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Distributed Generation as a Response to Rising Electricity Costs in Ohio

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Cleveland State University
Maxine Goodman Levin
College of Urban Affairs

Prepared for:
OHIO MANUFACTURERS' ASSOCIATION

Distributed Generation as a Response to Rising Electricity Costs in Ohio

Prepared by:
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February 2013

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Table of Contents

I. Executive Summary

Ohio faces significant challenges to its manufacturing in a global economy. Energy-intensive manufacturing, in particular, is threatened by rising electricity costs and a need to reduce carbon emissions. Electricity costs are projected to increase substantially in the coming years, especially in grid-constrained areas such as that found in Northern Ohio. Northern Ohio's Regional Transmission Organization (RTO) generation capacity charges are scheduled to go up by over 1400% in the next few years, rendering RTO capacity charges the second highest cost component to electricity, after the wholesale cost of electricity. In addition to this, Ohio manufacturers are incurring new costs meeting Environmental Protection Agency guidelines for steam and heat generation. Together, these forces have created a significant threat to Ohio manufacturing.

One answer to this threat is the adoption of distributed generation, especially in the form of combined heat and power, or CHP. Distributed generation is power generated in small amounts at or near the site of consumption, thereby reducing line losses and increasing the strategic value of that power. CHP offers the best near term solution for manufacturing, insofar as it is reliable and it enables the manufacturer to reduce its reliance on the grid. CHP can provide a solution to both the problem of rising capacity charges and to meeting the EPA requirements for steam generation. It may also be a solution for rising distribution charges, including those associated with the cost of meeting energy efficiency and renewable generation mandates.

However before CHP can be more fully adopted by manufacturing, regulatory impediments to its adoption must be addressed. The two major regulatory impediments relate to standby charges and to a lack of a market for surplus power that values its strategic location near other markets. If regulators do not recognize the value CHP can bring to ratepayers system-wide, standby fees are likely to render a CHP project uneconomic. In Ohio, policy makers sought to enable the adoption for CHP by passing legislation that qualified CHP as responsive to the State's energy efficiency mandate, but failed to provide a meaningful mechanism for those deploying CHP to realize value from this.

Policy makers should look at other impediments and/or enabling strategies for the adoption of CHP. Public support for financing CHP is currently available, including loans and tax incentives, but many manufacturers have a difficult time justifying the long-term investment required for most CHP projects. Strategies that mitigate the risk of stranded assets, such as the use of modular designs that enable easier recovery of key assets, might make for shorter and less risky third party financing agreements.

Other strategies that policy makers can deploy to encourage CHP include the decoupling of sales from utility profits, the development of self-generation investment portfolios, regulations that enable the advent of micro-grids, and regional energy planning that helps manufacturers identify opportunities for district heating and micro-grids.

Ohio manufacturers face multiple threats for which distributed generation and CHP could provide relief. However these threats also create an opportunity for manufacturers to position themselves to have a long-term competitive advantage over other manufacturers, especially those in Asia and Europe, who do not enjoy inexpensive natural gas like Ohio does. The advent of shale gas, which has created a promising long-term outlook for natural gas prices, may make the case for CHP even more compelling. However Ohio policy makers must ensure that Ohio's regulations support and do not impede the deployment of distributed generation in Ohio, especially for CHP.

II. Background and Introduction

Manufacturing is an energy-intensive business. Manufacturers account for roughly one half of America's natural gas and 30% of its electricity consumption.[1] Accordingly, a secure, reliable and affordable source of electricity is a top priority for Ohio's manufacturers. Those manufacturers for which electricity costs make up an especially significant portion of their product costs are most vulnerable to rapid rate increases.[2] The decline in manufacturing jobs throughout America has accelerated in recent years. Ohio has lost some 117,000 manufacturing jobs in the last five years alone – the second highest total in America.[3] Policy affecting energy costs is critical to Ohio manufacturing maintaining a competitive position in the global economy.

Electricity-intensive industries comprise a major part of Ohio's manufacturing landscape. In particular, manufacturers of chemicals, metal products and glass are significant employers in Ohio and are electricity-intensive businesses. Aluminum manufacturing leads the way, with 5.7% of its expenditures on electricity. The iron and steel, chemical, glass and foundry manufacturing follow, each with a 2.3% or greater portion of its expenses made on the acquisition of electricity. In terms of total dollars spent, chemical manufacturing leads the state, with expenditures of over $352 million per year on electricity. Iron and Steel industries, at $305 million, and Aluminum at $244 million per year, are next. These industries all employ many thousands in Ohio, and are highly sensitive to increases in electricity costs.[4]

Manufacturers are also facing multiple forces that are driving them toward a new energy paradigm: the shift from centralized to distributed generation. These forces include rising electricity costs due to transmission and generation capacity constraint, new EPA standards for coal fired steam and electricity generation, and a natural gas surplus that has made gas-fired distributed generation technologies such as combined heat and power more economical. This natural gas surplus stands in stark contrast to the situation in Europe and Asia, where natural gas prices are multiples of the cost of gas in America – promising a potential competitive advantage for energy intensive manufacturing in Ohio and elsewhere in America. Accordingly, manufacturers are now looking more closely than ever at distributed generation.

This study is intended to provide manufacturers with insights as to policies that may affect their ability to deploy distributed generation to reduce their cost

[1] "Retooling Ohio: A Bulletin for Leaders on Policy Issues Critical to Ohio Manufacturers," www.ohiomfg.com (Ohio Manufacturer's Association 2010).

[2] *Id*. at 2-3.

[3] S. Thomas, "Long Term Manufacturing Losses Affect All States," *The Business Journal* (July 11, 2012); http://www.bizjournals.com/bizjournals/on-numbers/scott-thomas/2012/07/longterm-manufacturing-decline-affects.html?page=2.

[4] I. Lendel, et al, "Moving Ohio Manufacturing Forward: Competitive Electricity Pricing," the Urban Center, Levin College, Cleveland State University (February 2013).

of electricity, and to provide ideas or strategies for manufacturers to consider for deploying distributed generation. In addition, this study is intended to help inform policy makers as they consider what can and should be done in Ohio to encourage distributed generation. A separate and companion study also includes an analysis of how changes in electricity pricing can affect manufacturing productivity.[5]

[5] *Id.*

A. The Role of Deregulation in Electricity Pricing.

Not surprisingly, given the above statistics, it has been energy intensive manufacturers in Ohio and elsewhere that have championed electricity policy reform in America over the past thirty years. Manufacturing has been successful in this endeavor – leading to what one energy writer called the "Quiet Revolution": governments around the world are liberalizing their energy markets, opening up their borders to energy markets for natural gas and electricity.[6] This "revolution" was originally instigated by energy-intensive industries seeking to open up electricity and natural gas markets in America. The industries were motivated in part by the energy shocks of the 1970's and the resulting legislation: the National Gas Policy Act (NGPA) and the Public Utilities Regulatory Policy Act (PURPA).[7] Both acts were passed to deal with the energy crisis that had gripped the nation and had catalyzed the onset of the "rust belt" in the Great Lakes region. The NGPA froze "old" gas sold on the interstate market at unsustainable prices, but rewarded producing companies who drilled for new natural gas production with market prices, thereby eventually alleviating the natural gas crisis. PURPA, however, was less successful in resolving electricity problems. Its goal was resolve electricity shortfalls by encouraging conservation and mandating that utilities purchase power from independent wholesale power producers. However the existing regulatory framework caused electricity prices to continue to rise even as new generation was brought on line.

Under PURPA the individual states were to encourage new generation from small (below 80 MW) facilities that used something other than fossil fuels, or used waste heat, by requiring utilities to purchase power there from at its "avoided cost" – the cost the utility would have had to pay if it had built new, centralized electricity generation of a like amount. But avoided costs were not based on market prices; there was no wholesale market for electricity at the time. Instead, prices were based upon "but for" forecasts, and regulators soon found that electricity prices had no relation to market realities. Independent power producers had no incentive to innovate or to provide electricity at a lower cost.[8]

For decades in America, electricity generation, transmission and distribution were all regulated, with utilities enjoying "cost plus" rate recovery for nearly all of their expenditures, regardless of their folly. The cost-plus strategy invited not only technology stagnation, but also bloated utility budgets, since there was no incentive to constrain costs. Inevitably, rates soared under this paradigm; average electricity rates in America rose 60% between 1969 and 1984, adjusted for inflation.[9] The biggest culprit for this problem lay with massive cost overruns associated with the

[6] V. Vaitheeswaran, *Power to the People: How the Coming Energy Revolution Will Transform an Industry, Change Our Lives and Maybe Save the Planet,* at 18 (Farrar, Straus and Giroux 2003).
[7] *Public Utilities Regulatory Act,* Pub.L. No. 95-617, 92 Stat. 3117 (1978); *Natural Gas Policy Act,* Pub.L. No. 95-621, 92 Stat. 3350 (1978).
[8] J. Lesser and L. Giacchino, *Fundamentals of Energy Regulation*, 9-11 (Public Utilities Reports 2007).
[9] Vaitheeswaran, *Power to the People,* at 31.

building of large centralized nuclear generation plants.

By the 1990's a wholesale electricity market was beginning to develop (partly in response to the Energy Policy Act of 1992). Further, due to a sluggish economy, demand for electricity was stagnant, and a surplus capacity developed. Yet power costs remained high due to the massive cost overruns and the cost-plus regulatory recovery schemes. Residential and commercial end users, with little voice for advocacy at the time, could do little about this. Energy intensive industrial users, on the other hand, had the wherewithal to influence energy policy in the United States. As a result, manufacturers, along with other large users of power, began to coordinate efforts to lobby for the right to bypass utilities and to take their loads to an open wholesale generation market. As a result, in 1994 deregulation was first introduced to America through sweeping regulatory reform in California.[10] Deregulation thereafter spread throughout the nation, and continues to develop to this day.

