ATTACHMENT C

FIRST NOTICE OF PUBLIC AVAILABILITY OF 15-DAY AMENDMENT TEXT

Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation

2021–2030 Allowance Allocation to Electrical Distribution Utilities

State of California

AIR RESOURCES BOARD

Release Date: December 21, 2016

ATTACHMENT C:

2021–2030 Allocation to Electrical Distribution Utilities

Background

The Cap-and-Trade Regulation (Regulation) serves multiple purposes. The most important of these purposes is the imposition of a cap on the vast majority of California's greenhouse gas (GHG) emissions to ensure that California meets its emissions reduction goals, as first required by Assembly Bill 32 (AB 32)(Nuñez, Statutes of 2006). The Regulation also ensures that emissions reduction targets will be reached even if complementary measures[1] underperform. Finally, the Regulation puts a price on carbon; this price signal is needed to drive long-term investment in cleaner fuels and more efficient use of energy (ARB 2010A).

Senate Bill 32 (SB 32)(Chapter 249, Statutes of 2016) requires the Air Resources Board (ARB) to ensure that statewide greenhouse gas emissions are reduced to 40 percent below the 1990 level by 2030. This target requires emissions reductions at a steeper trajectory than needed for the earlier goal of reducing emissions to 1990 levels by 2020. Senate Bill 350 (SB 350)(Chapter 547, Statues of 2015) requires that 50 percent of electricity generation come from renewable sources and doubling of building energy savings, all by 2030. Achieving these goals will require a comprehensive approach that includes carbon pricing through an effective, well-designed Cap-and-Trade Program (Program).

Electricity generators and importers face a compliance obligation for the GHG emissions associated with the energy they generate or import into California, and they may pass that cost on to the electrical distribution utilities (EDU) that supply the electricity to end-users. ARB allocates allowances to EDUs, rather than non-EDU generators or importers, because EDUs have direct relationships with retail customers. These relationships put EDUs in a position to use allocated allowances to benefit retail customers consistent with AB 32 goals, including via methods such as bi-annual rebates that do not counteract the price signal (i.e., non-volumetric climate credits) resulting from the Program.

In developing the Regulation, ARB recognized that allocation to EDUs should "reflect the 'cost burden' associated with Program emissions costs that is anticipated to be borne by the ratepayers for each distribution utility" (ARB 2010B). Cost burden is the effect on ratepayers of the incremental cost of power to serve load due to the compliance cost for GHG emissions caused by the Program. Cost burden was the primary basis for the original allocation, accounting for approximately 94 percent of the total 2013–2020 allocation to EDUs (ARB 2011). Current and proposed allocations to EDUs are based on this concept of cost burden.

[1] As described in the initial Climate Change Scoping Plan (ARB 2008), the 2013 Update to the Scoping Plan (ARB 2014A), and the 2030 Target Scoping Plan (ARB 2016A).

The Regulation requires investor-owned electric utilities (IOU) to sell all allocated allowances at auction, and allows them to return the value to ratepayers and use the auction proceeds for ratepayer benefit, consistent with the goals of AB 32. The cost of compliance is passed through to all ratepayers. Senate Bill 1018 (Chapter 39, Statutes of 2012) requires the California Public Utilities Commission (CPUC) to ensure that IOUs' auction proceeds are credited directly to the IOUs' residential, small business, and emissions-intensive, trade-exposed customers. The Regulation affords publicly owned utilities (POU) and electrical cooperatives (co-ops) more flexibility in that they are allowed to direct their allocation either to their own or an associated entity's compliance account[2] and/or to consign allowances to auction. Allowances allocated to POUs and co-ops must also be used for ratepayer benefit, consistent with the goals of AB 32. Staff is also considering requiring POUs and co-ops to consign allocated allowances to auction and requiring that the auction proceeds be used for specific purposes. Requiring consignment would align the use of allowance value amongst investor-owned EDUs, publicly owned EDU, electrical cooperatives, and natural gas suppliers. Additional proposed amendments would be proposed in a subsequent 15-day regulatory proposal.

