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SEE Action

STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK

Guide to the Successful Implementation of State Combined Heat and Power Policies

Industrial Energy Efficiency and Combined Heat and Power Working Group

Driving Ratepayer-Funded Efficiency through Regulatory Policies Working Group

March 2013

The State and Local Energy Efficiency Action Network is a state and local effort facilitated by the federal government that helps states, utilities, and other local stakeholders take energy efficiency to scale and achieve all cost-effective energy efficiency by 2020.

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Letter from the Co-Chairs of the SEE Action Industrial Energy Efficiency and Combined Heat and Power Working Group

To all,

This *Guide to Successful Implementation of State Combined Heat and Power Policies* is designed to inform state regulators, facility operators, utilities, and other key stakeholders about the benefits, costs, and implications of greater use of combined heat and power (CHP). Achieving greater use of CHP is consistent with President Obama's Executive Order 13626-Accelerating Investment in Industrial Energy Efficiency, which calls for 40 gigawatts (GW) of new, cost-effective CHP by 2020.

CHP can provide significant energy, energy system, and environmental benefits. CHP is inherently more efficient than obtaining electricity from a utility and generating heat or steam from an on-site boiler. By being more efficient, less fuel is consumed and greenhouse gases (GHGs) and other emissions are reduced. Properly designed CHP can bolster the grid, provide security benefits, and potentially support intermittent renewable energy sources.

An assumption of this guide is that CHP must have the potential to be economically viable. Chapter 2 describes the design of standby rates charged by utilities to a customer with CHP, a potential impediment to the implementation of CHP.

Economical CHP may encourage large energy users to reduce purchased electricity or leave the grid entirely by self-generating. This impacts regulators and utilities because large customers leaving the grid may shift costs to other customers, requiring these remaining customers to carry the costs of the departing CHP user. Therefore, the challenge for all affected parties is to identify the most equitable arrangement that encourages adoption of CHP while ensuring that costs are not inequitably transferred to those not participating in CHP. Among the policy considerations that must be evaluated are the following: (1) Can CHP be directed to provide system benefits for all customers? (2) How can standby rates be designed to avoid cross-subsidization?

Whether a CHP system exports excess electricity or not can create additional issues that must be considered. As noted in Chapters 3 and 4, CHP that is designed only to supply a facility's energy needs will require an interconnection agreement between the CHP facility and the local utility. However, a CHP project that generates excess electricity may compete with a utility or other generators, and merits different regulatory and contractual considerations.

Finally, Chapter 5 discusses the use of CHP as a clean energy resource, and identifies states where CHP qualifies for the clean energy portfolio standard. While advocates of renewable energy would agree that waste heat to power (also known as waste heat recovery or bottoming cycle CHP) is a clean energy source, others have expressed skepticism that CHP can truly be considered clean energy because it often fundamentally uses a fossil fuel, namely natural gas, albeit efficiently and with lower environmental impact. Considering if and/or how to credit the thermal outputs of CHP that use biomass or biogas can be an important clean energy portfolio standard discussion.

The working groups, authors, and contributors hope that this guide clearly and accurately describes the policy issues all parties must address when evaluating CHP. To ensure the process is transparent, members were given the option to include a statement of alternative perspectives; see Appendix F.

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Acronyms

AB	Assembly Bill
AEC	alternative energy credit
APS	alternative energy portfolio standard
Btu	British thermal unit
CCCT	combined-cycle combustion turbine
CCS	carbon capture and storage
CEC	California Energy Commission or clean energy credit
CEPS	clean energy portfolio standard
CES	community energy and sustainability
CHP	combined heat and power
CPUC	California Public Utilities Commission
DG	distributed generation
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables & Efficiency
EERS	energy efficiency resource standard
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIT	feed-in tariff
GHG	greenhouse gas
GW	gigawatt
HB	House Bill
HRSG	heat recovery steam generator
IEE	industrial energy efficiency
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent System Electricity Operator
IOU	investor-owned utility
ISO	independent system operator
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
MMBtu	million Btu
MPR	market price reference
MPUA	Missouri Public Utility Alliance
MW	megawatt
MWh	megawatt-hour
OPA	Ontario Power Authority
PACT	program administrator cost test
PG&E	Pacific Gas and Electric
PSC	Public Service Commission
PUC	Public Utilities Commission
PURPA	Public Utility Regulatory Policies Act
REC	renewable energy credit
RFO	requests for offer
RPS	renewable portfolio standard
RTO	regional transmission organization
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SEE	State and Local Energy Efficiency
T&D	transmission and distribution
UL	Underwriters Laboratories
WHP	waste heat to power

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Executive Summary

Combined heat and power (CHP) can be an efficient and clean[1] method of generating electric power and useful thermal energy from a single fuel source at the point of use. Instead of purchasing electricity from the local utility and burning fuel in an on-site furnace or boiler to produce needed thermal energy,[2] an industrial or commercial user can use CHP to provide both energy services in one energy-efficient step. Consequently, CHP can provide significant energy efficiency and environmental advantages over separate heat and power. As with all power generation, CHP deployment has unique cost, operational, and other characteristics, but it is a proven and effective available clean energy option that can help the United States enhance energy efficiency, reduce greenhouse gas (GHG) emissions, promote economic growth, and maintain a robust energy infrastructure.

Currently, 82 gigawatts (GW) of CHP capacity are in use at more than 4,100 sites in the United States. Although 87% of CHP is in manufacturing plants around the country, a growing number of facilities from other sectors are considering its use.[3] Estimates indicate the technical potential[4] for additional CHP at existing industrial and commercial/institutional facilities is more than 130 GW.[5] A 2009 study by McKinsey and Company estimated that 50 GW of CHP in industrial and large commercial/institutional applications could be deployable at reasonable returns with then-current equipment and energy prices.[6] Today's economic and technical potential likely exceeds these estimates given the improving outlook in natural gas supply and prices. The importance of CHP to the United States was highlighted in President Obama's Executive Order of August 30, 2012, which calls for deployment of 40 GW of new, cost-effective CHP by 2020.[7]

Source: CHP Installation Database, ICF International
www.eea-inc.com/chpdata/index.html

Figure ES.1. Locations of existing CHP capacity

[1] State policymakers, project developers, advocates, utilities, and others have various definitions of "clean" energy. This guide does not attempt to create one definition, but rather recognizes that the primary audiences for the guide are state regulators and that they define it as they see fit.

[2] In some cases, there are opportunities to purchase thermal energy from a district energy system or steam loop.

[3] U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA). *Combined Heat and Power: A Clean Energy Solution*. August 2012. www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf.

[4] The technical market potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. The technical potential includes sites that have the energy consumption characteristics that could apply CHP. The technical market potential does not consider screening for other factors such as ability to retrofit, owner interest in applying CHP, capital availability, fuel availability, and variation of energy consumption within customer application/size classes. All of these factors affect the feasibility, cost, and ultimate acceptance of CHP at a site and are critical in the actual economic implementation of CHP.

[5] Based on ICF International internal estimates as detailed in "Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power," report prepared for WADE and USCHPA, October 2010. These estimates are on the same order as recent estimates developed by McKinsey and Company (see below).

[6] McKinsey Global Energy and Materials. (2009). *Unlocking Energy Efficiency in the U.S. Economy*. www.mckinsey.com/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.

[7] The White House. August 30, 2012. Executive Order–Accelerating Investment in Industrial Energy Efficiency. www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency.

This guide provides state utility regulators and other state policymakers with actionable information to assist them in implementing key state policies that impact CHP. It discusses five policy categories and highlights successful state CHP policy implementation approaches within each category:

- Design of standby rates
- Interconnection standards for CHP with no electricity export
- Excess power sales
- Clean energy portfolio standards (CEPS)
- Emerging market opportunities—CHP in critical infrastructure and utility participation in CHP markets.

In addition, several related policy areas are discussed in the appendices:

- CHP in community planning: CHP zones
- Capacity and ancillary service markets: how CHP can participate
- Revision of utility distribution franchise regulations to allow non-utility CHP to serve neighboring load

A brief introduction to these five policy categories and the key policy implementation features follows.

Design of Standby Rates[8]

A primary motivation for industrial and commercial customers to install CHP systems is to meet electricity and thermal energy needs at a lower cost. Utility tariffs for "standby rates" or "partial requirements service"—the set of retail electric products for customers with on-site, non-emergency generation—can reduce these cost savings. The tariffs are meant to recover the utility costs of providing backup power, which would otherwise be passed on to non-CHP customers. In some cases, standby rates can pose a barrier to adoption of CHP systems when they are not designed to closely preserve the nexus between charges and cost of service. Standby rates that incorporate the following features encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system:

- Offer daily or monthly as-used demand charges for backup power and shared transmission and distribution (T&D) facilities
- Reflect load diversity of CHP customers in charges for shared delivery facilities
- Provide an opportunity to purchase economic replacement power
- Allow customer-generators the option to buy all of their backup power at market prices
- Allow the customer to provide the utility with a load reduction plan
- Offer a self-supply option for reserves.

Interconnection Standards for CHP with No Electricity Export

Technical requirements governing how on-site generators connect to the grid serve an important function, ensuring that the safety and reliability of the electric grid is protected; however, non-standardized interconnect requirements and uncertainty in the timing and cost of the application process have long been a barrier to more widespread adoption of customer-sited generation.[9] Forty-three states and the District of Columbia have adopted some form of interconnection standards or guidelines. Streamlined application timelines and procedures, simplified contracts, and appropriate cost-based application fees are necessary to ensure that CHP projects are

[8] Distributed generation (DG) customers in some utility territory have the option to receive a high load factor gas rate. Justification for providing this rate to DG customers has been that DG customers may provide benefits to all electric customers by reducing constraints on the electric grid or may be the result of a natural gas cost of service. Gas rates are not covered in this document.

[9] IEEE Standard 1547.6 recommends against interconnection unless the generation is a de minimis amount of the customer's load, or a reverse power relay or other protection is in place.

implemented.[10] For states that do not have standard interconnection rules for distributed generation (DG) that does not export electricity, effective standardized interconnection rules should have the following characteristics:

- Interconnection fees commensurate with system size and complexity
- Streamlined procedures with simple decision-tree screens
- Uniform technical interconnection requirements
- Standardized, simplified interconnection agreements
- Dispute resolution procedures
- The ability for larger (20 megawatt [MW] and larger) CHP systems to qualify under the standards
- The ability for on-site generators to interconnect to both radial and network grids, assuming careful operational planning and system protection review.[11]

Excess Power Sales

In industrial applications with very large thermal needs, such as in the chemical, paper, refining, food processing, and metals manufacturing, sizing the CHP system to the thermal load can result in more power generation capacity than can be used on-site.[12] Excess power sales may provide a revenue stream for a CHP project, helping the project move forward. Additional CHP may help achieve state energy goals. While this guide does not explore the merits or problems with the development of markets that facilitate excess power sales, it does identify 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:

- **Programs based on state implementation of the federal Public Utility Regulatory Policies Act (PURPA).**[13] States have significant flexibility in administering PURPA, although amendments made in 2005 and Federal Energy Regulatory Commission (FERC) decisions have limited the applicability of PURPA in some regions, particularly for facilities larger than 20 MW.[14] However, FERC recently ruled that California's "multi-tiered" avoided cost rate structure for a feed-in tariff (FIT) for CHP systems of up to 20 MW is consistent with PURPA.[15] Specifically, FERC affirmed that state procurement obligations can be considered when calculating avoided cost, for example, requirements that utilities buy particular sources of energy with certain characteristics (e.g., renewable energy) to meet procurement obligations. Successful implementation approaches include:
    - Technical criteria for CHP eligibility (e.g., system size and efficiency)
    - Use of standard contracts and pricing
    - Inclusion of locational adders for avoided T&D investments.
- **FIT and variations.** Although FITs are often focused on renewable resources, these tariffs can be used to acquire CHP as well. FIT prices must be set high enough to attract the types and amounts of generation desired, while protecting consumers from paying more than needed to achieve generation targets. Typically, program administrators set a fixed price varying by technology per unit delivered during a

[10] "Database of State Incentives for Renewables & Efficiency." Accessed October 2012. www.dsireusa.org.

[11] Personal communication between ICF and Bill Ash, IEEE standards liaison, January 2013. IEEE Std 1547.6 is a finalized standard as of September 2011; however, the website hasn't been updated yet to reflect this final standard. http://grouper.ieee.org/groups/scc21/1547.6/1547.6_index.html.

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

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

[14] The Energy Policy Act of 2005 limited PURPA's scope through an amendment (210(m)) that allows utilities to file a request to 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.

[15] 133 FERC ¶ 61,059, Oct. 21, 2010. See the discussion in this guide on California's AB 1613 program.

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. California offers standard program protocols and contract terms, while using competitive procurement to acquire least-cost eligible resources based on the generators' actual costs. FIT prices can be based on the value the generator provides to the electrical system or to society (e.g., the FIT program offered by the Sacramento Municipal Utility District). Successful implementation approaches include:

  - Technical criteria for CHP eligibility (e.g., system size and efficiency)
  - Use of standard contracts
  - Pricing based on avoided cost rates for specified technologies (i.e., renewables).

- **Competitive Procurement Processes.** In addition to FIT variations that employ market mechanisms, governments and load-serving entities that have established CHP targets or programs, such as California and Ontario, Canada, have used competitive procurement processes to acquire larger CHP projects. In restructured states, CHP projects also may bid into energy markets as well as any capacity and ancillary service markets if they can meet established protocols. Successful implementation approaches include:
  - Establishment of standard offer programs for small CHP
  - Competitive procurements for large CHP.

Clean Energy Portfolio Standards[16]

Many states have developed clean energy portfolio standards (CEPS) to increase the adoption of renewable energy generation, energy efficiency, and other clean energy technologies. Portfolio standards require utilities and retail energy suppliers (mostly electricity and sometimes gas) to procure a certain minimum quantity of eligible energy (typically from renewable sources and other specified supply-side resources) or achieve a minimum amount of energy efficiency savings (typically from demand-side measures). CHP systems offer on-site electricity generation, thermal energy production, and overall energy savings through increased efficiency compared to a baseline of centralized electric generation and on-site thermal production. State policymakers, including legislators and utility regulators, may determine that CHP can help states meet their CEPS while providing numerous benefits. Currently 23 states explicitly include CHP and/or waste heat recovery as an eligible CEPS resource.[17] State regulators should consider the following key elements in the incorporation of CHP in CEPS:

- CHP eligibility definitions
- Minimum efficiency requirements or performance-based metrics.

Emerging Market Opportunity—CHP in Critical Infrastructure

CHP offers the opportunity to improve critical infrastructure resiliency, mitigating the impacts of an emergency by keeping critical facilities running without any interruption in service. If the electricity grid is impaired, a properly configured CHP system can continue to operate, ensuring an uninterrupted supply of power and heat to the host facility. Following disruptions in 2001; the Northeast blackout in 2003; and natural disasters such as Hurricane Katrina in 2005, Hurricane Ike in 2008, and Superstorm Sandy in 2012; disaster preparedness planners have become increasingly aware of the need to protect critical infrastructure facilities and to better prepare for energy emergencies. Experience with Superstorm Sandy emphasizes the need to have qualified personnel on site to ensure safe start up once distributed generators have been brought down (e.g., by flooding). Resilient critical infrastructures enable a faster response to disasters, mitigating the extent of damage and impact on communities, and speed the recovery of critical functions. To ensure continued progress towards addressing grid and critical infrastructure resiliency through technologies such as CHP, improved coordination between government

[16] Clean energy portfolio standards can have a variety of names, such as renewable portfolio standards, alternative energy portfolio standards, energy efficiency resource standards, advanced energy portfolio standards, energy efficiency performance standards, and renewable energy standards.

[17] Based on ICF International Research and the Database of State Incentives for Renewable Energy (www.dsireusa.org).

emergency planners and the electricity sector must occur. State policymakers can facilitate that coordination and help reduce barriers to CHP so that these systems can be more easily installed in critical infrastructure applications.

Emerging Market Opportunity—Utility Participation in CHP Markets

A final, potentially significant policy option for increasing installed CHP capacity is to allow incumbent utilities to participate in CHP markets, either by owning CHP facilities directly, or by providing packages of services to customers who own their own CHP. This would be a policy that allows, but does not require, utility participation in CHP markets—a critical distinction. Key features of such a policy would include the following:

- Market rules to ensure non-discriminatory access by third parties wishing to enter the CHP market in the utility's service territory and compete with it
- Financial controls to prevent the utility from shifting costs from its CHP products and services to the revenue requirements of non-CHP customers.

Achieving the benefits provided by additional use of CHP is furthered by the successful implementation of the state policies discussed in this guide. Experience shows that successful implementation approaches often have three main features:

- They achieve the intent of state policy (a policy may be established but not successfully executed).
- They send clear market signals.
- Where applicable, they adhere to the principle of ratepayer benefits or neutrality.

This guide provides state utility regulators and other state policymakers with actionable information to assist them in implementing key state policies that impact CHP.

Introduction

Combined heat and power (CHP) is a proven commercial technology that has been used for more than a century. A variety of commercial and industrial facilities use CHP to provide both electric and thermal energy from one fuel source, instead of purchasing electricity from the utility and burning fuel in an on-site furnace or boiler to produce thermal energy or purchasing thermal energy.[18] Cost-effective,[19] clean[20] CHP can provide a suite of benefits to the user, the electric system, and to the nation.[21]

Source: Energy Solutions Center

Figure 1. A typical 1.5 MW gas turbine CHP system

Benefits of CHP for U.S. Businesses

- Reduces energy costs for the user
- Reduces risk of electric grid disruptions and enhances energy reliability
- Provides stability in the face of uncertain electricity prices.

Benefits of CHP for the Electric System

- Offers a low-cost approach to new electricity generation capacity
- Lessens the need for new transmission and distribution (T&D) infrastructure and enhances power grid security.[22]

Benefits of CHP for the Nation

- Improves U.S. manufacturing competitiveness through increased efficiencies and reduced energy costs
- Offers a low-cost approach to new electricity generation capacity
- Provides an immediate path to lower greenhouse gas (GHG) emissions, in many cases through increased energy efficiency[23]
- Uses abundant, clean, domestic energy sources
- Uses highly skilled American labor and American technology.

[18] Oak Ridge National Laboratory. (2008). *Combined Heat and Power, Effective Energy Solutions for a Sustainable Future*. CHP sites that are interconnected and require the utility to provide significant amounts of back-up electricity are not likely to defer investments because utilities invest to meet the peak demand and this back-up need must be part of the peak calculus. In some cases, there are opportunities to purchase thermal energy from a district energy system or steam loop.

[19] See Appendix A for a discussion of evaluating the cost-effectiveness of a CHP program.

[20] State policymakers, project developers, advocates, utilities, and others have various definitions of "clean" energy. This guide does not attempt to create one definition, but rather recognizes that the primary audiences for the guide are state regulators and that they define it as they see fit.

[21] U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA). *Combined Heat and Power: A Clean Energy Solution*. August 2012. www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf.

[22] www.fortnightly.com/fortnightly/2012/08/capturing-distributed-benefits?authkey=ed2f91bfeb755dc6c222d2a76b32f98d675ae9db26fee62ecd0f798b0e67528b.

[23] U.S. EPA. *Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power System.* August 2012. www.epa.gov/chp/documents/fuel_and_co2_savings.pdf.

Successful implementation of supportive state policies by state utility regulators and other state policymakers is critical to achieving the above benefits, as well as the Obama Administration's and State and Local Energy Efficiency Action Network (SEE Action) Industrial Energy Efficiency and CHP Working Group's goal of 40 gigawatts (GW) of new CHP by 2020.

There are many resources that provide information on the design of CHP policies. This guide will provide state utility regulators and other state policymakers with actionable information to assist them in implementing key state policies that address barriers to, and promote opportunities for, CHP development. This guide recognizes that the process for initiating and implementing legislative and regulatory reforms to develop markets for CHP are different in every state. Moreover, state approaches to facilitating the financing of CHP and developing long-term comprehensive energy and energy assurance plans differ across the nation. For this reason, the concepts put forth in this paper should be considered by legislators, governors, state energy officials, and utility regulators.

This guide provides a summary of key CHP policies and provides examples of successful state regulatory implementation strategies that meet one or more of the three criteria:

- They achieve the intent of state policy (a policy may be established but not successfully executed).[24]
- They send clear market signals.
- Where applicable, they adhere to the principle of ratepayer benefits or neutrality.

The guide assumes that statutes and/or regulations are already in place for these policies. The guide also recognizes that individual states will define clean energy and energy efficient technologies and practices consistent with their state goals and regulations. This guide does not explore the merits or problems with these policies and regulations.

[24] "Achieving the intent of state policy" focuses on implementation of certain features of the overall policy, or specific design features that may have unintended consequences that deter from meeting the final policy objective. For example, in Ohio, CHP was eligible under the state's renewable portfolio standard (as part of the advanced energy category); however, the state did not issue eligibility guidance for CHP resulting in no systems receiving credit under the standard (National Council on Electricity Policy, November 2009). Ohio recently amended the RPS, and waste heat to power is eligible now as a renewable resource. Ohio also adopted a separate energy efficiency resource standard with energy savings and peak demand reduction targets, and that includes CHP and waste heat to power systems as eligible.

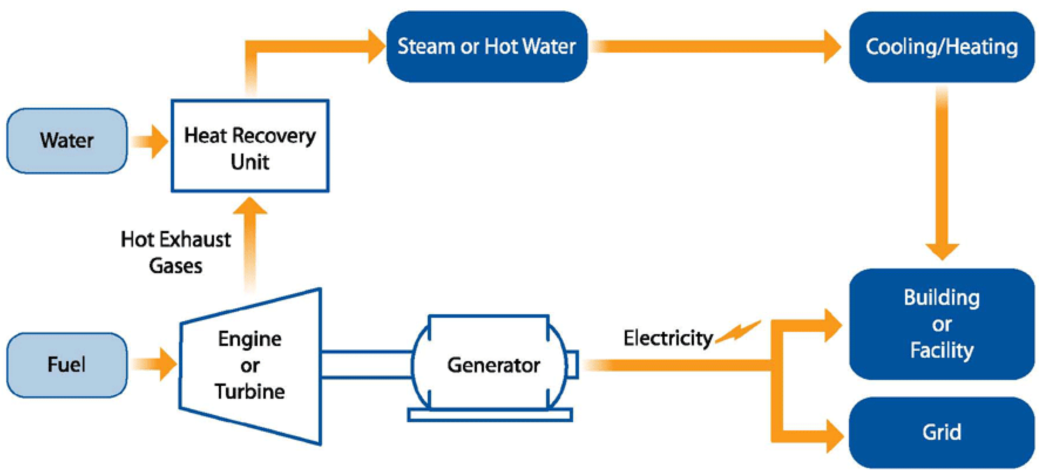
Chapter 1. CHP Defined

1.1 CHP Defined: Topping and Bottoming Cycle CHP

The average generation efficiency of grid-supplied power in the United States has remained at 34% since the 1960s—the energy lost in wasted heat-from-power generation in the United States is greater than the total energy use of Japan.[25] CHP systems typically achieve total system efficiencies of 60%–80% compared to only about 45%–50% for conventional separate heat and power generation[26] by avoiding line losses and capturing much of the heat energy normally wasted in power generation to provide heating and cooling to factories and businesses.[27] By efficiently providing electricity and thermal energy from the same fuel source at the point of use, CHP significantly reduces the total primary fuel needed to supply energy services to a business or industrial plant, saving them money and reducing air emissions.[28]

There are two types of CHP—topping and bottoming cycle. In a topping cycle CHP system (Figure 2), fuel is first used in a prime mover such as a gas turbine or reciprocating engine, generating electricity or mechanical power. Energy normally lost in the prime mover's hot exhaust or cooling systems is recovered to provide process heat, hot water, or space heating/cooling for the site.[29] Optimally efficient topping CHP systems are typically designed and sized to meet a facility's baseload thermal demand.

