean that they have underspent. It should also be noted that SCP has more than 100 MW of new renewable energy projects in its pipeline. It has only been operational since May of 2014.

2. ***Admin costs in workpapers***: This comment came from a draft version of the study. The actual admin costs are shown in Table 4 of the report.
3. ***Capacity Costs in workpapers:*** Both PG&E and the CCA always face the same cost for market RA and new capacity. Furthermore, the concerns expressed are for a period that is included in the generic model but not included in the results.
4. ***Opt-outs too low*:** The opt out rates were highest in Marin's original communities, but in the case of Sonoma Clean Power and for new areas added to MCE, the opt-out rates have been around 10%. The opt-out rates so far for CleanPower SF are below 5%. Thus, we believe the opt-out assumptions are reasonable and in any case, a 20% opt-out rate would not make a difference in the study's conclusions.
5. ***GHG emissions rates.*** A section will be added to the Appendix explicitly laying out the greenhouse allowance pricing and how the total emissions were calculated.
6. ***Renewable Costs***: The derivation of the renewable costs is shown on pages 13-16 of the Report as well as Appendix B. There are many renewable energy contracts signed by municipal utilities and other CCAs, where the contract pricing is known. MRW endeavored to be realistic yet conservative in its renewable cost estimates. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low.

IBEW (April 30)

General Comments

Need to see full documentation: Full documentation is provided in report, appendix and access to workpapers.

Impossible to forecast more than 5 years in advance: While it is difficult to forecast with precision the further out one is looking, the important matter here is that the PG&E and CCA forecasts rely on consistent underlying forecasts. Our analysis is internally consistent between the CCA and PG&E, and we have explored the sensitivity of the results to variations in the key parameters.

Specific Comments

"static load [forecast] for all sectors after 2019 is simply wrong" (emphasis original): The load forecast is from the California Energy Commission, and is developed by a dedicated staff there in consultation with PG&E.

"The estimate of 15% premium for Alameda County based solar projects is too small." MRW endeavored to be realistic yet conservative in its renewable cost estimates. All assumptions here documented. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low.

The proposed power supply should have ZERO reliance on unbundled RECs. No unbundled RECS were assumed in the analysis.

GHG issues in the three scenarios: There was an error in the preliminary results slide relied upon for this comment. It has been corrected.

Greater Local build-out of renewables. As noted above, a high local renewables case will be included as an addendum to the report.

High PCIA the status quo, not a sensitivity: While the PCIA will likely exist throughout the forecast period, there is uncertainty as to what the level will be. Thus, it's reasonable to look at potentially high PCIA levels and low PCIA levels to see how they affect CCA rates. In other words, it seems appropriate to include this variable in the sensitivity analysis. The PCIA was explicitly modelled so as to be consistent with the underlying power prices and retail rate forecasts. An arbitrarily high PCIA is presented as the sensitivity case.

Economic and Jobs Analysis: The concerns raised here are addressed in the final report and appendix.

Rivera, Sandra, CDA

From: Erik Pearson <Erik.Pearson@hayward-ca.gov>
Sent: Tuesday, June 14, 2016 5:34 PM
To: Rivera, Sandra, CDA
Subject: FW: Extending the CCA Technical / Feasibility Study comment period

Hi Sandra – I'm forwarding this to you in Bruce's absence. Thanks.

Erik

From: Erik Pearson
Sent: Tuesday, June 14, 2016 5:32 PM
To: 'Jensen, Bruce, CDA'
Cc: Alex Ameri
Subject: RE: Extending the CCA Technical / Feasibility Study comment period

Hi Bruce,

Thank you for extending the comment period for the Technical Study to June 15. We would like to see the Technical Study revised to include anticipated rates for commercial customers. Chapter 3 provides potential bill savings for residential savings, but as we market EBCE to the community, we will need to have information about rates for all customers. Please add to Chapter 3 information about anticipated rates for large and small commercial customers. Thank you.

Erik Pearson, AICP
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Utilities & Environmental Services Department
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From: Jensen, Bruce, CDA [mailto:bruce.jensen@acgov.org]
Sent: Thursday, June 09, 2016 11:00 AM
To: Jensen, Bruce, CDA
Subject: Extending the CCA Technical / Feasibility Study comment period

Hello, all – we have determined that we can provide a minor extension of the review / comment period on the Tech / Feas Study from June 10, tomorrow, to end of business on June 15 next week.

I will be away from the office that day and for some time, so I will provide contact and submittal information for this and other CCA issues either tomorrow or early next week.

Thanks, and as usual, if you have any questions, let me know.

Bruce Jensen
Alameda County Planning Department
224 West Winton Avenue, Room 111
Hayward, CA 94544
(510) 670-5400

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THE CITY OF

PLEASANTON.

June 15, 2016

Bruce Jensen
Alameda County Planning Department
224 West Minton Avenue, Room 111
Hayward, CA 94544

Re: Draft Technical Study for Community Choice Aggregation Program in Alameda County

Dear Mr. Jensen,

On behalf of the City of Pleasanton, I would like to acknowledge the effort that you and the Community Development Agency staff have put toward the Community Choice Aggregation Project and the East Bay Community Energy Steering Committee. The City of Pleasanton reviewed the aforementioned Technical Study and would like the following items to be considered prior to the County Board of Supervisors consideration of the Study.

1. The Study accurately highlights the key risks facing the County CCA as a financially viable organization; low power prices offered by PG&E, future high renewable prices and costs and Power Charge Indifference Assessment (PCIA). These risks are what other CCA organizations have faced as well. However, we believe the study lacked sufficient sensitivity analysis and could have provided a more robust assessment of these key risks, and how they impact customer retention and the financial viability of the CCA.

2. The Study's scenarios focus on two local renewable resources – wind and solar – as supplies for the CCA. Costs for these two sources have declined dramatically over the last decade, and in addition Alameda County does not have the potential for repowering its portion of the Altamont Pass wind project. We believe the Study could have developed a more robust analysis of the risks and impacts of high renewable prices and costs.

3. The Power Charge Indifference Assessment (PCIA) is assessed by PG&E on an annual basis on all customers who do not opt out of the CCA program. The PCIA charges by PG&E represent a significant cost to CCA customers. Some CCAs are working together in an attempt to manage upcoming risks associated with future PCIA charges. The future Alameda CCA should collaborate with the other CCAs in the Bay Area in ensuring that PCIA charges do not damage the competitive position of the new organization.

4. The loads and forecasts assumed in the report are quite lower at 0.3% compared to other municipal utilities that often use a 2% growth rate in electrical load in their long-range supply planning. This was also noted in the comments submitted by IBEW.

OPERATIONS SERVICES DEPARTMENT

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Support Services
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5. Although the scope of work (SOW) did include an analysis of rates from a scenario analysis and the Study did include such an analysis. The Study SOW did not request analysis of rates and billing issues from a customer perspective. We believe that additional consideration of the impact of rates on customers is crucial in understanding the risks to the CCA of customers either opting to remain with PG&E or returning to PG&E due to dissatisfaction with the prices offered by the Alameda CCA.

6. Local renewable energy development can provide an important long-term source of renewable electricity for the Alameda CCA. The Study's Cost and Benefit Analysis illustrates the importance of renewable costs and demonstrates how high renewable costs can all but eliminate any price advantage of the CCA over PG&E. As such, these costs represent a significant risk for the Alameda CCA.
    - Purchasing renewable power resources from within the State, but outside of Alameda County, can be carried out at a relatively low cost.
    - Building local solar and wind generation in the Bay Area is considerably more expensive.

   We are concerned that this premium underestimates the costs of renewable power development.

7. The sensitivity analysis presented in the Study highlights the key risks faced by the Alameda CCA. These risks are: low power prices offered by PG&E, future high renewable prices and costs, and PCIA charges. We recommend that additional modeling work be carried out on these three key risks and their impacts on Alameda CCA's balance sheet and reserve requirements.

Recommendations for further Study:

1. Over the past 6 years many communities have developed and implemented CCAs. As such, their experiences, strategies, and approaches to providing their customers with a cost competitive and cleaner energy alternative can be instructive. Although a comparison of CCAs was not included in the Technical Study RFP and therefore was out of scope for the Study, we believe that such a comparison could be beneficial for the CCA advisory steering committee as well as the individual municipal participants.

2. One of the key risks of a new CCA is the initial development of its rates. The RFP and the Study do not reference any specific goals or strategies around rate design. The approach to rate design should be included as it drives much of the operational and procurement decisions of the CCA.

3. Further assessment of the value and risk of hydropower is recommended based on the information provided in Scenarios 2 and 3, with each relying on a significant portion of the Alameda CCA supply portfolio being comprised on hydro generation. The consideration of purchasing hydro has financial, economic, regulatory and political risks and ramifications, which need to be further explored.

4. The Study does not assess in detail issues around customer opt-in retention. Rather the Study assumes that 15% of all customers, across all classes, would opt to remain with PG&E. Under Scenario 1 of the Study, the overall 15% opt out of customers is questionable given the negative GHG impacts of this Scenario. Because of this high opt-out rate, the viability of the CCA could be significantly at risk. Further study of Scenarios 1-3 should be conducted to further explore the opt-in retention and the viability

In summary, we find shortcomings in the Study's rate forecasting and its assessment of hydropower risks (availability and cost) and the risk of high-cost renewables creating a competitive and rate disadvantage for the CCA. Further, we suspect that some of the load forecasting and GHG savings estimates may be overly optimistic. We recommend further study of rate design, utility exit fees (Power Charge Indifference Assessment, or PCIA), and the cost premium for local (in County) renewable energy projects and the ability of the CCA to finance those projects. We further recommend benchmarking the Alameda CCA against existing Bay Area CCAs to evaluate the strategies and approaches used to provide their customers with a cost competitive and cleaner energy alternative to PG&E power.

