Chapter 4. Excess Power Sales

4.1 Overview

In industrial facilities with very large thermal needs, such as in chemical, paper, refining, food processing, and metals manufacturing, sizing the CHP system to the thermal load can result in more electricity generated than can be used on-site.[82] Excess power sales may provide a revenue stream for a CHP project, possibly enabling the project to go forward, and help achieve state energy goals. This chapter focuses on access to markets for the export of excess electricity from CHP facilities, and the development of fair, reasonable, and non-discriminatory pricing for that electricity. While this guide does not advocate for development of these markets, it identifies how policies can be successfully implemented to facilitate this aspect of CHP if such markets exist. Three types of programs can provide for excess power sales from CHP systems:

- Programs based on state implementation of the federal Public Utility Regulatory Policies Act (PURPA)[83]
- Feed-in tariffs (FITs) and variations
- Competitive procurement processes.

4.2 PURPA Avoided Cost Rates

The high efficiencies achieved in CHP systems are dependent on a facility's ability to utilize waste heat. As such, CHP systems are regularly designed to meet the on-site thermal needs, not the electrical needs. The electrical load of the system can generally be met by adjusting the power-to-heat ratio of the system.[84] Sizing the CHP system to maximize efficiency in many industrial facilities (i.e., thermal match) may result in electricity generation capacity in excess of the host site's needs, introducing the added market risk of power pricing to an end-user usually in a different core business.[85]

PURPA Contracts

Congress enacted PURPA to encourage resource competition and development of cogeneration (another term for CHP) and renewable energy technologies by providing a market for electricity generated by non-utility power producers. CHP of any size and renewable resources up to 80 MW are eligible.

PURPA requires FERC to prescribe and periodically revise rules that require electric utilities to offer to purchase energy and capacity from Qualifying Facilities at the utility's avoided cost.[86] PURPA specifies that the rates paid by utilities for electric energy purchased from Qualifying Facilities may not exceed "the incremental cost to the electric utility of alternative electric energy."[87] PURPA defines incremental cost as "the cost to the electric utility of the electric energy which, but for the purchases from [the Qualifying Facility], such utility would generate or purchase from another source."[88] PURPA also requires electric utilities to purchase power from Qualifying Facilities at rates that are just and reasonable to the utility's customers and in the public interest and do not discriminate against Qualifying Facilities.

[82] CHP systems that are sized to meet the facility's thermal needs operate at the highest efficiencies.

[83] Congress passed PURPA in 1978, codified at 16 U.S.C. § 824a-3.

[84] ACEEE. *Certification of Combined Heat and Power Systems: Establishing Emissions Standard*. Prepared by Anna Shipley, et al. September 2001. Report Number IE014. http://pcpower.in/doc/combined_heat_and_power_systems.pdf.

[85] U.S. DOE. Combined Heat and Power: A Clean Energy Solution. August 2012.

[86] FERC complied with its PURPA obligation by promulgating Title 18, Part 292 in the Code of Federal Regulations.

[87] 16 U.S.C. § 824a-3(b).

[88] 16 U.S.C. § 824a-3(d).

States have significant flexibility in administering PURPA. For example, in a recent case on California's FIT for CHP systems up to 20 MW, FERC ruled that a "multi-tiered" avoided cost rate structure is consistent with PURPA.[89] Specifically, FERC affirmed that state procurement obligations can be considered when calculating avoided cost:

> "…where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement."[90]

Amendments to PURPA in 2005 and related FERC decisions have limited the applicability of PURPA in certain regions, particularly for facilities larger than 20 MW.[91] On January 19, 2006, the Federal Energy Regulatory Commission (FERC) issued a Notice of Public Rulemaking (NOPR) to implement this provision of the Energy Policy Act of 2005. In the Notice, FERC made a preliminary finding that Qualifying Facilities interconnected with utilities that are members of the Midwest Independent System Operator (ISO), PJM, ISO New England (ISO-NE), and the New York Independent System Operator (NYISO) have non-discriminatory access to such wholesale markets and that those markets satisfy the statutory criteria for removing the obligation of those electric utilities to enter into new contracts or obligations with Qualifying Facilities. For all other utilities, FERC proposes to determine on a case-by-case basis whether a given utility meets the statutory requirements for relief from its purchase obligation.[92] PURPA must-buy obligations were also excused for Qualifying Facilities greater than 20 MW in Midwest ISO, PJM, ISO-NE, NYISO, Southwest Power Pool (SPP), and California ISO.[93] The U.S. Department of Energy keeps a list of specific U.S. utilities covered by Title I of PURPA.[94]

4.3 Feed-in Tariffs

Feed-in tariffs (FITs)—also called premium payments, advanced renewable tariffs, minimum price standards, and standard offers—are among the most common policies employed by governments around the world to support the development of renewable resources in the power sector. As of early 2012, at least 65 countries and 27 international states and provinces have adopted these programs.[95] Key features include a guaranteed price and buyer, access to the grid, and stable long-term contracts, all of which improve CHP system investor confidence.[96] While today these programs are focused on renewable resources, FITs can be used to acquire CHP as well.

Like PURPA, FITs establish standard rates, terms, and conditions for electricity purchases from eligible generators. FITs may go further by establishing priority access and dispatch.

FIT program administrators must balance the need to set prices high enough to attract the types and amounts of generation desired, while protecting consumers from paying more than needed to achieve generation targets.

