POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA)

ABOVE-MARKET COSTS

SAN JOSE CLEAN ENERGY
A Program of the City of San José

WHAT IS THE PCIA?

All California electricity customers, whether they are served by investor-owned utilities (IOUs) or Community Choice Aggregators (CCAs), pay a PCIA fee. The PCIA reflects the difference between the IOU's above-market costs related to legacy power supply commitments, including third-party energy contracts and operating costs for power plants they own, and today's market value for those resources. The California Public Utilities Commission (CPUC) updates each utility's PCIA every year based on updated IOU projected costs and CPUC estimates of IOU portfolio values.

These above-market costs are recovered for an indefinite time after customers leave the IOU to receive service from other providers, including CCAs. CCA customers may pay for above-market costs for the next 20 to 30 years. San José Clean Energy (SJCE) customers pay PG&E for their share of these costs for power previously purchased on their behalf and for the reduced-calculated value of these resources.

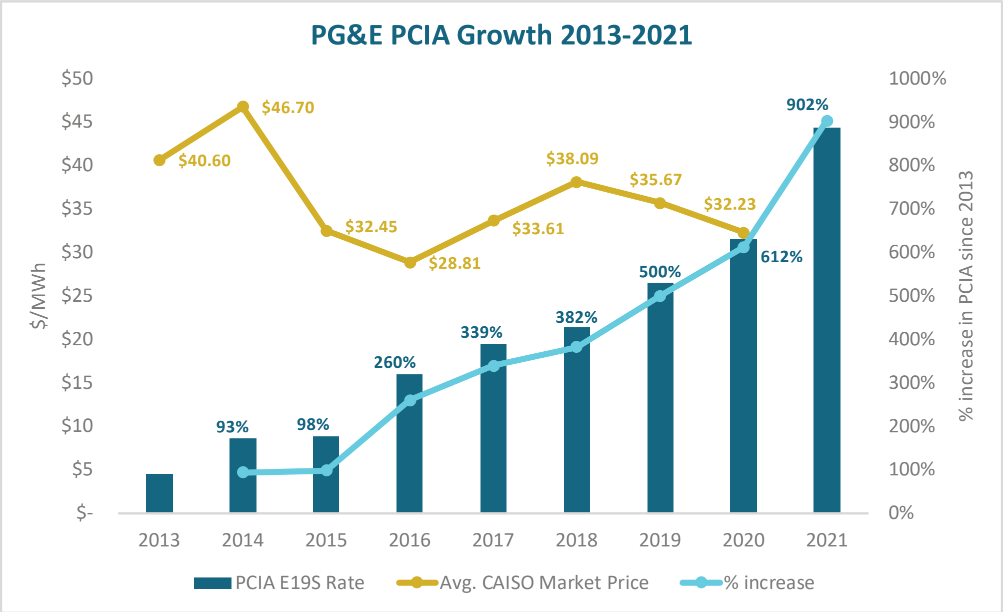
TOTAL PORTFOLIO COST − PORTFOLIO MARKET VALUE = INDIFFERENCE AMOUNT

IMPACT ON RATEPAYERS

The economic impact of the PCIA is of major concern as it has increased every year, imposing hundreds of millions of dollars in added costs on California ratepayers. The current regulatory system does not incentivize IOUs to maximize the value of their energy portfolios or keep operating costs down, **unfairly burdening all ratepayers**.

With Californians struggling to meet their monthly expenses, a situation that has been exacerbated by COVID-19, it is more important than ever that we look carefully for ways to scale back ratepayer costs, while simultaneously staying on track to achieve California's clean energy and reliability goals.

PG&E's average PCIA rates have risen 900% since 2013, from $1.70 per month to $18.60 per month for the average residential customer in San José.



SJCE customers paid $150 million in PCIA fees to PG&E in 2020.

SJCE rates are on average 35% lower without the PCIA.

MORE SHOULD BE DONE TO REDUCE THE PCIA

Under the current system, CCA customers pay the above-market costs for IOU-controlled resources, but do not benefit from the value of these resources. To address this inequity, the CPUC charged PCIA Working Group 3 with developing requirements to optimize IOU energy portfolios to more fairly distribute the costs and benefits across all ratepayers, including CCA customers. After nearly a year of work, the Working Group filed a consensus proposal with the CPUC in February 2020. The proposal would require utilities to proportionately sell energy resources attributable to the PCIA to third parties, including CCAs, to provide more equitable access to benefits in return for PCIA payments. The CPUC has yet to act on this proposal.

SJCE and other CCAs continue to advocate for a fair and open PCIA process that would:

- Reduce customer costs and increase rate stability
- Optimize IOU cost management and resource allocation
- Increase CCA and customer benefits from utility resources they pay for

For more information about the PCIA and its impact on all ratepayers, visit www.cal-cca.org/PCIA.

SB 612 (Portantino)

UTILITY ABOVE-MARKET COSTS

SAN JOSE CLEAN ENERGY
A Program of the City of San José

BACKGROUND

In the last decade over 12 million California ratepayers transitioned from investor-owned utilities (IOU) to Community Choice Aggregators (CCAs) for electric service. California's 23 CCAs are not-for-profit, locally-managed public agencies purchasing power on behalf of their residents and businesses in more than 180 cities and counties. They provide clean, reliable energy; operate under the direction of governing boards comprised of local elected officials that are accountable to the community; and comply with all State and Federal requirements governing power reliability and clean energy purchases.

CCAs have accelerated California's transition to clean energy by purchasing renewable energy in excess of the state's requirements (204% from 2011-2019).

UCLA Luskin Center for Innovation report: The Role of Community Choice Aggregators in Advancing Clean Energy Transitions

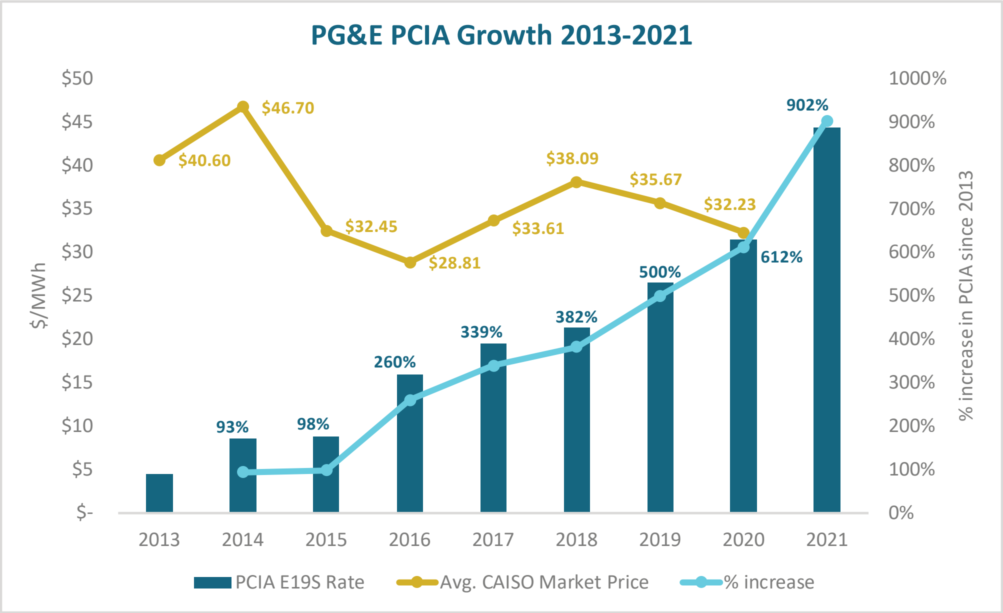
However, IOUs are not managing their portfolios to achieve the lowest costs possible, leading to higher rates for all ratepayers and inequitable treatment of CCA customers. This is especially problematic when the impacts of COVID-19 continue to exacerbate affordability for many Californians.

THE PROBLEM

IOUs charge customers the **Power Charge Indifference Adjustment (PCIA)** to collect above-market costs of their energy portfolios: legacy energy contracts, related resource products, and power plant operating costs. The PCIA is updated annually by the California Public Utilities Commission (CPUC). While all California ratepayers, including CCA customers, pay the PCIA, only IOU customers benefit from these IOU controlled products used to meet State clean energy and reliability requirements.

In addition, the current regulatory process does not require the IOUs to reduce their above-market portfolio costs, which have grown steadily over the last ten years. In 2021, IOUs are forecast to collect **$3.9 billion in above-market costs** for their energy portfolios from California ratepayers.

IOUs' lack of incentive to maximize the value of their energy resources, prepare for customer departure to CCAs or other energy service providers, and keep operating costs as low as possible combined with changing regulations has led to significant increases in the PCIA. **This puts an unfair burden on all ratepayers.**



This problem has been long recognized by regulators and stakeholders. It's time we do something to reduce excess IOU above-market costs and the failure to protect all California ratepayers.

SB 612

Goals:

✓ Balance customer costs with benefits received.

✓ Reduce IOU costs to lower charges for all ratepayers.

Provisions:

1. Provide IOU, CCA, and direct access customers equal right to buy legacy resource products that were procured on their behalf in proportion to their load share.

2. Require the CPUC to recognize the value of greenhouse gas (GHG)-free energy in assigning cost responsibility for above-market legacy resources, in the same way value is recognized for renewable energy and other products.

IOU Reasonableness Review Processes and Exit Fee Methodologies

A state by state review

Prepared for San Jose Clean Energy by EQ Research LLC and Keyes & Fox LLP

EQ Research

KEYES&FOX LLP

August 11, 2020

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Introduction

This memorandum provides a comparison of "exit fees" charged by various jurisdictions when customers depart investor-owned utility (IOU) service. We have compared the exit fee regime across several jurisdictions, and provided links to the relevant statutory or decision language.

This memorandum also compares the availability of "reasonableness reviews" of an IOU's energy procurement decisions across several jurisdictions, and how such reviews are brought forward.

For background, this memorandum provides a review of California law regarding the extent of oversight of IOU procurement decisions. Assembly Bill 57 (AB 57) modified the degree and methods by which parties may challenge or question IOU procurement decisions. A discussion of the oversight available prior to the passage of AB 57, and the oversight available now, is provided. In addition, this memorandum discusses the methods by which parties may raise and/or challenge IOU procurement decisions post-AB 57.

California IOU Procurement and AB 57

Prior to the enactment of AB 57 in 2002[1], contracts entered into by the IOUs in California were subject to the CPUC's review of the "reasonableness" of contract terms and prices. If found "unreasonable," contract costs were not available for cost recovery through rates.

Enacted to assist the IOUs in their ability to enter into long-term contracts, AB 57 inaugurated a process at the California Public Utilities Commission (CPUC or Commission) by which an IOU may obtain a determination that its proposed electricity procurement plans are deemed reasonable before the procurement expenses are incurred. The IOUs thus obtain certainty *before* procurement that procurement-related costs and expenses are recoverable from ratepayers, rather than receiving this determination *after*, as was the prior practice.

Pre-AB 57

California law requires that charges demanded or received by public utilities be just and reasonable, and assigns responsibility for ensuring the reasonableness of such charges to the CPUC.[2] According to the Bill Analysis prepared for the California Senate's Committee on Energy, Utilities and Communications when AB 57 was under consideration, "[t]his authority is a foundation of utility regulation, dating back to the establishment of the CPUC's predecessor, the Railroad Commission, in 1909. The power to review expenses that are recoverable from utility

[1] Assem. Bill 57 (2001-2002 Reg. Sess.) (AB 57).
[2] Cal. Pub. Util. Code, § 451.

ratepayers was judged necessary to protect the public from the exercise of monopoly powers."[3] Prior to the passage of AB 57, CPUC review of energy and capacity procurement contracts presented the possibility that recovery of certain contract expenses could be disallowed if the contract was judged to be an unreasonable deal. This could occur either because the price was determined to be an unjust price or the utility's conduct inappropriate.[4]

In 1996, the California electric market was restructured pursuant to AB 1890.[5] One of the features of the new structure was the creation of the California Power Exchange (Cal PX). The CPUC required IOUs to buy and sell from the Cal PX, which initially offered only day-ahead and hour-ahead markets, and IOUs were prohibited from entering into long-term bilateral contracts.[6] Purchases from the Cal PX were deemed "prudent per se" by the CPUC,[7] and thus were not subject to disallowance. In 2000, the CPUC began to authorize IOUs to purchase power through privately-negotiated bilateral contracts.

California experienced an energy crisis during the summer of 2000 and throughout 2001 caused by a variety of factors, including strong market forces affecting the price of energy and the state's reliance on short-term energy purchases. "The first five months of 2001 were characterized by soaring wholesale prices, energy emergencies, and a small number of rolling blackouts."[8] Beginning in February 2001 with the passage of AB 1X, California's Department of Water Resources was authorized to procure power under long-term contracts for sale to PG&E and SCE.[9] This authority to purchase was set to expire December 31, 2002.

