ANALYSIS

CALIFORNIA PUBLIC UTILITIES COMMISSION

SB 14 (Simitian)
As Amended February 17, 2009

SUMMARY

This bill would increase the renewables portfolio standard (RPS) target to 33% in 2020 and make several changes to the RPS program. This bill would also make several changes that affect electric rates, including codifying eligibility for the California Alternate Rates for Energy (CARE) program, barring mandatory dynamic pricing for residential electric customers, and lifting the current cap on some residential electricity rates. This bill would also modify low-income energy efficiency programs and relax some statutory constraints on existing direct access arrangements, while removing any Commission discretion on the complete reopening of direct access. Finally, this bill would modify the governance structure of the California Public Utilities Commission (CPUC) and require the CPUC to meet once a month in Sacramento.

CPUC POSITION AND SUPPORTING ARGUMENTS

OPPOSE UNLESS AMENDED. The CPUC supports the advancement of the renewable portfolio standard beyond 20% by 2010 towards a goal of 33% by 2020. Indeed, the Commission considers increased procurement from renewable sources to be a critical element of meeting AB 32's emission reduction goals and greening California's power production and consumption. However, the CPUC has concerns with several of the non-RPS-related provisions in SB 14, including the proposed modifications to the CPUC's governance structure, and believes these provisions should be placed in separate bills.

ANALYSIS

A. Renewable Portfolio Standard (RPS) program

<u>Increased RPS Target</u>

This bill would require investor-owned utilities (IOUs), energy service providers (ESPs), and publicly-owned utilities (POUs) to increase their procurement of renewable energy by an additional 1% of retail sales per year so that 33% of their retail sales are procured from renewables no later than December 31, 2020.

The CPUC supports increasing the RPS beyond 20%, and making the mandate enforceable for publicly-owned utilities as well. However, the Commission remains concerned about mandating hard targets without conducting analysis on the feasibility of attaining the targets, given potential supply, transmission availability, and permitting timelines. The CPUC recommends either: 1) requiring retail providers to annually increase their renewable procurement by a set percentage of delivered energy per year (i.e. 1.5%) without mandating 33% by 2020; OR 2) mandating 25% by 2015 and 33% in 2020 without requiring annual incremental increases. The latter would allow the CPUC the flexibility to develop and modify annual targets, pursuant to its long-term procurement planning process, to keep the utilities on track.

As drafted, SB 14 (in PU Code 399.15(b)(1)) would require both annual 1% incremental RPS targets and a 33% in 2020 RPS mandate, with penalties for both of these targets. The CPUC's experience has been that having both sets of requirements makes the rules too complex and unwieldy. The Commission would prefer having the authority and flexibility to determine appropriate intervals for assessing penalties. However, the Commission recognizes that the most recent amendments to SB 14 provide the CPUC with some discretion regarding these targets if they will not result in just and reasonable rates.

SB 14 would also require the CPUC to report to the Legislature by January 1, 2012, and every 2 years thereafter, on the progress and status of procurement activities, the identification of barriers, and policy recommendations for achieving the RPS goals. Based on this information, the Legislature and Governor will be able to monitor the viability of proceeding to 33% by 2020 based on actual data from the program, rather than on admittedly problematic forecasted data from 2009. These reports will facilitate the Legislature's consideration of appropriate and timely changes to the RPS statute.

Eligibility

SB 14 would modify the definition of "delivered" (PR Code §25741(a)) to say that energy shall be deemed delivered if it is located within the state or is "generated at a location outside the state and scheduled for simultaneous consumption by California end-use retail customers". The bill deletes the provision that out-of-state eligible renewable energy can be delivered regardless of whether the electricity is generated at a different time from consumption by California end-use customers.

This change would effectively eliminate the ability of eligible intermittent (e.g. wind and solar) out-of-state renewable energy facilities to participate in the California RPS. Currently, intermittent out-of-state energy is "firmed and shaped" with a non-intermittent product so that a California retail seller can buy out-of-state renewable energy.