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[89] 133 FERC ¶ 61,059, Oct. 21, 2010. See the discussion in this guide on California's AB 1613 program.

[90] Ibid, FERC Order, p. 15, number 29.

[91] The Energy Policy Act of 2005 limited PURPA's scope through an amendment (210(m)) that allows utilities to file a request with FERC for relief from the mandatory purchase obligation (beyond existing contracts), at least for large projects, if they can show that competitive markets provide sufficient access for power sales from qualifying facilities. FERC found that six Regional Transmission Organizations and the Electric Reliability Council of Texas met this requirement. In their applications to FERC, utilities located in those designated regions can rely on a rebuttable presumption that qualifying facilities greater than 20 MW have nondiscriminatory access to wholesale markets.

[92] Edison Electric Institute. *PURPA: Making the Sequel Better than the Original*. December 2006. www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/purpa.pdf.

[93] EUCI, *Utilizing PURPA in Today's Deregulated Wholesale Market*. June 5, 2012. http://lklaw.com/wordpress_dev2/wp-content/uploads/2012/08/5June2012-Utilizing-PURPA-in-todays-Deregulated-Wholesale-Market.pdf.

[94] http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/other-regulatory-efforts/public.

[95] See REN21, *Renewables 2012 Global Status Report* (pages 66 and 118). www.map.ren21.net/GSR/GSR2012.pdf.

[96] For more information on FITs, see National Association of Regulatory Utility Commissioners. *Feed-in Tariffs: Frequently Asked Questions for State Utility Commissions*. June 2010. www.naruc.org/Publications/NARUC%20Feed%20in%20Tariff%20FAQ.pdf; National Regulatory Research Institute. *What Is an Effective Feed-In Tariff for Your State? A Design Guide*. April 2010. www.nrri.org/pubs/multi-utility/NRRI_FIT_design_april10-07.pdf; National Renewable Energy Laboratory. *A Policymaker's Guide to Feed-in Tariff Policy Design*. June 2010. www.nrel.gov/docs/fy10osti/44849.pdf; and California Energy Commission. 2010. *Feed-In Tariff Designs for California: Implications for Project Finance, Competitive Renewable Energy Zones, and Data Requirements*. Prepared by KEMA, Incorporated. www.energy.ca.gov/2010publications/CEC-300-2010-006/CEC-300-2010-006.pdf.

Typically, program administrators set either a fixed price varying by technology per unit delivered during a specified number of years or a premium payment on top of the energy market price. Such pricing relies on the estimated cost of eligible generation plus a reasonable return to investors.

Administrative price setting that does not reflect market conditions is leading to new pricing mechanisms to replace FITs in the United States. These mechanisms use competitive procurement among all FIT-eligible resources with the utility selecting the lowest-cost qualifying bids. For example, in late 2010, the California Public Utilities Commission adopted a Renewable Auction Mechanism for renewable distributed generators from 3 to 20 MW. The program offers a non-negotiable contract and least cost procurement up to a capacity cap. The Oregon Public Utility Commission's pilot FIT program for solar photovoltaic systems uses a simplified competitive bidding process to procure all systems larger than 100 kW. In addition, the program uses competitive bidding for one of two annual enrollment windows for systems larger than 10 kW.

Alternatively, FIT prices can be based on the value the generator provides to the electrical system or to society. The Sacramento Municipal Utility District FIT program, described in this section, is an example of such a program.

4.4 Competitive Procurement

In addition to FIT variations that employ market mechanisms as described above, governments and load-serving entities have established CHP targets or programs using legislation, directives, or settlements to advance competitive procurement processes to acquire larger CHP projects. This chapter provides examples of these approaches in California and Ontario, Canada. In restructured states, CHP projects also may bid into energy markets, as well as capacity and ancillary service markets if they can meet established protocols. This process is discussed in Appendix E.

4.5 Successful Implementation Approaches

4.5.1 California's CHP Feed-in Tariff for Investor-Owned Utilities

California's Assembly Bill (AB) 1613 (2006 and 2007) directed the California Public Utilities Commission (CPUC) to establish a standard tariff for selling electricity from eligible CHP systems to investor-owned utilities.[97] The act also directed the California Energy Commission (CEC) to adopt technical criteria for eligibility of CHP systems and required publicly owned utilities serving end-use customers to provide a market for the purchase of excess electricity from eligible CHP systems. This chapter describes the feed-in tariff that the CPUC established in compliance with AB 1613 for the state's three largest investor-owned utilities—Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.[98]

The CPUC approved three standard form contracts for buying excess electricity from AB 1613-eligible CHP systems:

- Standard contract for systems with a capacity up to 20 MW
- Simplified standard contract for systems that export no more than 5 MW
- A further simplified contract for systems with a capacity of less than 500 kW with a term of up to 10 years at the discretion of the seller.

[97] AB 1613 (2006) directed the CPUC to have investor-owned utilities file a just and reasonable tariff for excess power from CHP systems 20 MW and below. The statute requires local publicly owned utilities to develop a rate for excess power from CHP systems with no specified size limit. Subsequently, the CPUC directed stakeholders to negotiate the pricing provisions and standard contract or PPA. The result, the Market Price Referent (MPR), effectively incorporates time-of-day delivery, season, and fuel cost adjustment. The MPR can include adders for environmental benefits and T&D deferral. This is a distinct departure from the utility-proposed use of short run avoided cost (SRAC). SRAC is an energy-only price sometimes referred to as the "spot market price" for energy; it does not capture capacity value or the time of delivery value. California's Waste Heat and Carbon Emissions Reduction Act, Assembly Bill (AB) 1613 (2007), directed the CPUC, the California Energy Commission, and publicly owned utilities to establish policies and procedures for purchasing excess electricity from new, highly efficient CHP systems with a generating capacity of 20 MW or less. To be eligible, the CHP system must "be sized to meet the eligible customer-generator's thermal load," and must "operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat."

