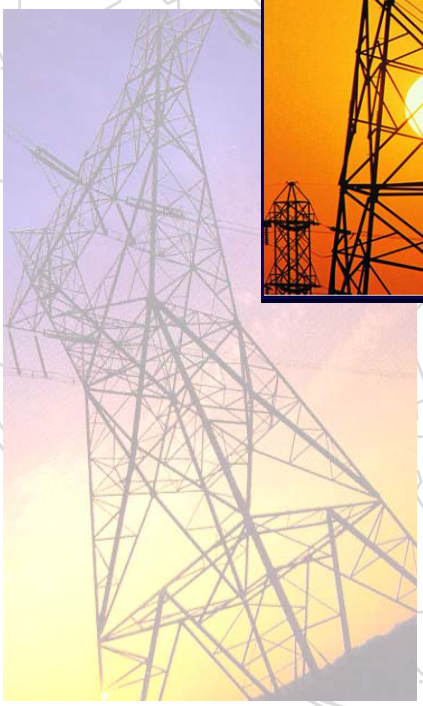
Report for Independent Technical Review

CARNEY'S POINT COGENERATION PROJECT

Submitted to Atlantic Power Management LLC



November 7, 2005

Shaw® Stone & Webster Management Consultants, Inc.

INDEPENDENT TECHNICAL REVIEW

OF THE

CARNEY'S POINT COGENERATION PROJECT

Prepared for

Atlantic Power Management LLC

November 2005

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TABLE OF CONTENTS

CARNEY'S POINT GENERATING PLANT 1

1.0 THE FACILITY 1
1.1 Site Conditions 1
1.2 Review of Technology 1
1.3 Facility Description and Condition Assessment 2
1.4 Remaining Useful Life 8
1.5 Permits and Approvals 9

2.0 OPERATIONS 11
2.1 Historical Performance 11
2.2 Operations and Maintenance 11
2.3 Regulatory Compliance 17

3.0 PROJECTED OPERATING RESULTS 21
3.1 Performance Projections 21
3.2 Operating Revenues 22
3.3 Operating Expenses 26
3.4 Debt Service 27
3.5 Distributions to Company 28
3.6 Power Market Analysis 28

4.0 CONCLUSIONS 30

ATTACHMENT

Summary Portfolio **33**

CARNEY'S POINT GENERATING PLANT

The Carney's Point Generating Plant (the "Plant or Facility") is a 285 megawatt (gross) pulverized coal fired cogeneration facility that is located on a site adjacent to the DuPont Chambers Works at Carneys Point, in southern New Jersey. The Facility is capable of providing electricity for sale to the local utility and steam and electricity to the adjacent DuPont Chambers Works facility. The Facility is owned by the Chambers Cogeneration Limited Partnership ("CCLP").

The Facility was designed to generate a net power output of 217.180 megawatts (MW) while delivering 550,000 lb/hr of turbine extraction steam flow to the DuPont's Chambers Works facility. The Facility supplies nominally 184 MW (187.6 MW summer and 173.2 MW winter) of dispatchable power to Atlantic City Electric Company ("ACE"), a wholly owned subsidiary of Conectiv, under an Agreement for Purchase of Electric Power ("Power Purchase Agreement" or "PPA"). It also supplies steam/electric power to the DuPont Chamber Works on a continuous basis under a Steam and Electric Purchase Agreement ("DuPont Contract"). Additionally, any available excess power is sold through a separate Power Sales Agreement ("PSA") with ACE.

The Facility is a Qualifying Facility ("QF") under PURPA and has maintained its QF status since initial Commercial Operation in 1994. At the time of Stone & Webster Consultants' site visit on May 28, 2004, the Facility was operating with the turbine valves wide open generating 235.8 MW to Conectiv along with 142,500 lb/hr of process steam and approximately 20 MW being supplied to the DuPont Chambers Works facility.

The two Foster Wheeler boilers are each capable of providing about 1,200,000 lb/hr of high pressure steam to an Alstom (formerly GEC Alsthom) steam turbine generator. The boilers utilize pulverized coal as the primary fuel (provided under the Coal Purchase Agreement) and No. 2 fuel oil as a startup and backup fuel to supply steam to the steam turbine to produce power and process steam. The auxiliary boiler is designed to burn No. 2 fuel oil and is used to supply auxiliary steam to only the Facility when both main boilers are not operating. Raw water for the Facility is provided by the DuPont Chambers Works. The wastewater from the Facility is sent to the DuPont Chambers Works for disposal.

Stone & Webster Consultants last toured the Facility and interviewed the Facility manager, engineering manager, operations manager, and environmental manager on May 28, 2004.

1.0 THE FACILITY

The Facility was operated and maintained by National Energy Power Company, LLC, a subsidiary of National Energy & Gas Transmission, Inc. ("NEGT"), the successor to PG&E National Energy Group in accordance with the Facility Operations and Maintenance Agreement. On February 1, 2005, the Operations and Maintenance Agreement was transferred from National Energy Power Company, LLC, Power Services to North American Energy Services (NAES). NAES is currently responsible for the operation and maintenance of the Facility.

1.1 SITE CONDITIONS

The site is located in an industrial area on land leased from DuPont which is part of the adjacent DuPont Chamber Works property. Road access to the Facility is via Interstate Route 295 to U.S. Route 130 and by rail via a Conrail siding.

The DuPont Chambers Works property is working under the New Jersey Department of Environmental Protection ("NJDEP") Industrial Site Recovery Act ("ISRA") program for site remediation; however, the Facility is not involved and is responsible only for proper control of operations to avoid additional soil or groundwater contamination. The site lease with DuPont provides the project an indemnity for pre-existing site conditions. Operating records indicate that in the period from July 1993 through February 1999, with the exception of one 50 gallon spill of caustic solution in April 1994, all oil, and chemical spills were less than 10 gallons. Management Reports in the period from January 2003 through August 2005 indicate no reportable spills at the Carney's Point plant.

Stone & Webster Consultants did not undertake an independent Environmental Site Assessment; however the observed general housekeeping condition of the Facility was excellent. A visual inspection of the Facility site during our May 2004 visit did not reveal any soil discoloration or other indications of material significance relative to potential site contamination. Except for underground fuel oil pipes serving the main and auxiliary boilers, there were no reported existing conditions that might result in material environmental liability to the Facility.

1.2 REVIEW OF TECHNOLOGY

The Facility uses two conventional pulverized coal fired boilers provided by Foster Wheeler Energy Corporation ("Foster Wheeler") included with low NO_X burners and selective catalytic reduction ("SCR") systems for NO_X emissions control. The coal that is burned in the boiler is a washed and blended 2% sulfur eastern bituminous coal. The boiler is also equipped with Babcock & Wilcox, (formerly Joy Environmental) spray dryers and fabric filters for control of SO_2 and particulate emissions. The spray dryer and baghouse arrangement is generally accepted to be proven and reliable technology. The use of two fifty percent boilers instead of one hundred percent boiler was required to support the reliability requirements for process steam supply to the DuPont Chambers Works.

The steam turbine is a single automatic extraction Alstom unit and is designed to accommodate a very high percentage (up to approximately 42%) of total steam to be potentially extracted as process steam. In practice, the historic process steam requirement varies over the range of

approximately 4 to 12 percent of total steam flow (10-30% of possible process steam flow). The turbine is also unusual due its use of the Alstom "Optiflow" combined intermediate pressure/low pressure ("IP/LP") module in a single casing consisting of a single central IP flow and two symmetrical and opposed LP flows located on either side of the IP section. The 759 mm (29.9 in.) last stage blade length is considered to be a proven Alstom design. The turbine has generally operated reliably except for multiple incidents of steam leaks in the crossover pipe expansion joint and a valve spindle failure. The valve spindle failure has not recurred and a reported final expansion joint solution was implemented during the fall 2004 outage.

The generator is an Alstom conventional hydrogen cooled with water cooled stator design. Many Alstom generators have been subject to vibration-related issues including the type of phase lead failure which occurred on this unit. The phase lead failure was repaired and is being monitored during the steam turbine outages.

1.3 FACILITY DESCRIPTION AND CONDITION ASSESSMENT

Boilers

Foster Wheeler supplied the drum-type steam generators (boilers) and related boiler auxiliary equipment. There are two 50 percent capacity boilers connected to a single steam turbine-generator. The total design steam capacity of the two boilers is 2.4 million lb/hr (1.2 million lb/hr each) at a temperature of 1,005°F and a pressure of 1,900 psig. DuPont Chamber Works process steam is supplied from either turbine extraction steam or conditioned boiler main steam when the turbine is not operational. The process steam design requirements range from 100,000 lb/hr to 1,000,000 lb/hr at 250 psia and 416°F at the Facility.

The boilers are inspected annually and general preventative maintenance performed as required, however beginning in 2004 the boiler inspections are scheduled every 18 months unless required more frequently. Since the boilers have only been operating about 11 years, the Facility operations have been performing non-destructive examinations to monitor tube wall thickness status on critical boiler components. Normal burner and auxiliary hardware maintenance issues are addressed during the periodic inspections with major boiler work being completed every two to three years based on the annual inspections. The operators have developed a 20 year outage forecast table, listing all the major pieces of equipment, that the Facility operations uses to track equipment maintenance and estimated maintenance cost. The two boilers have been operating as required and are being maintained to support the DuPont Chamber Works' requirement of 100 percent steam availability.

The boilers have periodically experienced slagging in the furnace area as a result of a lower ash fusion temperature coal. The operations group worked with the coal supplier to correct the low ash fusion temperature issue. The boilers are able to operate reliably with the lower ash fusion temperature coal, but require periodic load reductions and extra soot blowing cycles to control the slag buildup.

A visual inspection of the operating boilers during our site visit did not reveal any significant gas leaks, vibration, noises, hot casing spots, or buckstay distortions.

