LEG 2014-0818

September 15, 2014

Clerk of the Board
California Air Resources Board
1001 I Street
P. O. Box 2815
Sacramento, CA 95812

Re: Sacramento Municipal Utility District's Comments on July 29, 2014 Proposed Amendments to the Mandatory Reporting Regulation

Dear Ladies and Gentlemen:

SMUD appreciates the opportunity to provide comments regarding the Air Resources Board's proposed amendments to California's Mandatory Reporting Regulation. SMUD's comments primarily address four issues:

1) *The proposed change to the MRR structure that would include in MRR § 95111(g)(1)(N) a requirement to perform a "lesser of" calculation for certain specified resources.* SMUD remains opposed to this requirement in general, but appreciates the continued narrowing of application apparent in the proposed text for § 95111(g)(1)(N). SMUD recommends at least additional narrowing, if not complete removal, of this proposed policy, and provides a rationale for our proposal below.

2) *The proposed new data reporting requirements in § 95892(d)(5) for wholesale sales into the California Independent System Operator (CAISO) markets.* ARB already has the data necessary for this calculation through CITSS, and hence sees no need for this additional reporting requirement. The additional burden of an unnecessary reporting requirement may be small if it is truly "aggregate", such as reporting only the annual sales into the CAISO market. However, the proposed language goes beyond this aggregate requirement to require reporting of these sales "by source", without including a "system sales" option. SMUD believes that the administrative burden of anything other than annual totals for

this purpose makes the requirement onerous, and requests the addition of a "system sales" option to reduce this burden.

3) *SMUD believes that there are nuances to the addition of transmission loss factor adjustments to imported power emissions that are not yet reflected in the proposed language.* For example, there is no need to include a transmission loss factor that would increase the imported emissions in circumstances where the contractual transaction accounts for the losses locally or via return generation. Doing so in these circumstances in effect "double counts" the emissions associated with losses on the transaction, and inaccurately increases the obligation and cost of the reporting entity.

SMUD suggests that ARB remove the proposed change to use EIA data to calculate emission factors for imported electricity from specified generating facilities. The MRR currently is based on reporting the same data to US EPA under 40 CFR Part 98 and to ARB under the MRR for Cap-and-Trade. If the ARB switches to emissions calculated based on EIA data there would be a discrepancy in the way out-of-state facilities and in-state facilities under the Cap-and-Trade are assessed, which could create an advantage for one group of resources over the other.

I. SMUD Recommends Removal of or Alternative Language for New Meter Data Reporting And Subsequent Calculations For Specific Resources

ARB staff proposed new language in § 95111(g)(1)(N) to clarify existing requirements about what is supposed to happen with hourly meter generation data that is currently required to be retained for verification purposes. The new language (shown below) indicates that for certain resources an hourly comparison between metered and "scheduled" data must be made and the sum of the lesser of these hourly values be calculated for reporting.

(g) Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment.

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(1) Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment. The following information is required:

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(N) For verification purposes, retain meter generation data <u>from all specified sources</u> to document that the power claimed by the reporting entity was generated by the facility or unit at the time the

power was directly delivered. *<u>This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to the following equation:</u>*

<u>Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)</u>

<u>Where:</u>

<u>ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh).</u>

<u>MGsp = metered facility or unit net generation (MWh).</u>

<u>TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).</u>

A. SMUD's Recommendation and Suggested Language. SMUD appreciates the ARB staff's attempt to clarify this requirement. The "lesser of" calculation has not previously been required in the text of the MRR, but has been addressed and requested in various reporting guidance documents or templates with some ambiguity. The revised proposed language significantly narrows of the application of the "lesser of" structure from prior expectations in GHG reporting, but SMUD does not think that the proposed clarification yet gets this right.

SMUD continues to recommend that the ARB completely remove the requirement for a "lesser of" analysis in the MRR. We believe that the "lesser of" analysis merely adds complication and administrative burden without any commensurate benefit in terms of accuracy of GHG reporting or ability to verify such reports. If the rationale is to match the "lesser of" analysis required by the CEC and the CPUC for certain resources in California's 33% RPS, then the proposed language will not achieve this purpose because the proposed language distinguishes between renewable and fossil emissions, whereas the structure in the RPS arena is intended to distinguish between types of renewables. However, if ARB desires to maintain the "lesser of" structure several issues should to be addressed.