California, predictably, also was the source of the first major problems with deregulation. First out of the gate, California took some serious missteps, the most problematic being that it only partially opened up its electricity markets. California's public service administrators froze retail electric rates -- at a time when power generation there was already in a tight market -- thereby creating no incentive for consumers to cut back usage. Then, in the face of this tight power supply, California officials adopted what has since been described as the "BANANAS" (Build Absolutely Nothing Anywhere Near Anybody) strategy: a combination of uncertainty, tough environmental laws and politics discouraged new generation from being built. On top of this, wholesalers like Enron found ways to rig the markets. The result was that wholesale prices shot up, retail prices remained frozen, and utilities fell into financial disarray, with two utilities pushed to the point of insolvency.[11] A backlash to deregulation began to occur in that state, led by the long, hot summer of 2000 when electricity prices skyrocketed and blackouts became commonplace. None of the promised cost reductions had materialized. By 2001 calls for "re-regulation" began to be heard.

In 1999, before the California problems emerged, Ohio took its first steps towards deregulation with the enactment of Senate Bill 3 in 1999. At the time, electricity prices varied dramatically between northern and southern Ohio; southern Ohio enjoyed coal generation and lower rates, while northern Ohio used a mixture of coal and the more expensive nuclear power.[12] The result was that manufacturers and consumer groups lobbied the Ohio legislature to open up the state's electricity markets. Ultimately, however, a competitive market for electricity failed to fully materialize. Many argued that too many concessions to the utilities had discouraged, rather than encouraged, competition. The result was the 2008 partial "re-regulation" of the

[10] Lesser, *Fundamentals of Energy Regulation*, at 10.

[11] Vaitheeswaran, *Power to the People*, at 74-82.

[12] *See e.g.* D. Gearino, *Former PUCO Officials and Legislatures Say State Regulatory Process Favors Utilities Over Customers in Setting Rates*, The Columbus Dispatch, Dec. 18, 2011, at 1A.

electricity industry through Senate Bill 221.[13]

It remains to be seen how successful deregulation will be in creating an open market for wholesale electricity in Ohio and elsewhere. Wholesale electricity prices have dropped significantly since 2008, but this appears to be more related to the deep recession than to a more robust wholesale market. Further, the evidence of the effects of deregulation has been obscured by the fact that only those states where electricity prices were high chose to deregulate. So while it may appear that electricity price increases have slowed in the deregulated states as a result of deregulation, the fact remains that those states that restructured their markets continue to have electricity prices that are substantially higher than those who did not – and that gap has actually grown, not gotten smaller, since deregulation began in the late 1990's.[14]

One significant reason why deregulation has failed to fully develop a fully unencumbered wholesale market is that this markets remains captured by regional transmission organization ("RTO") capacity charges. "Capacity" in this sense refers to the amount of electricity locally available to be delivered when demand on the grid is at its peak – typically in late afternoons in high summer. Because transmission is tied so closely to generation, generation does not enjoy a completely free market. High RTO capacity charges commonly result when constrained transmission combines with insufficient local generation. Since this power supply is essentially on standby, awaiting peak system wide requirements, it tends to use the most expensive – and most profitable – energy generation technology.

Nowhere is the problem of capacity costs more evident than in Northern Ohio's First Energy-Ohio region, known as "American Transmissions Systems, Inc., or ATSI." In May 2012 First Energy's RTO, PJM, held a capacity auction that resulted in RTO capacity costs for the ATSI region that were three times higher than the rest of the PJM territory. While the resulting costs consumers bear will depend upon the coincidence of their peak demand with system wide peak demand, the average capacity costs in northern Ohio will increase by 1700% by 2015 – ultimately becoming the second largest component of electricity prices for most customers, and for some, the highest.[15]

In theory, high capacity charges should lead to the building of new generation. But there is not always a direct relationship between short-term price signals and the building out of long-term capacity.[16] Under Ohio regulations, for instance, the utilities will prefer to build new grid in response to grid congestion rather than to build new generation capacity, since a return is guaranteed on the grid investment, but not

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[13] *Id*.

[14] Retail Electric Rates in Deregulated and Regulated States: 2011 Update, American Public Power Association, April 2012, http://publicpower.org/files/PDFs/RKW_Final_-_2011_update.pdf

[15] M. Brakey, "Skyrocketing First Energy-Ohio Capacity Costs," at 1 (September 2012). *See* http://www.brakeyenergy.com/white-papers-special-reports/

[16] *See e.g*. R. Michaels, "MW Gamble: The Missing Market for Capacity," *The Electricity Journal*, at 56-64 (December 1997) ("Reluctance to commit to generation in anticipation of markets may indicate that we have not thought through the consequences of the institutions we are putting in place.)

the generation. Indeed, it has been shown in Europe, where generation has also been deregulated, that short term price signals sent by high capacity charges do exactly the opposite: they induce utilities to under invest in aggregate capacity, and to profitably distort the technology mix towards peaking units.[17] It may prove more profitable in Ohio for utilities to maintain capacity constraint and to continue to tack large peaking unit capacity charges onto wholesale power prices. In short, utilities strategically limit their investment into local generation to maintain higher prices.[18]

Other problems with deregulation, such as incomplete open access to transmission lines, remain to be resolved. However the biggest current threat to deregulation, and to Ohio manufacturers, is the capacity charge problem. All of this is outside the scope of the Public Utility Commission of Ohio (PUCO) to control. That said, however, the threat of rising capacity charges can be mitigated in principal part through self-generation. This will require a regulatory scheme in Ohio that is friendly to distributed generation.

[17] *See* G. Meunier, "Capacity Choice, Technology Mix and Market Power," 32 *Energy Economics*, at 1306-1315 (April 2010).
[18] *Id*. at 1307.

B. Distributed Generation: the Next Energy Revolution

While deregulation problems continue to be worked out, industrial manufacturers are left to consider how to constrain costs on the regulated side. This will inevitably lead to the next "quiet revolution" to our national energy paradigm: the shift from centralized to distributed electricity generation (DG). The best way to constrain grid costs, as well as RTO generation capacity charges, is to substantially reduce reliance upon the grid. DG is the best available strategy to accomplish this.

It has long been thought that energy intensive industries like steel, glass and chemical manufacturing could be "ground zero" for rethinking how energy is generated and used in America. These industries consume large amounts of fossil fuels and electricity to melt scrap iron, iron ore, and sand, and to produce chemicals. Recycling the waste heat from these industries could itself generate some 5% of America's electricity needs.[19] Likewise, in Gotherburg, Sweden two refineries use waste heat to provide nearly half the 450,000 residents of that town with district heating. None of the 150 refineries in America, including the several that operate in Ohio, recycle waste heat for use in residential heating.[20]

Ohio is uniquely placed to play a leading role in the advent of distributed generation. That is because the many locations where DG is likely to first become economical are those involving generation at industrial sites, and Ohio is among the nation's leaders in generation capacity from industrial waste heat. According to the Environmental Protection Agency, Ohio has enough waste heat to generate the equivalent power of 8 nuclear power plants, leading some observers to characterize Ohio as the "Saudi Arabia of cogeneration."[21] The Oak Ridge National Laboratory projects that waste heat recovery systems can be available for around $1500/kW installed[22] – a price that should be attractive for electricity intensive manufacturing. The potential to avoid future carbon taxes and to create jobs also makes this of considerable interest to Ohio's policy makers.[23]

Two other factors will likely lead to the advent of distributed generation in Ohio. The first is the April 2012 adoption of new federal EPA Clean Air Act pollution standards (the so-called "Boiler MACT" regulations)[24] that will cause area-wide

[19] Vaitheeswaran, *Power to the People,* at 32.
[20] *Id*.

[21] L. Marginelli, "The Case for Gray Power," The Nation, February 15, 2010 (http://www.thenation.com/article/case-gray-power).
[22] *Id*.
[23] According to Policy Matters, Ohio, as many as 20,000 jobs could be created from cogeneration, and the release into the atmosphere of 13 metric tons of carbon could be avoided. *See* "Capturing Waste Energy In Ohio: Using Combined Heat and Power to Our Electric System," Policy Matters Ohio (March 2012) (http://www.policymattersohio.org/combined-heat-power-march2012).
[24] See http://www.epa.gov/airquality/comustion/docs/20111202overviews.pdf. The Ohio Public Utilities Commission resolved in February 2012 to develop an educational forum to begin a pilot program designed

capital investment into new, cleaner steam generation capacity. Many Ohio industries have large, old coal boilers producing large volumes (over 100,000 lbs/hr) of steam. These boilers tend to work continuously, are inefficient, and require as fuel low sulfur "compliance coal."[25] Industrial users that are considering an upgrade of their coal boilers in order to comply with the new rules may find this to be a convenient time to convert to more efficient heat creating systems, such as combined heat and power (CHP). With these systems, electricity made as a byproduct of generating heat can be converted for use on site, thereby dramatically improving systemic efficiency.