Steam Turbine Generator

The steam turbine generator was supplied by Alstom (formerly GEC Alsthom). The turbine is a 20-stage tandem compound, two flow non-reheat design with a single IP flow located between two symmetrical and opposed LP flows within the same casing with 759 mm (29.9 inch) last stage blades of proven design. It has a nameplate rating of 285 MW with throttle steam conditions of 1,800 psig, 1,000ºF at 3.25 in. Hg. exhaust pressure and a throttle steam flow of 2,400,000 lb/hr. The non-reheat design was utilized due to the high and variable process steam flow relative to the throttle steam flow and the required process steam pressure. There are a total of 6 extraction points including a single automatic extraction at the exhaust of the high pressure turbine that is capable of providing up to 1,000,000 lb/hr steam at controlled steam conditions for DuPont's process requirements. However, historic DuPont Chamber Works process steam demand varies between 100,000 lb/hr and 350,000 lb/hr with an average annual steam flow of about 200,000 lb/hr. Depending on the process steam demand, maximum electrical output will vary. The generator is a direct driven, synchronous 3600 rpm, water and hydrogen cooled machine with a nameplate rating of 335.3 MVA at 23 kV with a 0.85 power factor. The turbine generator is located indoors.

Major overhauls on the turbine are performed at 7-year intervals as dictated by condition with valves overhauled at 3 year intervals on a rotating basis. The first major turbine overhaul since initial commercial operation in 1994 was carried out in 2001 and included the HP turbine, IP/LP turbine, three of the eight turbine valves including actuators, turbine/generator alignment, and a steam path audit. A light coating of iron was observed along the steam path, prompting a glass bead blast cleaning which appears to have resulted in about a 4 MW restoration due to reduction in surface roughness. Major repairs included weld repair of moisture undercut damage to the welds attaching diaphragm blades to the carrier on the L1 and L2 stages and pad welding of water erosion damage on the last stage diaphragm diffuser on the turbine side flow. Fractured spill strips were observed on the IP turbine, most likely the result of an initial rub according to Alstom. The IP spill strips repair was deferred during the 2001 overhaul but it is intended that they be totally replaced and the diaphragm welds coated to control further erosion during the next major overhaul currently scheduled for 2009.

The upstream right side metal bellows expansion joint on the turbine crossover pipe was subject to seven incidents of steam leaks beginning between January 2000 and April 2002. Replacement joints to date have been of a 316L stainless steel rather than the original 18-10 material that is more resistant to the presumptive stress corrosion cracking failure mechanism. The April 2002 repair eliminated the excessive stress but the material retained the increased susceptibility to stress corrosion cracking. Although there have been no further failures to date, the Facility operator replaced both of the 316L right side expansion joints with joints constructed of Inconel material during the fall 2004 outage.

In addition, the turbine controls were upgraded to a new Siemens Westinghouse system during the fall 2004 outage because the current system is no longer being supported by the manufacturer. This will be an "island" system and not interfaced with the Facility's distributed control system.

In 1999, a generator phase lead loosened due to vibration, and shorted to ground. Carbon from the resulting arcing contaminated the generator stator, necessitating a lengthy outage to remove the rotor and clean the stator. As a result of the incident, Alstom recommended that a hammer test be performed on the phase leads at 18 month intervals in order to detect potential vibration problems and a partial discharge monitoring system (the Alstom "GOLD" system) was installed for on-line monitoring of generator deterioration. The Facility operator also performs thermographic preventative maintenance inspections on the exciter and changes out the brushes periodically as required.

During the 2001 major turbine overhaul, an inspection of the generator terminal box revealed some greasing at the clamping points. A bump test indicated that the amplitude was too high on one of the six phase leads and a 12 kg weight was added to "tune" and dampen the vibrations which could have been contributing to the insulation greasing.

The Facility experienced a generator ground fault trip in January 2003. The root cause was determined to be a faulty potential transformer that was replaced rather than a fault within the generator itself.

In general, the turbine generator and related auxiliary systems appear to be well maintained and in good condition. The generator is scheduled for a major overhaul in 2006.

Flue Gas Desulfurization System

The flue gas desulfurization system removes SO_2 and particulates from the flue gas prior to discharge into the atmosphere. The Facility uses a dry scrubber which consists of a spray dryer that initiates SO_2 removal reactions. A baghouse located downstream from the dry scrubber removes particulates from the flue gas and completes the SO_2 removal reactions. Dry scrubbers have been used for many years and have performed reliably.

The dry scrubber system was designed with an emergency spray header that could be used in the event the main spray atomizer was removed for maintenance or repair when the boiler was in service. Since initial operation the emergency spray header was never able to maintain SO_2 removal efficiency to the level of the main spray atomizers. The operations group was able to work around this issue by going to three hours SO_2 averaging and by having a spare main spray atomizer available to install into the scrubber vessel. After 11 years of operation the operation's group has noted some thinning of the scrubber vessel wall. The necessary repairs were implemented to maintain the wall thickness and integrity during the subsequent major outage.

In our opinion the flue gas desulfurization system has demonstrated its ability for controlling SO_2 emissions within permitted levels.

Selective Catalytic Reduction System

In order to satisfy New Jersey's NO_X emissions regulations, low NO_X burners with overfire air and SCR were selected for the Facility. The SCR system removes NO_x from the flue gas by reacting ammonia with the NO_X in the flue gas and passing it over a catalyst located between the

economizer and the air heater. The SCR system consists of three subsystems: 1) the SCR catalyst located in the flue gas stream, 2) the ammonia storage and preparation system, and 3) the manifold that injects the ammonia/air mixture into the flue gas immediately ahead of the catalyst bed.

The SCR system has operated successfully in removing NO_X emissions in accordance with permit requirements. The SCR catalyst has operated as expected and the additional space for the third row of catalyst has been utilized. Plans are to clean and add new catalyst as required to maintain the SCR catalyst efficiency.

Balance of Plant

The Facility has a single condensate and feedwater system including two 100% capacity motor driven condensate pumps, three low pressure feedwater heaters, a full-sized primary deaerator, a recently installed partial capacity standby deaerator, three 50% capacity motor driven feedwater pumps, and two high pressure feedwater heaters. The standby deaerator permits maintenance of the primary deaerator without requiring a Facility outage and is sufficient to support the turbine on minimum load while providing for the DuPont Chamber Works process steam demand. The primary deaerator was internally inspected and found to be in generally good condition with no issues with welds or corrosion. There was some washing out (erosion) observed where the recirculation line entered the deaerator and the nozzle entry direction was altered to discourage further erosion and a monitoring program initiated. The No. 6 feedwater heater was replaced with a new unit in 2000 in order to resolve a problem with flow-induced vibration. The single feedwater system with no bypass capability makes valve maintenance difficult without a Facility outage. The No. 1 boiler feedwater control valve was replaced with a more efficient design and the valve for No. 2 boiler was replaced during the fall 2004 outage. The operator repaired a leaking boiler feed pump discharge valve without having to install a line stop due to the lack of a bypass since there is no bypass piping installed.

The condenser is equipped with 90/10 Cu Ni (copper nickel) tubes, of which only approximately 1% have been plugged which is less than anticipated and less than the 3% margin that is normally installed. Eddy current testing has shown no significant tube wall loss and there are no signs of ammonia gouging in the air section tubes. However, there was evidence of a reduction in flow in the lower tubes which required tube cleaning during the fall 2004 outage. The No. 4 extraction expansion joint located within the condenser failed (exploded) in 2003 and was replaced with an improved design meeting today's stricter code. All other extraction expansion joints within the condenser are being surveyed in order to determine any further replacement needs.

The circulating water system for cooling the condenser includes two 50% capacity circulating water pumps and a Hamon forced draft wooden cooling tower with PVC fill. Eighty percent of the wood in the air section has been replaced with treated redwood, all hangers replaced with stainless steel, and the drift eliminators replaced with a high efficiency design in order to reduce detrimental water drift onto adjacent Plant structures. The fill is original and still serviceable however the operator is economically evaluating the addition of another half or full layer of fill in order to improve hot weather performance and restore an approximate loss of 3-4 MW in

summer peak temperature conditions. The cooling tower is equipped with a fire protection (sprinkler) system. Because of extensive corrosion of the original galvanized cooling tower fire protection piping, the cooling tower fire system piping was replaced in March and April of 2005 with 304 grade stainless steel piping. The fire piping was tested for leaks before returning it to service. The wooden top decking of the cooling tower was deteriorating and was replaced with fiberglass-reinforced plastic decking over the 2003-2004 time period.

Raw water for the Facility is received at approximately 5,500 gpm under contract from DuPont. The water is chlorinated, clarified, and filtered to be used for cooling tower make up and is further treated in three, 3-bed demineralizer trains for boiler feedwater makeup. The water treatment system design is based on providing 1,000,000 lb/hr steam to DuPont Chamber Works with no condensate return. Based on the current low process steam demand there is considerable excess water treatment system capacity. The DuPont Chamber Works primary source of the raw water is the Salem Canal (surface runoff water). During a 40-year drought in 2002, the canal dropped to level of 1 ft, compared to the normal 5 ft level. The drought plan that was in place showed that DuPont Chamber Works had backup water wells, and could draw from the Sportsman's Club pond and the Clemente gravel pit if required. Stone & Webster Consultants did not investigate the potential capacity of these backup water supplies but are reported to be reasonable.

The service water system includes two 100% capacity pumps taking suction from the cooling tower basin and discharging into the condenser circulating water return line.

The Facility is equipped with rotary screw service air and instrument air compressors. The operators did not report any operating problems with either of the compressed air systems.

The above balance of plant systems and equipment appear to be in generally good condition and are supporting the Facility's high reliability.

Electrical Power System

Electrical power produced by the 335 MVA station generator is exported to two Conectiv 230 kV transmission lines via the Facility's 230 kV gas/air insulated switching station and to DuPont Chambers Works via seven 11.5 kV tie lines.