As plans were made the following year for the IOUs to resume their own procurement, long-term power purchase contracts were viewed by some as an attractive way to stabilize the volatile and high prices to which the IOUs and their customers were subject. Proponents also argued that long-term agreements would allow for accurate forecasting of supply. The IOUs viewed after-the-fact review of reasonableness of these contracts by the CPUC as a deterrent to entering such contracts.[10] The IOUs felt the reasonableness review process could constrain contract prices or could be time-prohibitive and result in vacated contracts or less favorable terms due to the extended time required for such reviews.[11]

AB 57

Assembly Bill No. 57 of 2001[12] (AB 57) was intended to better facilitate the IOUs' continued pursuit of such long-term contracts. It was considered important to encourage long-term

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[3] Sen. Com. on Energy, Utilities and Communications, Analysis of Assem. Bill 57 (2001-2002 Reg. Sess.) June 10, 2002.
[4] *Id*.
[5] Assem. Bill No.1890, (1995-1996 Reg. Sess.).
[6] D.95-12-063.
[7] *Id*.; *Pac. Gas & Elec. v. FERC (In re Cal. Power Exch. Corp.)*,(2001) 245 F.3d 1110, 1115.
[8] *The California Electricity Crisis: Lessons for the Future*, James L. Sweeney, https://web.stanford.edu/~jsweeney/paper/Lessons%20for%20the%20Future.pdf.
[9] Assem. Bill No. 1 (2000-2001 1st Ex. Sess.).
[10] Sen. Com. on Energy, Utilities and Communications, Analysis of Assem. Bill 57 (2001-2002 Reg. Sess.) June 10, 2002.
[11] *Id*.
[12] Assem. Bill 57 (2001-2002 Reg. Sess.).

procurement to provide IOUs with some flexibility during periods of supply adequacy, "to not have to purchase large quantities of generated electricity on the sport market at what may be higher prices."[13] In addition, the proposal was intended to permit long-term contracts only pursuant to a plan that included competitive solicitations to reinforce the goal of eliciting reasonable, stable long-term energy prices.

Section 1 of AB 57 set out the Legislature's intention to "[d]irect the Public Utilities Commission … to review each electrical corporation's procurement plan in a manner that assures creation of a diversified procurement portfolio, assures just and reasonable electricity rates, provides certainty to the electrical corporation in order to enhance its financial stability and creditworthiness, and eliminates the need, with certain exceptions, for after-the-fact reasonableness reviews of an electrical corporation's prospective electricity procurement performed consistent with an approved procurement plan."[14]

AB 57 added Section 454.5 to the Public Utilities Code. This section provides that the commission will review and accept, modify, or reject each electrical corporation's procurement plan if the plan includes certain features.[15] One required feature is that the plan include "[u]pfront achievable standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to the execution of the bilateral contract for the transaction. The commission shall provide for expedited review and either approve or reject the individual contracts submitted by the electrical corporation to ensure compliance with its procurement plan."[16]

These approved procurement plans are intended by the legislation to enable the IOU to fulfill its obligation to serve its customers at "just and reasonable" rates, and to "[e]liminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses."[17] The statute does provide, however, that the Commission may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved.[18]

The legislative history of AB 57 details lawmakers' concerns with enabling and encouraging long-term contracting. It was thought that the elimination of the reasonableness review, provided certain conditions were met, would ensure that contract terms could be locked in to help lower the overall cost of such contracting.[19] The limited oversight required was thought to encourage generators to engage in long-term contracting.[20] Lawmakers also considered that the bill required reporting in significant detail by electrical corporations to allow the CPUC to ascertain long-term pricing levels and supply levels.[21]

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[13] Assem. Com. on Utilities and Commerce, Analysis of Assem. Bill 57 (2001-2002 Reg. Sess.) April 24, 2001.
[14] AB 57, § 1(c).
[15] Pub. Util. Code, § 454.5(c).
[16] Pub. Util. Code, § 454.5(b)(3).
[17] Pub. Util. Code, § 454.5(d)(2).
[18] *Ibid*.
[19] Assem. Com. on Utilities and Commerce, Analysis of Assem. Bill 57 (2001-2002 Reg. Sess.) April 26, 2001, at 4.
[20] *Ibid*.
[21] *Id*. at 3.

The ability of consumers to protest against particular contracts, or particular conduct, was considered. When the bill was reviewed by the Senate Energy, Utilities and Communications Committee in July of 2001, one of the comments raised was that "[p]ower costs resulting from affiliate abuse, self-dealing, quid pro quo arrangements with non-affiliates, fraud or any other inappropriate activity could be passed through to ratepayers without exception. This bill places all the risk on ratepayers, but doesn't give ratepayers any mechanism to manage that risk."[22]

Reasonableness Challenges Post-AB 57

Following AB 57, the opportunities for oversight of particular contracts or decisions made with respect to those contracts are limited. However, interested parties can contest an IOU's procurement decisions by participating in the IOU's advice letter process when the particular contract or decision is submitted to the Commission for approval, and by questioning particular contract administration actions through the IOU's Energy Resource Recovery Account (ERRA) Compliance Application and review process. Interested parties may also petition to modify the procurement plan under which a particular procurement is proposed to be made.

In general, if the question involves an action the IOU is planning to take, the advice letter process may be appropriate. If, however, the question involves action the IOU should have taken, but did not pursue, the only available option is the ERRA Compliance Application and review process.

Bundled Procurement Plans and Other Regulatory Oversight Mechanisms

The Commission reviews and adopts each of the IOUs' proposed "Bundled Procurement Plans" (BPPs) pursuant to Public Utilities Code Section 454.5, and requires modifications if necessary. Originally subject to review every two years through the Commission's Long Term Procurement Planning proceeding, BPPs are adopted through the Commission's "umbrella" planning proceeding for the Integrated Resource Proceeding, R.16-02-007. Modifications to BPPs are now approved only via advice letters filed with the Energy Division under authority granted via Commission resolution.[23] On May 11, 202, PG&E filed a BPP that will remain in effect until December 31, 2024, or until it is superseded by a subsequent Commission-approved BPP.[24]

Certain policy directives govern the oversight of procurement activities performed by the IOU pursuant to its BPP. According to the Commission, the primary requirements are the use of an Independent Evaluator (IE), oversight of a Procurement Review Group (PRG) and Cost Allocation Mechanism (CAM) group, Commission Energy Division oversight, and employee standards of conduct.[25]

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[22] Sen. Com. on Energy, Utilities and Communications, Analysis of Assem. Bill 57 (2001-2002 Reg. Sess.) July 10, 2001.

[23] See, e.g., Resolution E-5075, Request by Southern California Edison to Extend the Procurement Authority of Its 2014 Conformed Bundled Procurement Plan, June 25, 2020.

[24] Pacific Gas & Electric Company, Bundled Procurement Plan, May 11, 2020, https://www.pge.com/pge_global/common/pdfs/about-pge/company-information/regulation/BundledProcurementPlan.pdf

[25] California Public Utilities Commission AB 57, AB 380 and SB 1078 Procurement Policy Manual, June 2010 (CPUC Procurement Manual), available at

The IE's role is to advise an IOU on the consistency of its solicitation activities with CPUC rules and procedures and its Commission-approved procurement authority. An IE is under contract to the IOU and is retained for all competitive solicitations that involve affiliate transactions, or utility-owned or Purchase and Sale Agreement bids, and for all competitive Requests for Proposals (RFPs) seeking products with terms of two years or greater in duration regardless of bidders.[26] IEs are also retained for IOUs' utility-scale solicitations under the Renewables Portfolio Standard.

In response to the need for expedited review of utility procurement contracts following the energy crisis, the Commission in 2002 also required the IOUs to establish "Procurement Review Groups."[27] The PRGs are made up of interested parties who are not "market participants," including CPUC Energy Division staff and the Office of Ratepayer Advocates (now Public Advocates Office of California) staff. The PRG is organized "to review and make recommendations concerning proposed contracts and procurement processes on an expedited basis."[28] The purpose of the PRGs is to review and assess the details of each utility's overall interim procurement strategy and specific proposed contracts and processes prior to an IOU's submission of filings to the Commission.[29]

In addition to the BPP, load-serving entities (LSEs) that are subject to Commission jurisdiction are required, pursuant to Section 399.13 (a)(1) of the Public Utilities Code, to annually prepare a "renewable energy procurement plan" to satisfy its obligations under the renewable portfolio standard ("RPS"). The plans include a framework for utilities to sell excess RPS products. The plans filed are subject to a comment period, and reply comments may also be filed. The Commission then reviews the plans, and may accept them as filed or require modifications.[30] Each LSE must file a final RPS procurement plan that complies with the Commission's decision within 30 days of the decision, or risk enforcement action.[31]

Finally, when procuring or potentially procuring Cost Allocation Mechanism (CAM) resources pursuant to Commission Decisions ("D.") 06-07-029 and 07-09-044, or Combined Heat and Power resources under D.10-12-035, where the costs are allocated to all "benefitting customers" (e.g., bundled, direct access, and community choice aggregation (CCA) customers), IOUs utilize an advisory CAM group consistent with the proposal adopted in D.07-12-052, Attachment D. The IOU evaluates nominated organizations for participation in the CAM group, and then the IOU may recommend the organization(s) and individual(s) to ED for approval. PRG members are automatically part of the CAM group. Organizations and/or individuals on the PRG and/or CAM group must be non-market participants and are required to execute a Non-Disclosure Agreement.

https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10906 at 5-2.

[26] *Id*.; D.07-12-052 at 140.

[27] D.02-08-071 at 25.

[28] D.02-08071 at 25.

[29] CPUC Procurement Manual at 5-6.

[30] See D.19-12-042.

[31] *Id*. at 11.

Potential Paths for Intervention

Interested parties who are not members of the PRG or CAM group may also have concerns regarding IOU procurement decisions or processes. In addition to the groups mentioned above, interested parties can participate in review of IOU procurement activities via the following methods: 1) commenting on an IOU's RPS Procurement Plan; 2) questioning an IOU's activities by commenting on its ERRA Compliance Application; 3) protesting or responding to an IOU's advice letter by which individual contracts or revisions to filed procurement plans are submitted for approval; and/or 4) petitioning to modify an IOU's BPP.

RPS Procurement Plans

As noted above, LSEs subject to Commission jurisdiction are required to prepare annual RPS Procurement Plans that include a framework for PG&E to sell excess RPS products. The plans are subject to revision via a comment period, meaning one path available to interested parties to revise components of those plans—including the sales framework—is to intervene in the recurring RPS proceedings and comment on the draft RPS Procurement Plans.

ERRA Compliance Applications

AB 57 provides for the Commission to establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and that contract disputes which may arise are reasonably resolved.[32] That process is each IOU's annual application for compliance review of its utility owned generation operations, portfolio allocation balancing account entries, energy resource recovery account entries, and contract administration, et al., known as the IOU's "ERRA Compliance Application."

The issues typically determined in an ERRA Compliance Application include whether the IOU "prudently administered and managed [its utility-owned generation facilities and contracts] in compliance with all applicable rules, regulations and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4)." If not, the Commission also considers what adjustments, if any, should be made to account for imprudently managed or administered resources."[33] In addition, an ERRA Compliance Application addresses whether the IOU achieved "least cost dispatch of its energy resources and economically-triggered demand response programs pursuant to SOC 4."[34]

Standard of Conduct 4 requires: "The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner." The "reasonable manager standard" applies to review of that administration. "[The IOUs] are held to a standard of reasonableness based upon the facts that are known or should have been known at the time. The act of the utility should comport with what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision and act."[35]

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32 Pub. Util. Code, § 454.5(d)(2).
33 E.g., *Assigned Commissioner's Scoping Memo and Ruling*, A. 20-02-009, June 19, 2020 at 2-3.
34 *Id*. at 3.
35 D.14-05-023 at 15 (citing D.90-09-088, 137 CPUC 2d 488, 499). Public Utilities Code Section 454.5(h) also states that AB 57 does not alter, modify or amend the Commission's authority to investigate and impose penalties on the IOU for "alleged fraudulent activities," or to disallow costs "incurred as a result of gross incompetence, fraud, abuse, or similar grounds."

With respect to contract administration issues, the conduct required for a violation of SOC 4 has proved difficult to demonstrate. ERRA Compliance proceedings last less than one year. In addition, these proceedings frequently devolve into battles over discovery, as parties simply attempt to obtain evidence of IOU conduct or understand circumstances surrounding procurement.

Advice Letters

As discussed above, if an IOU seeks to enter into a new contract or materially revise an existing contract, it must go through an advice letter process. The IOU must seek Commission approval that the contract complies with its filed strategies and procurement plans. Per the Commission's General Order 96-B, an advice letter is subject to disposition by the Commission's reviewing Industry Division whenever such disposition would be "ministerial,"[36] which in general means it can be disposed by determining the action proposed is or is not within the scope of what has already been authorized by statutes or Commission orders.[37]

Thus, interested parties could participate in the process at this stage by submitting a protest or response to the advice letter under General Order 96-B with respect to individual contracts or revisions. This may yield slightly better results than challenging the transactions at the ERRA Compliance stage, since the perception is that protesting parties may enjoy more leverage prior to the contract or revision being entered than they will once the contract is executed.

However, the protest period in an advice letter only lasts 20 days,[38] and the grounds for protest are limited.[39] For example, a protest to an advice letter is *not* available if the relief requested "would require relitigating a prior order of the Commission."[40] In addition, the advice letter format does not provide a formal or realistic opportunity to conduct discovery, and, indeed, limits the ability to request additional information to the relevant Commission Division.[41] Finally, the advice letter process does not include an opportunity for interested parties to test an IOU's factual assertions via cross examination or testimony. As a practical matter, the IOUs submit hundreds of advice letters each year, and tracking such advice letters would be a resource-intensive endeavor.

