Alliance for Retail Energy Markets

Direct Access Workshops

PRESENTATIONS BY
ALLIANCE FOR RETAIL ENERGY MARKETS

ON

SWITCHING RULES
FINANCIAL SECURITY REQUIREMENTS
ENSURING UNIFORM COMPLIANCE
DIRECT ACCESS PROCESS IMPROVEMENTS

CA PUBLIC UTILITIES COMMISSION

SAN FRANCISCO, CALIFORNIA
JULY 12-13, 2010

Topics

- **Switching Rules**
- **Financial Security Requirements**
- **Transition Bundled Service Update**
  (AReM has no position this at this time)
- **Ensuring Uniform Compliance**
- **Direct Access Process Improvements**

Switching Rules

- **Existing Rule:**
  - Six month notice required to switch from utility service to direct access
- **Proposal:**
  - Eliminate six month notice to switch to direct access, such that switching is accomplished by submission of the Direct Access Service Request (DASR) – services commences on next meter read date that is at least 5 days after submission
- **Rationale:**
  - Existing exit fee structure addresses cost shifting
  - True-ups for local and system RA address RA issues
  - As such, bundled customer protections are not enhanced by a six month notice period
  - When exit fees are reviewed, switching rules can be re-evaluated

Switching Rules

- **Existing Rule:**
  - Six month notice to return utility service from direct access
- **Proposal:**
  - While AReM does not support unnecessary restrictions, we have no position at this time on whether this rule should be changed.
  - Will respond to positions after workshops are concluded and various proposals have been discussed.

Switching Rules

- **Existing Rule:**
  - Customers returning to utility service from Direct Access must remain for three years (after six months on Transition Bundled Service)
- **Proposal:**
  - Minimum stay should be eliminated, or no longer than one year (depending on coming and going rules)
- **Rationale:**
  - Existing exit fee structure addresses cost shifting
  - True-ups for local and system RA address RA issues
  - When exit fees are reviewed, minimum stay rules can be re-evaluated

Switching Rules – Scoping Memo Questions

- **Scoping Memo Question 1:** Do the current switching rules adequately account for all costs determined to be non-bypassable? (e.g., stranded resource adequacy/renewable portfolio standard cost)? If not, what changes in the switching rules (or cost recovery mechanisms) may be appropriate? Should the commitment period when switching to a bundled service be modified in view of the IOUs' obligations to follow the State loading order
    - **Answer:** Existing exit fee structures address cost shifting.

- **Scoping Memo Question 2:** What risks, if any, are associated with adjusting the six-month notice requirements or modifying other processes to mitigate identified risks that may not already be covered?
    - **Answer:** No risks that AReM can discern at this time.

Switching Rules – Scoping Memo Questions

- **Scoping Memo Question 3:** What limits, if any, should be placed on the amount of load allowed to transfer into or out of DA within a given year, in addition to or instead of the existing advance notice requirements?
  - **Answer:** Statute already imposes cap; no further limitations are necessary under law

- **Scoping Memo Question 4:** If the compensation through the transitional bundled service (TBS) rate and the vintaged new generation charge are fully compensatory, is an advance notice requirement for transfers into or out of DA still necessary?
  - **Answer:** No. Prior slides describe proposed modifications to switching rules

Financial Security Requirements

- **Scoping Memo Question 1:** What cost exposure does each IOU face with respect to returning load previously served by an ESP that requires a bond?
  - **Answer:** The basic structure underlying the CCA Bond Requirement is applicable to address the situation where an ESP defaults under its ESP Service Agreement and customers are involuntarily returned to utility service:
    - Stressed Cost to the IOU to provide procurement services to the returned customers for one year, less the revenue those customers would bring to the host IOU.
    - ***As discussed under Scoping Memo Question 4, there are differences in how that would be calculated for an ESP compared to that of a CCA.***

Financial Security Requirements

- **Scoping Memo Question 2:** What forms of ESP collateral are appropriate and subject to what qualification and documentation procedures?
  - **Answer:** Forms of collateral should include (1) no collateral requirement for entities that have an investment grade credit rating, (2) parent company guarantee, (3) surety bond, (4) letter of credit, or (5) cash.