Summary of 2021–2030 EDU Allocation Proposal

As part of this rulemaking, ARB staff proposes to continue allocation to EDUs for the benefit of ratepayers, consistent with the goals of AB 32, beyond 2020. The current amendments to the Regulation (in Table 9-4) include proposed 2021–2030 allocations to each EDU. Staff proposes to use a methodology similar to that used to calculate 2013–2020 EDU allocations, but with some important differences. This proposal builds on staff's proposal outlined in the 2016 Initial Statement of Reasons to the proposed amendments to the Regulation (ARB 2016B), in that allocation would be calculated based on the Program cost burden.

As with the 2013–2020 allocation, the proposed 2021–2030 allocation methodology would allocate to EDUs based on the GHG cost burden faced by electricity ratepayers. Each year's allocations would be adjusted by the cap decline factor, consistent with the 2013–2020 allocation. Differences between the 2013–2020 and 2021–2030 EDU allocation methodologies are described below in "Comparison of Current Proposal with 2013–2020 EDU Allocation Methodology," and details on the exact EDU-specific allocations are provided below in "Details of Proposed 2021–2030 EDU Allocation Calculations," as well as in the associated 2021-2030-edu-allocation.xlsx spreadsheet.[3] Updated information on staff's current proposal for the Renewables Portfolio Standard (RPS) adjustment is also included below under "RPS Adjustment."

The methodology proposed as part of these 15-day amendments reflects staff consideration of stakeholder comments in response to the ISOR (ARB 2016B), an

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[2] Per the requirements outline in section 95892(b)(2) of the current Regulation.
[3] https://www.arb.ca.gov/regact/2016/capandtrade16/2021-2030-edu-allocation.xlsx, ARB 2016D.

October 21, 2016 workshop,[4] and meetings with the Joint Utilities Group, individual EDUs, and other stakeholders. Staff previously considered allocating to individual EDUs based on calculated cost burden for 2020 and, for each year after 2020, reducing the allocation by multiplying the 2020 cost burden by the cap adjustment factor.

The current proposal instead calculates cost burden for each year and multiplies by the cap adjustment factor for each year after 2020. Calculations rely primarily on projections from 2015 S-2 forms utilities submitted to the California Energy Commission (CEC 2015) and CEC's 2015 Energy Demand Forecast (CEC 2016A). These CEC documents provide the most recent, publicly available projections of load and EDU resources, and thereby provide the most robust basis for estimating future cost burden. As noted in the 2016 ISOR, the electricity sector has changed significantly in recent years, including load and energy source changes that significantly diverge from 2009 predictions (ARB 2016B). The current calculation of allowance allocations represents an appropriate time to update EDU allocations based on updated predictions from utilities.

In response to the October 2016 workshop proposal, many commenters argued that the drop in allocation that would occur between the current Regulation's 2020 allocation and the proposed 2021 allocation would penalize EDUs and their customers.[5] Staff strongly disagrees with this characterization, and asserts that the drop in allocation is entirely appropriate since it reflects the most recent load projections. When allowances are allocated in advance of a period based on projected load and resulting cost burden, there is a risk that the load projections will be too high or too low. Load projections used for allocation that fall below actual load will result in under-allocation with respect to cost burden, and load projections that exceed actual load will result in over-allocation. The most recent CEC forms show that 2013–2020 EDU allocation likely results in an over-allocation of allowances to EDUs with respect to Program cost burden. Staff argues that the fairest approach to allocation under a Program cost burden methodology is to use the most recent load project data. Staff is not proposing to change this during the pre-2021 period (indeed, this is out of the scope of current regulatory amendments), but asserts that using the most recent projected loads to calculate cost burden results in the best protection of electricity ratepayers and does not result in over-allocation.

