DRAFT

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

I.D. #8257

ENERGY DIVISION **RESOLUTION E-4199**
February 20, 2009

<u>R E S O L U T I O N</u>

Resolution E-4199. This Resolution sets a limitation on total costs expended above the market price referent for Bear Valley Electric Service, Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison renewable power purchase agreements from competitive solicitations. This Resolution adopts eligibility criteria and guidelines for approving requests for above-market costs of renewable energy contracts negotiated through a competitive solicitation.

This Resolution is made on the Commission's own motion.

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1. SUMMARY

In this Resolution we implement the remaining requirements of Senate Bill (SB) 1036[1], which modifies the cost containment provisions of the Renewables Portfolio Standard (RPS) program. SB 1036 eliminates the responsibility of the California Energy Commission (CEC) to award supplemental energy payments (SEPs) to eligible renewable energy resources to cover above-market costs of renewable energy contracts. In place of the SEPs program, SB 1036 directs the Commission to establish, for each electrical corporation, a limitation on the total costs expended above the market price referent (MPR) for the procurement of eligible renewable energy resources. As a result, rather than renewable generators seeking SEPs from the CEC for the above-market costs of RPS contracts negotiated through competitive solicitations, the electrical corporations are now required to seek above-market cost recovery from the Commission for eligible RPS contracts.

As a result, this Resolution establishes the above-MPR funds (AMFs) program by adopting:

1) Cost limitations for Bear Valley Electric Service, Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison;
2) Eligibility criteria for above-MPR RPS contracts to be applied to the cost limitation;
3) Reasonableness standards for Commission review of above-MPR contracts;
4) AMFs Calculator to calculate contract-specific AMFs requests and to track an electrical corporation's AMFs balance;

[1] Statutes of 2007, Chapter 685, Perata

5) Administration rules for the AMFs.

2. BACKGROUND

2.1. SB 1078 established the RPS program and the mechanisms for funding the above-market costs of RPS contracts

The California RPS Program was established by SB 1078[2] and codified in California § 399.11, et seq.[3] The statute required that each retail seller of electricity increase its total procurement of eligible renewable energy resources by at least one percent of annual retail sales per year so that 20 percent of its retail sales are supplied by eligible renewable energy resources by 2017. On September 26, 2006, Governor Schwarzenegger signed Senate Bill 107[4], which officially accelerated the State's RPS target to 20 percent by 2010. Also, on November 17, Governor Schwarzenegger signed an Executive Order (S-14-08) which established a 33 percent by 2020 RPS goal.

In order to contain the total costs of the RPS program, SB 1078 established the supplemental energy payments (SEPs) program. SEPs were funds collected from ratepayers as part of the Public Goods Charge (PGC) and remitted to the CEC.[5] The CEC was authorized to allocate SEPs to cover above-market costs of

[2] Statutes of 2002, Chapter 516, Sher

[3] Unless otherwise indicated, all subsequent citations to sections refer to the Public Utilities Code.

[4] Statutes of 2006, Chapter 464, Simitian

[5] Assembly Bill (AB) 1890 authorized the electrical corporations to collect the PGC in rates for the period from 1998 to March 2002. AB 995 reauthorized the funding through January 1, 2012. The PGC is a non-bypassable rate component intended to fund in part energy efficiency, renewable resource energy technology , and public interest research and development. A portion of the PGC funds are remitted to the CEC, and prior to SB 1036, some of the funds went

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long-term RPS-eligible contracts executed through a competitive solicitation.[6] The statute allowed electrical corporations to limit their RPS procurement to contracts that were at or below market prices if these funds were exhausted.[7]

In order to calculate the above-market costs of renewable energy contracts, § 399.15(c) requires the Commission to adopt a methodology to estimate the long-term market price of electricity. The Commission adopted a market price referent (MPR) to represent the presumptive cost of electricity from a non-renewable energy source, which this Commission holds to be a natural gas-fired baseload or peaker plant.[8] The MPR establishes a benchmark at or below which approved RPS contracts will be considered *per se* reasonable, and can be recovered in rates; pursuant to SB 1078, SEPs were to cover the costs above the MPR.

2.2. The Commission adopted guidelines for public goods charge and supplemental energy payments collection

§ 399.8 requires the three major California investor owned electric utilities (IOUs)[9] to assess a PGC to customers in order to fund certain public interest programs for energy efficiency (EE), renewable resource energy technology

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to the New Renewables Resource Account (NRRA) in the Renewable Resource Trust Fund to fund SEPs.

[6] To receive SEPs, the developer of a Commission-approved SEP-eligible contract applied to the CEC for SEPs. The SEPs need was calculated as the net present value of the above-market costs, accounting for the IOU's time-of-delivery (TOD) profile, over the term of the contract. No RPS contract ever received SEPs from the CEC.

[7] § 399.15(b)(4)

[8] D.04-06-015, as modified by D.05-12-042.

[9] PG&E, SDGE, and SCE were directed pursuant § 399.8 to collect the PGC. BVES requested, and was approved (Resolution E-3556 and E-3856), to also collect funds.

(Renewables), and public interest research and development (RDD) from January 1, 2002 through January 1, 2012. Because the statute did not specify how much of the annual total[10] was to be collected by each IOU, the Commission issued Resolution E-3792[11], which set forth the IOUs' individual funding allocations. Table 1 shows the aggregate funding that the statute required to be collected for each program. Table 2 shows the IOUs' individual funding allocations, as determined by the Commission.[12]

Table 1
Required Yearly Program Funding Starting 2002[13]
($ million)

EE Programs	$228.0
Renewables	$135.0
RDD	$62.5
Total	$425.5

Table 2
Allocation to Programs by Utility, 2002-2011
($ million)

Utility	*EE*	*Renewables*	*RDD*	*Totals*
PG&E	$106.0	$67.7	$31.4	$205.1
SDGE	$32.0	$12.0	$5.5	$49.5
SCE	$90.0	$55.3	$25.6	$170.9
Totals	$228.0	$135.0	$62.5	$425.5

10 except for the Energy Efficiency programs

11 http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/22164.htm

12 Resolution E-3792 also describes how § 399.8 requires adjustments to this funding in future years at a rate equal to the lesser of the annual growth in electric commodity sales or inflation, as defined by the national Gross Domestic Product (GPP) deflator.

13 § 399.8(d)(1)

Of the PGC that were collected for Renewables programs, 51.5% were allocated to the SEP fund.

2.3. SB 1036 amends RPS cost containment mechanism

SB 1036 modifies the mechanism for awarding above-market costs to eligible renewable energy contracts negotiated through competitive solicitations. The bill eliminates the CEC's authorization to administer the SEP funds.[14] SB 1036 also requires the CEC to transfer all unencumbered funds in the New Renewable Resources Account (NRRA) back to the electrical corporations serving customers subject to the PGC, allocated among retail sellers on the basis of retail sales of electricity.[15] SB 1036 further reduces the amount of PGC collected for Renewables programs (from $135 to $65.5 million), so that SEPs are no longer collected.[16]

The Commission must establish a "cost limitation" for each electrical corporation to replace the SEP program as the RPS cost containment mechanism. The cost limitation is "a limitation on the total costs expended above the MPR for the procurement of eligible renewable energy resources procured to satisfy RPS goals".[17] As a result, rather than renewable generators seeking SEPs from the

[14] Formerly § 399.13(c)

[15] Public Resources Code § 25743

[16] § 399.8(d)(1)

[17] § 399.15(d). The limitation must be equal to the amount of funds currently accrued in the New Renewable Resources Account, plus the portion of PGC funds that would have been collected for SEPs through January 1, 2012.

CEC, electrical corporations are now required to seek Commission approval for the eligible[18] above-market RPS contract costs up to the utility's cost limitation.

2.4. Commission implemented certain aspects of SB 1036

The Commission mailed Draft Resolution E-4160[19] on March 12, 2008 to implement SB 1036.[20] On March 26, 2008, a Joint Party Request for Bifurcation of Issues Addressed in Draft Resolution E-4160 (Joint Party Request) was sent to the Commission's Executive Director.[21] The Joint Party Request asked the Commission to bifurcate the non-controversial ratemaking issues[22] of the resolution from the policy-related issues[23], and include only the former in Resolution E-4160.

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[18] SB 1036 sets forth eligibility criteria for the RPS contracts that may be counted towards the cost limitation (§399.15(d)(2)).

[19] http://docs.cpuc.ca.gov/published/COMMENT_RESOLUTION/80089.htm

[20] Comments to Draft Resolution E-4160 were filed by Pacific Gas & Electric Company (PG&E), San Diego Gas and Electric Company (SDGE), Southern California Edison (SCE), Sempra Utilities, California Manufacturers & Technology Association (CMTA), California Large Energy Consumers Association (CLECA), The Center for Energy Efficiency and Renewable Technologies (CEERT), Central California Power (CCP), and jointly by California Wind Energy Association (CalWEA) and Concentrated Solar Power Alliance (CSPA). Reply comments were filed by CEERT, PG&E, SDGE and SCE.

