2010 Connecticut Integrated Resource Plan:

Policy and Technology Options for Repowering Connecticut's Generation Fleet

Whitepaper prepared for the Connecticut Energy Advisory Board

by NRG Energy, Inc.

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Executive Summary

The 2010 Integrated Resource Plan ("IRP") for Connecticut should recommend that the Department of Public Utility Control ("Department") issue a competitive procurement, even in the absence of a projected capacity shortfall, to determine if the state can achieve economic and environmental benefits by replacing existing fossil steam capacity in the state with new, more efficient and lower-emitting capacity. Testing the market with such a repowering RFP is the only way to ensure that the most beneficial resource mix for Connecticut ratepayers from both a cost and environmental perspective is put in place going forward. Recent studies by ISO New England, including one commissioned by the governors of the six New England states, show that a strategy of replacing the existing fossil steam resources in the region with new natural gas-fueled combined cycle resources will produce substantial economic and environmental benefits as compared to even very aggressive development of demand resources or renewable generation. By adopting a procurement mechanism which links new resource development to retirement of existing fossil steam capacity as outlined in Section II of this whitepaper, Connecticut can begin to secure these benefits and to stabilize its future energy supply and costs.

The current surplus of capacity in Connecticut provides an ideal opportunity to implement a pro-active plan to replace and update the existing fossil steam capacity in the state. These resources, which represent over 30% of the state's electrical resource capacity, are under increasing economic and environmental regulatory pressure, and may become unavailable within the planning horizon, perhaps with inadequate time to plan and implement economical replacement capacity in time to avoid reliability concerns. Repowering or replacing these resources will take several years, during which time some capacity may be unavailable due to construction on the existing sites. These factors, coupled with the anticipated economic and environmental benefits to be gained by replacing the older capacity with new technology, suggest that the time to implement the state's repowering effort is now, before a reliability issue arises due to the retirement of existing resources.

A fundamental goal of the IRP is to develop the lowest cost resource procurement plan that meets key energy policy goals set forth by statute. A generation procurement plan should:

- Fulfill the vision established in the IRP for Connecticut's energy future
- Maximize benefits to Connecticut ratepayers
- Maximize efficiency of energy usage and of energy production
- Minimize environmental impacts of power generation
- Maximize electric reliability over the planning horizon
- Use competitive mechanisms to ensure greatest efficiency and lowest possible cost

In order to achieve these objectives, it is critical to establish a resource baseline and to make appropriate recommendations to guide planning for the future composition of Connecticut's electric generation fleet. In establishing this baseline it is critical to recognize the fact that new generation investment is not justified by current and projected market revenues, and further, some existing generators are earning insufficient revenues to continue operating, particularly in light of changing environmental regulations. Moreover, it is critical that generation resource planning in Connecticut recognize Connecticut's non-attainment status for Ozone and PM2.5, consider potential regulations that the Department of Environmental Protection may issue to achieve attainment, and evaluate their likely impact on existing generation units in the state. The Department, in collaboration with the Connecticut Energy Advisory Board ("CEAB") and the Department of Environmental Protection ("DEP"), must develop a coordinated transitional generation plan which ensures that resource availability and reliability needs are met at the same time as the state significantly transforms its power generation infrastructure to more efficient and environmentally-friendly sources of electric energy.

The state has an opportunity in the 2010 IRP to seize upon current market conditions and take a pro-active approach to renewing and reusing the state's valuable existing electric energy infrastructure in a way that will produce both economic and environmental benefits for Connecticut ratepayers. The 2010 IRP recommends a procurement plan targeted at repowering, reuse and replacement of existing capacity, with the goal of affirmatively retiring one or more existing fossil steam units and replacing the capacity with new, efficient gas-fired combined cycle technology or renewables and demand resources. The opportunity is created by the relative surplus of capacity existing in Connecticut and the region right now and for several years into the future. While the surplus exists, it is much less risky to shut down an existing unit while a new one is constructed in its place, or major modifications are performed. System reliability and economy will not be severely harmed by this activity, whereas in a tight supply situation, it could be very ill-advised to shut down a unit for months or years while building its replacement.

On the other hand, failing to take proactive steps toward repowering the existing sites on a planned schedule increases the risk of a potential equipment failure or a new environmental regulation that could force an immediate shutdown of one or more of these existing units, leading to reliability issues and sub-optimal economic outcomes for ratepayers. In the first two iterations of the Connecticut Integrated Resource Plan, the decision to not proceed with a resource procurement has been based on the lack of a projected need for incremental MW of capacity in the state within the planning horizon. The process outlined below would lend itself to the current situation in which Connecticut may not have an immediate, apparent need for incremental MW, but would nonetheless create significant net ratepayer benefits from repowering parts of the existing fleet.

Section I of this paper describes the legislative background supporting the development of comprehensive procurement plans for the state and the specific focus on existing sites, as well as both a qualitative and quantitative discussion of the benefits of repowering and reusing existing power plant sites. This section supports the concept that Connecticut should adopt a pro-active strategy for achieving the repowering and reuse of its existing infrastructure sites.

Section II presents a process by which the state can accomplish that strategy, through a competitive procurement that includes as a threshold a requirement that each new project proposal be accompanied by a significant retirement of existing capacity and associated air and water permits. Such a process would allow the state to obtain lower electricity costs along with efficiency, environmental and economic development benefits during the current surplus that will secure the state's energy security for years to come.

Section III discusses the potential candidate sites for repowering or reuse, the technology and fuel supply considerations involved in selecting repowering and reuse configurations for each site, and the environmental challenges facing the state's power industry in meeting statewide and federal objectives. This section also includes a discussion of the potential opportunities for combined heat and power installations in Connecticut.

Section I – Benefits of Repowering/Reuse

A. Legislative Background

In establishing the Integrated Resource Planning process, the legislature clearly contemplated the benefits that could be achieved by making use of existing infrastructure and power plant sites. Connecticut General Statute § 16a-3a(d)(3) requires the Connecticut Energy Advisory Board to:

> *“ review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources”*

Conn. Gen. Stat. § 16a-3a(d)(3) further requires energy resource procurement plans to:

> *“…develop a comprehensive plan for the procurement of energy resources… in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.”*

And to:

> *"consider … the optimization of the use of generation sites and generation portfolio existing within the state …”*

> *“assess… the impact of current and projected environmental standards, including, but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals… energy security and economic risks associated with potential energy resources, and the estimated lifetime cost and availability of potential energy resources.”*

The statute is clear in directing that the resource procurement plan developed in the IRP minimizes customer cost while maximizing customer benefits consistent with the state’s environmental goals. It does not require that a resource ‘gap’ needs to be demonstrated in order to trigger a resource procurement. In fact, as is discussed below, there is good reason to believe that a procurement specifically targeted to repowering, reusing and replacing existing fossil capacity in the state will produce overall benefits to consumers, in the form of lower electricity costs, more efficient use of limited resources, lower environmental impacts, and economic development benefits. Further, the statute clearly recognizes the economic and societal benefits to Connecticut ratepayers of repowering existing generation on existing, permitted sites, with extensive infrastructure and interconnections to the region's electrical system.

B. Qualitative Benefits of Repowering

The 2010 IRP proposes to position Connecticut to replace, in an orderly manner, its older, less efficient generation with new, highly-efficient and environmentally-superior generation sources.

As called for by statute, procurement planning needs to recognize the economic and societal benefits to Connecticut ratepayers of repowering existing generation currently in operation at existing, permitted sites, given their extensive infrastructure and interconnections to the region's electrical system. By converting these existing sites to significantly more efficient and lower-emitting generating sources, Connecticut will achieve both economic and environmental benefits, while minimizing the need for difficult permitting processes and land-use controversies associated with siting new generation on greenfield properties. Modernizing Connecticut's generation fleet with new or repowered generation will require several years to complete[1], and although the lead time needed to engineer, permit and construct a new or repowered facility is significantly shorter than a green-field site, critically needed capacity could be off-line for an extended period during the construction period at existing sites. As a result it is imperative that the critical analyses of generation options and procurement recommendations take place now.