Sincerely,

Kathleen Yurchak
Director of Operations and Water Utilities

Cc: Mayor Jerry Thorne
Vice Mayor Kathy Narum
Councilmember Karla Brown
Councilmember Jerry Pentin
Councilmember Arne Olson
Nelson Fialho, City Manager

June 14, 2016

Bruce Jensen
Alameda County Planning Department
224 West Winton Avenue, Room 111
Hayward, CA 94544

Dear Mr. Jensen,

The Berkeley Climate Action Coalition, whose membership includes over 650 East Bay residents, community organizations, and educational and religious institutions working to help the City of Berkeley reach its Climate Action goals and promote greenhouse gas reductions throughout the Bay Area, writes to submit comments regarding the June 2016 technical study conducted by MRW concerning the formation of East Bay Community Energy. We are very excited about the prospect of having a community choice program in Alameda as we believe it will significantly advance our climate action and sustainable economic development goals.

We would like the final draft of the technical study to include an expanded analysis of community solar and demand reduction as follows:

1. Community solar

The MRW study estimates that the development of small-scale local solar (<3MW) will cost 55% more than projects in "areas with the best solar resource" (which we understand to mean utility-scale solar projects located in the central valley and desert of southern California). A recent report by the highly respected Rocky Mountain Institute (RMI) states that "community-scale solar" (.5-5MW) can be cost-competitive with utility-scale solar. RMI identifies measures that can be taken to reduce costs of community solar by up to 40%.

Furthermore, RMI notes that community solar is inclusive of renters and low-income households (equity goals to which that EBCE subscribes) and has siting and transmission advantages over remote utility-scale solar projects. RMI concludes that community solar is the "sweet spot" between behind-the-meter and utility-scale solar.

MRW should model buildout scenarios that substitute various quantities of community-scale for utility-scale solar development. We'd like to see how the inclusion of community solar would impact economic development and rates.

2. Demand side management

MRW models 6 Gwh of annual incremental energy efficiency savings. This represents only 0.075% of load. (We are a bit confused by figures in Appendix G suggesting a much higher potential for energy efficiency and would like clarification as to what percentage of load reduction has actually been analyzed.)

SB350 calls for energy efficiency standards that are projected to reduce energy demand by 30% by 2030. Much of this demand reduction will be achieved in the electricity sector.

MRW should incorporate scenarios in which EBCE achieves demand reduction of 5% (matching Marin Clean Energy's demand reduction goal) and 18% by 2025, a national goal prescribed by RMI. Such reductions can be achieved using demand side management methods in addition to making energy efficiency improvements in buildings. Also, we propose that EBCE explore the possibility of a performance-based compensation arrangement in which the demand reduction contractor is compensated on the basis of "negawatt-hours" of energy savings.

It's important to understand now how big a role demand reduction will play in EBCE as this will affect the content of the RFP and, ultimately, the choice of program service provider(s).

Thank you for your consideration.

On behalf of the Berkeley Climate Action Coalition,

Rebecca Milliken
Climate Action Coordinator, Ecology Center
2530 San Pablo Ave, Berkeley, CA 94702
Email: rebecca@ecologycenter.org, Tel: 510-548-2220, x 240

Response to the MRW "Technical Study for Community Choice Aggregation Program in Alameda County"

Presented By: Chuck Rosselle

E-mail: crosselle@yahoo.com

Telephone: 510-206-4412

The Technical Study takes a conservative approach to the implementation of a CCA program for Alameda County by extrapolating current guidelines and practices well into the future. This approach ignores the fact that the power supply environment in both California and the nation is highly dynamic. Nevertheless, the Study provides a service in that it describes the requirements of the implementing legislation, benefits and risks inherent in the near term energy supply environment and a reasonable range of near term operational scenarios that responsible authorities can consider in establishing such a program.

The Study concludes there is a high probability that Alameda County can successfully implement a Community Energy program meeting statutory requirements which initially provides at least a minimal benefit to the ratepayers of Alameda County. This should not be surprising; Marin Clean Energy is currently providing a similar program delivering exactly this result. The Technical Study does provide assurance for decision makers that there are no current conditions in Alameda County that would preclude the implementation of an Alameda County CCA similar in function to Marin Clean Energy.

In my opinion, the Technical Study does not address biggest risk inherent in the successful operation of the CCA as an on-going business entity. In addition, it would also seem to underestimate the scope of effort required to successfully deliver value to its constituent customers. The purpose of this response is to identify the risk and describe actions necessary to mitigate the risk and successfully deliver the necessary scope of services necessary provide value. These actions are presented for consideration by those responsible for implementation of the Alameda CCA.

The single biggest risk for the Alameda County CCA program is that the overall trend towards County CCA's may be too successful. MWR has indicated that nearly all coastal counties in California (including most of the high population counties) have active plans to establish a CCA. As the number of CCA's grows, they will increasingly compete with the each other for the same sources of generation, some of which (in particular the most attractive low GHG sources) are currently controlled by the IOU's. This will likely place upward cost pressure upon these sources of power and potentially cause shortages, particularly in key power supply categories.

Additional CCA's will also put upward pressure upon the size of the PCIA. Not only will the IOU's fixed costs be spread across a smaller user base, but also the risk of stranded cost increases. This risk will continue until the CPUC and the IOU's permanently resolve any ongoing stranded asset and cost issues arising from the changing role of the IOU. High cost along with uncertainty threatens to impact the ability of the CCA's to succeed in the marketplace. If the Alameda County CCA cannot differentiate itself by offering better service or attractive pricing (hopefully both), ratepayers could fail to see the benefit of being served by the CCA as opposed to the incumbent utility, e.g. PG&E.

For the first sixty years of its existence, stable technology and fuel costs allowed the utility industry to cost effectively electrify nation utilizing the regulated monopoly model. In the 1970's the model created an overhang of stranded asses and failed projects as fuel cost volatility, turbine technological advances and regulatory compliance issues (particularly in the nuclear industry) caused utilities to make bad business decisions leading to failed capital projects. Ratepayers typically paid for these decisions as guaranteed cost recovery permitted the utilities to pass the costs of their decisions through to their customer base. Over the last twenty years the industry and its regulators have struggled to evolve a new model that rectifies the perverse incentives of the cost recovery model for an industry undergoing rapid technological change. There is no final consensus as the effort is on-going. Appendix A "The Evolution of the Power Grid" provides additional detail for anyone interested in the history of this era.

Technological advances in renewable generation, energy storage and network technology are now creating conditions which could easily lead to a new round of stranded asset risk not only for the natural gas generation infrastructure but also for the "peaking" plants being replaced by cheaper storage and the related transmission infrastructure which may become obsolete. Further complicating matters from a CCA perspective is the fact that the IOU's have traditionally favored support for their transmission infrastructure (which is subject to cost recovery) over support for an increasingly fragile distribution infrastructure, which is a cost of maintenance. Many specifics of these issues, as they relate to the Bay Area are documented by Bill Powers in "Bay Area Smart Energy 2020".

Assuming current plans come to fruition, within the next few years CCA's could easily become the majority electric power vendors for residential and commercial consumers in California. The joint CCA IOU energy supply model has the potential to succeed as the true successor to the traditional regulated monopoly model. The Alameda County CCA representing one of the largest and most diverse counties in the state, contains an enviable cross section of some of California's leading EV, battery, and solar energy technology expertise. It has the opportunity to be a leader in this transition to locally supplied power. If the CCA's do not aggressively assume this role, they risk being embroiled in the spillover from the cost pressures associated with a potentially expanding stranded asset regime along with the operational issues associated with the existing distribution network.

For many years, the utility industry presented an aspirational model of American life. Reddy Kilowatt represented the convenience and labor saving potential of wonderful devices and appliances that improved the quality of our existence. This was a direct link to Samuel Insull, the pioneering founder of Commonwealth Edison in Chicago; an early champion of the development of electric appliances as a way to increase the utilization of his turbine generators that were idle during the day when the lights were off. The entire electric appliance industry was an entrepreneurial response to this rather simple decision.

The industry's more recent struggles to restructure itself have had an unfortunate by-product of commoditizing electric power and often making its increased cost seem more like rent seeking then an opportunity for creativity. Nevertheless, some of the most innovative re-structuring is occurring at the municipal utility level; the cities of Boulder, CO and Austin, TX come to mind. The CCA initiative could achieve a similar outcome.

For a number of years, both the environmental and entrepreneurial community have recognized the potential of enhanced electrification. Not only is there great flexibility regarding how it is generated (including many which are environmentally benign), but also the economic potential is enormous. The electric power industry is the largest in the world. The biggest hurdles to enhanced electrification have been the lack of low cost, easily accessible sources of generation and the inability to store electric power in a low cost, high density, easily transportable fashion that competes with refined hydrocarbon fuels. As personally accessible electric power generation evolves and storage becomes readily accessible, the barriers to access are being lowered. Creative electrification has become an aspirational vocation for many individual entrepreneurs. What has been missing is a proper delivery mechanism.

The key is to delivery is a roadmap for the future, the framework to allow it to happen and the flexibility to respond to unexpected outcomes. The result can be a future electric power environment which is closer to the user, encouraging to innovation, and supporting the tenets of the "sharing economy":

- Enhancing experience and lifestyle
- Supporting mixed use of assets
- Supporting small scale entrepreneurialism
- Eliminating commoditization
- Taking maximum advantage of the local environment

What would such a roadmap and framework look like?