First, while the proposed language is more closely aligned with the CEC/CPUC "lesser of" analysis for the RPS, it still does not achieve the purpose of matching the

CEC/CPUC structure. The language attempts to reach that match by enumerating specific types of specified resources that are excluded from the "lesser of" analysis requirement. As virtually all specified source resources are excluded, this is cumbersome. A better structure would simply list the specified source resources to which the analysis would apply to match the CEC/CPUC treatment.

Second, the proposed "lesser of" language is misplaced in § 95111(g)(1) because the operational data requested in new paragraph (N) would not be available to meet the reporting deadline there. Subsection (g)(1) of § 95111 is aimed at prior registration of specified sources, with data due by February 1st of each year, so that emission factors can be determined and provided for these sources for the full reporting later in the year. Parts (A)-(L) in § 95111(g)(1) request "static" information -- not dependent upon any operational data from the previous year. Operational data is not fully available by February 1st, hence the proposed "lesser of" analysis cannot be accomplished in the timeframe expected in the proposed regulations. The same constraint applies to § 95111(g)(1)(M), which refers to the status of RECs for the previous year – this information is not fully available by the due date. SMUD suggests that both § 95111(g)(1)(M) and (N) be moved in the regulation to be separate requirements in § 95111(g), as shown as (g)(6) and (g)(7) below, to meet a June 1st reporting date.

Third, in addition to specified sources that are directly delivered, subsection (g)(1) of § 95111 also requests prior registration information for resources that will require use of the RPS adjustment. It is SMUD's understanding from discussions with ARB staff that the "lesser of" analysis is not intended to apply for resources needing the RPS Adjustment, yet there remains apparent confusion about this amongst market entities, in part because § 95111(g)(1) applies to both types of resources. The proposed language attempts to address this confusion by including language that limits the "lesser of" analysis just to "specified sources". This is another reason to remove the language from this subsection to a place where it is less confusing.

Fourth, it is unclear from the proposed language how the proposed "lesser of" analysis should affect emission factors used in mandatory reporting. The implication is that the specified source emission factor would only be used for the generation that results from the "lesser of" calculation, but this is not explicitly stated by the language. Nor is there clarity in the proposed language about what emission factor should be used for the remaining generation that is scheduled into California. It may seem reasonable to use the "unspecified" emission factor for this remaining generation, but this is not explicitly stated. If that is the expectation, there is a potential mismatch with CEC/CPUC RPS policy, since in that structure the "lesser-of" analysis does not divide between zero-emission renewable and unspecified emitting resources, but rather between "categories" of zero-emission renewable sources. If the ARB handles this potential discrepancy by allowing the "RPS adjustment" to be used to offset the associated emissions from the generation excluded by the "lesser of" analysis, there is a potential conflict with the MRR and Cap and Trade regulations, since the emissions are associated with energy from directly delivered specified sources, while the "RPS Adjustment" is clearly limited to renewable sources that are NOT directly delivered.

SMUD is suggesting the following language to "cure" the issues discussed above, with comments and redline/strikeout edits:

> *(g) Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment.*
>
> *Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with ARB pursuant to subsection 95111(g)(1) ~~and~~ by February 1 following each data year to obtain associated emission factors calculated by ARB for use in the emissions data report required to be submitted by June 1 of the same year. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to subsection 95111(g)(2)-(~~5~~7) in the emissions data report. Each reporting entity claiming an RPS adjustment, as defined in section 95111(b)(5), pursuant to section 95852(b)(4) of the cap-and-trade regulation must include registration information for the eligible renewable energy resources pursuant to subsection 95111(g)(1) in the emissions data report. ~~Prior registration and subsection 95111(g)(2)-(5) do not apply to RPS adjustments~~. Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified within 45 days following the emissions data report due date.*
>
> *(1) Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment. The following information is required:*
>
> *~~(M) Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:~~*
>
> *~~1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.~~*
>
> *~~2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that were subsequently withdrawn from the retirement~~*

~~subaccount, or modified the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.~~

~~3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount.~~

~~(N) For verification purposes, retain meter generation data from all specified sources to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to the following equation:~~

~~Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)~~

~~Where:~~

~~ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh).~~

~~MGsp = metered facility or unit net generation (MWh).~~

~~TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).~~

(6) Additional Information for Renewable Specified Sources. Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the:

(A) RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and document whether or not the RECs have been placed in a retirement subaccount.

