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Reviving Manufacturing with a Federal Cogeneration Policy

By Marilyn A. Brown,* Matt Cox, and Paul Baer

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Georgia Institute of Technology
D. M. Smith Building
Room 107
685 Cherry Street
Atlanta, GA 30332 - 0345

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**Corresponding author*
DM Smith Building, 685 Cherry Street, Room 312
Atlanta, GA 30332-0345
Email: Marilyn.Brown@pubpolicy.gatech.edu
Telephone: 404-385-0303 Fax: 404-385-0504

Abstract

Improving the energy economics of manufacturing is essential to revitalizing the industrial base of advanced economies. This paper evaluates a federal policy option aimed at promoting industrial cogeneration – the production of heat and electricity in a single energy-efficient process. Detailed analysis using the National Energy Modeling System and spreadsheet calculations suggest that industrial cogeneration could meet 18% of U.S. electricity requirements by 2035, compared with its current 8.9% market share. Substituting less efficient utility-scale power plants with cogeneration systems would produce numerous economic and environmental benefits, but would also create an assortment of losers as well as winners. Multiple perspectives to benefit/cost analysis are therefore valuable. Our results indicate that the federal cogeneration policy would be highly favorable to manufacturers and the public sector, cutting energy bills, generating billions of dollars in electricity sales, making producers more competitive, and reducing pollution. Traditional utilities, on the other hand, would likely lose revenues. From a public policy perspective, deadweight losses would be introduced by market-distorting federal incentives (ranging annually from $30 to $150 million), but these losses are much smaller than the estimated net social benefits of the federal cogeneration policy.

INTRODUCTION

The ability of the United States to manufacture goods and sell them to world markets has propelled the nation into its current position as a world superpower. Despite this historic strength, global competition for export markets, foreign investments, and raw materials is intensifying, and U.S. manufacturing is now struggling to remain competitive. Since 1957, manufacturing has declined from 27% of U.S. GDP to only 11% today (PCAST, 2011, p. 2). Over the past decade, China has become the world's largest producer of steel, aluminum, and cement (IPCC, 2007), and in 2010, it surpassed the U.S. as the world's leading producer of manufactured goods (PCAST, 2011). Starting with furniture, clothing and textiles, and now extending to information technology and other high-tech commodities, production facilities are moving offshore. Some contend that developing countries naturally transition from agriculture to manufacturing and finally, services; however, when manufacturing migrates offshore, so do many of the capabilities that spur innovation and help to create new industries (Pisano and Shih, 2009), suggesting it can be a perilous transformation. Furthermore, expanding industries overseas have the opportunity to use the most modern and high-efficiency technologies, while older U.S. industries frequently have inefficient legacy technologies that can be expensive to upgrade.

A recent report by the President's Council on Science and Technology (PCAST, 2011) on *Ensuring American Leadership in Advanced Manufacturing*, and President Obama's announcement of the Advanced Manufacturing Program both underscored the link between manufacturing and innovation. As Pisano and Shih (2009) explain it, product and process innovation are intertwined, making essential the co-location of manufacturing and process design. When manufacturing is exported, subsequent generations of U.S. inventions and innovations may also be compromised. Without process engineering, companies find it difficult to develop the next generation of process technologies, which in turn makes it difficult to create new products. The outsourcing of manufacturing thus creates a downward spiraling chain reaction.

One way to make U.S. manufacturing more competitive is to cut its energy costs by improving the energy efficiency of its operations, as noted by PCAST (2011). An additional way is for manufacturers to create a new revenue stream by generating electricity from "opportunity fuels" that would otherwise be waste products at their manufacturing plant, including thermal heat, high pressure steam, black liquor, and hot exhaust gases. Industry currently purchases 25% of the electricity generated by utilities in the U.S. (EIA, 2011, Table A8). If manufacturers could instead cogenerate enough power to meet their own needs, and possibly sell excess power back to the grid or to other consumers, their profitability could grow considerably.

Industry accounts for nearly one-third of total U.S. energy consumption, including the direct combustion and conversion of petroleum products, natural gas, and coal (EIA, 2011, Table A2). Large firms with more than 250 employees are responsible for about two-thirds of industry's energy consumption and many of them are also excellent candidates for cogeneration – the production of electricity and heat in a single process. Also called combined heat and power (CHP), cogneration uses about 40% less energy than conventional production of heat and electricity. A traditional system separately producing heat and power operates at 45% to 49% efficiency, while a CHP system can be 75% to 80% efficient (EPA, 2011 and Shipley et al., 2008).

Approximately two-thirds of industrial CHP systems are fueled by natural gas, although many fuel types and waste energy can be used in CHP systems, including biomass, oil, coal, and hot exhaust gases (ICF, 2009). Various technologies are also employed in CHP systems, like reciprocating engines, gas turbines and boiler steam turbines. Based on U.S. technology assessments and comparisons with CHP markets in other countries such as Japan, Denmark, and Germany, there is a large potential for expanded CHP usage in this country (Brown et al., 2001; Shipley et al., 2008; Granade et al., 2009). Despite the apparent economic attractiveness of CHP, the technology is penetrating the market slowly.

BARRIERS AND DRIVERS

The broader application of high-efficiency industrial technologies is impeded by a range of technical, corporate, regulatory, and workforce barriers. While chemical manufacturing, petroleum refining, pulp and paper production, iron and steel, and cement manufacturing dominate industrial energy use, the sector is diverse in terms of products, manufacturing processes, and business practices. This diversity promotes competition and innovation, but also complicates the process of transformation and modernization. In addition to the difficulty of sharing lessons across industries, numerous other financial, regulatory, and workforce barriers stall the market penetration of CHP systems (CCCSTI, 2009; Brown, Cortes, and Cox, 2010). CHP suffers generally from high upfront cost and inexpensive electricity (Chittum and Kaufman, 2011). Financial barriers also include a lack of access to credit and project competition within firms (Canepa and Stoneman, 2005; Rohdin, Thollander, and Solding, 2006; Worrell, et al 2001). Broadly defined, regulatory barriers impose significantly on CHP – these include input-based emissions standards, the Sarbanes-Oxley Act of 2002, utility monopoly power, and grid access difficulties that require interconnection standards and net metering rules (Shirley, 2005; Brooks, Elswick, and Elliott, 2006; Brown and Chandler, 2008). Lastly, adopting a new technology like CHP without a trained workforce and adequate engineering know-how increases the perceived risk to managers, lessening technology transfer and deployment (Bozeman, 2000; Worrell et al, 2001).

Of particular note is the fact that electric utilities typically do not support industrial cogeneration because they can experience a loss of profits from the erosion of utility sales. Thus, this promising source of clean electricity and industrial competitiveness will likely not flourish in the absence of federal regulations and subsidies. While CHP represents 9% of power generation in the U.S.; in contrast, it represents more than 50% of the power generation in Denmark, the world leader, and nearly 40% in the Netherlands (Casten and Ayres, 2007, p. 210). Cogeneration has been a priority for the supply of power in these countries, partly because of the high price of electricity in European markets and the denser populations. Government programs in Europe have promoted CHP with supporting regulations and RD&D programs.

Drivers that could motivate greater industrial CHP usage are also numerous and illuminate the choice of effective policy interventions. While the uncertainty of future energy costs is a deterrent to capital-intensive energy upgrades, firms can achieve greater financial stability through energy efficiency and on-site power generation. Energy efficiency will help meet energy needs. In combination with peak load pricing for electricity, energy efficiency and demand response can be a lucrative enterprise for industrial customers, especially when an additional revenue stream from the sale of electricity can be created. Several state and federal programs have made significant contributions to strengthening the CHP market, notably the U.S. Department of Energy's Regional Clean Energy Application Centers and the federal CHP investment tax credit (Chittum and Kaufman, 2011). In addition, pressure from shareholders, consumers, regulators, and internal actors to set and attain sustainability and environmental goals encourages investments in CHP (National Academies, 2009).

THE PROPOSED FEDERAL CHP POLICY: A TWO-PART APPROACH

Numerous federal policy interventions to address the U.S. shortfall of CHP systems have been examined and debated. Since the 1980's, the U.S. Department of Energy has recognized the need to develop improved technologies so that CHP systems could become more competitive. Over time, its support for research, development, and demonstration (RD&D) has waxed and waned as Congressional Appropriations Committees have disagreed over the merits of applied research. In recent years, two additional approaches have gained considerable traction: the creation of a federal Energy Portfolio Standard (EPS) that includes CHP as an eligible technology, and investment tax credits that subsidize the cost of purchasing CHP systems. This paper examines a federal policy where these two new policies are implemented in coordination with an ongoing RD&D effort.