The CPUC supports the participation of out-of-state renewable energy in California's RPS program. The Commission generally supports allowing renewable energy facilities that meet the current technology requirements from anywhere in the Western Interconnection (within WECC) to count towards compliance. Bundled contracts should have a requirement of delivery of the energy to California because they provide a hedging benefit since the underlying energy is bought at a fixed price. However, out-of-state eligible renewable energy credit (REC) contracts should not have a delivery requirement because by definition, the utility buying the REC is not buying the energy. This approach takes advantage of the GHG reduction potential of renewables in the Western Region as a whole, helps California meet its AB 32 goals, mitigates in-state RPS costs, and provides the state more options for reaching its RPS goals. Further, the CPUC supports keeping existing language that gives the CPUC the authority to determine the appropriate cap on such REC-only transactions.

Along these lines, the CPUC recommends modifying the definition of "procure" in PU Code §399.12(d) as follows:

"Procure" means that a retail seller or local publicly owned electric utility *contracts for renewable energy credits* or receives delivered electricity generated by an eligible renewable energy resource that it owns or for which it has entered into an electricity purchase agreement.

Procurement Plans and Contract Evaluation

This bill would require the RPS annual Procurement Plans to be more robust and would tie the content of the Plans, as well as contract bid evaluation criteria and renewable energy contract evaluation, to long-term procurement planning.

Currently, the RPS statute is very prescriptive and does not allow the CPUC to update RPS rules according to market and regulatory realities that affect renewable energy development. Also, RPS program implementation is very insular, specifically 1) the CPUC does not evaluate renewable energy contracts based on how they affect the rest of the utility's portfolio from a long-term planning perspective, and 2) the utilities do not to plan their fossil procurement and transmission in light of RPS obligations. This bill would enable the CPUC and utilities to evaluate RPS contracts in light of the utility's portfolio need.

Proposed PU Code §399.14(a)(3)(D) would require utilities to provide a "status update on the development schedule for all renewable resources currently under contract." The Commission already requires a robust Project Development Status Report with each semi-annual compliance report (D.06-05-039) from the utilities, so this proposed statutory requirement is unnecessary. Further, Energy Division staff is currently working with parties to better align project viability with bid selection, contract review and approval, and flexible compliance.

Proposed PU Code §399.14(d) would require the CPUC to identify project development milestones for renewable projects under contract and take action against developers for not meeting milestones. Utilities and developers already negotiate project development milestones for each contract, and the consequences for missing milestones are captured in the contract terms and conditions. The CPUC is concerned that its interference with contract negotiations would unnecessarily create program complexity, as well as negatively impact renewable energy developers' ability to finance new projects in California by creating market uncertainty.

Cost Containment Mechanism

The CPUC is committed to cost containment within the RPS program. Pursuant to PU Code §701.1, the CPUC has an obligation to ensure that the principal goal of electric utilities' resource planning and investment is to minimize the cost to society of reliable electric services, and to improve the environment and to encourage renewable energy resources.

The CPUC generally supports replacing the Market-Price Referent (MPR) approach to cost containment, which essentially caps the amount by which renewable energy contract costs can exceed those of gas-fired alternatives. Stakeholders have rightly questioned why there should be a cap on what the state pays for renewable energy when there is not a cap on the cost of fossil-fired power. In the present context of climate policy, the more appropriate comparison may be between renewable energy costs and those of other GHG reduction measures.

This bill would eliminate the MPR and cost limitation (PU Code Sections 399.14(a)(2)(A), 399.15(c), 399.15(d)), and would replace them with a "just and reasonableness" standard, which would allow the CPUC to review RPS costs in light of market realities and a utility's overall portfolio. This is appropriate because pursuant to existing PU Code §454.5, the CPUC has the authority to approve IOU procurement plans and contracts that comply with the plan. Renewable procurement should be treated no differently than other forms of procurement, which are evaluated based on comparable market prices and the reasonableness of project costs relative to other projects bid into the same solicitation.

Commission staff has presented a proposal in the context of the Long Term Procurement Planning proceeding to use a long term portfolio analysis to evaluate all utility procurement decisions from the perspective of cost, system reliability, and greenhouse gas impact. This approach would be consistent with the CPUC's existing statutory authority and could potentially support comparisons with other GHG reduction measures within the electric sector.