The second factor relates to grid congestion, especially in Northern Ohio. It has been recognized for some time that the traditional American energy model -- large centralized generation plants with a robust grid system with a nearly ubiquitous reach – is no longer the best model for future planning. Northern Ohio, in particular, has been grid constrained for a number of years. As a result, and in anticipation of retiring old coal burning generation facilities, First Energy now plans to undertake a $1 billion transmission upgrade.[26] Some experts have questioned the wisdom of such an investment when distributed generation has become increasingly cost effective, and passing these transmission costs through to manufacturers will inevitably lead to product price increases and possibly compromise competitiveness.[27]

In the meantime, as set forth earlier, RTO capacity charges are on the rise. PJM anticipates that there will be changes in the next several years to Ohio's generation fleet on an "unprecedented scale."[28] PJM announced in May 2012 that it had purchased as power supplies in its auction for 2015-16 a "record amount of new generation." Northern Ohio suffered the highest prices in the PJM market -- $357 per Megawatt, more than twice the PJM base price of $136 per Megawatt.[29]

In addition to rising transmission and capacity charges, Ohio manufacturing faces an additional threat that could be resolved, in part, by switching to distributed generation: carbon regulation. Driven in part by EPA requirements to either clean up or shut down old coal plants and in part by a depressed natural gas market, much of coal electricity generation will be replaced by natural gas in the coming years. According to one recent study, even

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to develop and share information about combined heat and power as a strategy for compliance with the new Boiler MACT rules.

[25] S. Casten "EPA's Boiler MACT Is an Economic Growth Opportunity," (June 15, 2012) http://grist.org/article/epas-boiler-mact-is-an-economic-growth-opportunity/. Compliance coals run around $90/ton, or $3.60/mmbtu. If a boiler is 75% efficient, this means that the cost of delivered steam would be $4.80/mmbtu. *Id*.

[26] J. Funk, "First Energy Will Spend $1 Billion on High Voltage Transmission Lines and Substations," *Cleveland Plain Dealer* (May 18, 2012); http://www.cleveland.com/business/index.ssf/2012/05/firstenergy_will_spend_1_billi.html.

[27] *See e.g*. L. Traves, "Another Bad Energy Policy for Ohio," *Crain's Cleveland Business* (May 29, 2012), http://www.crainscleveland.com/article/20120529/BLOGS05/120529844/1241/newsletter04.

[28] PJM News Release, "PJM Capacity Auction Secures Record Amounts of New Generation, Demand Response and Energy Efficiency" (May 18, 2012); http://pjm.com/about-pjm/newsroom/announcements-and-news-releases.aspx.

[29] *Id*. at 2.

accounting for a marginal increase in life cycle greenhouse gases generated through hydraulic fracturing, burning natural gas emits less than half the carbon that burning coal does.[30] This reduction in carbon emissions will likely become a critical economic element to the viability of Ohio manufacturing in the coming years, as increasing restrictions are placed on carbon emissions.

[30] N. Hultman, et al, "The Greenhouse Impact of Unconventional Gas for Electricity Generation," Environmental Research Letters (IOP Science October 2011)(Online at: stacks.iop.org/ERL/6/044008).

III. Distributed Generation in Manufacturing

Distributed generation (DG) has become increasingly the focus of energy policy research. DG promises not only improved energy efficiency, but also improved environmental quality and lower costs. However capturing the full range of advantages offered by a DG system depends upon the circumstances of each location. It may depend, for instance, upon the integration of energy management systems and complementary technologies such as control systems or uninterruptible power supplies.[31]

However the benefits do not inure solely to the industrial users. Utilities, too, can and should benefit from DG systems. Besides the development of ancillary generation services from this industry, utilities also benefit from avoided transmission and distribution improvements, more predictable demand profiles and improved asset utilization.[32] As noted by energy pundit Amory Lovins of the Rocky Mountain Institute, the old model of centralized generation with a ubiquitous grid was based upon the 20th century idea that generation was less reliable than the grid. But the 21st century reality turns this model on its head – today, generation, especially gas turbine, is more reliable than the grid. Accordingly, one of the fundamental reasons for centralized generation no longer exists.[33] As Lovins notes, today "the cheapest, most reliable power" is that which is "produced at or near the customers."[34]

Ohio policy makers have recognized the value of DG, and have enacted regulatory reform designed to encourage its deployment. In 2008 Ohio Senate Bill 221 revised current rules for the adoption of DG such that manufacturing companies need no longer own the DG facilities, but need only "host" facilities owned by others. This enabled manufacturers to have third parties own and operate the generation facility, potentially avoiding not only an up front capital outlay, but also having to operate a facility which may be beyond the scope of their expertise. Second, SB 221 enabled net metering for certain forms of DG, specifically wind, solar and biomass generation, such that the full value of electricity delivered at that site could be realized. Net metering for these specific forms of generation is such that the meter runs backwards when production is greater than that used on site. Senate Bill 315, enacted in May 2012, added waste heat recovery systems to this category of electricity generation.[35] Third, Senate Bills

[31] D. King, "The Regulatory Environment for Interconnected Electric Power Micro-grids: Insights from State Regulatory Officials," Carnegie Mellon Electricity Industry Center Working Paper CEIC-05-08 (2008).
[32] *Id*. at 2.
[33] A. Lovins, E. Datta, T. Feiler, K. Rabago, J. Swisher, A. Lehmann, and K.Wicker, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size* at 2, Rocky Mountain Institute: Snowmass, Colorado (2002); http://www.rmi.org/Knowledge-Center/Library/U01-13_SmallIsProfitable.
[34] A. Lovins, *Small is Profitable* at 2.
[35] Since waste heat recovery systems can be quite large, this may prove controversial. The Public Utilities Commission of Ohio (PUCO) had previously ruled that SB 221 had an implied limitation to the size of the system qualifying as a renewable because, by statute, a net-metered system must be intended to offset part or all of the customer-

221 and 315 also provide for Renewable Energy Credits for generation of renewable energy, including Waste Heat Recovery.

Combined heat and power, however, has no similar program in place. CHP systems can be operated behind the meter in Ohio, but otherwise SB 221, as originally crafted, offered little more help.[36] Utilities do not have to pay the value of electricity delivered when taking power back onto the grid. Instead, they pay what they consider to be the value of displaced power, calculated at the cost of generation at some distant centralized point. The actual electrons may be delivered to a manufacturer down the road 100 yards, but the utility is not required to compensate for the strategic location of the power generation.[37]

This policy, along with the general policy of guaranteeing a "cost plus" recovery on expenditures on the still-regulated grid, has led to the traditional utilities being incentivized to allocate as much of their costs as possible to the grid, and as little as possible to generation. Not surprisingly, we see as a result widely disparate estimates for the cost of power production from centralized generation. Utility accounting under this system, which may not include such things as the anticipated cost of decommissioning a nuclear power plant, typically sets a low generation cost for nuclear power. Yet the cost for nuclear energy generation, by most measurements, is very high.[38]

generator's electricity requirements. However waste heat recovery systems found in industrial settings may offset a large load. The result is that the classification of waste heat recovery systems as renewable under SB 221 may impact the rate of adoption of other renewable systems, such as wind or biomass.

[36] As set forth in Section III(A), *infra*, Senate Bill 315 did provide new incentives for CHP by modifying SB 221 to allow large energy users to potentially obtain a waiver on a rider that is designed to enable utilities to recover costs incurred in meeting the energy efficiency programs set forth in SB 221.

[37] Ohio's original net-metering law was enacted in 1999 as part of the state's electric-industry restructuring legislation. The Public Utilities Commission of Ohio (PUCO) later revised its net metering rules in March 2007, prompted by the federal Energy Policy Act of 2005. Initially, PUCO required utilities to credit customer net excess generation at the utility's full retail rate. However, in June 2002, the Ohio Supreme Court ruled that each utility must credit excess generation to the customer at the utility's unbundled generation rate. *See*: http://energy.gov/savings/ohio-net-metering.

[38] *See e.g*. Vaitheeswaran, *Power to the People*, at 274-290. This policy of allocating costs when possible to the grid rather than to generation, in addition to ensuring the cost-plus return, also ensures that the existing utility generation is highly competitive in the wholesale market.

A. Limited Sales Options for Net Excess Generation Discourage Self-Generation

Unless the on site generation falls under the Senate Bill 221 or 315 definition of a "renewable energy," excess generation must be sold back into the grid at the unbundled "generation rate" for power. Under such circumstances, the return for generation is significantly diminished: there is no value attributed to the strategic location of the generation near a market. If the generation is sufficiently big (above 138 kV), there will likely be an available interstate market, although there will also likely be a queue of companies looking to sell such power therein.[39] Even when such sales are available, however, there will still be no allocation of value for the strategic location of the generation. The result is that excess power placed into the grid is likely to get off-peak, wholesale prices for such electricity.

For systems generating power below 138 kV, however, no interstate market is available. Utilities are required to purchase the power if the generation is from a qualified facility, but only at the displaced generation price (i.e. the "avoided cost of generation"). In Ohio, the avoided cost has been set as low as $0.012/kw-hr.[40] Accordingly, smaller systems will likely not even recover the going rate for unbundled wholesale generation.

[39] K. Wissman, "CHP and PUCO" Public Utilities Commission of Ohio Workshop on CHP (March 2012). *See*: http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/combined-heat-and-power-in-ohio/. The Federal Energy Regulatory Commission would regulate an interstate sale of power by a distributed generator into the wholesale market.

[40] *Id*.