[98] www.cpuc.ca.gov/PUC/energy/CHP/feed-in+tariff.htm.

Purchase rates are based on the costs of a new combined-cycle gas turbine operating as a baseload resource, determined by the CPUC to be a reasonable proxy for the marginal unit the utilities avoid by purchasing from an eligible CHP facility. This approach is a distinct departure from PURPA approaches in some states that rely on short-run avoided costs, energy-only prices that do not capture the capacity value of CHP resources. Further, the CPUC determined that the utilities should bear any compliance costs for meeting GHG requirements associated with the excess electricity they purchase from eligible CHP facilities.

In addition, a locational adder is applied to CHP systems in high-value areas that meet certain requirements, reflecting savings from avoided T&D upgrades. Specifically, the CPUC adopted a 10% location bonus for CHP systems interconnected in areas with local resource adequacy requirements—grid-constrained areas that require purchases from local resources to avoid grid system failure. Based on determination of the utilities' expected T&D costs, as established in their general rate cases, the CPUC found the adder to be a conservative estimate for avoided T&D costs for the following reasons:[99]

- The bonus is applied only to the amount of energy sold to the utility, not the amount of energy that the utility avoids producing or purchasing due to the CHP generator.
- The adder level was based on average costs of avoided T&D investments in the utility's entire service area, not just the local resource adequacy areas where avoided costs are higher.
- T&D costs are likely to increase as a result of utility filings at FERC for increases in transmission rates, as well as for increases in distribution rates in CPUC proceedings.

CHP systems must comply with CPUC and California Independent System Operator Resource Adequacy requirements or, pending compliance, the facility will be paid pursuant to the standard "PURPA Contract" developed under the Qualifying Facility CHP Settlement approved by the CPUC (see Section 4.5.3).

Eligible systems also must receive certification by the CEC under its AB 1613 guidelines,[100] and the system must maintain that certification for the duration of the contract period. The CEC guidelines include emissions limits, an energy conversion efficiency standard, and other technical requirements.

The CPUC submitted a petition for declaratory order to FERC asking that the agency find that the Federal Power Act, PURPA, and FERC regulations do not preempt the CPUC's decision to require California utilities to offer a specified price to CHP generating facilities of 20 MW or less that meet energy efficiency and other requirements under AB 1613. On July 15, 2010, FERC issued an order finding that the CPUC could implement its program pursuant to PURPA under two conditions: (1) the CHP generators must be certified as PURPA qualifying facilities,[101] and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility.[102]

In a subsequent clarification order, FERC noted that states have a wide degree of latitude in implementing PURPA. FERC also stated that states can apply a multi-tiered avoided cost rate structure. Specifically, the CPUC could set avoided cost rates for AB 1613-compliant qualifying facilities based on higher, long-run avoided cost rates assuming these facilities avoid capacity purchases, and non-AB 1613 compliant qualifying facilities could continue to receive rates based on lower, short-run avoided costs. Further, FERC affirmed that state procurement obligations can be considered when calculating avoided cost (e.g., requirements that utilities buy particular sources of energy with certain characteristics or under long-term contracts).[103] FERC thereby affirmed that where a

[99] CPUC Decision 11-04-033. April 19, 2011. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/133787.htm.

[100] www.energy.ca.gov/wasteheat/index.html.

[101] Unless the customer is a public agency described in 16 USC §824(f), facilities may submit to FERC a self-certification application for Qualifying Facility status, "a certification by the applicant itself that the facility meets the relevant requirements for [Qualifying Facility] status, and does not involve a determination by the PUC of Oregon as to the status of the facility…. An applicant self-certifying may, however, receive a rejection, revocation or deficiency letter if its application is found, during periodic compliance reviews, not to comply with the relevant requirements." See www.ferc.gov/docs-filing/forms/form-556/form-556.pdf. For more information, see www.ferc.gov/industries/electric/gen-info/qual-fac/obtain.asp.

[102] 132 FERC ¶ 61,047.

[103] 133 FERC ¶ 61,059.

state requires a utility to procure a certain percentage of energy from generators with certain characteristics, it may make separate avoided cost calculations for generating facilities with those same characteristics in order for that utility to meet its state procurement obligations.

AB 1613's intent is to help decrease the risk of the cost of project financing by providing an additional stream of revenue. As of October 2012, four projects have been certified as meeting the technical requirements of AB 1613 and one is pending. However, no power purchase contracts have been signed. Some project owners and developers have expressed concern with daunting interconnection hurdles and continue to negotiate with both the California ISO and the local utility.[104] The CPUC and the CEC are aware of the difficulties and are expected to address and resolve the issues.

