Appendix A:
Staff Proposal for Allocating Allowances to Electricity Distribution Utilities

This document describes the process ARB staff used to determine allowance allocation to electricity distribution utilities. It explains how staff gathered utility data and the assumptions made in projecting utility resource profiles; explains the proposed method for allocating allowances to the electricity distribution utilities; and clarifies which entities are eligible to receive allocations.

Building on the Previous Work

Staff's Initial Proposal for 15-day Changes to Address Electricity Sector Allowance Allocation (Appendix 1)[1] was released in December as an appendix to Board Resolution 10-42. Appendix 1 included a number of recommendations to finalize the allowance allocation method for the electricity sector. Below we briefly revisit these recommendations and describe how staff's recent work builds upon this prior document. The details of staff's more recent work is then presented in subsequent sections.

Data Gathering
Appendix 1 to the Board Resolution contained the following text:

> *ARB staff recommends working with stakeholders to verify the data needed to evaluate and execute the allowance allocation methods. ARB staff recommends that the dataset developed by the JUG be the starting point for the data work, but that ARB staff independently validate the data and their sources.*

Since December staff has recreated the Joint Utility Group (JUG) dataset from publicly available and survey data. Using this data staff has independently validated the accuracy of individual utility data.

Sector Allocation
Appendix 1 to the Board Resolution contained the following text:

> *The ISOR recommends that a set number of allowances are set aside each year for the electricity sector, starting with the 2012 allocation at 90% of 2008 electricity sector emissions and declining linearly to 85% of that value by 2020. Using the mandatory reporting data, the 2008 emissions from electric generating facilities and imports were 98.9 million metric tons (MMT), so that 90% would be 89 MMT. Additionally, a portion of the electricity produced at facilities that identified themselves as cogeneration facilities was purchased by electricity distribution utilities. Using publicly filed data for 2008 and a heat rate based on the pending PUC QF*

[1] Appendix 1 to Board Resolution 10-42 may be accessed at: http://www.arb.ca.gov/regact/2010/capandtrade10/res1042app1.pdf.

> *settlement, the estimated equivalent emissions from QF purchases is 9.67 MMT, so that 90% of this value is 8.7 MMT. The recommended 2012 allowance allocation to the electric sector is therefore 97.7 MMT (89 MMT plus 8.7 MMT). The recommended sector allocation declines linearly to 83 MMT in 2020.*

Since December, staff has made no changes to the apportionment of allowances to the electricity sector. The total amount of allowances apportioned to the sector in the discussion draft of the regulation is still 97.7 MMT. This value may be found in Subarticle 8 of the regulation.

Allocation to Individual Utilities
Appendix 1 to the Board Resolution contained the following text:

> *ARB staff recommends that the promising allocation methods developed based on the evaluation using preliminary data be refined and evaluated using the final data developed by ARB staff. ARB staff recommends that the method incorporate the three main elements discussed above: ratepayer cost burden; energy efficiency accomplishment; and early action as measured by investments in qualifying renewable resources.*

Staff has retained these three primary bases for allowance allocation to individual utilities (cost burden, projected cumulative energy efficiency, and early investment in renewables). Table 9-3 of the discussion draft of the regulation presents the amount of allowances that each utility will receive annually as a percentage of the sector total. Table 9-3 may be found in Subarticle 9 of the regulation.

Updating
Appendix 1 to the Board Resolution contained the following text:

> *ARB staff recommends that allowances be allocated to individual utilities at the start of the program for 2012 to 2020. The allocation will not be automatically updated, so that each utility would know its allocation for the nine-year period and could plan accordingly. If needed, the periodic program review could recommend adjustments to the allocation during the program.*

Staff has made no changes to this portion of the recommendation. As shown in Table 9-3 the annual allocation to each utility is predetermined and is not expected to be updated over time, unless it is required due to unforeseen changes in the electric sector.

Public Process
Appendix 1 to the Board Resolution contained the following text:

ARB staff recommends that the process for developing the final method for allocating emission allowances to electricity distribution utilities include at least one public workshop at which the data and methods are reviewed and public comment is received.

Staff intends to hold a public workshop to discuss these and other recommended changes to the regulation on July 15th, 2011.