Compliance Rules

The bill would delete PU Code §399.14(a)(2)(C)(ii), which requires flexible rules for compliance for a lack of transmission, and would allow the CPUC to implement more appropriate flexible compliance rules, if any. The CPUC supports this approach because it will reduce the complexity of the program.

Enforcement

Proposed PU Code §399.14(e) would require the CPUC to consult with CARB on developing enforcement rules for the RPS program that provide for the imposition of penalties by CARB upon referral and recommendation by the CPUC.

The CPUC generally supports enforcing the requirements of the RPS program for the entities it regulates, and supports the creation of an enforcement and penalty mechanism that can be equally applied to publicly-owned utilities. However, the CPUC has previously been required to work with another agency to implement a two-stop process as part of the RPS program, and it failed. It was subsequently eliminated by SB 1036 (2007). The CPUC would prefer clarification in this proposed statute that the Commission retains its jurisdiction over the determination of penalties related to RPS targets outside the parameters of AB 32 implementation, and that CARB would only collect penalties recommended by the CPUC. Further, the statute must be clear that utilities will not be double-penalized for missing RPS obligations.

Suggested Technical Amendments for RPS-related provisions:

- Amend proposed PU Code §399.14(a)(3)(A) as follows:

This assessment shall be consistent with the electrical corporation's long term portfolio planning conducted pursuant to Section 454.5 *or Section 399.17* ~~and shall consider the electrical corporation's optimal portfolio to reach the state's goals for reducing emissions of greenhouse gases~~. Consistent with an electrical corporation's long term portfolio planning, the commission may require analyses, including, but not limited to, the rate impact, effects on system reliability, and the environmental and economic benefits *and costs* of the proposed procurement.

- Amend proposed PU Code §399.15(e) to include in the list of contract review metrics:

Consider any other factors that the commission determines may be necessary for adequate review of the contract.

- Amend existing PU Code §399.20 (feed in tariff) to reflect this bill's elimination of the market price referent (MPR) in PU Code §399.15:

The tariff shall provide for payment for every kilowatt-hour of electricity generated by an electric generation facility at ~~the market~~ *a* price ~~as~~ *to be* determined by the commission ~~pursuant to Section 399.15~~ for a period of 10, 15, or 20 years, as authorized by the commission.

B. Transmission

This bill would advance several transmission-related goals, including: efficient permitting of transmission needed to meet RPS goals; discretion for the CPUC to approve recovery in retail rates of certain "justified" transmission costs disallowed by FERC; improved operational and planning coordination among California's different transmission owners and operators; and efficient integration of renewable generation needed to reach the state's 33% RPS goal by 2020.

Transmission Permitting

The CPUC has the responsibility for permitting high-voltage, utility-owned transmission facilities, including responsibility as the lead agency under CEQA for preparing environmental reports associated with what can be very extensive and complex transmission projects. The CPUC has recently streamlined its permitting process, including increased attention to pre-filing activity such that when an application reaches the CPUC, it is more likely to be complete or nearly so.

This bill would require the CPUC to approve transmission projects within one year of receiving a completed application unless the Commission makes certain findings including finding that the line threatens the environment, and therefore, requires a longer process. This one-year requirement, practically speaking, is unlikely to produce significant changes in permitting or significantly shorter timelines for processing permit applications. The main reason that completed applications are processed over more than a year is, in fact, the complexity of environmental issues, the existing legal requirements to address such impacts and the need to coordinate such environmental reviews with federal agencies that are not under the same time constraints as California agencies.

Transmission Cost Recovery

In the process of permitting transmission projects, the CPUC establishes cost caps, and as a result of Decision 06-06-034 (implementing Public Utilities Code § 399.25), may approve eligibility for recovery in retail rates of transmission costs incurred in support of renewable energy goals in the event FERC disallows recovery. The CPUC also participates on behalf of California interests in proceedings through which FERC approves rates for recovery of transmission costs, including costs of major projects permitted by the CPUC.

This bill would require the CPUC to approve “reasonable and cost-effective” transmission projects that support RPS goals and are not under FERC ratemaking authority. In practice, projects not under FERC ratemaking authority will not be under CPUC permitting authority either. Also, CPUC “backstop cost recovery” policy (Decision 06-06-034 described above) already addresses approval and cost recovery for transmission projects needed to support RPS goals.

