TESTIMONY

BEFORE THE

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

SENATE SUBCOMMITTEE ON ENERGY

TESTIMONY OF

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"Legislative hearing regarding net metering, interconnection standards, and other policies that promote the deployment of distributed generation to improve grid reliability, increase clean energy deployment, enable consumer choice, and diversify our nation's energy"

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Barriers to Increased use of Cogeneration, Distributed Generation and Recycled Energy

MeadWestvaco Corporation (MWV) is a global leader in packaging and packaging solutions with $6.6 billion in revenue and 22,000 employees worldwide. We currently have facilities in 30 countries and serve the world's largest consumer product brands with packaging in healthcare and pharmaceuticals; cosmetics and personal care; food and beverage; home and garden; and media and entertainment. Our other leading businesses include Consumer & Office Products, and Specialty Chemicals, which uses byproducts of the papermaking process to develop solutions for air and water purification, asphalt performance additives, and emulsifiers and dispersants.

MWV is part of the forest products industry which is the leading producer and user of renewable biomass energy, and is a member of American Forest and Paper (AF&PA), the national trade association for the industry. Much of my testimony today is based on my experience as a member and chair of the AF&PA Energy Committee, leading the industry's advocacy efforts on energy policy.

Sixty-five percent of the total energy used at AF&PA member paper and wood products facilities is generated on-site from carbon-neutral biomass. The industry also is a leader in highly efficient co-generation of electric power (also called Combined Heat and Power or CHP), much of it from biomass, both for internal use and for sale to the power grid. Since 1972, AF&PA member pulp and paper mills have decreased the use of fossil fuels and purchased energy per ton of product by 56%. From 2004 to 2006, they reduced their use of fossil fuels and purchased energy per ton of production by 9%. This was mostly achieved by extensive use of CHP technologies. In 2006, AF&PA member pulp and paper mills produced more than 28.5 million megawatt hours of electricity. This represents one third of the industrial CHP-generated energy in the U.S.

Co-generation or CHP is the sequential or simultaneous generation of electricity and thermal energy (usually in the form of steam) from the same fuel for use at a host facility that makes both electricity and another useful product or service requiring heat. With CHP, relatively little heat value of fuel is wasted compared to conventional generating processes. This is the basis for the savings. In general, CHP is about twice as efficient at using fuel compared to the standard electricity generating technology. Because CHP systems use less fuel, they produce fewer emissions to the air; so there is also less particulate, Carbon Dioxide (CO_2), sulphur oxides (SO_x), nitrogen oxides (NO_x) and other pollution emitted than in utility systems using the same fuels. Adding CHP power generation units widely dispersed throughout the electrical grid also improves system reliability in that the electrical system is less dependent upon any single generation unit. Since the power which is cogenerated is typically used locally, investments needed in transmission infrastructure are reduced and electric transmission and distribution line losses are also lower, often as much as 7%.

MWV's three domestic mills co-generated 1.86 million megawatt hours of power in 2007 which represents almost 70 percent of these mills' total power requirements. Use of CHP saves millions of dollars in energy costs annually and reduces our CO_2 emissions significantly compared to purchasing all of our power from the local utility. In addition, since most of the fuel used in our cogeneration facilities is biomass-based, our CO_2 emission reductions are further enhanced.

The Department of Energy (DOE) stated in a report issued in December 2008 that then- current use of CHP nationwide avoids more than 1.9 Quadrillion Btu of fuel consumption and 248 million metric tons of CO_2 emissions compared to traditional separate production of electricity and heat. This CO_2 reduction is the equivalent of removing more than 45 million cars from the road. According to the DOE, CHP was almost 9% of US power capacity in 2007. In the same report, the DOE states that if CHP were to supply up to 20% of U.S. electricity generating capacity by 2030 (241 GW of CHP out of 1,204 GW total), the projected increases in CO_2 emissions would be cut by 60%.