Repowering or reusing existing sites can provide the following benefits for Connecticut ratepayers:

- Moderate market clearing prices for energy and reserves, reducing overall consumer costs. New gas-fired combined cycle technology and renewable technologies have lower energy costs than existing fossil plants.
- Maintain jobs and renew local tax base. If existing plants shut down without repowering, high-paying jobs are lost and local tax revenues can be severely impacted.
- Maximize use of existing generation sites and transmission infrastructure. The bulk power system is a complex, interconnected grid that is built around generation sources at specific locations.
- Minimize need for new greenfield generation sites and transmission rights-of-way. New industrial sites and rights-of-way require substantial amounts of land and tree clearing.
- Improve generation efficiency (heat rate) at these stations by 30-40% or more. Combined cycle technologies are 30-40% more efficient than existing steam plants.
- Minimize congestion and transmission losses by siting efficient and economical base-load generation in close proximity to load pockets. Relying on power imports from areas remote from load centers causes losses and congestion on transmission lines, and has reliability and security implications, raising costs for Connecticut consumers.
- Reduce emission rates relative to the existing plants. In addition to the more efficient conversion of fossil fuel to electricity, combined cycle plants use natural gas which has inherently fewer emissions than oil or coal, and will be fitted with state-of-the-art emissions control technology.
- Increase the operational flexibility of the plants and the system overall, resulting in lower costs and a greater ability to integrate intermittent and other renewable resources. New

[1] Typical repowering projects require a construction period in which the existing capacity is unavailable; a notable exception to this is NRG's Montville 5 biomass conversion project, which can be accomplished with only a minimal outage during the switch to biomass capability.

combined cycle plants, especially with fast-start capability, are highly flexible and are well-suited to react to changes in the output of wind and other intermittent generation sources.

- Retain the use of highly-assimilated generation sites. Communities that host power plants are accustomed to the industry and rely on the plant owners for tax revenues and other community support programs.
- Stability and predictability of energy costs. By converting the existing fleet of fossil plants to more efficient gas or renewable technologies through long-term contracts, the state can substantially hedge its future costs.

C. Quantitative Benefits of Repowering/Reusing Existing Sites

The existing generating fleet in Connecticut is dominated by plants using 50 year old boiler technology, with heat rates in the range of 10,000 Btu/kWh at full load and 12,000 Btu/kWh at part-load. The current state of the art in fossil generation technology utilizes very efficient industrial frame gas turbines in combined cycle configuration, which produces heat rates on the order of 7,000 Btu/kWh. Replacing an older plant with new technology, therefore, presents the opportunity for a ±30% improvement in the efficiency with which the plant converts chemical energy (natural gas) to electrical energy. These efficiency gains, and their impact on the broader New England electrical system, are borne out in several recent studies.

2009 ISO New England Regional System Plan

ISO New England's 2009 Regional System Plan ("RSP09")[2] presents a range of potential system resource expansion scenarios, and evaluates the economic and environmental attributes of each. The plan found that the cases which assume 2,400MW of new, efficient gas combined cycle added in Connecticut and another 2,400MW added in the Boston area produce among the lowest overall energy costs of all the simulations studied, as shown below in the data point at the far right in Figure 9-3 from the RSP09 report.

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2 ISO New England, Inc., 2009 Regional System Plan, October 15, 2009, http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf, at Section 9.

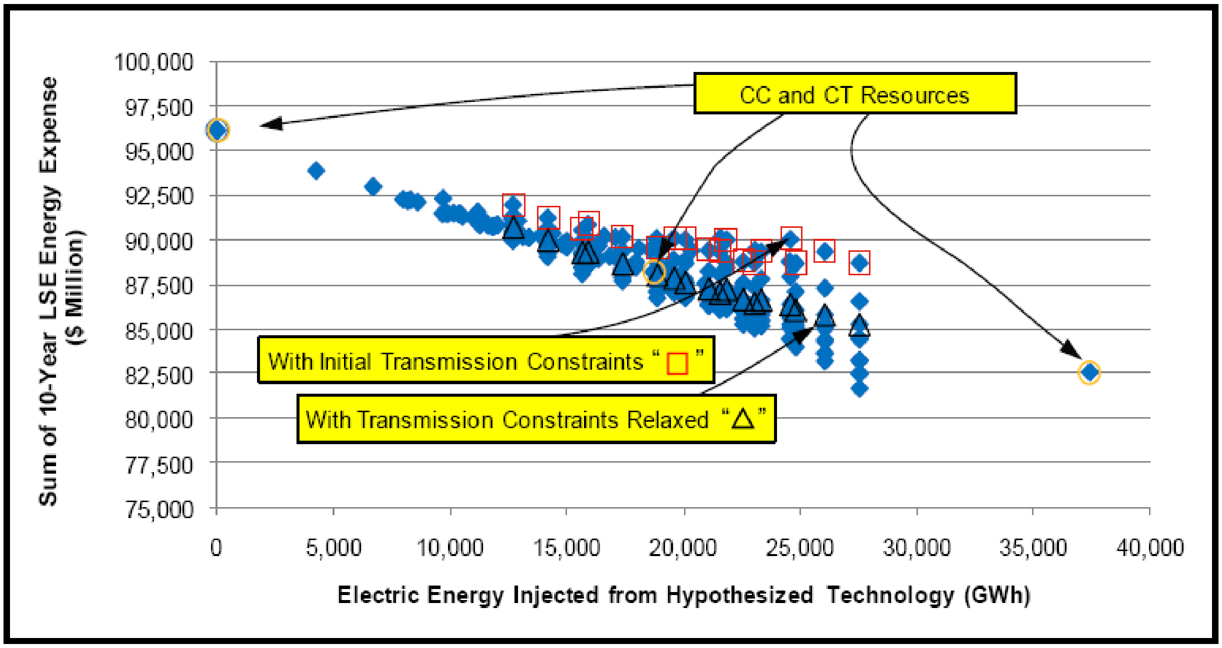

Figure 9-3: Total 10-year LSE electric energy expense without FTR/ARR offsets for the New England load.

By adding substantial capacity with very efficient heat rates, the marginal heat rate of the system is reduced, lowering energy prices across virtually the entire load range in virtually all hours of the year. In addition, these generators will be economical in the ISO's centralized economic dispatch and will run as 'baseload' resources, eliminating the need for ISO to dispatch higher-cost resources to run in standby mode to protect against reliability events. These trends result in substantially lower costs and reduced emissions compared to the existing system.

ISO-NE Study for Governors' Energy Blueprint

To support their effort to create a long-term energy vision for the New England region early in 2009, the six New England governors asked ISO-NE to study a number of 'horizon' cases with different mixes of resource expansion. The study looked at a range of potential renewable and fossil-based resource mixes in the year 2030, and evaluated both economics and environmental impacts. Of note, the governors' blueprint concluded that adding new efficient natural gas combined cycle ("NGCC") capacity would exert downward pressure on the marginal price of energy in the region.[3] Among all of the renewable and other scenarios evaluated, the lowest costs would result from a scenario in which 8,610 MW of fossil fueled steam generators at least 50 years old as of 2030 are replaced with highly-efficient new NGCC capacity[4]. This would include all of the existing oil, gas and coal-fueled steam capacity in Connecticut.