How the Criteria Are Addressed

Policy Intent. The CPUC's implementation of AB 1613 addressed the directive to increase CHP deployment to help meet GHG reduction goals (providing the ability to sell excess power encourages optimal sizing of CHP projects) and to "ensure that ratepayers not utilizing combined heat and power systems are held indifferent to the existence of this tariff."[105] Other principles addressed by the CPUC include consistent and transparent terms and conditions for each utility, lowering transaction costs, providing sufficient payment to attract new projects but not overpaying, and complementing other programs such as the Self-Generation Incentive Program, which is designed for use of electricity on-site rather than for export.[106]

Market Signals. California AB 1613 provides clear direction to the CPUC and the state's utilities that CHP is a priority resource and payment should be at the utility's avoided cost. This sends a clear message to the market.

Ratepayer Impact. AB 1613 requires that the program and the price paid to eligible CHP systems for excess electricity represent fair compensation and hold ratepayers indifferent. The CPUC found that the MPR is an avoided cost and that it should be based on the costs of a combined cycle gas turbine and comprised of a fixed and a variable component.[107] The CPUC further concluded that to ensure ratepayers are held indifferent, a 10% location bonus should be applied to eligible CHP located in high-value areas to account for societal, environmental, and locational benefits.[108]

4.5.2 Oregon's Standard PURPA Contracts and Avoided Cost Rates

In 2004, the Public Utility Commission (PUC) of Oregon began a thorough investigation into rates, terms and conditions for PURPA Qualifying Facilities. The PUC of Oregon also adopted complementary procedures for interconnection[109] and dispute resolution.[110] This section focuses on standard contracts and avoided cost rates for CHP Qualifying Facilities up to 10 MW and guidelines for negotiating contracts and avoided cost rates for larger projects.[111]

[104] California Energy Commission. *A New Generation of Combined Heat and Power: Policy Planning for 2030*. 2012. Prepared by Bryan Neff. www.energy.ca.gov/2012publications/CEC-200-2012-005/CEC-200-2012-005.pdf. Also, ICF conversation with Bryan Neff, Oct. 16, 2012.

[105] Pub. Util. Code § 2841, subd. (b)(4).

[106] CPUC Decision 09-12-042. December 21, 2009. http://docs.cpuc.ca.gov/published/FINAL_DECISION/111494.htm.

[107] CPUC Decision 09-12-042. December 17, 2009. http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/111494.PDF. See discussion, page 69 and Finding of Fact 22.

[108] Ibid, see discussion, page 69, and Conclusions of Law 3, 4, 10 and 11.

[109] The PUC of Oregon adopted interconnection procedures and standard-form interconnection applications and agreements for CHP qualifying facilities and other generating facilities under state jurisdiction up to 10 MW (see http://apps.puc.state.or.us/orders/2009ords/09-196.pdf) and greater than 20 MW (see http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=10-132). Interconnection regulations for distributed generation between 10 MW and 20 MW have not yet been established.

[110] *See Order No. 08-355 (Docket AR 526) at* http://apps.puc.state.or.us/orders/2008ords/08-355.pdf.

[111] The key decisions updating Oregon's PURPA policies for regulated utilities are detailed in Order Nos. 05-584, 06-538 and 07-360. Order Nos. 06-586 and 07-407 provide clarifications and corrections. See the case file for Docket UM 1129 at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=11114.

Standard Contracts and Avoided Cost Rates

PURPA requires utilities to provide standard contracts and avoided cost rates for Qualifying Facilities up to 100 kW.[112] State utility regulators have discretion to direct regulated utilities to increase that cap.[113] Doing so reduces market barriers for small Qualifying Facilities to sell excess power to utilities. Further, minimum project size and other requirements for competitive utility solicitations and wholesale energy markets may preclude participation by small Qualifying Facilities.

As a result of its investigation, the PUC of Oregon directed regulated utilities to offer standard-form contracts and standard avoided cost rates for Qualifying Facilities up to 10 MW. In doing so, the PUC of Oregon concluded:

> "Standard contracts are designed to eliminate negotiations and to thereby remove transaction costs….In addition to transaction costs, which in economics and related disciplines are traditionally considered to encompass only those costs that are incurred to make an economic exchange, parties identified other market barriers such as asymmetric information and an unlevel playing field that obstruct the negotiation of non-standard [Qualifying Facility] contracts. Just like transaction costs, these market barriers can render certain [Qualifying Facility] projects uneconomic to get off the ground if an individual contract must be negotiated."[114]

The PUC of Oregon further required that Qualifying Facilities of any size should have the option to enter into contracts up to 20 years.[115] In making this determination, the PUC of Oregon's objective was to establish a maximum term that enables Qualifying Facilities to obtain project financing. At the same time, the PUC of Oregon limited the impact of standard (forecasted) avoided cost rates diverging from actual avoided costs by allowing fixed pricing only for the first 15 years of the contract, with market pricing required for the last five years of the 20-year term.

Avoided cost rates adopted by the PUC of Oregon distinguish whether the utility is in a resource deficient position or a resource sufficient position. When the utility is resource deficient, avoided cost rates reflect longer term resource decisions that are subject to deferral or avoidance due to power purchases from the Qualifying Facility. Thus, costs are based on the variable and fixed costs of a natural gas-fired, combined-cycle combustion turbine (CCCT). When a utility is resource sufficient, as may be the case in the early years of the contract term, avoided cost rates are based on projected monthly on- and off-peak market prices as of the date of the utility's avoided cost filing.

Utilities must file avoided cost rates every two years and 30 days after the PUC of Oregon issues its acknowledgment order on the utility's integrated resource plan. The filings update both CCCT costs and forward market prices and are vetted in a public process, with rates subject to Commission approval.