The two 230 kV transmission lines serving the Facility can be sectionalized within the Facility's switching station to ensure that loss of one transmission line will not impair the export or import of electrical power. Startup and emergency power will be provided to the Facility from Conectiv's 230 kV transmission line.

The main step-up transformer was manufactured by VA Tech and it converts the generator 23kV voltage to the 230 kV transmission voltage. The main step-up transformer is sized for the expected output to Conectiv, DuPont, and the station auxiliary loads plus some spare capacity for future growth.

Typical utility industry practice is to schedule transformer oil and gas analysis in one-month, to one-year intervals. Oil samples, taken from the Facility main transformer on March 22, 2004, were found to contain higher levels of dissolved gases than expected for the comparable analysis from the preceding annual test in 2003. The purpose of the transformer oil tests is to identify any abnormal constituents in the transformer oil that could indicate a potential problem. Each abnormal constituent has a unique signature linking the particular constituent to a specific potential problem. While the most recent combustible gas levels in the oil continue to rise, they remain less than the index used to monitor the flammability of the oil.

The Facility utilizes oil filled transformers with circulating pumps and fans, which are standard in the utility industry for main service transformers. While the cooling system is typically operated only in hot weather, the cooling system can be run at any time with little or no impact on station performance. On April 15, 2004, the operator started the main transformer oil circulating pump motors and cooling fans to provide some additional oil cooling to any hot spots within the transformer, and to dilute the dissolved gases in the transformer oil.

The operator took a station outage at the end of April 2004 to perform a limited internal inspection of the transformer. Acoustic monitoring testing prior to the outage had detected three areas of high acoustic activity. Two areas were near the bushing connections, and one near the center of one of the transformer cores. Acoustic monitoring is another diagnostic tool for monitoring power plant equipment. During the limited internal inspection of the transformer, the transformer oil level was lowered to a point not to uncover the main core coils, the access hatch was removed, and a technician inspected the transformer bushing connections. To the extent accessible, the bushings connections and insulation in the vicinity of the high levels of acoustic activity near the bushings were checked and no unusual conditions were found. The third area of high acoustic activity near the middle of the transformer core was not accessible for inspection. The transformer was refilled to the required oil level and the oil was filtered, and dried before restarting the station. The limited internal inspection did not identify the specific reason for the high transformer gas readings.

The operator has replaced the original transformer with a new unit which was delivered to the site in late October 2004 and installed during the December 2004 major outage. The original transformer is currently being stored on site and can be used as a spare.

Two station service transformers, served from the 230 kV station bus, have separate medium voltage windings to establish the revenue metering fee for the DuPont Chambers Works and the station auxiliaries. Each station service transformer has an 11.5 kV winding which is connected to two 3000 amp, 11.5 kV, 750 MVA busses, based on three phase symmetrical interrupting capability. Circuit breaker switching permits each winding to feed one or both busses. Each winding has adequate capacity to serve both busses with capacity for future growth. Each station service transformer also has a 13.8 kV winding which is connected to one 3000 amp, 13.8 kV, 750 MVA bus, based on three phase symmetrical interrupting capability. The two 13.8 kV busses can be connected together by a 2000 amp tie breaker so that both 13.8 kV busses may be served by either one of the station service transformers for operational flexibility. Each 13.8 kV winding has acceptable capacity to serve both busses with capacity for future growth.

Two uninterruptible power supplies are provided for critical loads such as the distributed digital control system at the burner management system and critical field instrumentation for which the loss of power would immediately affect unit operation.

A 125 volt DC battery distribution system is provided to supply critical equipment and protective devices, such as turbine generator bearing and shaft seal oil emergency pumps, circuit breaker controls, vital AC inverter, and various other control circuits for a minimum period of 2 hours following a complete loss of station normal AC power. Protective relaying is provided in accordance with industry standards.

Revenue metering is furnished and installed by Conectiv at each of the two points of delivery to Conectiv, to the main feeders from the Facility to the DuPont Chambers Works, and to the main feeders to the station auxiliary busses. Revenue quality metering is provided for generator gross output. Non-revenue metering for DuPont Chambers Works is provided on each of the seven 11.5 kV feeders.

The operations group recently enclosed the Facility motor control center and breakers in a control atmosphere room to prevent potential corrosion and moisture problems that were being identified with the electrical equipment. The equipment problems were addressed before the control atmosphere room was installed.

Control Systems

Controls and instrumentation are provided to permit normal operation in a central control room with local controls for coal handling, ash unloading, lime handling and slurry preparations, baghouse controls, feedwater heater drains, and boiler feed pump recirculation. There are no major issues with the control system operations other than the obsolescence concerns and spare parts availability. Plans are being developed to upgrade the control and instrumentation systems as schedule dictates.

The turbine is controlled by a hydraulic governor system from the central control room, with startup controls from local panels adjacent to the turbine-generator. Generator and electrical system controls for synchronization, voltage regulation, switchgear operations, and large motor control is hardwired for control from the central control room.

Continuous stack emissions monitoring and recording are provided to measure oxygen, carbon monoxide, nitrogen dioxide, sulfur dioxide, opacity, and ammonia in accordance with U.S. Environmental Protection Agency (“EPA”) and New Jersey requirements. These data also are shared by the distributed control system for Facility performance monitoring.

1.4 REMAINING USEFUL LIFE

There are only a few technical issues that can lead to an abrupt or unpredicted end of life of an electric generating station. In most cases, decisions to retire generating units are made for economic reasons, which may be the result of technical or environmental issues. The primary technical reasons that would cause units to be retired are likely to be the costly repair or

replacement of fatigue and creep damage to major components such as the boiler and turbine-generator that would exceed the net present value of the Facility.

The Facility has not accumulated sufficient operating hours and thermal cycles to begin to show damage from processes such as metal creep since it is only 11 years old. In addition the Facility dispatch is changing from a cycling mode to more of a base loaded mode. The relatively low pressure and temperature of the main steam further reduces possible component damage and loss of life. The Facility operator also initiated a continuing program of performing root cause analysis of failures which is expected to result in less repetitive failures and ultimately increased reliability and the potential for extended component life.

Given the current overall condition of the Facility and the continued application of continuous operation and maintenance combined with an appropriate level of capital expenditure as the Facility ages, the remaining useful life of the Facility is expected to exceed the term of the PPA.

1.5 PERMITS AND APPROVALS

Construction of the Carneys Point Generating Plant was complete and commercial operation commenced in March 1994. Construction was permitted under USEPA and New Jersey Department of Environmental Protection ("NJDEP") requirements for Prevention of Significant Deterioration, New Source Review, and Best Available Control Technology. The NJDEP initially issued a construction permit and subsequently issued and has periodically reissued Permits to Operate for the Facility and the various emissions sources.

Because the Facility is a certified QF, the Title IV Acid Rain regulations do not apply and a Title IV Acid Rain Permit is not required.

In 1995 an application was submitted with NJDEP for a Title V Operating Permit. On May 28, 2003 a draft Title V Permit was issued. However, in May and December 2003 the Facility requested minor modifications and a revision relating to a coal throughput limit and the magnehelic gauge levels for compliance documentation for the small fabric filter systems. The Facility personnel now indicate that the permit modifications have been resolved and the permit revised. The Title V permit is next scheduled to expire in 2008 and should continue to be renewed in the normal course of business.

Because all industrial wastewater from the Facility is sent to the adjoining DuPont Chambers Works for treatment and discharge, no discharge permit is needed for boiler and cooling tower blowdown and wastewaters other than stormwater runoff. Stormwater is directed to five storage basins whose overflows are sampled under requirements of a NJDEP Surface Water Discharge Permit. In addition a Groundwater Protection Permit is required, which is in place.

The status of key permits is summarized in the following table.

Status of Key Permits and Approvals
Carneys Point Facility

Permit	Permit Number	Permit Expiration	Issuing Authority
NJPDES/Discharge to Groundwater	NJ0128996	4/30/09	NJDEP
NJPDES/Discharge to Surface Water	NJ0073750	Administrative Revocation issued on 9/30/03 due to extended compliance on stormwater samples which are reported to no longer be required	NJDEP
Title V Permit Modification Request (May 9, 2003) to increase annual throughput of selected coal conveyors. Plant staff reports issues resolved. Modification Request (Dec 23, 2003) to increase the differential pressure range on selected small source baghouses. Plant staff reports issues resolved.	BOP990001	3/27/08	NJDEP
DPCC/DCR Plan (SPCC Cross reference)	DIFF 171300121000	4/10/2006	NJDEP
RCRA ID No. (Small Quantity Generator)	NJD986625952	N/A	N/A

2.0 OPERATIONS

2.1 HISTORICAL PERFORMANCE

The past several years of operating history for the Facility are summarized in the following table. The data was taken from year-end and year-to-date operating reports for the Facility.

Carney's Point Facility Operating History

Year	Capacity Factor (%)	Overall Availability Factor (%)	Net Generation Sold (MWh)	Overall Heat Rate (Btu/KWh)	Steam Production Sold (Klbs)	Equivalent Forced Outage Rate (%)
2000	63.11	91.94	1,352,211	11,512	2,057,706	4.77
2001	70.03	87.58	1,496,360	11,059	1,740,629	0.55
2002	80.83	95.84	1,726,649	10,844	1,634,912	0.84
2003	80.13	87.26	1,721,728	11,212	1,726,218	7.63
2004	87.27	90.75	1,883,262	11,073	1,838,584	2.27
2005 YTD	90.89	93.67	1,301,783	10,932	1,206,645	2.95

Note: YTD 2005 is January through August

The average availability factor over the five year period 2000-2004 was 90.67%. This compares favorably to the industry average 87.49% for similar size and type plants over the period 1999-2003, based on North American Electric Reliability Council Generating Availability Data System data.

