Conversion to Dual Fuel Capability in Combustion Turbine Plants

Addition of Distillate Oil Firing for Combined Cycles

Technical Report

Conversion to Dual Fuel Capability in Combustion Turbine Plants

Addition of Distillate Oil Firing for Combined Cycles

1004599

Interim Report, September 2001

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Powerhouse Engineering Ltd.

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CITATIONS

This report was prepared by

Powerhouse Engineering Ltd.
802 North Harvard Avenue
Arlington Heights, Illinois 60004

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This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Conversion to Dual Fuel Capability in Combustion Turbine Plants: Addition of Distillate Oil Firing for Combined Cycles, EPRI, Palo Alto, CA: 2001. 1004599.

REPORT SUMMARY

During development of combined cycle projects, key assumptions and estimates regarding markets and technology on which the project is based may change. With fuel costs of combined cycle plants representing over 90% of annual operating cost, sudden changes in fuel pricing demand attention and reevaluation. Conversion from natural gas fuel only to dual fuel capability with the addition of distillate oil firing systems is a technical response to market conditions that may have long-term as well as short-term benefits.

Background

For many reasons, the predominant fuel of choice for combined cycle cogeneration plants has been natural gas. However, during the fall and winter of 2000-2001, natural gas prices surpassed those of alternate fuels, such as distillate oil. This price differential led to significant interest in converting single fuel plants to dual fuel plants, especially in the case of plants under development, which stand to gain the most when gas prices are higher than distillate prices. This report is a direct response to fuel market conditions in late 2000 when seasonal shortages drove gas prices up significantly. The issue of converting from single fuel to dual fuel is complex, however, and cannot be evaluated based on short-term market conditions alone. With market volatility increasing, deregulated markets emerging, and the importance of having uninterrupted generation rising with increased prospects for interruption of natural gas supplies during seasonal periods, a systematic evaluation of dual fuel conversion is appropriate.

Objectives

To determine the key factors impacting the decision of whether to convert natural gas fired combined cycle plants to dual fuel operation; to discuss the technological and physical feasibility of performing a dual fuel conversion; to quantify the capital costs for a dual fuel conversion and to present an objective means of economic evaluation for dual fuel conversion based on life cycle cost considerations.

Approach

The project team conducted extensive research into the present energy market to gather detailed information on electricity pricing, fuel price history, short-term and long-term outlooks, and the reasons behind recent market actions. The team examined what is technologically feasible in converting a combined cycle plant to dual fuel use, taking into account the conversion process, difficulties and limitations, and project development timing. The team performed a detailed, quantitative analysis of the economic aspects of dual fuel conversion and demonstrated how information from many perspectives must be integrated to conduct a well-justified project-specific evaluation.

Results

Historical research shows that natural gas has usually been less expensive than distillate fuel. This pricing advantage, along with air permit restrictions favoring gas firing, has justified the dominant use of gas. Typically, dual fuel capability has been justified on the basis of interruptible gas supplies and an obligation to generate power during periods of interruption.

The conversion to dual fuel is not difficult to accomplish, unless the decision is made after construction has begun or after plant start up when the level of complexity and associated cost to convert is much greater. Several components of major equipment require modification in order to convert to dual fuel. Several new balance of plant (BOP) systems must be designed and installed. Physical area requirements for the plant increase due to the additional systems.

The minimum fuel pricing differential between gas and distillate needed to justify a minimal distillate operating regime of 92% gas firing and 8% distillate firing was found highly unlikely to occur over a long duration. For a plant operating on gas 50% of the time and distillate 50% of the time, the fuel pricing differential was more feasible. Potentially high electricity prices during periods of gas interruption are the most likely economic reason to convert to dual fuel capability. Long-term fuel pricing expectations still favor natural gas as the least expensive fuel; but short-term offsets of this condition may be enough to justify conversion, especially for the plant that must provide little or no interruption to generation capability.

EPRI Perspective

This report consolidates information on capital costs and O&M costs in a case study format to provide an incremental evaluation of the costs to convert a natural gas fired combined cycle plant to dual fuel capability with the addition of distillate oil firing systems. Long-term fuel price forecasts generally indicate that natural gas will be the preferred fuel of choice wherever and whenever it is readily available. However, dual fuel firing capability provides the option to fire distillate oil at sites in which natural gas could become unavailable on a seasonal basis and may be justified where the differential price between firm and interruptible contracts is significant.

Keywords

Combustion turbine
Combined cycle
Technology risk
Dual fuel technology
Business interruption
Distillate oil

ABSTRACT

This report presents the issues involved in converting a single fuel (natural gas fired) combined cycle plant, assumed to be under development, to dual fuel (adding distillate oil firing). The impetus for this evaluation came from the sudden and dramatic rise in natural gas prices in the fall and winter of 2000-2001 when many dual fuel capable plants began to fire distillate instead of gas for economic reasons. Changes in the energy market now warrant a thorough analysis of whether dual fuel conversion is a sound decision, even for projects already under development. This report provides background history, recent changes to the market, discussion of dual fuel conversion modifications, capital cost estimates, a complete case study analysis, discussion and quantification of operating and maintenance impacts, discussion of underground gas storage options, and a reference list for further study. EPRI's SOAPP-CT (State-of-the-Art Power Plant-Combustion Turbine Combined-Cycle) WorkStation Software and CT Project Risk Analyzer software packages were utilized in the preparation of this report.

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1 INTRODUCTION

Overview

Due to the volatility of fuel costs for combined cycle and cogeneration power plants, and volatility in electricity price in a deregulated marketplace, configuration and process changes can become economical during project development and after initial operation. A current design consideration is fuel selection for combustion turbine operation and supplemental firing of heat recovery steam generators (HRSGs). Historically, low prices for natural gas have made gas the primary fuel of choice economically, not to mention its superior emissions characteristics. However, in early 2001, distillate oil fuel became competitive in price with natural gas due to dramatically increased natural gas prices. See figure below:

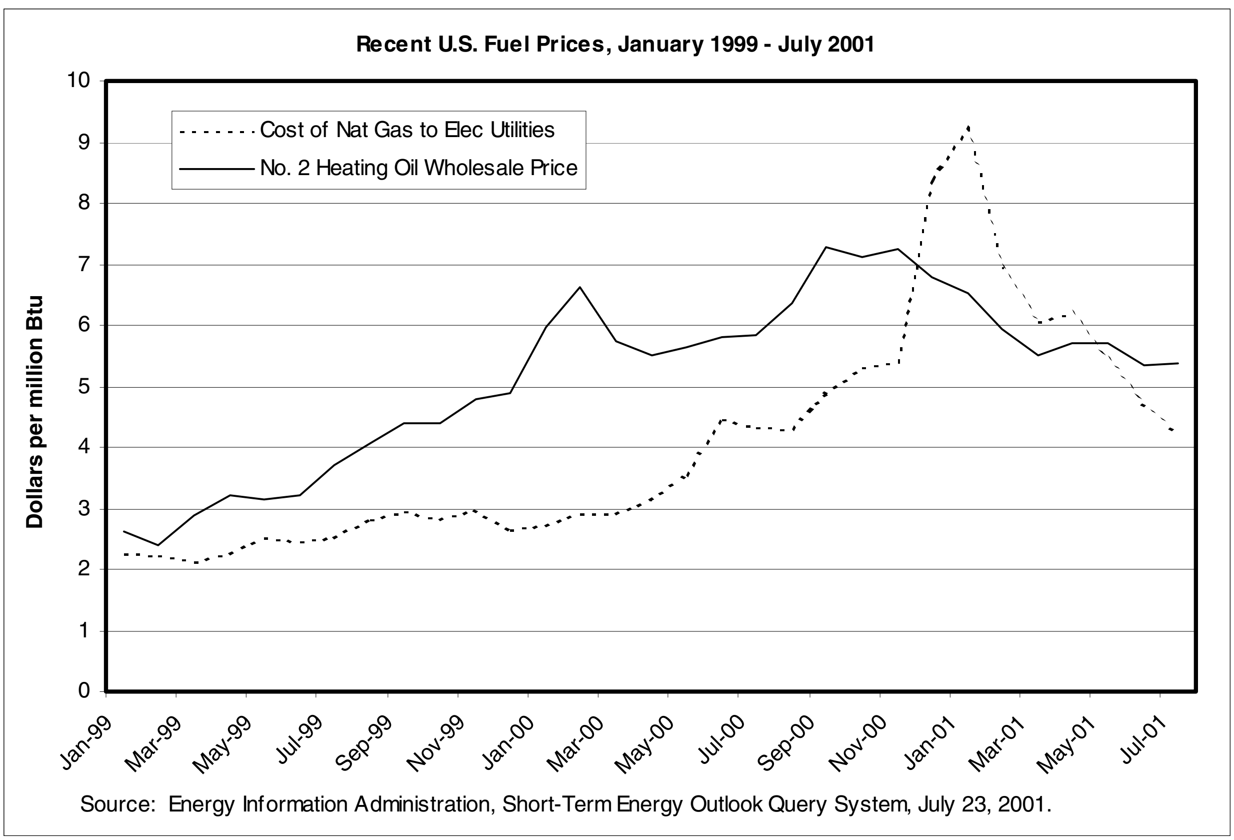


Figure 1-1
Recent U.S. Fuel Prices, January 1999 - July 2001

There are many factors which impact whether or not a power plant developer should consider dual fuel firing, the ability to switch between two different fuel types, other than purely fuel cost reasons. The level of carbon monoxide and nitrous oxide (NOx) emissions is different, and requires specific permitting. The level of operating and maintenance (O&M) will be considerably different. Additional acreage will be required for distillate oil tanks, treatment systems, and forwarding pumps. Combustion turbine life expectancy and degradation will be impacted. These and other concerns must all be evaluated prior to committing to a large capital investment for converting a plant to dual fuel firing. However, many plants have distillate oil firing capability, most often because of the possibility of the interruption of the natural gas fuel supply. Before describing the specific issues relevant to dual fuel conversion, it will be helpful to briefly review the traditional combined cycle plant design environment.

Traditional Primary Fuel Selection

Natural gas has long been the primary fuel of choice for technologically advanced combined cycle power plants. For one, the delivery system is convenient -- natural gas can be safely and economically delivered directly to the plant site via underground pipe line. Delivery is continuous, and does not require "batch" delivery, such as is normally required for distillate oil delivery via truck. Secondly, natural gas is a favorable fuel choice due to its clean burning properties. NO_x, CO, CO_2, and sulfur emissions are each lower with gas than with distillate oil firing. In today's age of competitive emissions strategies, burning low emission fuel is extremely advantageous. O&M costs favor natural gas fired plants for a number of reasons: lack of distillate oil tank maintenance, reduced pump maintenance for fuel forwarding, smaller demineralized water treatment systems, and reduced combustor and turbine blade maintenance. Details of O&M cost differences are discussed later in this report.

Historical Fuel Pricing

Historical pricing, as can be seen in the following figure, has long favored natural gas on a dollar per Btu basis:

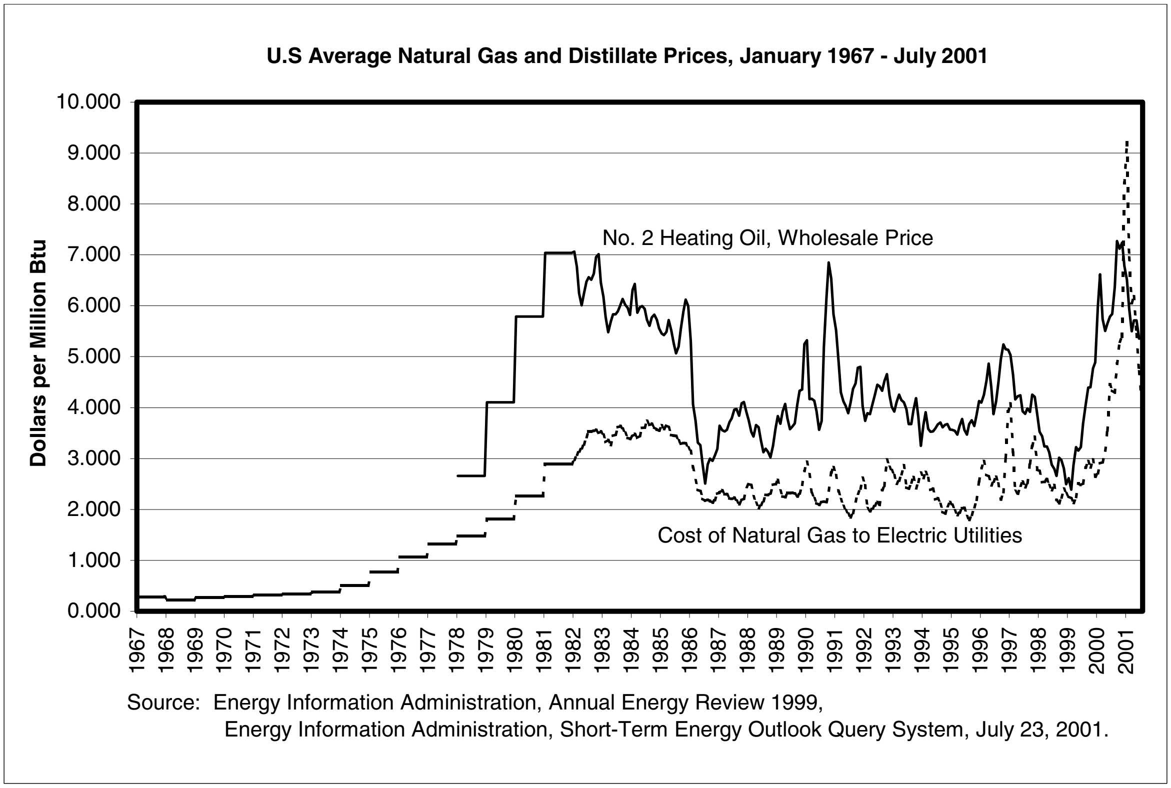


Figure 1-2
U.S. Average Natural Gas and Distillate Prices, January 1967 - July 2001

Because of this historical trend, there has not been a true economic reason to justify firing distillate instead of natural gas, if both were available for consumption. In fact, the low cost of natural gas has led to the economic justification for many projects for natural gas only firing; keeping capital and operating costs low.

Traditional Purpose for Secondary Fuel

Large consumers of natural gas, such as electricity generators, often have fuel-switching or dual-fuel capabilities and can receive natural gas through a lower priority, less expensive service, known as interruptible service. The traditional purpose of maintaining a secondary fuel alternative is to provide a viable fuel supply during gas supply curtailment periods. Interruptible service contracts have become part of standard business practices for many large-volume energy users. Until recently, electricity generators using natural gas as their primary fuel have been reluctant to commit to firm contracts because of high cost. With reliable lower cost gas available, the incentive has been to contract for interruptible service.

Power generators with interruptible service utilize dual-fuel facilities to burn the alternative fuel if it is critical that operations continue even during a natural gas curtailment period. While the cost of installing dual-fuel capable equipment is higher than for single-fuel only equipment, the paybacks have traditionally occurred over the life of the plant, as the plant owner carefully manages costs by the appropriate usage of fuels. Another benefit that companies with dual-fuel burning capability have is the possibility to contract for a more favorable interruptible tariff for natural gas. Dual-fuel capable facilities will, in nearly every case, have the capability to store their own reasonable supply of the secondary fuel in the form of above ground distillate oil tanks. By having such supplies on-site, the plant can actually operate from its own stored fuel for a period of time, generally four to ten days, effectively reducing its exposure to short-term price fluctuations or availability shortfalls. By and large, the traditional purpose for operating on a secondary fuel has been to prevent loss of generation in the event of gas curtailment.

Summary

The foundational reasons for firing natural gas as the primary fuel of choice at combined cycle power plants have recently been questioned due to market changes. Since the economic benefit of firing natural gas has decreased (and even reversed on occasion), the plant owner of a single-fuel only facility (or one under development) is faced with the decision of whether to continue to plan to fire natural gas only, or to evaluate the benefits of converting to a dual-fuel facility in light of the very real incremental capital investment, increased plant complexity, versus cost savings for interruptible gas supplies coupled with the very real prospect of interruption during periods of high gas demand.

For a plant under development, the capital cost to add dual fuel capability is significant. In order to justify pursuit of a plant modification of this magnitude, the economic benefit must likewise be significant, and must also be low enough risk that it will prove worthwhile over a long-term analysis.

Since the scenario of sustained elevated natural gas prices is a brand new concept, very little industry information has yet been presented which addresses this issue and the key factors warranting a project modification. The purpose of this report is:

- To provide a thorough discussion of what is involved in dual fuel conversion.
- To perform a detailed comparison of three potential operational scenarios with and without dual fuel capability.
- To evaluate the impact of dual fuel conversion on Operation and Maintenance.
- To discuss the key technical factors of dual fuel conversion with respect to major plant equipment.
- To develop a basis for further discussion that will assist a project developer in conducting further research into the issue of dual fuel conversion.

2
DUAL FUEL CONVERSION

Introduction

The process of converting a plant under development from single fuel to dual fuel requires additional complexity in the plant design, including the addition of fuel tanks, a truck unloading facility, transfer pipework, and new gas turbine engine combustor. This system also brings with it the need to add (in the case of a simple cycle combustion turbine) or significantly increase the demineralized water treatment system, to produce the condensate (or steam) used for combustion turbine NO_x control.

This chapter will first discuss the general concepts of what is involved in converting from single fuel to dual fuel. Then, each major system will be presented from both a technical perspective and an economic perspective. The technical modifications required will be discussed, so that a thorough understanding can be obtained regarding the physical changes that must be made.

Dual Fuel Conversion - General Concepts

Depending on the pressure and cleanliness of the gas entering the plant, the natural gas flow path typically encompasses the following:

- Gas enters plant via below ground pipeline at property limit.
- Gas is metered, and usually passed through a dry gas scrubber or filter/separator.
- If necessary, gas is compressed to pressure required by combustion turbine.
- Gas is heated for efficiency improvement reasons.
- Gas is filtered once more.
- Gas is routed to turbine accessory module for throttling control, then admission to engine.

A typical natural gas control system is shown in the following figure:

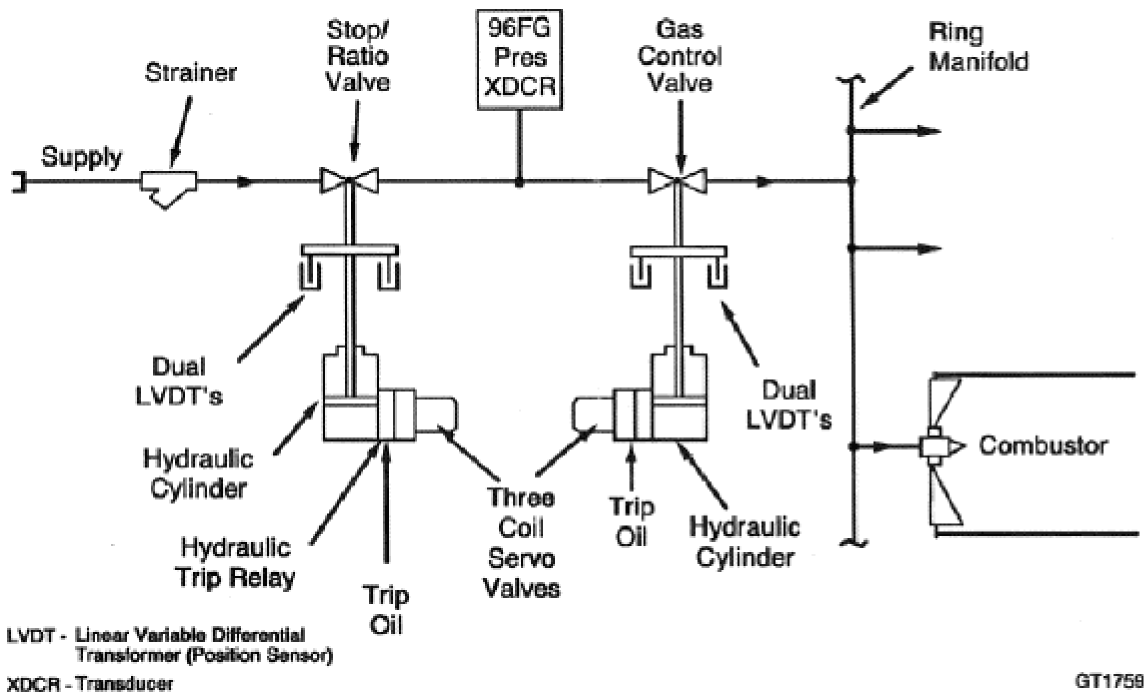


Figure 2-1
Conventional Gas Fuel Control System

When the decision is made to add distillate oil firing, several key systems are forced to change or be added:

- Distillate oil storage must be added in the form of one or more distillate oil tanks.
- Since distillate oil is rarely delivered by pipeline, a distillate oil terminal is usually added for off-loading of distillate from trucks, or from trains.
- Fuel forwarding skids, with associated piping, pumps, controls, etc must be added.
- Combustion turbine must be converted to dual fuel, and supplied with additional systems.
- The supplemental firing duct burner, if included, may be replaced with dual fuel firing capability if cost justified. Most of the time, retrofitting of duct burner with dual fuel firing is cost prohibitive if already installed due to level of difficulty to accommodate. In such case, gas only firing of duct burner would remain. However, if early enough in project development, the supplemental duct burner can be designed and furnished from the outset as a dual fuel unit.
- The heat recovery steam generator (HRSG) must be checked to ensure it can accommodate different combustion turbine exhaust composition, flow, and temperature.
- The selective catalytic reduction (SCR) system for reduction of NO_x must be modified if not already compatible with oil firing.
- Compressed air system capacity for atomizing air may be increased.

- Administratively, the plant air permit must be modified to allow distillate firing, which will impact annual emissions of NO_x, CO, and CO_2, and possibly particulates.
- Operationally, additional operation and maintenance (O&M) needs will be imparted on daily plant activities due to additional systems and more frequent parts replacement schedules. SCR design life is shortened as distillate firing is increased. Similarly, the hot gas path parts within the combustion turbine will experience a 20-25% reduction in life due to distillate firing.
- Required plant site area is increased for distillate oil storage tanks, surrounding berms, oil terminal.
- The existing fire protection system must be significantly augmented for protection of the distillate oil tanks and equipment.
- The plant drainage system and oil/water separator capacity will probably need to be increased for rain runoff from the oil tank and equipment area.

Depending on the specific condition of the distillate oil supplied to the plant, and the plant's proximity to a major oil terminal, the necessary handling of the fuel will vary. However, the following process encompasses the typical flow path of distillate fuel:

- Distillate oil is off-loaded from truck.
- Distillate oil is pumped via off-loading pumps through distillate oil filter and fuel metering.
- Distillate oil is transferred to distillate oil storage tank.
- Distillate oil is pumped via distillate oil forwarding pumps to electric heater, then to gas turbine liquid fuel / atomizing air module.
- Distillate oil is routed through combustion turbine fuel control system, and then admitted to engine.

A typical liquid fuel control system is shown in the following figure:

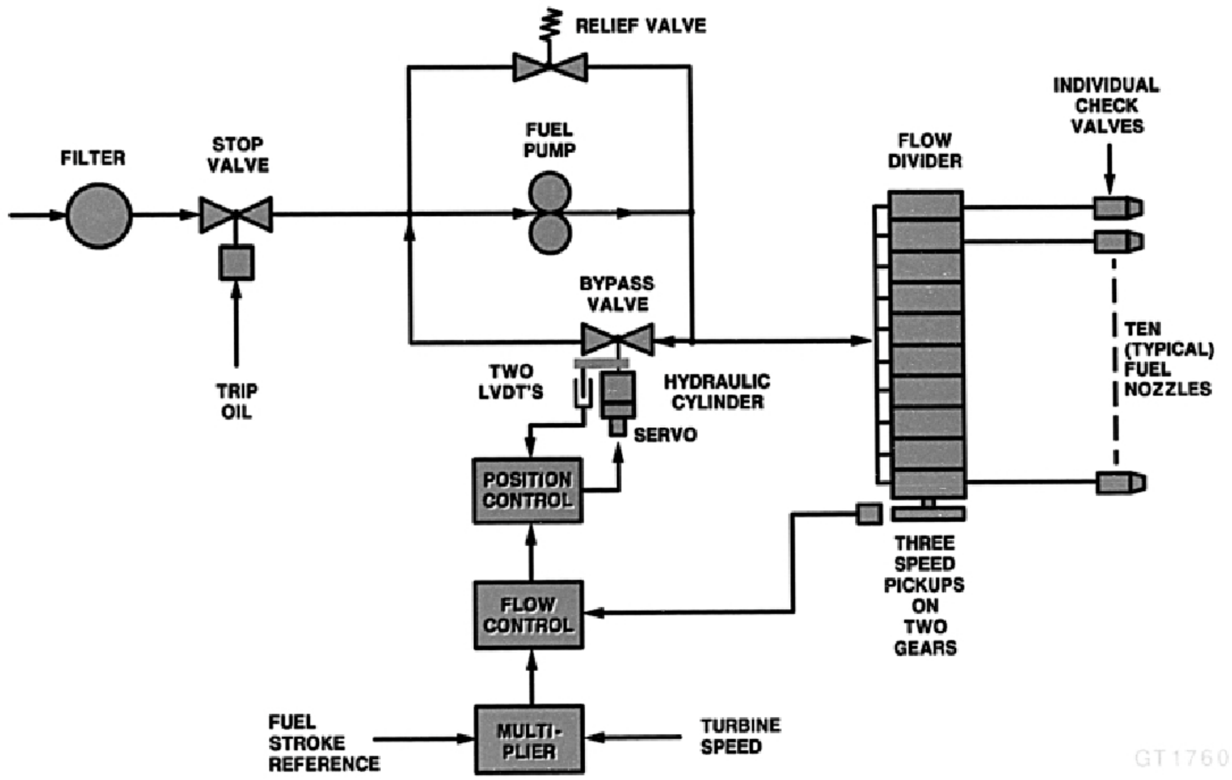


Figure 2-2
Conventional Liquid Fuel Control System

Fuel Treatment and Suitability

Utilization of more than a single type of fuel within a combustion turbine results in a reduction in both the life and power output of the turbine system. Operating techniques must be altered to fit the needs of the various types of fuels. Combustion turbine fuels must adhere to limitations on fuel contaminants, particularly vanadium, sodium, potassium, lead, and calcium in order to achieve acceptable turbine parts life[1]. The corrosive effect of sodium and vanadium is detrimental to the life of a turbine. Vanadium originates as a metallic compound in crude oil and becomes concentrated by the distillation process into heavy oil fractions. Sodium compounds are most often present in the form of salt water, which results from numerous production and transportation environments. Removal of these compounds through their water solubility can be done via fuel washing.

[1] "Design Considerations For Naphtha Fuel Systems in Combustion Turbines". John Brushwood and Tim McElwhee, Westinghouse Electric Corporation. April 1997.

The hot gas path components of the combustion turbine experience the greatest reduction in operable life when subjected to distillate fuel firing. For combustion turbines with firing temperatures above 1700°F (927°C), combustor liners experience 25% reduction in life; first stage nozzles, 12% reduction in life; and first stage blades, 14.3% reduction in life[2]. Advanced turbines with higher firing temperatures may suffer even greater reductions in expected life.

It is significant to note that present fuels flexibility is being maintained at firing temperatures and machine sizes that are far beyond the technological capabilities of just ten to fifteen years ago. Fuel treatments are costly and do not remove all traces of the offending metals. As long as the fuel oil properties fall within specific limits, no special treatment is necessary. However, methods to remove sodium, potassium, and calcium rely on the water solubility of these compounds, and is known as fuel washing. Fuel washing systems fall into four categories: centrifugal, DC electric, AC electric, and hybrids. Selection of these options, as well as several others, depends on careful examination of the proposed fuel's heating value, cleanliness, corrosiveness, deposition and fouling tendencies, and availability. Cost of fuel treatment systems for liquid fuel can rise to as much as $30 per kW for light distillate (costs for crude oil and residual fuel treatment systems can be many times higher).

Several other considerations regarding fuel suitability should also be made. Provision to protect against bacterial fouling is needed in storage and transfer lines, particularly when infrequently used. Low sulfur distillates may be especially prone to bacterial growth. Biocides have been effective in preventing fouling and gumming. In general, long term storage of fuel oil may alter physical properties. Furthermore, continuous circulation and centrifuging of oil may breakdown additive polymers and increase the tendency for oxidation. Particular caution should be raised with fuels with greater concentrations of low boiling point constituents, as indicated by low cetane number, as they are more prone to explosive conditions in tanks.

[2] "Gas Turbine Fuel Analysis", Dr. Meherwan Boyce, The Boyce Consultancy, July 2001.

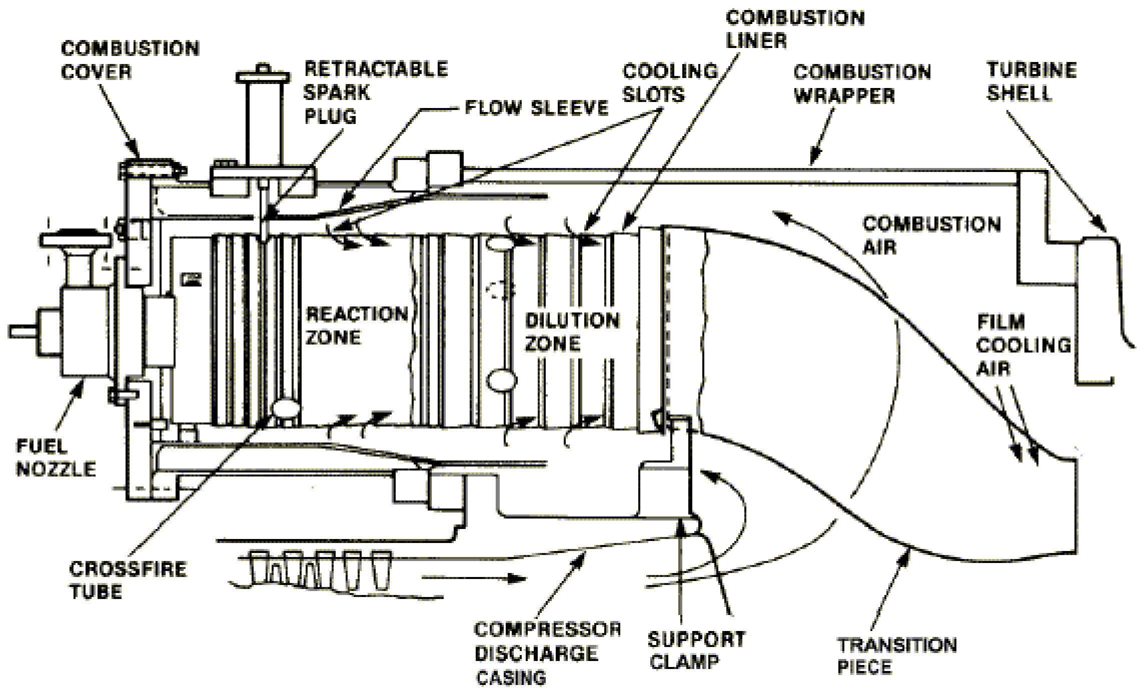


Figure 2-3
Reverse-Flow Combustion System[3]

Combustion Turbine Mechanics for Dual Fuel Operation

The modern heavy-duty gas turbine utilizes multiple reverse-flow combustors (see Figure 2-3 above). Each combustor is composed of a liner, transition piece, and fuel nozzle, chosen for its fuel flexibility and maintainability. Compressor discharge air flows around the transition pieces while cooling them. Fuel injected into the combustion reaction zone burns with a portion of the available air entering the head end of the combustor. Recirculating flow patterns of air and burning gases provide flame stability. The temperature profile of hot gases entering the turbine section is controlled to maximize the life of the turbine parts. Dual fuel nozzles must be used to allow transfer between fuels without shutdown. Dual fuel firing usually present major challenges relative to flame stability, low emissions, and/or fuel nozzle reliability.