B. Excessive Standby Rates Threaten Combined Heat and Power Generation

Manufacturers that operate or host distributed generation on their property commonly need to have back up power available for those times when the DG is not generating electricity. The Federal Public Utility Regulatory Act (PURPA) requires utilities to provide standby service to its customers who develop "qualified" distributed generation facilities. Rates, terms and conditions for standby power are typically set by the state utility regulatory commission.[41]

Utilities use two sorts of contracts to sell power to large-scale power users. The first is the "Full Requirements Contract," pursuant to which the customer agrees to purchase his entire electrical load from the provider. Under these contracts, there are two principal costs: (1) the Energy Charge, which is the charge for actual consumption of kW-hrs), and (2) the Demand Charge (sometimes also called a "Capacity Charge,")[42] which is a charge for the incurred cost of maintaining a sufficient peak demand delivery capability. The latter charge is priced on a per kW basis, and is based on a peak demand interval of between 15 to 30 minutes during a given period, commonly one month.[43]

The second type of power purchasing contract is for those customers who generate a portion of their own electricity on site. These "Partial Requirements Contracts" include provisions that address the need for not only supplying the normal shortfall between requirements and on site generation ("supplemental power"), but also supplying back up power during periods of scheduled or unscheduled outages. These sorts of contracts have four categories of charge: (1) supplemental service, charged on a kW-hr basis for actual power used under a rate schedule; (2) scheduled back up service, for those times when maintenance is scheduled (usually during non-peak hours); (3) unscheduled back up service, for when the customer's system goes off line unexpectedly, and usually immediately; and (4) Capacity Charge, which is a per kW cost for capacity reserved to be delivered in the event that the customer has to be served for any

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[41] 18 CFR Section 292.303(b) ("obligation to sell to qualifying facilities.")

[42] Demand charges are used to recover the capital costs of maintaining the capacity necessary to meet the customer's peak load requirements, but also the system as a whole. Residential and small commercial contracts oftentimes do not separate Demand and Energy charges, but instead roll them into one charge. *See* R. Weston, et al, "Standby Rates for Customer-Sited Resources," U.S. Environmental Protection Agency, Office of Atmospheric Programs, at 3 (December 2009); www.epa.gov/chp/documents/standby_rates.pdf. Unfortunately, the electricity industry does not always have uniform terminology for its different charges, and this creates considerable confusion for those who are trying to understand billing protocols. *See e.g*. http://www.teachmefinance.com/Scientific_Terms/Capacity_charge.html.

[43] G. Miller, C. Haefke and J. Cuttica, "Iowa On-Site Generation Tariff Barrier Overview," at 7, Environmental Law & Policy Center (April 2012). Miller, et al, also refers to "capacity" charges as "reservation" charges. There are also other smaller charges, such as a fixed "Customer Charge" for administration costs, and for taxes.

length of time at the maximum load possible.[44]

A more recent study characterizes these four groups as “supplementary, backup, maintenance and interruptible power” – all of which can be grouped together in a single “standby tariff.” [45] For purposes of determining a standby rate, the author considers three charges: (1) fixed charges, (2) volumetric charges and (3) demand charges. Fixed charges are intended to cover infrastructure supply and delivery costs, regardless of the customer’s actual monthly requirements. Volumetric charges are set by the actual energy consumed, and can be metered. The demand charges are set by the maximum power used during a specified time period, and are intended to compensate the utility for the fixed costs of infrastructure shared with other customers, in proportion to the capacity each requires.[46]

Simplicity and transparency in standby rate design is apparently not so easy to accomplish. Disaggregating and determining the cost components of a standby rate can make for a complex and confusing rate structure. Any of these charges can bear portions of what amounts to a “standby charge.” However it appears to be the demand/capacity (depending upon the nomenclature) charge that creates the most controversy.

It is within this fee that many argue utilities overcharge. This is especially so for those where demand/capacity charges are based upon a “ratchet” device. Ratchets commonly set demand/capacity charges at the highest priced power used in any interval within a given period of time (for example, a year) – with the interval oftentimes as small as fifteen minutes.

At the outset, it should be noted that the public policy case for the assessment of *any* standby fee is by no means clear. Utilities justify them by arguing that (1) they are necessary to recover the costs associated with providing the ability to generate and deliver peak power in the event of an outage, and (2) they prevent cross-subsidization of DG customers by non-DG customers.[47] Further, utilities argue, customers with DG systems have no obligation to generate power; if a customer decides to discontinue DG operations, the utility could, in theory, be required to serve that full load on an ongoing basis.

Proponents of DG argue that these arguments are self-serving. First, standby does not create a material cost for the utilities. Only the last several hundred feet of wire is typically unique to the end user – the vast majority of the grid is spread among multiple users. Moreover, it is highly unlikely that all DG would malfunction at a “coincident peak time.” In short, having all customers paying for maximum back up peak power assumes that all customers will have a simultaneous, unplanned DG outage – a scenario that defies logic. Second, non-DG users will actually benefit from DG; therefore, no cross-subsidization exists. Any measures

[44] *Id*. at 7-8.
[45] T. Stanton, “Electric Utility Standby Rates: Updates for Today and Tomorrow” at 2, National Regulatory Research Institute (July 2012).
[46] Id. at 8-9.
[47] S. Casten, “Are Standby Rates Ever Justified? The Case Against Electric Utility Standby Charges as a Response to On-Site Generation,” at 58, *The Electricity Journal*, 1040-6190/03 (Elsevier Science Inc. May 2003).

that reduce the need for repair or construction of distribution and transmission assets inures to the benefit of all users, not just the DG end users.[48] At an average cost for grid development of approximately $1300-1400/kW[49] -- a cost close to that of installing CHP – it is easy to see how ratepayers as a whole benefit from DG. If, for instance, some or all of the planned $1 billion First Energy investment into upgrading the grid could be avoided by ramping up DG, this avoided cost would be shared by all of its customers. Indeed, according to one expert, the only cross-subsidization going on with the build out of DG under current regulations is by the ratepayers to the utilities.[50]

Nevertheless, regulatory bodies are inclined to accept the utility arguments for the need for standby fees. The problem, then, is to determine what charges are reasonable under the circumstances – and what charges can be borne by distributed generators without rendering the project unviable. The Environmental Protection Agency has determined that unless the customer, by installing CHP, can avoid at least 90% of its otherwise applicable rate costs, CHP will not be viable.[51]

Unfortunately, this number is one that is not commonly met with existing standby charges in most jurisdictions. In a study by the Midwest Clean Energy Application Center, avoided cost percentages from utilities in Iowa, for instance, ranged from a low of 74% to a high of 81% among Iowa investor owned utilities.[52]

Avoided cost, in this context, is that of a kW-hour not purchased from a utility due to on-site generation. The closer the avoided cost comes to matching the price that would have been otherwise paid under a full requirements contract, the more the customer maximizes his savings with the CHP project. These conditions are most likely met, according to the EPA, when (1) demand charges are small in relation to the energy costs; (2) demand charges are not ratcheted, or if they are, the window for determining the ratchet is reasonable; and (3) the supplemental contract prices for actual energy consumed are similar to what they would have been under a requirements contract.[53] Accordingly, the EPA admonishes state regulators to "pay close attention to ensuring that the design of partial requirement rate structures captures the economic and environmental benefits of reduced energy consumption."[54]

Ohio does not have a statewide policy on standby rates[55], and standby fees are in part subject to private negotiations. The

[48] Casten, supra at 60-61. See also Miller, supra, at 8.
[49] Casten, supra at 61.
[50] *Id*. at 62. For a counter perspective, *see* J. Morrison, "Why We Need Standby Rates for On-Site Generation," *The Electricity Journal*, at 74-80, 1040-6190 (Elsevier Science Inc. October 2003).
[51] Weston, et al, U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, "Standby Rates for Customer-Sited Resources (Washington D.C. 2009).
[52] Miller, *supra* at 17. At the time of this report, The Midwest Clean Energy Institute had undertaken no similar study of standby rates in Ohio.
[53] Weston, Standby Rates for Customer-Sited Resources, at 17.
[54] *Id*.
[55] However this may change. In the winter of 2013 the Public Utilities Commission of Ohio had opened a docket for the purpose of taking comments on regulations controlling standby rates for CHP. *See* In the Matter of the Commission's Review of Chapter 4901:1-22 Ohio Administrative Code Regarding Interconnection Services, Case Record 12-2051-EL-ORD.

American Electric Power Company provides standby energy, but the commodity itself is purchased from another provider. The standby fee is demand based, and billed from the contract demand. Cincinnati Gas & Electric Company (Duke Energy) also has no specific standby rate, however charges fees based on peak demand.[56] For Cincinnati Gas & Electric, the demand rate will be at least 85% of the highest monthly kilowatt demand as established in the summer period.[57]

Ohio Edison's Public Utilities Commission of Ohio tariff allows charges of up to $3.02 per kW for secondary voltage “Backup Capacity Reservation and Daily Backup Power.” Accordingly, based on this rate, a 25 MW industrial co-generation or commercial building CHP project could pay a monthly demand charge of $75,500, with total annual standby costs of $906,000.[58]

The Cleveland Illuminating Company has both “capacity” and “demand” charges for supplemental contracts. The “Capacity Reservation Charge” is broken down into “transmission and distribution” and “generation” charges, and is billed on a per kW basis, depending upon the voltage. Demand charges are broken down into two categories: (1) supplemental demand and (2) back up demand. Supplemental power is set by the rate schedule. Back up demand, which covers both back up and maintenance situations, allows the customer to choose one of two charge methods, the latter of which is eligible on only 15 days per year. On top of these charges, there is a “maintenance charge,” plus “energy,” “reactive demand,” “emergency power” and “customer service” charges.

The minimum charge for a month under the supplemental contract is “the sum of the Capacity Reservation charge multiplied by the Capacity Reservation, plus the Customer Charge, plus the minimum charges of any applicable Rate Schedules.” So, if no electricity is taken, the minimum monthly charge for a 25 MW high voltage system would be the customer charge ($95.59) plus $3.38(25,000) = $84,595.50.[59] This totals over $1 mm per year in back up charges for a system that never even uses back up power – clearly a number that will have a chilling effect on any development of CHP.