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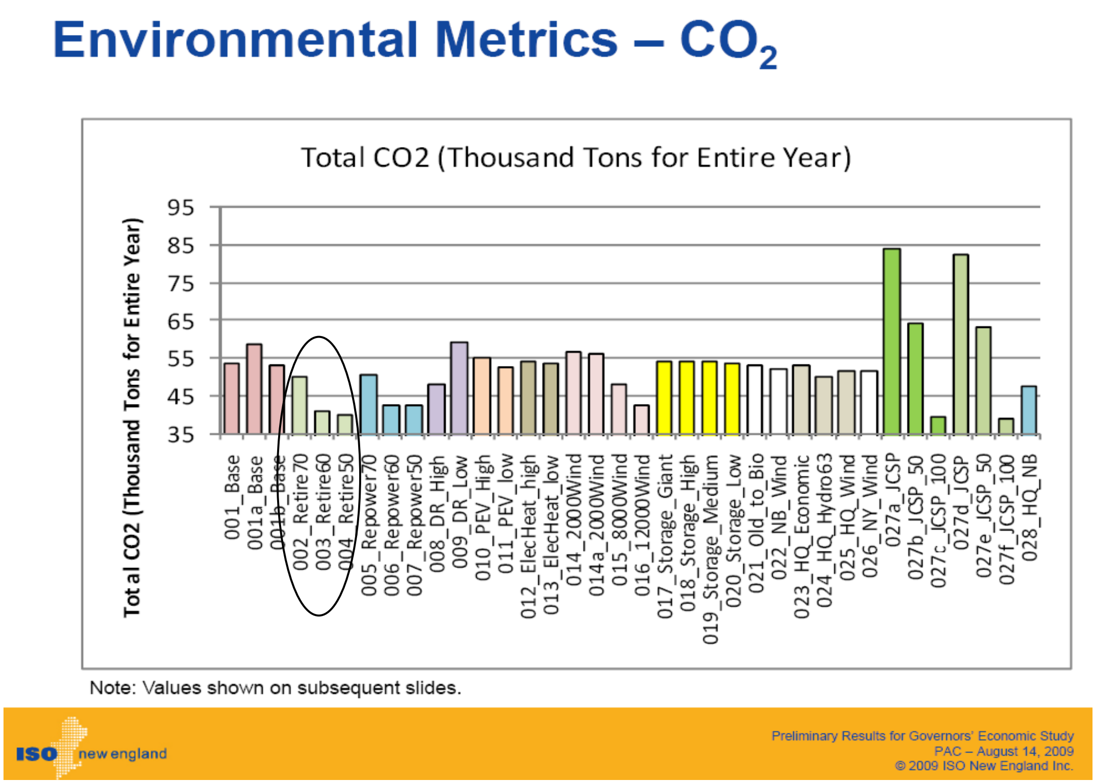
3 New England Governors' Renewable Energy Blueprint, September 15, 2009, http://www.nescoe.com/uploads/September_Blueprint_9.14.09_for_release.pdf , at 6.

4 This scenario produces the lowest costs, with the exception of a case which assumes 9,600MW of hybrid coal/wind energy from the upper Midwest is delivered to a point in southwestern Connecticut. Note that the ISO studies did not include in the scenario metrics the cost of transmission within the New England

The ISO's study indicates that the maximum benefit to the system is achieved by introducing very efficient (low heat rate) new capacity. This is consistent with the intuitive observation that there is a substantial benefit to be gained by replacing capacity with a heat rate of 10,000+ BTU/kWh with capacity that only requires 7,000 BTU to produce a kilowatt-hour.

In addition to the economic benefits, the ISO's study in support of the governors' blueprint effort also showed that the cases in which the older fossil plants are replaced with new NGCC capacity will result in lower emissions of CO_2, SO_2 and NO_x than virtually all of the other renewable scenarios modeled. These replacement cases are shown in the chart below from ISO's presentation to the Planning Advisory Committee on August 14, 2009, in the bars that are circled. The case names, 'Retire70,' 'Retire60,' and 'Retire50' refer to the retirement and replacement with new, efficient NGCC capacity of all of the fossil steam capacity in the region that is 70, 60 and 50 years old as of 2030, respectively. These results indicate that by eliminating these sources of emissions fueled by oil and coal and replacing them with substantially more efficient plants fueled by natural gas, which has lower inherent carbon emissions, the region can achieve substantial emissions gains, generally better than in the cases that focused on substantial wind and other renewable resources or demand resources.



region, and made no attempt to estimate the cost of transmission or the source resources external to the region. Including such costs would substantially harm the relative economics of the 'midwest' case.

Section II - Repowering Procurement Process

Basis for Repowering Procurement

The statutory basis for Connecticut's Integrated Resource Plans calls for the plans to secure needed resources in a manner that maximizes benefits to Connecticut consumers. As described in earlier sections, there is a substantial benefit to renewing the fleet, replacing and repowering older plant sites into cleaner and more efficient generation units. In addition, the statutory basis explicitly places high value on optimizing the use of existing sites. This lowers the impact on land-use of permitting new greenfield sites for heavy industrial use, and lowers the cost of developing new plants because much of the infrastructure is already in place on existing sites to support new plants.

The state has an opportunity in the 2010 IRP, and for several years, to take a pro-active approach to renewing and reusing the state's valuable existing electric energy infrastructure in a way that will produce both economic and environmental benefits for Connecticut's citizens. The 2010 IRP should include a procurement plan targeted at repowering, reusing and replacing existing capacity with new capacity with better performance and environmental characteristics, such as efficient gas-fired combined cycle technology, renewables or demand resources while retiring one or more existing fossil steam units.

The opportunity is created by the relative surplus of capacity existing in Connecticut and the region right now and projected to exist for several years. While the surplus exists, it is much less risky to shut down an existing unit while a new one is constructed in its place or major modifications are performed. System reliability and economy will not be affected, whereas in a tight supply situation, it would be very ill-advised to shut down a unit for months or years while building its replacement.

On the other hand, failing to take proactive steps toward repowering the existing sites risks the potential for an equipment failure or a new environmental regulation to force an immediate shutdown of one or more of these existing units, which could lead to reliability issues and sub-optimal economic outcomes if there is no plan in place for procuring replacement capacity. In the first two iterations of the Connecticut Integrated Resource Plan (2008 and 2009), the decision to not proceed with a procurement was based on the lack of a projected need for incremental MW of capacity in the state within the planning horizon. The process outlined below would lend itself to the current situation in which Connecticut may not have an immediate, apparent need for incremental MW, but would nonetheless create significant net ratepayer benefits from repowering parts of the existing fleet.

Repowering Procurement

To meet economic and environmental benefits objectives (absent the need for incremental MW), the Department should issue a procurement as outlined below:

i. The procurement would be for in-state resources (generation and demand-side) that would replace existing in-state capacity and produce net economic and environmental benefits.
ii. Project submittals must include verifiable plans to retire existing in-state generating capacity equal to at least 75% of proposed new project MW. Development projects would not be limited to existing generation sites, but must include the linkage to retirement of existing fossil steam capacity.
iii. Project submittals must demonstrate that any new air permit would result in lower allowable emission rates than the currently allowable rates for the capacity being retired.
iv. Project submittals must demonstrate that existing use of surface water resources will be improved through reduced water use, reduced thermal discharges and/or reduced mortality of fish and their larvae.
v. Evaluation of the proposals would utilize production cost modeling to determine wholesale energy prices and costs to Connecticut load, and emissions of major pollutants, under the 'as is' case and in change cases with proposed projects and associated retirements. Appropriate fuel price and other sensitivities would be evaluated.
vi. If proposed projects and associated retirements result in net present value savings and net environmental reductions compared to the 'as is' case, the Department would approve those projects and direct that contracts be signed.

This process would address several objectives. First, it would determine the extent of energy savings that could be achieved by replacing older fossil steam capacity with new NGCC, renewable or demand resource capacity, in the context of specific projects and binding cost proposals. The ISO's recent studies have concluded that such savings are achievable, and Connecticut should access the marketplace to secure those savings. Second, the retirement of existing fossil steam units would produce both real emissions benefits in terms of emissions on High Electric Demand Days and 'allowable permit' emissions benefits. When evaluating compliance with federal ambient air standards, the DEP must consider not only emissions that actually occur, but what is allowable under existing permits ("potential emissions"). A very effective way to make real progress in compliance is to retire potential emissions associated with older units with relatively high emission rates and replace them with newer, more efficient and lower emission rate facilities.

Third, to the extent that any of the existing fossil steam plants is uniquely located such that it is needed for local area reliability, replacing a high heat rate generator with a very efficient generator vastly reduces the potential for consumers to have to support out-of-market payments specifically to meet the reliability need. Whereas the older units have been uneconomic in the energy markets for a number of years, forcing ISO-NE to incur costs above market prices to ensure that the units are on-line in case of contingencies, the new units will be economic in virtually all hours, so will be economically dispatched on-line to support local and system reliability. Finally, NGCC capacity, especially with quick-start capability, is highly flexible and can respond quickly to changes in system conditions. As more wind and other intermittent capacity are added to the system, the region will need more of this flexible and responsive capacity to ensure that the system can remain balanced even as the wind speed varies during the day and across the region.