Some EDUs have argued that the drop in allocation between 2020 and 2021 will result in rate shocks in 2021. This is especially untrue for IOU customers, since they currently see a full GHG cost in their electricity rates. Decreasing allocation would only reduce their climate credits and should have no effect on rates. Under the current allocation scheme for POUs and co-ops, these entities could plan ahead for the decrease in allocation by banking auction proceeds, passing the GHG cost through to their customers, and returning auction proceeds to ratepayers in a non-volumetric manner. This will have the dual benefit of incentivizing reductions in electricity consumption while protecting ratepayers from Program costs.

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[4] The workshop proposal, presentation, and stakeholder comments are all included as Attachment E to the 15-day notice.
[5] Ibid.

Staff received comments from some EDUs that assuming constant load for the post-2020 period was problematic because their loads were expected to grow post-2020, and the allocation methodology outlined in the 2016 ISOR would not appropriately reflect their cost burden. Staff agrees that this is an issue, and therefore has modified the proposed allocation calculation methodology to calculate annual cost burden for each EDU, which included a decreasing cost burden due to increasing sales of renewable power. At the October 2016 workshop, staff presented two options for proposed EDU allocation that would calculate cost burden annually; one option would change cost burden with anticipated load changes, and the other would assume fixed load over the 2021–2030 period. All commenters either preferred that staff assume changing load, or did not state a preference. Many commenters also argued that staff should not assume increasing purchases of renewable electricity. Staff proposed that the EDU allocation reflect increasing purchases of renewable electricity with SB 350 RPS requirements because this factor significantly reduces the Program cost burden. Staff believes that calculating annual cost burden must account for the significant decrease in cost burden that is associated with increasing renewable electricity purchases.

Proposed EDU allocations also incorporate declining cap adjustment factors to align with the declining cap and SB 32's 2030 target. Proposed allowance allocations incorporate the cap decline factors used in other sectors to equitably spread the effects of the declining cap across entities, and to spread them across years to encourage continually decreasing emissions.

Finally, staff is committed to continuing to assess the potential for adjusting allocation amounts to reflect emissions that result from electrification of transportation. At this time, it is not clear to staff how this increase in electricity demand (and cost burden, if non-renewable electricity is utilized) could be quantified in a manner consistent with allowance allocation within a market program in the context of a decreasing supply of allowances to meet the 2030 emissions goal. Staff will continue to coordinate with energy agencies and stakeholders to work on the development of a methodology to allocate for this purpose. As indicated in the ISOR, it is important to ensure any method used to calculate any allocation for increased electrification is as accurate and verifiable as the methods used to allocate for industrial sectors for product-based allocation (ARB 2016B).

Comparison of Current Proposal with 2013–2020 EDU Allocation Methodology

The current proposal in this 15-day package maintains the original approach to determining each EDU's cost burden. Cost burden would be calculated by estimating emissions for each year from 2021–2030 associated with generation from natural gas resources and the coal-fired Intermountain Power Plant, which is the only remaining specified coal resource after 2020.[6] The proposed method accounts for retirements of

[6] Cost burden is determined differently for the multi-jurisdictional EDU PacifiCorp, which also has coal resources in its portfolio. See Table 2 for details.

coal plants and the Diablo Canyon nuclear facility by assuming that these facilities are replaced by natural gas-powered electricity after they retire. Electricity from natural gas resources continues to be estimated as total generation less generation from coal and zero-emission resources. This calculation is based on the idea that natural gas power is most often used to provide energy not already contracted for from other sources or required to meet renewable energy requirements. As in the original methodology, zero-emission resources include large hydroelectric and nuclear power, and also include power from facilities eligible under the RPS Program, with the assumption that each EDU procures RPS-eligible power that increases from the mandated 33 percent in 2020 to 50 percent in 2030. As with the 2013–2020 allocation, each year's allocation would be adjusted by the cap adjustment factor. This treatment of RPS and the cap adjustment factor is consistent with the approach used for 2013–2020 allocation.