Details on the Electrical Utility Dataset

Data Gathering

To allocate allowances to the electricity sector staff gathered a dataset that includes estimates of demand, resource mix, projected cumulative energy efficiency, and historical early action for each of the distribution utilities serving California end-use customers.

For the largest Independently Owned Utilities (IOU) and Publicly Owned Utilities (POU) historical and projected resource mixes for 2007-2018 have been previously collected in California Energy Commission (CEC) form S-2, and are publicly available as documentation supporting the 2009 Integrated Energy Policy Report (IEPR).[2] These data include estimates of future load, projected cumulative energy efficiency,[3] early action,[4] and resource mix.[5] For these utilities, 2019-2020 data were imputed holding load growth rates, committed resource levels, and energy efficiency investment fixed at 2018 values.

For those utilities that did not submit long-range S-2 forms (Other Utilities), uniform sources of forecasted load and resource mix were not publicly available. To gather data on the Other Utilities staff prepared a survey soliciting information

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[2] The 2009 IEPR and the publicly available utility S-2 data may be accessed at: http://www.energy.ca.gov/2009_energypolicy/documents/

[3] Cumulative energy efficiency is comprised of utility sponsored industrial, commercial, and residential building and appliance programs.

[4] For the purpose of the allowance allocation to the electricity sector, "early action" is defined as investment in renewables during the period 2007-2011. This includes investment in geothermal, hydroelectric (Output<30MW), solar, wind, and Qualifying Facility (QF) renewable contracts.

[5] In many cases the reported levels of committed resources sum to a quantity less than the projected level of annual load served by a particular utility. In these cases it is assumed that the utility will supplement the projected portfolio of contracted resources with marginal natural gas or unspecified market resources. Thus, *specified* supply is always made to meet load for each utility in each year.

on historical load and resource mix for the years 2001-2010.[6] From historical data, estimates of total load, large hydroelectric (Output>30MW), nuclear, renewable, coal, and natural gas resource levels for the years 2011-2020 were imputed. Load was estimated taking the 2010 load served and applying a 3% annual growth rate.[7] Baseline levels of committed renewable, nuclear, and coal resources were held constant at 2010 levels for the period 2011-2020. Baseline levels of large hydroelectric resources were calculated as the average of levels for all reported years and held constant during 2011-2020. In all cases, residual load – load net of committed resources – was assumed to be served by marginal natural gas facilities or unspecified market power. Early action was calculated for each utility as the sum of investment in renewables for years 2007-2011. Cumulative energy efficiency was projected to be 2% of annual load.[8] Incorporating these data and assumptions staff was able to construct a uniform data set for the Other Utilities that was similar to that constructed for the larger utilities from the S-2 data reported to the CEC.

Finally, for PacifiCorp, a multijurisdictional utility and electricity marketer with resources located in California and out-of-state, the resource mix for the years 2011-2020 was projected using Mandatory Reporting Regulation (MRR) data for 2008-2010. The methodology used to project the PacifiCorp load, resource mix, and early action credit is exactly similar to the method used for the Other Utilities, with the exception that the growth rate applied to PacifiCorp is 1%, as PacifiCorp's load growth has historically been somewhat ambiguous.

[6] In many cases utilities were not able to report data for all years 2001-2010. In some cases this was because the utilities had not been in existence during the entire period and in other cases it was the result of missing data. In all cases missing data were for the early years of the survey period.

[7] The 3% annual growth rate was determined to be appropriate after staff conducted an analysis of the distribution of historical growth rates amongst the Other Utilities. While the rate is somewhat higher than the average growth rate projected for the utilities submitting long-range S-2 forecasts, Staff believes that it accurately reflects the potential for higher growth from the Other Utilities, which are uniformly smaller and have historically grown more quickly.

[8] Limited projections of future energy efficiency investment by Other Utilities are available. After an analysis of historical energy efficiency investment historically achieved by small and large utilities, staff determined that 2% is an achievable level. This is somewhat lower than larger utilities' average future projected energy efficiency goal of 3% of annual load.