Based on the historical performance, the contractual payment and incentive provisions, and general observations of the Plant and O&M practices, we are of the opinion that the Facility should be capable of achieving the projected annual generation, availability factor, capacity factor, heat rate, steam production, and equivalent forced outage rates assumed in the Projected Operating Results.

2.2 OPERATIONS AND MAINTENANCE

Organization and Staffing

The Facility was previously operated and maintained by National Energy & Gas Transmission ("NEGT"), an entity reorganized from PG&E National Energy Group, under an Operation and Maintenance Agreement originally established between Chambers Cogeneration Limited Partnership (Owner) and PG&E Operating Services Company (Operator) in 1991. On February 1, 2005, the Operations and Maintenance Agreement was transferred from National Energy

Power Company, LLC, Power Services to North American Energy Services (NAES). NAES is responsible for the operation and maintenance of the Facility.

The Facility staff totals an equivalent 55 including 49 full time personnel plus personnel who are shared with the nearby Logan plant (but operated by Cogentrix) and is included in the total count as required. These positions include the O&M staff, as well as management, and administrative staff for the Facility. The staff includes 19 operators, 5 material handlers, 7 maintenance technicians, 2 electricians, 2 I&C technician, and a material specialist. There are 4 shift supervisors and a full time plant engineer, maintenance planner, and accountant. The Facility has a full time General Manager who is responsible for the overall management of the Facility including personnel, safety, public relations, environmental compliance, and plant performance. He is assisted by a full time maintenance manager, engineering manager, and operations manager. Other positions, including several of administrative nature, are filled by shared personnel.

The Facility is operated on four-12 hour shifts with one control room operator, three operators in the plant, and a roving shift supervisor.

O&M Expenses

Non-fuel operating expenses include labor, routine and planned maintenance, consumables, operator and management fees, taxes and insurance, and general operating expenses and are summarized in the following table.

Carney's Point Non-fuel Operating Expenses ($000)

Year	**2001**	**2002**	**2003**	**2004**
Non-fuel operating expense	23,477	17,814	21,419	23,723

The total non-fuel operating expense averages $21,608 over this four-year period. The 2004 forecast forms the basis for the 2005-2025 projections presented later.

Stone & Webster reviewed the actual and budgeted operating and maintenance costs for the years 2003, 2004 and year-to-date August 2005. The following presents a comparison of actual to budget for 2003 and 2004.

Non-Fuel Operating and Maintenance Expenses ($000)							
Year	**2003**			**2004**			**2005**
	Budget	**Actual**		**Budget**	**Actual**		**Budget**
O&M							
Site Labor & Supervision							
Labor		5,335		5,309	5,106		5,610
Labor Related Expenses		158		304	570		316

Non-Fuel Operating and Maintenance Expenses ($000)							
Year	**2003**			**2004**			**2005**
	Budget	**Actual**		**Budget**	**Actual**		**Budget**
Maintenance							
Routine		2,628		1,800	4,405		2,675
Planned		1,454		910	2,215		1,164
Standby Power		1,237		857	1,794		573
Consumables		252		178	187		178
Permitting & Compliance		-		-	-		2
Operator / Manager Fees		3,187		2,590	2,222		2,446
Property Taxes PILOT		1,634		2,000	1,984		2,100
Insurance		991		1,061	1,035		1,090
Professional Services		1,820		1,976	1,951		2,027
Other		2,723		2,666	2,254		2,723
Total Non-Fuel O&M		21,419		19,651	23,723		20,904

The 2004 actual maintenance expenses are approximately $4 million over the budget. This variance is mainly attributed to non-budgeted items for certain maintenance expenses. Routine maintenance was $2,605,000 over budget due to non budgeted items such as the transformer, aux boiler duct, heat trace, roof purlins, flyash exhauster, SCAH safeties, and pumps. The Project was over budget on the overhaul of B hotwell pump, scaffolding, and tie boiler cables. Planned maintenance was $1,306,000 over budget due to non budgeted items such as the FD and ID fan drives, and valve replacement. The Facility was over budget on the SDA vessel repair, valves, air preheater baskets (APH), and removal of soot blowers.

The 2004 actual operating expenses include several major maintenance activities:

- Replacement of generator step-up transformer
- Replacement of turbine controls system
- Overhaul six of eight turbine valves
- Replacement of air preheater baskets
- Replacement of ID fan inlet vanes and coating of impeller
- Refurbishment of SDA vessel
- Installed layer of SCR catalyst

Most of the noted over budget operating expenses, such as the generator start-up transformer, should be non-reoccurring expenses and not expected to continue or will be scheduled in future budgets based on their expected operating life.

The standby power is $937,000 higher than budgeted due to rescheduling of an outage, non budgeted reactive demand charges and higher real time PJM pricing.

While a variance occurred in 2004, Stone & Webster Consultants finds the projected operating budgets to be sufficient to support proper maintenance of the plant and to be used as a basis for the financial projections.

Planned Maintenance

Maintenance is typically done on a preventative basis. The main steam turbine generator was overhauled in 2001 and an 8-year interval is expected to be approximated in the future, based on continuing condition assessments of the turbine. The generator overhaul is based on a 7 year interval. The generator overhaul is decoupled from the turbine overhaul due to limited laydown space. Typically the turbine and generator is fully inspected including NDT and visual inspection, diaphragms and blades are blast cleaned, touched up and repaired as necessary. Seals and bearings are repaired and replaced as necessary. Valves are overhauled on a more frequent basis including stem replacement and seat replacement as necessary. Boiler overhauls have historically been performed annually, which consists of a scheduled two week outage for each boiler on a rotating basis and generally include inspection and such procedures as tube thickness mapping, refractory repairs, etc. There are currently few incidences of boiler tube leaks although the boilers will be acid cleaned within the next two years. Repairs on pumps, water treatment equipment, circulating water system equipment and electrical items such as breakers and motors are done throughout the course of the year on an opportunity basis.

The following table presents the Facility's ten-year outage forecast.

Year	Equipment	Spring Days	Activity	Equipment	Fall Days	Activity
2005	Boiler 1	14	Annual boiler outage			
2006	Boiler 2	21	Annual boiler outage, SCR catalyst addition	Turbine, Generator, Boiler 1	45	Major overhaul, chemical cleaning, SCR catalyst, turbine, overhaul 8 turbine valves, generator overhaul
2007	-			Boiler 2	28	Major overhaul, chemical cleaning, mill overhaul
2008	Turbine, Boiler 1	21	Annual outage, SCR catalyst addition	-	-	
2009	Turbine, Valves, Boiler 2	45	Annual boiler outage, major turbine overhaul, overhaul 8 turbine valves	Boiler 1	14	Annual turbine outage

Year	Equipment	Spring Days	Activity	Equipment	Fall Days	Activity
2010	-	-		Turbine, Boiler 2	14	Annual boiler outage, SCR catalyst addition, turbine work, APH
2011	Boiler 1	14	Annual boiler outage, SCR catalyst addition, APH	-	-	
2012	Turbine, Valves, Boiler 2	14	Annual boiler outage, turbine work, overhaul 8 turbine valves, baghouse overhaul	Boiler 1	14	Annual boiler outage, baghouse overhaul
2013	-	-		Boiler	14	Annual boiler outage, turbine work,
2014	Boiler	14		-	-	

The following table presents the Facility's estimate for certain major maintenance activities.

Year	Turbine Overhaul ($000)	Generator Inspection ($000)	Turbine Valves ($000)	Baghouse ($000)	Boiler Overhaul ($000)	SCR Catalyst Replacement ($000)
2005						250
2006		642	572		1,847	
2007					1,520	
2008						
2009	2,094		643			
2010						1,238
2011						
2012			724	1,539		
2013						
2014						
2015		914	814			
2016						
2017						
2018	2,980		916			
2019					3,075	4,948
2020				2,107		

Year	Turbine Overhaul ($000)	Generator Inspection ($000)	Turbine Valves ($000)	Baghouse ($000)	Boiler Overhaul ($000)	SCR Catalyst Replacement ($000)
2021			1,600			
2022						
2023						
2024						

Stone & Webster Consultants finds that the estimate for the above major activities are sufficient to support the efforts and to be used in the Financial Model.

Current ongoing issues of significance with respect to the operation and maintenance of the Facility include the following:

1. The single feedwater system with no bypass capability complicates valve maintenance. The capital budget for 2005 includes funds for the installation of a bypass system. As of August 2005, the work is 60% complete.
2. The Burner Management System is anticipated to become obsolete within the next five years, which will require the replacement of the entire system. Replacement of the BMS on boiler 1 is planned for 2005. As of August 2005, the work is 75% complete.
3. The effect of plant aging continues to appear in the form of corrosion. Recent inspections have resulted in the need for repairs to the ID fan inlet ductwork, either by coating or plating. The CP Facility has committed to recoat critical vessels and structures that are being aggressively attacked by corrosive agents originating in the cooling tower drift/mist and flue gas path. Repairs are scheduled for 2005-2006. Repairs to boiler 1 are scheduled for 2005.
4. The Facility is expected to operate at high capacity factors. An effect of the high capacity factor has been an increase in the cumulative amount of ammonia that passes through the SCR catalyst and into the APH, resulting in more frequent APH washing. To mitigate this problem, the catalyst requires more frequent change out. A new top layer catalyst was installed in 2004 for Unit 2 SCR, Unit 1 is scheduled for 2005
5. The Facility labor force voted for representation by the International Brotherhood of Electrical Workers (“IBEW”) Union on May 28, 2003 and negotiations over contract terms have continued since. North American Energy Service and IBEW met in August 2005 to continue labor negotiations. The employees have approved a one year union contract with NAES that is reflected in the budget.

Fuel

Coal costs currently represent about 70% of production costs and determine the price competitiveness of Facility into the regional market. The Facility has a 20 year contract from the date of commercial operation with CONSOL. The coal is sourced from mines in West Virginia and from southwestern Pennsylvania and delivered to the site by rail. The coal provided is a medium sulfur bituminous coal with a sulfur content of approximately 2 percent and a heating value of approximately 13,000 Btu/lb. The average sulfur value for August YTD is 1.84%.

Coal pile inventory the beginning of August was 51,805 tons (approximately 27 days of operation at full load) and 41,635 tons (approximately 21 days of operation at full load) the end of the month. There have been seven missed coal deliveries for 2005.

The price paid for coal includes a supply and transportation component. The base price as of January 1, 1990, was $40.25/ton. This base price consisted of a supply price of $27.25/ton and a transportation price of $13/ton. The contract includes quarterly price adjustment provisions based on the net change in prices reported to FERC by twenty five mid-Atlantic utility power plants over a twelve month period ending six months before the quarterly adjustment date. Because the index inherently trails, it lags current market conditions. Consequently, any change in coal prices tends to take at least six months to be realized at the Facility. The Facility coal price is currently significantly below short term or spot market prices. The August YTD cost of coal is $50.49/ton, which compares favorably to the budget of $53.41/ton

At issue with the coal contract is the cost of coal delivered to produce power in excess of the 185 MW under the PSA. CONSOL argues that it should receive the market price instead of the contract price for this increment of coal supply. The spot market price is approximately $20 per ton higher than the current contract price, but plant management believes that if necessary it could enter into a contract for the quantities at approx. $10 per ton more than the current Consol agreement. The partnership strongly believes its interpretation of the contract will prevail in court and has filed suit against CONSOL to enforce its interpretation. The Facility does have a backup for market coal and its operations would not be affected.

Maintenance is typically done on a preventative basis. The main steam turbine generator was overhauled following its first seven years of operation and this interval is expected to be approximated at eight years in the future, based on continuing condition assessments of the turbine. Typically the turbine and generator is fully inspected including non-destructive testing and visual inspection, diaphragms and blades are blast cleaned, touched up, and repaired as necessary. Seals and bearings are repaired and replaced as necessary. Valves are overhauled on a more frequent basis including stem replacement and seat replacement as necessary. Boiler maintenance overhauls have historically been performed annually but beginning in 2004 will be scheduled every 18 months unless required more frequently. This will consist of a scheduled two week outage for each boiler on a rotating basis and generally include inspection and such procedures as tube thickness mapping, refractory repairs, etc. There are currently few incidences of boiler tube leaks although it is likely that the boilers will be acid cleaned within the next two years. Repairs on pumps, water treatment equipment, circulating water system equipment and electrical items such as breakers and motors are done throughout the course of the year on an opportunity basis.

2.3 REGULATORY COMPLIANCE

Emissions source testing is required by NJDEP to confirm compliance with NO_x, CO, SO_x, VOC, NH_3 and PM limits. A source test was conducted on January 19-29, 2004, which demonstrated compliance with permit requirements. In addition tests were run for HF, HCl, PCDF/TCDF, PAH and metals. Levels of these contaminants were found to be acceptable.

Emissions of NO_X, CO, SO_2 and opacity are continuously monitored by the CEMS in accordance with the Operating Permit requirements. Monthly Management Reports for the period from January 2003 through March 2004 indicate that measured emissions are generally in compliance with emissions limits. On October 13 and again on December 28, 2003 NO_X emissions from Unit 2 and then Unit 1 exceeded the three hour average limit by approximately 4%. On January 10, 2004 Unit 1 exceeded the three hour average SO_2 limit. Monthly Management Reports for the period from May through July 2005 indicate that no excess emission event occurred in the year through July 2005.

Intermittent, random exceedances of emission limits are not unusual for coal fired power plants. Periodically enforcement issues are initiated by the responsible, regulatory agency. The following table prepared by the Facility personnel summarizes the active enforcement issues and penalties initiated by NJDEP. No violation notices were received in 2001 and 2002.

Active Emissions Enforcement Issues with NJDEP
Carneys Point Plant

Action	Date of Action	Status	Description
Excess Opacity Emission	June 7, 2005	Affirmative Defense Filed	On June 7, 2005, Unit 2 had an opacity excess emission for 4 minutes greater than 10%. An affirmative defense was submitted based on an equipment malfunction of the outlet poppit valves. There has been no Departmental action to date.
Administrative Order and Assessment of Civil Administrative Penalty	June 28, 2005	Open. Request for Adjudicatory Hearing was filed on July 15, 2005.	Carneys Point received an Administrative Order and Notice of Civil Administrative Penalty Assessment (AONOCAPA) for failure to conduct the initial stack test on Units 1 and 2 within 180 days of the Title V Operating Permit.

The above issues are primarily procedural. The emission issues related to performance are limited, and indicate no pattern of non-compliance amenable to significant upgrade or modification. Although it is likely that the Facility will continue to be assessed modest (<$5000/year) penalties for procedural matters, Stone & Webster Consultants does not consider the intermittent emission excursions over this period indicative of a significant operating concern or emission issue predicating significant equipment upgrade.

The Facility has operated in compliance with ozone season NO_X emission budget programs since 1999. Starting in 1999 it participated in NO_X allowance trading under the Ozone Transport Commission program, and starting May 31, 2004 has been complying with the NJDEP administered NO_x ozone season budget program. Although the Facility has been a modest consumer of allowances, the NJDEP provides excess allowances (available from the Growth

Fund) to cover the excess based on the Facility's compliance with energy efficiency provisions. As a result, there is currently no cost to the Facility for allowance purchases. The following table summarizes ozone season allowance activity for the Facility.

Ozone Season NO_x Emissions and Allocations
Carneys Point 2003-2005

Year	Emissions	Allocation	Growth Fund
2003	582	419	163
2004	731	455	276
2005	~700 (estimated)	545	~155 (estimated)

Under a new NJDEP regulation the Facility will be required to achieve 90% removal of mercury emissions by 2007. Because of the current system design of the emission control system and use of lime spray absorber with a fabric filter system, it appears that the Facility is capable of complying with this requirement. On May 21, 2003 mercury emissions testing on the boilers indicated that the mercury emissions are reduced by approximately 95%. Additional testing is to be performed annually to confirm and document compliance performance. The Facility reports that for the last emission test, mercury was found to be below detection. In 2007 the Facility is required to perform additional mercury compliance testing. Although not currently planned, enhanced future mercury control may involve additional adsorbent injection which is less costly than control measures needed for other plants and coals.

In addition to compliance with currently effective permits and regulations, the Facility may also be subject to future air pollution control requirements for multi-pollutant control and greenhouse gas management as would other facilities. No plans have been developed for future mercury, NOx, SO2, PM and greenhouse gas emission compliance beyond what has been defined by enacted regulations for the Facility. The Facility expects to meet the requirements of future regulations as they are promulgated.

Because the Facility discharges the wastewater to the DuPont Chambers Works POTW, there are no permitted wastewater discharge pollutant limits. The Facility is required to sample the effluent of the stormwater basins. The stormwater, coal pile runoff basins, and the coal pile are lined which protects the groundwater from contaminated leachate. The Facility has no requirements to perform groundwater monitoring and relies on the DuPont Chamber Works groundwater monitoring system.

Bottom ash and fly ash are sampled prior to disposal or delivery to ash purchasers for beneficial reuse to confirm that it is not a hazardous waste and is suitable for its intended use.

Hazardous Waste Activity notifications are required to be filed and ID numbers obtained from US EPA and NJDEP. Annual audits have been performed for toxic material practices at the Facility. Inspection results have indicated general compliance.

The Facility operates with a number of oil and chemical tanks including a 724K gal fuel oil tank, clean and used lube oil tanks (each 8.8K gal), 19.8K gal ammonia tank, and four acid and caustic tanks (2.7K to 15K gal). Under NJDEP Discharge Prevention, Containment and Countermeasure ("DPCC") Rules these tanks are inspected and tested for integrity every five years. A satisfactory inspection was reported in September 2003. The next test is scheduled for 2008.

Fuel oil for the boilers is piped underground from the oil storage tank into the Facility.

A DPCC spill prevention and control plan has been established and revised most recently in November 2003 for the Facility. It includes a spill event summary that indicates that in the period from July 1993 through February 1999, with the exception of one 50 gallon spill of caustic solution in April 1994, all oil and chemical spills were less than 10 gallons. Management Reports in the period from January 2003 through July 2005 indicate no reportable spills at the Facility.

Although early studies (pre-construction) of the site indicated the potential for soil and groundwater contamination, the Facility site is leased from the present owner, DuPont Chambers Works and DuPont provides indemnity for pre-existing conditions in the site lease. Further the Facility is built on a twenty foot mat of clean soil and has a Safe Dig policy protecting workers from hazardous material exposure for minor excavation activities at the Facility.

An Emergency Response Plan was revised in October 2003 and is scheduled to be revised once more in December 2005. The Plan was developed in accordance with applicable requirements associated with the storage and use of hazardous substances at the Facility.

The Facility has no other known environmental compliance issues, and has not received any notices of violation for water, hazardous materials, ash management or other issues. To our knowledge the Facility is not the subject of any private or governmental legal actions, or studies of environmental damage or impact.

3.0 PROJECTED OPERATING RESULTS

Stone & Webster Consultants reviewed the Financial Model which includes estimates and projections of the electrical capacity and electricity sales, steam generation capacity and steam sales, fuel consumption and operating costs for the CP Facility. Stone & Webster Consultants performed the market analysis, which is included in the Financial Model. Presented in Attachment 1 are the Projected Operating Results ("Projections") for each calendar year from 2005 through 2024.

Revenues for CCLP are derived from the sale of electricity energy and capacity under the PPA and PSA with ACE. Additional revenues are realized from the sale of steam and electricity to DuPont under the DuPont Contract. Expenses consist of fuel, non-fuel operating expenses, and debt service. The supply and transportation of coal is the largest fuel-related expense. Coal is provided under a long-term Coal Purchase Agreement with Consol. Epsilon Power Holding receives 40% of the cash available for distributions.

The terms of all the major contracts are through 2024 with the exception of the PSA and the Coal Purchase Agreement. The current PSA has a three-year term which runs through July 2006. The current PSA is similar in form to prior PSA's entered into with ACE. We have assumed a PSA similar to the current PSA will be in place through 2024. The Coal Purchase Agreement has an initial 20 year term (expires in 2014) with an initial extension of between 5 and 10 years. We have assumed that the Coal Purchase Agreement would be extended through 2024. The Projections are based on current contractual commitments through 2024, as described herein and have been prepared using assumptions and considerations set forth in the Report.

Stone & Webster has not reviewed the calculation of interest, principal and fee payments of project debt and confirmation that cash distributions to Epsilon Power Holding are consistent with ownership terms and provisions.

3.1 PERFORMANCE PROJECTIONS

The primary performance parameters are the electrical generating capacity, equivalent availability factor, capacity factor (electric generation), heat rate, and steam sales. In the Projections, the minimum and maximum capacity levels for the Facility are 46 MW and 233 MW for electric generation under the PPA and PSA. An additional 20 MW of capacity is provided to DuPont. Steam sales to DuPont are projected to average 196 klb/hr (approximately 1,700,000 klb/year).

A measure of the reliability of power generation facilities is the equivalent availability factor. This factor includes generation losses from forced outages, planned outages, and derates. The equivalent availability factor for the Facility is projected to vary based on the major maintenance outages. In addition, the forced outage rate is projected to slowly increase over time from 4% to 7%. The average availability over the forecast period is approximately 89%.

In order to develop a forecast of energy sales under the PPA and PSA, the 2003-August 2005 Facility performance and hourly PJM locational marginal prices for the Carney's Point facility were analyzed. Based on the locational marginal prices, the PPA contract on-peak and off-peak prices, the Facility's market initiatives, and the marginal cost for operating the Facility, a

baseline was developed for the energy sold under the PPA and PSA. For the Projections, this baseline was adjusted based on the generation in the Stone & Webster Consultants market forecast for the Facility. The average capacity factor for the Facility, which is a measure of the energy generation, averages 89% over the forecast period. Due to the high natural gas prices relative to coal prices for the forecasted period, the Facility is dispatched during both on and off-peak periods whenever it is available.

While most of the Facility energy is contracted, profitability is significantly affected by PJM energy prices. The PJM energy prices drive both the PPA and PSA dispatch. Further, the PSA revenues are a factor of market price. As part of its 2005 market initiatives, the Facility has established the goal to achieve 268 equivalent MW at least 88% of the time when the dispatch price is greater than $35 per MW and 268 equivalent MW at least 91% of the time when the dispatch price is greater than $50 per MW. The PJM market price has been substantial. The 2005 YTD average peak price is $106.57/MWh, which is significantly greater than the 2005 budget $60.25/MWh. The 2005 operating experience to date has a 90.9% capacity factor, which is consistent with the 89.3% budget capacity factor.

The average heat rate is projected to range between 10,662 Btu/kWh and 10, 890 Btu/kWh at an average capacity factor of approximately 89%. A heat rate degradation of 0.08% per year is assumed to approximate the performance degradation due to normal wear and tear.

3.2 OPERATING REVENUES

Revenues for the Carney's Point Project are derived from electric power and capacity sales to Atlantic City Electric Company ("ACE") and DuPont and steam sales to DuPont. Stone & Webster Consultants performed the market analysis used for the revenue projections. Operating revenues for select years of the Projections are shown in the following table:

Year	Capacity	Energy			Steam	Total
	PPA ($000)	PPA ($000)	PSA ($000)	DuPont ($000)	DuPont ($000)	($000)
Historical						
2001	58,137	23,125	14,448	12,398	6,717	114,825
2002	58,137	27,961	17,896	11,153	5,911	121,058
2003	58,137	31,653	22,676	12,217	7,889	132,572
2004	58,137	36,719	23,820	12,179	8,384	139,239
Projections						
2005	58,137	39,844	32,449	12,159	8,243	150,831
2006	58,137	35,298	29,123	12,280	8,820	143,658
2008	58,137	39,833	32,399	12,562	8,638	151,569
2009	58137	36,275	29,164	12,653	8,515	144,742
2010	58,137	41,412	33,162	12,779	8,728	154,218

Year	Capacity	Energy			Steam	Total
	PPA ($000)	PPA ($000)	PSA ($000)	DuPont ($000)	DuPont ($000)	($000)
2012	58,137	41,158	32,296	13,072	8,854	153,517
2015	58,137	41,541	30,747	13,431	8,841	152,697
2020	58,137	44,709	36,019	14,155	9,940	162,960

The prices for electric capacity and energy and steam sales are tied closely to the price of coal for the Facility. The coal prices have increased in the near term and this has increased the revenues. In addition, with the high gas prices in the region, the energy from the Facility, even with the higher coal prices, is very competitively priced. This has resulted in a substantial increase in generation during the off-peak hours, which has also increased the revenues. Specific terms and conditions for the contracted energy and capacity sales are described below.

Power Purchase Agreement

The Carney's Point Project has a Power Purchase Agreement ("PPA") with Atlantic City Electric Company ("ACE"). The PPA has a term of 30 years from the Commercial Operation Date. Commercial Operation was achieved in March 1994.

The PPA is for the sale of electric power and capacity from the Facility. The capacity obligation is 187.6 MW for the summer season and 173.2 MW for the winter season. Capacity payments are based on 184 MW. ACE makes a monthly payment for capacity based on 184 MW, a capacity price of $26.33/kW-month, and an availability adjustment factor. Stone & Webster Consultants reviewed the actual capacity charges reported for 2000 through August 2005. The capacity charge in each year (2000–2004) was $58.137 million (184 MW x 12 months x $26.33/kW-month). Through August the capacity payment has been $38,758 (184 MW x 8 x $26.33/kW-month).

ACE's energy purchase obligation is to purchase up to the net Facility output on a dispatchable basis. ACE can dispatch the Facility from a minimum load of 46 MW to the net Facility output. In consideration for the ability to dispatch the Facility, ACE has an obligation to pay for a minimum quantity of power. The minimum energy payment is based on 3,500 hours of operation at 182.2 MW multiplied by the energy price. A minimum of 58% of the operating hours are to be during on-peak periods. On-peak periods are defined as being from 9 AM to 11 PM, seven days per week. All other hours are off-peak hours. Under the PPA, if the Project is paid for power during periods it did not produce power, then the payments from ACE for these periods will be net of the fuel and variable operating costs.

The energy price under the PPA is separated into an on-peak and off-peak price. Both prices are based on a formula that includes a fixed and variable price. The variable price is adjusted annually by an index equal to the annual average coal cost to New Jersey utilities as reported on FERC Form 423. There is only one plant that is currently reporting under the index. Discussions are ongoing over a newly proposed index for 2006, similar to that of the Consol 25 plant index. The August Monthly Operating report indicates that the 423 Index increased the

indexed portion of the variable energy by 25% and has been confirmed but the 2006 period is still uncertain. The Financial Model did not assume the 25% run-up, instead the model incorporates a 15% increase from 2004 based on the mid-Atlantic index.
The recent on-peak and off-peak pricing is shown below:

Year	Index	On-Peak Price ($/MWh)			Off-Peak Price ($/MWh)		
		Fixed Price	Var. Price	Total Price	Fixed Price	Var. Price	Total Price
2000	81%	21.42	14.76	36.18	14.71	10.15	24.86
2001	78%	21.42	14.22	35.64	14.71	9.78	24.49
2002	85%	21.42	15.38	36.80	14.71	10.61	25.32
2003	112%	21.42	20.33	41.75	14.71	13.97	28.68
2004	103%	21.42	18.70	40.12	14.71	12.85	27.56
2005	115%	21.42	21.51	42.92	14.71	14.78	29.49

The CCLP is required to demonstrate annually that it can meet the summer and winter capacity requirements under the PPA. If the Project cannot meet at least 95% of the summer or winter capacity, then it must pay ACE the current PJM Capacity Deficiency Charge for each kW below 95% of the capacity requirements.

The CCLP must maintain Qualifying Facility ("QF") Status. If the Facility loses QF Status, the PPA remains in effect except that the payments to the Project are the lower of the contract price (capacity price plus energy price) and 99% of the hourly locational marginal price.

In the PPA, ACE acknowledges that the CCLP will provide electric energy and capacity to DuPont that is not part of the summer and winter capacity obligation to ACE. ACE further acknowledges that during periods when ACE dispatches the Facility below the summer and winter capacity, then the Project can sell the excess capacity and energy to DuPont.

Power Sales Agreement

The PSA between ACE and CCLP governs CCLP's sale of Excess Energy and Undispatched Energy and Excess Capacity from the Facility. The current PSA has a term from August 1, 2003 through July 31, 2006.

Excess Energy is defined as energy generated by the Facility when it operates above 187.6 MW during the summer and 173.2 MW during the winter. Undispatched Energy is the energy generated by the Facility above the amount dispatched by ACE but less than the summer and winter capacity levels of 187.6 MW and 173.2 MW. Excess Capacity is the capacity of the Facility, as tested, in excess of the summer and winter capacity levels of 187.6 MW and 173.2 MW.

The energy prices for Excess and Undispatched Energy is based on a threshold price of $21/MWh with an adder based on either the day-ahead or real-time locational marginal price at the Chambers CCLP 230 kV bus ("LMP"). For Excess Energy, the energy price adder is the 75% of the difference between the LMP and $21/MWh. For Undispatched Energy, the energy price adder is 60% of the difference between the LMP and $21/MWh. When the LMP is below $21/MWh, the price paid is the LMP. CCLP is to pay ACE a fixed annual administration fee of $125,000. ACE also has title to all Excess Capacity from the Facility at no additional charge. The CP Facility reports that in renewing the PSA, it will be negotiating for an increase in the threshold price due to facility cost increases.

Stone & Webster Consultants has assumed that the PSA will be extended with similar conditions for the remainder of the Projections. The price projected for on-peak and off-peak Undispatched Power in 2005 is $33.21/MWh and $26.49/MWh, respectively. This price was determined based on the 2005 average contract price and cost of fuel when Undispatched Power was likely sold. The Undispatched Power prices are assumed to vary from year to year based on the change in the all hours market price forecasted for the Facility.

The price received for Excess Power is assumed to be the all-hours average market price forecasted for the Facility.

Steam and Electricity Purchase Contract

The Project has a Steam and Electricity Purchase Contract with DuPont ("DuPont Contract"). DuPont operates a chemical facility in Deepwater, New Jersey known as the Chambers Works. The Chambers Works uses a substantial quantity of steam and electricity. The term of the DuPont Contract is 30 years from the initial reliable delivery of steam and electricity. Associated with the DuPont Contract is a Ground Lease for the Project site. The Project site is owned by DuPont and leased to the Project.

Under the DuPont Contract, the Project provides DuPont with all the steam and electricity required for the operation of the Chambers Works up to the maximum contract quantities. The maximum contract quantities or Peak Requirements for steam and electricity are as follows:

- 650,000 lb/hr of steam during the months of June through September
- 700,000 lb/hr of steam during the months of May and October
- 1,000,000 lb/hr of steam during the remainder of the year
- 40,000 kW of electricity

The Project may sell steam and electricity to DuPont in excess of the Peak Requirements but is not obligated to do so. DuPont must purchase a minimum quantity of steam from the Project to insure that the Project meets its QF requirements under the PPA. This minimum obligation, as defined in the DuPont Contract, is 525.6 million lb of steam per year.

The price for steam was originally set at $3.75 per 1,000 lb of steam. The steam price is adjusted quarterly based on the change in the Project's coal price. The steam price in April 2004 was $4.49 per 1,000 lb steam. The price for electricity sold to DuPont is the lower of 1)

$67.45/MWh adjusted quarterly by the change in the Project's coal price and 2) $64.5/MWh adjusted quarterly by the changes in the ACE average retail rate.

At the end of the 20th year, DuPont may elect to construct and operate its own steam generation facility to provide the steam requirements for the Chambers Works in excess of the minimum obligation to the Project. The ability of DuPont to develop its own steam generation facility is dependent on DuPont being able to demonstrate that it can provide steam more economically than the Project. The Project then has an option to provide the steam at an equivalent price as the steam generation facility proposed by DuPont.

Under the DuPont Contract, the Project agrees that steam sales to DuPont take priority over any obligation to provide electricity or sell steam to a third party. The Project will not sell steam from the Facility to a third party without the DuPont's prior consent.

3.3 OPERATING EXPENSES

The projected annual operating expenses consist of fuel, non-fuel operating expenses, and other operating expenses. The recent historical values and projections during select years for the operating expenses are shown as follows:

Operating Expenses ($000)

Year	Fuel	Non-Fuel O&M	Fees	Total
Historical				
2001	32,567	20,312	3,165	56,044
2002	39,284	14,485	3,329	57,098
2003	41,900	18,232	3,187	63,319
2004	48,449	21,501	2,222	72,172
Projections				
2005	50,303	19,218	2,342	71,863
2006	45,881	22,646	2,381	70,908
2008	51,799	20,311	2,460	74,570
2009	49,284	24,216	2,501	76,001
2010	55,560	23,209	2,348	81,118
2012	57,073	25,473	2,432	84,978
2015	60,352	27,803	2,592	90,747
2020	67,563	31,253	2,910	101,726

The major operating expense is fuel. CCLP has contracted with Consol for the supply and transportation of coal for the Facility. The fuel expenses also include certain other cost items such as the purchase of limestone for the dry scrubber, the purchase of ammonia for the SCR, ash disposal costs, and the purchase of emission allowances (if needed).

Coal Purchase Agreement and Prices

Coal is purchased through a contract with Consol. The contract has an initial term of 20 years with options for an extension option for between 5 and 10 years. The coal is sourced from mines in West Virginia and from southwestern Pennsylvania and delivered to the site by rail. The coal provided is a medium sulfur bituminous coal with a sulfur content of approximately 2 percent and a heating value of approximately 13,000 Btu/lb. Stone & Webster Consultants has assumed that the Coal Purchase Agreement will be extended through 2024.

The price paid for coal includes a supply and transportation component. The base price as of January 1, 1990, was $40.25/ton. This base price consisted of a supply price of $27.25/ton and a transportation price of $13/ton. The August YTD cost of coal is $50.49/ton, which compares favorably with the budget of $53.41/ton. The price is adjusted quarterly based on an Eastern Utility Coal Index. The Eastern Coal Utility Index is the weighted average price of coal delivered to a defined group of coal-fired power plants in the Eastern U.S. over a twelve month period ending six months before the quarterly adjustment date. Consequently, any change in coal prices tends to take at least six months to be realized at the Facility.

Eastern bituminous coal prices have recently risen dramatically from around $30/ton to over $50/ton at the mine. This increase is expected to be a short-term increase and the price is forecasted to fall back down to the previous levels. A review of the coal prices for some of the reference plants in the Eastern Coal Index showed that a substantial amount of coal was being purchased under multiple year contracts. Thus, short-term spikes in the coal prices will not pass completely through to the Eastern Coal Index. For modeling the commodity portion of the delivered contract coal price, Stone & Webster Consultants used the Facility's actual commodity cost of $30/ton for coal delivered in 2004 as a starting point for the forecast. We escalated this value annually by the product of 1) the real escalation for Central Appalachian coal (medium sulfur) as reported in the EIA 2005 Annual Energy Outlook (Table 112, and 2) an inflation factor assumption of 2.5% per year. The final result was a coal commodity pricing assumption that reflected the existing coal commodity agreement's structure, with escalation that is reflective of detailed market forecasting.

The coal requirements for the Facility is based on the projected generation and an average heat rate of 10,770 Btu/kWh, that is between 10,662 Btu/kWh and 10,890 Btu/kWh, depending on the level of electrical generation (more generation results in a lower heat rate) and time-related degradation.

3.4 DEBT SERVICE

The existing debt, all of which is non-recourse to the Project Owners, consists of a term loan and tax-exempt bonds. The term loan is split into four tranches. The outstanding balance as of January 1, 2005 and principal repayment period for each tranche is provided below:

- Tranche 1 – Current balance of $29.146 million. Principal repayments are complete by the 2nd quarter of 2006.
- Tranche 2 – Current balance of $62.555 million. Principal repayments begin in 3rd quarter of 2006 and are complete by the 2nd quarter of 2009.

- Tranche 3 – Current balance of $53.659 million. Principal repayments begin in 3rd quarter of 2009 and are complete by the 2nd quarter of 2011.
- Tranche 4 – Current balance of $73.494 million. Principal repayments begin in 3rd quarter of 2011 and are complete by the 1st quarter of 2014.

The outstanding balance on the tax-exempt bonds is $100 million. The tax-exempt bonds are repaid in 2022.

Besides the interest and principal payments on the term loan and the tax-exempt bonds, there are also fees incurred for letters of credit to support the credit rating of the tax-exempt bonds and to provide a debt service reserve fund. In addition, there is a working capital facility fee.

In addition to the project level debt, Epsilon Power Partners, LLC the wholly owned subsidiary of Atlantic Power Holdings, LLC which owns a 40% partnership interest in CCLP, has an outstanding $43.3MM non-recourse loan balance as of the Atlantic acquisition date. Principal on this loan amortizes through 2019. The loan interest rate floats at LIBOR plus a 312.5 bps spread.

3.5 DISTRIBUTIONS TO COMPANY

Cash available for distribution, before income taxes, is equal to the operating income less debt service payments and certain adjustment. Epsilon Power Holding's distributions are equal to 40% of the cash available for distribution.

3.6 POWER MARKET ANALYSIS

The Chambers facility is located within the PJM Interconnection ("PJM") market area. PJM is a Regional Transmission Organization ("RTO") that coordinates the dispatch, operation, and delivery of wholesale electricity in all or parts of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia. PJM administers bid-based markets in which participants buy and sell spot market energy, capacity credits, fixed transmission rights, spinning reserves and regulation services. PJM administers real-time and day ahead energy markets and daily and monthly capacity credit markets. Real-time markets are liquid and bid-based, spot energy and capacity markets. Generator bids set the hourly market-clearing price for electric energy. The market for capacity is also established through a bid based system where generation owners bid capacity prices into a central market just as in the energy market.

The PJM market is a summer peaking system with a peak demand of approximately 57,700 MW in 2005, and currently maintains installed capacity in the amount of 68,300 MW, net of purchase and sales. PJM's peak demand is projected to grow at a rate of approximately 1,100 MW per year over the next several years. Based on PJM planning studies, there is approximately 5,000 MW of generation planned to enter commercial operation between 2005 and 2008. This includes mostly peaking resources. However, even if all of this planned generation were to reach commercial operation, the system is still projected to be in need of additional capacity by 2010, when its reserve margin falls below 15%.

Stone & Webster Consultants modeled the PJM control area and seven other, interconnected neighboring control areas. For this analysis Stone & Webster Consultants used PROSYM, an energy market simulation model. PROSYM is specifically designed to simulate operator bidding strategies and dispatch in bid-based energy markets, and provides results that are relevant for assessing generator dispatch, environmental performance, transmission line flows, and other useful parameters for this assessment. We modeled the operation of the system, and included first combustion turbines, and then a mix of combined cycles and coal resources for the expansion plan over the 20-year study period. This analysis provided the projected plant dispatch and operation information and the time differentiated energy market clearing prices data used for modeling spot energy sales to the PJM market. ACE is allocated all of the Facility's installed capacity (ICAP), therefore, no capacity is available to be sold in the wholesale market. Based on this, no ICAP revenue was modeled for the Facility. The following table represents the results of our analysis.

Market Analysis Summary Table

2005$

PJM East Transmission Area			
	Peak	**Off-Peak**	**Average**
	($/MWh)	**($/MWh)**	**($/MWh)**
2005	100.57	45.05	71.48
2006	102.27	48.14	73.90
2007	93.74	49.96	70.80
2008	93.73	48.67	70.12
2009	87.61	48.28	67.00
2010	87.91	48.59	67.30
2011	79.65	47.61	62.86
2012	78.66	47.31	62.23
2013	74.86	45.73	59.60
2014	72.27	43.15	57.01
2015	67.80	39.66	53.05
2016	66.80	39.67	52.58
2017	67.75	39.93	53.17
2018	70.20	42.55	55.71
2019	72.19	44.98	57.94
2020	72.61	45.73	58.53
2021	73.28	47.63	59.84
2022	73.31	49.28	60.72
2023	74.31	49.36	61.24
2024	73.31	50.69	61.46
2025	72.71	51.01	61.34

4.0 CONCLUSIONS

Set forth below are the principal findings and conclusions which Stone & Webster Consultants has reached regarding the Carney's Point Facility and CCLP. For a complete understanding of the estimates, assumptions, and calculations upon which these findings are based, this Report should be read in its entirety. Based on our analysis and review the Carney's Point Facility and the principal project agreements and the assumptions set forth in this Report, we are of the opinion that:

- The Facility uses proven and appropriate technology to generate electricity and steam for sale.
- The Facility has been operated successfully for 11 years during which it has met the obligations under the principal project agreement.
- Given the well maintained condition of the Facility and the continued application of continuous operation and maintenance combined with an appropriate level of capital expenditure as the Facility ages, the remaining useful life of the Facility is expected to exceed the term of the PPA.
- The Facility operates at a minimum output of 46 MW and a maximum output of 270 MW. For purposes of electric energy sales to ACE under the PPA and PSA, a maximum output of 233 MW is assumed, along with 196 klb/hr of steam sales and about 20 MW of electricity sales to DuPont.
- The Facility has operated reliably with low forced outage rates and high availability rates. The availability in the near term is projected to be approximately 88% due to the upcoming major maintenance outages in 2006 and 2009. The average availability over the projected period is approximately 89%
- The Facility is projected to operate with an average capacity factor of approximately 89% Due to the market conditions, the facility has recently been operating at approximately 91% capacity factor. Provided the economics justify it, there is no technical reason that the Facility cannot meet this level of electrical production in the future.
- The average heat rate realized by the Facility is projected to be between 10,662 Btu/kWh to 10,890 Btu/kWh depending on the level of dispatch (i.e., capacity factor) and degradation of performance through normal wear and tear. This heat rate is not directly comparable to natural gas plant heat rates as it measures efficiency on a MMBtu/MWh basis, and the per MMBtu cost of fuel must also be considered when determining the all-in variable fuel cost. Currently, the project benefits from high natural gas prices relative to coal prices, making the project competitive on a variable cost basis vs. most gas fired plants in PJM.
- The Facility has been in compliance with its environmental permits with only intermittent emission excursions and minor violations, all of which have been addressed.
- The Facility is equipped with a dry scrubber for SO_2 control, low NO_X burners and SCR for NO_X control, and a baghouse for particulate control. The air pollution control technology employed has been effective and is compliant with all the permits required to operate the Facility. With the exception of the potential addition of sorbent injection for mercury control, which could potentially be required in the future if new mercury regulations are imposed on the Facility, no additional emissions control equipment is expected to be required during the term of the Projections.

- The Projections are a reasonable forecast of the financial results for CCLP under the base case assumptions.
- For most of the forecast period, the capacity payment under the PPA with ACE covers in excess of 100% of the fixed operating costs (exclusive of debt service) for the Facility. Overall, the projected revenues from the sale of capacity and energy, as well as steam, are more than adequate to pay the fuel-related expenses, annual operating and maintenance expenses, major maintenance expenses, other operating expenses and fees, and debt service, based on Stone & Webster Consultants' analysis of the Facility and the assumptions set forth in this Report.

ATTACHMENT 1

FINANCIAL PROJECTIONS

Carneys Point

Cash Flow Summary
($ thousands)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES																				
Contract Capacity Revenues	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	58,137	9,689
Contract Energy Revenues	52,003	47,578	52,531	52,394	48,927	54,191	55,779	54,229	56,036	56,243	54,972	57,505	57,717	53,622	53,992	58,864	60,517	59,318	62,470	10,686
Merchant Capacity Revenues	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Merchant Energy Revenues	32,449	29,123	32,612	32,399	29,164	33,162	33,100	32,296	33,208	32,772	30,747	32,495	33,043	30,999	31,980	36,019	37,921	37,608	40,089	6,446
Steam Revenues	8,243	8,820	8,820	8,638	8,515	8,728	8,946	8,854	8,715	8,779	8,841	9,005	9,205	9,436	9,671	9,940	10,253	10,603	10,868	1,857
Other Revenues/ Residual Value	177	177	177	177	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	73,423
Total Revenues	**151,008**	**143,834**	**152,276**	**151,745**	**144,742**	**154,218**	**155,961**	**153,516**	**156,095**	**155,931**	**152,697**	**157,142**	**158,103**	**152,194**	**153,780**	**162,960**	**166,827**	**165,666**	**171,563**	**102,101**
EXPENSES																				
Fuel	50,303	45,881	50,893	51,799	49,284	55,560	57,818	57,073	60,005	61,013	60,352	63,770	64,587	60,675	61,564	67,563	70,132	69,394	73,911	12,267
Operating Expenses	17,739	21,094	20,020	18,607	22,430	21,340	22,453	23,428	22,628	22,455	25,471	23,459	25,500	32,652	32,940	28,370	27,738	29,324	28,656	10,289
G&A	3,820	3,933	4,047	4,164	4,286	4,217	4,345	4,477	4,615	4,767	4,925	5,087	5,255	5,428	5,607	5,792	5,983	6,181	6,385	1,099
Total Expenses	**71,863**	**70,908**	**74,959**	**74,570**	**76,001**	**81,118**	**84,615**	**84,979**	**87,249**	**88,236**	**90,747**	**92,316**	**95,341**	**98,755**	**100,111**	**101,726**	**103,853**	**104,900**	**108,952**	**23,655**
OPERATING INCOME	**79,145**	**72,926**	**77,317**	**77,176**	**68,742**	**73,100**	**71,346**	**68,537**	**68,846**	**67,695**	**61,950**	**64,826**	**62,762**	**53,439**	**53,669**	**61,234**	**62,974**	**60,766**	**62,611**	**78,446**
PROJECT DEBT SERVICE																				
Fees	2,273	2,273	2,273	2,278	2,431	2,431	2,431	2,596	2,590	2,590	2,590	2,596	2,340	2,079	1,807	1,524	1,224	25	-	-
Interest Payments	18,967	17,591	16,107	14,580	13,089	11,106	8,907	6,643	4,271	2,778	2,738	2,609	2,262	1,900	1,521	1,124	710	56	0	0
Principal Amortization	19,196	19,899	19,963	20,729	23,827	27,628	28,235	30,439	26,957	1,980	0	12,470	13,031	13,618	14,231	14,871	15,540	16,239	0	0
Total Debt Service	**40,436**	**39,763**	**38,343**	**37,587**	**39,347**	**41,166**	**39,573**	**39,678**	**33,818**	**7,348**	**5,328**	**17,675**	**17,634**	**17,597**	**17,558**	**17,520**	**17,474**	**16,320**	**0**	**0**
Adjustments[1]	(2,199)	1,577	(275)	(1,214)	1,091	(905)	495	809	(432)	(762)	1,814	(3,316)	(4,456)	2,283	4,203	397	481	316	199	9,451
CASH AVAILABLE FOR DISTRIBUTION	**36,510**	**34,740**	**38,699**	**38,375**	**30,486**	**31,030**	**32,268**	**29,669**	**34,597**	**59,586**	**58,436**	**43,835**	**40,671**	**38,125**	**40,314**	**44,111**	**45,980**	**44,762**	**62,810**	**87,897**
EPSILON AVAILABLE CASH FLOW ($000)[2]	**4,521**	**13,896**	**15,480**	**15,350**	**12,194**	**12,412**	**12,907**	**11,867**	**13,839**	**23,834**	**23,375**	**17,534**	**16,269**	**15,250**	**16,126**	**17,644**	**18,392**	**17,905**	**25,124**	**35,159**
EPSILON DEBT SERVICE[2]																				
Interest Payments	991	3,279	3,366	3,259	3,151	3,070	2,989	2,867	2,745	2,501	2,095	1,607	1,120	612	88	-	-	-	-	-
Principal Amortization	331	1,569	1,325	1,325	1,000	1,000	1,500	1,500	3,000	5,000	6,000	6,000	6,250	6,450	1,082	-	-	-	-	-
Total Debt Service	**1,322**	**4,848**	**4,691**	**4,584**	**4,151**	**4,070**	**4,489**	**4,367**	**5,745**	**7,501**	**8,095**	**7,607**	**7,370**	**7,062**	**1,170**	-	-	-	-	-
CASH AVAILABLE TO ATLANTIC POWER HOLDINGS[2]	3,199	9,048	10,788	10,766	8,043	8,342	8,419	7,501	8,094	16,333	15,280	9,927	8,899	8,188	14,955	17,644	18,392	17,905	25,124	35,159

(1) Majority of Adjustments are Net Withdraws (Deposits) into the Major Maintenance Reserve

(2) 2005 reflects partial year data for Atlantic's ownership period beginning in September 2005.