(B) For verification purposes, retain meter generation data when available from all imported specified sources that meet the requirements of Public Utilities Code 399.16(b)(1)(A) to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. For these resources, a specified source emission factor only applies to the amount of generation calculated by the following equation:

$$\text{Sum of Lesser of MWh} = \Sigma HMsp \min(MGsp, TGsp)$$

Where:

$\Sigma HMsp$ = Sum of the Hourly Minimum of MGsp and TGsp (MWh).

MGsp = metered facility or unit net generation (MWh).

TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).

Any remaining generation should use the unspecified emission factor and is considered not directly delivered and eligible for RPS adjustment treatment.

(7) Additional Information for RPS Adjustments. Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the:

1. *RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.*

2. *RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that were subsequently withdrawn from the retirement subaccount, or modified the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.*

If the ARB insists on including a "lesser of" analysis, but is unable at this stage of the regulatory process to make all of the changes recommended for easing confusion and adding consistency, SMUD suggests the following changes to the proposed modifications, and recommends that the ARB provide guidance to clarify the other issues described above until they can be addressed in the regulations:

> *(N) For verification purposes, retain meter generation data when available from all specified sources that meet the requirements of Public Utilities Code 399.16(b)(1)(A) to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. ~~This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to~~ For these resources, a specified source emission factor only applies to the amount of generation calculated by the following equation:*
>
> *Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)*
>
> *Where:*
>
> *ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh).*
> *MGsp = metered facility or unit net generation (MWh).*
>
> *TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).*
>
> *Any remaining scheduled energy should use the unspecified emission factor and is considered not directly delivered and eligible for RPS adjustment treatment.*

B. SMUD's Initial Statement of Reasons: As stated above, SMUD recommends complete removal of the "lesser of" analysis proposed by ARB staff for the following reasons. We believe that the proposed "lesser of" analysis merely adds complication and administrative burden without any commensurate benefit in terms of accuracy of GHG reporting or ability to verify such reports. The proposed language:

- Does not match CEC/CPUC RPS policy
- Is inconsistent with market scheduling and tracking processes
- Is inconsistent with other MRR and Cap and Trade rules and definitions
- Provides no improvement in emission reporting accuracy

Mismatch with CEC/CPUC RPS Policy: The CEC and CPUC have interpreted SBX1 2 to mean that certain specific renewable contracts must be tracked/verified on an hourly basis. However, this policy only applies to eligible renewable contracts signed after 6/1/2010 from resources that are located outside of CA (generally) and where the power is “directly scheduled” into California, without either using substitute power explicitly or being dynamically scheduled. The proposed language appears to attempt to match this policy, although in a seemingly confusing manner, and with the clear mismatch of also applying to specified large hydro sources.

In addition, even when the resources subject to the ARB GHG “lesser of” policy are the same as the resources subject to the CEC/CPUC RPS “lesser of” policy, the end result may end up being inconsistent with without further changes to the ARB proposal. The CEC/CPUC “lesser of” policy has the intent of dividing between two “types” of renewable generation to be counted. The CEC/CPUC “lesser of” total is deemed “product content category 1” (PCC1), while any scheduled power above this total is deemed to be either a “product content category 2” (PCC2) or “product content category 3” (PCC3) resource, depending on contract specific circumstances (this remainder will almost certainly be considered PCC3 by the CEC). The point here is that ***all*** of the scheduled power is deemed renewable under the RPS, even when the “lesser of” analysis yields a smaller number. It is unclear in the proposed regulations, but it would appear from previous discussions with ARB staff, that the proposed ARB policy would result in a “lesser of” total that would be deemed to have specified source emissions (zero-GHG renewable), while any scheduled import above this total would presumably acquire a default emissions factor.

Hence, there could be a situation where the CEC/CPUC are counting imported power as “renewable”, but the ARB is imposing a default emissions factor for this same power. This normally is accounted for under the Cap and Trade Program by using the “RPS Adjustment”, and that may be feasible here as well, but it would seem that such use of the RPS adjustment would require further changes in MRR and the Cap and Trade regulations to clearly allow this treatment (see below for more discussion of the potential inconsistency and complications with MRR/C&T regulations and the proposed policy).

Inconsistent with Market Scheduling and Tracking Practices: Commercial transactions are typically structured with monthly or even annual reconciliation of contracted-for and transmission-scheduled imported power, in contrast to the hourly “reconciliation” envisioned by the proposed MRR policy. The CEC’s policy to reconcile certain, limited renewable transactions on an hourly basis also suffers from this problem, but it has limited application and the CEC believes that they are required by SBX1 2 to follow this path. The ARB has no similar legal language to interpret as a potential requirement its hourly reconciliation proposal.