In a bottoming cycle CHP system (Figure 3), also referred to as waste heat to power, fuel is first used to provide thermal input to a furnace or other high temperature industrial process, and a portion of the heat rejected from the process is then recovered and used for power production, typically in a waste heat boiler/steam turbine system. Waste heat to power systems are a particularly beneficial form of CHP in that they utilize heat that would otherwise be wasted from an existing thermal process to produce electricity without directly consuming additional fuel.



Source: U.S. Environmental Protection Agency (EPA) CHP Partnership www.epa.gov/chp/basic/index.html

Figure 2. Topping cycle CHP: gas turbine or reciprocating engine with heat recovery

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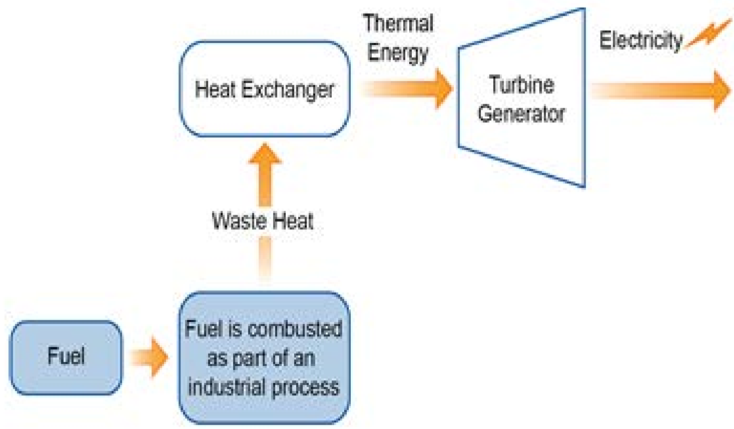
[25] Oak Ridge National Laboratory. *Combined Heat and Power, Effective Energy Solutions for a Sustainable Future*. 2008.

[26] Total system efficiency is equal to the power and useful thermal energy divided by the total fuel consumed to generate both energy services.

[27] U.S. DOE, U.S. EPA. *Combined Heat and Power: A Clean Energy Solution*. August 2012. www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf.

[28] U.S. EPA. *Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power System*. August 2012. www.epa.gov/chp/documents/fuel_and_co2_savings.pdf.

[29] In another version of a topping cycle CHP system, fuel is burned in a boiler to produce high pressure steam. That steam is fed to a steam turbine, generating mechanical power or electricity, before exiting the turbine at lower pressure and temperature and used for process or heating applications at the site.



Source: U.S. EPA CHP Partnership www.epa.gov/chp/documents/waste_heat_power.pdf

Figure 3. Bottoming cycle CHP: waste heat to power

1.2 Market Status and Potential

CHP is already an important resource for the United States—the existing 82 GW of CHP capacity at more than 4,100 industrial and commercial facilities represents approximately 8% of current U.S. generating capacity and more than 12% of total megawatt-hours (MWh) generated annually.[30] Compared to the average fossil-based electricity generation, the existing base of CHP saves 1.8 quads of energy annually and eliminates 240 million metric tons of CO_2 emissions each year (equivalent to the emissions of more than 40 million cars).[31]

While investment in CHP declined in the early 2000s due to changes in the wholesale market for electricity and increasingly volatile natural gas prices, CHP's potential role as a clean energy source for the future is much greater than recent market trends would indicate. Efficient on-site CHP represents a largely untapped resource that exists in a variety of energy-intensive industries and businesses (Figure 4). Recent estimates indicate the technical potential[32] for additional CHP at existing industrial facilities is slightly less than 65 GW, with the corresponding technical potential for CHP at commercial and institutional facilities at slightly more than 65 GW,[33] for a total of about 130 GW. A 2009 study by McKinsey and Company estimated that 50 GW of CHP in industrial and large commercial/institutional applications could be deployable at reasonable returns with then current equipment and energy prices.[34] These estimates of both technical and economic potential are likely greater today given the improving outlook in natural gas supply and prices.

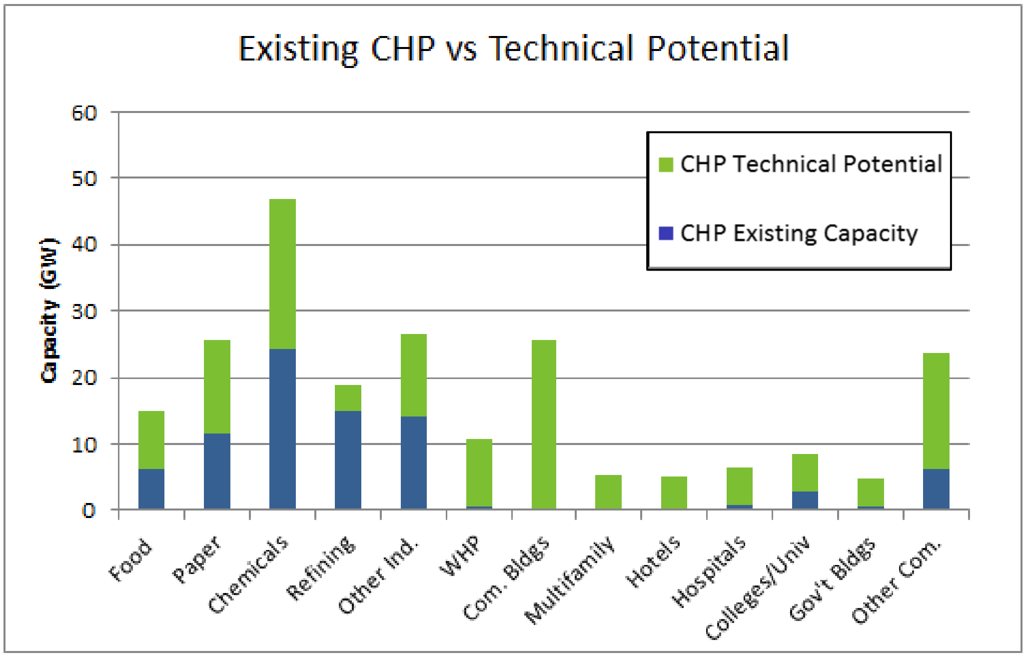
[30] CHP Installation Database developed by ICF International for Oak Ridge National Laboratory and the U.S DOE. 2012. Available at www.eea-inc.com/chpdata/index.html.

[31] www.epa.gov/chp/basic/environmental.html.

[32] The technical market potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. The technical potential includes sites that have the energy consumption characteristics that could apply CHP. The technical market potential does not consider screening for other factors such as ability to retrofit, owner interest in applying CHP, capital availability, fuel availability, and variation of energy consumption within customer application/size classes. All of these factors affect the feasibility, cost, and ultimate acceptance of CHP at a site and are critical in the actual economic implementation of CHP.

[33] Based on ICF International internal estimates as detailed in the report *Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power*, prepared for WADE and USCHPA, October 2010. These estimates are on the same order as recent estimates developed by McKinsey and Company (see below).

[34] McKinsey Global Energy and Materials. (2009). Unlocking Energy Efficiency in the U.S. Economy. www.mckinsey.com/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.



Source: Internal estimates by ICF International and CHP Installation Database developed by ICF International for Oak Ridge National Laboratory and DOE. 2012. www.eea-inc.com/chpdata/index.html.

Figure 4. Technical potential for CHP at industrial and commercial facilities

The outlook for increased use of CHP is improving. Policymakers at the federal and state level are beginning to recognize the potential benefits of CHP and the role it could play in providing clean, reliable, cost-effective energy services to industry and businesses. A number of states have developed innovative approaches to increase the deployment of CHP to the benefit of users as well as ratepayers. CHP is being looked at as a productive investment by some companies facing significant costs to upgrade old coal- and oil-fired boilers. In addition, CHP can provide a cost-effective source of new generating capacity in many areas confronting retirement of older power plants. Finally, the economics of CHP are improving as a result of the changing outlook in the long-term supply and price of North American natural gas—a preferred fuel for many CHP applications.[35]

Key to capturing this potential is the market structure for CHP at the state level. Markets with unnecessary barriers to the development of CHP will see less than the economically and environmentally desirable development of the resource, resulting potentially in higher cost resources or resources with greater environmental impacts incorporated into the nation's electricity system.

The chapters that follow provide state utility regulators and other state policymakers with actionable information to assist them in implementing key state policies that address barriers to, and promote opportunities for, CHP development. They discuss five policy categories and highlight successful state CHP policy implementation approaches within each category:

- Design of standby rates
- Interconnection standards for CHP with no electricity export
- Excess power sales
- Clean energy portfolio standards (CEPS)

Emerging market opportunities—CHP in critical infrastructure and utility participation in CHP markets.

[35] U.S. DOE. *Combined Heat and Power: A Clean Energy Solution*. August 2012. www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf. Note that the existing fleet of CHP uses a wide variety of fuels in addition to natural gas including coal, oil, landfill gas, waste heat, process wastes, wood, and other forms of biomass.

Chapter 2. Design of Standby Rates

2.1 Overview

A primary motivation for industrial and commercial customers to install CHP systems is to meet electricity and thermal energy needs at a lower cost. One potential impediment to the adoption of CHP[36] is standby rates, or partial requirements service, which the utility charges to compensate for providing certain services and which can affect CHP customer cost savings.[37] Utility rates should optimally allocate the total cost of service for a utility to recover costs from customer classes, reflecting each class's use of the system. This principle of "cost causation" is implemented through rate designs that fairly allocate costs based on measureable customer characteristics.

Utility standby rates cover some or all of the following services:

- *Backup power* during an unplanned generator outage
- *Maintenance power* during scheduled generator service for routine maintenance and repair
- *Supplemental power* for customers whose on-site generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class
- *Economic replacement power* when it costs less than on-site generation
- *Delivery* associated with these energy services.

In the rate design process, utility costs are allocated to various components of customer services, including charges for billing and metering, energy, distribution, and transmission. Costs for each of these components are based on an average user profile for each customer rate class, such as large nonresidential customers, rather than customized for individual users.

For large customers, costs of utility service are separated into customer, energy, and demand charges. Customer charges are designed to recover costs incurred to provide metering and billing services and service drop facilities. Energy charges recover the variable costs incurred to generate electricity (i.e., chiefly fuel cost).[38] Demand charges are designed to recover the utility investment cost incurred to provide generating, transmission, and distribution capacity and may vary by season and time of day.[39] Generation costs may also vary by season and time of day.

Commonly, demand charges in standby rates are "ratcheted," meaning the utility continues to apply some percentage (often as high as 100%) of the customer's highest peak demand in a single billing month up to a year after its occurrence. The use of ratchets can be controversial—some view them as increasing the equity of fixed cost allocation, while others view them as barriers to economic applications by CHP customers. Although demand ratchets may be appropriate for recovering the cost of delivery facilities closest to the customer-generator, they arguably do not reflect cost causation for *shared* distribution and transmission facilities, which are farther removed from the customer. Distribution and transmission facilities are designed to serve a pool of customers with diverse loads, not a single customer's needs, and coincident outages drive their costs. In addition, unplanned CHP system outages occur randomly; CHP systems will not all fail at the same time or during the utility system's peak. Further, the customer's use of standby service may not coincide with the peak demand of the utility facility providing the service.[40] Use of standby service by CHP customers with low forced outage[41] rates typically is significantly less likely to coincide with the utility's peak demand than peak use by a full requirements customer. Arguably, billings based

[36] U.S. EPA. *Standby Rates for Customer-Sited Resources—Issues, Considerations, and the Elements of Model Tariffs*. December 2009. www.epa.gov/chp/documents/standby_rates.pdf.

[37] In restructured states, the utility may provide only delivery services and provider-of-last-resort energy service.

[38] Some fixed costs may be recovered through variable energy charges.

[39] In restructured markets, generation-related costs are not recovered in regulated revenue requirements, but in market-based supply prices.

[40] See Regulatory Assistance Project. "Distribution System Cost Methodologies for Distributed Generation." 2001. www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGeneration_2001_09.pdf.

[41] Forced outages are unplanned or unscheduled outages of the CHP system due to equipment failure.

on ratcheted demands fail to recognize the diversity in load among CHP customers and the cost savings associated with that diversity, particularly as regards shared T&D facilities. Requiring CHP customers to pay ratcheted demands may result in CHP customers overpaying for utility-supplied electricity relative to full requirements customers.

2.2 Improving Standby Rates

Standby rates were originally designed to reflect an environment in which a utility operated within a fairly closed system with a few inter-ties with other utilities for backup emergency purposes. Today, many utilities rely on and participate in regional markets where electricity and capacity are pooled and can be purchased with relative ease. The ability to more easily transact energy and capacity allows a utility to take account of the probability of various CHP loads needing standby service at the same time, which will lower ratcheted demand charges.

Working with utilities and other stakeholders, some state utility regulators have improved the nexus between standby tariffs and cost causation, provided customer-generators with options to avoid charges when they do not impose costs, and established a reasonable balance between variable charges versus contract demand or reservation charges.

For standby or "partial requirements" customers, the following service components are the most common:[42]

- **Backup Service.** Backup or standby service supports a customer's load that would otherwise be served by DG, during unscheduled outages of the on-site generation.
- **Scheduled Maintenance Service.** Scheduled maintenance service is taken when the customer's DG is due to be out of service for routine maintenance and repairs.
- **Supplemental Service.** Supplemental service provides additional electricity supply for customers whose on-site generation does not meet all of their needs. In many cases, it is provided under the otherwise applicable full requirements tariff.
- **Economic Replacement Power.** Some utilities offer economic replacement power—electricity at times when the cost of producing and delivering it is below that of the on-site source.

Together, the following features encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system:[43]

- **Reflect load diversity of CHP customers in charges for shared delivery facilities.** Charges for transmission facilities and shared distribution facilities such as substations and primary feeders should reflect that they are designed to serve customers with diverse loads. Load diversity can be recognized by designing demand charges on a coincident peak demand basis as well as the customer's own peak demand and by allocating demand costs primarily or exclusively to usage during on-peak hours. Differentiating on-peak demand from off-peak demand provides standby customers with an incentive to shift their use of the utility's assets to off-peak hours, when the marginal cost of providing service is typically much lower.
- **Allow the customer to provide the utility with a load reduction plan.** The plan should demonstrate its ability to reduce load within a required timeframe and at a specified amount to mitigate all, or a portion of, backup demand charges for local facilities. This allows the standby customer to use demand response to meet all, or a portion of, its standby needs. The utility would approve the load reduction plan, evaluating whether it provides sufficiently timely load shedding to avoid reserve costs incurred by the utility. The utility would approve the load reduction plan after evaluating and determining that it provides sufficiently timely load shedding to avoid reserve costs incurred by the utility.

[42] The four bulleted service components are not necessarily subject to a demand charge. It depends on the utility's rate structure. www.epa.gov/chp/documents/standby_rates.pdf.

[43] For more on alignment of standby rates with rate design principles, see *Standby Rates for Customer-Sited Resources: Issues, Considerations and the Elements of Model Tariffs*, prepared by Regulatory Assistance Project and ICF International for the U.S. Environmental Protection Agency. December 2009. www.epa.gov/chp/documents/standby_rates.pdf.

- **In states with retail competition, offer a self-supply option for reserves.** This can be in the context of the load reduction plan discussed above, through utility-controlled interruptible load, or some other means that can both save costs for the customer and avoid costs for the utility. The self-supply plan can be structured to reflect actual performance of the customer over time.
- **Offer daily, or at least monthly, as-used demand charges for backup power and shared transmission and distribution facilities.** Moving away from annual ratcheted charges gives the CHP customer a chance to recover from an unscheduled outage without eroding savings for an entire year. Daily charges encourage customers to get their generators back online as quickly as possible. Daily charges for backup power should be market-based to provide appropriate price signals to CHP customers.
- **In states with retail competition, allow customer-generators the option to buy all of their backup power at market prices.**[44] The customer can avoid any utility reservation charge for generation service because the utility is relieved of the obligation to acquire capacity to supply energy during unscheduled outages of the customer's CHP unit.
- **Schedule maintenance service at nonpeak times.** In general, because this service can be scheduled for nonpeak times, it is considered to create few additional or marginal costs to the utility's system, and tariffs are typically structured to exempt the customer from capacity-related costs (e.g., reservation charges or ratchets, for either generation or delivery).
- **Provide an opportunity to purchase economic replacement power.** During times of the year when energy prices are low, the utility can provide on-site generators energy at market-based prices at a cost that is less than it costs to operate their CHP systems, and at no harm to other ratepayers. Such arrangements must be compatible with the structure of retail access programs, which the CHP customer may otherwise be relying on, and should allocate any incremental utility costs of purchasing such power (including general and administrative fees) to the CHP customer.

These features can create a standby rate regime consistent with standard ratemaking principles, avoiding cost shifting from CHP customers to other customers, while providing appropriate incentives to operate CHP facilities in a manner most efficient for the utility system as a whole, by aligning the economics for the CHP facility with the cost to serve that customer.

2.3 Successful Implementation Approaches

Pacific Power—Oregon Partial Requirements Service

Pacific Power provides standby services in Oregon under four primary tariffs and riders.[45] Taken together, this set of tariffs provides many of the customer-generator benefits discussed above, while allowing recovery of actual costs incurred by the utility and protecting other customers.

- The utility assesses charges for shared distribution facilities such as substations and transmission facilities based on the customer's actual 15-minute net demand recorded for the month during on-peak hours, using the same rate and billing determinants as the full requirements tariff. There is no annual ratchet.
- Cost recovery for local distribution facilities—those designed solely to serve the customer as well as those closest to end-users, such as transformers and low voltage lines—is based on the average of the two highest non-zero monthly on-peak demands for the past 12 months, same as for full requirements customers. The starting point and minimum level for the charge is the "baseline"—the customer's peak demand on the utility system assuming normal operation of the customer's generator. However, the

[44] This guide does not explore the merits or problems with the development of standby rates; it identifies how standby rate policies can be successfully implemented to facilitate CHP.

[45] These four tariffs include Schedule 48: Large General Service Partial Requirements 1,000 kW and Over Delivery Service, Schedule 76R: Large General Service Partial Requirements Service Economic Replacement Power Rider Delivery Service, Schedule 247: Partial Requirements Supply Service, and Schedule 276R: Large General Service Partial Requirements Service Economic Replacement Power Rider Supply Service. "Oregon Regulatory Information." Pacific Power. www.pacificpower.net/about/rr/ori.html.

baseline can be adjusted with a load curtailment plan for generator outages, installation of energy efficiency measures, and to accommodate planned, long-term changes in loads or generator operations.

- The customer's baseline also sets charges for reserves the utility holds to maintain capability to serve loads during outages of the on-site generator. The tariff provides self-supply options for reserves, including through an approved load reduction plan for supplemental reserve requirements.
- Scheduled maintenance service must be scheduled 30 days in advance, in take-or-pay blocks at a forward market-based price. Pacific Power also offers partial requirements customers the option to buy replacement energy (usage above baseline) at market prices when beneficial for the customer. For a CHP customer, the determination of favorable conditions includes the total benefits derived from the CHP system (electricity plus heat) compared with advantageously priced replacement power and boiler fuel.
- Energy service for unscheduled outages is based on real-time market prices. Importantly, demand and transmission charges for scheduled maintenance, economic replacement power and unscheduled outage service are based on daily demands and do not affect charges for distribution and transmission services under the base standby tariff.

Consolidated Edison Partial Requirements Service

Consolidated Edison offers replacement or supplemental service for approved projects for self-generation customers whose generation capacity is greater than 15% of their potential load. Pricing for this service is based on a contract demand representing the highest demand the facility is likely to meet for the customer under any circumstances. The charge for the contract demand reflects both the customer's contribution to local facilities used on a regular basis for baseload demand, as well as customer-specific infrastructure necessary to meet the maximum potential demand with or without the customer's generation in service. The rate for the entire contract demand is generally lower than the otherwise applicable rate. If the customer selects a contract demand level, the utility applies penalties if the maximum demand exceeds the contract demand by more than 10% or 20%.[46] If the contract demand level is utility-determined there is no penalty for exceeding that level. In both cases, when the original contract demand is exceeded, contract demand is re-set to the new highest demand.

In addition, the company assesses a demand charge based on the actual demand recorded each day. The rate varies by season and time of day—peak versus off-peak.[47, 48] This variable charge recovers shared system (upstream) costs. It is calculated on a daily basis.

Georgia Power[49]

Georgia Power provides backup service under a tariff rider. The rider allows a customer to contract for firm or interruptible standby capacity, or both, to replace capacity from a customer's generation when it is not in service. Customers may designate the level of service they wish to purchase from the utility. For firm backup power, the customer must provide notification within 24 hours of taking such service. Interruptible backup power requires advance permission from the company, except in the case of an unplanned outage where a 30-minute notice is required after beginning service.

Maintenance power, supplied for outages, must be scheduled 14 days in advance. Maintenance power is available as firm service during the off-peak months and as interruptible service during peak months. Customers purchase supplemental power (power required during normal operation of the generator and normal demands by the facility) at normally applicable rates.

[46] www.coned.com/documents/elecPSC10/GR1-23.pdf, leaf 164; No penalties are assessed if the utility determines the contract demand.

[47] www.coned.com/documents/elecPSC10/SCs.pdf, leaf 453.

[48] The charge is zero for off-peak hours.

[49] www.georgiapower.com/pricing/files/rates-and-schedules/12.30_BU-8.pdf.

The utility computes the level of standby power as the difference between the "maximum metered demand measured during the time standby service is being taken, less the maximum metered demand during the time in the billing period when standby service is not being taken." This demand determination can be made on a peak versus off-peak basis.

All billing determinants are based on monthly values, with no ratchets. However, demand charges are subject to a standby demand adjustment factor, which adjusts the billed standby demand once a customer uses backup service for more than 876 hours during the most recent 12-month period. This provides an incentive for a customer to use standby service as efficiently as possible.

How the Criteria Are Addressed

Policy Intent. The policy intent is to charge CHP customers only for costs they impose on the system consistent with ratemaking principles, encourage customer-generators to use electric service most efficiently to minimize costs they impose on the electric system, and ensure that costs for backing up CHP customers are not passed on to non-CHP customers. The customer and the utility can work together to schedule planned outages at times that are best for the utility system.

Market Signals. CHP users and potential CHP adopters are motivated by expected cost savings available from their systems. By shifting risk to CHP users and appropriately charging for services actually rendered, both utilities and customers can benefit through appropriate market signals.

Ratepayer Indifference. By more accurately balancing the charges for service actually rendered with appropriate market signals and incentives for operational efficiencies, all customers should benefit from appropriately structured standby tariffs.

2.4 Conclusions

Standby charges should be designed to most closely preserve the nexus between charges and cost of service. Standby rates were originally designed to reflect an environment in which a utility operated within a fairly closed system with a few interties with other utilities for backup emergency purposes. Today, many utilities rely on and participate in regional markets where electricity and capacity are pooled and can be purchased with relative ease. The ability to more easily transact energy and capacity allows a utility to take into account the probability of various CHP loads needing standby service at the same time. Together, the features listed below encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system.

KEY IMPLEMENTATION APPROACHES: DESIGN OF STANDBY RATES

- Offer daily or monthly as-used demand charges for backup power and shared transmission and distribution facilities.
- Reflect load diversity of CHP customers in charges for shared delivery facilities.
- Provide an opportunity to purchase economic replacement power.
- Allow customer-generators the option to buy all of their backup power at market prices.
- Allow the customer to provide the utility with a load reduction plan.
- Offer a self-supply option for reserves.

Chapter 3. Interconnection Standards for CHP with No Electricity Export

3.1 Overview

Standardized interconnection rules typically address the technical requirements and the application process for DG systems, including CHP, to connect to the electric grid.[50] Most CHP systems are sized to provide a portion of the site's electrical needs, and the site continues to remain connected to the utility grid system for supplemental, standby, and backup power services, and, in select cases, for selling excess power. A key element to the market success of CHP is the ability to safely, reliably, and economically interconnect with the existing utility grid system. However, uncertainty in the cost, timing, and technical requirements of the grid interconnection process can be a barrier to increased deployment of CHP.