Petition for Modification of BPP

As noted, the Commission reviews and adopts proposed modifications to BPPs via advice letters filed with the Energy Division. General Order 96-B provides in Rule 8.2 that "any person may petition for modification of a resolution and respond to such petition to the same extent and under the same procedures" as provided by Rule 16.4 of the Commission's Rules of Practice and Procedure.[42] Under that rule, except as specifically provided, the petition for modification must be filed within one year of the effective date of the decision.[43]

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[36] California Public Utilities Commission, General Order 96-B, Rule 7.6.
[37] *Id*. However, "whenever such determination requires more than ministerial action, the disposition of the advice letter on the merits will be by Commission resolution. . . ." *Id.*
[38] California Public Utilities Commission, General Order 96-B at 12.
[39] *Id*., at 13.
[40] *Ibid*.
[41] *Id*. at 14.
[42] California Public Utilities Commission, General Order 96-B, Rule 8.2.
[43] CPUC Rules of Practice and Procedure, Rule 16.4(d).

A timely filed petition to modify a resolution approving an advice letter request could potentially result in a stay of a particular order or proposed action. However, unless the Commission orders otherwise, the filing of a petition for modification *does not* stay or excuse compliance with the order of the decision proposed to be modified.[44] Regardless, a petition for modification could be filed to revise a utility's BPP.

Conclusion

In practice, those who seek to challenge IOU contract administration and resource management face an uphill battle. However, challenges are possible. If a party feels the standard against which IOU procurement activities are judged should be revised, the post AB-57 framework requires that party to seek modification of those standards through comment on an IOU's RPS plan or seek revision to its BPP.

If a party wishes to challenge specific IOU procurement activity (or inactivity, in situations where a party feels the IOU should have done more to optimize its portfolio), the most effective approach to reviewing IOU procurement is to participate actively in both the advice letter and ERRA Compliance processes. While such an approach is certain to be resource-intensive for one party, or a small group of parties, leveraging the resources of numerous parties to develop (or contract for) a service to flag key advice letter filings, and issue template-based protests to such filings, could allow for a reasonable path to participation in both advice letter filings and the ERRA Compliance proceedings.

[44] *Id*., Rule 16.4(h).

Exit Fees and Retail Choice by State

Though Illinois, Massachusetts, New York, New Jersey, Ohio, and Rhode Island have CCAs, California is the only state that has an exit fee on these customers.[45] Below are descriptions of retail choice or CCA customer exit fee policies or proposed legislation in three non-retail choice states (New Mexico, Colorado and Montana) and in retail choice states:

See Appendix A. Comparative Matrix on Exit Fees by State.

California: Customers in California have limited retail choice through CCAs or through Direct Access Electric Service Providers (ESPs). Customers of CCAs and ESPs pay an exit fee known as the Power Charge Indifference Adjustment (PCIA).[46]

Colorado: Customers in Colorado do not have retail choice, but an exit fee methodology has been developed for smaller cooperatives such as United Power, Inc. (United Power), which serves approximately 80,000 bundled customers to exit from generation and transmission cooperatives like Tri-State Generation and Transmission Association, Inc. (Tri-State). The approved Exit Charge Calculation methodology is a Member's pro rata share of Tri-State's indebtedness (based on Tri-State's Security Exchange Commission filings) minus the Member's patronage capital. Under the methodology, the exit charge for United Power would be calculated as follows if using a PPA obligation: $354,678,000 (debt) -$119,903,000 (Patronage Capital) = $234,775,000 Exit Charge.[47]

Connecticut: All customers in Connecticut have access to retail choice but no CCAs exist. Exit fees existed through 2004 with exemptions for self-generation facilities that serve up to four residential units and those installed in conjunction with the expansion of industrial plants.[48] The competition transition assessment (CTA) was in place through 2004 to collect for stranded costs after netting any proceeds from above book value sales and sales of other company property.[49]

[45]Power Mag "As Community Choice Aggregation Expands, the Battle Over "Exit Fees" Intensifies" April 30, 2017 https://www.powermag.com/as-community-choice-aggregation-expands-the-battle-over-exit-fees-intensifies/

[46] *See* MCE. White Paper on the Evolution of Non–Bypassable Charges on Community Choice Aggregation. 2018. https://cleanpowerexchange.org/wp-content/uploads/2018/02/MCE-NonBypass-Charges_Whitepaper_2017-Update-2.1.18.pdf; California Public Utilities Commission D.18-10-019.

[47] Colorado Proceeding 19F-0620E. La Plata Electric Association v. Tri-State Generation. Recommended Decision. July 10, 2020. https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=929187

[48] Public Act 98-28, An Act Concerning Electric Restructuring discussed in Docket #98-07-01 and enacted through House Bill 5005 in 1998. https://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm

[49] Florida Public Service Commission September. 2000. P. 28 Key Aspects of Electric Restructuring Supplemental Volume: The State Summaries Division of Policy and Intergovernmental Liaison http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/keysupp.pdf

Delaware: All customers in Delaware have retail choice but there are no CCAs. The "Transition Period" for all customers ended on March 31, 2005,[50] and with it, the Competitive Transition Charge (CTC).[51] Utilities were permitted to recover all reasonably incurred, non-mitigable stranded and transition costs. The costs recovered were to be allocated in a manner that avoided, to the extent possible, inter-class or intra-class cross-subsidization. The CTC was collected during the Transition Period (April 1, 2000 to March 31, 2005). Delmarva Power and Light recovered $16 million over three years through a non-residential wire surcharge per a decision issued by the Commission on August 31, 1999.[52]

Illinois: Retail choice and CCAs are available to customers of all types in Illinois. A Competitive Transition Charge (CTC) was calculated based on lost revenues variable by the price of power and the "mandatory transition period" ended in 2005 along with the CTC.[53] CCAs became active in 2009[54] from legislation introduced in 1998[55] and CCA customers do not pay an exit fee to the incumbent utility.

Maine: Retail choice is available to both residential and non-residential customers in Maine but CCAs are not active. Law permitted electric utilities to collect on stranded costs more liberally until 1995 with more limits on the ability to collect on stranded costs between April 1, 1995 and March 1, 2000.[56] Formerly, utilities had a reasonable opportunity to recover legitimate, verifiable and unmitigable costs that are otherwise unrecoverable as a result of retail competition in the electric industry.[57] Stranded costs were re-set every two to three years.[58] The Public Utilities Commission set an amount of recoverable stranded costs after calculating the net aggregate value of all divested assets that had proceeds exceeding book costs against the aggregate value of all other stranded electricity generation assets while ensuring that cost-shifting would be prevented to the extent possible.[59]

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[50]Electric Utility Restructuring Act of 1999. Delaware Code Chapter 10 and enacted through House Bill 10. https://delcode.delaware.gov/sessionlaws/ga140/chp010.shtml

[51] In Delaware, the CTC was formerly included as §1007 TITLE 26 Public Utilities CHAPTER 10. Electric Utility Restructuring and is no longer part of the law. HB 10 (1999) established the CTC.

[52] Delaware Public Service Commission Docket 99-163, Order, August 31, 1999, page 5

[53] Illinois, P.A. 90-561 (1997) was amended by Senate Bill 3202 (2007)

[54] U.S. Environmental Protection Agency. Green Power Partnership. Community Choice Aggregation. https://www.epa.gov/greenpower/community-choice-aggregation

[55] Illinois House Bill 362 (1997-1998) https://www.ilga.gov/legislation/Legisnet90/HBgroups/HB/900HB0362enr.html

[56] Maine Legislature's Revised Statutes Title 35-A: Public Utilities Part 3: Electric Power Chapter 32: Electric Industry Restructuring https://legislature.maine.gov/statutes/35-A/title35-Asec3208.html

[57] Maine, LD 1804 (1997)

[58] Concentric Energy Advisors, Inc. Retail Competition In Electricity What Have We Learned In 20 Years? July 23, 2019. P. 57 https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf

[59] Abel and Shimabukuro. RL30405: State-by-State Comparison of Selected Electricity Restructuring Provisions. January 13, 2000. https://digital.library.unt.edu/ark:/67531/metacrs1173/m1/1/high_res_d/RL30405_2000Jan13.html

Maryland: Retail choice is available to both residential and non-residential customers in Maryland but CCAs are not active. The 1999 Act[60] permitted utilities to recover two types of "prudently incurred" and "verifiable" net transition costs through a CTC (1) stranded costs of generation assets that the utility would have traditionally recovered through rate-of-return regulation, and (2) costs associated with the restructuring process. The Commission also mitigated for cost-shifting to the extent possible.[61]

The Maryland Public Services Commission describes the calculation of stranded costs as follows:

"Stranded costs are measured by the amount that utilities' generation assets in a regulated regime exceed their value in a competitive market. Stranded costs are derived by taking the difference between the asset's "regulated" value (which is based on its depreciated book value) and its fair market value (which is its forward-looking value under a competitive market structure or its sale price). At the time Maryland was evaluating whether to deregulate retail generation, the principal methods used to measure stranded costs were administrative determinations (i.e., discounted cash flow or "DCF" calculations), asset sales (or comparisons to sales), and capital market valuations. Id. at 13-15. The 1999 Act required the Commission to consider six factors (1) book value and fair market value, (2) auctions and sales of comparable assets, (3) appraisals, (4) the revenue the company would receive under rate-of return regulation, (5) the revenue the company would receive in a restructured electricity supply market, and (6) computer simulations provided to the Commission, in addition to other evidence of value."[62]

The Delmarva settlements in 1999 identified $16 million of transition costs on a Maryland-retail basis for the Utility, with half of the costs being attributed to commercial customers and half to residential customers but ultimately, residential customers were exempt.[63]

For Baltimore General Electric (BGE), the settlement was more complicated. The BGE settlement was for BGE to recover $528 million (after-tax, present values as of January 1, 2000). Residential customers' share was $193.8 million, about one-third of the settlement amount. Residential customers paid a CTC of $0.00800 – $0.00264/kWh for six years, beginning July 2000. Transition costs were set as a function of other negotiated provisions, e.g.,

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[60] Maryland Senate Bill 300, as amended (Mar. 25, 1999)

[61] Maryland Public Service Commission. Analysis of Retail Restructuring In Maryland: Electricity Rates, Stranded Costs From Generation Asset Divestiture, and Decommissioning Funding. P. 13. January 16, 2008. https://www.psc.state.md.us/wp-content/uploads/Kaye-Scholer-Stranded-Costs-Analysis.pdf

[62] Maryland Public Service Commission. Analysis of Retail Restructuring In Maryland: Electricity Rates, Stranded Costs From Generation Asset Divestiture, and Decommissioning Funding. P. 23. January 16, 2008. https://www.psc.state.md.us/wp-content/uploads/Kaye-Scholer-Stranded-Costs-Analysis.pdf

[63] Maryland Public Service Commission. Analysis of Retail Restructuring In Maryland: Electricity Rates, Stranded Costs From Generation Asset Divestiture, and Decommissioning Funding. P. 15. January 16, 2008. https://www.psc.state.md.us/wp-content/uploads/Kaye-Scholer-Stranded-Costs-Analysis.pdf

the rate reduction measures and duration of rate freezes, shopping credits, acceleration of retail choice, and other negotiated provisions.[64]

Massachusetts: Retail choice and CCAs are available to residential and non-residential customers in Massachusetts. There is no specific exit fee for retail choice or CCA customers in Massachusetts. However, there were charges approved when retail choice was approved in 1997.[65] The Department of Public Utilities (DPU) conducts annual reviews regarding the transition fees.[66] "Transition Costs" eligible for recovery through the "Transmission Charge" that remain after incurred prior to January 1, 1996, are subject to determination by DPU and can include the sale of capacity, energy, Ancillary Services, reserves, and emission allowances along with residual value, assets both real and intangible, and debt obligation.[67] According to a 2018 report to the legislature regarding self-generation, utilities "recovered nearly all of their transition costs through 2018 (last reporting date available)[68] since 2017"[69]. Eversource[70] still charges a small fee (see Summary 2020 rates) and National Grid[71] is now crediting back and no longer charging customers the transition charge.