This bill would also allow the CPUC to approve “justified” transmission costs disallowed by FERC. Whereas the existing § 399.2.5 is limited to renewable projects, it is unclear whether the author intended to extend this cost recovery discretion beyond renewable-related transmission projects. If not, the CPUC’s existing “backstop cost recovery” policy described above already takes care of cost recovery for transmission needed to support renewable energy goals.

SB 14 would generally not change these CPUC efforts regarding transmission cost recovery, either in the CPUC’s own proceedings or at FERC, because SB 14 would not actually provide additional cost recovery options beyond what is already available. The one exception would be if the CPUC was given discretion to approve recovery in retail rates of <u>any</u> justified (not just renewable energy-related) transmission costs disallowed by FERC. Implementation of this expanded discretion could require additional staff effort to assess whether a potentially broad range of transmission costs meets these criteria, even though actual situations warranting this treatment are unlikely to arise.

<u>Transmission Operational and Planning Coordination</u>

This bill would direct the California Energy Commission (CEC) to facilitate: the development of annual statewide transmission plans with the California Independent System Operation (CAISO) and the siting and approval of new transmission that can be jointly owned or utilized between the CAISO, POUs, and IOUs.

The California-wide Renewable Energy Transmission Initiative (RETI) involving the CPUC, CEC, CAISO, non-CAISO transmission owners and various generation-related and other stakeholders, is currently working to establish conceptual transmission plans for identified high priority renewable energy zones. This process is intended to inform the CAISO’s Transmission Planning Process (TPP) and its stakeholders, in a manner similar to the way that SB 14 would require a coordinated annual statewide transmission plan.

The CPUC supports and participates in the CAISO’s transmission planning process and supports improved joint planning and operating (“seams”) arrangements between the CAISO and non-CAISO transmission owners. CPUC staff also participate extensively in FERC proceedings regarding transmission access, planning, and cost recovery, since these matters tend to be both FERC jurisdictional and of considerable import to ratepayers and other California interests.

Additionally, a major responsibility of the CPUC is administering the resource procurement programs of CPUC-jurisdictional load serving entities (LSEs). This procurement and its support of the state's overall energy goals is significantly affected and informed by transmission plans and developments, and in turn itself impacts transmission planning. If SB 14 were to alter transmission planning and development, or perhaps even the conditions of access to transmission (e.g., via "seams" agreements), this would affect access to and cost of resources, and thus would affect the CPUC-administered procurement programs. These interdependencies are a major reason for CPUC's close involvement and interest in transmission planning and transmission access issues.

C. Rate-related Issues

CARE Program

The California Alternate Rates for Energy (CARE) program, codified in PU Code section 739.1, provides a 20% discount on electric and natural gas monthly bills for eligible low- or fixed-income ratepayers. This bill would amend PU Code section 739.1(a) to define income eligibility for the CARE program at 200% of federal poverty guidelines.

Currently, the eligibility guidelines for the CARE program are not in statute. Since 2005, the CPUC has set CARE eligibility at 200% of federal poverty guidelines (see CPUC Decision 05-10-044). The CPUC would prefer to retain the flexibility of changing the eligibility criteria for CARE depending on the state's changing economic conditions. In order to leverage funds from federal programs and be in a position to provide low income energy assistance to more deserving people, the CPUC should be afforded the discretion to reform the eligibility guidelines, or adopt a new set of guidelines, within existing CPUC authority.

This bill would also codify the cost recovery method for the CARE program as an equal cents per therm basis. The CPUC consistently resists statutory attempts at ratemaking, and this is no exception. The CARE program is currently funded by surcharges on the electric and natural gas bills of all customer classes (residential, commercial and agricultural) on an equal cents per therm basis. However, the CPUC is currently examining in proceeding A.07-12-006 whether to change this basis to an equal percent of base revenue, which would shift a larger portion of the program costs to the residential customer class. The CPUC should be left the discretion to exercise its ratemaking authority in determining the appropriate allocation method.