Interconnection requirements for on-site generators have an important function. They ensure that the safety and reliability of the electric grid is protected, supporting the utilities' ultimate responsibility for system safety and reliability. For utilities and state regulators, there are three primary issues:

- The safety of the utility line personnel must be maintained at all time; utilities must be assured that CHP and other on-site generation facilities cannot feed power to a line that has been taken out of service for maintenance or as the result of damage.
- The safety of the equipment must not be compromised. This directly implies that an on-site system failure must not result in damage to the utility system to which it is connected or to other customers.
- The reliability of the distribution system must not be compromised.

There is no question about the importance and legitimacy of these basic requirements. However, non-standardized interconnect requirements and uncertainty in the timing and cost of the application process have long been seen as barriers to more widespread adoption of customer-sited DG. The following issues cause uncertainty for the end-user in the interconnection process and may add time and cost to CHP projects:

- The interconnection rules may not clearly establish requirements for timelines and fees.
- The interconnection rules may not be consistently applied by utilities in a state.
- Protection requirements and required protection equipment may not be commensurate with the size and potential impact of smaller generators.[51]
- Requirements for high-cost utility studies may also not be commensurate with the size of the generator.

As of November 2012, the Database of State Incentives for Renewables & Efficiency (DSIRE) has listed 43 states and the District of Columbia as having adopted some form of interconnection standards or guidelines, which are shown in Figure 5.[52] Not all of these states have standardized interconnection rules that include streamlined procedures, clear timelines, simplified contracts, and appropriate application fees.[53] State utility regulators strive to identify an appropriate balance between the needs of the utility and the needs of the customer in developing and approving the standardized interconnection rules.

[50] U.S. EPA. "Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States—Chapter 5. Energy Supply Actions." April 2006. www.epa.gov/statelocalclimate/resources/action-guide.html.

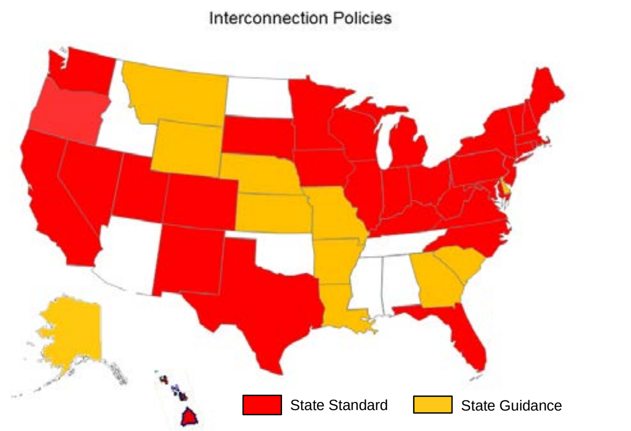
[51] The Federal Energy Regulatory Commission has "small generator" interconnection standards for three levels of interconnection—inverter-based systems no larger than 10 kW, systems up to 2 MW, other systems no larger than 20 MW.

[52] DSIRE. Accessed September 2012. www.dsireusa.org.

[53] Some states use net metering rules to govern interconnection of smaller distributed generation systems. Also, some state net metering provisions are limited in scope. For example, net metering rules often apply only to relatively small systems, specified technologies, or fuel types of special interest to policymakers. Some rules lack detailed specifications and procedures for utilities and customers to follow and vary across utilities within the state. See www.epa.gov/statelocalclimate/documents/pdf/guide_action_full.pdf.

3.2 Successful Implementation Approaches

Effective state standardized interconnection rules for DG/CHP systems with no electricity export often have the following characteristics:[54]



Source: Database of State Incentives for Renewables & Efficiency (DSIRE). Accessed November 2012. www.dsireusa.org/documents/summarymaps/interconnection_map.pdf

Figure 5. States with established interconnection standards or guidelines

- Interconnection fees commensurate with system complexity[55]
- Streamlined procedures with simple decision-tree screens (allowing faster application processing for smaller systems and those unlikely to produce significant system impacts)[56]
- Practical and predictable technical requirements, often based on existing technical standards Institute of Electrical and Electronics Engineers (IEEE) 1547 and Underwriters Laboratories (UL) 1741[57]
- Standardized, simplified interconnection agreements
- Dispute resolution procedures to resolve disagreements
- The ability for larger CHP systems, and those not captured under net metering rules, to qualify under the standards[58]
- The ability for on-site generators to interconnect to both radial and network grids.[59]

An overview of these characteristics is provided below.[60]

1. Appropriate interconnection fees. High application and technical study fees associated with interconnection, along with high insurance requirements, can easily impair CHP project economics. Thus, some states have turned to a more effective approach—setting upper and lower bounds on application and study fees commensurate with the size of the system and potential safety impacts on the grid, and sometimes waiving application fees for small

[54] National Renewable Energy Laboratory. *Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*. 2000. www.nrel.gov/docs/fy00osti/28053.pdf. This report discusses a number of barriers to interconnection and includes "A Ten-Point Action Plan for Reducing Barriers to Distributed Generation." For a discussion of factors affecting interconnection of distributed generation, see Regulatory Assistance Project. *Survey of Interconnection Rules*. 2007. www.epa.gov/chp/documents/survey_interconnection_rules.pdf.

[55] Size is only one element that may affect the interconnection process and resultant cost. As an example, under Rule 21 in California there are eight screening steps in the "Initial Review" process, including the type of distribution grid (radial or network), whether power is exported, whether the interconnection equipment is certified, the aggregate capacity of the line in relation to peak line load, the line configuration, potential for voltage drop, and the potential for creation of a short circuit. www.energy.ca.gov/distgen/interconnection/application.html.

[56] Such as the FERC Small Generator Interconnection Procedures and Agreement.

[57] IEEE Standard for Interconnection Distributed Resources with Electric Power Systems (IEEE 1547) and Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources (UL 1741).

[58] FERC small generator interconnection standards include three levels of interconnection—inverter-based systems no larger than 10 kW, systems up to 2 MW, and all other systems no larger than 20 MW.

[59] IEEE 1547.6 Recommended Practice For Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks (finalized September 2011). This standard focuses on the technical issues associated with the interconnection of distribution secondary networks with distributed generation. The standard provides recommendations relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. The standard gives consideration to the needs of the local electric power system to be able to provide enhanced service to the DR owner loads as well as to other loads served by the network. The standard identifies communication and control recommendations and provides guidance on considerations that will have to be addressed for such interconnections.

[60] For a discussion of recommendations for technical requirements, procedures and agreements, and emerging issues, see Regulatory Assistance Project. *Interconnection of Distributed Generation to Utility Systems*. 2011. www.raponline.org/document/download/id/4572.

CHP systems completely.[61] Costs are often apportioned between the applicant and the utility in a manner that state utility regulators deem appropriate. In general, interconnection fees should be just and reasonable and reflect the true costs of interconnection; this approach can mitigate rate impacts for non-participating customers.

2. Streamlined procedures with decision tree screens (allowing faster application processing for smaller systems and those unlikely to produce significant system impacts). A criticism of some state interconnection standards is the lengthy approval process and complicated application requirements. To facilitate rapid application turnaround, successful state interconnection standards have well-defined application processing timelines and simple decision trees that show, based on the system size and other characteristics, which interconnection procedures apply. Colorado has a streamlined process for systems up to 2 MW that involves several different screens to determine if more detailed review is needed.[62] If a proposed project fails one of the screening tests the owner may have to pay for additional tests or move to the next level analysis. Maine's level 2 and 3 interconnection processes (for systems up to 2 MW and 10 MW respectively) have timelines of 15 and 17 business days for the utility to approve the application.[63] Kentucky's Level 1 interconnection process requires that utilities notify the customer whether the interconnection application has been approved or denied within 20 business days.[64] Ohio provides for a checklist for applicants to determine whether they need to complete the "short form" or a standard interconnection form.[65]

3. Standardized Technical Requirements. Standardization of technical and safety requirements ensures consistent safety for the utility, lessens the complexity of the interconnection process, and helps reduce costs for some project developers by alleviating the need to hire expert consultants. States commonly specify technical requirements based on national safety standards—IEEE 1547 and UL 1741—or use these two standards as a basis for developing their own requirements. These two standards focus on the technical specifications for, and testing of, the interconnection itself. They provide guidelines relating to the performance, operation, testing, safety considerations, and maintenance of the interconnection and form the basis of many state standards. California's technical requirements are similar to those established in IEEE 1547, although Rule 21 is more specific on certain issues.[66] Also, some states exempt project types that meet IEEE and UL guidance from specific additional criteria. For example, New Hampshire does not require an external disconnect switch for inverter-based systems that comply with IEEE 1547 and UL 1741.[67] In Delaware, interconnection requests for systems up to 2 MW may be eligible for expedited review if they use lab certified equipment or field approved interconnection equipment.[68]

4. Standardized, simplified application forms and contracts. Providing standardized and readily accessible interconnection application and contract forms to end-users and project developers is important. Standardized forms used by all utilities in the state helps state regulators assess the interconnection process and handling disputes, and also make it easier for project developers to comply with requirements. For example, Maryland's interconnection application forms are limited to eight pages.[69] Massachusetts proposed the creation of a uniform on-line interconnection application form,[70] and California has a model interconnection application in investor-owned utilities to adopt.[71] Illinois offers a standardized interconnection agreement applicable to all system sizes.[72]

[61] Regulatory Assistance Project. *Survey of Interconnection Rules*. 2007. www.epa.gov/chp/documents/survey_interconnection_rules.pdf. State interconnection application process information begins on page 23.

[62] DSIRE. Colorado Interconnection Standards. Accessed January 10, 2013.

[63] DSIRE. Maine Interconnection Standards. Accessed January 10, 2013.

[64] DSIRE. Kentucky Interconnection Standards. Accessed August 30, 2012. Applies to systems up to 30kW.

[65] DSIRE. Ohio Interconnection Standards. Accessed August 30, 2012.

[66] DSIRE. California Interconnection Standards. Accessed August 30, 2012.

[67] DSIRE. New Hampshire Interconnection Standards. Accessed August 30, 2012. "Systems that connect to the grid using inverters that meet IEEE 1547 and UL 1741 safety standards do not require an external disconnect device. However, the customer-generator assumes all risks and consequences associated with the absence of a switch."

[68] DSIRE. Delaware Interconnection Standards. Accessed January 10, 2013.

[69] Maryland Public Service Commission. http://webapp.psc.state.md.us/intranet/electricinfo/home_new.cfm. Applicable up to 1 MW.

[70] DSIRE. Massachusetts Interconnection Standards. Accessed August 30, 2012.

[71] DSIRE. California Interconnection Standards. Accessed August 30, 2012.

[72] DSIRE. Illinois Interconnection Standards. Accessed January 10, 2013.

5. **Defined process to address disputes.** A defined process to address interconnection disputes between an end-user and a utility if an impasse is reached is important. Con Edison appointed a Distributed Generation Ombudsperson in 2002 in response to increased customer interest and the role was formalized in a 2005 order (CASE 04-E-0572) from the New York State Department of Public Service. Massachusetts has proposed requiring that an arbitrator is hired to resolve any disputes in its interconnection process. Other states have dispute resolution clauses in their interconnection standards including Hawaii, Colorado, and Maryland.[73] For example, Hawaii standardized rules include a timeline for dispute resolution—a meeting to resolve disputes must be scheduled within 15 days of a written request being submitted.

6. **The ability for larger CHP systems and those not captured under net metering rules to qualify under the interconnection standards.** Some states only allow for relatively small systems to interconnect under streamlined standards,[74] often assuming that smaller DG systems are more likely to produce power primarily for their own use. In states with a multi-tiered interconnection process, small systems that meet IEEE and UL standards or certification generally pass through the interconnection process faster, pay less in fees, and require less protection equipment because there are fewer technical concerns. However, restricting capacity limits for streamlined interconnection standards to only small systems does not help facilitate broad investment in all sizes of CHP in applications where it makes economic sense. State regulators can consider the size threshold for streamlined standards that is appropriate for their states.

A number of states have established standardized interconnection for medium and large systems. Connecticut allows for systems up to 20 MW in size to interconnect.[75] California and a handful of other states have set interconnection capacity limits at 10 MW.[76] FERC initially adopted interconnection standards for facilities larger than 20 MW in 2003, then adopted interconnection standards for smaller DG units up to 20 MW in 2005. The FERC standards apply only to facilities subject to the jurisdiction of the commission—these facilities mostly include those that interconnect at the transmission level. However, FERC has noted that its interconnection standards for small generators should serve as a useful model for state-level standards.[77]

7. **Allow CHP systems to interconnect to both radial and network grids.[78]** Network grids are present in many large cities where a significant amount of CHP potential exists. Interconnection, particularly in network or local distribution networks, present protection and grid operational challenges to address inadvertent back feed into the local grid that can cause safety concerns and failure to serve loads. However, with careful operational planning and system protection review, DG can be accommodated. It is important to allow interconnection to both radial and network grids, with protections in place to minimize system impacts, in order to realize the full potential of CHP. For example, New York's interconnection standards first adopted in 1999 allowed for DG systems up to 300 kW in size to connect to radial distribution systems.[79] In 2005, New York modified its interconnection requirements to allow for DG systems up to 2 MW in size to interconnect to radial and secondary network systems. In 1999, the Texas Public Utility Commission adopted standardized rules that allow for the interconnection of systems that are 10 MW or less in size to connect to distribution-level voltages at the point of common coupling. These rules apply to both radial and secondary network systems. Note that IEEE Standard 1547.6 includes recommended practices for interconnecting distributed resources with distribution secondary networks. This standard focuses on the

[73] DSIRE. Hawaii, Colorado, and Maryland Interconnection Standards. Accessed August 30, 2012.

[74] For example, the Alaska limit is 25 kW, Kentucky is 30 kW, and Nebraska is 25 KW (DSIRE. Accessed August 30, 2012). For this interconnection chapter, typically "small" refers to systems 25 kW and under, "medium" refers to systems up to 2 MW, and "large" is defined as systems up to 20 MW. FERC uses these size thresholds with the exception of the last simplified interconnection level which applies to systems up to 20 MW.

[75] DSIRE. Connecticut Interconnection Standards. Accessed August 30, 2012.

[76] DSIRE. California, Colorado, Delaware, District of Columbia, Illinois, Iowa, Maine, Maryland, Minnesota, Montana, Oregon, South Dakota, and Texas allow for systems up to 10 MW to interconnect, and in some cases may have established procedures for systems larger than 10 MW.

[77] DSIRE. "Federal Interconnection Standards for Small Generators." Last reviewed October 12, 2011. www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06R&re=1&ee=1.

[78] Regulatory Assistance Project. *Interconnection of Distributed Generation to Utility Systems*. September 2011. www.raponline.org/document/download/id/4572www.raponline.org/document/download/id/4572. Provides recommendations for technical requirements, procedures and agreements, and emerging issues. It also discusses how interconnection to radial and network grids has been approached by a variety of states.

[79] DSIRE. New York Interconnection Standards. Accessed August 30, 2012.

technical issues associated with the interconnection of distribution secondary networks with inverter-based distributed generation, and provides recommendations relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. The standard gives consideration to the needs of the local electric power system to be able to provide enhanced service to the DG owner loads as well as to other loads served by the network.[80]

How the Criteria Are Addressed

Policy Intent. In some cases, distributed generation, including CHP, can delay or reduce the need for new costly infrastructure such as transmission and distribution upgrades. They can also help reduce peak demand on the system and lessen transmission losses. The overall policy intent is to encourage CHP deployment by providing project owners with a simple, easy to understand, and reasonable cost process and timeline for connecting to the grid, while ensuring that utilities are adequately compensated, safety requirements are met, and concerns of potential grid instability are addressed. Establishing the elements discussed in this chapter, including timelines and fees (application, technical study, and insurance), streamlined procedures, straightforward and commonly used technical requirements, and standardized simplified agreements help prevent interconnection barriers to CHP.

Market Signals. Interconnection policies that are unclear, have lengthy timelines, or have cost requirements that are not commensurate with the system size or risk can result in delays and unnecessary costs in developing CHP projects. An end-user interested in CHP may find the interconnection process too cumbersome, uncertain or costly, and may even abandon their plans. This may send the signal to the broad project development community that the state is not an attractive market for CHP.

Ratepayer Impact. The interconnection costs for project developers and the costs of review and processing incurred by the utility need to be cost of service based to hold the ratepayer indifferent. For example, the Massachusetts Department of Energy Resources may investigate whether the state’s interconnection fees for applicants are consistent with actual utility cost to provide such services.[81] Ensuring cost-based services is necessary to protect both the applicant and the utility and its ratepayers.

3.3 Conclusions

Well-designed statewide CHP interconnection standardized rules are crucial to a project’s success. While developing state standards or revising existing standards, the following elements have been used successfully by states across the country.

KEY IMPLEMENTATION APPROACHES: INTERCONNECTION STANDARDS
• Interconnection fees commensurate with system complexity • Streamlined procedures with simple decision-tree screens (allowing faster application processing for smaller systems and those unlikely to produce significant system impacts) • Practical and predictable technical requirements (often based on existing technical standards such as IEEE 1547 and UL 1741) • Standardized, simplified application forms and contracts • A dispute resolution procedure to resolve disagreements • Allow for larger CHP systems (greater than 20 MW) to qualify under the standards

[80] Personal communication between ICF and Bill Ash, IEEE standards liaison, January 2013. IEEE Standard 1547.6 is finalized as of September 2011, however the website hasn't been updated yet to reflect that. http://grouper.ieee.org/groups/scc21/1547.6/1547.6_index.html.

[81] DSIRE. Massachusetts Interconnection Standards. Accessed August 30, 2012.

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]

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[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,

[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.

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[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.

Chapter 5. Clean Energy Portfolio Standards (CEPS)

5.1 Overview

Clean energy portfolio standards (CEPS) are tools states can use to increase the adoption of clean energy technologies,[152] including CHP,[153] by requiring electric utilities and other retail electric providers to meet a specified amount of load through eligible clean energy sources.[154] One of the goals of CEPS is to stimulate market and technology development so that, ultimately, clean energy will be economically competitive with conventional forms of electric power.[155] A number of states have explicitly included some form of CHP as an eligible resource in the CEPS. CEPS, which can be used in both regulated and restructured electricity markets, can be designed in a different ways to meet various objectives. CHP can be incorporated into all three of the CEPS types described below.

- *Renewable portfolio standard (RPS)* is the most common form of a portfolio standard and is usually focused on traditional renewable energy such as wind, solar, and biomass projects. This type of portfolio standard may incorporate other technologies and fuel types in addition to renewable energy and may have separate tiers or target mandates based on the form of generation. RPS are often market-based—qualifying projects receive tradable credits, typically referred to as renewable energy credits (RECs), which can then be sold for compliance purposes. Connecticut is an example of a state with CHP included in an RPS.
- *Energy efficiency resource standards (EERS)* require utilities to save a certain amount of energy every year. To do this, utilities implement energy efficiency programs to help their customers save energy in their homes and businesses.[156] EERS can be market-based and have a trading system of credits, although this is not as common as in RPS. EERS are typically defined as including end-use energy savings. Some states include other types of efficiency, including distribution system savings and CHP and other efficient distributed generation technologies.[157] Many states have an EERS and a separate RPS, but some combine an RPS and EERS into one comprehensive portfolio standard program. Michigan is an example of a state that passed legislation creating a renewable energy standard (RES). In addition to renewables, the standard requires that both electric and natural gas utilities meet certain energy savings requirements (i.e., EERS targets).
- *Alternative energy portfolio standards (APS)* often set targets for a certain percentage of a supplier's capacity or generation to come from alternative or advanced energy sources such as CHP, coal with carbon capture and storage (CCS), coal co-fired with biomass, or municipal solid waste projects. These standards are often market-based and credit eligible projects with alternative energy credits or some other form of credit, which can then be purchased by electricity suppliers to meet compliance obligations. Examples of states with APS include Massachusetts and Pennsylvania.

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[152] State policymakers, project developers, advocates, utilities, and others have various definitions of "clean" energy. This guide does not attempt to create one definition, but rather recognizes that the primary audience for the guide is state regulators, and that they define it as they see fit.

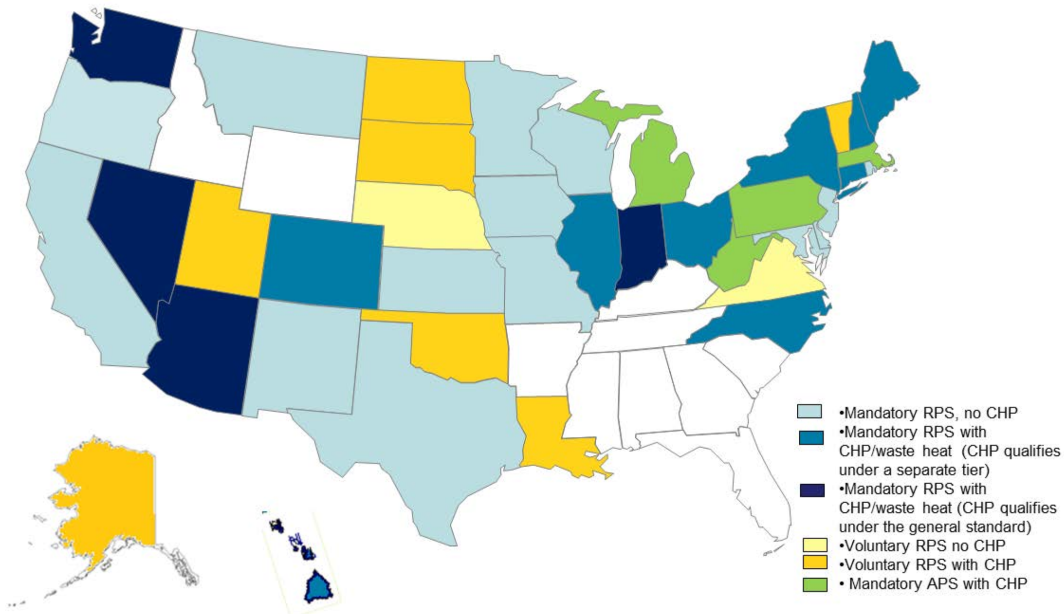
[153] Individual states will define clean energy and energy efficient technologies and practices specific to their state goals and regulations. CHP may or may not be considered for inclusion in a state's CEPS depending on how CHP's specific benefits such as GHG reductions support the state's goals and objectives.

[154] U.S. Environmental Protection Agency. *Renewable Portfolio Standards Fact Sheet*. April 2009. www.epa.gov/chp/state-policy/renewable_fs.html.

[155] U.S. Environmental Protection Agency. Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States—Chapter 5. Energy Supply Actions. April 2006. www.epa.gov/statelocalclimate/documents/pdf/guide_action_chapter5.pdf.

[156] ACEEE. *EERS in Practice.* April 1, 2009. http://aceee.org/fact-sheet/eers-practice-basic-april-2009

[157] DSIRE. www.dsireusa.org. Center for Climate and Energy Solutions (C2ES). "Energy Efficiency Standards and Targets." www.c2es.org/us-states-regions/policy-maps/energy-efficiency-standards.



Source: Map based on ICF International research. December 2012.

Figure 6. States with CEPS and how CHP qualifies (under RPS or APS)[158]

5.2 CEPS Activity in States

States with Clean Energy Portfolio Standards that Include CHP

Most CEPS have been enacted through state legislation. As of February 2013, some form of CEPS has been established in 42 states plus the District of Columbia (see Figure 6).[159] Of these states, 24—Arizona,[160] Connecticut, Colorado, Delaware, Hawaii, Indiana, Louisiana, Maine, Massachusetts, Michigan, Minnesota, Nevada, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Dakota, Utah, Vermont, Washington and West Virginia—specifically call out a form of CHP and/or waste heat to power as an eligible resource in some portion of their CEPS program guidelines (RPS, APS, or EERS). While a number of states have recognized CHP in RPS or EERS programs, many of the RPS programs limit qualified CHP systems to waste heat to power CHP (CHP bottoming cycles), and most EERS programs do not set separate targets for CHP reducing the effectiveness of these programs in promoting CHP development.