For the California RPS, renewable generation nearly always must be tracked in the Western Regional Energy Generation Information System (WREGIS). This tracking occurs through WREGIS “certificates”, with each “certificate” (essentially a REC) representing a MWh of renewable generation. These certificates are created, held, moved from one account to another, and retired with reference to the month of generation, not the hour. Hourly generation is ***not*** tracked in WREGIS, only monthly generation. Hence, the CEC/CPUC policy has required creating a tracking structure outside of WREGIS to consider hourly generation versus scheduled data, which will then presumably be used to divide the monthly WREGIS numbers into different “categories” of renewable generation.

Non-renewable, but zero-emission, generation is not tracked in WREGIS, but reconciliation of what is generated versus what is actually delivered (via e-tags) is typically done on a monthly basis. While it is true that e-tags are hourly, market transactions are normally not reconciled on an hourly basis, allowing for typical small differences between actual generation and transmission-scheduled power to “factor out” over time. This allows baseload generating facilities to be procured and scheduled across transmission lines without either: 1) suffering the transaction costs of accounting for minor differences between the generation and the scheduled amounts, or 2) using up space on the transmission system by overscheduling to insure receiving the full amount of contracted generation.

What this comes down to for the importer is usually a monthly import total from a specified source that is simply the sum of the hourly e-tags. The importer ***in most cases does not have access to the metered generation data***, nor do they perform any hourly “matching” or “true-up” procedures – they simply verify that they are getting the delivered amounts, properly “tagged”, as per contract. Importers do not normally see or participate in the reconciliation between tags and generation. This reconciliation happens between the generator and their respective balancing authority to account for any small hourly deviations.

In addition, some contracts are not for the entire output for a particular generator. In these cases, just like with full-output contracts, the contracting party simply depends on the proven, scheduled, delivery of the contracted amount of power, verified by e-tags. As usual, ***the importer or contracting party will not normally have access to or rights to information about the metered generation from the facility, particularly in cases where a portion of the generation is being sold/used by some other party***. Here, there is no market or contractual reason for the importing party to have knowledge of what the total amount of generation from a particular facility is, or where any generation beyond that contracted for goes, on any timeframe. All that really matters is that the contracted-for generation amount is scheduled as per agreement, which is verified by the schedule e-tags. ***In general, SMUD believes that ARB should avoid requesting information from importers that they do not normally have as part of market transactions.***

Finally, it is unclear exactly how the ARB policy being proposed (or the more limited CEC policy, for that matter) would apply to “multi-fuel” facilities. The hourly metered generation from these facilities may or may not correspond well to annual renewable totals being determined and used. Generally, a facility can use up to 2% fossil fuels and have all the generation counted by the RPS as renewable, above that percentage, only the renewable portion counts. This is, SMUD believes, determined on an annual basis – certainly not on an hourly basis.

Inconsistent with MRR and Cap And Trade Rules: It is unclear in the proposed text exactly how emissions would be attributed to power remaining from the “lesser of” calculation. However, previous discussions with ARB staff suggested that the RPS Adjustment could be used to, in effect, restore the zero-emissions aspect of the imported power falling above the “lesser of” total. If that is the concept, it appears to be inconsistent with the definitions and rule requirements in the MRR and Cap and Trade regulations, requiring ARB to either make modifications to these definitions and rules or suggest in guidance that they be used for hourly reconciliation even though inconsistent.

For example, the MRR and Cap and Trade regulations define substitute power as:

> “Substitute power” or “substitute electricity” means electricity that is provided to meet the terms of a power purchase contract with a specified facility or unit ***when that facility or unit is not generating electricity***. ***[emphasis added]***

This is consistent with a typical use of substitute power, for a “firmed and or shaped” contract, where the scheduled power from a contract comes in hours when a facility is not generating. However, the proposed ARB “lesser of” policy appears to imply use of the “substitute power concept” in hours where a specified facility or unit is generating electricity almost as expected, but not exactly at the level in the hourly import schedule for the contract. This seems inconsistent with the definition of “substitute” power in the regulations.

Also, the Cap and Trade regulations in § 95852 (b)(4)(D) state regarding the RPS Adjustment requirement:

> (D) No RPS adjustment may be claimed for an eligible renewable energy resource when its electricity is directly delivered.