EDU allocation for 2013–2020 included a top-down component based on an electricity sector-wide allocation with a percentage of the sector allocation amount designated for each EDU. A bottom-up component was also utilized, and the difference between the top-down and bottom-up cost burdens was distributed as allocated allowances to recognize energy efficiency and early action to reduce GHG emissions. Because energy efficiency and RPS requirements are now essentially the same for all EDUs, and the Program will enter its ninth year in 2021, staff proposes to eliminate energy efficiency and early action allocation. Instead, staff proposes that the 2021–2030 EDU allocation calculation methodology be calculated only in the bottom-up manner and apply to each EDU individually. This will make each EDU's annual allocation more transparent and will simplify changes in allocation when load is sold among EDUs. The proposed calculation of the 2021–2030 cost burdens would also not include the costs of zero-emission power priced at market, as was done previously for qualifying facility (QF) renewable power.[7]

Finally, each EDU's allocation would be reduced by an amount equivalent to the emissions resulting from power that serves that EDU's industrial covered entities. That is, the calculated cost burden for each EDU with industrial covered entity customers would be reduced to account for emissions associated with electricity purchased by these entities. Allocation for electricity consumed by industrial covered entities would be done through direct allocation to these entities, such that the emissions associated with their electricity use would be included in calculated industry-specific benchmarks. This change will encourage pass through of program costs to industrial entities, thus incentivizing them to reduce emissions, while direct allocation will provide emissions leakage prevention in line with existing industrial allocation policy. This change will also remove the potential inequity between IOU-customer industrial covered entities, which already see a GHG cost and receive distribution of IOU auction proceeds to prevent against emissions leakage, and POU-customer industrial covered entities that may not be protected from emissions leakage.

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[7] The total amount of renewable QF power is projected to decline from 3,121 gigawatt-hours (GWh) in 2013 to 251 GWh in 2020 and 101 GWh in 2024. (CEC 2015)

Details of Proposed 2021–2030 EDU Allocation Calculations

Staff proposes to allocate allowances to each EDU equal to the cost burden adjusted by annual cap adjustment factors for each year from 2021–2030. Table 1 shows the steps, in sequence, for determining each EDU's allowance allocation, and sections following Table 1 provide further details on the allocation calculations. For some EDUs, staff made exceptions to the steps outlined in Table 1 when standard data were not available; these exceptions are outlined in Table 2. Full details describing how each utility's allocations were calculated are provided in spreadsheet 2021-2030-edu-allocation.xlsx.[8] A separate sheet (tab) for each EDU shows the steps used to determine that utility's allocation. The resulting allocation amounts are shown both in the EDU-specific spreadsheet tab as well as in Table 9-4 of the proposed Regulation.

[8] https://www.arb.ca.gov/regact/2016/capandtrade16/2021-2030-edu-allocation.xlsx (ARB 2016D). All allocation details for Merced Irrigation District and Modesto Irrigation District are redacted from this spreadsheet because providing these details would reveal protected confidential business information regarding electricity purchased by industrial covered entities.

Table 1: Steps for Calculation of 2021–2030 EDU Allowance Allocation

a	STEP	DATA SOURCE
1	Select appropriate data source for each EDU's projected generation. Depending on the data source, data are available for 2021-2026 (CEC Forms 1.5 and 1.1c, and updated S-2s provided by Northern California Power Agency (NCPA 2016)), 2021-2024 (S-2s submitted by large utilities), or 2013–2015 (S-2s submitted by smaller utilities)[9,10]. In each case, use data for available years. For the first year for which data are not available, calculate generation by applying the "Average Annual Growth" factor to the average quantity of generation for the most recent three years available. For subsequent years, multiply the generation from the prior year by the Average Annual Growth.	In order of preference: a) "Net Energy for Load" from Form 1.5a of "LSE and BA Tables Mid Demand Baseline – No AAEE." b) "Adjusted Energy Demand" from the EDU's 2015 S-2. c) Retail sales from Form 1.1c of the Tables cited above, adjusted to account for average State transmission losses of 7 percent.[11] d) "Average Annual Growth 2014–2026" from Form 1.5a, or from Form 1.1c for EDUs not listed or mapped to regions listed in Form 1.5a.
2	Select appropriate retail sales data. In each case, use data for available years. For the first year for which data are not available, calculate retail sales by applying the "Average Annual Growth" factor to the average quantity of retail sales for the most recent three years available. For subsequent years, multiply the retail sales from the prior year by the Average Annual Growth.	Form 1.1c. If retail sales data are inconsistent with generation, assume retails sales are generation less 7 percent losses.
3	Select resource data for coal, large hydroelectric, and nuclear resources (S-2 forms) and calculate estimated generation for years for which public data are not available.	2015 S-2s. For EDUs without S-2s, staff worked with the EDUs to identify the appropriate resource data.
4	Calculate mandated RPS resource generation as the product of the annual RPS factor (rounded to the nearest whole percent) and annual retail sales.	
5	Subtract coal, nuclear, large hydroelectric and RPS generation from total generation to calculate natural gas generation.	