State Development and CEPS Design Features

CHP systems can offer three beneficial products: electricity generation, thermal energy production, and end-user energy savings through increased efficiency. Each of these products can help states meet their portfolio standard targets when appropriately evaluated. CHP benefits and how they are evaluated may vary by which type of CEPS a state has in place. For instance, an RPS or an APS may provide credit for the supply side attributes of CHP—the electric and thermal generation. EERS may be structured in a manner to credit the demand-side savings from CHP—the energy efficiency savings.

States have incorporated CHP into their CEPS using a diverse array of eligibility definitions, efficiency thresholds, targets, and crediting techniques. All states with a RPS allow CHP systems using eligible renewable fuel types to

[158] Florida and Arkansas also have EERS programs. Florida's is voluntary and Arkansas' is mandatory.

[159] Based on ICF International Research, the Database of State Incentives for Renewable Energy (DSIRE), and C2ES. www.dsireusa.org.

[160] Arizona only allows for renewably-fueled CHP to qualify.

qualify, but may not account for the thermal production, thus treating CHP like an electric-only generator. There are 23 states that allow for fossil fuel-fired CHP systems under some type of CEPS (RPS, APS, or EERS).[161] Some states, including Massachusetts in the APS and Connecticut in the Class III RPS, have separate targets for energy efficiency that include CHP. States such as Colorado, and Nevada, only allow for waste heat to power CHP systems to qualify under their RPS programs.[162] Below are several common elements for successful incorporation of CHP in CEPS during the development of implementation rules by state utility regulators and other state policymakers.

5.3 Successful Implementation Approaches

5.3.1 Qualifying Resources Definition—How CHP is Defined

A key component of CEPS is the definition of technologies and fuels that qualify towards compliance with the standard. This decision may be made in legislation or by the utility commission as part of implementing the standard,[163] or by other policymakers. Since the utility commission has jurisdiction to implement these standards, this component is addressed in this guide but could be also addressed in the policy design at the legislature. How narrowly eligibility is defined may impact the feasibility of the CEPS targets and may affect compliance costs and the ultimate achievement of benefits sought by the program.

How CHP is defined in a CEPS varies by state. For instance, some state CEPS only allow for bottoming cycle CHP systems (waste heat recovery or waste heat to power) to qualify, some states allow for all types of CHP regardless of fuel type used, whereas other standards may only allow for renewably-fueled CHP to qualify. Two examples where renewable and certain forms of fossil fuels qualify are Massachusetts and Connecticut:

- **Massachusetts (APS)**. CHP systems using renewable fuels and natural gas qualify. CHP systems must have begun operation (including incremental additions) on or after January 1, 2008. Existing units can receive credit for their added incremental useful thermal energy or useful electrical energy. The APS provides credit for both the electric and thermal output from the CHP system.
- **Connecticut RPS Class III.** In 2005, Connecticut added a third tier to the RPS resource requirements, establishing a new RPS Class III that must be fulfilled with CHP, demand response, and electricity savings from conservation and load management programs. Eligible CHP systems must have been developed on or after January 1, 2006. In 2007, the Class III standard was expanded to include systems that recover waste heat. Eligible systems that recover waste heat or pressure from commercial and industrial processes must be installed on or after April 1, 2007. Existing units that have been modified on or after January 1, 2006, may earn certificates only for the incremental output gains.

How the Criteria Are Addressed

Policy Intent. It may make sense if a state wants to encourage all cost-effective CHP to allow for a range of CHP technology types and fuels. A wide variety of system sizes may help achieve the policy intent of many CEPS programs, including encouraging the development of resources with greater environmental benefits compared to conventional sources of generation, while also focusing on projects that are cost-effective.

Market Signals. Eligible resources in CEPS often receive a credit, typically called a renewable energy credit (REC) or alternative energy credit that can be sold to those utilities that must comply with the standard.[164] The value of these credits can enhance CHP project economics providing a long-term source of sustainable financing that can

[161] The U.S. EPA's Combined Heat and Power Partnership (CHPP) has a fact sheet on Portfolio Standards. The information cited is from information in this fact sheet.

[162] In these states, topping cycle CHP generally does not qualify.

[163] In most states, the utility regulator implements the CEPS, but in some states like Massachusetts, the state energy office implements the standard.

[164] Massachusetts APS credits under which CHP qualifies were selling for $19.75/credit whereas Class I credits (for traditional renewables) were valued at $42.67/credit for 2012 vintages. SNL. "CSAPR NOx, SO2 Allowance Bids Move Higher." January 20, 2012. Connecticut Class III credits were priced at $10/credit as of September 2011. BGC Environmental Brokerage Services. www.bgcebs.com/Renewables.

encourage a range of clean energy projects, including CHP. This can send signals to the market that a specific state has a favorable economic environment for CHP.

Ratepayer Impact. Technology eligibility definitions along with target levels are key CEPS elements that have rate impacts. The states eligibility definition may have significant impact on the compliance costs. Considerations that state policymakers must weigh include the following:

- Narrowly defined eligibility may result in higher compliance costs that are commonly passed along to ratepayers.[165]
- Including a wider range of eligibility in CEPS, such as all CHP technologies using a variety of fuels, can help reduce ratepayer impacts since there would be a greater amount of potential resources available to fulfill the standard, reducing overall compliance costs for utilities.[166]

State regulators must carefully consider these options as they implement CEPS.

5.3.2 Minimum Efficiency Requirements or Performance-Based Metrics

An efficiency threshold for CHP projects is an important feature of incorporating CHP in CEPS. CHP efficiency is defined as the amount of useful energy output (electricity and heat) divided by fuel input. The efficiency of CHP systems varies according to the power and thermal needs of the customer, the type of generating technology employed and the amount of waste heat captured for useful purposes.[167] An appropriate eligibility threshold for CHP systems is one that is set high enough that so that it is clear that the CHP is achieving energy savings compared to separate heat and power, but not at a level that many CHP systems considered to be "high efficiency" would be excluded. Connecticut, Ohio, and Washington are examples of states with minimum efficiency requirements. As an overlay or as a stand-alone policy, progressive incentives for greater energy efficiency requirements in CEPS can also serve as a market driver for the development of systems with greater efficiency.[168] For example, a performance-based metric, instead of a minimum efficiency threshold, such as what Massachusetts has implemented in the APS, can also be used to encourage highly efficient CHP systems.

Minimum Efficiency Example. To ensure that CEPS are encouraging technologies that help achieve their policy goals, states commonly set an efficiency threshold for CHP systems or some sort of a performance based metric. By setting such a requirement, only well designed and operated CHP systems qualify—systems correctly sized to the thermal load so very little thermal energy is wasted. States such as Connecticut credit all electricity (kWh) generated from systems that meet or exceed the minimum efficiency threshold of 50%. In Washington State, CHP systems must have a useful thermal output of at least 33% to qualify.[169]

Performance Metric Example. The Massachusetts APS does not have an explicit minimum efficiency threshold, but instead has a performance-based incentive. The credits are allocated on the basis of one credit per MWh of net source fuel savings. Source fuel savings are determined by metering the CHP generated electrical and useful thermal energy as well as the fuel energy consumed and comparing the CHP fuel energy consumed with what would have been needed to generate an equal amount of electricity by the grid and thermal energy from a boiler or furnace. An empirical formula is used to quantify the net source fuel reduction. Systems that operate with either a low electrical and/or overall efficiency will generate very few or no credits. In addition, this approach

[165] Summit Blue Consulting. *An Analysis of Potential Ratepayer Impact of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives*. Prepared for the New Jersey Board of Public Utilities. Revised Draft. July 31, 2007. www.njcleanenergy.com/files/file/SACP_RPI_Analysis0731.pdf.

[166] U.S. EPA. *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States—Chapter 5. Energy Supply Actions*. April 2006. www.epa.gov/statelocalclimate/resources/action-guide.html.

[167] A minimum efficiency requirement doesn't apply to bottoming cycle CHP systems.

[168] U.S. EPA. *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States—Chapter 5. Energy Supply Actions*. April 2006. www.epa.gov/statelocalclimate/resources/action-guide.html.

[169] Washington State only allows for renewably fueled CHP systems to qualify under the Renewable Portfolio Standards.

encourages designers and developers to achieve high capacity factors through sound design, optimized sizing, and appropriate preventative and scheduled maintenance.

How the Criteria Are Addressed

Policy Intent. CEPS are designed to encourage clean sources of generation (as defined by the state).To also achieve a policy's energy efficiency and/or GHGs reduction goals, states have selected efficiency thresholds or performance criteria that exceed the performance of conventional separate heat and power (i.e., central station electricity purchased via the grid and the use of an on-site boiler or heater). In contrast, allowing systems that do not meet a minimum efficiency or performance level lessens the achievement of the CEPS objective, and hence does not satisfy the policy intent.

Market Signals. Setting an efficiency threshold or establishing performance metrics for CHP systems to qualify for CEPS encourages optimal design for CHP projects, ensuring that systems are appropriately sized to the thermal load and maximizing the utilization of available thermal energy. Well designed and operated CHP systems matched to the thermal loads of the facility will have higher annual capacity factors, typically resulting in greater energy and emissions savings, and better project economics. Setting an efficiency requirement of performance-based metric encourages the development of efficient, well-designed CHP systems.

Ratepayer Impact. Setting the efficiency or performance bar at high but achievable levels for CHP systems ensures that the energy and emissions savings objectives, if applicable, of the CEPS are met with cost-effective options.[170]

5.3.3 Separate, Distinct Targets for CHP and Other Technologies

Establishing separate targets or tiers for different categories of resources ensures that a certain class of resource is not encouraged to the detriment of others.[171] If a policy goal is to encourage diversity of supply, this can also help achieve the goal.

The following are two state implementation approaches that have proven effective:

- To set a separate tier for CHP and related energy efficiency technologies and require a specified percentage of the target to be met by each of these tiers (Examples: Connecticut's Class III and Pennsylvania's Tier II).
- To establish a separate portfolio standard program (distinct from the RPS) which is devoted to CHP and/or other energy efficiency technologies (Example: Massachusetts' APS and Michigan's Energy Optimization Savings Standard).

How the Criteria Are Addressed

Policy Intent. As CEPS look to encourage clean energy there are two key considerations. The first is that if CHP and energy efficiency measures qualify under the same general target as conventional renewable energy, the more cost-effective resources may be installed first.[172] This may or may not achieve the policy intent (some states explicitly identify a policy goal of greater renewable energy). The second consideration is how targets are established—whether they are total capacity targets (kW or MW) or whether the targets are set as a percent of utility sales over a definitive time period. When targets are set as a percentage of sales, CHP or other efficiency measures, by reducing load, can reduce the amount of renewable energy that must be procured by utilities pursuant to CEPS targets. Another option is to set a more aggressive target to account for the expected reduction of utility load.

[170] See Appendix A for a discussion on evaluating the cost-effectiveness of a CHP program.

[171] Setting separate targets for different resources can also diminish competition between technologies.

[172] This ensures that each category of resource (e.g., renewable energy, energy efficiency, and CHP) is encouraged to the same extent as before energy efficiency or CHP was added to the target, or allows a state to encourage in-state technology development (e.g., fuel cells) while also stimulating energy efficiency and/or CHP development.

Market Signals. The development of CHP and other efficiency measures is more likely if there is a supportive policy structure in place, such as having clear targets for CHP in CEPS. A mixed signal may be sent to the market if CHP is included as an eligible resource along with energy efficiency, since the lowest-cost resource will be developed first, which in most cases is energy efficiency.[173] States will weigh their policy goals, including clean energy resource development, with cost impact, and reach an appropriate decision and communicate that to the market.

Ratepayer Impact. As discussed above, CEPS inherently have ratepayer impacts. Allowing for a wider range of projects to qualify can help reduce ratepayer costs since there is also more variety in costs associated with eligible projects. Since CHP may be lower in cost compared to some other supply-side resources eligible under the CEPS, allowing for CHP systems can help lower overall ratepayer costs associated with the CEPS.

5.4 Conclusions

CEPS can be used by states to successfully increase the use of clean energy. A number of states have explicitly included CHP as an eligible resource in the CEPS. There are three implementation approaches that state regulators should focus on when implementing CHP as a resource for CEPS. While this guide does not explore the merits or problems with the development of CEPS, it identifies how such policies can be successfully implemented to facilitate CHP.

SUCCESSFUL IMPLEMENTATION APPROACHES: CLEAN ENERGY PORTFOLIO STANDARDS
• Qualifying resources definition—how CHP is defined • Minimum efficiency requirements or performance-based metrics • Separate, distinct targets for CHP and other technologies.

[173] ACEEE. *Across the Nation, State Energy Efficiency Policies Deliver, Save Consumers Billions*. June 15, 2011. "These states are demonstrating that energy efficiency programs deliver real savings for utilities and ratepayers, and it is more affordable than any supply-side energy source," said Michael Sciortino, Policy Analyst and the report's lead author. By law and rule, the energy efficiency programs implemented in a state with EERS must cost less than the electricity that would have been produced if not for the programs.

Table 2. Examples of CHP Eligibility in State Portfolios[174]

State	RPS with CHP	APS with CHP	EERS with CHP		Characteristics[175]
			CHP Explicitly Included	EERS unspecified technology	
AZ	Yes, only includes renewably fueled CHP	NA[176]	Yes		Under Arizona's Renewable Electricity Standard, systems installed on or after[177] January 1, 1997, using eligible renewable fuels qualify. Credit is granted to CHP systems based on a calculation which accounts for their thermal output; 3,415 BTUs equals one Renewable Energy Credit (REC), or one kWh of electric generation is equal to one REC. Arizona also has an EERS. CHP systems are mentioned in the standard in the following context: "energy savings from CHP installations that do not qualify under the RPS may count towards the EERS."
CO	Yes, separate DG tier	NA		Yes	Under Colorado's RPS, only renewably fueled CHP and waste heat to power (WHP) systems 15 MW or less qualify as "recycled energy" under the standard. CHP systems are not specifically mentioned in the state's EERS but can potentially qualify pending approval by the Colorado Public Utilities Commission.
CT	Yes, CHP is in a separate tier—a Class III resource	NA	Yes, as part of the RPS (Class III)		Under Connecticut's RPS, CHP systems that began operation on or after January 1, 2006, are eligible. CHP systems must meet a minimum 50% efficiency threshold. WHP systems that were installed on or after April 1, 2007, and recover waste heat or pressure from commercial and industrial processes also qualify. Both fossil fuel-fired topping cycle CHP and WHP are eligible as Class III resources. Renewably fueled CHP systems may qualify as Class I or Class II resources. Connecticut has specified calculation methodologies to account for the electric output from topping-cycle CHP systems and the thermal output from waste heat to power systems.
DE	Yes, only renewably fueled CHP[178]	NA	Yes		Waste heat to power defined as "recycled energy" is eligible under Delaware's EERS. For waste heat to power systems to qualify, savings must be from systems that began operation prior to July 29, 2009.

[174] U.S. EPA Combined Heat and Power Partnership. Table derived from forthcoming EPA fact sheet on Portfolio Standards. The table only includes those states that specifically call out CHP and WHP as eligible; there may be others states with CEPS that CHP could potentially qualify.

[175] Under all state RPS programs, CHP systems using eligible renewable fuels qualify (renewably fueled CHP is specifically called out as eligible in AZ and ME CEPS). However, in most states, only the electric output of the renewable-fueled CHP system qualifies (not the thermal output), effectively treating the CHP as a power-only resource.

[176] "Not Applicable (NA)" indicates that a state does not have this type of standard in place.

[177] Vintage Eligibility indicates the year in which system operation and/or modification must have begun for that project to be considered eligible under the CEPS. For example, in Arizona, a CHP system must have an operation date of on or after January 4, 1997, to qualify for credit in the CEPS.

[178] "No" indicates that the state has this type of standard in place, but it does not include CHP and/or waste heat to power as eligible.

State	RPS with CHP	APS with CHP	EERS with CHP		Characteristics[175]
			CHP Explicitly Included	EERS unspecified technology	
HI	Yes	NA	Yes, full implementation begins in 2015		Under Hawaii's RPS, CHP, excluding certain fossil-fueled units that sell excess electricity, may qualify. The regulations state that "Renewable Electrical Energy" defined as "electric energy savings brought about by the use of rejected heat from cogeneration and combined heat and power systems, excluding fossil-fueled Qualifying Facilities that sell electricity to electric utility companies and central station power projects" qualifies. Energy efficiency, including CHP, is eligible in the state's RPS until 2015 when it will then be eligible under the state's Energy Efficiency Portfolio Standard.
IN (voluntary goal)	Yes (goal)	NA		Yes	Indiana has a Clean Energy Portfolio Goal (CEPG) under which CHP qualifies. WHP is defined as "waste heat recovery from capturing and reusing the waste heat in industrial processes for heating or for generating mechanical or electrical work." CHP is credited in the following manner—one Clean Energy Credit (CEC) is granted for each MWh of clean energy generated. Indiana also has an EERS. CHP systems are not specifically mentioned in the standard but can potentially qualify pending approval by the Indiana Utility Regulatory Commission.
LA (voluntary program)	Yes, only WHP (pilot)	NA	NA		Louisiana has a Renewable Energy Pilot Program in place. WHP defined as "waste heat recovery" (WHR) qualifies. Systems that began operation on or after January 1, 2010, qualify.
MA	CHP not explicitly mentioned , renewably fueled CHP only	Yes, stand-alone EE program, separate from the state's RPS	Yes, targets as part of the Green Communities Act		Under Massachusetts APS, CHP systems using any fuel type that began operation on or after January 1, 2008, qualify. To qualify, CHP must have a net CO_2 emissions rate of 890 lbs/MWh or lower. Credit for CHP systems under this standard is calculated as the energy savings on a quarterly basis compared to utilizing grid electricity at a conversion of 33% for the electric load, and fuel for the thermal load at a net 80% conversion efficiency. CHP is also eligible for a Capital Expenditure incentive under the state EERS program. Qualifying CHP must pass cost effectiveness screen with an overall efficiency ≥ 60%.
ME	Yes	NA		Yes, unspecified technologies qualify (potentially CHP)	Fossil fueled CHP systems in operation prior to January 1, 1997, qualify under Class II of the RPS. CHP systems must also meet a minimum 60% efficiency threshold. Under the state's EERS, CHP systems are not specifically mentioned in the standard but can potentially qualify pending approval by the Maine Public Utilities Commission.

State	RPS with CHP	APS with CHP	EERS with CHP		Characteristics[175]
			CHP Explicitly Included	EERS unspecified technology	
MI	NA	Yes, renewable standard with EERS component	Yes, part of APS		Advanced cleaner energy facilities (including industrial WHP) that began operation on or after October 6, 2008 qualify under the state's APS/EERS combined standard. Industrial CHP qualifies defined as "a facility that generates electricity using industrial thermal energy or industrial waste energy."
MN	No	NA	Yes		Under Minnesota's EERS, renewably fueled CHP and WHP (measured by electricity output) qualify, although certain exceptions apply.
NV	Yes	NA	Yes, part of RPS		Under Nevada's EERS, renewably fueled CHP and WHP (15 MW or less) qualify. The system must have begun operation on or after January 1, 2005. Under the standard, one Portfolio Energy Credit is granted for each one kWh generated from an eligible resource. Energy efficiency gets a credit multiplier of 1.05.
NC	Yes	NA	Yes, part of RPS		CHP using renewable fuels qualifies under the renewable portion of the standard. Fossil-fueled CHP and waste heat to power systems qualify as efficiency measures, which can provide up to 25% of the RPS requirements. After 2018, up to 40% of the standard can be met through energy efficiency, including CHP. Systems must have been installed on or after January 1, 2007. CHP systems are credited using the following methodology—thermal energy that is not used to generate electric power and is measured accurately in British thermal units (Btu) shall earn equivalent RECs based on the end-use energy value of electricity of 3,412 Btu per kWh. One REC is equivalent to one MWh of generation.
OH	NA	Yes	Yes		Under the APS, WHP using fossil fuels and renewably fueled CHP systems qualify. Typical CHP, meaning fossil fuel-fired topping cycle systems qualify as an "advanced energy resource," but compliance with these targets does not have to be demonstrated until 2025. CHP systems must have an overall efficiency of at least 60%, and at least 20% of total energy output must be thermal. WHP systems must have been installed on or after September 10, 2012, to qualify. Renewably fueled CHP must have been placed into service on or after January 1, 1998. All forms of CHP using any fuel type qualify under the state's separate EERS. The same efficiency thresholds apply as under the APS. Systems must have been installed or retrofitted on or after September 10, 2012, to qualify.

Chapter 6. Emerging Market Opportunities

6.1 CHP in Critical Infrastructure Applications[179]

6.1.1 Overview

The U.S. electric power system is vast and complex, with thousands of miles of high-voltage cable that serve millions of customers around the clock, 365 days per year. Although normally this “instant” supply of electricity is taken for granted, terrorist attacks and natural disasters remind us how dependent we are on electricity and how fragile the grid can be. Water systems; oil and gas pipelines; communications systems; residential, commercial, industrial, and institutional buildings; transportation; health systems; emergency operations; and nearly every other category of critical infrastructure is in some way dependent on electricity.

Critical infrastructure collectively refers to those assets, systems, and networks that, if incapacitated, would have a substantial negative impact on national or regional security, economic operations, or public health and safety.[180] These applications include hospitals, water and wastewater treatment facilities, financial institutions, police and security services, and places of refuge.[181] Facilities that may serve as places of refuge include, but are not limited to—schools, colleges, and universities; armories; government buildings; hotels and convention centers; and sports arenas. Prior to September 11, 2001, emergency management planning focused primarily on preparedness and response—that is, what happens at the moment of an emergency and in the minutes, hours, days, and weeks thereafter. In the years since 2001, however, the idea of infrastructure resilience in key assets, systems, and functions—that is, the ability to maintain operations despite a devastating event—has become a key principle in disaster preparedness.

How does CHP Fit into Critical Infrastructure Applications?

CHP offers the opportunity to improve and contribute to critical infrastructure (CI) resiliency, mitigating the impacts of an emergency by keeping critical facilities running without any interruption in service. If the electricity grid is impaired, a properly configured CHP system can continue to operate, ensuring an uninterrupted supply of power and heat to the host facility. The installation of CHP systems at select CI facilities could increase the ability of these facilities to ride through a prolonged electrical grid outage; and the uninterrupted functioning of critical facilities would increase the resiliency of the surrounding community. CI facilities are typically outfitted with backup generators to take over the supply of electricity for on-site needs in the case of a grid failure; however, CHP systems have several advantages over backup generators. In some sectors, such as hospitals, the presence of a CHP system may not override the necessity of having a backup generator, which is required by current law. CHP systems, however, provide benefits to their host facilities all the time, rather than just during emergencies. Some advantages that CHP systems have over backup generators include the following:

- Backup generators are seldom used and are sometimes poorly maintained, so they can encounter problems during an actual emergency; CHP systems run daily and are typically highly reliable.
- Backup generators typically rely on a finite supply of fuel on site,[182] often only enough for a few hours or days, after which more fuel must be delivered if the grid outage continues. CHP systems have a more reliable source of fuel on demand.
- Backup generators may take time to start up after grid failure, and this lag time, even though it may be quite brief, can result in the shutdown of critical systems. Also, in many cases, backup generators must be delivered to the sites where they are needed, leading to further delays in critical infrastructure recovery.

[179] National Association of State Energy Officials (NASEO). *State Energy Assurance Guidelines*. December 2009. http://naseo.org/eaguidelines/State_Energy_Assurance_Guidelines_Version_3.1.pdf.

[180] Patriot Act of 2001 Section 1016 (e).

[181] “Places of refuge” is a commonly used term in the realm of emergency planning. See, www.iupui.edu/~prepared/procedures/shelter and www.purdue.edu/emergency_preparedness/faq.htm.