RPS Compliance
To accurately reflect the expected level of renewable resources utilized by each utility, staff imposed a constraint on all[9] utilities requiring compliance with a 33% Renewable Portfolio Standard (RPS). This constraint begins at 20% compliance in 2012 and increases linearly to 33% in 2020. In cases where the constraint was binding, the utility's resource plan was adjusted to incrementally invest in a sufficient amount of renewables to meet the standard and "lay off" or divest an equivalent amount of natural gas (and then coal) resources to keep supply and load in equilibrium. In cases where the constraint was not binding the utility was assumed to achieve their projected level of renewable resources.

Allowance Allocation

Preferred Method of Allowance Allocation to Electric Utilities
After reviewing the finalized utility data, ARB staff has identified a preferred method of allocating allowances to the electricity sector that incorporates ratepayer cost burden, projected cumulative energy efficiency and early investment in qualifying renewable resources during the period 2007-2011. Below is a description of each of the factors contributing to the electricity sector allocation and the fraction of allocation awarded by that criteria.

Cost Burden
A central principle of the allowance allocation to the electricity sector is the incorporation of customer cost burden. Cost burden is expected to result from emissions costs associated with fossil, QF, and non-emitting resources priced at market being passed from generators and marketers to utility customers. Under this proposal, the complete annual expected cost burden for each utility is initially allocated. Expected cost burden is calculated by first assigning an emission factor to each fossil generation resource type and non-emitting resources prices at market.[10] Then an annual emissions profile for each utility is calculated by summing the emissions associated with the reported quantities of each resource type. In this way, each utility can expect to be able to fully compensate their customers for the costs associated with the cap and trade program that are expected to be passed through to customers. Under this proposal nearly 94% of allowances are allocated to defray expected costs.

Energy Efficiency

[9] Utilities that receive more than half of their electric load from large hydro are exempted from this constraint. These utilities are Trinity and SFPUC.

[10] Fossil generation emission factors for Bituminous Coal (2143Lbs/MWh), Natural Gas (960Lbs/MWh), Cogeneration (950Lbs/MWh), and Fuel Oils (1500Lbs/MWh) were set equal to average emission factors identified from Mandatory Reporting Regulation (MRR) and Energy Information Administration (EIA) data. Non-emitting resources priced at market were assigned a default emission factor of 960Lbs\MWh.

Energy efficiency is incorporated into the allocation through utilities annual projections of cumulative load reduction. Energy efficiency is assumed to come from decreased demand for natural gas resources, so the quantity reductions are weighted by the emission factor of natural gas. Each utility is awarded 25% of their expected energy efficiency savings. This number was chosen to ensure that at least 1% of allowances could be allocated for energy efficiency achievements. Under this proposal slightly more than 1% of allowances are allocated in recognition of projected energy efficiency.

Early Action

As described above, early action is defined as a utility's investment in qualifying renewable energy during the period 2007-2011. Credit for early action is capped at 25% of a utility's expected cost burden. That is, the share of early action allowances that each utility receives is equal to the lesser of either their share of the total investment in renewables multiplied by the total allowances available for early action or 25% of their expected cost burden. For nearly all utilities this constrain is non-binding.[11] Under this proposal slightly less than 5% of allowances are allocated in recognition of early action.

The Recommended Allocation to Individual Utilities

Table A identifies staff's preferred annual allowance allocation to each electric utility in thousands of metric tons of carbon dioxide equivalent. This table corresponds to Table 9-3 of the discussion draft of the regulation, where the values are expressed as percentages of the total allowances set aside for the electricity sector annually.

Distribution Relative to Cost Burden

As a matter of policy the approach to allocating allowances to the electric sector has been to ensure that each utilities allocation is at least equal to their customers' total expected cost burden in each year.

[11] In the case of utilities for which the early action constraint is binding, the "excess" quantity of allowances is redistributed to ALL utilities according to their share of total expected cost burden.

Table B reports allocation to each utility by year as a percentage of expected customer cost burden. As is easily verified, each utility is expected to receive allocation in excess of their total annual expected cost burden. This is because each utility not only receives an initial allocation of allowances equal to their expected cost burden, but each utility also receives a share of allowances awarded on the basis of projected cumulative energy efficiency and early action.

