M E M O R A N D U M

TO: California Air Resources Board

FROM: Modesto Irrigation District
Redding Electric Utility
Turlock Irrigation District

SUBJECT: Cap-and-Trade Preliminary Draft Regulation

DATE: January 11, 2010

Introduction

Modesto Irrigation District ("MID"), Redding Electric Utility ("REU"), and Turlock Irrigation District ("TID"), collectively the "Utilities," appreciate the opportunity to comment on the Cap-and-Trade Preliminary Draft Regulation (PDR). There are numerous complicated issues to be addressed as part of a well-designed cap-and-trade program, and the Utilities appreciate the work that the California Air Resources Board (CARB) has done on the PDR throughout the past year which has allowed for multiple opportunities to provide stakeholder input. The Utilities acknowledge that the PDR does not present a complete and comprehensive proposal, and there are many issues yet to be determined.

The Utilities are supportive of the goals of AB 32 and look forward to continuing the dialogue with CARB to ensure AB 32 is implemented in a cost effective manner that promotes the success of environmental goals while preserving and stimulating the economy of California. However, we are concerned that the cap-and-trade proposal presented in the PDR has the potential to create a similar market as that which led to the California energy crisis in 2000-2001. The energy crisis developed from a flawed market design that permitted participants to withhold energy, driving up market prices even though there was adequate supply. Ultimately, those that required the commodity were unable to afford the costs of the supply and the system broke down. CARB's AB 32 cap-and-trade program should be designed to avoid the same flaws.

When assessing the total costs of the AB 32 emission reduction program it is imperative to pay attention to the cumulative effects that the cost of compliance will have on every citizen through their electric rates, groceries, gas and other every day needs. Consumers will receive a "price signal" based on these total costs, which will include not only the cap-and-trade program costs generated through the market, but also the costs of the complementary and voluntary programmatic measures undertaken by the covered entities. The costs of many AB 32 regulatory measures have already begun to embed themselves in electricity rates, most notable through investments in renewable energy and energy efficiency programs. More rigorous mandates in both these areas will increase electricity costs even further. This increasing price signal in the electric sector due to AB 32's complimentary policies will reduce the need for an additional price signal from the cap-and-trade program.

With a disproportionate share of the emission reduction burden falling on the electric sector, the Utilities continue to focus on achieving AB 32 compliance with the lowest possible impact on ratepayers and grid reliability. Electric utilities face unique challenges compared with other covered entities. For example, fuel shifting to the electric sector will create additional compliance requirements. Local distribution companies (LDCs) have every incentive to reduce costs and find alternative mechanisms to meet various compliance obligations. Consumers can be assured that allowance value granted to LDCs will be spent on greenhouse gas (GHG) reductions given that LDCs, including publicly owned utilities governed by elected boards, are regulated entities with public oversight. Thus, retail electric service providers, or LDCs, must have the ability to manage their portfolio of options (tools) to meet GHG emission goals in a way that is locally cost effective and best serves their customers. The cap-and-trade program should function as a complimentary tool to assist LDCs in meeting their compliance obligations. Escalating electricity rates could increase public criticism of the cap-and-trade program in general. The Utilities believe that allocating allowance value to LDCs will mitigate the cost of the AB 32 complementary programs while it fosters investments in GHG reduction activities and technologies.

The cap-and-trade program design must encompass not only setting an appropriate cap trajectory to meet the goal of reducing Statewide emissions to 427 MMT CO2e by 2020, but must also include a method for distributing and surrendering allowances that incorporates the needed flexibility as described above (such as through the use of offsets, early action credits, banking, borrowing, and multi-year compliance periods). A clear outline of who is allowed to participate in the market, appropriate enforcement and market oversight mechanisms, and a guide for the distribution and use of revenues derived from the market are key to the success of the program. These program design details must equitably balance conflicting policy and economic interests of the various economic sectors as well as impacted entities and cost-bearing citizens.

The same balance must be achieved in establishing enforcement provisions for AB 32 obligations. Enforcement penalties must be proportional to the infraction and take into consideration the actual harm resulting from the infraction. In addition, the knowledge and intent of the violator, the maintenance and other measures taken to comply with all the various regulations, the financial burden on the violator, as well as the availability of alternatives to avoid or remediate the infraction, the relative cost impact of such penalties on California consumers and economy must be considered. It is important that regulated entities be entitled to participate in the process through which such considerations can be weighed and penalty determinations can be appealed.