A. It would emphasize local generation.

- Local distributed generation resources reduce dependence upon competitively sourced external generation and enhance the ability to provide greater benefits to the user base and local entrepreneurs.
- Alameda County has considerable resources potentially supportive of local distributed generation (about 300,000 rooftops - many west facing, a significant commercial community, wind resources, synthetic gas generation potential, etc.). The Alameda CCA should conduct a realistic review and establish its ability to achieve eventual local energy independence, either in its entirety or for significant portions of the county. This Alameda CCA should also establish aggressive local development targets to be achieved through a combination of residential, commercial and utility grade renewables coupled with local CHP. These should be expected to be at least in the range of 50%.
- While historically uncompetitive, the cost of home PV generation is rapidly approaching competitive rates. See Appendix B for a recent LCOE discussion. The Alameda CCA should support and accelerate the adoption of this evolving capability.

- Similarly, distributed energy storage costs are rapidly approaching commercial viability. The maturation of this technology is being driven by the evolution of the EV. The Alameda CCA should support and accelerate the adoption of this technology as well.
- Net Metering has a limited lifetime. In the near future, a more realistic tariff structure will evolve in California. The Alameda CCA will be able to procure locally developed power at a competitive marginal price.

B. It would create a "one stop shop" for the local implementation of desirable generation and supporting technologies. This would include:

- A catalog of local community scale solar locations (open space, covered parking, commercial rooftops, etc.) and program to solicit local development by offering financing and permitting assistance
- A catalog of other attractive local sources of generation (wind, CHP, etc.) and a program to solicit development by offering assistance as described above
- Pre-established financing options for locally qualified suppliers. The Alameda CCA should make attractive financing for qualified suppliers a condition of any banking relationship and/or establish bond financing for local development once permitted by the maturity of the program.
- A streamlined process that supports fast-tracked permitting for projects that conform to pre-established standards (see below).

C. It would establish standards for the technologies necessary to develop the resources required to develop local energy generation and storage

- Germany has installation costs for local solar PV that are roughly half of US costs. "Soft costs" are the primary driver of this cost differential and complex permitting structures are the biggest driver of these soft cost differentials. The Alameda CCA should develop standardized configurations that support fast track permitting in order to reduce costs. Similar standards should be developed for the full spectrum of desirable generation and storage projects.
- Standardization should also include instrumentation that supports interoperability with distributed power control systems and supports demand response management.
- By providing a market and standardizing the configuration of local distributed generation technologies, the county could create configurations that enhance project asset values. This should overall enhance lender acceptance and could permit FNMA and FMCC to reduce their opposition to PACE programs, enhancing the viability of this financing option.

D. It should establish standards for a next generation Distribution Network

- The distribution network is the least robust component of the generation, transmission and distribution hierarchy. It is difficult to cost justify distribution improvements in a power generation hierarchy which classifies remote generation and transmission as high value revenue producing assets and distribution assets as a maintenance expense. In a distributed energy environment, where a greater proportion of the generating assets exist at the periphery, a robust distribution network assumes a greater level of importance.

- Further, the preponderance of events which cause unreliability in the electric supply network occur within the distribution network. Hurricane Katrina was an extreme example of this phenomenon. Several Northeastern and Mid-Atlantic States noted that micro-grids performed extremely well in comparison to the legacy network. They are aggressively pursuing the broader development of micro-grids to enhance distribution network performance. They are finding that not only do micro-grids improve customer satisfaction (due both to enhanced reliability and undergrounding), but they also improve overall network reliability and demand management capability.
- The Alameda CCA should develop a program to enhance the existing distribution network by deploying micro-grid technology.

E. It should expand the scope of the IT Services needed for success

- In addition to the basic business services described in the MRW Technical Study, the Alameda CCA should also develop the basic system support structure necessary to provide distributed generation monitoring and management. The CCA should also provide Demand Monitoring and Management capability. These services should be built to interoperate with customer devices such as PC's, smart phone and tablets.
- The services provided by these systems are critical for customer support and will provide the CCA with a valuable ability to demonstrate its value to the customer base.

F. It should aggressively promote its programs and services to the local community and take a leadership position in coordinating and lobbying for common actions within and among its peers

- Some of the initiatives and programs defined in this document may not be part of the scope of effort being currently considered by the CCA or may even be within the scope of responsibility of the IOU (PG&E).
- Nevertheless, if the CCA is to provide a successful, value added service to the citizens of the county (its customer base, I would strongly encourage that the CCA either on its own initiative or in conjunction with its peers negotiate to provide a complete set of services of the type defined herein.

Appendix A

The Evolution of the Power Grid

The Development of the Modern Power Industry

Thomas Edison opened the first commercial power plant in the United States on Pearl Street in Manhattan in September of 1882. The Pearl Street plant used a coal fired boiler to drive a reciprocating steam engine that in turn provided direct current (DC) power to one square mile of Lower Manhattan. The DC power generated by Edison could only be distributed up to a mile from the generation site. The Pearl Street plant was the first to standardize power generation for multiple users, as up to that time industrial users choosing to use electricity generated their own. In the same month, the country's first renewable power was generated in a hydroelectric power plant operating on the Fox River in Appleton, Wisconsin. The plant, later named the Appleton Edison Light Company, was constructed by Appleton paper manufacturer H.J. Rogers, who had been inspired by Thomas Edison.

The modern utility system evolved in Chicago in 1892. When Samuel Insull, the British-born secretary of Thomas Edison arrived in Chicago in 1892 the town hosted more than twenty companies commercially producing electricity. Insull assumed the presidency of the small Chicago Edison company, one of many Edison franchises around the country. While Insull did not pioneer all of the early utility innovations, he was the first to combine all of the managerial and technological innovations that transformed the utility system into its modern company form.

Insull realized that his company could make more money by increasing what became known as the "load factor", the ratio of average daily or annual power load to the maximum load sustained during the same period. Insull installed equipment to meet the peak load of use during a day, typically in the evening when customers used electric lights. He understood that if he could find customers who would use electricity during off-peak times, he could increase income without additional capital expenditure. Those customers existed, but many generated power for themselves. He enticed customers such as street railway companies, ice houses, and other businesses by offering off-peak power for a lower cost than they incurred themselves.

Insull also exploited new technologies. During the late 1880s and 1890s, electricity was generated using reciprocating steam engines. Large, bulky, noisy, and hard to maintain, the reciprocating engines of the day converted up-and-down motion to rotary motion for use by electric generators through the use of a large flywheel. Steam turbines on the other hand, produced rotary motion directly, as steam passed through vanes on a long shaft. Much smaller in size, simpler mechanically, and quieter than reciprocating engines, steam turbines produced a greater amount of power from a smaller package. More importantly, the turbines could be scaled up to produce even more power with proportionally less investment in material, allowing a utility to produce electricity at an even lower unit cost. Insull ordered his first turbine-generator set from the General Electric Company in 1903, a 5 MW unit. Pleased with the unit's performance, he ordered a second 12 MW unit in 1911.

Unlike his former patron Edison, Insull was an early adaptor of Alternating Current (AC) generators and transformers. Developed in the 1880s, AC transformers overcame the technical limitation of transmitting low-voltage direct-current to distances beyond one mile. When power produced with already existing AC generators was transformed up to high voltages, current could flow for many miles without significant degradation. In 1896, Edison competitor Westinghouse Electric built a system of hydroelectric power plants at Niagara Falls that produced power for transmission to Buffalo, 20 miles away. The AC power illuminated lights, just like direct current, but more importantly, it powered the new AC motors that had recently come to market. AC motors, in turn became increasingly popular for their use in small electric appliances. These appliances not only increased overall power usage, they also helped spread power usage throughout the day, thus increasing utility load factors.

Finally, Insull also realized that competition in the electric power supply business would never allow him to effectively invest in the scalable turbine-generators and AC transmission systems he needed. To remedy the problem, Insull sought a monopoly position for his company. He took a two-step approach. The first step was to eliminate competition by acquiring the 20 other companies he competed with in Chicago. By 1907 he was the only remaining utility and he renamed the firm "Commonwealth Edison. The second step was to protect his monopoly position by aggressively supporting beneficial regulation.

The Regulated Power Monopoly

Modern regulation evolved during the Progressive era. At the heart of progressivism was a governmental acceptance of the notion that some industries constituted "natural monopolies." According to academic economists, industries like utilities required economies of scale in order to support the capital investment necessary for creating infrastructure and services. Municipal ownership and state regulation were the common methods for creating “natural monopolies”. Progressives preferred state regulation. Wisconsin and New York pioneered regulation by establishing jurisdiction over the rates, schedules, service, and operations of their state's railroad companies. In July 1907, the Wisconsin legislature extended similar regulation to that state's electric utilities.

The Wisconsin Regulatory Commission compelled utilities to develop standard accounting techniques. It had the right to investigate the companies' books as part of the process for determining rates based on the physical valuation of a company's properties. Regulation, as viewed by its initiators, was intended to enforce the electric power companies’ “obligation to serve” their customers. They were required to build infrastructure and serve all customers with as few interruptions as possible without discrimination. To fulfill their obligation, they needed to be able to raise capital and build plants to meet their projected loads. Utilities rates for service were based upon their operating costs plus their investments in equipment (the “base rate”) plus a fair rate of return. In return, a utility company earned valuable rights. The most important right was the right to operate as a natural monopoly within its service territory. It also earned the right of eminent domain, formerly a power reserved by the state, so it could obtain property for its generating plants, transmission towers, and other equipment.