Michigan: Electricity choice was available to non-residential customers in Michigan who signed up between 2000 and 2008 but the 10% cap has been reached and CCAs are not legal. Approximately 5,425 commercial and industrial (C&I) customers participated in the program as of 2009. The Michigan Commission initiated retail competition in June of 1997, issuing its initial order in Case U-11290. Utilities include Consumers Energy, DTE Electric, UPPCo, UMERC and Cloverland, which are fully subscribed at 10% participation.[72]

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[64] Maryland Public Service Commission. Analysis of Retail Restructuring In Maryland: Electricity Rates, Stranded Costs From Generation Asset Divestiture, and Decommissioning Funding. P. 52. January 16, 2008. https://www.psc.state.md.us/wp-content/uploads/Kaye-Scholer-Stranded-Costs-Analysis.pdf

[65]See statute on transition fees approved with deregulation in 1997: Part I: Administration Of The Government, Title xxii Corporations, Chapter 164, Section1 1997 https://malegislature.gov/laws/generallaws/parti/titlexxii/chapter164/section1

[66] Department of Public Utilities Annual Report 2019 Submitted to the General Court of the Commonwealth of Massachusetts https://www.mass.gov/doc/dpu-annual-report-2019/download

[67] Rules Governing the Restructuring of the Electric Industry Code of Massachusetts Regulations (CMR) 220 Section 11.03(2)(d) and (e): Department of Public Utilities https://www.mass.gov/files/220_cmr_11.00_6_17_16_0.pdf

[68] 2019 Annual Report Concerning Self-Generation July 1, 2019 The Commonwealth of Massachusetts Department of Public Utilities pursuant to Section 193 of the Electric Restructuring Act https://malegislature.gov/Reports/8222/OSGF%202018%20Report_7.1.19.pdf

[69] 2017 Annual Report Concerning Self-Generation June 19, 2018 The Commonwealth of Massachusetts Department of Public Utilities pursuant to Section 193 of the Electric Restructuring Act https://malegislature.gov/Bills/190/SD2692.pdf

[70] 2020 Eversource's Summary of Eastern Massachusetts Electric Rates Rates Effective: July 1, 2020 https://www.eversource.com/content/docs/default-source/rates-tariffs/ema-greater-boston-rates.pdf?sfvrsn=c27ef362_38

[71] National Grid Summary of Rates Massachusetts 2019 https://www.nationalgridus.com/media/pdfs/billing-payments/electric-rates/ma/cm4394_maweb.pdf

[72] Department of Licensing & Regulatory Affairs Michigan Public Service Commission. Readying Michigan to Make Good Energy Decisions. October 15, 2013 :https://www.michigan.gov/documents/energy/electric_choice_437312_7.pdf

A utility can apply to the Public Service Commission (PSC) to recover its qualified costs via securitization bonds.[73] The PSC will issue a financing order if it finds that the net present value of the revenues to be collected under the financing order is less than via conventional financing methods.[74] Bonds will be paid back via a nonbypassable charge (securitization charge).[75]
For Consumers and DTE Electric, stranded assets were determined as nuclear plant assets, regulatory assets, and Qualifying Facilities.[76] An annual true-up mechanism is used.

Montana: Montana was a retail choice state from 1997 until 2007 for large industrial customers but there were never CCAs. In January 1997, the Montana Power Company (MPC) and a number of Montana's large customers brought forward a legislative proposal, Senate Bill No. 390, to deregulate retail electricity supply. The legislation passed 36-14 in the Senate and 78-21 in the House of Representatives.[77] Initially, Montana's main IOU, Montana Power Company (MPC), sold off all its generation, so the utility had to purchase power in wholesale power markets, including RTO-operated markets.[78] Default supply service was meant to provide consumers with a stopgap energy supply source until they moved to a competitive supplier. After deregulation, MPC in 2002 sold its electric transmission and distribution utility operations to NorthWestern.[79] Montana developed a Competitive Transition Charge (CTC) not as an exit fee but as a charge for distribution regardless of a customer's choice of supplier and in 2020 the CTC was $0.003317 per kWh.[80] Montana was the only retail choice state not entirely in an RTO during that time. If a customer received default supply service, they had to have a fully-paid account with the default supplier in order to exit the service in favor of a competitive supplier.[81]

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[73] Michigan Senate Bill 937 (2000) Section 10a. (8) https://www.legislature.mi.gov/documents/1999-2000/publicact/pdf/2000-PA-0141.pdf
[74] Michigan Public Act (P.A.) 141 and P.A. 142 in 2000 P.A. 286 in 2008
[75] Florida Public Service Commission September. 2000. P. 72 Key Aspects of Electric Restructuring Supplemental Volume: The State Summaries Division of Policy and Intergovernmental Liaison http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/keysupp.pdf
[76] Michigan Public Service Commission. Customer Choice Program in Michigan. 2010. https://pubs.naruc.org/pub.cfm?id=5378EB0D-2354-D714-51B7-01FAF4A3AF6E
[77]Understanding Energy in Montana 2018 Montana Department of Environmental Quality Report for The Energy and Telecommunications Interim Committee https://leg.mt.gov/content/Committees/Interim/2017-2018/Energy-and-Telecommunications/Understanding%20Energy%202018.pdf
[78] American Public Power Association. p. 5 Retail Electric Rates in Deregulated and Regulated States 2018 Update. April 2019. https://www.publicpower.org/system/files/documents/2019%20%282018%20data%29%20Retail%20Electric%20Rates_final.pdf
[79] Montana Legislature Overview of NorthWestern Energy Customer Billing for the Committee on Energy and Telecommunications (2013-2014) https://leg.mt.gov/content/Committees/Interim/2013-2014/Energy-and-Telecommunications/Committee-Topics/NWEOverview.pdf
[80] NorthWestern Energy Montana Residential CTC-QF Rate Effective August 1, 2020 http://rates.northwesternenergy.com/residentialelectricrates.aspx
[81] Florida Public Service Commission September. 2000. P. 83. Key Aspects of Electric Restructuring Supplemental Volume: The State Summaries Division of Policy and Intergovernmental Liaison http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/keysupp.pdf

Retail choice did not develop for small residential and commercial customers. The "Electric Utility Industry Generation Reintegration Act" by the 2007 Legislature ended retail choice and initiated a transition of Montana Power Company into a vertically integrated utility, owning both generation assets and transmission and distribution assets.[82]

Nevada: Residential customers do not have retail choice but certain large industrial customers have the option to opt-out of electric service from Nevada Power Company or Sierra Pacific Power Company (both doing business as NV Energy; the only IOUs serving the state). CCAs are not authorized in Nevada. It should be noted that Nevada explored retail choice most recently from 2016-2018; but it is not an adopted policy of the state.[83]

Since 2001, Nevada law (NRS 704B[84]) has allowed the PUC of Nevada (PUCN) to approve large electricity consumers to leave (or "exit") NV Energy's system and become a delivery customer only and purchase their electricity from alternative providers. To date, the process has required that the PUCN determine an exit fee. Generally, for customers to be eligible to exit the system, the customer must have an average annual load of 1 MW or more in the utility's service territory. The customer files an application (called the "Exit Application") to purchase energy, capacity, and/or ancillary services from a provider of new electric resources. The PUCN is authorized to charge an exit or impact fee; originally there was no set formula prescribed in regulations, although the PUCN did follow a model it developed (each individual order approving an exit application details how the impact fees imposed are calculated.) Typically brand new customers who had not taken service prior to filing their applications were not charged an impact fee (since they had never been a customer of NV Energy) and others were charged based on the circumstances of their service and application. In addition, exited companies typically had some ongoing nonbypassable fees (i.e. economic development fee) and in some cases, there were certain components of the exit fee that could not be incorporated at the time of calculation and would be charged later after a general rate case, such as decommissioning and remediation of certain coal-fired generating plants. Eighteen companies[85] have been *approved* to "exit" NV Energy's system and purchase energy, capacity and/or ancillary services from an alternative provider (not all have exercised their right to exit based on their approvals since recently NV Energy has been authorized to offer a variety of alternative tariffs that the companies may ultimately take advantage of instead of going with an alternative supplier.)

- Barrick (2004, built generation)
- Newmont (2004, built generation)
- Switch

[82] Understanding Energy in Montana 2018 Montana Department of Environmental Quality Report for The Energy and Telecommunications Interim Committee https://leg.mt.gov/content/Committees/Interim/2017-2018/Energy-and-Telecommunications/Understanding%20Energy%202018.pdf
[83] *See* PUC of Nevada website for more information, including a final report on retail choice in Nevada: http://energy.nv.gov/Programs/TaskForces/2017/EnergyChoice/
[84] NRS Chapter 704B, https://www.leg.state.nv.us/nrs/nrs-704b.html
[85] *See* Legislative presentation from May 23, 2109: 2019https://www.leg.state.nv.us/Session/80th2019/Exhibits/Senate/GRI/SGRI1295C.pdf

- MGM
- Wynn
- Ceasar's Casino
- Peppermill Reno
- SLS Las Vegas
- MSG Las Vegas
- Boyd Gaming
- Raiders' Stadium (ultimately withdrew its application; stayed a bundled NV Energy customer)
- Fulcrum Sierra BioFuels
- Station Casinos
- Georgia-Pacific Gypsum
- South Point Casino
- Air Liquide
- Cosmopolitan
- The Drew

In 2019, the state enacted Senate Bill 547[86] reforming the exit approval process, specifically requiring the PUCN to consider additional criteria in its evaluation of a customer's exit application, capping the aggregate amount electricity exiting businesses may purchase from sources other than NV Energy and establishing a formulaic methodology for the calculation of transition period charges/credits (i.e. the impact or exit fee). There is an open rulemaking underway to implement the changes.[87] The May 2020 proposed rules lay out how the utility is to calculate fees.[88] There will be nonbypassable monthly charges on these customers, and as proposed will include the customer's share of ongoing "out-of the money portion" of the costs of long-term renewable energy contracts (this fee is described in detail in the proposed regulations), other public policy programs that are required (the PUCN may determine this), and decommissioning and remediation costs of energy generation resource used to provide service (prior to exiting) to the eligible customer. In addition, exiting customers are to pay its load share of any regulatory asset or receive a credit equal to its load share of any regulatory liability (if applicable). Exiting customers are also required to make a one-time recapture payment of all incentive payments or credits received from a utility in the five years preceding the date the customer applies to exit the system for EE measures installed, BTM solar and storage funded by NV Energy programs (authorized by the PUCN). (Since SB 547 was enacted, no entity has filed to exit the system, likely since they are waiting for the regulations to be promulgated.)

New Hampshire: Retail choice is available to both residential and non-residential customers but CCAs do not operate in New Hampshire. The Stranded Cost Recovery Charge (SCRC)

[86] Senate Bill 547 https://www.leg.state.nv.us/App/NELIS/REL/80th2019/Bill/7057/Overview
[87] The existing rules are found in NAC-704B at https://www.leg.state.nv.us/nac/nac-704b.html; See docket 19-06029 for the rulemaking: http://pucweb1.state.nv.us/puc2/Dktinfo.aspx?Util=Electric
[88] *See* the May 27, 2020 Proposed Rules, which have been submitted to the Legislative Counsel Bureau for review: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2019-6/45096.pdf

recovery mechanism was established pursuant to the Agreement to Settle PSNH (now known as Eversource) Restructuring in Docket No. DE 99-099 (Restructuring Agreement). The residential SCRC was 1.862 cents per kWh for residential customers effective April 1, 2018.[89] The New Hampshire PUC follows these principles to evaluate stranded costs attributable to retail choice[90]:

- Stranded costs should be determined on a net basis;
    - Legislation from 1996[91] defined "Stranded costs" as *"costs, liabilities, and investments, such as uneconomic assets, that electric utilities would reasonably expect to recover if the existing regulatory structure with retail rates for the bundled provision of electric service continued and that will not be recovered as a result of restructured industry regulation that allows retail choice of electricity suppliers, unless a specific mechanism for such cost recovery is provided."*
    - *"Stranded costs should be determined on a net basis, should be verifiable, should not include transmission and distribution assets, and should be reconciled to actual electricity market conditions from time to time. Any recovery of stranded costs should be through a nonbypassable, nondiscriminatory, appropriately structured charge that is fair to all customer classes, lawful, constitutional, limited in duration, consistent with the promotion of fully competitive markets and consistent with these principles. Entry and exit fees are not preferred recovery mechanisms. Charges to recover stranded costs should only apply to customers within a utility's retail service territory, except for such costs that have resulted from the provision of wholesale power to another utility. The charges should not apply to wheeling-through transactions."*
- Utilities have an obligation to take all reasonable measures to mitigate stranded costs;
- Any recovery of stranded costs should be through a nonbypassable, nondiscriminatory charge;
- Entry and exit fees are not preferred recovery mechanisms; and
- Charges to recover stranded costs should apply only to customers within a utility's retail service territory, except for such costs that have resulted from the provision of wholesale power to another utility.

New Jersey: New Jersey residential and non-residential retail choice exists along with CCAs. Retail choice began on November 14, 1999.[92] In New Jersey, default electric service is known as Basic Generation Service (BGS). BGS is also the Provider of Last Resort. A utility may recover stranded costs through a Market Transition Charge (MTC) collected as a limited-

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[89] New Hampshire Public Utilities Commission Petition for Adjustment to Stranded Cost Recovery Charge Order Approving Stranded Cost Recovery Charge Order No. 26,116 (March 29, 2018). https://www.puc.nh.gov/regulatory/Orders/2018orders/26116e.pdf

[90] Abel and Shimabukuro. RL30405: State-by-State Comparison of Selected Electricity Restructuring Provisions. January 13, 2000. https://digital.library.unt.edu/ark:/67531/metacrs1173/m1/1/high_res_d/RL30405_2000Jan13.html

[91] New Hampshire House Bill 1392 (1996) http://www.gencourt.state.nh.us/legislation/1996/HB1392.htm codified as New Hampshire Public Utilities Commission Restructuring Policy Principles in RSA 374-F http://www.gencourt.state.nh.us/rsa/html/XXXIV/374-F/374-F-3.htm

[92] New Jersey Senate Bill (1999) ftp://www.njleg.state.nj.us/19981999/S0500/7_I1.PDF

duration nonbypassable charge payable by all of the utility's customers over a set period of time and through the issuance of transition bonds by the utility or another financing entity approved by the New Jersey Board of Public Utilities. A utility's ability to assess an MTC and issue transition bonds is subject to the Board's approval.[93] As of December 1, 2016, PSE&G's MTC has been $0.[94]

New Mexico: New Mexico is not a retail choice state[95] but it did have CCA legislation which failed to pass a senate committee in March 2019.[96] The New Mexico legislation levied three separate exit fees payable by CCAs (not their customers) until the incumbent utility has recovered 92.5% of its revenues from the sale of electricity in benchmark year 1999.