California's GHG reduction program must be coordinated and adjusted to harmonize with regional and/or federal GHG reduction programs so that there is a single system without multiple layers of compliance complicated by jurisdictional overreach. To that end, the Utilities would like to see the Western Climate Initiative (WCI) partners identify a clear deadline by which the individual partners will have legislation in place in order for them to participate in the market beginning in 2012. Not doing this introduces added uncertainties into an already uncertain program, which could unnecessarily promote additional emissions "leakage", market complexities and manipulation – resulting in increased costs to participating States and Provinces.

Finally, the Utilities observe that an extraordinary level of authority has been given to the Executive Officer in the PDR provisions. The exercise of such authority must be consistent, transparent and predictable. To that end, the Utilities would support provisions included in the regulations that provide clear guidelines and criteria for the exercise of authority by the Executive Officer.

The Utilities

MID, REU and TID are local publicly owned electric utilities. MID and TID are irrigation districts located in the Central Valley and REU is a municipal electric utility within the City of Redding. MID serves over 110,000 electric customers with a peak load around 650 Megawatts (MW). TID serves about 100,000 electric customers with a peak load of approximately 600 MW. REU serves 42,000 customers with a peak load of 247 MW. The Utilities maintain similar resource mixes, including hydroelectric, eligible renewables and fossil fuel sources. They also share similar challenges, including weather patterns, demographics and economics. The Utilities have consistently supported the goals of AB 32 and participated in CARB's effort to create a successful implementation program. The Utilities continue to urge CARB to move forward in a manner that protects the reliability of the electric grid and maintains the Utilities' efforts to provide reliable and affordable power to their customers.

PROPOSED DRAFT REGULATION (PDR)

Subarticle 1. Table of Contents

The Utilities have no comments on this section of the PDR.

Subarticle 2. Purpose and Definitions

<u>Biomass</u> - The Utilities believe this definition needs to reflect that used by the California Energy Commission (CEC). This would ensure that biomass facilities, both existing and in development, are in compliance with AB 32.

Compliance period – The Utilities support a 3-year compliance period. For all the reasons previously articulated by CARB, multi-year compliance periods are an important cost containment tool.

Hold - This term is referred to in multiple places throughout the PDR as a way of using compliance instruments. As it seems to be used as a specific term of art in the context of the cap-and-trade program, the Utilities ask CARB to define this term within this section.

Opt-in participant – The Utilities believe the PDR reflects an imprecise definition for this term. Voluntary participation in the cap-and-trade market should be limited to ensure that the availability of compliance instruments is not artificially constrained for entities with compliance obligations. Please see the Utilities comments on this item under Subarticle 3.

Purchase Limit – The word "percentage" as used in this definition is vague as it does not indicate how the "percentage" is factored. The Purchase Limit should be a function of compliance obligation, available allowances, allowable offsets, and frequency of auctions in the compliance period.

Renewable energy – The Utilities believe that the definition of technologies qualifying as "eligible renewable resources" needs to be continuously updated and reviewed to include new emerging renewable technologies. While the Utilities believe the CEC should retain the authority for developing these eligibility criteria, the Utilities would support CARB's evaluation of restrictions on current eligible renewable resources, including the treatment of small hydro. However, to ensure some level of certainty in development and procurement planning, eligibility criteria should never backtrack; those resources once deemed eligible should always remain eligible.

Renewable energy credit – This definition should include a reference to the WREGIS tracking system.

Subarticle 3. Applicability

95820 Covered Entities

Based on prior statements by staff in meetings and workshops the Utilities understand that fuel delivered to electric generating facilities will not be subject to a compliance obligation. Because the emissions associated with such fuel would be captured through the electric generation resource, the Utilities believe exclusion is necessary to avoid double counting.

95840 Opt-in Participants

It is imperative that only those entities with a compliance obligation be eligible to participate in the primary cap-and-trade auction. This will ensure allowances are available to those who will need them (the covered entities) and that allowance prices are not inflated or manipulated by speculators.

CARB includes opt-in participants as a mechanism for allowing participation in the cap-and-trade system from the voluntary market. The Utilities are concerned that allowing opt-in participants to participate in the market, thus providing an opportunity for non-compliance entities to purchase and surrender compliance instruments, will result in less available compliance instruments to cover the emissions of entities with real compliance obligations. Marketers will make every attempt to profit from the allowance market and could retire allowances unnecessarily to inflate market prices. In addition, environmental advocates have the desire to retire allowances to force additional carbon reductions, further increasing the cost of allowances and effectively the cost to consumers.