[9] LSE and BA Tables, Mid-Demand Baseline, No AAEE, prepared in support of the 2015 Demand Forecast, CEC 2016B.
[10] S-2 Forms, CEC 2015. Large EDUs file long S-2 forms that estimate load and resources through 2024. Smaller EDUs report actual 2013 and 2014 data, and estimated 2015. NCPA uses a single S-2 to report generation and resources for ten EDUs that receive all of their power through NCPA. NCPA broke down the data by utility into separate S-2 forms, extended the estimated load and resources through 2026, and submitted this information to ARB. ARB has made these spreadsheets available at https://www.arb.ca.gov/regact/2016/capandtrade16/ncpa-breakdown.xlsx, NCPA 2016.
[11] A 2011 report on California transmission losses (Wong 2011) found typical losses in the 6 to 7 percent range. In addition, a comparison between projected generation and projected retail sales from Forms 1.5c and 1.1a (CEC 2016B) shows annual losses varying between 7 and 8 percent. Based on these analyses, staff utilized a 7 percent transmission loss for allocation calculations that utilized a default transmission loss value.

a	STEP	DATA SOURCE
6	Determine EDU emissions as the sum of natural gas generation (megawatt-hours (MWh)) multiplied by the natural gas emission factor, and coal generation multiplied by the coal generation factor. For all EDUs except those with industrial covered entity customers, the calculated cost burden is equal to the emissions determined in this step.	Natural gas emission factor is the same emission factor used for the 2013–2020 EDU allocation (0.4354 $MTCO_2e$/MWh),[12] which represents the marginal resource available for dispatch. The coal emission factor, 0.9184 $MTCO_2e$/MWh, is calculated as the 2013–2015 average of emission factors for Intermountain Power Plant as determined pursuant to section 95811 of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR)[13] and published in each year's version of "Workbook 1 EPE Importers and Exporters."[14]
7	For each EDU with industrial covered entity distribution customers, calculate emissions associated with electricity services purchased by industrial covered entities.	
a	For each EDU, sum the MWh electricity reported through MRR by all industrial covered entities that purchase electricity from the EDU for each year 2013 through 2015. For the adjusted MWh for each year, divide the sum for each year by the cap adjustment value for each year 2013 through 2015. The average of the three years' adjusted MWh is the pre-Program baseline electricity purchases for all industrial covered entities served by the EDU.	MWh of purchased electricity reported by industrial covered entities from 2013–2015 pursuant to MRR. Cap adjustment factors from Table 9-2, proposed Regulation.
b	To determine emissions associated with industrial covered entity purchased electricity, multiply purchased electricity for each year (as calculated in 7a) by the EDU's emission factor for each year. The EDU emission factor is equal to calculated emissions (Step 6) divided by generation to serve load (Step 1).	
8	To determine cost burden for each EDU with covered entity customers for each year, subtract the average annual industrial covered entity emissions from the EDU's calculated emissions.	
9	To determine each year's allocation, multiply the cost burden determined in Step 6 or Step 8 by the annual cap adjustment factor divided by the 2020 cap adjustment factor.	Cap adjustment factors from Table 9-2, proposed Regulation.

[12] Even updated with the global warming potentials that ARB has proposed to use for reporting of post-2020 GHG emissions (ARB 2016C), this value remains the same as the value used for the 2013–2020 allocation.