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[56] *See* Energy & Environmental Analysis (2008); http://www.eea-inc.com/rrdb/DGRegProject/States/Newsite/OHrevised.html.

[57] *Id*.

[58] L.Traves, “Another Bad Energy Policy for Ohio,” Crain’s Cleveland Business, May 29, 2012; http://www.crainscleveland.com/article/20120529/BLOGS05/120529844

[59] Partial Service Schedule, CEI 2012 Electric Service – 2011 PUCO Tariff at Original Sheet No. 46, PUCO No. 13 pages 1-9. The CEI Partial Service Schedule can be found at: See: https://www.firstenergycorp.com/content/customer/customer_choice/ohio_/ohio_tariffs.html

IV. Strategies for Enabling Manufacturing-Based Distributed Generation in Ohio

A. Energy Efficiency Credits Under Senate Bills 221 and 315

Ohio Senate Bill 221, passed in 2008, requires that investor owned utilities in Ohio undertake energy efficiency improvements, among other mandates.[60] Those requirements are set forth as benchmarks. The costs of meeting the mandate are passed along to ratepayers through a rider, known as the DSE-2. To date, the DSE-2 rider has been relatively small. However, as the requirements to improve efficiency increase over time, and as the easiest, least expensive work is completed, the DSE-2 rider is expected to rise.

Large-scale electricity users, like manufacturers, can obtain a waiver for some or all the DSE-2 rider if they undertake energy efficiency improvements on their own. Under SB 221 such manufacturers qualify as "mercantile" consumers, and as such, are eligible to follow a protocol leading ultimately to the Public Utility Commission approving the waiver.

However SB 221 did not include any sort of incentive for manufacturers to utilize waste heat or combined heat and power systems, either under the renewable portfolio or under the energy efficiency portfolio. This oversight was addressed recently by the passage of Senate Bill 315. Under SB 315, Waste Energy Recovery (WEH) systems are classified as "renewable" generation for purposes of qualifying for Renewable Energy Credits (RECS), and, importantly, for net metering purposes.[61] SB 315 will have a catalyzing effect on the considerable WER potential market in Ohio, especially for large scale, energy intensive manufacturing where current processes generate large amounts of waste heat.

But SB 315 did not include natural gas-fired CHP in the renewable category.[62] Accordingly, CHP enjoys neither the ability to generate RECS nor the ability to convert the value of surplus power to the value of electricity near the site of consumption. SB

[60] SB 221 requires that investor owned utilities obtain 12.5% of its energy generation from renewable sources by 2025. Benchmarks were included on a year-to-year basis designed to reach that goal. SB 221 also requires that utilities undertake efforts to meet a cumulative energy usage savings, compared against a base load set in 2008, of 22% by 2025. The energy usage savings is also benchmarked on a year-to-year basis. *See* Ohio Revised Code Section 4928.01 *et seq*.

[61] Waste heat recovery systems – called Waste Energy Recovery under SB 315 -- can also be placed under the energy efficiency category, which may, under certain circumstances, be of more value than being classified as a renewable. A waste energy recovery system is a facility that generates electricity through the conversion of byproduct heat from an industrial process. *See* Ohio Revised Code Section 4928.01 (36).

[62] Presumably the reason CHP was not included as a renewable is because, unlike for WER systems, which use byproduct heat from existing industrial processes, gas-fired CHP introduces fossil fuels into the system. *See e.g*. T.Odonnell, et al, "Governor Kasich Signs Far-Reaching Energy Bill Into Law," Bricker & Eckler Bulletin, June 14, 2012; http://www.bricker.com/services/service-details.aspx?serviceid=140

315 did, however, provide that CHP (and WEH) would qualify as a form of energy efficiency under the portfolio requirements as set forth in SB 221. As the costs associated with meeting the SB 221 energy efficiency mandates increase over time, this could prove to be a significant incentive to develop CHP in distributed settings.

Unfortunately it appears that manufacturers will have only a limited ability to take advantage of this incentive. Normally a manufacturer who implements energy efficiency measures enjoys the waiver of the DSE-2 rider on the remaining load he purchases from the utility. But if the manufacturer goes off the grid by adding CHP, or otherwise reduces its load to a small supplemental contract, then the DSE-2 rider waiver has little value. The only way for a manufacturer to obtain value from the waiver under these circumstances is if it aggregates its energy efficiency portfolio with other consumers who otherwise have no ability to obtain a waiver, and they in turn pay some value to the manufacturer for this purpose.

The utility of course can install CHP itself to meet the standards, and then sell power therefrom through the grid. Indeed, this would also enable utilities to not lose the sale, which of course is the principal reason why utilities oppose DG – their profits are tied to their sales volume. However so long as regulatory law guarantees a rate of return for the grid but not for generation, utilities will in general prefer using increasing centralized generation and grid capabilities over developing their own distributed generation.

If manufacturers hope to monetize the value of CHP under the energy efficiency portfolio set forth in SB 221, it may have to engage the public utilities commission in developing a creative way for these credits to be passed through to the manufacturers who develop CHP. If no such strategy can be found, it may have the effect of thwarting the intent of the legislature in passing this particular section of SB 315.

Senate Bill 221 also includes qualifying CHP facilities as an "advanced energy" technology, which technologies are also required to be adopted by the investor-owned utilities in a manner similar to how renewable is to be adopted. However that Bill did not set benchmarks to accomplish this. Accordingly it is difficult to ascertain what, if any, value can be attributed to a CHP facility that qualifies as advanced technology under SB 221.

Finally, Investor Owned Utilities can also incentivize CHP through their rebate programs designed to encourage energy efficiency, which could be taken in lieu of the DSE-2 rider waiver. While the costs of the DSE-2 remains highly speculative, it appears that the rebates will not, over time, be as valuable as a waiver of the DSE-2 rider, at least as most experts have been projecting the rider costs. But if the waiver has little value to the manufacturer who is significantly reducing his utility load through CHP, this rebate could be of significant value. Investor Owned Utilities are, however, likely to resist offering rebates for CHP facilities that reduce the consumer to supplemental contracts, since that would in turn reduce sales.

B. Strategies for Funding Distributed Generation

1. Financing Options

Manufacturing faces another substantial impediment when it comes to adopting DG. Upfront investments in CHP projects are high, and project returns often do not correspond to those required by manufacturers or commercial developers.[63] Unlike with universities, hospitals or cooperative utilities, where DG is likely to find its earliest opportunities, manufacturing does not have a long-term mandate to continue operations. It can be difficult enough to get a manufacturer to agree to take on plant maintenance as part of its business portfolio, but when discussions are raised about commitments that will run 10 to 15 years out, manufacturers become skittish. This is especially so because natural gas companies no longer offer fixed price contracts more than five years out, leaving the last 10-15 years of plant operation susceptible to an often volatile natural gas market.[64] This certainly adds to the risk manufacturers face in converting coal boilers to gas-fired CHP.

Usually one sees this issue manifest itself as a "competition for capital" – projects with long-term payouts simply cannot compete effectively for capital investment within a company. One way around this "payout" problem is for third parties to own and operate the plant. This also tends to resolve the problem of manufacturers having to become plant operation experts. However it also involves having a company commit to a long-term power purchase agreement – an obligation that could become problematic in the event that manufacturing is cut back or the plant is forced to close.

The critical element to manufacturing-based CHP finance, inevitably, is heat generation. Manufacturers may not be keen to make long-term investments into electricity generation (or purchases), but they have little choice in most instances when it comes to generating heat. Unless there is a thermal utility nearby capable of delivering their steam requirements under a short-term contract, the manufacturer will have to undertake some form of a capital commitment to acquire steam regardless. Accordingly, the best time for manufacturers to look at CHP is when they need to replace or upgrade their heat generation system. With the onset of the new Boiler MACT rules, the time may well be now for many manufacturers.

[63] T. Kerr, "Cogeneration and District Energy," at 20, International Energy Agency (2009). A commonly used figure for the required payout for manufacturers is two years.

[64] When natural gas first became available as a fuel, it was produced as a byproduct of oil production, and as such was oftentimes flared if no market existed. This led to a nationwide effort to find markets for natural gas. Producers and pipeline companies alike routinely entered into 20-25 year contracts at fixed rates, with little price adjustment. By the mid 1970's, prices had skyrocketed for natural gas, as did costs for production, and those saddled with supplying these contracts were in financial trouble. In the 1980's, the reverse happened – prices crashed, and end users who were paying long-term prices on gas contracts experienced the same sort of financial distress the suppliers did in the 1970s – leading to years of "take or pay" litigation. The result of all of this turmoil caused by market fluctuation is that few distribution or transportation companies will now enter into long-term contracts for fixed prices. However with the advent of shale gas, and the resulting current gas surplus, this may change. Indeed, in places like Ohio, where gas production is rich in liquids, gas is produced once again as a byproduct – a circumstance echoing the advent of the long-term gas contracts of the 1960's.

Manufacturers that face uncertainty in investment into a CHP system – or that face a shortage of available capital to invest – will look for innovative financial strategies to enable CHP projects. These will include state and federal programs for subsidized loans, loan guarantees, and the use of energy service companies (ESCOs).