[3] Source: "Fuels Flexibility in Heavy-Duty Gas Turbines". A.D. Foster, H.E. von Doering, and M.B. Hilt. GE Company. December 1983.

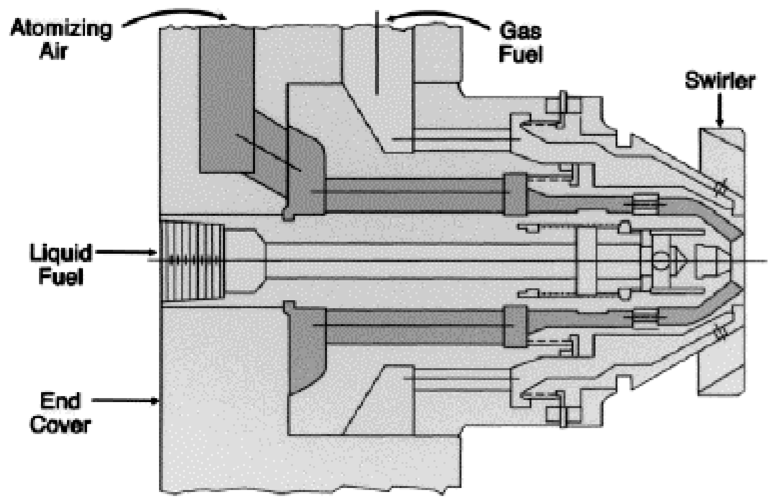


Figure 2-4
Typical Dual Fuel Nozzle[4]

One of the advantages of a combustion turbine equipped with dual fuel firing capability is the ability to start on either fuel, and transfer from one fuel to the other prior to completion of the starting sequence or at any time after start-up. It is common for transfer from natural gas to distillate to be initiated automatically upon low gas pressure, provided that liquid fuel is available, and that there is adequate time to start the fuel forwarding pump. Transfer back to natural gas is usually by operator only, in order to prevent oscillatory operation if gas supply pressure is close to fuel transfer pressure. During transition, both gas and oil are fired and proportions are gradually changed until 100% firing on the new fuel is achieved.

Modern gas turbine dual fuel systems operate within a permissible load fluctuation range of 10% of full load. The energy equivalent of the fuel flow as the function of fuel command is matched between the two fuels, so that equal gas and liquid commands will result in equal energy release in the gas turbine combustors. The fuel signal divider then splits the signal to each fuel system in a manner that maintains the sum of the two signals equal to the total required fuel demand. After the transfer sequence is complete, the inactive fuel system is purged. Purging may cause a minimal load disturbance when a small amount of remaining fuel is injected into the turbine. The final step in the fuel transfer process is the automatic resetting of the emissions control system to meet the needs of the new fuel.

The natural gas fuel system for the combustion turbine consists of the following components:

Table 2-1
Combustion Turbine Natural Gas Fuel System

System	Item	Comment
Gas Fuel	Gas fuel valves	Located in off-skid module

[4] Source: "Design Considerations for Gas Turbine Fuel Systems". G.R. Hubschmitt and W.I. Rowen. GE Power Systems. GER-3648E.

System	Item	Comment
Gas Fuel	Fuel gas strainer	Mounted off-skid
Gas Fuel	Dual (i.e. qty 2) fuel gas strainers	Mounted off-skid
Gas Fuel	Stainless steel fuel piping	Mounted on-skid
Gas Fuel	Fuel gas stop/speed ratio and control valves	
Gas Fuel	Fuel gas inlet pressure gauge and flow meter	Instrumentation
Gas Fuel	Gas control valve discharge pressure gauge	Instrumentation
Gas Fuel	Gas stop/ratio valve discharge pressure gauge	Instrumentation
Gas Fuel	Transmitters: Fuel gas pressure, temperature, flow	Instrumentation, Electronic

When dual fuel conversion is necessary, the entire liquid fuel system must be added, as well as a water injection system (or steam injection system) for NOx control. Finally, an atomizing air system must also be added to provide high-pressure air to atomize liquid fuel for combustion. For the combustion turbine system, the following components are therefore added upon specifying dual fuel operation:

Table 2-2
Combustion Turbine Liquid Fuel System

System	Item	Comment
Liquid Fuel	Distillate oil filter differential pressure gauges	
Liquid Fuel	Skid enclosure	Includes ventilation, lighting, and maintenance power
Liquid Fuel	AC Motor-driven pump	One 100% capacity
Liquid Fuel	Bypass valve	Electro-hydraulically controlled
Liquid Fuel	Distillate oil stop valve	
Liquid Fuel	Fuel flow divider	
Liquid Fuel	Distillate oil pressure gauges	
Water Injection	Off-base skid	
Water Injection	Skid enclosure	Includes ventilation, lighting, and maintenance power

System	Item	Comment
Water Injection	Space heater	For freeze protection
Water Injection	Water injection pump	With variable frequency drive
Water Injection	Water filter	
Atomizing Air System	Air-to-water U-tube heat exchanger	For cooling cycle air for entry to atomizing air compressor
Atomizing Air System	Full flow filter	One micron
Atomizing Air System	Motor-driven atomizing air compressor	
Atomizing Air System	Gauge/switch panel	
Atomizing Air System	Module enclosure	
Atomizing Air System	Stainless steel piping	Including flexible fuel nozzle pigtails
Transmitters: Liquid fuel temperature, differential pressure, gauge pressure, flow	Instrumentation, Electronic	

Operationally, there are several additional concerns with oil firing. Fuel transfer from oil to natural gas is problematic and purge systems can be an operational issue. Some systems have fuel oil accumulators that must be serviced. Some vendors utilize a water backflush system to eliminate oil from the firing train; the water/oil mixture is then injected into the burner. For DLN combustors with dual fuel capability, some vendors recommend firing natural gas for some period of time after firing oil to burn off hydrocarbon deposits. To generally avoid coking in the burners, generally lower temperatures in the burner vicinity may be required. High moisture may interfere with flame detectors in dual fuel units and some vendors recommend against on-line water washing. In general, oil systems need to be exercised at least monthly, and preferably weekly, to keep them operational and ready if gas is curtailed. Although fuel transfers may be more work for operators and occasionally cause upsets or trips, the fuel oil systems may not be ready to perform when needed without regularly exercising the equipment.

Environmental Permitting

When deciding on fuel oil firing the impacts to emission permits must be considered. Although fuel oil firing may also require consideration of the addition of a storage tank for fuel oil and introduction of other hazardous materials and waste streams (e.g., hazardous waste, waste water, spill prevention) from equipment cleaning and operations, air emission limits and modifying the air permit are one of the most critical issues to consider. Specifically, an existing combined cycle plant maintains a complex air quality permit that is issued by a local or state agency. Additionally, the plant may also maintain a federal operating permit. (Some states combine these two permits.) These permits will typically specify the type of fuel that can be fired and will have emission levels that cannot be exceeded. In order to provide for dual fuel firing, the permits must be modified prior to certain construction activities. Construction and turbine modifications cannot commence until air agency approval is granted. In addition to agency review and approval, a 30 to 45 day comment period for public input may be required. The procedural issues alone can lengthen the start-date for conversion to dual fuel, as well as raise public concern.

An example of a "worst case" situation would be that fuel oil firing would not be allowed because of higher emission rates not only of oxides of nitrogen (NOx) but of particulate matter (PM10) and sulfur dioxides (SO2). Additionally, in some regions, the emissions of hazardous air pollutant and air toxics may also be a concern. The added emissions may result in air quality modeled impacts that show an exceedance of air quality standards or an unacceptable impact to nearby national parks and forests considered in clean air regions. If this is the case, the dual fuel conversion cannot go forward until emissions are reduced to acceptable levels.

The concern about higher emission rates might exist under two cases: (1) when the combination of lowest achievable emissions from the combustion turbine and SCR would not meet the stringent-low limits for the project site because of the stringent local emission limits and/or (2) when the fuel oil emission levels originally proposed is not sufficiently controlled. The first case may exist if there is an annual emissions level or cap (e.g., tons per year) on the plant's permitted emissions. In order to minimize concern regarding this situation, this could involve limiting the annual fuel oil firing hours. This may also involve ensuring that existing controls and/or add-on controls result in acceptable control efficiencies for low emission levels. The second case is most likely to exist because an air agency will stipulate a separate emission level when firing fuel oil. Similar to the first case, lowering the overall emissions is one approach. More importantly, BACT may be required for fuel firing. BACT may be the same control technology equipment already in place for natural gas (e.g., DLN, water injection, SCR) with an acceptable higher emission limit on fuel oil. However, in relatively stringent areas, the conversion of fuel oil and desire to have more hours of operation may require add-on control or special fuel oil. For example, if an existing combined cycle plant is equipped only with DLN, and the plant wants relatively high hours of operation flexibility on fuel oil, an agency may require the add-on control of SCR or fuel oil with lower sulfur and/or nitrogen content than the traditional EPA-certified fuel oil.

Another major impact would involve the timing of the submittal of the modified permit. Attempting to modify a permit after it is submitted for approval and before the permit is received could cause adding months to the permitting review process and significantly delay the project schedule. The reason for this potential delay is that the agency must now consider revisions to the air quality modeling, as well as determine the acceptable emission rate for fuel oil firing. For the modeling issue, an agency may need to evaluate what the emissions impacts is from fuel oil under three possible cases: (1) fuel oil only under "worst-case" scenario (e.g., emissions over the course of a day and a year), (2) the combination of splitting fuel oil and natural gas firing, and (3) natural gas only under "worst-case" conditions. The reason for these cases is that it may be necessary for the agency to look at the air quality modeling impacts. This is especially true for regions that are near pristine park and forest areas (e.g., Class I), in the Grand Canyon visibility region, and in areas where the current regional levels may be approaching non-attainment.

Additionally, for agencies that consider hazardous air pollutants and air toxics, this is yet another new consideration typically not a concern with natural gas only. Finally, as far as determining an acceptable emission rate, just as the agency must specify a NOx ppm for gas firing, it must also specify a NOx ppm for fuel oil firing. This determination must be justified in the BACT analysis. If the permit applicant agrees with the agency, delays can be minimal; however, if there is any disagreement, this will result in an iterative process. Examples of BACT (and LAER) determinations for various turbine operations are presented in Table 2-3.

Table 2-3
Examples of emission levels for dual fuel fired gas turbines

Plant	NOx, gas/oil	Controls	Location; Permit Year
El Paso Milford, Combined Cycle	2 ppm /5.9 ppm (3-hr average)	DLN, SCR	Connecticut; 1999
Brooklyn Navy Yard, Combined Cycle	3.5 ppm / 10 ppm (1-hr average)	DLN, WI, SCR (both fuels)	New York; 1997
Basic American Foods, Combined Cycle	9 ppm / 15 ppm (23 ppm (oil) determined to be BACT by agency)	SCR, Steam Inj. (both fuels)	California; 1987
Wildflower Energy LP Larkspur, Simple Cycle	5 ppm / 13 ppm (3-hr average)	SCR, WI (both fuels)	California; 2001
Gainsville Regional Utilities, Simple Cycle	15 ppm / 42 ppm	DLN (gas), WI (oil)	Florida; 1995
Mid-Georgia Cogen, Combined Cycle	9 ppm / 20 ppm	DLN (gas), WI (oil)	Georgia; 1996

References: Various BACT/LAER determinations compiled by CARB and EPA.

It should be noted that the above information in Table 2-3 is based on permit information and does not necessarily reflect final performance of the turbines. Additionally, some facilities have limits on annual hours. It is important to know this information because air agencies will rely on permitted levels for determining BACT emission levels. It is the responsibility of the plant to justify levels less stringent than other permitted levels.

The potential broad range of BACT NOx emission levels that may be imposed on a dual fuel fired plantis generally as follows:

- Combined Cycle (100% capacity factor)
  Natural gas: 2.0 – 3.5 ppmvd NOx @ 15% O2 with SCR
  Liquid fuel: 9.0 – 15.0 ppmvd NOx @ 15% O2 with SCR and limited annual hours
  Ammonia slip:5.0 - 10.0 ppmvd@ 15% O2

- Simple Cycle (25%-50% capacity)
  Natural gas: 5.0 – 15.0 ppmvd NOx @ 15% O2 with DLN, SCR/DLN, or SCR/WI
  Liquid fuel: 13.0 – 42.0 ppmvd NOx @ 15% O2 with DLN, SCR/DLN, SCR/WI, WI, and/or limited annual hours
  Ammonia slip:5.0 – 10.0 ppmvd @ 15% O2

The variable range of NOx emissions is dependent on the type of control technologies required and expected control efficiency imposed by an air agency. Generally, areas that are non-attainment for ozone will require more stringent and lower NOx levels. Inherently, many of these areas will also require the more stringent control technologies when firing liquid fuel. With respect to the limited annual hours of operation, hours may range from allowing liquid fuel firing for only natural gas curtailment episodes to not more than 20% of the capacity factor. The annual hours may be constrained by the following regulatory considerations: (a) maintaining NOx levels below an unacceptable and more stringent source classification level (e.g., major modification, LAER trigger level), (b) maintaining hazardous air pollutant or air toxics level below health risk thresholds, and/or (c) maintaining other pollutant emissions at levels where the air quality modeling impacts are still acceptable.

Requesting the change after the plant is operating should not impact ongoing plant operations, but this situation would incur the equipment modification difficulties and additional costs discussed in other sections of this report. With respect to modifying the plant after it has received a permit, it is important to note that construction and equipment modifications cannot commence until the permit has been modified to allow for fuel firing. Additionally, in many cases, there is likely to be public comment period if the resulting emissions are higher that the currently permitted emissions. It is acceptable to have higher emissions due to fuel oil firing, but typically the agency must evaluate and accept the modeling and proposed controls. In some regions, if there is a significant enough emissions increase, emission offsets may be needed. Because combined cycle plants also will maintain a federal Title V Operating Permit, it will be necessary to ensure that the procedural requirements are met. Most notably, the Title V process will likely require additional public review particularly if there is an increase in emissions. Finally, the acid rain requirement of 40 CFR Part 75 must be met. This will require ensuring that the continuous emission monitoring system meets federal requirements both from a hardware and software perspective. Therefore, emission permitting can impose significant constraints on adding fuel oil firing.

3
MAJOR EQUIPMENT ISSUES

Introduction

The decision to change the design of a combined cycle plant from single fuel (natural gas only) to dual fuel requires more analysis than just evaluating fuel price differentials. In order to accomplish the design change, several key modifications must be performed on the various pieces of major equipment. Since this design change is being presented with respect to plants under development, delays to the combustion turbine manufacturing schedule and delivery date may be an important factor in the decision of whether or not to undertake the change itself.

In this chapter, the key issues of modification for major equipment are presented and discussed so that the project developer will be able to make a more informed decision regarding dual fuel conversion.

Combustion Turbine

The primary technical issues involving modifications to the combustion turbine system were discussed in the preceding chapter in conjunction with overall dual fuel conversion concepts.

Combustion Turbine: Cost and Schedule Impact

Depending upon how late in the design or manufacturing process determines the difficulty, and, in turn, the cost of accommodating dual fuel capability. At minimum, any project-specific design drawings and calculations the manufacturer may have created will need to be redone. However, the manufacturer may have dual fuel drawings available. If key engine components such as combustor manifolds have been specified and manufactured, then specific re-allocation of parts will need to be done as well. There have been occasions when the combustion turbine manufacturer has begun substantial construction in engine build or base assembly, and then received confirmation from the buyer that the dual fuel conversion was desired. Costs for major design change increase with time due to these factors. Consequently, it is in the buyer's best interest to decide on such matters earlier rather than later.

Presently, the cost differential between a single fuel GE PG7241FA combustion turbine and a dual fuel GE PG7241FA combustion turbine (with all accessories) is approximately $1.7 million, a cost increase of approximately 4.3%. This differential applies to the initial order. If the decision to convert a single fuel order to a dual fuel order is made approximately halfway into the project schedule (12-18 months after order), then the cost increase could rise to $1.9 million per combustion turbine. Further, a decision to convert made after shipment of the combustion turbine could result in a cost increase of $ 2.2 million per unit, or a 5.4% increase.

A decision to change the combustion turbine order from natural gas only fuel to dual fuel will impact the delivery schedule. The timing of the change, the level of activity in the manufacturer's facility, the availability of additional parts, and the stage of completion of the order are all factors which contribute to determining schedule impact. Manufacturers find difficulty in determining the impact of such a change, except on a case-by-case basis. For planning purposes, a project developer should anticipate a delivery extension of two to four months from the combustion turbine manufacturer for rough planning purposes.

Combustion Turbine: Field Retrofit Issues

The level of difficulty of performing a dual fuel conversion in the field is several times more difficult than performing it in the manufacturer's shop. The availability of equipment to lift and maneuver the turbine engine is greatly decreased, and is accompanied by greater risk. All parts need to be shipped to the project site in advance. Field service representatives need to be dispatched to the project site, and remain for an extended length of time. A new performance test may be required. The new liquid fuel skid, the water injection skid, and the atomizing air skid all need to be located and installed near the turbine base, which may require the relocation of several other systems or roadways. If at all possible, it is recommended that conversion to dual fuel be made before turbine shipment. If this is not possible, then substantial increases in project cost and project schedule are required to accommodate such change.

Heat Recovery Steam Generator (HRSG)

HRSG: Technical Issues

There are several design issues associated with the HRSG when converting to dual fuel capability. First, since the distillate fired combustion turbine will be emitting approximately 5% more exhaust mass flow (at about the same temperature), the HRSG will need to be designed to utilize this increase effectively, thus resulting in a greater tube / fin surface area. In the process simulation studies conducted for this report, it was found that HRSG surface area would need to increase by approximately 4% to accommodate this change.

Second, when distillate is fired in the combustion turbine, the composition of the exhaust changes to one that is more likely to corrode the external surfaces of the HRSG tubes and fins. It is standard design practice to allow an exit temperature of no less than 270 to 280°F (132 to 138°C) when firing distillate due to acidic condensation which occurs on the low temperature surfaces such as the condensate heater (LP economizer). To obtain a higher exit temperature, a combination of LP economizer bypass (of the entering condensate), condensate recirculation (through the LP economizer), and HRSG surface area design are all required to effectively control and regulate stack exit temperature and limit corrosion. Instrumentation and controls for this process is also required, not usually required in the natural gas only scenario.

Third, converting HRSG supplemental duct firing to dual fuel requires major modifications because a dual fuel duct burner actually consists of two separate burner systems, each equipped with its own instrumentation and control system. If this change is implemented during the design phase, the dual fuel burner will add length to the exhaust path, thus slightly increasing exhaust pressure drop and requiring additional footprint area downstream of the combustion turbine. The feasibility of adding dual fuel duct firing capability to an existing HRSG requires a determination of the required additional burner space. If the decision to convert to dual fuel is made after substantial fabrication of the duct burner has already begun, the project developer may decide to leave the supplemental firing system as a single fuel system due to the difficulties of conversion. In this case, the only loss is the ability to supplemental fire distillate, which may still be acceptable, given that the combustion turbine would still have the ability to fire distillate.

Fourth, some HRSG manufacturers may recommend that the internal materials of construction change for dual fuel fired HRSG systems. By carefully monitoring and controlling stack exit temperature, the need for changing to alternate materials may be avoided.

HRSG: Cost and Schedule Impact

Due to the slightly increased size of the HRSG due to reasons mentioned in the previous section, the cost of the dual fuel-scenario HRSG will likewise be greater. For instance, an HRSG sized to serve a single GE PG7241FA results in a cost increase of about 2.5% ($250,000). This is exclusive of the duct burner cost. Duct burner cost, in contrast, will increase dramatically with dual fuel capability. The second burner system, along with the increased duct size will increase duct burner cost by over 100%, from about $150,000 for gas only operation to about $400,000 for dual fuel operation.

Unless construction of the HRSG has already physically begun, incorporation of the changes to dual fuel should not be difficult to accommodate. The exception to this would be if material changes are necessary, in which case the provisioning of necessary tubes and fins for the new material would need to take place. Relative to the expected delivery time increases for the combustion turbine, the delivery time for the modified HRSG and duct burner should be considerably less. Depending on construction order at site, an HRSG or duct burner delivery delayed by even two to three months will probably not replace the combustion turbine as the critical path component.

Steam Turbine

Steam turbine power output remains approximately the same due to the increased steam flow from the HRSG with distillate fuel. The reason it does not increase with the increased CT exhaust is that not as much of the heat energy can be taken out of the exhaust within the HRSG: Minimum exhaust temperature while firing distillate should be 270 to 280 °F (132 to 138 °C). (If exhaust temperature were permitted to be drawn down to gas-fired levels, the anticipated load increase for the steam turbine would be approximately 8 to 10 MW with a single GE PG7241FA.) An analysis is required of the specific steam turbine and auxiliary equipment design, schedule, cycle efficiency, power output and modification costs impacts. For the most part, the steam turbine design will not change much since its load remains approximately constant. However, due to the slightly different steam conditions (pressure, temperature, flow differences), a thorough analysis of the new conditions must be made with respect to the steam turbine design. A summary of important parts of such an analysis include the following:

- Steam turbine design and maximum output is often based on lower ambient temperatures when the condenser cooling water temperature is lower, which may result in steam turbine available additional steam turbine capacity at higher ambient temperatures that can be used for the distillate oil firing condition.
- Steam turbine blading and staging design must be considered for the new conditions to make sure that design margins are not being compromised due to the new conditions.

Since HRSG exhaust temperature is greater during distillate-fired operation, overall cycle efficiency decreases significantly. Since cycle efficiency and plant output are usually the highest plant priorities, the decision to convert to dual fuel would be better served if made early in project development when overall design guarantees are still in their formative stages, and project economics are still being developed.

SCR Catalyst

An assessment of SCR and CO catalyst performance and HRSG exchange surface fouling is required when fuel oil firing is being considered. The first step is to determine the emission limits for compliance with environmental permits. Please refer to the applicable section in this report for a discussion on this topic. If it is necessary to use the SCR system during fuel oil firing there are important catalyst, HRSG, operating and cost considerations. A brief summary of the results of an investigation and testing for fuel oil firing described in EPRI report 108169 Oil-Fired Combustion Turbine SCR NOx Control Testing and Evaluation (1997) follows (including direct quotations):

- "There is comparatively little commercial experience with high sulfur fuel oil (up to 0.4%) combustion and SCR catalyst performance". Generally, fuel oil sulfur content is in the range of .05%. This EPRI report describes test results for determining the technical feasibility for a SCR to control NOx using a pilot scale plant using 0.2% sulfur in fuel oil. Projections of operation with 0.4% sulfur are described. Operating experience at Tekniska Verken's Garstad Generating Station in Linkoping, Sweden, "confirmed the pilot plant observations". The applicability of the results in this report need to be confirmed and/or appropriately adjusted for the specific plant fuel analysis and planned annual fuel oil consumption when assessing adding fuel oil firing. This would involve defining the SCR catalyst and HRSG impacts, usually by getting the supplier's responses.
- The testing and assessment reported addressed catalyst performance and life in the oil-fired exhaust gas environment, discharge of sulfuric acid and ammonium sulfate and bisulfate particulate, and HRSG performance impacts resulting from ammonium salt deposition on heat transfer surfaces.
- The report concludes that SCR catalyst performance will decline somewhat more quickly with high sulfur fuel because of fouling and catalyst poisoning requiring higher ammonia injection rates and possibly a shorter catalyst replacement schedule.

- The reaction of ammonia with salt producing fuel constituents (e.g., ammonia sulfate) results in tendency to foul the HRSG heat exchange surfaces downstream of the SCR causing an increase in HRSG pressure drop and lower CT output. In addition, a reduction in HRSG steam production can occur causing lower steam turbine output. HRSG water washing with the CT shutdown may be the best solution. Sootblowers installed in the applicable HRSG zones at Linkoping were not effective because of the difficulty in cleaning surfaces in the middle of the HRSG heat exchanger surface modules. Sootblowers may result in unacceptable stack discharge of particulate materials.
- "Another approach for managing ammonium salt deposition is annual replacement of the catalyst. In this strategy, frequent catalyst replacement eliminates the need for frequent water washing after the first year of operation since the ammonia slip concentration will remain relatively low". This approach is the suggested best solution.
- Applicable capital costs based on the report's Management of Ammonium Salt Deposits Using Annual Catalyst Replacement concept would increase the catalyst volume, increasing the heat exchange surface spacing and using stainless steel fin material, waste water handling system. Annual costs to be included are annual catalyst replacement, annual water washing expenditures, including increased outage time, an increase for more frequent catalyst replacement, and a reduction in ammonia costs. The annual operating cost comparison showed an increase from 1.93 mills / kWh to 4.03 mills / kWh for a plant with two unit 24.65 MW combustion turbines.

In summary, when adding fuel oil firing to a unit a thorough investigation of permit emission limits, SCR catalyst performance and costs based on the plant's specific fuel oil analysis, planned annual operating fuel oil firing time, HRSG design and annual costs needs to be developed.

Balance of Plant (BOP)

There are several additional technical modifications that must be made to the plant due to dual fuel conversion. First, systems to support the delivery, storage, and forwarding of distillate fuel are needed. The amount of plant land area that these components will require depends, in part, on the fuel tank size. Most likely delivery of distillate fuel will be by truck. In this scenario, an off-loading terminal is necessary, complete with fire prevention and suppression equipment, metering equipment, and forwarding pumps. The size of the distillate oil tank is determined by the philosophy of operation of the plant. Most larger plants only maintain a capacity for three to four days of continuous distillate operation. Smaller plants tend to maintain storage of ten to fourteen days supply. For a single unit GE PG7241FA combustion turbine, a four-day supply of distillate fuel would require a 1.4 million gallon (5.3 million liter) tank. Also included in the plant distillate oil system would be a "false start" distillate oil tank, piping, instrumentation, and valves. Additionally, the NFPA area classification may change where the oil piping is routed due to it being an increased combustion hazard. The cost for the combustion turbine distillate oil control and flow system is included in the additional combustion turbine cost. However, for the BOP distillate oil system, a capital cost addition of 1.5-1.8% of total plant capital should be anticipated. For a single GE PG7241FA combustion turbine, this is approximately an additional $1.5 million.

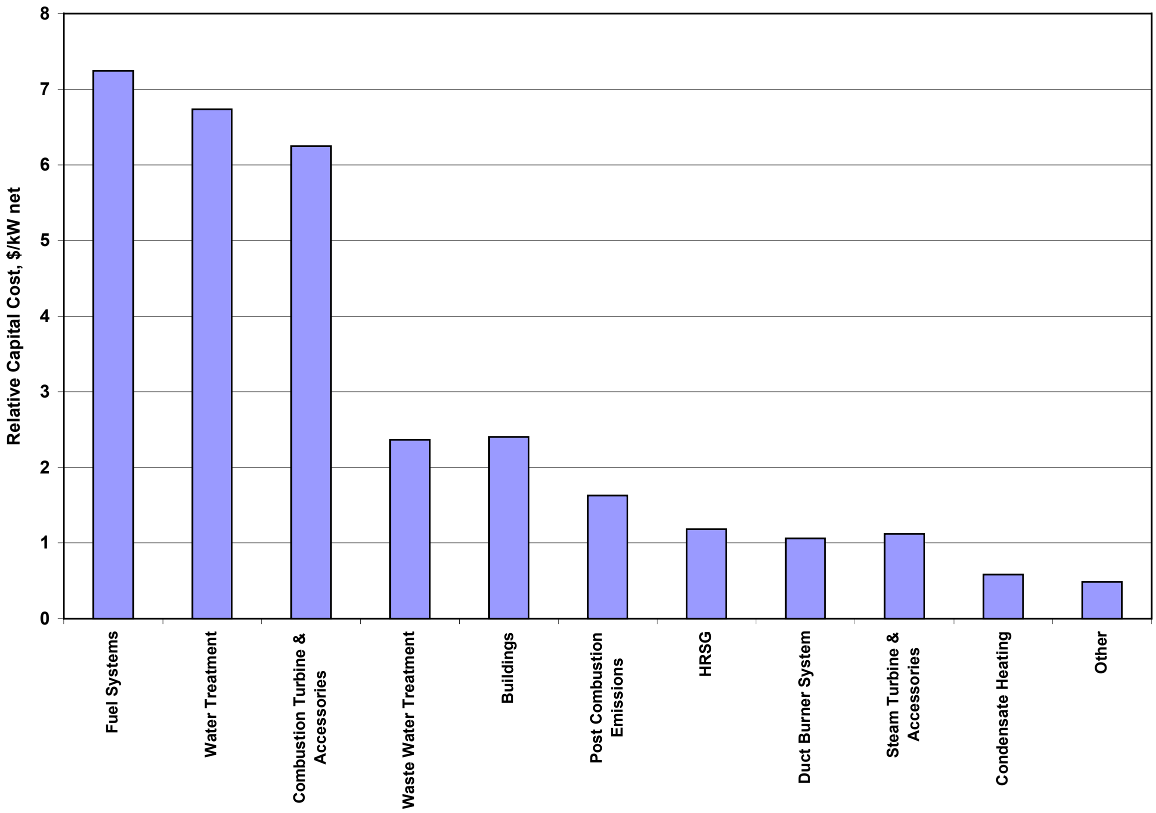
Second, in order to permit water injection for effective NOx control while firing distillate fuel, a demineralized water system must be added to the BOP scope of supply. For a new combined cycle plant, the demineralized water system will most likely be a new system, since it is not otherwise needed at the plant. The demineralized water will be injected into the combustion turbine hot gas path, and therefore must be of very high quality to prevent corrosion, fouling, mineral buildup, and advanced degradation of turbine performance. The demineralized water system will include a raw water source, a demineralizer treatment system, a storage tank for several days' consumption of demineralized water, pumps, piping, instrumentation, and valves. An increased plant waste water system will also be required to dispose of water not rejected in the treatment process. In all, a capital budget equivalent to approximately 2.0-2.5% of total plant capital cost should be anticipated. This is a very significant and expensive new system to add to the plant, but necessary for low NOx operation of the combustion turbine while firing distillate fuel. In addition, the tank and piping system will occupy significant plant land area, which must be planned for as well.

Third, with the potential increase in steam production due to distillate fired operation, all associated steam/water path systems must be evaluated for piping size increases, pump motor upgrades, disposal system upgrades, condenser size increase, cooling system size increase, etc. Under some conditions, such increases in size or rating could require equipment movement, increased auxiliary electrical load, and the need to layout plant components differently.

Chapter Conclusion

The chart below summarizes the additional capital cost required to perform dual fuel conversion for a combined cycle cogeneration plant. Details underlying the values shown below will be discussed in Chapter 6. However, it is important to note that for an approximate plant cost of $400-425 per kW, the cost to implement a dual fuel conversion is approximately $30-35 per kW, or a 7.0-8.5% capital cost increase. The costs below are approximate, and are displayed on a dollar per kW of net plant output basis.

Table 3-1
Cost of Dual Fuel Conversion



When the varying components in a combined cycle plant are modified or added in order to convert from single fuel (natural gas fired) to dual fuel (adding distillate oil firing), there are more issues than just capital cost. The major equipment components have complex technical modifications that must be made. Making the modifications late in the project development process becomes more difficult and costly. Many factors depend upon site-specific parameters, such as available plant area, proximity to distillate oil refueling facilities, and site climate. Major equipment manufacturers will seldom commit to estimating cost or schedule impact on a general basis, preferring to evaluate all proposals on a case-by-case basis.

The issue of dual fuel conversion requires an in-depth analysis due to the many factors at play. The following chapter will describe the study scenarios that will provide the context for analysis for the balance of the report.