- **Scoping Memo Question 3:** How frequently should the ESP financial security requirement be revisited in view of ESP potential load fluctuations over time?
  - **Answer:** Once a year should be sufficient, and is consistent with practices in other states.

Financial Security Requirements

- **Scoping Memo Question 4:** To what extent does the proposed settlement in R.03-10-003 applicable to CCA bonding requirements provide a framework for ESP security requirements? Identify any pertinent differences between ESPs and CCAs that warrant different treatment with respect to security requirements.
  - **Answer:** Three elements warrant different treatment
  - The TBS rate is applicable to returned DA customers but not CCA customers
  - The possibility of a returned DA customer being picked up by another ESP
  - Phase-in of financial security for ESPs should not be necessary as ESPs are subject to security requirement already

Financial Security Requirements

- **The TBS rate is applicable to returned DA customers but not CCA customers**

Proposal: Adjust financial security formula to reflect that no bond is required for the 6 months of TBS service.

- **The possibility of a returned DA customer being picked up by another ESP**

Proposal: Reduce financial security amount to reflect a reasonable estimate of how much returned load would by served by a different ESP.

- **Phase-in of Bond for CCAs assumes new entity; ESPs are ongoing concerns.**

Proposal: No need to phase in ESP financial security amount.

Financial Security Requirements

Proposed Financial Security Requirement formula:

- 1^{st} six months = Zero because customers are on TBS service,
- Plus 2^{nd} six months:

[6 months Stressed IOU Cost to Serve
- (6 months load @ stressed bundled gen. rate]
x (1 - percent switching to another ESP)
Incremental Generation Costs
+ admin. costs
- Holdback (as applicable)
Financial Security Amount

Transition Bundled Service

- AReM does not have a specific proposal for TBS rate modifications at this time.
- Will provide comments after review of proposals offered at the workshops.

Ensuring Uniform Compliance

- **SB 695 states, in part, that:**
  - Once the commission has authorized additional direct transactions, it shall ensure that other providers are subject to the same requirements that are applicable to the IOUs to implement:
    - the resource adequacy provisions of P.U. Code § 380;
    - the renewables portfolio standard provisions commencing with P.U. Code § 399.11; and
    - the requirements for the electricity sector adopted by the State Air Resources Board pursuant to AB 32.

Ensuring Uniform Compliance

- The Commission has already ensured that other providers are subject to the same requirements to implement:
  - The resource adequacy provisions of P.U. Code § 380. A series of decisions issued in dockets R.05-12-013 and R.08-01-025 provide that ESPs must
    - Meet the same RA requirements as IOUS; and
    - Are subject to the same penalties for noncompliance.
    - ESPs are also subject to a unilateral cost allocation mechanism related to IOU RA expenditures although IOUs are not subject to a similar obligation vis-à-vis ESP procurement
  - The RPS provisions of Article 16 et seq. ESPs must:
    - Meet the same 20% by 2010 goal, will be subject to any increase to 33% and are subject to the same penalties for noncompliance.
    - Implementation of this SB 695 provision with respect to the RPS program will take place in R.08-08-009 and need not be considered here.

Ensuring Uniform Compliance

- The requirements for the electricity sector adopted by the State Air Resources Board pursuant to AB 32.
  - In D.06-02-032, the Commission stated an intent to apply a load-based GHG emissions cap to the three major IOUs, and also to CCAs and ESPs operating within the service territory of the three major IOUs.
  - D.07-01-039 adopted "an interim greenhouse gas (GHG) emissions performance standard for new long-term financial commitments to baseload generation undertaken by all load-serving entities (LSEs), consistent with the requirements and definitions of Senate Bill (SB) 1368 (Stats. 2006, ch. 598)."
  - D.07-09-017 recommended to ARB a "proposed electricity sector reporting and verification protocol …that…would apply to all retail electricity providers in California, including investor-owned utilities (IOUs), multi-jurisdictional utilities, electric cooperatives, publicly-owned utilities (POUs), energy service providers (ESPs), and community choice aggregators (CCAs)."
- This issue is now in the hands of the ARB, with the Commission's clear recommendation on AB 32's applicability to all LSEs.