[21] Joint Parties include SCE, SDGE, PG&E, CEERT, and CalWEA

[22]
1. Directing IOUs to adjust their respective Public Purpose Program rate components collecting PGC;
2. Directing IOUs to amortize funds transferred from the New Renewable Resources Account, administered by the CEC, in their PPP rate component;
3. Directing BVES to establish an account to record unencumbered renewable funds transferred from the CEC back to BVES.

[23]
1. Setting a limitation on total costs expended above the MPR
2. Establishing AMFs eligibility criteria
3. Adopting guidelines for approving requests for above-market funds.

The Executive Director responded (March 28, 2008) to the Joint Party Request in a letter stating that the final resolution for Commission consideration would include only the rate-changing issues and that Energy Division would hold a workshop on SB 1036 policy-related issues.

Resolution E-4160[24] was approved implementing only the rate-changing aspects of SB 1036. On May 29, 2008 Energy Division staff held an SB 1036 implementation workshop.[25] After the workshop, Administrative Law Judge Simon issued a Ruling (June 20, 2008) Requesting Post-workshop Comments on Implementation of SB 1036.[26]

3. DISCUSSION

This Resolution implements SB 1036 in the following ways:

1) Establishes cost limitations for BVES, PG&E, SDGE, and SCE;
2) Adopts eligibility criteria for above-MPR RPS contracts to be applied to the cost limitation;
3) Adopts reasonableness standards for Commission review of above-MPR contracts;
4) Sets forth administration rules for the above-MPR funds (AMFs);
5) Adopts an AMFs Calculator to calculate contract-specific AMFs requests and to track an IOU's AMFs balance.

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[24] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/81476.htm

[25] On May 1, 2008 Energy Division circulated a request for pre-workshop comments. Comments were received from PG&E, SDGE, SCE, CEERT, CalWEA and Large-Scale Solar Association (LSA), Division of Ratepayer Advocates (DRA), The Utilities Reform Network (TURN), and Coral Power L.L.C.

[26] Comments were timely received from PG&E, SDGE, SCE, CEERT, CCP, CalWEA/LSA, DRA, TURN, and jointly by PG&E, SDGE, SCE, and CalWEA/LSA (Joint Parties). Reply comments were received from CalWEA/LSA, CEERT, PG&E, SCE, and TURN.

3.1. Guiding Principles

In the post-workshop ruling, the Commission requested that parties identify guiding principles that can be used to inform the implementation of SB 1036. Also, parties were asked if the Commission should establish rules that specifically use AMFs to promote the RPS program goals (e.g. in-state renewable energy development, hedging against volatile fossil fuel prices) or whether eligible projects should receive AMFs on a first-come, first-serve basis regardless of the characteristics of the project. Energy Division staff provided the following examples of SB 1036 implementation goals in the post-workshop ruling:

- Promote the goals of RPS program
- Support viable least-cost best-fit renewable energy projects
- Develop transparent standards for allocating above-market funds (AMFs)
- Simplify administration of AMFs.

3.1.1 Party Comments

DRA, TURN[27], and CCP agree SB 1036 implementation rules should be designed to promote the statutory goals of the RPS program.[28] DRA and TURN suggest that because AMFs are limited, the Commission should prioritize the allocation of AMFs to viable least-cost best-fit projects and to in-state RPS resources. They argue that implementing prescriptive eligibility rules and

[27] TURN also says that the most relevant goals for the SEPs program were providing a cost cap for ratepayer-funded renewable energy and supporting renewable project financing by ensuring ratepayer funding for above-market costs.

[28] More specifically: promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels (§399.11(b))

review standards to allocate AMFs only to such projects will promote the goals of the RPS program and maximize ratepayer benefit.

Alternatively, the Joint Parties and CEERT recommend that the Commission consider that the legislative intent of SB 1036 was to streamline the regulatory process by eliminating duplicative agency review, enhance seller certainty by ensuring contract financeability, and continue ratepayer cost protection.[29] Consequently, they support AMFs rules to allocate AMFs to contracts on a first-come, first-served basis, and they recommend against the Commission establishing additional eligibility rules or review standards for RPS contracts. They think that the Commission's highest priority should be streamlining the AMFs process to enable projects with executed RPS contracts to obtain Commission approval, begin the project development process, and start generating renewable power to help meet the State's RPS mandate.

3.1.2 Discussion

While the Joint Parties, CEERT, and TURN disagree on how the AMFs should be allocated, they all generally agree that the purpose of the AMFs program is to provide a ratepayer cost cap and ensure that renewable energy contracts are financeable. The Commission agrees, and in addition, acknowledges parties comments that the primary goal of SB 1036 was to streamline the RPS program's cost containment mechanism.

Also, while SB 1078 and SB 107 set forth detailed rules for implementing the SEPs program, SB 1036 repealed Public Resources (Pub. Res.) Code Section 25743, which included prescriptive rules for allocating SEPs (e.g. only 10% of

[29] SB 1036 § 1

SEPs could be allocated to out-of-state facilities).[30] As a result, we reject DRA, CCP, and TURN's proposal to adopt eligibility rules that SB 1036 eliminated. Instead, we suggest that if parties think that IOUs should value certain types or characteristics of projects (e.g. location) over others, that they pursue it in the revisit of the least-cost best-fit methodology in R.08-08-009.

However, we also do not fully adopt the Joint Parties' request to award AMFs on a first-come first-serve basis because this would imply that the Commission would approve AMFs to any project that requests them. We have always had the discretion to evaluate RPS contracts' viability, and in this case, recognizing that AMFs are limited, neither developers nor ratepayers would be served well if the Commission knowingly allocated AMFs to non-viable projects. This would reduce our ability to reach the 20% by 2010 RPS goal.

Thus, our guiding principles for implementing SB 1036 will be:

- Develop simple, streamlined and transparent rules for administering the AMFs program
- Maintain a cost cap for ratepayer-funded renewable energy
- Promote renewable energy development to meet 20% by 2010 RPS goal
- Enhance seller certainty by ensuring contract financeability

Implementing transparent and streamlined rules is typically a goal for Commission decisions, and this is no exception. It is particularly important in this Resolution because parties note that SB 1036 was primarily intended to streamline the RPS cost recovery mechanism. In this Resolution, we will aim to

[30] Five of the rules were re-codified in § 399.15(d)(2) as the eligibility rules we discuss in Section 3.3.

create rules that facilitate easier administration of the program. Also, the purpose of the SEPs, and now the AMFs, program has been to maintain a total cost cap on the RPS program. Thus, to the greatest extent possible the rules implemented in this Resolution should not allow RPS procurement costs to exceed the cost limitation, except in the cases in which the statute already creates exceptions. Additionally, because there are limited funds that can be applied to above-market contracts, we also understand our responsibility to use the funds in a manner that does not prevent or stall reaching the 20% goal. Lastly, we will aim to implement rules that do not create unnecessary risks for developers, so that they can more easily finance and develop projects.

3.2. Cost Limitation

Pursuant to SB 1036, the Commission must establish a cost limitation for each electrical corporation. The inputs for calculating the cost limitation were set forth in SB 1036 and codified in §399.15(d)(1):

> The cost limitation shall be equal to the amount of funds transferred to each electrical corporation by the Energy Commission pursuant to subdivision (b) of Section 25743 of the Public Resources Code and the 51.5 percent of the funds which would have been collected through January 1, 2012, from the customers of the electrical corporation based on the renewable energy public goods charge in effect as of January 1, 2007.

Because the cost limitation is defined to include only the funds transferred by the CEC to electrical corporations serving customers that paid the renewable energy PGC plus the PGC funds that would have been collected for SEPs, we are setting cost limitations only for those electrical corporations to which funds have been transferred (namely BVES, PG&E, SDGE, and SCE; henceforth "the IOUs").

Amount of Funds Transferred

Pursuant to SB 1036[31], the CEC was required to transfer the remaining unencumbered funds in the NRRA to electrical corporations serving customers subject to the PGC. Accordingly, the CEC approved CEC Resolution 08-0227-9 (February 27, 2008), which transferred each electrical corporation's respective contribution to the NRRA minus the amount that was loaned to the General Fund[32], as listed in Table 3:

Table 3
NRRA Funds Transferred

Utility	*Amount of Funds Transferred*
BVES	$ 213,016
PG&E	$ 229,010,519
SDGE	$ 41,198,658
SCE	$ 191,259,591

Funds that "would have been collected"

The Commission, with assistance from the IOUs, calculated the amount representing 51.5 percent of Renewable PGC funds, which would have been collected for SEPs, for each IOU from January 1, 2008 through January 1, 2012. Because the amount of funds collected in a year depends on the previous year's collection, Energy Division staff used the amount of Renewables program funding each IOU collected in 2007 as the starting point. Staff then calculated the

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[31] the new Public Resources Code § 25743

[32] Approximately $18.2 million was borrowed pursuant to Item 3360-011-0382 of Section 2.00 of the Budget Act of 2002 (Statutes of 2002, Chapter 379). If and when the IOUs' portion of the loan

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subsequent increases in annual funding amounts, "at a rate equal to the lesser annual growth in commodity sales or inflation, as defined by the gross domestic product deflator".[33] Using this data, Table 4 shows the annual amounts of Renewables program funding for above-market funds (or SEPs) that would have been collected for each utility from 2008 through 2011.[34]

Staff did not apply any discounting to the estimated collection of funds through 2012 because the mechanism used to establish the limit is based on "virtual" funds that would have been collected - no interest or financing costs would have been incurred. Also, this methodology is simple and transparent.