The many benefits and value provided by CHP was recognized with the passage of the Public Utility Regulatory Policy Act (PURPA) in 1978. PURPA sought to encourage cogeneration and small power production as well as renewable power production by guaranteeing that these facilities would not be discriminated against when connecting to the electrical grid, by ensuring that they could get supplemental, back-up and maintenance power at just and reasonable rates and by requiring that utilities purchase power from facilities that met PURPA qualifications at the cost the utilities avoided by not having to build additional power plants or purchase power from the wholesale market. For 20 years since the law's passage in most parts of the country the increased use of CHP and power generation from renewable energy sources was fostered by implementation of these basic principles. Over that time period cogeneration and power production from renewable resources increased from 4% to nearly 9% of US power generation.

In certain parts of the country there was continued resistance to implementing the federal law. As a result, policies were put in place which continued to provide preferential treatment for utilities' power plant build options. For example, in some jurisdictions there were no provisions for mandatory competitive bidding, utilities' true avoided costs were not transparent and the tariffs established by the state regulator for PURPA-qualified facilities to sell power to the local utility did not provide the assurances needed to secure financing for CHP facilities. Developers asserting their federal PURPA rights at the state level incurred significant litigation costs. Many ultimately gave up and developed their projects in more CHP friendly parts of the country where they could also find the steam hosts they needed to build these PURPA-based projects.

In some states the Public Utility Commissions required the costs of purchase power agreements to flow through the fuel adjustment mechanism at cost. Since the utilities involved were not afforded an opportunity to earn a return on the capacity component of these agreements, they resisted entering into PURPA based purchased power agreements. In contrast, utilities are typically given an opportunity to earn a return on the equity invested under the self build option. Therefore this regulatory treatment created a bias against CHP.

Over the last 10 years, regulatory barriers, often in the name of improving the reliability of the nation's power grid, have negatively affected the growth in CHP. The problem was further exacerbated with the passage of the Energy Policy Act (EPAct) of 2005, which substantially revised PURPA. Under the Federal Energy Regulation Commission's (FERC) interpretation of this law, utilities are not required to demonstrate that their markets were functionally competitive before being relieved of their PURPA mandatory purchase obligation. In effect, the utility simply has to be a member of an established Regional Transmission Organization (RTO) or Independent System Operator (ISO) to be automatically exempt.

In its interpretation of the law, the FERC also placed the burden on CHP generators to prove discrimination in the implementation of an Open Access Transmission Tariff (OATT). An OATT is a FERC approved tariff designed to provide non-discriminatory open access to the transmission system. Under the FERC OATT, all non-utility users of the grid are to be afforded access under the same terms and conditions as utility users. However, in practice, non-utility users have not received nondiscriminatory access as was intended by the FERC. This is primarily because of utilities' right to preserve transmission capacity for future native load.

In mid-December 2008, the D.C. Circuit Court affirmed the FERC's decision. These interpretations are important because they effectively end the purchase obligations for utilities in a large part of the nation. Although existing contracts were not affected, any qualified facility seeking a new arrangement for expanded or additional capacity may find itself with little leverage in negotiating with utilities. They will have to interconnect with the RTO or ISO and deal with the barriers associated with doing so, discussed below.

Barrier #1: Interconnection Standards Remain a Deterrent to CHP Entry

Interconnection policy has broad implications for competitive entry of co-generators and other forms of distributed generation. FERC has finalized new generation interconnection rules for both small facilities with capacity less than 20 MW and for larger generators with capacity greater than 20 MW. These rules represent an improvement in many areas of interconnection policy. The FERC standards are the default only if the RTO or ISO has not set its own unique standard. The following RTOs or ISOs have been developed in the U.S.: ERCOT ISO, California ISO, SPP RTO, MISO RTO, PJM RTO, NY ISO and NE ISO.

A significant barrier to entry for co-generators is a concept called "deliverability" which requires generators and CHP seeking to interconnect to potentially have to finance transmission facility upgrades. This standard requires that generators have to prove that their output is deliverable to load and if it is not, then they have to finance the transmission upgrades necessary to make the power deliverable. This approach is generally incompatible with competitive entry into ISO/RTO markets.