A Federal Energy Portfolio Standard that Qualifies CHP

Energy portfolio standards have been one of the strongest policy instruments supporting clean electricity in the U.S. (REN21, 2010, p. 32). The most common quotas for clean electricity are state renewable portfolio standards (RPS's). An RPS is a legislative mandate requiring electricity suppliers (often referred to as "load serving entities") in an area to employ renewable resources to produce a certain amount or percentage of power by a fixed date. Typically, electric suppliers can either generate their own renewable energy or buy renewable energy credits. This policy blends the benefits of a "command and control" regulatory paradigm with a free market approach to environmental protection. As of August 2011, RPS's have been established as requirements in 29 states and as goals in an additional eight states.[1]

There is no universal definition of a renewable resource. Several states have expanded the scope of qualifying energy resources to include energy efficiency, and some of these allow CHP and other technologies that re-use waste heat. Eligibility of CHP may require meeting a minimum system efficiency percentage, such as the 50% total efficiency required in Connecticut. Alternatively, CHP may be eligible only if it is a "qualifying facility" under the Public Utilities Regulatory Policies Act (PURPA) of 1978.[2] In addition, there may be a minimum thermal efficiency requirement, such as the 20% threshold required by Connecticut. Finally, the RPS may set maximum emissions limits for CHP systems. For example, California requires that CHP and other distributed generation technologies stay under the 2007 state emission limits to qualify[3] (EPA, 2009, p. 2-3).

Many of the states that have an RPS also have an Energy Efficiency Resource Standard (EERS). While EERS and RPS regulations have similarities, the distinction between them is that the former requires a level of energy *demand or generation reduction* whereas the latter requires an increased level of renewable energy *supply*. In addition, some states include energy efficiency as an acceptable "source" of renewable energy supply for an RPS (Harmin, Vine, and Sharick, 2007). This extension of the RPS rules reflects the growing recognition of energy efficiency as a "resource" – on par with raw energy supplies – that can lower energy demand and provide

[1] http://www.dsireusa.org/

[2] "Qualifying facilities" fall into two categories: small power production facilities and cogeneration facilities.

[3] www.arb.ca.gov/energy/dg/dg.htm

economic and environmental benefits including the reduction of greenhouse gases (GHGs) and preservation of water quality, since significant quantities of water are consumed and withdrawn during power generation.[4] Savings are generally achieved by helping utility customers save energy through energy efficiency programs including rebates and incentives such as tax credits. As of August 2011, 27 states nationwide had implemented EERS's or targets.[5]

Conceptually, CHP could qualify as an eligible resource for either an RPS or an EERS. This "crossover" status of CHP reflects the fact that CHP recycles energy that would otherwise be wasted (similar to renewable energy resources), while it also converts fuels into electricity at a high rate of efficiency (qualifying it as an energy-efficiency resource). At least 14 of the states that have either an RPS or an EERS include CHP or waste heat recovery as a qualifying resource (EPA, 2009). The inclusion of CHP as an eligible technology in a federal EPS could not only stretch available energy resources but could also provide retail electricity price relief to manufacturers and consumers (Elliott, 2006). Brown and Baek (2010), for example, have shown that the escalation of electricity prices resulting from an RPS could be moderated by the simultaneous implementation of policies to promote energy efficiency. It would also overcome the difficulty of developing national markets for CHP and other technologies caused by state-by-state inconsistencies in eligibility, measurement and verification (M&V) protocols, and other procedures. A federal EPS would complement existing state-level quotas and goals by requiring a minimum level of performance without preventing states from implementing more demanding requirements. The variation in implementation details is one of the justifications for developing a federal policy, since state-by-state inconsistencies make it difficult to develop national markets for cogeneration systems. Many states have increased their annual energy-savings goals over time and have been achieving or are on track to achieve their stated energy-savings goals. For example, the first 19 states to implement an EERS are positioned to achieve 5% electricity savings in 2020 (Furrey, Nadel and Laitner, 2009).

Several recent U.S. House and Senate bills have proposed establishing a federal EPS. The American Clean Energy and Security Act of 2009 (ACESA) would have required electricity providers to meet a combined renewable energy and energy-efficiency standard, gradually increasing to 20% by 2020. Up to 5% could be achieved through energy efficiency, or with a governor's petition, up to 8% for utilities in that state. The American Clean Energy Leadership Act of 2009 (ACELA) would have required electricity providers to meet a combined 15% renewable energy and energy-efficiency standard by 2021; up to 4% could be met through energy efficiency in a given state if a governor petitions for it; industrial CHP would be encouraged if such petitions were to be granted.

An Investment Tax Credit for CHP Resources

The U.S. has a long history of using investment tax credits to encourage the growth of CHP. Shortly after enacting PURPA in 1978, Congress passed a limited term investment tax credit (ITC) of 10% and a shortened depreciation schedule for CHP systems. PURPA and the tax incentives spurred the growth of CHP from an installed capacity of 12 GW in 1980 to 66 GW in 2000 across the industrial, commercial and institutional sectors (Shipley et al., 2008). A 10% ITC for CHP projects was authorized again in the Energy Improvement and Extension Act of

[4] For a general introduction to future electricity-water challenges, see generally Andrew McNemar (2007). For an analysis of the relationship between energy savings and water consumption in the U.S. South, see Brown, Gumerman et al., 2010a.

[5] http://www.pewclimate.org/what_s_being_done/in_the_states/efficiency_resource.cfm

2008, which applies to the first 15 MW of capacity for projects up to 50 MW in size.[6] The credits began in 2008 and are currently scheduled to continue through 2016. Senators Feinstein and Merkley have supported an option to increase the ITC for CHP to 30%. This has been supported by the U.S. Clean Heat and Power Association, which advocates that this expanded tax credit should be applied to the first 25 MW of a project of any size. Another proposal (Tonko – H.R. 4751) has considered establishing a 30% ITC for highly efficient CHP projects. This is similar to recent levels of federal support provided to electricity generated by solar photovoltaics.

To achieve the desired stimulus effect, the current ITC for CHP resources of 10% through 2016 could be strengthened and extended. In addition to being time-limited, the current incentive applied only to projects that are 50 megawatts (MW) or smaller, and is limited to a project's first 15 MW. As alternatives, the ITC could be increased to 30%, extended to 2020 or 2035, and the 50 MW limit could be removed or replaced with a requirement for high-efficiency CHP. Such changes would accelerate the implementation of CHP in response to a federal EPS. Without a strong financial incentive, the risks, lack of familiarity, and other adoption barriers associated with CHP would remain strong deterrents to the installation of new CHP systems.

Sustained RD&D for CHP

The cost of producing a manufactured good generally decreases as a function of cumulative production. Indeed, learning curves have been used extensively in the energy sector to provide a rough tracking of the production-to-cost relationship (Kammen and Nemet, 2007). It is likely that the increased production of CHP systems resulting from supportive portfolio standards and federal tax credits would improve the performance and lower the costs of CHP systems. However, the advancement is likely to be slow, unless the current CHP RD&D effort is maintained. DOE's current CHP RD&D program received federal appropriations of approximately $25 million annually between 2009 and 2011 (Trombley and Elliott, 2011); as with other existing laws, policies and regulations, NEMS assumes that this RD&D program continues.

With this sustained research effort, the NEMS Reference case projects that the capital cost and overall efficiency of CHP systems would improve over the next two decades. CHP systems are typically identified by the type of prime mover deployed: for example, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells (Shipley et al., 2008).[7] Eight systems are modeled in NEMS, each with unique cost and performance characteristics. To illustrate the trajectory of system improvements over time, consider two of the eight systems represented in NEMS.

- In 2010, a new 25 MW gas turbine CHP system is assumed to operate at a 71% rate of energy efficiency, and would cost $987/KW. In the Reference case its efficiency remains stable through 2020 but increases to 73% by 2035, and its cost drops by 13% to $860/KW.
- In 2010, a 100 MW combined cycle CHP system is assumed to operate at a 70% rate of energy efficiency, and would cost $723/KW. In the Reference case its efficiency rises to 72% in 2020 and 73% by 2035, and its cost drops by 5% to $684/KW.