Table 4
Projected "Future SEPs" Funding Amounts for Each Utility
2008-2011

Utility	*2008*	*2009*	*2010*	*2011*	*Projected Totals*
BVES[35]	$57,680	$57,680	$57,680	$57,680	$115,360
PG&E	$37,476,875	$37,981,201	$38,479,483	$39,021,374	$152,958,933
SDGE	$6,803,459	$6,908,219	$7,009,355	$7,109,173	$27,830,206
SCE	$31,900,373	$32,434,647	$32,982,478	$33,530,656	$130,848,153

is returned, the transferred funds shall be treated in the same manner as outlined in Resolution E-4160.

[33] § 399.8

[34] Staff used the annual growth in commodity sales figures from the Energy Commission's load forecast (CEC California Energy Demand, Staff Revision Forecast 2008 to 2018 (November 2007)) for the particular utility, and inflation figures were determined from GDP deflator index (GDP Price Deflator Index - Global Insight).

[35] BVES' PGC collection did not escalate per Pub. Util. § 399.8(d)(2). Therefore, estimated future collections are assumed also to not escalate.

Total cost limitation

Table 5, the total cost limitation for each IOU, sums the nominal amounts in Tables 3 and 4.

Table 5
Total Cost Limitation/AMFs for Each Utility

Utility	*Amount (2008$)*
BVES	$ 328,376
PG&E	$ 381,969,452
SDGE	$ 69,028,864
SCE	$ 322,107,744
Total	$ 773,434,436

3.3. Eligibility Criteria

SB 1036 sets forth five criteria that a contract must satisfy be applied to an IOU's cost limitation (i.e. to be allocated AMFs):[36]

1. The contract has been approved by the Commission and was selected through a competitive solicitation pursuant to the requirements of subdivision (d) of Pub. Util. Code Section 399.14.
2. The contract covers a duration of no less than 10 years.
3. The contracted project is a new or repowered facility commencing commercial operations on or after January 1, 2005.[37]
4. No purchases of renewable energy credits may be eligible for consideration as an above-market cost.
5. The above-market costs of a contract do not include any indirect expenses including imbalance energy charges, sale of excess energy,

[36] § 399.15(d)(2). As discussed previously, this is a subset of the rules that governed the SEPs program.

[37] When SB 1036 amended Public Resource Code § 25743, the definition of "repowered" was deleted from statute. As a result, the Commission defers to the CEC RPS Eligibility Guidebook for the definition of "repowered".

decreased generation from existing resources, or transmission upgrades.

In the post-workshop ruling, parties were asked: 1) whether or not the Commission should implement additional AMFs eligibility criteria and 2) how the Commission should quantify and subtract the indirect expenses identified in criterion #5 from the AMFs request. We will address the latter in Section 3.5.5, where we set forth rules related to calculating a project's AMFs need.

3.3.1 Parties' Comments

TURN, DRA, and CCP support the adoption of additional eligibility criteria. In particular, TURN and DRA support an additional eligibility criterion requiring projects to be located in California.

The Joint Parties and CEERT recommend having the five criteria set forth in § 399.15(d)(2) as the only eligibility criteria, and specifically oppose an additional eligibility criterion requiring projects to be located in California.[38] They instead recommend that AMFs eligibility should extend to any renewable facility that meets the definition of "in-state renewable electricity facility" as defined in Public Resource Code § 25741(b).[39]

3.3.2 Discussion

Pursuant to SB 1036, the Commission must adopt the five eligibility criteria in § 399.15(d)(2).[40] In every advice letter or application requesting approval of an

[38] In the Joint Parties' Comments (July 8, 2008) it is noted that Shell Energy America (US) LP supports this point.

[39] Joint Parties' Comments Regarding Implementation of SB 1036 (July 8, 2008), p.10

[40] The eligibility criteria must apply to Commission-approved RPS projects as well as pending and future above-MPR RPS projects.

RPS contract that has an above-MPR price, the IOU must identify whether the PPA complies with these eligibility criteria.

No parties argue that SB 1036 maintained the additional SEPs allocation criteria that were in Pub. Res. Code Section 25743, thus, we will not require them. Rather, the legislation aimed at streamlining the cost containment process so that above-MPR contracts could be financeable and the state could reach its RPS goals at a reasonable cost. We suggest that if parties think that IOUs should value certain types or characteristics of projects (e.g. location) over others, that they pursue it in the revisit of the least-cost best-fit methodology in R.08-08-009.

3.4. Reasonableness Review Standards

The Commission is responsible for maintaining reasonable rates for its ratepayers, while ensuring safe and reliable service. Accordingly, when an IOU files for approval of an RPS contract, the Commission evaluates whether the proposed contract price is reasonable, the project is viable, the contract terms and conditions comply with Commission decisions, the project complies with the IOU's approved procurement plan, and if the project is, on balance, in the best interest of the ratepayer. Parties have recognized that reviewing project viability and evaluating the reasonableness of a contract with an above-market price has additional connotations in the context of reviewing contracts that are eligible for AMFs. In this section, we discuss what standards should be used when evaluating the project viability and price of an RPS contract negotiated through a competitive solicitation. Additionally, we adopt rules for evaluating contracts that are re-submitted for approval of a price amendment to a Commission-approved contract.

Project viability

If a project that requires AMFs is approved but never comes online, the project has "tied up" AMFs and may have prevented other viable RPS projects that need AMFs from being developed. This is particularly problematic for implementation because AMFs are limited and there is a statutory "waiver" that allows an IOU to limit RPS procurement to contracts that are at or below the MPR, after the IOU has exhausted its AMFs.[41]

Price reasonableness

While RPS contracts are considered *per se* reasonable if priced at or below the MPR,[42] Commission decisions and RPS statute are silent on what the price reasonableness standard is for an above-MPR contract. Adopting clear, transparent standards for price reasonableness of projects priced above the MPR will streamline review and simplify administration of AMFs. The following are examples of criteria that could be used to evaluate the reasonableness of above-MPR contract prices:

- IOU's least-cost best-fit analysis
- Bid supply curves from recent solicitations
- Technology-specific bid supply curves from recent solicitations
- Technology cost curves developed as part of RETI
- Review of a cash flow model
- Rate impact of contract

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[41] § 399.15(d)(3)

[42] D.04-06-015 (http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/37383.pdf)

Review standards for amended contracts

In the post-workshop ruling requesting comments, the Commission asked if there should be any different viability and price review standards for newly proposed contracts versus those requesting approval of an amendment affecting the contract price.[43]

3.4.1 Party Comments

Project viability

Joint Parties and CEERT recommend that the current project viability standards should be used for all contracts, including for above-MPR contracts, whether or not the contract is eligible for AMFs. Alternatively, TURN recommends that the Commission adopt some additional assessment criteria for evaluating the viability of AMF-eligible projects requesting $50 million or more in AMFs. If the project is above the MPR and AMFs have been exhausted, TURN suggests that the project is either rejected or treated as a bilateral.[44]

TURN's proposes that the Commission require projects that are above the MPR and requesting $50 million or more in AMFs to demonstrate "50% site control".[45] TURN asserts that "if projects that stand little chance of being

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[43] We also asked whether the standards should apply to contracts that are not eligible for AMFs (e.g. bilateral and short-term contracts), however, this issue will instead be addressed in R.06-02-012 or R.08-08-009, as appropriate.

[44] TURN includes a detailed proposal for the review of above-MPR bilateral contracts. TURN recommends that bilateral contracts are reviewed more stringently than AMF-eligible contracts, which includes at a minimum, their proposal for the review of AMF-eligible contracts that are above the MPR.

[45] In its initial comments, TURN recommends that the viability assessment include: a project-specific IE report reviewing the reasonableness of the PPA and project's financial model; demonstration of 50 percent site control at the time of contract approval and demonstration that 100 percent site control will be obtained in a reasonable time frame; and completion of resource

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developed by the proposed [online date] reserve AMFs, other potentially more viable short-term projects may be precluded from obtaining financing."[46]

The Joint Parties assert that SB 1036's legislative history shows that the legislature "explicitly articulates the expectation that 'the PUC would use the current practices it has in place to review renewable contracts for reasonableness'"[47]. TURN disagrees, saying that the additional reasonableness standards are not inconsistent with the goal of SB 1036, which was to eliminate problems caused by the two-agency process involved in awarding SEPs.