The FERC interconnection rule defines a dual approach with two new types of interconnection services: "Energy Only Service" and "Network Resource Service." The standard is based upon the PJM model of interconnection. Facilities that qualify as a Network Resource Service are guaranteed a much higher price for their electric power than Energy Only Service. To obtain Network Resource Service status in PJM for example, facilities must go through an extensive three prong interconnection process and pay the cost of upgrading the transmission system if the studies show that such upgrades are necessary for the power to be "deliverable" to load. Even though this money is refunded with interest over time in bill credits for transmission service, facilities seeking to interconnect must put up this money upfront to fulfill the interconnection requirements. Facilities can only participate in PJM's auctions to receive a capacity payment from the administered capacity market if they are fairly far along in the interconnection process toward becoming a Network Resource.

The "deliverability" standard provides for the reduced price paid to "Energy Only Service" providers which do not become "Network Resource Service" providers. This is because these new entrants are treated as the "marginal unit" which must be worked into the mix and be capable of running simultaneously without disturbing the incumbent units' "right" to run. This preference of Network Resource Service units over Energy Only Service units is used even when the Energy Only Service units can provide power at a lower price than Network Resource Service units. Under FERC's dual Energy/Network interconnection standard, the concept of "deliverability" limits competition from new entrants who wish to displace higher cost incumbents from the transmission system.

Another aspect of meeting the "deliverability" standard for CHP facilities in some RTOs is that they must demonstrate that their power output is "deliverable" to the market. In the impact study phase of the interconnection process the RTO assesses what upgrades are necessary to deliver power from the CHP to the market without the industrial load being present. It is virtually impossible for the CHP to be able to deliver this power if the industrial site to which it is intrinsically tied is assumed to not exist. Unlike merchant generators, larger scale CHP facilities cannot be sited to minimize interconnection costs posed by the deliverability standard as they usually co-locate at the already existing industrial site. As a result, CHP plants oftentimes limit themselves to making sales into the non-firm energy market (Energy Service Only – lower price) in order to avoid the burden imposed by the deliverability standard.

Barrier #1: Solution

It should not be the responsibility of the new entrant offering a lower price designed to displace the incumbent's facility for the benefit of consumers to build transmission facilities in order to compete for the same load. In a purely physical sense, any unit connected reliably to the electric grid and capable of delivering energy to any load is "deliverable" to that load. The interconnection standards which rely on the "deliverability" concept are overly burdensome, but they need not be so. This is evidenced by the approach taken by the New York and New England ISOs that adopted a non-discriminatory standard as a regional variation to FERC's rule. This standard, known as the Minimum Interconnection Standard, maximizes competitive entry to the grid. In RTOs that have adopted this alternative standard, any unit which is interconnected to the grid in a fashion which preserves the reliability, stability and existing transfer capacity of the grid (without expanding the grid) is entitled to compete in both the capacity and energy markets. If there is not enough transmission infrastructure to "deliver" the output from both the new and existing units, then the units are forced to compete on the basis of price to determine which unit gets dispatched. **The current FERC and PJM concept of "deliverability" in the interconnection standards should be abandoned. The Minimum Interconnection Standard**

used in the New York RTO and New England ISO should be adopted by the FERC as the default and by all the RTOs and ISOs in the nation.

Barrier #2: Discriminatory Treatment of Behind the Meter CHP

RTOs and ISOs have repeatedly attempted to interfere with CHP in the area of "Behind the Meter" pricing. "Behind the Meter" generation refers to electricity generated on site at a facility that is not sold to a RTO or ISO or to another wholesale entity. The RTOs and ISOs have attempted to charge customers who supply their own needs with "Behind the Meter" generation as if they had taken their entire power supply from the RTO/ISO - controlled grid. They try to charge for transmission, ancillary services and administrative fees based upon the total electrical consumption of a manufacturing facility, rather than the "net" amount actually taken from the grid. This cost allocation scheme is known as "Gross Load" pricing.