Ensuring Uniform Compliance

Potential obligations to purchase from Qualifying Facilities (QFs), including combined heat and power

Qualifying Facilities

- The Commission is authorized under PURPA (codified at 16 U.S.C. § 2601 et seq.) to require "electric utilities" to purchase electricity from QFs at "avoided cost" rates.
- ESPs are not subject to the CPUC's ratemaking authority and, therefore, are not "covered electric utilities" that are subject to PURPA provisions with regard to purchases of electricity from QFs. (See 16 U.S.C. § 2621)
- The RPS Stature expressly separates the RPS program from the CPUC's QF program. (See P.U. Code § 399.15(e))
  - (e) The establishment of a renewables portfolio standard shall not constitute implementation by the commission of the federal Public Utility Regulatory Policies Act of 1978 (Public Law 95-617).
- The QF program is separate and distinct from the Resource Adequacy program or the GHG programs (as authorized by AB 380 and AB 32 respectively), and is not included in SB 695.
- Therefore, the CPUC's authority under SB 695 does not include authority to require ESPs to purchase electricity from QFs._

Ensuring Uniform Compliance

Combined Heat and Power Systems_

- The CPUC is authorized by AB 1613 (codified at P.U. Code § 2840 *et seq.*) to require "electrical corporations" to purchase electricity from CHP systems. (See P.U. Code § 2841).
  - **2841**. (a) The commission may require an electrical corporation to purchase from an eligible customer-generator, excess electricity that is delivered to the grid that is generated by a combined heat and power system that is in compliance with Section 2843.
- ESPs are not "electrical corporations" as that term is defined for purposes of the CHP program. (See P.U. Code § 2840.2(c); see also P.U. Code §§ 218 and 218.3)
- The CHP program is not addressed in SB 695
- Therefore, the CPUC's authority under SB 695 does not include authority to require ESPs to purchase electricity from CHP systems._

Ensuring Uniform Compliance

Greenhouse gas "cap-and-trade" and program measures pursuant to AB 32 implementing regulations or federal legislation

- See Slide 16, above

Ensuring Uniform Compliance

<u>Costs from Commission-mandated new generation resources needed for system reliability</u>

- P.U. Code § 365.1(c)(2) "requires that the costs of resources acquired by the IOU to meet system and local reliability needs for the benefit of all customers be allocated to all benefitting customers, including DA and CCA customers, along with associated RA credits." [June 15 AC and ALJ Ruling]
- D.06-07-029 already provides for such cost allocation
  - SB 695 modifies D.06-07-029 in two ways:
    - It adds that UOG is eligible for cost allocation; and
    - specifies that a capacity auction need not be held as a methodology for determining the cost allocation
- Track III of the new LTPP, R.10-05-006, will address "Updates to Procurement Rules to Comply with SB 695 and Refinements to the D.06-07-029 Cost Allocation Methodology."
- This proceeding can and should defer to the new LTPP docket with regard to implementation of any needed changes to the cost allocation mechanism.

Ensuring Uniform Compliance

Multi-year requirements to procure Combined Heat and Power generation and renewables under feed-in tariffs.

- Pursuant to AB 1969, as codified in P.U. Code § 399.20, every "electrical corporation" (as defined in § 218) is required to have in place a tariff for the purchase of electricity generated from RPS-certified facilities with a capacity of up to 1.5 MW that are operated by public water and wastewater agencies.
- AB 1969 also specified that every "electrical corporation" is required to make its feed-in tariff available to eligible customers until the facilities served under such tariffs reach a statewide cumulative of 250 MW.
  - The statute therefore is expressly applicable solely to electrical corporations.
  - Therefore, there is no statutory authority for the Commission to apply utility-based FIT obligations to other LSEs
- Furthermore, the Commission is statutorily forbidden from regulating the rates and terms and conditions of service of ESPs, pursuant to P.U. Code § 394(f): "Registration with the commission is an exercise of the licensing function of the commission, and does not constitute regulation of the rates or terms and conditions of service offered by electric service providers. Nothing in this part authorizes the commission to regulate the rates or terms and conditions of service offered by electric service providers."

Direct Access Process Improvements

- Rule 22 Working Group, if under Commission coordination and direction, could be valuable
  - Specific issue to be addressed: Rule modifications to limit anti-competitive actions by the IOUs.