[6] http://www.uschpa.org/files/public/ITCjust.pdf
[7] http://www1.eere.energy.gov/industry/distributedenergy/chp_basics.html

The new 25 MW gas turbine CHP system is one of the most common systems in operation today. If it were to increase at the rate that CHP is forecast to grow in the NEMS Reference case (2.25 times by 2035), its 13% reduction in cost would be equivalent to a learning curve of approximately 10% – that is, for every doubling of production, costs would decline by 10%. It is generally agreed that experience or learning curves should be "explicitly considered in exploring scenarios to reduce CO_2 emissions and calculating the cost of reaching emission targets" (Wene, 2000). Some argue that a faster pace of learning, such as 20%, is applicable to new energy generation technologies (Kammen and Nemet, 2007). On the other hand, CHP systems are not as novel as wind farms, solar thermal, and solar photovoltaic systems; as a result, their cost reductions may not reduce as rapidly as in earlier years, as worker productivity becomes optimized, production is fully scaled up, and incremental process improvements are made. Tables 1a and b provide the specific assumptions made in the NEMS Reference case for each of the eight CHP systems.

Table 1a. Eight CHP Systems Modeled in GT-NEMS: Total Installed Costs (in 2005$/KW)

CHP System	2005	2010	2020	2035
1 Internal Combustion Engine—1,000 KW	1373	1440	1129	576
2 Internal Combustion Engine—3,000 KW	1089	1260	949	396
3 Gas Turbine—3,000 KW	1530	1719	1646	1496
4 Gas Turbine—5,000 KW	1180	1152	1101	1023
5 Gas Turbine—10,000 KW	1104	982	929	869
6 Gas Turbine—25,000 KW*	930	987	898	860
7 Gas Turbine—40,000 KW	805	876	856	830
8 Combined Cycle**—100,000 KW	846	723	1099	684

*Assumed system for cost analysis

**Two 40 MW Gas Turbine and a 20 MW Steam Turbine

Table 1b. Eight CHP Systems Modeled in GT-NEMS: Overall System Efficiencies

CHP System	2005	2010	2020	2035
1 Internal Combustion Engine—1,000 KW	0.70	0.81	0.84	0.89
2 Internal Combustion Engine—3,000 KW	0.70	0.83	0.87	0.92
3 Gas Turbine—3,000 KW	0.69	0.76	0.77	0.78
4 Gas Turbine—5,000 KW	0.70	0.77	0.78	0.78
5 Gas Turbine—10,000 KW	0.70	0.77	0.77	0.78
6 Gas Turbine—25,000 KW*	0.70	0.71	0.71	0.73
7 Gas Turbine—40,000 KW	0.72	0.72	0.73	0.74
8 Combined Cycle**—100,000 KW	0.70	0.70	0.72	0.73

*Assumed system for cost analysis
**Two 40 MW Gas Turbine and a 20 MW Steam Turbine.

Other Complementary Efforts

A federal CHP policy would benefit from being accompanied by a nationwide market for trading energy-efficiency credits. Such a market could be used to trade or bank energy savings between utilities across the nation. With a confident market – supported by financial incentives and reliable measurement and verification – the energy savings from CHP could be traded to achieve savings at competitive costs.

Renewable and energy-efficiency certificates (RECs and EECs) could lead to the integration of EPS programs within and across regions. These certificates are tradeable commodities that can be used to meet EPS requirements if allowed by state regulators. Most RPS programs measure compliance by calibrating the purchase of RECs from renewable generators. Trading energy savings via Energy Savings Certificates, Tradable White Certificates (TWC), or White Tags™[8] fits well within the these policies by allowing crediting, banking, or trade of savings to keep aggregate costs low (WRI, 2008).

Measurement and verification (M&V) requirements also need to be clearly defined and designed so that the benefits of cost-effective CHP projects outweigh the time and expense of the M&V burden. To this end, the federal government could issue guidelines on M&V methods for CHP projects. Whether enforcement of M&V methods is at the federal or state level, if parties agree to M&V methods, non-compliance can be dealt with swiftly rather than spending time litigating accounting issues. Robust M&V is also essential to maintaining a credible, transparent, and viable market trading system in which all parties have confidence that investments in CHP will be cost-effective and will deliver the anticipated benefits. M&V protocols are particularly important if a federal EPS were to include industrial waste energy recovery from hot exhaust, flared gas, and pressure drops, where much less experience with on-the-ground projects and verification exists.

Some of the effort to create robust M&V protocols may be provided by private efforts already undertaken. For example, the North American Renewables Registry claims to be prepared to meet the need for energy-efficiency trading markets by providing a market infrastructure solution to ensure trust and transparency for these new environmental commodities.[9]

Summary of Policy Rationale

On the one hand, implementing policies such as the RPS and EERS simultaneously in multiple states encourages innovation and experimentation. Decentralized environmental decision-making, in general, provides for inter-jurisdictional competition and creates "laboratories of democracy," a metaphor coined by Justice Brandeis in 1932. It encourages adaptation to local circumstances and needs, creating "ecologies of scale" that can maximize social welfare and minimize cost. State and local policies tend to be more representative, creating regulations and public services that better match local interests and preferences, in contrast to federally imposed uniformity (Anderson and Ostrom, 2008; Sovacool and Brown, 2009b).

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[8] Any of these names can be considered "an instrument representing a unit of energy savings that has been measured and verified" (Friedman, Bird, and Barbose, 2008).
[9] http://narenewables.apx.com/about/FAQ.asp

On the other hand, a federal EPS could reduce the regulatory confusion and administrative burdens that have resulted from the patchwork of state-regulated EPS efforts. A federal EPS mandate would produce a standardized regulatory environment, providing manufacturers and industry with consistent and predictable business rules that are important when attempting to create national markets for green technologies such as combined heat and power. In contrast, a multiplicity of state standards increases transaction costs, causes confusion in the marketplace, and prevents economies of scale.

Furthermore, a patchwork of state policies allows stakeholders to manipulate the existing market to their advantage, using regulatory loopholes to waste energy and emit GHG wherever regulators are the most lax. An example of this is provided by the Regional Greenhouse Gas Initiative (RGGI), a regional carbon cap-and-trade initiative involving 10 northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont). RGGI has experienced "leakage" rates as high as 60% to 90% due to coal-generated electricity being imported into RGGI states. Power plants in adjacent states have actually increased their output to sell into the higher-priced RGGI electricity markets (Weiner, 2007).

CONSTITUENCIES AND STAKEHOLDERS

The community of constituencies and stakeholders for CHP is complex. As a result, a brief assessment is conducted to identify the principal organizations that would likely advocate for the creation of our recommended federal CHP policy and those groups that would represent the greatest opposition. Critical stakeholder analysis provides many important benefits such as revealing power asymmetries between stakeholders, making stakeholder and their power relations more visible, promoting a common understanding of key agendas, and identifying zero sum tradeoffs and incommensurable views among stakeholders that must be resolved before consensus about a policy option can occur (Brown and Sovacool, 2011, Chapter 6).

CHP developers and manufacturers of CHP equipment such as boilers, turbines, and heat recovery steam generators should be supportive of making CHP an eligible resource in a federal EPS since the growth of cogeneration systems in U.S. markets has been sluggish. By qualifying CHP systems to meet federal EPS requirements and by providing financial incentives, a strong national market for CHP could emerge in the U.S. The website of the U.S. Clean Heat and Power Association (USCHPA) provides evidence that the industry recognizes the value of this policy option. The USCHPA, which represents CHP developers and equipment suppliers, "encourages states to adopt policies that recognize energy efficiency and clean heat and power as an integral component of a renewable portfolio standard."[10]

Industrial firms and facilities that could host CHP systems would be supportive because the energy savings and power revenues from industrial CHP technologies are significant and they compound over time as industrial energy prices have trended up over the past several years (EIA, 2008a, Table 8.10). The provision of an ITC to subsidize investment costs will allow many facilities to adopt CHP that would otherwise be unable to afford the capital costs. In addition to reducing on-site energy costs, industrial facilities could sell excess electricity to utilities, creating an additional revenue stream for their operations. Industries with the largest technical potential for CHP would appear to gain the most from this policy option and would therefore probably be most supportive. This includes chemical, paper, food processing,

[10] http://www.uschpa.org/i4a/pages/index.cfm?pageid=3282

petroleum refining, primary metals, and lumber and wood (ICF International, 2010, Table 5, p. 13). The policy would not be as attractive to entities that do not have tax liabilities, such as wastewater treatment districts and other government facilities, because they would not benefit from an investment tax credit. Equivalent forms of direct purchase subsidies would also be possible.