Gross load pricing failed in the PJM RTO when an equitable settlement was reached between PJM and Behind the Meter generators, most of which were owners of CHP installations. However this issue continues to be raised in the context of a resource adequacy cases and in other proceedings. In a rehearing of a MISO case (Dkt. ER08-394-001), the FERC reversed itself and decided to disallow the netting of Behind the Meter generation from gross load for purposes of utility native load forecasting and for calculations of planning reserve margin requirements. This illustrates that owners of Behind the Meter CHP facilities must remain continually vigilant in their advocacy efforts on this issue as the challenges to the appropriate treatment of Behind the Meter generation is a recurring problem.

Barrier #2: Solution

In order to prevent this issue from being a continual deterrent to increased CHP implementation, legislative language should be developed which would ensure that CHP and distributed generators will not be required to pay for services on a "Gross Load" basis and that services paid for will be based on the "net" amount actually taken from the grid or utility.

Barrier #3: Operational Challenges Faced by CHP in an RTO/ISO Environment

CHP facilities like those operated by the manufacturing industry are different than merchant or utility power plants that only have one purpose which is to produce electricity for sale. While a CHP may elect to sell power into an electrical transmission grid, its primary function is to support the host facility by providing electric power and steam or other useful thermal energy for the manufacturing process. The FERC program to standardize the use of the grid through the development of RTOs and ISOs fails to recognize this important difference.

Generally the operating rules developed by RTOs and ISOs fail to recognize the significant operational differences between cogenerators and merchant generators. This is the case even though the FERC has acknowledged in a California case where the issue was specifically addressed that qualified CHP facilities differ in purpose and operation from traditional generators and that reducing the host facility's control over the curtailment and dispatch of their power could lead to process, safety and health problem for the host facility.

RTOs and ISOs often require that interconnected generators, including onsite CHP, be under their control, even if the generator is not making sales to the market. This requirement allows an RTO to dispatch a CHP's entire power production capability to other uses based on the needs of the electrical transmission grid, irrespective of the needs of the CHP's primary business. This requirement is a significant disincentive for any industrial CHP facility seeking access to the grid.

Barrier #3: Solution

The RTO or ISO cannot accommodate the dynamic requirements of CHP's industrial processes when the first priority of a CHP facility is the provision of steam or heat to the industrial host. **The RTOs and ISOs should not mandate that CHP facilities comply with all the operational rules developed for merchant generators listed in their generic tariff provisions and mandated by execution of their operating agreements. Instead, they should increase flexibility of the tariff to allow for the refinement of contract terms to accommodate any particular needs and concerns with respect to the curtailment and dispatch of CHP.** This accommodation of CHP is warranted in light of the economic and environmental benefits that accrue from CHP operations.

Barrier #4: Financial Barriers to CHP

CHP projects with power sales to RTOs are much harder to finance than sales under long term contracts with utilities at avoided cost under PURPA. This is because power sales agreements with utilities under PURPA would typically establish a capacity payment for about a 20 year term. In RTOs such as PJM where a separate capacity market exists, sellers can have price certainty for capacity payments on a three year maximum forward basis. For example, by the end of May 2009, sellers of capacity on PJM's system will know what they will be paid through May 2013. The lack of long term price certainty, which was afforded by PURPA's mandatory purchase obligation, is a major deterrent to financing the installation of new CHP.

Despite the guidelines provided in PURPA for the design of just and reasonable utility rates for standby and maintenance power needed for CHP facilities, some Public Utility Commissions approved very high rates for these services. This has proven to be a real barrier.

Barrier #4: Solution

Develop a Clean Energy Standard Offer Program (CESOP) as national policy to reduce the barriers to entry for CHP and recycled waste energy facilities. The federal government should require states to offer long term contracts for the purchase of electric power from facilities that utilize waste energy, recycled energy and other clean technology. Under CESOP, state regulators determine the cost of delivering electricity from the best new, electric only power plant that meets environmental standards and then offers long term contracts for clean energy at 80% of that cost. Two different CESOP rate structures are possible depending on whether the power is generated from industrial waste energy or from new CHP that meets the annual efficiency tests. Both structures would ensure that the state obtains clean energy at a cost below what it would pay for power from new coal fired centralized facilities. Utilities would be allowed to earn a return on the capacity provided by the new CESOP facility. The contract term of 20 years would remove the financing problem mentioned above.