Price reasonableness

The Joint Parties recommend that a contract's price should be considered reasonable if it successfully competes against the market in an RPS solicitation. The Joint Parties and TURN agree that the most reliable and relevant measures for evaluating the value of an RPS contract are the IOU's least-cost best-fit (LCBF) bid evaluation rankings and bid supply curves from recent solicitations. However, the Joint Parties and TURN recommend against using technology cost curves from the Renewable Energy Transmission Initiative (RETI) or cash flow models.[48] SCE claims that because of the confidential nature of cash flow models, requiring them might deter developers from negotiating with the IOUs. PG&E

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studies showing that the resource is viable. However, in reply comments, TURN revises its recommendation "in appreciation of the practical reality that it is difficult for project developers to demonstrate viability through documentation of their financial model and with resource studies." (page 4)

[46] TURN comments, page 6

[47] Joint Parties' comments, page 8

[48] In its pre-workshop comments, TURN supported the use of cash flow models, but in its post-workshop comments amended its position saying that it isn't valuable to only require cash flow models for above-MPR contracts.

and CalWEA/LSA assert that using cash flow models implies that the Commission is evaluating the reasonableness of a developer's profit margin, which is not part of the Commission's authority. CalWEA/LSA offers an alternative - have the independent evaluator (IE) comment on the reasonableness of the proposed contract price from a market perspective. CEERT recommends that an above-MPR contract price should be considered reasonable if the price is below a pre-determined reasonable renewable energy credit price plus MPR.

Review standards for amended contracts

Several parties propose how price amendments should be reviewed. SDGE, supported by DRA, recommends the use of cash flow models, asserting that developers should be required to justify their new price by providing a thorough review of all project costs since the new price is no longer comparable to the solicitation it was initially competitive with. TURN suggests that either the project is completely re-evaluated against the most recent solicitation's bid supply curves or that the developer provides financial models and documentation concerning project costs. SCE and PG&E assert that contract price amendments should not require any additional information or a new IE report and that the Commission should review price amendments on a case-by-case basis. SCE says that requiring additional documentation would delay the contract approval process. CalWEA/LSA do not support looking at a developer's financial information.

3.4.2 Discussion

Project viability

While the Commission reserves judgment on the review standards for bilateral contracts[49], we agree with the Joint Parties and CEERT that all above-MPR contracts negotiated through a competitive solicitation should be reviewed in the same manner regardless of whether the IOU's cost limitation has been reached.[50] This is in the best interest of the ratepayer, helps maintain a total cost cap on the RPS program, and promotes renewable energy development to meet RPS goals.

The Commission agrees with TURN that some extra level of scrutiny on project viability is prudent if a contract is above the MPR. The above-MPR funds are limited and there are real and significant implications if the funds are exhausted. There are additional problems if the funds are reserved for projects that never get built. For these reasons, we find it prudent to have additional viability review criteria for projects that require a significant amount of AMFs. This decision is in-line with our guiding principles because having standards that are clear, transparent and provided upfront will create a more streamlined review of above-MPR contracts. Also, in order to promote RPS procurement and reach our 20% RPS goal, the limited AMFs must be used to the greatest extent possible on projects that have a reasonable likelihood of delivering renewable energy. Further, adopting some viability criteria avoids the need to develop more complex rules to evaluate whether projects are missing their milestones and whether the Commission should revoke the AMFs in favor of more viable projects.

[49] In R.06-02-012 or R.08-08-009, as appropriate

[50] § 399.15(d)(4) allows the IOUs to voluntarily procure RPS contracts at above-market prices that are not counted toward the cost limitation.

Thus, we adopt a modified version of TURN's proposal. The Commission shall evaluate the project viability for all AMF-eligible projects above the MPR according to current standards for project viability review.[51] Additionally, if the AMFs request is greater than $50 million (nominal $), then the IOU must demonstrate in the advice letter that the project has 1) obtained site control[52] of at least 50% of the land area required for building the project, or the phase of the project, for which AMFs are requested, and 2) secured a position in a transmission queue[53]. We agree with TURN that without a site, there is no project. We also think that being in the queue is a necessary first step for any developer that is serious about building a project, and that requiring these criteria will better enable the Commission to assess whether the project milestone timeline and online date is realistic.

<u>Price reasonableness</u>

The Commission agrees with the Joint Parties and TURN that we should evaluate above-MPR contract prices against existing review standards, including bid supply curves from the IOU's recent solicitation and the project's least-cost

[51] The Commission assesses whether, on balance, the project is viable after reviewing: site control, financing, permitting, resource studies, transmission upgrade needs, performance obligations, developer experience, and dependence on federal tax credits and incentives.

[52] "Site Control" is defined as (i) owning property, holding a leasehold interest in property or otherwise having rights to property sufficient for the construction and operation of the proposed generating facility; (ii) holding a binding option agreement that, upon execution, will provide the rights referred to in (i) above; (iii) an exclusivity or other business relationship between the interconnection customer and the entity having the right to sell, lease or grant interconnection customer the right to possess or occupy a site that will provide the rights referred to in (i) above; or (iv) submission of a valid application for the use of BLM or other public lands, which application is not subject to a superior claim on the property in accordance with the rules of the BLM.

[53] CAISO queue position or equivalent from appropriate transmission authority

best-fit ranking relative to the other projects that bid into the solicitation.[54] Energy Division staff may also use RETI cost estimates to assess whether the contract price reflects recent engineering estimates of renewable project costs. The Commission should not require that IOUs assess the rate impact of each above-MPR contract nor require that all above-MPR contracts submit cash flow models. However, Energy Division staff should have the option on a case-by-case basis to request data to substantiate the contract price, if for example, the price does not compare favorably to bid supply curves. We also adopt CEERT's proposal to require the project-specific IE report to discuss the project's price reasonableness from a market perspective. These rules are consistent with all of our guiding principles.

Review standards for amended contracts

If a developer requests a price amendment to an approved contract, the IOU should re-evaluate the competitiveness of the amended project as compared to the projects that the IOU is negotiating and to its most recent shortlist. The IOU must provide a sufficient showing in the advice letter that the amended contract is competitive based on current market data. Additionally, contracts that are re-filed with the Commission for approval of a price amendment will have to explain why the contract price change is needed, and provide all relevant data to justify the change.

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[54] CEERT proposes that we evaluate prices based on MPR + REC. This is not consistent with Commission review of other RPS contracts, nor consistent with our understanding of how bundled contracts are priced.

Party comments are split on whether cash flow models should also be required to justify contract price amendments.[55] The Commission agrees with SDGE that while bid supply curves are most appropriate to evaluate contracts the first time they are submitted, if a project has increased its price, the solicitation information may no longer be relevant. The Commission disagrees with SCE's comment that additional documentation would delay the contract approval process or deter developers from participating in California's RPS. The Commission instead has experienced that data requests delay the approval process and that if standard information is provided upfront, the Commission can streamline the approval process.

Thus, the developer must provide the Commission and the IE with a cash flow model for projects that are re-filed with the Commission for approval of a price amendment.[56] The confidential project-specific IE report must, at a minimum, include its assessment of the reasonableness of the new price, based on market information and a review of the cash flow model. An IE's conclusions must not be based on whether the developer's rate of return is reasonable, but rather if the model inputs affecting the price change are reasonable. (Please see Appendix A for an example of the inputs that may be required for the cash flow model.)

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[55] DRA, SDGE and TURN support the use of cash flow models. PG&E, SCE and CalWEA/LSA disagree.

[56] If other amendments are filed that affect the contract price, Energy Division staff have the discretion to ask for cash flow model, but we will not require it. Also, due to the highly sensitive information contained in cash flow models, the IOUs and developers can work with the Commission to use non-disclosure agreements (NDA), if desired. The Commission has already drafted an NDA that an IE and developer found acceptable, though we do not reproduce it in this resolution because of certain project-specific information.

These reasonableness standards for project viability and contract price for AMFs-eligible contracts that are above the MPR will only apply to RPS projects that have not yet been approved or rejected by the Commission. However, the review will apply if a contract is re-filed for approval of an amendment that affects the contract price. This review process will be applied to contracts pending approval because we have limited AMFs and have several pending and soon-to-be-filed RPS contracts that will require AMFs.

3.5. AMFs Request Calculation

The CEC developed a "SEPs Spreadsheet" that was used to calculate the SEPs required for each RPS project. Similarly, the Commission has created an "AMFs Calculator". This Calculator will be used to determine a contract's AMFs need and to keep track of an IOU's AMFs balance.

In addition to adopting an AMFs Calculator, we must establish the following guidelines to be able calculate the inputs for the Calculator:

- whether the AMFs request is calculated in nominal dollars or is discounted,
- rules for choosing the appropriate MPR (which solicitation year),
- rules for using the appropriate contract online date (COD), which is needed to choose the appropriate MPR and year deliveries start,
- how to calculate the contract's levelized price if the project's specifications are uncertain or if the price is indexed to an unknown variable, and
- what other costs, besides the energy price, are counted in the AMFs calculation.