[182] Some backup generators run off natural gas as well.

CHP systems are the consistent baseload source of electricity for the site they serve, and if properly sized and configured, are impacted by grid failure.

- Backup generators typically rely on reciprocating engines burning diesel fuel, an inefficient and polluting method of generating electricity.[183] CHP systems typically burn natural gas, a cleaner fuel, and achieve significantly greater efficiencies, lower fuel costs, and lower emissions by capturing waste heat. Moreover, CHP systems are capable of using multiple fuels, which makes them that much more versatile in emergency situations.
- Backup generators only supply electricity; whereas, CHP systems supply thermal loads as well as electricity to keep facilities operating as usual.
- The economics of operating a CHP system on-site, especially if allowed to obviate the need for a backup generator, may prove more favorable than procuring and operating a backup generator solely during emergencies.

The requirements for a CHP system to deliver power reliability, as in a critical infrastructure facility, are fairly straightforward, but they may add some costs relative to CHP in a non-critical facility.

6.1.2 Benefits of Successful Implementation Approaches

Following the terrorist attacks in 2001; the Northeast blackout in 2003; and natural disasters such as Hurricane Katrina in 2005, Hurricane Ike in 2008, and Superstorm Sandy in 2012, disaster preparedness planners have become increasingly aware of the need to protect critical infrastructure facilities and to better prepare for energy emergencies. Resilient critical infrastructures enable a faster response to disasters when they occur, mitigate the extent of damage that communities endure, and speed the recovery of critical functions. CHP can answer this need while making energy more cost- and fuel-efficient for the user, as well as more reliable and environmentally friendly for society at large. The use of CHP systems for critical infrastructure facilities can also improve overall grid resiliency and performance by removing significant electrical load from key areas of the grid. This is possible when CHP is installed in areas where the local electricity distribution network is constrained or where load pockets exist. The use of CHP in these areas eases constraints and load pockets by reducing load on the grid. To ensure continued progress towards addressing grid and critical infrastructure resiliency via technologies such as CHP, improved coordination between government emergency planners and the electricity sector must occur.

There are a variety of examples of CHP systems in hospitals that have continued operating throughout grid failures enabling the hospital to continue serving the community[184] Even though sustaining hospital operations is always a high priority, it is perhaps one of the highest and most widely recognized priorities during emergency incidents. It is imperative to ensure that hospitals function during an incident to provide essential emergency response services. The following examples provide insight into how hospitals can serve this critical function.

South Oaks Hospital (Long Island, New York). South Oaks Hospital originally installed its 1.3 MW CHP system to reduce energy costs; however, reliability has been a large advantage of having CHP. The system is grid-connected but can operate off the grid during emergencies. During the major northeast blackout in August 2003, South Oaks never lost power, while the area around the hospital lost power for 14 hours. Employees were not even aware of the blackout at first because they saw no interruption in their service. During the recent Superstorm Sandy, the hospital continued to operate as usual and was able to receive patients from other facilities that were without power due to the failure of backup generators. About 30 psychiatric patients from South Beach Psychiatric Center on Staten Island were shifted to South Oaks.[185]

[183] Some backup generators have installed environmental controls to help reduce emissions.

[184] U.S. Department of Education/Oak Ridge National Library. "CHP Enabling Resilient Infrastructure: Powering Through Superstorm Sandy." March 2013.

[185] www.medicaldaily.com/articles/12942/20121030/hospitals-emergency-mode-hurricane-sandy-death-toll.htm#qePwdJUKkUWvTRtm.99.

Montefiore Medical Center (Bronx, New York). Montefiore has a 14 MW CHP system that generates almost all of the electric and thermal needs of the facility.[186] In advance of Superstorm Sandy, a command center was set up and connected to the NYC Office of Emergency Management. Twenty patients were seamlessly transferred from NY Downtown Hospital, and as the storm and its effects worsened, additional patients were taken in from NYU Langone, Bellevue Hospital, and nursing homes across the region. Montefiore was the only institution in the area that kept its outpatient services open on both days, and residents and faculty kept the teaching clinics fully staffed. During the Northeast blackout in August 2003, Montefiore was reportedly the only hospital in New York City that continued to admit patients, perform surgeries, and continue normal operations.[187] At the time of the blackout the hospital was fairly full and did not have a large number of open beds, but non-critical patients were discharged to make room for patients from other facilities, including those dependent on life support equipment that required power. The hospital's lobbies became a refuge for elderly people in the neighborhood who needed to cool off in the air conditioning. The cafeteria also remained open and was able to serve food late into the night to local residents, policemen, and service personnel.

A variety of facilities from several different sectors may be identified as potential places of refuge, and these facilities can play a crucial role in supporting public health and safety. These facilities possess attributes that suit them for a role as places of refuge. They can provide accommodations for large numbers of people, are widely distributed in communities, and typically possess kitchens and sanitary facilities, which are required to sustain people dislocated during a crisis.

Salem Community College (Salem County, New Jersey). Serving as a Red Cross Disaster Relief Shelter, Salem's CHP system consists of three Capstone C65 microturbines that provide heating, cooling and emergency power to the critical facility. During Superstorm Sandy, the shelter was fully operational as it was continuously powered and heated by the CHP system. The shelter took in a peak of about 80 to 90 residents between Monday and Tuesday.[188]

New York University (New York City). During Superstorm Sandy, approximately 6,000 of New York University's students found themselves in dorms without power. After 48 hours without power due to the storm, those who could not find refuge with friends in dorms with power or elsewhere in the city were ordered to evacuate on Wednesday and spend the night in the Kimmel Center, NYU's student life building. The Kimmel Center's CHP plant kept the lights on and the heat and water running for displaced students. The second floor of the building became a temporary health center, as NYU's permanent health center was closed. The power provided by the CHP plant also allowed the university to distribute hot meals. Five NYU dorms (such as Goddard Hall, which also runs on power from NYU's CHP system) that still had power also became centers of refuge, as displaced students were allowed in to sleep on floors and in hallways.[189, 190]

Additionally, Superstorm Sandy resulted in considerable disruption to businesses. The economic research firm Moody's Analytics attributed almost $20 billion in losses from suspended business activity.[191] For example, Wall Street's extended closure included a two-day shutdown of the New York Stock Exchange, which halted financial market trading at a cost of about an estimated $7 billion. CHP systems located at data centers and at other corporate locations can help prevent significant interruptions in normal business operations.[192]

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[186] PR Newswire. "Clean NYC Energy Project Honored by the Association of Energy Engineers." June 27, 2012. www.prnewswire.com/news-releases/clean-nyc-energy-project-honored-by-the-association-of-energy-engineers-54944777.html.

[187] Midwest CHP Application Center. *Combined Heat & Power for Minnesota Healthcare Facilities*. Jan. 8, 2004. http://gulfcoastcleanenergy.org/Portals/24/Events/Hospitals%20Audiocast/CHP_haefke_StPaul_MN.pdf.

[188] www.nj.com/salem/index.ssf/2012/10/salem_county_deals_with_afterm.html.

[189] www.thedailybeast.com/articles/2012/11/01/inside-the-nyu-refugee-camp-for-displaced-students.html.

[190] Midwest CHP Application Center. *Combined Heat & Power for Minnesota Healthcare Facilities.* Jan. 8, 2004. http://gulfcoastcleanenergy.org/Portals/24/Events/Hospitals%20Audiocast/CHP_haefke_StPaul_MN.pdf.

[191] http://money.cnn.com/2012/10/29/news/economy/hurricane-sandy-business/index.html.

[192] www.osborneadvisors.com/HOT-TOPIC-Disastrous-Sandy-The-Financial-Effects-of-a-Historic-Storm.c4293.htm.

Public Interest Network Services (Manhattan, New York). The Public Interest data center provides hundreds of companies with office communications support. It is connected via three different fiber networks to multiple carriers for voice calls, provides multiple tier-1 Internet backbone operators, and is protected against power failure by a full-scale Uninterruptible Power Supply (UPS) and combined heat and power system. The 65 kW microturbine based CHP system provides for all of the computer and office lighting electric loads as well as providing space cooling from absorption chillers. During Superstorm Sandy the power to the building and surrounding area was out for more than two days, however the data center was able to remain fully operational. The CHP system was even able to provide the building landlord with power to continue to run their computer and security systems.[193]

6.1.3 Successful Implementation Approaches

States with Critical Infrastructure Policies that Include CHP

Texas. Texas bills HB 1831 and HB 4409[194] require that beginning in September 1, 2009, all government entities (including all state agencies and all political subdivisions of the state such as cities, counties, school districts, institutes of higher education, and municipal utility districts) must do the following:

- Identify which government-owned buildings and facilities are critical in an emergency situation.
- Prior to constructing or making extensive renovations to a critical governmental facility, the entity in control of the facility must obtain a feasibility study to consider the technical opportunities and economic value of implementing CHP.

This legislation was enacted because of several major natural disasters (hurricanes Katrina, Rita, and Ike) that showed the vulnerability of the state's critical infrastructure. It was found that these natural disasters could knock out portions of the electric grid for weeks and backup generators were not reliable. Texas has found that the high pressure pipeline system that supplies natural gas throughout the state has provided highly reliable service throughout recent hurricanes. Underground natural gas pipelines provide a secure source of energy to on-site CHP systems, which can then deliver electricity, steam, and chilled water securely throughout the facility.

To determine whether a government building or facility is critical, it must meet the following criteria:

- Owned by the state or a political subdivision of the state
- Expected to continue serving a critical public health or safety function throughout a natural disaster or other emergency situation, even when a widespread power outage may exist for days or weeks
- Continuously occupied and maintain operations for at least 6,000 hours each year
- Have a peak electricity demand exceeding 500 kilowatts.

Examples of government buildings and facilities that may meet the 'critical' definition include hospitals, nursing homes, command and control centers, shelters, prisons and jails, police and fire stations, communications and data centers, water or wastewater facilities, research facilities, food preparation or food storage facilities, hazardous waste storage facilities, and similar operations.

Louisiana. On June 1, 2012, the Louisiana Legislature passed resolution No. 171, which requests that the Department of Natural Resources and the Louisiana Public Services Commission establish guidelines to evaluate CHP feasibility in critical government facilities. Critical facilities are defined as command and control centers, hospitals, shelters, prisons, jails, police and fire stations, communications centers, data centers, and water and wastewater facilities, among others. Important criteria for CHP feasibility include being operational 6,000 hours per year and having a peak electricity demand exceeding 500 kW. CHP may be deemed feasible if it can provide a facility with 100% of its critical electricity needs, can sustain emergency operations for at least 14 days, and has

[193] www.cornerstonetelephone.com/about.

[194] www.txsecurepower.org.

60% efficiency. The energy savings must also exceed installation, operating and maintenance costs during a 20-year period.[195]

New York. The State Energy Research and Development Authority (NYSERDA) has been a strong supporter of CHP technology development and implementation for more than 10 years. NYSERDA recently partnered with the New York State Office of Emergency Management to educate the state's emergency managers about CHP so that it can be included in strategic plans for emergency and place of refuge facilities.[196] The purpose of this effort was to provide the "connecting links" between national homeland security efforts and regional/state infrastructure resilience activities.

The final report[197] detailed the CHP potential in critical infrastructure applications in New York and provided outreach information to these sectors (e.g., hospitals, water treatment plants, financial institutions, places of refuge) to present the benefits of CHP to infrastructure resiliency.

How the Criteria Are Addressed

Policy Intent. States and other local governments are developing policies to include CHP in critical infrastructure planning to ensure the energy security and reliability of emergency facilities. A focus on infrastructure resilience instead of protection suggests that critical infrastructure security is most enhanced by investing resources in such a way that no matter what the attack or disaster, as much of the nation's critical infrastructure system as possible will remain functional, and that those parts of the system that are compromised will resume functionality in as short a time as possible. In this context, the value of CHP to infrastructure resiliency becomes clear, with careful attention to the ways in which the various sectors of the nation's infrastructure are dependent upon electricity; critical assets across sectors can be insulated from disruption to the grid through the use of CHP and other forms of distributed energy. Focus can be placed on the crucial points of infrastructure interdependence, where relatively small investments in distributed energy provide marked increases in the resilience of our nation's system of critical infrastructure.

Market Signals. Including CHP in critical infrastructure facilities as a priority in state and local emergency planning activities can greatly incentivize development of this resource. The increased occurrence of blackouts and extreme weather events that affect the grid can also serve as clear market signals by costing millions of dollars in lost revenues to facilities without a reliable source of backup power.

Ratepayer Indifference. The costs associated with incorporating CHP into critical infrastructure planning still needs to be evaluated further to ensure they are lower cost than alternatives, on a lifecycle basis. However, there is a strong history of economically-sound CHP systems that have helped hospitals and critical industrial facilities to continue operating in the face of an emergency, while also providing financial savings during non-emergency operation.

6.1.4. Conclusions

Successful application of CHP in critical infrastructure sectors will depend on overcoming institutional barriers, and engaging the support of decision-makers who build, manage, and operate these facilities. An element of "out-of-the-box" thinking is also required as the needs of our infrastructure evolve to contend with growing and changing risks. Emergency management professionals are an additional key group that must be engaged in the effort, for they provide a gateway to their stakeholders who play an important role, at the local level, in developing emergency response plans and taking action when needed. To ensure continued progress towards addressing grid and critical infrastructure resiliency via technologies such as CHP, improved coordination between government

[195] http://files.harc.edu/sites/gulfcoastchp/newsletters/Newsletter_20120626.pdf.

[196] Pace Law School. Newswire. August 2011. http://newswire.blogs.law.pace.edu/2011/08/30/thomas-bourgeois-deputy-director-of-the-pace-energy-climate-center-on-keeping-power-flowing-to-critical-infrastructure-in-the-wake-of-natural-disaster.

[197] www.nyserda.ny.gov/en/Publications/Research-and-Development/~/media/Files/Publications/Research/Other%20Technical%20Reports/nyserda-chp-final-report-optimized.ashx.

emergency planners and the electricity sector must occur. State utility regulators and other state policymakers can facilitate that coordination and help reduce regulatory barriers to CHP so that these systems can be more easily installed in critical infrastructure applications.

6.2 Emerging Market Opportunity—Utility Participation in CHP Markets

6.2.1. Overview

A significant policy option for increasing installed CHP capacity may be to allow incumbent natural gas and electric utilities to participate in CHP markets. Utility participation may take many forms. A utility could own CHP facilities directly on the customer side of the meter or provide packages of services to customers who own their own CHP, or it could incorporate combined heat and power solutions into ratepayer-funded efficiency programs.

Today, utilities are constrained in the provision of CHP services. Most do not have the regulatory approval to build and own CHP facilities. Neither do most have the flexibility to negotiate custom service packages for customers who own their own CHP systems. This represents a significant barrier to the growth of cost-effective CHP because incumbent utilities are uniquely positioned to facilitate new CHP development. Utilities understand CHP technology, which has been present in the market about as long as central station power supply. They generally are very familiar with their customers' process needs and concerns. Utilities may be in a unique role to assume the risk and responsibility of installing and maintaining a complex energy system so that the customer can concentrate on its primary mission or business—they may also be able to accept longer paybacks and lower internal rates of return than their customers. Direct support could involve investments in equipment and infrastructure over a long investment horizon, a proposition that aligns with the utility business model. Utilities understand their own delivery systems—where new energy capacity is needed and where CHP can provide the most benefits to the system. Allowing or enabling utilities to participate in CHP markets may be a way to stimulate cost-effective CHP development and provide system benefits.

There are various ways in which a utility can participate in CHP markets depending on the regulatory environment. A utility can build and own CHP facilities, it can negotiate a custom package of services to support a CHP customer who owns his own CHP, or it can support CHP customers pursuant to a system of regulatory incentives. In some states utilities are pursuing CHP as part of ratepayer-funded energy efficiency programs.

Considerations for utility participation in CHP markets may include the following:

- Rules to ensure non-discriminatory access by third parties wishing to enter the CHP market in the utility's service territory and compete with i
- Financial controls to prevent the utility from shifting costs from its CHP products and services to the revenue requirements of non-CHP customers
- A policy determination about how to treat CHP-related earnings for rate making purposes (e.g., either imputing CHP earnings as offsets to required revenues, or allowing the utility to retain CHP earnings). Policy may differ for utilities in restructured versus traditional electricity markets.
- Models for joint utility-customer ownership of CHP assets or utilization of utility service performance contracts
- Allowing for utility incentives for CHP, including innovative financing mechanisms, discounted natural gas rates, or utility partnerships with government.

6.2.2. Successful Implementation Approaches

Alabama Power Company

The Alabama Power Company works with individual customers to manage their rates and loads. This includes considering CHP options, where feasible. For CHP options to be viable for Alabama Power support, they must offer benefits for the individual customer, for all other customers on the system, and for the utility. Alabama Power, its customers, and the Alabama Public Service Commission have worked together successfully to find such “win-win-win” projects.

Today, there is approximately 2,000 MW of CHP on the Alabama Power system. Approximately 1,500 MW is customer-owned and more than 500 MW is company-owned and operated at large industrial sites. Customer-owned generation has allowed Alabama Power to avoid building approximately 1,700 MW of central station capacity, which has benefitted all customers. During the 1990’s when the utility needed to add new generation to reliably meet the load obligations of its customers, Alabama Power was able to develop new generation resources near certain customer facilities based on combined heat and power. By having the ability to work with these customers and having a flexible regulatory process, these new generation facilities were certified by the Alabama Public Service Commission through its regulatory process. This certification process allowed the non-steam aspect of these generation facilities to be allowed in rate base.

Due to the impacts of the recession and the development of other cost-effective energy efficient measures, Alabama Power does not have a reliability-based need for new generation for the rest of this decade. Nevertheless, given the flexibility allowed under Alabama’s regulatory process, the utility was able to recently certify two purchase power agreements from customer-owned CHP facilities. Alabama allows projects that offer extraordinary value to be certified even if there is not an immediate need. The company was able to negotiate prices, terms and conditions of these two purchase power agreements that captured extraordinary benefits for all of its customers. Due to the uniqueness of each CHP application, a custom service agreement between the customer and the utility must be negotiated for each project to go forward.

Philadelphia Gas Works (PGW)

The municipal gas utility in Philadelphia, PA, PGW provides an example of a natural gas utility serving a central role in developing a CHP technology solution for one particular customer. PGW worked closely with the Four Seasons hotel, in downtown Philadelphia, to develop an efficient solution to meet the hotel’s energy needs. Working closely with PGW representatives, the hotel evaluated the project requirements and identified CHP as a viable solution that would offer savings at a reasonable payback. PGW provided assistance with project evaluation and engineering, and introduced the hotel to the microturbine technology solution it would eventually utilize. The project identified that three 65kw natural gas fired microturbines could provide 100% of the building’s day-to-day domestic hot water, 25% of its electric, and 15% of its heating needs.

The upfront cost of the project remained a hurdle. To address this, PGW developed a business scenario where it would provide $1.2 million for an upfront capital incentive for the purchase and installation of the CHP unit on-site at the Four Seasons. The hotel posted a letter of credit to keep PGW and Philadelphia ratepayers whole. PGW was then able to recover the costs of the incentive through a surcharge on the hotel’s energy bill. Full recovery of incentive costs to PGW was calculated to take three years. After PGW cost recovery, the customer enjoys the benefits of the energy savings during the lifetime of the CHP equipment. The arrangement required coordination between PGW representatives, its Board of Directors, the Philadelphia Gas Commission, and the customer.

Baltimore Gas and Electric (BGE)

Maryland utilities support CHP implementation by using incentives through their ratepayer-funded energy efficiency programs. As an example, BGE supports qualified projects as part of its Combined Heat and Power Program by providing incentives for industrial and commercial customers who install an on-site CHP system. The primary objective is to encourage the use of CHP to support the EmPOWER Maryland energy efficiency initiative which seeks to reduce per capita energy and demand use by 15% by 2015. The program is limited to projects where the full CHP capacity is used on-site, that meet BGE’s cost effectiveness requirements and have an overall minimum efficiency of 65%. Projects that qualify can receive up-front incentives for design and installation, and a production incentive for 18 months of operation of the system after commissioning. The total incentive cannot exceed $2 million.

New Jersey Natural Gas (NJNG)

NJNG has a Fostering Environmental and Economic Development (FEED) program designed to provide financial assistance for energy-efficiency upgrades and economic development opportunities for commercial and industrial customers. FEED will provide access to investment capital, incentives, and/or discounted rates to encourage the installation of energy-efficient equipment, including combined heat and power projects, as well as business growth, expansion, and retention in the state. Upfront funding will be provided by NJNG with the principal and interest repaid by the customer over an agreed upon period of time. Long term, fixed price contracts for the purchase of natural gas are also available under FEED. This program provides no risk to ratepayers and no associated costs will be recovered through NJNG's rates.

Other Examples

- Examples of joint ownership of CHP assets in the ethanol industry include Missouri Ethanol LLC in Laddonia, MO, a 45 million-gal/yr ethanol plant that began operation in September 2006. The plant uses approximately 5 MW of power and 100,000 lbs/hr of steam. It is one of two ethanol plants in the state that employ gas turbine-based CHP through a utility-ethanol plant partnership. The CHP system is comprised of a 14.4 MW Solar Titan gas turbine and an unfired heat recovery steam generator (HRSG). The CHP system is jointly owned by Missouri Ethanol and the Missouri Joint Municipal Electric Utility Commission (MJMEUC)—a statewide joint action agency that supplies power and capacity services to 56 municipal Missouri utilities. The Missouri Ethanol project is patterned after an earlier CHP partnership between the City of Macon, MO, and the Northeast Missouri Grain LLC ethanol plant in Macon. In both Macon and Laddonia, the utilities own and are responsible for gas turbine operation. However, the ethanol plants own and are responsible for the heat recovery equipment, including the HRSGs and downstream steam systems. Natural gas costs are shared between the utilities and ethanol plants in both cases. The Missouri Public Utility Alliance (MPUA) views the Laddonia project as a 'win-win-win' effort, as it provides a cost-competitive power supply for MJMEUC, reduced steam costs for the ethanol plant and additional baseload gas demand for the Missouri Municipal Gas Commission. In addition to these benefits, the project directly supports a number of MPUA goals, including increasing the diversity of its supply portfolio, increasing local control of supply assets and promoting economic development for rural Missouri.[198]
- Austin Energy, a municipal electric utility in Texas, is sole owner and operator of a 4.5 MW CHP plant that is used to power, heat and cool a number of buildings, including IBM Research Labs, in the Domain industrial park in northwest Austin. Austin Energy has characterized this plant as a "mini-grid solution," and a response to increasing demands on Austin's power generation assets. Austin Energy also owns and operates a 4.4 MW CHP system at the Dell Children's Medical Center; the system provides 100% of the hospital's power, heating, and cooling needs.
- Gainesville Regional Utilities owns and operates the South Energy Center, a 4.3 MW natural gas fired CHP system that serves the Shands Cancer Hospital at the University of Florida with 100% of its energy needs.
- Ameren developed and formerly owned and operated a 44 MW CHP facility in Mossville, Illinois, through a non-regulated subsidiary, Ameren Energy Medina Valley Cogen LLC. The system produces electricity, steam, and chilled water for the adjacent Caterpillar engine manufacturing facility.

[198] District Energy Magazine. "Utility-Ethanol Partnerships: Emerging Trend in CHP." 2nd Quarter 2007. International District Energy Association.

Appendix A: Evaluating the Cost-Effectiveness of a CHP Program

In evaluating the cost-effectiveness of a CHP program administered by a utility or third party, it is useful to use the standard tests[199] that are used in evaluating the cost-effectiveness of energy efficiency programs. While all CHP programs may not be characterized as "energy efficiency," these tests are nonetheless useful because they capture the impacts of the programs on the several different affected parties. In the case of CHP, the affected parties include the host customer (i.e., the participant), the electric utility, and the gas utility.