Another suggestion for consideration is to provide feed-in tariffs to encourage the development of CHP resources. This approach is being used in the European Union as part of their cogeneration directive. A feed-in tariff is an agreement between an electricity generator and a utility whereby the former is paid an agreed-upon rate (could be the CESOP rate or another rate set by the regulator) for electricity that is fed back onto the grid. This kind of arrangement can be used to deliver all of the CHP production to the utility or it can be used to deliver the excess electricity produced. The over-arching principle is that it allows for optimization of the CHP facility to ensure maximum efficiency.

All states should be encouraged to review the design of their standby and maintenance rates to ensure that they are consistent with the guidelines provided in PURPA.

Barrier #5: Exit Fees and Life of Contract Demand Ratchets at State Level

In 1996, the Code of Alabama (37-4-30) was amended to allow electric utilities to impose exit fees on industrial customers who seek to serve their power requirements from CHP facilities owned by entities other than themselves (third-party CHP). The argument used to support this practice was that utilities incurred "stranded costs" due to the industrial seeking more energy efficient options for their steam and power supply. The utilities argued that recovering these "stranded costs" through an exit fee on those who obtain power from such CHP facilities and who leave the utility system is justified since it protects those customers who remain on the system. Many third-party CHP facilities which should have been built in Alabama to serve industrial load since 1996 were not built because the threat of an exit fee significantly affected the economics of the project. This law, which has not been repealed, protects the utility's franchise, continues to sanction a highly discriminatory practice and prolongs inefficiency in the generation of power.

Some utilities throughout the country have life of contract demand ratchets in their tariffs for large industrial customers. These serve as a deterrent to increased installation of CHP since the industrial customer must pay for up to 75% of the demand listed in its contract regardless of whether it takes the power or not. Many customers faced with the cost of this potential demand ratchet wait to install or upgrade their CHP facilities until after the initial term of their contract has expired. Often the contract can then be cancelled during an annual rollover period to minimize costs incurred from this demand ratchet. Sometimes, if the customer will continue to buy any power, the utility has the discretion under their tariff to decide whether it will allow the contract to be cancelled. The customer may have to file a complaint with the state PUC if the utility is unwilling to voluntarily reduce the contract demand level.

Barrier #5: Solution

It is a national imperative to require State Public Utility Commissions to remove tariff language which can be a barrier to increased use of CHP. State legislatures should also be encouraged to review their Code to ensure that any laws still on their books that are a barrier to increased use of CHP are repealed as soon as possible. Federal legislative language should encourage states to not tolerate any discriminatory practices in either their Rules and Regulations or in the Code.

Barrier #6: Environmental Permitting

The lengthy and extensive process to secure environmental permitting for CHP is a barrier to entry. The DOE has stated that 31 states regulate emissions based on heat input levels (lb/MMBtu). Such approaches do not recognize or encourage the higher efficiency or the pollution prevention benefits offered by CHP. In addition, major new emission sources are required to meet New Source Review (NSR) requirements to obtain operating and construction permits. NSR sets emission rates for criteria pollutants and requires installation of the Best Available Control Technology (BACT). New sources are also required to offset existing emissions in non-attainment areas. As a result of these environmental deterrents, CHP facilities are often times not installed because even though they may represent marginal improvements, they do not achieve BACT or sufficient offsets are not available in these non-attainment areas for the new facility to get built.

Barrier #6: Solution

Expedited and streamlined permitting procedures for CHP facilities, which will increase the energy efficiency of an industrial operation, are greatly needed.

The DOE has rightly pointed out that output based approaches to regulation that include both the thermal and electrical output of a CHP process can recognize the higher efficiency and environmental benefits of CHP. Although some states, primarily in the northwest, have adopted output based approaches, the majority of the states have not done so. Legislation could encourage states to move in that direction.