General Procurement

A similar procurement structure could be used in years in which the IRP does forecast a need for incremental new MW of capacity. In those instances, there would not necessarily be a need for demonstrating a linkage to retirement of existing capacity and permits, but the general outline would be the same.

i. Procurement would be for in-state resources that will add generation or demand-side MW capacity in the most economical manner, consistent with the state's environmental and renewable resource goals.
ii. The quantity procured should be sufficient to meet the identified need in at least year 5 of the forecast period, to ensure time to complete the RFP and contracting process, and to synchronize with ISO-NE's Forward Capacity Market
iii. Evaluation of the proposals should utilize production cost modeling to determine wholesale energy prices and costs to Connecticut load, and emissions of major pollutants, in cases with individual and groups of proposed projects. Appropriate fuel price and other sensitivities should be evaluated.
iv. The proposed projects that result in the lowest net present value costs and lowest emissions over the evaluation horizon would be approved and the Department would direct that contracts be signed.

The lead time for a general procurement for incremental capacity needs is at least four and possibly five years in order to obtain the full benefits of participating in the ISO-NE Forward Capacity Market ("FCM"). The process for qualifying and clearing a new project in that market starts over 52 months in advance of the date when physical deliveries must begin, and the auction itself takes place 40 months in advance of the delivery date. In order to synchronize project construction with market benefits, the Department should ensure that its procurement is sufficient to meet the needs five years out in the planning horizon, and that its process concludes, with approved contracts, in time to allow contracted suppliers to take on obligations in the auction 40 months in advance of the contract and FCM delivery date.

Procurement Timeline

With planning and good communication of events and deadlines, it is possible that the IRP process, including procurement, could be accomplished within a year. It would be advisable to establish an expectation of completing the entire process within no more than thirteen months, to ensure synchronism with FCM, as discussed above. Given the statutory requirement that procurement plans must be filed on January 1, and with FCM auctions due to occur in February of each year in the long run, completing the contracting and all approvals by the middle of January one year after the submittal of the plan could allow for participation by winners in the Forward Capacity Auction immediately. If contracts are not finalized and approved until after January, FCM participation would have to be delayed by another year. The timeline below suggests a schedule by which the process could be accomplished within a year.

i. IRP (including procurement plan) submitted January 1
ii. CEAB review complete and submitted to DPUC (60 days by statute, ~March 1)
iii. DPUC review complete and decision issued (60 days by statute, ~May 1)
iv. DPUC order on IRP includes timeline for procurement
    a. qualifications and notice of intent due 30 days after order (~June 1)
    b. full proposal due 75 days after order (~July 15)
    c. DPUC decision 75 days after proposals submitted (~October 1)
    d. execute agreements within 60 days after order (~December 1)
    e. DPUC approval of agreements within 30 days (~December 31)

Contract Structure

As has been the case since the early 2000s, newly developed generation, like projects that would respond to a Department procurement, requires a long-term off-take agreement in order to obtain the necessary capital financing. In light of the current economic and financial crisis, the need for such long-term agreements has become even more paramount. A contract for differences ("CfD") structure is a beneficial form for any such long-term agreement, and should encompass sales of both energy and capacity, much as the Department employed in the 2008 procurement of peaking generation projects. Other contract structures are possible, but a CfD, based on cost-of-service or other fixed or indexed pricing, provides the best balance of competitive procurement, reliance on wholesale markets, cost transparency, and efficient risk allocation. The Department should consider adopting a pro-forma contract for use as the basis for all procurements under the IRP.

Structure

Under a CfD structure, Connecticut consumers would receive the financial benefits of the projects procured through the IRP. Project proponents would offer their project output into the ISO-NE markets, and bear responsibility for fuel procurement, with the goal of maximizing ISO-NE revenues to offset overall contract costs to Connecticut consumers. Additionally, the presence of the new facilities within the state of Connecticut will benefit ratepayers overall through the addition of low heat rate generation in the dispatch stack, as well as their reliability benefits.

Pricing

Capacity and ancillary services could be priced based on a fixed or indexed $/kw-month charge. Energy could be sold through a heat rate call option using variable rates for fuel, start up costs and other commodities. The heat rate option could settle against the day-ahead ISO-NE energy market for the appropriate Connecticut Load Zone. Commodity pricing for the variable components could be based on publicly-available indices to the extent possible. The fixed elements of pricing could be levelized or customized by contract year to meet the needs of the buyer.

This structure provides an excellent balance of risk allocation. A fixed capacity payment ensures that the project sponsor is responsible for any risks associated with construction costs, fixed operation and maintenance ("O&M") costs, equipment repairs and upgrades. The fixed heat rate multiplier in the energy call option ensures that the project sponsor is responsible for all risks associated with equipment degradation over time. The indexed variable component for fuel and other variable commodity inputs to energy production (emission allowances, water, chemicals, variable O&M) recognizes that these costs are quite volatile and can vary widely over time. In order to provide a fixed-price, long-term contract, project sponsors would typically need to place a risk premium on these costs. However; with this approach (*i.e.*, indexing such costs to visible market prices for the input commodities), consumers receive efficient and transparent pricing throughout the contract term.

Term

A minimum contract term of 15 years is advisable in order to provide sufficient time for recovery of plant financing costs. A 15-year term also provides the benefit of long-run cost certainty to consumers. In general, longer terms will allow even lower fixed prices and may facilitate financing.

Section III – Site and Technology Considerations

A. Environmental Considerations

The environmental impact of electricity generation has been a major focus of environmental and civic leaders for decades, and today's generation fleet is substantially 'cleaner' than ten or twenty years ago. Nonetheless, there is more that can be done, and regulators and policy-makers continue to explore mechanisms to achieve further reductions in emissions and improvements in air and water quality. Achieving these important societal objectives comes at a cost, putting pressure on existing plants to continually reduce their environmental footprint. Several of the significant regulatory initiatives on the horizon are described below.

High Electric Demand Day Reductions

On March 2, 2007 the DEP became a signatory to the Ozone Transport Commission's Memorandum of Understanding ("MOU") targeting High Electric Demand Day ("HEDD") emission reductions to achieve Ozone Attainment. Under the MOU, the signatory states agreed to pursue NOx reductions from 'HEDD units' on high electric demand days in the Ozone Season (May – September). As specified in the MOU, the reductions are to begin as early as the 2009 Ozone Season and no later than the 2012 Ozone Season. The MOU lists the expected reduction in Connecticut as 11.7 tons per day.

There is no precise definition for an 'HEDD unit' in the MOU, but the DEP generally describes the HEDD units as the load-following boilers and older combustion turbine units that have the majority of their operations when electric demand is high. All of the oil-fueled units listed units in Section III.B are considered by DEP to be HEDD units.

The repowering or reuse of these units can be a critical component in reaching the state's HEDD commitment. For evaluating NOx reductions from HEDD units, the DEP will compare the baseline emissions from the HEDD units to the future actual emissions from the units. Because any repowered unit would be required to install NOx controls to meet the Lowest Achievable Emission Rate ("LAER"), the NOx rate from the unit should be considerably lower than the baseline NOx from the existing units, up to 90%. As a result, DEP would be able to confirm reductions in HEDD emissions.

Ozone Attainment

Connecticut is currently in non-attainment of the 8-hour National Ambient Air Quality Standard ("NAAQS" or "standard") for ozone. This 8-hour standard is being reconsidered by the Environmental Protection Agency ("EPA"). An EPA notice to issue proposed regulations is expected by December 31, 2009 with the final NAAQS issued in August 2010. Because the reconsideration involves a lowering of the standard, it is expected that Connecticut will continue to be in non-attainment of the NAAQS. As a result, DEP would be required to file with EPA by December 2013 a State Implementation Plan ("SIP") that discusses measures taken and to be taken in the state to achieve attainment with the NAAQS by August 2017.