SB 374 would have established the "Local Choice Energy Act" thereby enabling CCA in the state of New Mexico. The bill allows municipalities, counties, or Native American nations, tribes or pueblos to combine the loads of multiple end-use customers for the sale or purchase of electric energy (or related electric energy-related services) and establishes the overall authorization and framework for these local governments to implement local choice.
Among the provisions, the bill:

- Prohibits local choice energy programs from operating in an existing municipal utility service territory;
- Requires the community offering the local choice program to be responsible for all procurement and comply with the RPS;
- Establishes a default opt-in policy for customers;
- Defines the process for developing and the content to be covered in the implementation plans, which must include rate setting and workforce development (for example);
- Establishes the framework for cooperation and the relationship with the IOUs and cooperatives and the local choice energy provider and allows the utility to charge an exit fee (subject multiple requirements and PRC approval);
- The PRC is directed to adopt rules to implement this legislation.

New York: New York retail choice is available to residential and non-residential customers and also includes CCAs. New York does not have any specific law on exit fees for CCAs or their

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[93] Abel and Shimabukuro. RL30405: State-by-State Comparison of Selected Electricity Restructuring Provisions. January 13, 2000.
https://digital.library.unt.edu/ark:/67531/metacrs1173/m1/1/high_res_d/RL30405_2000Jan13.html
[94] PSE&G Implementation of a Tariff change effective December 1, 2016 as per Board approval of changes to the Securitization Transition Charges (STC) resetting the Transition Bond Charge (TBC) and the Market Transition Charge-Tax Charge (MTC-Charge) components to zero.
https://nj.pseg.com/aboutpseg/regulatorypage/electrictariffs/-/media/4f7284a682bd48d380a7236664686c3a.ashx
[95] In 1999, New Mexico passed the Electric Utility Industry Restructuring Act of 1999 but deregulation never took place.
[96] New Mexico Senate Bill 374, failed to pass in March 2019
https://www.nmlegis.gov/Legislation/Legislation?Chamber=S&LegType=B&LegNo=374&year=19

customers. During the 2019-2020 legislative session, a pair of bills (S 3604[97] & A136[98]) would, if enacted, expressly authorize local municipalities (villages, towns and cities, but not counties) to become direct energy supply CCAs in the style of California. Neither of these bills address any type of exit fee. Existing CCAs in the state are established under the Municipal Home Rule Law[99] through local ordinances and resolutions. In New York's unregulated electricity market, CCAs operate by aggregating the load of their inhabitants and brokering supply contracts with Energy Service Companies (ESCOs) through public solicitation processes. The CCA framework in the state was adopted by the PSC on April 21, 2016 in its *Order Authorizing Framework for Community Choice Aggregation Opt-Out Program*[100] in Case 14-M-0224[101], which does not include any discussion of exit fees associated with a customer or group of customers leaving the incumbent distribution utility. While not an exit fee, New York municipalities are subject to fees for access to aggregated community load data from utilities, as well as the customer information needed for opt-out mailings for CCA programs. The data access fee is set at $0.80 per account for all utilities.[102]

Ohio: Ohio is a retail choice state for residential and non-residential customers but it does not have CCAs. Previously, stranded cost recovery extended through 2005 for generation-related assets, and through 2010 for regulatory assets.[103] Though there is no exit fee today, there are dozens of riders are included on paid by both bundled and unbundled customers regardless of who their supplier is which go into paying for system generation through nonbypassable charges for the uneconomic generation (e.g., Ohio Valley Electric Corporation coal plants; nuclear subsidies to start in 2021[104]).

Oregon: Residential customers do not have retail choice but non-residential customers with over 30 kW in monthly peak demand do have retail choice in Oregon.[105] The transition adjustments are included in Direct Access customer bills.[106]

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[97] New York Senate Bill 3604, introduced in 2019 and in committee as of January 2020 https://www.nysenate.gov/legislation/bills/2019/s3604

[98] New York Assembly Bill 136, introduced in 2019 and in committee as of January 2020 https://www.nysenate.gov/legislation/bills/2019/a136

[99] Municipal Home Rule Consolidated Laws of New York https://www.nysenate.gov/legislation/laws/MHR

[100]http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={38EFD3B0-48BC-400E-9795-98CB5EFAE0FA}

[101] http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=14-m-0224

[102] Order Establishing Community Choice Data Access Fees (December 14, 2017), p. 22. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9F78977A-ED74-4EC5-929A-6C092C0B208E}

[103] Concentric Energy Advisors, Inc. Retail Competition In Electricity What Have We Learned In 20 Years? July 23, 2019. P. 57 https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf

[104] Both per House Bill 6 (2020)

[105] Oregon Restructuring Law SB 1149 (1999) codified, in part, at ORS 757.600 et seq. House Bill 3633 passed by the 2001 Legislative Assembly, delays the implementation of SB 1149 from October 1, 2001 to March 1, 2002.

[106] See Pacific Power Oregon Direct Access Price Summary (April 1, 2020) Schedule 294 and 295, p. 7 https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/Oregon_Direct_Access_Price_Summary.pdf

Failed legislation to enable CCAs, House Bill 2852, set the cost recovery mechanism to only apply for a 5-year period and expressed as a $/kWh charge/credit.[107]

- This bill authorizes local governments to form authorities for the purpose of implementing CCA programs. It places certain requirements on electric companies and the Public Utilities Commission (PUC) related to implementation of CCA programs. It applies an RPS to CCA programs implemented by authorities. It includes authorities in list of persons subject to public purpose charge.
- CCAs cannot be formed until three years after the date that the PUC establishes by order a cost recovery mechanism for customers located in Multnomah County or a city with a population of 500,000 or more.
- To form a new CCA, an authority formed under this bill must prepare an implementation plan. The PUC has 180 days to review the implementation plan for the limited purpose of adopting the cost recovery mechanism. The PUC will also adopt a registration process for new CCAs. It will also review the CCA's power supply plan for the limited purpose of ensuring it "demonstrates adequate resource planning by the authority to ensure that the authority will meet the reasonably forecast loads of eligible retail electricity consumers served by the authority."
- Cost Recovery: The PUC will establish a cost recovery mechanism for each CCA. The cost recovery mechanism may "take the form of an exit fee, a nonbypassable charge or a credit applied to retail electricity consumers served by the authority," the purpose of which is "to prevent unwarranted shifting of costs," from CCA customers to non-CCA customers. The cost recovery mechanism can only apply for a 5-year period and will be expressed as a $/kWh charge/credit. The bill specifies specific details about calculating the cost recovery mechanism.
- Utility Obligations: Utilities must continue to provide for retail electricity consumers whose load is served by CCAs:
    - Under the same rates, terms and conditions that apply to non-CCA utility customers transmission services, distribution services and ancillary services;
    - All metering, billing, collection and customer service.
    - Serve the load for retail electricity consumers that decline to participate in the CCA.
    - Utilities are precluded from marketing or lobbying against a CCA program using funds collected through rates. Utilities are also prohibited from using customer-specific information it has by virtue of being the customer's utility for any marketing or lobbying purposes.
- RPS: CCAs must meet the same RPS requirements that utilities have, including the 8% small-scale renewables by 2025 requirement.

Pennsylvania: Pennsylvania allows retail choice for residential and non-residential customers but there are no CCAs in Pennsylvania. The law permitted stranded cost recovery through the Competition Transition Charge (CTC) until 2011. "The Electricity Generation Customer Choice

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[107] Oregon House Bill 2852 (failed to pass in 2019) https://olis.leg.state.or.us/liz/2019R1/Measures/Overview/HB2852

and Competition Act (HB 1509) was enacted in December 1996. A pilot phase began in late 1997, and then a phase-in allowed one-third of consumers to join each year. Different utilities received different treatment with respect to initial rate decreases and the size of stranded cost recovery and competitive transition charge. A shopping credit was advertised to allow customers to compare competitive rates with the "price to compare" or "shopping credit." After several years the Pennsylvania PUC approved a change in default service rates because some consumers were gaming the system by returning to the utility rate for the summer when competitive prices typically rose, making default service rates more attractive. Under the revised system, utilities were able to impose switching restrictions and exit fees (a market based penalty called the “generation rate adjustment”) to discourage this gaming."[108] "In exchange for the recovery of stranded costs, generation, transmission and distribution rates were capped at 1996 levels. The caps on transmission and distribution rates all have expired. After litigated proceedings before the PUC, the generation rates were extended for many of the electric companies. As determined by those proceedings, all utility rate caps have expired as of Jan. 1, 2011."[109]

Rhode Island: Rhode Island allows retail choice for residential and non-residential customers and also has CCAs. Retail competition for all IOU customers was implemented in 1996.[110] CCAs became legal in 2002.[111] A nonby-passable transition charge for the recovery of generation-related stranded costs is to be collected from all distribution customers through December 31, 2029.[112] In 2019 the residential charge was 0.114¢ per kWh[113]. Transition charges Any nonregulated power producer may pay all or a part of its customers' transition charges.[114] but in practice the customers pay directly. The transition charge costs must be associated with (1) regulatory assets related to the generation business; (2) nuclear obligations; (3) above market payments to power suppliers for purchased power contracts of the wholesale power supplier in place as of December 31, 1995; and (4) The net unrecovered commitments and capital costs of all generating plants owned directly or indirectly by the electric distribution company and its wholesale power supplier as of December 31, 1995.

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[108] Distributed Energy Financial Group LLC (DEFG) July 2015 p. 136 Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS) http://www.energychoicematters.com/stories/ABACCUS2015.pdf
[109] Pennsylvania Public Utilities Commission. p. 1. The Expiration of Electric Generation Rate Caps. 2010. http://www.puc.state.pa.us/general/consumer_ed/pdf/Rate_Caps.pdf
[110] Rhode Island Utility Restructuring Act (1996) http://www.energy.ri.gov/policies-programs/ri-energy-laws/rhode-island-utility-restructuring-act-1996.php
[111] Rhode Island House Bill 7786 (2002) http://webserver.rilin.state.ri.us/BillText02/HouseText02/H7786Baa.htm
[112] Concentric Energy Advisors, Inc. Retail Competition In Electricity What Have We Learned In 20 Years? July 23, 2019. P. 57 https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf
[113] For A-16 Residential Delivery Service from National Grid Rhode Island https://www.nationalgridus.com/media/pdfs/billing-payments/bill-inserts/ri/cm4394_ri_bus-and-res-summary.pdf
[114] Rhode Island Title 39 Public Utilities and Carriers Chapter 39-1 Public Utilities Commission Section 39-1-27.4 http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.4.HTM

Texas: Retail competition for all IOU customers in Texas was implemented in 2002 but there are no CCAs in Texas.[115] A Competition Transition Charge (CTC) is allocated among retail customer classes and approved by the PUC in a true-up proceeding until the charge is final. As of March 2020, Texas New-Mexico Power's CTC is between $0.00/kWh and $0.00212/kWh for residential customers and CenterPoint's residential CTC is a credit of $0.001839/kWh.[116] A utility may securitize 100% of its regulatory assets and up to 75% of its estimated stranded costs for recovery through the CTC, in accordance with a financing order issued by the PUC; implement, under bond a nonbypassable charge of up to 100% of its estimated stranded costs; or use a combination of the two methods. A utility must pursue commercially reasonable means to reduce its potential stranded costs.[117]

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[115] Texas Senate Bill 7 Electric Restructuring, Section 11.003 https://capitol.texas.gov/tlodocs/76R/billtext/html/SB00007F.htm

[116] Public Utility Commission of Texas Comparison of Utilities' Other Nonbypassable Charges (March 1 2020). P. 6. http://www.puc.texas.gov/industry/electric/rates/trans/tdgenericratesummary.pdf

[117] Texas Senate Bill 7 Electric Restructuring, Section 11.003 https://capitol.texas.gov/tlodocs/76R/billtext/html/SB00007F.htm

IOU Reasonableness Review Processes

This section describes energy contract oversight practices in Minnesota, Utah, Colorado, Colorado, Arizona, Virginia and North Carolina. and their processes for reviewing energy plans with regards to evaluating affordability and clean energy targets. These states were selected to compare with California on the basis of having similar general commission jurisdictional authority over energy procurement of IOUs.

See Appendix B. Comparative Matrix on IOU Reasonable Review Processes by State.