3.5.1. AMFs Calculator

The AMFs Calculator is based on the SEP Spreadsheet used by the CEC, but was modified by Energy Division. The AMFs Calculator now includes an 'AMFs Summary' tab showing an IOU's cost limitation, prior AMFs allocations, and AMFs balance. The Calculator also has only one input tab ('Input Contract Data' tab) because it is no longer necessary to have separate tabs for bid price and contract price since the contract review and AMFs request will now occur simultaneously. Also, the ten year payment limitation for SEPs has been removed. Finally, the separate tab calculating the time of delivery (TOD)-weighted average contract price has been removed because the calculations are consolidated in the Input and Results tabs.

IOUs must include the AMFs Calculator with every advice letter seeking approval of an RPS contract.[57] The AMFs Calculator will be maintained and modified, as needed, by the Energy Division.

The Calculator can be found at http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/hot/SB1036implementation.htm

3.5.2 AMFs Request – nominal or discounted

In the AMFs Calculator proposed in Resolution E-4160, the AMFs requests were discounted by the utility weighted average cost of capital (WACC) to calculate a net present value of the request. This value was then compared to the nominally calculated cost limitation to determine the AMFs need.[58] The rationale for calculating the requests in this manner was:[59]

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[57] The AMF Calculator is not designed to cumulate the AMFs request for contracts with multiple phases that each have different online dates, even though all phases will be reviewed at the same time by the Commission and count cumulatively towards the same AMFs request. As a result, separate AMFs Calculators should be completed and submitted for each phase.

[58] As explained in Section 3.2 above, we adopt the IOU's cost limitations in 2008$ (nominal dollars).

[59] Draft Resolution E-4160, page 15

> Since the approved AMFs will be allowed into utility rates, the AMFs will be included in utility rates as cost of purchased power. When evaluating purchased power costs for a utility, it is appropriate to apply the utility Weighted Average Cost of Capital (WACC) to discount future payments to a net present value (NPV). This is consistent with standard utility evaluation of supply and demand-side options in resource planning. In addition, credit rating agencies now treat purchased power contracts as equivalent to debt. Thus, although purchased power costs are a pass-through in utility rates, additional financing at the utility WACC may be necessary on the margin to maintain appropriate utility debt to equity ratios.

3.5.2.1 Party Comments

In comments to Draft Resolution E-4160, both PG&E and SCE disagreed with the methodology used to calculate the AMFs request value. PG&E said that AMFs requests should not be discounted using an IOU's WACC, but rather be based on actual payments, adjusted by the GDP deflator. SCE disagreed that the AMFs request should be discounted at all because the future contributions to the cost limitation were not. Instead, SCE suggested either discounting both the cost limitation and AMFs request or tracking the AMFs balance like you would balance a checkbook.[60]

SCE and PG&E agreed on a new methodology in advance of the workshop and presented a modified Calculator. This Calculator uses a nominally calculated cost limitation as well as a nominally calculated AMFs request. In post-workshop comments, PG&E supports the use of this Calculator, saying that if there is a zero rate of return on the AMFs fund then there should be a zero discount rate on approved AMFs requests. SDGE supports the use of the jointly proposed Calculator, CCP does not, and no other parties comment on it.

[60] SCE provided a sample calculation in Appendix B to their pre-workshop comments.

3.5.2.2 Discussion

The Commission agrees with comments that the cost limitation and AMFs requests calculations should logically be treated in the same manner. No party provides rationale otherwise. Because we do not find it prudent to discount the estimated SEPs funds that would have been collected through 2012 (see Section 3.2), the AMFs Calculator will also not apply any discounting to the AMFs requests. Thus, we adopt PG&E and SCE's jointly proposed Calculator methodology[61] - the AMFs Calculator will sum the nominal value of the AMFs requested for each eligible contract[62] and the total will be applied against the nominally-calculated cost limitation[63] established by the Legislature and defined above in Section 3.2. This is consistent with our guiding principle of implementing simple AMFs rules. The total AMFs cost limitation will be reached once the Calculator shows no available funds are left.[64]

3.5.3 Appropriate MPR for AMFs Request

The Commission calculates and adopts, by resolution, MPR values for each annual solicitation to ensure we are using values that most accurately reflect current market conditions, especially related to natural gas prices, forward energy price curves, and capital cost escalation. Each resolution provides a matrix of MPR values that vary according to a project's contract online date (COD) and term length. The MPR is an important input needed to calculate a

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[61] A few changes have been made to the proposed Calculator to reflect the decisions in this resolution, remove the IOUs' notes, and to match the extension of the MPR to 25 years.

[62] AMFs Calculator, AMFs Summary tab, Cell C5.

[63] AMFs Calculator, AMFs Summary tab, Cell C3

[64] AMFs Calculator, AMFs Summary tab, Cell C7

project's AMFs need, which is the difference between the project's levelized contract price ($/MWh) and the applicable levelized MPR (multiplied by the amount of generation expected to be delivered over the term of the contract).[65] In this section, we discuss which solicitation year's MPR matrix and what COD should be used to identify the appropriate MPR value to use in the AMFs Calculator.[66]

Solicitation year

While a new set of MPRs are approved for each annual solicitation, contracts are not always executed shortly after the solicitation closes. In the post-workshop ruling, parties were asked whether a project that is still in negotiations 18 months or more after the close of the solicitation should be required to bid into a new solicitation, be considered a bilateral, or be compared to a more recent MPR. The ruling also asked what MPR should be used if a contract amends its price and is resubmitted for Commission approval.

Contract online date

Once the MPR solicitation year is determined, Energy Division uses the contract's COD to select the appropriate MPR value as provided by the MPR matrix.[67] This can be difficult for two reasons. First, while the developer and IOU negotiate a COD for the contract, the actual start date may occur later if

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[65] Both the contract price and MPR are also adjusted by the utility's time of delivery factors.

[66] One must also know the contract term length, however we will not discuss it because the duration of the contract is certain.

[67] An accurate COD is also needed for the AMFs calculation to reflect the start date of payments; using an inaccurate start date in the Calculator would lead to an inaccurate calculation of the total amount of AMFs needed.

contractual terms and conditions allow delays to the COD (e.g. due to delays in completing construction of a new transmission line or in extending the federal production tax credit). Many times this contractual flexibility is necessary because there are uncertainties when a contract is executed. Second, sometimes it is apparent that the contractual COD is not realistic given, for example, known transmission construction schedules or the time it takes to receive permit approvals. Parties were asked in the post-workshop ruling whether and how the Commission should determine a realistic COD if there are uncertainties in the contract or it is apparent to Energy Division that the contractual COD is not realistic.

3.5.3.1 Party Comments

Solicitation year

The Joint Parties and CCP recommend using the most recently adopted MPR and time of delivery (TOD) factors[68] to calculate the AMFs request for contracts with prolonged negotiations. The Joint Parties do not recommend that a contract be considered a bilateral if the contract negotiations are prolonged because, they say, this would penalize a project (i.e. by making it ineligible for AMFs). They also do not think that the Commission should require a project to re-bid into a new solicitation. Joint Parties justify both of these positions saying that it might not be the developer's fault that negotiations were complex, and they wouldn't want to prolong project development as a result. PG&E further

[68] Each utility submits its utility-specific TOD factors with its annual RPS Procurement Plan. They determine TOD factors based on its analysis of the forward value of energy and capacity during different times of day and times of the year. This results, in practice, in each utility valuing electricity at different hours differently, sometimes significantly so. As relevant to the MPR calculation, the three large utilities use between six and nine TOD periods.

states that many projects may benefit from negotiations extending beyond 18 months. The Joint Parties note that the benefit of using a more recent MPR is that it more accurately reflects current energy prices.

DRA supports considering projects with prolonged negotiations as bilaterals to ensure that AMFs are used in a cost-effective manner. TURN disagrees with DRA, saying that this would provide an incentive for contracts to delay negotiations to sign high priced contracts because there is no cost limitation for bilateral contracts. TURN instead recommends that projects in negotiations for more than 18 months be required to re-bid into the next solicitation to provide the appropriate motivation to expedite contract negotiation.

Joint Parties also recommend that the most recent MPR and TODs are used for contracts resubmitted for approval of a price amendment.

<u>Contract online date</u>

The Joint Parties recommend that the appropriate COD to use in AMFs calculations is the COD in the contract. They argue that the counterparties make an effort to identify a realistic COD during contract negotiations, and they say that if the Commission finds that the project is not viable as written, the Commission should reject the contract. SDGE notes that it would be difficult to develop an objective method for the Commission to determine an alternate "realistic" COD. Joint Parties also say that if a project COD changes, the Commission will receive the information in the semi-annual project development status reports. No parties present an alternative recommendation or proposal for determining the appropriate COD.

3.5.3.2 Discussion

Solicitation year

We agree that the projects that are bid into a solicitation and execute a contract after prolonged negotiations should be compared to the most recent MPR and TODs. Using a more recent MPR is preferable because it more accurately reflects current energy prices and the market that the project should be evaluated against. At the same time, the IOU should evaluate whether the contract is still competitive with newer bids and provide the Commission with this evaluation in its advice letter.