Dynamic Pricing

This bill would add proposed section 745 to the Public Utilities Code to prohibit the CPUC from employing mandatory dynamic pricing for residential customers. Dynamic pricing is a rate structure that that reflects the time of the energy's use (TOU). TOU rates have great public policy benefits like reduced costs, improved grid reliability, and reduced greenhouse gas emissions. In an AB 32-implementation world, the state should not be limiting the CPUC's ability to use innovative rate design options to encourage reductions in peak load usage and conservation. The CPUC would carefully consider the impacts of mandatory TOU rates on customers, including low income customers, and the need for substantial customer education before adopting such rates.

130% of Baseline Rate Restrictions

This bill would delete Section 80110 (e) of the Water Code, thereby eliminating the statutory rate cap established under AB 1X (2001) that bars the CPUC from increasing rates for electricity usage that falls under 130% of the baseline quantity for residential customers. This bill would also add Section 739.9 to the Public Utilities Code to allow the CPUC to increase rates charged to residential customers for electricity usage that falls under 130% of baseline quantity by a change in the CPI plus 1%. This rate increase should be at least 3% but not more than 5% per year.

Residential electricity rates feature a “tiered” structure, whereby usage is measured against as many as 5 tiers, each of which is associated with a specific rate, charged in cents per kilowatt-hour—as a customer consumes more electricity, that consumption is tracked in higher and higher tiers. In currently-adopted rates, a higher-usage customer is charged higher rates for that usage. “Tier 1” consists of usage up to a customer’s “baseline” level; this is defined as the quantity that is necessary to supply a significant portion of the reasonable energy needs of the average residential customer. “Tier 2” is defined as usage between the baseline amount, and up to 130% of that amount.

Since 2001, AB1X has prevented the CPUC from increasing rates for the residential electricity usage under 130% of baseline (Tiers 1 & 2). During this time, electricity generation, transmission and distribution costs have escalated due to increases in infrastructure, fuel and labor costs. These increased costs have been disproportionately borne by customers whose usage exceeded 130% of baseline (Tiers 3, 4 & 5). Since electricity usage subject to the rate cap is approximately 70% of investor-owned utility sales, requiring that the utilities cover cost increases by increasing rates on the remaining 30% of usage has resulted in very high rates for Tiers 3, 4 and 5. While the CPUC supports lifting the AB 1x cap, this bill is overly prescriptive in requiring that rates should increase by at least 3 percent and not more than 5 percent per year. This requirement unnecessarily limits the CPUC’s authority to set rates that accurately reflect utility costs.

D. Miscellaneous Provisions

Low-Income Energy Efficiency Programs

This bill would amend PU Code section 327 to require energy efficiency and solar programs for low-income ratepayers to target customers in Tiers 4 and 5, as well as multifamily customers, in a manner that will result in long-term permanent reductions in electricity usage.

The CPUC does not support targeting specific customer segments within its low income programs. Decision 08-11-031 on utility budgets for low income programs clearly emphasizes that “the IOU’s must serve all eligible low income customers.” Targeting specific customers, like high energy users and multifamily customers, is discriminatory against low-income individuals in need of assistance that fall outside of the targeted customer classifications. The Commission’s current directive is for IOUs to expand outreach efforts to customers with high energy use, burden, or insecurity, so they may have an equal opportunity to participate in low-income programs.

Also, the criteria that energy efficiency programs should result in ‘long term permanent reductions’ in energy use could be in conflict with the stated goal of the Low Income Energy Efficiency (LIEE) program to 'improve the quality of life of the low income population'. For example, the installation of air-conditioning in a hot climate zone will improve the quality of life of the low-income individual, but it would not result in long term permanent energy reductions.

This bill would also amend PU Code section 382 by adding subparagraph (f) to require electric utilities to deploy LIEE programs designed to reach as many eligible customers as possible by December 31, 2014.

In CPUC Decision 07-12-051 and the Commission’s Long-term Energy Efficiency Strategic Plan, the CPUC’s stated long term vision for the LIEE program is: “By 2020, 100% of eligible and willing customers will have received all cost effective Low income energy efficiency measures.” Furthermore, in its November 2008 decision on the budget applications of Investor Owned Utilities (D.08-11-031), the CPUC approved substantial budget increases to provide LIEE assistance to 25% of eligible and willing customers during 2009 to 2011. D.08-11-031 clearly emphasizes that the IOU’s must serve all eligible low income customers. This bill’s approach of targeting specific customers, like multifamily housing residents, is a diminished approach compared to the CPUC’s current directives. Instead, the CPUC can direct utilities to focus their outreach and marketing efforts on particular segments such as those suggested in the bill. This flexible approach can be modified depending on the necessity for focus on specific customer segments that may change over time.