Opt-in participation should be sufficiently limited to prevent such unintended market impacts. One approach would be to limit the purchase and surrender quantities allowed by opt-in participants. Another option is to restrict the type of allowances that opt-in participants could surrender to offsets, the allowance market would not be compromised and the offset market could be expanded, resulting in additional GHG reductions from un-capped sources. In this example, an opt-in participant would register with CARB in order to sell their approved offset credits to covered entities in the secondary market. Opt-in participants would be limited in the number of compliance instruments they could hold and the length of time they may hold such instruments.

Subarticle 4. Compliance Instruments

98950 Compliance Instruments issued by the Air Resources Board

The Utilities strongly agree with 95850 (c) that states each compliance certificate represents 1 ton of CO2e emissions or offsets. Set criteria must be established for the Executive Officer’s authority on terminating or limiting such authorization to emit, once issued. The Utilities believe such criteria should be strictly limited to instances of fraud or other intentional misrepresentation by the allowance holder.

95860 Compliance Instruments Issued by Approved External Greenhouse Gas Emissions Trading Systems

The Utilities agree with the proposed list of compliance instruments issued by external GHG trading systems that could be accepted by CARB to meet a surrender obligation. A broad market is favorable in that it will decrease the costs covered entities will incur in meeting their compliance obligations, which in turn will provide available revenue to invest in real GHG reductions through and beyond direct regulatory requirements.

Subarticle 5. Registration and Tracking System

95870 Registration and Tracking System

The Utilities agree with the general design presented in the PDR on the compliance registration and tracking system. Any compliance tracking system used by CARB should be compatible with a region-wide system used by the WCI.

The Utilities are confused by the various registration dates and timelines presented in the PDR. Why is it necessary to "register with CARB" and also register to participate in the auction? Every covered entity registering with CARB should automatically be registered to participate in the auction. There should be a minimum of 90 days to accomplish any registration requirement and registrations should be coordinated as much as possible.

It is unclear what is meant in subsection (c) by an entity's ability to "hold" a compliance instrument. As distinct from the ability to own or have an ownership interest in an instrument, "holding" an instrument appears to refer solely to the assignment of an instrument to an entity's specific "holding" account created by CARB pursuant to the regulations. The Utilities recommend a definition for "hold" be included in the PDR.

Subarticle 6. California Greenhouse Gas Allowance Budgets

95890 Annual Base Allowance Budgets for Calendar Years 2012-2020

It is essential that California's base allowance budget be relative to the other WCI participants. Uniform budgets will reduce the opportunity for leakage, market manipulation, and disproportionate impacts throughout the WCI region.

The Utilities believe that all compliance entities should begin participation in the cap-and-trade program in 2012.

95910 Modifications to the Annual Base Budgets

The Utilities agree with the rationale proposed in the PDR as to why modifications may be necessary to the annual base allowance budgets. There are many factors that can influence the annual base GHG allowance budget. For example, California's reliance on its vast hydro resources will impact the state's emissions from one year to the next. For example, TID's retail sales from hydroelectric generation ranged from 11% in 2008 to 51% in 1998. Both natural events as well as man-made events can cause these fluctuations and related impact to revenue.

Adjustments to the base budget because of higher than realized emissions compared to the initial budget would require additional allowances be put into the market. However, increasing the cap this way would result in a steeper trajectory for compliance over the period, potentially increasing costs above initial modeling because compliance entities will need to adjust their planning efforts in the later years. No adjustments to the base budget should ever be made after the compliance period begins that result in fewer allowances being released into the market – this would create market instability because most compliance entities will have already initiated long-term plans based on expected allowance availability. Thus, the Utilities believe the best way to respond to higher than planned for emissions levels is through the use of the cost containment methods described in Subarticle 9. More specifically, the utilities recommend relaxing the offset usage requirement as this would meet the goals outlined under 95910 (a).

The PDR suggests the possibility of adjusting the base budget by removing allowances equal to the renewable energy credits created by voluntary investments in renewable energy. The Utilities do not fully understand how such dual renewable energy markets would function and are concerned that such a program element would exacerbate an already difficult planning process. Most of California's renewable resources are intermittent in nature and difficult to forecast and/or dispatch. Further, experts have long questioned whether sufficient resources will be available to meet the 33% renewable energy mandate with available technologies. Constraining the cap-and-trade allowance market by diverting existing resources to a "voluntary market" would appear to reduce both the availability of renewable resources and GHG allowances.

Subarticle 7. Surrender Requirements for Covered Entities

The Compliance Cycle

The Utilities believe that more frequent auctions are preferable – this will enable compliance entities to adjust their bid strategies to respond to their resource and load changes, price fluctuations, and other real time impacts similar to the strategies currently used by electric utilities in their resource planning work. Compliance entities will require this flexibility and fluidity. Holding more frequent auctions will be reflective of existing markets, such the natural gas market. However, the increased costs and administrative complexity of doing this will need to be assessed before proceeding.