Environmentalists and consumer groups represent the interests of citizens, but from different perspectives. A federal CHP policy would be supported by clean air advocates, but it could be considered suboptimal by the climate change community because it would subsidize natural gas power generation. While natural gas has approximately half the carbon content of coal, it is more carbon intensive than most renewable power options such as wind and solar photovoltaics. The CHP policy may also be attacked on environmental justice grounds if trading mechanisms allow energy savings and pollution reductions to accrue in some areas while others face new plant construction and increased pollution. In addition, a federal CHP policy could move emissions sources closer to population centers. Thus, while the overall emission reductions of a CHP system may be significant, local effects in nonattainment regions could be an issue. Opposition may also be grounded in issues of equity including the subsidies provided to "free riders." While difficult to identify and quantify, free riders range from companies that would have installed the same CHP system at the same time whether or not a subsidy existed (called "total free riders"), to companies that would have installed a smaller CHP system or would have installed a system at a later time (called "partial free riders") (NAPEE, 2007, p. 72). To the extent free riders exist, the economic efficiency of the public policy is compromised.

Local, state and federal agencies concerned with environmental protection will recognize the air pollution reduction potential of CHP over conventional fossil-fueled plants that operate at much lower efficiency levels. Since many CHP components are manufactured in the U.S., enhanced tax credits and a federal EPS could help grow the nation's industrial base. Economic development agencies and governors in states with significant industrial activity would recognize that the inclusion of CHP as an eligible resource in a federal energy portfolio standard would provide them with a potentially low-cost option for meeting clean electricity quotas. With 50% of U.S. industrial energy use, the South would have the most to gain from a CHP policy (especially Texas and Louisiana) and with 26%, the Midwest would also benefit (especially Ohio and Indiana) (EIA, 2010). Still, the current emphasis on government debt reduction would result in considerable scrutiny of expanded taxpayer-funded programs.

Research has shown that federal funding can crowd-out state funding of projects (Knight, 2002), and federal regulations can preempt more aggressive state actions (National Academy of Sciences, 2010). Governors have shown a willingness to accept less grant funding for fewer restrictions (Volden, 2007), and it may be just as effective for the federal government to make clear statements of its preferences for state policy action (Allen, Pettus, and Haider-Markel, 2004). However, multiple and diverse state and local standards and incentive programs can place a heavy burden on business interests that operate in multiple states, providing a strong justification for federal action (National Academy of Sciences, 2010).

Finally, **electric utilities** would likely not support a federal CHP policy unless their rate recovery procedures were adjusted to ensure that they will be held harmless from the loss of profits due to customer owned generation and the erosion of utility sales (i.e., "decoupling"). Utilities have historically discouraged distributed generation because it erodes their revenue base (Freedman, 2003; Brown et al., 2009a). Only 10 states and the District of Columbia have passed electricity decoupling rules that would limit the utility incentives to oppose distributed generation.[11] Electric utilities might be supportive of including CHP in a national portfolio standard if they were convinced that a national standard was inevitable. They might see CHP as a more predictable and cost effective source than some other options. Since natural gas suppliers would gain market share if CHP projects were to grow, they would likely support a federal CHP policy.

QUANTITATIVE POLICY EVALUATION

The Georgia Institute of Technology's version of NEMS ("GT-NEMS") is the principal modeling tool used in this study, supplemented by spreadsheet calculations. Specifically, we employ the model of NEMS that generated EIA's *Annual Energy Outlook 2011* (EIA, 2011), which forecasts energy supply and demand for the nation out to 2035. NEMS models U.S. energy markets and is the principal modeling tool used to forecast future U.S. energy supply and demand. Twelve modules represent supply (oil and gas, coal, and renewable fuels), demand (residential, commercial, industrial, and transportation sectors), energy conversion (electricity and petroleum markets), and macroeconomic and international energy market factors. A thirteenth "integrating" module ensures that a general market equilibrium is achieved among the other modules. Beginning with current resource supply and price data and making assumptions about future consumption patterns and technological development, NEMS carries through the market interactions represented by the thirteen modules and solves for the price and quantity of each energy type that balances supply and demand in each sector and region represented (EIA, 2009). Outputs are intended as forecasts of general trends rather than precise statements of what will happen in the future. As such, NEMS is highly suited to projecting how alternative assumptions about resource availability, consumer demand, and policy implementation may impact energy markets over time.

The NEMS "Reference case" projections are based on federal, state, and local laws and regulations in effect at the time of the analysis. The baseline projections developed by NEMS are published annually in the *Annual Energy Outlook*, which is regarded as a reliable reference in the field of energy and climate policy. We have used NEMS to perform scenario analysis under a consistent modeling framework in order to compare policy options to the Reference case projections. As shown in Table 1, the model represents CHP as a combination of eight technology systems, including two internal combustion CHP systems (ranging from 1 to 3 MW), five gas turbine CHP systems (3 to 40 MW) and one combined cycle system (with two 40 MW gas turbines and a 20 MW steam turbine).

Investments stimulated by the EPS policy are assumed to begin in 2012 and to occur through 2035. The ITC is modeled by reducing the installed cost of a CHP system to represent a 30% subsidy. In the early years of the policy, it is assumed that an increase in demand spurs a supply bottleneck, allowing producers to charge a higher market price than in the initial equilibrium position. (Specifically, it is assumed that only half of the ITC is passed on to consumers in the form of lower prices between 2012 and 2014, rising to 30% in 5% increments over the following three years.) As production capacities expand to meet the new demand levels, the ability of the producers to capture so much of the subsidy declines. By 2017, the initial GT-NEMS assumption of consumers capturing the entirety of the subsidy is restored for the remainder of the modeled period. Energy savings are modeled to decline at a rate of 5% each

[11] The Database of State Incentives for Renewable Energy, www.dsireusa.org/

year after 2035, due to the degradation of equipment, such that all benefits from the policy have ended by 2055.

The *AEO 2011* also provides estimates of the carbon intensity of electricity generation based on generation resources over time. The CO_2 intensities of various types of combustion fuels used in industry were derived from the EPA (2007). The benefit of reduced CO_2 emissions are estimated by subtracting the emissions in the Reference case from the policy scenario and then multiplying by the "social cost of carbon" (SCC). The SCC is an estimate of the monetized damages caused by a metric ton of CO_2 emitted in a given year. The social cost of carbon used in this analysis is the central value of the U.S. Government Interagency Working Group on the Social Cost of Carbon (EPA, 2010), growing from $23/metric ton in 2011 to $47/metric ton in 2050 (all values are in 2008-$, and take account of avoided damages globally).

The public health and environmental benefits of reduced emissions of criteria pollutants are estimated using the damage estimates contained in a recent National Research Council report (NRC, 2010). This analysis excludes climate change, mercury, ecosystem impacts, and other environmental damages, and thus is a conservative estimate, but does include public health and crop damages, for example. Damage estimates are provided for SO_2, NO_x, $PM_{2.5}$, and PM_{10}. For this analysis, emissions from the electricity sector and from industrial heat production are included and the policy scenarios are compared to the *AEO 2010* Reference case.

The federal CHP policy is evaluated from multiple perspectives, starting with an assessment of the business case for the required private-sector leverage. Without providing sufficient motivation to invest private capital, industrial policies will not achieve their goals. While an enterprise-specific financial analysis of this policy is not feasible within the NEMS energy-economic model, assessing the up-front private-sector investment costs relative to the stream of energy-expenditure reductions provides a basis for approximating the overall cash-flow attractiveness of the policy to industry. Present-value calculations for the private-sector assessment were conducted using a 7% discount rate to be consistent with Office of Management and Budget guidelines (OMB, 2002; 2009), which recommend the use of 3% and 7% discount rates when evaluating regulatory proposals. Our use of a 7% discount rate for evaluating the private industrialist's perspective is less than the 10% value used in some other energy-efficiency studies such as McKinsey and Company's analysis (Granade, et al., 2009).

The federal CHP policy is then evaluated in terms of its net societal benefits and its total social benefit-cost ratios. On the benefits side of the metrics we include monetized energy savings and estimates of social benefits from the mitigation of CO_2 and criteria air pollutants. On the costs side, we include both the private investments required as well as the public investments and administrative costs, and estimates of the deadweight loss. Present value calculations for the societal benefit-cost analysis were conducted using a 3% discount rate, with a 7% rate used in sensitivity analyses, consistent with Office of Management and Budget guidelines (OMB, 2002; 2009). As a policy design sensitivity, we evaluate a CHP policy supported by an investment tax credit that operates for only 10 years. Cost effectiveness also involves assessing the overall public costs of the CHP policy and the ability of these public investments to leverage energy savings and carbon dioxide emission reductions. The focus on overall government costs is particularly important given current concerns regarding public deficits, the federal debt ceiling, and the desire to constrain government spending.