Table A. Recommended Allocation to Individual Utilities (Thousands of Metric Tons CO_2e)

	2013	2014	2015	2016	2017	2018	2019	2020
Statewide	95,844	94,085	92,229	90,373	88,614	86,758	84,901	83,143
PG&E	25,035	24,872	24,071	23,765	24,190	23,426	23,186	22,733
LADWP	13,624	13,379	12,946	13,070	13,243	13,285	12,733	11,713
SCE	32,700	31,689	31,484	29,631	26,954	25,976	25,110	24,808
SDG&E	6,931	6,560	6,436	6,416	6,470	6,298	6,198	6,156
SMUD	3,161	3,104	2,977	2,997	3,069	3,113	3,161	3,204
City of Anaheim	2,062	2,069	2,025	2,061	2,031	2,037	2,014	2,002
City of Azusa (Azusa Light & Water)	173	174	174	176	178	179	179	181
City of Banning	94	96	95	96	98	98	99	100
City of Burbank	802	807	807	813	820	825	824	826
City of Cerritos	18	18	18	18	19	18	19	19
City of Colton	235	237	239	240	243	242	243	244
City of Glendale (Glendale Water and Power)	633	625	611	608	613	605	606	616
City of Pasadena (Pasadena Water and Power)	778	774	764	762	758	773	774	782
City of Riverside	1,132	1,123	1,114	1,142	1,140	1,146	1,126	1,120
City of Vernon	397	395	396	391	392	383	372	362
Imperial Irrigation District	1,582	1,585	1,568	1,585	1,607	1,589	1,555	1,534
Modesto ID	1,215	1,210	1,176	1,182	1,193	1,176	1,164	1,168
City of Alameda	51	54	54	55	55	63	63	63
City of Biggs	7	7	6	6	7	6	6	6
City of Gridley	15	15	15	14	15	14	14	14
City of Healdsburg	32	31	29	30	32	33	33	35
City of Lodi	160	159	152	152	155	153	149	150
City of Lompoc	48	47	45	47	48	47	46	47
City of Palo Alto	342	337	324	322	326	319	312	312
City of Redding	431	475	464	463	471	475	465	467
City of Roseville	469	473	470	480	494	476	465	459
City of Ukiah	34	33	30	32	35	37	37	37
Plumas-Sierra Rural Electric Cooperation	62	62	62	61	61	60	59	57
Port of Oakland	31	31	31	31	31	30	29	29

	2013	2014	2015	2016	2017	2018	2019	2020
Silicon Valley Power	1,091	1,087	1,056	1,097	1,154	1,163	1,141	1,158
Truckee-Donner Public Utility District	116	117	118	118	119	119	119	120
Turlock Irrigation District	904	917	913	918	937	929	910	906
Anza Electric Cooperative, Inc.	19	20	20	20	21	20	20	20
Bear Valley Electric Service	0	0	0	0	0	0	0	0
City of Needles	10	10	11	11	11	11	11	11
City of Rancho Cucamonga	25	25	25	26	26	26	26	26
City and County of San Francisco	95	109	124	139	154	170	187	201
City of Shasta Lake (Shasta Dam Area PUD)	50	51	51	51	53	53	53	54
Lassen Municipal Utility District	49	50	51	51	52	51	52	52
Merced Irrigation District	164	167	169	170	173	172	172	173
Moreno Valley Utilities	38	38	39	39	40	39	40	40
Mountain Utilities	3	3	3	3	3	3	3	3
Port of Stockton	5	5	5	5	5	5	5	5
Power and Water Resource Pooling Authority	64	65	65	67	71	71	71	73
Liberty Pacific Power Company	217	221	224	226	229	227	228	227
Surprise Valley Electrical Corporation	52	52	53	54	55	54	54	54
Trinity Public Utility District	0	0	0	0	0	0	0	0
USBR WAPA Boulder City Area Parker-Davis	319	334	349	353	369	360	363	358
Valley Electric Association, Inc.	0	0	0	0	0	0	0	0
Victorville Municipal	23	23	24	24	24	24	24	24
Hercules	6	6	6	6	7	7	7	7
City of Industry	9	9	9	9	9	9	9	9
Corona	58	59	59	60	61	61	61	61
Pittsburg Power/ Island	4	4	4	4	4	4	4	4
Eastside	5	5	5	5	5	5	5	5
PacifiCorp	270	268	260	269	280	289	294	306