There are several programs at the federal and the state levels to assist financing of CHP systems. These programs typically fall under the categories of: loans and loan guarantees, bonds, tax credits, tax exemptions, grants, rebates, and other credits and incentives. At the federal level programs are offered by the U.S. Department of Energy (DOE), the Department of Treasury, the Department of Agriculture, and the Environmental Protection Agency. At the state level, programs are offered by the Ohio Department of Development - Office of Energy, Ohio Air Quality Development Authority, and investor-owned electric utilities such as Dayton Power and Light & First Energy Ohio. A significant number of the programs are geared towards financing energy efficiency capital expenditures and renewable energy production. However the DOE, along with other Departments and State Agencies, have several incentives specifically for developing combined heat and power projects.

The most notable resource at the federal level is the DOE Loan Guarantee Program. Manufacturing is one of the three categories for which the DOE actively promotes projects. With a project target size of $25 million and up, this program may be suitable for financing large manufacturing CHP projects. At the state level the Ohio Department of Development – Energy Loan Fund is the most suitable for manufacturers willing to invest in a CHP system. The Energy Loan Fund provides financing through federal and state funding resources to eligible entities for energy efficiency and renewable energy projects. The projects funded through this program must result in energy savings of at least 15 percent. In addition to the Energy Loan Fund, The Ohio Air Quality Development Authority (OAQDA) provides assistance for new air quality improvement projects in Ohio.

A list of some of the programs available to support CHP project financing include[65]:

Federal

- U.S. Department of Energy – Loan Guarantee Program
- Qualified Energy Conservation Bonds

State of Ohio

- Ohio Department of Development – Energy Loan Fund
- Ohio Job Stimulus Plan (Advanced Energy Program)

[65] *See e.g.* http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06F&re=0&ee=1; http://development.ohio.gov/Energy/Incentives/EnergyLoanFund.htm; http://development.ohio.gov/Energy/Incentives/documents/EnergyRLFOverviewGuidelines20120420.pdf; and http://www.ohioairquality.org/advanced_energy_program/. *See also* C. Cain and A. Samanta, "New Energy for Older Cities," at 19, Northeast Midwest Institute (Sept. 2012), http://www.nemw.org/index.php/news-archive/342-nemwi-releases-report-on-new-energy-for-older-cities

- Investor Owned Utility Rebate Programs
- Ohio Air Quality Development Authority

Another option for manufacturers for obtaining financing is to lease, rather than to purchase, the CHP system. Leasing can allow for the transfer of tax advantages, such as credits or accelerated depreciation, to the party that can most benefit from them.[66] The best strategy for manufacturers to lease such systems is to identify readily leasable standard gas-fired gensets, micro-turbines, and full size gas turbines as the basis of their programs. By avoiding custom-designed generators, manufacturers can expect on the order of 80% of the cost of a CHP installation to be covered by a lease, since these units can easily be recovered by the lessor and re-used. The susceptibility of the units to recovery also reduces the risk of stranded assets, and thereby increasing the likelihood of getting a shorter-term lease (or power purchase agreement, for that matter).

Manufacturers may also expect support from their gas supplier, who can provide both an attractive supply contract for CHP, and possibly some support for the installation. Ohio's large gas suppliers such as NiSource-Columbia and Dominion, are likely to be highly interested in supporting incremental CHP use – especially as they continue to invest heavily in developing midstream infrastructure for the Utica and Marcellus Shale natural gas extraction.

Programs to monetize environmental revenue streams may also provide additional funding for DG, including CHP. In particular, under certain circumstances Emission Reduction Credits (ERCs) generated from a CHP facility may be "banked" under Ohio regulatory law, and emission reductions of nitrogen oxides, sulfur dioxide, volatile organic compounds and fine particulates can be tracked, accounted for, and ultimately traded.[67]

2. Tax Incentives

Tax incentives also provide a significant resource for financing a CHP or other DG project. Incentives that are in the form of tax credits have the most value, especially those that are convertible to cash. However accelerated depreciation schemes also can have a significant impact on financing. The federal government also includes an "Accelerated Modified Accelerated Cost-Recovery System" for depreciating capital investment costs for clean energy.

Manufacturers may qualify for the Business Energy Investment Tax Credit, a federal energy tax credit totaling up to 30% of the total price for renewable distributed generation systems and up to 10% for gas-fired CHP systems. Qualifying renewable technologies include geothermal heat pumps, solar energy systems, wind energy systems, and fuel cells. These systems

[66] *See*: "Procurement Guide: CHP Financing" at 12, U.S. Environmental Protection Agency, Combined Heat and Power Partnership; www.epa.gov/chp/documents/pguide_financing_options.pdf.

[67] *See*: Ohio Environmental Protection Agency "Emission Reduction Credit Banking Program", http://www.epa.state.oh.us/dapc/ERC/deposit.aspx *See also*: United States Environmental Protection Agency, CHP Partnership, "Monetizing Environmental Benefits," (March 2012); http://www.epa.gov/chp/funding/monetizing.html.

must be put into service by December 31, 2016 in order to qualify for the tax credit.[68]

Eligible CHP projects include systems of up to 50 MW that exceed 60% efficiency, and are subject to certain limitations and reductions for larger systems. The credit is equal to 10% of expenditures, with no maximum limit stated. Biomass CHP systems may be eligible for the 30% tax credits.[69]

An example of a State-based tax incentive is Ohio's Qualified Energy Project Tax Exemption for businesses and industry, which "provides owners (or lessees) of renewable, clean coal, advanced nuclear, and cogeneration energy projects with an exemption from the public utility tangible personal property tax." Applicants with "clean coal, advanced nuclear, and cogeneration projects" must apply prior to December 31, 2013 to potentially qualify for the tax exemption. "Qualified Energy Projects" will be tax exempt as long as certain criteria continue to be met.[70]

For qualifying projects, OAQDA financing may also lead to tax benefits. The OAQDA can provide a 100 percent exemption from the tangible personal property tax, real property tax, and a portion of other taxes, such as the sales and use tax. Furthermore, interest income on bonds and notes issued by OAQDA is exempt from state income tax.[71]

[68] *See:* http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1 (citing 26 USC § 48). *See also*: United States Department of Energy, "Tax Incentives for Energy Efficiency (2011); http://www.energysavers.gov/financial/70010.html.

[69] *Id*.

[70] Ohio Department of Development, "Qualified Energy Project Tax Exemption," (2011), http:/development.ohio.gov/Business/AlternativeEnergyExemtption.htm.

[71] ACEEE's Energy Efficiency State Ranking (2010); http://www.aceee.org/energy-efficiency-sector/state-policy/ohio/207/all/195. Ohio ranked 24th among the 50 states, according to the ACEEE.

C. Microgrids

One way to capture the full potential of DG is through a distribution system architecture called a "microgrid." Although some do not distinguish between DG and a microgrid, a microgrid consists of much more than a single point of generation. Like DG, however, a microgrid should have the ability to isolate itself (islanding) from the utility's distribution system during a grid disturbance. This is accomplished through power electronic interfaces and a single, high-speed switch. During a disturbance, the microgrid can be separated from the utility's distribution system, isolating the microgrid's load from the disturbance without harming the integrity of the utility's system. Islanding has the potential to provide a higher level of reliability to end users than that provided by the macrogrid system as a whole. Once normal conditions are returned, the microgrid automatically resynchronizes and reconnects itself to the grid.[72]

The microgrid is capable of using an assortment of power generation resources, including renewable generation. However the most common use considered is in those areas where heat generation is also required, since this is where efficiencies can be maximized. Accordingly, the typical microgrid uses DG and cogeneration to provide both electricity and heat to multiple customers joined together on a local network. It is interconnected with the local utility a single point, and operates in parallel with that system. The most successful forms of micro-grids will be "smart," meaning they will provide their customers with the ability to manage their demand, so as to optimize performance and cost.[73] In addition, they will enable the grid managers to remove common causes of market failure in centralized generation, such as an underinvestment in energy efficiency, by retaining responsibility for not only generation and fuel choices, but also for end-use equipment, storage capacity, and waste stream opportunities.[74]

Microgrids also offer potential advantages in power quality and reliability (PQR); indeed, one analyst calls this the fundamental distinction between the micro and macrogrids.[75] Utilities place much effort and value on producing high-quality, homogeneous power, sufficient to meet the needs of most end-users. End-users, in turn, try to build their usage models around this quality. Notwithstanding this, end-users, especially manufacturers, have heterogeneous quality requirements, and the microgrid offers a way to tailor quality to their needs. Indeed, most PQM problems originate in the distribution

[72] A. Neville, "Microgrids promise improved power quality and reliability," at 1, *Power* (June 15, 2008), http://www.powermag.com/business/Microgrids-promise-improved-power-quality-and-reliability_134_p3.html. For purposes of this discussion, non-grid connected microgrids are not considered, although these may have some application in more isolated areas.

[73] D. King, "The Regulatory Environment for Interconnected Electric Power Micro-Grids: Insights from State Regulatory Officials," Carnegie Mellon Electricity Industry Center Working Paper CEIC-05-08, at 3 (May 2008) (www.cmu.edu/electricity).

[74] C. Marnay, H. Asano, et al, *Policy Making for Microgrids,* IEEE Power & Energy Magazine at 67 (May/June 2008).

[75] Neville, "Microgrids promise improved power quality and reliability" at 2.

network, and the closer the control over PQM is to the point of use, the easier it is to control. Unfortunately, however, under current economic models, PQR is not valued,[76] which is a significant deterrent to the adoption of microgrids.

Microgrids maximize the value of both power and heat provided by co-generation because the power and heat are used close to the location where they are generated. The generator is able to sell the power to a neighboring customer without having to go through the local utility. Microgrids also improve efficiency in distribution of energy and mitigate environmental consequences of generation. In addition, they can help utilities reduce equipment expenditures and help with asset utilization.[77] Unfortunately, in most states, microgrids are allowed only in limited circumstances under current regulatory schemes.