Repowering or replacing the existing fossil steam units in Connecticut with more efficient and lower-emitting generating sources will lower the permitted levels of NOx, a precursor to ozone and a major contributor to Connecticut's non-attainment status. Similar to the benefits that can be achieved toward the state's HEDD targets, the repowering or reuse of these units can be a component in reaching the state's attainment requirement under NAAQS.

Clean Air Interstate Rule – Replacement

On May 12, 2005, EPA issued the Clean Air Interstate Rule ("CAIR") which limited SO2 and NOx emissions in 28 states via a cap and trade system. On July 11, 2008, the rule was vacated and remanded to EPA to be corrected. However, on December 23, 2008, CAIR was stayed and allowed to be implemented while the rule is being rewritten. EPA plans to propose a CAIR replacement rule in spring 2010 with final issuance in early 2011.

The significance to existing generation of the replacement rule for CAIR will be dependent on the level at which EPA sets the caps for SO2 and NOx. The new rule is expected to be no less stringent than CAIR, with indications that it could in fact be more stringent. The new rule has the potential to require substantially lower SO2 and NOx emissions, and to make it costly to emit large amounts of these pollutants. Repowering or replacing the existing fossil steam units in Connecticut with more efficient, lower-emitting generation could lower emissions and the costs of producing energy.

Maximum Achievable Control Technology for Hazardous Air Pollutants

EPA is considering the regulation of Hazardous Air Pollutants ("HAPs") from coal and oil fueled units. Proposed regulations are expected in late 2010, final regulations in 2011, with an effective date of late 2013. Such regulations could result in a requirement for scrubbers for coal plants and electro-static precipitators ("ESPs") for oil-fueled units where this technology is not currently installed. These major capital investments would not likely be justified on the existing fossil steam units in Connecticut, leading to their retirement.

Regulation of Carbon Emissions

Regional Greenhouse Gas Initiative

RGGI is a cap and trade system designed to reduce overall regional emissions of CO2 and other greenhouse gases by 10% by 2018 from a baseline of approximately 150 million tons per year. RGGI covers ten states in the northeast U.S. RGGI is intended to create an economic incentive for lower-carbon sources of energy by producing a market-based price for carbon emissions through an auction process. In general, a coal-fired generating unit has a CO2 emission rate twice the rate of a gas-fired unit, and thus will have twice the cost of carbon allowances.

Federal CO2 Cap and Trade Legislation

Federal legislation on a national CO_2 cap-and-trade program is expected in 2010. While there are many proposed version of the legislation, there are common themes in all the proposals. It can be expected that year 2005 CO_2 emissions will set the baseline for future reductions, reductions up to 20% by 2020 are anticipated, there will be incentives for improving energy efficiency, and some, if not all, of the allowances must be procured through an auction process.

Unlike RGGI, which only regulates the electric generating industry, a federal program will encompass numerous industries. It remains to be seen if the federal allowance market dynamics will be similar or dissimilar to what has been observed in the RGGI market.

Additionally, the DEP RGGI regulations do not contain a sunset provision for RGGI when a federal program is enacted. If the DEP deems a federal program to not be as stringent as RGGI, the RGGI program may stay in effect thus causing "double regulation" of CO_2 emissions from generating sources.

Under either case (a federal program with or without RGGI), a repowered source will have a lower CO_2 cost on a pounds per megawatt-hour basis, both because of using lower-carbon natural gas and by virtue of the substantially lower heat rate.

GHG Tailoring Rule

On October 27, 2009, EPA proposed a rule that would "tailor" existing air permit programs to create a new emissions threshold that is applicable to greenhouse gas emissions from new and existing facilities. This rule, if implemented, will require a Best Available Control Technology ("BACT") analysis for CO_2 for any new generating sources or major modifications at existing sources. EPA has set up a working group to establish some guidance on what BACT would be. It is anticipated that projects that improve energy efficiency, such as a repowered unit, will be considered to be BACT.

Cooling Water Use

EPA and DEP have recently increased their attention, review and assessment of once-through cooling uses at existing generating stations. Under Section 316 of the Clean Water Act, sites must demonstrate that their once-through cooling activities do not have a significant thermal impact on the receiving water body of the discharge (316(a)) and do not have a significant level of impingement or entrainment ("I&E") of fish and their larvae (316(b)).

EPA and DEP are considering the extent to which they might require cooling towers at existing units as opposed to the existing once-through systems as a way to reduce thermal and I&E issues. Of the sources listed in Section III.B, only Middletown Unit 4 has a cooling tower. Cooling towers are a major capital investment, and a requirement to install them at an existing plant could very likely lead to the retirement of the unit.

Repowering or reusing the existing sites with new combined cycle technologies would almost certainly require cooling tower or similar technology that would minimize, if not eliminate, thermal discharge and I&E concerns associated with once-through cooling. Such a requirement could be justified as part of a new project that is supported by a contract and the prospect of meaningful revenues from the wholesale markets, unlike an existing unit.

B. Potential Candidate Sites for Repowering/Reuse

Two primary factors drive the identification of likely candidate sites for reuse or repowering: technology and age. The two are highly correlated, since the industry relied on boiler steam technology almost exclusively until the 1980's, when the introduction of gas turbine-based combined cycle technology set a new standard for baseload plant costs, efficiency and environmental performance. The prime candidates for repowering or reuse are the existing fossil-fueled steam plants that are currently in operation and that were built prior to 1980.

The table in Appendix A shows that the primary candidates for repowering or reuse comprise over 2,500 MW, or 36.2% of the capacity currently installed in the state. Even taking into account the anticipated additions of the Kleen combined cycle plant, the Waterbury peaker, and the GenConn and PSEG peakers, the fossil steam plants will make up over thirty percent of the state's installed capacity. Given the substantial portion of the state's resource mix represented by these units, the substantial role these sites play in the reliability of the state's and region's interconnected electrical grid and their integration into the local economies, there is a good basis for focusing on repowering and reuse of these sites.

In the sections below, there is a brief description of each station's current technology and configuration and existing fuel and electrical interconnection infrastructure, and a brief discussion of potential NGCC configurations as well as other technology options that might be considered on each site.

<u>Norwalk Harbor (NRG)</u>

The steam station at Norwalk Harbor consists of two similar oil-fueled units, Unit 1 at 162MW and Unit 2 at 168MW. The units were first commissioned in 1960 and 1963, respectively. There is also a 12MW oil-fueled combustion turbine on the site. The Norwalk Harbor site comprises approximately 124 acres on Manresa Island on Long Island Sound. The plant has barge access and fuel oil storage capabilities. The units interconnect to the CL&P 115kV substation on the Norwalk Harbor site. That substation is also the terminus of the 1385 cable which extends across Long Island Sound to Northport, NY.

The most efficient repowering configuration without substantially expanding the interconnection at Norwalk Harbor would be to retire one of the existing steam turbines and then install a 'G' class combustion turbine in conjunction with the remaining steam turbine in a combined cycle configuration. This would result in approximately the same total output as the two existing steam turbines, but with more than a 35% improvement in efficiency and a significantly improved environmental profile, based on using natural gas. In this configuration, the plant could achieve a heat rate of approximately 7,000 Btu/kWh. To support a NGCC configuration, a gas pipeline would have to be extended from an existing pipeline, likely either from the Iroquois interstate pipeline six miles offshore in Long Island Sound, or from the new Iroquois lateral from their Brookfield compression station.

Other NGCC options include a larger 2x1 configuration with a rating of approximately 800MW. While this configuration would make more efficient use of the site's space and the new gas pipeline infrastructure, it would also require substantial upgrades to the electrical interconnection, likely involving extending 345kV transmission to the Norwalk Harbor site from CL&P's Norwalk substation.

Additional options for the Norwalk Harbor site include solar photovoltaic panels on the capped ash landfill area on the site. Initial estimates are that approximately 10MW of photovoltaics could be installed on this area. Alternatively, the site might be developable into a 'renewable energy education and resource center,' with small wind turbine, photovoltaic, fuel cell and perhaps other demonstration-scale renewable installations and an educational resource center.