The Utilities are concerned with any proposed change to the mandatory reporting deadlines that would decrease the time allowed for verification.

95920 General Requirements

95920 (c) indicates that records must be retained at the covered entities designated place of business. The Utilities believe this is too restrictive as many entities keep records such as these at offsite storage facilities. Further, this is inconsistent with the CARB mandatory reporting regulations which do not specify location requirements, and does not recognize hosted document management systems which can sometimes be hosted in other states. The Utilities believe that CARB's intent is to require covered entities to maintain their records in a location that can be made easily available to CARB, should they request it. The Utilities agree with this accessibility goal and request CARB to clarify the PDR accordingly.

95940 Phase-in of Surrender Obligation for Covered Entities

The Utilities believe all compliance entities should begin participation in the cap-and-trade program in 2012. It is important that all covered entities included within the 2020 goal be included in the 2012 base allowance budget. If additional sectors are included under the cap after 2012, both the cap at the time of the new entry and the trajectory needed to reach the 2020 goal will have to be adjusted to account for this new entry. If new sectors are added after 2012, the overall trajectory for total reductions will become steeper in the remaining years since the added sectors will have less time to achieve their required reductions. In addition, these new sectors could increase their GHG output before they come under the cap, further increasing the required trajectory when they are finally brought in. It is critical that the introduction of new sectors under the cap after 2012 does not steepen the reduction trajectory for covered entities, but only the new entries. Although this will create multiple trajectories based on the multiple entry years, it is the only equitable way to incorporate staggered entries and avoid placing an unfair burden on those covered sectors beginning participation in 2012.

95950 Emissions Categories Used to Calculate Surrender Obligations

(b) Electricity Deliverers –

The PDR sets forth a surrender obligation for emissions associated with electricity imported into California from a jurisdiction where a GHG emissions trading system has not been approved by CARB. The Utilities acknowledge that CARB has been working on a Default Emissions Factor Calculator with the WCI for electricity imported into the WCI region. The Utilities filed comments to the WCI on this process as we believe there will always be unspecified power imported into California from the Pacific Northwest because of the nature of power trading. It is important that the calculator address imported electricity from both non-WCI regions as well as within those states/provinces participating in the WCI. The inclusion of electricity deliverers (which are defined in the PDR as the first deliverers of electricity to the California Electricity Transmission and Distribution System, or first jurisdictional deliverers (FJD) in the WCI program) as covered entities in the PDR confirms that the Utilities concern is valid. The calculation of the default emissions factor is extremely important as it serves as the basis for other issues.

In 2008 REU imported approximately 48% of its energy portfolio from the Pacific Northwest, of which 74% is unspecified, TID imported 65% of its energy portfolio of which 68% is unspecified, and MID imported 44% of its energy portfolio of which 94% is unspecified energy from the Pacific Northwest. For energy imported from the Pacific Northwest, the Utilities each take title to this power at either Malin or Captain Jack in Oregon near the border, which means that the Utilities are the FJD for this energy brought into California. The Utilities also typically purchase more energy than they consume in a given year and sell this power to other utilities within California.

The Utilities report unspecified imported energy in their annual mandatory reporting filings which documents that all unspecified energy brought into California, regardless of origin, is given an emissions profile of 1,100 lbs. per megawatt-hour. As outlined in the PDR, the Utilities will be responsible for surrendering allowances for this unspecified energy brought into California. Thus, the carbon content of unspecified energy for which the Utilities hold title to as FJD will determine the number of allowances needed by the Utilities.

The Utilities believe that the various regions within the United States, and particularly within the Western half of the US have very different emissions profiles, and thus regional differences must be accounted for. For example, during an average water year in 2007 the Pacific Northwest had a generation portfolio of 69% from hydroelectric resources. Whereas, during this same year, the Southwest's generation portfolio consisted of 47% from coal generation and only 5% from hydroelectric. Further, the California GHG Inventory for 2000 – 2006 shows Pacific Southwest imported electricity as having more than twice the CO2e content as imported electricity from the Pacific Northwest for every year except in 2000[1].

Further, due to transmission ownership characteristics, some entities may import a larger share of electricity than others, creating an unfair burden on those entities' proportionate share of the compliance obligation under the cap. Even if those same entities are only importing the electricity to immediately sell to another party, previously signed contracts may prohibit that contract from being immediately renegotiated and the allowance burden passed on. The idea that all entities will be able to pass on the cost of the allowance is not correct.