By 1914, state regulation had become standard and 44 states had established oversight of electric utilities using the Wisconsin model. Unlike railroad executives who resisted regulation, utility executives like Insull embraced the benefits. Regulation strongly supported electrification and infrastructure development. Investors knew that regulators not only oversaw the financial accounts of utilities (in an era before public disclosure of accounts was required) but also guaranteed a profit. Investments in utility companies were not as speculative as those in unregulated companies. Utilities were awarded high investment grade bond ratings. They could favorably raise money at attractive interest rates which reduced the costs of their capital projects. Regulators not only ensured that these project costs went into the utility rate base but also that generation and transmission assets were fully utilized. Eventually, regulators even allowed them to pass on-going project costs through to customers before the projects were actually completed, a practice known as Construction Work in Progress (CWIP).

Federal Government Involvement in the Power Industry

By 1940, all states had formed regulatory commissions with authority over their in-state utilities. Nevertheless, it was still not economical for private utilities to fully develop all available generation resources and provide complete electrification throughout the country. Under its interstate commerce mandate, the federal government became involved in the power industry for the first time in order to support the development of large hydropower generation facilities which were beyond the financial capability of even the largest utilities. The government developed and subsequently sold wholesale hydropower to utilities regardless of jurisdiction. In 1930 the Federal Power Commission (FPC), was established to coordinate such interstate federal hydropower development.

In 1933, the Tennessee Valley Authority was created as a federally owned corporation to provide electricity generation and economic development to the hard hit multi-state Appalachian region. In 1935, the federal government established the Rural Electrification Administration (REA) to provide electric power to the remote areas of the country previously not considered to be economically feasible to electrify. REA cooperatives pioneered the development and implementation of high voltage rural distribution networks. Today, most rural electrification is the product of locally owned rural electric cooperatives that got their start by securing government backed loans from the REA to build lines and provide service on a not-for-profit basis. REA funding is currently administered by the Department of Agriculture. That same year, under the Federal Power Act, the FPC was transformed into an independent regulatory agency and its authority was expanded to regulate both hydropower and interstate electricity transmission.

Growth and Transition

For over sixty years, state regulated electric power monopolies were successful in achieving the goal of national electrification. Unlike their regulated brethren in the transportation industry, power companies did not need to worry about competition from other forms of service. Indeed, few considered market alternatives. Power demand grew faster than GDP and technological advances, particularly more efficient large turbines and high voltage transformers, lowered the production costs for large generation plants while increasing the distance over which power could be economically transmitted. The industry became more capital intensive. Utility load planners, mindful of their dual mandate of low costs and reliable power planned and constructed large, efficient “base load” generating plants along with “peaking” plants for short duration use. In the Pacific Northwest, hydropower supplied both base load and peaking generation. The industry established an enviable record of successfully building and operating these ever larger generation plants. Most importantly, the prices for the industry's main fuels, coal and oil remained low and stable, allowing planners to comfortably build for the future.

The extended period of financial and business stability caused the industry to become highly dependent upon large "base load" generating plants for their business model. Unless generating capacity outstripped demand, regulated power utilities could operate their largest units at maximum capacity whenever they were available and be guaranteed a negotiated rate of return. In fact, the moment a shovel broke ground on most projects, they were already part of the rate base. This favorable environment ensured both a positive cash flow and a healthy return on invested capital. When coupled with the industries traditionally high credit rating, it also allowed utilities to confidently invest for the future. Unfortunately, it also made them extremely vulnerable to any disruption in the underlying factors that supported the business model, namely industry financial quality, stable fuel prices, technological change and the regulatory climate. Over the last forty years the industry has seen disruption in each of these four areas. It has responded with varying degrees of success. The story began, innocently enough as a response to the impending clean air legislation embodied in the Clean Air Act of 1970.

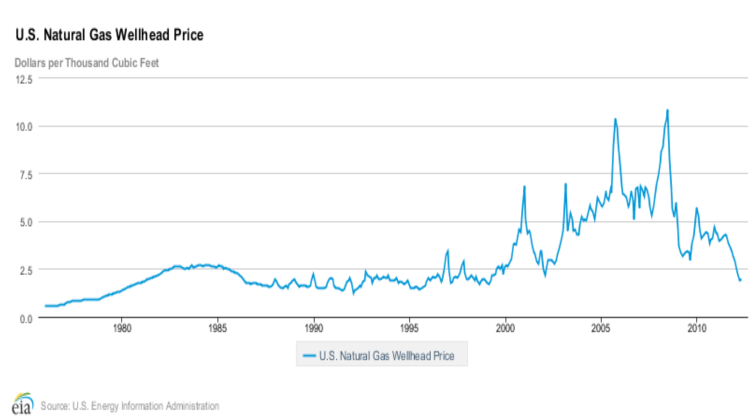
Disruption Leading to Deregulation and Restructuring

Anticipating the Clean Air Act and potential coal plant emission restrictions, low and stable crude oil prices in the late 1960's caused the industry to briefly shift its new construction base load emphasis from coal to cleaner burning petroleum-fired generation. The OPEC inspired oil price shock of 1973 created rising and unstable oil prices, questioning the wisdom of this shift. With environmental concerns threatening regulatory uncertainty in coal and global dependencies creating pricing instability in oil, the power industry was faced with potential disruption in their traditionally stable fuel supplies. There was wide industry interest in finding a stable and cost effective long term fuel source for large thermal power generation. Such a source appeared available in the form of nuclear power. With no apparent atmospheric pollutants and fuel costs that were a small percentage of the cost of generated power; nuclear provided an apparent economic and environmental advantage over coal and oil.

In the 1970's, power utilities made a major commitment to large base load nuclear power generation projects. Indeed, had all of the planned capacity been successfully deployed nuclear power today would be the largest single base load power source in the United States. Instead by the mid-1980s well over half of the planned nuclear plant projects were no longer viable due to a slowing rate of growth in electricity demand, significant cost and time overruns on projects, and increasingly complex regulatory requirements. Of the 249 nuclear power reactors originally ordered during this period, 120 were canceled and 26 were prematurely shut down. Even when successfully constructed, the technology proved to be operationally more complex than the industry was expecting. It took until the early 2000's for the overall capacity factor of the eventual nuclear fleet to reach acceptable levels. In making the transition to nuclear power, the industry faced significant financial and technological disruption.

It is difficult to overstate the impact this disruption had upon utilities, state regulators and the financial community. Regulators disallowed construction costs for failing base load power projects. Utilities could no longer automatically count on being reimbursed for their projects. In 1985, this action coupled with severe project cost overruns caused the financial industry to lower their recommendations for utility equity and reduce the credit ratings for the most heavily impacted utilities. The industry did not fully recover until the early 1990's. Many academic economists attributed this period of industry disruption to a concept termed "rate-of-return bias". They posited that not only does regulation cause utility companies to over-use capital during construction of their generating plants, but also when fuel costs become uncertain they tend to utilize that capital inefficiently. There was growing interest in the possibility of restructuring the power industry. The goal was the elimination of inefficient or unusable captive generating capacity, known as "stranded cost", and its replacement with competitively provided generation.

Power industry restructuring could not occur without deregulation. Deregulatory activity had already begun with Congress' attempt to forge an integrated energy policy in 1977 through the passage of the DOE Organization Act. This act consolidated various energy-related agencies into a Department of Energy (DOE). The following year, Congress passed the Public Utility Regulatory Policies Act (PURPA) of 1978 which opened the wholesale power markets to non-utilities. Prior to PURPA, utilities could utilize their monopoly status and refuse to interconnect or purchase power from non-utility generators at will. PURPA encouraged industrial power generation from waste heat ("cogeneration") by requiring utilities to purchase it at the "avoided cost" of building and operating their own plants. Congress also insisted that a separate independent regulatory body be retained, and accordingly the FPC was renamed the Federal Energy Regulatory Commission (FERC), preserving its independent status. FERC was asked to administer the new program described above.



Originally intended as a limited initiative to promote cogeneration and renewable power development, PURPA initiated a much broader set of changes. The industry consensus in the mid-seventies was that price controlled natural gas fueled generation would remain expensive, particularly relative to the average cost of the utility owned generation fleet. This was thought to make self-supply with natural gas burning generators uneconomic for most industrial users. Instead of remaining expensive however, the Natural Gas Policy Act of 1978 lifted the price controls on natural gas which had artificially reduced its supply and inflated its price since 1954. As decontrol of natural gas ended its artificial shortage, there was a dramatic reduction in natural gas prices. This trend lasted from 1980 through 2000 (see chart, above).

Technologically, newly developed combined cycle gas turbines rivaled and even exceeded the efficiency of the large steam turbines in use by the power industry. This overturned the prevailing wisdom that greater power generation efficiency could only be achieved through ever larger power plants. The power industry was now faced with additional regulatory and technological disruption. At the prevalent low gas prices, generators under 100 MW were as cheap to operate as coal or nuclear fired plants ten times their size. They had many operational advantages. They could be built quickly and cheaply, located where necessary and quickly amortized. They were flexibly capable of intermittent operation with minimal costs of regulation and environmental compliance. Distributed power provided by small gas turbines was a viable alternative to base load power. The Energy Policy Act of 1992 (EP Act) removed the final obstacle to supplier competition in the power market by allowing FERC to order transmission owners to carry power for other wholesale parties.