Middletown Station (NRG)

There are four steam units at Middletown, one of which is deactivated, and a 17MW oil-fueled combustion turbine. Middletown 2 is a 117MW steam unit dating from 1958, and can burn both natural gas and residual oil. Middletown 3 is a 236MW steam unit dating from 1964 and is also dual-fuel capable. Middletown 4 is a 400MW steam unit dating from 1973 and is fueled exclusively with oil. Units 1, 2 and 3 are interconnected to the 115kV system, and Unit 4 is interconnected at 345kV. The Middletown Station site is also the site of the new 200MW GenConn peaker project, which NRG is building in partnership with the United Illuminating Company. Middletown Station is located on the shore of the Connecticut River in the Maromas section of Middletown. The site has barge access, oil storage capability, and a high-pressure natural gas pipeline on the site.

The most viable options for repowering at Middletown include conversion of the existing Unit 4 steam turbine into a combined cycle with the installation of two or three combustion turbines in a 2x1 or 3x1configuration. The re-powered output would be approximately 800 MW. It would also be possible to retrofit the existing Unit 1 boiler to burn biomass with an output of approximately 40 MW. An additional renewable opportunity would be, as with the Norwalk site, to use the capped ash ponds to site solar photovoltaic panels. Finally, Middletown Station would also be an ideal location, based on its connection on both the 115 and 345 kV systems, for various smart-grid applications including fly-wheel or battery electricity storage technologies.

Montville Station (NRG)

The Montville Station has two operating steam units and two small diesel units. Unit 5 is an 81MW dual-fuel steam unit dating from 1954 and Unit 6 is a 407MW oil-fueled unit dating from 1971. he site has rail and barge access on the Thames River, on-site oil storage, a natural gas pipeline, and both 115kV and 345kV electrical interconnections.

NRG is in the process of repowering Montville 5 to use clean wood biomass to produce 40MW of baseload renewable power. The repowered unit would also be capable of using natural gas or ultra-low sulfur distillate oil to produce the full 81MW rating of the unit if needed by ISO

New England to meet high demand for electricity or for other emergencies. The project includes the addition of new back-end emission controls. The Unit 5 boiler is well-suited to conversion to biomass, and the ability to operate in baseload mode on renewable fuel, but respond to emergencies with the full output of the unit provides valuable environmental and reliability benefits. The biomass fuel supply in the Montville area is estimated to be more than sufficient to support a plant of this size, and the project will produce Class 1 RECs.

The most logical repowering option for Montville 6 is a new NGCC unit on the footprint currently occupied by Unit 6 or a conversion of Unit 6 to combined cycle configuration with various combustion turbine options. As with the other NRG stations this would result in more than a 35% efficiency improvement, a vastly improved emissions profile, and an "in-market" facility that would dispatch frequently based on relatively low marginal operational costs.

New Haven Harbor (PSEG Power Connecticut LLC)[5]

New Haven Harbor Station is a single 466MW oil fired steam unit located at 1 Waterfront Street at the Port of New Haven. The unit entered commercial operation in 1975 and operates primarily on No. 6 0.3% sulphur fuel oil, and is capable of co-firing with natural gas up to 40% of the fuel input. The property encompasses approximately 43 acres of land on the eastern edge of New Haven Harbor. It includes a marine bulk loading and unloading facility, two above-ground oil storage tanks in a diked containment area each with a capacity of 13.6 million gallons. The facility is connected to Southern Connecticut Gas Company's distribution system currently limited to about 2,500 mcf per hour, and subject to further restriction depending upon weather conditions and the concomitant load on the SCC system. The capacity factor of the unit has declined over the past several years to below 10% in 2009, and has operated under a Reliability Must Run contract since 2004. The station has been deemed needed for reliability by ISO-NE through May 2011.

New Haven Harbor Station is also the site of a new 130MW peaker project to be constructed by PSEG pursuant to a contract with CL&P that was awarded through an RFP process sponsored by the CT DPUC under Public Act 07-242. The peaking project will consist of 3 General Electric LM6000 PC turbine generating units and related facilities. The peaking units will operate primarily on natural gas and will have distillate fuel back up using ultra-low sulphur distillate.

Early stage options for repowering New Haven include building a new combined cycle plant of two potential sizes: 550MW or 770MW, the configuration for which would be based upon operational and economic objectives (i.e.: 2 train 1x1; 2x1; 3x1 configuration), either of which would be adjacent to the existing plant. Additional consideration will be given to the potential for the re-use of the existing steam turbine to be incorporated into a combined cycle configuration.

Bridgeport Harbor (PSEG Power Connecticut LLC)

[5] The sections describing New Haven Harbor and Bridgeport Harbor stations were contributed by PSEG Power Connecticut LLC.

The Bridgeport Harbor Station is comprised of three operating units and one non-operational unit. Unit 2 is a 130MW oil fired steam unit that entered commercial operation in 1961. Unit 2 has been operating under a Reliability Must Run Contract since 2004 and has been deemed needed for reliability by ISO-NE through May 2011. Unit 3 is a 410MW coal fired steam unit built in 1968. In 2008, PSEG added a bag house for particulate and mercury control reducing mercury emissions by over 85%. Bridgeport Unit 4 is a 22MW fast start jet unit built in 1967. The facility has a marine bulk unloading facility for both solid fuel (coal) and oil. The site can inventory approximately 400,000 tons of coal, and also has four oil storage tanks.

Early stage options for the redevelopment of Bridgeport are for the repowering of Units 1 and 2 and replacing those units with a new combined cycle facility in the existing unit's footprint with an approximate rating of 360MW. Additional consideration will be given to the potential for the re-use of the existing steam turbines to be incorporated into a combined cycle configuration. Although natural gas is not currently directly connected to the facility, a large pipeline is nearby the facility (at the adjacent Bridgeport Energy facility).

C. Technology Considerations

Natural gas-fueled generation, with appropriate oil back-up capability, is the only significant and meaningful option for New England and Connecticut, for the next decade at least. That is however, good news based on recent structural changes in gas supply in the New England and the east coast. With the advent of our country's ability to economically drill and bring to market shale gas from various basins in the United States, Connecticut has its choice of six abundant and distinct gas commodity sources delivered from three separate interstate pipelines to competitively supply new and existing natural gas-fueled combined cycle plants. This diverse supply coupled with the increased availability of LNG in the region significantly alleviates concerns in previously planning cycles regarding the long term supply availability and associated price volatility of natural gas in Connecticut and New England.

Unlike other regions of the nation, Connecticut's options for large-scale carbon-neutral energy generation are relatively limited. While there is significant potential for nuclear in the South, solar in the West and wind in the Midwest, New England's options are not as extensive. Connecticut makes great use of hydro generation, but there are no significant new sources available. There are significant off-shore wind options near Connecticut and on-shore wind in more remote parts of the Northeast that could potentially be used to serve Connecticut's consumers. However, wind and other renewable resources are intermittent and need "firming" capacity to ensure that supply will always meet instantaneous demand for electricity. Additionally, solar photovoltaic and wind capacity within Connecticut is likely to account for only a small part of the state's daily energy needs. For instance, approximately seven acres of land are needed for one megawatt of solar photovoltaic capacity, enough to power about 100 homes at its average output. Similarly, land based wind turbines require a significant amount of land per wind turbine tower. Siting on-shore wind turbines has proven to be very contentious due to visual and other impacts on neighbors and wildlife, further limiting the potential for widespread deployment of wind in a densely-populated state like Connecticut. And wind is highly intermittent and needs so be supported by some sort of firming capacity that can respond to changes in the wind farm's output, sometimes in a matter of minutes.

Traditional fossil options such as new coal plants are not likely to be practical in Connecticut, given their relatively high carbon emissions and the lack of suitable geology to sequester carbon captured from an emission stream. Similarly, it is highly unlikely that new nuclear units could be sited in Connecticut in the next 20 -30 years. Oil-fueled generation is currently cost-prohibitive and has substantially more environmental performance and permitting issues than natural gas.

Natural gas-fueled combined cycle plants are Connecticut's best option for a dispatchable source that can provide substantial amounts of low-carbon energy, and should be deployed to replace the existing fossil steam fleet and to "firm" or back-stop the incipient renewable sources that New England is currently working so hard to bring on-line. Installing dual-fuel capability with ultra-low sulfur distillate oil back-up provides an additional level of reliability.