4 STUDY DEFINITION

Introduction

A significant need for evaluation of dual fuel conversion is in response to the market conditions existing in early 2001, as noted in Chapter 1, and with respect to the potential benefits of converting a single-fuel combined cycle power generation plant to dual-fuel, as noted in Chapter 2. Since documentation of this topic is normally only available in general, non-market specific terminology, the goal of this study is to provide a very specific context upon which the technological upgrade can be evaluated.

This report will present a thorough study of the design, the required capital costs, the anticipated O&M costs, the technological benefits and disadvantages, the anticipated financial benefit, and a commentary of the level of financial risk. The study focuses on adding distillate firing to a project originally intended to fire natural gas fuel only, early in the project development phase.

Project Development Continuum

Since this study involves converting a plant from single fuel to dual fuel after project development has already begun, there are several points along the development continuum where the conversion could occur.

First, at the earliest stage, if the major equipment has not yet been ordered, the conditions are most flexible because the developer or owner has not committed funds binding a particular configuration of major equipment yet. Plants at this early stage of development could be changed to dual fuel with little trouble because time is still quite available, and detailed development has not bound the project team to one configuration over another.

Second, if the major equipment has already been ordered, the added difficulty of changing an order after contractual terms have already been agreed to may exist. This may consequently involve any combination of the following:

- Increased purchase price
- Incurred financial penalties
- Delayed equipment delivery
- Increased design or drawing complexity - potential conflicts or errors

Late changes almost universally lead to increased cost and complexity due to the increased level of design commitment engaged.

Analysis Tools: The SOAPP-CT WorkStation and the CT Project Risk Analyzer

To simulate the capital costs, performance, and overall financial impact of dual fuel conversion, EPRI's SOAPP-CT WorkStation software is used.

The SOAPP-CT WorkStation allows the user to define unit configurations, site variations, economic scenarios, and fuel costs. Once selected and associated together as a conceptual design, the programming for performance, cost, and financial analyses output are fully automated.

The WorkStation integrates performance, cost, and financial analysis capabilities into one product, combining them with a flexible data input structure. This allows the user to optimize the plant design to technical and financial criteria, and assess it against project and market uncertainties. Because so many project-specific site and financial variables interact with the design, no single parameter can be used to judge the optimum solution for any particular project. "What if" scenarios can be provided, and are an invaluable tool for evaluating the impacts of key design decisions on overall performance and financial return to reduce project risk.

To accurately estimate the operating and maintenance costs of the varying design scenarios, EPRI's CT Project Risk Analyzer software is used.

The CT (combustion turbine) Project Risk Analyzer is a software tool specifically developed for estimating costs of O&M and its variability, for quantifying the likelihood and costs of unplanned events leading to higher maintenance costs and lost revenues, and for evaluating risk mitigation alternatives. When used with its Monte Carlo statistical analysis component, the level of total project risk can be evaluated and projected with varying levels of risk mitigation options employed. For this study, CT Project Risk Analyzer was utilized for purposes of direct O&M cost estimation, including calculation of scheduled maintenance costs and costs of unplanned maintenance.

Scenario Components - Plant Model

For the purpose of providing a benchmark by which the simulation can be evaluated, a standardized plant model was created. The plant model was intentionally designed to represent a common configuration as a baseline plant design recognizing that particular plant designs with project-specific attributes must be individually evaluated regarding their suitability for dual fuel conversion. The sections below highlight the basic configuration modeled.

In addition, detailed SOAPP WorkStation input data may be found in Appendix B for the conceptual designs evaluated.

Unit Sizing

In order to specify a straightforward conventional design, a 1x1x1 configuration was chosen, which represents one combustion turbine feeding one HRSG feeding one steam turbine. The combustion turbine chosen was the GE PG7241 FA, due to its prominent use within today's combined cycle cogeneration market. Additional details can be found in the table below:

Table 4-1
SOAPP Unit Component Definition

Design / Model Parameter	Value
Cycle Type	Combined Cycle Cogeneration
Plant Duty	Base Load (Capacity Factor = 85%)
Application (New vs. Repowered vs. Modified)	New
Configuration	One (1) Combustion Turbine One (1) Heat Recovery Steam Generator (HRSG) One (1) Steam Turbine
Combustion Turbine	GE PG7241 FA Single Fuel (natural gas), DLN Combustor [base] Dual Fuel (gas + distillate), DLN + Water Injection [option]
Heat Recovery Steam Generator (HRSG)	Three Pressure w/ Reheat, Integral Deaerator, 1800 psia HP, 490 psia IP, 60 psia LP, Supplemental fired at 25% additional steam generation
Steam Turbine	Reheat, 2 Casing, 1 Flow, Axial Exhaust
Heat Rejection System	Mechanical Draft Cooling Tower

Site Definition

The site definition within the evaluation was chosen to be representative of the upper Midwest portion of the United States. Specifically, the climate conditions of Kenosha, Wisconsin were utilized as the study's benchmark. Site conditions are summarized in the following table:

Table 4-2
SOAPP Site Component Definition

Design / Model Parameter	Value
Site Elevation	600 feet (183 meters)
Minimum Ambient Dry Bulb Temperature	-20 °F (-29 °C)
Maximum Ambient Dry/Wet Bulb Temperature	85 / 73 °F (29.4 / 22.8 °C)
Performance Point Dry / Wet Bulb Temperature	59 / 51 °F (15 / 10.6 °C)
UBC Seismic Zone	Zone 0

Economic Definition

The economic component of the analysis is the most variable component of the analysis. Due to the widely fluctuating nature of electricity prices, natural gas prices, distillate prices, equipment prices, and financing rates, the result of such a study as this can vary from extremely profitable to extremely unprofitable. Data will be shown in the following chapter that demonstrates the influence of fuel pricing on the annual economics of a combined cycle plant.

Because of the variety of economic conditions, the project developer must take care to ensure that the data being input into the model is accurate and appropriate for the scenario. For this reason, the use of comprehensive spreadsheet-based calculations is recommended for case study analysis. The output of the following chapter depicts such an analysis that was generated for this study.

Further discussion will be presented regarding key issues such as natural gas pricing and distillate pricing in later sections of this report. For the base conceptual design of this study, the following economic parameters were utilized: (See Appendix B for a full tabulated list.)

Table 4-3
SOAPP Economic and Fuel Component Definition

Design / Model Parameter	Value
Ownership Type	Independent Power Producer
Inflation Rate	2.0 %
Return on Debt	9.0 %
Present Worth Discount Rate	12.0 %
Sale Electricity Price	$ 65.00 / MWh
Natural Gas Fuel Price	$ 3.00 to 10.00 / MBtu ($2.85 to 9.48 / GJ)
Distillate Fuel Price	$ 4.00 to 8.00 / MBtu ($3.79 to 7.59 / GJ)
Output Degradation, Power	3.0 %
Output Degradation, Heat Rate	1.5 %

Dual Fuel Conversion -- Technical Discussion

For the purposes of scenario definition, and to outline the specific changes necessary in order to implement a plant's conversion to dual fuel, the measures in the following sections are presented:

Combustion Turbine Operation

Successful dual fuel firing capability can be significantly more difficult than single fuel. The combustors are more complicated due to the necessity of routing two independent fuel systems through the combustion turbine package to the actual firing nozzles. Controls for the two fuels need to be carefully established such that smooth operation is ensured, along with the required level of emissions control. For natural gas operation, dry low NOx flame control is sufficient; however, for liquid fuel control, the regulated addition of demineralized water is necessary in order to control emission levels. On-line fuel transfers require additional control software. Conversion of the combustion turbine involves significant additional physical components (as discussed in Chapter 2), but also involves significant controls components.

Heat Recovery Steam Generator (HRSG) Design and Operation

In order to safely operate a HRSG under a dual fuel configuration, several key design differences must be incorporated. For one, it is necessary to raise the HRSG stack exit temperature to approximately 270 °F (132 °C) to avoid acid condensation and corrosion on the external surfaces of the HRSG tubes. Elevated HRSG stack exit temperature is normally accomplished by bypassing the HRSG condensate economizer (preheater) section, and by recirculating preheated condensate to reduce the amount of heat transfer taking place in the preheater. Instead of raising the HRSG stack exit temperature, corrosion resistant materials could be used for the HRSG economizer, exit duct, and stack. This is usually not done because of cost considerations and a tendency for corrosion to still be a problem. HRSG economizer and low pressure (LP) evaporator heat exchanger fins need to be spaced wider for distillate oil firing.

Because of these changes, the cost of the HRSG rises and the required surface area increases. This differential will be notable in the output reports of the following Chapter.

Selective Catalytic Reduction (SCR) Design and Operation

The presence of unburned distillate oil and trace amounts of metals and salts in the combustion turbine exhaust path leads to a shortened life cycle of the selective catalytic reduction (SCR) system, and may in fact "poison" the catalyst itself. The cost and O&M impact of this is shown in output data of the following Chapter.

Economic Factors

Due to the sensitivity of this study to the range of electricity and fuel prices that could be foreseen, the following sections discuss their interaction with the results of this report.

Electricity Pricing

Wide fluctuations in electricity pricing provide considerable economic justification for developing combined cycle and cogeneration plants in the first place. The current electricity capacity shortage in California notwithstanding, electricity prices have surged above $1000 per MWh during peak periods of high demand. The primary intent of this study has not been to incorporate electricity price ranges directly into the decision of whether or not to convert to dual fuel. However, several points merit mentioning.

First, with higher electricity prices prevailing, any time when generating ability is fully lost due to lack of fuel (i.e. single fuel operation under a curtailment period), the level of lost revenue is proportionally greater. For this reason, operability of the plant under broader conditions is highly advantageous.

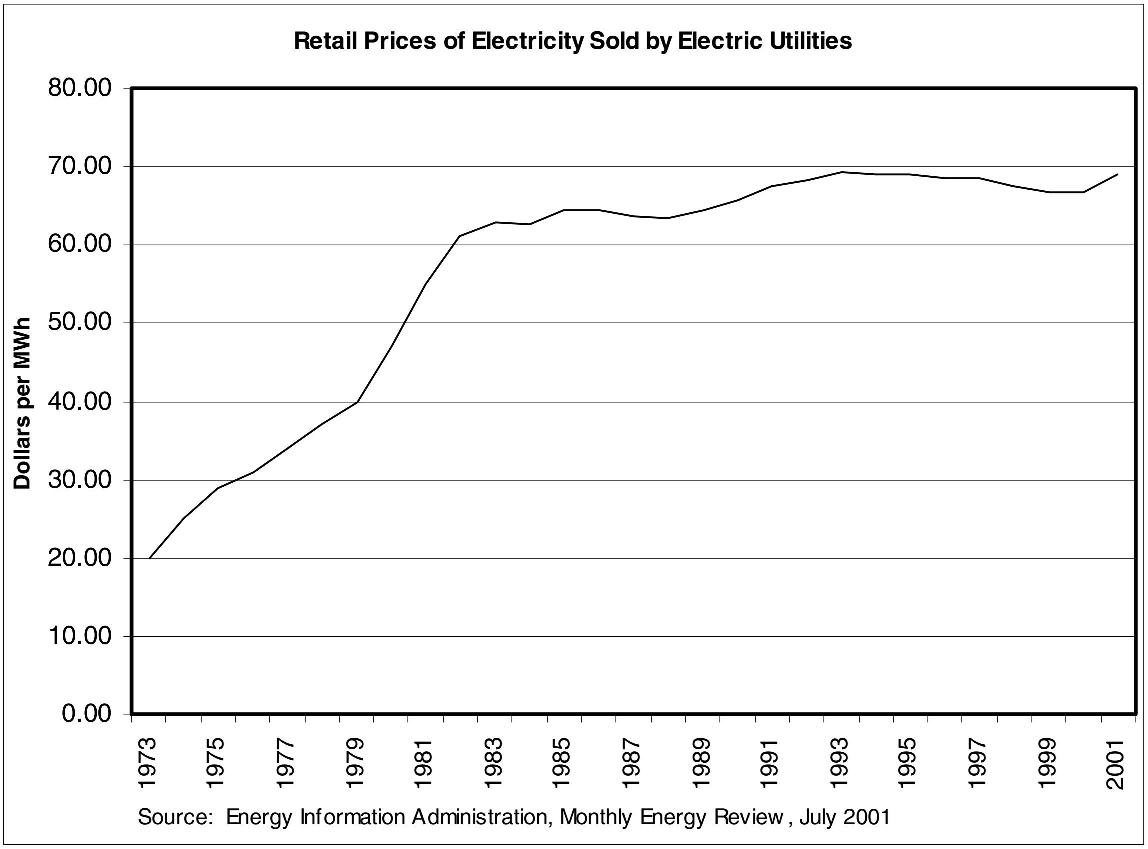


Figure 4-1
Retail Prices of Electricity Sold by Electric Utilities

Second, with the advent of deregulated markets, the ability to generate power when it is most needed is rewarded more richly than under less-market-driven pricing scenarios. Independent Power Producers are developing plants with dual fuel capability more often because of this reason. The Energy Information Administration reported in January 2001 that large-volume (i.e. electric utilities) and small-volume (i.e. independent power producers) have contrasting distillate inventories and inventory capacities: "Based on maximum potential interruption levels, the small customers had 14.3 days of distillate storage capacity available and 9.8 days of distillate inventories on hand. In contrast, large customers had only 3.7 days of storage capacity and 3.1 days of inventory."[5] This indicates a stronger preference for the smaller customer (that is, the independent power producer) to maintain generating capability longer when gas service may not be available.

[5] "Impact of Interruptible Natural Gas Service on Northeast Heating Oil Demand", Energy Information Administration. January 2001.

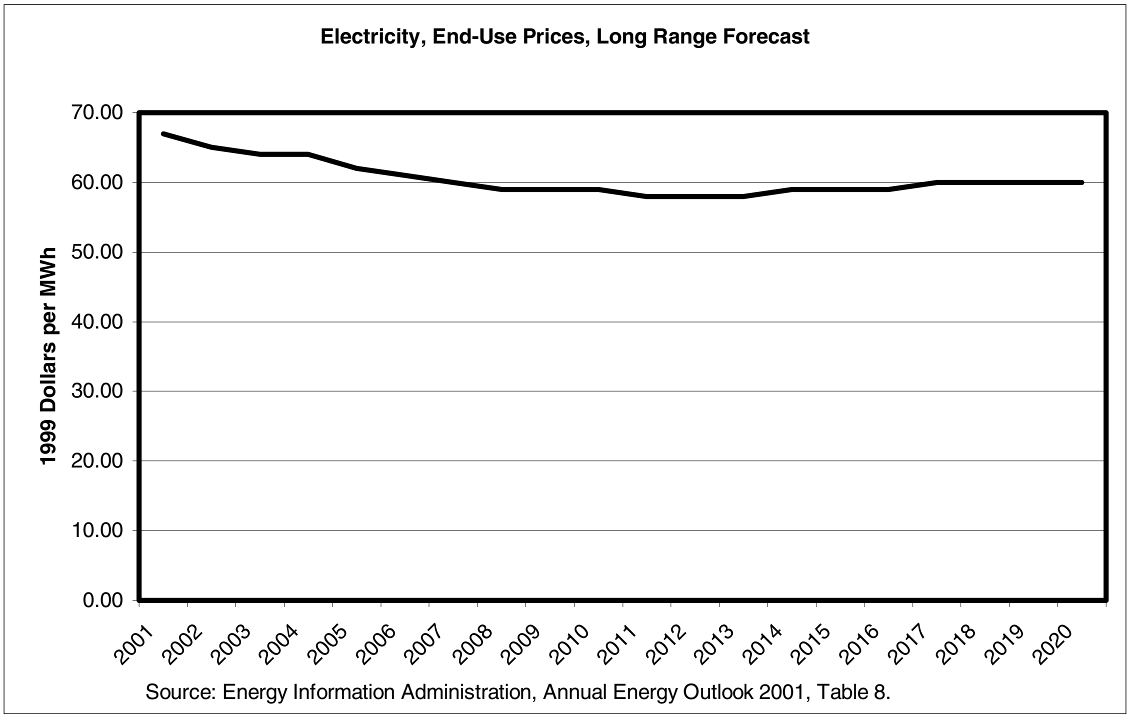


Figure 4-2
Electricity, End-Use Prices, Long Range Forecast

The Energy Information Administration predicts an overall electricity price forecast that is quite flat, when viewed in 1999 dollars. Not shown in this forecast are the anticipated short-term "spot" prices that open market forces will bring. However, the forecast does provide a good basis for using the average $65.00/MWh price used in the SOAPP model.

Natural Gas Pricing

Historically, natural gas prices have been comfortably low, providing a clean, inexpensive, reliable source of energy that was both environmentally advantageous and convenient to deliver. Combined cycle plant development projects of the mid to late 1990's began to capitalize on this fact, leading to explosive levels of growth in capacity under construction as the new millennium arrived. See the chart presented in Chapter 1 for example of this principle.

However, natural gas prices began an ascent that originated in the summer of 2000 primarily in response to low levels of underground gas storage. Spot prices rose well past the $4.00 per thousand cubic feet ($0.141 per cubic meter) mark in June 2000, even exceeding $10.00 per thousand cubic feet ($0.353 per cubic meter) several times during the winter of 2000-2001. Over the period of October 2000 to March 2001, natural gas prices at the wellhead averaged approximately $5.74 per thousand cubic feet ($0.203 per cubic meter), more than double the previous winter's price. The duration of this high gas prices is unprecedented. Moreover, the Energy Information Administration even announced in April 2001, "…we continue to believe that, given the current state of the natural gas market, it will be a while (if ever) before prices at the wellhead return to the low level of $2.00 per thousand cubic feet ($0.071 per cubic meter)…"[6]

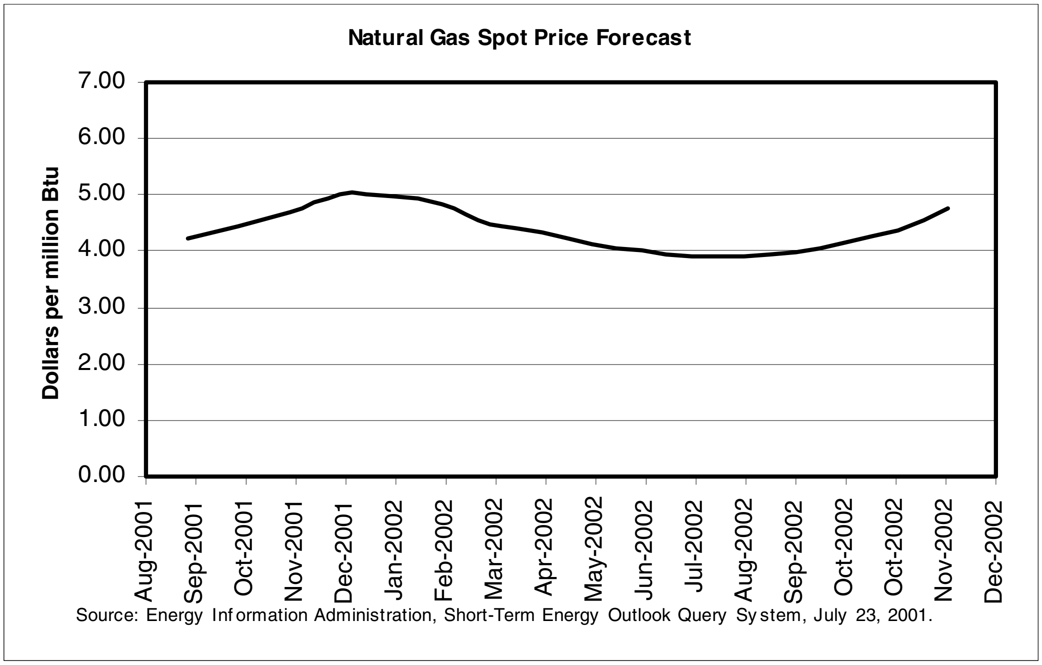


Figure 4-3
Natural Gas Spot Price Forecast

Certainly, this is a case where spreadsheet case study analysis plays a large part in the development decision. While $6.00 ($5.69 / GJ) gas may be probable under a very short term, to establish an economic model based on $6.00 ($5.69 / GJ) gas over the entire design life of a new plant would be improper. Consequently, spreadsheet analysis must resort to a differential fuel price justification for an economic decision such as dual fuel conversion.

Distillate Oil Pricing

Like natural gas, distillate oil has exhibited a fluctuating price history over both short and long term analyses. Reaching peaks of $6.50 to $7.00 per million Btu ($6.16 to $6.63 per GJ) several times over the past twenty years, and distillate fuel has rarely dipped below $3.50 per million Btu ($3.32 / GJ). Perhaps most significant regarding the pricing of distillate is the fact that it has nearly always been a higher priced fuel to fire than natural gas. Add to that the fact that distillate burns dirtier (higher NO_x, SO_2, and CO emissions) and is more difficult to deliver to site, and one quickly sees why natural gas has long been the preferred fuel for combined cycle plants.

In similar fashion to motor gasoline prices, distillate prices have been sliding down from its winter peak of $7.24 per million Btu ($6.86 / GJ) in November 2000, to a recent spot price of $5.30 per million Btu ($5.02 / GJ). Unlike gasoline prices, distillate oil prices have not

[6] Source: Energy Information Administration, Short-Term Energy Outlook. April 2001.

experienced the precipitous price drop that occurred in June and July of 2001; though prices for distillate have been easing. The primary reason for this is that gasoline imports have been strong and refiners have been electing to produce gasoline at the cost of distillate production. As of the end of July 2001, distillate stock levels are somewhat tight, resulting in a price premium for the fuel.

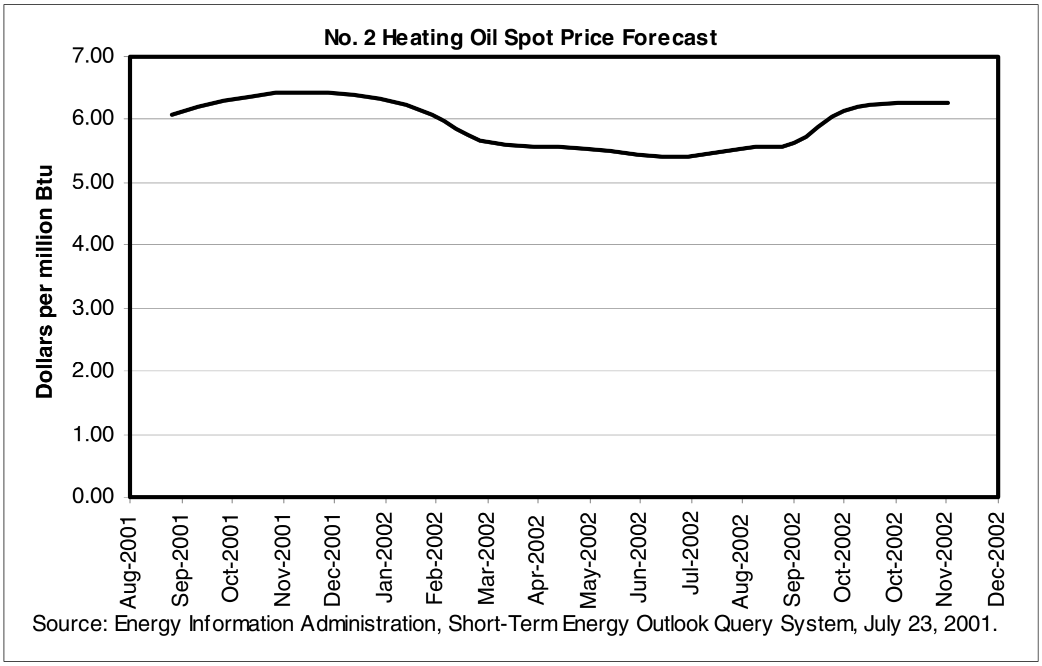


Figure 4-4
No. 2 Heating Oil Spot Forecast

Distillate fuel oil demand grew by 3.4 percent in 2000. However, demand for distillate fuel oil is only expected to grow by 1.8 percent in 2001.[7] This demand compares with anticipated natural gas demand growth of 1.6 percent in 2001. Distillate pricing is expected to stay relatively low, with less fluctuation than natural gas.

[7] Source: Energy Information Administration, Short-Term Energy Outlook. July 2001.

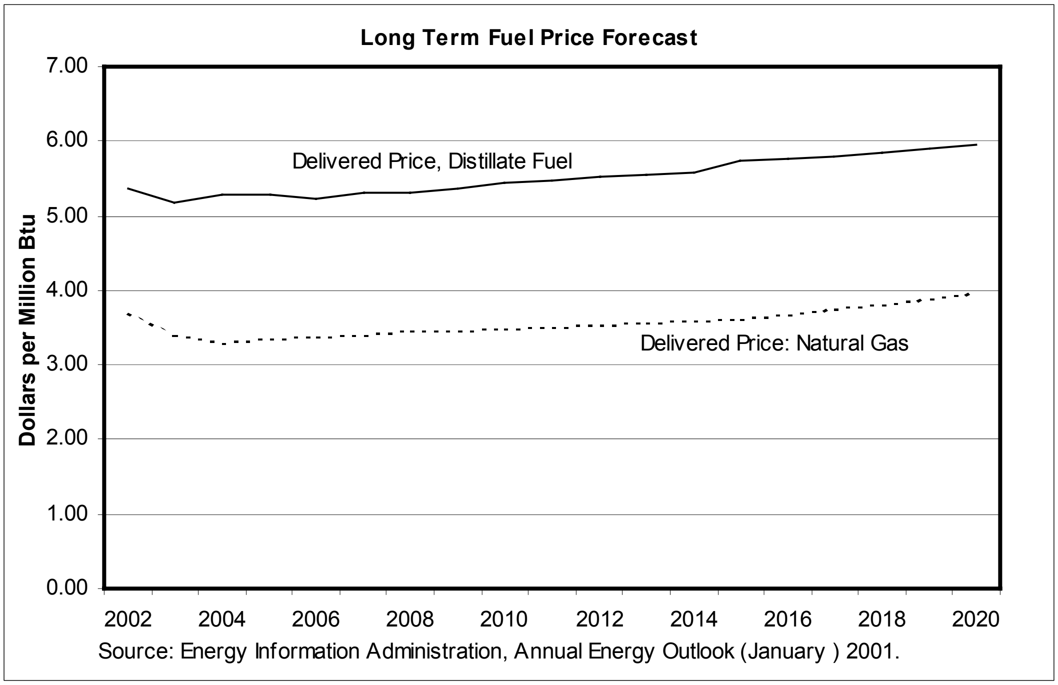


Figure 4-5
Long Term Fuel Price Forecast

The Energy Information Administration, in its Annual Energy Outlook 2001, forecasts that distillate pricing, over the next fifteen to twenty years, will remain higher than natural gas pricing, as the above figure reflects. This differential, while not indicative of the short-term situation of winter 2000-2001, is something that the project developer must incorporate into his decision of whether to convert to dual fuel firing due to economic reasons. What remains to be seen is how the pricing differential behaves over the next twelve to eighteen months, which may then give indication toward a revised long term forecast. Given long term forecasts, there still may be regional or local conditions that could indicate an economic choice for dual fuel capability.

Justification Criteria

Based on the preceding discussion, the following list comprises the bulk of the justification criteria for this decision:

- Incremental economics -- The incremental benefit afforded as a direct result of converting to or not converting to dual fuel.
- Catastrophic economics -- The non-revenue consequence of not being able to generate due to lack of natural gas supply, most likely due to gas curtailment and no dual fuel option available.
- O&M Impact -- The differential cost and resource requirement to be imposed whether the additional systems of distillate oil storage and transport, and demineralized water storage, treatment, and transport.

- Permitting / Emissions Impact -- The result of having to apply for new air permitting, and also the possibility of having to reduce generating ability due to annual emissions restrictions.
- Plant Life Expectancy Impact -- The long-term result of firing distillate oil in the combustion turbine and HRSG systems: Shortened life of hot gas path parts, leading to increased O&M costs and potentially reducing plant life expectancy due to wear and increasing system degradation (power and heat rate).

The following chapters 5 and 6 quantify the O&M costs, capital costs, and financial impact of converting to dual fuel firing.

5
OPERATION AND MAINTENANCE (O&M) IMPACT

Introduction

It is important to evaluate how the long term operation and maintenance (O&M) of a combined cycle plant would be impacted by the decision to convert from natural gas only to dual fuel. Driving the primary decision in the current market is fuel price differential versus incremental capital cost. In addition, there will be impact in several O&M areas resulting in additional annual expenses:

- Maintenance of a new fuel system: tanks, pumps, offloading devices, distillate oil treatment
- Maintenance of a demineralized water system: tanks, pumps, treatment, piping, instrumentation.
- Increased combustion turbine life degradation: increased fouling, corrosion resulting in decreased parts life.
- Operations involving distillate oil re-supply

The purpose of this chapter is to evaluate these results in a quantitative manner to assess the O&M impact accurately.

Methodology: Use of EPRI CT Project Risk Analyzer Software

The CT Project Risk Analyzer program, developed by EPRI, was used in the preparation and generation of the O&M data to be presented in the following sections. The Project Risk Analyzer was developed in response to increasing need to (a) provide a systematic approach for using deterministic information to estimate CT operation and maintenance costs, and (b) to permit consideration of Monte Carlo-based statistical analysis in the estimation of CT project costs, with and without risk mitigation options. This analysis did not utilize the statistical analysis portion of the Risk Analyzer, but only the O&M cost estimation portion. The object was to utilize a proven and systematic approach to obtain deterministic cost information for O&M concerns. The version of the program used in this analysis was Version 1.01, released in January 2001.

SOAPP-CT Conceptual Design Model Definition

In the preceding chapter, the project scenarios were defined and described to provide the technical basis for the analysis which would follow. In this chapter, scenario data is introduced

The SOAPP WorkStation was used to provide performance, design, estimated capital and O&M costs, and financial results. Additional calculations were managed within external spreadsheets in order to produce the results that follow.

The three conceptual design cases under review are:

- Case 1 -- Base case; single fuel plant, natural gas only.
- Case 2 -- Dual fuel, with distillate oil fired 8% of the time; natural gas is fired for the remaining 92% of time; interruptible natural gas supply.
- Case 3a -- Dual fuel, with distillate oil fired 50% of the time; distillate is primary fuel for extended periods of time.

Note: Due to methodology chosen in SOAPP, several additional cases were evaluated in parallel with the above. Several "Case 3" conceptual designs were developed, with subtle differences. The case of record, however, is Case 3a. The 'a' suffice is a difference in nomenclature only.

Risk Analyzer Input Data

Data was input into the CT Project Risk Analyzer program in a manner consistent with the configuration and intended operating philosophy of each plant. Please refer to Appendix E for a full tabulation of all input data utilized for the three design cases.

Several significant factors varied between cases with regard to input data:

- Fixed staffing of the plant was input as follows:
  - Case 1 (base): 18 employees, based upon plant size and scope
  - Case 2: 19 employees; one additional Assistant Operator added
  - Case 3: 20 employees; further increased by one Lead Operator
- Plant chemical analysis cost, emissions analysis cost, and fuel analysis services cost were each increased from Case 1 to 2 to 3a due to increasing plant requirements of these services.
- Annual cost for SCR replacement and disposal was increased from Case 1 to 2 to 3a due to increasing consumption of catalyst as percentage of distillate firing was increased.
- Cost of raw water supply was increased from $653,400 in Case 1 to $665,500 in Case 2, to $729,200 in Case 3. These values were calculated within SOAPP-CT WorkStation, and transferred to CT Project Risk Analyzer. The reason for this is based upon the amount of water consumed as condensate in demineralized water system.
- Cost of combustion turbine inspection and overhaul was increased for Cases 2 and 3a due to increased complexity and scope due to dual fuel components and systems. With more components to inspect and repair, cost of maintenance likewise increases.
- Cost of HRSG inspection was increased for Cases 2 and 3a due to the increased size of the HRSG in dual fuel fired cases and due to the anticipated increase in acidic corrosion and fouling due to distillate firing.