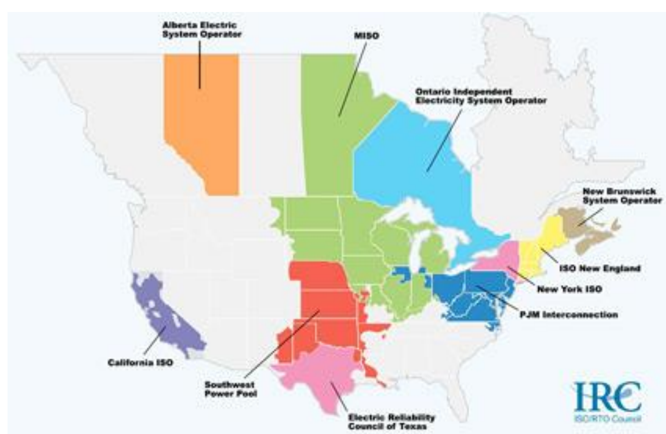
Throughout the latter portion of the 1980's and early 1990's both regulators and utilities in the largest power markets struggled to find stability amidst competition from natural gas and the increasing cost of power from large retail power plants caused by the fallout from the nuclear construction period, the rising cost of oil and the emission requirements being placed upon coal fired generators. Utilities were passing through the high costs of inefficient, un-built or delayed generation projects when at the same time they could often buy power more cheaply than they could produce it through the unregulated power exchanges arising under PURPA. If they could restructure, regulators felt they could direct their utilities to divest themselves of inefficient assets and cancel uncertain projects. Following the EP Act in 1992, many state regulators believed that the elimination of this barrier to entry, coupled with functioning, unregulated power exchanges created the conditions necessary for a smooth transition to a competitively restructured market. It was a position championed by ENRON.

In 1994, there was a second round of financial disruption in the power industry caused by the uncertainty created by PURPA and the EP Act. Utilities were now also open to a new business model. ENRON's delivered a message of unregulated power exchanges controlled by larger utilities wielding market power throughout the country. It was seductive. Larger utilities created unregulated "merchant" utility business units to competitively generate power. Between 1995 and 2001 state regulators directed their Investor Owned Utilities (IOUs) to divest themselves of 305 generating plants, comprising 156,000 MW or nearly 20% of all generating capacity in the country. About 75% of these divestitures went to the merchant utility subsidiaries of other IOUs. The non-utility generators (NUGs) supplying gas fired generation under PURPA and the merchant power subsidiaries of Investor Owned Utilities became known collectively as Independent Power Producers (IPPs). The combination of IPPs and power exchanges grew rapidly. From 1995 through 2005, utility purchases of unregulated power from IPPs grew more than twice as fast as the utilities own retail sales. In 1995, IPPs traded less than 8 million MW-h of electricity. By 1999 they were trading more than 1.5 billion MW-h of electricity.

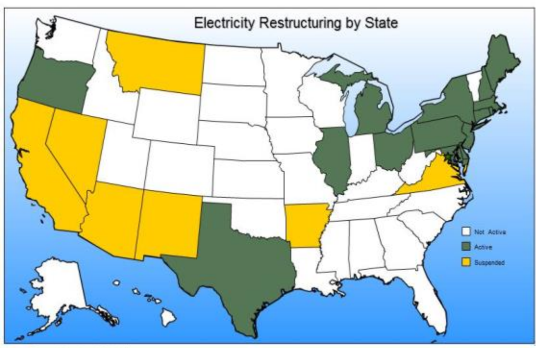
Power exchanges became the mechanism for delivering unregulated power. As more of the nation's power became supplied through these exchanges rather than through dedicated generation, the potential for retail price abuse increased. Retail users only had access to power through transmission and distribution owned by a single utility. High cost utilities could use their ownership position to abusively pass those costs through to the end user. Industrial and commercial users had self-generation options and high costs therefore fell disproportionately upon the retail user. It was becoming apparent that there was a need to standardize the unregulated wholesale power delivery structure. Consensus emerged regarding two areas of standardized structure: elimination of inefficient "stranded costs" and open access to transmission and distribution.

The issue came to a head in 2000 as a result of events in California. In 1998 California became the first state to attempt to provide retail choice through the elimination of inefficient stranded costs and the provision of open and transparent transmission access. In 2000 this initiative created a crisis when IPP's and natural gas fuel suppliers withheld or manipulated power and fuel in order to create artificial power shortages and increase short term power costs. ENRON (the power exchange operator) had orchestrated the abuse of poorly conceived power exchange rules in order to dramatically inflate costs, leading to the bankruptcy of the state's largest utility, Pacific Gas and Electric. In 2001, when ENRON failed as a business its manipulation along with the complicit actions of its power and fuel supply partners exposed the full scope of the potential for the abuse of power trading through unregulated power exchanges. Exchange operators around the country began to standardize and tightly control their operations, reducing the profitability of many of the merchant power providers. In 2002, the ENRON business failure subsequently led to bankruptcies and re-structuring in the merchant power sector, challenging the merchant power providers and exposing their utility counterparties. It created a third round of power industry financial disruption.

FERC had recognized that utility restructuring impacted interstate electricity transmission. Between 1996 and 1999 they issued standards for utilities to dispose of uneconomic assets by recovering their stranded costs. They also established a mechanism for transparent power pricing and control of transmission assets. They defined the voluntary role of an Independent System Operator (ISO) or Regional Transmission Organization (RTO) to provide non-discriminatory access to transmission and consistent operation and management over power exchanges. In order to level the playing field, the Energy Policy Act of 2005 also expanded FERC's authority to impose mandatory power availability and reliability standards on the bulk transmission system and impose penalties on entities that manipulate pricing in the electricity and natural gas markets. The California experience enhanced the role of the ISO's and RTO's as power exchange operators. Today, states that trade deregulated power through power exchanges operated by ISOs and RTOs serve 68% of the electricity consumers in the United States by volume (see chart, right); the remainder still receive some form of traditional cost-of-service regulated power.



In 1999 Texas passed the Texas Electric Restructuring Act, becoming the first state to successfully introduce a complete restructuring of its electric power market to promote competitive power delivery. Restructuring included open transmission, choice for the state's retail consumers and a requirement to fully eliminate the vertical integration common in regulated utilities. Texas' utilities were directed to unbundle their power generation, transmission and distribution, and retail electric services in the form of three separate (but possibly affiliated) companies. They were also directed to divest generation capacity to the point at which 40% or more of the residential and commercial customers in their former service areas were competitively served. Control over the state's transmission network was consolidated under the state's Regional Transmission Operator, ERCOT and retail electric customers were subsequently given choice in the selection of their power provider. Currently fifteen states and the District of Columbia have restructured electric power markets along the lines of the Texas model. This includes all large northeastern states, as well as Illinois, Ohio, Michigan, Oregon and Texas (see chart, left). These states comprise 50% of US retail power sales by volume. An additional seven states partially implemented restructuring but have subsequently suspended completion as a result of the California experience.



Both electric power deregulation and power industry restructuring were facilitated by the availability of low cost distributed power generated from inexpensive natural gas. Beginning in late 2000 natural gas prices began to rise and experience volatile price swings (see chart on page 5). From a stable price below \$2.50 per 000-ft^3, natural gas prices peaked at well over \$10 per 000-ft^3 prior to 2008. Since exchange pricing allows all qualified suppliers to sell power at the price established by the last selected bidder, high natural gas prices worked to the advantage of merchant power suppliers who owned coal or nuclear generation capability. By 2001, the nuclear fleet had begun to operate with a high level of utilization. Merchant power suppliers such as Exelon and Entergy that had focused primarily on the purchase of nuclear generation units at a significant discount were benefiting financially from higher power prices.

A combination of pent up utility demand, government financial incentives, the desire of international vendors to enter the US market and recently streamlined regulatory processes caused there to be a "nuclear renaissance". By 2009, the Nuclear Regulatory Commission had received applications for construction and operating licenses to build 25 new nuclear power reactors. Unfortunately, the case for widespread nuclear plant construction eroded fairly quickly. Natural gas prices fell as abundant supplies returned along with the concurrent issues of slow electricity demand and financing unavailability. Licenses were issued for four plants (not coincidentally in cost-of-service regulated states) while schedules for the remaining license applications were significantly extended, suspended or cancelled.

The cause of the newly abundant natural gas supply was the successful expansion of hydraulic fracturing ("fracking") to release natural gas trapped in shale rock formations. By 2011, natural gas prices had fallen below pre-2000 levels at nearly $2.00 per 000-ft^3. Consequently, merchant nuclear and coal fired power began experiencing pricing pressures. Nearly half of all nuclear power falls into the merchant category along with a quarter of all coal fired power. There has been some rebound as by early 2013 natural gas prices reached $4.00 per 000-ft^3. Many natural gas drillers have indicated that they do not intend to expand drilling of existing shale reserves until natural gas pricing becomes more favorable. The EIA projects that this "favorable" price will be in the range of $4.00 to $6.50 per 000-ft^3 over the next 20 years. Time will tell, but this is still a low price range for natural gas and should the EIA projection come to pass, the resultant situation creates an equilibrium scenario for the US economy that assures:

- Natural gas remains competitive with nuclear and most coal for electric power generation
- Renewable electric power generation becomes cost competitive with fewer subsidies
- LNG exports remain viable, including costs for liquefaction and transportation, and
- Industrial processes that require natural gas as a feed stock remain domestically viable

Nuclear advocates were not alone in assuming that rising natural gas prices would make traditional generation sources more attractive. From 2000 through 2008, there was a renewed financial interest in all forms merchant power, including the largest Leveraged Buyout in history in 2007. As a result, the return of low natural gas prices has also initiated an additional round of merchant power financial difficulties, bankruptcies and restructuring:

- **Exelon Corporation** stock fell over 7 percent when the PJM Interconnection announced that competitive bidding from external sources plus new natural gas power providers had produced a clearing price for future pricing of just $59.37 per megawatt-day, about half of what analysts were forecasting and less than half of the $136 per megawatt-day set in the 2015-16 future auctions. For Exelon, capacity revenue will fall about 41 percent in the year beginning June 1, 2016. After failing in an attempt to exempt its nuclear operations from Exchange bidding procedures, Exelon recently announced its intent to shut down its Clinton and Quad-Cities nuclear plants.
- **Energy Future Holdings** is undergoing restructuring under bankruptcy. The plan will restructure $32B in debt in its Texas Competitive Holdings Business Unit with investors and creditors absorbing losses. Energy Future Holdings (the former Texas Utilities, Inc.) was the largest power supplier in Texas, created in 2007 as part of the largest leveraged buyout in history ($47B). Note that this bankruptcy helps validate Texas' utility re-structuring model. Investors and creditors, rather than ratepayers are absorbing the results of poor business decisions.
- **Edison Mission Energy** (the merchant subsidiary of Southern California Edison) filed for bankruptcy protection in December of 2012 citing the costs necessary to bring its coal units into compliance with EPA Emissions requirements.
- **Dynegy,** an IPP has agreed to assume the Illinois coal and gas generation assets along with the debt of Ameren's merchant power subsidiary, **Ameren Genco**. Ameren, a Missouri utility has announced a re-structuring of **Ameren Genco** and will exit the merchant power business.