Natural-gas fueled combined cycle plants have the lowest capital cost per installed kW of any type of generation available[6] As noted by the Energy Information Agency, combustion turbines applied in combined cycle present the lowest capital cost option of all generation types. And except for nuclear, natural gas offers the lowest environmental impact of any generation option that is fully dispatchable on a 24/7 basis.

D. Combined Heat and Power

The deployment of natural gas-fueled Combined Heat and Power ("CHP") technology can be a very effective complement to NGCC technology. The effective use of CHP, however, is normally restricted to customers (or groups of customers) with significant on-site or near-site thermal requirements (i.e., heating and/or cooling). These include business districts in major cities and large institutional/commercial/industrial facilities (e.g., hospitals, data centers, research centers, manufacturing facilities, airports).

CHP is a well-established, proven and mature technology that supports the following goals:

- Maximize efficiency of energy production
- Minimize environmental impacts of power generation
- Maximize electric reliability over the planning horizon

The first two, regarding efficiency and environmental impacts, are supported by the fact that, for a given amount of useful energy output, CHP systems consume less fuel and generate fewer emissions than even the most efficient conventional generation systems. CHP efficiencies are typically ~70%. The third, regarding reliability, is supported by the fact that CHP systems are normally built at or near customer locations, eliminating (or significantly reducing) reliability issues associated with transmitting and distributing electricity over long distances. Related transmission and distribution line losses and costs are also dramatically reduced.

The State of Connecticut already has in place the legislative framework for utilizing CHP in its cities. Energy Improvement Districts (EIDs) were established by C.G.S. §16-32(g)(9)-(24). EIDs allow businesses and local governments to work collectively to own and operate distributed

[6] EIA Report #:DOE/EIA-0554 (2009), Release date: March 2009, Next release date: March 2010.

energy facilities for the purpose of providing electricity and thermal energy at lower cost and with higher reliability than otherwise available. District energy systems produce steam, hot water and/or chilled water and sometimes electricity at a central plant. The steam or water is then piped underground to individual buildings within a specific area for heating, cooling or industrial use. District energy systems exist in many cities in the US, including Minneapolis, Harrisburg, Pittsburgh, San Francisco and San Diego. The concept is proven and district energy is an energy-efficient, environmentally sound method of heating and cooling buildings while providing reliable electricity production.

Two Connecticut cities, Ansonia and Stamford, have established such districts and others are considering them. EIDs represent an available mechanism for cities and towns to harness the efficiencies of CHP in partnership with local businesses.

Beyond EIDs, other potential CHP would require large energy-intensive installations, especially with large and steady thermal energy needs (heating/cooling). The Connecticut Academy of Science and Engineering has performed an extensive review of waste heat and CHP potential, and the necessary policy and infrastructure considerations for the state, which is available at http://www.ctcase.org/reports/waste_heat.pdf.

E. Fuel Supply Considerations

There are several recent developments in natural gas supply that together mitigate many of the concerns in previous Connecticut energy policy documents around the availability and security of natural gas supply as well as concerns over future price volatility associated with natural gas supply and demand. Connecticut benefits from being served by three interstate pipelines capable of delivering natural gas from six distinct gas basins or supply areas. The increasingly interconnected pipelines are Spectra's Algonquin Gas Transmission pipeline, the Iroquois Gas Transmission pipeline, and the Tennessee interstate pipeline. Commodity can be moved from multiple areas including the Gulf Coast, Western Canada, Eastern Canada (mainly offshore Nova Scotia, but with some onshore production and future potential, including shale gas), Appalachia (conventional and Marcellus Shale), the Rockies, and LNG.

Iroquois is still predominantly a conduit for Western Canadian gas, but there is more gas entering Ontario from Chicago via Michigan that finds its way into Iroquois and that gas is from a blend of supply sources. Tennessee and the Algonquin/Texas Eastern system both pull from the Gulf Coast, but have also traditionally tapped into Appalachian supplies and underground storage in western Pennsylvania, West Virginia and western New York, both directly and through connections to regional pipelines such as Dominion Transmission. The Rockies Express ("REX") pipeline was recently completed to Clarington, Ohio where it connects with Dominion and Texas Eastern (TETCO). REX also has a direct connection with Tennessee. The Marcellus production is also located near the existing Tennessee and Texas Eastern pipelines and both of these pipelines have expansion projects in the works that will move both Rockies and Marcellus gas to markets further east. Specifically to this year's IRP process, Iroquois has presented their so-called NYMarc project that will connect their pipeline system to the Millennium pipeline from which the Marcellus could be shipped into Connecticut.

The Maritimes pipeline was expanded from 400 MMcfd to 833 MMcfd at the beginning of 2009 and the Repsol/Irving Canaport import terminal has been online since July of 2009. Production from the Sable Island offshore project is declining, but the Encana Deep Panuke field is scheduled to come on line with an additional 200-300 MMcfd by the end of 2010. By some time next year both the Excelerate Northeast Gateway and GdF Neptune offshore LNG receiving terminals will be in service in Massachusetts Bay. All of this commodity will contribute to an ample supply for Connecticut.

Greater diversity of supply and the fact that the Tennessee and Algonquin systems now draw gas from sources both west and east of Connecticut as well as the Iroquois system being able to draw gas from north and south of Connecticut should also help avoid situations where upstream pipeline constraints cause the New England price to exceed that in other parts of the country. Shale is one part of the picture, but LNG and other conventional sources will also continue to be important.

Appendix A

Generation Resources in Connecticut

From: ISO New England, 2009-2018 Forecast Report of Capacity, Energy, Loads and Transmission (CELT), April 2009

RESOURCE NAME	FUEL GEN TYPE DESC	IN-SERVICE DATE (EXPECTED)	SECTION 2.1 SUMMER SCC JAN 1, 2009	SECTION 2.1 WINTER SCC JAN 1, 2009	
Primary Repower/Reuse Candidates					
MIDDLETOWN 1	OIL STEAM	01-Oct-96	-	-	
MIDDLETOWN 2	GAS/OIL STEAM	01-Jan-58	117.000	120.000	
MIDDLETOWN 3	GAS/OIL STEAM	01-Jan-64	236.000	245.000	
MIDDLETOWN 4	OIL STEAM	01-Jun-73	400.000	402.000	
MONTVILLE 5	GAS/OIL STEAM	01-Jan-54	81.000	81.590	
MONTVILLE 6	OIL STEAM	01-Jul-71	407.401	409.913	
NEW HAVEN HARBOR	GAS/OIL STEAM	01-Aug-75	447.894	454.644	
BRIDGEPORT HARBOR 2	OIL STEAM	01-Aug-61	130.495	147.509	
BRIDGEPORT HARBOR 3	COAL STEAM	01-Aug-68	383.426	384.984	
NORWALK HARBOR 1	OIL STEAM	01-Jan-60	162.000	163.995	
NORWALK HARBOR 2	OIL STEAM	01-Jan-63	168.000	172.000	
	Sub-total		**2,533.216**		**36.2%**
Other Connecticut Generation Resources					
CDECCA	GAS/OIL COMBINED CYCLE	01-Nov-88	55.254	61.334	
BRISTOL REFUSE	BIO/REFUSE	01-May-88	13.200	12.736	
DEXTER	GAS/OIL COMBINED CYCLE	01-May-90	38.000	39.000	
EXETER	BIO/REFUSE	01-Dec-91	24.174	25.661	
FALLS VILLAGE	HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-14	3.483	7.568	
FRANKLIN DRIVE 10	OIL COMBUSTION (GAS) TURBINE	01-Nov-68	15.417	20.527	
LISBON RESOURCE RECOVERY	BIO/REFUSE	01-Jan-96	12.961	13.036	
MIDDLETOWN 10	OIL COMBUSTION (GAS) TURBINE	01-Jan-66	17.123	22.023	
MILLSTONE POINT 2	NUCLEAR STEAM	01-Dec-75	876.923	878.414	
MILLSTONE POINT 3	NUCLEAR STEAM	01-Apr-86	1,137.483	1,237.196	
MONTVILLE 10 and 11	OIL INTERNAL COMBUSTION	01-Jan-67	5.296	5.354	
NORWICH JET	OIL COMBUSTION (GAS) TURBINE	01-Sep-72	15.255	18.800	
RAINBOW	HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-80	8.200	8.200	
SECREC-PRESTON	BIO/REFUSE	01-Jan-92	16.011	16.514	