[13] ARB 2014B.

[14] ARB 2014C, ARB 2015A, ARB 2016E. These annual versions of Workbook 1, updated every year, are used to report imported electricity pursuant to MRR. The emission factors determined pursuant to MRR are adjusted to account for updates to the global warming potentials for CH_4 and NO_2 based on the IPCC Fourth Assessment Report (Christensen 2007), as ARB (2016B) has proposed to use in MRR and the Program after 2020.

Annual Generation (Energy To Serve Load (Generation))
Energy to serve load (generation) is the total amount of power required for serving an EDU's retail sales, taking into account transmission and other losses, and is the starting point for determining allocation to EDUs. Values from CEC's 2015 Form 1.5a are used, if available. If not, values form CEC Form 1.1c are used; if these are also unavailable, values from 2015 S-2 forms are used. Generation for the three large IOUs includes that needed to serve distribution customers that purchase generation from community choice aggregators or electricity service providers. PacifiCorp, Liberty Utilities, and Golden State Water Company (Bear Valley) are not included in Table 1.5a and do not submit S-2s. Generation for Liberty Utilities and Golden State Water Company were derived from retail sales (Form 1.1c) by assuming a transmission loss factor of 7 percent.[15] Because of its unique position and data availability, the allocation method for PacifiCorp is unique and discussed below.

Staff uses "Average Annual Growth" factors to project generation for years not included in the data sources. Average annual growth factors from Form 1.5a are used for EDUs listed or EDUs that can be mapped to one of the regions (Column B of Form 1.5a) of Form 1.5a; otherwise, average annual growth factors from Form 1.1c are used.

Retail Sales
Retail sales forecasts are used to calculate the zero-emission power needed to meet the RPS requirements of SB 350 for all EDUs except PacifiCorp. The difference between actual generation for load and retail sales is equal to transmission and other losses. The CEC's 2015 forecast of retail sales—as shown in Form 1.1c (CEC 2016B)—is available through 2026 for all EDUs except Eastside Power Authority and Power and Water Resources Pooling Authority (PWRPA). As described previously, statewide, losses are approximately 7 percent. Staff tested projected CEC retail sales against energy to serve load to determine if the retail sales amount is plausible given generation quantities determined as discussed above, and to generate an apparent loss factor. Staff assumed that losses between zero and 15 percent are possible. For EDUs for which the apparent loss factor is outside this range, instead of using CEC retail sales data, staff calculated retail sales from energy to serve load by assuming a 7 percent loss factor. For 2027–2030, retail sales are estimated by multiplying the previous year's sales by the average annual growth factor described above.

Coal Power
S-2 forecasts are used to calculate the quantity of coal electricity generation for the six California EDUs that will still have coal power in their supply portfolio after 2020.[16] A single facility, the Intermountain Power Plant, serves these six EDUs. Coal emissions for each EDU are the product of the adjusted average IPP emission factor calculated pursuant to MRR for 2013–2015 and the annual quantity of coal power. Staff adjusted the MRR emission factor to account for changes to the global warming potentials in the IPCC Fourth Assessment Report (Christensen 2007) relative to the Second Assessment Report, which was used to calculate the existing IPP emission factor. Because S-2 data exist only through 2024, quantities of coal assumed for 2025 and 2026 are assumed to be

[15] See footnote 11 for more details on the 7 percent transmission loss assumption.
[16] PacifiCorp will continue to have coal power through the allocation period, and is included as described elsewhere in determining the amount allocated to PacifiCorp.

the average quantity for 2022–2024. The EDU contracts with IPP end in June 2027. Coal power for 2027 is assumed to be half of the three-year average amount, and no coal power is assumed after 2027.

Nuclear and Hydroelectric Power

The S-2 forms show the quantity of hydroelectric and nuclear generation for each EDU for which they are available (i.e., for 2013–2015, 2021–2024, or 2021–2026).[17] Staff assumed that large (greater than 30 MW) hydroelectric sources are those listed on line 10b of the S-2s, and resources included as long-term bilateral hydroelectric contracts on lines 15a-z of the S-2s. Hydroelectric sources of less than 30 MW capacity are considered to be RPS-eligible resources and their generation is not subtracted from total generation in determining natural gas power.