CT Project Risk Analyzer -- Results

The results of the O&M analysis, as conducted through the use of EPRI's CT Project Risk Analyzer reflected increased costs as dual fuel capability was added and as distillate firing increased. This behavior was to be expected; however, quantification of the result was needed for this evaluation to be complete.

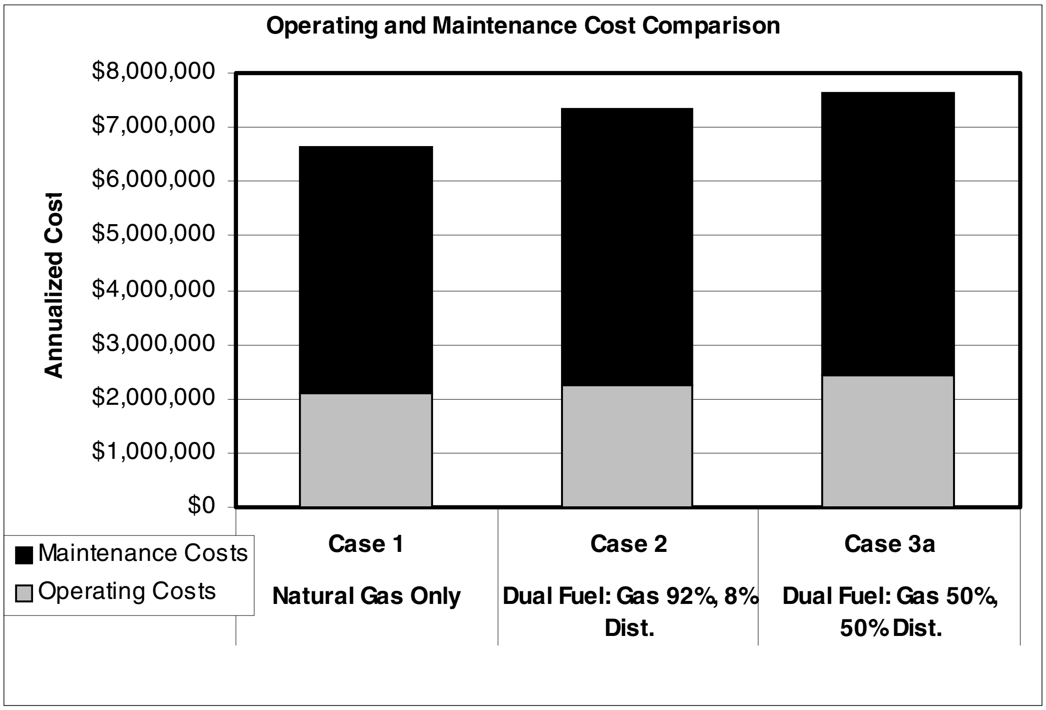


Figure 5-1
Operating and Maintenance Cost Comparison

As can be seen from the previous graph, costs rose in both operations and in maintenance. When dual fuel capability is added (Case2), the annual operating cost increased 6.1% and the annual maintenance cost increased 12.2%. When distillate firing is increased to 50% of the time (Case 3a), the operating cost increases by another 8.6%, while the maintenance cost increases by another 2.4%. For both Case 2 and Case 3a, the primary reason for the operating cost increase is the addition of operating personnel with each case. Case 2 added an Assistant Operator, while Case 3a added an additional Lead Operator. This increase in plant personnel is necessary to handle the additional fuel system on a daily basis, and to handle the increased responsibilities of increased distillate firing use. The increase in maintenance cost is very similar for both Cases 2 and 3a. To add distillate fuel capability, the plant maintenance budget is forced to make a step increase to handle the additional system. The difference in operating percentage between 8% distillate firing and 50% distillate firing affects the maintenance schedule, resulting in a minor increase to maintenance parts and materials.

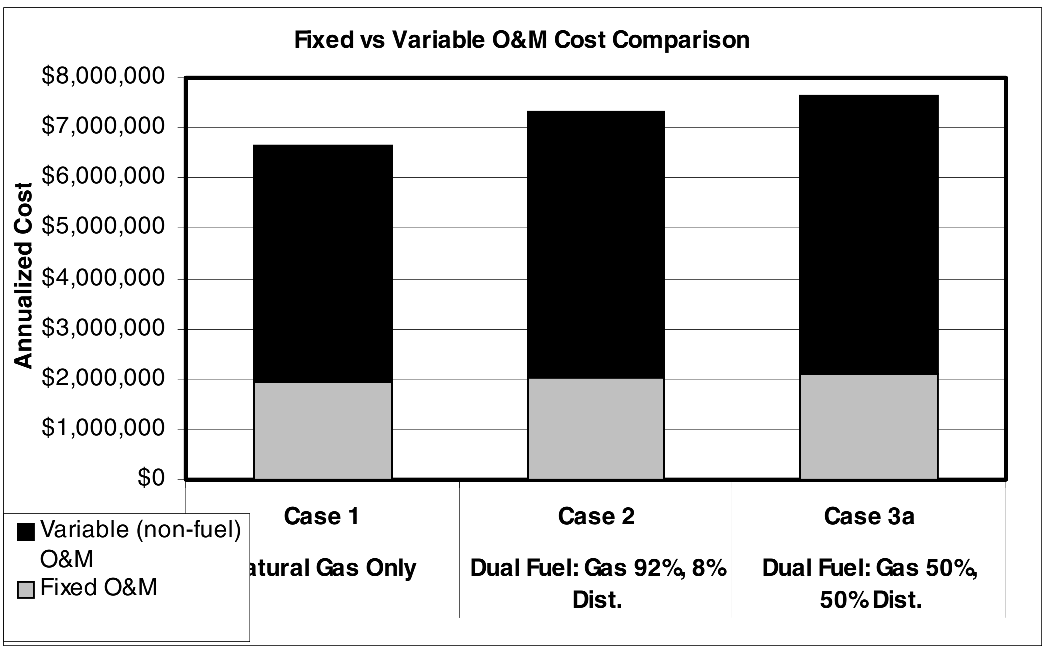


Figure 5-2
Fixed vs Variable O&M Cost Comparison

With regard to fixed and variable cost differences, the fixed cost rose 4.9% from Case 1 to Case2, and another 4.9% from Case 2 to Case 3a. Variable (non-fuel cost increased 12.5% from Case 1 to Case 2, while increasing another 4.1% from Case 2 to Case 3a.

Tabulated Results

Full tabulation of the CT Project Risk Analyzer results can be found in Appendix F. However, the following table presents the key O&M data generated.

Table 5-1
CT Project Risk Analyzer Output Data

	Natural Gas Only	Dual Fuel: Gas 92%, 8% Dist.	Dual Fuel: Gas 50%, 50% Dist.
	Case 1	**Case 2**	**Case 3a**
	Annualized Cost	Annualized Cost	Annualized Cost
Basis			
Plant Net Output, (Mwe, net arg)	266.8	268.1	274.7
Operating Costs			
Direct Labor (base, OT, bonus)	$744,000	$798,000	$864,000
Benefits (Indirect)	$217,000	$232,800	$252,000
Home Office/Support (Indirect)	$338,000	$341,000	$354,000
Catalyst Replacement	$57,600	$70,600	$72,700
Other Consumables	$720,500	$760,800	$851,300
Disposal Charges	$8,900	$11,000	$11,300
Purchased House Power	$19,100	$19,200	$19,600
Subtotal	**$2,105,100**	**$2,233,400**	**$2,424,900**
Maintenance Costs			
Direct Labor (base, OT, bonus)	$360,000	$360,000	$360,000
Benefits (Indirect)	$105,000	$105,000	$105,000
Annual O&M Services, Materials	$150,500	$172,000	$172,000
Scheduled Maintenance Parts/Mat'ls	$3,360,200	$3,786,800	$3,898,400
Scheduled Maintenance Labor	$420,900	$511,700	$523,000
Unplanned Maintenance	$141,000	$157,800	$159,000
Subtotal	**$4,537,600**	**$5,093,300**	**$5,217,400**
Grand Total	**$6,642,700**	**$7,326,700**	**$7,642,300**
Fixed and Variable Cost Summary	Annualized	Annualized	Annualized
Fixed O&M	$1,933,600	$2,027,900	$2,126,600
Variable (non-fuel) O&M	$4,709,100	$5,298,600	$5,515,500
Grand Total	**$6,642,700**	**$7,326,500**	**$7,642,100**
Normalized Fixed & Variable Cost	Normalized	Normalized	Normalized
Fixed O&M ($ / kW-yr net)	7.25	7.56	7.74
Variable (non-fuel) O&M ($ / MWh net avg)	2.37	2.65	2.70
Variable O&M - Gas Fuel ($ / MWh net avg)	2.37	2.36	2.30
Variable O&M - Dist Fuel ($ / MWh net avg)	----	6.04	3.09

Implication and Analysis of Results

For the scope of combined cycle plant evaluated in this study, the addition of dual fuel firing capability added $680,000 per year in additional O&M cost, even with minimal use, at 8% firing. Firing distillate a total of 50% of the time increased O&M costs by $1,000,000 per year, when compared with the natural gas fuel only plant. These cost increases do not reflect fuel price, but just the additional cost of operating and maintaining the plant. These increased annual costs were incorporated into the incremental analysis conducted in the previous chapter, which is an important point worth noting.

Stated in proportional terms, the cost of adding dual fuel capability and using it for 8% firing adds 10.3% to the annual O&M budget. Dual fuel firing at 50% gas and 50% distillate adds 15.0% to the O&M budget, when compared to the natural gas only plant.

Such increases should be considered moderately significant: they will not force an entirely different annual O&M budgetary position, but they do have a presence. The project developer should continue to consider catastrophic economics when weighing the reality of O&M cost increases of 10% and 15%. The cost of not being able to generate power during a gas curtailment may be far more significant, in the event that the plant is built with only gas firing. With lost generating revenue of $350,000 to $400,000 for just one day, an annual differential O&M cost of $680,000 may justifiable.

6
CAPITAL COST AND FINANCIAL IMPACTS

Conceptual Design Case Definitions

The three conceptual design cases that were introduced in the previous chapter will continue to be utilized in this chapter. For continued reference, the cases have been defined as:

- Case 1 -- Base case; single fuel plant, natural gas only.
- Case 2 -- Dual fuel, with distillate oil fired 8% of the time; natural gas is fired for the remaining 92% of time; interruptible natural gas supply.
- Case 3a -- Dual fuel, with distillate oil fired 50% of the time; distillate is primary for extended periods of time.

Conceptual Design -- Input Data

The plant profiled in this study is a typical design, recognizing there are often design differences between specific plants. The analysis was performed on an average ambient temperature basis and at full load for the stated capacity factor. During the last few years, there has been a trend to include duct firing more often. Therefore, this study included supplemental duct firing to generate approximately 25% more steam than combustion exhaust alone would have generated. The SOAPP WorkStation conceptual design input data for Cases 1, 2, and 3a can be found in its entirety in Appendix B. For convenience, the following is a table of primary conceptual design data:

Table 6-1
SOAPP Conceptual Design Input Data – Summary

SOAPP Case		**1**	**2**	**3a**
(Primary Fuel is always listed first)		**Nat Gas Only**	**Dual Fuel; 92% Gas, 8% Dist**	**Dual Fuel; 50% Gas, 50% Dist**
Variable	Units			
Unit Data		CCCG - 1 GE7FA - NG only	CCCG - 1 GE7FA - Dual Fuel - Case 2	CCCG - 1 GE7FA - Dual Fuel - Case 3a
CT Model Number	N/A	GE PG7241(FA)-60 Hz	GE PG7241(FA)-60 Hz	GE PG7241(FA)-60 Hz
Number of CT's	N/A	1	1	1
Duty Cycle/Mission	N/A	Base Load	Base Load	Base Load
HRSG Data				
Number of Pressure Levels	N/A	Three Pressure	Three Pressure	Three Pressure
HP Steam Pressure	psia	1800	1800	1800
IP Steam Pressure	psia	490	490	490
LP Steam Pressure	psia	60	60	60
Hot Reheat Pressure	psia	490	490	490
HP Steam Temp	F	1000	1000	1000
IP Steam Temp	F	600	600	600
LP Steam Temp	F	460	460	460
HP Pinch Point	F	15	14	14
IP Pinch Point	F	15	13	13
LP Pinch Point	F	10	9	9
HP Evap Approach	F	20	19	19
IP Evap Approach	F	20	18	18
LP Evap Approach	F	13	13	13
Include Duct Burners	N/A	Yes	Yes	Yes
DB HP Stm Flow Increase	%	25	25	25
Duct Burner Use	N/A	Full-Time	Full-Time	Full-Time
Duct Burner Fuel Capability	N/A	Primary Fuel Only	Dual Primary/Secondary Fuel	Dual Primary/Secondary Fuel
SCR Configuration	N/A	Anhydrous Ammonia Injection	Anhydrous Ammonia Injection	Anhydrous Ammonia Injection
Include CO Oxidation Catalyst	N/A	No	No	No
Steam Turbine Data				
Steam Turbine Arrangement	N/A	G-Reheat, 2 Casing, 1 Flow, Direct Drive	G-Reheat, 2 Casing, 1 Flow, Direct Drive	G-Reheat, 2 Casing, 1 Flow, Direct Drive
HP ST Efficiency	%	87	87	87
IP ST Efficiency	%	89	89	89
LP ST Efficiency	%	91	91	91
Plant Data				
Capacity Factor	%	85	85	85
Service Factor	%	90	90	90
Equivalent Availability Factor	%	95	95	95
Output Degradation Factor	%/yr	3	3	3
Heat Rate Degradation Factor	%/yr	1.5	1.5	1.5
Site Data		Kenosha, WI - Case 1	Kenosha, WI - Case 2	Kenosha, WI - Case 3a
Max Ambient Dry Bulb Temp	F	85	85	85
Max Ambient Wet Bulb Temp	F	73	73	73
Min Ambient Dry Bulb Temp	F	-20	-20	-20
Perf Point Dry Bulb Temp	F	59	59	59
Perf Point Wet Bulb Temp	F	51	51	51

SOAPP Case		1	2	3a
Site Elevation	ft	600	600	600
Stack Natural Gas NOx Limit	ppmvd @ 15% O2	5	5	5
Stack Fuel Oil NOx Limit	ppmvd @ 15% O2	9	9	9
Economic Data		Base Econ	Base Econ	Base Econ
Ownership Type	N/A	Independent Power Producer	Independent Power Producer	Independent Power Producer
Capital Costs Esc Rate	%/yr	2	2	2
O&M Costs Esc Rate	%/yr	2	2	2
Common Equity Fraction	N/A	0.25	0.25	0.25
Debt Fraction	N/A	0.75	0.75	0.75
Return on Debt	%	9	9	9
Return on Debt During Construction	%	10	10	10
Energy Payments	$US/MWh	65.00	65.00	65.00
Fuel Data		Nat Gas	Nat Gas	Nat Gas
Primary Fuel Type	N/A	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	N/A	None	No. 2 Fuel Oil	No. 2 Fuel Oil
Secondary Fuel Usage	%	0	8	50
Primary Fuel Price	$US/MBtu	6.00	6.00	6.00
Secondary Fuel Price	$US/MBtu	5.30	5.30	5.30
Gas Supply Pressure	psig	400	400	400

Conceptual Design -- Results

Analyzing three different design cases involving single fuel vs. dual fuel configurations involves having to make several concerted decisions regarding how to ensure uniformity of design, yet providing the correct differences where necessary. The stated goal is to provide an objective, controlled comparison between configurations. In order to capitalize on the data generated by the SOAPP WorkStation, supplemental calculations were made within an external spreadsheet to generate the results to follow.

Conceptual Design -- Performance

The design analysis shown in Table 6-2 demonstrates the increased output and MW hours for distillate oil firing. It has been assumed that the decision for distillate oil firing was decided early in the project schedule when it is possible to have the larger HRSG surface areas for efficient distillate operation.

The net plant output from the three cases, when operating on natural gas, is slightly different when the single fuel case (Case 1) is compared to the dual fuel cases (Case 2 and 3a). The reason for this is that the HRSG for the dual fuel cases is slightly larger due to modifications that were made to allow for the greater exhaust production when distillate firing occurs. Although gross plant output is greater in Cases 2 and 3a at 272.4 MW, the net plant output for the same cases is approximately equal, at 266.8 MW. The dual fuel plants have slightly greater auxiliary load losses, offsetting the slightly greater gross plant output.

When reviewing performance on secondary fuel (distillate), the reader will notice that combustion turbine gross output is greater than when fired on natural gas (181.5 MW vs. 165.5 MW) this is inherent with the combustion turbine design and performance, when operated on different fuels. When extrapolated to an annual electricity output comparison, this difference resulted in the greatest level of production from Case 3a (2,217,000 MWh), the second greatest from Case 2 (2,164,000 MWh), and the least from Case 1 (2,154,000 MWh). The increase in megawatt-hours in Case 3a, on an annual basis, is 63,400 MWh, which represents an increase of 2.9% over the single fuel only configuration. The financial impact of this difference will be evaluated later in this chapter.

Table 6-2
SOAPP-CT Technical Results

SOAPP Design Analysis

Case		**Case 1**	**Case 2**	**Case 3a**
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
TECHNICAL RESULTS				
Primary Fuel				
CT Gross Output, per CT	kW	165,492	165,492	165,492
CT Heat Input (HHV), per CT	MBtu/h	1,744.65	1,744.65	1,744.65
CT Exhaust Flow per CT	lb/h	3,458,391	3,458,391	3,458,391
HRSG Surface Area, Total	ft^2	1,695,979	1,764,634	1,764,634
HP Steam Flow at HRSG	lb/h	518,507	520,568	520,568
Duct Burner Heat Input (HHV)	MBtu/h	104.6	104.6	104.6
Stack Exhaust Temperature	F	181	178	178
Hot Reheat Steam Flow at ST	lb/h	576,936	577,367	577,367
Gross ST Output	kW	106,728	106,923	106,923
Gross Plant Output	kW	272,220	272,415	272,415
Auxiliary Power	kW	5,385	5,587	5,587
Net Plant Output, Primary Fuel	kW	266,835	266,829	266,829
Equipment Availability Factor		0.95	0.95	0.95
Output Degradation	%	3%	3%	3%
Primary Fuel Usage		100%	92%	50%
Net Generation, Primary Fuel, annual	**MWh**	**2,153,983**	**1,981,620**	**1,076,967**
Secondary Fuel				
CT Gross Output, per CT	kW	0	181,544	181,544
CT Heat Input (HHV), per CT	MBtu/h	0.00	2,017.75	2,017.75
CT Exhaust Flow, per CT	lb/h	0	3,616,524	3,616,524
Net Plant Output, Secondary Fuel	kW	0	282,552	282,552
Equipment Availability Factor		0.95	0.95	0.95
Output Degradation	%	3%	3%	3%
Secondary Fuel Usage		0%	8%	50%
Net Generation, Secondary Fuel, annual	**MWh**	**0**	**182,468**	**1,140,427**
Net Generation, Total, annual	**MWh**	**2,153,983**	**2,164,088**	**2,217,394**

Conceptual Design -- Capital Cost

The capital cost of the plant for each of the three cases was calculated using the SOAPP WorkStation, and is presented in Table 6-3. The incremental capital cost for the case study scenario is approximately $8 million, which excludes costs for additional land. In generating this information, updated costs were utilized for major equipment components. The capital costs for Cases 2 and 3a reflect a dual fuel conversion decision made early in the project development schedule. The capital costs reflect modest increases due to design change, but not the level that would be required to convert a plant that was in the middle of physical construction, or later.

In order to better display and assess the capital cost differences, several additional quantitative parameters were added as follows:

- Percent Change (%): This is the percent increase in capital cost over Case 1. This parameter provides an assessment of how much additional cost is added, by category, when dual fuel conversion occurs.
- Change Percent of Total Capital (%): This is the cost increase expressed as a percent of total capital cost. The merit of this parameter is that the dollar value of the increase may be compared to the dollar value of the entire plant. Where a category may have a high percent change relative to its category value, its actual impact on the whole plant cost increase may be very marginal.
- Cost of Change ($/kW): This is the cost increase expressed in dollars per net plant output in kW. This parameter provides a scalable basis for the cost increase -- comparing the number of dollars of cost increase relative to the size of the plant.

The results displayed in the following table reveal several important principles:

- First, the categories displaying the largest dollar value increases are the ones that would be expected: the combustion turbine cost rises by $1.7 million for both Case 2 and 3a, fuel system cost rises by $1.63 million for Case 2 and by $1.99 million for Case 3a, water treatment and waste water treatment cost rises by $2.5 million for both Case 2 and 3a.
- Second, the plant planning to operate on distillate the most (Case 3a) also reflects the greatest cost increase $8.53 million due mostly to the increase in distillate oil tank storage size. The 8% distillate fired plant (Case 2), only reflected a cost increase of $8.17 million when compared to the base case.
- Third, the overall cost increase for the two dual fuel plants, when expressed as the 'cost of change', reflected an anticipated cost increase of $30.5 to $31.0 per kW of net plant output. Depending on additional factors, such as late decision to convert to dual fuel, lack of raw water supplies, difficult distillate oil delivery costs, or very high air permitting costs, the cost of the dual fuel conversion could be significantly greater -- up to $40.00 to $50.00 per kW.

The impact of the incremental capital cost to perform the dual fuel conversion on overall project economics will be presented later in this chapter.

Table 6-3
Capital Cost Comparison

Case	1	2				3a			
(Primary Fuel is always listed first)	**Nat Gas Only**	**Dual Fuel; 92% Gas, 8% Dist**				**Dual Fuel; 50% Gas, 50% Dist**			
Description	CapCost Total ($x1000)	CapCost Total ($x1000)	Pct Change	Change Pct of Total Capital	Cost of Change ($/kw)	CapCost Total ($x1000)	Pct Change	Change Pct of Total Capital	Cost of Change ($/kw)
Combustion Turbine & Accessories	**43,200**	**44,900**	**4.0%**	**1.6%**	**6.40**	**44,900**	**4.0%**	**1.6%**	**6.25**
Inlet Filtration System	800	800	0.0%	0.0%	0.00	800	0.0%	0.0%	0.00
Electrical Systems - Combustion Turbine	3,400	3,400	0.0%	0.0%	0.00	3,400	0.0%	0.0%	0.00
Condensate Heating System	2,000	2,100	8.1%	0.1%	0.60	2,100	8.1%	0.1%	0.58
HRSG's & Accessories	12,100	12,400	2.7%	0.3%	1.21	12,400	2.7%	0.3%	1.18
Deaeration System	200	200	0.5%	0.0%	0.00	200	0.5%	0.0%	0.00
Duct Burner System	200	500	150.0%	0.3%	1.09	500	150.0%	0.3%	1.06
Post Combustion Emissions Controls	900	1,300	52.5%	0.4%	1.67	1,300	52.5%	0.4%	1.63
Steam Piping	1,200	1,200	2.2%	0.0%	0.10	1,200	2.2%	0.0%	0.09
Electrical Systems - HRSG's	200	200	1.9%	0.0%	0.01	200	1.9%	0.0%	0.01
Steam Turbine & Accessories	18,400	18,700	1.7%	0.3%	1.15	18,700	1.7%	0.3%	1.12
Steam Bypass System	1,200	1,200	0.0%	0.0%	0.00	1,200	0.0%	0.0%	0.00
Electrical Systems - Steam Turbine	3,600	3,600	0.8%	0.0%	0.11	3,600	0.8%	0.0%	0.11
Condenser & Accessories	1,700	1,700	0.1%	0.0%	0.01	1,700	0.1%	0.0%	0.01
Circulating Water System	4,800	4,800	0.1%	0.0%	0.02	4,800	0.1%	0.0%	0.02
Water Treatment System	**1,000**	**2,900**	**177.5%**	**1.7%**	**6.90**	**2,900**	**177.5%**	**1.7%**	**6.73**
Waste Water Treatment System	**300**	**900**	**236.9%**	**0.6%**	**2.42**	**900**	**236.9%**	**0.6%**	**2.36**
Boiler Feed System	1,000	1,000	2.0%	0.0%	0.07	1,000	2.0%	0.0%	0.07
Condensate System	200	300	2.0%	0.0%	0.02	300	2.0%	0.0%	0.02
Buildings	7,600	8,200	8.7%	0.6%	2.46	8,200	8.7%	0.6%	2.40
Fire Protection System	1,000	1,000	3.3%	0.0%	0.12	1,000	3.3%	0.0%	0.12
Fuel Systems	**500**	**2,100**	**336.2%**	**1.5%**	**6.10**	**2,500**	**409.5%**	**1.8%**	**7.24**
Main Exhaust Stack	700	700	-0.1%	0.0%	0.00	700	-0.1%	0.0%	0.00
Station & Instrument Air System	600	600	0.8%	0.0%	0.02	600	0.8%	0.0%	0.02
Closed Cooling Water System	400	400	0.2%	0.0%	0.00	400	0.2%	0.0%	0.00
Cranes & Hoists	300	300	0.0%	0.0%	0.00	300	0.0%	0.0%	0.00
Plant Control System	1,100	1,100	0.0%	0.0%	0.00	1,100	0.0%	0.0%	0.00
Continuous Emission Monitoring System	600	600	0.9%	0.0%	0.02	600	0.9%	0.0%	0.02
Total Process Capital	**109,000**	**117,200**	**7.5%**	**7.5%**	**30.49**	**117,500**	**7.8%**	**7.8%**	**31.05**

Cap Cost Total:	Combined total of equipment, material, and labor, in thousands of dollars.
Pct Change:	Percent increase over Case 1 total.
Change Pct of Total Capital:	Cost increase expressed as percent of total capital cost.
Cost of Change:	Cost increase expressed in dollars per net plant output in kW.

Conceptual Design – Financial Analysis

A valuable measure of an incremental capital investment is its impact on annual cash flow. The results derived from the SOAPP WorkStation were incorporated into an external spreadsheet to perform a detailed revenue vs. expenses comparison. Revenue was calculated by multiplying actual power by operational time by energy price. Fuel expenses were calculated by applying actual fuel consumed to associated fuel price. Results of the CT Project Risk Analyzer provided detailed O&M cost data. The resulting annual cash flow, for the base year, can be seen in Table 6-4 below.

Table 6-4
Financial Results

SOAPP Design Analysis

Case		**Case 1**	**Case 2**	**Case 3a**
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
FINANCIAL RESULTS				
REVENUE				
Energy Payments	$/MWh	$65.00	$65.00	$65.00
Net Revenues	**$/yr**	**$140,008,885**	**$140,665,721**	**$144,130,642**
OPERATING EXPENSE				
O&M Cost	$/yr	6,891,505	7,298,406	7,839,622
Property Taxes & Insurance	$/yr	2,651,164	2,850,319	2,859,008
Primary Fuel				
Net Plant Heat Rate, HHV	Btu/kwh	6,930	6,931	6,931
Primary Fuel Input, HHV	MBtu/hr	1,849.17	1,849.39	1,849.39
Annual Primary Fuel Consumed	MBtu	14,927,101	13,734,606	7,464,460
Primary Fuel Price	$/MBTU	6.00	6.00	6.00
Ann. Primary Fuel Expense	$/yr	$89,562,607	$82,407,635	$44,786,758
Secondary Fuel				
Net Plant Heat Rate, HHV	Btu/kwh	0	7,162	7,162
Secondary Fuel Input, LHV	MBtu/hr	0.00	2,023.64	2,023.64
Ann. Secondary Fuel Consumed	MBtu	0	1,306,838	8,167,740
Secondary Fuel Price	$/MBTU	5.30	5.30	5.30
Ann. Secondary Fuel Expense	$/yr	$0	$6,926,244	$43,289,023
Tax Depreciation	$/yr	9,908,709	10,638,494	10,676,323
Interest Expenses	$/yr	10,686,334	11,573,563	11,695,742
Net Expenses	**$/yr**	**$119,700,319**	**$121,694,661**	**$121,146,476**
COMPILED RESULTS				
Net Income	$/yr	$20,308,566	$18,971,061	$22,984,166
Internal Rate of Return, 30 yr scope	%	24.55%	18.94%	5.82%

Implication and Analysis of Results

Unlike traditional methods of evaluating project economics, such as financial analysis of rate of return over the life of a plant, the evaluation of dual fuel conversion must be conducted differently. To confidently compare the economics of dual fuel conversion over an entire accounting book life (i.e. thirty years), one would have to be certain of the long-term fuel prices employed. Earlier in this report, it was shown that the long-term fuel price outlook was significantly different than its short-term outlook.

With present market conditions and fluctuations, a sustained gas surcharge differential of $0.70 per million Btu (0.66 per GJ) over thirty years is subject to a high degree of uncertainty. Absolute fuel pricing can be estimated with some assurance, i.e. "fuels will cost roughly $4.00 to 5.00 per million Btu ($3.79 to $4.74 per GJ)". Because an incremental investment such as dual fuel conversion is based on short-term factors, it is best evaluated on an annual cash flow basis. Under this convention, its value will be measured within the metric of "payout" time, that is the length of time at a prescribed fuel price differential that would be required for the capital cost of the investment to equal the incremental benefit derived. The following table is presented on this basis:

Incremental Basis

Table 6-5
Incremental Analysis

SOAPP Design Analysis

Case		**Case 1**	**Case 2**	**Case 3a**
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
INCREMENTAL ANALYSIS				
Net Income	$/yr	20,308,566	18,971,061	22,984,166
Incremental Capital Expense	$		8,173,000	8,529,000
Capital Cost, Total Plant	$/net kW	408.45	437.03	427.82
Capital Cost, Dual Fuel Sys	$/net kW		30.49	31.05
Incremental Income Increase	**$/yr**		**-$1,337,505**	**$2,675,599**
Investment Payout Time	**Months**		**No Payout**	**38.3**
Fuel Price Differential	$/MBTU	0.70	0.70	0.70
Estimated Number of Months/Yr at Differential	Months	4	4	4
Investment Payout Time, Real Time	**Years**		**No Payout**	**9.6**

Case 2 reflects a very significant economic result. Under the conditions of the study, the capital investment results in an incremental annual decrease in net income. The reason why Case 2 shows a negative incremental income increase is that, for the fuel price differential assumed, the increased revenue generated from firing distillate oil 8% of the time was less than the operational expense of running the plant, which is more expensive due to the additional fuel system and demineralized water system. Net income decreased in Case 2 from $20.31 million to $18.97 million. Although the plant in Case 2 now would benefit from having the technical ability to continue power generation under conditions of exceedingly high gas prices or gas curtailment, the direct economics of a $0.70 per million Btu ($0.66 per GJ) fuel price differential will not justify the investment.

Case 3a, on the other hand, does reflect a positive incremental increase of $2.68 million annually. With an incremental capital investment of $8.53 million, the investment (ignoring inflation and present worth discounting) achieves a payout of 38 months. If the fuel price differential were assumed to exist for four months of each year, the investment would pay out in nearly ten years. This is based on direct economics; again, the indirect benefits of dual fuel firing are not reflected with this analysis.

Many additional financial parameters are disclosed in the Appendices of this report. This concept of payout leads to an additional discussion of determining the minimum fuel price differential to directly favor the investment.

Minimum Required Fuel Price Differential

Based on the preceding information regarding investment payout, it is of interest to calculate the minimum required fuel price differential for distillate versus natural gas which would justify the capital investment on a purely economic basis. Given that the direct economic benefit only results when natural gas price is greater than distillate price, the minimum differential would be the point at which incremental income increase is zero. For Case 2, based on an incremental capital expense of $8,173,000 to convert to dual fuel, the minimum fuel price differential is **$1.72 per MBTU ($1.63 per GJ)**. Thus, if distillate pricing were $4.00 per MBTU, the investment would only pay out if natural gas pricing could be assumed to be at least $5.72 per MBTU ($5.42 per GJ). Likewise, for Case 3a, based on an incremental capital expense of $8,529,000 to convert to dual fuel, the minimum fuel price differential is **$0.37 per MBTU ($0.35 per GJ)**. The latter scenario is more likely to occur over a long term analysis.

Case Study Analysis

Due to the large number of pertinent parameters which impact ultimate results, an ancillary case study was performed based upon the SOAPP WorkStation data and the external spreadsheet presented in preceding sections. The purpose of the case study was to show the interrelation between the contributing factors. The following three figures show how the financial results vary with changes in natural gas and distillate prices. All three figures utilize the same base electricity price of $65.00 per MWh. The first figure reflects a constant distillate price of $4.00 per million Btu ($3.79 per GJ). The second figure reflects a distillate price of $6.00 per million Btu ($5.69 per GJ). The third figure reflects a distillate price of $8.00 per million Btu ($7.58 per GJ).

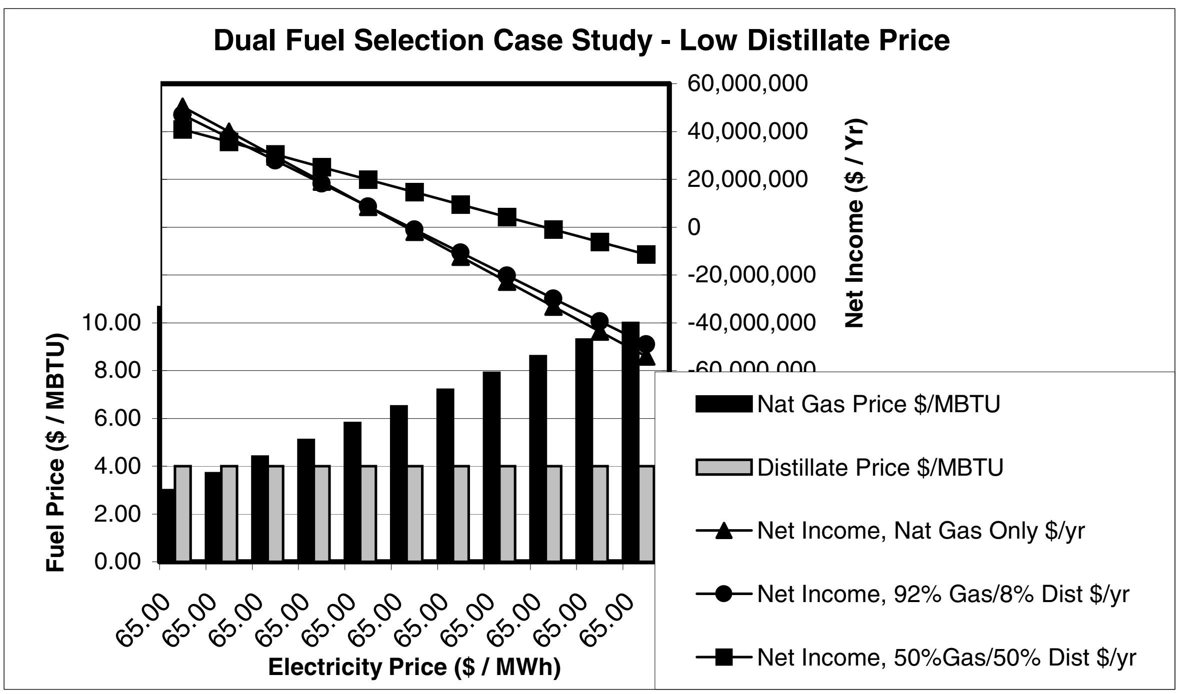


Figure 6-1
Dual Fuel Selection Case Study - Low Distillate Price

This first figure, with a low distillate price, shows that, except for the first two cases, the 50% gas/50% distillate operating plan is the most profitable. The clear indication is that, for a low distillate price scenario, the dual fuel plant offers positive net income, even with gas prices over $8.00 per MBtu ($7.58 per GJ).

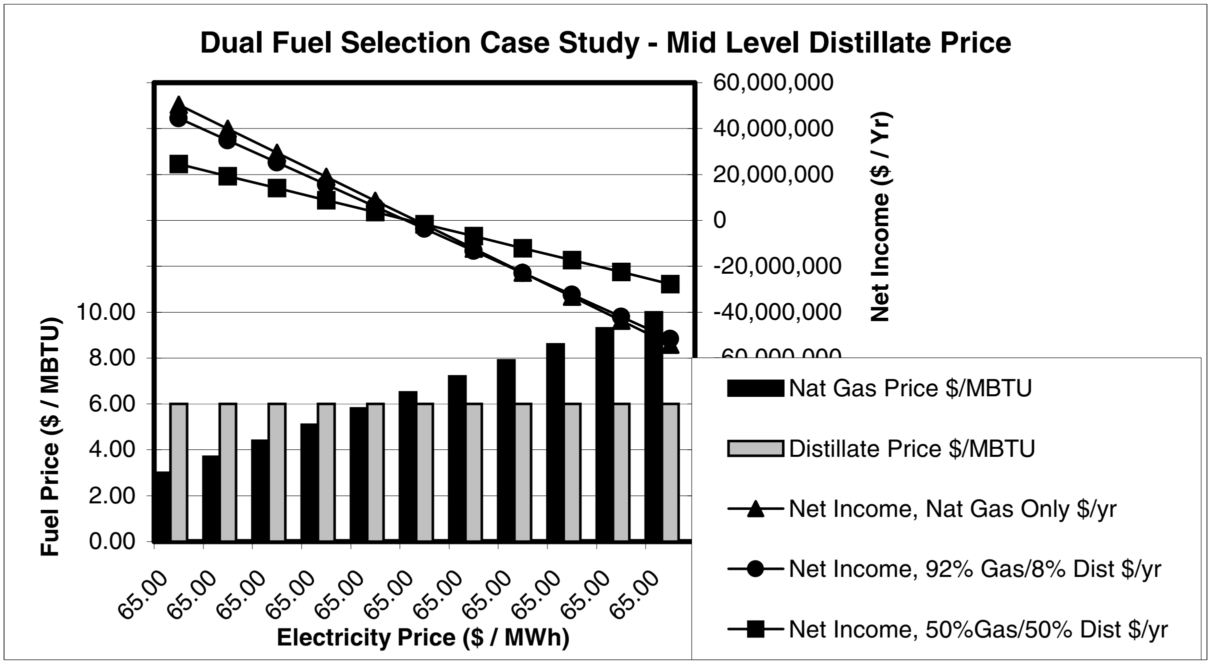


Figure 6-2
Dual Fuel Selection Case Study - Mid Level Distillate Price

In a mid-level price distillate scenario, the benefit of the 50% gas/50% distillate case is much less pronounced, although still economic for high gas price scenarios. The single fuel case demonstrates the greatest level of net income for low gas price scenarios, although it does not offer the protection of dual fuel operation.

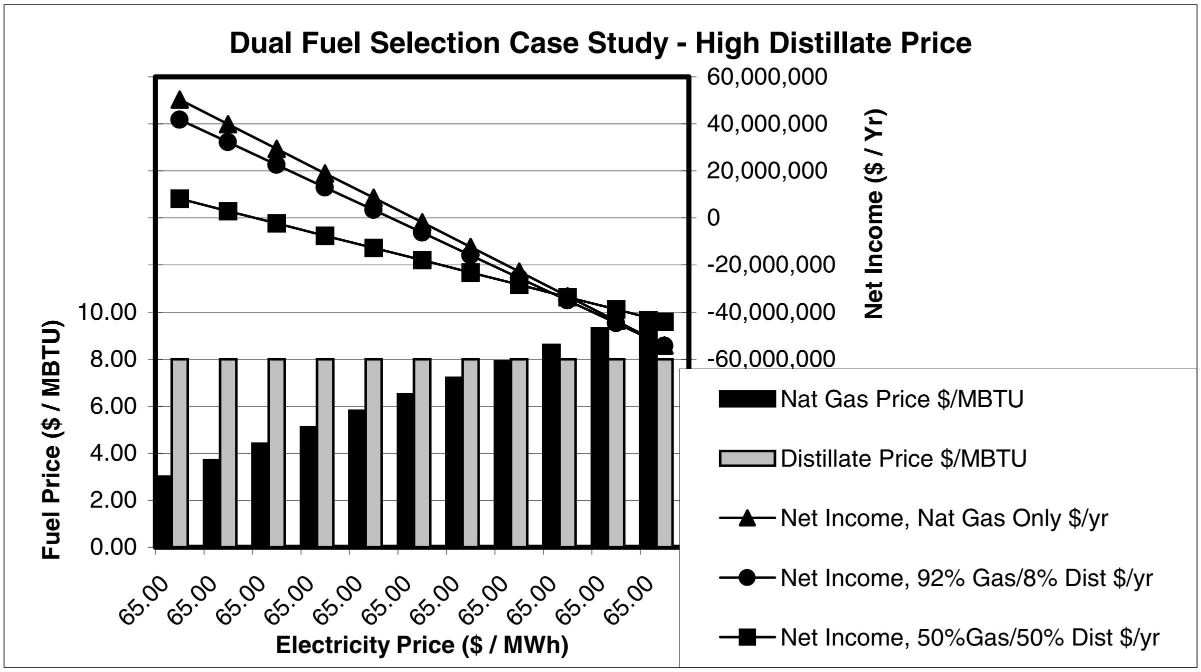


Figure 6-3
Dual Fuel Selection Case Study - High Distillate Price

For high distillate pricing scenarios, operating in either of the two dual fuel modes proves to be less economic than the single fuel plant except in highest gas price scenarios (greater than $9.00 per million Btu ($8.53 per GJ)). By viewing the interaction of the parameters of electricity price, gas price, distillate price, and primary/secondary fuel selection, one can more readily understand the conditions that must be present to justify dual fuel conversion.

Firm Versus Interruptible Gas Contracts

Although conversion to dual fuel capability is unlikely to be justified based on differntial costs between distillate and gas, it could be justified based on cost differntial between prices for firm versus interruptilbe contracts for natural gas. Quantification of these differentials is beyond the scope of this report but is discussed in other forthcoming EPRI reports dealing with fuel supply and CT project risks. As an example, if the differential were as little as $.30 /MMBtu for natural gas, the payback period for the incremental costs of dual fuel conversion for the scenario studied in this report would be about 2 years and worthy of consideration.

Chapter Conclusion

The results of the incremental analysis indicated a marginal benefit of conversion only when either the fuel price differential strongly favored distillate firing or when the percentage of distillate firing was high, in combination with a slightly favorable fuel price differential toward distillate. The significant risk is that gas prices do not have historical precedent for remaining above distillate prices, except for short periods of time. The project developer must consider how likely gas prices are forecast to be high, in the future. Extracting figures from this analysis, if natural gas will be more than $0.70 per million Btu ($0.66 per GJ) greater than distillate, for a period of at least four months of the year, then the investment will pay out in nine and one-half years. Of course, larger differentials will pay out the investment in proportionately less time.

The direct economics are marginal under most scenarios. This fact must be coupled with the additional factors of increased maintenance, increased emissions, greater operating costs, and greater fuel flexibility when ultimately committing to dual fuel conversion. The case studies therefore demonstrate why decisions to have dual fuel firing capability are based fundamentally on gas availability and/or the requirement to generate even in times of gas supply interruption. Detailed analysis to determine the impact of firm versus interruptible gas costs is required to justify dual fuel conversion and depends significantly on gas supply constraints, particularly during seasonal periods.

7
ALTERNATIVE ISSUE: GAS STORAGE OPTIONS

Introduction

To this point in the report, the only proposed remedy in response to the increased volatility in the gas market has been the conversion of plant firing to dual fuel technology. However, a new alternative is becoming increasingly pursued, and bears mention in this context.

The alternative is natural gas storage, below ground in proven geologic reservoirs, in quantities that permit price hedging in today's constantly changing gas market. Natural gas storage has long been the domain of gas distribution companies, but conditions may be appropriate for project developers to pursue this further as an avenue for the gas-fired combined cycle power plant. At least one company has already embarked on this strategy.

Background

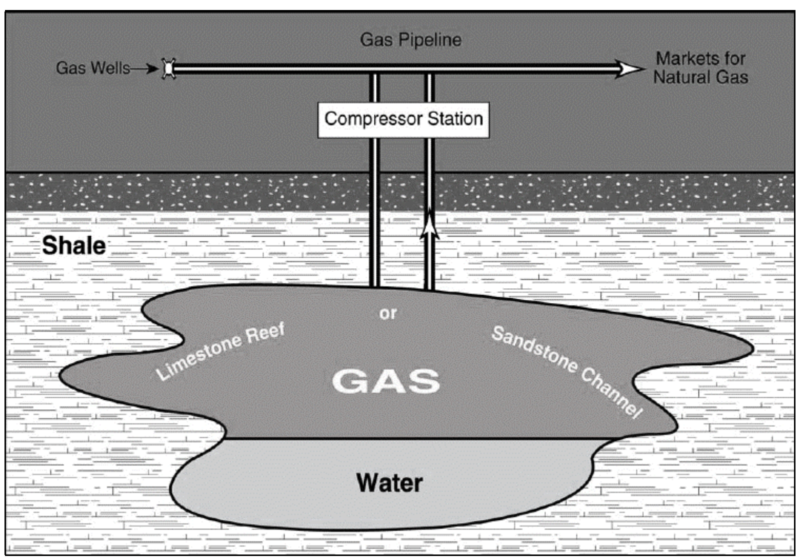


Figure 7-1
Simplified Diagram: Natural Gas Storage Field[8]

Natural gas storage is accomplished via the injection and removal of natural gas into and from depleted gas production reservoirs. Where some gas fields have demonstrated variable gas producing ability, those that prove to be the best candidates for gas storage are those where the

[8] Source: Progas Storage Services, Inc. http://www.progas.net.

formation structure is clearly defined and rock porosity is high and uniform. These formations can contain 30% or more pore space by volume. A typical type of reservoir, known as a volumetric-drive reservoir, is contained beneath a dome of low permeability, low porosity material, usually salt. By drilling wells from the earth's surface into this domed reservoir, access can be provided to a very large volume of porous rock. Gas storage reservoirs can be repressurized multiple times by using high-pressure gas compression equipment to inject gas during periods when demand is low, but the need is present to safely store gas for rapid withdrawals at a later date.

Most new gas-fired generation does not presently have the capability to switch between fuels when gas prices rise or gas itself is curtailed. Storage is becoming more important to power plant owners in today's volatile gas market. Consultant Jeffrey Schroeter, of Genovation Group Inc., stated the following recently in an article for Oil & Gas Journal Online: "Instead of fuel switching, storage can be used for some power plants as a physical hedge to deal with gas volatility. These strategies make sense in today's volatile market. Before storage was used just for peaking plants. Now it may be more interesting for base load too."[9]

Nationally, natural gas consumption is rising 2.3%/year, and is driven by new power plant development. The Energy Information Administration estimates that electric generators account for 57% of the increase in domestic natural gas consumption. In 2000, 28% of annual gas demand was related to electricity.[10] However, EIA economists do not necessarily believe that new gas storage capacity is the solution to increased gas demand. To the EIA's natural gas team, the gas infrastructure is adequate for reasonable uses today. The problem is the volume of gas in storage, not the capacity. As of April 6, 2001, the amount of gas in storage was 641 BCF (18.15 BCM), or just 19% of total storage volume, according to EIA.[11]

In the early 1990's, regulatory changes separated the storage function from distribution and transportation. Local distribution companies (LDCs) had little economic incentive to develop new facilities. Unseasonably mild winters and plenty of $2.00 to $2.50 per thousand cubic feet ($0.071 to $0.089 per cubic meter) gas further diminished the incentive to develop localized storage. However, power plant needs are different from LDCs. They need to ramp up and down very quickly; gas is needed on demand and often in quantities not readily available directly from the main pipeline.

Options for Combined Cycle Plants

In response to such conditions, owners of combined cycle power plants are increasingly evaluating underground gas storage as a viable method of stabilizing prices, and ensuring a readily available supply independent of natural gas transmission companies. One company has already taken action. In February 2001, the Federal Energy Regulatory Commission (FERC) granted an affiliate of Houston-based eCorp Holding LLC a permit for its new Stagecoach storage field, a 12 BCF (0.34 BCM) storage project near Oswego, New York. A field of this size represents approximately a 285 day supply of natural gas for a single GE 7FA combustion turbine. The storage field is conveniently located between several interstate gas pipelines running

[9] "Gas Storage Increasingly Linked to Electric Power Plants' Needs", OGJ Online. A. de Rouffignac. March 2001.
[10] Annual Energy Outlook 2001. Energy Information Administration. Department of Energy. 2001.
[11] Natural Gas Weekly Market Update. Energy Information Administration. April 16, 2001.

to the north and to the south. The field will serve a new 520 MW combined cycle plant to be constructed on the Lounsberry Industrial Park Site in Nichols, New York, by Twin Tier Power.

Storage is expected to play a more dominant role because of high deliverability facilities that can provide injection or withdrawal services on an hour's notice. High deliverability storage is attractive to power plant owners who need to power up and down quickly during peak demand and to marketers who want to take advantage of volatile gas prices.

Chapter Conclusion

Applying the principles of underground natural gas storage to the fuel needs of combined cycle cogeneration plants is a relatively new concept. Until recently, it has not been pursued by many companies due to prevailing economics. However, with projections for sustained higher gas prices, and increasing demand, economics of local storage may prove feasible under some circumstances. Several gas storage consultant companies exist, and should be contacted if project developers or plant owners wish to pursue such endeavors.

8 CONCLUSIONS

Energy market predictions are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, and technological breakthroughs. The decision to convert a plant under development to dual fuel must be made with this level of understanding. Historically, distillate fuel has been more expensive than natural gas, and any economic model dependent upon high natural gas pricing scenarios will need to directly address this trend.

As was discussed in Chapter 1 and again in Chapter 4, the recent behavior of natural gas prices is unprecedented. This condition created some increase in the amount of distillate used for power generation, as signs do show that dual fuel-capable plants made the switch to distillate and other fuel oils throughout the winter of 2000-2001. However, the issue that became critical was how reasonable a conversion to dual fuel would be, if the plant had not previously been designed or funded for this. Many options could be considered, with most of them heavily dependent on wide gas-over-distillate pricing differentials – a bold notion to consider.

While it is very difficult to forecast fuel pricing with a high degree of accuracy, it is extremely important for the project developer to have a solid basis of analysis prior to initiating any major decision, such as dual fuel conversion. Before quickly moving into a plan to add a secondary fuel, the project developer must carefully evaluate the likelihood of ongoing price differentials. The project developer must determine the how important operation during gas curtailment periods really is. The project developer should consider non-conventional solutions such as gas storage. The intent of this paper has been to provide focus upon the key issues that affect such a decision, and to provide a method to quantify the technical and economic return on such investment.

Key Factors and Concerns

Through this report, many relevant factors and concerns have been presented in order to depict the clearest perspective possible for effectively evaluating the decision to convert an in-progress plant design from single fuel to dual fuel. In brief summary, the most prominent issues to evaluate are:

- Fuel Price Economic Model, short and long term, firm and interruptible supplies
- Expected Capital Costs to Convert, dependent upon many parameters
- Expected Impact to Operating and Maintenance Budget
- Technical Feasibility of Dual Fuel Conversion, major equipment and balance-of-plant

- Impact to Plant Life Expectancy, due to distillate firing
- Air Permitting Difficulties and Increased Emissions
- Physical Feasibility, due to plant layout and proximity to distillate supply chains
- Importance of Uninterrupted Generating Ability, hedge against gas curtailment

Recommended Resources

Due to the volatility of fuel price markets, and the speed of change in short-term outlook predictions, maintaining a current focus on economic conditions is vital for the properly informed project developer. Several Internet-based information sources exist, and should be consulted frequently. A few recommended sites are:

- Crude Oil and Natural Gas Prices http://www.oilprices.com/
- Electric Power Research Institute http://www.epri.com
- Energy Central http://www.energycentral.com
- Energy Information Administration http://www.eia.doe.gov
- Platt's Global Energy http://www.platts.com
- Power Engineering Magazine http://pe.pennwellnet.com/home.cfm
- Power Online Digital Marketplace http://www.poweronline.com

Summary

This report has presented numerous factors pertaining to the contemporary issue of dual fuel conversion. The basis for all statements made can be found in the references to follow in the Appendices. The reader is encouraged to perform his or her own project-specific analyses to accurately predict and justify any decision to recommend a dual fuel conversion for a particular plant under development, or one which is already in operation.

A
SI – ENGLISH UNIT CONVERSION

Throughout this report units have been reported in both English and System Internationale (SI) units. The following table is provided for assistance in converting between units:

Table A-1
Unit Conversions

To Convert From	To	Multiply By
Btu	kJ	1.05506
MBtu	GJ	1.05506
Degrees F	Degrees C	(F-32)/1.8
Diff Degrees F	Diff Degrees C	0.55556
$ / MBtu	$ / GJ	0.9478
Btu/kWh	kJ/kWh	1.05147
MBtu/hr	MW	0.29307
lb/hr	kg/hr	0.45359
psia	kPa	6.8948
in H_2O	kPa	0.248
in Hg	kPa	3.38565
foot	meter	0.3048
barrel	liter	158.99
\$ / 1000 ft^3	\$ / m^3	0.03531

B
SUPPORTING DATA – SOPP-CT CASE INPUT DATA

The following table comprises the SOAPP WorkStation input data that was utilized for the analyses discussed in this paper:

Table B-1
SOAPP-CT Case Input Data

Case		1	2	3a
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
Variable	Units	Value	Value	Value
Unit Data		CCCG - 1 GE7FA - NG only	CCCG - 1 GE7FA - Dual Fuel - Case 2	CCCG - 1 GE7FA - Dual Fuel - Case 3a
CT Model Number	N/A	GE PG7241(FA)-60 Hz	GE PG7241(FA)-60 Hz	GE PG7241(FA)-60 Hz
Number of CT's	N/A	1	1	1
Cycle Type	N/A	Combined Cycle Cogeneration	Combined Cycle Cogeneration	Combined Cycle Cogeneration
Duty Cycle/Mission	N/A	Base Load	Base Load	Base Load
CT NOx Control, Natural Gas	N/A	Dry Low NOx Combustors	Dry Low NOx Combustors	Dry Low NOx Combustors
CT NOx Control, No 2 Fuel Oil	N/A	Water Injection	Water Injection	Water Injection
CT Natural Gas NOx Limit	ppmvd @ 15% O2	9	9	9
CT No 2 Fuel Oil NOx Limit	ppmvd @ 15% O2	42	42	42
CEM's Included	N/A	Yes	Yes	Yes
Inlet Air Filtration	N/A	Pulse Type	Pulse Type	Pulse Type
Inlet Air Cooling	N/A	No Cooling	No Cooling	No Cooling
Inlet Air Cooler Status	N/A	In Use	In Use	In Use
Air Cooling Discharge Temp	F	59	59	59
Evaporative Cooler Effectiveness	%	85	85	85
CT Pressure Loss Method	N/A	Workstation Calculated	Workstation Calculated	Workstation Calculated
CT Inlet Pressure Loss	in H2O	3.75	3.75	3.75
CT Exhaust Pressure Loss	in H2O	14	14	14
Heater Selection	N/A	Condensate Heater	Condensate Heater	Condensate Heater
Deaerator Selection	N/A	Integral Deaerator	Integral Deaerator	Integral Deaerator
Number of Pressure Levels	N/A	Three Pressure	Three Pressure	Three Pressure
HP Steam Pressure	psia	1800	1800	1800
IP Steam Pressure	psia	490	490	490
LP Steam Pressure	psia	60	60	60
Hot Reheat Pressure Calc Method	N/A	User-Specified	User-Specified	User-Specified
Hot Reheat Pressure	psia	490	490	490
HP Steam Temp	F	1000	1000	1000
IP Steam Temp	F	600	600	600
LP Steam Temp	F	460	460	460
HP Pinch Point	F	15	14	14
IP Pinch Point	F	15	13	13
LP Pinch Point	F	10	9	9
HP Evap Approach	F	20	19	19
IP Evap Approach	F	20	18	18
LP Evap Approach	F	13	13	13
Include Duct Burners	N/A	Yes	Yes	Yes

Case		1	2	3a
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
Duct Burner Performance Calc Method	N/A	Specify % Increase Over Unfired	Specify % Increase Over Unfired	Specify % Increase Over Unfired
Duct Burner Firing Temperature	F	1300	1300	1300
Duct Burner HP Stm Flow Increase	%	25	25	25
Duct Burner Use	N/A	Full-Time	Full-Time	Full-Time
Duct Burner Fuel Capability	N/A	Primary Fuel Only	Dual Primary/Secondary Fuel	Dual Primary/Secondary Fuel
SCR Configuration	N/A	Anhydrous Ammonia Injection	Anhydrous Ammonia Injection	Anhydrous Ammonia Injection
Include CO Oxidation Catalyst	N/A	No	No	No
Steam Turbine Arrangement	N/A	G-Reheat, 2 Casing, 1 Flow, Direct Drive	G-Reheat, 2 Casing, 1 Flow, Direct Drive	G-Reheat, 2 Casing, 1 Flow, Direct Drive
ST Exhaust Configuration	N/A	Axial	Axial	Axial
ST Sizing Criteria	N/A	Excluding Max Exports/Extractions	Excluding Max Exports/Extractions	Excluding Max Exports/Extractions
Number of ST Extractions	N/A	0	0	0
ST Efficiency Method	N/A	User-Specified	User-Specified	User-Specified
HP ST Efficiency	%	87	87	87
IP ST Efficiency	%	89	89	89
LP ST Efficiency	%	91	91	91
Include a Steam Bypass	N/A	Yes	Yes	Yes
Cooling System Type	N/A	Wet Mech Draft Cooling Twr	Wet Mech Draft Cooling Twr	Wet Mech Draft Cooling Twr
Cycles of Concentration	N/A	5	5	5
Condenser Pressure Calc Method	N/A	Workstation Calculated	Workstation Calculated	Workstation Calculated
Design Condenser Pressure	in Hg	2.83	2.83	2.83
Condenser Tube Material	N/A	304 SS	304 SS	304 SS
Condenser Tube Cleaning	N/A	None	None	None
Circ Water Pump Sparing	N/A	2 - 50%	2 - 50%	2 - 50%
Include an Auxiliary Boiler	N/A	No	No	No
Boiler Feed Pump Sparing	N/A	2 - 100%	2 - 100%	2 - 100%
Boiler Feed Pump Design	N/A	HP Pump with IP Takeoff	HP Pump with IP Takeoff	HP Pump with IP Takeoff
Condensate Pump Sparing	N/A	2 - 50%	2 - 50%	2 - 50%
HRSG Enclosures	N/A	No	No	No
Power Block Enclosure	N/A	Yes	Yes	Yes
Water Treatment Enclosure	N/A	Yes	Yes	Yes
Warehouse Included	N/A	No	No	No
Include Fire Protection System?	N/A	Yes	Yes	Yes
Fire Water Source	N/A	River/Lake	River/Lake	River/Lake
Substructure Requirements	N/A	Steel Piles	Steel Piles	Steel Piles
Fuel Oil Storage Duration	days	1	4	7
Fuel Oil Storage Basis	N/A	Oil Tank Size W/O DB Operating	Oil Tank Size W/O DB Operating	Oil Tank Size W/ DB Operating
Bypass Stack/Diverter Valve	N/A	No	No	No
Main Stack Height	ft	150	150	150
Switchyard Voltage	kV	115	115	115
Book Life	years	30	30	30
Tax Life	years	20	20	20
Commercial Operating Year	N/A	2003	2003	2003
Commercial Operating Month	N/A	January	January	January

Supporting Data – SOPP-CT Case Input Data

Case		1	2	3a
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
Capacity Factor	%	85	85	85
Service Factor	%	90	90	90
Equivalent Availability Factor	%	95	95	95
Output Degradation Factor	%/yr	3	3	3
Heat Rate Degradation Factor	%/yr	1.5	1.5	1.5
Number of Starts Per Year	N/A	5	5	5
Tax Depreciation Method	N/A	MACRS	MACRS	MACRS
Tax Depreciation Schedule	%/yr			
Capital Tax Adjustment	%			
Import Duties Adjustment	%			
Freight Adjustment	%			
Royalties Adjustment	%			
User Specified Adjustment	%			
Salvage Values	%			
Capital Cost Adders	$			
Site Data		Kenosha, WI - Case 1	Kenosha, WI - Case 2	Kenosha, WI - Case 3a
Max Ambient Dry Bulb Temp	F	85	85	85
Max Ambient Wet Bulb Temp	F	73	73	73
Min Ambient Dry Bulb Temp	F	-20	-20	-20
Perf Point Dry Bulb Temp	F	59	59	59
Perf Point Wet Bulb Temp	F	51	51	51
Site Elevation	ft	600	600	600
Ambient Air Quality	N/A	Dusty	Dusty	Dusty
Max Daily Rainfall	in/day	7	7	7
Average Annual Rainfall	in/yr	31	31	31
Max Cooling Water Temp	F	80	80	80
Perf Point Cooling Water Temp	F	60	60	60
Heat Rejection Water Source	N/A	River	River	River
Unit Makeup Water Source	N/A	Well Water	Well Water	Well Water
Makeup Raw Water Consump Charge	$US/1,000 gal			
Circulating Water Thermal Charge	$US/MBtu			
UBC Seismic Zone	N/A	Zone 0	Zone 0	Zone 0
Stack Natural Gas NOx Limit	ppmvd @ 15% O2	5	5	5
Stack Fuel Oil NOx Limit	ppmvd @ 15% O2	9	9	9
Ammonia Emission Limit	ppmvd @ 15% O2	5	5	5
Construction Labor Index Value	N/A	1	1	1
Productivity Multiplier	N/A	1	1	1
General Facilities Capital	%	5	5	5
Eng. & Home Office Fees	%	6	6	6
Project Contingency	%	10	10	10
Process Contingency	%	0	0	0
Land Cost	$US/acre	10,000	10,000	10,000
Ammonia (Delivered)	$US/ton	180	180	180
NaOH (Delivered)	$US/ton	240	240	240

Case		1	2	3a
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
H2SO4 (Delivered)	$US/ton	300	300	300
SCR Catalyst (Delivered)	$US/ft3	280	280	280
CO Catalyst (Delivered)	$US/ft3	2,100.00	2,100.00	2,100.00
Other Waste Disposal	$US/ton	12	12	12
Catalyst Disposal	$US/ft3	21	21	21
Non-operating Purchased Power Cost	$US/MWh	80	80	80
O&M Cost Method	N/A	User-specified 11 Annualized Categories	User-specified 11 Annualized Categories	User-specified 11 Annualized Categories
Fixed O&M Direct Operating Labor	$US/yr	744,000	798,000	864,000
Fixed O&M Direct Maintenance Labor	$US/yr	360,000	360,000	360,000
Fixed O&M Annual Services, Materials & Purch Power	$US/yr	150,500	161,500	165,500
Fixed O&M Indirect Labor Costs	$US/yr	660,000	678,800	711,000
Variable O&M Sched Maintenance Parts & Materials	$US/yr	3,360,200	3,590,600	3,913,100
Variable O&M Sched Maintenance Labor	$US/yr	420,900	466,600	501,100
Variable O&M Unplanned Maintenance Allowance	$US/yr	141,000	150,600	150,600
Variable O&M Catalyst Replacement	$US/yr	57,700	60,600	62,400
Variable O&M Other Consumables	$US/yr	720,600	738,900	797,800
Variable O&M Disposal Charges	$US/yr	9,000	9,400	9,700
Variable O&M Byproduct Credit	$US/yr	0	0	0
O&M Labor Index Value	N/A	1	1	1
O&M Labor Productivity Multiplier	N/A	1	1	1
Maintenance Cost Adjustment	N/A	1	1	1
Operating Tax Rates	%			
Insurance Rate	%	0.5	0.5	0.5
Economic Data		Base Econ	Base Econ	Base Econ
IPP Loan Period	years	15	15	15
Evaluation Basis	N/A	Current Dollar Analysis	Current Dollar Analysis	Current Dollar Analysis
Ownership Type	N/A	Independent Power Producer	Independent Power Producer	Independent Power Producer
IPP Analysis Method	N/A	Solve for Return on Equity	Solve for Return on Equity	Solve for Return on Equity
IPP Equity Repayment Period	years	20	20	20
IPP Loan Repay Method	N/A	Mortgage Style	Mortgage Style	Mortgage Style
Inflation Rate	%/yr	2	2	2
Base Year	N/A	2001	2001	2001
Const Sched Calc Method	N/A	Workstation Calculated	Workstation Calculated	Workstation Calculated
Capital Costs Esc Rate	%/yr	2	2	2
O&M Costs Esc Rate	%/yr	2	2	2
Common Equity Fraction	N/A	0.25	0.25	0.25
Preferred Equity Fraction	N/A	0	0	0
Debt Fraction	N/A	0.75	0.75	0.75
Return on Debt	%	9	9	9
Return on Debt During Construction	%	10	10	10
Investment Tax Credit Rate	%	0	0	0
Capacity Payments	$US/kW-yr	0.00	0.00	0.00
Energy Payments	$US/MWh	65.00	65.00	65.00
Byproduct Payments	$US/klb	0	0	0
HP Steam Export Sales	$US/klb			
IP Steam Export Sales	$US/klb			

Supporting Data – SOPP-CT Case Input Data

Case		1	2	3a
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
LP Steam Export Sales	$US/klb			
ST Extraction 1 Steam Sales	$US/klb			
ST Extraction 2 Steam Sales	$US/klb			
ST Extraction 3 Steam Sales	$US/klb			
ST Extraction 4 Steam Sales	$US/klb			
Fuel Data		Nat Gas	Nat Gas	Nat Gas
Primary Fuel Type	N/A	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	N/A	None	No. 2 Fuel Oil	No. 2 Fuel Oil
Secondary Fuel Usage	%	0	8	50
Primary Fuel Price	$US/MBtu	6.00	6.00	6.00
Secondary Fuel Price	$US/MBtu	5.30	5.30	5.30
Natural Gas Supply Pressure	psig	400	400	400

C
SUPPORTING DATA – SOAPP-CT OUTPUT DATA

Table C-1
SOAPP-CT Output: Performance Summary

SOAPP Design Analysis Performance Summary				
Case		**1**	**2**	**3a**
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
Variable	Units	Value	Value	Value
PLANT DESIGN BASIS				
Ambient Air Temperature	F	59	59	59
Site Elevation Above MSL	ft	600	600	600
Cycle Type		Combined Cycle Cogeneration	Combined Cycle Cogeneration	Combined Cycle Cogeneration
Primary Fuel Type		Natural Gas	Natural Gas	Natural Gas
CT NOx Control, Natural Gas		Dry Low NOx Combustors	Dry Low NOx Combustors	Dry Low NOx Combustors
CT NOx Control, No 2 Fuel Oil				
Inlet Air Cooling System				
CT Air Precooler Discharge Temperature	F	59	59	59
Cooling System Type		Wet Mech Draft Cooling Twr	Wet Mech Draft Cooling Twr	Wet Mech Draft Cooling Twr
SCR Configuration		Anhydrous Ammonia Injection	Anhydrous Ammonia Injection	Anhydrous Ammonia Injection
Duct Burner Use		Full-Time	Full-Time	Full-Time
Duct Burner Fuel Capability		Primary Fuel Only	Dual Primary/Secondary Fuel	Dual Primary/Secondary Fuel
COMBUSTION TURBINE DATA				
Combustion Turbine Model		GE PG7241(FA)-60 Hz	GE PG7241(FA)-60 Hz	GE PG7241(FA)-60 Hz
Number of CT's Operating		1	1	1
CT Gross Output, per CT	kW	165,492	165,492	165,492
CT Heat Input (HHV), per CT	MBtu/h	1,744.65	1,744.65	1,744.65
CT Exhaust Flow per CT	lb/h	3,458,391	3,458,391	3,458,391
CT Exhaust Temperature	F	1,127	1,127	1,127
CT NOx Emissions	ppmvd @ 15% O2	9	9	9
HRSG DATA (per HRSG)				
HRSG Gas Inlet Temperature	F	1,228	1,228	1,228
HP Steam Flow at HRSG	lb/h	518,507	520,568	520,568
HP Steam Pressure at HRSG	psia	1,849	1,849	1,849
HP Steam Temperature at HRSG	F	1,005	1,005	1,005
Duct Burner Heat Input (HHV)	MBtu/h	104.61	104.61	104.61
HP Export Steam Flow				
Hot Reheat Steam Flow at HRSG	lb/h	576,936	577,367	577,367
Hot Reheat Steam Pressure at HRSG	psia	504	504	504
Hot Reheat Steam Temperature at HRSG	F	1,005	1,005	1,005
IP Steam Flow at HRSG	lb/h	58,429	56,798	56,798
IP Steam Pressure at HRSG	psia	514	514	514
IP Steam Temperature at HRSG	F	530	529	529
IP Export Steam Flow				
LP Steam Flow at HRSG	lb/h	47,016	47,841	47,841
LP Steam Pressure at HRSG	psia	72	72	72
LP Steam Temperature at HRSG	F	304	304	304
LP Export Steam Flow				
Stack Exhaust Flow	lb/h	3,463,382	3,463,383	3,463,383
Stack Exhaust Temperature	F	181	178	178
STEAM TURBINE DATA				

Supporting Data – SOAPP-CT Output Data

SOAPP Design Analysis Performance Summary				
Case		**1**	**2**	**3a**
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
Throttle Steam Flow at ST	lb/h	518,507	520,568	520,568
Throttle Steam Pressure	psia	1,800	1,800	1,800
Throttle Steam Temperature	F	1,000	1,000	1,000
Hot Reheat Steam Flow at ST	lb/h	576,936	577,367	577,367
HP ST Efficiency	%	87	87	87
IP ST Efficiency	%	89	89	89
LP ST Efficiency	%	91	91	91
Turbine Backpressure	in Hg	2.09	2	2.09
Gross ST Output	kW	106,728	106,923	106,923
PLANT DATA				
Gross Plant Output	kW	272,220	272,415	272,415
Auxiliary Power	kW	5,385	5,587	5,587
Net Plant Output	kW	266,835	266,829	266,829
Total Plant Heat Input (HHV)	MBtu/h	1,849.27	1,849.27	1,849.27
Net Process Heat Rate (HHV) at 100% Load				
Net Process Heat Rate (LHV) at 100% Load				
Net Plant Heat Rate (HHV) at 100% Load	Btu/kWh	6,930	6,931	6,931
Net Plant Heat Rate (LHV) at 100% Load	Btu/kWh	6,244	6,244	6,244
Net Output at 75% Load	kW	200,126	200,121	200,121
Net Plant Heat Rate (HHV) at 75% Load	Btu/kWh	7,453	7,454	7,454
Net Plant Heat Rate (LHV) at 75% Load	Btu/kWh	6,715	6,715	6,715
Net Output at 50% Load	kW	133,418	133,414	133,414
Net Plant Heat Rate (HHV) at 50% Load	Btu/kWh	8,279	8,280	8,280
Net Plant Heat Rate (LHV) at 50% Load	Btu/kWh	7,459	7,459	7,459
Net Output at 25% Load	kW	66,709	66,707	66,707
Net Plant Heat Rate (HHV) at 25% Load	Btu/kWh	11,679	11,679	11,679
Net Plant Heat Rate (LHV) at 25% Load	Btu/kWh	10,522	10,522	10,522

The table to follow represents the SOAPP-CT performance results while firing secondary fuel. Case 1, being natural gas fired only, did not have a secondary fuel. For Cases 2 and 3a, the secondary fuel is No. 2 fuel oil.

Table C-2
SOAPP-CT Output: CT Performance, Secondary Fuel

Case		1	2	3a
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
	Units		Value	Value
Combustion Turbine Model			GE PG7241(FA)-60 Hz	GE PG7241(FA)-60 Hz
Gross Output, per CT	kW		181,544	181,544
Gross Heat Rate (LHV)	Btu/kWh		10,104	10,104
Gross Efficiency (LHV)	%		33.78	33.78
Fuel Flow Rate (LHV), per CT	lb/h		100,236	100,236
Water/Steam Injection Flow Rate, per CT	lb/h		136,612	136,612
Exhaust Gas Temperature	F		1,111	1,111
Exhaust Gas Mass Flow Rate, per CT	lb/h		3,616,524	3,616,524
Exhaust Gas Enthalpy	Btu/lb		283.51	283.51
Generator Type			Hydrogen Cooled	Hydrogen Cooled
Ambient Air Temperature	F		59	59
Site Elevation	ft		600	600
Ambient Air Pressure	psia		14.3815	14.3815
Inlet Air Cooling Type			No Cooling	No Cooling
Compressor Inlet Air Temperature	F		59	59
Compressor Inlet Air Relative Humidity	%		58.08	58.08
Compressor Inlet Air Pressure Drop	in H2O		3.75	3.75
Exhaust Gas Pressure Drop	in H2O		15.25	15.25
Fuel Type			No. 2 Fuel Oil	No. 2 Fuel Oil
Fuel Lower Heating Value (LHV)	Btu/lb		18,300	18,300
NOX Control Type			Water Injection	Water Injection
NOX Emissions	ppmvd @ 15% O2		42	42
Exhaust Gas Constituent - AR	vol %		0.8464	0.8464
Exhaust Gas Constituent - CHX	vol %		0	0
Exhaust Gas Constituent - CO	vol %		0.0032	0.0032
Exhaust Gas Constituent - CO2	vol %		5.5852	5.5852
Exhaust Gas Constituent - COS	vol %		0	0
Exhaust Gas Constituent - H2	vol %		0	0
Exhaust Gas Constituent - H2O	vol %		11.7199	11.7199
Exhaust Gas Constituent - H2S	vol %		0	0
Exhaust Gas Constituent - N2	vol %		70.8348	70.8348
Exhaust Gas Constituent - O2	vol %		10.9537	10.9537
Exhaust Gas Constituent - SO2	vol %		0.0601	0.0601

The table below documents the surface areas of each of the HRSG sections, as calculated by the SOAPP WorkStation in the Heat Balance computation.

Table C-3
SOAPP-CT Output: HRSG Surface Area

SOAPP Design Analysis HRSG Surface Area				
Case		**1**	**2**	**3a**
(Primary Fuel is always listed first)		Nat Gas Only	Dual Fuel; 92% Gas, 8% Dist	Dual Fuel; 50% Gas, 50% Dist
SOAPP: hrsgtext4.txt file				
HPECON1 SA	ft^2	224,131	240,935	240,935
HPECON2 SA	ft^2	188,129	187,659	187,659
HPECON3 SA	ft^2	0	0	0
HPEVAP SA	ft^2	355,758	363,553	363,553
HPSHT SA	ft^2	121,337	122,034	122,034
IPECON SA	ft^2	24,747	25,612	25,612
IPEVAP SA	ft^2	166,634	176,597	176,597
IPSHT SA	ft^2	3,197	3,074	3,074
LPEVAP SA	ft^2	222,885	233,270	233,270
LPSHT SA	ft^2	528	457	457
LPECON SA	ft^2	331,184	353,886	353,886
REHT SA	ft^2	57,449	57,558	57,558
HRSG LTZ SA	ft^2	331,184	353,886	353,886
TOTAL Surface Area	**ft^2**	**1,695,979**	**1,764,634**	**1,764,634**

The following table documents the capital cost estimates generated by SOAPP WorkStation for the three conceptual design cases.

Table C-4
SOAPP-CT Output: Capital Cost Summary

SOAPP Design Analysis
Capital Cost Summary
All values in Thousands of dollars.

Case	**1**				**2**				**3a**			
(Primary Fuel is always listed first)	**Nat Gas Only**				**Dual Fuel; 92% Gas, 8% Dist**				**Dual Fuel; 50% Gas, 50% Dist**			
Description	Equip.	Material	Labor	Total	Equip.	Material	Labor	Total	Equip.	Material	Labor	Total
Combustion Turbine & Accessories	39,795	1,055	2,363	43,213	41,512	1,055	2,363	44,930	41,512	1,055	2,363	44,930
Inlet Filtration System	501	70	262	833	501	70	262	833	501	70	262	833
Inlet Air Precooling System												
Electrical Systems - Combustion Turbine	2,945	74	346	3,365	2,945	74	346	3,365	2,945	74	346	3,365
Condensate Heating System	1,517	15	441	1,973	1,641	16	476	2,133	1,641	16	476	2,133
HRSG's & Accessories	9,741	104	2,236	12,081	9,973	106	2,327	12,406	9,973	106	2,327	12,406
Deaeration System	71	37	87	195	71	38	87	196	71	38	87	196
Duct Burner System	144	17	33	194	425	18	42	485	425	18	42	485
Post Combustion Emissions Controls	623	111	117	851	978	122	198	1,298	978	122	198	1,298
Steam Piping	0	647	515	1,162	0	666	522	1,188	0	666	522	1,188
Electrical Systems - HRSG's	29	37	94	160	29	38	96	163	29	38	96	163
Steam Turbine & Accessories	14,912	697	2,809	18,418	15,182	704	2,839	18,725	15,182	704	2,839	18,725
Steam Bypass System	957	49	188	1,194	957	49	188	1,194	957	49	188	1,194
Electrical Systems - Steam Turbine	1,868	849	842	3,559	1,891	851	846	3,588	1,891	851	846	3,588
Condenser & Accessories	1,329	23	346	1,698	1,331	23	346	1,700	1,331	23	346	1,700
Circulating Water System	1,594	1,332	1,836	4,762	1,596	1,333	1,838	4,767	1,596	1,333	1,838	4,767
Water Treatment System	361	101	580	1,042	904	283	1,705	2,892	904	283	1,705	2,892
Waste Water Treatment System	162	23	89	274	585	61	277	923	585	61	277	923
Auxiliary Boiler & Accessories												
Boiler Feed System	554	173	274	1,001	564	178	279	1,021	564	178	279	1,021
Condensate System	54	78	113	245	55	80	115	250	55	80	115	250
Buildings	0	3,580	4,006	7,586	0	3,888	4,358	8,246	0	3,888	4,358	8,246
Fire Protection System	538	24	406	968	556	24	420	1,000	556	24	420	1,000
Fuel Systems	141	132	213	486	946	403	771	2,120	1,141	428	907	2,476
Fuel Gas Compressor & Accessories												
Bypass Stack & Diverter Valve												
Main Exhaust Stack	0	516	201	717	0	515	201	716	0	515	201	716
Station & Instrument Air System	353	131	118	602	353	135	119	607	353	135	119	607
Closed Cooling Water System	175	92	167	434	175	92	168	435	175	92	168	435
Cranes & Hoists	97	97	96	290	97	97	96	290	97	97	96	290
Plant Control System	960	0	149	1,109	960	0	149	1,109	960	0	149	1,109
Continuous Emission Monitoring System	189	106	282	577	189	107	286	582	189	107	286	582
Total Process Capital	79,610	10,170	19,209	108,989	84,416	11,026	21,720	117,162	84,611	11,051	21,856	117,518

The table below is the first year (base year) cost summary for each of the three cases.

Table C-5
SOAPP-CT Output: Base Year Cost Summary

SOAPP Design Analysis Base Year Cost Summary								
Case	**1**			**2**			**3a**	
(Primary Fuel is always listed first.)	**Nat Gas Only**			**Dual Fuel; 92% Gas, 8% Dist**			**Dual Fuel; 50% Gas, 50% Dist**	
Category								
Total Capital Requirements								
Excluding Escalation and								
AFUDC or IDC in Base								
Year (2001) $								
TOTAL PROCESS CAPITAL	108,989,000			117,162,000			117,518,000	
General Facilities	5,449,450			5,858,100			5,875,900	
Engineering and Home Office Fees	6,539,340			7,029,720			7,051,080	
Project Contingency	10,898,900			11,716,200			11,751,800	
Process Contingency	0			0			0	
TOTAL PLANT COST	131,876,688			141,766,016			142,196,784	
AFUDC or IDC								
See Capital Outlay Table								
TOTAL PLANT INVESTMENT	131,876,688			141,766,016			142,196,784	
TOTAL PLANT INVESTMENT ($/gross kW)		484.45			484.94			486.41
Prepaid Royalties	0			0			0	
Preproduction Costs	5,314,102			5,555,848			5,649,911	
Inventory Capital	659,383			2,117,290			3,275,691	
Initial Cost - Catalyst and Chemicals	0			0			0	
Land	70,550			130,776			148,752	
Capital Cost Adders	0			0			0	
TOTAL CAPITAL REQUIREMENT	137,920,720			149,569,936			151,271,136	
TOTAL CAPITAL REQUIREMENT ($/gross kW)		506.65			511.63			517.45
O + M and Fuel Costs								
(in Base Year (2001) $)								
Fixed O + M								
Direct Operating Labor	744,000			798,000			864,000	
Direct Maintenance Labor	360,000			360,000			360,000	
Annual Services, Materials, & Purchased Power	150,500			161,500			165,500	
Indirect Labor Costs	660,000			678,800			711,000	
TOTAL FIXED O+M	1,914,500			1,998,300			2,100,500	
TOTAL FIXED O+M ($/gross kW)		7.03			6.84			7.19
Variable O+M								
Scheduled Maintenance Parts & Materials	3,360,200			3,590,600			3,913,100	
Scheduled Maintenance Labor	420,900			466,600			501,100	
Unscheduled Maintenance Allowance	141,000			150,600			150,600	
Catalyst Replacement	57,700			60,600			62,400	
Other Consumables	720,600			738,900			797,800	
Disposal Charges	9,000			9,400			9,700	
Byproduct Credit	0			0			0	
Total Variable O+M	4,709,400			5,016,700			5,434,700	
Total Variable O+M ($/MWh)		2.32			2.30			2.50
Total Fixed and Variable O+M	6,623,900			7,015,000			7,535,200	
Fuel Cost								
Fuel Cost	83,857,112			84,136,504			85,603,304	
Fuel Cost ($/MWh)		41.37			38.65			39.33

Table C-6
SOAPP-CT Output: IPP Pro Forma, Case 1

SOAPP Design Analysis
IPP Pro Forma (First 8 Years only)

Case	**1**							
(Primary Fuel always listed first)	**Nat Gas Only**							
Category	1	2	3	4	5	6	7	8
Calendar Year (Jan 1 - Dec 31)	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Payments	0	0	0	0	0	0	0	0
Energy Payments	125,271,136	127,150,200	129,057,456	130,993,320	132,958,224	134,952,592	136,976,880	139,031,536
Steam Sales	0	0	0	0	0	0	0	0
Byproduct Credits	0	0	0	0	0	0	0	0
Salvage Values	0	0	0	0	0	0	0	0
Total Revenues	125,271,136	127,150,200	129,057,456	130,993,320	132,958,224	134,952,592	136,976,880	139,031,536
(-)Revenue Taxes	0	0	0	0	0	0	0	0
Net Revenues	125,271,136	127,150,200	129,057,456	130,993,320	132,958,224	134,952,592	136,976,880	139,031,536
O and M Costs	6,891,505	7,029,335	7,169,922	7,313,321	7,459,587	7,608,779	7,760,954	7,916,173
Property Taxes and Insurance	2,651,164	2,651,164	2,651,164	2,651,164	2,651,164	2,651,164	2,651,164	2,651,164
Primary Fuel Cost	87,244,936	88,989,832	90,769,632	92,585,024	94,436,728	96,325,456	98,251,968	100,217,008
Secondary Fuel Cost	0	0	0	0	0	0	0	0
Total Operating Expenses	96,787,608	98,670,336	100,590,720	102,549,512	104,547,480	106,585,400	108,664,088	110,784,344
Tax Depreciation	9,908,709	10,568,484	9,786,416	9,043,603	8,373,259	7,745,189	7,165,432	6,732,124
Interest Expenses	10,686,334	10,322,370	9,925,648	9,493,222	9,021,878	8,508,112	7,948,107	7,337,702
Taxable Income	7,888,485	7,589,010	8,754,672	9,906,983	11,015,607	12,113,890	13,199,252	14,177,365
Income Taxes	3,166,043	3,045,849	3,513,687	3,976,167	4,421,114	4,861,909	5,297,519	5,690,085
Net Income	4,722,441	4,543,161	5,240,984	5,930,815	6,594,493	7,251,980	7,901,732	8,487,280
Loan Balance Start of Year	118,737,040	114,692,992	110,284,976	105,480,240	100,243,080	94,534,576	88,312,304	81,530,024
Principal	4,044,050	4,408,014	4,804,736	5,237,162	5,708,506	6,222,272	6,782,277	7,392,682
Cash Flow to Equity	10,587,100	10,703,630	10,222,664	9,737,256	9,259,246	8,774,898	8,284,887	7,826,722
Debt Coverage Ratio *	1.93	1.93	1.93	1.93	1.93	1.93	1.92	1.92
Return on Equity (Cash Flow) % **	26.75	27.04	25.83	24.6	23.39	22.17	20.93	19.77
IRR Present Value Factor	0.8029	0.6447	0.5176	0.4156	0.3337	0.2679	0.2151	0.1727
PV Net Flow To Equity	8,500,587	6,900,409	5,291,511	4,046,915	3,089,832	2,351,112	1,782,336	1,351,932
Cumulative PV Net Flow To Equity	8,500,587	15,400,996	20,692,508	24,739,424	27,829,256	30,180,368	31,962,704	33,314,636
IRR ***	24.55							
Capacity & Energy Charges								
Salvage Values	0	0	0	0	0	0	0	0
Total Capacity Payments ($/yr)	0	0	0	0	0	0	0	0
Total Energy Payments ($/yr)	125,271,136	127,150,200	129,057,456	130,993,320	132,958,224	134,952,592	136,976,880	139,031,536
Total Capacity Payments ($/kW-yr)	0	0	0	0	0	0	0	0
Total Energy Payments ($/MWh)	65	65.97	66.96	67.97	68.99	70.02	71.07	72.14

Supporting Data – SOAPP-CT Output Data

SOAPP Design Analysis
IPP Pro Forma (First 8 Years only)

Case	**1**							
(Primary Fuel always listed first)	**Nat Gas Only**							
Total Capacity & Energy Payments ($/yr)	125,271,136	127,150,200	129,057,456	130,993,320	132,958,224	134,952,592	136,976,880	139,031,536
Present Value Factor	0.8029	0.6447	0.5176	0.4156	0.3337	0.2679	0.2151	0.1727
PV Capacity & Energy Payments ($/yr)	100,582,608	81,971,104	66,803,424	54,442,324	44,368,480	36,158,672	29,467,982	24,015,314
Cum PV Capacity & Energy Payments ($/yr)	100,582,608	182,553,712	249,357,136	303,799,456	348,167,936	384,326,592	413,794,560	437,809,888
Levelizing Factor	0.2458	0.2458	0.2458	0.2458	0.2458	0.2458	0.2458	0.2458
Levelized Capacity & Energy Pay ($/yr)	133,320,944	133,320,944	133,320,944	133,320,944	133,320,944	133,320,944	133,320,944	133,320,944
Levelized Capacity & Energy Pay ($/MWh)	69.18	69.18	69.18	69.18	69.18	69.18	69.18	69.18
Geometric Gradient Factor	0.226	0.2305	0.2352	0.2399	0.2447	0.2495	0.2545	0.2596
Geometric Gradient Capacity & Energy ($/MWh)	63.61	64.88	66.18	67.51	68.86	70.23	71.64	73.07
Base Year Capacity & Energy Pay ($/MWh)	61.14							
Net Generation (MWh)	1,927,248	1,927,248	1,927,248	1,927,248	1,927,248	1,927,248	1,927,248	1,927,248

Table C-7
SOAPP-CT Output: IPP Pro Forma, Case 2

SOAPP Design Analysis
IPP Pro Forma (First 8 Years only)

Case	**2**							
(Primary Fuel always listed first)	**Dual Fuel; 92%Gas, 8% Dist**							
Category	1	2	3	4	5	6	7	8
Calendar Year (Jan 1 - Dec 31)	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Payments	0	0	0	0	0	0	0	0
Energy Payments	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
Steam Sales	0	0	0	0	0	0	0	0
Byproduct Credits	0	0	0	0	0	0	0	0
Salvage Values	0	0	0	0	0	0	0	0
Total Revenues	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
(-)Revenue Taxes	0	0	0	0	0	0	0	0
Net Revenues	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
O and M Costs	7,298,406	7,444,374	7,593,261	7,745,127	7,900,029	8,058,030	8,219,190	8,383,574
Property Taxes and Insurance	2,850,319	2,850,319	2,850,319	2,850,319	2,850,319	2,850,319	2,850,319	2,850,319
Primary Fuel Cost	80,265,344	81,870,648	83,508,064	85,178,224	86,881,784	88,619,424	90,391,808	92,199,648
Secondary Fuel Cost	7,413,526	7,635,932	7,865,010	8,100,960	8,343,989	8,594,309	8,852,139	9,117,703
Total Operating Expenses	97,827,592	99,801,272	101,816,656	103,874,632	105,976,120	108,122,080	110,313,456	112,551,248
Tax Depreciation	10,638,494	11,346,862	10,507,194	9,709,672	8,989,957	8,315,629	7,693,172	7,227,951
Interest Expenses	11,573,563	11,179,381	10,749,721	10,281,393	9,770,915	9,214,494	8,607,995	7,946,911
Taxable Income	5,228,423	4,819,573	5,980,725	7,124,415	8,217,976	9,297,093	10,358,912	11,302,034
Income Taxes	2,098,427	1,934,335	2,400,364	2,859,384	3,298,284	3,731,388	4,157,549	4,536,071
Net Income	3,129,995	2,885,237	3,580,361	4,265,031	4,919,691	5,565,705	6,201,363	6,765,962
Loan Balance Start of Year	128,595,144	124,215,336	119,441,344	114,237,696	108,565,720	102,383,264	95,644,384	88,299,008
Principal	4,379,807	4,773,989	5,203,649	5,671,977	6,182,455	6,738,876	7,345,375	8,006,459
Cash Flow to Equity	9,388,682	9,458,110	8,883,906	8,302,726	7,727,193	7,142,458	6,549,160	5,987,455
Debt Coverage Ratio *	1.72	1.71	1.71	1.7	1.69	1.68	1.67	1.66
Return on Equity (Cash Flow) % **	21.9	22.06	20.73	19.37	18.03	16.66	15.28	13.97
IRR Present Value Factor	0.8407	0.7069	0.5943	0.4996	0.4201	0.3532	0.2969	0.2496
PV Net Flow To Equity	7,893,497	6,685,501	5,279,568	4,148,394	3,245,980	2,522,531	1,944,640	1,494,723
Cumulative PV Net Flow To Equity	7,893,497	14,578,999	19,858,568	24,006,962	27,252,942	29,775,474	31,720,114	33,214,838
IRR ***	18.94							
Capacity & Energy Charges								
Salvage Values	0	0	0	0	0	0	0	0
Total Capacity Payments ($/yr)	0	0	0	0	0	0	0	0
Total Energy Payments ($/yr)	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
Total Capacity Payments ($/kW-yr)	0	0	0	0	0	0	0	0
Total Energy Payments ($/MWh)	65	65.97	66.96	67.97	68.99	70.02	71.07	72.14
Total Capacity & Energy Payments ($/yr)	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
Present Value Factor	0.8407	0.7069	0.5943	0.4996	0.4201	0.3532	0.2969	0.2496
PV Capacity & Energy Payments ($/yr)	105,318,640	89,874,408	76,694,976	65,448,216	55,850,708	47,660,608	40,671,520	34,707,340

Supporting Data – SOAPP-CT Output Data

SOAPP Design Analysis IPP Pro Forma (First 8 Years only)								
Case	**2**							
(Primary Fuel always listed first)	**Dual Fuel; 92%Gas, 8% Dist**							
Cum PV Capacity & Energy Payments ($/yr)	105,318,640	195,193,056	271,888,032	337,336,256	393,186,976	440,847,584	481,519,104	516,226,432
Levelizing Factor	0.1905	0.1905	0.1905	0.1905	0.1905	0.1905	0.1905	0.1905
Levelized Capacity & Energy Pay ($/yr)	135,617,808	135,617,808	135,617,808	135,617,808	135,617,808	135,617,808	135,617,808	135,617,808
Levelized Capacity & Energy Pay ($/MWh)	70.37	70.37	70.37	70.37	70.37	70.37	70.37	70.37
Geometric Gradient Factor	0.1711	0.1745	0.178	0.1816	0.1852	0.1889	0.1927	0.1966
Geometric Gradient Capacity & Energy ($/MWh)	63.22	64.49	65.78	67.09	68.44	69.8	71.2	72.62
Base Year Capacity & Energy Pay ($/MWh)	60.77							
Net Generation (MWh)	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201

Table C-8
SOAPP-CT Output: IPP Pro Forma, Case 3a

SOAPP Design Analysis IPP Pro Forma (First 8 Years only)								
Case	**3a**							
(Primary Fuel always listed first)	**Dual Fuel; 50% Gas, 50% Dist**							
Category	1	2	3	4	5	6	7	8
Calendar Year (Jan 1 - Dec 31)	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Payments	0	0	0	0	0	0	0	0
Energy Payments	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
Steam Sales	0	0	0	0	0	0	0	0
Byproduct Credits	0	0	0	0	0	0	0	0
Salvage Values	0	0	0	0	0	0	0	0
Total Revenues	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
(-)Revenue Taxes	0	0	0	0	0	0	0	0
Net Revenues	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
O and M Costs	7,839,622	7,996,414	8,156,343	8,319,469	8,485,859	8,655,576	8,828,688	9,005,261
Property Taxes and Insurance	2,859,008	2,859,008	2,859,008	2,859,008	2,859,008	2,859,008	2,859,008	2,859,008
Primary Fuel Cost	43,622,468	44,494,916	45,384,816	46,292,512	47,218,364	48,162,728	49,125,984	50,108,504
Secondary Fuel Cost	46,334,540	47,724,580	49,156,316	50,631,004	52,149,936	53,714,432	55,325,868	56,985,640
Total Operating Expenses	100,655,640	103,074,920	105,556,480	108,101,992	110,713,168	113,391,744	116,139,552	118,958,416
Tax Depreciation	10,676,323	11,387,209	10,544,556	9,744,197	9,021,923	8,345,198	7,720,527	7,253,652
Interest Expenses	11,695,742	11,297,398	10,863,203	10,389,931	9,874,064	9,311,769	8,698,868	8,030,804
Taxable Income	2,240,367	1,387,561	2,090,057	2,753,992	3,345,813	3,900,585	4,414,588	4,785,271
Income Taxes	899,171	556,897	838,844	1,105,314	1,342,842	1,565,499	1,771,795	1,920,568
Net Income	1,341,195	830,663	1,251,212	1,648,677	2,002,971	2,335,085	2,642,793	2,864,702
Loan Balance Start of Year	129,952,680	125,526,640	120,702,256	115,443,672	109,711,816	103,464,096	96,654,080	89,231,160
Principal	4,426,042	4,824,386	5,258,581	5,731,853	6,247,720	6,810,015	7,422,916	8,090,980
Cash Flow to Equity	7,591,476	7,393,486	6,537,187	5,661,021	4,777,173	3,870,267	2,940,404	2,027,375
Debt Coverage Ratio *	1.53	1.49	1.46	1.42	1.38	1.34	1.29	1.24
Return on Equity (Cash Flow) % **	17.53	17.07	15.09	13.07	11.03	8.93	6.79	4.68
IRR Present Value Factor	0.945	0.893	0.8439	0.7975	0.7536	0.7122	0.673	0.636
PV Net Flow To Equity	7,173,960	6,602,597	5,516,824	4,514,667	3,600,267	2,756,370	1,978,957	1,289,425
Cumulative PV Net Flow To Equity	7,173,960	13,776,558	19,293,382	23,808,050	27,408,318	30,164,688	32,143,644	33,433,070
IRR ***	5.82							
Capacity & Energy Charges								
Salvage Values	0	0	0	0	0	0	0	0
Total Capacity Payments ($/yr)	0	0	0	0	0	0	0	0
Total Energy Payments ($/yr)	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
Total Capacity Payments ($/kW-yr)	0	0	0	0	0	0	0	0
Total Energy Payments ($/MWh)	65	65.97	66.96	67.97	68.99	70.02	71.07	72.14
Total Capacity & Energy Payments ($/yr)	125,268,072	127,147,088	129,054,296	130,990,112	132,954,968	134,949,296	136,973,536	139,028,144
Present Value Factor	0.945	0.893	0.8439	0.7975	0.7536	0.7122	0.673	0.636
PV Capacity & Energy Payments ($/yr)	118,378,592	113,546,024	108,910,744	104,464,696	100,200,152	96,109,688	92,186,216	88,422,904
Cum PV Capacity & Energy Payments ($/yr)	118,378,592	231,924,608	340,835,360	445,300,064	545,500,224	641,609,920	733,796,160	822,219,072
Levelizing Factor	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713

SOAPP Design Analysis IPP Pro Forma (First 8 Years only)								
Case	**3a**							
(Primary Fuel always listed first)	**Dual Fuel; 50% Gas, 50% Dist**							
Levelized Capacity & Energy Pay ($/yr)	147,447,872	147,447,872	147,447,872	147,447,872	147,447,872	147,447,872	147,447,872	147,447,872
Levelized Capacity & Energy Pay ($/MWh)	76.51	76.51	76.51	76.51	76.51	76.51	76.51	76.51
Geometric Gradient Factor	0.0572	0.0583	0.0595	0.0607	0.0619	0.0631	0.0644	0.0657
Geometric Gradient Capacity & Energy ($/MWh)	61.39	62.62	63.87	65.15	66.45	67.78	69.14	70.52
Base Year Capacity & Energy Pay ($/MWh)	59.01							
Net Generation (MWh)	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201	1,927,201

D
SUPPORTING DATA – DUAL FUEL SELECTION CASE STUDY

The tables to follow contain the information that was used to generate the case study charts presented in Chapter 4. All data in these tables is based on the output from the SOAPP WorkStation.