SO. MEADOW 11	OIL COMBUSTION (GAS) TURBINE	01-Aug-70	35.781	46.921
SO. MEADOW 12	OIL COMBUSTION (GAS) TURBINE	01-Aug-70	37.701	47.867
SO. MEADOW 13	OIL COMBUSTION (GAS) TURBINE	01-Aug-70	38.317	47.917
SO. MEADOW 14	OIL COMBUSTION (GAS) TURBINE	01-Aug-70	36.746	46.346
SO. MEADOW 5	BIO/REFUSE	01-Nov-87	25.596	29.210
SO. MEADOW 6	BIO/REFUSE	01-Nov-87	27.113	28.116
AES THAMES	COAL STEAM	01-Dec-89	181.000	182.150
TORRINGTON TERMINAL 10	OIL COMBUSTION (GAS) TURBINE	01-Aug-67	15.638	20.748
TUNNEL 10	OIL COMBUSTION (GAS) TURBINE	01-Jan-69	16.962	22.062
GOODWIN DAM	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	3.000	3.000
CEC 003 WYRE WYND U5	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-97	1.225	2.780
COLEBROOK	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	1.550	1.550
WILLIMANTIC 1	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	0.225	0.770
WILLIMANTIC 2	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	0.225	0.770
TOUTANT	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-94	0.400	0.400
PUTNAM	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	0.163	0.575
GLEN FALLS	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-98	-	-
MECHANICSVILLE	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-95	0.054	0.267
CEC 004 DAYVILLE POND U5	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	-	0.100
SANDY HOOK HYDRO	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-89	0.077	0.105
PINCHBECK	BIO/REFUSE	01-Jul-87	-	0.011
QUINEBAUG	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-90	0.305	1.298
BANTAM	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-05	0.065	0.320
TUNNEL	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-19	1.256	2.100
ROBERTSVILLE	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	0.354	0.624
SCOTLAND	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	1.674	2.200
TAFTVILLE CT	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-06	2.025	2.025
NEW MILFORD	BIO/REFUSE	01-Aug-91	1.296	1.296
CRRA HARTFORD LANDFILL	BIO/REFUSE	01-Aug-98	2.215	2.215
Manchester Methane LLC East Windsor Facility	BIO/REFUSE	07-May-07	-	-
BRIDGEPORT HARBOR 4	OIL COMBUSTION (GAS) TURBINE	01-Oct-67	15.414	20.214
WHEELABRATOR BRIDGEPORT, L.P.	BIO/REFUSE	01-Apr-88	58.517	58.741
BRANFORD 10	OIL COMBUSTION (GAS) TURBINE	01-Jan-69	15.840	20.950
BULLS BRIDGE	HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-03	3.484	8.400
DERBY DAM	HYDRO (DAILY CYCLE - RUN OF	01-Mar-89		7.050

	RIVER)		7.050	
DEVON 10	OIL COMBUSTION (GAS) TURBINE	01-Apr-88	14.407	19.186
DEVON 11	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	29.299	38.819
DEVON 12	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	29.227	38.437
DEVON 13	OIL COMBUSTION (GAS) TURBINE	01-Oct-96	29.967	38.967
DEVON 14	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	29.704	40.274
SHEPAUG	HYDRO (WEEKLY CYCLE)	01-Jan-55	41.511	42.559
STEVENSON	HYDRO (WEEKLY CYCLE)	01-Jan-19	28.311	28.900
WALLINGFORD REFUSE	BIO/REFUSE	01-Mar-89	6.350	6.900
ROCKY RIVER	HYDRO (PUMPED STORAGE)	01-Jan-28	29.350	29.001
KINNEYTOWN A	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	-	-
KINNEYTOWN B	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	0.585	1.510
MCCALLUM ENTERPRISES	HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	-	-
SHELTON LANDFILL	BIO/REFUSE	01-Jun-95	-	-
BRIDGEPORT ENERGY 1	GAS COMBINED CYCLE	01-Aug-98	445.144	524.388
PPL WALLINGFORD UNIT 1	GAS COMBUSTION (GAS) TURBINE	31-Dec-01	42.922	48.410
PPL WALLINGFORD UNIT 2	GAS COMBUSTION (GAS) TURBINE	07-Feb-02	40.129	51.129
PPL WALLINGFORD UNIT 3	GAS COMBUSTION (GAS) TURBINE	31-Dec-01	42.942	47.837
PPL WALLINGFORD UNIT 4	GAS COMBUSTION (GAS) TURBINE	23-Jan-02	42.497	47.782
PPL WALLINGFORD UNIT 5	GAS COMBUSTION (GAS) TURBINE	07-Feb-02	41.154	52.154
MILFORD POWER 1	GAS/OIL COMBINED CYCLE	12-Feb-04	260.279	288.516
MILFORD POWER 2	GAS/OIL COMBINED CYCLE	03-May-04	260.841	295.380
Pierce	GAS COMBUSTION (GAS) TURBINE	01-Oct-07	75.441	94.941
JOHN STREET #3	OIL INTERNAL COMBUSTION	26-Sep-07	2.000	2.000
JOHN STREET #4	OIL INTERNAL COMBUSTION	26-Sep-07	2.000	2.000
John Street #5	OIL INTERNAL COMBUSTION	01-Nov-07	2.011	2.011
John Street 1	OIL INTERNAL COMBUSTION	15-May-08	2.000	2.000
Cytec 1	OIL INTERNAL COMBUSTION	15-May-08	1.929	1.924
Cytec 2	OIL INTERNAL COMBUSTION	15-May-08	1.945	1.930
Cytec 3	OIL INTERNAL COMBUSTION	15-May-08	1.941	1.939
NORWICH WWTP	OIL INTERNAL COMBUSTION	29-May-08	2.000	2.000
Kimberly-Clark Corp Energy Independence Project	HYDRO (DAILY CYCLE - RUN OF RIVER)	19-Mar-08	1.500	1.500
Kimberly-Clark Corp Energy Independence Project	GAS COMBINED CYCLE	15-Jul-08	9.450	16.850
Waterbury Generation Facility	GAS COMBUSTION (GAS) TURBINE	01-Jul-09		
COS COB 10	OIL COMBUSTION (GAS) TURBINE	01-Sep-69	19.497	24.397

COS COB 11	OIL COMBUSTION (GAS) TURBINE	01-Jan-69	16.941	21.841	
COS COB 12	OIL COMBUSTION (GAS) TURBINE	01-Jan-69	18.461	23.361	
NORWALK HARBOR 10 (3)	OIL COMBUSTION (GAS) TURBINE	01-Oct-96	11.925	17.125	
WATERSIDE POWER	OIL COMBUSTION (GAS) TURBINE	01-May-04	71.218	72.758	
Cos Cob 13&14	OIL COMBUSTION (GAS) TURBINE	29-May-08	19.201	24.201	
Cos Cob 13&14	OIL COMBUSTION (GAS) TURBINE	29-May-08	19.603	23.478	
Norden 1	OIL INTERNAL COMBUSTION	26-Feb-09	-	-	
NORDEN 2	OIL INTERNAL COMBUSTION	26-Feb-09	-	-	
NORDEN 3	OIL INTERNAL COMBUSTION	26-Feb-09	-	-	
	Sub-total		**4,463.730**		**63.8%**
	Total Generation Resources		**6,996.946**		**100.0%**
Committed Generation Additions					
Waterbury			96.000		
Kleen			620.000		
GenConn Devon			187.600		
GenConn Middletown			187.600		
PSEG Peaker			130.000		
	Sub-total		1,221.200		
	Repower Candidates		2,533.216		**30.8%**
	Other Generation		4,463.730		**54.3%**
	Committed Additions		1,221.200		**14.9%**
			8,218.146		**100.0%**