Minnesota IOU Reasonableness Review Process

In Minnesota Docket 17-568[118] an Order[119] and a Report[120] were issued stating the PUC has the authority to "approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in sections 216B.169, 216B.2423, and 216B.2424, and to satisfy the renewable energy objectives and standards set forth in section 216B.1691…"[121] Under Minnesota law, the PUC may exercise its authority under subdivision 2b to modify or delay implementation of a standard obligation as part of an Integrated Resource Planning proceeding under section 216B.2422.[122]

Utilities may select resources to meet their projected energy demand through a bidding process approved or established by the PUC. Utilities must use the environmental cost estimates determined under subdivision 3 in evaluating bids.[123]

Utilities are required to "include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources."[124] Utilities also must indicate in its resource

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[118] Minnesota PUC Docket 17-568 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&docketYear=17&docketNumber=568#

[119] Minnesota PUC Order Approving Affiliated Interest Agreements with Conditions January 24, 2019 in Docket 17-568 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30DE8168-0000-C712-8B93-95EC082C7FCD}&documentTitle=20191-149543-01

[120] See Minnesota PUC Report--Findings of Fact, Conclusions of Law, And Recommendation July 2, 2018 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&docketYear=17&docketNumber=568#{50ED5C64-0000-CA1B-A67D-CF5C54EDB586}

[121] 2019 Minnesota Statutes 216B.1645 Power Purchase Contract Or Investment. Subdivision 1.Commission authority. https://www.revisor.mn.gov/statutes/cite/216B.1645

[122] 2019 Minnesota Statutes 216B.1691 Renewable Energy Objectives. Subd. 2c.Use of integrated resource planning process. https://www.revisor.mn.gov/statutes/cite/216B.1691

[123] 2019 Minnesota Statutes 216B.2422 Resource Planning; Renewable Energy. Subd. 5.Bidding; exemption from certificate of need proceeding. (a) https://www.revisor.mn.gov/statutes/cite/216B.2422

[124] 2019 Minnesota Statutes 216B.2422 Resource Planning; Renewable Energy. Subd. 2. Resource plan filing and approval.(c) https://www.revisor.mn.gov/statutes/cite/216B.2422

plan whether it intends to site or construct a large energy facility, and if the PUC approves the proposed facility in the resource plan, a separate certificate of need proceeding is not required.[125] A certificate of need proceeding is also not required for an electric power generating plant that has been selected in a bidding process approved or established by the commission, or such other selection process approved by the commission, to satisfy, in whole or in part, the wind power mandate of section 216B.2423 or the biomass mandate of section 216B.2424.[126]

Utah IOU Reasonableness Review Process

On July 17, the PSC issued an Order approving Rocky Mountain Power's (RMP) 2020 All Source Request for Proposals (2020AS RFP) and granting its request to waive blind bidding requirements required by Utah Administrative Code.

- RMP's RFP satisfies the solicitation approval requirement for utilities seeking to meet an energy need by:
  - Soliciting a large number of bids from a diverse mix of generation resources;
  - Likely soliciting bids from lowest cost, least risk alternatives; and
  - Designing a reasonable process for evaluating and selecting bids to select resources that are in the public interest.[127]
- The Independent Evaluator must "blind" all bids and supply blinded bids to the Soliciting Utility and make blinded bids available to the Division of Public Utilities subject to the provisions of an appropriate Commission-issued protective order.[128]
- The Soliciting Utility, monitored by the Independent Evaluator, shall conduct a thorough evaluation of all bids in a manner consistent with the Act, Commission Rules and the Solicitation.[129]
- An affected electrical utility shall file with the commission any action plan developed as part of the affected electrical utility's integrated resource plan to enable the commission to review and provide guidance to the affected electrical utility.[130,131]
- In accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act, the commission shall make rules providing a process for its review of an action plan.[132]

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125 2019 Minnesota Statutes 216B.2422 Resource Planning; Renewable Energy. Subd. 6. Consolidation of resource planning and certificate of need. https://www.revisor.mn.gov/statutes/cite/216B.2422
126 2019 Minnesota Statutes 216B.2422 Resource Planning; Renewable Energy. Subd. 5.Bidding; exemption from certificate of need proceeding. (c) https://www.revisor.mn.gov/statutes/cite/216B.2422
127 Docket 20-035-05: Application of Rocky Mountain Power for Approval of Solicitation Process for 2020 All Source Request for Proposals
https://psc.utah.gov/2020/01/24/docket-no-20-035-05/
128 Utah Rule R746-420. Requests for Approval of a Solicitation Process. Includes the role of Independent Evaluators.(10) Evaluation of Bids.(a) https://rules.utah.gov/publicat/code/r746/r746-420.htm
129 Utah Rule R746-420. Requests for Approval of a Solicitation Process. Includes the role of Independent Evaluators.(10) Evaluation of Bids.(e) https://rules.utah.gov/publicat/code/r746/r746-420.htm
130 Utah Code Chapter 17 Energy Resource Procurement Act. 54-17-301 Review of integrated resource plan action plans. (1) https://le.utah.gov/xcode/Title54/Chapter17/C54-17_1800010118000101.pdf
131 Amended by Chapter 382, 2008 General Session
132 Utah Code Chapter 17 Energy Resource Procurement Act. 54-17-301 Review of integrated resource plan action plans. (2)(a) https://le.utah.gov/xcode/Title54/Chapter17/C54-17_1800010118000101.pdf

- The rules required under Subsection (2)(a) shall provide sufficient flexibility to permit changes in an action plan between the periodic filings of the affected electrical utility's integrated resource plan.[133]
- To obtain the approval required by Subsection (1), the affected electrical utility shall file a request for approval with the commission.[134]
- If pursuant to Part 2, Solicitation Process, an affected electrical utility is required to conduct a solicitation for a significant energy resource or obtains a waiver of the requirement to conduct a solicitation under Section 54-17-501, but does not obtain a waiver of the requirement to obtain approval of the significant energy resource decision under Section 54-17-501, the affected electrical utility shall obtain approval of its significant energy resource decision:
    - after the completion of the solicitation process, if the affected electrical utility is required to conduct a solicitation; and
    - before an affected electrical utility may construct or enter into a binding agreement to acquire the significant energy resource.[135]

Colorado IOU Reasonableness Review Process

Utilities must meet the Renewable Energy Standard (RES) in the most cost-effective manner. To this end, the competitive acquisition provisions and exemptions of the Commission's Electric Resource Planning Rules apply to the acquisition of eligible energy resources by Xcel Energy. Xcel Energy must acquire renewable distributed generation in accordance with a process set forth in a Commission-approved compliance plan or by separate application.[136]

Xcel Energy may apply to the Commission, at any time, for review and approval of renewable energy credit contracts of any size, and renewable energy supply contracts with renewable distributed generation. The Commission will review and rule on these contracts within 90 days of their filing. The Commission may set the contract for expedited hearing, if appropriate, under the Commission's Rules of Practice and Procedure. If Xcel Energy enters into a renewable energy supply contract or a renewable energy credit contract in a form substantially similar to the form of contract approved by the Commission as part of its compliance plan, that contract will be approved by the Commission.[137]

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[133] Utah Code Chapter 17 Energy Resource Procurement Act. 54-17-301 Review of integrated resource plan action plans. (2)(b) https://le.utah.gov/xcode/Title54/Chapter17/C54-17_1800010118000101.pdf
[134] Utah Code Chapter 17 Energy Resource Procurement Act. 54-17-302 Review of integrated resource plan action plans. (2)(a) https://le.utah.gov/xcode/Title54/Chapter17/C54-17_1800010118000101.pdf
[135] Utah Code Chapter 17 Energy Resource Procurement Act. 54-17-302 Approval of a significant energy resource decision required. (1) https://le.utah.gov/xcode/Title54/Chapter17/C54-17_1800010118000101.pdf
[136] 4 CCR 723-3 Rules Regulating Electric Utilities Rule 3656. (a) Resource Acquisition https://www.sos.state.co.us/CCR/DisplayRule.do?action=ruleinfo&ruleId=2259&
[137] 4 CCR 723-3 Rules Regulating Electric Utilities Rule 3656. (e) Resource Acquisition https://www.sos.state.co.us/CCR/DisplayRule.do?action=ruleinfo&ruleId=2259&

Arizona IOU Reasonableness Review Process

Proposed rules in Arizona Corporation Commission (ACC) Docket No. RU-00000A-18-0284 would establish All-Source RFPs as IOUs' primary acquisition tool along with related requirements.[138] Electric Utilities must demonstrate the delivery of clean energy resource and renewable energy resources to its customers by providing documentation such as: (1) the transmission rights to deliver energy from clean energy resource or renewable energy resources to the utility's system, if applicable; (2) a control area operator scheduling the energy from clean energy resources or renewable energy resources for delivery to the electric utility's system, if applicable; and (3) for an energy storage system used to meet the Distributed Renewable Storage Standard, the source of the energy that is being used to charge the energy storage system. If the utility's Clean Energy Implementation Plan does not contain sufficient information for ACC Staff to analyze the submission for compliance, Staff must request additional information from the utility, which may include the data used for the utility's analysis.

Integrated Resource Plan (IRP) Proposed Rules

- The IRP must contain a summary of supply-side resources and demand-side resources that have the potential to meet its load forecast;
- Each portfolio of resources that will be analyzed by the LSE in its IRP;
- Summary of how the LSE's Advisory Council has contributed to developing its preliminary IRP; and
- A description of how the LSE's IRP will be developed over the following year and specifying: (a) participation opportunities for the general public; (b) LSE's plans for hosting at least one technical workshop that is open to the general public and the ACC; (c) how the LSE's IRP Advisory Council will contribute to development of its IRP; and (d) a schedule of dates reflecting when the LSE plans to meet with its IRP Advisory Council;
- The ACC must host a workshop that is open to the general public, in coordination with the LSE, within 60 calendar days after an LSE files its preliminary IRP to discuss the following aspects of the preliminary IRP, at minimum: (1) load forecast developed by the LSE; (2) each portfolio of resources the LSE plants to analyze in its IRP; and (3) modeling assumptions, outputs, and methodologies used.
- A Clean Energy Implementation Plan;
- An Action Plan including the following minimum requirements: (a) summary of the results of the LSE's RFP process; (b) for the next three calendar years, the resource procurement actions the LSE plans to undertake based on proposals received in response to its RFP processes; and (c) a three year timeline describing the LSE's loads and resources;
- An executive summary describing the LSE's preferred resource portfolio;
- An explanation of the LSE's future planning and public advisory process;
- An explanation of the LSE's resource needs, including the following minimum information requirements: (1) planning period forecast of system coincident peak load

[138] Arizona Corporation Commission Docket RU-00000A-18-0284 http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=21658

(MW) and energy consumption (MWh) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible service, for resale, and for energy losses; (2) disaggregation of the load forecast into a component wherein no additional Demand-Side Resources are assumed, and a component assuming the change in load due to addition forecasted demand-side resources; (3) documentation of all sources of data, analyses, methods, and assumptions for the load forecasts, including a description of how the forecasts were benchmarked and justifications for the assumptions; (4) forecast of customer-owned DG; (5) forecast of power produced from customer-owned DG; (6) an evaluation of the LSE's load forecasting model and its accuracy; (7) comparison of previous load forecasts with the current load forecast and demand; and (8) description of the LSE's existing resources and the ability of those resources to meet the forecasted load;

- An assessment of the LSE's resource needs, including the following minimum information requirements: (1) identification of current and future capacity and energy requirements resulting from the expected or contractual retirement of existing supply and demand-side resources; (2) expected planning reserve margin used to maintain reliable service over the planning period and a description of its reasonableness; (3) description of the methodology used to establish the planning reserve margin; and (4) table that lists the expected capacity of each existing supply-side and demand-side resource throughout the planning period, by year, of each existing supply-side and demand-side resource, the load requirements, and the planning reserve margin;
- A description of the LSE's supply-side resources, which must include: (a) the LSE's fuel procurement strategy; (b) summary of supply-side technologies and benefits; (c) summary of future resource options; (d) summary of the ISE's participation in energy markets; (e) description of the LSE's resource adequacy strategy; and (f) list and description of supply-side resources the LSE selected from the results of its All-Source RFP;
- A description of the LSE's demand-side resources, which must include: (a) summary of all DSM programs in effect and corresponding costs and benefits; (b) an update on DSM savings achieved since the LSE's last IRP; (c) plan describing how the LSE will develop and encourage DSM programs using customer-owned DG; (d) description of EE programs in effect, along with corresponding costs and benefits; (e) plan detailing the LSE's goal to meet a portion of its load forecast using demand-side resources; and (f) summary of future demand-side resource technologies;
- A description of the LSE's most recent transmission planning activities;
- A description of the LSE's distribution planning activities, which must include: (a) planning period forecast of the LSE's customer-sited DG in terms of annual peak production (MW) and annual energy production; (b) planning period forecast of the total costs of customer-sited DG; (c) documentation supporting the analysis of customer-sited DG; (d) summary of evolving distribution system technologies with the potential to assist the LSE in meeting demand; (e) analysis of current and forecasted distribution system technologies' ability to meet forecasted demand; (f) plan describing how customer-sited DG can be utilized to meet current and future demand; (g) summary of programs under consideration or development by the LSE to encourage customer-owned DG to meet

current and future demand; (h) summary of any and all initiatives to perform hosting capacity analyses of the LSE's distribution systems; and (i) assessment of areas on the LSE's distribution system that may be vulnerable to outages due to high coincident peak or energy demand, lack of adequate resources, or an emergency;
- Summary concerning environmental regulations applicable to the LSE;
- Summary of risk and uncertainty management analyses performed by the LSE;
- Summary of portfolio analyses performed by the LSE, which must include: (a) retirement portfolio analysis that identifies generating units planned to be retired, discontinued, decommissioned, mothballed, or derated, along with associated costs, spending schedule, supporting reasons, identification of least-cost replacement capacity, evaluation of retirement portfolios, and a description of the selected retirement portfolio; (b) analysis of a wide range of resource portfolios addressing resource needs identified for the planning period; and (c) the LSE's selection of a preferred resource plan to meet forecasted load over the planning period based on comprehensive consideration of supply-side and demand-side resources;
- Description of the LSE's efforts towards customer engagement; and
- An index indicating the LSE's planned compliance with IRP requirements, along with relevant definitions.