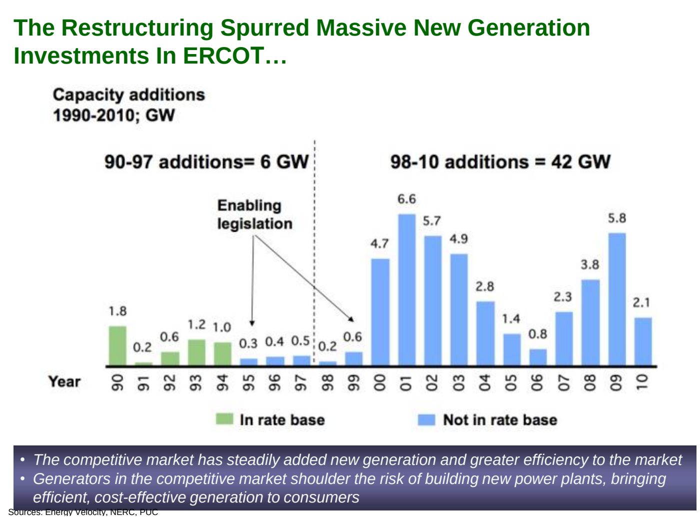
- **Dominion Resources** of Virginia is selling three fossil fueled merchant power plants in order to reduce the debt in its merchant power unit. Dominion is reducing debt to help cover the costs associated with the shutdown of its single unit Kewaunee Nuclear Plant in Wisconsin.

The Future of Deregulation and Restructuring

ENRON understood both the benefits of unregulated power exchanges along with their potential for abuse. When low cost power is available, an exchange offers the potential to acquire it at competitive prices with no risk of stranded costs. But an exchange can't overcome the realities of the existing generation and fuel supply infrastructure coupled with the complexity of a grid not optimized for exchange use. Even when the worst examples of abuse were eliminated, a lack of competitive generation alternatives has made it difficult to gain pricing advantage. Indeed, many complain that the bid system used to set power procurement policies actually causes exchange pricing to exceed regulated cost-of-service pricing. This is the primary criticism leveled by the American Public Power Association (the primary utility industry trade group).

The larger exchanges, such as the California ISO, The Electric Reliability Council of Texas and the PJM Interconnection (Mid-Atlantic) have been aggressive in implementing a series of initiatives designed to enhance exchange benefit and reduce overall power costs. California and Texas were early adopters of detailed grid modeling that allowed them to better monitor and predict their power needs and reduce or eliminate power shortages and grid congestion. PJM pioneered the development of Capacity Payments, a mechanism for contracting with power providers on a future basis to reserve power at an established price in order to eliminate short term pricing abuses. Detailed grid modeling and Capacity Payments (power price hedging in California) are now standard features of exchange operations and the results seem to reflect improved performance. The latest PJM Capacity auction incented a number of new bidders to offer power resulting in over a fifty percent reduction in the offered price.

Texas is the most aggressive proponent of a disciplined restructuring in order to create a competitive electric power market. In the opinion of the Texas legislature and service commission, a functioning power exchange, disaggregated generation, distribution and marketing and unrestricted consumer choice are all required in order to create the conditions necessary for competition. For nearly ten years, Texas struggled to enhance and adjust this model in order to bring down its retail prices. Eventually, their success in attracting new, competitively supplied generation paid off.



Texas Compared to the Rest of the Southeast

The chart on the left contrasts the recent performance of Texas and its restructured electric market with the seven other southeastern states, all of which are regulated cost-of-service states. As can be seen in the Independent Power Producer Column (IPP) on the left, nearly 70% of all power generated in Texas comes from providers classified as IPP's. Most of this power has been competitively sourced, as Texas has constructed over 42,000 MW of in-state generation since 2000 (see graphic, left). By way of contrast, over 87% of the power generated in the other seven southeastern states comes from conventional utility sources, all of which are currently part of the rate base of their utilities. In spite of the significantly lower stranded cost risk in Texas, the cost of retail power across the region is comparable and moderate with Texas at 10.89 cents/kw-h while the weighted average of the other seven is 10.55 cents/kw-h.

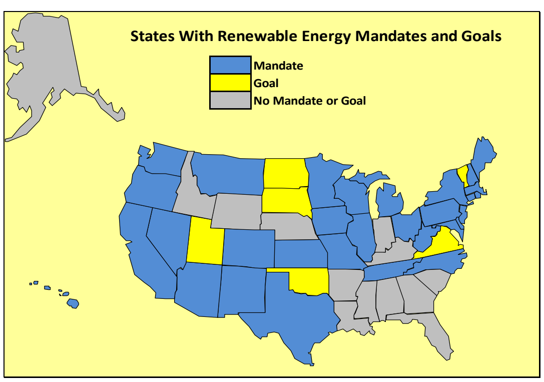
Selected Power Usage Data for January 2013: Texas vs. US Southeast Region (AR, LA, MS, AL, GA, SC, FL)

(All Data in cents/kw-hr or Thousands of MW-Hours)

	Res. Rates (cents/kw-h)	Power Providers(1/13 - MWh - 000)					Power Sources(1/13 - MWh - 000)			
		Tot	Util	IPP			Nucl	Coal	Nat Gas	Renew
TX	**10.89**	**33734**	**7047**	**23080**	**68.4%**		**2951**	**11733**	**15853**	**2734**
Pctg of Total							**8.7%**	**34.8%**	**47.0%**	**8.1%**
AR	8.74	5689	4109	1396	24.5%		1389	2718	1285	149
LA	8.76	8089	3730	1831	22.6%		959	1860	4344	228
MS	9.99	4041	2992	816	20.2%		311	463	3153	113
AL	10.84	12748	9515	2444	19.2%		3825	3573	3722	269
GA	10.25	10205	8836	942	9.2%		3045	3251	3412	284
SC	11.63	8316	8135	0	0.0%		5011	2095	919	154
FL	11.34	16220	14940	799	4.9%		2101	3262	10136	398
Wtd. Avg	**10.55**									
Total		**65308**	**52257**	**8228**	**12.6%**		**16641**	**17222**	**26971**	**1595**
Pctg of Total							**25.5%**	**26.4%**	**41.3%**	**2.4%**

Source: US Energy Information Administration (eia) - Electric Power Monthly with Data for January 2013

Energy from Renewable Sources



While not specifically a part of an unregulated or restructured power market, power from renewable sources is often included in any discussion of the transformation occurring in the power industry. Renewable power development has been significantly enhanced through Renewable Power Standards (RPS'). An RPS is a requirement for power suppliers to either procure or provide a certain minimum quantity of their total energy from renewable energy supply sources. Currently 29 states plus the District of Columbia have RPS' in the form of a goal or mandate (See chart, below).

RPS' vary widely, but generally renewable power is assumed to include power from wind, solar, biomass, hydro or geothermal sources. One state (Ohio) classifies nuclear as a renewable power source. The RPS establishes numeric targets for renewable energy supplies and seeks to encourage competition among renewable developers in meeting those targets in the least cost fashion possible. These targets are usually backed with some form of penalty if not met. Many RPS programs allow developers to utilize renewable energy certificates (REC's) to increase the flexibility and reduce the cost of compliance. Developers of non-conforming power supply projects can purchase REC's from developers that have an excess. REC's have become widespread in certain parts of the country and are electronically traded in Texas, New England, Wisconsin and within the PJM Interconnect (the Mid-Atlantic Regional Transmission Area). RPS' are designed to work in conjunction with other clean energy incentives, including federal and state clean energy tax incentives, renewable energy funds, and state integrated resource plans. California recently augmented their RPS with a cap and trade auction system for large carbon dioxide emitters.

Power industry disruption has overturned the orderly nature of this previously regulated industry and created a smorgasbord of overlapping structures. It is overly simplistic to think of power delivery in the form of regulated vs. unregulated states or traditional vs. restructured power markets. Many states are wrestling with seemingly contradictory structures. To pick just two of many examples, Oregon has chosen to become a restructured power market in order to introduce service provider competition and greater energy efficiency. They do not see the need for a power exchange given the stable nature of their hydropower. Florida, on the other hand is a traditional cost-of-service regulated state. Nevertheless, because of ratepayer dissatisfaction over the costs of failed power projects, their legislature requires cost disallowances in the case of failed, abandoned or over budget power projects. As in restructuring, this action shifts project risks from the ratepayers back to their utilities.