Table D-1
Case Study Parameters and Notes

Parameters			
Net Plant Output, Natural Gas	kw	266,829	<-- Do NOT Change
Net Plant Output, Distillate	kw	282,552	<-- Do NOT Change
Equipment Availability Factor		0.85	<-- Do NOT Change
Output Degradation	%	3%	<-- Do NOT Change
Electricity Price	$/MWh	65.00	<-- USER MAY VARY
Minimum Nat Gas Price	$/MBTU	3.00	<-- USER MAY VARY
Maximum Nat Gas Price	$/MBTU	10.00	<-- USER MAY VARY
Minimum Distillate Price	$/MBTU	4.00	<-- USER MAY VARY
Maximum Distillate Price	$/MBTU	8.00	<-- USER MAY VARY

NOTES
This Case Study allows the user to view impact of making various changes. All data is based upon the SOAPP-CT runs recorded on other worksheets.
* Vary electricity price to show profitability changes.
* Vary gas and distillate prices to show relative profititability between Dual Fuel Operation modes.

Results from Case Study analysis follow. First, the results from the low distillate price scenario:

Table D-2
Case Study Results: Low Distillate Price

LOW DISTILLATE PRICE	1	1	2	3	4	5	6	7	8	9	10	11
Electricity Price	$/MWh	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
Nat Gas Price	$/MBTU	3.00	3.70	4.40	5.10	5.80	6.50	7.20	7.90	8.60	9.30	10.00
Distillate Price	$/MBTU	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Fuel Price Differential	$/MBTU	-1.00	-0.30	0.40	1.10	1.80	2.50	3.20	3.90	4.60	5.30	6.00
Revenue, Nat Gas Only	$/yr	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291
Op Expense, Nat Gas Only	$/yr	74,919,015	85,367,986	95,816,957	106,265,928	116,714,898	127,163,869	137,612,840	148,061,811	158,510,782	168,959,752	179,408,723
Net Income, Nat Gas Only	**$/yr**	**50,349,275**	**39,900,305**	**29,451,334**	**19,002,363**	**8,553,392**	**-1,895,579**	**-12,344,549**	**-22,793,520**	**-33,242,491**	**-43,691,462**	**-54,140,432**
Revenue, 92%Gas / 8% Dist	$/yr	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803
Op Expense, 92% Gas / 8% Dist	$/yr	78,791,953	88,406,177	98,020,401	107,634,626	117,248,850	126,863,074	136,477,298	146,091,522	155,705,746	165,319,970	174,934,194
Net Income, 92% Gas/8% Dist	**$/yr**	**47,066,850**	**37,452,626**	**27,838,402**	**18,224,178**	**8,609,954**	**-1,004,270**	**-10,618,494**	**-20,232,718**	**-29,846,943**	**-39,461,167**	**-49,075,391**
Revenue, 50%Gas / 50% Dist	$/yr	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995
Op Expense, 50%Gas / 50% Dist	$/yr	88,135,035	93,360,157	98,585,279	103,810,400	109,035,522	114,260,644	119,485,766	124,710,887	129,936,009	135,161,131	140,386,253
Net Income, 50%Gas/50% Dist	**$/yr**	**40,823,960**	**35,598,839**	**30,373,717**	**25,148,595**	**19,923,473**	**14,698,351**	**9,473,230**	**4,248,108**	**-977,014**	**-6,202,136**	**-11,427,258**

Next, the results from the low mid distillate price scenario:

Table D-3
Case Study Results: Low Mid Distillate Price

LOW MID DISTILLATE PRICE												
	2	1	2	3	4	5	6	7	8	9	10	11
Electricity Price	$/MWh	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
Nat Gas Price	$/MBTU	3.00	3.70	4.40	5.10	5.80	6.50	7.20	7.90	8.60	9.30	10.00
Distillate Price	$/MBTU	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Fuel Price Differential	$/MBTU	-2.00	-1.30	-0.60	0.10	0.80	1.50	2.20	2.90	3.60	4.30	5.00
Revenue, Nat Gas Only	$/yr	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291
Op Expense, Nat Gas Only	$/yr	74,919,015	85,367,986	95,816,957	106,265,928	116,714,898	127,163,869	137,612,840	148,061,811	158,510,782	168,959,752	179,408,723
Net Income, Nat Gas Only	**$/yr**	**50,349,275**	**39,900,305**	**29,451,334**	**19,002,363**	**8,553,392**	**-1,895,579**	**-12,344,549**	**-22,793,520**	**-33,242,491**	**-43,691,462**	**-54,140,432**
Revenue, 92%Gas / 8% Dist	$/yr	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803
Op Expense, 92% Gas / 8% Dist	$/yr	80,098,792	89,713,016	99,327,240	108,941,464	118,555,688	128,169,912	137,784,136	147,398,360	157,012,584	166,626,809	176,241,033
Net Income, 92% Gas/8% Dist	**$/yr**	**45,760,012**	**36,145,788**	**26,531,564**	**16,917,339**	**7,303,115**	**-2,311,109**	**-11,925,333**	**-21,539,557**	**-31,153,781**	**-40,768,005**	**-50,382,229**
Revenue, 50%Gas / 50% Dist	$/yr	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995
Op Expense, 50%Gas / 50% Dist	$/yr	96,302,775	101,527,897	106,753,019	111,978,141	117,203,262	122,428,384	127,653,506	132,878,628	138,103,749	143,328,871	148,553,993
Net Income, 50%Gas/50% Dist	**$/yr**	**32,656,220**	**27,431,098**	**22,205,977**	**16,980,855**	**11,755,733**	**6,530,611**	**1,305,489**	**-3,919,632**	**-9,144,754**	**-14,369,876**	**-19,594,998**

Third, the results from the mid level distillate price scenario:

Table D-4
Case Study Results: Mid Level Distillate Price

MID LEVEL DISTILLATE PRICE												
	3	1	2	3	4	5	6	7	8	9	10	11
Electricity Price	$/MWh	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
Nat Gas Price	$/MBTU	3.00	3.70	4.40	5.10	5.80	6.50	7.20	7.90	8.60	9.30	10.00
Distillate Price	$/MBTU	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Fuel Price Differential	$/MBTU	-3.00	-2.30	-1.60	-0.90	-0.20	0.50	1.20	1.90	2.60	3.30	4.00
Revenue, Nat Gas Only	$/yr	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291
Op Expense, Nat Gas Only	$/yr	74,919,015	85,367,986	95,816,957	106,265,928	116,714,898	127,163,869	137,612,840	148,061,811	158,510,782	168,959,752	179,408,723
Net Income, Nat Gas Only	**$/yr**	**50,349,275**	**39,900,305**	**29,451,334**	**19,002,363**	**8,553,392**	**-1,895,579**	**-12,344,549**	**-22,793,520**	**-33,242,491**	**-43,691,462**	**-54,140,432**
Revenue, 92%Gas / 8% Dist	$/yr	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803
Op Expense, 92% Gas / 8% Dist	$/yr	81,405,630	91,019,854	100,634,078	110,248,302	119,862,526	129,476,751	139,090,975	148,705,199	158,319,423	167,933,647	177,547,871
Net Income, 92% Gas/8% Dist	**$/yr**	**44,453,173**	**34,838,949**	**25,224,725**	**15,610,501**	**5,996,277**	**-3,617,947**	**-13,232,171**	**-22,846,395**	**-32,460,619**	**-42,074,844**	**-51,689,068**
Revenue, 50%Gas / 50% Dist	$/yr	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995
Op Expense, 50%Gas / 50% Dist	$/yr	104,470,515	109,695,637	114,920,759	120,145,881	125,371,003	130,596,124	135,821,246	141,046,368	146,271,490	151,496,611	156,721,733
Net Income, 50%Gas/50% Dist	**$/yr**	**24,488,480**	**19,263,358**	**14,038,236**	**8,813,115**	**3,587,993**	**-1,637,129**	**-6,862,251**	**-12,087,373**	**-17,312,494**	**-22,537,616**	**-27,762,738**

Fourth, the results from the high mid distillate price scenario:

Table D-5
Case Study Results: High Mid Distillate Price

HIGH MID LEVEL DISTILLATE PRICE												
		4	1	2	3	4	5	6	7	8	9	10	11
Electricity Price	$/MWh	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
Nat Gas Price	$/MBTU	3.00	3.70	4.40	5.10	5.80	6.50	7.20	7.90	8.60	9.30	10.00
Distillate Price	$/MBTU	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
Fuel Price Differential	$/MBTU	-4.00	-3.30	-2.60	-1.90	-1.20	-0.50	0.20	0.90	1.60	2.30	3.00
Revenue, Nat Gas Only	$/yr	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291
Op Expense, Nat Gas Only	$/yr	74,919,015	85,367,986	95,816,957	106,265,928	116,714,898	127,163,869	137,612,840	148,061,811	158,510,782	168,959,752	179,408,723
Net Income, Nat Gas Only	**$/yr**	**50,349,275**	**39,900,305**	**29,451,334**	**19,002,363**	**8,553,392**	**-1,895,579**	**-12,344,549**	**-22,793,520**	**-33,242,491**	**-43,691,462**	**-54,140,432**
Revenue, 92%Gas / 8% Dist	$/yr	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803
Op Expense, 92% Gas / 8% Dist	$/yr	82,712,469	92,326,693	101,940,917	111,555,141	121,169,365	130,783,589	140,397,813	150,012,037	159,626,261	169,240,485	178,854,709
Net Income, 92% Gas/8% Dist	**$/yr**	**43,146,335**	**33,532,111**	**23,917,887**	**14,303,663**	**4,689,438**	**-4,924,786**	**-14,539,010**	**-24,153,234**	**-33,767,458**	**-43,381,682**	**-52,995,906**
Revenue, 50%Gas / 50% Dist	$/yr	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995
Op Expense, 50%Gas / 50% Dist	$/yr	112,638,256	117,863,377	123,088,499	128,313,621	133,538,743	138,763,865	143,988,986	149,214,108	154,439,230	159,664,352	164,889,473
Net Income, 50%Gas/50% Dist	**$/yr**	**16,320,740**	**11,095,618**	**5,870,496**	**645,374**	**-4,579,747**	**-9,804,869**	**-15,029,991**	**-20,255,113**	**-25,480,235**	**-30,705,356**	**-35,930,478**

Fifth, the results from the high distillate price scenario:

Table D-6
Case Study Results: High Distillate Price

HIGH DISTILLATE PRICE												
		5	1	2	3	4	5	6	7	8	9	10	11
Electricity Price	$/MWh	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
Nat Gas Price	$/MBTU	3.00	3.70	4.40	5.10	5.80	6.50	7.20	7.90	8.60	9.30	10.00
Distillate Price	$/MBTU	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Fuel Price Differential	$/MBTU	-5.00	-4.30	-3.60	-2.90	-2.20	-1.50	-0.80	-0.10	0.60	1.30	2.00
Revenue, Nat Gas Only	$/yr	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291	125,268,291
Op Expense, Nat Gas Only	$/yr	74,919,015	85,367,986	95,816,957	106,265,928	116,714,898	127,163,869	137,612,840	148,061,811	158,510,782	168,959,752	179,408,723
Net Income, Nat Gas Only	**$/yr**	**50,349,275**	**39,900,305**	**29,451,334**	**19,002,363**	**8,553,392**	**-1,895,579**	**-12,344,549**	**-22,793,520**	**-33,242,491**	**-43,691,462**	**-54,140,432**
Revenue, 92%Gas / 8% Dist	$/yr	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803	125,858,803
Op Expense, 92% Gas / 8% Dist	$/yr	84,019,307	93,633,531	103,247,755	112,861,979	122,476,203	132,090,427	141,704,652	151,318,876	160,933,100	170,547,324	180,161,548
Net Income, 92% Gas/8% Dist	**$/yr**	**41,839,496**	**32,225,272**	**22,611,048**	**12,996,824**	**3,382,600**	**-6,231,624**	**-15,845,848**	**-25,460,072**	**-35,074,296**	**-44,688,520**	**-54,302,744**
Revenue, 50%Gas / 50% Dist	$/yr	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995	128,958,995
Op Expense, 50%Gas / 50% Dist	$/yr	120,805,996	126,031,118	131,256,239	136,481,361	141,706,483	146,931,605	152,156,727	157,381,848	162,606,970	167,832,092	173,057,214
Net Income, 50%Gas/50% Dist	**$/yr**	**8,153,000**	**2,927,878**	**-2,297,244**	**-7,522,366**	**-12,747,488**	**-17,972,609**	**-23,197,731**	**-28,422,853**	**-33,647,975**	**-38,873,097**	**-44,098,218**

E
SUPPLEMENTAL DATA – CT PROJECT RISK ANALYZER INPUT DATA

The EPRI CT Risk Analyzer program (ver 1.01) was utilized in order to determine Operation and Maintenance cost information for this report. This Appendix section contains the Input data that was utilized for each of the three design cases.

Case 1: Natural Gas Only - Risk Analyzer Input Data

This section contains input tables for Case 1 of the study.

Table E-1
Case 1: Input Summary Sheet

CT Project Risk Analyzer

Input Summary sheet

Plant/Economic Basis	User Selection Menu		Range/Comments
Combustion Turbine Manufacturer	General Electric		(sets maint. inspection frequency)
CT Model	GE 7 FA		(sets maint. reliability statistics)
Cycle Type	Combined Cycle / Cogen		(sets staffing req'ts)
Duty Cycle - Mission	Baseload: 40-95% Service Factor		(sets staffing req'ts)
SCR of NOx in Flue Gas	Yes (for CC or Cogen)		(activates SCR costs)
	User Input	Default Value	
Number of CT's	1		(Integer user input-no default)
Number of HRSG's	1	1	(Integer less than or equal No. of CT's)
Number of Steam Turbines	1	1	(Integer less than or equal No. of CT's)
Plant Net Output, MW Rating	266.8	245	(user input required)
Service Factor (SF)	90.0%	75.0%	(default depends on mission)
Capacity Factor (CF)	85.0%	84.0%	(must be less than service factor)
Percent Time on Natural Gas	100.0%		(user input-no default)
Percent Time on Distillate Oil	0.0%		(user input-no default)
Other Fuels (by difference)	0.0%		(check between 0 and 100%)
Percent Time at Peak Load	1.0%	1%	(typically 0 - 2%)
Number of Normal Starts/Yr	5	5	(default depends on Service Factor)
Number of Full Load Trips/Yr	3	3	(default depends on Capacity Factor)
CT Model First Commercial Year of Use	1994	1994	(input four digit integer)
Base Year (for cost reference)	2001		(input four digit integer-no default)
Plant Startup Year	2003		(on or after base year-no default)
Plant Economic Life, Years	30	30	(input integer; maximum 30 yrs)

CT Project Risk Analyzer

Input Summary sheet

Plant/Economic Basis	User Selection Menu		Range/Comments
Average Inflation/Escalation	2.0%	2.5%	(inflation less than equity ROR)
Present Worth Discount Rate	12.0%	15.0%	(equity ROR greater than inflation)
Fixed O&M Staffing Quantity	*Defaults depend on duty cycle and type - see Operations Inputs for wage basis*		
Plant Manager	1	1	
Operating Supervisor	1	1	
Lead Operator/Technician	0	0	
Lead Operator	4	4	
Assistant Operator	4	4	
Adminstrative Assistant	1	1	
Other Operating Employees	1	1	
Maintenance Supervisor	1	1	
Combined O&M Supervisor	0	0	
Maintenance Technician	1	1	
Instrument Technician	1	1	
Maintenance Engineer	1	1	
Warehouse/Purchasing Assistant	1	1	
Chemistry Technician	1	1	
Other Maintenance Employees	0	0	
Total Direct Staff	18		
Average Overtime Factor	10.0%	10.0%	(applied to all base labor)
Average Incentive/Bonus Factor	10.0%	10.0%	(applied to all base labor)
Average Benefits Factor	35.0%	35.0%	(applied to all base labor)
Case Description (user input text)	Dual Fuel Case 1 Nat Gas Only Rev B		

Table E-2
Case 1: Operations Inputs Sheet

CT Project Risk Analyzer
Operations Inputs Sheet

(Enter in Base Year Dollars)

Fixed Direct Labor - Direct Employee Staffing			
Staff Position	Base Wage ($/yr)	Default Estimate	Number of Employees (from Input Summary)
Plant Manager	$80,000	$80,000	1
Operating Supervisor	$70,000	$70,000	1
Lead Operator/Technician	$60,000	$60,000	0
Lead Operator	$55,000	$55,000	4
Assistant Operator	$45,000	$45,000	4
Adminstrative Assistant	$35,000	$35,000	1
Other Operating Employees	$35,000	$35,000	1
Maintenance Supervisor	$65,000	$65,000	1
Combined O&M Supervisor	$70,000	$70,000	0
Maintenance Technician	$55,000	$55,000	1
Instrument Technician	$50,000	$50,000	1
Maintenance Engineer	$60,000	$60,000	1
Warehouse/Purchasing Assistant	$35,000	$35,000	1
Chemistry Technician	$35,000	$35,000	1
Other Maintenance Employees	$35,000	$35,000	0
Total Direct Base Labor	$920,000	(depends on Input Summary staffing)	
Total Number of Employees			18
Base hours per year	2,080	2080	
Resulting average base labor rate $/hr	$24.57		(reference only - not used)

Fixed Home Office & Employee Support Services				
Other Employee Expenses	Persons per year	Default	$/person	Default
Recruiting/Relocation	8	8	$500	$500
Training/Certification/Seminars	15	15	$1,000	$1,000
Travel/Expenses	15	15	$1,000	$1,000
Subtotal	$34,000			

Home Office Support Expenses	Cost per Year	Default	
Fixed Labor (fully loaded, incl. benefits)	$230,000	$280,000	(Purchasing, Sales, Human Resources, etc.)
Travel & Communications	$2,000	$2,000	
Professional Services	$8,000	$8,000	
Tools / Safety Equipment	$2,000	$2,000	
Office Supplies/Equip/Computers	$2,000	$2,000	
Telecommunications / Postage	$2,000	$2,000	
Vehicle Lease/Fuel/Maintenance	$4,000	$4,000	
Misc. Services (based on No. of employees)	$54,000	$54,000	Est. $3,000 per employee
Subtotal	$304,000		
Total Home Office & Employee Support	$338,000		(entry on Cash Flow sheet)

Fixed Non-Labor Operating Costs

Operating Services (contract)			
OEM Technical Representatives	$4,500	$6,000	(not active defaults-user estimate)
Plant Chemical Analysis	$2,000	$2,000	
Emission Testing	$5,000	$5,000	
High Voltage Equipment Testing	$7,500	$10,000	
Insurance - Auto / Employee Liability	$2,000	$2,000	
Accounting Service	$22,500	$25,000	
Heavy Equipment Lease	$2,500	$3,000	
Engineering Consultant	$5,000	$5,000	
Fuel Analysis Services	$2,000	$2,000	
Subtotal	$53,000		

Miscellaneous O&M Materials			
Calibration Gases	$2,000	$2,000	(not active defaults-user estimate)
Hydrogen - Bottled Gas	$2,000	$2,000	
Nitrogen - Bottled Gas	$2,000	$2,000	
Minor Spares Replacement	$7,500	$10,000	
Equipment Rental	$3,000	$3,000	
Potable water (not process)	$1,000	$1,000	
Sanitary Sewer (not process)	$1,000	$1,000	

Supplemental Data – CT Project Risk Analyzer Input Data

	Other Misc. Materials	$2,000	$2,000	
	General Solid Waste Disposal (not process)	$2,000	$2,000	
	Subtotal	$22,500		
	Operating Services and Misc. Materials	$75,500	(incl. in Annual Plant O&M Services and Materials)	
Variable Non-Fuel Operating Cost Items				
	Catalyst Replacement	Cost per Year	Default	
	SCR Catalyst Replacement	$57,611	$57,611	
	CO Catalyst Replacement	$0	$0	
	Subtotal	$57,611		(entry on Cash Flow sheet)
	Disposal Charges			
	SCR Catalyst Disposal Charges	$3,973	$3,973	
	CO Catalyst Disposal Charges	$0	(user-specified)	
	Byproduct Waste Disposal (variable)	$4,966	$4,966	
	Subtotal	$8,940		(entry on Cash Flow sheet)
	Other Consumables			
	Ammonia for SCR of NOx	$15,893	$15,893	
	Misc. Consumables for CT	$19,866	$19,866	
Rev 8/2/01	Raw Water Consumed	$653,388	$635,710	
	Thermal Discharge Charge(Circ. Water)	$0	(user-specified)	
	Water Treatment Chemicals (H2SO4, NaOH, etc.)	$29,799	$29,799	
	Other (Balance of Plant)	$0	(user-specified)	
	Subtotal	$718,946		(incl. in Other Consumables on Cash Flow)
	Auxiliary Power Cost Estimate	User Entry	Default	
	Electrical energy cost - operating, $/kWh	0.045	0.030	(typically price charged for electricity sales)
	Electrical energy cost - non-operating, $/kWh	0.080	0.060	(typically retail purchased electricity cost)
	Auxiliary power - operating, % of gross	2.00%	2.00%	(default depends on cycle type)
	Auxiliary power - non-operating, % of gross	0.10%	0.10%	(default depends on cycle type)
	Auxiliary power - starting motor, % of gross	1.40%	1.40%	(default depends on cycle type)
	Number of minutes per start	20	20	
	Starting Motor Power Costs, $/yr	$584		

Other Startup Aux. Power Costs, $/yr	$1,000	(user-specified)	
Total Startup Aux. Power Costs	$1,584		(incl. in Other Consumables on Cash Flow)
Total Variable Non-Fuel Operating Costs	$787,081	(ref. only - individual components used on cash flow)	
Total Non-Operating Aux. Power Costs	$19,079	$19,079	(separate line item on cash flow sheet)
Operating aux. power costs (from gross)	$1,931,741	$1,931,741	(excluded from O&M estimate since
(for reference only)			net power output is assumed for revenue)

<u>Fuel Cost and Replacement Electricity (for Business Interruption Estimates)</u>

Selected Energy Base Units

Average Fuel Cost, $/MMBtu net	6.00	3.50	(user input required)
Average Heat Rate, Btu/kWh net	6,928	7,500	(default depends on comb. cycle or simple cycle)
Equivalent Efficiency, % net	49.3%		
Hourly Fuel Cost, $/hr	$11,090		
Average Replacement Electricity Cost, $/kWh	0.052	0.052	(purchased electricity cost for replacement;
Hourly Electricity Replacement Cost, $/hr	$13,874		typically between revenue price and retail price)

Case: Dual Fuel Case 1 Nat Gas Only Rev B

Table E-3
Case 1: Maintenance Inputs Sheet

CT Project Risk Analyzer
Maintenance Inputs Sheet

Maintenance Service Costs (Annual or Periodic)	Cost per Activity	Default	
Combustion Turbine Boroscopic Inspection	$20,000	$20,000	(per CT)
Fuel Gas Compressor Overhaul	$5,000	$5,000	(per CT)
Mechanical Equipment Inspection / Repair	$10,000	$10,000	(per CT)
Electrical Equipment Inspection / Repair	$10,000	$10,000	(per CT)
Instrument Calibration	$5,000	$5,000	(per CT)
Miscellaneous Balance of Plant	$25,000	$25,000	(per CT)
Maintenance Service per CT	$75,000		
Total Maintenance Services (Fixed)	$75,000 per year		(incl. in Annual Plant O&M Services and Materials)

Variable Maintenance Costs

CT Scheduled Maintenance (per CT Basis, for 'Generic' Models)		Parts	Labor*	Parts default+	Labor default+
Combustor Inspection/Overhaul	(CI)**	$860,000	$120,000	860,000	120,000
Hot Gas Path Inspection/Overhaul	(HG)**	$6,000,000	$540,000	6,000,000	540,000
Major Inspection/Overhaul	(MJ) **	$10,700,000	$1,110,000	10,700,000	#####
Other Scheduled Maintenance - (Total Plant Basis)					
HRSG Inspect/Refurbish (annualized, for given service factor)		$131,000	$40,000	$131,000	$40,000
Steam Turbine/Generator Inspection (annual, for S.F.)++		$24,000	$10,000	$24,000	$10,000
Steam Turbine/Generator Major Maintenance++		$1,540,000	$160,000	$1,540,000	#####
Balance Of Plant Inspect/Refurbish (annualized, for S.F.)		$113,000	$30,000	$113,000	$30,000

* Labor as contract services (or additional fully loaded in-house)

**Event Values can be overridden on individual CT Maint sheet

++Event Values can be overridden on ST Maint sheet

+Rough estimates based on Plant MW.
Enter refined values for parts and labor.

Frequency of Steam Turbine Major Maintenance, Operating Hours: 48,000 (per ST Major Maintenance event)

Unplanned Maintenance (annual allowance per CT)			Parts default+	Labor default+
Unplanned CT maintenance & repairs (for 'Generic' models)+++	$66,000	$11,000	66,000	11,000
Unplanned HRSG/ST/Gen./BOP maint. & repairs (total basis)	$49,200	$14,800	49,200	14,800
+++Override in cash flow summary if Monte Carlo simulation selected			+Rough estimates based on Plant MW.	

CT Inspection/Overhaul Interval	Adjustment Factor	Default	
User Adjustment Factor for Factored Hours (50-150%) ***	100%	100%	(affects selected OEM Intervals)
User Adjustment Factor for Factored Starts (50-150%)	100%	100%	(affects selected OEM Intervals)

*** Also used for Equivalent Operating Hours Adjustment

Case 2: Dual Fuel, Natural Gas 92%, Distillate 8%

Table E-4
Case 2: Input Summary Sheet

CT Project Risk Analyzer
Input Summary sheet

	Plant/Economic Basis	User Selection Menu		Range/Comments
	Combustion Turbine Manufacturer	General Electric		(sets maint. inspection frequency)
	CT Model	GE 7 FA		(sets maint. reliability statistics)
	Cycle Type	Combined Cycle / Cogen		(sets staffing req'ts)
	Duty Cycle - Mission	Baseload: 40-95% Service Factor		(sets staffing req'ts)
	SCR of NOx in Flue Gas	Yes (for CC or Cogen)		(activates SCR costs)
		User Input	Default Value	
	Number of CT's	1		(Integer user input-no default)
	Number of HRSG's	1	1	(Integer less than or equal No. of CT's)
	Number of Steam Turbines	1	1	(Integer less than or equal No. of CT's)
Rev 8/2/01	Plant Net Output, MW Rating	268.1	245	(user input required)
	Service Factor (SF)	90.0%	75.0%	(default depends on mission)
	Capacity Factor (CF)	85.0%	84.0%	(must be less than service factor)
Changed	Percent Time on Natural Gas	92.0%		(user input-no default)
Changed	Percent Time on Distillate Oil	8.0%		(user input-no default)
	Other Fuels (by difference)	0.0%		(check between 0 and 100%)
	Percent Time at Peak Load	1.0%	1%	(typically 0 - 2%)
	Number of Normal Starts/Yr	5	5	(default depends on Service Factor)
	Number of Full Load Trips/Yr	3	3	(default depends on Capacity Factor)
	CT Model First Commercial Year of Use	1994	1994	(input four digit integer)

	Base Year (for cost reference)	2001		(input four digit integer-no default)
	Plant Startup Year	2003		(on or after base year-no default)
	Plant Economic Life, Years	30	30	(input integer; maximum 30 yrs)
	Average Inflation/Escalation	2.0%	2.5%	(inflation less than equity ROR)
	Present Worth Discount Rate	12.0%	15.0%	(equity ROR greater than inflation)
	Fixed O&M Staffing Quantity	*Defaults depend on duty cycle and type - see Operations Inputs for wage basis*		
	Plant Manager	1	1	
	Operating Supervisor	1	1	
	Lead Operator/Technician	0	0	
	Lead Operator	4	4	
Changed	Assistant Operator	5	4	
	Adminstrative Assistant	1	1	
	Other Operating Employees	1	1	
	Maintenance Supervisor	1	1	
	Combined O&M Supervisor	0	0	
	Maintenance Technician	1	1	
	Instrument Technician	1	1	
	Maintenance Engineer	1	1	
	Warehouse/Purchasing Assistant	1	1	
	Chemistry Technician	1	1	
	Other Maintenance Employees	0	0	
	Total Direct Staff	19		
	Average Overtime Factor	10.0%	10.0%	(applied to all base labor)
	Average Incentive/Bonus Factor	10.0%	10.0%	(applied to all base labor)
	Average Benefits Factor	35.0%	35.0%	(applied to all base labor)
Rev 8/2/01	Case Description (user input text)	Dual Fuel Case 2 DualFuel 92Gas Rev B		

User must update Operations Inputs and Maintenance Inputs for valid estimate.
Specific changes to scheduled maintenance events for gas turbines and steam turbine are optional.
See current ReadMe document for details.