We acknowledge TURN's concern that there may be unintended incentives for developers to delay negotiations if a newer MPR is higher. However, we find that this does not outweigh the risk of requiring projects to be re-bid into a new solicitation, which would further prolong negotiations and project development, and may unfairly penalize developers. This is consistent with all of our guiding principles, in particular enhancing seller certainty and promoting renewable development. Of course, an IOU may ask a counterparty to re-bid into a new solicitation.

Thus:

- Contracts executed within 18 months from the close of the solicitation should be compared against the MPR and TODs associated with the solicitation year it participated in.
- Contracts executed after 18 months from the close of the bid's solicitation should be compared against the most recently approved MPR and the TODs associated with that solicitation year.
- Contracts re-filed for approval of a price amendment should be compared against the most recently approved set of MPRs and the TODs associated with that solicitation year.

These rules only apply to new contracts and contract amendments that have not yet been approved by the Commission.

Contract online date

To be consistent with our principle of simple and streamlined AMFs rules, the Commission will use the contractual COD in an AMFs calculation. While it would not be difficult to determine that a COD is not realistic, we agree with SDGE that it may be complex to determine an alternate COD that is "realistic". The Commission already requires IOUs to provide information on project milestones and transmission upgrade information in the advice letter, so the Commission can assess whether the contractual online date is realistic. And, if the Commission finds the project not viable, for instance due to an unrealistic COD, then the PPA and AMFs request can be rejected or conditionally approved.

3.5.4 Calculating a contract's levelized price

Contract prices can be structured in a number of different ways, but the price must be translated into a levelized price in order to calculate a project's AMFs need. If the contract price is fixed or escalating at a pre-established rate, then it is relatively simple to calculate the levelized price. However, if the contract price is indexed to unknown future equipment prices, forward energy prices, or inflation, it is impossible to calculate the actual levelized contract price. It may also be difficult to calculate the costs of a contract even if the contract price is fixed if project specifications (e.g. capacity or capacity factor) are not finalized until later in the project development process or if the price or online date depends on the final results of transmission or resource studies.

3.5.4.1 Party Comments

The Joint Parties recommend that, in the cases when the contract price is indexed, such as to forward energy prices, the Consumer Price Index (CPI), or equipment prices, that a forecast (submitted by the IOU with the advice letter) be used by the Commission to estimate the AMFs for the contract. Also, the Joint Parties request that if a contract's specifications aren't finalized at the time of the advice letter filing, the Commission should use an estimated value of the maximum amount of AMFs that could be needed.

While TURN does find it reasonable to award AMFs to projects indexed to equipment prices, TURN and DRA recommend against awarding any AMFs to a contract whose price is indexed to forward fossil energy prices since that pricing structure does not promote price stability, a primary goal of the RPS program. TURN also argues that there is no valid reason why a renewable contract should have future prices indexed to the CPI. PG&E, supported by SCE, alternatively asserts that a contract with an indexed price may be the most cost effective way to allocate cost risk between the buyer and seller. SCE says that there is no legal support for excluding projects with certain types of indexed pricing from receiving AMFs.

3.5.4.2 Discussion

The Commission agrees that the most prudent way to calculate a levelized price for a contract whose exact price is uncertain is to use a best-guess estimate of what the maximum price may be. It would not be prudent to count a lesser amount towards the cost limitation because if too few AMFs are allocated to a project, then the IOU may have to come back to the Commission requesting more, which would be inconsistent with our goals to create streamlined AMFs rules and to enhance seller certainty. Thus, if a contract has an indexed price or if the contract allows for a range in contract specifications, the IOU must identify in the advice letter the possible range of levelized prices and AMFs that the project could require. The advice letter must include a calculation of the maximum levelized price as well as a description of the calculation methodology and assumptions. All relevant documentation used to develop forecasts of CPI, equipment prices, or energy prices must also be included in the advice letter. The IOU must submit an AMFs Calculator with the maximum levelized price from this range. The AMFs Calculator and the calculation including price-sensitive information may be submitted confidentially, but the methodology must be included in the public version of the advice letter.

While the Commission agrees with DRA and TURN that indexing a long-term RPS contract price to forward fossil energy prices does not necessarily promote stable energy prices nor necessarily benefit the ratepayer, we will not make such projects ineligible for AMFs at this time. No party asserts that the legislation requires long-term contracts to contain fixed prices, and it is possible to hedge such contracts so that ratepayers are ultimately paying a fixed price for the contract.

3.5.5 Accounting for indirect and 'other' expenses in the AMFs calculation

SB 1036 explicitly requires that indirect costs are not to be applied toward an IOU's cost limitation. The post-workshop ruling asked parties to propose a methodology for identifying, calculating, and subtracting indirect costs from the AMFs calculation.

Since the ruling was mailed, the Commission has realized that there may also be contractual terms and conditions that identify other expenses in addition to the $/MWh contract price that the IOU is obligated to pay.[69] The Commission

[69] See Resolution E-4183 (July 31, 2008), pg 14

Footnote continued on next page

must decide which, if any, of those costs should be included in the AMFs calculation.

3.5.5.1 Party comments

Indirect costs

The Joint Parties comment that it is unusual for indirect costs to be included in an RPS contract, and thus they are unlikely to be included in an AMFs calculation. They do not provide a methodology to calculate the expenses if included in the contract, but instead say that if it were to occur, the Commission should be able to identify it and handle it on a case-by-case basis.

Other direct costs

In SCE's pre-workshop comments, they point out that firming and shaping costs of out-of-state RPS contracts should also be included in AMFs requests because such costs are inherently included in the MPR calculation.

3.5.5.2 Discussion

Indirect costs

It is prudent to adopt an upfront process to identify and calculate any indirect costs in RPS contracts because doing so will result in streamlined AMFs rules. It is also reasonable to require an IOU to identify whether a contract's AMFs request includes any indirect costs, such as those identified in § 399.15(d)(2), in each advice letter requesting review and approval of an RPS contract.[70] If such costs are included in the contract, then the IOU must include

[70] To keep contract review and approval consistent, IOUs must include this information in advice letters or applications for all RPS contracts, whether the IOU thinks the contract is or is not eligible for AMFs.

in the advice letter: 1) a calculation that subtracts the indirect expenses from the contract's total above-market costs and 2) a written description of the methodology and any supporting documentation used for the requested calculation.[71] In the contract-specific IE report accompanying the advice letter, the IE must also identify whether the contract includes indirect expenses, review the IOU's calculation, if applicable, and report whether the IE agrees with the IOU's assessment of indirect expenses.

Other direct costs

IOUs should identify in the advice letter all costs associated with the contractual terms and conditions. However, at this time, only the firming and shaping costs associated with delivering intermittent out-of-state generation to California should be added to the AMFs calculation. This enables a fair and equitable comparison of in-state and out-of-state contracts to the MPR. The firming and shaping costs should be identified and calculated whether they are included in the RPS contract or not. These costs will be considered part of the AMFs request.

These rules apply to all contracts, including those already Commission-approved.

3.6. Administration of AMFs

The Commission must resolve the following issues related to the administration of AMFs:

[71] Pursuant to the Commission's confidentiality rules, the specific values of each indirect cost included in the calculation may remain confidential, but the written descriptions of which indirect costs may be implicated and the methodology for the calculation will not be redacted.

A. Whether all approved AMF-eligible contracts must be applied toward an IOU's cost limitation
B. Whether partial allocation of AMFs is allowed
C. When and how to calculate an IOU's current AMFs balance
D. How to track AMF "true-ups", which may need to occur if contract specifications (e.g. capacity, COD) change or become more certain after the contract is approved
E. Whether a project's AMFs need and am IOU's AMFs balance is public
F. Whether the Commission can revoke AMFs allocations

3.6.1 Party Comments

A. Application of eligible contracts to cost limitation

PG&E, SCE, SDGE, and TURN comment that all eligible above-MPR projects should be applied toward the cost limitation until the AMFs are exhausted. CalWEA/LSA and DRA disagree, saying that counting a contract toward the cost limitation is optional. CalWEA/LSA, citing §399.15(d)(4)[72], says that IOUs should be able to choose whether an eligible contract requests AMFs or not. DRA cites §399.15(d)(2)[73], arguing that the Commission should be able to choose whether an AMF-eligible contract gets applied to the cost limitation.[74] TURN and SCE recognize that the statutory language may allow such optionality, however, both parties and PG&E argue that overall statutory

[72] Nothing in this section prevents an electrical corporation from voluntarily proposing to procure eligible renewable energy resources at above-market prices that are not counted toward the cost limitation. Any voluntary procurement involving above-market costs shall be subject to commission approval prior to the expense being recovered in rates.

[73] "The above-market costs of a contract selected by an electrical corporation may be counted toward the cost limitation if all of the following conditions are satisfied…"

[74] DRA's argument reflects their desire to adopt rules that out-of-state RPS contracts can not receive AMFs.

directive in SB 1078 was to limit total costs, and thus, it would not be consistent with the legislative intent to approve but not apply AMF-eligible contracts to the cost limitation.

B. Partial allocation

The Joint Parties and TURN recommend that a project should either receive all of the AMFs it requests or be rejected; the Commission should not approve only partial amount of requested AMFs. TURN points out that if the Commission finds that a contract is overpriced it should be rejected outright instead of being given a partial award. DRA disagrees, saying that the Commission should have the discretion to award less than the requested amount of AMFs to any particular contract.

C. Calculating an IOU's current AMFs balance

The Joint Parties recommend that within 30 days of the adoption of the AMFs rules, each IOU file an accounting of its AMFs balance to-date with previously approved contracts credited against their cost limitation. The IOUs and TURN request that this filing be kept confidential, and CalWEA/LSA recommends that it should be public.

D. True-ups

Joint Parties recognize that AMFs true-ups may be necessary if a contract is terminated or if a project's online date, capacity, or price changes from the original information in the advice letter. PG&E and SCE recognize that while some contract amendments must be approved by the Commission (and thus, the Commission will approve the AMFs true-up in the resolution), other amendments can be executed as a matter of contract administration. In the latter case, PG&E suggests that the IOU confidentially notify Energy Division within 30 days of the contract amendment execution to adjust the AMFs balance in a timely manner after the amendment takes effect. SCE instead recommends that there be a "true-up" after each semi-annual Project Development Status Report (PDSR)[75] filing and that the Energy Division can update the IOUs' AMFs balances through a letter or other report issued after the filing.

E. Confidentiality of AMFs needs and AMFs balance

PG&E, SCE, SDGE, and TURN assert that an IOU's AMFs balance should be kept confidential to ensure that bidders pricing decisions are not improperly influenced. PG&E and SCE also contend that the AMFs balance is entitled to confidential treatment under D.06-06-066.

PG&E, SDGE and TURN also think that it should remain confidential when an IOU exhausts its AMFs. PG&E and SDGE recommend that the resolution approving the contract that exhausts the IOU's AMFs should confidentially note that the IOU has reached its cost limitation. SCE, however, does not oppose publicly disclosing the fact that an IOU's AMFs are exhausted because they say that this would not make confidential contract pricing information public. SCE recommends that once an IOU exhausts its AMFs, the Energy Division Director should send a letter to the relevant IOU indicating the AMFs are exhausted and copy the letter to the relevant service lists.

CalWEA/LSA asserts that neither an AMFs balance nor the exhaustion of AMFs should be confidential. They reason that confidential price information can remain protected if the Commission releases aggregated AMF balance updates (rather than balance updates after each contract is approved towards the

[75] D.06-05-039 requires each IOU "to provide us with information on whether each approved RPS project… is on target with the project's milestones and projected initial operation date."

Footnote continued on next page

cost limitation). They cite D.06-06-066, which says that there should be greater access to RPS information "due to the strong public interest in the RPS program".[76] Also, CalWEA/LSA counters the assertion that disclosing AMFs balances will improperly influence bidding behavior. They argue that bids are influenced by a myriad of factors and an IOU's diligence in evaluating the viability and reasonableness of bids is a better mechanism for normalizing bid prices than redacting AMFs balances. Further, CalWEA/LSA asserts that having such information publicly available is in the public interest because it enables parties to lobby the Legislature for more AMFs, if necessary.

F. Revoking AMFs

PG&E, SCE, and SDGE recommend that AMFs should only be revoked if the contract is terminated. While CalWEA/LSA agrees that AMFs should be revoked when a contract is terminated, they also support the Commission revoking AMFs when a developer misses a milestone deadline so that non-viable projects do not tie-up AMFs.

3.6.2 Discussion

A. Application of eligible contracts to cost limitation

We agree with PG&E, SCE, SDGE, and TURN that all AMF-eligible contracts approved by the Commission must be credited against an IOU's cost limitation. This is consistent with the intent of the statute and our guiding principle of creating a ratepayer cost cap for the RPS program. IOUs can voluntarily procure AMF-eligible RPS contracts above the MPR and not apply

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This information must be provided with each compliance report (currently due March 1 and August 1 of each year; see D.05-07-039, Ordering Paragraph 17)." (D.06-05-039, page 23)

[76] D.06-06-066, page 59

them to the cost limitation only after AMFs are exhausted. However, IOUs can voluntarily procure above-MPR renewable energy contracts that are not AMF-eligible (e.g. bilaterals) before the cost limitation is reached.

B. Partial allocation

We agree that the Commission should not be able to award only a portion of the necessary AMFs to a project. If the Commission does not think that the price is reasonable or that the project is viable, the project can be rejected or conditionally approved. This will promote developer certainty and maintain our goal for streamlined AMFs rules. If, however, the amount of AMFs remaining for an IOU is insufficient to cover the full AMFs request of a project, then the IOU should identify in its advice letter whether it is willing to voluntarily procure the total costs of the contract, even if they exceed the IOU's cost limitation; in this case, the project's above-MPR costs will only be partially covered by AMFs.[77]

C. Calculating an IOU's current AMFs balance

The Commission has already approved AMF-eligible, above-MPR RPS contracts for each IOU and has stated in the resolutions that the contracts would be applied to the IOU's cost limitation. In order to determine the IOUs' current AMFs balances, we adopt the Joint Parties' recommendation that within 30 days of the adoption of this Resolution, each IOU must confidentially file an AMFs Calculator accounting of its AMFs balance with previous credits against the account. A qualitative report should accompany the Calculator explaining the

[77] This is consistent with § 399.15(d)(4), which allows IOUs to enter into and seek Commission approval for RPS contracts that have contract prices above the MPR even if the IOUs AMFs cost limitation has been reached.

calculations (pursuant to the rules in this Resolution) for each approved contract already applied to the cost limitation.

D. True-ups

In order to promote streamlined rules and not true-up AMFs balances continually throughout the year, we adopt SCE's proposal for AMFs true-ups. If a project's specifications has changed since the Commission approved the project, but the revision falls under contract administration,[78] the change should be identified in the semi-annual PDSRs. Each utility must submit with their PDSRs updated AMFs Calculators, and all relevant documentation, for the projects that have modified AMFs needs. Because of the timing of the approval of this Resolution, the IOUs should begin truing-up AMFs needs in the August 2009 compliance filing.

However, if Commission approval is needed to approve a contract amendment changing a project's AMFs, the IOU will include an updated AMFs Calculator with the advice letter. If the amendment is approved, the AMFs balance will be updated in a confidential appendix of the Resolution approving the contract amendment.[79] While PG&E would like have a more timely update to an AMFs balance when a contract change is implemented administratively, we find that this would create too much complexity. It is simpler to handle all such true-ups as part of the PDSRs.

[78] Parties were asked to comment on what amendments are within the scope of contract administration in the Amended Scoping Memo and Ruling of Assigned Commissioner Regarding 2009 RPS Procurement Plans (June 20, 2008).

[79] This change must then be incorporated into the next PDSR. The service lists will not be updated of the IOU's AMFs balance until after the PDSRs are reviewed.

E. Confidentiality of projects' AMFs needs and IOUs' AMFs balances

Because RPS contract prices are confidential per D.06-06-066, a project's specific AMFs need must also be kept confidential. As a result, we can not release an IOU's AMFs balance after each contract is applied toward an IOU's cost limitation. However, this rationale does not justify keeping the balance confidential in all circumstances. We agree with CalWEA/LSA that it is prudent for the market and legislature to have regular updates on each IOU's AMFs balance. We also agree that the least-cost best-fit bid evaluation methodology, used to assess the viability and competitiveness of bid prices, and the contract review standards established in this Resolution, should create sufficient incentives to set bid prices at competitive levels. We also agree with SCE that confidential information can not be gleaned from publicly notifying parties when an IOU's AMFs have been exhausted. Publicly noticing AMFs balances on a regular basis is consistent with our goals of enhancing seller certainty and promoting renewable development.

Thus, the Energy Division Director will send a letter to each IOU stating their AMFs balance (and whether the AMFs are exhausted) after their semi-annual PDSRs are reviewed by staff.[80] This letter will be copied to the relevant service lists. We also accept SCE's proposal to have the Director of the Energy Division write a letter to the IOU when their cost limitation has been reached and

[80] The Director will also send such a letter following the IOUs' submission of their current AMFs balances, which will occur within 30 days of the adoption of this Resolution.

to copy this letter to all relevant service lists.[81] This letter will be posted to the RPS website.

F. Revoking AMFs

While we agree with CalWEA/LSA that it is not desirable for non-viable projects that miss their milestones to tie-up AMFs, we have previously recognized that the intent of SB 1036 was to ensure the financeability of above-MPR contracts. As a result, the Commission should not be able to revoke AMFs before a contract is terminated pursuant to contractual terms and conditions.[82] If either the IOU or developer terminates the contract, this should be noted in the PDSR and the funds will be applied back to the IOU's AMFs balance.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived or reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

[81] This letter can be written after the Commission approves a contract that uses up an IOU's AMFs, after a true-up in the PDSR leads the AMFs exhaustion, or after the IOU's submit their 'current AMF balance' shortly after this Resolution is approved.