As was noted earlier, restructuring has created a two tier electric power industry where approximately 70% of the power consumed in the country flows through open transmission markets operated by ISOs or RTOs, while 30% is provided under the traditional cost-of-service regulated model. Restructuring has been in place for over ten years, which is a sufficient enough period of time to analyze the results and determine whether any trends are apparent.

States that opt for traditional regulation generally have experienced a lower than average cost of power and therefore do not have a "rate-of-return" bias. It is easier to justify large base load projects in these traditionally regulated states since there is a guarantee that the plant will be operated whenever it is available, that costs will be recovered and in some cases even that CWIP is available. States that opt for restructured power delivery generally have experienced a higher than average cost of power and have a strong "rate-of-return" bias. It is easier economically to provide flexible, distributed power generation in the restructured model. Perhaps nowhere in the country is it easier to see the distinction between the performance of the restructured electric power market and the regulated rate-of-return electric market than in the eight southeastern states of Texas, Arkansas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and Florida. Texas was an early adopter of open transmission access via their RTO, ERCOT. It was also an early and aggressive adopter of retail choice and utilized an RPS in order to help create a major wind power infrastructure. Texas is one of the most complete examples of a state that has adopted a restructured electric market. All of the other seven southeastern states are strong proponents of the regulated rate-of-return model.

It is, however in the plans for future capacity addition where Texas' distributed generation concept contrasts most strikingly with the traditional planning model in use in the other seven states. In the latest twenty year plan reported by the Southeast Regional Reliability Planning entity (SERC), both Georgia and South Carolina reported that they had initiated construction on a total of 4900MW of new base load nuclear generation facilities. Florida reports future plans to build approximately 2500MW of new base load nuclear and across the region approximately 12,000MW of new gas generation and 1400MW of new coal generation is planned. In the aggregate 20,800 MW of new construction is planned all of it included in the rate base. No renewable generation is included in any part of the region.

In contrast, the Texas Regional Transmission Operator (ERCOT) has a very different plan. In the "*Long Term System Assessment for the ERCOT Region dated December 28, 2012*", ERCOT has developed six different business oriented electric power scenarios. In each scenario, up to 28,000 MW of new natural gas generation capability is paired with various combinations of wind, solar and geothermal power in order to provide for overall system reliability. Prominently noted in the ERCOT report is the following: "*The capital costs for pulverized coal, integrated gasification combined cycle, and nuclear units are too high for them to be competitive under the future scenarios evaluated*". ERCOT is planning the addition of around 50,000 to 70,000 MW of competitively supplied distributed generation. All the project risk is retained by the bidders and not the Texas electricity ratepayer. Further, since the individual Texas projects are relatively small and dispersed across a twenty year timeline, ERCOT retains the option, and indeed intends to modify its plans on an on-going basis as technology and business conditions change.

The future stakes are large; globally the power industry is the largest single industry in the world. In the United States alone it generates $737B in annual revenue and nearly 3% of GDP. As the industry and regulators attempt to come to grips with the issue of providing stable low cost retail power options, several significant changes have recently occurred that have the potential to significantly change the way power is generated in the United States.

The power industry is undergoing structural and technological transformation comparable to other large network oriented industries. Like the computer and telecommunications industries, power generation is becoming less centralized. Moderate natural gas prices make combined cycle gas turbine generators competitive with much larger thermal power generators. Automated metering has introduced two way communications between power suppliers and their customers, creating the opportunity for greater network monitoring efficiency and demand response management. PC's, and now smart phones and tablets enabled distributed information processing. "Point of sale" data capture allowed the retail industry to radically re-structure its distribution model, and centralized ticketing permitted the airline industry bypass the "hub-and-spoke" terminal model in favor of more efficient point-to-point routing based upon ticket price yield analysis. The fact that automated metering is introducing two way communications between power suppliers and their customers, creates the potential for greater customer driven power supply efficiency and service.

Lazard

Levelized Cost of Energy (LCOE) V.9.0

July 19, 2016

Albany Sustainability Committee
c/o Claire Griffing – Sustainability Coordinator

Thank you for the opportunity to comment on the draft "Technical Study for Community Choice Aggregation Program in Alameda County". My general impression is that the study is a through and fair-minded analysis of complex issues. This is no surprise: The primary contractor, MRW and Associates, is well-regarded by everyone I know in the electricity business. Below I suggest some minor additional work that may help in interpreting their results and assisting the discussion of the Alameda CCA.

- Include a historical comparison of electricity rates charged by PG&E and other CCAs. The expectation of lower rates was part of the appeal of each CCA. How has that worked out?
- For each scenario, include an estimate of the change in Greenhouse Gas emissions for the entire Northern California electricity sector, relative to the Base Case. In one scenario in the Technical Study, attribution of GHG emissions shifts from one entity to another, but there may be no overall reduction in emissions.
- Address in greater detail the operational concerns stated by the California Independent (Grid) Operator, or CAISO, regarding additions of solar electricity and possible curtailment of solar generators.
- Include two additional sensitivity cases on the assumed shutdown of the Diablo Canyon nuclear plant.

Each of these suggestions is described below. At the end, I present an analogy between the electricity grid and a tandem bicycle. I assume that people discussing the CCA understand how the grid works. However, newcomers (like me when I began work in the electric industry) may be assuming that the electricity grid works like Amazon or FedEx, e.g., I sign up for solar electricity and the grid delivers it to me. This is incorrect, and the correct view has policy implications.

Once again, thank you for the opportunity to comment.

Historical Comparison of CCA and PG&E Rates

Formation of each existing CCA was accompanied by an expectation of electricity rates lower than those charged by PG&E. How did that turn out? I was unable to find a comprehensive historical comparison. Instead, I found two snapshots. One shows what I expected: Sonoma Clean Energy's current monthly electricity bills are roughly 5% to 10% lower than those of PG&E. The other snapshot was surprising: Marin Clean Energy's bills are currently 5% to 10% higher than PG&E's. It would be helpful to have more than two data points.

Developing a complete historical comparison may be challenging, but MRW clearly has the expertise to do it, though it may require an addendum to the consulting contract.

> The comparisons of monthly bills are at these links:
> https://sonomacleanpower.org/wp-content/uploads/2015/11/2015-09-01-SCP_Joint-Rate-Comparison.pdf
> http://www.pge.com/includes/docs/pdfs/myhome/customerservice/energychoice/communitychoiceaggregation/mce_rateclasscomparison.pdf

GHG Emissions from Northern California's Electricity Sector

In the Technical Report, two scenarios appear to change the <u>attribution</u> of GHG emissions among different entities in Northern California, without major changes in total emissions from that sector. Adding estimates of electricity-sector GHG emissions to the Technical Study would clarify important results from Scenario 1 and Scenario 2.

For Scenario 1, the Technical Study states that:

> "there are no greenhouse benefits for Scenario 1 [for the Alameda CCA]—in fact there are net incremental emissions" (p. vii).

This statement seems unduly pessimistic. It appears that in Scenario 1, customers leaving PG&E to join the Alameda CCA are no longer credited with a share of PG&E's GHG-free electricity (hydro and nuclear), but there is no change in overall emissions.

In Scenario 1, the Alameda CCA meets 33% of its customers' demand with renewables, and meets the other 67% with purchases of non-renewable electricity from the wholesale market. This treatment increases the GHG emissions attributed to the customers who leave PG&E to join the Alameda CCA, because they are no longer credited with shares of PG&E's GHG-free electricity. However, Alameda's purchases of non-renewable electricity are offset by reduced purchases by PG&E, because it has fewer customers than in the Base Case.

A similar observation applies to Scenario 2, where it is more important. The Technical Study notes that

> "The Alameda CCA's GHG emissions under Scenario 2 are much lower than those under Scenario 1. This is due to the higher renewable content in the CCA's generation mix under Scenario 2, but <u>more importantly</u>, the 50% hydro content in the non-renewable generation mix." (p. vii, emphasis added)

In other words, the Alameda CCA has lower GHG emissions in Scenario 2 than in the Base Case or Scenario 1 partly because it builds or pays for construction of more GHG-free generators. This is "steel in the ground", and causes a drop in the GHG emissions of the Northern California electricity sector. So far, so good, but how about that more important part--the "50% hydro content in the non-renewable generation mix".

To the best of my knowledge, all of California's good sites for hydroelectric generators are already being used, so new hydro is not an option. The Technical Study may be assuming that, when an existing contract to sell hydroelectricity expires, the Alameda CCA will outbid other CCAs and utilities to sign a new contract in order to achieve "50% hydro content". This is how I interpret the statement in the Technical Study that "if carbon reductions are a high priority for the CCA, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed" (p. xiii).

If my interpretation is correct, Scenario 2 assumes that the Alameda CCA would outbid competitors for electricity from existing hydroelectric plants. Outbidding would change the allocation of GHG emissions among parties in Northern California, without any change in the total GHG emissions.

It seems reasonable to assume aggressive bidding by many entities for hydroelectricity when current contracts expire. The Alameda CCA could be trying to outbid the Marin and Sonoma CCAs and utilities including PG&E, the Sacramento Municipal Utility District, Palo Alto, Modesto, Turlock and others

CAISO's Operational Concerns

The California Independent [Transmission] System Operator, or CAISO, has repeatedly expressed concern about its ability to provide reliable service due to operational difficulties caused by increasing additions of solar generators. This concern may be relevant to the Alameda CCA because CAISO can address it partly by forcibly "curtailing", or disconnecting solar PV from the grid.