<u>Energy Rules: Annual LSE Reporting Requirements</u>
Beginning on October 1, 2022, LSEs must file a report with the ACC including demand-side resource data or the LSE's best corresponding estimate and a description of the LSE's determination of its estimate for the following:
- Average hourly demand for the previous calendar year, disaggregated by: sales to end users, sales for resale, energy losses, and other disposition of energy;
- Coincident peak demand and energy consumption month by month for the previous planning period, disaggregated by customer class;
- Average number of annual customers by customer class for each of the previous planning period; and
- Reduction in load in the previous calendar year due to existing demand management measures by type of demand management measure.

Beginning on October 1, 2022, LSEs must file a report including supply-side resource data or the LSE's best corresponding estimate and a description of the LSE's determination of its estimate for the following:
- Various data points including in-service dates, type of generating unit, average fuel cost, and maximum generating capacity, among others, for each generating unit and purchased power contract for the previous calendar year;
- Various data point including production costs, reserve requirements, and energy losses, among others, for each supply-side resource in the previous calendar year;
- Total capacity of DG in the LSE's service area for the previous calendar year; and
- An explanation of any resource procurement processes undertaken by the LSE during the previous calendar year that did not include the use of an RFP.

Beginning on May 1, 2024, LSE's must file a procurement activity report providing at least the following information:

- Procurement activities the LSE plants to undertake in the following calendar year to implement its ACC-approved Action Plan;
- All associated cost information related to the LSE's planned procurement activities; and
- A timeline describing each planned procurement activity.

Energy Rules: Public Advisory Process: Within 90 days after the ACC's approval of an LSE's Action Plan, ACC Staff's proposed rules establish a public advisory process wherein the LSE submits a report for compliance to the ACC for the following IRP, regarding the identification of a Stakeholder Advisory Group, how the advisory group will contribute to IRP development, a meeting date, and a preliminary timeline of opportunities for public participation. LSE's may, at minimum, consider Stakeholder Advisory Group input relating to the following:

- The LSE's load forecast;
- Technology costs and assumptions;
- Economic scenarios; and
- Resource portfolios.

Energy Rules: Resource Procurement

The rules require that the LSEs must use an All-Source RFP (ASRFP) as its primary acquisition process for the wholesale acquisition of energy and capacity, unless one of these specific exceptions applies:

- An emergency;
- Immediate acquisitions to maintain system reliability;
- Other components of energy procurement are needed such as fuel, fuel transportation, and transmission projects;
- An LSE's planning horizon is two years or less;
- The transaction presents the LSE with a genuine, unanticipated opportunity to acquire a supply-side resource or demand-side resource at a clea and significant discount, compared to the cost of acquiring new generating units, and will provide unique value to the LSE's customers;
- The transaction is necessary for an LSE's compliance obligations; or
- The transaction is necessary for the LSE's supply-side resource.

The following procurement methods are authorized for wholesale acquisition of energy or capacity and for physical power hedge transactions if one of the above exceptions applies:

- Purchase through a third-party on-line trading system;
- Purchase from a third-party independent power broker;
- Purchase from a non-affiliated entity via auction or an RFP process;
- Bilateral contract with a non-affiliated entity;
- Bilateral contract with an affiliated entity, if non-affiliated entities were provided notice an an opportunity to compete against the proposal before the transaction was executed; and
- Any other competitive procurement process approved by the ACC.

When a LSE receives approval of its preliminary IRP, the LSE must:

- Collaborate with interested stakeholders to develop its ASRFPs;
- Issue the ASRFP to address its approved load forecast and any other resources needs;
- Utilize the results of its ASRFPs in the development of each IRP portfolio analyses;
- Report the results of its ASRFPs in its IRP; and
- Report the resource selections in its Action Plan.

The ACC's determination regarding acknowledgement of an LSE's IRP will consider the following:

- Total cost of energy services;
- Degree to which factors affecting demand and demand management have been accounted for;
- Degree to which supply-side resource alternatives such as DG have been accounted for;
- Uncertainty in demand and supply analyses, forecasts, and plans, and whether plans are sufficiently flexible to enable the LSE to respond to unforeseen changes in supply and demand factors;
- Reliability of power supplies, including fuel diversity, and non-cost considerations;
- Reliability of the transmission grid;
- Degree to which relevant resources, risks, and uncertainties were considered;
- Degree to which the LSE's future resource plan is in the best interest of its customers;
- Best combination of expected cost and associated risks for the LSE and its customers; and
- Degree to which the LSE's IRP allows for coordinated efforts with other LSEs.

Virginia IOU Reasonableness Review Process

Certificate of Public Convenience and Necessity

Virginia's two IOUs, Dominion Energy Virginia and Appalachian Power Company, and non-utility generators are required to obtain a Certificate of Public Convenience and Necessity (CPCN) from the State Corporation Commission (SCC) prior to the construction and operation of any electric generation facility.[139] In order to grant a CPCN, the SCC must find that the proposed generation facility (i) will have no material adverse effect on system reliability, (ii) is required by the public convenience and necessity, and (iii) is not otherwise contrary to the public interest.[140] Small renewable energy generators (under 150 MW) are approved via a separate "permit by rule" process through the Virginia Department of Environmental Quality.[141]

Renewable Portfolio Standard

State law requires both IOUs to procure certain specified amounts of solar, wind and energy storage and petition the SCC "for the recovery of the costs of such facilities either through its

[139] Va. Code § 56-580(D), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-580/.
[140] Va. Code § 56-580(D), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-580/.
[141] Va. Code § 56-580(D), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-580/.

rates for generation and distribution services or through a rate adjustment clause."[142] Beginning in 2020, each IOU must submit an annual plan and petition for approval for the development of new solar and onshore wind generation capacity. This petition must include any request for approval to construct the facility (i.e., CPCN) and a request for approval or update of a rate adjustment clause (RAC) for cost recovery of such facilities.[143]

Cost Recovery

Triennial Rate Reviews (i.e., Base Rate Cases)

On a triennial basis, the SCC must "review the rates, terms and conditions for the provision of generation, distribution and transmission services of each investor-owned incumbent electric utility" to determine if they are just and reasonable, and determine "fair rates of return on common equity applicable to the generation and distribution services of the utility."[144] IOUs are able to request cost recovery of generation facilities during the triennial review proceeding and have the burden of proof to show that all proposed rates are just and reasonable.

Outside of a triennial review, a utility is able to petition the SCC "for a prudency determination with respect to the construction or purchase by the utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic Shoreline or the purchase by the utility of energy, capacity, and environmental attributes from solar or wind facilities owned by persons other than the utility."[145]

The General Assembly has expressly provided that certain types of generation facilities and the purchase of energy, capacity, and environmental attributes from renewable generation facilities are in the public interest,[146] and directed the SCC to find that such facilities are in the public interest when considering the approval of an IOU petition for cost recovery. For example:

> In connection with planning to meet forecasted demand for electric generation supply and assure the adequate and sufficient reliability of service, … planning and development activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore or offshore wind are in the public interest.[147]

Rate Adjustment Clauses

In lieu of seeking cost recovery through base rates, an IOU can petition the SCC for approval of a RAC for the recovery of certain cost categories, including generation costs.[148] An IOU must "[p]rovide all documents, contracts, studies, investigations or correspondence that support projected costs proposed to be recovered via a rate adjustment clause."[149] In addition, for a RAC for the recovery of costs of proposed new generating facilities, a IOU must demonstrate the reasonableness and prudence of the facility by providing the following:

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[142] Va. Code § 56-585.5(D) and Va. Code § 56-585.5(E), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.5/.

[143] Va. Code § 56-585.1(D)(4),

[144] Va. Code § 56-585.1(A), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/.

[145] Va. Code § 56-585.1:4(H), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1:4/.

[146] *See, e.g.*, Va. Code § 56-585.1:4(A) and Va. Code § 56-585.1:4(B), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1:4/..

[147] Va. Code § 56-585.1(A)(6), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/.

[148] Va. Code § 56-585.1(A)(6), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/.

[149] 20VAC5-201-90, https://law.lis.virginia.gov/admincode/title20/agency5/chapter201/section90/ (see requirements for Schedule 46).

(a) Feasibility and engineering design studies that support the specific plant type and site selected;
(b) Fuel supply studies that demonstrate the availability and adequacy of selected fuels;
(c) Detailed support for planning assumptions regarding plant performance and operating costs, including historical information for similar units;
(d) Economic studies that compare the selected alternative with other options considered, including sensitivity analyses and production costing simulations of the applicant's overall generating resources that demonstrate that the selected option is the best alternative;
(e) Load and generating capacity reserve forecast information that demonstrates the need for the plant in the in-service year proposed; and
(f) Detailed cost estimated for the facility, included projected costs of construction, transmission interconnections, fuel supply related infrastructure improvements and project financing.[150]

During a base rate case or a RAC proceeding, the SCC may determine "the reasonableness or prudence of any cost incurred or projected to be incurred" by the petitioning utility.[151] When considering the reasonableness or prudence of costs associated with renewable energy resources, the SCC:

> … shall consider the extent to which such renewable energy resources, whether utility-owned or by contract, further the objectives of the Commonwealth Energy Policy … and shall also consider whether the costs of such resources is likely to result in unreasonable increases in rates paid by customers.[152]

Integrated Resource Planning
Virginia IOUs are required to file an Integrated Resource Plan for SCC approval in each year preceding a triennial review filing.[153] The IRP forecasts an IOU's load obligations and plans for meeting those obligations through supply-side and demand-side resources over a 15-year period. However, IRP approvals are non-binding and any future generation project must be approved by the SCC via the CPCN process.

North Carolina IOU Reasonableness Review Process

Certificate of Convenience and Necessity
A public utility or any other person proposing to construct an electrical generator for the purpose of providing public utility service must obtain a Certificate of Convenience and Necessity (CCN) from the North Carolina Utilities Commission (NCUC) prior to commencing construction.[154] CCN

[150] 20VAC5-201-90, https://law.lis.virginia.gov/admincode/title20/agency5/chapter201/section90/ (see requirements for Schedule 46).
[151] Va. Code § 56-585.1(D), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/.
[152] Va. Code § 56-585.1(D), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/.
[153] Va. Code § 56-599, https://law.lis.virginia.gov/vacode/title56/chapter24/section56-599/.
[154] N.C.G.S. § 62-110.1(a), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-110.1.pdf.

requirements do not apply to non-utility-owned renewable energy generation facilities under 2 megawatts.[155]

The NCUC is required to maintain an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina.[156] The NCUC is prohibited from approving a CCN application unless it "has approved the [proposed generation facility's] estimated construction costs and made a finding that construction will be consistent with the Commission's plan for expansion of electric generating capacity."[157] With respect to coal or nuclear generation facilities, the NCUC must also determine "that energy efficiency measures; demand-side management; renewable energy resource generation; combined heat and power generation; or any combination thereof, would not establish or maintain a more cost-effective and reliable generation system and that the construction and operation of the facility is in the public interest."[158] Once a CCN is granted, a public utility is not permitted to cancel the construction of a generation facility without NCUC approval.[159]

Cost Recovery Review
Public utilities must recover the actual costs of constructing a generation facility that has a CCN through a general rate case.[160]

Renewable Portfolio Standard Review
North Carolina electric public utilities (Duke Energy Carolinas, Duke Energy Progress, and Dominion Energy North Carolina) are subject to a Renewable Energy Portfolio Standard (REPS), which requires them to procure an amount of renewable energy equivalent to 12.5% of 2020 North Carolina retail sales by 2021 and each year thereafter.[161] The NCUC is required to adopt rules to implement the REPS, including rules that provide for the monitoring and control of compliance with and enforcement of the REPS.[162]

The NCUC requires each public utility to file an annual REPS plan which describes the entity's actions to achieve compliance with the REPS. These plans must include, among other things, "a list of executed contracts to purchase renewable energy certificates (whether or not bundled with electric power), including type of renewable energy resource, expected MWh, and contract duration."[163] If an electric power supplier is subject to the state's integrated resource plan

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155 N.C.G.S. § 62-110.1(g), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-110.1.pdf.
156 N.C.G.S. § 62-110.1(c), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-110.1.pdf.
157 N.C.G.S. § 62-110.1(e), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-110.1.pdf.
158 N.C.G.S. § 62-110.1(e), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-110.1.pdf.
159 N.C.G.S. § 62-110.1(e), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-110.1.pdf.
160 N.C.G.S. § 62-110.1(f1), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-110.1.pdf.
161 N.C.G.S. § 62-133.8(b), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-133.8.pdf.
162 N.C.G.S. § 62-133.8(i), https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-133.8.pdf.
163 North Carolina Utilities Commission Rule ("NCUC Rule") R8-67(b), https://www.ncuc.net/ncrules/Chapter08.pdf.

requirements, the NCUC requires the supplier to incorporate its REPS plan into that filing.[164] Separately, each public electric utility must file a REPS compliance report detailing, among other things, "the sources, amounts, and costs of renewable energy certificates, by source, used to comply with [the REPS]."[165] Utilities recover REPS compliance costs through a rider that is reviewed on an annual basis.[166]

[164] NCUC Rule R8-67(b)(3), https://www.ncuc.net/ncrules/Chapter08.pdf.
[165] NCUC Rule R8-67(c), https://www.ncuc.net/ncrules/Chapter08.pdf.
[166] NCUC Rule R8-67(e), https://www.ncuc.net/ncrules/Chapter08.pdf.