It is because of these reasons that the Utilities recommend that CARB readjust the default emissions factors to be more reflective of realistic electricity imports. All marginal and non-marginal resources should be used when calculating the default emissions factor, and at a minimum, Pacific Northwest hydro must be included as a marginal resource. Likewise, the Utilities don't agree that it is necessary for the default emissions factor to be the same value for energy from the Pacific Northwest and Southwest to prevent leakage.

The Utilities agree that biomass fuels should not be obligated to surrender allowances in the cap-and-trade program.

Finally, the Utilities support the staff recommendation in the PDR that emissions from the combustion of natural gas be covered at the upstream fuel source. This is consistent with the calculation of the AB 32 Administrative Fee.

<u>95960 Timing for Calculation of Covered Entity's Surrender Obligation</u>

<u>Addressing Bankruptcy of Covered Entities</u>

[1] See the CARB "California Greenhouse Gas Inventory for 2000–2008 – by IPCC Category", located on the CARB website.

The PDR notes concern with emissions that are not covered by surrendered allowances due to bankruptcy of the covered entity. The PDR identifies potential options for dealing with the avoidance of compliance obligations through bankruptcy. The Utilities are open to the consideration of Option 1 addressed in the PDR as a method for reducing the magnitude of bankruptcy. Covered entities could be asked to transfer a sufficient number of compliance instruments into their compliance accounts on an annual basis to cover a portion of their annually reported emissions. The portion to be covered would be calculated based on the covered entity's emissions previously emitted and would take into account load forecast adjustments. The portion would not exceed a small percentage of reported emissions subject to compliance obligation. The transferred compliance instruments would not be surrendered from the compliance account until the end of the compliance period. The compliance periods should not be shortened. Such intermediate transfer obligations would not be subject to any penalty that could increase an entity's compliance obligation. Enforcement efforts should take into consideration market constraints. Offset limitations would not be applied until the surrender at the end of the compliance period.

The Utilities do not agree with Option 2 as proposed in the PDR to address bankruptcy. We are concerned that shortening the compliance period will be inconsistent with the WCI program and the cost containment benefits of multi-year compliance periods will be lost. Multi-year compliance periods provide capped entities with the ability to adjust their long-term planning criteria and to manage uncontrollable variables such as weather, the economy and population growth patterns. While some of these reasons could be satisfied by permitting compliance entities to borrow against future allowances, caution must be applied to any such borrowing in order to ensure the integrity of the system and avoidance of substantial market impacts at the end of the program period.

We would urge CARB to hold a separate workshop on this issue to more fully analyze the available options.

95970 Quantitative Usage Limit on Designated Compliance Instruments

The Utilities are all members of the Offset Working Group (OWG) and refer to the comments submitted by the OWG on this provision of the PDR.

95980 Surrender of Compliance Instruments by a Covered Entity

Entities with compliance obligations will need flexibility in deciding which holdings the entity will surrender to cover its compliance obligations at the end of a compliance period. For example if estimates of surrender obligations change, adjustments to the number of offset credits that a compliance entity surrenders may need to be made within their Compliance Account. Thus, subsection (c) should be revised to provide for substitutions.

The Utilities understand the need to require remedial transfers, but question whether 30 days is a sufficient amount of time to obtain the required additional instruments. This is especially true in instances where the entity having the compliance obligation complied with Subsection (e) requirements for surrender in a timely manner based on reasonable estimates of the third year obligations. Therefore, the utilities recommend this period be extended through the next scheduled auction and should be a minimum of 90 days.

Subarticle 8. Distribution of Allowance Value

The Utilities believe that allowances should be allocated administratively to those capped entities with compliance obligations and joined in the letter submitted to the Economic and Allocation Advisory Committee (EAAC) on January 8, 2010[2] by a coalition of investor and publicly owned utilities.

Allowance value is essentially the cost to abate the equivalent emissions (1 allowance = 1 ton of emission abatement). The Utilities continue to assert that the allocation of allowances and allowance value to LDCs will promote all the objectives of AB 32, and is the most cost effective and direct method for achieving the multiple uses for allowance value identified by both the EAAC and reiterated in the PDR.