RPS Power

Staff assumed that all EDUs would meet each year's RPS requirements. Staff determined annual RPS requirements by assuming the RPS power would grow from 33 percent of retail sales in 2020 to 50 percent in 2030 on a linear path. Each year's computed RPS percentage was rounded to the nearest integer.

Natural Gas Power

Staff assumed that all power not supplied by coal, nuclear, hydroelectric, or calculated RPS resources would be natural gas power. For years when non-natural gas resources comprised more than 95 percent of an EDU's resource portfolio, staff assumed that the EDU would require natural gas power equivalent to five percent of energy to serve load, consistent with the expectation that EDUs will need some natural gas power to support variable renewable resources.

Surplus Power

Two EDUs have large amounts of surplus power due to long-term contracts with natural gas facilities and out-of-State coal facilities. To determine the most reasonable cost burden associated with supplying load, it is necessary to select what generating sources are most likely to be associated with the power that will be sold. Staff assumed that RPS power and hydroelectric power would be used by the EDU first, and that each EDU required a minimum of five percent (of the EDU's total load) natural gas power. This natural gas minimum represents the dispatchable power required to support variable renewables. Staff assumed that natural gas power beyond this five percent minimum would be sold first, due to resource shuffling provisions of the Regulation that prohibit sales of the contracted coal out of State. If the coal power sold was imported by the EDU, the EDU would incur a compliance cost which would be passed through to the purchaser.

PacifiCorp

Staff is in discussions with PacifiCorp regarding the appropriate information and methods to project PacifiCorp's Program cost burden and resulting allocations. Staff are considering whether changes to the proposal shown here may be appropriate, in which case these changes would be proposed as part of a subsequent 15-day regulatory

[17] SCE has not publicly released data on nuclear and hydropower post-2014. Staff assumed that average hydro and nuclear power from those two years are representative for 2021–2030. Different assumptions are used for PacifiCorp, Liberty, Bear Valley, and WAPA since they do not submit S-2s.

proposal. To calculate the current proposal, staff used data from PacifiCorp's 2015 Update of its Integrated Resource Plan (IRP Update)(PacifiCorp 2016A[18]) to calculate future EDU emissions and load, and derived 2021–2030 emission factors from these quantities for use in calculating cost burden. This approach is proposed to align with PacifiCorp's compliance obligation, which is the product of its electricity brought into California and its calculated emissions factor calculated pursuant to MRR section 95111. This approach is consistent with the Program cost burden approach used for other utilities. PacifiCorp's IRP Update modifies PacifiCorp's earlier 2015 resource plan to account for California's 50 percent RPS target in 2030 mandated by SB 350, other states' current RPS requirements, and other changes in variables affecting future load and resource mix. PacifiCorp's IRP Update incorporates the RPS requirements mandated by the CPUC, and is subject to CPUC approval.

[18] In addition to the IRP Update, staff used supplemental materials (PacifiCorp 2016B, and PacifiCorp 2016C) derived from the IRP Update modeling and published by PacifiCorp in response to staff's data request.

Table 2: Exceptions to Methodology Described in the Text and Table 1.