Guidelines for Negotiating Contracts Over 10 MW

The PUC of Oregon also adopted procedures for negotiating contracts for Qualifying Facilities larger than 10 MW.[116] The procedures outline steps in the negotiation process with timelines and provide guidance to utilities for adjusting standard avoided cost rates to account for each of the factors promulgated by FERC. These include availability of Qualifying Facility capacity or energy during peak periods, contribution of the Qualifying Facility to deferral of capacity additions, reduced use of fossil fuels, and reduced line losses.[117] Utilities must provide the

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[112] The Law Offices of Carolyn Elefant. Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and a Proposed Path for Reform. 2011. www.cleanenergy.org/images/files/Elefant_Reviving_PURPA_Avoided_Costs_2011.pdf

[113] 18 C.F.R. §292.304(c)(2).

[114] Order No. 05-584 at 16.

[115] The standard-form contracts approved by the PUC of Oregon establish other important terms and conditions such as creditworthiness and default security.

[116] See Order Nos. 07-360 and 07-407.

[117] 18 CFR 292.304(e).

Qualifying Facility with a description of the methodology for each adjustment. The PUC of Oregon also directed the utilities to evaluate whether the Qualifying Facility's location may avoid or defer transmission or distribution system upgrades. Utilities were instructed not to make adjustments to standard avoided cost rates other than those consistent with the guidelines or otherwise approved by the PUC of Oregon.

Separate Rates for Renewable Qualifying Facilities

Recently, the PUC of Oregon adopted separate avoided cost rates for renewable Qualifying Facilities, including CHP facilities fueled by biomass resources eligible under the state's Renewable Portfolio Standard.[118] Rates are based on the timing and cost of the next utility-scale renewable resource identified in the utility's integrated resource plan.

When entering into a new PURPA contract with the utility, renewable Qualifying Facilities can choose the renewable avoided cost rates or the standard avoided cost rates. The renewable avoided cost rates are available only during the period of renewable resource deficiency, when the utility projects a need for a new large-scale renewable resource. That resource is considered avoidable until a utility makes an irreversible commitment to acquire it—after the execution of power purchase agreements or selection of a utility self-build alternative at the conclusion of the competitive bidding process. To receive the renewable rates, the facility must transfer its renewable energy credits to the utility.

In the early years of the contract when the utility may be renewable resource sufficient, avoided cost rates are based on forward market prices, just as they are for non-renewable Qualifying Facilities. During this period, the renewable facility retains its renewable energy credits.

In 2011, FERC concluded that "where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement."[119]

How the Criteria Are Addressed

Policy Intent. The PUC of Oregon's goal is "to encourage the economically efficient development of these [Qualifying Facilities], while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing [Qualifying Facility] power."[120] Results to date suggest their approach achieves the policy intent.

Market Signals. Oregon's avoided cost rates recognize the difference in Qualifying Facility value when a utility is resource-sufficient versus when it is resource-deficient. When the utility does not need large-scale thermal or renewable resources, as may be the case in the early years of the Qualifying Facility contract, avoided cost rates are based on projected monthly on- and off-peak electricity market prices at the appropriate trading hubs. Conversely, when the utility is resource-deficient, rates are based on the projected cost of a new CCCT, with its cost and timing vetted in the utility's integrated resource planning process. Further, while Qualifying Facilities may choose fixed avoided cost rates for the first 15 years of the contract, during the last five years the fuel price component of the rates are based on monthly natural gas price indexes.[121] Qualifying Facilities also may choose these market-based options for the entire contract term.

Ratepayer Impact. Under PURPA, utilities may not be required to pay more than avoided costs for Qualifying Facilities. The regulations adopted by the PUC of Oregon for small and large Qualifying Facilities uphold this principle. In addition, the PUC of Oregon's guidance on contract provisions related to creditworthiness, security,

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[118] See Order No. 11-505 (Docket UM 1396) at http://apps.puc.state.or.us/orders/2011ords/11-505.pdf.

[119] 133 FERC 61,059, pp.13-14.

[120] Order No. 05-584 at 1.

[121] Qualifying facilities selling to Portland General Electric have an additional market-based option, a daily indexed rate based on the Dow Jones Mid-Columbia electricity price index.

default, and insurance also protect ratepayers. Further, the PUC of Oregon's adoption of a separate rate for renewable resource Qualifying Facilities holds ratepayers indifferent. Under the state's Renewable Portfolio Standards, electric utilities must acquire such resources, and the renewable avoided cost rates are based on the cost of the next large-scale renewable resource identified in the utility's integrated resource plan.

4.5.3 California Qualifying Facility and CHP Program Settlement Agreement

In December 2010, the CPUC adopted a settlement agreement[122] that in part established a replacement program for PURPA contracts through 2020 for CHP Qualifying Facilities located in the state that are larger than 20 MW.[123] The new CHP procurement program features requests for offers (RFOs) exclusively for CHP resources,[124] with prices negotiated on a contract-specific basis and contract terms based on, but not limited to, a CPUC-approved pro forma contract.[125] The settlement also adopted an overall GHG emissions reduction target of 4.8 million metric tons of carbon dioxide equivalent for all investor-owned utilities, electric service providers and community choice aggregators to promote efficient CHP systems.[126]

The program was designed to preserve existing CHP facilities facing expiring PURPA contracts and to encourage the development of new CHP resources in the state. Under the settlement, parties agreed not to oppose a joint application to FERC by the three large investor-owned utilities to terminate their requirement under PURPA to enter into new contracts with qualifying facilities larger than 20 MW.[127] CHP facilities less than 20 MW can choose to participate in the new program or the traditional PURPA program.