Potential uses for allowance value have been identified as falling into three categories: compensation to those bearing disproportionate burden for meeting the AB 32 goals; investment in programs that further the AB 32 goals, including abatement projects, energy efficiency and demand reduction, research and development; and dividends or tax reductions to the general public. The draft recommendations prepared by the EAAC recommend auction proceeds should be used to prevent the potential adverse impacts of climate change, as well as to finance public and private investments that would achieve emissions reductions, adaptation, and environmental remediation - the Utilities agree with this and believe that direct allocation of value to LDCs, such as is proposed by the CPUC/CEC Joint Decision[3] and in federal climate change legislation, can achieve each of these goals. The EAAC also supports the return of auction proceeds to individuals either through fixed dividends or through cuts in individual income tax rates - the Utilities disagree with this because the State of California's budget is in too great of peril. Once these funds reach the State's control, the Utilities believe it will be extremely difficult for such funds to be diverted for AB 32 purposes. Furthermore, if the allowance value is apportioned to direct dividends or tax rebates/reductions, the allowance value is not being fully utilized as it would not be funneled into uses that serve the dual purpose of cost containment and emissions abatement. Direct allocation of allowance value to LDCs, on the other hand, would avoid these problems.

LDCs have the ability to apply the value of the allowances directly to emission abatement programs and consumer relief. Money not spent on purchasing allowances by LDCs will result in real, additional GHG reductions through increased investments in renewable and other low emission resources to replace existing higher GHG emitting electricity generation, additional energy efficiency and demand response programs, and direct

[2] REU and TID are members of the Northern California Power Agency, a signatory of this letter.
[3] See CPUC Rulemaking 06-04-009 Title 5. Distribution of GHG Emission Allowances in a Cap-and-Trade Program.

investments in the development and implementation of new technologies. Any savings derived from the allocation of allowance value to LDCs will not eliminate all cost impacts on the utilities and their consumers, but rather will provide the utilities with the opportunity to direct funding into areas that may reach abatement goals sooner and reduce the overall program compliance costs. Thus, one of the prime directives of AB 32 – cost effectiveness – is achieved.

The EAAC draft report states “the Committee believes that preventing increases in electricity prices would undercut a main purpose of AB 32: to provide incentives for reduced electricity consumption.” The Utilities believe that the costs incurred by the electric sector to abate GHG emissions will have an exponential impact on consumers. These costs will, for the most part, be passed on to the consumer. For publicly owned utilities, their rates are the only source of revenue to recover these costs. Not only is the consumer paying their own increased electric bill, but also the increased costs associated with every good and service the consumer must purchase. Industrial producers who have their own compliance costs will of course also have to bear the impacts from increased electricity costs. The resulting increase in costs for the industrial producer will then be passed on to the next in the supply chain. The next entity would have those increased costs along with their own increased electricity costs to pass along. This ripple effect will continue through the chain and finally end at the consumer. If any one entity within this chain cannot bear the costs, there is the risk that the chain will be broken or the entire system will collapse. The exponential impact of AB 32 compliance can be minimized by providing allowance value directly back to the LDCs. This is similar to the position advocated by the Blueprint for Legislative Action issued in January 2009 by the United States Climate Action Partnership (USCAP) which advocates for federal climate change legislation to distribute a significant portion of free allowances to LDCs to facilitate “the transition for consumers and businesses as consumers of electricity.”

The Utilities also agree with many points set forth in the Sacramento Municipal Utility District (SMUD) letter to the EAAC dated December 24, 2009. The electric sector is unique and exhibits qualities that provide compelling reasons for returning allowance value to their consumers through apportionment to LDCs. For example, electric utilities have invested in early actions, they have heavy obligations to meet the AB 32 complimentary measures, and they will bear a disproportionate burden compared with other sectors in achieving AB 32’s goals. Sufficient price signals already exist in the electricity sector and will continue to rise due to the high cost of AB 32’s complimentary reduction measures. Moreover, as noted by SMUD, the wholesale level is an effective place for a market-delivered price signal because that is where most power purchase decisions are made. For the very reasons that the electric sector is an easy target for emission reduction regulations, failure to mitigate the rate impacts of such regulations will result in public opinions and political pressures against AB 32 and its programs.

Subarticle 9. Auction Design and Mechanisms for Distributing Auction Proceeds

<u>96030 Format for Auction of California GHG Allowances</u>

The Utilities believe that holding more frequent auctions, including the use of a double auction, will be reflective of existing markets – this will enable compliance entities to adjust their bid strategies to respond to their resource and load changes, price fluctuations, and other real time impacts similar to the strategies currently used by electric utilities in their resource planning work. Compliance entities will require this flexibility and fluidity. All auctions should be open and transparent, including price(s) and amounts of the successful bids. Clear rules and effective oversight must be established and understood by all participants before the auction begins.