Appendix A. Comparative Matrix on Exit Fees by State

State	Is electric Retail Choice Available to non-residential customers?	Electric Retail Choice Available to residential customers?	Are CCAs legal?	Exit Fee Methodology	End Date of Exit Fee (if applicable)
California	Yes	Yes	Yes	Power Charge Indifference Adjustment[167]	No end date
Colorado	No	No	No	Pro rata share of a cooperative member's indebtedness to the G&T utility minus the cooperative member's patronage capital.	One-time fee
Connecticut	Yes	Yes	No	Exit fees existed through 2004 with exemptions for self-generation facilities that serve up to four residential units and those installed in conjunction with the expansion of industrial plants.[168] The competition transition assessment (CTA) was in place through 2004 to collect for stranded costs after netting any proceeds from above book value sales and sales of other company property.[169]	2004

[167] California Public Utilities Commission D.18-10-019.
[168] Public Act 98-28, An Act Concerning Electric Restructuring discussed in Docket #98-07-01 and enacted through House Bill 5005 in 1998. https://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm
[169] Florida Public Service Commission September. 2000. P. 28. Key Aspects of Electric Restructuring Supplemental Volume: The State Summaries Division of Policy and Intergovernmental Liaison http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/keysupp.pdf

Delaware	Yes	Yes	No	Delmarva Power and Light recovered $16 million over three years through a non-residential wire surcharge.[170]	2005
Illinois	Yes	Yes	Yes	Transition charge was calculated based on lost revenues but this no longer applies.[171] CCAs became active in 2009.[172]	2005[173]
Maine	Yes	Yes	No	The Public Utilities Commission set an amount of recoverable stranded costs after calculating the net aggregate value of all divested assets that had proceeds exceeding book costs against the aggregate value of all other stranded electricity generation assets while ensuring that cost-shifting would be prevented to the extent possible.[174] The costs were re-set every two to three years.[175]	2000
Maryland	Yes	Yes	No	Residential customers were exempt from an exit fee for Delmarva.[176]	2007

[170] Delaware Public Service Commission Docket 99-163, Order, August 31, 1999, page 5

[171] Abel and Shimabukuro. RL30405: State-by-State Comparison of Selected Electricity Restructuring Provisions. January 13, 2000. https://digital.library.unt.edu/ark:/67531/metacrs1173/m1/1/high_res_d/RL30405_2000Jan13.html

[172] U.S. Environmental Protection Agency. Green Power Partnership. Community Choice Aggregation. https://www.epa.gov/greenpower/community-choice-aggregation

[173] Illinois, P.A. 90-561 (1997) was amended by Senate Bill 3202 (2007)

[174] Abel and Shimabukuro. RL30405: State-by-State Comparison of Selected Electricity Restructuring Provisions. January 13, 2000.

[175] Concentric Energy Advisors, Inc. Retail Competition in Electricity What Have We Learned In 20 Years? July 23, 2019. P. 57 https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf

[176] Maryland Public Service Commission. Analysis of Retail Restructuring in Maryland: Electricity Rates, Stranded Costs From Generation Asset Divestiture, and Decommissioning Funding. P. 15. January 16, 2008. https://www.psc.state.md.us/wp-content/uploads/Kaye-Scholer-Stranded-Costs-Analysis.pdf

				Residential customers of Baltimore Gas & Electric paid an exit fee of $0.00800 – $0.00264/kWh for six years, beginning July 2000. Stranded costs were derived by taking the difference between the asset's "regulated" value (which is based on its depreciated book value) and its fair market value (which is its forward-looking value under a competitive market structure or its sale price). The 1999 Act required the Commission to consider six factors: (1) book value and fair market value, (2) auctions and sales of comparable assets, (3) appraisals, (4) the revenue the company would receive under rate-of return regulation, (5) the revenue the company would receive in a restructured electricity supply market, and (6) computer simulations provided to the Commission, in addition to other evidence of value.[177]	

[177] Maryland Public Service Commission. Analysis of Retail Restructuring in Maryland: Electricity Rates, Stranded Costs From Generation Asset Divestiture, and Decommissioning Funding. P. 23. January 16, 2008. https://www.psc.state.md.us/wp-content/uploads/Kaye-Scholer-Stranded-Costs-Analysis.pdf

Massachusetts	Yes	Yes	Yes	"Transition Costs" eligible for recovery through the "Transmission Charge" that remain after incurred prior to January 1, 1996, are subject to determination by DPU and can include the sale of capacity, energy, Ancillary Services, reserves, and emission allowances along with residual value, assets both real and intangible, and debt obligation.[178]	Costs recovered[179] since 2017"[180] but one utility is still charging and another is crediting customers.
Michigan	Yes but 10% cap reached	No	No	A utility can apply to the Public Service Commission (PSC) to recover its qualified costs via securitization bonds.[181] The PSC will issue a financing order if it finds that the net present value of the revenues to be collected under the financing order is less than via conventional financing methods. Bonds will be paid back via a nonbypassable charge (securitization charge).[182]	Bonds still being used for collection.

[178] Rules Governing the Restructuring of the Electric Industry Code of Massachusetts Regulations (CMR) 220 Section 11.03(2)(d) and (e): Department of Public Utilities https://www.mass.gov/files/220_cmr_11.00_6_17_16_0.pdf

[179] 2019 Annual Report Concerning Self-Generation July 1, 2019 The Commonwealth of Massachusetts Department of Public Utilities pursuant to Section 193 of the Electric Restructuring Act https://malegislature.gov/Reports/8222/OSGF%202018%20Report_7.1.19.pdf

[180] 2017 Annual Report Concerning Self-Generation June 19, 2018 The Commonwealth of Massachusetts Department of Public Utilities pursuant to Section 193 of the Electric Restructuring Act https://malegislature.gov/Bills/190/SD2692.pdf

[181] Michigan Senate Bill 937 (2000) Section 10a. (8) https://www.legislature.mi.gov/documents/1999-2000/publicact/pdf/2000-PA-0141.pdf

[182] Florida Public Service Commission September. 2000. P. 72 Key Aspects of Electric Restructuring Supplemental Volume: The State Summaries Division of Policy and Intergovernmental Liaison http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/keysupp.pdf

Nevada	Yes	No	No	There will be nonbypassable monthly charges on these customers, and as proposed will include the customer's share of ongoing "out-of the money portion" of the costs of long-term renewable energy contracts.[183]	To Be Determined
New Hampshire	Yes	Yes	No	The Stranded Cost Recovery Charge (SCRC) recovery mechanism was established pursuant to the Agreement to Settle PSNH (now known as Eversource) Restructuring in Docket No. DE 99-099 (Restructuring Agreement). The residential SCRC was 1.862 cents per kWh for residential customers effective April 1, 2018.[184]	Ongoing
New Jersey	Yes	Yes	Yes	A utility may recover stranded costs through a Market Transition Charge (MTC) collected as a limited-duration nonbypassable charge payable by all of the utility's customers over a	As of December 1, 2016, PSE&G's MTC has been $0.[186]

[183] See the May 27, 2020 Proposed Rules, which have been submitted to the Legislative Counsel Bureau for review: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2019-6/45096.pdf

[184] New Hampshire Public Utilities Commission Petition for Adjustment to Stranded Cost Recovery Charge Order Approving Stranded Cost Recovery Charge Order No. 26,116 (March 29, 2018). https://www.puc.nh.gov/regulatory/Orders/2018orders/26116e.pdf

[186] PSE&G Implementation of a Tariff change effective December 1, 2016 as per Board approval of changes to the Securitization Transition Charges (STC) resetting the Transition Bond Charge (TBC) and the Market Transition Charge-Tax Charge (MTC-Charge) components to zero. https://nj.pseg.com/aboutpseg/regulatorypage/electrictariffs/-/media/4f7284a682bd48d380a7236664686c3a.ashx

				set period of time and through the issuance of transition bonds by the utility or another financing entity approved by the New Jersey Board of Public Utilities. A utility's ability to assess an MTC and issue transition bonds is subject to the Board's approval.[185]	
New Mexico	No	No	No, failed legislation only	New Mexico is not a retail choice state but it did have CCA legislation which failed to pass a senate committee in March 2019.[187] The New Mexico legislation levied three separate exit fees payable by CCAs (not their customers) until the incumbent utility has recovered 92.5% of its revenues from the sale of electricity in benchmark year 1999. Those exit fees are the Societal Benefits Charges (SBC), Market Transition Charges (MTC), and Transition Bond Charges.	N/A - Failed legislation
New York	Yes	Yes	Yes	No exit fee	N/A
Ohio	Yes	Yes	No	The PUC approves a utility application to recover costs that are prudently incurred and directly assignable to retail electric generation	2005 for generation-related assets, and through 2010 for regulatory assets.[189]

[185] Abel and Shimabukuro. RL30405: State-by-State Comparison of Selected Electricity Restructuring Provisions. January 13, 2000. https://digital.library.unt.edu/ark:/67531/metacrs1173/m1/1/high_res_d/RL30405_2000Jan13.html
[187] New Mexico Senate Bill 374, failed to pass in March 2019 https://www.nmlegis.gov/Legislation/Legislation?Chamber=S&LegType=B&LegNo=374&year=19
[189] Concentric Energy Advisors, Inc. Retail Competition In Electricity What Have We Learned In 20 Years? July 23, 2019. P. 57 https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf

				consumers; the costs are unrecoverable in a competitive market; and the utility would otherwise be entitled an opportunity to recover the costs.[188]	
Oregon	Yes	No	No	Failed legislation to enable CCAs, House Bill 2852, gave the PUC jurisdiction to establish a cost recovery mechanism for each CCA. The cost recovery mechanism may "take the form of an exit fee, a nonbypassable charge or a credit applied to retail electricity consumers served by the authority."[190]	Failed legislation to enable CCAs, House Bill 2852, set the cost recovery mechanism to only apply for a 5-year period.[191]
Pennsylvania	Yes	Yes	No	The law permitted stranded cost recovery through the Competition Transition Charge (CTC) and costs were approved by the PUC.	2011[192]
Rhode Island	Yes	Yes	Yes	The nonbypassable transition charge for the recovery of generation-related stranded costs was 0.114¢ per kWh in 2019[193]. Transition charge costs must be associated	2029

[188] Abel and Shimabukuro. RL30405: State-by-State Comparison of Selected Electricity Restructuring Provisions. January 13, 2000. https://digital.library.unt.edu/ark:/67531/metacrs1173/m1/1/high_res_d/RL30405_2000Jan13.html
[190] Oregon House Bill 2852 (failed to pass in 2019) https://olis.leg.state.or.us/liz/2019R1/Measures/Overview/HB2852
[191] Oregon House Bill 2852 (failed to pass in 2019) https://olis.leg.state.or.us/liz/2019R1/Measures/Overview/HB2852
[192] Pennsylvania Public Utilities Commission. p. 1. The Expiration of Electric Generation Rate Caps. 2010. http://www.puc.state.pa.us/general/consumer_ed/pdf/Rate_Caps.pdf
[193] For A-16 Residential Delivery Service from National Grid Rhode Island https://www.nationalgridus.com/media/pdfs/billing-payments/bill-inserts/ri/cm4394_ri_bus-and-res-summary.pdf

				with (1) regulatory assets related to generation; (2) nuclear obligations; (3) above market payments for purchased power contracts in place as of December 31, 1995; and (4) The net unrecovered commitments and capital costs of all generating plants owned by the utility as of December 31, 1995.[194]	
Texas	Yes	Yes	No	As of March 2020, Texas New-Mexico Power's CTC is between $0.00/kWh and $0.00212/kWh for residential customers and CenterPoint's residential CTC is a credit of $0.001839/kWh.[195]	Ongoing but near zero or a credit in 2020 with a true-up until final
Montana	No	No	No	Montana was a retail choice state from 1997 until 2007. If a customer received default supply service, they had to have a paid-up account with the default supplier in order to exit the service in favor of a competitive supplier.[196] Rate is X[197]	1997

194 Rhode Island Title 39 Public Utilities and Carriers Chapter 39-1 Public Utilities Commission Section 39-1-27.4 http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.4.HTM
195 Public Utility Commission of Texas Comparison of Utilities' Other Nonbypassable Charges (March 1 2020). P. 6. http://www.puc.texas.gov/industry/electric/rates/trans/tdgenericratesummary.pdf
196 Florida Public Service Commission September. 2000. P. 83. Key Aspects of Electric Restructuring Supplemental Volume: The State Summaries Division of Policy and Intergovernmental Liaison http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/keysupp.pdf
197 NorthWestern Energy Montana Residential CTC-QF Rate Effective August 1, 2020 http://rates.northwesternenergy.com/residentialelectricrates.aspx

Appendix B. Comparative Matrix on IOU Reasonable Review Processes by State

State	Approver of Contracts	Is it an IRP-related process?	Is it an RPS-related process?	Other Requirements for Approval
Arizona	Commission	Yes	Yes	Numerous requirements detailed in the text
Colorado	Commission	Yes	Yes	CPCN for some projects
Minnesota	Commission	Yes	Yes	CPCN for large projects
North Carolina	Commission in some cases		Yes	CPCN
Utah	Commission			Approval of the significant energy resource decision under Section 54-17-501
Virginia	Commission	No	Yes	CPCN