The settlement agreement covers three periods: a transition period, an initial program period, and a second program period. The settlement established an overall procurement target of 3,000 MW of capacity from CHP facilities.[128] The utilities can meet these targets through a combination of procurement options, including the CHP-only RFOs, bilaterally negotiated contracts, or one of several pro forma contracts approved by the settlement.

Table 1 shows the utilities' individual targets by Nov. 22, 2015 (during the initial program period), for each of three solicitations—A, B, and C:[129]

Table 1. California Utility Solicitation Target[130]

Utility	Target A	Target B	Target C	IOU Total
SCE	630 MW	378 MW	394 MW	1,402 MW
PG&E	630 MW	376 MW	381 MW	1,387 MW
SDG&E	60 MW	50 MW	50 MW	160 MW
Total	1,320 MW	804 MW	825 MW	2,949 MW

[122] http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.pdf.

[123] Decision 10-12-035. December 21, 2010. http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128624.pdf. The CPUC also issued two clarifications through Order Nos. 11-03-051 (http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/132685.pdf) and 11-07-010 (http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/139237.pdf).

[124] The following types of CHP systems larger than 5 MW are eligible for the requests for offers: existing facilities, new facilities, repowered facilities, expanded facilities, and facilities converted to utility prescheduled facilities—utility-dispatchable generation.

[125] www.pge.com/includes/docs/pdfs/b2b/energysupply/qualifyingfacilities/settlement/exhibit_5.pdf.

[126] The three large investor-owned utilities are required to procure CHP resources on behalf of electric service providers and community choice aggregators to meet the settlement's greenhouse gas reduction goals.

[127] FERC approved the joint application in Docket No. QM11-2-000 on June 16, 2011 (135 FERC ¶ 61,234).

[128] Existing CHP systems could fully subscribe to the 3,000 MW target under the program. See California Energy Commission. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Prepared by ICF International. June 2012. www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf. An as-available contract also is available, paid at the utility's published Short Run Avoided Costs, but is capped for each utility at low MW levels.

[129] To meet the total of 3,000 MW, the CPUC directed SDG&E to acquire an additional 51 MW by 2018 (during the second program period).

[130] CPUC. *Qualifying Facilities and CHP Program Settlement,* www.cpuc.ca.gov/PUC/energy/CHP/settlement.htm.

During the second program period, utilities must procure CHP resources to fill any portion of their megawatt targets unmet during the first program period. The CPUC may establish in its Long Term Procurement Planning preceding any additional CHP capacity needed to meet the utilities' GHG emissions reduction targets. Each utility must report semi-annually to the CPUC on progress toward both megawatt and GHG emissions reduction targets.

The utilities issued their first RFOs in late 2011/early 2012 and are beginning to submit resulting contracts to the CPUC for approval. For example, SCE has executed five CHP contracts under its first solicitation resulting in more than 750 MW.[131] The CPUC posts updated results on its website.[132]

How the Criteria Are Addressed

Policy Intent. According to the settlement agreement, "The purpose of the State CHP Program is to encourage the continued operation of the State's existing CHP facilities, and the development, installation, and interconnection of new, clean, and efficient CHP Facilities, in order to increase the diversity, reliability, and environmental benefits of the energy resources available to the State's electricity consumers." The agreement further states that the agreement will retain existing efficient CHP units, support operational changes for inefficient CHP facilities to provide greater benefits to the state, and attract efficient new CHP systems. Based on the early results, it seems that the program will achieve the policy intent.

Market Signals. The program provides greater regulatory and market certainty for CHP facilities, encourages upgrading of inefficient facilities through repowering or a change of operations, and provides market-based compensation to sustain California CHP resources at fair prices.

Ratepayer Impact. The RFOs will result in competitive prices that are ultimately subject to Commission approval. The utilities will select the best offers among the CHP resources bidding in the RFOs up to their CPUC-assigned megawatt targets. This process is similar to the utilities' solicitations for conventional power plants as well as resources eligible for the state's Renewable Portfolio Standards. A utility may cite excessive bid prices as a justification for failing to meet its CHP megawatt targets.

4.5.4 Ontario Power Authority CHP Program

Ontario's existing supply resources are expected to decline by about half by 2030, including 3,500 MW of coal plant retirements. The province is planning for more than 8,000 MW of new renewable generation by 2018 and expects transmission to reach its limit in some areas. The province sees CHP as an important contributor to its future energy supply, with opportunities for projects located in growing or dense urban areas, at industrial plants as they replace inefficient boilers, and where strategically sited CHP can serve as an alternative to transmission upgrades.[133]

Beginning in 2005, the Ontario Minister of Energy issued a series of directives to the Ontario Power Authority (OPA) resulting in several solicitations for high efficiency CHP facilities delivering electricity to the Independent System Electricity Operator (IESO)-controlled grid, a local distribution company, or an end user. The initial directive instructed the OPA to procure 1,000 MW of CHP in the province.[134] In 2007, the Minister directed the OPA to establish a standard offer program for small CHP facilities.[135] A 2008 directive[136] required the OPA to develop a

[131] www.sce.com/EnergyProcurement/renewables/chp/rfo.htm.