96040 Auction Operation and Registration

(a) The Utilities do not have a recommendation whether CARB or a third party should act as auction operator at this time; however the choice of operator should minimize any potential conflicts of interest. An analysis should also be conducted to identify the comparative costs of alternative options and this data should be provided to stakeholders for further input. The most cost effective method would create the most efficient system possible.

(b) The auction operator should be directed to make auction documents, including bids, available to the public after the bid opening; bids will not be held confidential after opening. The auction operator should operate as a public entity subject to the public records act.

(d) CARB must ensure that sufficient time is allowed to meet the registration requirements prior to the start of an auction. As indicated above, the Utilities are confused by the various registration dates and timelines presented in the PDR. There should be a minimum of 90 days to accomplish any registration requirement, and registrations should be coordinated as much as possible. Clarification needs to be included to identify when and how notices regarding an upcoming auction will be provided. Further the provisions in the PDR imply that non-compliance entities will be permitted to participate in the auction. The Utilities disagree with this and urge CARB to reconsider this position (see the Utilities comments to Section 95840 above).

(e) As stated above, it is imperative that only those entities with a compliance obligation should be eligible to participate in the cap-and-trade market. This will ensure that allowances are available to those who will need them (the covered entities) and that allowance prices are not inflated or manipulated by speculators.

Cost Containment

The Utilities strongly support the concept of cost containment. However, the first option outlined in the PDR, the use of a reserve account, could be problematic. The Utilities believe a reserve would both weaken and complicate a cap-and-trade program. By removing allowances from the marketplace, fewer allowances are available for the covered entity, which in effect reduces the cap below the goal set by legislation.

The Utilities believe that the second option presented in the PDR, to relax the quantitative usage limit on offsets, is the best cost containment approach. This method would maintain the integrity of the offset market without flooding the market with available allowances – the downfall of Phase 1 in the European Union cap-and-trade market.

Option 3, expansion of the list of acceptable offsets would decrease the integrity of the offset market, and as such the Utilities disagree with this proposal.

Option 4, borrowing should be cautiously permitted and kept to a minimum. Excess use of borrowing in early years could cause a tightening of the market before the end of the compliance period. However, the Utilities believe that a special appeal process should be made available for allowing borrowing in circumstances where, due to events beyond the capped entity's control, an anticipated low carbon resource does not become available within the current compliance period provided.

Finally, the Utilities disagree with setting a soft price floor.

Subarticle 10. Free Allowance Mechanisms

The Utilities urge CARB to review the EAAC recommendations as just that - recommendations. While the EAAC has spent considerable time developing their report, the report was developed prior to completion of any economic analysis of the impacts of their recommendation on the compliance entities. Further, the EAAC recommendations on allocations are based on the cap-and-trade program in isolation and not from the perspective of the entire AB 32 program as a whole.

In general, the EAAC draft report recommends that CARB rely on auctioning as the primary method for distributing allowances and that free allocation of allowances should only be considered to address problems associated with energy-intensive, trade-exposed industries, and only a very small share of allowances should be used for this purpose. The Utilities strongly disagree with this position. As stated above in Subarticle 8, there are many benefits from distributing allowances and/or allowance value to LDCs, and the Utilities are not the only entities that advocate this position. For example, the USCAP Blueprint[4] states that "a significant portion of free allowances should be initially distributed to capped entities and economic sectors particularly disadvantaged by the secondary price effects of a cap, and that the free distribution of allowances should be phased out over time." This is also consistent with the recommendations of the CPUC/CEC in their Joint Decision. These entities assert that allocation of allowances to LDCs enables the smooth transition to a low carbon future by mitigating the financial impacts of climate policy on consumers, businesses and the overall economy by reducing the direct cost impact of climate policies while accelerating the deployment of energy efficiency and other GHG reduction technologies.

[4] The US CAP's January 2009 "Blueprint for Legislative Action – Consensus Recommendations for U.S. Climate Protection Legislation" can be found at http://www.us-cap.org/pdf/USCAP_Blueprint.pdf

Additionally, the allocation of allowances to LDCs provides a mechanism for addressing utilities' load growth. Even as consumers are educated and encouraged to participate in energy efficiency programs, load growth can result naturally from population changes. Load growth can also result from carbon abatement programs implemented in other sectors that shift their fuel use to electricity. Some examples being examined by CARB include plug-in hybrid vehicles, truck idling restrictions, and port electrification.

By apportioning allowances directly to regulated entities, such as the LDCs, all of the allowance value uses outlined in the EAAC report (with the exception of tax reductions) can be served, and served more cost effectively, by avoiding the administrative costs of having the State manage such programs. LDCs would use the value of the allowances simply, transparently, and with the oversight of the utility's regulating bodies and CARB's AB 32 program. Equally as important, distributing allowances to LDCs will accomplish the goals outlined in the report without the potential for the value to be "hi-jacked" for other uses, such as government deficit reduction or programs unrelated to GHG emission reductions.