Manufacturer's Perspective

The federal CHP policy is first evaluated from the manufacturer's perspective; if the business case cannot be made for the required private-sector leverage, then this policy will not achieve its goals. This financial analysis compares the Reference case to the policy cases in terms of the up-front private-sector investment costs relative to the stream of energy-expenditure reductions, providing a basis for approximating the overall cash-flow attractiveness of the policy to manufacturers. Based on GT-NEMS modeling, the U.S. economy would see significant growth in industrial CHP systems from 2011 to 2035 without any additional policy interventions. CHP capacity, for example, would more than double over that timeframe, increasing from 32 GW in 2011 to 72 GW in 2035 (Figure 1a). CHP could expand further as a result of the federal CHP policy, increasing from 32 GW in 2011 to 79 GW in 2035 with a 10-year ITC, and increasing further to 93 GW in 2035 with a 24-year ITC. These growth estimates are comparable to an analysis by ICF International, which evaluated the projected impact on CHP development of the introduction of a 30% ITC for high efficiency CHP (projects with overall efficiencies of 70% lower heating value or greater). The 30% ITC is estimated to increases CHP deployment by more than 60% over a no-ITC baseline (ICF, 2011).

The accelerated deployment of CHP would avoid the need to construct alternative types of utility-scale power plants, which would likely be dominated by natural gas combined cycle plants. The 21 GW of capacity growth estimated for the above the 24-year ITC versus the Reference case could mean that 70 plants would not have to be built, assuming that each plant had a typical size of 300 MW. Alternatively, the new CHP systems might displace some coal-fired power, nuclear power, or renewable-powered generation. The mix will depend upon the resources, regulations, and costs faced by different utilities.

Electric generation from industrial CHP as a percentage of national electricity generation grows from 8.9% in 2011 to 14.3% in 2035 in the Reference case. In the 10-year and 24-year ITC scenarios, industrial CHP expands to 15.6% and 18.2%, respectively. The electricity generation from industrial CHP facilities is estimated to grow about 30% more under the federal CHP policy, compared with the Reference case forecast, from 480 billion kWh in the Reference case in 2035 to 630 billion kWh in the Policy case in the same year (Figure 1b). This increment of power produced from CHP plants in 2035 (just the one year) would be worth more than $10 billion in 2008-$ (without discounting) at today's average industrial retail rate of 6.8 cents/kWh. To the extent that these CHP systems more than meet the power needs of the host manufacturing plants, they could produce a significant new revenue stream for the industrial sector in the U.S. This is an additional benefit of CHP for manufacturers, and for the nation, by reducing the emission of negative externalities like SO_2 in the power sector, depending on the type of displaced power generation.

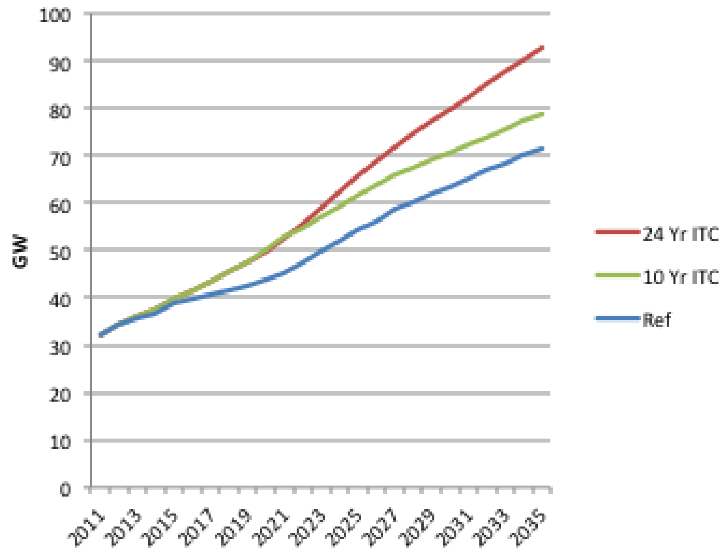


Figure 1a. Total Industrial CHP Capacity as the Result of a Federal CHP Policy

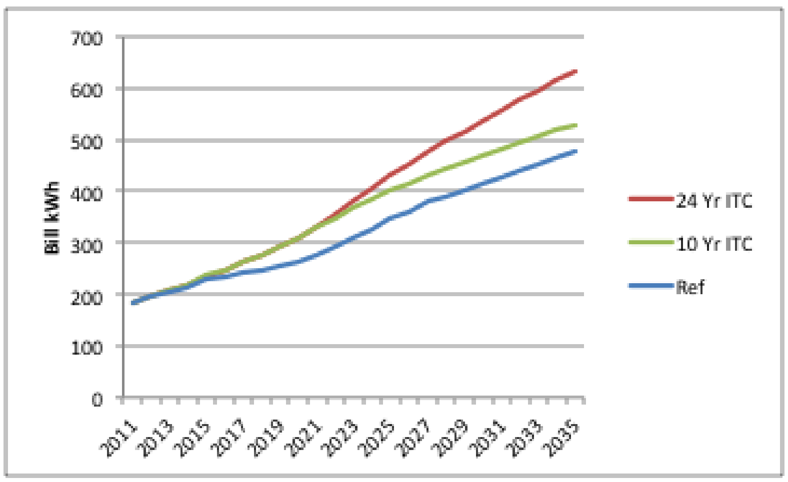


Figure 1b. Total Industrial CHP Generation as the Result of a Federal CHP Policy

Throughout the modeled period, manufacturers are providing CHP-generated power to the grid at an increasing level in all scenarios. In 2011, 21 billion kWh of electricity is sold to the grid, increasing to 40 billion kWh in the Reference case. With a 24-year ITC, these grid sales nearly double to 77 billion kWh, which are worth about $5 billion at today's average industrial retail rate of 6.8 cents/kWh. The industries with the largest CHP grid sales are bulk chemicals (which grows from 12 to 37 billion kWh under the 24-year ITC, between 2020 and 2035), paper (which grows from 4 to 15 billion kWh), and food processing (which grows from 1 to 9 billion kWh). The results show highly variable growth rates for CHP-produced electricity generation across different industries, with the food industry increasing its electricity sales to the grid almost nine-fold, exceeding today's grid sales by the paper industry, which is currently one of the largest industrial cogenerators in the country.

For each of these three large industries, the 24-year ITC scenario appears to initiate a notable uptick in the sales to grid in the last several years of the planning horizon. Figures 2a and 2b show this transition clearly for the paper industry: the slope of the own-use and grid sales lines deviate from the established pattern beginning in 2029-2030. Presumably the uptick in grid sales indicates that industrial CHP has reached a level where the industry's own need for electricity is being met by its own CHP systems and the economics of grid sales are more attractive for manufacturers than further on-site consumption, accelerating the use of CHP generation for grid sales. This is seen even more vividly when we remove the technology bottleneck at the introduction of the ITC, accelerating the growth of cogeneration and resulting in an earlier and more distinct turn from "own use" to "grid sales" in the paper industry.