[132] www.cpuc.ca.gov/PUC/energy/CHP/settlement.htm.

[133] Slides 9-11: https://cms.powerauthority.on.ca/sites/default/files/page/CHPSOP_Stakeholder_Presentation.pdf; slides 11 and 12: www.powerauthority.on.ca/sites/default/files/page/CHPIV_Information%20Session_v4_0.pps; and slide 24: http://powerauthority.on.ca/sites/default/files/news/APPRO%202011%20Presentation%20by%20Amir%20Shalaby%20FINAL.pdf.

[134] See www.powerauthority.on.ca/sites/default/files/619_15-06-2005_MOE_Letter_to_JCarr.pdf.

[135] www.powerauthority.on.ca/sites/default/files/page/4820_June_14,_2007_–_Clean_Energy_and_Waterpower_in_Northern_Ontario_Standard_Offer_Directive.pdf.

[136] www.powerauthority.on.ca/sites/default/files/page/6933_April_10_2008_Procurement_RFP_CHP.pdf.

procurement process to achieve the Minister's target of 100 MW of CHP fueled by renewable energy sources, since OPA did not receive any offers from such facilities in its prior solicitation.[137]

The Minister's 2010 directive[138] largely replaces these earlier orders. It instructs the OPA to acquire incremental CHP projects to reach the 1,000 MW target through: (1) individually negotiated contracts with CHP projects larger than 20 MW, and (2) a standard offer program for projects up to 20 MW that are cost-effective and located in areas where the local distribution system can accommodate them.

The OPA must consider a number of factors in procuring CHP projects under the current directive, including:

- Cost-effectiveness
- Local benefits
- Viability and sizing for heating requirements
- Load following capability and other operability requirements
- Reasonableness of contract terms and risk/reward balance for Ontario electricity consumers.

Competitive Procurements for Large CHP Facilities

The OPA awarded seven contracts totaling 415 MW through its first CHP procurement in 2006, open to facilities that could provide at least 5 MW of capacity (2 MW for district energy facilities) and be operational by June 1, 2012. A second solicitation in 2008 for CHP facilities with a minimum contract capacity of 10 MW yielded no contracts. A third request for proposals issued in 2009, for renewable-fueled CHP projects larger than 10 MW, resulted in two contracts for an incremental 45 MW of CHP.[139]

In 2011, the OPA initiated its fourth CHP solicitation with a target of 300 MW of projects larger than 20 MW, connected at the distribution or transmission level.[140] Projects using natural gas, by-product fuels, renewable biomass, biogas, and "under-utilized" energy were eligible. The OPA identified five geographic areas where CHP projects could be sited.[141] The OPA determined that none of the proposals submitted met the criteria in the solicitation and offered no contracts.[142] However, the OPA has also negotiated contracts with large CHP facilities outside of the competitive process.[143]

Standard Offer Program for Small CHP Facilities

The OPA is currently acquiring distribution system-connected CHP projects up to 20 MW under its Clean Energy Standard Offer Program with a target capacity of 200 MW. The program has two tracks:

- The standard offer for natural gas-fired CHP projects has an initial allocation of 150 MW.[144]
- The standard offer for energy recovery projects has an initial allocation of 50 MW.[145] Eligible projects include energy recovery from pressure reduction facilities, hot exhaust streams (other than from electricity generating facilities) and by-products of flared processes.

[137] The complexity of program rules and the form contracts are considered to be possible reasons for the lack of bids. Subsequently, the OPA increased its outreach and education to market participants.

[138] www.powerauthority.on.ca/sites/default/files/new_files/about_us/pdfs/MC-2010-4477.pdf.

[139] www.powerauthority.on.ca/gp/procurement-archive.

[140] http://powerauthority.on.ca/chp-iv-procurement.

[141] http://powerauthority.on.ca/sites/default/files/page/Appendix%20K_v2%20(Eligible%20Areas)%20(Posted).pdf.

[142] Other than the bids not meeting the necessary criteria, the determinations are treated as confidential. Also, see www.powerauthority.on.ca/chp-iv-procurement.

[143] Currently, this information is confidential.

[144] https://cms.powerauthority.on.ca/combined-heat-power-standard-offer-program-chpsop.

[145] https://cms.powerauthority.on.ca/energy-recovery-standard-offer-program-ersop.

Any remaining capacity under the overall 200 MW target will be available on a first-come, first-served basis to either type of project. Contract terms for the CHP standard offer program are up to 20 years for new projects and, for existing projects built no earlier than 2005, 20 years less the number of days between in-service and application dates. Capacity payments are $28,900 per MW-month, designed to cover the cost of investment, ongoing operating expenses, and a deemed rate of return, with 30% of this amount escalated annually based on the Consumer Price Index. Any additional payment is determined by a formula that takes into account the imputed gross revenue the CHP facility makes in the IESO energy market and the imputed variable operation and maintenance costs of the facility, including day-ahead natural gas prices. Each month, the OPA makes a "Contingent Support Payment" to the project owner if the fixed capacity payment exceeds the facility's imputed net revenue, or the project owner makes a payment to the OPA if the imputed net revenue exceeds the fixed capacity payment.[146]

The CHP standard offer program was available only in certain locations,[147] with some exceptions, for the initial period, which closed on June 30, 2011. The program was open to all locations for the second period, ending later that summer. The same location restrictions applied to the energy recovery standard offer program, which was offered in a similar timeframe.