Provisions should be made to allow CHP facilities to get permitted even if they are not necessarily achieving BACT as some improvement is better than no improvement at all.

Barrier #7: Treatment of Existing and New CHP in Proposed Climate Change Legislation

Another potential deterrent to the expansion of CHP looming on the horizon is in the treatment of existing and new CHP facilities in any greenhouse gas reduction program. All climate change cap and trade proposals presented so far provide inadequate recognition of, and incentives for, CHP in the manufacturing sector. Although producing power via CHP uses energy more efficiently than producing utility power, direct (onsite) emissions of a facility using CHP will typically be higher than if the facility only produced thermal energy and purchased all electricity from off-site. Since the benefit of a CHP system is reducing <u>indirect</u> emissions (i.e., from purchased electricity), a cap-and-trade program where compliance is measured solely on reducing direct emissions will not adequately account for the benefits of CHP. It is critical that the efficiency gains associated with CHP systems of all sizes be properly recognized in a cap-and-trade system. Otherwise industry with untapped cogeneration potential will be hesitant to install new CHP because they will have to secure allowances to emit from the new facility while not receiving any credit for the reduced power consumption.

Another barrier will potentially emerge when developing the methodology for allocating free allowances in any cap and trade program. The two most commonly discussed methodologies for allocating free allowances are based on either: 1. historic direct emissions (not including purchased power) or 2. a percentage of a product benchmark within that industry sector.

The problem with the historical emissions approach is that it does not consider the superior energy efficiency attributes of existing CHP and treats such facilities similarly to a utility plant. The historical emissions approach imposes a cost on polluters but provides no incentive to existing clean energy sources such as CHP. Emissions based approaches also do not provide an incentive mechanism as its basic construct for the nation to become as energy efficient as possible through CHP and distributed generation resources. This will be a major deterrent to new CHP being developed.

The problem with providing a percentage of a product benchmark within the industry is that it does not provide any credit for any industry that has, in order to remain competitive in a global marketplace, already taken great measures in becoming as energy efficient as possible through the extensive use of CHP. As a result, their specific product benchmark will be lower, reflective of the extent to which this industry has embraced CHP or other energy efficiency technologies over the years. This is especially true for the pulp and paper industry that has an exemplary track record in having embraced and installed CHP technologies. Such industry should be awarded for that activity, not compared to its own industry benchmark that by its very construct already reflects that activity.

Barrier #7: Solution

Climate change policies should recognize the benefits of, and promote investment in, CHP **by providing credit for the avoided emissions associated with an existing and new CHP units.** If a cap and trade program is established, special provisions will need to be made for CHP systems as current cap and trade approaches provide no credit for the energy efficiency provided by such systems. Any climate change proposal should promote investment in CHP by providing credit for the avoided emissions associated with a CHP unit. The accounting credit for energy efficiency increases should be equal to the difference in CO_2 emissions generated by a CHP system as compared to the equivalent CO_2 emissions associated with generation of electricity by utility companies and the separate on-site generation of thermal energy. Each facility may then deduct those CO_2 emissions savings associated with that CHP unit from emissions regulated under a GHG regulatory program. Any surplus credits generated by a facility shall be eligible for an emissions reduction credit.

Another option to consider as an alternative to the emissions based approach for allocation of allowances is an output based approach which is based on efficient energy production instead of efficient product production. One such output based approach would award each electric producer, including a CHP facility, with initial allowances of 0.62 metric tons of CO2 emissions per delivered megawatt-hour of electricity. In addition, each thermal energy producer would be provided with an initial allowance of 0.44 metric tons of CO_2 emissions per delivered megawatt-hour of thermal energy. These allowances reflect the 2007 average national emissions for electric and thermal. The next step requires every plant that generates heat and or power to obtain allowances equal to its CO_2 emissions. This encourages all actions that lower greenhouse gas emissions per unit of useful output and penalizes above average pollution per unit of output, thereby unleashing innovation and creativity. It also would measure an industry based on its efficient energy production and award those industries that have historically already undertaken those initiatives.