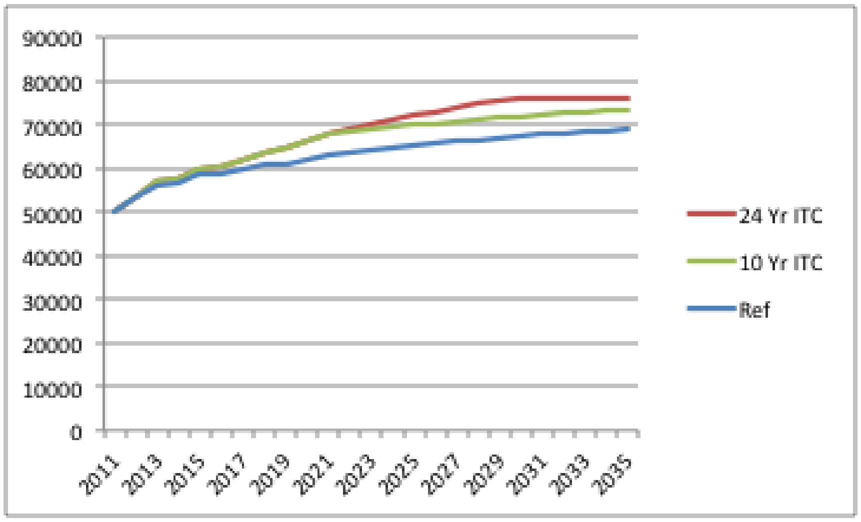


Figure 2a. CHP Generation by the Paper Industry for Its Own Use (in GWh)

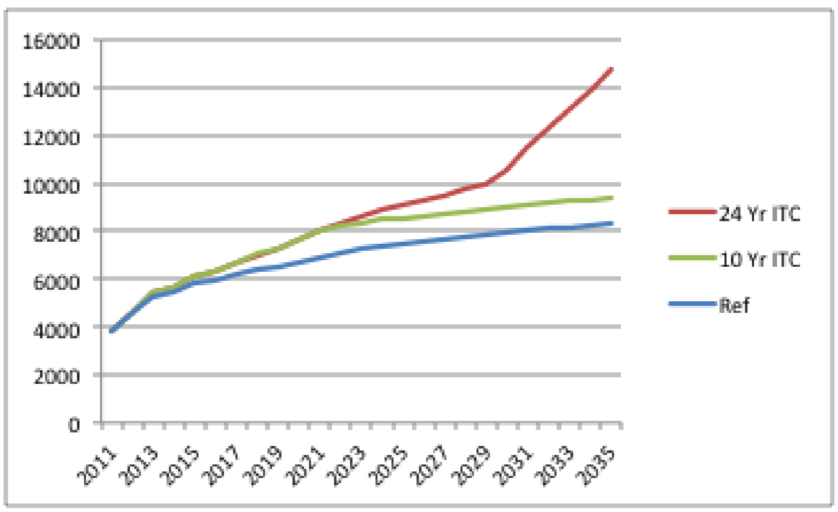


Figure 2b. CHP Generation by the Paper Industry Sold to the Grid (in GWh)

Sales of electricity from industrial CHP to the grid grow more rapidly in some regions than others. One of the determinants of this is the geographic distribution of industrial energy use. The South has the greatest share of industrial energy use (Table 2) and the largest installed CHP capacity. The West is third in overall industrial energy use (following the Midwest, which is second), but it generates more electricity from CHP and is forecast to grow more rapidly than any other region both in the Reference case and especially with a 24-year ITC. The dominance of food processing in California and the large paper industry in the Pacific Northwest contribute to the strong regional forecast.

Table 2. Share of Industrial Energy Use by Census Region

Census Region	Industrial Energy Use in Quads in 2008	Share of U.S. Industry Total Energy Use	Share of U.S. Total Energy Use for All Sectors
Northeast	2.63	8.4%	14.1%
Midwest	7.99	25.5%	23.9%
South	15.55	49.6%	42.7%
West	5.13	16.4%	19.4%

Source: EIA, 2010a

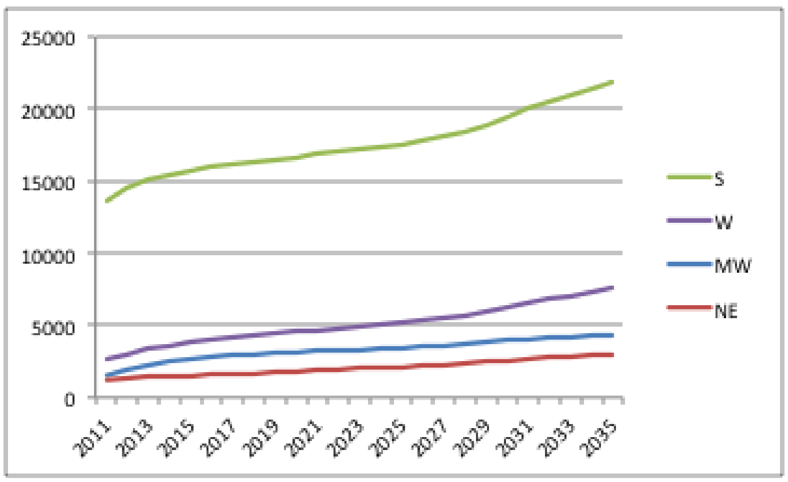


Figure 3a. Generation Sold to the Grid (in GWh), by Region, in the Reference Case

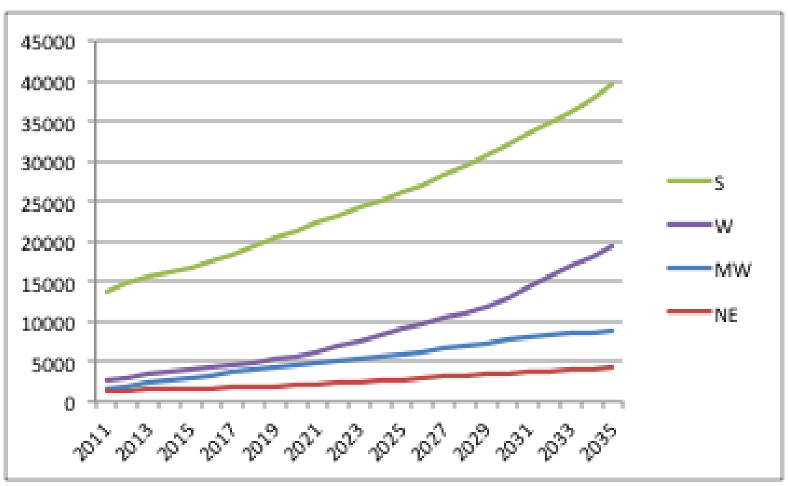


Figure 3b. CHP Generation Sold to the Grid (in GWh), by Region, in the 24-Year ITC Scenario

Table 3 presents the results of the analysis in terms of energy consumption and energy expenditures from the perspective of industry, utilizing a 7% discount rate. It is estimated that

133 TBtu could be saved in 2020, representing 0.5% of the business-as-usual industrial energy consumption in that year. By 2035, the estimated savings rise to 463 TBtus, representing a reduction of 1.9% of the business-as-usual industrial energy consumption in that year. Over the lifetime of equipment installed through 2055, an accumulation of 10 quads of energy would be saved.

Table 3. The Federal CHP Policy from the Manufacturers' Perspective*

Year	BAU Energy Consumption**	Annual Energy Savings ***			Cumulative Energy Savings****		Annual Private Cost	Cumulative Private Cost
	Trillion Btu	Trillion Btu	$M (2008)	%	Trillion Btu	$M (2008)	$M (2008)	$M (2008)
2012	25,205							
2020	26,899	133	1,659	0.50	395	7,311	311	1,703
2035	24,747	463	2,559	1.87	5,365	44,042	82	2,803
2055	--	--	--	--	9,767	68,354	--	2,803

* Present value of costs and benefits were calculated using a 7% discount rate.
** Reference case industrial energy consumption excludes refining. These Business-as-Usual (BAU) estimates are output from the GT-NEMS industrial module. They differ slightly from the *AEO 2010* (EIA, 2010) published estimates, which are produced from a fully integrated NEMS analysis.
*** The percentages refer to the percent of energy use and carbon dioxide emissions from industrial energy use.
****Investments stimulated from the policy occur through 2035. Energy savings are then modeled to degrade at a rate of 5% after 2035, such that all benefits from the policy have ended by 2055.

These energy savings come at a private investment cost of $311 million in 2020 and $82 million in 2035. These private investment costs are estimated by GT-NEMS, based on the assumed costs of eight different types of CHP systems per KW of installed capacity, minus the 30% investment tax credit. These costs are considerably less than the value of the energy saved – $1.7 and $2.6 billion in 2020 and 2035 – suggesting a highly positive NPV from the manufacturer's perspective.

If the 30% investment tax credit for CHP systems were designed to end in 2020, the cumulative energy savings from this policy would be reduced by approximately 25%. The savings are identical through 2020, but the rate of CHP-generated energy savings declines after that, since installation costs rebound to their higher levels as modeled in the EIA Reference case forecast and new installations decline accordingly.

Social Perspective

Turning to the social perspective, we examine the ability of public expenditures to leverage energy savings and CO_2 reductions, the deadweight loses associated with the policy, the welfare benefits from cleaner air and the mitigation of climate change, and overall cost-benefit metrics.

Tables 4 and 5 characterize the ability of the public sector to leverage energy savings and CO_2 reductions in the industrial sector with a federal CHP policy. Through 2035, cumulative public expenditures are estimated to be nearly $12 billion using a 3% discount rate. These expenditures, in turn, lead to cumulative energy savings of almost 10 quads. This yields an energy leveraging ratio of 0.8 MMBtu for each 2008-$ dollar expended.