<u>Direct Access</u>

This bill would amend Section 80110 of the Water Code to maintain the current “suspension” of Direct Access, but specify that the commission may allow individual retail end-use customers who are either currently taking service from an electric service provider, or eligible to take service from an electric service provider under Commission rules, to acquire service for new accounts from an electric service provider. The CPUC supports relaxing the direct access suspension. However, the bill would also prohibit the CPUC from allowing the reopening of direct access without express statutory authority. The CPUC opposes this provision.

Direct Access was originally implemented by the Commission on April 1, 1998, as an integral part of a comprehensive restructuring program to bring retail competition to California electric power markets. Under this competitive restructuring program implemented pursuant to Assembly Bill (AB) 1890, retail customers have the choice either to subscribe to traditional bundled utility service or to purchase electricity on a competitive basis from an electric service provider (ESP). A direct access customer receives distribution and transmission services from the utility, but purchases electricity directly through an independent ESP. Although the ESP supplies electricity to the direct access customer, the utility remains the electricity provider of last resort.

In 2001, after the Department of Water Resources (DWR) had contracted for power on behalf of the state’s IOUs during the energy crisis, the Legislature suspended direct access in order to ensure that cost responsibility for the DWR procurement was assigned in a fair manner among retail electric customers and to assure a stable customer base. Pursuant to the legislative mandate of AB1X, the CPUC suspended the right to enter into new contracts for direct access after September 20, 2001. A "standstill approach" was applied, permitting no new direct access contracts, but allowing preexisting contracts to continue in effect.

The CPUC believes that the underlying concerns previously identified by the Commission and the Legislature as reasons for the suspension of direct access have been addressed in various Commission proceedings. For example, DWR bonds were issued at investment grade, and the Commission established non-bypassable charges for recovery of DWR bond costs. The Commission has also established cost recovery mechanisms for DWR to be reimbursed for its power costs from both bundled and direct access customers. California energy markets have become more stable and the Commission has adopted various policy reforms to eliminate the conditions that prompted the energy crisis of 2000-2001. In addition, the Commission has implemented its resource adequacy program pursuant to AB 380, and its Long Term Procurement Planning process pursuant to AB 57. The CPUC is currently examining options for relieving DWR of its responsibility as a power provider, potentially making it possible to resume direct access under current law. This bill would remove CPUC discretion in this area until express statutory authority is granted at some future point.

CPUC Governance

This bill would provide that the general counsel and the executive director of the CPUC shall both operate as directed by the CPUC rather than as directed by the president of the CPUC, and that the Commission shall meet in Sacramento once a month.

This bill's requirement that the Commission as a whole direct the activities of the CPUC's executive director and general counsel runs contrary to the Legislature's intent in 1999, when it enacted SB 33 (Peace).

SB 33 explicitly centralized accountability for the functioning of the CPUC by putting the Commission's executive director and the general counsel directly under the control of the president. The president's ability to direct the executive director and general counsel on routine matters enhances the efficient operation of the CPUC.

Finally, the requirement that the CPUC meet in Sacramento once a month will increase costs with no known benefit since the CPUC already webcasts its commission meetings. The CPUC's Administrative Law Judge (ALJ) Division estimates that holding twelve meetings in Sacramento over the course of a year will cost approximately $82,000, which includes the costs of renting an auditorium with a seating capacity of 150-200 people and the travel expenses for approximately 50 CPUC employees.