Evaluating the cost-effectiveness of CHP programs is more involved than that for energy efficiency programs because there will be an increase in gas consumption, as well as a reduction in electricity consumption. Thus, the participant's gas bill is affected, as well as the electric bill, and gas costs are increased while electricity costs are reduced.

Tables A.1 and A.2 below show how the different costs and benefits of a CHP project should be accounted for in evaluating cost-effectiveness. Under the Program Administrator Cost (PAC) test, the Total Resource Cost (TRC) test, and the Rate Impact Measure (RIM) test, there are three different ways of looking at cost-effectiveness—from the perspective of an electric utility that implements a CHP program that does not provide gas to the host customer, from the perspective of a gas utility that implements a CHP program that does not provide electricity to the host customer, and from the perspective of a gas and electric utility that implements a CHP program that provides both gas and electric services to the host customer.

Table A.1. Costs and Benefits of CHP Programs under the TRC and PAC Tests

	PAC: Electric	PAC: Gas	PAC: Electric & Gas	TRC: Electric	TRC: Gas	TRC: Electric & Gas
Benefits						
Avoided Electric Energy	Yes	---	Yes	Yes	---	Yes
Avoided Electric Capacity	Yes	---	Yes	Yes	---	Yes
Avoided T&D	Yes	---	Yes	Yes	---	Yes
Increased Revenues (gas)	---	Yes	Yes	---	Yes	Yes
Reduced Bills (electric)	---	---	---	---	---	---
Reduced Emissions (electric)	---	---	---	---	---	---
Costs						
Utility Program Administration	Yes	Yes	Yes	Yes	Yes	Yes
Utility Incentive to Customer	Yes	Yes	Yes	Yes	Yes	Yes
Customer Install Costs	---	---	---	Yes	Yes	Yes
Customer Annual O&M	---	---	---	Yes	Yes	Yes
Increased Bills (gas)	---	---	---	---	Yes	Yes
Increased Emissions (gas)	---	---	---	---	---	---
Reduced Revenues (electric)	---	---	---	---	---	---

[199] National Action Plan for Energy Efficiency. November 2008. *Understanding Cost-Effectiveness of Energy Efficiency Programs*. www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf.

Table A.2. Costs and Benefits of CHP Programs under the RIM, Participant, and Societal Tests

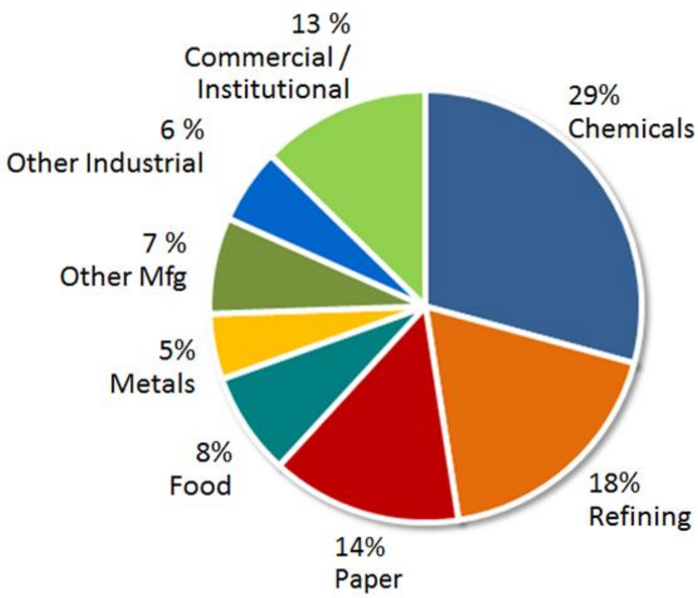
	RIM: Electric	RIM: Gas	RIM: Electric & Gas	Participant	Societal
Benefits					
Avoided Electric Energy	Yes	---	Yes	---	Yes
Avoided Electric Capacity	Yes	---	Yes	---	Yes
Avoided T&D	Yes	---	Yes	---	Yes
Increased Revenues (gas)	---	Yes	Yes	---	Yes
Reduced Bills (electric)	---	---	---	Yes	---
Reduced Emissions (electric)	---	---	---	---	Yes
Costs					
Utility Program Administration	Yes	Yes	Yes	---	Yes
Utility Incentive to Customer	Yes	Yes	Yes	---	Yes
Customer Install Costs	---	---	---	Yes	Yes
Customer Annual O&M	---	---	---	Yes	Yes
Increased Bills (gas)	---	---	---	Yes	Yes
Increased Emissions (gas)	---	---	---	---	Yes
Reduced Revenues (electric)	Yes	---	Yes	---	---

Appendix B: CHP Outlook

CHP is already an important resource for the United States—the existing 82 GW of CHP capacity at more than 4,100 industrial and commercial facilities represents approximately 8% of current U.S. generating capacity and more than 12% of total MWh generated annually.[200] CHP can be utilized in a variety of applications that have significant and coincident, power and thermal loads. Figure B.1 shows the sectors currently using CHP—87% of existing CHP capacity is found in industrial applications, providing power and steam to energy intensive industries such as chemicals, paper, refining, food processing, and metals manufacturing. CHP in commercial and institutional applications is currently 13% of existing capacity, providing power, heating, and cooling to hospitals, schools, university campuses, hotels, nursing homes, office buildings, and apartment complexes. District energy CHP systems in cities and university campuses represent approximately 5 GW of installed CHP.[201]

Current United States CHP installations use a diverse set of fuels, although natural gas is by far the most common fuel at 72% of installed CHP capacity. Biomass, process wastes, and coal comprise the remaining CHP fuel mix. Compared to the average fossil-based electricity generation, the entire existing base of CHP saves 1.8 quads of energy annually and mitigates 240 $MMTCO_2e$ each year (equivalent to the emissions of more than 40 million cars).

There is a long history of using CHP in the United States. Decentralized CHP systems located at industrial and municipal sites were the foundation of the early electric power industry in the United States. However, as power generation technologies advanced, the power industry began to build larger central station facilities to take advantage of increasing economies of scale. CHP became a limited practice primarily utilized by a handful of industries (paper, chemicals, refining, and steel) which had high and relatively constant steam and electric demands and access to low-cost fuels. Utilities had little incentive to encourage customer-sited generation, including CHP. Various market and non-market barriers at the state and federal level served to further discourage broad CHP development.[202]



Source: "CHP Installation Database." ICF International. www.eea-inc.com/chpdata/index.html.

Figure B.1. Currently installed CHP capacity by application

[200] "CHP Installation Database." Developed by ICF International for Oak Ridge National Laboratory and the U.S. DOE. 2012. www.eea-inc.com/chpdata/index.html.

[201] International District Energy Association.

[202] Oak Ridge National Laboratory. 2008. *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future*." ORNL/TM-2008/224.

Spurred by the oil crisis, in 1978, Congress passed PURPA to encourage greater energy efficiency. PURPA provisions encouraged energy efficient CHP and small power production from renewables by requiring electric utilities to interconnect with "qualified facilities." Qualifying Facilities CHP facilities had to meet minimum fuel-specific efficiency standards[203] in order to become a qualified facility. PURPA required utilities to provide Facilities with reasonable standby and back-up charges, and to purchase excess electricity from these facilities at the utilities' avoided costs.[204] PURPA also exempted Qualifying Facilities from regulatory oversight under the Public Utilities Holding Company Act and from constraints on natural gas use imposed by the Fuel Use Act. Shortly after enacting PURPA, Congress also provided tax credits for investments in cogeneration equipment under the Energy Tax Act of 1978 (P.L. 95-618; 96-223) and the Crude Oil Windfall Profits Tax Act of 1980 (P.L. 96-223; 96-471). The Energy Tax Act included a 10% tax credit on waste-heat boilers and related equipment, and the Windfall Profits Tax Act extended the 10% credit to remaining CHP equipment for qualified projects.[205] The Windfall Profits Act limited the amount of oil or natural gas that a Qualifying Facility could use.[206] The implementation of PURPA and the tax incentives were successful in dramatically expanding CHP development; installed capacity increased from about 12,000 MW in 1980 to more than 66,000 MW in 2000.[207]

The environment for CHP changed again in the early 2000s with the advent of restructured wholesale markets for electricity in several regions of the country. Independent power producers could now sell directly to the market without the need for Qualifying Facility status. The movement toward restructuring (deregulation) of power markets in individual states also caused market uncertainty, resulting in delayed energy investments. As a result, CHP development slowed. These changes also coincided with rising and increasingly volatile natural gas prices as the supply demand balance in the United States tightened. This further dampened the market for CHP development.

While recent investment in CHP has declined, CHP's potential role as a clean energy source for the future is much greater than recent market trends would indicate. Like other forms of energy efficiency, efficient on-site CHP represents a largely untapped resource that exists in a variety of energy-intensive industries and businesses (Figure B.2). Recent estimates indicate the technical potential[208] for additional CHP at existing industrial facilities is slightly less than 65 GW, with the corresponding technical potential for CHP at commercial and institutional facilities at more than 65 GW,[209] for a total of about 130 GW. A 2009 study by McKinsey and Company estimated that 50 GW of CHP in industrial and large commercial/institutional applications could be deployable at reasonable returns with then current equipment and energy prices.[210] These estimates of both technical and economic potential are likely greater today given the improving outlook in natural gas supply and prices.

[203] Efficiency hurdles were higher for natural gas CHP.

[204] Avoided cost is the cost an electric utility would otherwise incur to generate power if it did not purchase electricity from another source.

[205] Congressional Research Service. "Energy Tax Policy: Historical Perspectives on the Current Status of Energy Tax Expenditures." May 2011.

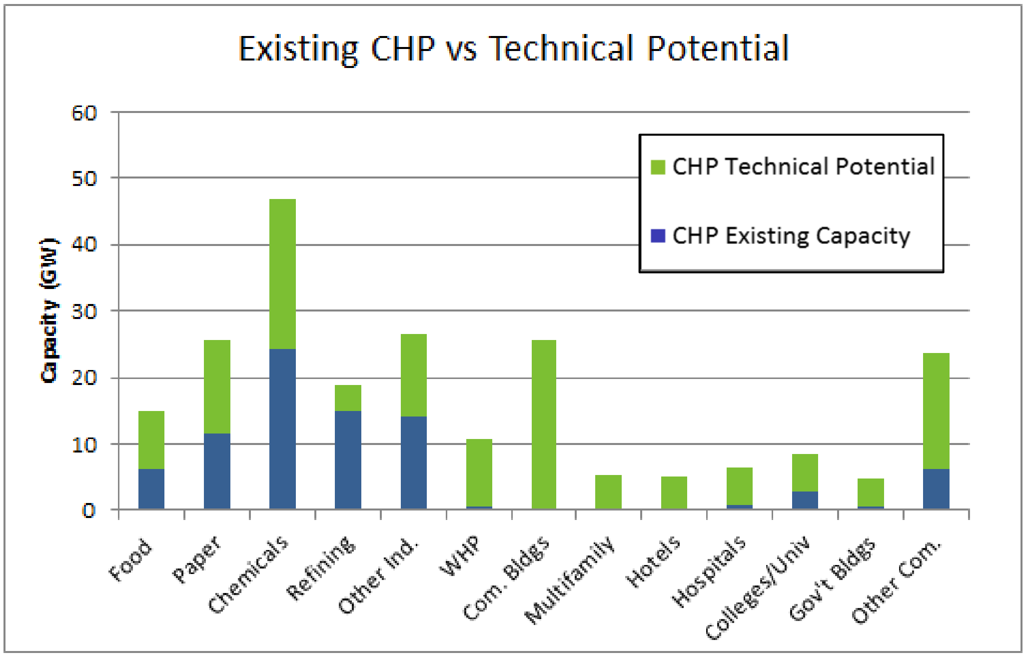
[206] G Fowler, A Baugher, and S Jansen. "Cogeneration." Illinois Issues. Northern Illinois University. December 1981.

[207] "CHP Installation Database." Developed by ICF International for Oak Ridge National Laboratory and the U.S. DOE. 2012. www.eea-inc.com/chpdata/index.html.

[208] The technical market potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. The technical potential includes sites that have the energy consumption characteristics that could apply CHP. The technical market potential does not consider screening for other factors such as ability to retrofit, owner interest in applying CHP, capital availability, fuel availability, and variation of energy consumption within customer application/size classes. All of these factors affect the feasibility, cost and ultimate acceptance of CHP at a site and are critical in the actual economic implementation of CHP.

[209] Based on internal estimates as detailed in ICF International. *Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power.* October 2010. Prepared for WADE and USCHPA. These estimates are on the same order as recent estimates developed by McKinsey and Company (see following footnote).

[210] McKinsey Global Energy and Materials. (2009). *Unlocking Energy Efficiency in the U.S. Economy*. www.mckinsey.com/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.



Source: Internal estimates by ICF International and "CHP Installation Database." Developed by ICF International for Oak Ridge National Laboratory and the U.S. DOE. 2012. www.eea-inc.com/chpdata/index.html.

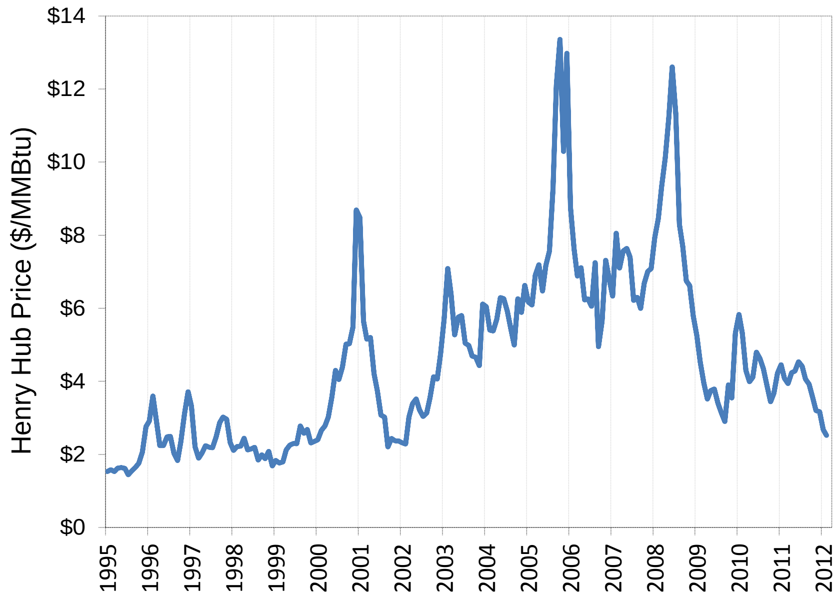
Figure B.2. Technical potential for CHP at industrial and commercial facilities

The outlook for increased use of CHP is improving. Policymakers at the federal and state level are beginning to recognize the potential benefits of CHP and the role it could play in providing clean, reliable, cost-effective energy services to industry and businesses. A number of states have developed innovative approaches to increase the deployment of CHP to the benefit of users as well as ratepayers. CHP is being looked at as a productive investment by some companies facing significant costs to upgrade old coal and oil-fired boilers. In addition, CHP can provide a cost-effective source of new generating capacity in many areas confronting retirement of older power plants. Finally, the economics of CHP are improving as a result of the changing outlook in the long-term supply and price of North American natural gas—a preferred fuel for many CHP applications.

Regarding natural gas prices, a recent report[211] summarizes the changing supply outlook for natural gas in North America and its impact on prices and CHP deployment:

> "The development of shale gas has had a significant moderating effect on natural gas prices. Prices in the five years prior to the recession averaged approximately $7.50/MMBtu; since 2008, gas prices have averaged approximately $4/MMBtu. Continuing advancements in technology are driving reassessments of long term gas outlook as analysts project more and more shale gas is economically recoverable at prices below $5/MMBtu. Estimates of the natural gas resource base in North America that can be technically recovered using current exploration and production technologies now range from 2,000 to more than 4,000 trillion cubic feet—enough natural gas to supply the United States and Canada for 100 to 150 years at current levels of consumption. Henry Hub gas prices remain in the $4 to $7 range through 2030 in current EIA projections; sufficient to support the levels of supply development in the projection, but not high enough to discourage market growth. Continuing moderate, and less volatile, gas prices will be a strong incentive for CHP market development. As detailed above, 72% of existing CHP capacity is fueled by natural gas, and the clean burning and low carbon aspects of natural gas will make it a preferred fuel for future CHP growth."

[211] U.S. DOE. *Combined Heat and Power: A Clean Energy Solution*. August 2012. www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf.



Source: Energy Information Administration. www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

Figure B.3. Henry Hub natural gas prices

Appendix C: CHP in Community Planning—CHP Zones

C.1 Overview

What are CHP Zones?

CHP zones are designated areas for CHP development in brownfields (e.g., land previously used for industrial or commercial purpose and slated for redevelopment), greenfields (e.g., new business enterprise zones and research campuses) and areas on the utility distribution grid where it is impractical to upgrade or install new lines. CHP zones are similar to economic development zones, which are present in many states, in that they seek to enhance development in a particular area through beneficial policies or financial incentives. As discussed in this Appendix, state regulators and policymakers can play a pivotal role in the development of CHP in these zones.

Why is CHP Practical in these Zones?

Brownfield and greenfield development integrating infrastructure for transportation, housing, and commercial/industrial businesses can capitalize on energy density needs and the opportunity to install electric and other energy distribution systems coincident with new construction or re-development. District energy with CHP can be a critical element of this infrastructure.[212] By combining individual user loads, district energy systems using CHP can potentially deliver energy services in a more efficient, economic, and environmentally friendly manner. Properly designed and maintained district energy systems can reduce energy costs and greenhouse gas emissions while freeing up valuable space in customer buildings by centralizing production equipment and, through economies of scale and equipment management, optimizing the use of fuels, power and resources. Since the focus of this guide is state CHP and policy implementation, and the role of the state regulator is secondary to the local government efforts.

Cities are embracing sustainability measures in their planning in order to achieve carbon reduction goals, create/retain jobs, and enhance quality of life. Electric and gas utilities also have prominent roles in the planning process to ensure that the energy needs of redeveloped areas are adequately addressed. State commissions and publicly owned utility boards can drive achievement of clean energy goals by encouraging their regulated utilities to assist in evaluating district energy and CHP energy solutions. Integrated resource planning and long term procurement proceedings are two areas where district energy and CHP can also be addressed. State utility commissions can also set forth the parameters and rules for incentive programs for distributed generation, and research and development programs to include district energy and CHP systems. California is a state with such a program specific to CHP.[213]

C.2 Benefits of Successful implementation Approaches

District energy and CHP are the energy solutions of choice by many cities. Cities conducting comprehensive planning and construction of energy and water systems, transit, mixed use and recreational space endeavor to achieve long term economic, sustainability and self-sufficiency goals. Integrated systems also facilitate achievement of critical infrastructure and energy security goals. By aggregating the thermal requirements of many different buildings, the district energy system can employ industrial grade equipment designed to utilize multiple fuels and employ technologies that would otherwise simply not be economically or technically feasible for individual buildings, such as deep lake water cooling; direct geothermal or waste wood combustion. The diversity of energy options and fuel flexibility creates a market advantage for district energy/CHP systems and establishes

[212] District energy systems produce steam, hot water, or chilled water at a central plant. The steam, hot water, or chilled water is then piped underground to individual buildings for space heating, domestic hot water heating, and air conditioning. As a result, individual buildings served by a district energy system don't need their own boilers or furnaces, chillers or air conditioners. To further improve the efficiency, the reject heat can be used to spin turbines and generate electricity, thus making it a district energy CHP system. Source: International District Energy Association. www.districtenergy.org/what-is-district-energy.

[213] CPUC. Decision 12-05-037. "Electric Program Investment Charge." May 24, 2012.

the district energy/CHP system as an asset for community energy planning. Additionally, the availability of district energy service can reduce the capital cost of constructing and operating office buildings by eliminating the need to build a boiler and chiller plant as part of the project and can optimize leasable and useful space by reducing mechanical space and vaults in basements, core and rooftops. A corollary benefit is that developers may qualify for energy efficiency and renewable energy incentives that would lessen overall cost impacts. The systems are viewed as cornerstones of smart growth and sustainable cities. Examples from San Francisco and Arlington County, Virginia, are discussed below.

C.3 Successful Implementation Approaches

San Francisco, California

The City of San Francisco is moving forward on a large redevelopment project—termed the Transit Center District Plan.[214] The Plan identifies district energy and CHP as a priority to take advantage of the dense mixed use development in the Transbay redevelopment area. The Board of Supervisor unanimous approval occurred July 31, 2012, and the Mayor signed the Plan on August 8, 2012.[215] In the next phase, the city's planning department will evaluate alternative financing mechanisms that include impact fees, private only and public-private investment structures. Private participation is an important consideration because it preserves eligibility for federal tax treatment and accelerated depreciation.[216] At the same time, city planning staff will prepare a sustainability paper that integrates energy and water systems with building performance, having earlier studied and found that district energy/CHP systems were feasible.[217]

> *There is a great opportunity with the Transit Center Plan to establish a highly energy efficient district-scale approach to energy procurement and consumption, including combined heat and power (CHP), setting up the area to be an exemplar low carbon development. This will help the City to achieve its Climate Action Plan, Electricity Resource Plan and carbon reduction goals. With respect to CHP, the strategy could also future-proof the Plan Area to be able to take advantage of local renewable biomass energy sources as, and when, an appropriately scaled plant(s) becomes viable.*
>
> -Transit Center District Plan, San Francisco Planning Department, p. 60, May 3, 2012

Eight specific policies related to district energy and CHP are included in the Plan[218].

Objective 6: Streamline Potential Implementation of a District Energy Distribution Network by Phasing Major Streetscape and Utility Works In Line With New Building Development in the Transit Center District and Transbay Redevelopment Area.

- Policy 6.1—Pursue creation of efficient, shared district-scale energy systems in the district.
- Policy 6.2—Pursue a combined heat and power (CHP) system or series of systems for the Transit Center District and the Transbay Redevelopment Area (Zone 1).

[214] Interconnection of CHP is governed by CPUC Rule 21 and network issues such as backfeed and network system protectors are addressed at the engineering design stage. Such issues need to be studied but is not an insurmountable issue with modern technology and careful evaluation.

[215] www.sfmayor.org/index.aspx?page=846&recordid=66&returnURL=%2findex.aspx.

[216] The Energy Improvement and Extension Act (2008) provides a 10% investment tax credit for the costs of the first 15 megawatts of CHP property fulfilling certain eligibility requirements. The Act also provides for a five-year accelerated depreciation for CHP. A CHP facility owned and operated by a for profit company selling the electrical and thermal under an Energy Services Agreement would be able to claim the ITC and five year accelerated depreciation. Tax exempt or non-profit organizations do not pay taxes and therefore, do not qualify for the ITC or accelerated depreciation.

[217] ICF personal communication with Kate McGee, Lead Planner, SF Planning Department, July 9, 2012.

[218] Transit Center District Plan Initiation Packet Executive Summary, Hearing Date May 3, 2012. http://commissions.sfplanning.org/cpcpackets/2007.0558MTZU.pdf.

- Policy 6.3—Require all new buildings to be designed to plug into such a system in the future.
- Policy 6.4—Require all buildings undergoing major refurbishment (defined as requiring new HVAC plant) to be designed to plug into such a system in the future
- Policy 6.5—Identify and protect either suitable public sites or major development sites within the plan area for locating renewable or CHP generation facilities.
- Policy 6.6—Require all major development to demonstrate that proposed heating and cooling systems have been designed in accordance with the following order of diminishing preference:
  - Connection to sources of waste heat or underutilized boiler or CHP plant within the transit center district or adjacent areas
  - Connection to existing district heating, cooling, and/or power plant or distribution networks with excess capacity
  - Site-wide CHP powered by renewable energy
  - Site-wide CHP powered by natural gas
  - Building level communal heating and cooling powered by renewable energy
  - Building level communal heating and cooling powered by natural gas
- Policy 6.7—Investigate City support for energy service companies to finance, build, operate, and maintain transit center district energy networks; and work with necessary private utilities to facilitate connection of new electricity supply from CHP to the grid
- Policy 6.8—Require all major development in the plan area to produce a detailed energy strategy document outlining how the design minimizes use of fossil fuel driven heating, cooling and power—through energy efficiency, efficient supply, and no or low carbon generation.