In 2020, the federal CHP policy is estimated to produce 8 million metric tons of CO_2 savings, representing 0.5% of EIA's Reference case forecast for CO_2 emissions for the industrial sector that year (1,590 MMT). In 2035, public expenditures lead to CO_2 savings of 29 million metric tons, representing 1.9% of the Reference case CO_2 emissions forecast for the industrial sector that year (1,575 MMT). Over the lifetime of the equipment installed by 2035 as a result of this policy change, 590 million tons of CO_2 emissions are avoided, yielding a carbon-dioxide leveraging ratio of 0.05 tons per dollar.

Shortly before embarking on his trip to the United Nations Climate Change Conference in Copenhagen in December 2009, President Obama announced a target for reducing U.S. greenhouse gas emissions. The goal was to bring U.S. emissions 17 percent below 2005 levels in 2020, with an ultimate reduction of 83 percent by 2050. U.S. industry emitted 1,671 MMT of CO_2 in 2005, down from a high of 1,932 in 1979 (EIA, 2010c, Table 12.3). The Reference case forecast of 1,590 MMT for 2020 is 81 MMT (or 4.8%) below the 2005 level. With the addition of the federal CHP policy, this reduction could increase to 100 MMT (6.0%) below the 2005 level. Much of the historic reduction in emissions can be attributed to the offshoring of U.S. manufacturing, leading to a compensating increase in carbon "embodied" in imported goods (Weber and Matthews, 2007), while the reduction estimated to result from a federal CHP policy would be the result of energy-efficiency improvements and a transition to less carbon-intensive fuels.

Table 4. Leveraging of Energy Savings from Cumulative Public Investments in a Federal CHP Policy*

Year	Public Costs (Million 2008-$)				Cumulative Energy Savings (TBtus)	Leveraging Ratio* (MMBtu/$)
	Annual Administration Cost	Annual Investment Cost	Total Annual Costs	Total Cumulative Costs		
2020	10.99	550	561	3,784	395	--
2035	7.29	364	372	11,612	5,365	--
2055	--	--	--	11,612	9,767	0.8

*Ratio of cumulative energy savings in MMBtu to cumulative public costs in 2008-$. Present value of public costs was calculated using a 3% discount rate.

Table 5. Leveraging of CO_2 Emission Reductions from Cumulative Public Investments in a Federal CHP Policy*

Year	Public Costs (Million 2008-$)	CO_2 Emission Reductions (Million Metric Tons CO_2)			Leveraging Ratio*
	Cumulative Costs	Annual MMT Saved	% Annual Emissions	Cumulative MMT Saved	Metric Tons/$
2020	3,784	8	0.46	23	--
2035	11,612	29	1.86	317	--
2055	11,612	--	--	591	0.05

*Ratio of cumulative emission reductions in million metric tons to cumulative public costs in 2008-$. Present value of public costs was calculated using a 3% discount rate.

For both energy and CO_2, the leveraging metrics are greater for the 10-year ITC when the 3% discount rate is used. This reflects the lower level of free ridership per dollar of public expenditure for the short-term policy (Figure 4). In contrast, the 7% discount rate produces more favorable leveraging statistics for the longer-term ITC because the financial expenditures are deeply discounted while the energy saved and CO_2 avoided are in physical units that are not discounted.

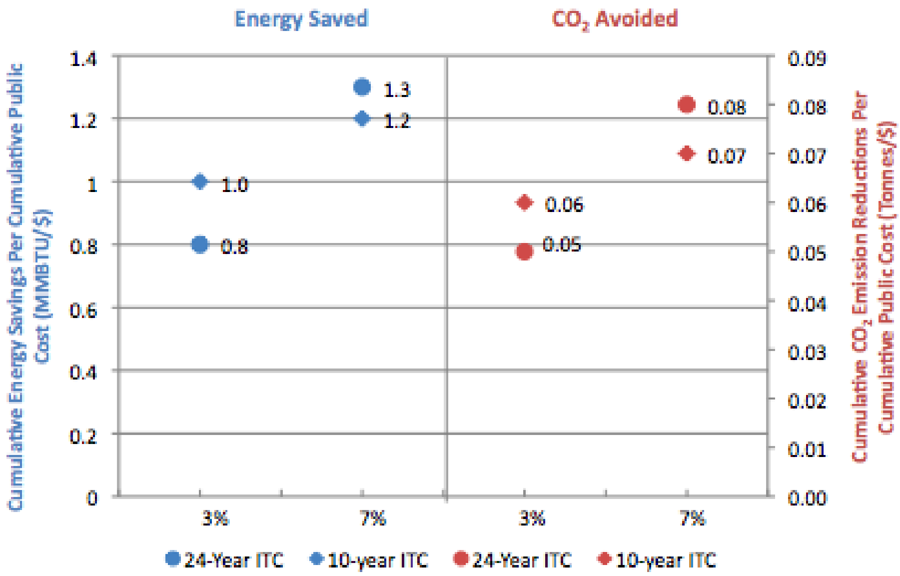


Figure 4. Energy and CO_2 Leveraging for a Federal CHP Policy

As a result of the ITC operating as a subsidy for the installation costs of CHP systems, the policy incurs social deadweight loss. That is, the policy produces a loss of economic efficiency, assuming that it distorts a free market equilibrium Due to the increase in demand and the corresponding supply bottleneck, the ITC policy is modeled to represent new market conditions post-subsidy. For the first three years, the producers and consumers are modeled as each receiving equal parts of the subsidy, but as production capacities increase to meet the new demand and the supply bottleneck is addressed, the producers capture less of the subsidy. Producers may also be expected to be able to receive this level of additional surplus due to the 3-to-5 years regularly required to bring a new CHP project online. By 2017, the initial GT-NEMS model assumptions of perfectly elastic producers are restored and the consumers are able to capture the subsidy for the remainder of its existence. The amount of the annual deadweight loss is estimated to range from $30 million to $150 million, increasing over the first decade as shown in Figure 5, but gradually declining to $70 million by 2035, the final year of the modeled subsidy. Although the percent of the subsidy that is deadweight loss varies annually, it averages 18.5%.

While our deadweight loss calculations estimate the reduction in market efficiency from the federal tax subsidy, those losses are more than offset by the social benefit produced by addressing the negative externalities from air pollution and climate change. Estimates of the value of avoided criteria pollutant are shown in Table 6. Of the four criteria pollutants considered, SO_2 emission reductions deliver the greatest human health and environmental benefits, totaling roughly $24 billion in avoided damages through the year 2055, as the result of the federal CHP policy. In total, these emissions reductions represent additional significant benefits of a federal CHP policy, with savings of more than $26 billion. The avoided costs of NO_x, SO_2, PM_{10}, and $PM_{2.5}$ due to the energy-efficiency measures are calculated using a 3% discount rate. The present value of avoided damages for all four local pollutants drops to less than $13 billion using a 7% discount rate.

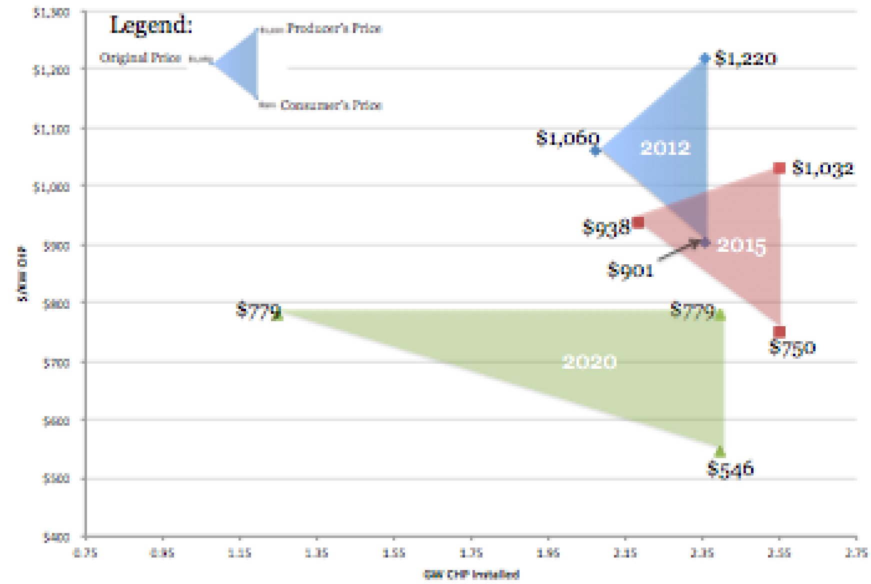


Figure 5. Changes in Deadweight Loss for a Federal CHP Policy in 2012, 2015, and 2020

Table 6. Value of Avoided Damages from Emissions of Criteria Pollutants from a Federal CHP Policy (Billion 2008-$)*

	NO_x		SO_2		PM_{10}**		$PM_{2.5}$	
	Annual	**Cumulative**	**Annual**	**Cumulative**	**Annual**	**Cumulative**	**Annual**	**Cumulative**
2020	0.011	0.033	0.494	1.82	0.003	0.010	0.043	0.156
2035	0.017	0.319	0.965	14.4	0.005	0.077	0.086	1.27
2055		0.480		23.5		0.127		2.09

*Values are based on the National Research Council report estimating damages from energy production and consumption in the U.S. (NRC, 2010). They exclude avoided pollutant damages from petroleum and coal for industrial heat. The present value of avoided damages was calculated using a 3% discount rate.
**Excludes PM_{10} from the production of industrial heat.