EDU Name[19]	EDU-Specific Exception to Methodology
Bear Valley Electric Service (BVES)	Because Bear Valley does not submit an S-2 to CEC, staff obtained resource data from Bear Valley. All of Bear Valley's supply is natural gas generation or unspecified power.
City of Anaheim, Public Utilities Department, Anaheim City Hall West	Anaheim has significant surplus coal and natural gas power from 2012–2026. For those years, it is assumed that Anaheim takes natural gas power equivalent to 5 percent of generation, and that all other surplus is coal power that must be sold with Anaheim passing through the cost of compliance. Assumptions for nuclear, hydroelectricity, and RPS are not affected by Anaheim's surplus.
Liberty Utilities (CalPeco Electric) LLC	Liberty Utilities does not submit an S-2 to CEC. All power to serve Liberty's load is imported as unspecified power reported by Liberty pursuant to MRR section 95111. It is assumed that Liberty will meet the RPS requirements, and all other energy to serve load is natural gas power.
Pacific Gas and Electric Company (PG&E) - Electric Power Entity	Form 1.5a includes three different portions of PG&E's service territory, which are summed to equal total generation for load. Generation and retail sales data are inclusive of community choice aggregators and electricity service providers that receive distribution service from PG&E.
PacifiCorp	See the section entitled "PacifiCorp" above.
Pasadena Water and Power, 91101	Pasadena has significant surplus coal and natural gas power from 2012–2026. For those years, it is assumed that Pasadena takes natural gas power equivalent to 5 percent of generation in order to support variable renewables, and that all other surplus is coal power that must be sold with Pasadena passing through the cost of compliance. Pasadena imports over 95 percent of its entitlement of coal power from IPP. Assumptions for nuclear, hydroelectricity, and RPS are not affected by Pasadena's surplus.
Power and Water Resources Pooling Authority (PWRPA)	No "Average Annual Growth" factor is listed in Forms 1.5a or 1.1c for PWRPA. Because PWRPA provides power in multiple regions, it was not possible to map PWRPA's load to a known average annual growth factor; therefore, staff assumed no change in load.
Southern California Edison (SCE)	Form 1.5a includes three different portions of SCE's service territory, which are summed to equal total generation for load. Generation and retail sales data are inclusive of community choice aggregators and electricity service providers that receive distribution service from SCE. Staff assumed that generation from large hydro and nuclear power for 2021–2030 would be equal to the average of 2013–2014 shown in the S-2 (the most recent publicly available data).
Surprise Valley Electrification Corp.	Because Surprise Valley procures mostly hydroelectric power, staff assumed that Surprise Valley would acquire natural gas power equivalent to 5 percent of load.
WAPA - Sierra Nevada Region	WAPA does not submit an S-2 to CEC. WAPA provided staff with 2013–2015 load data and resource data (quantities of hydroelectric and unspecified power). Staff used the averaging convention described in the text to estimate load and resources for 2021–2030.

[19] Name as reported as used by the EDU in the Program's Compliance Instrument Tracking System Service.

RPS Adjustment

In the 2016 Initial Statement of Reasons, staff had proposed ending the RPS adjustment (see section 95852(b)(4) of the Regulation) after 2020 and instead increasing allocations by assuming a requirement of only 28 percent instead of 33 percent RPS power to account for a portion of the RPS Category 2 power that is not directly delivered to California. In response to stakeholder comments, staff now proposes to retain the RPS adjustment post-2020, consistent with the rationale put forth in the 2011 Final Statement of Reasons (2011 FSOR)(ARB 2011), and to not provide any additional 2021–2030 allocation to account for investments in out-of-State RPS power that is not imported into California.

As discussed in the December 14, 2015 workshop, issues with RPS adjustment reporting were discovered through staff's quality control efforts. The RPS adjustment was originally included in the Regulation to recognize investments in out-of-State RPS-eligible power that is not directly delivered to California. This adjustment is a voluntary option, and it is only applicable when the importer purchases both electricity and renewable energy credits together and can demonstrate that the electricity was not delivered to California.

Based in part on comments submitted during the 45-day comment period and at the September 2016 Board hearing, and continued discussions with stakeholders, staff's modified proposed allocation methods do not include allocation for higher emitting electricity generation that replaces RPS electricity that is not directly delivered. Instead, staff proposes to continue the RPS adjustment after 2020 with the existing reporting and verification requirements pursuant to MRR and as outlined in the 2011 FSOR, and to not provide any additional 2021–2030 allocation as a substitute for the RPS adjustment since it will remain in effect.[20]

References

Assembly Bill 32, Nuñez, Statutes of 2006, Global Warming Solutions Act of 2006. http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html.

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