These policies can serve as a model for other city redevelopment efforts.

Arlington County, Virginia

Arlington County declared that it "must find ways to reduce our dependence on the inexpensive fossil fuels that have fueled our progress since the Industrial Revolution in favor of efficiency and cleaner, more sustainable energy sources and systems."[219] Arlington formed the Community Energy and Sustainability (CES) Task Force in January 2010 to help identify ways to improve the "economic, energy, and environmental future" in the County and one of the areas of focus is on district energy systems using CHP.

> *The CES Task Force Report includes a step-wise approach to creating cleaner and more cost-effective energy supply structures that produce fewer emissions. District energy systems, commonly found in other parts of the world, facilitate the efficient use of the heat from local combined heat and power (CHP) generation, greatly reducing the fuel waste normally associated with making electricity. District energy systems can be tailored to the specific needs of each neighborhood and retain flexibility to adapt to changing technologies and future demands.*
>
> -Executive Summary, Community Energy and Sustainability Final Draft

The Task Force includes individuals from across the public and private sectors, including the involvement of Washington Gas and Dominion Virginia Power. Regarding district energy, the Task Force concluded that mandatory district energy zoning where "the combination of district energy-ready development, scale project planning, and county sponsorship" can be used as a viable alternative to standard zoning. The Task Force recognized that the

[219] Arlington County. *Arlington County Community Energy and Sustainability Task Force Report*. Final Draft. March 11, 2011. http://news.arlingtonva.us/pr/ava/community-energy-plan.aspx.

"positive involvement of Dominion Virginia Power and Washington Gas, along with major property developers and owners in the evolutionary planning of the County's district energy strategies, could be a crucial factor in any alternative zoning's early success."[220] A new district energy company that wholly or partly owns, and operates and maintains the district energy network is another key policy recommendation.[221] Arlington's Board of Supervisors instructed the County Manager to turn the Task Force's recommendations into an implementation plan that was presented before the Board in November 2012.

How the Criteria are Addressed

Policy Intent. Cities and other local governments are seeking ways to promote economic development while meeting their environmental targets. To meet these goals, while also providing development zones with low cost energy, planning agencies have begun to incorporate district energy and CHP and other efficiency measures as a priority in new redevelopment projects. Utilities are important stakeholders at the infrastructure planning stage.[222] State utility commissions and municipal utility boards can play a pivotal role by working with their utilities to support greater district energy and CHP as key tools to help draw in commercial development through easy access to energy infrastructure, as well as achieving local government sustainable energy and environmental goals. When conducting integrated resource planning and long term procurement proceedings, utility commissions can investigate district energy and CHP utility planning efforts with local governments in their service territory. In addition, State utility commissions that approve energy efficiency programs that promote clean energy technologies and can specify the consideration and/or the inclusion of district energy and CHP systems in such programs.[223] These efforts will help meet the intent of a redevelopment effort that also meets related state and city goals.

Market Signals. Including district energy and CHP as a priority in city planning activities can greatly incentivize development of this resource by market participants. Additionally, having the infrastructure for CHP included in the initial guidance (zoning/building codes) for a new site development can accelerate CHP project deployment, and importantly provide the flexibility for future installation of advanced technologies when they become cost-effective.

- Both Arlington County's Community Energy Plan and San Francisco's Transit Plan reflect a comprehensive and long-term vision. Both plans capitalize on community scale energy solutions—district energy and CHP—on a district rather than individual building basis.
- San Francisco's district energy center housing the primary energy systems would be "future proofed" or capable of being modified to allow changes in fuel sources or advancements in technology "should biomass gasifiers and fuel cells (or other new technology) become cost-effective." Further, bulk fuel buying would help stabilize price volatility and operation and maintenance tasks would be streamlined for building operators. Collectively, San Francisco endeavors to reduce their energy use and carbon footprint.[224] The city was one of the first American cities to take action against climate change, publishing a climate action plan in 2004 with short, mid, and long-term GHG reduction targets, with a final goal of reducing emissions 80% below 1990 levels by 2050. CHP and district energy systems have been identified as a way to help meet this emissions goal and other objectives. Notably, the planning department's education and outreach of the plan and future study of financing mechanisms for energy projects manifest a commitment to the consideration of private only ownership as well as public-private

[220] Ibid, p. 55.

[221] Ibid, p. 31.

[222] Pacific Gas & Electric has involved many San Francisco Bay Area cities in its Local Government Partnership proposal as well as with the Bay Area Regional Energy Network (BayREN). For example, the City of Oakland is confident that the partnership and BayREN "can collectively achieve deeper energy savings and greenhouse gas reductions than would otherwise be possible." Response Comments, City of Oakland on the Motion for Consideration of the San Francisco Bay Area Regional Energy Network. CPUC Application A.12-07-11. Aug. 3, 2012. http://docs.cpuc.ca.gov/efile/RESP/172268.pdf.

[223] CPUC Decision 11-09-015. Sept. 8, 2011. Findings of Facts 3-6. In addition, California's Self-Generation Incentive Program which already includes CHP on renewable and non-renewable fuel could be evaluated and modified to include district energy systems.

[224] Transit Center District Plan, p 61.

partnerships. While district energy and CHP systems could be built on either mechanism, the federal CHP tax incentive applies to third parties but not to tax exempt state and local governments. In fact, some private developers set up CHP project financing on a build, own and operate basis to secure the tax incentive to lower total project costs. This reduction is reflected in the cost of the electricity and thermal energy they sell to consumers.

Ratepayer Impacts. The costs associated with incorporating district energy with CHP into city development projects should be evaluated by each city to ensure they are lower cost than alternatives. If it is determined to be cost-effective, there is a strong history of economically sound district energy systems, with more than40 urban district energy systems in the country currently utilizing CHP that can be looked to for lessons learned.[225] Both San Francisco and Arlington County will be evaluating all financial funding options as alternatives to traditional development impact fees to determine the best role for local government, private enterprise and public-private partnerships. Policymakers, including utility regulators, could formulate similar objectives requiring utilities to consider district energy with CHP as a way of meeting future demand at a benefit to ratepayers. Synergistic efforts by cities and utility regulators could result in achievement of energy, environmental, fiscal, and other objectives through the use of CHP and other forms of clean energy.

C.4 Conclusions

Arlington County and San Francisco are showcase urban areas, melding energy, environmental, transit, housing, and lifestyle goals into their planning. Each expended considerable time and effort, involving stakeholders from across the spectrum to fashion smart growth and sustainability plans. District energy and CHP are their solutions of choice for their energy infrastructure. State utility commissions can support these decisions and ensure that state ratepayers benefit.

[225] "CHP Installation Database." Maintained by ICF International for Oak Ridge National Laboratory. 2012. www.eea-inc.com/chpdata/index.html.

Appendix D: Capacity and Ancillary Service Markets: How CHP can Participate

D.1 Overview

Regional Transmissions Organizations/Independent System Operators (RTO/ISOs) administer and manage capacity and ancillary services markets. Demand reduction which includes CHP can participate in these markets depending on size (varies by RTO/ISO but can be as low as 1 MW for CHP in ISO-NE), metering, performance and registration requirements. State utility regulators have the ability to influence market rules, particularly when multiple states petition for a market rule change together. There are several opportunities for this influence on rules that impact CHP, including metering (requirements and meter cost) and planning (ensuring the balancing authority knows about CHP and includes it in their planning). In addition, there are opportunities advance the dialogue of the potential role that distributed generation can play in capacity and ancillary services markets, as well as any challenges it poses. This can be done through discussions with stakeholders inside the state or to the balancing authority. This section is focused on this opportunity.

D.2 What Additional Markets can CHP Participate In?

In areas of the United States with organized wholesale markets,[226] a CHP facility can sell energy, capacity and ancillary services, depending on the facility's operational characteristics and the requirements of the particular market[227] (see Figure D.1 for a map of organized markets). For example, some markets require participants to determine how much energy or capacity will be available to the market at each hour. Other markets require participants to accept dispatch instructions with short notice and for specific amounts of energy over time (i.e., adjust their electricity output up or down by specified amounts within specific timeframes). Each of these markets provides CHP facilities with an opportunity to generate an additional revenue stream that improves project economics, but may require changes in the design or in the operation of the CHP asset.

The power grid is a dynamic system that requires constant balancing or regulation of generator power flows and customer loads that constantly fluctuate. Grid operators use regulation response services also known as automatic generator control, by transmitting real-time control signals to generators to adjust their output in relation to demand. Operators automatically adjust generator output from a central location to balance momentary fluctuations in generation and load; maintain synchronized reserves which is unloaded generation that is synchronized with the grid and ready to serve additional demand (or customer load that can quickly be removed from the system); and voltage support, reactive power and frequency regulation, which are needed to keep the system within electrical and safety tolerances. These services are traditionally provided by load serving entities connected at the transmission level with resources that are dispatchable by the RTO/ISO or purchased from third parties.

Such services are also purchased by the ISO/RTOs from third parties. Specific services markets include the following:

- *Capacity or Forward Capacity Markets* are markets whereby new and existing resources bid into grid operator auctions that acquire capacity sufficient for reliable system operation for future years at competitive prices.
- *Ancillary Services* markets include the following:
    - *Operating & Spinning Reserves* supply electricity if the grid has an unexpected need for more power on short notice. Operating reserves are operating generating units that can be increased quickly to supply the needed energy to balance supply and demand; spinning reserves are

[226] Organized wholesale electric markets (the markets operated by ISO New England, NYISO, PJM, Midwest ISO, CAISO, and SPP) are regulated by FERC under the authority of the Federal Power Act. These markets are engaged in interstate electricity transmission and wholesale electricity sales (sale for resale between load serving entities and not retail sales). www.ferc.gov/about/ferc-does/ferc101.pdf.

[227] CHP facilities operating as demand response resources or interruptible load are not addressed here.

unloaded synchronized units that are ready to serve additional demand; demand resources also can bid to supply synchronized reserve by reducing their energy use on short notice.

- *Regulation and Frequency Response* service corrects for short-term changes in electricity use that might affect the stability of the power system. This service helps match generation and load and adjusts generation output to maintain the desired frequency.
- *Reactive Power and Voltage Control* service corrects for reactive power and voltage fluctuations caused by customer operations. This service helps maintain voltage within limits set by the National Electric Reliability Council for the reliable operation of the system.

As more distributed generation resources are being added as electric supply resources, ISO/RTOs are allowing or evaluating participation by these resources in capacity and ancillary services markets. CHP systems with appropriate metering can provide these services at the transmission or distribution level and companies are currently providing these resources on behalf of CHP customers in the PJM market.[228] Single prime mover, or modular prime mover applications, such as multiple engine or turbine CHP systems may have capacity available to provide operating and spinning reserves and other ancillary services. Microgrids that incorporate distributed generation are also technically capable of providing ancillary services.[229]

> *Ancillary services are essential to keep the system balanced and prevent it from cascading into a blackout. And it turns out that demand response, local storage, and DG are among the best "dance partners" to ensure we can reliably integrate renewable energy resources into the grid. Indeed, it has been demonstrated that these distributed resources are more efficient than central station fast response natural gas fired generators at matching load variations and providing ancillary services needed to ensure reliability. They are even faster, generally cheaper, and have a lower carbon footprint than the traditional power plant provided ancillary service.*
>
> -Remarks of FERC Chairman Jon Wellinghoff , CAISO Stakeholder Symposium, October 7, 2009

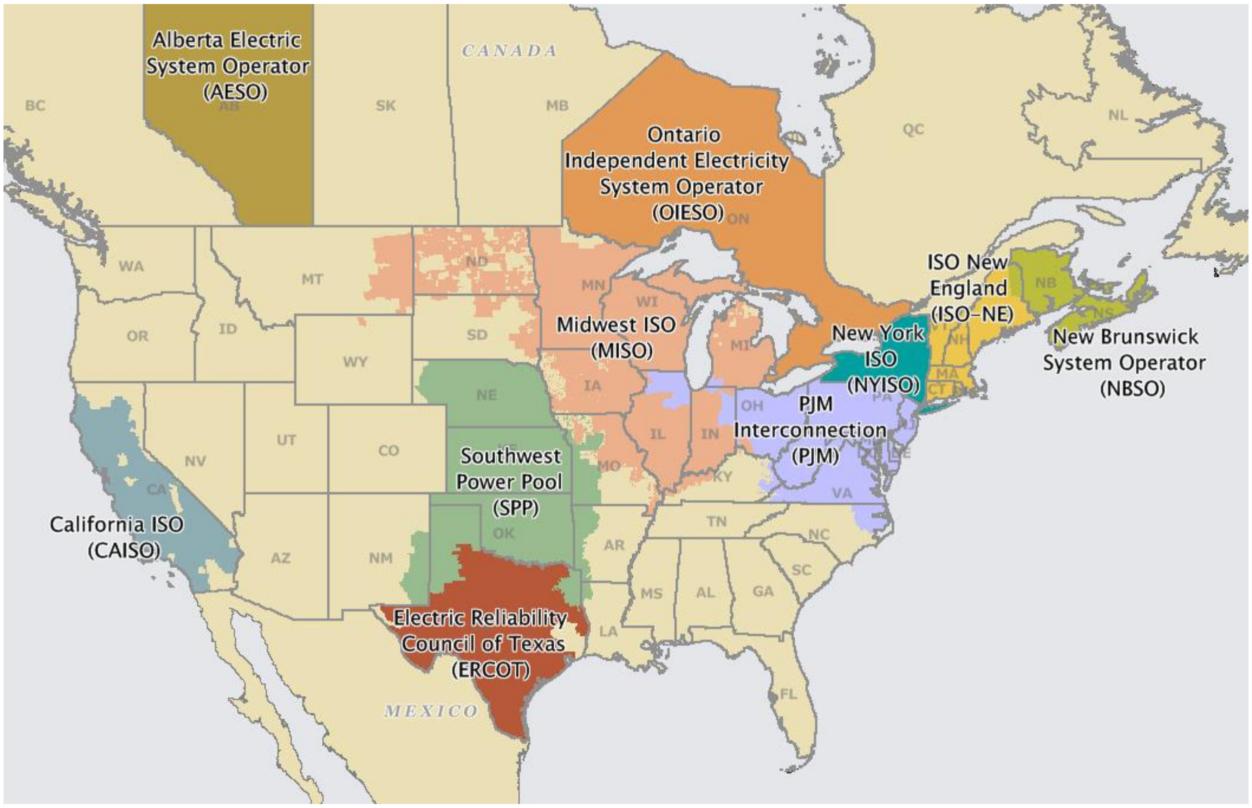
Capacity and ancillary services are unique commodities. Capacity markets support future market needs. Ancillary services support daily operation of the grid to maintain system reliability.[230] Provision of these services is tied to the design of the energy market and the location of the resources relative to the locational need on the grid. Procurement of these services can be through regulated systems or market-based. Rules for procurement and financial settlement are fairly complex. Service providers are paid by the ISO a regulated fixed cost price or, in restructured markets, a market based price. While this section focuses on market designs in the United States, these markets have been developed in many regions in the world.[231]

[228] The argument that CHP is firm capacity and contributes to resource adequacy has been raised by the CHP industry. The theory is that such resources should qualify for a capacity payment as CHP capacity is a new utility power plant that would otherwise be built. The California PUC is currently addressing the role of distributed generation resources in meeting local reliability requirements and resources needed for the next 20 year planning period—Long Term Procurement Proceeding, R1203014.

[229] Appen, Marnay, Stadler, et al. "Assessment of the Economic Potential of Microgrids for Reactive Power Supply." Presented at the ICPE2011-ECCE Asia 8th International Conference on Power Electronics—ECCE Asia, Shilla Hotel, Jeju, Korea, 30 May—3 June 2011. http://der.lbl.gov/publications/assessment-economic-potential-microgrids-reactive-power-supply.

[230] If properly located and reliably operated, offer an alternative generation resource that relieves the strain on utility infrastructure, helping to keep rates low for other utility customers. See http://www.fortnightly.com/fortnightly/2012/08/capturing-distributed-benefits?authkey=ed2f91bfeb755dc6c222d2a76b32f98d675ae9db26fee62ecd0f798b0e67528b.

[231] Ela, Kirby, Navid and Smith. "Effective Ancillary Services Market Designs on High Wind Power Penetration Systems." Conference Paper, NREL/CP-5500-53514. December 2011.



Source: Federal Energy Regulatory Commission. www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0

Note: ERCOT and the system operators of Alberta and Ontario are not under the jurisdiction of FERC.

Figure D.1. Regional transmission organizations and independent system operators

Current CHP participation in capacity, reserves and ancillary services markets is very low across the United States.[232] One reason for the low participation is that each of the markets for these services is highly specialized with detailed rules to ensure that the electric system remains safe and reliable. In capacity markets also known as Forward Capacity Markets, compensation is established through a competitive auction and paid to resources that commit several years forward to being available to meet peak demand.[233] Failure to meet the contractual obligation invokes a penalty. The ancillary services market is also governed by detailed rules and system aggregators or the load serving entity arrange participation on behalf of the CHP owner. Participation requirements include metering that allows for financial settlement, active market engagement, and periodic ISO training courses to maintain certification.

Another reason for low participation is that CHP operating characteristics may not align with participation requirements. CHP systems are usually sized to meet site thermal loads and are normally operated in a baseload manner or follow the operating schedule of the facility to maximize savings. Electricity produced is typically less than customer demand and no excess is generated. If there is no export capability, participation in capacity markets is precluded. CHP could participate in ancillary services markets if operational flexibility is designed into the system (e.g., the CHP system is sized with single or multiple prime movers that provide excess capacity when needed or the system can operate during times when the thermal load is predictably lower affording excess

[232] Personal communication between ICF and PJM and ISO-NE staff and their perspectives of CHP market participation in their own and neighboring ISO/RTOs. However, there are companies actively working with CHP systems to provide this service in PJM.

[233] Regulatory Assistance Project. "The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects." Prepared by Meg Gottstein. Brussels. June 2010. http://raponline.org/search/document-library/page/3?keyword=Gottstein&submit=Submit&publish_date_preset=&publish_date_start=&publish_date_end=&document_type_id=&sort=publish_date&order=desc.

electrical generation to be available). Again thermal matching considerations will affect the ability of CHP to successfully compete in this market. Finally, CHP systems with a synchronous generator or a generator with a power electronic interface have the advantage that they can be controlled to provide or absorb reactive power.[234] However, thermal load that do not match well may lead to system inefficiencies and perhaps greenhouse gas emissions increases.

FERC is encouraging third party participation in the ancillary services market, particularly distributed generation with synchronous generators or with a power electronic interface.[235]

D.3 Successful Implementation Approaches

Participation in capacity and ancillary services markets requires dedicated time by the end-user to understand the rules of participation. The technical and procedural requirements may be complicated but the ISO/RTOs have training and certification courses available and aggregators and load serving entities are also be able to help end-users participate.

How the Criteria Are Addressed

Policy Intent. CHP participation in these markets enables grid operators to correct system imbalances close to load, increasing the efficiency of the system in a potentially more cost-effective manner. Markets are designed to serve customers with reliable electric service at the lowest cost.[236] The markets do not provide a preference for a particular type of technology; rather, the most efficient technologies, with the most competitive bids, will tend to prevail. To the extent that CHP facilities compete well against other technologies, they will succeed in these markets. Such programs achieve the policy intent of obtaining power when and where required on the system. Inclusion of CHP in capacity, reserves and ancillary markets can be viewed as a key measure by state regulators to achieve resource adequacy, energy efficiency, and GHG reduction goals.

Market Signals. As stated earlier, participation in these markets is challenging and requires dedication and commitment. However, prices paid for market services versus the costs of participation will usually be a net benefit. ISOs/RTOs active in these markets conduct annual market outreach, on-line market tools and workshops to educate and acquire participation from private businesses. These market signals are vital to participation. For example, in PJM, CHP facilities can see these market signals using several on-line tools, including day-ahead and real-time market statistics and an annual state of the market report produced by an independent Market Monitor.[237]

Ratepayer Impact. The regulatory framework for the markets described is to ensure a reliable and secure supply of electricity at an affordable cost to consumers while promoting and engaging private businesses to participate. Generally, grid operators use these services when the existing or future resources are not available or in sufficient quantities. The costs of the services are what would otherwise have been built, or purchased from another generator. In what are termed scarcity conditions—when inadequate supplies to meet demand are not available—the price paid for capacity and ancillary services bid through auction or related programs do not exceed market clearing prices and sometimes may be less than the cost of new generation that would otherwise have been built. The utility is therefore held neutral. The ratepayer base is also neutral to the costs or held “indifferent” as CHP imposes no more costs on the market than any other type of resource and may indeed benefit from a cost savings from the avoidance of having to build new resources.

[234] Ferry August Viawan. “Voltage Control and Voltage Stability of Power Distribution Systems in the Presence of Distributed Generation.” PhD Thesis. Chalmers University of Technology. Göteborg, Sweden. 2008.

[235] NOPR, Docket Nos. RM11-24-000 and AD10-13-000. June 22, 2012.

[236] “A Review of Generation Compensation and Cost Elements in the PJM Markets.” PJM. 2009. http://pjm.com.

[237] See www.pjm.com/home.aspx.

D.4 Conclusions

CHP participation in these markets is at an evolutionary point. Despite the benefits described above, current CHP participation in these markets is very limited due in part to complexity of the rules and requirements. Growth potential for CHP participation is generally perceived to be significant. As an example, ISO-NE provides financial incentives to aggregators who in turn reach out to the commercial and industrial sectors for demand resource measures that include CHP.[238] State utility regulators can express the importance of this outreach and in including CHP in these markets. Inclusion of CHP in capacity and ancillary markets can be viewed as a key measure by state regulators to achieve resource adequacy, energy efficiency and greenhouse gas reduction goals. The market for third party grid balancing services and local voltage support is growing.[239] Integration of distributed generation and storage technologies continues to be a focus of FERC as it seeks to promote robust competitive markets for the provision of ancillary services from a variety of sources.[240] As the rules evolve and the opportunity for an additional revenue stream begins to outweigh the cost of participation, greater CHP participation in these markets seems likely.

[238] Personal communications between ICF and Henry Yoshimura and Laura Corcoran, Demand Resource Strategy Analyst, ISO-NE, May 15 and July 5, 2012. Email from Laura Corcoran, Oct. 17, 2012.

[239] Tighe, Mary Beth. "Electricity Market Opportunities: Revenues Improve Paybacks." FERC, Heat is Power Annual Meeting. Aug. 15, 2012.

[240] FERC NOPR, Docket Nos. RM11-24-000 and AD10-13-000. June 22, 2012.

Appendix E: Revision of Utility Distribution Franchise Regulations to Allow Non-Utility CHP to Serve Neighboring Load

E.1 Overview

The focus of this Appendix is utility distribution franchise regulations that prohibit non-utility CHP systems from serving neighboring electric and thermal demands.[241] Specifically, a discussion of whether a non-utility CHP system serving its own load and other nearby electric and thermal loads is exempt from being defined as a public utility subject to regulatory oversight; and if CHP is exempt, the conditions that must be considered by which contiguous loads can be served.

Allowing CHP systems, including CHP in microgrids,[242] to sell power and/or thermal energy to neighboring retail customers may provide certain additional benefits beyond those of using the CHP system for on-site power and thermal use only:

- Grid operators:
    - Reduce congestion on the T&D system, improve electrical flows and grid operating efficiency, resulting in reduced operating costs[243, 244]
    - Increase energy security for the microgrid and consequently, may increase the security of portions of the grid as a whole.[245]
- CHP end-user:
    - Enable more appropriate sizing of the generator or the use of multiple/mixed generation units to meet electric and thermal loads
    - Allow the CHP operator to negotiate rates with potential customers, creating mutual energy cost savings.[246]
- Microgrid operators:
    - Promote efficiency by consolidating demand loads, allowing for better balancing of loads and resources (CHP, demand side management, renewable resources, and storage)[247]
    - Potentially enhance the resiliency of the microgrid to respond to outages on the interconnected system outages[248]
    - Reduce capital costs of all systems through economies of scale and integrated usage.[249]

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[241] There are other considerations to prohibiting non-utility generators, including CHP, from serving neighboring electric and thermal demands. This appendix is not an exhaustive discussion, but rather focuses on the impacts to CHP of revising distribution franchise .