PROGRAM BACKGROUND:

RPS Program

The RPS program was adopted in SB 1078 (2002), and subsequently modified by SB 107 (2006) and SB 1036 (2007). The CPUC is statutorily responsible for 1) requiring each utility to submit an RPS Procurement Plan, 2) adopting a pricing benchmark to evaluate RPS contracts, 3) adopting a process that utilities must use to evaluate renewable energy projects bid into their solicitations, 4) adopting RPS compliance rules, 5) reviewing and approving or rejecting utilities' RPS contracts, and 6) reporting to the

Legislature, on a quarterly basis, on the RPS program. The CPUC has adopted approximately 30 decisions to implement these aspects of the RPS program and has approved over 110 RPS contracts for nearly 7,000 megawatts (1,000 megawatts of which have already begun delivering RPS-eligible energy).

Each year, the utilities each submit an RPS Procurement Plan, which includes, in part, a description of their renewable energy procurement supply and demand and a description of how they will evaluate RPS bids. The CPUC evaluates and approves each Plan. Then, the utilities rank each bid, select which bids to negotiate with, and execute a number of contracts. The CPUC evaluates each executed contract in light of its compliance with the utility's Plan and other CPUC decisions, the reasonableness of the contract price, and the viability of the project. In order to contain the costs of the RPS program, if the contract price is at or below a CPUC-calculated price benchmark (based on the cost of a fossil fuel plant), the price is considered reasonable. However, if it exceeds the benchmark, the utility has a limited amount of funds that it can use towards those above-market contract costs.

The CPUC has also become involved in other activities to improve the RPS program, to coordinate with agencies statewide to facilitate renewable energy development in California, and to provide robust information to the public and Legislature on the progress of the RPS program and the trends in the renewable energy market. For example, we started the Renewable Energy Transmission Initiative (RETI), and involved the CEC, CAISO, developers, environmental groups in order to facilitate statewide renewable transmission planning for new renewable energy projects. We maintain numerous databases of project characteristics and viability and produce robust analyses on the barriers facing renewable energy development. We have also begun an analysis of the feasibility and cost of a 33% RPS, which will result in a better understanding of the barriers and solutions for reaching a higher RPS target in California.

<u>Transmission siting and permitting</u>

Existing constitutional authority exists for CPUC jurisdiction over transmission siting and approval. Also, per the California Environmental Quality Act (CEQA), the CPUC has discretionary authority regarding electric infrastructure owned and / or operated by investor owned utilities, therefore the CPUC is the lead agency in preparing the environmental impact report (CEQA).

Currently, for siting transmission lines to be constructed by investor owned utilities, the IOU prepares a plan of service and submits it to the CAISO for approval. After the CAISO approves the project based on economic and reliability analysis, the IOU prepares an application and Proponent's Environmental Assessment (PEA) and submits it to the CPUC. Once the application is filed with and deemed complete by the CPUC, an environmental document is prepared, often in coordination with an appropriate federal agency if the transmission line crosses federal lands. During the process of preparing the environmental document, the CPUC staff holds extensive public meetings and agency consultations in order to site a transmission line. Preparation of the environmental document and the CPUC's CPCN process take place concurrently. Eventually, the environmental document is used in the CPCN process. When the applicant receives the CPCN approval, they may start construction.

CPUC staff currently participate in the CAISO's transmission planning process including issues related to renewable and other resource priorities as well as the need for and efficiency of transmission projects.

CPUC staff plays a leading role in the RETI process to prioritize renewable energy zones and associated transmission, and generally works closely with CAISO and stakeholders to coordinate supply and transmission planning on an increasingly forward-looking basis.

Transmission Operational and Planning Coordination

The CAISO has developed a reformed, open transmission planning process (TPP) approved by FERC and consistent with FERC policy under recent Order 890. The CAISO is also seeking to develop a joint planning process with non-CAISO member transmission owners in California, via the Pacific Southwest Planning Association (PSPA), which is consistent with both Order 890 and with the role of subregional planning groups (of which PSPA would be one) as one tier within the WECC (western grid) planning structure . The CAISO also manages a range of market and reliability programs for its control area, which are in the midst of a major reform, Market Redesign and Technology Update, to be rolled out this spring after lengthy and complicated stakeholder and FERC processes. Furthermore, the operating (market and reliability) implications of integrating large, unprecedented (almost unimaginable) amounts of variable renewable generation into the CAISO system are being assessed in the CAISO's Integration of Renewable Resources Program (IRRP), providing substantial upfront opportunity for stakeholder input, and emphasizing coordination with the RETI and LTPP processes.

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