Table B. Allocation in Excess of Expected Cost Burden

	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	9.24%	7.46%	4.15%	5.40%	7.18%	8.66%	8.93%	9.24%
LADWP	4.25%	3.35%	1.43%	2.24%	3.45%	4.26%	4.70%	4.25%
SCE	7.40%	6.15%	3.29%	4.58%	6.94%	8.47%	9.01%	7.40%
SDG&E	4.76%	4.17%	2.57%	3.08%	3.87%	4.48%	4.59%	4.76%
SMUD	11.25%	8.94%	4.33%	6.22%	9.03%	10.88%	11.24%	11.25%
City of Anaheim	1.80%	1.45%	0.70%	1.02%	1.52%	1.84%	1.95%	1.80%
City of Azusa (Azusa Light & Water)	2.46%	1.93%	0.84%	1.30%	1.95%	2.40%	2.52%	2.46%
City of Banning	3.51%	2.67%	1.10%	1.74%	2.68%	3.33%	3.50%	3.51%
City of Burbank	1.19%	0.95%	0.46%	0.67%	0.98%	1.18%	1.23%	1.19%
City of Cerritos	2.43%	2.01%	1.17%	1.52%	2.02%	2.39%	2.49%	2.43%
City of Colton	1.13%	0.95%	0.51%	0.70%	0.96%	1.14%	1.18%	1.13%
City of Glendale (Glendale Water and Power)	4.26%	3.35%	1.44%	2.28%	3.51%	4.42%	4.66%	4.26%
City of Pasadena (Pasadena Water and Power)	2.78%	2.24%	1.02%	1.55%	2.34%	2.81%	2.96%	2.78%
City of Riverside	3.80%	2.99%	1.27%	1.97%	3.06%	3.77%	4.06%	3.80%
City of Vernon	0.25%	0.26%	0.27%	0.31%	0.28%	0.26%	0.23%	0.25%
Imperial Irrigation District	2.50%	1.97%	0.87%	1.35%	2.04%	2.53%	2.73%	2.50%
Modesto ID	4.35%	3.40%	1.46%	2.32%	3.57%	4.49%	4.79%	4.35%
City of Alameda	25.50%	25.48%	24.01%	25.48%	25.50%	25.46%	25.46%	25.50%
City of Biggs	4.75%	3.47%	1.51%	2.51%	3.78%	4.98%	5.40%	4.75%
City of Gridley	3.13%	2.42%	0.98%	1.60%	2.50%	3.16%	3.43%	3.13%
City of Healdsburg	17.78%	13.67%	5.43%	8.78%	13.72%	16.88%	17.84%	17.78%
City of Lodi	9.34%	7.20%	2.94%	4.86%	7.64%	9.80%	10.67%	9.34%
City of Lompoc	11.23%	8.63%	3.43%	5.56%	8.77%	11.29%	12.29%	11.23%
City of Palo Alto	8.02%	6.25%	2.63%	4.27%	6.69%	8.59%	9.35%	8.02%
City of Redding	8.39%	5.78%	2.30%	3.81%	6.01%	7.49%	8.13%	8.39%
City of Roseville	4.21%	3.24%	1.38%	2.14%	3.24%	4.14%	4.47%	4.21%
City of Ukiah	25.15%	20.37%	7.90%	12.76%	19.92%	24.40%	25.23%	25.15%
Plumas-Sierra Rural Electric Cooperation	1.62%	1.26%	0.52%	0.87%	1.39%	1.82%	2.03%	1.62%
Port of Oakland	0.17%	0.17%	0.15%	0.18%	0.20%	0.22%	0.23%	0.17%
Silicon Valley Power	11.94%	9.12%	3.68%	5.76%	8.75%	10.95%	11.86%	11.94%
Truckee-Donner Public Utility District	0.79%	0.64%	0.34%	0.49%	0.69%	0.82%	0.85%	0.79%
Turlock Irrigation District	5.64%	4.30%	1.78%	2.85%	4.36%	5.47%	5.92%	5.64%
Anza Electric Cooperative, Inc.	0.67%	0.67%	0.66%	0.69%	0.71%	0.74%	0.76%	0.67%

Bear Valley Electric Service	0.67%	0.67%	0.66%	0.69%	0.71%	0.74%	0.76%	0.67%
City of Needles	0.23%	0.24%	0.25%	0.29%	0.31%	0.34%	0.35%	0.23%
City of Rancho Cucamonga	0.05%	0.05%	0.03%	0.04%	0.06%	0.07%	0.08%	0.05%
City and County of San Francisco	2.64%	2.35%	2.12%	1.95%	1.81%	1.70%	1.60%	2.64%
City of Shasta Lake	4.00%	3.12%	1.31%	2.06%	3.11%	3.88%	4.09%	4.00%
Lassen Municipal Utility District	0.18%	0.18%	0.16%	0.22%	0.29%	0.34%	0.36%	0.18%
Merced Irrigation District	1.17%	0.92%	0.43%	0.65%	0.95%	1.17%	1.23%	1.17%
Moreno Valley Utilities	0.09%	0.09%	0.08%	0.09%	0.10%	0.10%	0.10%	0.09%
Mountain Utilities	0.56%	0.55%	0.54%	0.56%	0.58%	0.61%	0.63%	0.56%
Port of Stockton	0.67%	0.67%	0.66%	0.69%	0.71%	0.74%	0.76%	0.67%
Power and Water Resource Pooling Authority	11.58%	8.97%	4.31%	6.12%	8.53%	10.51%	11.01%	11.58%
Liberty Pacific Power Company	0.67%	0.67%	0.66%	0.69%	0.71%	0.74%	0.76%	0.67%
Surprise Valley Electrical Corporation	0.67%	0.67%	0.66%	0.69%	0.71%	0.74%	0.76%	0.67%
WAPA	1.93%	1.85%	1.75%	1.81%	1.83%	1.96%	2.01%	1.93%
Valley Electric Association, Inc.	0.97%	0.96%	0.95%	0.98%	1.00%	1.05%	1.08%	0.97%
Victorville Municipal	0.67%	0.67%	0.66%	0.69%	0.71%	0.74%	0.76%	0.67%
Hercules	4.63%	3.58%	1.49%	2.35%	3.56%	4.44%	4.69%	4.63%
City of Industry	0.73%	0.73%	0.72%	0.74%	0.76%	0.80%	0.82%	0.73%
Corona	2.24%	1.86%	1.12%	1.44%	1.89%	2.22%	2.33%	2.24%
Pittsburg Power/ Island	1.66%	1.57%	1.41%	1.50%	1.58%	1.71%	1.76%	1.66%
Eastside	1.93%	1.88%	1.83%	1.87%	1.85%	1.96%	2.01%	1.93%
PacifiCorp	11.24%	8.74%	3.84%	5.76%	8.57%	10.33%	10.73%	11.24%

Eligibility

Criteria for Receiving Allowances as Part of the Electricity Sector Allocation
In order to receive allowances as part of the electricity sector allocation, entities must provide electricity serve end-use customer load and receive payment for that load from end-use customers. Each of the utilities listed in Table 9-3 of the regulation are end-use customer sellers with the required transactional relationship. Generators, marketers, and other providers of electricity that do not have a transactional relationship to end-use customers are not eligible for allowance allocation. This requirement is essential to correctly incorporating the emissions price signal in electricity markets and appropriately compensating electric customers for the costs of the program. If entities without a transactional relationship to consumers are allocated allowances for the benefit of end-use customers their only means of directly defraying the programmatic costs would be reduce prices. This outcome is explicitly <u>not</u> the goal of cap and trade.

The Water Sector
In December the Board directed staff to further evaluate the appropriateness of allocating allowances directly to the State Water Project (SWP) and the Metropolitan Water District (Metropolitan). After consideration of the potential benefits and dis-benefits to consumers and the integrity of the program, staff has determined that it is not appropriate to include SWP or Metropolitan in the allocation to the electricity sector. While each of these entities use electricity to transport water into and around California, and the emissions associated with this activity are included in the pool of allowances set aside for the electric sector, staff view the role of these entities as analogues to electricity marketers, and not distribution utilities. As described above, these entities do not maintain direct relationships with the end-use consumers of their projects. Rather, they market water to utilities and intermediaries. As such, allocating directly to these entities could result in either the deterioration of the emissions price signal in the water sector, if they used the value to reduce prices, or lost value for end-use customers, if they used the allowance value for something other than direct compensation, which they are not well positioned to provide to end-users.