[242] A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity relative to the grid. Microgrids can connect and disconnect from the grid to enable operation in both grid-connected or island-mode. For more information, see http://energy.gov/sites/prod/files/Microgrid%20Workshop%20Report%20August%202011.pdf and http://law.pace.edu/energy/presentations/rob-thornton-capturing-benefit-microgrids-district-energy-communities.

[243] The Effect of Private Wire Laws on Development of Combined Heat and Power Facilities, Pursuant to Section 1308 of The Energy Independence and Security Act of 2007, p. 58. Jan. 12, 2009.

[244] Viawan F. "Voltage Control and Voltage Stability of Power Distribution Systems in the Presence of Distributed Generation." PhD Thesis. Chalmers University of Technology. Göteborg, Sweden. 2008.

[245] Ibid, p. 3.

[246] These opportunities would occur in electric and thermal sales to customers on adjacent properties and customers separated from the CHP facility by a public street.

[247] http://ssi.ucsd.edu/index.php?option=com_content&view=article&id=416:smart-power-generation-at-ucsd-november-1-2010&catid=8:newsflash&Itemid=20.

[248] Microgrids: An Assessment of the Values, Opportunities, and Barriers to Deployment in New York State. Final Report 10-35. September 2010. http://nechpi.org/wp-content/uploads/2012/07/NYS-Microgrids-Roadmap.pdf.

[249] Ibid.

- Microgrid customers:[250]
    - Ensure energy supply for critical loads
    - Control power quality and reliability at the local level
    - Promote customer participation through demand-side management and community involvement in electricity supply.

Vertical Integrated Utility Context

Traditionally, most electrical service is served by vertically integrated utilities (generation, transmission and distribution under single ownership) as a regulated monopoly franchise.[251] As a monopoly supplier with the exclusive right and obligation to serve for their service territory, no competition is allowed and in exchange the utility is regulated by the state utility commission. The relationship is considered to be protected in that utilities receive a fair rate of return for their investment in serving the customers, and regulators achieve ratepayer protection and the goal of ensuring a safe and reliable supply of electricity. Whether in restructured or non-restructured (distribution of electricity is decoupled from generation and transmission) states, customers serving their own load represent franchise erosion—the loss of a customer and attendant electricity sales.

Service to Multiple End-Users on Neighboring Property

An on-site CHP system primarily serves the facility's electric and thermal demands. Serving multiple loads on contiguous properties begs whether the facility is functioning in much the same manner as the franchise utility and therefore should be subject to regulation. Non-restructured and restructured states have addressed service to neighboring loads in different ways, dependent to an extent on whether retail choice is allowed in the state:[252]

- Retail choice states generally allow service to neighboring properties.
- Non- retail choice states generally do not allow service to neighboring properties and those few states that do, allow service under limited conditions.

The factors considered for service range from the relationship between the producer and the end-user, the number of customers served, and/or the contiguous relationship of the properties involved.

Private Wires versus Utility Distribution Wires

For the past 20 years, states with restructured electricity markets have allowed non-utility electric generators of to compete in generation and retail sales. However, the electric distribution grid, the wires that carry the electricity to end-users, remains a natural monopoly.

Each state has rules governing the use of utility lines or private wires to deliver power to serve neighboring loads. Section 1308 of the Energy Independence and Security Act of 2007 directed the U.S. Department of Energy to undertake a study of the laws affecting the siting of privately-owned distribution wires on or across public rights of way and to consider the impact of those laws on the development of CHP facilities, as well as to determine whether a change in those laws would impact utility operations, costs or reliability, or impact utility customers. The study also considered whether changing the laws would result in duplicative facilities and, if so, whether that would be desirable.[253] The study defined private wires as "wires that are not owned by an electric utility and that are designed to provide electric service directly from a non-utility generator to one or more end-use customers on terms negotiated between the parties without regulatory oversight or involvement." The findings of the study include the following:

[250] http://energy.gov/sites/prod/files/Microgrid%20Workshop%20Report%20August%202011.pdf.

[251] The Effect of Private Wire Laws on Development of Combined Heat and Power Facilities, Pursuant to Section 1308 of The Energy Independence and Security Act of 2007, p. 58. Jan. 12, 2009. Page 36.

[252] Ibid.

[253] http://energy.gov/oe/downloads/effect-private-wire-laws-development-combined-heat-and-power-facilities.

- In states with retail choice, alternative suppliers are exempt from the definition of a public utility. Distribution of electricity remains the responsibility of the franchise utility, and except for states with limited exceptions, alternative retail suppliers must use the utility wires and compensate the utility according to tariffed rates.
- In states without retail choice, end-use customers can only buy power from the franchised utility. Self-generation is allowed but in most states, the generator cannot serve other customers. However, some States permit a CHP owner to serve other customers under limited conditions (Minnesota, California, Texas, New Jersey, New York, and Iowa).
- Private wires are inconsistent with the regulated utility franchise model. However, several states have nonetheless chosen to permit private wires under limited circumstances, including, in some states where the wires are used to provide generation specifically from CHP units. The issues surrounding private wires are complex. There are operating, planning, and rate issues, in addition to potential concerns regarding public safety and grid safety. The customer and utility impacts of permitting private wires could be significant and could vary from utility to utility, as well as from state to state.
- It is not clear that existing restrictions on private wires per se are materially hampering the development of CHP.[254] There are many different factors that impact the development of CHP, including the economics of particular projects, as well as the economy of a region. Not every state has the same technical potential for CHP. Other factors are cited as more significant by some developers. Nonetheless, private wires restrictions may be a factor in some cases, where they may improve the economics of the project.
- Private distribution wires, if constructed, would be duplicate facilities in many respects. Customers served by the private wires would likely also be connected to the local utility's distribution system. While there are potential benefits from duplicate facilities, there are also operational, reliability, and safety challenges from the utility's perspective, since the wires would not be controlled by the utility. In addition, multiple sets of wires and other distribution facilities raise concerns as to aesthetics, public safety, and public inconvenience.

E.2 Successful Implementation Approaches

There are several states that have chosen to specifically exempt CHP from being a public utility in order to achieve clean energy and environmental policy goals.

California

California allows a narrow exception to CHP facilities selling power to neighboring loads. A CHP facility, under existing regulatory rules, selling to contiguous loads is not an electrical corporation under certain conditions.[255] A CHP facility can, in addition to using power to meet its own load, sell electrical power to its neighbors over private wires to not more than two other corporations on the same property or to the immediately adjacent properties. These sales are known by their public utility code section as "over-the fence" transactions.[256] When there is an intervening public street constituting the boundary between the property of the CHP facility and the adjacent property, the following apply:[257]

- The two properties cannot be under common ownership or be a subsidiary or affiliate of the company selling the output.
- The thermal output cannot be used on the adjacent property for petroleum production refining.

[254] Thermal sales are an important economic consideration. For a discussion of utility participation in CHP markets, including thermal sales, see Chapter 6.2.

[255] California PUC Code Section 218(b).

[256] California PUC Code 353.13 (a).

[257] California PUC Code 218 (b) (2).

Approximately six over-the-fence transactions exist in California.[258] These applications are mostly in oil refining areas of the state such as in Bakersfield and Contra Costa County; however confidentiality rules prevent specific customer identification.

One novel case of CHP development and exemption from the definition of public utility involves two commercial buildings under common ownership in San Diego. A CHP system was installed at Regent 1 to serve electrical loads in both buildings (Regent 1 and 2) and thermal load at Regent 1 only. Underground electrical conduits run from the CHP system at Regent 1 to Regent 2.[259] To avoid being designated as an electrical corporation, the developer kept the street between the two buildings under private ownership.

New Jersey

New Jersey allows electricity sales in a limited fashion for CHP systems that sell electricity to thermal customers that are non-contiguous or separated by a right-of-way. To address this and a number of related issues, New Jersey enacted a law in 2010 that provided the following:[260]

- Clarified that a CHP facility is not a public utility.
- Clarified, for purposes of electric or thermal sales, that the properties of the end-use customer and of the CHP facility are contiguous regardless of whether the customer is located across a street, easement or utility right-of-way.
- Extended the definition of "on-site generation" to include CHP facilities that service non-contiguous thermal loads (heating or cooling or both) of an end-use customer that may be located across a street, easement or utility right-of-way.
- Extended the sales tax exemption for sales of energy from CHP built after January 1, 2010
- Mandates that the delivery of electric power from a CHP facility is to be through the local utility's distribution facilities at the normal applicable tariff rate. New Jersey desired "to avoid duplication of distribution infrastructure and to maximize economic efficiency and electrical safety."

The 2010 law has not yet had immediate results. This may in part be due to the potentially small number of qualified CHP systems that meet the narrowly defined ruling, and the time required to implement the law.[261] CHP project developers are expected to confer with the Board of Public Utilities to determine consistency with the law.

New York

The New York Public Service Commission will review the circumstances of CHP generated electricity sales across public rights- of-way on a case-by-case basis. An example is the Burrstone Energy Center, located in Oneida Country, New York. This project is a 3.6 MW CHP system at St. Luke's Hospital with electric service to St. Luke's residential Health Care Facility on the same property, and electric service via privately-owned underground wires to Utica College across the street.[262] The thermal output is used on-site at the hospital. A number of design and legal issues confronted the project. The design of the CHP system was dictated by Public Service Commission rules that require that each of the loads be served separately and not be tied together into a common electrical interconnection point. If the loads could have been electrically tied together at a common bus, the efficient design solution would have been a single turbine. Instead, four engines were installed to meet the separate loads.

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[258] Personal communication between ICF and Pacific Gas and Electric Company.

[259] Personal communication between ICF and Randy Minnier, electrical engineer for the CHP system installed at Regents 1 and 2.

[260] P.L. 2009, Chapter 240, amending and supplementing C.48:3-51 (enacted Jan. 16, 2010). www.njleg.state.nj.us/2008/Bills/AL09/240_.htm.

[261] A utility commission needs 12 to 18 months to promulgate regulation; sales and negotiation of contract between the project developer and the end-user can take 18 to 24 months; permit acquisition and engineering design can take one to two years; and construction time can take 1 to 2 years; total time can range from four to six years.

[262] Communication with John Moynihan, Division Manager, Cogen Power Technologies. Bette & Cring. Aug. 28, 2012.

The legal issues of the Burrstone project were reviewed by the NY Public Service Commission (PSC) in 2007. The first legal issue was whether the project was subject to PSC regulation. The second issue was whether the service to multiple users separated by a street, was an acceptable departure from precedent which held that CHP facilities could only serve one user owning property on both sides of the street.

Burrstone sought a declaratory ruling that its CHP facility and the line to the college constitute related facilities located at the same project site, and therefore it is not subject to PSC regulation under Public Service Law. In addressing the legal issues, the PSC, consistent with a set of previous rulings, expanded the rights of CHP operators to provide service to third parties at or near a project site. The PSC found:[263]

- Burrstone's electric and steam distribution lines to the hospital, electric line to the health care facility, and the underground line to Utica college are related cogeneration facilities and therefore not subject to regulation.
- Public Service Law contemplates multiple users and does not require users share property ownership rights.

Source: Presentation by John Moynihan, Senior Project Manager, Cogen Power Technologies. U.S. EPA CHP Partnership 2009 Annual Partners Meeting.

Figure F.1. Schematic showing the physical layout of the Burrstone Energy Center at the hospital, the St. Luke's nursing home, and Utica College.

[263] Declaratory Ruling on Exemption from Regulation. Case 07-E-0802. Issued and effective Aug. 28, 2007.

The Burrstone example delineates the following legal boundaries that would need to be examined by the PSC in future CHP project-specific reviews:

- How many customers may be served by the CHP facility?
- How widespread geographically may the CHP facility, “its related facilities,” and its users be?
- At what point do public health and safety concerns become issues?
- Will the same rules and policies be applied uniformly across the state? There are more potential CHP customers per square mile in New York City as compared to a typical upstate project site. Would the number of customers, or the geographic footprint, impact the PSC’s analysis of downstate CHP projects?

A CHP project attempting to cross public ways within New York City would require an additional “revocable consent” from the NYC Department of Transportation.

How the Criteria Are Addressed

Policy Intent. Establishing explicit rules that provide for multiple loads on contiguous properties to be served by electric and / or thermal outputs from a CHP facility requires careful balancing of policy considerations. The fulfillment by utilities of its obligation to serve in exchange for a monopoly franchise and a reasonable return on its investments is a cornerstone of the regulatory compact. New York and New Jersey are examples of “leading states” whose experience provide lessons learned for other utility commissions. In the broader context, CHP serving multiple loads on contiguous properties can help achieve a state’s efficiency and environmental goals.

Market Signals. Regulatory rules that provide for the delivery of electricity and/or thermal output to multiple contiguous loads on adjacent properties or across a public thoroughfare signal the market for such development. Such rules can be a factor for businesses that seek increased reliability, have expansion plans, and job retention/creation objectives that become achievable due to potential lower energy costs. The examples described for New York, New Jersey, and California represent energy savings through increased efficiencies of the CHP system compared to separate heat and power to help sustain local business.

Ratepayer Impact. The concern of customer load leaving the utility rate base is a significant policy consideration that state regulators will balance in context of their clean energy goals and other requirements. New Jersey’s approach was to seek greater CHP deployment and at the same time prevent cross-subsidies by requiring payment of their state-specific fees—the societal benefits charges, market transition charge, and transition bond charge. This minimizes ratepayer impact and provides the CHP customer with electric and natural gas bill savings.

E.3 Conclusion

A number of states have exempted CHP serving off-site loads from being an electrical corporation. Though some states prohibit any electric and thermal sales to end-users on contiguous properties, other states allow CHP facilities to serve off-site customers separated from the on-site CHP facility by a public street or other right-of-way. State regulators can address the issues associated with regulation invoking the definition of an electrical corporation and the implications of multiple loads on contiguous property. CHP offers efficient and practical solutions for the on-site customer hosting the facility and for multiple other customers on contiguous properties.[264] The following issues can be considered in developing a successful state implementation approach:

- Whether to allow electricity and /or thermal energy to be served only to immediately adjacent customers or to non-contiguous customers or customers across a public thoroughfare
- How restrictive or expansive in determining what constitutes CHP “related facilities”
- Whether to allow private wires or mandate use of local utility wires
- Whether to allow service to the same owner or different owners of load on contiguous properties.

[264] http://law.pace.edu/energy/events/capturing-benefits-microgrids-and-district-energy-systems-communities.

Appendix F: Statements of Alternative Perspectives

Edison Electric Institute

CHP-related issues must be viewed from the perspective of rapidly changing electricity markets. New technologies are changing the distribution system in ways that challenge investor-owned electric utilities and the grid they operate for the benefit of consumers, businesses, and the economy. However, because the grid is designed around a central station paradigm, the integration of increasing amounts of CHP needs to be done in a way that ensures that reliability is maintained and costs to all customers remain reasonable. Also, because our existing regulatory and incentive mechanisms mirror the needs and workings of that system, it is important that they, too, be looked at in conjunction with all other technical and commercial changes that the industry introduces to accommodate increasing levels of CHP so that fairness of rates is maintained. Increasingly, public policy needs to approach these issues in the context of generator interconnection agreements, identifying the services distributed generators will be taking from the grid, and any benefits they will be providing the grid. Agreements and policies should be structured accordingly.

The public review process conducted by SEE Action has been very constructive and consensus-based. Nevertheless, a number of concerns still remain. EEI members urge policy makers to consider the following:

<u>Standby rates need to recover fixed network costs</u>. (Executive Summary at page x, Chapter 2 at page 9) T&D assets are sized to supply customers, and related costs are incurred, whether power flow over the lines continuously or not. By recommending only "as-used" demand charges the Guide proposes an approach that would, inevitably, shift fixed costs to non-CHP customers. Proper rate policy should include contract terms (e.g., contract demand) to collect the CHP customer's fair share of fixed network costs.

<u>Standby rate policy needs to take account of retail market structure</u>. (Executive Summary at page x, Chapter 2 at page 9) Rates offered by traditional, vertically integrated utilities should take account of the outage rate of other distributed generators on the system, the combined outage rate of the utility's generators (not just the single best), and the utility's required reserve margin. Wires-only utilities (e.g., those that procure supply to provide Provider of Last Resort Service) may handle this by simply procuring load-following service. The Guide does not recognize differences in market structure, recommending only one approach to pricing standby generation

<u>Interconnection fees should reflect the actual cost of engineering services needed to ensure safety and reliability</u>. (Executive Summary at page xi, Chapter 3 at pages 14-15) In order to interconnect a distributed generator safely and reliably, the utility must analyze how the generator's output will affect the circuits into which its power will flow. The costs incurred to do this may not vary directly with the size of the generator. Nevertheless, the Guide recommends that fees be commensurate with the generator's size and complexity. This approach would lead to a policy that arbitrarily limits utility cost recovery, regardless of the true cost of performing required engineering analyses.

<u>The larger the unit, the less feasible it is to rely on "standard" interconnection requirements</u>. (Executive Summary at page xi, Chapter 3 at page 16) Every CHP interconnection is unique, and the scope and scale of potential reliability and safety impacts increase as the size of the generator increases. Nevertheless, the Guide recommends that generators 20 MW and larger be allowed to qualify for "standardized" interconnection procedures. Rather, utilities should have flexibility to ensure safety and reliability. Where larger generators are concerned, utilities should not be constrained by the arbitrary requirement for a standard procedure.

<u>Programs based on "multi-tiered" avoided cost would harm non-CHP customers</u>. (Executive Summary at page xi, Chapter 4 at pages 19-20) FERC has allowed avoided cost to be unbundled so that it no longer reflects marginal costs avoided by the utility, but the marginal costs of specific categories of favored renewable technologies (e.g., photovoltaic conversion, biomass based synthetic fuels, etc.). This is not an appropriate strategy for encouraging cost-effective CHP. Multi-tiered avoided cost is an innovation that was motivated precisely by the desire to achieve higher purchase prices. It will increase utility costs, which must be borne by other, non-CHP customers. There is no

way to reconcile multi-tiered avoided cost-based purchase rates for CHP with a desire to protect non-CHP customers.

Feed in tariffs for CHP can harm non-CHP customers. (Executive Summary at page xii, Chapter 4 at pages 20-21) Like multi-tiered avoided cost-based purchase rates, feed-in tariffs can be designed to induce new uneconomic supply by offering purchase rates that are higher than the prevailing market value of (utility cost for) electricity supply. FITs frequently are substantially higher than the fully bundled retail rate in effect for the purchasing utility (i.e., the rate which includes costs for generation, transmission, distribution, and customer care). It stands to reason that such tariffs have a significant potential to increase costs for non-CHP customers.

National Rural Electric Cooperative Association

The National Rural Electric Cooperative Association (NRECA) is the national service organization dedicated to representing the national interests of cooperative electric utilities and the consumers they serve. NRECA represents more than 900 not-for-profit rural electric utilities that provide electric energy to over 42 million people in 47 states or 12 percent of electric customers. NRECA members generate approximately 50 percent of the electric energy they sell and purchase the remaining 50 percent from non-NRECA members. Cooperative electric utilities (co-ops) were formed to provide safe, reliable electric service to their owner-members at the lowest reasonable cost. NRECA is on the Executive Group of the State and Local Energy Efficiency Action Network (SEE Action) and is participating, along with some of its members, in several SEE Action working groups, including the Industrial Energy Efficiency and Combined Heat and Power Working Group (Working Group).

NRECA appreciates the opportunity to participate as a Working Group member in the collaborative process of developing the "Guide to the Successful Implementation of State Combined Heat and Power Policies" (Guide). We thank the Working Group for providing us the opportunity to express alternative perspectives.

NRECA believes the Guide misses an opportunity to address the initial question that state and local decision makers should ask and answer: Can Combined Heat and Power (CHP) be developed cost-effectively in a way that makes sense for my state or area? Cost-effectiveness is an underpinning of SEE Action and the Obama Administration's Executive Order "Accelerating Investment in Industrial Energy Efficiency" (Executive Order). Within SEE Action, DOE and EPA are tasked with facilitating efforts "to achieve all cost-effective energy efficiency by 2020."[265] SEE Action was intended to provide resources to state and local decision makers "as they provide low-cost, reliable energy to their communities through energy efficiency".[266] Similarly, the Executive Order encourages deployment of 40 gigawatts of new, cost-effective CHP by 2020, a goal that is also noted in the Guide.[267]

Given that "cost-effectiveness" is fundamental to SEE Action efforts and to meeting the Obama Administration's goal, the fact that the Guide does not provide guidance on how to consider what is cost-effective is a missed opportunity. The Guide assumes that "CHP must have the potential to be economically viable." While NRECA agrees that holding CHP to this measure is essential, we do not believe that it can be assumed, especially in the context of a roadmap on developing CHP. In making this predetermination, the Guide also misses an opportunity to assist state and local decision makers in evaluating whether or not CHP is the right resource under given circumstances. Instead, the Guide focuses on providing tools for implementing CHP through subsidies and other policies that can shift costs from CHP providers to non-CHP customers.

By way of example NRECA offers comments on a few categories that are essential to developing CHP, and where, we believe, the Guide misses an opportunity to assess the cost-effectiveness and reliability of CHP.

Standby rates should not shift fixed costs to non-CHP customers. Overall, rates for CHP facilities are comprised of different combinations of standard, supplemental service, standby, emergency, and economic replacement rates.

[265] www.seeaction.energy.gov.

[266] Id. emphasis added.

[267] www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency and pages ix and 2 in Guide.

One cannot identify a unique structure that fits all CHP customers, utility rate designs, and market characteristics. However, there are basic rate structures that could potentially provide savings to CHP facilities and appropriate cost recovery to utilities and their customers. The retail rate utilities charge includes not only the marginal cost of power, but also recovers costs incurred by utilities for transmission, distribution, generating capacity, and other utility services not provided by the customer-generator.

Interconnection standards must ensure safety and reliability. NRECA takes an alternate perspective on the ability for larger CHP systems (20 MW and larger) to qualify under standardized interconnection rules. Standard approaches do not apply to large units. Custom analysis and solutions are required for large unit interconnections to ensure safety and reliability.

Feed-in tariffs (FITs) raise the cost of power for retail consumers by requiring utilities such as co-ops to pay, under long-term contracts, far more for certain favored resources then they would otherwise pay, in order to attract investment in that resource industry. For example, a feed-in-tariff could require a co-op to purchase power from a customer with a CHP unit at a higher cost per kilowatt hour, when the co-op could otherwise have acquired power from an existing resource for less, say at the avoided cost. Under this scenario, FIT resources would not be most cost-effective resource, increasing the costs borne by non-CHP customers.

In summary, while NRECA appreciates the time and effort the Working Group has dedicated to the Guide, the decision not to address whether or not CHP is cost-effective is an omission that calls into question the value of the Guide to state and local decision makers. CHP has the potential to bring substantial benefits to electric cooperatives and their consumers, and to support energy efficiency efforts within the United States. However, these benefits will only be realized if state and local decision makers are given the tools necessary to encourage development of CHP in ways that are cost-effective, do not unfairly shift costs among customers and do not risk degrading electric reliability or safety.

As an example of a guidance document that NRECA has developed and maintains for its members is a "Distributed Generation Interconnection Toolkit" that can be used as a resource for developing policies and procedures related to distributed generation. The Toolkit can be found online at:

http://www.nreca.coop/issues/FuelsOtherResources/DistributedGeneration/Pages/default.aspx.

SEE Action

STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK