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Presented to:

New York City Economic Development Corporation

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Hunts Point Food Distribution Center

Energy Strategy Plan- Phase1

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Introduction

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Introduction

The New York City Economic Development Corporation (NYCEDC) teamed with DMJM Harris to produce a preliminary Energy Strategy Plan for the Hunts Point Food Distribution Center (FDC) located in the Bronx, New York. Situated on 329 acres, the Hunts Point Food Distribution Center is among the largest distribution centers in the world. Approximately $2 billion in gross annual revenues are generated by the Produce Market alone. The success and growth of the FDC is vital to the economic development of the Hunts Point peninsula as well as the South Bronx.

NYCEDC, as administrator of the FDC, is currently exploring a number of development projects at the FDC. Among these is an energy strategy that will both reduce current energy consumption and supply a substantial portion of the energy needs of the FDC with distributed generation (DG).

In coordination with the Hunts Point Vision Plan and PlaNYC, this report is the first phase of an energy strategy plan that seeks to identify economically and environmentally viable energy approaches for the Food Distribution Center.

Acknowledgements

This project could not have been completed without the input and assistance of many individuals and organizations. First and foremost, the staff of the NYCEDC namely, Alison Kling, Jim Gallagher, Eric Wilson, Josh DeFlorio, Jen Becker, Liz Kim, Cindy Lo, and Mike Delaney who provided invaluable assistance throughout the duration of this project.

Other notable contributors to the success of this project include:

George Maroulis, Market Manager of the New Fulton Fish Market
Steve Bettencourt, Director of Maintenance of the New Fulton Fish Market
Caleb Haley Inc. of the New Fulton Fish Market
Bruce Reingold, General Manager of the Hunts Point Cooperative Market
Brian Kenny, Operations Manager of the Hunts Point Cooperative
J.R. McIntyre, General Manager of the NYC Terminal Produce Cooperative Market
Michael Muzyk, President of Baldor Specialty Foods
Rocco D'Amato, Chief Executive Officer of Bazzini Nuts
Ruben DeMille, Plant Facilities Manager of Krasdale Food Distribution Center
Sigmund Balka, Vice President of Krasdale Food Distribution Center
Phil Del Prete, Chief Executive Officer of R. Best Produce
Rich Brown, Customer Project Manager of Con Edison
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Without the support of these people and parties, this report would not have been possible. Thank you.

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Executive Summary

Executive Summary

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Executive Summary

The New York Economic Development Corporation (NYCEDC) commissioned DMJM Harris to assess sustainable energy approaches for the Hunts Point Food Distribution Center (FDC), located in the Hunts Point neighborhood of the South Bronx. The FDC is the site of the City's major wholesale markets, including the Hunts Point Cooperative Market (Meat Market), the New York City Terminal Produce Market (Produce Market) and the New Fulton Fish Market at Hunts Point (Fish Market). As the FDC is entirely City-owned property, NYCEDC, on behalf of the City, administers long-term leases to these and other food-related businesses. In addition to the major markets, other tenants included in this report are:

- Krasdale Food Distribution Center
- Bazzini Nuts, Inc.
- R. Best Produce
- Baldor Specialty Foods, Inc.
- Anheuser Busch
- Citarella
- Sultana Distribution Services, Inc

OBJECTIVES

This report has five components:

1. *Existing energy consumption patterns of individual tenants,* including facility electrical and thermal load profiles, current condition of the facilities, potential energy conservation measures (ECMs) and interviews to understand tenants' receptivity to district generation.

2. *Utility infrastructure assessment*, including an evaluation of the Con Edison distribution system for its ability to provide the electrical load needed for future FDC growth and to accept power onto its grid.

3. *Feasibility assessment of a combined heat and power (CHP) plant* based on the energy needs of FDC tenants. The plant was sized to supply the electrical load of the entire FDC. An economic feasibility analysis is included.

4. *Evaluation of applicable alternative energy technologies,* including solar and fuel cells.

5. *List of regulatory impacts,* including an investigation of the utility interconnection requirements, issues such as franchise rights and fault current, and the application process required to utilize Con Edison's grid for district generation.

PRINCIPAL RESULTS

Existing Energy Consumption

The ten FDC tenants investigated in this report purchase an estimated 168,066,405 kWh of electricity and 185,141 MMBTUs of fuel annually at a cost of $25.7M. The estimated aggregate peak load of these ten facilities is about 23 MW. The facilities have constant heavy refrigeration loads but the overall load profiles are typical in that the peak electrical load occurs in the summer, while peak thermal load occurs in the winter. The majority of gas consumption is due to heating rather than processing.

The majority of the tenants were very proactive about energy savings. However, some easily implementable ECMs were identified for each facility. The ECMs recommended in this report cost a total of $3.5M, however would reduce annual electricity consumption by 2.7 MWh, generating a total annual savings of $479,102 to FDC tenants, equating to a 7.3 year payback.

Of the major wholesale markets, the Meat Market has only four electric meters and charges subtenants for common power on a square foot basis that is incorporated into their leases. Subtenants at the Fish and Produce Markets each have at least one electric meter tied directly to Con Edison. The advantage of common power, such as at the Meat Market, is that a single entity may have more negotiating leverage in purchasing greater amounts of power. However, individually-metered subtenants tend to be more energy conscious since they are responsible for the bill. Because the tenants in both the Fish and Produce Markets are submetered, The specific usage histories and utility agreements for these tenants would have to be investigated further if a developer were to be brought onboard to provide third party power generation.

Utility Infrastructure Assessment

The majority of the FDC is on a 480 V network. This is not an optimal arrangement for receiving power supply from a distributed source, such as would be the case with district generation. However, Con Edison's South Bronx network is served by a newly upgraded delivery system and there is enough capacity to support an additional demand of 10-20MW, the projected load if the FDC expands to full capacity.

The Meat Market is the sole tenant on 13kV power, while the other tenants are on 480 V feeders. 13kV power is preferable for the integration of a CHP plant, and should be incorporated into future FDC developments, if possible.[1]

Combined Heat and Power

The benefits of CHP are that it could provide power at a greater efficiency and lower emissions rate than a central power plant. It would also reduce the burden on the grid during peak loads. Further, the Meat Market, with its central cooling load, could reduce its electrical consumption by up to 2.2 MW if it were to utilize the steam produced by a CHP facility to run a steam turbine coupled to the ammonia chillers.

The ideal site for a CHP is next to the Meat Market utility building because it would be in close proximity to incoming Con Ed 13kV service and near the ammonia refrigeration system. The three fuels utilized in the preliminary assessment were: natural gas, the Hunts Point Water Pollution Control Plant anaerobic digester gas and biomass as outlined in the "Organics Recovery Feasibility Study"[2].

Discussions with the Meat Market Facilities Manager revealed that they would be interested in entering into a subtenant agreement with a future developer for a CHP. Also, the interconnection was technically feasible and the CHP plant emissions would be below New York State Department of Environmental Conservation major source emissions limits for know as "Title V Thresholds", therefore limiting the duration of the permitting process to about a year. However, given the current subsidized energy rates paid by FDC tenants, it is not economically feasible for a CHP plant to supply power to the tenants. When tenant subsidies expire and the average rate of the FDC more closely reflects market pricing for

[1] The size of service feeders that Con Edison installs to service new loads is handled on a case by case basis and is highly dependant on the configuration of the local utility distribution infrastructure. The process begins when a load letter is submitted to Con Edison notifying them that the customer will be seeking new service capacity. Any customer requirements that specify feeder service characteristics that are not readily available can result in additional costs from Con Ed to meet those requirements.

[2] *Hunts Point Food Distribution Center Organics Recovery Feasibility Study,* final report December 30, 2005. Prepared by DSM Environmental Services, Inc for NYCEDC. Available at NYCEDC website at http://www.nycedc.com/NR/rdonlyres/3138BD0F-08EC-4601-AA60-B3ED7392C0C2/0/HPOrganicsRecoveryFeasibilityStudy.pdf

commercial and industrial facilities, a CHP plant should be reevaluated. This should happen within the next few years but it is dependant on whether NYCEDC and Con Ed decide to renew these favorable terms with the various FDC tenants.

Alternate Energy Technologies

The FDC has several assets that are appealing to a solar application: large horizontal roof areas, low rise buildings, low urban density setting, no shading from adjacent buildings and contiguously located buildings that are under a single management entity. Given the 3.2 million square feet of existing rooftop area, and possible future rooftop space of 1.4 million square feet, there is the potential for 20-25 MW of power at the FDC, an unprecedented volume of solar for New York City. It is recommended that an in-depth solar feasibility study be pursued for the FDC.

Con Edison should conduct a detailed analysis of the South Bronx "4-X" network in terms of its capacity to accept 25 MW of solar PV. If utility infrastructure upgrades are necessary to accept large scale solar PV, NYCEDC should advocate on behalf of grid improvements at the New York State Public Service Commission (PSC) level as well as in other forums. It would also be important to partner with Con Edison to prepare a simplified interconnection process specifically tailored to large scale solar PV deployment at the FDC.

The other alternative energy evaluated was fuel cells. Fuel cells do not emit greenhouse gases and they are quiet, fuel versatile and efficient. However, there is currently a lack of performance data available due to the limited amount of deployment. Therefore, due to costs and unknown life expectancy, fuel cells are not a recommended technology for further exploration for FDC applications at this time.

Regulatory Impact

There are a number of different electrical distribution configurations that a distributed generation developer could use to bring power to the FDC tenants, however, initial review of the site conditions indicate that installing dedicated feeders would be cost prohibitive. Therefore, though interconnecting to Con Edison may have its challenges, it is the only feasible option for the FDC. In order to facilitate a distributed generation plant at the FDC, the facility should be designed to achieve Qualifying Facility[3] status. For this status, the total efficiency of the plant should be above 42.5%, which is easily attainable.

When planning the interconnect phase of future properties, the developer should require 13kV feeder service from Con Edison. Further, for new construction, a distributed generation should be built into the development criteria as a requirement and the plant should be designed to offset the potential load.

Lastly, Con Edison currently limits DG generation capacity to 10MW for tie-ins to feeders and 20 MW for tie-ins at substations. The current and future FDC loads will require much larger generation capacity from a CHP. Therefore, it is recommended that the NYCEDC encourage the exploration of Con Edison's methodology for estimating feeder capacity.

Summary of Major Findings

- ECMs could save the FDC tenants an aggregate $479,102 per year. At an estimated investment of $3.5 million, this would result in a 7.3 year payback

[3] A Qualifying Facility (QF) refers to a class of generator that meets specific criteria, including a requirement that the generator utilizes either CHP or alternative energy technology. In New York State, a QF must meet both federal and state guidelines. The federal guidelines are under the purview of the Federal Energy Regulatory Commission (FERC). Additional information can be found on FERC's website at http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp . The state statutes defining a QF are administered by the New York State Public Service Commission (PSC).

- CHP is technically viable but under the current incentivized electricity rates from Con Ed, NYPA and NYCEDC, it is not economically competitive. Once the existing incentivized rates expire, CHP is projected to be economically competitive against utility electricity costing $.212/kWh. This is the projected energy cost on the forward market.
- Fuel cells are not economically viable for the needs of the FDC. They are also not the preferred technical solution to the FDC's back-up power needs
- Solar PV is promising energy strategy for the FDC. Utilizing current building rooftop space and well planned future construction, there is a possibility of deploying from 20 to 25 MW of solar power at the FDC.
- A number of technical and regulatory initiatives specific to the South Bronx utility network would need to be undertaken to enable the deployment of large scale solar PV.
- The existing utility infrastructure can support load growth, but a network study would have to be done to determine if the grid can support distributed generation.

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Section 1 Site investigation

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Section 1: Site Investigation

1.1 INTRODUCTION

The NYCEDC commissioned DMJM Harris to evaluate the potential for third party development of a central Combined Heat and Power (CHP) facility and other energy conservation measures.

Prior to making this determination, it was necessary to tour these facilities with the intent to obtain information regarding the operations of each. During these tours, detailed data was recorded relating to each facility's electrical and thermal configuration along with consumption. Also documented was information relating to the building envelope and the varied uses of each facility. Lastly, during these tours, any potential Energy Conservation Measures (ECMs) were also noted; these ECMs may achieve a reduction in wasteful energy consumption and result in cost savings.

1.2 TENANT SITE INVESTIGATION SUMMARY

During the course of the site tours, it was noted that many of the facilities varied in age, condition and usage. The sites visited are listed below:

- Hunts Point Cooperative Market (Meat Market)
- Krasdale Food Distribution Center
- NYC Terminal Produce Cooperative Market
- The New Fulton Fish Market
- Bazzini Nuts, Inc.
- R. Best Produce
- Baldor Specialty Foods, Inc.

Our team was able to use information provided to us by NYCEDC to project energy loads for Anheuser Busch, Citarella, and Sultana Distribution Services, Inc. During each facility site visit, information was gathered regarding the electrical distribution, gas heating, refrigeration, freezing and air conditioning. Also investigated were the lighting and electrical plug loads at each facility. Electrical utility and gas utility invoicing was received for a portion of the listed facilities. Where invoicing was not available, consumption estimates were made based on the square footage, area usage, condition of equipment, time of operation and mode of operation. Estimates are based on standards set by the American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE) and the Association of Energy Engineers (AEE). The finding of the site walkthroughs are listed below:

1.2.1 Hunts Point Cooperative (Meat Market)

The Meat Market performs as a meat distribution and storage facility, with a small amount of processing. The Meat Market operates five days a week, twenty-four hours a day with administrative offices operating between 9:00 AM and 5:00 PM. The facility operates with just over 2,000 personnel operating 45 businesses.

The market operates in 7 buildings labeled “A” through “G”. Buildings A through C are comprised of approximately 367,650 square feet. Building D (Central Plant) is approximately 45,000 sq ft. Buildings E and F are storage buildings and are about 150,000 sq ft. total. Bldg G is the newest of the buildings and is about 110,000 sq ft. Buildings A through F were built in the 1970’s with building G built around 2001-02. Tenants of the Meat Market rent space on a square foot basis and this includes heating, refrigeration and freezing. The tenant is responsible for other plug loads, lighting and garbage. Buildings A, B, C and E each have a total of 50 “bays” or “booths”. The office spaces are located on the second floor of these buildings. The buildings are primarily concrete and cinder block construction with single pane windows. The office spaces are outfitted with heating, air conditioning and ventilation services. The storage areas are well insulated to maintain lower temperatures.

1.2.2 Krasdale Food Distribution Center

The Krasdale Food Distribution Center stores and distributes dry goods and non-perishable produce. The facility and offices are open five days a week, twenty-four hours a day. The administrative offices operate between 8:00 AM and 6:00 PM Monday through Friday with a staff of about 80-90 personnel in the warehouse and about 100 personnel in the offices.

The warehouse area is approximately 280,000 square feet and the office space is about 20,000 square feet. The first floor office and the main section of the warehouse were built around 1972. In 1980 the office was expanded with a second floor and the warehouse was extended southward. The warehouse and office is primarily concrete and cinder block construction. The office windows are single pane with aluminum mullions and no thermal breaks. The windows are noted for drafts and poor insulating value; they occasionally frost over on the inside during winter months. The entire facility recently installed a foam and silicon seal roof upgrade.

1.2.3 NYC Terminal Produce Cooperative Market (Produce Market)

The Produce Market stores and distributes fruit and vegetable produce. The market and offices are open five days a week, twenty-four hours a day. The office operates between 8:00 AM and 6:00 PM Monday through Friday with a staff of about 200 personnel in the office and hundreds in the tenant spaces.

The tenant area is approximately 728,000 square feet. The office space is about 182,000 square feet. The buildings were constructed around 1967 with extensions being done in 1975. The warehouse is primarily concrete and cinder block

construction. The office spaces are similar construction. The office windows are single pane with aluminum mullions and no thermal breaks. The windows are noted for drafts and poor insulating value.

1.2.4 The New Fulton Fish Market (Fish Market)

The New Fulton Fish Market stores, processes and distributes seafood. The market is open from 12:00 AM on Sunday through 9:00 AM on Friday. The offices are open five days a week from 2:00 AM through 12:00 PM with a staff of about 100 office personnel and warehouse personnel ranging from 800 to 1,200.

The warehouse area is approximately 350,000 square feet. The office space is about 78,000 square feet. The offices and the main section of the warehouse were built around 2002. There are currently thirty-four tenants occupying the facility. The warehouse is primarily concrete block, steel and metal cladding with well insulated walls. The office spaces are similar construction. The office windows are double pane with aluminum mullions and thermal breaks. The construction is relatively new and thermally tight.

1.2.5 Bazzini Nuts, Inc.

The Bazzini Nuts facility processes nuts and other dried goods into packaged food products. The facility is open from Monday through Friday from 5:00 AM through 9:00 PM and Saturdays from 8:00 AM through 2:00 PM. The facility operates with about 30 office personnel and with plant personnel ranging around 70.

The entire facility is approximately 70,000 square feet with about 7,000 square feet of this being office space.
The plant and office building is primarily concrete block with steel frame and metal cladding with insulated walls. There are no office windows. Thermal and plastic strip doors are used in the plant between refrigerated rooms but not on the loading docks. The construction is relatively old and thermal infiltration is apparent around doors. Some of the doors could use trim weather seals.

1.2.6 R. Best Produce

The R. Best facility stores and distributes fruit and vegetable produce. The facility operates around the clock Monday through Saturday and from 3:00 PM through midnight on Sunday with a staff of about twenty office personnel and with around sixteen plant personnel.

The entire facility is approximately 72,000 square feet with about 7,000 square feet of this being office space. The plant and office building is primarily concrete block with steel frame and metal cladding with insulated walls built in the 1960's. There are no office windows. Thermal and plastic strip doors are used in the plant between refrigerated rooms and on the loading docks. The construction is relatively old and thermal infiltration occurs. The dock seals are in need of replacement.

1.2.7 Baldor Specialty Foods, Inc.

When we interviewed Baldor, it had just relocated to its newly refurbished facility and parts were still under construction. The facility processes, stores and distributes produce, meats and dry goods. The warehouse operates twenty-four hours per day with the offices operating on a staggered shift between 5:00 AM and 1:00 AM with a staff of around 100 office personnel and with plant personnel ranging around 500.

The entire facility is approximately 180,000 square feet with about 15,000 square feet of this being office space. The building used to be the old A&P distribution center. Baldor has completely retrofitted the building envelope and mechanical systems with a modern warehouse, office and a world headquarters type facility complete with employee gym and studio type classroom center with television capability. There has been an extensive amount of capital incorporated in the building upgrade.

1.3 ELECTRICAL AND THERMAL LOAD PROFILES

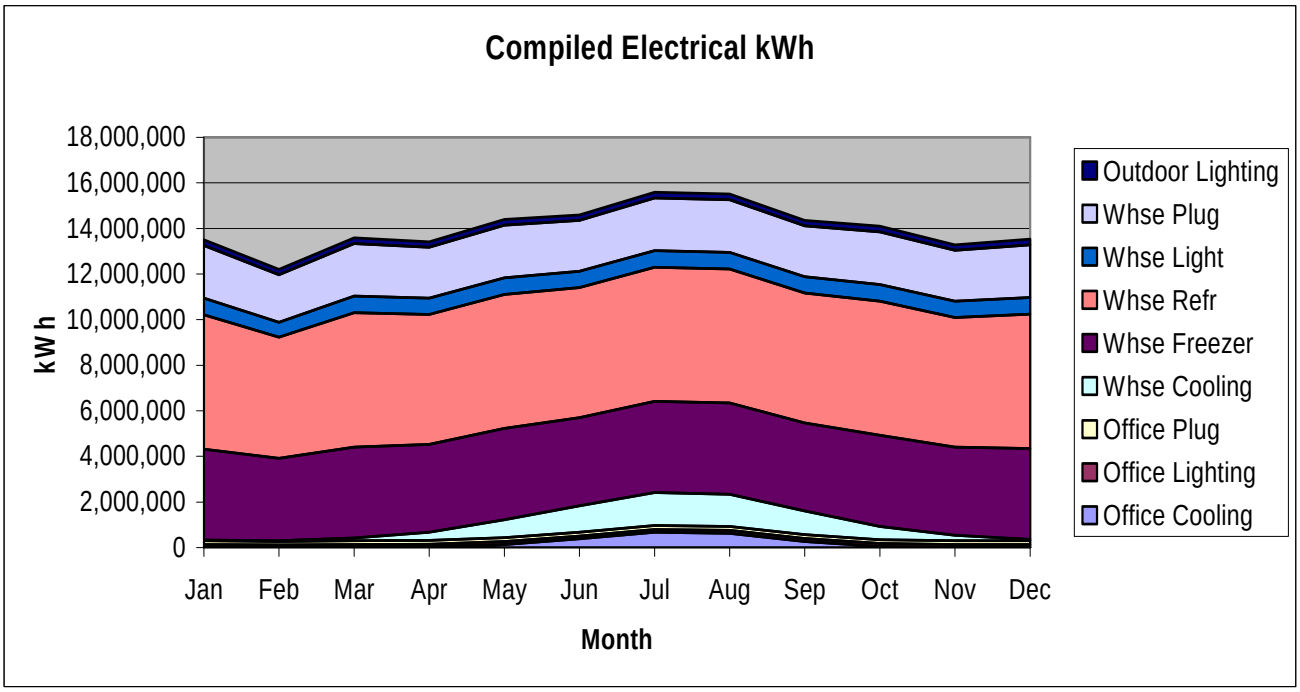
The electrical and thermal load profiles for the Hunts Point major tenants are determined by the supplied utility invoicing. As stated previously, when invoicing or collected data was not available, estimates were compiled based on square footage, area usage, condition of equipment, time of operation and mode of operation. Factors used are based on standards set by the American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE) and the Association of Energy Engineers (AEE).

1.3.1 Electrical Profile

The following electrical consumptions were calculated:

- Office Air Conditioning/ Lighting/ Plug loads
- Warehouse Air Conditioning/ Refrigeration/
- Warehouse Freezing/ Lighting Plug Loads
- Outdoor Lighting

Electrical loads are based on the supplied monthly kWh and demand kW. The facility hours of operation are used to formulate the daytime and evening loads. The majority of the facilities operate with minimal downtime and most have around the clock refrigerator/freezer loads that dominate the electrical consumption. This is the cause of many facilities having a high load factor. The load factor is the average kW/hr consumed for the month divided by the monthly kW demand, indicating that many of the facility loads are near constant. A chart of the calculated electrical loads for the facilities investigated is below.


Compiled Electrical kWh
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16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
kWh
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
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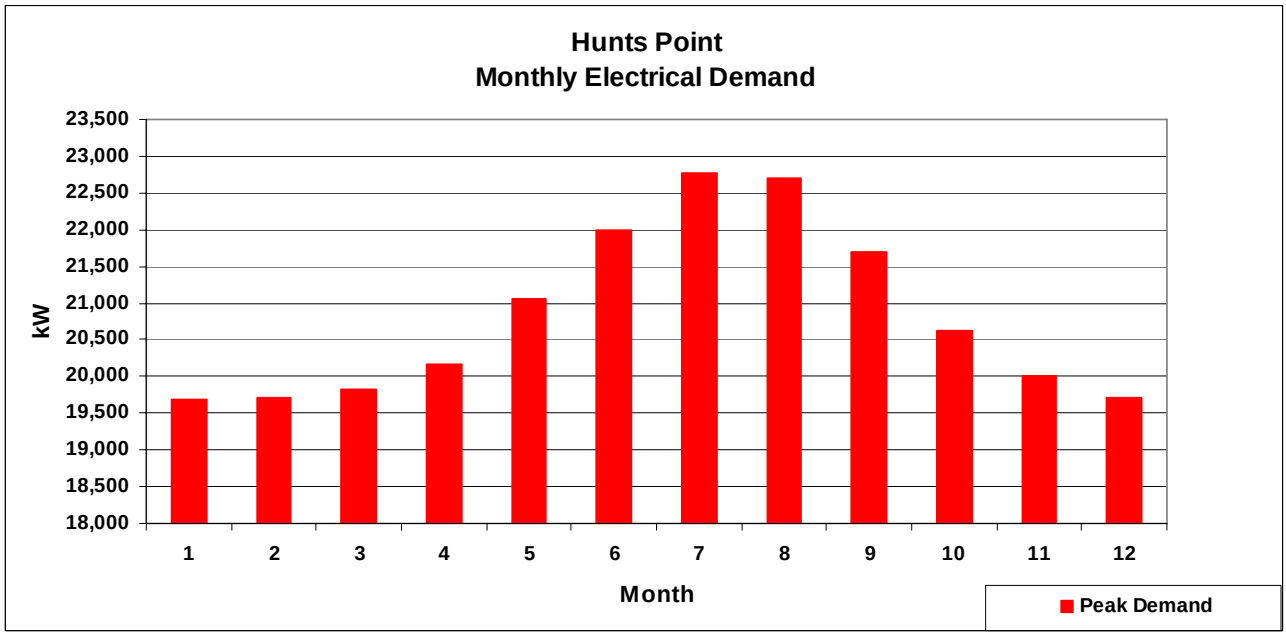
Office Lighting
Office Cooling


Hunts Point
Monthly Electrical Demand
23,500
23,000
22,500
22,000
21,500
21,000
20,500
20,000
19,500
19,000
18,500
18,000
kW
1
2
3
4
5
6
7
8
9
10
11
12
Month
Peak Demand

1.3.2 Thermal Profile

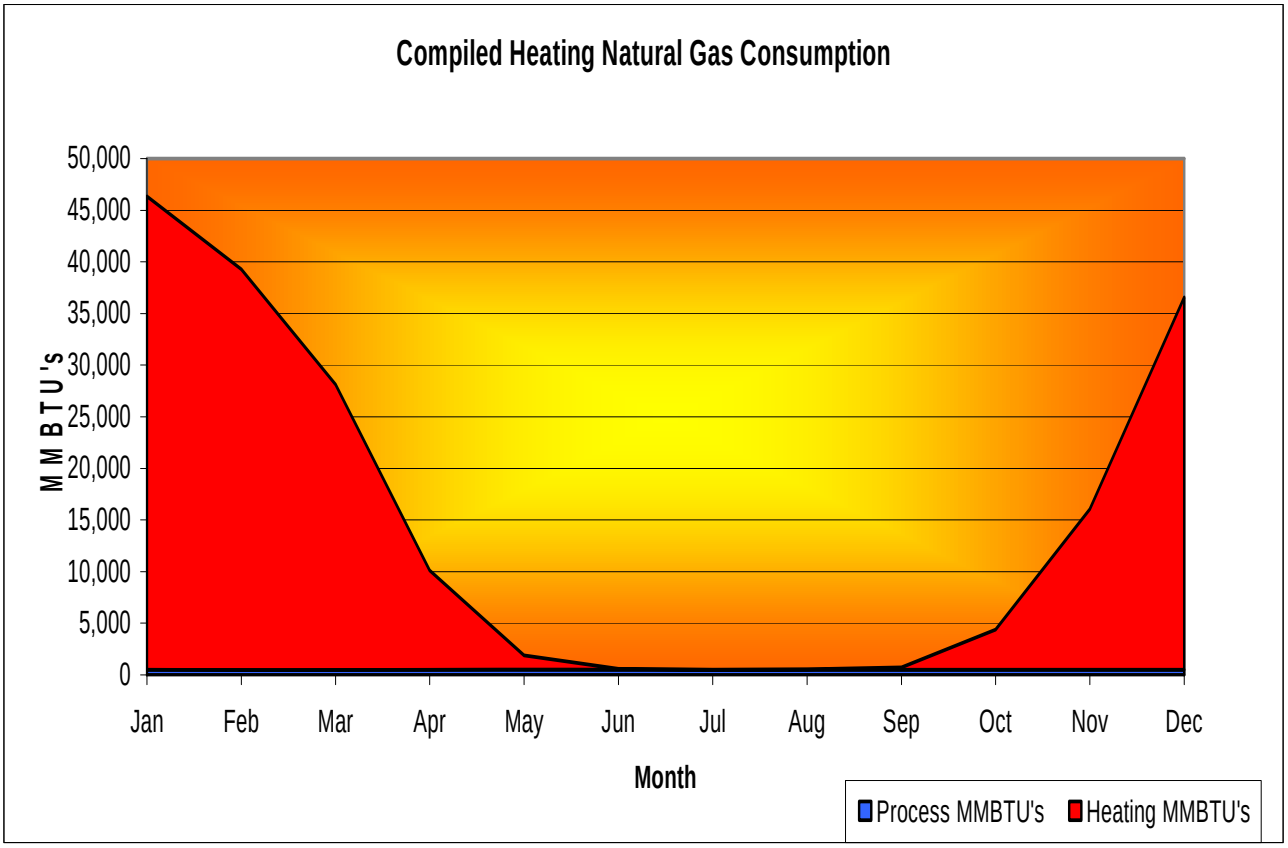
The total natural gas consumption is based upon a combination of facility heating and process loads. Facility heating is calculated based on the design heating load and local weather bin data. The weather bin data utilizes local National Oceanographic and Atmospheric Administration (N.O.A.A.) weather bin data for the Hunts Point location. This source compiles the actual hours that the local weather was at a particular outdoor ambient temperature in 1°F intervals by each month. Using this data, the facility heating design loads are determined based on actual fuel consumption. The design set points are based on actual operating conditions and ASHRAE design standards for the locality.

Facility thermal energy consumption Million British Thermal Units (MMBTUs) were determined by calculations estimating the fuel consumed for the facility heating load at each average hourly outside air temperature for each month. The months are then summed for annual consumption.

The following thermal loads were determined:

- Office Heating Load
- Warehouse Heating Load
- Process Gas Load

A chart of the calculated Natural Gas Thermal Loads for the facilities investigated is presented below. In the chart below, process MMBTU's refer to any natural gas that is used for non-space heating purposes, such as drying.



Total Compiled Heating Natural Gas MMBTU

1.4 CONCLUSION

Upon completion of the site tours at the FDC, DMJM Harris determined that each building varies in equipment and conditions. In some cases the newer buildings have been designed with energy efficient machinery. However, the older the building, the less the initial design catered to energy efficiency, leaving the individual tenants in the position to make these changes. Most of the tenants have taken some measures towards energy efficiency with different levels of aggressiveness in this goal.

Many of the tenants are agreeable to the idea of a central type Combined Heat and Power (CHP) plant if it will supply them with reliable energy at a reduced cost. After the site tours, it was determined that there was only a minimum of skepticism towards this possible venture. Since the majority of the goods distributed from these facilities are perishable, a key concern is reliable electric power.

Peak electrical load occurs in July and is 15,592,646 kWh/month, indicating that much of the electrical consumption is focused on cooling and freezing. Peak thermal consumption takes place in January and is 45,840 MMBTU/ month and indicates that the majority of thermal is used for heating. We calculated peak monthly load because we were not able to obtain meter data for all of the tenants.

The Meat Market differs from the Fish Market and the Produce Market in that it has four electrical meters and includes the cost of the refrigeration, heating and freezing in the tenant lease. The tenants of the Fish Market and the Produce Market are individually metered. There are benefits and drawbacks to both methods. Through individual metering, the tenants are responsible for monitoring their own energy usage and cost. This will usually lead to the implementation of more energy conservation methods than if there was no economic incentive. However, since the meat market is organized into a true cooperative, it has a stronger negotiating power with a possible third party power provider or developer than do the individual tenants at the produce and fish markets. A party interested in developing a CHP plant (developer) to supply energy to the tenants would also find it more favorable to negotiate with a single party representing a large load than multiple individual tenants because of tenant turnover. For instance, every time a new tenant moved in, the developer would have to negotiate a new contract. There is a risk that the new tenant would defer to another electric supplier. However, if the fish market and produce market negotiated as individual entities representing their respective tenants, then they would have a better ability to guarantee a minimum load. The impact on a developer of negotiating with individual tenants versus a cooperative was not explored in depth in this report, but should be addressed if a latter stage feasibility study takes place.

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Section 2 Energy Conservation Measures

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Section 2: Energy Conservation Measures

2.1 INTRODUCTION

During its tour of the FDC, DMJM Harris noted potential Energy Conservation Measures (ECMs). The listed ECMs will assist FDC tenants in reducing energy consumption throughout the visited buildings. The recommended ECMs will usually pinpoint items in the everyday operation of a facility that lead to wasteful energy use. Generally, older equipment and inefficient lighting are the most noticeable prospects. Other opportunities could be the use of normally wasted heat energy that can be used in domestic water heating applications.

The implementation of these ECMs can lead to some energy reductions and reduced operating costs for FDC tenants. DMJM Harris performed a cursory overview of ECMs and calculated a rough estimate of the cost savings per facility. In order to obtain a more precise determination of savings, an energy audit of each facility would need to be performed.

2.2 SUMMARY OF POTENTIAL ENERGY CONSERVATION MEASURES BY TENANT

During the course of the site tour of various tenants, it was noted that many of the facilities could benefit by the implementation of ECMs. The sites are listed below:

- Hunts Point Cooperative Market (Meat Market)
- Krasdale Food Distribution Center
- NYC Terminal Produce Cooperative Market
- The New Fulton Fish Market
- Bazzini Nuts, Inc.
- R. Best Produce
- Baldor Specialty Foods, Inc.

2.3 CONCLUSION

The findings of the FDC site tours indicate that many of the tenants have already had thorough energy audits. Various degrees of ECMs have already been implemented. However, there continues to be opportunities for FDC tenants to reduce current energy consumption. DMJM Harris recommends that individual tenants consider implementing ECMs to reduce current consumption. In addition, should facilities have plans to expand, it is recommended that the ECMs be incorporated into the new construction at that time. The newer buildings are already taking steps to reduce their energy consumption and should incorporate the ECMs to contribute to those efforts. The Buildings that are in the process of complete retrofit can benefit from incorporating the ECMs to insure optimal reduction in energy consumption.

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Section 3 Utility Assessment

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Section 3: Utility Assessment

3.1 INTRODUCTION

DMJM Harris performed a utility assessment at the FDC. This section examines the existing utility infrastructure serving the FDC and its capacity to support future growth plans. In the case that the utility infrastructure does not have sufficient capacity to provide for the energy consumption needs of a distributed generation plant, or if the local electrical system is inadequate for the distribution of electricity back onto the grid, then the existing utility infrastructure would need to be upgraded in order to site a generation facility in this location.

Con Edison serves as both the electrical utility and the gas utility for most of the FDC tenants. Some of the tenants purchase their electricity from a source other than Con Edison, including the New York Power Authority. However, regardless of the source of the electricity, the transmission and distribution (T&D) of this electricity falls under a regulated monopoly granted to Con Edison by state statute.

The electrical distribution system in the FDC, as in much of the City, is underground and unavailable for casual inspection. Therefore the information compiled for this report came from a number of sources including email correspondence, telephone communications and meetings with Con Edison, previously published documents, and web searches. This information is, to the best of our ability, accurate and descriptive of the existing electrical distribution system in the FDC as a whole. However, actual development of any distributed generation system will require much more in depth research into the detailed design of the area network, as well as of the single line electrical diagrams depicting interconnection details between the utility and FDC tenant facilities that are being considered for deployment of distributed generation.

3.2 ELECTRICAL ASSESSMENT

The FDC is supplied by feeders from the recently completed Mott Haven 138/345 kV substation that connects to the existing Dunwoodie to Rainey 345 kV transmission circuits. The Mott Haven facility houses both a transmission substation (345kV) and an area substation (138 kV). The area substation serves an approximately 140 MW network load which was transferred from the Bruckner area substation. This state of the art Mott Haven substation was energized in May of 2007 and was designed to accommodate an additional 250 MW for future growth in the Bronx load pocket[1].

Power is brought to the Hunts Point area of the South Bronx “4X” network via 13 kV feeders. Four of these feeders supply a number of transformers located within Food Center Drive. The distribution system in the Hunts Point peninsula, as with much of the rest of the South Bronx, is a network type system. While this type of system enables a high level of reliability, due to

[1] Steven Brown and Kathleen Davis, *2007 Projects of the Year Award Winners Break New Ground*. Utility Automation & Engineering T&D, E-newsletter available at http://uaelp.pennnet.com/

built-in redundancy, it also exacerbates the potential impact of interconnection of additional generation sources to the system.

With the exception of the Hunts Point Cooperative Market, which is supplied by four 13 kV feeders, the rest of the FDC tenants are on 480V isolated networks. This is unusual as Con Edison's standard distribution network at the customer level is 120/208 V, but necessary because of the resultant heavy motor loads due to the refrigeration requirements of the FDC tenants.

The entire distribution system, from the area substation all the way to the feeder connections to the network is designed for second contingency operation, that is, the loss of any two pieces of equipment or feeders can be sustained on a peak load day without interruption of service.

Currently, there are no plans for any electrical system infrastructure upgrades in the Hunts Point peninsula. In terms of any planned expansion of individual FDC tenant facilities, Con Edison's infrastructure in the area is adequate to handle any foreseeable loads that would be imposed on its distribution system.[2] It should also be noted that in the currently unlikely event that any portion of Con Edison's delivery system were inadequate for planned expansion of the FDC tenant's facilities, Con Edison would upgrade their delivery system to accommodate the new load per regulatory requirements.

While there is adequate capacity within the South Bronx network for new load, the addition of generating capacity to the networks in the FDC area is not as clear-cut. Whether using synchronous, induction or inverter based generation, as long as the possibility exists for power to travel back onto the distribution network, a detailed system network analysis will need to be conducted by Con Edison to determine the impact on its system as well as the necessity for additional protective equipment for the generators or any upgrades to its system.[3]

3.3 NATURAL GAS ASSESSMENT

New York State is heavily dependant on the interstate pipeline system, with at least 80% or its supply being delivered over the interstate system[4]. New York City is a major delivery point for several of the largest pipeline systems, including:

- Texas Eastern Transmission Company
- Transcontinental Gas Company
- Tennessee Gas Pipeline Company, and
- Iroquois Gas Transmission Company

Con Edison has a gas compressor station located in the FDC area within Food Center Drive. Although this compressor station, which was built in 1988, is located in the FDC, it does not serve any of the FDC tenants. The gas supply to the FDC tenants is delivered via a 4" high pressure service line which comes from elsewhere on Con Edison's natural gas distribution system serving the South Bronx.

In addition to Con Edison's natural gas pipeline, the Iroquois pipeline, an interstate pipeline that brings natural gas to New York State from Canada, also transects a portion of the FDC property. This line, however, just passes through the FDC; it does not serve any of the tenants.

The gas distribution service was recently upgraded to supply the steam plant that serves the Meat Market. There are currently no plans for expansion of the natural gas distribution infrastructure in the

[2] Interview with Con Ed. May 22, 2008
[3] Interview with Con Ed. May 22, 2008
[4] Energy Information Administration, Interstate Natural Gas Supply Dependency (website), accessed at http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/dependstates_map.html

FDC. However, Con Edison continually conducts maintenance and upgrade work on their compressor station at the site.

The primary question that arises when considering either expansion of existing FDC facilities requiring gas service, or development of a natural gas fired CHP plant, is whether there is adequate capacity to service these upgrades. The fact is that this cannot be determined until such time as application is made to Con Edison for gas supply. This is usually done by means of a load letter to Con Edison in the early design stage of a project when all of the relevant requirements have been established. All service requests are evaluated by Con Edison's Gas Engineering Department to determine service adequacy. While Con Edison has an obligation to provide service to customers, any extension of their gas distribution facilities could be at the customer's expense. Whether or not cost of distribution upgrades is charged to the customer is determined on a case by case basis.

As was discussed in the previous sections on the existing utility electrical and natural gas infrastructure, Con Edison has no current plans for expansion or infrastructure upgrade of either its electrical or gas system in the near future.

3.4 CONCLUSION

The existing electric infrastructure at the FDC combines some very beneficial attributes with some more problematic aspects. The local 480 V network is questionable for transmission of any excess electricity generated by a distributed generation facility back onto the grid. This reduces the number of buildings that could be considered suitable for interface between a distributed generator and the grid. Without further detailed analysis of the local network design, it cannot be determined for certain where on the local 480V network, interconnection would be possible.

On the other hand, the South Bronx network is served by a newly upgraded and very robust delivery system. There are 13 kV feeders coming into the FDC area from a new substation, with two of these feeders directly connecting to the Hunts Point Cooperative. Due to the recent upgrades to Con Edison's delivery system, there is more than enough capacity available on the delivery system to accommodate any plans for future growth that the FDC may have.

Con Edison's natural gas infrastructure at the FDC is currently capable of supplying more than the current needs of the FDC. However, any additional gas requirements related to future growth at the Hunt Point Distribution Center would have to be evaluated to determine if existing natural gas infrastructure would need to be expanded.

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Section 4 CHP Evaluation

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Section 4 CHP Evaluation

Section 4: CHP Evaluation

4.1 INTRODUCTION

This section preliminarily assessed the feasibility of a CHP system at the FDC. The analysis included a cursory review of the following four distinct load areas:

- Hunts Point Cooperative (Meat Market)
- New York City Terminal Produce Market (Produce Market)
- New Fulton Fish Market (Fish Market)
- East side leased buildings (Anheuser Busch, Baldor Specialty Foods Inc, Bazzini Nuts, Inc., Citarella, Krasdale Food Distribution Center, R. Best Produce, and Sultana)

The baseline assumption for this evaluation is that natural gas would be the primary fuel for the combustion turbine and duct burner. The additional fuels of biomass, as outlined in the "Organics Recovery Feasibility Study" [1]and anaerobic digester gas (ADG) from the existing Hunts Point Water Pollution Control Plant (HPWPCP) were also evaluated.

The study considers several key issues. First is identifying optimum CHP plant configurations based upon the thermal and electric load shapes of the host facility. Second is identifying the economic break-even points (shown in the life cycle cost tables) as determined by each plant configuration scenario (i.e. plant performance vs. host loads). An economic analysis was performed for three types of fuel: natural gas, anaerobic digester gas, and biomass. Third are the interconnection options for development, including "wheeling"[2] and localized distributed power plants.

The CHP plant that best fits the FDC operating requirements is a system that combines a combustion turbine-generator with a heat recovery steam generator (HRSG) located at the parcel directly east of the Meat Market utilities building. The steam produced by the CHP plant would be delivered to the Meat Market's central utilities building where it would be used to run steam turbines which would be coupled to ammonia refrigeration chillers. The electricity generated will tie into the current Meat Market service and the remainder will be exported to participating FDC tenants. Our preliminary analysis indicates that a CHP facility will yield the following benefits:

Proposed CHP Plant Location

- Reduced overall electricity demand in New York City.
- Greater ability to manage rising energy costs
- Lower emissions from the facility (in comparison to local utility plants)
- Reduces Zone J capacity constraints

[1] *Hunts Point Food Distribution Center Organics Recovery Feasibility Study*, December 30, 2005. Prepared for NYCEDC by DSM Environmental Services, Inc.

[2] Wheeling refers to the transmission of electric power generated at a plant owned by one entity over transmission lines owned by another entity. Typically, the owner of the transmission lines is paid for their use by the generator owner who is using these transmission lines to move power.

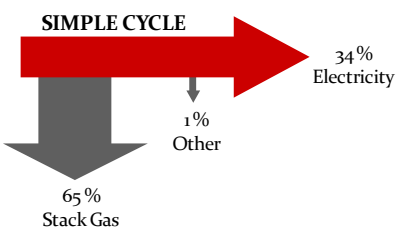
4.2 COMBINED HEAT AND POWER (CHP)

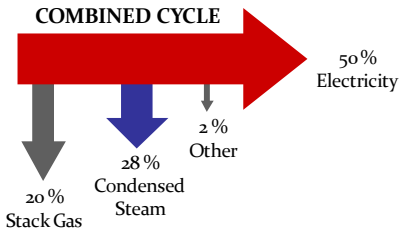
Combined Heat and Power (CHP) refers to an energy system that utilizes the waste heat created from a combustion driven engine plant which simultaneously generates electricity. Because such installations are typically situated within buildings or industrial plants, the terms “distributed generation,” (DG) “cogeneration,” and “small power production” are interchangeable. In the case of the FDC, the CHP facility contemplated will generate electric energy and steam using natural gas as fuel with options for ADG and natural gas blending or biomass.

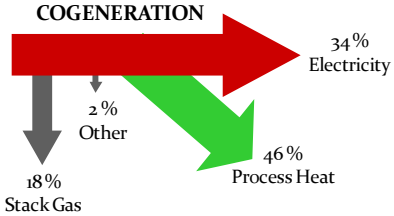
Combustion Turbines (CTs), often called Gas Turbines (GT), are a mature technology with broad acceptance in industrial and utility power generation applications. CTs are available with electric outputs ranging from a few kW to hundreds of megawatts. The key attributes of CTs include the following:

- Highly efficient when at or near full-load and when taking both electrical and thermal energy into use
- Produce lower emissions than reciprocating engines and traditional utility power plants
- Ideal for combined heat and power (CHP) or combined cycle applications
- High energy density (power to weight ratio) and smaller footprint than reciprocating engines
- Proven technology with wide range of currently available products and established service channels

Locating the generation close to its point of use, as is proposed in this project, enables greater use of a device’s overall energy output. Historically, the average efficiency of central-station power plant systems in the United States has been approximately 33%, and until quite recently had remained virtually unchanged for 40 years. This means that about two-thirds of the energy in the fuel cannot be converted to electricity at most power plants in the United States and is released to the environment as low temperature heat. CHP systems (Cogeneration) by contrast capture and convert waste heat to achieve effective electrical efficiencies of 50 to 80%. Furthermore, centrally located facilities typically lose 5 to 8% of their rated output through transmission and distribution losses. By being at or near the point of use, CHP systems avoid most of these losses. The figure below illustrates the efficiency of the two predominate utility power plant configurations, simple cycle and combined cycle, against a CHP system as defined in this report.







Generation Type	Total Efficiency
Simple Cycle	34%
Combined Cycle	50%
Cogeneration	80%

4.3 EXISTING ENERGY USE AND COSTS

Currently, Con Edison provides electric service to the entire FDC. There are a myriad of services at the FDC including high voltage, medium voltage and spot network low voltage services. Below is a summary of Base Year Energy Metrics for FDC Tenants. This data was used to create a DG scenario for the FDC.

Electrical Energy & Capacity Requirements

Electrical Energy & Capacity Requirements	
Electrical Energy Consumed	168,066,405 MWhr
Electrical Peak Demand	22.8 MW
Electrical Energy Cost	$22.9 Million
Avg. Delivered Unit Cost	$.136 per kWhr

4.4 METHODOLOGY

4.4.1 Criteria

The basic tenets for the CHP analysis focused on the following rules. Our analysis reviewed several generation and fuel types and presents here the best option for CHP at Hunts Point based on which combinations meet these criteria most effectively.

- Acceptable (above 12%) Return on Investment (ROI)
- Neutral or Positive Environmental Impact
- No technology without proven long term performance
- Twenty year minimum life

4.5 RECOMMENDED CHP TECHNOLOGY

4.5.1 CHP Model

DMJM Harris developed various generation options in comparing the natural gas base case information against other generation technology. All viable technology was explored in the development of these options. The list below summarizes the best fit prime mover types. Each technology was evaluated on the following characteristics:

- Capacity to serve the FDC tenants – Based on usage and load information the target size for generation was 15 MW[3].
- Efficiency – Overall CHP efficiency was of primary importance as the higher use of each Btu directly resulted in increased bottom line savings.
- Prime Mover Capital Costs – The core of the economics starts with installed costs. Therefore, the prime movers with the lowest incremental capital costs were given the highest rankings.
- O&M Costs – O&M recurring costs enter into the overall life cycle costs. The higher the recurring cost, the lower the return on investment. Low O&M costs were given the highest scores.
- Emissions – One of the greatest concerns for the City and State of New York is emissions and the ability to reduce a facility's emissions footprint. Installing low emissions equipment now and planning for even lower acceptable emissions levels in the future has a great benefit. Therefore, equipment with a low emissions footprint was given considered preferable.

[3] This is slightly lower than the estimated low load for the FDC, which is allows the CHP plant to run at a steady baseload level. This results in maximum efficiency for the turbine.

The efficient utilization of the CHP system is paramount to faster project return on investment. For example, if a facility has a peak load of 10 MW 25% but operates at 5 MW 75% of the time, a CHP plant capable of outputting 10 MW would be running at half of its capacity most of the time. This is an inefficient way for a turbine to operate. In this case, the CHP plant should be designed to operate at or near full capacity to supply the 5 MW load. This is known as “base loading”.

Given the above, the proposed development for the FDC is a Solar Titan 130 gas turbine coupled with a Rentech heat recovery steam generator (HRSG). The turbine is rated at 14,990 kWh at 59 degrees Fahrenheit assuming no inlet and outlet losses. For this analysis we used ISO conditions[4] to calculate economics. The HRSG will produce approximately 62,500 pounds of steam per hour at 175 psig. Additional fuel could be burned in a duct increasing the steam rate of the HRSG up to a maximum of 140,000 pounds per hour.

The selection of the Solar Turbines Titan unit was accomplished by determining the combined usage of the FDC tenants and potential reductions in this usage that could be achieved by utilizing waste steam. A continuous runtime that was not harnessed by outages due to usage constraints was preferred. Usage constraints, in this case, were defined as steam use developed by the CHP facility that could not be used by the site and would thus have to be condensed. The Titan generates over 60,000 pounds per hour (60Mlbs) of steam from the waste heat of the turbine exhaust. In order to achieve optimal efficiency, there must be a steam load high enough and steady enough to utilize this waste heat generated steam.

4.5.2 Electrical Production

The generator in the Solar package will be a synchronous type generator at 13.2kV. Isolation transformation will be necessary between the generator and Con Edison. Since the Meat Market takes service at 4160V, the transformation should be 13.2kV to 4160V before entering the existing service.

4.5.3 Thermal Production

The cogeneration plant will need to provide steam to host users in order to meet the minimum required efficiencies required by FERC regarding qualifying facilities. This could be done by providing steam to the Meat Market to drive new steam turbines coupled to existing ammonia chillers. This could be accomplished through the removal of existing electrical motors in favor of steam turbine drives or by the introduction of dual drives and a clutch system from manufacturers like SSS Clutch. In this scenario, the existing motors will remain coupled to the refrigeration compressor and a steam turbine will be clutched to the other end of the shaft. It is beyond the scope of this report to determine the technical feasibility and detail of this retrofit.

There exists about 3,000 horsepower of compression for the ammonia chillers that, if served by steam, would require about 90,000 pounds per hour of steam at full load. These steam turbines would be backpressure type turbines that would exhaust at about 12 psig. The resultant steam could be used in conventional low pressure absorption chillers for cooling loads of 55 degrees and above or heating steam for winter operations. If used for cooling, approximately 4,500 tons of absorption could be introduced. Currently these loads are served by a 17 degree brine loop which uses significantly more electricity to perform the same cooling. By using absorption, the only electricity used (besides the water pumping) is a small solution pump for the lithium bromide. In the heating season, steam can also be used instead of the existing high temperature hot water boilers for space heating, domestic hot water and defrosting loop.

It is anticipated that the drive change in ammonia refrigeration can reduce demand by upwards of 2,200 kW. Also, low pressure absorption could replace existing brine chilling creating a reduction of greater

[4] In the context of this paragraph, ISO refers to a published set of reference conditions provided by the International Organization for Standardization that are used to compare gas turbine performances.

than 1.3 kW/ton delivered. Both savings values above are not additive as the entire 3,000 hp of ammonia refrigeration would not be running if the portion of the 17 degree loop currently used for comfort cooling would be served by new absorption.

4.5.4 Construction Siting

The site selected, due east of the utilities building, is geographically advantageous. It is directly adjacent to the incoming Con Edison incoming electrical service and close to the ammonia refrigeration system where new high pressure steam will need to be delivered.

The unit would have to be interconnected with Con Edison's grid, and system impact studies would need to be performed to determine the validity of the approach outlined in this document.

4.5.5 Interconnection

The interconnection intent is to tie the new generator into the current Meat Market utilities building and feed power down to the Meat Market, as well as up to the grid. This would be accomplished by a single connection to the existing incoming switchgear. The feeders need to run from the existing utilities building to the new facility directly east at a distance under 100 feet.

Currently, several gas supplies exist at the FDC. These may all require a significant upgrade in size if the new facility were to use these as an incoming service. The new CHP facility should install a new four inch gas service expressly for the plant. In doing so, service can be contracted on Rider H Rate II of the SC9 rate which is expressly for distributed generation. This is a firm gas rate, that is, there would be no oil to backup the facility. Gas is available in the street but requires further contact with Con Edison to gain a better understanding of what delivery points are possible. Extension of a new service beyond 75 feet would entail additional costs and have not been estimated in this report.

The design requirements for interconnection to the Con Edison high tension system require the following elements:

- Generator fault current control to prevent the plant from contributing to the utility system in the event of a fault on the Con Edison system. Similar applications have employed pyrotechnic fuse devices that are capable of clearing fault current from the interconnected generator within ¼ cycle of the event.
- The utility has required on similar projects that a transfer trip communication system be installed to coordinate the utility and facility 13kV circuit breakers to clear common faults simultaneously. This reduces the risk of a protection failure creating a widespread outage.
- The utility has not been consulted to determine what, if any, modifications they will require to provide the feeders and substation capacity to allow for the installation of a CHP system.
- The CHP facility will need to become a Qualifying Facility (QF) in order to participate in the SC-11 Buyback rate from Con Edison. This SC-11 rate is required in order for a generator to be able to sell electricity back to the gird. To achieve QF status, the total efficiency of the CHP plant needs to be above 42.5%. This is calculated by taking the electrical efficiency and adding it to 50% of the thermal efficiency. The planned efficiency of this plant will be well above 42.5%.

The Con Edison fault map in Appendix 2 depicts the Hunts Point area in green. This means that synchronous generation is likely possible without fault current protection. However, we have left those costs in the project as they are likely to be required.

4.6 PERMITTING

Any construction within New York City requires obtaining approvals, usually in the form of permits, by multiple regulating entities. Some of these are relatively straightforward and simple to obtain, while

others can involve a lengthier process. Following is a brief overview of the permits that may be required for the construction and operation of a CHP plant.

4.6.1 Air Quality Permitting

The most extensive of the permits to obtain will almost certainly be the permits required to adhere to air quality and emissions standards. In New York, this falls under the purview of the New York State Department of Environmental Conservation (DEC).

The DEC provides guidelines that specify emissions limits, or "thresholds," and set forth the approval process. The guidelines can be found in the Uniform Procedures Act (UPA) of Article 70 of the New York State Environmental Conservation Law.[5] Thresholds are dependant on whether the location under consideration is categorized as "Downstate" or "Upstate."[6] As a Downstate city, New York is considered a severe non-attainment zone. As a source of emissions, a CHP facility will be required to obtain one of three permits: 1) a Title V permit, 2) a state facility permit, or 3) an air facilities registration, unless otherwise exempted. Following is a brief description of each. It is likely that the CHP plant chosen will be able to avoid Title V permitting but will be subject to State Facilities Permitting

4.6.2 Title V Permitting

Facilities whose emissions levels have a potential to emit (PTE) that exceeds the Major Source threshold must obtain a T*itle V Permit*. The PTE is the maximum capacity of the specified air pollutants that would be emitted if the source were operated full time (8,760 hours per year).

The Title V process can be lengthy and complicated and has the potential to increase a project's development costs by hundreds of thousands of dollars for additional engineering, consulting and legal fees. This is in addition to the $1,250 permitting fee. The extent of the air quality permitting process depends on the size of the CHP installation and whether the projected cumulative annual emissions of the CHP and the facilities whose systems it is supplementing exceed those levels allowed for New York City.

Once a Title V permit is issued, the facility must pay an annual fee to DEC based on the amount of regulated pollutants that it emits.

4.6.3 State Facilities Permitting

This is applicable to Major Sources that do not have emissions levels requiring a Title V permit but are unable to meet the requirements for Minor Facility Permits. These facilities have a potential emissions level that exceeds one-half of the Major Source threshold. The facility must identify emissions sources and control technologies to be employed in order to get permits to construct and operate. The cost of the permit application is $1,250.

4.6.4 Minor Facilities Registration

This is applicable to facilities with emissions that are 50% or less than Major Source threshold levels for criteria air pollutants. DEC is required to issue these permits within 30 days from the date of application. The cost of this permit application is $200.

[5] New York State Department of Environmental Conservation, *Uniform Procedure Act*, accessed at http://www.dec.ny.gov/permits/6081.html on June 20th, 2008.
[6] Downstate= New York City, Nassau, Suffolk, Westchester, Rockland Counties, and portions of Lower Orange County.

4.6.5 Construction

New York City has its own set of codes and enforcement agencies that are separate from the rest of the state. These are generally administered by the New York City Department of Buildings (DOB).

4.6.5.1 Bureau of Electrical Control

Any project that exceeds 1,000kVA must go through the Bureau of Electrical Control (BEC) Advisory Board for a review. Any unit with more than 480 V but less than 1,000 kVA still needs to be on file with the BEC but will not have to go through a review. This project would require BEC Advisory Board review.

4.6.5.2 Materials and Equipment Acceptance

Certain products and materials, including combustion and generating equipment, must go through the "Materials & Equipment Acceptance" (MEA) process.

The standard permits involved in construction would also apply to the CHP facility. Some of them are pulled by the general contractor (GC) supervising the construction and some are pulled by the specific licensed contractors.

Building Permit (by GC)

- Once an application to do construction work has been approved by the DOB, the GC must apply for the building permit to begin the work.

Plumbing (by licensed contractor)

- Required for the installation, alteration, maintenance or repair of any waste, domestic water, gas, or fire standpipes in any building or piping systems.[7]

Electrical (by licensed contractor)

- Required for the installation, alteration, maintenance or repair of any electric wires and wiring apparatus and other appliances used for the transmission of electricity for light, heat power, signaling, communications, alarm or data transmission.[8]

Boiler Permit

- All new boiler installations with input greater that 350,000 BTUs and operating at more than 15 PSI must be inspected by the DOB's Boiler Division. High pressure boilers must annually be inspected by DOB Boiler Division staff or by a duly authorized insurance company. Additionally there are other permits which may be required due to site specific circumstances.

Fire Department Approval

- Material sand equipment affecting fire safety is also subject to review by the Fire Department of New York. A CHP plant utilizing compressed natural gas would fall under this category.

Cranes & Derricks Permits

- Required for operation of equipment used for hoisting or lifting purposes, as well as other types of rigging setups, such as suspension scaffolds.

After Hours Permit

- Construction activities are normally limited to Monday through Friday, from 7:00 AM to 6:00PM. Any work done outside of those hours requires an after hours permit. These variances are granted on a case by case basis by the DOB.

[7] New York City Department of Buildings, *Applications and Permits*, (website) accessed at http://www.nyc.gov/html/dob/html/applications_and_permits/applications_and_permits.shtml
[8] Ibid

4.7 ECONOMIC ANALYSIS

DMJM Harris included current and projected utility rates, capital costs, and operating costs in the economic analysis of the recommended CHP plant at the FDC. The outcome of the analysis shows that while CHP is not economically attractive at the current time, it may be in the future if current energy cost subsidies to FDC tenants end.

For the economic analysis, it was assumed that a total of 60,000 lbs /hr of steam would provide 2,000 hp of ammonia refrigeration requirement and 3,000 tons of the low pressure absorption load. The unit will also provide for full electrical power at these conditions.

4.7.1 Current and Projected DG Utility Rates at the FDC

4.7.1.1 New York City Energy Pricing

Because generation capacity sets the market price for the zone, and In-City generators burn fossil fuels, the market price of electricity must follow the price fluctuations of fuel oil and natural gas. This relationship is beneficial for our proposed facility as our own cost of producing electricity will be dependent on natural gas pricing. Since both the CHP facility and market generation rely on natural gas to generate power, the risk of fuel volatility is removed from our life cycle cost analysis because the CHP facility will be subject to the same cost drivers that move the market. The following chart illustrates the strong correlation between natural gas and On Peak Zone J power prices.

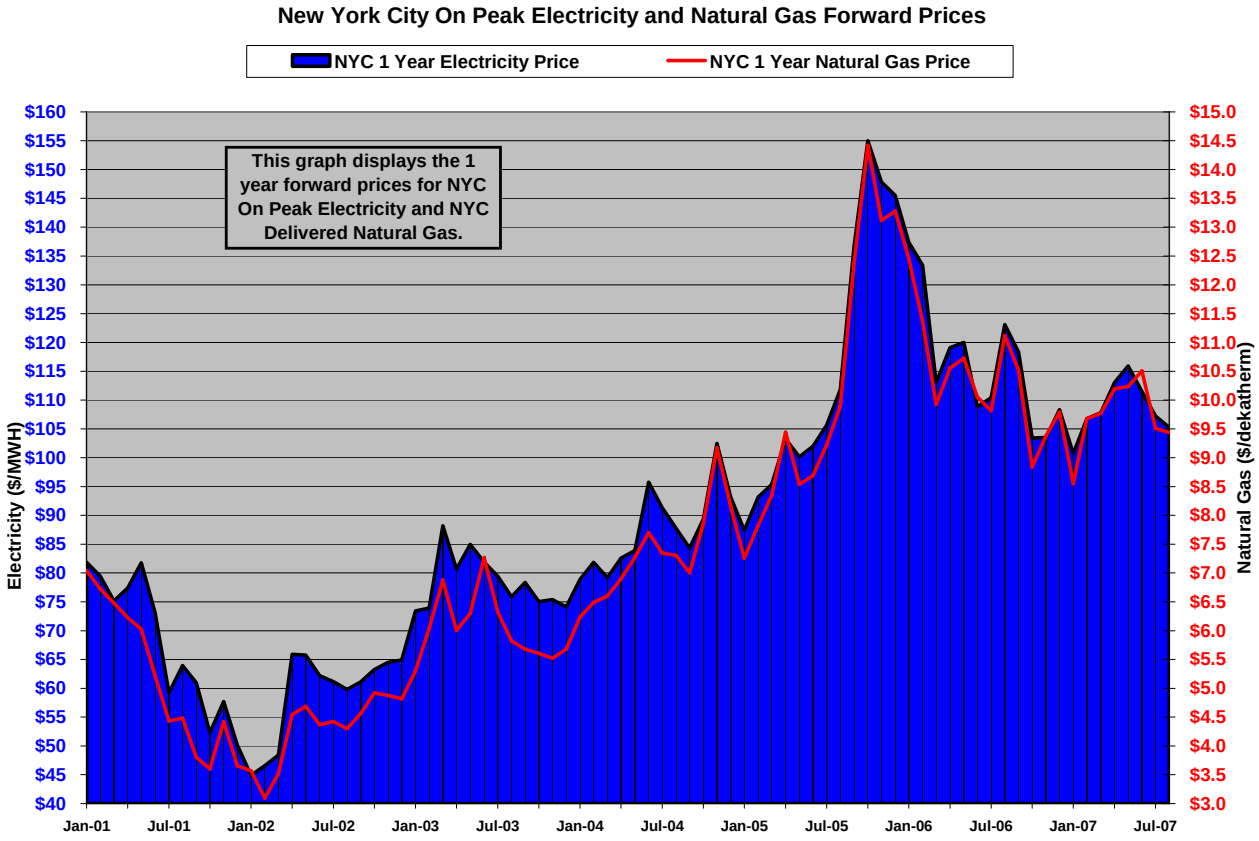


Chart provided by Con Ed Solutions / Data as of 7/25/07

Noting that electrical price in Zone J is dependent on gas and oil pricing, the return on investment for a CHP plant will vary with the cost of both commodities. As electrical prices (and therefore gas pricing) increase, the economics provide better returns as the offset of commodities provided by the cogeneration facility are at a higher basis cost. A sharp depression in both electrical and gas cost will slow the ROI due to the opposite dynamic, the displaced cost is less thus generating lesser incremental savings.

4.7.1.2 Energy Rates at Hunts Point FDC

Currently there is a greatly subsidized energy rate for many customers at the FDC. For some of the tenants, these subsidies are on an order of magnitude of one half the retail cost of delivered electricity. If these rates continue, they will make the return on investment of a CHP facility extremely long. If the FDC rates move closer to the rates of a standard commercial/industrial retail customer, a CHP would be viable at the FDC for two primary reasons:

- The cost to produce power and steam (used for cooling) is lower than the cost to buy electricity from Con Edison due to the higher efficiency of the selected equipment.
- Transmission losses are virtually eliminated because generation occurs in close proximity to the utility delivery point.

Currently, the FDC does not have any appreciable gas use besides high temperature hot water systems and process and comfort heating for tenants. New gas facilities will need to be constructed and contracted as part of this project. Any CHP developer would contract with Con Edison for the transportation of the gas for the cogeneration facility under the firm DG gas rate. This will enable the unit to not be curtailed and pricing is relatively the same as the non-firm boiler rate. The developer will need to contract with a gas and oil market supplier to supply the commodity.

The new facility will need to take electric service on the Con Edison rate SC14 which basically provides standby service in case the turbine goes down (either for maintenance or an inadvertent outage) and the SC11 rate which creates a contract for buyback of exported power. In addition, the developer will take service on the SC9 rate for all delivered energy. This rate will be for the as-used energy while the SC14 is for the total capacity of instantaneous demand of the facility as well as daily as used demand. Currently, the forward price of electricity in the zone is as follows:

- Energy charge $167/MWhr
- Delivery charge $45/MWhr
- Total $212 /MWhr

Futures for natural gas are currently at the following rates:

- Energy commodity $12/MMBtu
- Delivery charge $0.70/MMBtu
- Basis charge $2.25/MMBtu
- Total $14.95/MMBtu

The prices above are for current commercial or industrial customers who would purchase power and fuel today for the next year's requirements; it does not include any NYPA subsidies or additional layered subsidies like Business Incentive Rate (BIR) or Energy Cost Savings Program (ECSP).

4.7.2 Fuel Rate

For this facility, the turbine produces power as a function of its heat rate and fuel cost described below:

$$Heatrate\ (HHV)\ x\ Fuel\ Cost \frac{\$}{MMBTU}\ x\ Power\ kW = Fuel\ Cost \frac{\$}{hr}$$

For this facility at full load using natural gas, this would be the following:

$$10674 \frac{BTU}{kWhr}\ x\ 14.95 \frac{\$}{MMBTU} x \frac{MMBTU}{1{,}000{,}000 BTU}\ x\ 14990\ kW = \frac{\$2392}{hr}$$

The CHP facility will have approximately 600 kW of parasitic loads. The majority of this load is due to a fuel gas compressor. Therefore, the net kW delivered by the CHP system would be 14,390 kW.

Based on the current cost of retail power in zone J (commodity only), the CHP system would offset the retail power purchase based on the following:

$$MW\ produced\ x\ avg\ cost \frac{\$}{MW} = avg\ cost\ \$$$

$$14{,}390\ kW\ x \frac{MW}{1000 kW}\ x\ 212 \frac{\$}{MW} = 3050 \frac{\$}{hr}$$

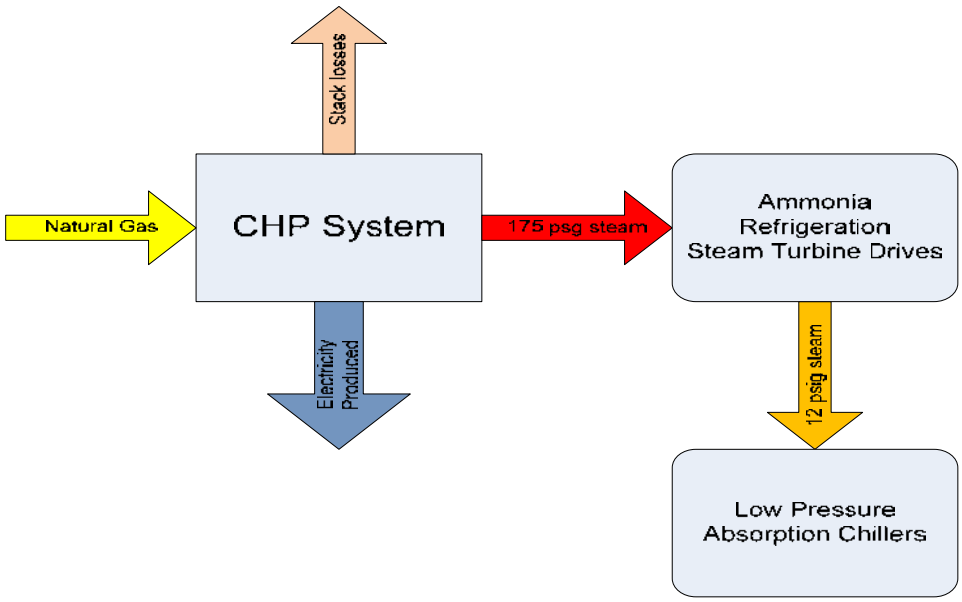
Since the CHP facility will also generate steam to offset electrical cost of ammonia refrigeration, an additional electrical benefit will be obtained as follows:

$$HP\ x\ .746 \frac{kw}{HP}\ x \frac{MW}{1000 kW}\ x\ electrical\ cost \frac{\$}{MW} = Hourly\ Benefit\ due\ to\ Steam\ Drive$$

$$3000\ x\ .746 \frac{}{1000}\ x\ 212 = 474 \frac{\$}{hr}$$

Steam turbines will exhaust steam at 12 psig, which can be directed into low pressure absorbers. This is waste steam from the turbine drives. In this case, the mechanical refrigeration of the 17 degree brine loop can be replaced with absorption cooling. It is important to note that each connection point of the 17 degree loop will need to be evaluated to determine if the load can be served by the new absorbers in totality or if some of the loop (for low temperature cooling) must remain. Assuming the pumping loads are relatively the same, the reduction of load will be based on the efficiency differential between the 17 degree brine loop and the absorber. Considering steam is free for the absorber the only operating utility cost for the absorber will be a solution pump which can be estimated at 50 HP per 1,500 ton machine. This has been taken into consideration in the parasitic load of the turbine above.

The CHP facility at the FDC will take a single input fuel, natural gas, and with it, generate electricity and 175 psig steam. The steam will be used to drive new turbine drives for existing electric motor driven ammonia compressors. The exhaust from this steam will be delivered to new absorption chillers to be used as fuel to supply space cooling. A simple system diagram is depicted below:



The tables in Appendix 3 show the utility analysis for the different fuels driving the CHP facility. Since the HPWPCP ADG is at the same net cost per BTU, the utility analysis will remain the same for each case. It is assumed that the Biomass ADG will be delivered at a commodity cost equal to 75% of natural gas.

4.7.3 Capital Costs

Please see Appendix 4 for estimates of initial investment requirements.

4.7.4 Fuel Cost Scenarios

Three distinct fuels were evaluated for their economic and technical potential within this study: natural gas, HPWPCP ADG and biomass. Each of these relate to a different cogeneration development option at the FDC: a natural gas turbine driven CHP, a mixed natural gas and HPWPCP ADG driven CHP, and a mixed natural gas and biomass ADG driven CHP facility.

Natural gas cogeneration has the lowest first cost economics based on typical $/kW capital costs for various generation technologies**.**

Because the HPWPCP ADG gas will require approximately 3,700 foot of pipeline to connect to the wastewater treatment plant and the addition of a fuel processing skid blending station, it has a much higher capital cost of construction. According to DEP, this fuel will be sold to the prospective CHP facility at the equivalent cost per BTU of natural gas. Although the cost of operation will be the same, the greater cost of installation will make for a longer return on investment.

In the Organics Recovery Feasibility Study, DSM reported that 24,350 tons of biomass[9] is produced annually. This is considered very low for use in an incineration steam plant. Therefore, converting the biomass to ADG was deemed the only viable way to utilize the fuel, and even then will still only produce slightly more than two megawatts of power based on the volumes of the biomass. Therefore, steam cycle biomass incineration was discounted due to the following factors:

[9] There is potential for participation in the New York State Renewable Portfolio Standard program (RPS) for the MWhrs produced from the ADG fuel. Initial talks with NYSERDA have suggested that the fuel input from ADG qualifies if metered separately. There are some provisions in the RPS program that preclude the sale of RPS attributes to customers who enter into a net metering arrangement with the local distribution company, in this case Con Edison. Further regulatory research will need to be done to determine the eligibility of RPS participation and the potential revenue generation from RPS to this project.

- An entire incineration steam plant would have to be built for a very small amount of steam generated.
- There is no complement to the gas turbine CHP facility as they would operate independently. The GT may need to be down sized due to having too much power in the two systems.
- Emissions permitting would become more difficult with two sources (a gas turbine and an incineration steam plant) as opposed to one.

After reviewing the above options, DMJM Harris has determined that natural gas is the most economic type of fuel for this CHP system. As demonstrated in the chart below, natural gas has the lowest first cost investment as well as the second-lowest $/kwh cost of electricity. However, as noted above, the average delivered unit cost of electricity for FDC tenants is $.136/kwh; the lowest projected cost here is still six cents above that. These effective prices per kWh are still below the current predicted forward market price for electricity.

Our analysis indicates that a CHP plant will require an investment of $48 to $60 million and will return up to $6.9 million in savings based on forward electric and gas pricing. Please refer to Appendix 4 for full CHP capital cost estimates.

Projected Economics By Fuel Scenario (7% Discount Rate)				
Scenario	**Investment**	**Cost Savings†**	**$/kWh***	**IRR**
Natural Gas	$46,004,116	$6,949,279	$0.1910	23.10%
Natural Gas + HPWPCP	$49,085,361	$6,662,613	$0.1919	21.69%
Natural Gas + Biomass ADG	$60,187,790	$6,696,587	$0.1917	19.33%
Natural Gas + Biomass ADG (no plant)	$48,580,167	$7,776,513	$0.1885	23.86%

† Net savings after O&M, ICAP, and debt service
* $/ kWh assumes developer and FDC tenants develop 50% cost share mechanism and Electric and gas rates are assumed at rates published in this report.

4.7.5 Engineering Cost

Current estimates are provided for review in Appendix 4. These costs include all mechanical electrical and plumbing tasks.

4.7.6 Operations & Maintenance Cost

Annual operations and maintenance for plants of this size are based on power delivery and complexity. The annual cost estimate provided below uses standard industry averages to generate a rolled up cost of operation. This cost is represented below along with additional costs for personnel and insurance. Escalation on O&M is held at 3% through the life cycle of the asset (20 years). ADG facility requirements are not considered maintenance requirements of the new CHP facility and thus have not been incorporated into the O&M chart below.

Annual Operating Costs	
Operators X 5	$500,000
Maintenance contract*	$1,111,000
Insurance	$48,000
Manager	$125,000
Total	$1,784,000

* Maintenance contract includes $737,000 for all CHP equipment and $374,000 for balance of plant equipment.

4.7.7 Life Cycle Cost Benefit Analysis

The life cycle cost model below depicts the financial considerations for CHP development. The first three years are investment years where the initial engineering will be performed, equipment purchases contracted and construction started. Year three will conclude the construction and begin the commissioning of the project. Due to anticipated electrical and gas utility price escalations, the savings will increase over the term. Maintenance will also increase as these predominately labor heavy contracts are traditionally adjusted yearly by a published Consumer Price Index (CPI). As stated earlier, the cost estimates are quite conservative as is the savings estimate. Escalations are noted above each Scenario. There are no escalations for cost of construction represented in the life cycles, and no credits for infrastructure deferrals. Each life cycle shows two finance options: the first is capital financing at a rate of 7% and the second is a straight payback on a capital purchase. Because the development will take two years, the capital investment is split in half per year.

The following life cycle costs represent the project economics for four scenarios investigated for CHP facilities at HPC. The first is a natural gas only driven gas turbine, the second adds the current wastewater treatment facility ADG and the third uses natural gas with HPC delivered ADG. The fourth scenario is identical to the third but capital cost for the biomass ADG facility is not included in the cost of the CHP project. In each case the project will be built out in two years labeled as C1 and C2. The savings column is pure energy savings before any costs. This is based on a pure avoided cost of purchasing power versus the cost to generate and purchase the remainder of the power from Con Edison. The ICAP column is a payment received for installed capacity. This value is available yearly and with increased load in the zone will potentially increase yearly. Due to this, a modest 2% increase was used.

The table in 4.7.4 lists the comparative fuel source economics. The natural gas only option has the most favorable economics. This may change if tipping fees were added to the third scenario. If HPC currently pays to remove waste that would otherwise be delivered to the Biomass ADG site on HPC property then these fees would diminish and could potentially provide equal or better economics than the natural gas only scenario. All projects at this point would not provide the economics listed above due to the highly subsidized electrical rates now in place at HPC. This table shows what the economics would be if these subsidies were removed and the HPC was uninsulated from market conditions.

Hunts Point Natural Gas Scenario Life Cycle

Discount rate	7.00%					Finance rate	7.00%	20 year term
Project Cost	($46,004,116)		Investment year 2	($23,002,058)		Operations escalation	3%	
			Investment year 1	($23,002,058)		ICAP escalation	2%	
IRR	23.10%					Utilities escalation	2%	
NPV	$70,153,279							
						Capital Finance	Capital Purchase	
Year	**Savings**	**Operations**	**ICAP**	**NYSERDA Grants**	**Finance Payment**	**Net Yearly Benefit**	**Total Annual Savings**	**Cash flow (year 1)**
C1							($23,002,058)	($23,002,058)
C2				$1,600,000	($4,280,033)	($2,680,033)	($21,402,058)	($43,003,981)
1	$11,645,000	($1,784,000)	$1,368,312	$400,000	($4,280,033)	$7,349,279	$11,629,312	($32,846,490)
2	$11,761,450	($1,837,520)	$1,395,678		($4,280,033)	$7,039,575	$11,319,608	($23,606,318)
3	$11,879,065	($1,892,646)	$1,423,592		($4,280,033)	$7,129,978	$11,410,011	($14,901,675)
4	$11,997,855	($1,949,425)	$1,452,064		($4,280,033)	$7,220,461	$11,500,494	($6,701,982)
5	$12,117,834	($2,007,908)	$1,481,105		($4,280,033)	$7,310,998	$11,591,031	$1,021,611
6	$12,239,012	($2,068,145)	$1,510,727		($4,280,033)	$7,401,561	$11,681,594	$8,296,321
7	$12,361,402	($2,130,189)	$1,540,942		($4,280,033)	$7,492,121	$11,772,154	$15,147,822
8	$12,485,016	($2,194,095)	$1,571,760		($4,280,033)	$7,582,649	$11,862,682	$21,600,335
9	$12,609,866	($2,259,918)	$1,603,196		($4,280,033)	$7,673,111	$11,953,144	$27,676,707
10	$12,735,965	($2,327,715)	$1,635,260		($4,280,033)	$7,763,476	$12,043,509	$33,398,492
11	$12,863,325	($2,397,547)	$1,667,965		($4,280,033)	$7,853,709	$12,133,743	$38,786,018
12	$12,991,958	($2,469,473)	$1,701,324		($4,280,033)	$7,943,776	$12,223,809	$43,858,464
13	$13,121,877	($2,543,557)	$1,735,350		($4,280,033)	$8,033,637	$12,313,671	$48,633,918
14	$13,253,096	($2,619,864)	$1,770,057		($4,280,033)	$8,123,257	$12,403,290	$53,129,441
15	$13,385,627	($2,698,460)	$1,805,459		($4,280,033)	$8,212,593	$12,492,626	$57,361,126
16	$13,519,483	($2,779,414)	$1,841,568		($4,280,033)	$8,301,604	$12,581,637	$61,344,150
17	$13,654,678	($2,862,796)	$1,878,399		($4,280,033)	$8,390,248	$12,670,281	$65,092,829
18	$13,791,225	($2,948,680)	$1,915,967		($4,280,033)	$8,478,479	$12,758,512	$68,620,664
19	$13,929,137	($3,037,141)	$1,954,286		($4,280,033)	$8,566,250	$12,846,283	$71,940,387
20	$14,068,429	($3,128,255)	$1,993,372		($4,280,033)	$8,653,513	$12,933,546	$75,064,008

Hunts Point Natural Gas + HPWPCP Scenario Life Cycle

Discount rate	7.00%					Finance rate	7.00%	20 year term
Project Cost	($49,085,361)		Investment year 2	($24,542,681)		Operations escalation	3%	
			Investment year 1	($24,542,681)		ICAP escalation	2%	
IRR	21.69%					Utilities escalation	2%	
NPV	$67,367,805							
					Capital Finance		Capital Purchase	
Year	**Savings**	**Operations**	**ICAP**	**NYSERDA Grants**	**Finance Payment**	**Net Yearly Benefit**	**Total Annual Savings**	**Cash flow (year 1)**
C1							($24,542,681)	($24,542,681)
C2				$1,600,000	($4,566,699)	($2,966,699)	($22,942,681)	($45,984,438)
1	$11,645,000	($1,784,000)	$1,368,312	$400,000	($4,566,699)	$7,062,613	$11,629,312	($35,826,946)
2	$11,761,450	($1,837,520)	$1,395,678		($4,566,699)	$6,752,909	$11,319,608	($26,586,774)
3	$11,879,065	($1,892,646)	$1,423,592		($4,566,699)	$6,843,311	$11,410,011	($17,882,132)
4	$11,997,855	($1,949,425)	$1,452,064		($4,566,699)	$6,933,794	$11,500,494	($9,682,439)
5	$12,117,834	($2,007,908)	$1,481,105		($4,566,699)	$7,024,332	$11,591,031	($1,958,845)
6	$12,239,012	($2,068,145)	$1,510,727		($4,566,699)	$7,114,895	$11,681,594	$5,315,864
7	$12,361,402	($2,130,189)	$1,540,942		($4,566,699)	$7,205,455	$11,772,154	$12,167,365
8	$12,485,016	($2,194,095)	$1,571,760		($4,566,699)	$7,295,982	$11,862,682	$18,619,878
9	$12,609,866	($2,259,918)	$1,603,196		($4,566,699)	$7,386,445	$11,953,144	$24,696,251
10	$12,735,965	($2,327,715)	$1,635,260		($4,566,699)	$7,476,810	$12,043,509	$30,418,035
11	$12,863,325	($2,397,547)	$1,667,965		($4,566,699)	$7,567,043	$12,133,743	$35,805,562
12	$12,991,958	($2,469,473)	$1,701,324		($4,566,699)	$7,657,109	$12,223,809	$40,878,008
13	$13,121,877	($2,543,557)	$1,735,350		($4,566,699)	$7,746,971	$12,313,671	$45,653,462
14	$13,253,096	($2,619,864)	$1,770,057		($4,566,699)	$7,836,590	$12,403,290	$50,148,984
15	$13,385,627	($2,698,460)	$1,805,459		($4,566,699)	$7,925,926	$12,492,626	$54,380,669
16	$13,519,483	($2,779,414)	$1,841,568		($4,566,699)	$8,014,938	$12,581,637	$58,363,693
17	$13,654,678	($2,862,796)	$1,878,399		($4,566,699)	$8,103,582	$12,670,281	$62,112,372
18	$13,791,225	($2,948,680)	$1,915,967		($4,566,699)	$8,191,813	$12,758,512	$65,640,207
19	$13,929,137	($3,037,141)	$1,954,286		($4,566,699)	$8,279,584	$12,846,283	$68,959,931
20	$14,068,429	($3,128,255)	$1,993,372		($4,566,699)	$8,366,847	$12,933,546	$72,083,551

Hunts Point Natural Gas + Biomass ADG Scenario Life Cycle

Discount rate	7.00%				Finance rate	7.00%	20 year term
Project Cost	($60,187,790)		Investment year 2	($30,093,895)	Operations escalation	3%	
			Investment year 1	($30,093,895)	ICAP escalation	2%	
IRR	19.33%				Utilities escalation	2%	
NPV	$67,964,993						

					Capital Finance		Capital Purchase	
Year	**Savings**	**Operations**	**ICAP**	**NYSERDA Grants**	**Finance Payment**	**Net Yearly Benefit**	**Total Annual Savings**	**Cash flow (year 1)**
C1							($30,093,895)	($30,093,895)
C2				$1,600,000	($5,599,624)	($3,999,624)	($28,493,895)	($56,723,703)
1	$12,711,899	($1,784,000)	$1,368,312	$400,000	($5,599,624)	$7,096,587	$12,696,211	($45,634,341)
2	$12,839,018	($1,837,520)	$1,395,678		($5,599,624)	$6,797,553	$12,397,176	($35,514,552)
3	$12,967,408	($1,892,646)	$1,423,592		($5,599,624)	$6,898,731	$12,498,354	($25,979,618)
4	$13,097,082	($1,949,425)	$1,452,064		($5,599,624)	$7,000,097	$12,599,721	($16,996,191)
5	$13,228,053	($2,007,908)	$1,481,105		($5,599,624)	$7,101,627	$12,701,250	($8,532,811)
6	$13,360,334	($2,068,145)	$1,510,727		($5,599,624)	$7,203,292	$12,802,916	($559,799)
7	$13,493,937	($2,130,189)	$1,540,942		($5,599,624)	$7,305,066	$12,904,689	$6,950,848
8	$13,628,876	($2,194,095)	$1,571,760		($5,599,624)	$7,406,918	$13,006,542	$14,025,545
9	$13,765,165	($2,259,918)	$1,603,196		($5,599,624)	$7,508,819	$13,108,443	$20,689,212
10	$13,902,817	($2,327,715)	$1,635,260		($5,599,624)	$7,610,737	$13,210,361	$26,965,359
11	$14,041,845	($2,397,547)	$1,667,965		($5,599,624)	$7,712,639	$13,312,263	$32,876,163
12	$14,182,263	($2,469,473)	$1,701,324		($5,599,624)	$7,814,491	$13,414,114	$38,442,544
13	$14,324,086	($2,543,557)	$1,735,350		($5,599,624)	$7,916,255	$13,515,879	$43,684,235
14	$14,467,327	($2,619,864)	$1,770,057		($5,599,624)	$8,017,897	$13,617,520	$48,619,851
15	$14,612,000	($2,698,460)	$1,805,459		($5,599,624)	$8,119,375	$13,718,999	$53,266,950
16	$14,758,120	($2,779,414)	$1,841,568		($5,599,624)	$8,220,650	$13,820,274	$57,642,095
17	$14,905,701	($2,862,796)	$1,878,399		($5,599,624)	$8,321,681	$13,921,304	$61,760,907
18	$15,054,758	($2,948,680)	$1,915,967		($5,599,624)	$8,422,422	$14,022,045	$65,638,119
19	$15,205,306	($3,037,141)	$1,954,286		($5,599,624)	$8,522,828	$14,122,452	$69,287,629
20	$15,357,359	($3,128,255)	$1,993,372		($5,599,624)	$8,622,853	$14,222,476	$72,722,543

Hunts Point Natural Gas + Biomass ADG (no plant) Scenario Life Cycle								
Discount rate	7.00%					Finance rate	7.00%	20 year term
Project Cost	($48,580,167)		Investment year 2	($24,290,084)		Operations escalation	3%	
			Investment year 1	($24,290,084)		ICAP escalation	2%	
IRR	23.86%					Utilities escalation	2%	
NPV	$78,458,390							
					Capital Finance		Capital Purchase	
Year	**Savings**	**Operations**	**ICAP**	**NYSERDA Grants**	**Finance Payment**	**Net Yearly Benefit**	**Total Annual Savings**	**Cash flow (year 1)**
C1							($24,290,084)	($24,290,084)
C2				$1,600,000	($4,519,698)	($2,919,698)	($22,690,084)	($45,495,769)
1	$12,711,899	($1,784,000)	$1,368,312	$400,000	($4,519,698)	$8,176,513	$12,696,211	($34,406,407)
2	$12,839,018	($1,837,520)	$1,395,678		($4,519,698)	$7,877,478	$12,397,176	($24,286,618)
3	$12,967,408	($1,892,646)	$1,423,592		($4,519,698)	$7,978,656	$12,498,354	($14,751,683)
4	$13,097,082	($1,949,425)	$1,452,064		($4,519,698)	$8,080,023	$12,599,721	($5,768,256)
5	$13,228,053	($2,007,908)	$1,481,105		($4,519,698)	$8,181,552	$12,701,250	$2,695,123
6	$13,360,334	($2,068,145)	$1,510,727		($4,519,698)	$8,283,217	$12,802,916	$10,668,135
7	$13,493,937	($2,130,189)	$1,540,942		($4,519,698)	$8,384,991	$12,904,689	$18,178,782
8	$13,628,876	($2,194,095)	$1,571,760		($4,519,698)	$8,486,844	$13,006,542	$25,253,479
9	$13,765,165	($2,259,918)	$1,603,196		($4,519,698)	$8,588,745	$13,108,443	$31,917,147
10	$13,902,817	($2,327,715)	$1,635,260		($4,519,698)	$8,690,663	$13,210,361	$38,193,294
11	$14,041,845	($2,397,547)	$1,667,965		($4,519,698)	$8,792,565	$13,312,263	$44,104,098
12	$14,182,263	($2,469,473)	$1,701,324		($4,519,698)	$8,894,416	$13,414,114	$49,670,478
13	$14,324,086	($2,543,557)	$1,735,350		($4,519,698)	$8,996,181	$13,515,879	$54,912,169
14	$14,467,327	($2,619,864)	$1,770,057		($4,519,698)	$9,097,822	$13,617,520	$59,847,785
15	$14,612,000	($2,698,460)	$1,805,459		($4,519,698)	$9,199,300	$13,718,999	$64,494,885
16	$14,758,120	($2,779,414)	$1,841,568		($4,519,698)	$9,300,576	$13,820,274	$68,870,029
17	$14,905,701	($2,862,796)	$1,878,399		($4,519,698)	$9,401,606	$13,921,304	$72,988,841
18	$15,054,758	($2,948,680)	$1,915,967		($4,519,698)	$9,502,347	$14,022,045	$76,866,053
19	$15,205,306	($3,037,141)	$1,954,286		($4,519,698)	$9,602,754	$14,122,452	$80,515,563
20	$15,357,359	($3,128,255)	$1,993,372		($4,519,698)	$9,702,778	$14,222,476	$83,950,477

4.7.8 Cost Options Summary

In conclusion, a natural gas-fired Solar Turbine makes the best economic case for CHP at the FDC with a five year break even point and a 23% internal rate of return (IRR). However, with the current subsidies enjoyed by many of the tenants, CHP is not currently an economically attractive option for a developer. In future, if the low utility rates enjoyed by the FDC tenants were to lapse, CHP electricity production could be an economically viable option for a developer.

In the next section, we discuss the benefits of a CHP plant, along with various incentive programs and policy goals that may assist in making the FDC CHP plant feasible.

4.8 BENEFITS AND INCENTIVES

4.8.1 Project Benefits

The improvement in efficiency provided by CHP reduces emissions on a per megawatt-generated basis. Because CHP requires less fuel for a given energy output, it reduces the demand for key fuels such as natural gas, coal, and uranium, as well as reducing overall Citywide carbon dioxide emissions. CHP can help reduce congestion on the electric grid by removing or reducing load in areas of high demand and can also help decrease the impact of grid power outages. NYSERDA comments that "energy savings [from CHP systems] represent a social benefit in lowering the pressure on fuel and electricity supply and infrastructure, thereby providing lower prices for all consumers."

4.8.2 Emissions Benefits

Due to the high efficiencies of the CHP facility, less fuel is burned to produce the same amount of useful benefit. This means that there is a reduction in emissions for the CHP facility in relation to the surrounding power plants in NYC and Westchester. Below is a table showing the environmental performance of the CHP facility versus the current power facilities in New York City and Westchester.

Emissions				
Exhaust Emissions At Stack		CHP w/out SCR	CHP facility with SCR	NYC & Westchester[10]
NO_x	lb/MWhr	0.980	0.097	0.896
CO	lb/MWhr	1.1939	0.117	N/A
UHC	lb/MWhr	0.338	0.297	N/A
PM_{10}	lb/MWhr	0.331	0.331	N/A
SO_2	lb/MWhr	0.035	0.035	0.705
SCR Reduction Efficiency	%		90	
CO Catalyst Reduction Efficiency	%		90	
UHC Catalyst Reduction Efficiency	%		13.3	
Greenhouse Gas Emissions	CO2 lbs/MWhr		116	922

As this chart demonstrates, the emissions reductions are dramatic with select catalytic reduction (SCR) installed. NO_x reductions are almost 89% and CO reductions are 87%.

There may be a perceived local bias against a CHP plant due to the fact that it introduces a new point source of emissions if it is not replacing an existing source. While this may be true, this must be weighed against the fact that the power that the CHP plant produces results in less overall pollutants than the central plant power that it is displacing. This is because the power produced by the local CHP plant converts 60-75% of the fuel it consumes into useable energy vs. about 30-35% for a typical central utility plant.

[10] eGRID USEPA

4.8.3 Economic Incentive Programs

There are several current economic incentive programs that provide offsets to the capital investment required for a CHP project. A brief description of the most relevant energy incentive programs is provided below:

- **Installed Capacity** – ICAP represented by the reduced capacity to the electrical users of the facility. This is calculated by measuring the difference in electricity demand to the previous year of our CHP installation and multiplied by the average clearing price for ICAP: 15 MW reduction in electricity demand x $8.03/MW. It is unsure how this will be applied in a wheeling scenario as there is no precedence for this in Con Edison territory that we could locate.

- The New York State Energy Research and Development Authority (NYSERDA): NYSERDA continues its support of distributed generation projects with **PON 1101**[11] **Commercial and Industrial Performance Program** with a cost share of 30% to 70% of project costs up to a per-customer cap of $2 Million and a total to all participants in Con Edison territory of $12.5 million.

- **NYSERDA New Construction Program** – $16 million in incentives are available to offset a portion of the incremental capital costs to purchase and install energy-efficient equipment that reduces electric energy consumption. Applicants may choose among pre-qualified equipment, custom measure or whole building capital cost incentives. Applicants may also be eligible for technical assistance incentives to install advanced solar energy and de-lighting technologies; and evaluate green building and peak-load reduction opportunities in their building projects. Incentives offered for projects are available on a first-come-first-served basis and will be paid only if there are funds available. Limited incentives are available for projects that are in the latter stages of the design process (e.g., construction documents and beyond).

- **Distributed Generation as Combined Heat and Power** – A NYSERDA program effective October 2007 soliciting proposals in the following three categories: Demonstrating DG-CHP technologies in a variety of applications and end-use sectors in New York State (NYS); performing re-commissioning studies to improve the operation of existing NYSERDA funded DG-CHP systems which were placed into service prior to January 1, 2005; and conducting DG-CHP technology transfer, market transformation and policy studies of general interest to stakeholders throughout NYS.

4.8.4 City, State, and Federal Policy Initiatives

In general, there are a number of initiatives currently underway in New York and on a national level which seek to promote CHP construction. Among them are Mayor Bloomberg's PlaNYC, former Governor Spitzer's 15% by 2015 Energy Efficiency Plan and various energy planning studies which all highlight the need for greater efficiency, lowered emissions and new generation. The following initiatives all provide major policy support for CHP in New York State.

- Mayor Michael Bloomberg's New York City Energy Task Force, in considering options to reduce electrical capacity problems in the city, concluded that "distributed resources can reduce or reshape electric system load and thereby mitigate the need for increased generation and/or transmission resources. With appropriate policies and incentives, distributed resources are often the most readily available, cost-effective, and underutilized clean energy resources that can potentially reduce or defer the amount of required new electric supply from generation and transmission systems. While it can take many years to plan, design and build electric generation

[11] NYSERDA PON 1101 Funds remaining for energy efficiency = $9.2 million as of 7/2007

plants, most distributed resources can be deployed within a year." A dispersed network of distributed generation (DG) units is also less vulnerable to terrorism, whether from direct attacks or computer hacking, than a single large power station.

- The New York State Energy Plan sets forth "the goal of becoming a national leader in the deployment of distributed generation technology" and recommends that the State "should take all reasonable steps necessary to facilitate the interconnection of DG and CHP resources into the electricity system and increase the use of DG and CHP resources in the State."[12]
- In April 2007, New York City Mayor Michael Bloomberg unveiled PlaNYC, a challenge to New Yorkers "to generate ideas for achieving ten key goals for the city's sustainable future." The PlaNYC targets ten goals, ideally achievable by the year 2030, aimed to allow for the growth and sustenance of New York City's industry, population, environment, and infrastructure. Included in the goals of PlaNYC are three areas of importance to the FDC CHP project:

    1. Provide cleaner, more reliable power for every New Yorker by upgrading our energy infrastructure
    2. Achieve the cleanest air quality of any big city in America
    3. Reduce carbon emissions by more than 30%

- In April 2007, former Governor Eliot Spitzer outlined a plan to cut the state's electrical consumption 15% from consumption levels forecasted for 2015 while building enough clean generating capacity to lower power costs. The state's "15 by 15" plan is more aggressive than any other state's plan to reduce global warming. It also addresses the economic problems resulting from rising energy prices, which now are the second-highest in the nation behind only Hawaii. A key component of the plan is reducing peak demand. "We can spend billions of dollars to build every single one of the power plants needed to meet this demand," Mr. Spitzer said. "Or we can invest far less money to cut the demand for energy by 15% -- and on top of that, increase our power-generating capacity to lower energy bills. Common sense says that we should take the second approach -- which we should both build and conserve."

  "The Public Service Commission recently began the process of considering how to encourage such contracts", the governor said. "The first step occurred when the PSC agreed to the concept of revenue decoupling, which allows utilities to recoup revenues lost when energy conservation methods are enacted." The lack of decoupling was seen as a disincentive for utilities to promote conservation through their marketing and state-assisted financing.[13]

- The Bush Administration has supported CHP development in its National Energy Plan through the Energy Policy Act of 2005 which promotes the standard interconnection and development of CHP technologies.

4.9 CONCLUSION

A CHP plant offers many advantages ranging from reduced energy costs to higher reliability and reduced emissions levels. Technically, a CHP at the FDC is a good fit due to the following factors:

- High energy utilization – FDC requires a large amount of power at all times of day
- Year-round steam use – Current ammonia refrigeration requirements ensure operation year round
- CHP incentives – NYSERDA and others offer incentives to buy down the capital cost of construction for CHP projects

[12] Online reference from NYSERDA from www.nyserda.org/sep/sepsection1-3.pdf

[13] Sources: Text of Governor Spitzer's 15% by 2015 speech April 19, 2007; Crain's New York Business

- Ease of interconnecting to existing electric and steam systems – FDC currently has 4160 buss with ties installed making implementation of CHP easier.
- Future plans – Gas Turbine CHP will provide for future growth of thermal (cooling) requirements through additional steam generation.

In addition, a CHP plant would bring considerable overall emissions benefits as compared with traditional power plants due to the fact that it utilizes more energy output on a per fuel unit input basis. However, these ”big picture” environmental attributes are often discounted by local communities who view the CHP plant as a point source of emissions that did not previously exist.

CHP also brings public benefits by lessening the demand on Con Edison’s grid, and this project at Hunts Point would provide an example of New York City’s leadership in energy efficiency and distributed generation. In addition it would demonstrate a commitment to meeting Mayor Bloomberg’s goal of 30% carbon reduction by 2030.

However, it is the opinion of the team that this site is not viable in its current state due to economic factors. The current rate structures for electricity within the FDC are highly subsidized, removing the economic benefit of CHP. If in future tenants are subject to market rates, a CHP plant could become economically attractive to a developer.

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Section 5 Solar Evaluation

New York City
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Section 5 Solar Evaluation

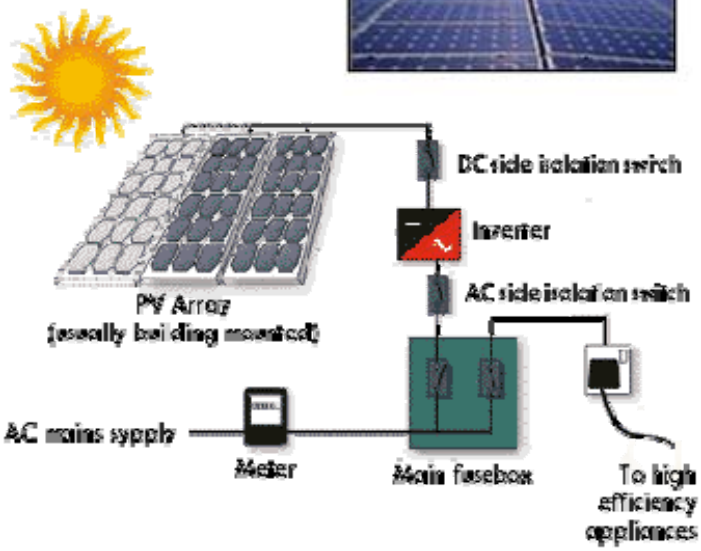
Section 5: Solar Evaluation

5.1 INTRODUCTION

As part of this study's overall assessment of potential distributed generation technologies, DMJM Harris has conducted an evaluation of the potential for solar utilization. This evaluation is a high level look at a number of issues that could affect the viability of deployment of solar technology, both positively and negatively. Included in these issues are the suitability of the existing site for solar power, integration of solar power into the future growth of the FDC, the potential output capacity of solar power at the FDC, installation and operating cost factors, and regulatory hurdles.

5.2 SOLAR PHOTOVOLTAICS

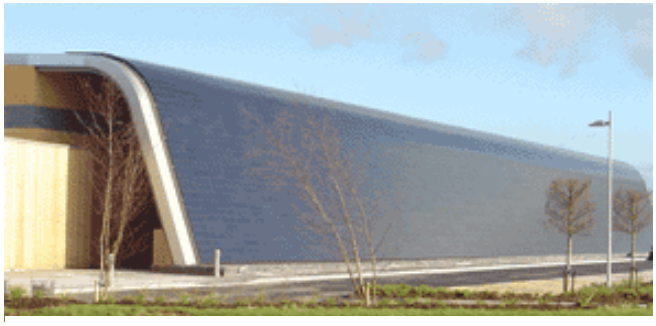
There are three primary applications of solar technology: solar photovoltaic (PV), solar thermal and concentrated solar power (CSP). Of these three, solar PV and solar thermal have potential application to the FDC tenants. CSP is a solar technology whose power output is measured in the hundreds of megawatts and development to date has focused on utility scale deployment, so it is not applicable to the FDC.



Solar PV systems produce direct current (DC) electricity, the same type of electricity provided by batteries. This DC power is converted to alternating current (AC) which is what is used to power almost all devices that are plugged into a socket.

Most solar systems are made up of silicon-based solar cells and other elements to convert sunlight directly to electricity. The basic power producing unit is a rectangular low profile solar module.

There are a host of advantages inherent in solar PV. Electricity generated by solar electric systems does not produce any atmospheric emissions or greenhouse gases. PV also offsets emissions that would have been produced if the same amount of electricity were generated from fossil fuels. Solar generated electricity is also not subject to the uncertainties of the fossil fuel based energy market.



85 KW Thin-film Based Building Façade (Shell Solar)

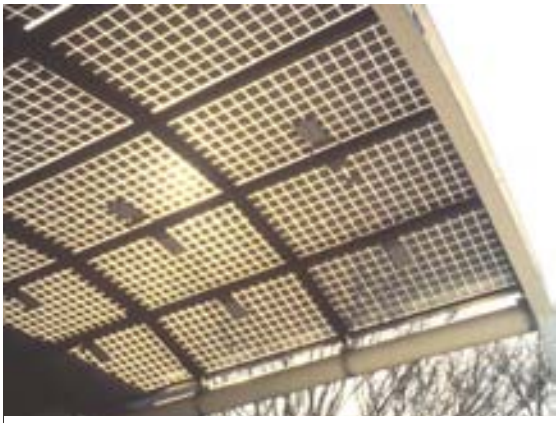
Solar PV systems can be configured in a number of different ways. The configuration that most think of when considering solar PV are the flat panels that are usually mounted on rooftops or within a solar generating array on the ground. Roof top solar has the advantage of turning otherwise unused real estate into a profitably used space. Within the same footprint, both business and electrical generation can be taking place. The selection of suitable existing roof areas must take into account orientation and slope of the roof as well as shading. These conditions are favorable on the existing roofs at the FDC. In new construction, minor design modifications can be made to easily accommodate the installation of solar panels.

Over the past decade, the interest in clean energy, architectural innovations, and the flexibility of solar PV, have combined to produce a number of configurations other than the standard flat panel arrays discussed above.

Building Integrated Photovoltaic (BIPV) solar is a configuration that has been increasing in popularity and use in recent years. BIPV integrates solar cells into the architectural elements of a building. This can be done in numerous ways and the menu of available options continues to grow.

The advance of thin-film technology has enabled solar PV to be applied to glazing, making it possible to use windows as solar PV based electricity generating elements in a building.

The capabilities and flexibility of solar PV enable it to be integrated into many double duty applications as with the use of thin film PV on windows. Another example of this is parking lot shade structures. These can be built with solar cells either mounted on the roof of the shade structure, or integrated as a structural element. This has the dual benefit of generating electricity while at the same time shading cars and mitigating the heat island effect caused by blacktop parking lots on hot sunny days. A potential use for this application of BIPV will be discussed in the next section.



Thin Film PV Cells in Glass Awning

Salinas Valley Memorial Hospital,

5.2.1 Potential Locations-Existing Facilities

The existing buildings at the FDC have a number of distinct advantages for solar energy production over the vast majority of buildings in New York City. First, they have large horizontal footprints with plenty of space in between the buildings, which is rare in the dense urban landscape of New York City. Second, the FDC facilities are low rise buildings, so rigging the rooftop panels into place is much simpler and less expensive than on typical New York City buildings. Third, because there are no tall buildings around, the FDC buildings are not shaded. The FDC buildings are also located within a central concentrated area and are under the management of one agency. These conditions combine to provide an excellent foundation for development of solar PV at the FDC.

The FDC buildings possess over three million square feet of roof top space, which is a substantial amount for a portfolio of buildings located in one area and managed by one agency. With the exception of college campuses and hospitals, most agencies that control building stock with comparable square footage must deal with dispersed properties.

Of course, not all of this rooftop square footage is available for installation of solar panels. A survey of each of the building rooftops in the FDC was conducted using aerial images available from several online satellite mapping resources. Based on this, DMJM Harris estimates that the percentage of rooftop space available for solar installations ranges from 40% to 70% depending on the building, with the exception of the Produce Market, for which the estimate was 15%.

The primary factor taken into account in estimating the percentage of useable space was the presence, amount and layout of rooftop mechanical equipment. For example, the roof of the building leased to Krasdale does not have any mechanical equipment on the roof except for relatively small vents which can easily be accommodated within a solar array layout. On the other hand, the roof of the Produce Market is very crowded with scattered mechanical equipment. Consequently, the only place where solar PV arrays in an appreciable quantity could be laid is on the awnings over the loading docks.

Rare Commodities in NYC

Any one of the following advantages is rare in NYC, but the FDC combines *all* of them.

- ***Large Horizontal Area***
- ***Low Rise Buildings***
- ***Low Urban Density Setting***
- ***No Shading from Adjacent Buildings***
- ***Contiguously Located***
- ***Under Management of Single Entity***

The square footage quantities of the FDC buildings, as well as the estimated area available for solar PV on each building, can be seen in the table in section entitled Solar Output Potential.

In estimating the area available to solar panels, the available rooftop square footage for Bazzini Nuts and R. Best were combined, since both businesses are housed in one building. Sultana and Citarella were also combined for the same reason.

In addition to the area available for the solar panels, there are several other factors that must be taken into account when considering integrating solar power into a facility. One of these is the actual physical effect of the array on the building structure. The weight of a typical PV array is 3 to 5 lbs/ft^2, which is well within the structural limits of most buildings. Some of the buildings are warehouse type buildings with wide span open joist type roof steel, so an analysis of the structural capacity of the existing roofs to support the solar panels will need to be done on a case by case basis.

The actual connection of a solar array to a building system will require an inverter, but is very straight forward. For commercial systems, this inverter is approximately the size of a refrigerator.

5.2.2 Potential Locations-Future Construction

There are two sites, totaling about 1.4 million square feet, in the FDC for which the NYCEDC is planning future expansion or construction, both of which will be very attractive for the deployment of solar PV. Both sites are large and currently in the pre-development phase.

The size of the sites renders them particularly suitable for large scale solar PV installations, which brings the related benefit of economies of scale. A larger installation is also likely to draw more interest from third party solar energy developers.

The first site is an area that is enclosed within the Food Center Drive circle. It consists of several contiguous undeveloped parcels, including two unleased sites (designated as voluntary clean-up sites AOU-2 and EOU-3), a street right-of-way, and an under-leased[1] area currently designated as an auxiliary parking lot for the Fish Market. The total area of this site is roughly 17.2 acres or 753,000 square feet. This is a large amount of available space for a solar array.

Site of Future Construction

DMJM Harris recommends that any new development in this area should integrate PV into the building design. It is assumed that a portion of this area will be allocated to parking, but this can also be considered useable space for a PV array if solar shade structures are used.

If it is assumed that 75% of the available site will be horizontal building square footage and that 75% of this building square footage is useable roof space, the available rooftop area on the new construction solar PV would be 423, 562 ft^2. Of the 25% of the land left over, if it is assumed that 50% of that is parking lot and the other 50% is used for storm water management and other green space needs, the parking lot area would be about 94,125 ft^2. Assuming that the shade structure would be designed to cover 75% of that parking lot, the area of the solar array would be 70,593 ft^2. Using the industry standard rule-of-thumb output of 10 watts per square foot of solar array, this would mean a generation potential of 4,235 kW for solar PV on the roof of the new construction and 706 kW for the solar PV on the parking lot shade structures.

[1] An under-leased site is a site that is being leased by someone but is not considered being used beneficially. An example would be a portion of a site that is being used as dumping area by others.

The second site that has potential for a PV array is the parking lot to the east of the Produce Market. If this site were to remain a parking lot then solar shade structures could be an option.

Area for Future Expansion of the Produce Market

According to the NYCEDC, up to 672,000 SF of new building space could be constructed in this area. If 25% of this roof were to be allocated to mechanical equipment, access/egress and other needs, that would leave 504,000 SF available for a solar array. At 10 watts per square foot of solar array, this would mean a generation potential of 5040 kW.

5.2.3 Solar Output Potential

The large amount of area available based on estimated available percentage of roof space available for each building gives the NYCEDC and FDC tenants an opportunity to develop solar PV capability of unusually large magnitude for one location in an urban environment. Based on industry standard average power output figures for solar PV systems, the total amount of power potentially available from solar PV deployed on the roof space of the existing FDC buildings is about 14 MW. Based on the development assumptions discussed under the “Future Construction” section, a generation capacity of an additional 10 MW capacity is possible.

The following tables show a breakdown of the estimated amount of PV generation capacity. The first table shows the square footage of each existing building along with the estimated percentage of available roof space for solar PV and the resulting estimated electrical output capacity.

The second table shows the assumptions for space utilization of future construction along with the estimated percentage of available space for solar PV and the resulting estimated electrical output capacity.

Potential Solar PV Output for Existing Facilities				
Location	**Total Area**	**Est. % of Roof Avail for PV**	**Solar PV Area**	**Estimated Capacity**
New York City Terminal Produce Coop Market	910,000 ft^2	15%	136,500 ft^2	1,365 kW
Hunts Point Cooperative Market (Meat Market)	875,000 ft^2	50%	437,500 ft^2	4,375 kW
Fulton Fish Market	428,000 ft^2	50%	214,000 ft^2	2,140 kW
Baldor Specialty Foods, Inc	185,000 ft^2	40%	74,000 ft^2	740 kW
Bazzini Nuts Inc. & R. Best Produce	175,500 ft^2	60%	105,300 ft^2	1,053 kW
Anheuser Busch*	128,000 ft^2	50%	64,000 ft^2	640 kW
Krasdale Foods Distribution Center	325,000 ft^2	70%	227,500 ft^2	2,275 kW
Sultana Distribution Services, Inc & Citarella	177,400 ft^2	60%	106,440 ft^2	1,064 kW
Totals	3,203,900 ft^2		1,365,240 ft^2	13,652 kW

*Estimated % of roof area available for PV is based on preliminary drawing review

Potential Solar PV Output for Planned Facilities				
Location	**Total Area** (est.)	**Est. % of Roof Avail for PV**	**Solar PV Area**	**Estimated Capacity**
Building on Parcels EOU-3, AOU-2, & Fish Market Parking	564,750 ft^2	75%	423,500 ft^2	4,235 kW
Parking Lot & Open Space on Parcels EOU-3, AOU-2, & Fish Market Parking	141,200 ft^2	50%	70,600 ft^2	706 kW
Produce Market Additions	672,000 ft^2	75%	504,000 ft^2	5,040 kW
Totals	1,377,950 ft^2		998,100 ft^2	9,981 kW

5.2.4 System Cost

The module shown above represents around 45-55% of the total installed cost of a solar energy system. Based on current module prices the system installed cost can be estimated to be in the range of about $8.00/ watt for roof mounted systems or $9.00/watt for a solar shade structure. Simple calculations would determine that the capital cost for 25 MW of solar PV would be over $200 million. However, it would be misleading to take the estimated number of watts generated and multiply them by $8.00 to calculate the cost of the system. First of all, for a system of this size, economies of scale would bring down the installed unit cost of the installation. Second, the $200 million cost does not take into account incentives and tax credits that would be available, such as the recently passed 35% property tax abatement for solar PV in New York City. Third, the price of solar PV continues to be driven downwards by continuously improving technology.

5.2.5 System Savings

A more detailed feasibility level analysis would need to be conducted to determine the savings that could be generated from solar PV generation at the FDC. One thing is certain, while the price of fossil fuels and electricity will only continue to go up; the price of the sun's energy will remain fixed at zero.

In addition to the future price volatility of fossil fuels, additional potential cost liability may be incurred by fossil fuel based electricity generators when the Regional Greenhouse Gas Initiative (RGGI) goes live in 2009. The RGGI will impose a cap on the production of CO_2 on electric generating plants of 25 MW and up. It is uncertain at this point how this will affect electricity prices, but it is certain that power produced by solar PV will not face this potential liability. This will provide an element of price stability to consumers of solar PV generated power.

Besides the sale of electricity, solar PV power will generate an additional revenue stream in the form of Renewable Energy Certificates (RECs), also known as " green tags". This market based mechanism alllows a producer of clean energy to sell RECs on the open market. Each REC is equivelant to 1 MWh of clean energy and can fluctuate in value from $5 to $90 per MWh, depending on numerous factors. The average price for a REC is $20[2]. If we conservatively assume a site with only 15 MW of generating capacity, and 30% PV capacity factor with 65% availabilty of sunny or partly sunny days, this would yield an output of 1056 MWh in a month. Assuming a price of $20 per MWh this would result in an additional $21,130 in one month from the sale of RECs. This additional revenue stream can be used in a number of different ways including increasing the operating profit to the owner of the solar array, increasing the savings summary of solar PV system or obtaining front end financing by selling these RECs on the forward market.

Additional savings may result based on the utility's time-of-use (TOU) tariff. Under this system, the price of electricity varies according to whether it is used during "On-Peak" or "Off-Peak" periods and is more expensive during the daytime peak periods. Electricity consumption of facilities typically peaks during these on-peak periods, which is also when solar electricity production peaks. The reduction of these peak loads by solar PV could mitigate demand charges substantially, thereby increasing the savings projections. Savings will also continue to increase over time as the price of electricity and fuel inevitably goes up.

[2] The Green Power Network, U.S. DOE, Energy Efficiency and Renewable Energy program. (website) accessed at http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

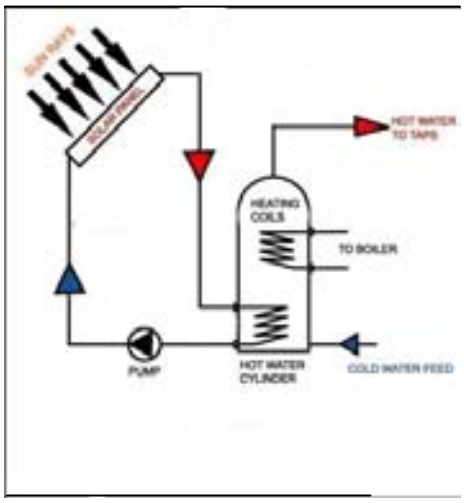
5.3 SOLAR THERMAL

Another use of solar radiance is for the generation of thermal energy. This application uses the sun's energy to directly heat another medium, usually water or a water solution mixture. Since this is a direct exchange of energy rather than a conversion of energy, as is the case with photovoltaics, much less energy is lost on a unit basis.

Solar thermal, also known as solar hot water heating, is a very simple and well proven technology. Its basic premise is that it uses clean, renewable energy (the sun) to replace fossil fuel based energy such as oil, natural gas or propane, as an energy source to heat water.

Solar thermal technology is a mature industry, having begun in the early 1970's. As such, not only has the technology continued to improve, but an extensive industry support infrastructure has also developed. Both are necessary features when considering capital investment into building systems.

There are a several different types of systems, but the basic principles are the same. A solar collector absorbs heat from the sun and transfers it either directly to the water or to a separate heat transfer fluid. The heated water is sent to a storage tank where it is available for on-demand use. Usually, a solar hot water system is supplemented by a conventional water heating system to provide for any additional heating that is not met by the solar thermal system. However, the energy requirements for this conventional heating system can typically be reduced by up to 80% and so these systems are often down-sized thereby displacing a portion of the capital cost of the solar thermal system.



Basic Solar Thermal Process

Flat Plate Solar Collector

5.3.1 Solar Cooling

One potentially intriguing use of solar thermal is for cooling by means of absorption chillers. Solar cooling is a combination of two very well established technologies. As mentioned earlier, solar thermal collectors have been in use for 30+ years, whereas absorption chillers have been in use for over 50 years. The combining of both technologies into solar cooling has come about within the past 10 years so the industry is still experiencing a maturation process with much research and testing still being conducted.

The payback period for a solar air conditioning system depends on a number of factors including geographical area, amount of solar radiation, annual usage of the system and incentives. However, with the right combination of these factors, it can be quite short. For example, in some states such as Arizona, Florida, Texas, North Carolina, and Florida, a solar HVAC system can be projected to pay for itself in a few as two years. As another point of comparison, an average household of four can expect to recover the cost of a solar system within four to six years[3] under the right set of circumstances.

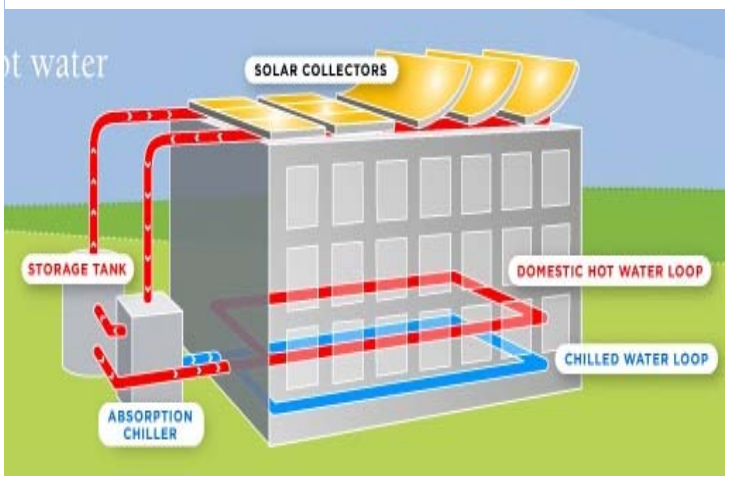
[3] Solar Panels Plus website, accessed at http://www.solarpanelsplus.com/solar-panels-faq/

5.3.2 Applicability

Solar Thermal

In most of the FDC facilities, the actual percentage of office space to total space is small, and hot water heating is solely for heating for domestic water use. Therefore, the system parameters and output of a residential unit are probably readily scalable to the domestic water heating load of the most of the FDC facilities. As a point of reference, a residential solar hot water heating system with a collector area of 64 ft^2 can deliver 86,000 Btu per day, enough to heat a 120 gallon tank for a 5 occupant home with an energy input ratio (solar input/total input) of 85% for solar.

Integrated Solar Thermal Cooling and Heating System



On a nationwide basis, water heating accounts for about 4% of the energy in commercial buildings. This figure is, of course, highly site specific and can be much higher, depending on the type operations at the facility. The estimated percentage of energy use for water heating by the FDC tenants was about 3-5% so they appear to fall in with the national average.

Normally, a facility looking to reduce its energy consumption targets the largest contributing factors and so 4% of the overall energy usage would not be considered a priority. However, if a particular FDC tenant's facility possessed the right set of circumstances, such as described in section 5.3.4, solar hot water heating could still be an attractive option as part of an overall portfolio of energy efficiency and clean energy strategies. Additionally, if any of the planned expanded or newly constructed facilities will house operations that meet the applicability criteria, solar thermal should be considered in the design at the outset of the planning process.

Solar Cooling

Although this application of solar thermal technology could not replace the food process refrigeration loads of the FDC, it could displace a substantial percentage of the space conditioning loads. Solar absorption cooling systems are available in sizes ranging from five tons to 100's of tons are typically sized to carry the full air conditioning load during sunny periods. These systems are usually not designed to replace conventional air conditioning systems, but rather to sit alongside these legacy systems and prevent them from operating up to 90% of the time.

5.3.3 Integration Considerations

Solar thermal systems can usually be retrofitted into existing facilities relatively easily. The portion of the system that takes up the most space is the solar thermal collector which is typically located on the roof, although it can also be located on grade. Most of the roofs in the FDC have the space to accommodate collector systems. The ability of these roofs to accept the weight of a suitably sized collector system would have to be determined on a case by case basis.

5.3.4 Cost Considerations

Solar thermal heating is likely to be cost effective under two situations: 1) any facility that pays high utility rates for conventional water heating or 2) large facilities with a consistent need for large volumes of hot water.

If hot water use is more than 1000 gallons per day, or conventional energy cost is more than $15-$20 per million Btus, a large solar water heating system could be cost effective. If the hot water consumption of a facility is more than 10,000 gallons per day, parabolic trough systems should be considered.[4]

The cost of a system will vary widely depending on what variant of the technology is used, the size of the heating load, available capital cost offsets, regional factors and other site specific data. However, some industry information has been gathered that can help provide order-of- magnitude estimates[5].

What Will it Cost?		
Collector System Size (SF)	**Collector Type**	**Cost per SF of Collector**
Small (<100)	**Flat Plate**	**$65 to $115**
Medium (1,000<10,000)	**Flat Plate**	**$50 to $60**
Large (>10,000)	**Flat Plate**	**$40 to $60**
Very Large (>20,000)	**Parabolic Trough**	**$30 to $50**

From observations made during site walkthroughs, the hot water consumption of the FDC tenants does not appear to be high enough to make solar hot water heating an area of focus as an energy reduction strategy.

5.4 REGULATORY HURDLES

The regulatory hurdles discussed in this section apply only to solar PV and do not affect either solar thermal heating or cooling.

For solar PV, the primary regulatory hurdle that constrains development of a solar installation is the interconnection process with the utility. This is the case from both an administrative perspective and a technical perspective.

Administratively, the application process currently lacks transparency and there is no certainty as to the length of the interconnection application process or the cost that will be incurred by Con Ed's review process.

Technically, there is uncertainty as to whether the grid can accept the electricity generated by the proposed solar PV array. This leads to a related uncertainty as to what infrastructure upgrades would be required on Con Ed's grid in order to accept the PV system's output, as well as to what the cost for these grid upgrades would be.

Another hurdle is the potential to infringe on Con Ed's transmission and distribution franchise rights if power from the panels is distributed to any facility other than the one upon which they are located, particularly if the power lines cross a mapped street

[4]Federal Energy Management Program, *Federal Technology Alert,* "Solar Water Heating-Well Proven Technology Pays Off in Several Situations", p 13

[5] Costs are national average costs and must be adjusted for regional factors. Data was obtained from FEMP Federal Technology Alert dated May 1998 and was adjusted to 2008 costs using the annual inflation rates from 1999 to 2007.

5.5 BENEFITS

The benefits of solar PV are well known. They include reduction of emissions due to the displacement fossil fuel produced power, reduction in electrical costs due to peak load shaving, long term energy cost stability, and generation of an additional revenue stream on the REC market.

The benefits of solar cooling are also numerous. Thermally driven chiller system can reduce the electrical energy consumption typical of compressor based chillers by up to 80% and a solar thermal driven system can further displace the fuel usage that is required for standard absorption chillers.

In a 2002 study prepared for the California Energy Commission testing conducted on a solar fire absorption chiller revealed that the net reduction in electrical demand was about 1.3 kW per ton of cooling[6].

Another study estimated that solar absorption cooling can save an average of two-thirds of the primary conventional energy used for space cooling in the U.S[7].

Another benefit would be the reduction in CO_2 caused by the displacement of electricity used for cooling. Burning natural gas for electricity production generates about 1 lb of CO_2 per kWh. Coal generated electricity will generate about twice that amount.

This means that if just one large facility with a 100 ton cooling load switched from electric chiller driven air conditioning to solar thermal driven air conditioning, about 10 tons of CO_2 emissions could be displaced in a month, assuming 8 hrs per day of solar cooling five days a week.

Ice from the Sun?

Energy Concepts has developed the Intermittent Solar Ammonia-water Absorption Cycle (**ISAAC**) system.

ISAAC uses a parabolic trough solar collector in concert with a compact absorption refrigeration system to generate liquid ammonia refrigerant during the day and ice during the night as the ammonia evaporates and is reabsorbed to the generator.

Because it is thermally driven the **ISAAC** Solar Icemaker supplies refrigeration without the need for electricity or fuel.

ISAAC produces about 12 lbs. of ice per 10 SF of collector on a sunny day. A typical set-up can make six 22 lb. blocks of ice per day.

ISAAC was designed as a low cost system for use in unelectrified rural communities around the world and currently had been deployed on twenty sites in seven countries.

[6] James Bergquam and Joseph Brezner, Bergquam Energy Systems. *Design and Optimization of Solar Absorption Chillers*, p 42. Submitted to California Energy Commission, Public Interest Energy Research March 2002.
[7] E. Thomas Henkel, PhD, *New Solar Thermal Energy Applications for Commercial, Industrial, and Government Facilities*. Energy & High Performance Facility Source Book, Proceedings of the 26th World Energy Engineering Congress, p 456

5.6 CONCLUSION

There is an opportunity to install a substantial amount of solar PV generation in the FDC. There is the potential for 14 MW on existing buildings and 10 MW on new construction, for a total of up to 25 MW. This is a huge number for solar PV generated power installed within a single industrial park, especially relative to the less than 2 MW of solar energy currently deployed within New York City.

The FDC combines a unique grouping of advantages that are unavailable in much of the rest of New York City which render it a compelling platform for a major solar generation facility. Its rare combination of physical advantages, along with a prevailing inclination of the leadership in the South Bronx towards sustainable development and environmental justice, create an environment that is primed for the development of clean energy.

Certainly, there are obstacles that need to be addressed. The most pressing of these are the uncertainties of the interconnection application process, the capability of local grid infrastructure to accept any power at all, the limits to the amount of solar generated power that can be currently connected to the grid and the amount of excess power that can be sold back to the utility[8].

However, given the set of circumstances which create a favorable platform for large scale solar PV in the FDC; it would seem that this is an opportunity around which the City and other clean energy stakeholders should rally. These stakeholders should include the NYCEDC, the FDC tenants, the Bronx Overall Economic Development Corporation, the PSC, NYSERDA, Con Edison, the Mayor's Office for Long Term Planning and Sustainability, and Bronx leadership.

Benefits to the city and the community would include the reduction of thousands of tons of CO_2 per year for power generated by the FDC solar array.

There are potential benefits to the business community in the FDC also. For example, the NYCEDC could structure a solar Request for Proposal so that the third party power developer would lease the roof space on which they would mount the solar arrays for the duration of the power purchase agreement. How much of this income would go to the NYCEDC and how much would go to the building tenant would be a subject for lease negotiations. The new construction can have this arrangement built into the lease terms. Various tenants could also opt to purchase the power from the solar panels located on their rooftops, although this arrangement would probably only work for the buildings that do not have numerous subtenants.

This potential installation would stand alone as a benchmark project not only in New York City, but in any urban area in the United States. As such, it merits specific efforts to prepare the way for successful implementation. These efforts will require the cooperation of a coalition of clean energy stakeholders, perhaps on a task force level. PlaNYC states that "we will work to set the stage for renewable energies such as solar…" It is DMJM Harris' belief that the FDC is not only a stage that should be set for solar energy, but one that will perhaps set a new paradigm for solar programs in American cities.

[8] The issue of selling excess power back to the utility, or net metering, would typically only apply to a host facility that owns and uses its own solar generation. Its applicability to future solar PV development at the FDC remains open until the ownership model is selected.

5.6.1 Recommendations

- Integrate solar PV and solar thermal into the early development for new construction at the FDC.
- Conduct detailed analysis of the South Bronx “4-X” network in terms of its capacity to accept 25 MW of solar PV.
- If utility infrastructure upgrades are necessary to accept large scale solar PV, advocate on behalf of grid improvements at the PSC level as well as in other forums.
- Partner with Con Ed to prepare simplified interconnection process specifically tailored to large scale solar PV deployment at the FDC.
- Pursue Qualified Facility status for all solar generation at the FDC.
- Engage the various alternative energy stakeholders around an FDC solar program.
- Engage a coalition of South Bronx constituencies around an FDC solar program.
- Perform more detailed feasibility analysis of large scale solar PV at the FDC. Include applicability of various ownership models.

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Section 6 Fuel Cells Evaluation

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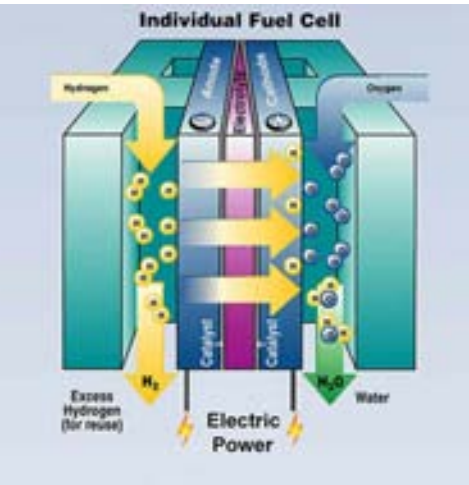
Section 6: Fuel Cells Evaluation

6.1 INTRODUCTION



A fuel cell is a non-combustion technology that uses the chemical energy of combining hydrogen and oxygen to directly produce electricity and heat. Water is the only by-product. The concept of fuel cells has been around for over 100 years, but practical application of the technology was first used in the space program in the 1960's.

A fuel cell does not involve the combustion of fuel; rather, it is similar to a battery in that it produces energy by an electro-chemical process. This electrochemical process produces negligible amounts of Nitrogen Oxides (NOx) and Sulfur Oxides (SOx) emissions and lowered CO_2 levels. If pure hydrogen is not available, other hydrogen-rich fuels such as natural gas, propane, methane or ethanol could be used by adding a fuel reformer to extract the hydrogen. By eliminating the fuel combustion process, the fuel cell converts its chemical energy into electrical energy at a much higher efficiency than conventional sources. Usually, the electrical power generating efficiency of a fuel cell is 40% or higher, based on the lower heating value (LHV) of the fuel. Electricity produced by a conventional fuel combustion process results in a power generating efficiency of 30% to 35%. By utilizing the heat produced in a fuel cell for applications such as domestic water heating or space heating, overall efficiencies often exceed 85%. Individual fuel cells provide a very small voltage, and to achieve useful voltage levels, the individual fuel cells are arranged in stacks.

There are four primary types of fuel cell technologies which include: Phosphoric Acid (PAFC), Proton Exchange Membrane (PEM), Solid Oxide (SOFC), and Molten Carbonate (MCFC). Each type operates at different temperatures and efficiencies, requires different construction materials, has different startup and load following characteristics, and is used in different types of applications.

PAFC is the most mature fuel cell technology and is commercially available today; however, electrical output capacities are generally limited to the ranges of 150 to 200 kW and 1 and 2 MW. Operating temperatures for PAFCs are in the range of 300°F to 400°F.

PEM fuel cells operate at relatively low temperatures, near 175°F. They are well suited for quick startups and electrical load following. They are targeted for light-duty vehicles and smaller building applications such as replacements for rechargeable batteries. PEM fuel cells are sensitive to fuel impurities, and cell electric outputs are generally in the range of 50 to 250 kW.

SOFC fuel cells are promising for large, high-power applications; however, proven applications are in the electrical output range of 25 to 220 kW for the tubular SOFC designs. Some fuel cell manufacturers are trying to develop smaller units in the 5 kW range. Operating temperature can reach 1,800°F and power generating efficiencies could reach 60 to 85% with cogeneration.

Below is a tabular summary of some of the characteristics of these four types of fuel cell.

Fuel Cells Overview				
	PAFC	SOFC	MCFC	PEMFC
Commercially Available	Yes	No	Yes	Yes
Size Range	100-200 kW	1 kW - 10 MW	250 kW - 10 MW	3-250 kW
Fuel	Natural gas, landfill gas, digester gas, propane	Natural gas, hydrogen, landfill gas, fuel oil	Natural gas, hydrogen	Natural gas, hydrogen, propane, diesel
Efficiency	36-42%	45-60%	45-55%	25-40%
Environmental	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions
Other Features	Cogen (hot water)	Cogen (hot water, LP or HP steam)	Cogen (hot water, LP or HP steam)	Cogen (80°C water)
Commercial Status	Some commercially available	Likely commercialization 2004	Some commercially available	Some commercially available

From California Energy Commission Distributed Energy Resource Guide

Other than hydrogen, natural gas (methane) is considered to be the cleanest and most readily available fuel source for distributed generation applications. Consequently, most current research into fuel source for stationary fuel cell systems in on converting natural gas into pure hydrogen fuel.

6.2 BENEFITS AND HURDLES

Fuel cells are still an emerging technology, and care must be exercised in planning, selecting and applying the proper fuel cell technology to given applications. Although limited electrical output ranges are available for large scale building systems, broader size ranges are still under development and are not yet commercially available.

Key advantages and disadvantages of fuel cells are summarized below.

6.2.1 Benefits

- High Reliability: Proven applications have achieved 99.99% reliability.
- Site Flexibility: Small footprints with minimal ancillary facilities required. Can use modular installations to obtain the desired quantity of electricity. Outdoor installations can be operated unattended.
- Fuel Versatility: Can operate with pure hydrogen, or can operate with hydrogen-rich fuels, such as propane, natural gas, methane or ethanol (requires a fuel reformer).
- High Efficiency: Direct electrochemical process (>40%) is more efficient than combustion processes (30-35%), and operates at nearly constant efficiency, independent of size and load. Applying CHP can increase overall efficiency to >85%.
- High Quality Power: Fuel cells produce DC power that is usually converted to high quality AC power. Some applications utilize the DC power for UPS backup power for computer systems.
- Environmentally Clean: Practically no environmental pollutants due to elimination of the combustion process.
- Quiet: Noise level is typically <60 dBa @ 1 meter.
- Waste Heat Applications: Waste heat offers CHP opportunities by heating domestic water, space heating or other applications.

- Permitting & Licensing: Permitting and licensing are usually shorter than combustion processes.
- Incentives: Often, financial incentives in the order of $1,000/kW are available for fuel cell applications.

6.2.2 Hurdles

- Limited Sizes: Although the first fuel cell was developed more than forty years ago and the technology has been emerging for the last decade, commercial applications have mainly focused on units in the 100 to 250 kW size range. Other sizes are limited and are either still under development, unproven in commercial applications or only available for customized special applications.
- High Capital Cost: Expensive fuel reformers added to the cost of the fuel cell itself have resulted in system installed costs in the range of $3,000/kW to $6,000/kW.
- Maintenance Cost: Although there are significant maintenance cost advantages for fuel cells over combustion processes, maintenance costs can still be high due to requirements for cleaning and/or replacing air and sulfur filters and replacing fuel cell stacks.
- Unknown Life Expectancy: Not enough historical data has been collected yet to reliably predict the life expectancy of fuel cell systems, and some manufacturers are only projecting 10 years.
- Fuel Reformer or Fuel Processor: Unless pure hydrogen is available, expensive fuel reformers (fuel processor) are required to extract hydrogen from hydrogen-rich fuels.
- DC to AC Inverter Required: Since DC electricity is produced in the electrochemical process; an expensive DC to AC inverter is required, which is usually built into the system.
- Slow Startup Times: Depending upon the fuel cell technology being applied, startup times from a cold shut-down can take from a few minutes up to about four hours.
- Economy of Scale: Because of high capital and maintenance costs for smaller size fuel cell systems, it is often difficult for the small size equipment to produce electricity more economically than what can be purchased from the local utility.

6.3 CONCLUSION

Fuel cell technology is promising, and early adopters are continuing to provide a useful service in logging operating histories and data that will be valuable in improving upon the current systems. However, some of the negative aspects of the technology present substantial reasons to be wary of considering them competitively with other forms of clean energy. The high costs and performance issues of current fuel cell technology are significant obstacles to mass deployment. Although fuel cells may be applicable under certain circumstances, we do not recommend their use at the FDC for the sole purpose of providing distributed generation capacity.

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Section 7 Regulatory Impact

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Section 7: Regulatory Impact

7.1 INTRODUCTION

This section discusses the various factors, considerations, options and issues involved in connecting a distributed generation plant in the Food Distribution Center (FDC) area to the electrical distribution grid owned and operated by Con Edison.

Distributed Generation (DG) refers to generation that is located at an end use consumer's site. DG usually includes standard fossil fuel based systems, and can include various types of energy sources such as solar, geothermal or fuel cells. Typically, a fossil fuel based DG system will consist of a cogeneration system, also known as combined heat and power (CHP) system. Con Edison generally defines a DG facility as a relatively small (20 MW or less) electric generating facility that is dedicated to supplying power to a nearby associated load. In the context of this discussion, the term distributed generation (DG) will be assumed to include CHP systems, and the two may be used interchangeably at times in this report. Unless otherwise noted, the use of the term DG can also be considered inclusive of alternative energy systems, such as solar photovoltaic (PV) systems, since most of the interconnection issues discussed are the same whether the system under discussion is CHP or solar PV based.

A developer contemplating installing distributed generation to sell power to a customer facility will most likely also be connecting that generation capacity to the utility's distribution grid. The typical operating scenario for a DG plant involves supplying a percentage of the electricity required by the customer facility (known as "base loading") with the remaining electricity requirements of that facility being met by the utility. This requires interconnection with the utility's grid. This arrangement wherein both the DG plant and the utility are simultaneously supplying the load facility is referred to as "paralleling" the utility. Virtually all CHP systems installed in the New York City area operate this way.

In the development stages of a DG project in the NYC area, perhaps the biggest wildcard factor is the utility interconnect process with Con Edison. Numerous complex and competing factors must be taken into account prior to initiating a project and an otherwise favorable economic analysis could be upset by the uncertainties of the outcome of the interconnect application process. A developer must account for these variables during the pre-development phase of a DG project and factor them into the project's economic analysis to determine whether they can be accommodated within the project's risk tolerance. In the following sections we will present the relevant information that a developer needs to consider prior to, or at least simultaneously with, the economic feasibility analysis phase of a project.
.
The term "developer" is most often used in this report's discussion of the utility interconnect process when referring to the potential DG load serving entity. This is because the focus of this study was to determine whether the FDC presents a business case viable enough to attract third party DG developers. Under this arrangement, a third party developer finances the project, installs, owns and operates the DG facility, and sells energy to a client under a long term (10+ years) contract.

7.2 INTERCONNECTION

Con Edison's official policy is to allow any customer to operate electric generating equipment in parallel with their electric system "provided there is no adverse effect on the company's other customers, equipment, or personnel, or the quality of service." However, this determination of "adverse effect" leaves a large amount of uncertainty as to the outcome of any effort to interconnect to Con Edison's system. To be equitable, Con Edison's system was not designed to accommodate distributed generation. Rather, it was developed around the large scale centralized generation model that evolved in the early 20th century. Consequently, connecting DG to Con Edison's distribution system involves the introduction a new source of power to the utility's distribution system at a point in the grid that was not initially designed to accept this power.

As with any other utility, connecting a DG facility to Con Edison's electrical system entails adherence to its standards. This requires that the necessary protection requirements are met and the appropriate approvals are obtained. These protection requirements are project and site specific and are determined by Con Edison on a case by case basis. There are three provisions available to a developer that will assist in navigating the potentially confusing interconnection process, described below.

7.2.1 Developer Assistance

- **The "Distributed Generation Process Guide"**

The first resource that a developer should take advantage of when considering DG, is Con Edison's 'Distributed Generation Process Guide". This Process Guide, available on Con Edison's website[1], lays out the options available to a DG facility in terms of service categories, incentive programs and generator configurations. These will be discussed more fully in a succeeding section entitled "Development Options"

- **The "Handbook of General Requirements for Electrical Services to Dispersed Generation Customers" (EO-2115)**

The second resource available to a DG developer is a set of guidelines provided by Con Edison entitled "Handbook of General Requirements for Electrical Service to Dispersed Generation Customers", more often referred to as EO-2115. Con Edison has prepared this guideline document in order to clarify the interconnection requirements for distributed generators who will be connecting to their grid. This document provides Con Edison's general design and operating requirements, tariff and interconnection cost information, customer interface procedures and technical requirements for the various types of generators. It should be noted that these guidelines apply only to generating equipment which will be interconnecting to Con Edison's or the customer's distribution systems. Generators connecting to the utility's transmission system must adhere to a different set of standards. That will not be the case for any generation under consideration in this study.

- **The New York State Standardized Interconnection Requirements and Application Process**

The third resource available to the DG developer is the New York State Standardized Interconnection Requirements and Application Process or Standard Interconnection Requirements (SIR). This procedure was developed to provide clarity, structure and timeliness to the process of applying for interconnection of a distributed generator to Con Edison's grid. Any developer pursuing distributed generation in New York State will have to comply with the SIR protocol. This SIR process will be discussed in the following "Application Process" section. A flow diagram depicting the process can be found in Appendix 5, "Interconnection Application Process Schematic".

[1] Con Edison, Distributed Generation Home(website), accessed at http://q050-w5.coned.com/dg/default.asp

7.3 PREDEVELOPMENT CONSIDERATIONS FOR DISTRICT GENERATION

Right at the outset of the pre-development phase, there are three exclusionary criteria that must be considered, each of which immediately sets predetermined constraints on the range of options available to the developer. These criteria are:

- **Franchise Rights**- The rights granted to Con Edison by state regulatory authorities to be the sole provider of transmission and distribution (T&D) services within its service territory.
- **Fault Current-** This is of concern when a DG facility has the potential to send current back into a portion of the grid that has experienced a "fault" (failure). When this occurs, and the grid has been de-energized and isolated by network protection, it can be overwhelmed by the DG facility's current.
- **Capacity**- The ability of Con Edison's system to accept additional generation capacity at a particular point in its grid.

7.3.1 Con Edison Franchise

If a developer plans to operate a DG plant with the intent of selling power to customers, one of the first issues that must be taken into account is Con Edison's franchise rights. Con Edison has franchise rights to transmission and distribution (T&D) within its service territory. The matter of franchise rights can be a complicated issue. The stance typically adopted by T&D utilities within the state is that a third party-owned generation plant that delivers power across a street for sale to a customer infringes on the utility's T&D franchise, which, among other things, would subject the developer to oversight by the PSC as a regulated utility. This would most likely be Con Edison's assertion. However, it is up for interpretation in almost every case[2]. Complicating matters is the fact that determining franchise rights could involve searching through documents dating back over a hundred years. Further, there is no single repository of statutes from which to obtain all the relevant information needed. Therefore, the developer would need to carefully weigh the chances of successfully dealing with franchise statutes prior to deciding on which DG path to pursue.

Assuming that the developer would not want to tackle franchise statutes through the regulatory process, the franchise boundary line that merits primary consideration is Food Center Drive (see orange boundary in figure). Although Food Center Drive is currently unmapped, according to the NYCEDC it will be a mapped street by the end of 2008.

[2] Communication with New York Public Service Commission's Director of Public Affairs who emphasized that it is nonbinding on the Commission, June 12, 2008.

Therefore, there is no place in the FDC locale where a DG plant can be located to bring power directly to all of the FDC tenants by means of its own distribution infrastructure without at least raising the specter of a regulatory appeals process . In this case, the developer would face the prospect of being required to become a regulated utility. However, even if a developer would not have to face becoming a regulated utility, the cost of implementing a new distribution infrastructure in the area for a CHP plant would likely be cost prohibitive.

Based on the foregoing information, it may seem that, from a regulatory standpoint, bringing DG to the FDC and either supplying multiple tenants or generating more than the requirements of one tenant, is not feasible. However, there are some options available to a developer that could enable operation either within, or around the constraints, of T&D franchise regulations. These will be addressed in the "Conclusion" subsection of this discussion.

7.3.2 Fault Current

When a synchronous generator is connected to the grid, it creates a source of electricity that could potentially back-feed electricity onto the utility's system when the system is not prepared to accept it. For example, if a portion of the network is de-energized due to an area outage caused by a short circuit or "fault", a generator will want to send its power onto the grid toward this fault since electricity follows the path of least resistance. This would endanger the safety of crews who may be working on lines thought to be de-energized, and compromise the condition of expensive equipment. This unwanted electricity is referred to as "fault current". Con Edison has provisions in place to protect its system against electricity flowing back onto the grid, but these protective devices have rated capacities, which if exceeded, could cause them to fail.

The fault current contribution of a DG facility is highly dependant on the type of generator used. The primary generation options available to a developer are *synchronous*, *induction* and *inverter based*. These generator types and their effect on fault current contribution are discussed later in the Interconnection Options section under "Generation", but for the present discussion, synchronous generation is the most problematic in terms of fault current contribution.

Consequently, whenever a synchronous based DG system proposes an interconnection to Con Edison's grid, the fault current contribution of the DG system must be reviewed by Con Edison prior to their acceptance of the developer's application. In some areas, the available fault current capacity (margin) may not be large enough to accept the additional fault current contribution that would be added to the system by the generator. In these cases, additional mitigation measures would be required of the developer by Con Edison. This adds cost to the project as it involves additional design time and protective equipment as well as engineering review time by Con Edison.

Because of the effect of this fault current issue on DG, in 2005 the New York State Public Service Commission (PSC)[3] required Con Edison to conduct a fault current study[4] of their entire grid. As a result of this study, Con Edison has placed a map on its website showing potential areas where synchronous generation can be installed without fault current mitigation.[5] According to this map for the Bronx, shown in Appendix 2, the distribution area corresponding to Hunts Point can be considered for synchronous

[3] State of New York Public Service Commission, Case 04-E-0572. *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. Order Adopting Three-Year Rate Plan. Accessed at PSC's website at http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/ViewCat?ReadForm&View=ArticlesByCategory&Cat

[4] Tim Taylor, Andrew Hanson, David Lubkerman and Mirrasoul Mousavi. *Final Report, Fault Current Review Study*. Report No.:2005-11222-1-R.04, ABB Inc. Electric Systems Consulting. Submitted to Con Edison on December 22, 2005

[5] *Con Edison, Synchronous Generation Placement by Region* (website) accessed at http://m020-w5.coned.com/dg/configurations/maps.asp

generation without fault current mitigation.

This fault current map functions as a preliminary siting preview which notifies the developer of those areas where fault current mitigation would be required. However, the fact that a distribution area is shown on Con Edison's fault current map as available for potential synchronous generation does not necessarily mean that interconnect of such generation will automatically be accepted. As mentioned on the fault current map, all boundaries are approximate, and are subject to change without notice. In all events Con Edison must be contacted for exact boundary details at the time the developer plans to initiate a project.

Additionally, the fault margin may be changing all the time. When a developer is considering a DG system, they must submit an application for synchronous generation which is placed into a queue under Con Edison's "Fault Current Margin Queuing Position Process". Under this process the developer's application will be evaluated in light of all prior fault current contributors currently on the queue.[6]

7.3.3 Capacity

The final exclusionary criteria that must be taken into account when considering a CHP system is the size limitation imposed by Con Edison for any systems that will be connecting to the grid. In general, Con Edison limits the size of generators connecting to and paralleling with its grid to 10 MW on a distribution feeder and 20 MW per network substation. These are maximum limits under ideal conditions[7] and could be subject to reduction, depending on the site specific actual conditions of the grid at the desired tie-in point. In order to verify the maximum capacity available to a DG plant, a site specific system study, at the expense of the developer, would need to be conducted by Con Edison. Therefore, a developer needs to contact Con Edison prior to pursuing a DG plant to ensure that that these limits have not already been reached in the area of the grid at which they propose to interconnect.

7.4 DEVELOPMENT OPTIONS FOR DISTRIBUTED GENERATION

Once the developer has made preliminary determinations regarding franchise, fault current and capacity constraints, there are numerous options available that will have to be weighed. The options selected will affect not only the technical requirements and configuration of the DG system, but also its operational requirements. These, in turn, will have a direct impact on capital cost and operating cash flow scenarios of a project and so deserve careful analysis.

These options can be organized under three main categories and then approached systematically using Con Edison's Distributed Generation Process Guide[8]. As enumerated by Con Edison, these three main categories are: 1) service classification, 2) incentive program and, 3) generation type.

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[6] Con Edison, "*Fault Current Margin Queuing Position Process for Parallel Synchronous Distributed Generation*", accessed at http://m020-w5.coned.com/dg/configurations/queuing%20procedures.pdf

[7] In this regard, it should be noted that Con Edison's methodology for calculating the capacity limits of interconnected DG is more stringent than that used by most other utilities. In the same 2005 fault current study that Con Edison was mandated to undertake as part of the PSC's approval of its three year rate plan, the authors of the study (ABB) compared Con Edison's methods of calculating capacity limits to industry leading interconnect practices. They found that while Con Edison determines feeder limits based on "all time light load", or the lowest amount of power demand in that area of the grid, most other utilities calculate their capacity limits based on percentage of peak load. This derivation of the 10 and 20 MW caps for distributed generation capacity tying into feeders and substations respectively, effectively limits DG to a relatively small percentage of the peak load of feeders and substations.

[8] Con Edison, *Distributed Generation Process Guide*, (website), accessed at http://m020-w5.coned.com/dg/process_guide/processGuide.asp

The "Distributed Generation Process Guide" presents these three categories as steps in a sequential decision making process. This step by step process is laid out in the DG Process Guide as follows:

- Step 1-Understand the basic service classifications, determine which option works best for project.
- Step 2-Review all available incentive programs. Determine which incentives are applicable to project.
- Step 3-Review electric generation configurations and connections for selected choice of energy strategy. Understand requirements that are general to all configurations as well as requirements specific to project configuration.
- Step 4-Determine which application process is required for selected configuration. Complete application and submit to Con Edison.

An important point to note in going through these steps is that Con Edison has written this process guide on the basis of a two-party arrangement, between the Utility and the Customer. In Con Edison's language, the customer is the end user of their electricity. When discussing distributed generation, the guide's presumption is that this generation is owned and operated by the customer and located at the customer's facility, with any electricity generated being consumed by the customer. The service classifications and incentive programs mentioned in steps 1 and 2 are specifically applicable to a Con Edison customer with no reference of applicability to a third party generator. It would remain to be seen how these provisions could be applied to a third party generator arrangement. The most likely scenario is that they would be somehow negotiated into the power purchase agreement between the generator and the load facility. In presenting steps 1 and 2, the term "customer" will be used in the same sense as Con Edison uses it. Step 3, involving generator types, is as equally applicable to third party generators as it is to load facilities (customers in Con Edison's parlance) and so the term "developer" will again be used.

The discussion of the service classifications and incentive programs are also considered relevant to this report because of the possibility of deployment of alternative power, such as solar PV, on FDC tenant buildings. If this PV were to be owned by the tenants, then consideration of the two party agreements for service classifications and incentive programs would be very applicable to this report. Following is a discussion of each of these steps as laid out in the Distributed Generation Process Guide.

7.4.1 Service Classifications (STEP 1)

The service category describes how a utility will interact with the facility in terms of power purchase and delivery agreements. Each service category requires a particular interconnect configuration which defines the minimum interconnect equipment requirements. These mandatory interconnect equipment configurations carry capital cost implications. Additionally, each of these service categories is subject to a particular utility tariff that defines the terms of the power purchase agreement and rate structure. The terms of these tariffs have a direct impact on the capital and operating costs of a DG project.

There are six service categories that are currently available to distributed generators. Following is a listing of them along with a short description of each:

Net Metering

- An arrangement whereby a small residential solar electric user or farm waste customer can provide some or all of their power from their respective renewable resource, and can also sell excess back to the utility. Previously, the 10 kW limit for solar PV rendered this service category inapplicable to a DG project at Hunts Point. However, the recent passage of new net metering legislation makes this category potentially applicable, depending on the ownership model employed.

Standby

- The customer supplies some or all of the electricity for their load in parallel with the utility. The utility supplies the electricity for the balance of the load that the customer's DG system does not supply. This option is a likely choice for consideration by a developer. Under this service category, the DG cannot continue to generate electricity if the utility source is interrupted so the needs and current emergency generation capabilities of the Hunts Point tenants would have to be carefully considered prior to pursuing this service category.

Stand-Alone

- The customer supplies all their electrical power in isolation from the utility. The utility will not supply the balance of electricity for any load that is not met by the DG facility, nor will it provide back-up power in the event that the DG system fails. This will not be a likely choice for a developer for two primary reasons.

    1. First, since the long term economic viability of a CHP system is dependant on utilizing the waste heat produced when generating electricity, the CHP system is usually sized to provide for the thermal load rather than the electric load. In many cases, when the CHP system is following the thermal load it may not be providing for the entire electric load. A DG configuration which cannot be counted on to supply the FDC tenant's electrical needs is an untenable alternative.

    2. Second, the FDC tenants would be fully dependant on the DG facility. This means that there will either have to be additional capital investment in order to provide emergency generation capacity in the case of failure of the DG system, or the FDC tenants will have to be without power. The second scenario is almost certainly unacceptable to the FDC tenants, and the first scenario will most likely have a large negative impact on the developer's business model.

Standby with Stand-Alone

- This option has similar features to a Standby agreement in that the customer supplies some or all of the electricity for their load in parallel with the utility while the utility supplies the electricity for the balance of the load that the customer's DG system does not supply. The difference is that the DG can continue to supply electricity to the FDC tenants if the utility's supply were to be interrupted. This combines the benefits of a standard paralleling arrangement with the comfort factor of emergency back-up capability in the case of loss of utility. This service category is also is a likely candidate for strong consideration by the developer. This option would be more costly than the Standby arrangement due to the need for additional equipment to isolate the DG from the utility when operating in stand-alone mode.

Buy Back

- Under buyback service, the customer sells power to the utility. The generator must meet the Federal Energy Regulatory Commission (FERC) definition of a Qualifying Facility[9] (QF). This option is a strong candidate for consideration by the developer.

Emergency Generation Only

- The name of this service category is self explanatory. Under this arrangement, the customer supplies all or some of their own power only when utility service is unavailable. This will not satisfy a developer's economic payback requirements and so this service category is not applicable for consideration in this report.

[9] See footnote in Conclusion section for brief discussion on Qualifying Facilities

7.4.2 Incentive Programs (STEP 2)

After the service categories have been sorted through, the next major factor that the developer must consider is which of the primary incentive programs, if any, to utilize. This consideration is important because incentive programs provide various possibilities for additional project operating revenues. However, all of these programs could involve load curtailment or reduction. Since the majority of the FDC's load is generated by the refrigeration needs of their food processing operations, a careful balancing of the benefits of incentive program revenue vs. on demand load reduction requirements would be required. Additionally, one of these programs (mentioned in next paragraph) would not be applicable to most CHP configurations. The major incentive programs are:

- Installed Capacity Program (ICAP)
- Emergency Demand Response Program (EDRP)
- Day-Ahead Demand Reduction Program (DADRP)
- Distribution Load Relief Program (DLRP)

Of the four primary incentive programs, three are provided by the New York Independent System Operator (NYISO) and one is provided by Con Edison. The Installed Capacity Program (ICAP) and the Emergency Demand Response Program (EDRP) are both demand response programs created by the NYISO to help support the reliability of the state's bulk power system by calling on participants to reduce load or produce excess capacity. The Day-Ahead Demand Reduction Program (DADRP) is an economic program provided by the NYISO but would not be applicable to customers with generators. The Distribution Load Relief Program (DLRP) is provided by Con Edison to support load reduction on its system during times when the localized grid is facing constraints, but relief measures to the state wide grid have not been invoked by the NYISO.

Each of these programs has specifically designed incentive rates and terms, which are spelled out in service "Riders". Additional information on these programs, as well as their associated riders can be found on Con Edison's website.[10]

7.4.3 Generation (STEP 3)

The third category that a developer must thoroughly evaluate in the pre-development phase of the project concerns which type of generation the DG plant will supply.

As explained in the fault current discussion, consideration of generation type must come into play early in the project development cycle when reviewing a selected location for the DG facility against Con Edison's fault current constraints. One of the major considerations in selecting a generator is its respective fault current contribution to the utility's grid. However, assuming that the location chosen by the developer is not subject to fault current constraints, there are now three types of generator configurations available for consideration: 1) *synchronous*, 2) *induction* and 3) *inverter based*. Among the factors that are affected by the type of generator selected are:

- Capital costs
- Operating costs
- Which service categories (step 1) can be utilized
- Where in Con Edison's service areas interconnects should be pursued
- Whether fault current mitigation is likely to be required

[10] Con Edison, *Distributed Generation Incentive Program,* (website) accessed at http://m020-w5.coned.com/dg/incentive_programs/incentivePrograms.asp

- What kind of distribution networks the DG system can be connected to
- Where within a distribution system the generator can interconnect
- At what voltage levels can the generator connect
- Interconnect application time

A detailed description of each of these types of generation would be very technical and beyond the scope of this investigation. However a basic understanding of the key comparison parameters and their relevance to a developer is essential in narrowing the choice of potential CHP configurations down to those that may be applicable to the Hunts Point FDC.

7.4.3.1 Synchronous Generation

A primary defining characteristic of synchronous generators is that they can be "self-started" without connection to a utility grid because of the fact that they contain internal excitation capabilities. This means that they can not only operate in parallel with the utility, but can also operate when power from the utility is not available[11]. This makes them the generator of choice for facilities that want to displace utility power most of the time, but also want or need the capability to operate in the event that utility power is lost. However, this is problematic in Con Edison's service territory because this also means that when their grid loses power and their lines are de-energized, the synchronous generator can back feed onto their system.

The interconnection of synchronous generation to Con Edison's system will almost certainly require a careful study of the effects of that generation on the system. This will invoke a CESIR which is much more involved than the SIR process. Some of the results of the CESIR may be:

- The DG plant may need to incorporate additional protective equipment in the design.
- Developer bears the costs of Con Edison's engineering evaluations DG impact on their distribution system.
- Developer may bear costs of purchase and installation of the any necessary additional protective equipment.
- Developer may incur own engineering and development costs to respond to CESIR.

7.4.3.2 Induction Generation

In the context of this discussion on interconnection, the most important difference between induction generation and synchronous generation is that induction generation normally cannot operate independently of the grid. Due to the fact that they do not have an exciter, they rely on current from the grid to start up and they continue to follow the frequency of this current while they are operating. For this reason, induction generators are commonly used in power plants that only need to operate in parallel with the utility grid. For this same reason, they would not be the generator of choice if one of the DG requirements were ability to operate in stand-alone mode.

Some considerations when contemplating induction generation are:

- Induction generators cannot operate if power from the grid is lost.
- Induction generators operate at relatively poor power factors[12] and will most likely have to be corrected to meet the utility's requirements. This will require the developer to submit a study

[11] This would be similar to the Standby with Stand Alone service category in Con Edison's service territory
[12] This is due to the fact that induction generators require reactive excitation from the utility's power system.

demonstrating the corrective effects of any power factor improvement measures that are implemented.

- Induction generators can be installed at any point on Con Edison's system regardless of existing fault current limits.

The fact that the proposed generation is induction does not preclude the possibility of a CESIR process. Depending on the impact of a particular design on the utility's system, a more in-depth review of the interconnection scheme may be necessary.

7.4.3.3 Inverter Based Generation

Inverter based generation differs from synchronous and induction generation fundamentally in that rather than converting mechanical energy into electrical energy, such as occurs when current is magnetically induced from a rotor (magnetic coil) attached to a spinning turbine shaft, it converts one type of electricity to another (i.e., DC to AC). Common types of inverter based generation are from sources such as fuel cells, solar photovoltaic (PV) panels and some types of micro-turbines. A few additional major differences are:

- Inverters use microprocessor based controllers that include embedded protective functions which correspond to many of the protective functions required of the utility for interconnection.

- The fault current contribution of an inverter based generator is usually not as large as that of a synchronous or an induction generator of the same size (rating).

- The fast switching response of the solid state transistors enable inverter based generator to stop producing energy much faster than a typical rotating machine, such as a synchronous or induction generator.

Additionally, some types of inverters can also quickly switch a DG system over to stand-alone mode, thereby enabling energy to be generated for the facility during times when utility based power is lost. Another factor in favor of inverter based generation is Con Edison's allowance that generators with inverters may be connected to any point on the distribution grid regardless of the fault current margin[13]

Although the aforementioned types of generation are by default inverter based, any type of DG technology can be fitted with inverters. This type of a scheme may be worth considering for a developer who is looking to ease the interconnection process for a DG system using synchronous or induction generators[14].

In order to help clarify the options available to the developer, Con Edison has created a matrix that shows the allowable combinations of generator type, voltage level and service category.

[13] Con Edison, Distributed Generation, *Synchronous Generation Placement Availability by Region* (website) access at http://m020-w5.coned.com/dg/images/maps/x.pdf

[14] If an inverter technology is being considered, the interconnection application process may be expedited somewhat by selecting equipment already certified by the PSC. The PSC maintains a certified equipment list available on its website[14]. This list lists mostly inverter manufacturers but also has several microturbine configurations. This list can be found at on PSC site website at http://www.dps.state.ny.us/SIRDevices.PDF

Con Edison Chart Showing Allowable Generation/Interconnection Configurations[15]

	Synchronous	Induction	Inverted
Secondary Voltage Non-Network, Radial	Standby Standby / Stand-alone	Standby	Net Metered (PV only) Standby Standby / Stand-alone
Secondary Voltage Grid Network Systems	Not Available	Standby	Net Metered (PV only) Standby Standby / Stand-alone
Spot Network 277/480 or 120/208	Standby Standby / Stand-alone	Standby	Standby Standby / Stand-alone
4KV to 33KV Primary (High Tension) Feeders	Standby Standby / Stand-alone Buy Back	Standby Buy Back	Standby Standby / Stand-alone Buy Back

Image obtained from Con Edison website on 6/13//08

7.4.4 Application Process (STEP 4)

The Standardized Interconnection Requirements[16] (SIR) were established by mandate of the New York Public Service Commission (PSC) in order to reduce the cost and complexity of the interconnection application process. The SIR breaks the interconnection application process down into an eleven step procedure with associated approval timelines. The time required to complete this eleven step process is dependant on the characteristics of the generation, the capacity or size class of the system, the intended operating modes of the generation, and the existing condition of the utility's distribution system in the area that will be affected by the DG system.

This process applies only to distributed generation projects up to 2 MW. Generation over this size does not fall under the SIR guidelines. Never the less, for DG applications of 2 to 5 MW, Con Edison will follow the approval timeline set forth in the SIR. For all applications larger than 5 MW, Con Edison states that it will follow the SIR guidelines where possible, but due to the increased size and complexity of such systems, additional time (and cost) requirements are probable. During the SIR process, Con Edison may determine that more detailed engineering studies are required. This requirement would invoke a Coordinated Electrical System Interconnection Review (CESIR). A CESIR will also be necessary for any DG systems not covered by the SIR, i.e., any systems over 5 MW.

It is important to understand that a CESIR will involve additional costs to the developer. These costs could be for system upgrades that Con Edison determines are necessary in order for the DG system to connect to their grid. Costs will also be incurred for Con Edison's engineering analysis time during the

[15] Con Edison, *Distributed Generation Configurations*, (website), accessed at http://m020-w5.coned.com/dg/configurations/configurations.asp
[16] New York State Public Service Commission, *New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less connected in Parallel with Utility Distribution System.* Accessed at http://www.dps.state.ny.us/SIR_Require_11_04.pdf

CESIR. Prior to initiating a CESIR, Con Edison will notify the developer of the estimated cost and will proceed only upon the developer's agreement to pay these costs. If the CESIR identifies any necessary system modifications, the cost of these modifications will be estimated and communicated to the developer, who must then inform Con Edison whether to proceed.

There is no specified timeframe for a CESIR but based on anecdotal information, a developer can expect the CESIR to take from three to six months. This should be considered an order of magnitude estimate and substantially longer timeframes have been reported. Therefore, in addition to the potential costs to a project implicit in the CESIR process, the developer would have to take into account its own extended overhead costs incurred by a prolonged interconnect application review process.

7.5 TRANSMISSION AND DISTRIBUTION ALTERNATIVES FOR DISTRICT GENERATION

In terms of navigating the T&D franchise issue, there are a number of possibilities available to a DG plant owner/operator that would allow them to install generation capacity in the FDC area and bring power to the tenant facilities. This franchise infringement issue could, in some cases, be mitigated if the DG distribution were to be to be located within an area from which it could serve several loads without crossing mapped streets. It could likewise, in some cases, be eliminated if the DG plant were within the same property as the load facility. This franchise issue could be eliminated if the facility were to gain Qualified Facility (QF) status. This option will be addressed later in this discussion.

Following is a more detailed discussion of these options. Although these strategies might be able to help mitigate franchise issues, the resulting technical and financial configuration of the DG arrangement within each strategy would have to then be modeled to assess its economic viability.

7.5.1 Alternative 1: Multiple DG

One alternative for a DG developer would be to install DG and distribute power only to FDC tenants within the same franchise defining boundary lines as the DG, so as to avoid invoking infringement on Con Edison's T&D franchise. It is obvious that in order to serve all the FDC tenants this approach would require multiple DG plants, each one serving power to the buildings within its associated zone. This approach, while avoiding the franchise infringement issues for distribution of power, would introduce a whole new set of potentially onerous issues associated with developing multiple sites, versus one site.

Additionally, some of the buildings within individual leased properties, such as the Fish Market, contain numerous metered tenants, each with individual power purchase agreements with either Con Edison or an energy services company. In these buildings, the developer would have to determine if the DG plant would serve only the common space loads, or if it would be sized to serve the common load and the tenant loads, along with all of the complications that this second arrangement would imply.

One situation under which this type of arrangement could work would be if the DG were solar PV based. Deployment of solar PV by a single developer across multiple facility rooftops is starting to become more common as a business model for third party developers. If the solar PV serves only the load of the building upon which it located, without sending electricity back into the grid, a number of technical and regulatory issues could be eliminated. Given the available roof space, the amount of power generated per square foot by current PV technology, and the fact that a large portion of the FDC tenant's electricity usage is comprised of round the clock seven day a week refrigeration loads, it is unlikely that any PV array on an FDC building would generate more power than the building consumes. A feasibility analysis would be required to determine whether an economic case could be made for such an arrangement. The success of this economic analysis would almost certainly be primarily dependant on the incentives available.

7.5.2 Alternative 2: Selling Power to Tenants

Another option available to a DG plant owner/operator would be to build one plant capable of servicing a selected percentage of the load for the FDC tenants, executing power purchase agreements with the tenants, and connecting to the local grid. This would require that the seller be regulated as a utility and would likely involve a "wheeling" arrangement to transport this power across Con Edison's grid[17]. A detailed network analysis would also have to be performed by Con Edison to determine the impact that the proposed new power source would have on the local distribution system, as well as what upgrades, if any, would be required to accommodate the new power source. The cost of the analysis and all upgrades would be borne by the DG developer.

A disadvantage to this option is the uncertainty associated with the CESIR process that would automatically be required due to the developers plans to push power back out onto the grid.

7.5.3 Alternative 3: Selling Excess Power

A third alternative available to a DG plant owner/operator would be to build one DG plant, preferably next to one of the more heavily loaded FDC facilities, connect to and sell power to this facility, and sell excess power to the grid. This would require the seller be regulated as a utility, unless the DG plant qualifies as a QF (See Alternate 4 in Section 7.5.4). This would also require a detailed network analysis to determine the effect of importing power back onto the grid.

This option contains the most promising technical configuration for development of a CHP plant. The most probable interconnect scenario would involve tying into the bus of a high load customer, such as the Hunts Point Cooperative (Meat Market) and supplying a percentage of its power. The Cooperative also has the advantage of being the only existing facility in the FDC connected to 13 kV feeders. Under this scenario, the developer would execute a power purchase agreement with the Cooperative and would also own the meter that measures the power pushed back onto the grid in excess of the power purchased by the Cooperative.

7.5.4 Alternative 4: Qualifying Facility

The most promising scenario for development of distributed generation and potentially district energy would be to use the technical configuration of Alternative 3 (See Section 7.5.3) in combination with the attainment of Qualifying Facility status for the generator.

There are both federal and state guidelines which define a Qualifying Facility, both of which are applicable. The federal guidelines are under the purview of the Federal Energy Regulatory Commission (FERC). Under these guidelines, a QF for a CHP configuration must meet three accounting criteria related to system efficiency and thermal utilization. For example, for a topping cycle CHP facility, at least 5% of the output must be useful thermal energy. For gas fired CHP systems, if the useful thermal energy is 15% or greater, the electric energy plus ½ the thermal energy must be greater than or equal to 42.5% of the input energy. Additionally, any utility ownership of the facility must be less than 50%. Additional information can be found on FERC's website[18].

The state statutes defining a QF are administered by the New York State Public Service Commission (PSC) and are more oriented towards the definition of entities and facilities that can be considered exempt from regulation by the PSC as a utility. These statutes also cap a QF at 80 MW (as does FERC).

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[17] An electric utility does not need to own transmission or distribution lines, it just needs to own a connection to the grid. Although in theory the DG plant owner would be selling the electrons generated by the plant to the customers with whom the power purchase agreement is signed, in actuality, the electrons follow the path of least resistance and go where they want to go. The DG plant is simply adding more power to the existing distribution network. Typically, the utility, in this case the DG plant, will have to pay the owner of the distribution lines, in this case Con Edison, for access to their network based on how much power is being moved and how congested the line is. This arrangement is known as wheeling.

[18] http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp .

Complete information can be found under Article 1 of New York State Public Service Law, available on the PSC's website[19].

Obtaining status as a QF would bring several benefits to the project, not the least of which would be avoidance of the T&D franchise issue. This is because QF status exempts a DG facility from regulation as a utility under federal and state statutes. Additionally, the utility must buy excess electricity generated by the QF at the utility's avoided cost and they must provide back-up power at a non-discriminatory rate.

The proximity to a suitable thermal load and high tension feeders (13 kV) are important considerations in the technical viability of a QF. The thermal load is required in order for the plant to meet overall energy efficiency criteria per federal criteria and state statutes as well as in order to meet favorable economic payback criteria. The proximity to high tension feeders is important because these feeders create a more favorable "highway" for sending power back into the grid than the 480 volt feeders that service the rest of the buildings on the FDC network.

Alternative 4 is the recommended configuration for further development. Alternative 1 (See Section 7.5.1) with solar PV as the DG energy source is also recommended for further investigation & potential development.

7.6 CONCLUSION

The road to development of distributed generation, especially for third party ownership with intent to sell power to multiple tenants, may face various obstacles. However, this does not close the case on distributed generation at the Hunts Point Food Distribution Center area.

Before a developer considers the transmission and distribution options, one choice should be categorically eliminated. We do not recommend building a centralized plant and running distribution infrastructure to all of the FDC tenants. Even if the T&D franchise issue was not on the table, the cost of running this distribution infrastructure would very likely be prohibitive for a DG plant of the scale that is being considered in this report. As an alternative, the FDC should consider the following recommendations:

- Any DG facility that is developed for the FDC should be designed and developed so as to achieve Qualifying Facility status.
- When developing the interconnection scheme with Con Edison, require 13 kV feeder service to any new construction planned by NYCEDC.
- If possible, develop the interconnection scheme with Con Edison for all of the planned new construction at the FDC so as to maximize the potential for dedicated feeders to a DG plant.
- When developing the RFP for design of new building construction as well as additions to existing buildings, build in requirements for design of the roof space to accommodate solar PV with allocation of a pre-designated minimum percentage of this roof space to PV.
- Select the most appropriate new construction project for co-location of a CHP plant. Build in requirements into design RFP for integration of CHP plant into development of selected construction project.
- Size and design CHP plant to offset new load due to planned tenants.

[19] http://public.leginfo.state.ny.us/menugetf.cgi?COMMONQUERY=LAWS

Finally, as was noted previously, DG generation that ties into feeders on Con Edison's system are limited to 10 MW. This cap may be unnecessarily limiting due to Con Edison's unusually rigid methodology of determining capacity limits. The current FDC load calls for larger generation capacity than 10 MW and the future expansion will certainly add to this load. It is recommended that the NYCEDC encourage modification of Con Edison's methodology for estimating capacity cap on their feeders so as to more closely mirror the less restrictive industry standards used by many other utilities.

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Section 8 FDC Development Plans

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Section 8 FDC Development Plans

Section 8: Food Distribution Center Development Plans

8.1 INTRODUCTION

Located on 329 acres, the Hunts Point Food Distribution Center is among the largest distribution centers in the world. There are approximately 115 wholesale firms present at the FDC. Approximately $2 billion in gross annual revenues are generated by firms in the Produce Market alone. The success and growth of the FDC is a vital component to the economic development of the Hunts Point peninsula and of the South Bronx as a whole. This growth will increase the energy needs of the FDC. It is important to investigate these increased energy needs in the context of the capacity of the existing utility infrastructure to accommodate them. Additionally, in light of the growing awareness of the link between environmental issues and energy consumption and production, it is also important to provide for these increased energy needs in an as environmentally benign manner as possible. This pushes technologies such as clean energy, (natural gas) and alternative energy (digester gas, fuel cells and solar PV) to the forefront when assessing energy strategies for Hunts Point.

NYCEDC, as administrator of FDC, is currently exploring a number of development projects in the FDC that range from retail alternative fuel sales to new food distribution uses. This section discusses projects currently underway and their implications on future electrical consumption.

8.2 FDC VACANT SITES AND DEVELOPMENT PROJECTS

There are several vacant or underutilized sites in the FDC, totaling about 25 acres in area.

8.2.1 Vacant or Underutilized Sites

There are currently five vacant or underutilized sites in the FDC. NYCEDC, together with other public stakeholders, is evaluating a variety of development options for these properties. Current vacant or underutilized sites include:

Fruit Auction Rail Shed	56,700 sq ft
Site A-OU2	139,000 sq ft
Site D	314,000 sq ft
Site E-OU2	160,000 sq ft
Site E-OU3	263,000 sq ft
TOTAL: 932,000 sq ft	

8.2.2 Planned Development Projects

Alternative Fueling and Service Station

In April 2008, NYCEDC released an RFP for a retail alternative fueling facility, which would include retail sales of conventional fuels and other retail needs, such as a small restaurant or a bank. This development would be located on a portion of Site E-OU2, comprising an 117,000 sq ft site at the southeastern corner of the Hunts Point Avenue/Food Center Drive/Halleck Street intersection. This development will add additional load to the FDC network, although it will be a relatively small percentage of the overall FDC load. This development does not affect the CHP modeling since proposed peak output

of the CHP plant is below peak consumption of the FDC. However, any new construction should incorporate solar PV technology.

8.2.3 Potential Projects under Study

In addition to this study, NYCEDC and other stakeholders are studying a variety of ways to utilize the scare remaining land resources in the FDC.

Anaerobic Digestion Study

NYCEDC has commissioned an Anaerobic Digestion Study as a follow-up to the 2006 "Organics Recovery Feasibility Study" (study) performed by DSM Environmental Services, Inc. According to the study, the anaerobic digestion (AD) processing plant is assumed to have a minimum a 3-acre footprint.[1] A specific site has not yet been proposed for this use; however Site D could potentially support this use due to its size and location directly off of Food Center Drive. This follow-up study will 1) expand the resource study area for waste stream generation to the entire Hunts Point Peninsula, 2) analyze energy production, 3) analyze site preparation, 4) perform a more detailed financial analysis and, 5) draft submission requirements for development of an AD facility. The intent is to dovetail this second phase of the organics recovery study with the CHP findings in this study to determine if a CHP plant powered by digester gas created by a waste stream from the Hunts Point peninsula would be technically and economically viable.

Additional Food Manufacturing Facilities

In addition to the above developments, NYCEDC is considering new food manufacturing tenants on vacant or underutilized sites.

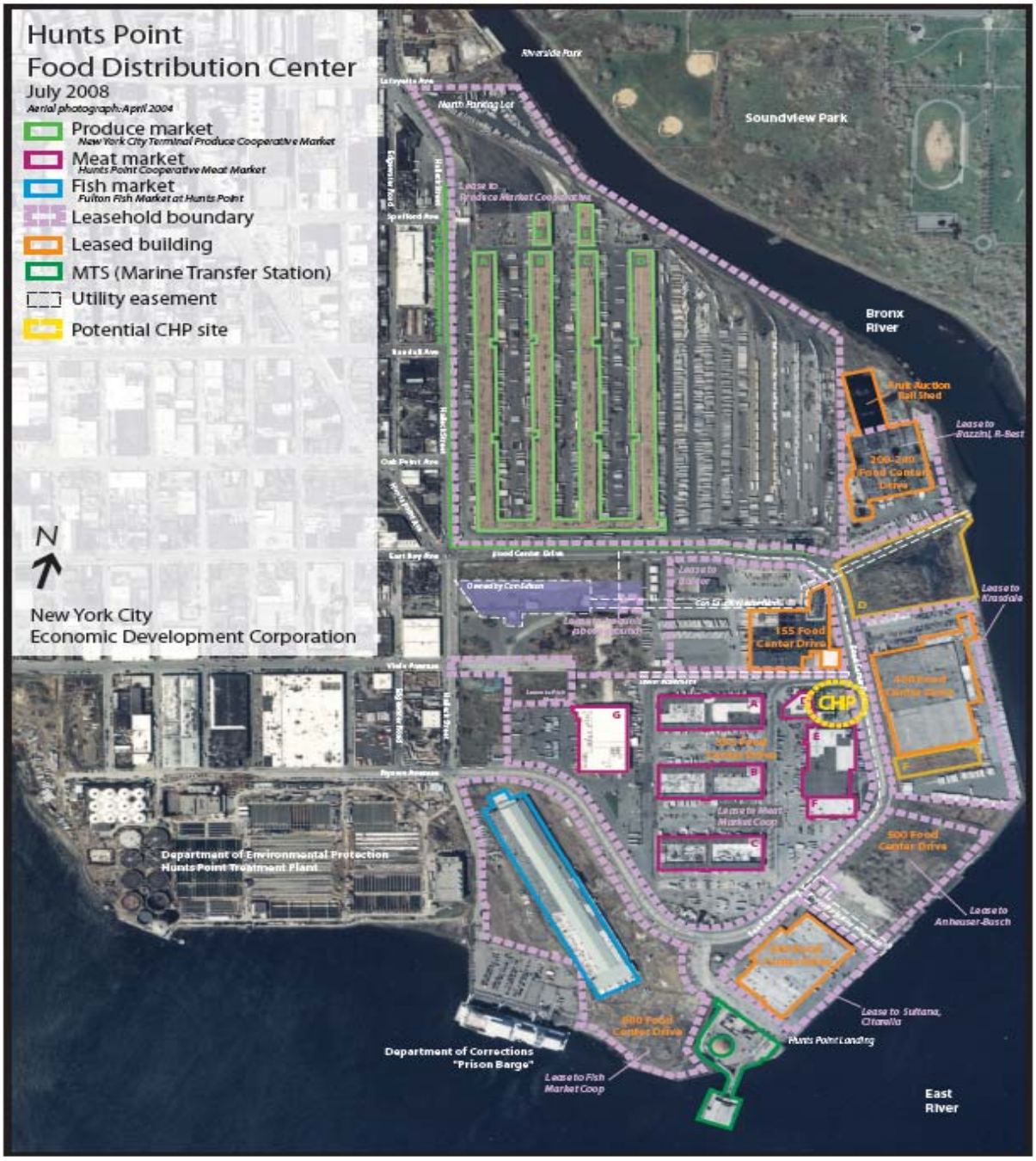
According to NYCEDC, vacant or underutilized sites in the FDC could accommodate the following conservative estimates of building area. For analysis purposes, the potential amount of future refrigerated space is considered equivalent to the total estimated building area that could be built on vacant or underutilized sites

Site	Site Area	Estimated Building Area
Fruit Auction Rail Shed	56,700 sq ft	100,000 sq ft (2-stories)
Site A-OU2	139,000 sq ft	75,000 sq ft (1-story)
Site D	314,000 sq ft	175,000 sq ft (1-story)
Site E-OU3	306,000 sq ft (including 43,000 sq ft from E-OU2 not occupied by the retail Alternative Fueling Facility	200,000 sq ft (1-story)
TOTAL:		550,000 sq ft

[1] *Hunts Point Food Distribution Center Organics Recovery Feasibility Study*, December 30, 2005. Prepared for NYCEDC by DSM Environmental Services, Inc.

8.3 CONCLUSION

Using the sum of these potential developments to represent a full-build scenario, approximately 1.37 million SF of refrigerated capacity could be added to the existing loads at the FDC in coming years. Depending on the usage breakdown of the facilities, i.e. percent facility refrigeration vs. freezing based on industry standard power density values (W/SF) for a range of typical industrial facilities, DMJM Harris projects that there could be an additional 10 MW to 20 MW of additional electrical consumption that will be brought online at the FDC. Based on discussions and feedback from Con Edison, the South Bronx network is capable of managing this additional load.



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Section 9 Appendix

New York City
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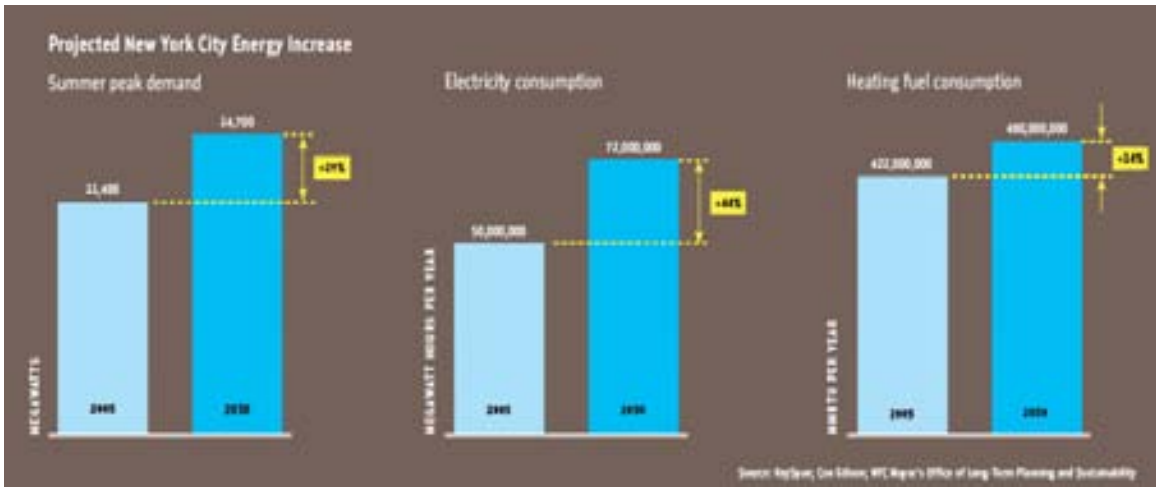
Appendix-1: Precedents

New York State has the second-highest electricity prices in the nation, ranking just behind Hawaii. At the current pace of consumption, at least another 10 to 15 percent of additional power generating capacity over the next 10 years will be required just to meet growing demand, and even more will be needed to drive down the cost of energy. Unchecked, the city's peak electricity demand—the highest amount of electricity needed over the course of a year—is projected to grow by 29% by 2030. Total electricity consumption is projected to rise by 44% (or more) and heating fuel consumption is expected to increase by 14%[1.] The chart below illustrates these increases. Within the current New York regulatory structure, there is no single entity currently capable of addressing the challenges posed by these projected shortfalls. There are eight organizations responsible for some dimension of energy planning in New York City, but none of them is designed to take the city's needs into account.[2.]



With respect to new generation in Zone J, there are no proposed projects on the horizon that will materially affect the cost of energy. Statewide, wind power projects, created by the state's Renewable Portfolio Standard accounted for 350 MW of new commercial generation in 2006. Although another 50 wind power projects representing more than 6,000 MW have been proposed for New York, these are not likely to provide enough power to meet demand growth (assuming 100% of them pass the regulatory and public domain hurdles and actually get built).

Plans have been scrapped for a 550MW connection from PSEG in northern New Jersey to NYC. While there are other transmission projects in permitting stages, of these, only one poses any potential threat to Zone J pricing and the future of the project is uncertain. This is the North Hudson Project, a power feed that is slated to cross from PJM to NYC and tie-in near 49th street. This project is stalled due to problems determining how to traverse the Hudson River drive and other significant issues. It is sized to bring 600 MW of power to Zone J which is a little more than six percent of the zonal supply requirement.

Proposed pipeline projects for natural gas are pictured below. These projects can alleviate some winter constraint and curtailment in the NYC area when and if they are finalized. There is currently one proposed LNG facility in planning stages. Importantly, there are no large expansions that would dramatically affect Zone J pricing. If future supply capacity was introduced, both NYISO generators and HUNTS POINT CHP would experience the same reductions.

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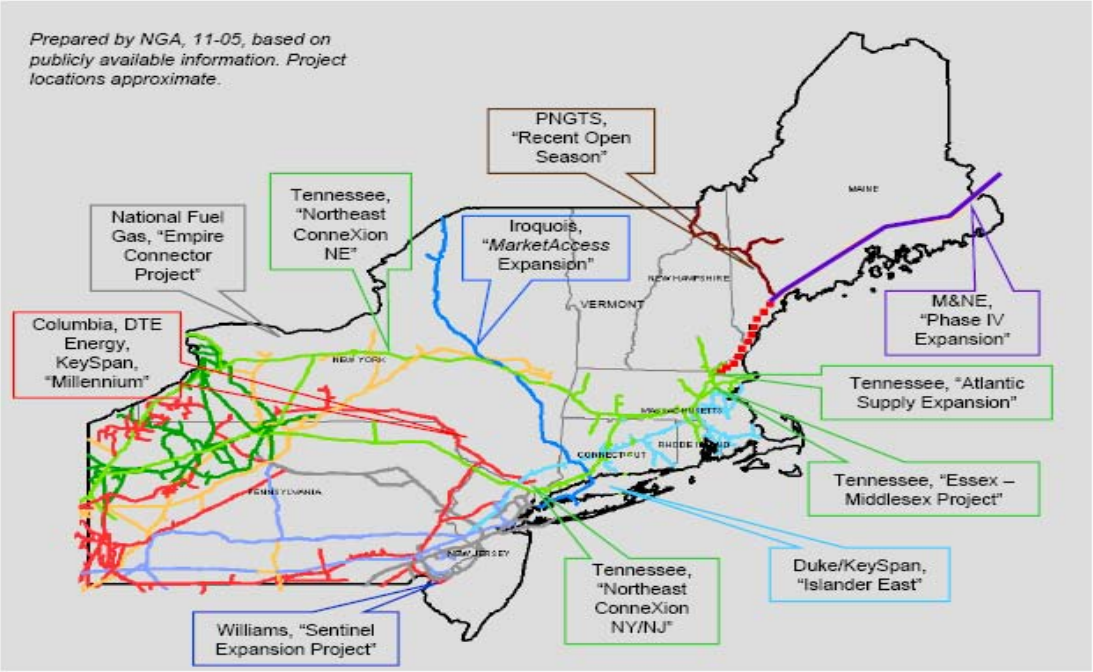
1 Governor Elliot Spitzer "15 by 15" Energy Plan
2 PlaNYC2030, Energy Section; page 102

Proposed Northeast Pipeline Projects



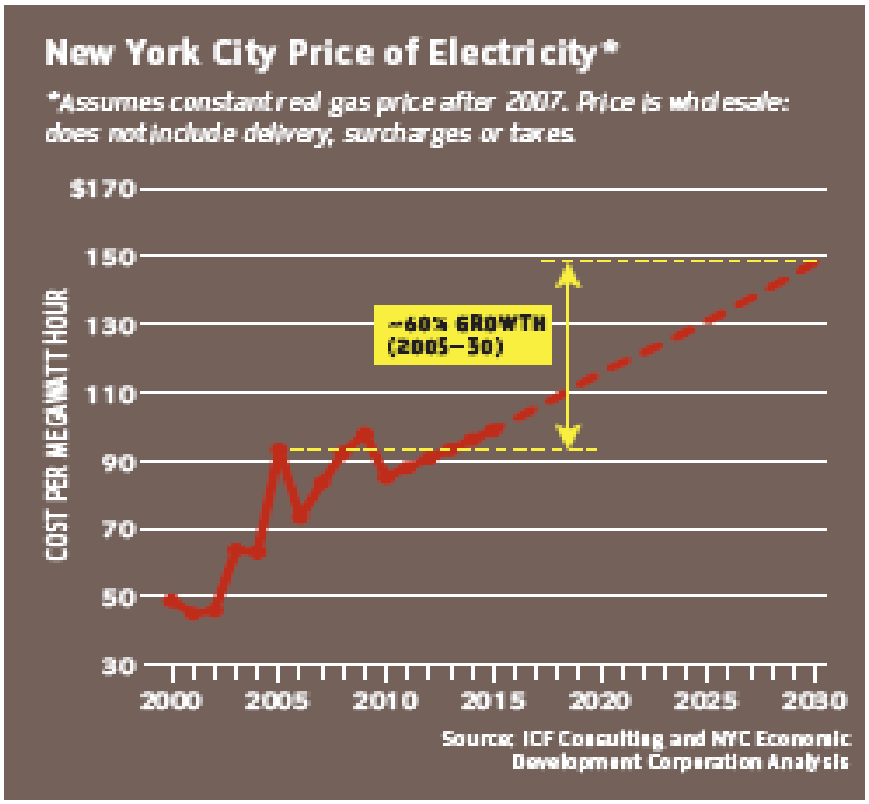
According to the NYISO[3], increasingly stringent air emission requirements such as the Regional Greenhouse Gas Initiative (RGGI), the New York State Acid Deposition Reduction Program (ADRP) and more restrictive mercury emission limits for generating plants will place increasing economic pressure on older generating plants as they incur increasing costs to meet these requirements. New York's older coal fired generating plants, in general, could be faced with an economic outlook that results in retirement in some number of the plants.

The New York Department of Public Service (DPS) Staff recently reviewed the results of an internal study on the potential impacts of RGGI alone. Their study found that most of the nine facilities which were reviewed showed net revenue reduction under the RGGI scenario, and that coal facilities were impacted significantly more than were oil or gas facilities. The report goes on to state "a variety of non-utility generators were constructed in New York during the 1980s and early 1990s in response to the Public Utility Regulatory Policies Act (PURPA) and state laws and regulatory initiatives. Many of these generators have long-term purchase power agreements with load serving entities and/or steam hosts, some of which expire during the Study Period. As these contracts expire, it is possible that these generators could come under increasing economic pressure with respect to their ongoing economic viability".

Although the regulatory aspects of these scenarios are unclear, the retirement of generating plants sooner than expected as a result of Global Warming or other drivers[4] could negatively impact Zone J, pushing prices higher and adding substantial value to CHP assets. The following chart clearly

[3] NYISO Comprehensive Reliability Planning Process (CRPP) 2007 Reliability Needs Assessment March 16, 2007
[4] There are a number of other environmental compliance requirements such as the Clean Water Act which could impact the economic viability of older generating units.

demonstrates the potential for significantly higher power prices in NYC absent any substantial initiatives to reduce demand or augment current generation capacity:

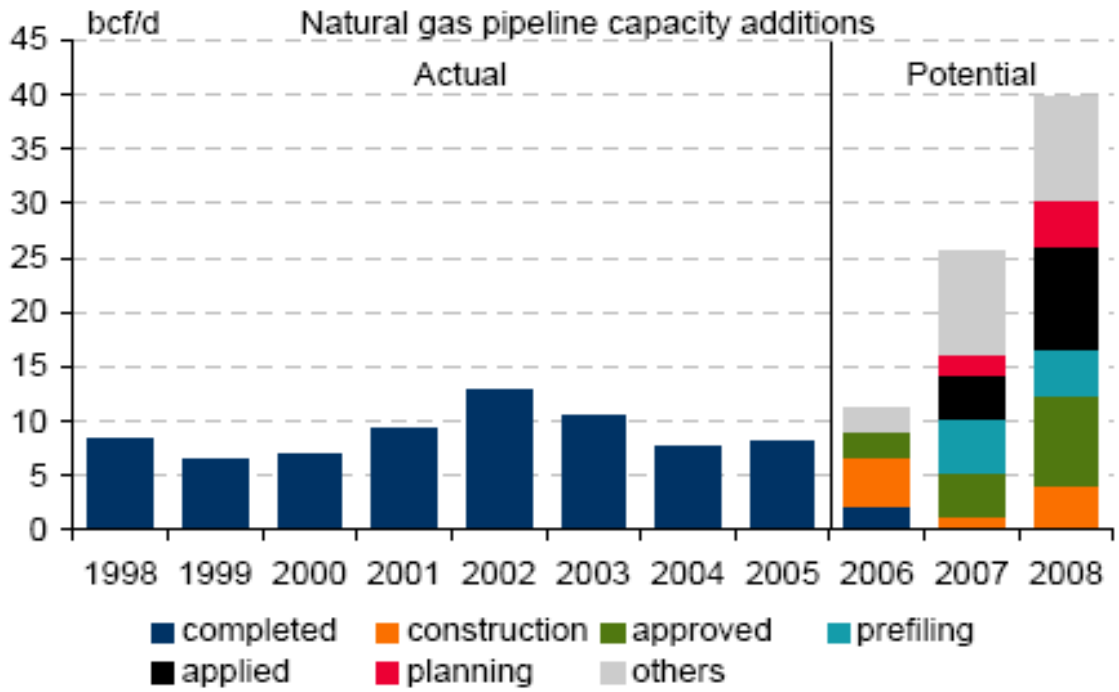


In the short term (2008 – 2009), the majority of Energy Supply Company (ESCO) representatives and trading professionals we interviewed for this report are bullish on oil and neutral to bearish on natural gas. With respect to oil, they see production decreasing and the escalating threat of geopolitical uncertainty as price drivers over the next few years. This is reflected in their trading strategies and advice to supply customers to monitor market conditions and purchase opportunistically (e.g. buy the dips). This consensus is adequately summed up in the following excerpt, taken from a major energy trading desk's medium range outlook[5]. With respect to natural gas, for the same 2008 – 2009 period there is a significant amount of neutral to bearish sentiment among the professionals interviewed for this report. Natural gas is not subject to the same geo-political issues as oil which makes underground storage levels and weather the two primary price drivers. The following outlook[6] summarizes the bearish to neutral consensus: "While industrial gas demand has modestly recovered on the back of refinery start-ups in the Gulf Coast, it remains stuck at the bottom of the 5-year range. In addition, forward-looking economic indicators now signal a rather sharp deceleration in the industrial economy in the United States, creating significant downside risks to US industrial gas demand. While the outlook for US natural gas demand is decidedly soft, we only expect prices to decline modestly. While LNG supplies should increase in 2007, strong demand and higher prices outside the United States will likely continue to draw supplies away until global liquefaction capacity surges in 2009. As neither pipeline nor storage capacity has expanded much in previous years, producing regions have hit major export constraints.

[5] The referenced trading outlook is highly proprietary and shared only with the consent not to publish the identity of the source. Excerpt dated July 26, 2007
[6] Energy Market Outlook, Merrill Lynch, dated 6/2007

A relatively rapid expansion in pipeline capacity and pipeline mileage over the next years should help to ease the current capacity issues. A planned doubling in pipeline capacity in the Rockies by 2009 will eventually contribute to increase Rockies exports, and production will likely continue to expand too. Most importantly, the 1.8 bcf/d Rockies Express pipeline running from Colorado to Ohio should help deliver Rockies gas production to the Mid-continent, Midwest and somewhat to the Northeast and is therefore likely to have a substantial impact on the West-to-East gas price spread.

Natural gas price volatility in the Northeast could also remain high due to storage capacity constraints, and competition for supplies in the Atlantic Basin. In addition to major pipeline capacity expansions, natural gas storage and secondary refining capacity are both seeing phenomenal growth. If all storage projects currently approved were built, storage capacity would grow by 197 bcf or 5% by end 2008. Currently, the Midwest and Southwest, including Texas and Louisiana, have the bulk of the US storage facilities. Going forward, more than half of the storage projects currently approved are in the Southwest producing region. In our view, the combination of new storage capacity and a narrower hydrocarbon price differential could contribute to reduce US natural gas price volatility by 2009." The following chart illustrates the potential natural gas pipeline capacity additions which are a key factor in the neutral to bearish outlook consensus:



Source: Energy Information Administration, Natural Gas Pipeline Projects Database

In summary, the New York City energy environment strongly favors the development of clean, energy efficient power generation. And while near term projections call for relatively neutral price pressures due primarily to current levels of natural gas storage, the longer range outlook remains bullish with respect to both power and fossil fuel prices. Demand increases appear inevitable and the likelihood of meeting the ambitious demand reduction and new generation goals outlined by both the Governor and Mayor will be challenging. The HPC CHP project will provide reduced capacity requirements and a general easing of transmission pressure in the area. It will also generate its power with natural gas thus providing for under 10 parts per million NOx for the majority of the hours of operation.

A-1.1 QUALIFYING FACILITIES FOR CHP

Burrstone Energy Center LLC (PSC Case 07-E-0802)

In a petition filed on July 9, 2007, Burrstone Energy Center LLC (Burrstone) issued a request to the PSC (the Commission) for a Declaratory Ruling finding that a cogeneration facility that it planned to build and operate in Oneida County would be granted exemption from regulation as a utility under Public Service Law.

The petition related that the cogeneration facility consists of 4 natural gas fueled engine generators, totaling 3.6 MW in capacity, and located in a building constructed to house the cogeneration facility on the campus of Faxton-St. Luke's Health Care, Inc (Hospital). From here, the cogeneration facility will supply steam and hot water to the Hospital for heating and cooling needs (by means of thermal absorption chillers), thereby satisfying the thermal energy requirements of a QF under the Public Utility Regulatory Act of 1978 (PURPA) as well as New York State Public Service Law PSL 2 (2-a).

The cogeneration facility will also supply electricity to the Hospital, as well as to St. Luke's Home Residential Health Care Facility, Inc. (the Home), and Utica College (the College). Burrstone intends to sell excess electricity to the local utility, National Grid, with which it will run in parallel. The Hospital, the Home and the College will remain National Grid customers, buying whatever electricity they require in excess of what Burrstone generates from the utility.

To reach the College, Burrstone will install approximately 3,800 feet of underground cable that will cross underneath Champlin Avenue, a public street separating the Hospital and the College.

In its petition, Burrstone's assertion was that it qualifies for exemptions from regulation as a utility granted to QFs under PSL because it is a cogeneration facility per the definitions of PSL §2 (2-a), it is sized at less than 80 MW, it generates electricity, and it produces thermal energy that is useful for commercial purposes. Burrstone further contended that its steam and electrical distribution lines, including the electrical lines crossing Champlin Avenue, are "related facilities" covered under the scope of QF exemptions.

Burrstone went on to address two particularly sticky issues in its quest for QF status. The first had to do with selling energy to more than one party. The fact that the cogeneration facility will be delivering electricity to more than one user, maintained Burrstone, is explicitly contemplated in the definition of related facilities in PSL §2 (2-d) in its reference to the transmission of electricity to "users", in the plural. Burrstone maintained that this wording conferred rights upon a QF to sell power to multiple users.

The second issue that Burrstone addressed was the fact that its electrical distribution lines would be crossing a public street, which typically opens up the issue of distribution franchise rights and knocks the seller of the electricity into the category of regulated utilities. Burrstone's contestation of this categorization hinges on the definition of "related facilities". Under Public Service Law, related facilities are considered part and parcel of the cogeneration plant, and therefore subject to the same exclusions as the plant, if it is granted QF status. Burrstone maintained that the fact that the lines bringing electricity to the College from the cogeneration facility at the Hospital will cross a public street does not exclude these lines from inclusion in the "related facilities" definition.

Burrstone applied PSL §2 (2-d), under which related facilities include "such transmission or distribution facilities as may be necessary to conduct electricity…to users located at or near a project site." Burrstone

cited two previous determinations, the Nassau District and Nissequogue Rulings[7], which granted QF status to cogeneration projects which were of similar configuration to Burrstone's proposed project. Burrstone pointed out that the lines that it plans to use to distribute electricity are similar to lines that were deemed related facilities in the Nassau District and Nissequogue Rulings, both of which projects included street crossings for electrical distribution lines. Burrstone therefore maintained that the fact that its electric lines cross a public street does not exclude these lines from being treated as related facilities.

The Commission's findings were in agreement with Burrstone's petition and concluded that the steam and electrical generation and transmission facilities proposed by Burrstone Energy Center LLC constitutes a cogeneration facility as defined in Public Service Law and was therefore granted the exemptions accorded to a QF from the provisions of Public Service Law.

Burrstone plans to go into operation by the end of 2008.

A-1.2 ALTERNATIVE ENERGY GENERATION

Steel Winds Project LLC (PSC Case 06-E-1203)

In a petition filed October 5, 2006 Steel Winds Project, LLC (SWP) and its affiliate Steel Winds LLC (SW) (collectively petitioners) sought a declaratory ruling that they, as well as Tecumseh Redevelopment Inc., were exempt from consideration as electric corporations under Public Service Law.

SWP plans to generate power using wind turbines, located on land leased from Tecumseh[8], and distributed on lines owned by Tecumseh through a substation owned by SW to two 115 kV transmission lines owned by National Grid.

SWP plans install eight wind turbines with a total generating capacity of 20 MW. The wind turbines will connect to nearby 115 kV transmission lines owned by National Grid through a substation (located 4,500 feet away from nearest wind turbine) via 13.8 collections lines. Steel Winds plans to purchase the substation from Tecumseh Redevelopment Inc (Tecumseh). This substation is the tie-in point between Tecumseh and National Grid, with billing meters located on the high side of the substation transformers. Currently, grid electricity is distributed from this substation to various tenant facilities on Tecumseh's land. All of these tenants are treated as a single customer by National Grid.

Tecumseh took over ownership of 1,300 acres of or property that had previously belonged to the Bethlehem Steel Lackawanna Plant. To support its steel making operations, Bethlehem owned and operated transmission infrastructure on its property including substations and transmission lines connecting its various on-site facilities.

Although all three entities own electric plant, they each petitioned for exemption from classification as an "electric corporation". SWP asserted that although it will own a generating station, this station will produce electricity solely from alternative energy resources. SW asserted that although it will own the substation, it will be distributing electricity from an alternative energy generation source to users located at or near the project site. Tecumseh asserts that although it owns distribution infrastructure, it does not generate electricity; rather, it distributes electricity from a single metering point to tenants on its property.

The Petitioners focused their arguments on the interpretation of the term "related facilities" in New York State Public Service Law (PSL). PSL grants "related facilities" the same exemptions that it grants the generating plant to which these related facilities are attached. The petitioners stated that all of the distribution infrastructure under their ownership should be considered "related facilities" as part and parcel

[7] Case 89-E-149, Nassau District Energy Corporation, Declaratory Ruling (issued September 27, 1989); Case 93-M-0564, Nissequogue Cogen Partners, L.P., Declaratory Ruling (issued November 19, 1993).
[8] The eight wind turbines will be located on 31 acres of land leased from Tecumseh

of the alternate energy production facility. Their grounds for this assertion was that "related facilities" include all associated infrastructure necessary to operate the wind turbines, connect to the grid, and distribute electricity to users at or near the site. The statute to which they pointed was in Subdivision (2-d) of PSL §2, which reads, in pertinent part:

> The term "related facilities" shall mean any land, work, system, building, improvement, instrumentality or thing necessary or convenient to the construction, completion or operation of any…alternate energy production…facility and include also such transmission or distribution facilities as may be necessary to conduct electricity…to users located at or near a project site.

Tecumseh was sought exemption on the basis of the fact that although it is a producer of electricity to the extent it purchases electricity from others; it distributes this electricity solely on its own property for its own use or the use of its tenants. It does not distribute electricity for sale to users located on property owned by others. This was based on statutory language from PSL §2 (13) which exempts from the definition of a regulated electric corporation any corporation where"

> "electricity is generated or distributed by the producer solely on or through private property…for its own use or the use of its tenants and not for sale to others."

The PSC noted that SWP's wind turbines and collection lines and SW's substation were all located on the same project site as the wind turbines. It was further noted that all of these facilities were located on the property of a single lessor, Tecumseh, and that the lines and substation are within on mile of the wind turbines[9].

The PSC concluded that "This unity of property interests and proximity of generators and other electric equipment is consistent with a reasonable design for a small wind project and justifies the conclusion that all of the SWP and SW facilities are components of one project located at the same site.[10]"

The PSC ruled in favor of SWP, SW and Tecumseh, and determined that they were not electric corporations.

The wind farm, which began construction in September of 2006 just prior filing the petition, went on line on line in April, 2007.

A-1.3 LARGE SCALE SOLAR DEVELOPMENT

New York City Department of Citywide Administrative Services

On April 8th, 2008 New York City's Department of Citywide Administrative Services (DCAS) issued an RFP to private solar developers to purchase, install, own and maintain solar panels providing a total of 2 MW of electrical capacity on city-owned buildings in all five boroughs[11]. Eleven sites, including 5 schools and a community college, have been identified by the City as potential platforms for deployment of the solar technology. DCAS will be executing a 20 year power purchase agreement with the successful developer.

[9] This one mile distance does not define the limits for related facilities. In a declaratory ruling on the Nassau District Energy Corporation (Case 89-E-148) the PSC concluded that the phrase "at or near a project site" included lines distributing steam to users extending up to 1.9 miles from the project site, primarily over property owned by such users. The ruling concluded that these steam lines were related facilities.

[10] Case 06-E-1203, Petition of Steel Winds Project LLC and Steel Winds LLC, Declaratory Ruling (issued December 13, 2006)

[11] Rooftop Solar Electricity on Public Buildings-RFP, accessed on New York City's (NYC.gov) website at http://home2.nyc.gov/html/dcas/html/agencyinfo/solarenergy_rfp.shtml

Numerous parties were involved in bringing this initiative to its current stage of development. The U.S. Department of Energy (DOE) is leading what is known as the "Solar America Initiative" (SAI) in an effort to accelerate the development of solar powered technologies, expertise and manufacturing infrastructure so as to make unsubsidized solar generated electricity economically competitive with conventionally generated electricity by 2015. New York City is one of 25 cities that have been designated by the DOE as a "Solar America" city, and as such was allotted a $200,000 planning grant and $200,000 in technical assistance from the National Renewable Energy Lab (NREL). The New York City Solar Initiative is a partnership involving the EDC, the Mayor's Office of Long Term Planning and Sustainability and the City University of New York, which is managing the program for the City.

Southern California Edison

On March 27, 2008 Southern California Edison (SCE) launched a five year program that will install 250 MW of solar PV arrays on over 100 large commercial rooftops totaling 65 million square feet. When completed, the nation's largest solar cell installation will generate enough power to serve approximately 162,000 homes.

SCE plans to have the first generation capacity in place by August. Recent advances in solar technology, as well as economies of scale will combined to reduce the unit costs of this installation to an estimated half that of the normal installation costs in California. According to SCE's request for approval to the California Public Utilities Commission, total project costs are estimated at $875 million in 2008 dollars.

Installation is slated to take place at a rate of 1 MW per week The need to build new transmission lines to bring this power to customers will be eliminated by connecting the solar modules to the local neighborhood circuits and distribution lines.

The first site targeted for deployment of solar panels is a 600,000 square foot facility owned by ProLogis, a distribution facility owner, manager and developer that owns more than 19 facilities with over 1 million square feet of roof space. CSE is negotiating a rental fee with the building owners whose roofs will be used.

Duke Energy Carolinas

On May 21, 2008 Duke Energy Carolinas announced it will purchase the entire electricity output of the nation's largest solar photovoltaic facility, which will be built in Davidson County, NC.

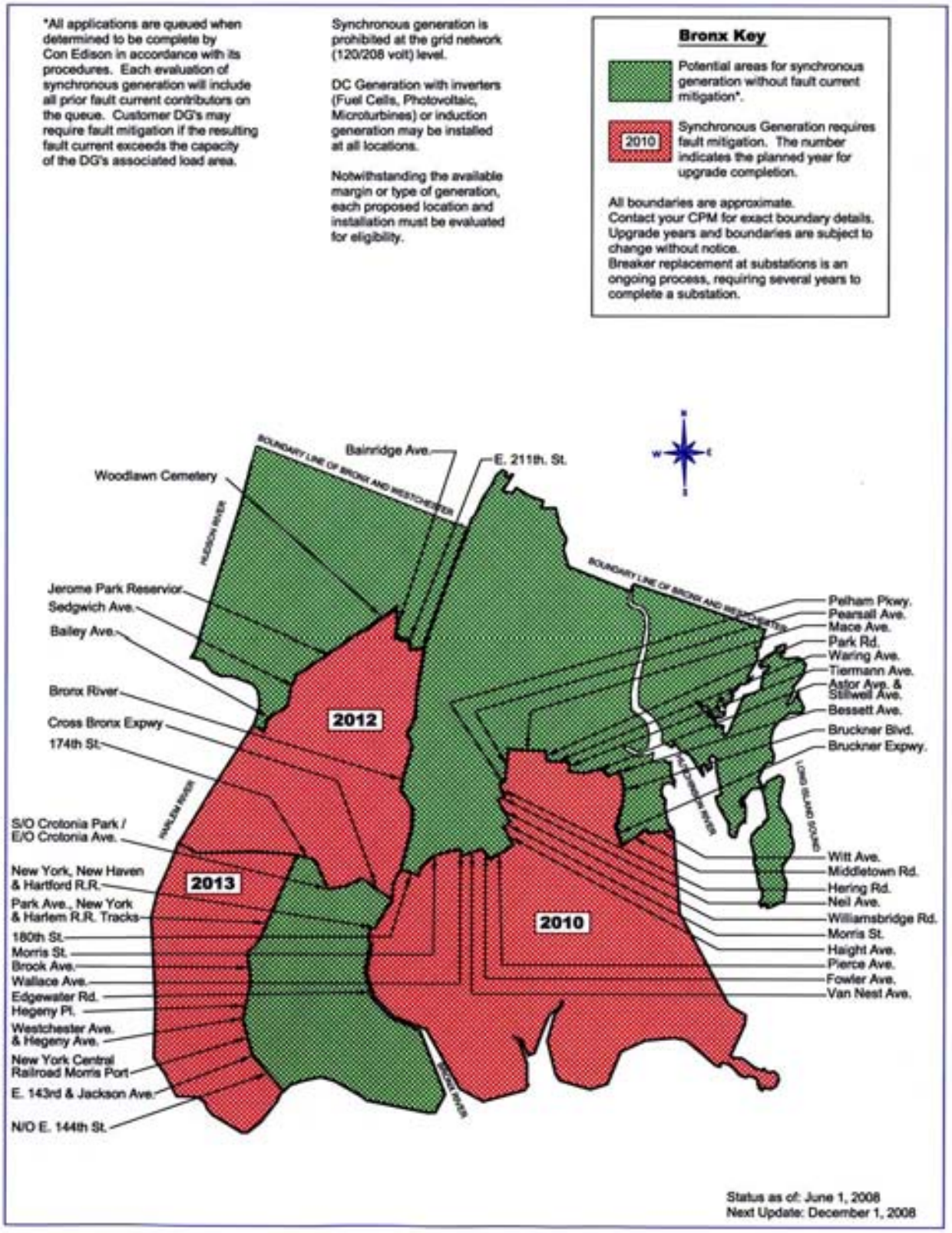
Under a 20 year power purchase agreement, the solar farm, which will be owned by SunEdison, will deliver 16 MW of power, with the first solar capacity coming on line by December 2010.

According to Duke, the plant will cover between 100-300 acres in an area that experiences sunny or partly sunny days about 60% of the time. With an estimated capacity factor of about 20%, the output is estimated at around 27GWh per year by the time the solar field is complete in 2011.

Since the solar plant will be built, owned and operated, there will be no capital cost to Duke rate-payers. The impact on overall electric rates is an expected increase of $.0.50 to $1.00 per year.

In addition to the SunEdison deal, Duke Energy is pursuing plans to develop its own distributed solar generation resources. Under this program, the company plans to invest $100 million over the next to years to install solar PV arrays on the rooftops of business and residential customers. Duke Energy plans to submit details to the North Carolina Utilities Commission

Appendix-2: Con Edison Fault Map



Appendix 3: CHP Utility Analysis

Natural Gas/Biomass ADG fueled

	2009			Electricity kWh												
	Electric Delivered $/kWh	Gas Delivered $/MMBTU	Total Fuel Turbine	without CHP	with CHP ConED import	Turbine Generated	displaced from ammonia	displaced from absorber	total kwhbenefit	Steam with CHP	Electric Base	Electric with CHP	Electric ConEd	SC11	Total ConEd	Total Electric
January	$0.212	$14.06	101,779	13,316,413	3,273,492	10,042,921	1,054,546	1240434	12,337,901	$ 949,088	$ 2,823,080	$ 481,927	$ 207,445	$ 112,299	$ 319,743	$ 801,671
February	$0.212	$14.06	91,930	12,038,619	2,967,593	9,071,026	952,493	1120392	11,143,910	$ 857,241	$ 2,552,187	$ 435,289	$ 189,678	$ 108,330	$ 298,008	$ 733,298
March	$0.212	$14.06	101,779	13,408,363	3,365,442	10,042,921	1,054,546	1240434	12,337,901	$ 949,088	$ 2,842,573	$ 481,927	$ 226,938	$ 110,659	$ 337,597	$ 819,524
April	$0.212	$14.06	98,496	13,231,003	3,512,047	9,718,956	1,020,528	1200420	11,939,904	$ 918,472	$ 2,804,973	$ 466,381	$ 273,713	$ 103,460	$ 377,173	$ 843,554
May	$0.212	$14.06	101,779	14,182,037	4,139,116	10,042,921	1,054,546	1240434	12,337,901	$ 949,088	$ 3,006,592	$ 481,927	$ 390,957	$ 103,759	$ 494,716	$ 976,644
June	$0.212	$14.06	98,496	14,308,508	4,589,552	9,718,956	1,020,528	1200420	11,939,904	$ 918,472	$ 3,033,404	$ 466,381	$ 502,144	$ 98,248	$ 600,392	$ 1,066,773
July	$0.212	$14.06	101,779	15,232,204	5,189,283	10,042,921	1,054,546	1240434	12,337,901	$ 949,088	$ 3,229,227	$ 481,927	$ 613,592	$ 97,019	$ 710,611	$ 1,192,538
August	$0.212	$14.06	101,779	15,165,432	5,122,511	10,042,921	1,054,546	1240434	12,337,901	$ 949,088	$ 3,215,072	$ 481,927	$ 599,437	$ 97,837	$ 697,273	$ 1,179,201
September	$0.212	$14.06	98,496	14,100,870	4,381,914	9,718,956	1,020,528	1200420	11,939,904	$ 918,472	$ 2,989,384	$ 466,381	$ 458,125	$ 101,704	$ 559,829	$ 1,026,210
October	$0.212	$14.06	101,779	13,907,595	3,864,674	10,042,921	1,054,546	1240434	12,337,901	$ 949,088	$ 2,948,410	$ 481,927	$ 332,775	$ 104,822	$ 437,597	$ 919,525
November	$0.212	$14.06	98,496	13,106,444	3,387,488	9,718,956	1,020,528	1200420	11,939,904	$ 918,472	$ 2,778,566	$ 466,381	$ 247,307	$ 96,497	$ 343,804	$ 810,185
December	$0.212	$14.06	101,779	13,348,344	3,305,422	10,042,921	1,054,546	1240434	12,337,901	$ 949,088	$ 2,829,849	$ 481,927	$ 214,214	$ 101,406	$ 315,620	$ 797,548
totals			1,198,368	165,345,832	47,098,534	118,247,298	12,416,424	14,605,110	145,268,832	$ 11,174,747	$ 35,053,316	$ 5,674,307	$ 4,256,324	$ 1,236,040	$ 5,492,364	$ 11,166,671

Natural Gas and Natural Gas/Wastewater ADG fueled

	2009			Electricity kWh												
	Electric Delivered $/kWh	Gas Delivered $/MMBTU	Total Fuel Turbine	without CHP	with CHP ConED import	Turbine Generated	displaced from ammonia	displaced from absorber	total kwhbenefit	Steam with CHP	Electric Base	Electric with CHP	Electric ConEd	SC11	Total ConEd	Total Electric
January	$0.212	$14.95	101,779	13,316,413	3,273,492	10,042,921	1,054,546	1240434	12,337,901	$ 1,009,166	$ 2,823,080	$ 512,434	$ 207,445	$ 112,299	$ 319,743	$ 832,177
February	$0.212	$14.95	91,930	12,038,619	2,967,593	9,071,026	952,493	1120392	11,143,910	$ 911,504	$ 2,552,187	$ 462,843	$ 189,678	$ 108,330	$ 298,008	$ 760,851
March	$0.212	$14.95	101,779	13,408,363	3,365,442	10,042,921	1,054,546	1240434	12,337,901	$ 1,009,166	$ 2,842,573	$ 512,434	$ 226,938	$ 110,659	$ 337,597	$ 850,030
April	$0.212	$14.95	98,496	13,231,003	3,512,047	9,718,956	1,020,528	1200420	11,939,904	$ 976,612	$ 2,804,973	$ 495,903	$ 273,713	$ 103,460	$ 377,173	$ 873,076
May	$0.212	$14.95	101,779	14,182,037	4,139,116	10,042,921	1,054,546	1240434	12,337,901	$ 1,009,166	$ 3,006,592	$ 512,434	$ 390,957	$ 103,759	$ 494,716	$ 1,007,150
June	$0.212	$14.95	98,496	14,308,508	4,589,552	9,718,956	1,020,528	1200420	11,939,904	$ 976,612	$ 3,033,404	$ 495,903	$ 502,144	$ 98,248	$ 600,392	$ 1,096,295
July	$0.212	$14.95	101,779	15,232,204	5,189,283	10,042,921	1,054,546	1240434	12,337,901	$ 1,009,166	$ 3,229,227	$ 512,434	$ 613,592	$ 97,019	$ 710,611	$ 1,223,045
August	$0.212	$14.95	101,779	15,165,432	5,122,511	10,042,921	1,054,546	1240434	12,337,901	$ 1,009,166	$ 3,215,072	$ 512,434	$ 599,437	$ 97,837	$ 697,273	$ 1,209,707
September	$0.212	$14.95	98,496	14,100,870	4,381,914	9,718,956	1,020,528	1200420	11,939,904	$ 976,612	$ 2,989,384	$ 495,903	$ 458,125	$ 101,704	$ 559,829	$ 1,055,732
October	$0.212	$14.95	101,779	13,907,595	3,864,674	10,042,921	1,054,546	1240434	12,337,901	$ 1,009,166	$ 2,948,410	$ 512,434	$ 332,775	$ 104,822	$ 437,597	$ 950,031
November	$0.212	$14.95	98,496	13,106,444	3,387,488	9,718,956	1,020,528	1200420	11,939,904	$ 976,612	$ 2,778,566	$ 495,903	$ 247,307	$ 96,497	$ 343,804	$ 839,707
December	$0.212	$14.95	101,779	13,348,344	3,305,422	10,042,921	1,054,546	1240434	12,337,901	$ 1,009,166	$ 2,829,849	$ 512,434	$ 214,214	$ 101,406	$ 315,620	$ 828,054
totals			1,198,368	165,345,832	47,098,534	118,247,298	12,416,424	14,605,110	145,268,832	$ 11,882,110	$ 35,053,316	$ 6,033,492	$ 4,256,324	$ 1,236,040	$ 5,492,364	$ 11,525,856

Appendix 4: CHP Cost Estimates

Hunts Point Cogen Solar Titan 15MW Cost Estimate 061308 Rev2

	A	E
1	**TOTAL COST ESTIMATE SUMMARY**	
2	**HUNTS POINT COGENERATION ONLY**	
3	**DATE:**	**6/1/2008**
4	**GENERATOR TYPE:**	**Solar Titan 130**
5	**CLIENT:**	**Hunts Point**
6	**SITE:**	**New York City**
7	**PREPARED BY:**	**Energistics, Inc.**
8	**TOTAL KW:**	**14990**
9	**BOILER PLANT PRICE;$/ MLBS**	**0**
10	**INCREMENTAL COST GENSET W/ HEAT RECOVERY; $/KW:**	**$ 477**
11	**TOTAL INSTALLED SELL PRICE PER KW:**	**$ 46,004,116**
12	**GRAND TOTAL SELL PRICE:**	**$ 3,069**
13	**ITEM**	**COST, $**
14	**Eng., Permitting, Licensing & Legal**	
15		
16	DESIGN SERVICES & EXPENSES	$ 2,463,250
17	DOCUMENTATION	$ 20,000
18	STUDIES AND PERMITS	$ 468,700
19		
20	**Subtotal Eng., PM, Permitting, Licensing & Legal =**	**$ 2,951,950**
21	**Construction Mgmt.**	
22	PROJECT/CONSTRUCTION MANAGEMENT	$ 307,307
23	SUBSISTENCE	$ 230,481
24	DEVELOPMENT FEE	$ -
25	**Subtotal Const. Mgmt. =**	**$ 537,788**
26	**Major Mechanical Equipment**	
27	TURBINE GENERATOR EQUIPMENT	$ 6,771,814
28	COGEN HEAT RECOVERY SYSTEM	$ 245,190
29	AIR POLLUTION CONTROL EQUIPMENT	$ 283,950
30	ABSORPTION CHILLER EQUIPMENT	$ 2,612,236
31	ELECTRIC CHILLER EQUIPMENT	$ -
32	STEAM TURBINE DRIVEN CHILLER EQUIPMENT	$ 2,985,221
33	GAS COMPRESSION EQUIPMENT	$ 936,232
34	FUEL TREATMENT SYSTEM	$ -
35	BOILERS	$ -
36	SPECIAL SYSTEM PUMP ASSEMBLIES	$ 89,143
37	STORAGE TANKS	$ 10,328
38	SPARE PARTS	$ 350,000
39		$ -
40	**Major Equipment Subtotal =**	**$ 14,284,114**
41	**Civil/Structural/Buildings**	
42	SITE WORK & UNDERGROUND UTILITIES	$ 340,625
43	OUTSIDE FOUNDATIONS	$ 537,468
44	BUILDING TASKS	$ 4,594,479
45		$ -
46	**Civil/Structural/Buildings Subtotal =**	**$ 5,472,572**
47	**Mechanical/Plumbing**	
48	OTHER MECHANICAL COSTS	$ 203,343
49	PLUMBING	$ 105,631
50	NATURAL GAS PIPING	$ 114,073
51	PIPING	$ 1,135,453
52	WATER TREATMENT	$ 29,427
53		$ -
54	**Mechanical/Plumbing Subtotal =**	**$ 1,587,927**
55	**Electrical**	
56	COGENERATION SWITCHGEAR - 15kV	$ 152,680
57	COGENERATION SWITCHGEAR - 5kV	$ 495,664
58	TRANSFORMERS	$ 372,100
59	MAIN UTILITY INTERCONNECTION	$ 1,480,202
60	COGENERATION AUXILIARY POWER SYSTEM	$ 436,578
61	SPECIAL ELECTRICAL SYSTEMS FOR ISLAND OPERATIONS	$ 305,000
62	MISCELLANEOUS ELECTRICAL EQUIPMENTS AND PARTS	$ 190,128
63	MAIN GENERATOR CONDUIT & WIRE	$ 465,044
64	MCC CONDUIT FOR MAJOR EQUIPMENT OTHER THAN PUMPS	$ 9,951
65	PUMP MCC ASSEMBLIES	$ 109,384
66	CONTROL CONDUIT FOR EQUIPMENT OTHER THAN PUMPS	$ 27,324
67	OTHER ELECTRICAL COSTS	$ 141,830
68		$ -
69		$ -
70	FIRE AND SECURITY	$ 335,000
71		$ -
72	**Electrical Subtotal =**	**$ 4,520,886**
73	**Inst. & Controls and Communication**	
74	COMMUNICATION SYSTEMS	$ 8,000
75	GENERATOR and COGEN METERING	$ 433,522
76	SOFTWARE	$ 210,000
77		$ -
78	**Controls Subtotal =**	**$ 651,522**
79	**Contractor Other Costs**	
80	CONTRACTOR TEMPORARY FACILITIES	$ 91,800
81	PERFORMANCE TESTING/COMMISSIONING	$ 700,000
82	SHIPPING CHARGES	$ 170,000
83		$ -
84	**Contractor Other Costs Subtotal =**	**$ 961,800**
85	**Base Contract Subtotals =**	**$ 30,646,078**
86	**Contractor Soft Costs**	
87	**TOTAL MARGIN**	$ 5,294,365
88	**OVERHEAD & WARRANTY**	$ 1,536,537
89	**CONTRACTOR SUBSISTANCE**	$ 230,481
90	**DEVELOPMENT FEE**	$ 307,307
91	**CONTINGENCY**	$ 5,377,881
92	**INSURANCE**	$ 875,693
93	**BONDING**	$ 875,693
94	**SALES TAX**	$ 860,083
95	**Contractor Soft Costs Subtotal =**	**$ 15,358,038**
96	**EPC Summary**	
97	**Subtotal Eng./PM/Permitting/Licensing/Legal =**	$ 4,359,738
98	**Subtotal Parts & Equipment =**	$ 23,611,267
99	**Subtotal Labor Costs =**	$ 2,675,073
100		
101	**Subtotal Soft Costs**	$ 15,358,038
102	**EPC COST SUBTOTAL =**	**$ 46,004,116**

Appendix 4: CHP Cost Estimates

Hunts Point Cogen Solar Titan 15MW W_ADG Cost Estimate 062108 Rev1

	A	E
1	**TOTAL COST ESTIMATE SUMMARY**	
2	**HUNTS POINT COGENERATION ONLY + ADG**	
3	**DATE:**	**6/1/2008**
4	**GENERATOR TYPE:**	**Solar Titan 130**
5	**CLIENT:**	**Hunts Point**
6	**SITE:**	**New York City**
7	**PREPARED BY:**	**Energistics, Inc.**
8	**TOTAL KW:**	**14990**
9	**BOILER PLANT PRICE;$/ MLBS**	**0**
10	**INCREMENTAL COST GENSET W/ HEAT RECOVERY; $/KW:**	**$ 477**
11	**TOTAL INSTALLED SELL PRICE PER KW:**	**$ 49,085,361**
12	**GRAND TOTAL SELL PRICE:**	**$ 3,275**
13	**ITEM**	**COST, $**
14	**Eng., Permitting, Licensing & Legal**	
15		
16	DESIGN SERVICES & EXPENSES	$ 2,568,750
17	DOCUMENTATION	$ 20,000
18	STUDIES AND PERMITS	$ 468,700
19		
20	**Subtotal Eng., PM, Permitting, Licensing & Legal =**	**$ 3,057,450**
21	**Construction Mgmt.**	
22	PROJECT/CONSTRUCTION MANAGEMENT	$ 327,749
23	SUBSISTENCE	$ 245,812
24	DEVELOPMENT FEE	$ -
25	**Subtotal Const. Mgmt. =**	**$ 573,560**
26	**Major Mechanical Equipment**	
27	TURBINE GENERATOR EQUIPMENT	$ 6,771,814
28	COGEN HEAT RECOVERY SYSTEM	$ 245,190
29	AIR POLLUTION CONTROL EQUIPMENT	$ 283,950
30	ABSORPTION CHILLER EQUIPMENT	$ 2,612,236
31	ELECTRIC CHILLER EQUIPMENT	$ -
32	STEAM TURBINE DRIVEN CHILLER EQUIPMENT	$ 2,985,221
33	GAS COMPRESSION EQUIPMENT	$ 936,232
34	FUEL TREATMENT SYSTEM	$ 1,441,232
35	NEW DIGESTERS FOR ORGANIC WASTE	$ -
36	SPECIAL SYSTEM PUMP ASSEMBLIES	$ 89,143
37	STORAGE TANKS	$ 10,328
38	SPARE PARTS	$ 350,000
39		$ -
40	**Major Equipment Subtotal =**	**$ 15,725,346**
41	**Civil/Structural/Buildings**	
42	SITE WORK & UNDERGROUND UTILITIES	$ 363,125
43	OUTSIDE FOUNDATIONS	$ 537,468
44	BUILDING TASKS	$ 4,594,479
45		$ -
46	**Civil/Structural/Buildings Subtotal =**	**$ 5,495,072**
47	**Mechanical/Plumbing**	
48	OTHER MECHANICAL COSTS	$ 203,343
49	PLUMBING	$ 105,631
50	NATURAL GAS PIPING	$ 114,073
51	PIPING	$ 1,600,350
52	WATER TREATMENT	$ 29,427
53		$ -
54	**Mechanical/Plumbing Subtotal =**	**$ 2,052,824**
55	**Electrical**	
56	COGENERATION SWITCHGEAR - 15kV	$ 152,680
57	COGENERATION SWITCHGEAR - 5kV	$ 495,664
58	TRANSFORMERS	$ 372,100
59	MAIN UTILITY INTERCONNECTION	$ 1,480,202
60	COGENERATION AUXILIARY POWER SYSTEM	$ 444,407
61	SPECIAL ELECTRICAL SYSTEMS FOR ISLAND OPERATIONS	$ 305,000
62	MISCELLANEOUS ELECTRICAL EQUIPMENTS AND PARTS	$ 190,128
63	MAIN GENERATOR CONDUIT & WIRE	$ 465,044
64	MCC CONDUIT FOR MAJOR EQUIPMENT OTHER THAN PUMPS	$ 12,120
65	PUMP MCC ASSEMBLIES	$ 109,384
66	CONTROL CONDUIT FOR EQUIPMENT OTHER THAN PUMPS	$ 27,324
67	OTHER ELECTRICAL COSTS	$ 141,830
68		$ -
69		$ -
70	FIRE AND SECURITY	$ 335,000
71		$ -
72	**Electrical Subtotal =**	**$ 4,530,883**
73	**Inst. & Controls and Communication**	
74	COMMUNICATION SYSTEMS	$ 8,000
75	GENERATOR and COGEN METERING	$ 433,522
76	SOFTWARE	$ 210,000
77		$ -
78	**Controls Subtotal =**	**$ 651,522**
79	**Contractor Other Costs**	
80	CONTRACTOR TEMPORARY FACILITIES	$ 91,800
81	PERFORMANCE TESTING/COMMISSIONING	$ 700,000
82	SHIPPING CHARGES	$ 170,000
83		$ -
84	**Contractor Other Costs Subtotal =**	**$ 961,800**
85	**Base Contract Subtotals =**	**$ 32,725,977**
86	**Contractor Soft Costs**	
87	**TOTAL MARGIN**	$ 5,682,090
88	**OVERHEAD & WARRANTY**	$ 1,638,744
89	**CONTRACTOR SUBSISTANCE**	$ 245,812
90	**DEVELOPMENT FEE**	$ 327,749
91	**CONTINGENCY**	$ 5,735,603
92	**INSURANCE**	$ 934,652
93	**BONDING**	$ 934,652
94	**SALES TAX**	$ 860,083
95	**Contractor Soft Costs Subtotal =**	**$ 16,359,384**
96	**EPC Summary**	
97	**Subtotal Eng./PM/Permitting/Licensing/Legal =**	$ 4,501,010
98	**Subtotal Parts & Equipment =**	$ 25,142,802
99	**Subtotal Labor Costs =**	$ 3,082,165
100		
101	**Subtotal Soft Costs**	$ 16,359,384
102	**EPC COST SUBTOTAL =**	**$ 49,085,361**

Appendix 4: CHP Cost Estimates

Hunts Point Cogen Solar Titan 15MW & ORGANIC ADG Cost Estimate 062108 Rev0

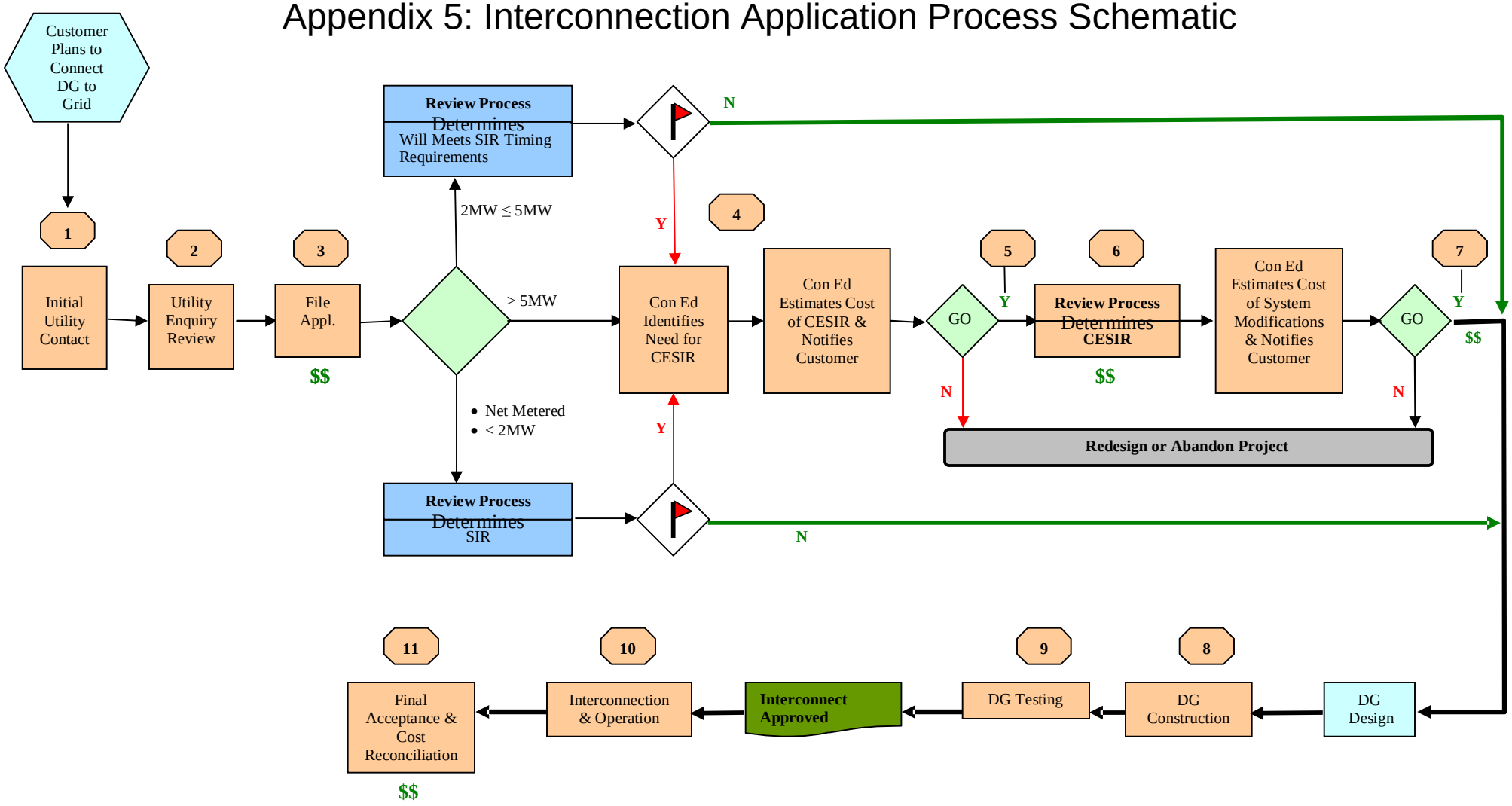
	A	E
1	**TOTAL COST ESTIMATE SUMMARY**	
2	**HUNTS POINT COGENERATION ONLY**	**& NEW ORGANIC ADG**
3	**DATE:**	**6/1/2008**
4	**GENERATOR TYPE:**	**Solar Titan 130**
5	**CLIENT:**	**Hunts Point**
6	**SITE:**	**New York City**
7	**PREPARED BY:**	**Energistics, Inc.**
8	**TOTAL KW:**	**14990**
9	**BOILER PLANT PRICE;$/ MLBS**	**0**
10	**INCREMENTAL COST GENSET W/ HEAT RECOVERY; $/KW:**	**$ 477**
11	**TOTAL INSTALLED SELL PRICE PER KW:**	**$ 60,187,790**
12	**GRAND TOTAL SELL PRICE:**	**$ 4,015**
13	**ITEM**	**COST, $**
14	**Eng., Permitting, Licensing & Legal**	
15		
16	DESIGN SERVICES & EXPENSES	$ 3,944,750
17	DOCUMENTATION	$ 40,000
18	STUDIES AND PERMITS	$ 518,700
19		
20	**Subtotal Eng., PM, Permitting, Licensing & Legal =**	**$ 4,503,450**
21	**Construction Mgmt.**	
22	PROJECT/CONSTRUCTION MANAGEMENT	$ 404,892
23	SUBSISTENCE	$ 303,669
24	DEVELOPMENT FEE	$ -
25	**Subtotal Const. Mgmt. =**	**$ 708,561**
26	**Major Mechanical Equipment**	
27	TURBINE GENERATOR EQUIPMENT	$ 6,771,814
28	COGEN HEAT RECOVERY SYSTEM	$ 245,190
29	AIR POLLUTION CONTROL EQUIPMENT	$ 283,950
30	ABSORPTION CHILLER EQUIPMENT	$ 2,612,236
31	ELECTRIC CHILLER EQUIPMENT	$ -
32	STEAM TURBINE DRIVEN CHILLER EQUIPMENT	$ 2,985,221
33	GAS COMPRESSION EQUIPMENT	$ 936,232
34	FUEL TREATMENT SYSTEM	$ 1,441,232
35	NEW DIGESTERS FOR ORGANIC WASTE	$ 3,848,480
36	SPECIAL SYSTEM PUMP ASSEMBLIES	$ 89,143
37	STORAGE TANKS	$ 10,328
38	SPARE PARTS	$ 500,000
39		$ -
40	**Major Equipment Subtotal =**	**$ 19,723,826**
41	**Civil/Structural/Buildings**	
42	SITE WORK & UNDERGROUND UTILITIES	$ 666,000
43	OUTSIDE FOUNDATIONS	$ 537,468
44	BUILDING TASKS	$ 4,594,479
45		$ -
46	**Civil/Structural/Buildings Subtotal =**	**$ 5,797,947**
47	**Mechanical/Plumbing**	
48	OTHER MECHANICAL COSTS	$ 203,343
49	PLUMBING	$ 536,982
50	NATURAL GAS PIPING	$ 114,073
51	PIPING	$ 1,267,569
52	WATER TREATMENT	$ 29,427
53		$ -
54	**Mechanical/Plumbing Subtotal =**	**$ 2,151,395**
55	**Electrical**	
56	COGENERATION SWITCHGEAR - 15kV	$ 152,680
57	COGENERATION SWITCHGEAR - 5kV	$ 495,664
58	TRANSFORMERS	$ 372,100
59	MAIN UTILITY INTERCONNECTION	$ 1,480,202
60	COGENERATION AUXILIARY POWER SYSTEM	$ 452,236
61	SPECIAL ELECTRICAL SYSTEMS FOR ISLAND OPERATIONS	$ 305,000
62	MISCELLANEOUS ELECTRICAL EQUIPMENTS AND PARTS	$ 190,128
63	MAIN GENERATOR CONDUIT & WIRE	$ 465,044
64	MCC CONDUIT FOR MAJOR EQUIPMENT OTHER THAN PUMPS	$ 12,120
65	PUMP MCC ASSEMBLIES	$ 109,384
66	CONTROL CONDUIT FOR EQUIPMENT OTHER THAN PUMPS	$ 27,324
67	OTHER ELECTRICAL COSTS	$ 141,830
68		$ -
69		$ -
70	FIRE AND SECURITY	$ 625,000
71		$ -
72	**Electrical Subtotal =**	**$ 4,828,712**
73	**Inst. & Controls and Communication**	
74	COMMUNICATION SYSTEMS	$ 8,000
75	GENERATOR and COGEN METERING	$ 433,522
76	SOFTWARE	$ 300,000
77		$ -
78	**Controls Subtotal =**	**$ 741,522**
79	**Contractor Other Costs**	
80	CONTRACTOR TEMPORARY FACILITIES	$ 122,400
81	PERFORMANCE TESTING/COMMISSIONING	$ 2,000,000
82	SHIPPING CHARGES	$ 320,000
83		$ -
84	**Contractor Other Costs Subtotal =**	**$ 2,442,400**
85	**Base Contract Subtotals =**	**$ 40,575,333**
86	**Contractor Soft Costs**	
87	**TOTAL MARGIN**	$ 6,639,641
88	**OVERHEAD & WARRANTY**	$ 2,024,461
89	**CONTRACTOR SUBSISTANCE**	$ 303,669
90	**DEVELOPMENT FEE**	$ 404,892
91	**CONTINGENCY**	$ 7,085,615
92	**INSURANCE**	$ 1,147,048
93	**BONDING**	$ 1,147,048
94	**SALES TAX**	$ 860,083
95	**Contractor Soft Costs Subtotal =**	**$ 19,612,457**
96	**EPC Summary**	
97	**Subtotal Eng./PM/Permitting/Licensing/Legal =**	$ 7,532,011
98	**Subtotal Parts & Equipment =**	$ 29,373,670
99	**Subtotal Labor Costs =**	$ 3,669,651
100		
101	**Subtotal Soft Costs**	$ 19,612,457
102	**EPC COST SUBTOTAL =**	**$ 60,187,790**

Appendix 4: CHP Cost Estimates

Hunts Point Cogen Solar Titan 15MW W_ORGANIC ADG PIPING ONLY Cost Estimate 062208 Rev0

	A	E
1	**TOTAL COST ESTIMATE SUMMARY**	
2	**HUNTS POINT COGENERATION ONLY + ADG PIPING ONLY**	
3	**DATE:**	**6/1/2008**
4	**GENERATOR TYPE:**	**Solar Titan 130**
5	**CLIENT:**	**Hunts Point**
6	**SITE:**	**New York City**
7	**PREPARED BY:**	**Energistics, Inc.**
8	**TOTAL KW:**	**14990**
9	**BOILER PLANT PRICE;$/ MLBS**	**0**
10	**INCREMENTAL COST GENSET W/ HEAT RECOVERY; $/KW:**	**$ 477**
11	**TOTAL INSTALLED SELL PRICE PER KW:**	**$ 48,580,167**
12	**GRAND TOTAL SELL PRICE:**	**$ 3,241**
13	**ITEM**	**COST, $**
14	**Eng., Permitting, Licensing & Legal**	
15		
16	DESIGN SERVICES & EXPENSES	$ 2,568,750
17	DOCUMENTATION	$ 20,000
18	STUDIES AND PERMITS	$ 468,700
19		
20	**Subtotal Eng., PM, Permitting, Licensing & Legal =**	**$ 3,057,450**
21	**Construction Mgmt.**	
22	PROJECT/CONSTRUCTION MANAGEMENT	$ 324,421
23	SUBSISTENCE	$ 243,316
24	DEVELOPMENT FEE	$ -
25	**Subtotal Const. Mgmt. =**	**$ 567,737**
26	**Major Mechanical Equipment**	
27	TURBINE GENERATOR EQUIPMENT	$ 6,771,814
28	COGEN HEAT RECOVERY SYSTEM	$ 245,190
29	AIR POLLUTION CONTROL EQUIPMENT	$ 283,950
30	ABSORPTION CHILLER EQUIPMENT	$ 2,612,236
31	ELECTRIC CHILLER EQUIPMENT	$ -
32	STEAM TURBINE DRIVEN CHILLER EQUIPMENT	$ 2,985,221
33	GAS COMPRESSION EQUIPMENT	$ 936,232
34	FUEL TREATMENT SYSTEM	$ 1,441,232
35	NEW DIGESTERS FOR ORGANIC WASTE	$ -
36	SPECIAL SYSTEM PUMP ASSEMBLIES	$ 89,143
37	STORAGE TANKS	$ 10,328
38	SPARE PARTS	$ 350,000
39		$ -
40	**Major Equipment Subtotal =**	**$ 15,725,346**
41	**Civil/Structural/Buildings**	
42	SITE WORK & UNDERGROUND UTILITIES	$ 363,125
43	OUTSIDE FOUNDATIONS	$ 537,468
44	BUILDING TASKS	$ 4,594,479
45		$ -
46	**Civil/Structural/Buildings Subtotal =**	**$ 5,495,072**
47	**Mechanical/Plumbing**	
48	OTHER MECHANICAL COSTS	$ 203,343
49	PLUMBING	$ 105,631
50	NATURAL GAS PIPING	$ 114,073
51	PIPING	$ 1,267,569
52	WATER TREATMENT	$ 29,427
53		$ -
54	**Mechanical/Plumbing Subtotal =**	**$ 1,720,044**
55	**Electrical**	
56	COGENERATION SWITCHGEAR - 15kV	$ 152,680
57	COGENERATION SWITCHGEAR - 5kV	$ 495,664
58	TRANSFORMERS	$ 372,100
59	MAIN UTILITY INTERCONNECTION	$ 1,480,202
60	COGENERATION AUXILIARY POWER SYSTEM	$ 444,407
61	SPECIAL ELECTRICAL SYSTEMS FOR ISLAND OPERATIONS	$ 305,000
62	MISCELLANEOUS ELECTRICAL EQUIPMENTS AND PARTS	$ 190,128
63	MAIN GENERATOR CONDUIT & WIRE	$ 465,044
64	MCC CONDUIT FOR MAJOR EQUIPMENT OTHER THAN PUMPS	$ 12,120
65	PUMP MCC ASSEMBLIES	$ 109,384
66	CONTROL CONDUIT FOR EQUIPMENT OTHER THAN PUMPS	$ 27,324
67	OTHER ELECTRICAL COSTS	$ 141,830
68		$ -
69		$ -
70	FIRE AND SECURITY	$ 335,000
71		$ -
72	**Electrical Subtotal =**	**$ 4,530,883**
73	**Inst. & Controls and Communication**	
74	COMMUNICATION SYSTEMS	$ 8,000
75	GENERATOR and COGEN METERING	$ 433,522
76	SOFTWARE	$ 210,000
77		$ -
78	**Controls Subtotal =**	**$ 651,522**
79	**Contractor Other Costs**	
80	CONTRACTOR TEMPORARY FACILITIES	$ 91,800
81	PERFORMANCE TESTING/COMMISSIONING	$ 700,000
82	SHIPPING CHARGES	$ 170,000
83		$ -
84	**Contractor Other Costs Subtotal =**	**$ 961,800**
85	**Base Contract Subtotals =**	**$ 32,387,373**
86	**Contractor Soft Costs**	
87	**TOTAL MARGIN**	$ 5,615,534
88	**OVERHEAD & WARRANTY**	$ 1,622,105
89	**CONTRACTOR SUBSISTANCE**	$ 243,316
90	**DEVELOPMENT FEE**	$ 324,421
91	**CONTINGENCY**	$ 5,677,366
92	**INSURANCE**	$ 924,985
93	**BONDING**	$ 924,985
94	**SALES TAX**	$ 860,083
95	**Contractor Soft Costs Subtotal =**	**$ 16,192,794**
96	**EPC Summary**	
97	**Subtotal Eng./PM/Permitting/Licensing/Legal =**	$ 4,495,187
98	**Subtotal Parts & Equipment =**	$ 25,076,220
99	**Subtotal Labor Costs =**	$ 2,815,966
100		
101	**Subtotal Soft Costs**	$ 16,192,794
102	**EPC COST SUBTOTAL =**	**$ 48,580,167**

Appendix 5: Interconnection Application Process Schematic



1 --Standard Interconnect Requirements (SIR) Process Steps