[82] We do encourage IOUs to negotiate terms that identify project milestones and have consequences if developers do not meet deadlines.

FINDINGS

1) It is reasonable to base the implementation requirements for above-market funds on the guiding principles discussed in Section 3.1.
2) Pursuant to SB 1036, the Commission must set cost limitations equal to the amount of funds transferred to each electrical corporation pursuant to Public Resources Code 25743(b) plus the amount of funds that would have been collected for supplemental energy payments (SEP) through January 1, 2012.
3) The California Energy Commission (CEC) approved Resolution 08-0227-9 (February 27, 2008), which transferred back Bear Valley Electric Service, Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison's SEP contributions minus the amount that was loaned to the General Fund.
4) Because Bear Valley Electric Service, Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison received funds from the Energy Commission pursuant to Public Resources Code 25743(b), the Commission should set cost limitations for these utilities.
5) It is reasonable that staff did not apply any discounting to the estimated collection of SEP funds because the SEPs that would have been collected from 2008 through 2011 would not have incurred interest or financing costs.
6) Public Utilities Code § 399.15(d)(2) sets forth five conditions that a contract must satisfy to be applied to an IOU's cost limitation.
7) Requiring more stringent project viability review standards for renewable energy contracts that are above the market price referent (MPR) is reasonable because the funds that can be used on above-MPR costs of contracts are limited and when the above-MPR funds (AMFs) are exhausted, utilities can curb their procurement of renewable energy to contracts that are at or below the MPR.
8) It is reasonable to review all above-MPR contracts negotiated through a competitive solicitation in the same manner regardless of whether the IOU's cost limitation has been reached.
9) TURN's recommendation that AMF-eligible projects requiring at least $50 million in AMFs be subject to more stringent project viability standards,

such as showing that a project has obtained site control for at least 50% of the land necessary for the project, is reasonable.

10) Requiring AMF-eligible projects requiring at least $50 million in AMFs to be in the relevant transmission queue is reasonable because it is a necessary first step for developing a renewable energy project.

11) The criteria discussed in Section 3.4.2 are reasonable review standards for renewable energy contracts that were negotiated through a competitive solicitation and have above-MPR contract prices.

12) It is reasonable to request additional financial information and extra justification from projects that have executed a price amendment to a Commission-approved RPS contract, as described in Section 3.4.2.

13) It is reasonable to require a utility to submit an AMFs Calculator with every advice letter or application filing requesting Commission-approval of a renewable energy contract.

14) Calculating both the utility's cost limitation and a project's AMFs need in nominal dollars is consistent with our guiding principle to implement simple AMFs rules.

15) It is reasonable to compare a renewable energy contract, that is not yet Commission-approved, and that was executed after prolonged negotiations to a more recent MPR.

16) It is reasonable to compare a Commission-approved contract requesting approval of a price amendment to a more recent MPR.

17) It is reasonable to require a utility to publicly provide the calculation methodologies used for a AMFs Calculator and to confidentially provide the assumptions and price-sensitive information used in the AMFs Calculation in the advice letter requesting approval of the contract.

18) It is consistent with the statutory intent of Pub. Util. Code §399.15(d) to require all eligible contracts to be applied to a utility's cost limitation until it is exhausted.

19) It is reasonable for the Commission to require a utility to provide timely information about its intentions to undertake voluntary RPS procurement of above-MPR costs when a utility requests approval of an RPS contract that is ineligible for AMFs or once the utility has reached its cost limitation.

20) It is reasonable to require utilities to update the Commission on the contract specifications affecting a project's AMFs need in its semi-annual Project Development Status Report, and to true-up the AMFs for each project in this filing.

21) It is reasonable to keep project-specific AMFs needs confidential because releasing such information would be inconsistent with D.06-06-066.

22) It is reasonable for the Director of Energy Division to notify utilities and service lists what each utility's AMFs balance is after Energy Division Staff reviews each utility's Project Development Status Report.

23) It is reasonable to publicly notice the utility and service lists when a utility's cost limitation has been reached.

24) Soon after this Resolution is adopted, it is prudent for the utilities to calculate what their AMFs balances are using the rules adopted in this Resolution.

ORDER

THEREFORE IT IS ORDERED THAT:

1) The following cost limitations shall be applied to Bear Valley Electric Service (BVES), Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDGE), and Southern California Edison (SCE):

Utility	*Amount (2008$)*
BVES	$ 328,376
PG&E	$ 381,969,452
SDGE	$ 69,028,864
SCE	$ 322,107,744
Total	$ 773,434,436

2) When BVES, PG&E, SDGE, or SCE submits an advice letter or application for approval of a power purchase agreement (PPA) for renewable energy or an amendment to an already-approved PPA that is above the market price referent (MPR), the utility shall identify whether the PPA complies with the statutory eligibility criteria codified in § 399.15(d)(2).

3) The utilities shall provide sufficient information in their advice letter filings to enable the Commission to evaluate the contract price and

viability of each renewable energy contract that was negotiated through a competitive solicitation and that has a contract price above the MPR using the criteria set forth in Section 3.4.2.

4) When BVES, PG&E, SDGE, or SCE submits an advice letter or application for approval of a PPA (including an amendment to a Commission-approved PPA) for renewable energy that has above-MPR costs exceeding $50 million, the utility shall identify in the advice letter whether the project has obtained site control for at least 50 percent of the necessary land and whether the project has secured a position in a relevant transmission queue. The utilities shall also supplement advice letters that are currently pending Commission review with the necessary information if the contract has above-MPR costs exceeding $50 million.

5) When BVES, PG&E, SDGE, or SCE submits an advice letter or application for approval of a PPA for renewable energy (including an amendment to a Commission-approved PPA) that was negotiated through a competitive solicitation and for which the contract price is above the MPR, the utility shall include a report from an independent evaluator (IE) discussing the reasonableness of the price from a market perspective.

6) When BVES, PG&E, SDGE, or SCE submits an advice letter or application for approval of an amendment to a Commission-approved PPA for renewable energy, the utility shall provide information on why the price change is needed and how the contract compares to offers from the most recent solicitation. Also, the utility shall provide an IE and the Commission with a cash flow model, and the IE shall submit a confidential report with the advice letter or application that includes the IE's review of the model and reasonableness of the amended price.

7) When BVES, PG&E, SDGE, or SCE submits an advice letter or application for approval of a PPA for renewable energy or a price amendment to a Commission-approved PPA, the utility shall submit an AMFs Calculator and supporting documents with the filing, as described in Section 3.5.

8) All eligible contracts shall be applied to a utility's cost limitation until it is exhausted.

9) IF BVES, PG&E, SDGE, or SCE submits an advice letter or application for approval of a PPA (or a price amendment to a Commission-approved PPA) with above-market costs, and there are insufficient AMFs to support the total AMFs need or the PPA is ineligible for AMFs, the utility shall

inform the Commission whether it would voluntarily procure the above-MPR costs.

10) When the utilities submit semi-annual Project Development Status Reports, starting with the August 2009 Report, they shall each update the contract specifications for each contract that has been applied to their cost limitations and provide AMFs Calculators and all necessary documentation for any contracts whose AMFs need has been modified.

11) The Director of Energy Division shall notify utilities and relevant service lists about what each utility's AMFs balance is after Energy Division Staff reviews each utility's Project Development Status Report.

12) The Director of Energy Division shall notify utilities and relevant service lists if a utility exhausts its AMFs.

13) In order to calculate each utility's AMFs balance, within 30 days of the effective date of this resolution, PG&E, SDGE, and SCE shall each confidentially submit to the Director of Energy Division an AMF Calculator and all relevant documentation, as described in Section 3.5, for each Commission-approved renewable energy contract and pending renewable energy contract with a contract price above the MPR.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on February 20, 2009 the following Commissioners voting favorably thereon:

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PAUL CLANON
Executive Director

Appendix A

1. Turbine equipment costs
2. Land-use-related costs (acquisition costs or annual lease payments)
3. Construction cost for the balance of each unit and tower
4. Site development costs (roads, transmission collection system, metering, monitoring)
5. Permitting costs
6. Financing costs (fees and projected accrued interest up to commercial operation)
7. All other project development costs not included in the above categories (and a description of what they are)
8. Project capital structure (percentages of debt/equity/other)
9. Debt rate
10. Project book value at commercial operation
11. Project tax value at commercial operation
12. Annual revenues
13. Annual operating and maintenance costs
14. Annual spare parts expenses and capital replacement activities
15. Annual federal tax obligations before PTCs
16. Annual PTCs
17. Annual federal tax payments
18. Annual deferred taxes
19. Annual state tax payments
20. Annual local tax payments
21. Annual property tax payments
22. Annual tax depreciation
23. Annual debt service (principal and interest payments, shown separately)
24. All other annual costs not included in the above categories (and a description of what they are)
25. Annual equity cash flow
26. Return on equity