However, should an emissions based approach be ultimately adopted, a solution to removing the deterrent to increased CHP would be, as discussed above, to establish a mechanism for transferring emissions allocations from a utility, which would see reduced emissions from the installation of CHP, to a CHP system, which would increase its direct emissions.

Barrier #8: Lack of Incentives for Large Scale CHP

There is some interest in promoting CHP in climate change proposals which have been filed to date but unfortunately they only focus on small CHP facilities. At the present time there are no incentives whatsoever for large scale CHP facilities, yet these facilities face the same barriers to entry as do the smaller CHP.

Recognizing the benefits of distributed generation, the American Clean Energy and Security Act discussion draft renewable energy provisions provide that distributed generation facilities receive three renewable energy credits (RECs) for each megawatt hour of renewable electricity they generate. This legislation defines distributed generation facility as a facility that: generates renewable electricity "other than by means of combustion"; "primarily serves 1 or more electricity consumers at or near the facility site"; and can be no larger than two megawatts in capacity.

The Energy Efficiency Resource Standard (EERS) provisions in the discussion draft, like other EERS bills, define CHP to exclude facilities with net wholesale sales of electricity exceeding 50 percent of the total annual electric generation by the facility. This disincentive for CHP is inconsistent with the EERS policy objectives. All the customer facility savings from electricity generated by CHP facilities should qualify under any EERS.

The recent revision of tax policy to provide incentives for any CHP up to 50 MW in size is a positive development but such incentives should not be size limited. There are many potential cogeneration facilities at industrial sites which are not eligible for the investment tax credit because they need to be larger than 50 MW to capture economies of scale.

There are state practices that are discriminatory towards CHP in the provision of natural gas delivery services to CHP facilities.

Barrier #8: Solution

As a member of an industry that is a leader in the use of CHP, we believe that our significant investment in CHP should be rewarded. Specifically, **any climate change or energy bill should provide extra renewable energy credits (REC) for electricity generated through CHP, regardless of the size of the generation facility.** It is inconsistent with the policy goals of an RES to limit extra RECs only to small facilities, as larger facilities provide the same environmental and greenhouse gas reduction benefits as do smaller facilities. The strained definition of distributed generation facility is unnecessary and should not be adopted.

The EERS portion of any proposal whether it is included in a renewable standard or on a stand alone basis should **allow <u>all</u> of the output of CHP facilities to qualify for energy savings regardless of the amount of the net wholesale sales of electricity generated by the facility. A facility should not be disqualified as a "CHP system" no matter how much electricity it sells, and all its electricity should be eligible for the CHP savings calculation.**

All CHP should be eligible for an investment tax credit, regardless of size.

It may also be appropriate to **establish targets for CHP and recycled energy** that increase capacity installation and operation. In particular, CHP and recycled energy should be declared acceptable to meet at least half of the requirements in any adopted policy requiring a percentage of power purchased for resale by utilities to come from renewable or energy-efficient sources of electric generation.

Incentives should be provided for states that adopt, for jurisdictional utilities, **a natural gas delivery tariff that provides delivery to CHP facilities at rates for transmission and distribution service no less advantageous than the rate at which natural gas is delivered to any other gas-fired electric generator**. This has already been implemented in much of New York State.

Barrier #9: Burdensome Reporting Requirements

Another deterrent related to CHP interconnection can be found in the EPAct of 2005 in the establishment of the Electric Reliability Organization (ERO) to ensure the reliability of the electric power transmission grid. All interconnected generators, including qualified CHP facilities must become members of their regional electric reliability organization if they want to sell any power to the grid. They must agree to extensive reporting and other requirements imposed by that reliability organization. Compliance with these new mandatory requirements is time consuming and expensive and poses another barrier to CHP connecting to the grid. These additional reporting requirements being imposed on CHP result from the general policy direction of not distinguishing between CHP and merchant type facilities.

Barrier #9: Solution

CHP and other distributed generation facilities making net sales to the grid that are incidental to their main purpose should be exempt from these new reporting requirements. Legislative language should be developed to provide such exemptions.