However, the proposed ARB hourly reconciliation policy applies, as SMUD understands it, only to specified source imports that are directly delivered. If the RPS Adjustment is contemplated for use here, it would seem that ARB staff and obligated entities would be using the RPS Adjustment in a manner inconsistent with the Cap and Trade regulations. In addition, this use of the RPS Adjustment is clearly different than the typical use, which requires RECs tabulated on an annual basis to determine an adjustment to emissions imported from entirely different sources, even in entirely different years than the underlying renewable generation.

No Real Improvement in Reporting Accuracy: SMUD understands from discussions with ARB staff that one rationale for the proposed "lesser of" hourly reconciliation policy is to achieve greater accuracy in reporting of emissions from imported power. The logic goes that in hours in which the scheduled import is *greater than* the specified source generation, the imported power is only partially from the specified source, with the remainder from an unspecified, default or "system" source. On the other hand, in hours where the scheduled import is *less than or equal to* the specified source generation, the imported power is fully from the specified source, but any excess generation in that hour is not imported to California, but normally used in the system where the generator is located. This leads to the concept that the accuracy of reported emissions from imports may be improved by hourly reconciliation as proposed by MRR staff -- by using the default emissions factor rather than the specified source factor to account for the emissions associated with the unspecified or "system" power in those hours where specified generation is less than scheduled. However, in reality, this policy is likely to only provide a false sense of improving the precision of identifying which sources are contributing in certain hours, while likely decreasing the overall accuracy of the imported emissions picture.

The default emission factor is a broad reflection of system or unspecified emissions over a timeframe of multiple years from systems outside of California in general, not an accurate measure of unspecified source emissions in any particular hour from any particular location. This works fine to attribute emissions to unspecified imports in general, particularly in the absence of a specified source being part of a particular transaction or contract (that is, a straight up purchase of unspecified power). It may be appropriate to update this factor periodically, to reflect changes in sources that have been specified in contracts, and hence removed from the "unspecified" mix.

In reality, there will be a highly variable mix of resources contributing to unspecified imports from a particular location on an hourly basis. Hence, using the default emission factor as it stands for the partial "system" or unspecified generation in those hours where the generation from an actual specified source is less than scheduled is in effect using a relatively constant approximation for the likely highly varying unspecified emissions from that location in those hours. We use a relatively constant, high-level default emissions factor because it would be problematic for the market to have a frequently varying default emissions factor for imports (not to mention cost-prohibitive, if not impossible).

In an individual case where a specified source is newly contracted for and imported to California, it alters the emissions that would come from any remaining, unspecified power in the system where the source is located, but we do not and should not change the default emissions factors to reflect this. The emissions from this remaining, unspecified, power also vary from hour to hour (and minute to minute), depending on what resources are generating in that hour (or minute) in the system, what resources are on the margin, and what other resources have been “tied up” already in specified contracts. But again we use a constant, high-level default emissions factor.

Examining what happens in reality to actual emissions on an hourly basis when a specified source generates more or less than scheduled leads to the conclusion that overall accuracy is not improved by using the default emissions factor for a portion of the specified generation in any hour. More specified source generation than scheduled will contribute more to the overall emission profile of a system than expected, and vice versa when generating less, all else being equal. A theoretical, completely “accurate” calculation would adjust the remaining system emissions based on the metered generation of the specified source. So, in this hypothetical structure, if we look at an hour in which a zero-emissions specified source is generating less than the scheduled amount, the remaining emissions would presumably be higher, reflecting the lower than expected generation from that zero-emission specified source in that hour. In an hour when the zero-emissions specified source is generating more than scheduled, the greater-than-expected (but not imported) generation from that source would tend to reduce the remaining emissions in the system in that hour. Hence, assigning a portion of the scheduled specified source import for an hour to unspecified power using the constant default emissions factor does not appear to improve emission reporting accuracy, and may in effect distort the overall picture of imported emissions. It is more accurate to simply use the specified source emission factor for all scheduled power, without a “lesser of” hourly reconciliation.

II. SMUD Recommends Alternative Language for Proposed New Data Reporting Requirements in § 95892(d)(5) for Wholesale Sales into the California Independent System Operator (CAISO) Markets.

SMUD recommends removing the proposed amendment regarding reporting of sales into the CAISO. SMUD does not see the necessity of adding a provision in the MRR of reporting sales into the CAISO, particularly for electric distribution utilities like SMUD that are not part of the CAISO, but merely sell wholesale power there as available and appropriate. SMUD believes that ARB already has the data necessary to examine these kinds of wholesale sales into the CAISO through the CITSS system. The additional burden of an unnecessary reporting requirement may be small if it is truly “aggregate”, such as requiring reporting of only that the overall annual sales into the CAISO market amount.