Generally, if the microgrid is controlled and operated by a utility, State regulators will view it with favor. If, on the other hand, it is controlled and operated by the customers or the generator, or by an independent firm that manages the microgrid, it will be viewed unfavorably. If the interconnection to the grid is high voltage, it may or may not be governed by a different set of rules. But it does enable the microgrid to participate in the wholesale electric market. This would introduce some regulatory components or rules that may be different, such as those imposed by the Federal Energy Regulatory Commission or the Regional Transmission Organization.[78]

[76] *Id*. at 3.
[77] King at 2.
[78] *Id*. at 4.

There is considerable uncertainty about the applicability of utility tariffs and interconnection procedures for microgrids. Utilities, of course, are concerned about safety issues as well as system stability. Procedures can and have been designed by such groups as the IEEE, PJM and FERC to mitigate problems. Even so, there is uncertainty in how these standards will be applied in the various states. [79]

In 2011, a significant step forward was taken by the development of the IEEE P1547.4 standard, which does much to mitigate utility safety and other concerns over grid-connected microgrids. Instead of viewing microgrids as potentially disconnecting their loads, now they can be viewed as a source of demand response.[80] However IEEE P1547.4 is, to date, a voluntary compliance rule in most jurisdictions.

In Ohio it is uncertain whether microgrids can be built at the distribution level.[81] It is also unclear whether Ohio's current interconnection procedures or requirements would be applicable to microgrids.[82] Clarity will be required in the regulatory law governing microgrids before they can be advanced as a macrogrid-

[79] *Id*. at 8.
[80] P.Carson, "Grid-tied microgrids: a utility's best friend?" *Intelligent Utility* (January 3, 2012), http://www.intelligentutility.com/article/12/01/grid-tied-microgrids-utilitys-best-friend.
[81] King at 16. Utilities, however, can undertake micro-grid development. AEP has, for instance, taken some first steps towards a micro-grid of sorts: they have installed community electricity storage devices (lithium ion batteries) in a few test locations. *See* https://www.aepohio.com/save/demoproject/newtechnology/CES.aspx.
[82] *Id*.

connected enabler of CHP or other distributed generation. Because of Ohio's regulatory laws governing investor-owned utilities, cooperative and municipal utilities are likely to move more quickly than manufacturers to take advantage of the microgrid's capabilities to deliver distributed generation.

D. Decoupling Electricity Sales from Utility Profits

One strategy that may help enable the adoption of DG is a regulatory device known as "decoupling." Utility regulators have long recognized the fundamental conflicts that exist in a regulatory system that seeks to reward utilities for both selling electricity and for encouraging consumers to conserve. Under traditional regulation, utilities make more money when they sell more electricity. But this is hard to reconcile with public policy objectives for using less electricity, or at least using electricity more efficiently. This dilemma is known as the "throughput incentive problem."[83]

Complicating this issue further is the phenomenon known as "Jevon's Paradox," (or sometimes, the "rebound effect") which states that the more one improves efficiencies in use of resource, the more one encourages new and additional uses of that resource.[84] Many have argued that state-regulated energy efficiency programs are doomed to failure due to Jevon's Paradox. A common example given is result of the federal program to improve energy efficiency in refrigerators, which, instead of reducing the electricity consumed from refrigeration, led to a proliferation of multiple refrigerator households. The counter argument to this is that energy efficiency programs are not necessarily about reducing electricity consumption, but about reducing waste. If two refrigerators in every home improve the quality of life in those homes (and perhaps also reduces food waste), then the goals of the energy efficiency programs have been met. In short, energy efficiency programs should be less about reducing energy consumption and more about reducing waste. In the end, we know what utilities think about Jevon's Paradox; they never voluntarily put demand side energy efficiency programs in place. To the extent that Jevon's Paradox is a real phenomenon, there would be no need for decoupling electricity throughput from profit – energy efficiency, distributed generation and demand response all should act to increase throughput and therefore utility profits under traditional regulatory schemes.

Jevon's Paradox is also insufficiently proven[85] to convince policy makers that programs like energy efficiency, distributed

[83] J. Lazar, F. Weston, et al, "Revenue Regulation and Decoupling: A Guide to Theory and Application," The Regulatory Assistance Project, at iv (June 2011).

[84] *See e.g*. D. Owen, "Annals of Environmentalism: The Energy Efficiency Dilemma" at 78, *The New Yorker*, December 18, 2010. URL: http://www.newyorker.com/reporting/2010/12/20/101220fa_fact_owen. William Stanley Jevon was an English economist. In his 1865 book entitled the "Coal Question," he observed that improvements in efficiency in coal burning technology had led to a proliferation of new coal burning uses, and a resulting increase in coal consumption.

[85] *See e.g. Think Progress*, "Debunking Jevon's Paradox," February 16, 2011; http://thinkprogress.org/climate/2011/02/16/207532/debunking-jevons-paradox-jim-barrett/?mobile=nc

generation or demand response are really encouraged under current utility revenue models. As a result more and more policy makers are coming to believe that the throughput model for measuring utility profits is not in the best interest of society. Instead, these policy makers have sought a model that decouples profits from throughput and realigns them with what they believe to be in society's interests.

Under traditional regulation, a utility's recovery of expenses (revenue requirement) is based upon determining the net equity investment (i.e. expenses) and adding thereto an allowed rate of return, plus taxes.[86] The rate case price is then determined by dividing that number by the sales in kWhs for the period of time the expenses were incurred. Expenses are broken down into production and non-production costs. Production costs are composed of fuel and purchased power costs, with some operation and maintenance and third party transmission expenses included. These expenses will vary directly with consumption. Non-production costs are those that are related to the delivery of electricity – transmission, distribution and retail services. This includes non-production operations and maintenance, depreciation on equipment and interest on debt. These normally do not vary much with consumption, at least not in the short run.[87]

There are several ways to approach decoupling, all of which share a goal of recovering a defined amount of revenue, independent of sales volume.[88] But the essential element is the migration of certain cost items into or out of the production cost recovery mechanism. Full decoupling insulates the utility's revenue collections from any deviation of actual sales from expected sales. Any deviation results in an adjustment of revenue to match a pre-arranged budget, such as the revenue recovered in the last rate case.

Under a decoupling scheme, a customer's bill is not decoupled from consumption. Accordingly, the customer retains a financial incentive to reduce energy consumption, while the utility retains its ability to recover costs and revenue.[89]

Decoupling eliminates a strong disincentive that utilities have to invest in energy efficiency. It does not, however, by itself incentivize distributed generation. It merely removes the natural hostility utilities might otherwise have for DG, since it no longer impacts near term profits.[90] As of 2009, 17 states have implemented decoupling mechanisms, including 28

[86] Lazar, "Revenue Regulation and Decoupling", at 4. If a utility with $100 mm in expenses is allowed a 10% rate of return, and it pays taxes at a 35% rate, its total revenue requirement is $115.38 mm ($100 mm + $10 mm + $5.38 mm). To get to the rate case price, the revenue requirement is then divided by the total sales in kWhs for the year. So if there is 1 billion kWhs delivered in the year those expenses are incurred, the $115.38 mm is divided by that number, leaving a rate price of $0.115/kWh. *Id.*

[87] *Id*. at 4-6.

[88] *Id*. at 8. Utah, Oregon, California, Hawaii and Massachusetts are among some of the states that employ some aspects of decoupling. *Id.* For a full explanation of the different decoupling mechanisms, *see id*. at 8-20.

[89] National Renewable Energy Laboratory, "Decoupling Policies: Options for Encouraging Energy Efficiency," (Dec. 2009); www.nrel.gov/docs/fy10osti/46606.p

[90] Lazar, "Revenue Regulation and Decoupling," at 12.

natural gas distribution utilities and 12 electric utilities. Six other states are in the process of implementing decoupling mechanisms. California, New York, Maryland and Wisconsin had decoupled both electricity and natural gas.[91]

In Ohio Senate Bill 221 established the authority for the Ohio Public Utilities Commission to establish rules for revenue decoupling mechanisms for electric distribution utilities, pursuant to Ohio Revised Code 4926.66(D)). Decoupling can be included in an electric utility's "Energy Security Plan" (*see* ORC 4928.143(B)(2)(h)). However to date it does not seem that any utilities in Ohio have sought to implement a full decoupling program.

[91] NREL, "Decoupling Policies," *supra*, at 6.

E. Self-Generation Investment Programs

California has the best-known incentive program for self-generation: the Self-Generation Incentive Program (SGIP). It provides rebates for customers of utilities for installing qualifying distributed generation technologies. The SGIP "represents a publicly funded rebate program that is intended to help reduce the price of DG technologies to the point where these technologies are competitive in the market place without incentives."[92] The program was originally designed as a "peak load reduction" strategy, as a response to the energy crisis California incurred in 2001.[93] According to an independent study undertaken by Itron, Inc., the benefits to society have met or exceeded the costs incurred for nearly all the DG technologies approved, with the notable exception of storage technologies.[94]

The technology installed should be designed to meet some or all of the on-site electricity requirements, with the potential for exporting some power back to the grid. Combined heat and power is among those technologies that qualify, although renewable technologies may enjoy greater support, depending upon their ability to achieve greenhouse gas emission reduction.

The program administrators are the three investor owned utilities in California, plus the California Center for Sustainable Energy. California Senate Bill 412 extended the SGIP from January 1, 2012 to January 1, 2016. Additionally, Senate Bill 412 revised the SGIP, making eligibility for the program based on the potential for greenhouse gas emission reductions.