The CAISO's concern is complicated and hard to explain, and even harder to analyze. Here is a description by the National Renewable Energy Laboratory of the CAISO's concern:

> "In 2013, the California Independent System Operator (CAISO) published a chart showing the potential for "overgeneration" occurring at increased penetration of solar photovoltaics (PV). The "duck chart"[2] shows the potential for PV to provide more energy than can be used by the system, especially considering the host of technical and institutional constraints on power system operation.
>
> During overgeneration conditions, the supply of power could exceed demand, and without intervention, generators and certain motors connected to the grid would increase rotational speed, which can cause damage. To avoid this, system operators carefully balance supply with demand, increasing and reducing output from the conventional generation fleet. The overgeneration risk occurs when conventional dispatchable resources cannot be backed down further to accommodate the supply of variable generation (VG). Overgeneration has a relatively simple technical solution,

> often referred to as curtailment. Curtailment occurs when a system operator decreases the output from a wind or PV plant below what it would normally produce."
>
> Source: "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart", November 2015, at http://www.nrel.gov/docs/fy16osti/65023.pdf

The Technical Study may not directly address the CAISO's concern. The Study does address hours when the Alameda CCA's renewable generators produce more electricity than its customers are using (pp. 11-12 and Appendix B-3), but it's not clear whether that approach addresses the problem at the grid level. If the Alameda CCA and other entities collectively build "too much" solar PV, the CAISO may accommodate electricity from Alameda's PV units by curtailing PV units owned by other entities.

I suggest that the Technical Study examine the possibility of curtailment of solar PV units, whether owned by the Alameda CCA or other entities. Curtailment might be a problem, especially if Alameda pursues a 100% renewable portfolio based largely on solar PV.

Sensitivity Study: Replacement of Diablo Canyon Nuclear Power Plant

The Technical Study assumes that PG&E retires Diablo Canyon Units 1 and 2 when their operating licenses expire in 2024 and 2025. The Technical Study apparently assumes that PG&E replaces Diablo with GHG-emitting electricity:

> The expected retirement of Diablo Canyon in 2025 increases PG&E's emissions by approximately 30% in 2025. (p. vii)

Would it be reasonable to include a sensitivity case in which PG&E replaces Diablo with renewable sources? Such a sensitivity case would presumably raise the Study's forecast of PG&E rates and cut its forecast of PG&E's GHG. It would be useful to see quantitative results.

Sensitivity Study: Extension of Diablo Canyon Operation

To justify the assumed retirement, the Technical Study cites several costs, notably a cost of $4.5 billion cost to install cooling towers "per state regulations implementing the Federal Clean Water Act" (p. C-3). This assumption is included in the Base Case and Scenarios 1 and 2, and clearly it deserves that treatment. Is it conceivable, however, that the impacts of climate change over the next several years cause a shift in public opinion and the law to promote relicensing? Would it be reasonable to perform a sensitivity case in which PG&E's cost to relicense Diablo is, say, $1 billion because of a change in the law?

Tandem Bicycle Analogy to the Electricity Grid:

Newcomers to electricity issues sometimes assume (as I once did) that the electricity grid works like Amazon or FedEx: I order a parcel of, say, electricity from solar panels, and, supposedly, it is delivered through the grid to my house. The reality is more complicated, and has policy implications. The analogy between the electricity grid and a tandem bicycle may help.

Imagine a long tandem bicycle, with many seats, ascending a long, even grade. Suppose that it must be kept ascending at a constant speed (e.g., because traveling faster or slower would cause excessive vibration). Some people (representing generators) are pushing on their pedals, providing mechanical energy to propel the bicycle. Others are passengers (representing demand or "load") who are free to jump on or off.

As passengers jump on or off, the pedalers must collectively adjust how hard they press on the pedals to keep the bicycle moving at a constant speed. If one pedaler suddenly stops pressing on the pedals, others have to press harder to maintain a constant speed.

Now suppose that new pedalers are added, but the new pedalers push hard on the pedals only when the sun breaks through the clouds. At those sunny times the other pedalers have to push lightly on the pedals, or not at all, to prevent the bicycle from achieving excessive speed.

In the terms of this analogy, the CAISO's operating concern is that, as more solar "pedalers" are added, their pedaling occasionally overwhelms the collective ability of other pedalers to back off. One solution is curtailment of the solar pedalers: The CAISO disconnects some pedals from the tandem bicycle's chain, thereby wasting some potential renewable electricity and not realizing its environmental benefits.

Thank you for considering these comments.

Sincerely,
Mark Meldgin
Albany CA

Notes:

1. The draft Technical Study and draft Appendices are at the following links: https://www.acgov.org/cda/planning/cca/documents/Feas-TechAnalysisDRAFT5312016.pdf and https://www.acgov.org/cda/planning/cca/documents/Feas-TechStudyappendices05312016.pdf
2. The tandem-bicycle analogy is presented in greater detail, aimed at an engineering audience, at this site: http://www.leonardo-energy.org/sites/leonardo-energy/files/root/Documents/2009/ElectricityTandem.pdf

Rivera, Sandra, CDA

Subject: FW: IBEW comments - MRW Work Papers

From: Stern, Hunter [mailto:hls5@IBEW1245.com]
Sent: Saturday, June 18, 2016 7:01 PM
To: Rivera, Sandra, CDA <sandra.rivera@acgov.org>; Jensen, Bruce, CDA <bruce.jensen@acgov.org>; 'mef@mrwassoc.com' <mef@mrwassoc.com>
Cc: 'Uno, Victor' <Victor_Uno@IBEW.org>
Subject: RE: IBEW comments - MRW Work Papers

Sandra,

Again thanks for the extra hours to submit these comments. More importantly, thanks to the County and MRW for making these Work-Papers available for review. This has given clear insight into the information contained MRW draft report and updated draft.

The "Big Picture" take away from these Work Papers is that the MRW Technical-Feasibility report errs in its approach and analysis. Partly, there is inadequate or missing documentation that does not substantiate the information and apparent conclusions made by the Report. But the fundamental error is the approach.

The MRW report is no more than a single snapshot of a series of single predictions regarding future PG&E rates, future cost of solar power, future cost of power from local renewable projects and numerous other distinct data points. In fact, these data points are, in most cases, no better than 'guesses and the resultant conclusions are entirely unreliable. The failure of this review and others associated with decisions to launch Community Choice Aggregation public agencies in Marin, Sonoma and San Mateo is that the Technical-Feasibility report relies on unsubstantiated estimates as if they are fact and then concludes to advise Alameda County that the CCE will be successful and should launch.

In fact, a proper Technical-Feasibility report should be made via Probability Analysis. Probability Analysis can take the variables of the needed data points, utilize these variants to include the likely value of each data point and then combine these probabilities to create an accurate determination of the likelihood that an Alameda CCE will achieve the desired objectives. The IBEW strongly urges that the Peer Review of the MRW Study include Probability Analysis of the information gathered by MRW as well as including the information missing which is needed to complete the analysis.

Here are specific comments on the Work Papers:

1. MRW uses Sonoma Clean Power (SCP) data for base A&G assumptions yet SCP has not met its promises/expectations of high RPS content (SCP has only 33% RPS), has not built any local projects (that I know of), and is in a dead heat with PG&E rates. Further, SCP was caught completely off guard by the PCIA increase, which, with adequate technical assistance, SCP should have been able to predict. Unless Alameda wants a track record like SCP, SCP A&G assumptions are not reliable.
2. "Admin Costs" at tab "Detail" F7-F11 states "these are just guess/placeholders" for $1.2mm in Admin Costs. On what basis is this guess made? Marin Clean Energy (MCE) has claimed as much as $2.5 Million in start-up costs. San Joaquin Valley Power Authority spent more than $2 Million. SCP has never discussed their costs but as the planning and project work was done by the Sonoma County Water Agency and they reportedly spent $1.5 million in its work. How can this be a guess and why use $1.2 Million. Given that the County has contracted for this work, we should expect more than guesses and placeholders for costs in the millions.

3. "PG&E Rate Model" at tab "PG&E Capacity Forecast" B10 states "Note: CPUC's October 2015 Scenario Tool in Long Term Procurement Proceeding (R.13-12-010) shows total system supply of 115.4% of system demand in 2035; we have assumed that new capacity will therefore be needed beginning in 2036 and that the tight capacity supply will begin to increase capacity prices in 2030" The presumptive impact of this assumption is that PG&E will pay more for capacity in 2030, but is that applied to CCA too? If so, where is it applied in the MRW analysis and how? If not, why? Besides, there is reason to believe this information is inaccurate. Most experts believe the push for increased renewable energy under SB350 will drive a need for more flexible capacity to replace baseload capacity, not necessarily increase capacity prices in general.
4. The Pro Forma assumes 15% opt outs. On what basis? MCE had its customers opt-out at over 20% rate for its first few years and has trended toward 25%. SCP has had its customers thus far trend to 15% opt-out rate. (Without any information that SCP is not achieving all its objectives. In short, a 20% Opt-Out rate should be the rule of thumb for essential service default programs.
5. We need further direction or clarity on the information MRW used to calculate greenhouse emission rates. We can't find specific information in the Work Papers that would substantiate the estimates given. Specifically, what is the baseload portfolio mix on non-renewable power that was used?
6. Previously, the IBEW questioned the voracity of the wind and solar future costs. We cannot find the basis of these estimates unless MRW has included the use of unbundled RECs, reducing the overall power costs.

Please advise as to the information MRW used for projected GHG emissions rates and whether the use of unbundled RECs are part of the analysis and in what amount.

Kind Regards,

Hunter Stern
IBEW Local 1245