However, the proposed language goes beyond this aggregate requirement to require reporting of these sales “by source”. SMUD’s sales into the CAISO are typically from SMUD’s “system”, known as a “system sale”. If the ARB does not remove the provision as SMUD has recommended, SMUD believes that a “system sales” option is required to be able to comply with the proposed requirement in all instances.

SMUD suggests the following edit:

SMUD Proposed Revision:

"Electrical Distribution Utility Sales into CAISO. All electricity distribution utilities except IOUs must report the annual MWh, by source **or by system as specified in the transaction,** of all electricity sold in the CAISO market, and the emission factor for each source **or system as applicable,** beginning with calendar years 2013 and 2014, reported in 2015.

III. SMUD Recommends Alternative Language for Inclusion Of Transmission Loss Factors When Reporting on Imported Resources

SMUD believes that the proposed revision to transmission loss factors to be used for scheduled imports from specified facilities or units requires further thought. The proposed change will result in an unfortunate overstatement of GHG emissions from electricity imports. A transmission loss factor of 1.02 is reasonable for those imports where losses from the source to a California balancing authority are "covered" by the source or by a non-California balancing authority. However, a transmission loss factor of 1.0 is appropriate for transactions where the source to California balancing authority losses are covered locally (by or within a California balancing authority), or contractually by the return scheduling of local generation (also known as "loss payback"). The emissions for the energy used to pay back the transmission losses are already accounted for under the reporting requirements, and should not be added again. Using a transmission loss factor of 1.02 in these latter circumstances in effect "double counts" the emissions associated with losses on the transaction, inappropriately increasing the GHG obligation and associated costs to the reporting entity

SMUD suggests the following edit:

(2) *Calculating GHG Emissions from Specified Facilities or Units.* For electricity from specified facilities or units, the electric power entity must calculate emissions using the following equation:

$$CO2e = MWh \times TL \times EFsp$$

Where:

CO2e = Annual CO2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EFsp = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EFsp = 0 MT of CO2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

TL = Transmission loss correction factor.

TL = 1.02 ~~when deliveries are not reported as measured at the busbar~~, to account for transmission losses **supported by generation outside of** between the busbar and measurement at first point of receipt in **a** California **balancing authority.**

TL = 1.0 when transmission losses are supported by a California balancing authority or paid back using electricity sourced from within California.

~~**TL = 1.0 when** deliveries are reported as measured at the busbar.~~

IV. SMUD Recommends Dropping Proposed Amendments Regarding Use of EIA Data To Calculate Certain Emission Factors

SMUD is concerned about the proposed change in § 95111(b)(2) to change the methodology used to calculate emissions factors for specified out-of-state electricity generating facilities (EGFs) to factors based on fuel use data from the U. S. Energy Information Administration (EIA), rather than the current factors based on GHG emission data reported to EPA under the federal Greenhouse Gas Emission Reporting Program pursuant to 40 CFR Part 98. SMUD recommends removing this proposed modification.

In-state generating facilities are required to report the same GHG emission data to ARB as they report to EPA under 40 CFR Part 98. Cap-and-Trade obligations are based on this data. It is important to maintain consistency in the emission calculations between in-state and out-of-state power plants. Emission factors calculated using fuel data reported to EIA will be almost certainly be slightly different than those calculated based on the Part 98 data. This could create a competitive advantage or disadvantage one group of resources over the other in the Cap-and-Trade Program.

In addition, the current methodology for calculating emissions factors for out-of-state EGFs using GHG emissions is based on CEMS data reported to EPA with rigorous quality assurance and quality checking standards. This is necessary to provide rigorous and consistent accounting of emissions for the Cap-and-Trade structure, and it is unclear whether this rigor exists in the fuel data reported to the EIA.

SMUD again appreciates the opportunity to informally comment on the proposed MRR changes.

/s/

WILLIAM W. WESTERFIELD, III
Senior Attorney
Sacramento Municipal Utility District
P.O. Box 15830, M.S., B406, Sacramento, CA 95852-1830

/s/

TIMOTHY TUTT
Program Manager, State Regulatory Affairs
Sacramento Municipal Utility District
P.O. Box 15830, M.S. B404, Sacramento, CA 95852-1830

cc: Corporate Files