The California SGIP is a California Public Utilities Commission program that incentivizes "clean, efficient, on-site distributed generation."[95] The generation system is installed on the customer side of the meter.[96] Most of the participants are commercial or industrial, with some limited participation from residential, government and other sectors.[97]

The 2011 SGIP budget was around $77 mm in total. About 75% of the funding was allocated for renewable and emerging technologies, with the other 25% designated for non-renewable technologies.[98] Funds for the SGIP are acquired through fees charged to the ratepayers for each utility company. As of December 31, 2010, a total of 441 projects

[92] California Public Utilities Commission, "Self Generation Incentive Program Handbook," (2007), http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/aboutsgip.htm. A few states, including California, also provide for price control on natural gas used in DG projects.
[93] *See* Itron, Inc., "CPUC Self-Generation Incentive Program: Cost Effectiveness of Distributed Generation Technologies" (2011), at 3-9, http://www.cpuc.ca.gov/NR/rdonlyres/2EB97E1C-348C-4CC4-A3A5-D417B4DDD58F/0/SGIP_CE_Report_Final.pdf
[94] *Id*. at 3-26.

[95] California Public Utilities Commission, "Self Generation Incentive Program Handbook," (2011), http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/.
[96] *Id*.
[97] *See* Itron, Inc., "CPUC Self-Generation Incentive Program: Cost Effectiveness of Distributed Generation Technologies," *supra*.
[98] *Id.* at 68.

had been completed under the SGIP, for a total capacity of 227 MW.[99]

California Investor Owned Utilities benefit from the SGIP insofar as it helps them meet the California Renewable Portfolio Standard (33% of the electricity by the year 2020) and energy efficiency goals. The incentive program also benefits the SGIP ratepayers through reduced electricity bills. Overall, "payments to SGIP participants benefit all ratepayers by reducing the need for utilities to invest in expensive transmission and distribution infrastructure."[100]

The incentive levels for eligible DG technologies range from $1250/kW installed costs for wind, waste heat to power and pressure reduction turbines to $500/kW installed, for gas-fired CHP or micro-turbines. Emerging technologies, such as energy storage and biogas enjoy a $2000/kW installed subsidy, and fuel cells $2,250/kW.[101] Projects greater than 30 kW are paid half up front, and the other half over a five-year period, based upon performance. The maximum incentive amount is $5 mm per project, never to exceed 60% of the project cost.[102]

Excess power produced can be exported to the grid. However, the amount of energy exported to the grid is not to exceed 25% of the energy produced on-site yearly.[103] When power is exported back to the electrical grid, customers receive net energy metering credits from only certain technologies, such as fuel cells and biogas-fueled systems. As with Ohio, gas-fired CHP does not receive the "full retail rate" for power exported to the grid.[104]

Ohio has no similar self-generation incentive program, although there are some similarities between Senate Bills 221/315 and the California SGIP. Ohio also allows net metering, for instance, for renewable generation and for waste heat recovery, but not for gas-fired combined heat and power. However subsidies of up to 60% and $5 mm per project would have a significant effect in enabling at DG in Ohio. Certainly a $500/kW installed cost subsidy would be a major impetus for the adoption of smaller scale gas-fired combined heat and power projects.

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[99] California Public Utilities Commission, "Self-Generation Incentive Program Statistics" (December 19, 2011); http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/SGIPstats_through12-31- 08.htm

[100] California Public Utilities Commission, "CPUC Regulatory Process and the SGIP," (2007). URL: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/pucregprocess.htm

[101] California Public Utilities Commission, "Self Generation Incentive Program Handbook," (2011), http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/. Solar energy has a separate program from the SGIP.

[102] *Id*. at 25-26. *See also* http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA23F.

[103] *Id*. at 31.

[104] Itron, *supra*, at 3-11.

F. Regional Energy Planning

Manufacturers interested in distributed generation might benefit from regional collaboration with local authorities and communities. Distributed generation, especially CHP, will not be a "one size fits" all application; every situation requires an analysis specific to those circumstances. Planning can help manufacturers identify strategies to deploy CHP, including more access to less expensive "off the shelf " technologies.

In particular, for regions with a large variety of manufacturing and other electricity intensive users, a coordinated regional CHP program may be useful to new and existing manufacturers trying to find a fit for their power and heat needs. Such a program might be set up to address three strategic areas:

1. Commercial buildings and small industrial applications – deploying similar equipment and with similar financial goals and capabilities;

2. Institutional facilities – with larger power and heat requirements, and with longer-term financing abilities, these facilities may be more amenable to ESCO savings and other finance structures; and

3. Major industrial and district heating CHP's, where large-scale power is generated, visibility is high, and the returns to the districts and industries involved are potentially great.

The development of an energy master plan could help manufacturers identify not only potential projects, but also potential project developers for on-site DG. Such a master plan might begin with a Geographical Information System based "energy map" that is prepared at a neighborhood, local authority or sub-regional scale. It might include an assessment of existing building energy demands as a baseline, identify likely locations for new business development and assess effects on energy demand. It might also include a "heat map," identifying anchor heat loads, such as large public buildings.[105]

These energy maps could reveal CHP generated district heating opportunities that local authorities or project managers might be willing to support. They may also inform growth options and serve as the starting point for energy planning for developers. A decentralized energy master plan could include technical, planning, financial, and legal support – all better enabling manufacturers to evaluate DG opportunities.

Local energy planning can provide a roadmap for manufacturing to identify strategies for developing on site DG opportunities. Traditionally, with centralized generation, transactional costs have been a small percentage of the total project costs, and as such, do not threaten planning. However transactional costs do not generally go down proportionally with the project size. These costs can serve as an impediment to the development of DG. Manufacturers are generally unwilling to

[105] M. King and R. Shaw, "Community Energy: Planning, Development and Delivery," at 7 (Ashford Colour Press 2011).

spend hundreds of thousands dollars identifying potential distributed generation projects, especially small projects below a few Megawatts. Regional energy planning may help reduce these costs for manufacturers by identifying for them not only potential projects, but also potential collaborators and sources of funding.

To date only a handful of regional energy plans have been developed in the United States. These included studies conducted in San Diego[106], Kane County (Illinois)[107] and New Hampshire.[108] All of these studies included a baseline investigation of energy production and projected needs for the region. All included an action plan to address climate change and to increase local energy production while decreasing reliance on fossil fuel generation. All three also developed strategies for enabling distributed generation systems to increase local energy production.

None, however, employed the energy mapping strategies that were developed for London, England in the aforementioned King study. This sort of investigation will be required to enable manufacturing to identify opportunities to provide district heating through CHP projects. The King study included a ten stage undertaking that included among other things, data gathering, project identification, financial modeling, and feasibility studies.[109] This sort of information would be more useful in developing manufacturing's appetite for undertaking DG.

[106] San Diego Regional Energy Plan by San Diego Association of Governments in December 1994. Complete energy plan can be found at: http://energycenter.org/uploads/energy_plan.pdf.

[107] The full energy plan for Kane County is available at: http://www.countyofkane.org/Documents/Office%20of%20Community%20Reinvestment/Energy%20Efficiency%20and%20Conservation%20Block%20Grants/Kane%20County%202040%20Energy%20Plan/KC2040EP_5_20_2011_FULL.pdf.

[108] Rockingham Planning Commission (2008), Regional Master Plan: Energy Chapter. Full text found at: http://www.rpc-lnh.org/PDFs/projects/energy/Energy%20Chapter%206-4-08.pdf

[109] King, supra, at 14-35.

V. Conclusions

Ohio today faces a considerable challenge in keeping its manufacturing base competitive. Energy-intensive manufacturing, in particular, is threatened by rising electricity costs and a potential need to reduce carbon emissions. Electricity costs are scheduled to go up considerably, especially in northern Ohio, as a result of increased capacity charges and the retirement of old coal plants. In addition to this, Ohio manufacturers are expected to incur significant capital investment costs in complying with new EPA guidelines for heat and steam generation. Both of these trends indicate a need for manufacturing to consider distributed generation, especially combined heat and power systems, to improve efficiencies and to reduce costs and emissions. The good news, however, is that the timing to do so could not be better: natural gas – the primary fuel for CHP systems – is currently inexpensive, and is likely to remain so for sometime as a result of the advent of shale development.

According to the companion study undertaken with this investigation, an increase in the industrial electricity price by 1 cent per kilowatt-hour decreases average manufacturing productivity by 2.2% per employee. Northern Ohio will face PJM capacity charge increases comparable to this amount by 2016. Continued price increases for electricity will likely have a material affect on Ohio manufacturing's ability to compete in a global market. The development of strategies to keep distribution and other charges from skyrocketing in the coming years will be critical. Among the most promising of these strategies is the adoption of Combined Heat and Power technology.

But investment by manufacturing into CHP or other DG systems will not be possible unless there is a regulatory framework in place that encourages the adoption of these systems. Current regulatory schemes in Ohio have taken some steps, such as Senate Bills 221 and 315, to encourage distributed generation and CHP. However there remain significant obstacles to the adoption of CHP, such as high standby fees, that threaten the widespread adoption of that technology.

It will require energy-intensive manufacturing to again take leadership in rethinking and reinventing our energy generation and distribution model, just as it did thirty years ago when it led America to deregulate its wholesale electricity markets. America's next energy "quiet revolution" – the switch to distributed generation -- will be just as important to the American economy as was the deregulation of wholesale electricity markets. This will be especially true for Ohio, where the economy is highly dependent upon energy-intensive manufacturing. Ohio's electricity generation and distribution models for the next fifty years may very well depend upon the leadership shown by manufacturing in the coming years.

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