To summarize the social perspective, we use traditional cost-benefit metrics including estimates of B/C ratios and net societal benefits including the value of avoided damages from CO_2 and the four criteria pollutants (Table 5). We determine the economic value of reduced CO_2 emissions in each year by multiplying the decrement in emissions by the "social cost of carbon" (SCC) for that year (described earlier). Consideration of these emissions benefits raises the B/C ratio for this policy to 7.4 with a 3% discount rate and 5.8 with a 7% discount rate. It should be noted that these estimates do not include savings from the expansion of CHP systems in the refining industry (because of the structure of GT-NEMS, which has a separate petroleum module), or the benefits to grid reliability that expanded CHP would provide to ratepayers. They also do not include the environmental benefits or energy savings of free riders because these companies are included in the Reference case projection, which forecasts some growth in CHP systems in the absence of federal intervention.

Table 5. Total Social Benefit/Cost Analysis of a Federal CHP Policy*

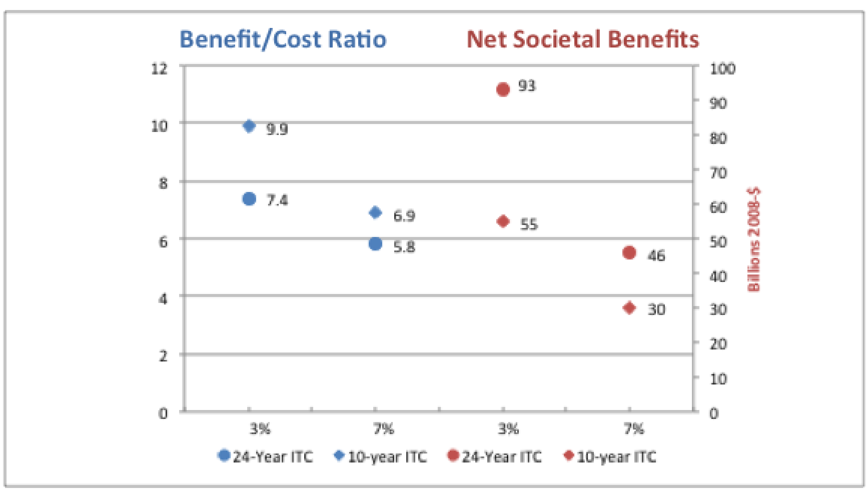
	Cumulative Social Benefits (Billions 2008-$)				Cumulative Social Costs (Billions 2008-$)			Benefit/Cost Analysis	
Year	**Energy Savings**	**Value of Avoided CO_2**	**Value of Avoided Criteria Pollutants**	**Total Social Benefits****	**Public Costs**	**Private Costs**	**Total Social Costs****	**Social B/C Ratio**	**Net Societal Benefits (Billions 2008-$)**
2020	7.3	0.50	2.09	9.9	3.78	1.7	5.5		
2035	44.0	6.4	16.5	67.0	11.6	2.8	14.4		
2055	68.4	11.6	27.0	107.0	11.6	2.8	14.4	7.4	93

* Present value of costs and benefits were calculated using a 3% discount rate.
**Total costs and benefits do not include various non-monetized values (e.g. mercury pollution reduction, increased productivity, water quality impacts, etc.).

Figure 6 provides a summary of the social benefit/cost ratios for the federal CHP policy with a 24-year ITC and with a 10-year ITC, analyzed using both a 3% and 7% discount rate. The policy sensitivity analysis highlights the greater societal benefits of the 24-year ITC, especially when the lower discount rate is used. It also shows that the shorter ITC has a more attractive benefit-cost ratio because the 10-year ITC benefits from a lower level of free ridership in combination with a sustained rate of CHP installation that occurs after initiating the subsidy.

The impact of a supply bottleneck of CHP equipment during the first five years of the ITC policy documents the importance of early action and the commitment to a long-term policy. If the supply bottleneck could be avoided, perhaps through an early policy announcement, nearly twice as much energy could be saved in 2020.

Figure 6. Social Benefit/Cost Analysis of Policy and Discount Rate Sensitivities



Another metric for evaluating the cost of carbon mitigation through a federal CHP policy is to consider the public and private investment costs per metric ton of CO_2 that is avoided. The ratio of cumulative costs to cumulative CO_2 avoided for the 24-year period beginning in 2012 is -$93. That is, the public and private investors in CHP systems would save $93 for every ton of avoided CO_2. Similar "negative costs" for carbon mitigation have been documented by Granade (2009) and other analysts for many energy-efficient technologies that cut energy costs while at the same time reducing environmental emissions.

SUMMARY AND CONCLUSIONS

The challenge of maintaining a domestic manufacturing base is compounded by the energy economics of typical U.S. plants today. With the rapid growth of manufacturing in expanding economies such as China, India, and Brazil, there is an opportunity for new facilities in those countries to deploy the latest energy-saving and lean technologies and practices. In contrast, the U.S. is saddled with an existing infrastructure of older, inefficient manufacturing facilities that need to be upgraded. Infrastructure investments will be key to regaining competitiveness.

We have shown that improved energy economics could result from the promulgation of a federal energy portfolio standard that qualifies CHP, accompanied by tax credits for CHP investments, and a sustained RD&D program. It is estimated that the energy-saving benefits of such a federal CHP policy could outweigh the policy's costs several times over, offering a positive cash-flow investment opportunity for manufacturers to sell electricity and recycle those profits into more competitively priced products.

We have also shown that when the full array of climate change and air quality benefits is considered, the return on the public investment is highly favorable. While the annual deadweight loss of the proposed federal CHP policy is estimated to range from $30 million to $150 million (2008-$), that is much smaller than the estimated annual social surplus of $150 million to $4.8 billion.

Opposition to a federal CHP policy will likely be grounded in issues of equity including the subsidies provided to "free riders," the reduced profits of electric utilities in states that have not decoupled profits from sales, the redistribution of environmental emissions, and federalist issues.

On the one hand, a more complete analysis of the impacts of industrial energy-efficiency investments might show increased social benefit-cost ratios of these policies. There is a growing literature that documents several categories of "non-energy" financial benefits including reduced operating and maintenance costs, improved process controls, increased amenities and other conveniences, water savings and waste minimization (Prindle, 2010). In addition, Colella (2003) argues convincingly that CHP reduces two non-environmental negative externalities: oligopoly pricing for peak demand requirements and the inability of those with thermal demand to buy the heat from CHP.

On the other hand, the avoidance of environmental damages that contributes to the high societal benefit-cost ratio of this federal policy option could be overstated if EPA regulations are tightened over the next several decades and if a price is put on the cost of carbon. Environmental regulations would incentivize cogeneration investments because of their lower emissions, thereby resulting in some of the CHP growth that we attribute to the federal CHP policy. Stronger pollution controls and carbon taxes would also cause environmental and energy-efficiency improvements to central station power plant technologies, thereby accounting for some of the benefits that we attribute to the federal CHP policy when comparing it to the Reference case forecast with limited electricity-sector modernization.

Our analysis has emphasized the need for multiple perspectives and sensitivity analysis when evaluating possible future policies. Coupled with an understanding of the likely position of key stakeholders and constituencies, policy analysts can provide valuable insights about the costs, benefits, feasibility, and likely fate of policy proposals.

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