Application requirements include a fee of $1,000, security of $20,000 per MW of annual average contract capacity, confirmation of an initial discussion on interconnection with the local distribution company, evidence of sufficient access to the site to build and operate the project, and a plan that demonstrates the facility will achieve a useful heat output of at least 15% beginning in the third contract year and on average during the first 10 years. The OPA performs a transmission availability test to determine whether there is sufficient transmission capacity for the CHP project even if it is connected at the distribution level; the local distribution company performs a distribution availability test for distribution-connected systems.

As of the end of 2011, the OPA had signed 6 MW of standard offer contracts and were reviewing remaining applications totaling 300 MW under the first track. OPA staff and project proponents expected additional contracts to be signed in 2012.[148] As of the end of 2011, OPA reports some 972 MW of non-renewable CHP facilities under contract as part of the second track, nearly all of which already have achieved commercial operation.[149]

How the Criteria Are Addressed

Policy Intent. The goal of Ontario's competitive procurements for larger CHP facilities is development of cost-effective, efficient resources to meet electricity demand in the province, with delivery of firm and reliable supply to the IESO-controlled grid or a local distribution company. The standard offer programs are intended to support development of cost-effective, efficient CHP and energy recovery facilities up to 20 MW, connected to the local distribution system where such generation can be effectively accommodated. These goals are being met through the policies documented by the OPA.[150]

Market Signals. The OPA selects CHP projects in its competitive procurements based on an economic evaluation using a bid statement format prescribed in the solicitation, as well as conformance with mandatory requirements such as facility eligibility, site control and demonstration that the facility will meet the heat output standard. Projects also must pass a screening process to ensure the distribution and transmission system has, or will have,

[146] Based on data from various sources for a reference 10 MW CHP facility, the OPA assumed a capital cost of $2,170 per MW. The 30% escalation factor is the ratio of costs that change annually to fixed costs. The reference plant has an assumed heat rate of roughly 6.0 MMBtu/MWh. See OPA's "Combined Heat and Power Standard Offer Program (CHPSOP) Stakeholder Session." Feb. 25, 2011 (slides updated March 3, 2011). https://cms.powerauthority.on.ca/sites/default/files/page/CHPSOP_Stakeholder_Presentation.pdf.

[147] https://cms.powerauthority.on.ca/sites/default/files/page/CESOP%20Locational%20Eligibility_0.pdf.

[148] http://magazine.appro.org/index.php?option=com_content&task=view&id=1816&Itemid=60.

[149] https://cms.powerauthority.on.ca/sites/default/files/news/OPA_ProgressReportonElectricitySupply_2011_Q4%20Final%20for%20posting%2020120508.pdf.

[150] Ibid.

sufficient connection resources to accommodate the CHP project by the required on-line date.[151] The OPA support for the standard offer programs is based on best estimates of costs for efficient, small CHP and energy recovery systems, taking into account day-ahead market prices for natural gas as well as sales to the Ontario energy market. The strong results of new CHP show the positive market signals being sent to Ontario's potential CHP users.

Ratepayer Impact. The competitive procurements elicit least-cost prices among potential suppliers of efficient and well-located CHP facilities. The OPA has rejected all offers in these solicitations when none of the proposals meet the criteria set out by the Ministry of Energy, including cost-effectiveness and benefits for the Ontario electricity grid. Applications for standard offer programs for small CHP and energy recovery facilities also must meet these criteria, and payment is based in part on prices in energy and natural gas markets. In addition, all of these programs are subject to overall capacity caps, limiting cost to consumers, and within these caps the OPA allocates the amount each program acquires over time. Further, the OPA gives priority to the most energy-efficient and best located projects to reap the greatest benefits for ratepayers.

4.6 Conclusions

While this guide does not explore the merits or problems with the development of the markets discussed in this chapter; it identifies how policies can be successfully implemented to facilitate this aspect of CHP if such markets exist. Excess power sales can be used by CHP projects while helping achieve state energy goals. The most efficient CHP systems are designed to meet the thermal needs of the host, so ensuring CHP systems are properly sized for the needs of the user is important during project consideration. However, should excess energy be available because of additional realized efficiencies or due to the large thermal demands of the facility, options are available for sale of that energy to the utility. Access to markets for the export of excess electricity from CHP facilities with fair, reasonable, and non-discriminatory pricing for sales of excess electricity are important enabling factors. There are three mechanisms states can use to provide for excess power sales from CHP systems, along with the following successful implementation approaches:

SUCCESSFUL IMPLEMENTATION APPROACHES: EXCESS POWER SALES

- Programs based on state implementation of PURPA:
  - Technical criteria for CHP eligibility (system size and efficiency)
  - Use of standard contracts and pricing
  - Inclusion of locational adders for avoided T&D investments
- Feed-in tariffs and variations:
  - Technical criteria for CHP eligibility (system size and efficiency)
  - Use of standard contracts
  - Pricing based on avoided cost rates for specified technologies (i.e., renewables)
- Competitive procurement processes:
  - Establishment of standard offer programs for small CHP
  - Competitive procurements for large CHP

[151] For an example of the detailed evaluation process, see the fourth CHP solicitation at https://cms.powerauthority.on.ca/sites/default/files/page/CHP%20IV%20RFP%20%28Posted%20on%20Aug%2031%202011%29.pdf.