Subarticle 11. Trading and Banking

96080 Trading

The purchase price mechanism, whether uniform or discriminating, must be simple and create a level playing field for all participants. Setting a limit on the amount of allowances a participant can purchase based on a bandwidth of their obligation (for example, plus or minus a 5 year emission average) will help prevent hoarding. Limiting the amount an entity can acquire will ensure allowance prices are not inflated or manipulated. Any amount over this would be deemed market manipulation. As with any precious commodity, the lack of availability ensures that will be a continuous review of market operations by those participating parties.

A secondary market for allowances will most likely emerge. If such a market develops, participation may or may not be limited; however the Utilities agree that additional oversight will need to be developed.

96090 Banking

The Utilities agree with the proposed banking regulations outlined in the PDR.

Subarticle 12. Linkage to External Trading or Offset Crediting Systems

The Utilities are all members of the Offset Working Group[5] and refer to those comments on the offset provisions of this Subarticle.

96200 Eligible Allowance Vintages

[5] The Offset Working Group is comprised of the Sacramento Municipal Utility District, Modesto Irrigation District, Redding Electric Utility, Roseville Electric, and Turlock Irrigation District.

Allowances should not be vintaged. Once an allowance is released into the market, that allowance should retain its value throughout all compliance periods until it is surrendered.

96210 Suspension of Linkage

The Utilities recommend that criteria for suspending linkages could include, but are not limited to, the following, should they remain unremedied: failure to provide documents or data as agreed to, failure to provide proper enforcement regulations, fraud or misrepresentations, or faulty GHG monitoring programs.

In no circumstance should suspensions be based on changes in science or available technology.

Subarticle 13. Offset Credits

The Utilities are all members of the Offset Working Group and refer to those comments on this Subarticle.

Subarticle 14. Enforcement and Penalties

The Utilities acknowledge that compliance is a critical component of any cap-and-trade program and understand that CARB, under AB 32, is directed to use existing penalty provisions: Article 3 Commencing with §42400 and Chapter 1.5 commencing with §43025.

The Utilities want to ensure fairness in determining compliance and recognition of the numerous extenuating circumstances that can affect an entity's ability to comply. We do believe that it is necessary to ensure that the penalty to be imposed is proportionate and relative to the nature of the non-compliance. The circumstances of the non-compliance as well as existing barriers to the compliance must be taken into account. The Utilities believe that attention has to be paid to the availability of transmission, the availability of low emitting technologies that are feasibly implemented, the shifting of emissions from other sectors (electrification), the responsibility of electric utilities to maintain grid reliability, the cost effectiveness of available compliance tools, and other mitigating circumstances such as unusual weather, hydro and economic conditions. Thus, a provision for dealing with extenuating circumstances must be included in any program design.

The Utilities recommend that an entity's full surrender obligation, or each 3 year ending date, be viewed as a single transaction with regard to penalties. Treating the surrender of each individual compliance instrument as separate transactions could likely lead to penalties that go beyond incenting compliance and would create unnecessary roadblocks to the achievement of AB 32 goals. This is particularly true in light of the proposals for intermediate Compliance Account transfers.

The Utilities oppose any effort to include a multiplier that would require the submission of additional compliance instruments. This approach would be counterproductive, setting the entities and the AB 32 cap-and-trade program up for failure. Furthermore, this type of multiplier would have the effect of penalizing compliant entities by constraining the future of the market.

96503 Penalties

The Health and Safety Code identifies a list of relevant circumstances to be considered when penalties are imposed. Additional criteria should also be considered to address unforeseen events, and to address instances where the lack of availability for low emitting technologies prevents GHG reductions from occurring.

96504 Violations

Violations for incomplete reports should not be assessed until notice is given of the failure and the problem is not remedied in a timely manner. If the agency that stands to collect financial benefits from the failure is also the one that gets to measure whether a failure has occurred, there is an innate bias and protection should be provided for the covered entity making a good faith effort towards compliance.

Dispute resolution provisions should be included. Because of the developing nature of the climate change arena, it would be advisable to provide a process and forum to address disputes between the regulating agency and the regulated entities.

Subarticle 15. Other Provisions

The Utilities have no comments on this section of the PDR.

CONCLUSION

The Utilities appreciate the opportunity to comment on the PDR and welcome the opportunity to discuss this with CARB to develop these concepts further.

Respectfully submitted,

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