Table E-5
Case 2: Operations Inputs Sheet

CT Project Risk Analyzer Operations Inputs Sheet

Fixed Direct Labor - Direct Employee Staffing

(Enter in Base Year Dollars)

Staff Position	Base Wage ($/yr)	Default Estimate	Number of Employees (from Input Summary)
Plant Manager	$80,000	$80,000	1
Operating Supervisor	$70,000	$70,000	1
Lead Operator/Technician	$60,000	$60,000	0
Lead Operator	$55,000	$55,000	4
Assistant Operator	$45,000	$45,000	5
Adminstrative Assistant	$35,000	$35,000	1
Other Operating Employees	$35,000	$35,000	1
Maintenance Supervisor	$65,000	$65,000	1
Combined O&M Supervisor	$70,000	$70,000	0
Maintenance Technician	$55,000	$55,000	1
Instrument Technician	$50,000	$50,000	1
Maintenance Engineer	$60,000	$60,000	1
Warehouse/Purchasing Assistant	$35,000	$35,000	1
Chemistry Technician	$35,000	$35,000	1
Other Maintenance Employees	$35,000	$35,000	0
Total Direct Base Labor	$965,000	(depends on Input Summary staffing)	
Total Number of Employees			19
Base hours per year	2,080	2080	
Resulting average base labor rate $/hr	$24.42		(reference only - not used)

Fixed Home Office & Employee Support Services

Other Employee Expenses	Persons per year	Default	$/person	Default
Recruiting/Relocation	8	8	$500	$500
Training/Certification/Seminars	15	15	$1,000	$1,000

	Travel/Expenses	15	15	$1,000	$1,000
	Subtotal	$34,000			
	<u>Home Office Support Expenses</u>	<u>Cost per Year</u>	<u>Default</u>		
	Fixed Labor (fully loaded, incl. benefits)	$230,000	$280,000	(Purchasing, Sales, Human Resources, etc.)	
	Travel & Communications	$2,000	$2,000		
	Professional Services	$8,000	$8,000		
	Tools / Safety Equipment	$2,000	$2,000		
	Office Supplies/Equip/Computers	$2,000	$2,000		
	Telecommunications / Postage	$2,000	$2,000		
	Vehicle Lease/Fuel/Maintenance	$4,000	$4,000		
	Misc. Services (based on No. of employees)	$57,000	$57,000	Est. $3,000 per employee	
	Subtotal	$307,000			
	Total Home Office & Employee Support	$341,000		(entry on Cash Flow sheet)	
<u>Fixed Non-Labor Operating Costs</u>					
	<u>Operating Services (contract)</u>				
	OEM Technical Representatives	$4,500	$6,000	(not active defaults-user estimate)	
Rev 8/2/01	Plant Chemical Analysis	$3,000	$2,000		
Rev 8/2/01	Emission Testing	$7,500	$5,000		
	High Voltage Equipment Testing	$7,500	$10,000		
	Insurance - Auto / Employee Liability	$2,000	$2,000		
Rev 8/2/01	Accounting Service	$26,000	$25,000		
	Heavy Equipment Lease	$2,500	$3,000		
	Engineering Consultant	$5,000	$5,000		
Changed	Fuel Analysis Services	$2,500	$2,000		
	Subtotal	$60,500			
	<u>Miscellaneous O&M Materials</u>				
	Calibration Gases	$2,000	$2,000	(not active defaults-user estimate)	
	Hydrogen - Bottled Gas	$2,000	$2,000		
	Nitrogen - Bottled Gas	$2,000	$2,000		
	Minor Spares Replacement	$7,500	$10,000		

Supplemental Data – CT Project Risk Analyzer Input Data

Rev 8/2/01	Equipment Rental	$5,000	$3,000	
	Potable water (not process)	$1,000	$1,000	
	Sanitary Sewer (not process)	$1,000	$1,000	
	Other Misc. Materials	$2,000	$2,000	
	General Solid Waste Disposal (not process)	$2,000	$2,000	
	Subtotal	$24,500		
	Operating Services and Misc. Materials	$85,000	(incl. in Annual Plant O&M Services and Materials)	

Variable Non-Fuel Operating Cost Items				
	Catalyst Replacement	Cost per Year	Default	
Rev 8/2/01	SCR Catalyst Replacement	$69,216	$57,889	
	CO Catalyst Replacement	$0	$0	
	Subtotal	$69,216		(entry on Cash Flow sheet)
	Disposal Charges			
Rev 8/2/01	SCR Catalyst Disposal Charges	$4,774	$3,992	
	CO Catalyst Disposal Charges	$0	(user-specified)	
Rev 8/2/01	Byproduct Waste Disposal (variable)	$5,966	$4,990	
	Subtotal	$10,740		(entry on Cash Flow sheet)
	Other Consumables			
Rev 8/2/01	Ammonia for SCR of NOx	$19,094	$15,969	
Rev 8/2/01	Misc. Consumables for CT	$23,868	$19,962	
Rev 8/2/01	Raw Water Consumed	$665,511	$638,776	
	Thermal Discharge Charge(Circ. Water)	$0	(user-specified)	
Rev 8/2/01	Water Treatment Chemicals (H2SO4, NaOH, etc.)	$35,802	$29,943	
	Other (Balance of Plant)	$0	(user-specified)	
	Subtotal	$744,275	(incl. in Other Consumables on Cash Flow)	

Auxiliary Power Cost Estimate	User Entry	Default	
Electrical energy cost - operating, $/kWh	0.045	0.030	(typically price charged for electricity sales)
Electrical energy cost - non-operating, $/kWh	0.080	0.060	(typically retail purchased electricity cost)
Auxiliary power - operating, % of gross	2.00%	2.00%	(default depends on cycle type)

	Auxiliary power - non-operating, % of gross	0.10%	0.10%	(default depends on cycle type)
	Auxiliary power - starting motor, % of gross	1.40%	1.40%	(default depends on cycle type)
	Number of minutes per start	20	20	
	Starting Motor Power Costs, $/yr	$587		
	Other Startup Aux. Power Costs, $/yr	$1,000	(user-specified)	
	Total Startup Aux. Power Costs	$1,587	(incl. in Other Consumables on Cash Flow)	
	Total Variable Non-Fuel Operating Costs	$825,819	(ref. only - individual components used on cash flow)	
	Total Non-Operating Aux. Power Costs	$19,171	$19,171	(separate line item on cash flow sheet)
	Operating aux. power costs (from gross) (for reference only)	$1,941,059	$1,941,059	(excluded from O&M estimate since net power output is assumed for revenue)
	<u>Fuel Cost and Replacement Electricity (for Business Interruption Estimates)</u>			
	Selected Energy Base Units			
<u>Changed</u>	Average Fuel Cost, $/MMBtu net	5.90	3.50	(user input required)
<u>Changed</u>	Average Heat Rate, Btu/kWh net	6,975	7,500	(default depends on comb. cycle or simple cycle)
	Equivalent Efficiency, % net	48.9%		
	Hourly Fuel Cost, $/hr	$11,032		
	Average Replacement Electricity Cost, $/kWh	0.052	0.052	(purchased electricity cost for replacement; typically between revenue price and retail price)
	Hourly Electricity Replacement Cost, $/hr	$13,941		

Case: Dual Fuel Case 2 DualFuel 92Gas Rev B

CT Project Risk Analyzer 1.01

Table E-6
Case 2: Maintenance Inputs Sheet

CT Project Risk Analyzer Maintenance Inputs Sheet

Maintenance Service Costs (Annual or Periodic)		Cost per Activity	Default	
Changed	Combustion Turbine Boroscopic Inspection	$24,000	$20,000	(per CT)
	Fuel Gas Compressor Overhaul	$5,000	$5,000	(per CT)
	Mechanical Equipment Inspection / Repair	$11,000	$10,000	(per CT)
	Electrical Equipment Inspection / Repair	$11,000	$10,000	(per CT)
	Instrument Calibration	$6,000	$5,000	(per CT)
	Miscellaneous Balance of Plant	$30,000	$25,000	(per CT)
	Maintenance Service per CT	$87,000		
	Total Maintenance Services (Fixed)	$87,000 per year		(incl. in Annual Plant O&M Services and Materials)

Variable Maintenance Costs						
	CT Scheduled Maintenance (per CT Basis, for 'Generic' Models)		Parts	Labor*	Parts default+	Labor default+
Rev 8/2/01	Combustor Inspection/Overhaul	(CI)**	$960,000	$150,000	860,000	120,000
Rev 8/2/01	Hot Gas Path Inspection/Overhaul	(HG)**	$6,200,000	$600,000	6,100,000	550,000
	Major Inspection/Overhaul	(MJ) **	$10,800,000	$1,120,000	10,800,000	#####
	Other Scheduled Maintenance - (Total Plant Basis)					
Rev 8/2/01	HRSG Inspect/Refurbish (annualized, for given service factor)		$135,000	$42,000	$132,000	$40,000
	Steam Turbine/Generator Inspection (annual, for S.F.)++		$24,000	$10,000	$24,000	$10,000
	Steam Turbine/Generator Major Maintenance++		$1,550,000	$160,000	$1,550,000	#####
Rev 8/2/01	Balance Of Plant Inspect/Refurbish (annualized, for S.F.)		$130,000	$32,500	$113,000	$30,000

* Labor as contract services (or additional fully loaded in-house)

**Event Values can be overridden on individual CT Maint sheet

++Event Values can be overridden on ST Maint sheet

+Rough estimates based on Plant MW.
Enter refined values for parts and labor.

Frequency of Steam Turbine Major Maintenance, Operating Hours	48,000	(per ST Major Maintenance event)		
Unplanned Maintenance (annual allowance per CT)			Parts default+	Labor default+
Unplanned CT maintenance & repairs (for 'Generic' models)+++	$75,000	$11,000	66,000	11,000
Unplanned HRSG/ST/Gen./BOP maint. & repairs (total basis)	$49,400	$14,900	49,400	14,900
+++Override in cash flow summary if Monte Carlo simulation selected			+Rough estimates based on Plant MW.	

CT Inspection/Overhaul Interval	Adjustment Factor	Default	
User Adjustment Factor for Factored Hours (50-150%) ***	94%	100%	(affects selected OEM Intervals)
User Adjustment Factor for Factored Starts (50-150%)	94%	100%	(affects selected OEM Intervals)

*** Also used for Equivalent Operating Hours Adjustment

Case 3a: Dual Fuel, Natural Gas 50%, Distillate 50%

Table E-7
Case 3a: Input Summary Sheet

CT Project Risk Analyzer
Input Summary sheet

Plant/Economic Basis	User Selection Menu		Range/Comments
Combustion Turbine Manufacturer	General Electric		(sets maint. inspection frequency)
CT Model	GE 7 FA		(sets maint. reliability statistics)
Cycle Type	Combined Cycle / Cogen		(sets staffing req'ts)
Duty Cycle - Mission	Baseload: 40-95% Service Factor		(sets staffing req'ts)
SCR of NOx in Flue Gas	Yes (for CC or Cogen)		(activates SCR costs)
	User Input	Default Value	
Number of CT's	1		(Integer user input-no default)
Number of HRSG's	1	1	(Integer less than or equal No. of CT's)
Number of Steam Turbines	1	1	(Integer less than or equal No. of CT's)
Plant Net Output, MW Rating	274.7	245	(user input required)
Service Factor (SF)	90.0%	75.0%	(default depends on mission)
Capacity Factor (CF)	85.0%	84.0%	(must be less than service factor)
Percent Time on Natural Gas	50.0%		(user input-no default)
Percent Time on Distillate Oil	50.0%		(user input-no default)
Other Fuels (by difference)	0.0%		(check between 0 and 100%)
Percent Time at Peak Load	1.0%	1%	(typically 0 - 2%)
Number of Normal Starts/Yr	5	5	(default depends on Service Factor)
Number of Full Load Trips/Yr	3	3	(default depends on Capacity Factor)
CT Model First Commercial Year of Use	1994	1994	(input four digit integer)
Base Year (for cost reference)	2001		(input four digit integer-no default)

Plant Startup Year	2003		(on or after base year-no default)
Plant Economic Life, Years	30	30	(input integer; maximum 30 yrs)
Average Inflation/Escalation	2.0%	2.5%	(inflation less than equity ROR)
Present Worth Discount Rate	12.0%	15.0%	(equity ROR greater than inflation)
Fixed O&M Staffing Quantity	*Defaults depend on duty cycle and type - see Operations Inputs for wage basis*		
Plant Manager	1	1	
Operating Supervisor	1	1	
Lead Operator/Technician	0	0	
Lead Operator	5	4	
Assistant Operator	5	4	
Adminstrative Assistant	1	1	
Other Operating Employees	1	1	
Maintenance Supervisor	1	1	
Combined O&M Supervisor	0	0	
Maintenance Technician	1	1	
Instrument Technician	1	1	
Maintenance Engineer	1	1	
Warehouse/Purchasing Assistant	1	1	
Chemistry Technician	1	1	
Other Maintenance Employees	0	0	
Total Direct Staff	20		
Average Overtime Factor	10.0%	10.0%	(applied to all base labor)
Average Incentive/Bonus Factor	10.0%	10.0%	(applied to all base labor)
Average Benefits Factor	35.0%	35.0%	(applied to all base labor)

Case Description (user input text): Dual Fuel Case 3a DualFuel 50Gas Rev B

Table E-8
Case 3a: Operations Inputs Sheet

CT Project Risk Analyzer
Operations Inputs Sheet

Fixed Direct Labor - Direct Employee Staffing

Staff Position	(Enter in Base Year Dollars) Base Wage ($/yr)	Default Estimate	Number of Employees (from Input Summary)
Plant Manager	$80,000	$80,000	1
Operating Supervisor	$70,000	$70,000	1
Lead Operator/Technician	$60,000	$60,000	0
Lead Operator	$55,000	$55,000	5
Assistant Operator	$45,000	$45,000	5
Adminstrative Assistant	$35,000	$35,000	1
Other Operating Employees	$35,000	$35,000	1
Maintenance Supervisor	$65,000	$65,000	1
Combined O&M Supervisor	$70,000	$70,000	0
Maintenance Technician	$55,000	$55,000	1
Instrument Technician	$50,000	$50,000	1
Maintenance Engineer	$60,000	$60,000	1
Warehouse/Purchasing Assistant	$35,000	$35,000	1
Chemistry Technician	$35,000	$35,000	1
Other Maintenance Employees	$35,000	$35,000	0
Total Direct Base Labor	$1,020,000	(depends on Input Summary staffing)	
Total Number of Employees			20
Base hours per year	2,080	2080	
Resulting average base labor rate $/hr	$24.52		(reference only - not used)

Fixed Home Office & Employee Support Services

Other Employee Expenses	Persons per year	Default	$/person	Default
Recruiting/Relocation	8	8	$500	$500
Training/Certification/Seminars	15	15	$1,000	$1,000
Travel/Expenses	15	15	$1,000	$1,000

	Subtotal	$34,000		
	Home Office Support Expenses	Cost per Year	Default	
Changed	Fixed Labor (fully loaded, incl. benefits)	$240,000	$280,000	(Purchasing, Sales, Human Resources, etc.)
	Travel & Communications	$2,000	$2,000	
	Professional Services	$8,000	$8,000	
	Tools / Safety Equipment	$2,000	$2,000	
	Office Supplies/Equip/Computers	$2,000	$2,000	
	Telecommunications / Postage	$2,000	$2,000	
	Vehicle Lease/Fuel/Maintenance	$4,000	$4,000	
	Misc. Services (based on No. of employees)	$60,000	$60,000	Est. $3,000 per employee
	Subtotal	$320,000		
	Total Home Office & Employee Support	$354,000		(entry on Cash Flow sheet)
Fixed Non-Labor Operating Costs				
	Operating Services (contract)			
	OEM Technical Representatives	$4,500	$6,000	(not active defaults-user estimate)
Changed	Plant Chemical Analysis	$3,000	$2,000	
Rev 8/2/01	Emission Testing	$7,500	$5,000	
	High Voltage Equipment Testing	$7,500	$10,000	
	Insurance - Auto / Employee Liability	$2,000	$2,000	
Rev 8/2/01	Accounting Service	$26,000	$25,000	
	Heavy Equipment Lease	$2,500	$3,000	
	Engineering Consultant	$5,000	$5,000	
Rev 8/2/01	Fuel Analysis Services	$2,500	$2,000	
	Subtotal	$60,500		
	Miscellaneous O&M Materials			
	Calibration Gases	$2,000	$2,000	(not active defaults-user estimate)
	Hydrogen - Bottled Gas	$2,000	$2,000	
	Nitrogen - Bottled Gas	$2,000	$2,000	
	Minor Spares Replacement	$7,500	$10,000	
Rev 8/2/01	Equipment Rental	$5,000	$3,000	

	Potable water (not process)	$1,000	$1,000	
	Sanitary Sewer (not process)	$1,000	$1,000	
	Other Misc. Materials	$2,000	$2,000	
	General Solid Waste Disposal (not process)	$2,000	$2,000	
	Subtotal	$24,500		
	Operating Services and Misc. Materials	$85,000	(incl. in Annual Plant O&M Services and Materials)	
Variable Non-Fuel Operating Cost Items				
	Catalyst Replacement	Cost per Year	Default	
Rev 8/2/01	SCR Catalyst Replacement	$69,216	$59,315	
	CO Catalyst Replacement	$0	$0	
	Subtotal	$69,216		(entry on Cash Flow sheet)
	Disposal Charges			
Rev 8/2/01	SCR Catalyst Disposal Charges	$4,774	$4,091	
	CO Catalyst Disposal Charges	$0	(user-specified)	
Rev 8/2/01	Byproduct Waste Disposal (variable)	$5,966	$5,113	
	Subtotal	$10,740		(entry on Cash Flow sheet)
	Other Consumables			
Rev 8/2/01	Ammonia for SCR of NOx	$19,094	$16,363	
Rev 8/2/01	Misc. Consumables for CT	$23,868	$20,453	
Rev 8/2/01	Raw Water Consumed	$729,160	$654,509	
	Thermal Discharge Charge(Circ. Water)	$0	(user-specified)	
Rev 8/2/01	Water Treatment Chemicals (H2SO4, NaOH, etc.)	$37,012	$30,680	
	Other (Balance of Plant)	$0	(user-specified)	

CT Project Risk Analyzer

Operations Inputs Sheet

Fixed Direct Labor - Direct Employee Staffing — (Enter in Base Year Dollars)

Staff Position	Base Wage ($/yr)	Default Estimate	Number of Employees (from Input Summary)
Plant Manager	$280,750	$36,905	6
Operating Supervisor	$300,507	$34,976	6
Lead Operator/Technician	$320,265	$33,048	7
Lead Operator	$340,022	$31,119	7
Assistant Operator	$359,779	$29,190	7
Adminstrative Assistant	$379,537	$27,262	8
Other Operating Employees	$399,294	$25,333	8
Maintenance Supervisor	$419,051	$23,405	8
Combined O&M Supervisor	$438,809	$21,476	9
Maintenance Technician	$458,566	$19,548	9
Instrument Technician	$478,324	$17,619	9
Maintenance Engineer	$498,081	$15,690	10
Warehouse/Purchasing Assistant	$517,838	$13,762	10
Chemistry Technician	$537,596	$11,833	10
Other Maintenance Employees	$557,353	$9,905	11
Total Direct Base Labor	$577,110	(depends on Input Summary staffing)	11.1850746
Total Number of Employees			12
Base hours per year	2,080	2080	
Resulting average base labor rate $/hr	$25.52		(reference only - not used)

Fixed Home Office & Employee Support Services

Other Employee Expenses	Persons per year	Default	$/person	Default
Recruiting/Relocation	20	20	$1,333	$1,333
Training/Certification/Seminars	23	23	$1,583	$1,583
Travel/Expenses	27	27	$1,833	$1,833
Subtotal	$34,001			

Table E-9
Case 3a: Maintenance Inputs Sheet

CT Project Risk Analyzer Maintenance Inputs Sheet

	Maintenance Service Costs (Annual or Periodic)	Cost per Activity	Default	
Rev 8/2/01	Combustion Turbine Boroscopic Inspection	$24,000	$20,000 (per CT)	
	Fuel Gas Compressor Overhaul	$5,000	$5,000 (per CT)	
	Mechanical Equipment Inspection / Repair	$11,000	$10,000 (per CT)	
	Electrical Equipment Inspection / Repair	$11,000	$10,000 (per CT)	
Rev 8/2/01	Instrument Calibration	$6,000	$5,000 (per CT)	
Rev 8/2/01	Miscellaneous Balance of Plant	$30,000	$25,000 (per CT)	
	Maintenance Service per CT	$87,000		
	Total Maintenance Services (Fixed)	$87,000 per year		(incl. in Annual Plant O&M Services and Materials)

	Variable Maintenance Costs	Parts	Labor*	Parts default+	Labor default+
	CT Scheduled Maintenance (per CT Basis, for 'Generic' Models)				
Rev 8/2/01	Combustor Inspection/Overhaul (CI)**	$960,000	$150,000	880,000	120,000
	Hot Gas Path Inspection/Overhaul (HG)**	$6,200,000	$600,000	6,200,000	560,000
	Major Inspection/Overhaul (MJ) **	$11,000,000	$1,120,000	11,000,000	1,140,000
	Other Scheduled Maintenance - (Total Plant Basis)				
	HRSG Inspect/Refurbish (annualized, for given service factor)	$135,000	$42,000	$135,000	$50,000
	Steam Turbine/Generator Inspection (annual, for S.F.)++	$24,000	$10,000	$24,000	$10,000
Rev 8/2/01	Steam Turbine/Generator Major Maintenance++	$1,550,000	$160,000	$1,580,000	$160,000
Rev 8/2/01	Balance Of Plant Inspect/Refurbish (annualized, for S.F.)	$130,000	$32,500	$114,000	$30,000

	* Labor as contract services (or additional fully loaded in-house)				+Rough estimates based on Plant MW.	
	**Event Values can be overridden on individual CT Maint sheet				Enter refined values for parts and labor.	
	++Event Values can be overridden on ST Maint sheet					
	Frequency of Steam Turbine Major Maintenance, Operating Hours	48,000	(per ST Major Maintenance event)			
	Unplanned Maintenance (annual allowance per CT)				Parts default+	Labor default+
Rev 8/2/01	Unplanned CT maintenance & repairs (for 'Generic' models)+++	$75,000		$11,000	67,000	11,000
Rev 8/2/01	Unplanned HRSG/ST/Gen./BOP maint. & repairs (total basis)	$50,300		$15,100	50,300	15,100
	+++Override in cash flow summary if Monte Carlo simulation selected				+Rough estimates based on Plant MW.	
CT Inspection/Overhaul Interval		Adjustment Factor		Default		
Rev 8/2/01	User Adjustment Factor for Factored Hours (50-150%) ***	101%		100%	(affects selected OEM Intervals)	
Rev 8/2/01	User Adjustment Factor for Factored Starts (50-150%)	101%		100%	(affects selected OEM Intervals)	
	*** Also used for Equivalent Operating Hours Adjustment					

F
SUPPLEMENTAL DATA - CT PROJECT RISK ANALYZER OUTPUT DATA

The following data was used in the presentation of Operation and Maintenance results in Chapter 5.

Case 1: Natural Gas Only

Table F-1
Case 1: Operation and Maintenance Cost Summary

CT Project
Risk Analyzer
Operating and Maintenance Cost Summary

Basis						
	Combustion Turbine Manufacturer	General Electric (GE)				
	CT Model	GE 7 FA				
	Number of CT's	1				
	Cycle Type	Combined Cycle/Cogen				
	Duty Cycle - Mission	Baseload: 40-95% Service Factor				
	Plant Net Output, MWe rating	266.8				
	Capacity Factor	85.0%				
	Present Worth Discount Rate	12.0%				
	Base Year	2001				
	Plant Economic Life, Years	30				
Operating Costs			Annualized Cost*	% of Total	Present Worth*	Cost Account
	Direct Labor (base, OT, bonus)		$744,000	11.2%	$6,493,000	Fixed
	Benefits (Indirect)		$217,000	3.3%	$1,894,000	Fixed
	Home Office/Support (Indirect)		$338,000	5.1%	$2,950,000	Fixed
	Catalyst Replacement		$57,600	0.9%	$503,000	Variable
	Other Consumables		$720,500	10.8%	$6,289,000	Variable
	Disposal Charges		$8,900	0.1%	$78,000	Variable
	Purchased House Power**		$19,100	0.3%	$167,000	Fixed
	Subtotal		$2,105,100		$18,374,000	
Maintenance Costs						

Direct Labor (base, OT, bonus)	$360,000	5.4%	$3,142,000	Fixed
Benefits (Indirect)	$105,000	1.6%	$916,000	Fixed
Annual O&M Services, Materials	$150,500	2.3%	$1,314,000	Fixed
Scheduled Maintenance Parts/Mat'ls***	$3,360,200	50.6%	$29,326,000	Variable
Scheduled Maintenance Labor ***	$420,900	6.3%	$3,673,000	Variable
Unplanned Maintenance	$141,000	2.1%	$1,231,000	Variable
Subtotal	$4,537,600		$39,602,000	
Grand Total	$6,642,700		$57,976,000	

Fixed and Variable Cost Summary	Annualized	Normalized
Fixed O&M	$1,933,600	$7.25 /kW-yr net
Variable (non-fuel) O&M	$4,709,100	$2.37 /MWh net (average)
Grand Total	$6,642,700	

* All costs in Base Year dollars over project life. See Cash Flow summary sheet for detailed accounts.
** For auxiliary loads during non-operation.
*** Annualized costs dependent on PW Discount Factor.

Case: Dual Fuel Case 1 Nat Gas Only Rev B

Table F-2
Case 1: Cash Flow Summary and Present Worth

CT Project Risk Analyzer
Annual Cash Flow Summary and Present Worth

		Cost Account	User Cost Adjustment	Annualized Cost	Present Worth Sum	Total Cost Over Project Life
Fixed O&M Cost Categories						
Operations Base Labor (Direct)		Fixed	100%	$620,000	$5,411,149	$26,168,358
Operations Overtime and Bonus (Direct)		Fixed	100%	$124,000	$1,082,230	$5,233,672
Operations Labor Benefits (Indirect)		Fixed	100%	$217,000	$1,893,902	$9,158,925
Maintenance Base Labor (Direct)		Fixed	100%	$300,000	$2,618,298	$12,662,109
Maintenance Overtime and Bonus (Direct)		Fixed	100%	$60,000	$523,660	$2,532,422
Maintenance Labor Benefits (Indirect)		Fixed	100%	$105,000	$916,404	$4,431,738
Home Office/Employee Support (Indirect)		Fixed	100%	$338,000	$2,949,949	$14,265,976
Annual Plant O&M Services and Materials		Fixed	100%	$150,500	$1,313,513	$6,352,158
Non-operating Purchased House Power*		Fixed	100%	$19,079	$166,514	$805,265
	Subtotal			$1,933,579	$16,875,620	$81,610,623
Variable O&M Cost Categories						
Catalyst Replacement		Variable	100%	$57,611	$502,811	$2,431,597
Other Consumables		Variable	100%	$720,530	$6,288,541	$30,411,430
Disposal Charges		Variable	100%	$8,940	$78,022	$377,317
Scheduled Maintenance (OEM Recommended)						
CT Combustor Inspection/Overhaul -	Parts/Mat'l	Variable	100%	$559,965	$4,887,181	$23,576,480
	Labor	Variable	100%	$84,434	$736,915	$3,564,732
CT Hot Gas Path Inspection/Overhaul -	Parts/Mat'l	Variable	100%	$1,019,029	$8,893,737	$45,723,423
	Labor	Variable	100%	$93,116	$812,689	$3,759,057
CT Major Inspection/Overhaul -	Parts/Mat'l	Variable	100%	$1,339,345	$11,689,347	$80,669,019
	Labor	Variable	100%	$145,264	$1,267,819	$8,159,689
HRSG Inspect/Refurbish -	Parts/Mat'l	Variable	100%	$131,000	$1,143,323	$5,529,121

	Labor	Variable	100%	$40,000	$349,106	$1,688,281
Steam Turbine/Gen. Inspect/Refurbish -	Parts/Mat'l	Variable	100%	$197,828	$1,726,576	$9,714,744
	Labor	Variable	100%	$28,060	$244,899	$1,326,151
BOP Inspection/Overhaul -	Parts/Mat'l	Variable	100%	$113,000	$986,226	$4,769,394
	Labor	Variable	100%	$30,000	$261,830	$1,266,211
Unplanned Maintenance (Allowance)						
CT Unplanned Maintenance		Variable	100%	$77,000	$672,030	$3,249,941
HRSG/ST/Gen/BOP Unplanned Maint.		Variable	100%	$64,000	$558,570	$2,701,250
	Subtotal			$4,709,123	$41,099,622	$228,917,837
Total Operating and Maintenance Costs			O&M Cash Flow Summary:	$6,642,702	$57,975,242	$310,528,460
			Fixed O&M Costs:	$1,933,579	$16,875,620	
			Variable O&M Costs:	$4,709,123	$41,099,622	
Business Interruption Costs						
Net Loss Due to Unplanned Outages - No Insurance				$175,667	$1,533,158	$7,146,650

Economic Basis	
Average Inflation/Escalation rate	2.0%
PW Discount Rate	12.0%
Plant Economic Life, Years	30

* Non-operating auxiliary load assigned as "fixed". Auxiliary load during operation not included in total O&M costs

** Convention: costs are defined at the beginning of each year,
i.e. the PW of costs occurring within the base year is the same as actual costs

Case: Dual Fuel Case 1 Nat Gas Only Rev B

Case 2: Dual Fuel, Natural Gas 92%, Distillate 8%

Table F-3
Case 2: Operating and Maintenance Cost Summary

CT Project
Risk Analyzer
Operating and Maintenance Cost Summary

Basis					
	Combustion Turbine Manufacturer	General Electric (GE)			
	CT Model	GE 7 FA			
	Number of CT's	1			
	Cycle Type	Combined Cycle/Cogen			
	Duty Cycle - Mission	Baseload: 40-95% Service Factor			
	Plant Net Output, MWe rating	268.1			
	Capacity Factor	85.0%			
	Present Worth Discount Rate	12.0%			
	Base Year	2001			
	Plant Economic Life, Years	30			
Operating Costs		Annualized Cost*	% of Total	Present Worth*	Cost Account
	Direct Labor (base, OT, bonus)	$798,000	10.9%	$6,965,000	Fixed
	Benefits (Indirect)	$232,800	3.2%	$2,031,000	Fixed
	Home Office/Support (Indirect)	$341,000	4.7%	$2,976,000	Fixed
	Catalyst Replacement	$70,600	1.0%	$616,000	Variable
	Other Consumables	$760,800	10.4%	$6,640,000	Variable
	Disposal Charges	$11,000	0.2%	$96,000	Variable
	Purchased House Power**	$19,200	0.3%	$167,000	Fixed
	Subtotal	$2,233,400		$19,491,000	
Maintenance Costs					
	Direct Labor (base, OT, bonus)	$360,000	4.9%	$3,142,000	Fixed

Benefits (Indirect)	$105,000	1.4%	$916,000	Fixed
Annual O&M Services, Materials	$172,000	2.3%	$1,501,000	Fixed
Scheduled Maintenance Parts/Mat'ls***	$3,786,800	51.7%	$33,050,000	Variable
Scheduled Maintenance Labor ***	$511,700	7.0%	$4,466,000	Variable
Unplanned Maintenance	$157,800	2.2%	$1,377,000	Variable
Subtotal	$5,093,300		$44,452,000	
Grand Total	$7,326,700		$63,943,000	

Fixed and Variable Cost Summary	Annualized	Normalized
Fixed O&M	$2,027,900	$7.56 /kW-yr net
Variable (non-fuel) O&M	$5,298,600	$2.65 /MWh net (average)
Grand Total	$7,326,500	

* All costs in Base Year dollars over project life. See Cash Flow summary sheet for detailed accounts.

** For auxiliary loads during non-operation.

*** Annualized costs dependent on PW Discount Factor.

Case: Dual Fuel Case 2 DualFuel 92Gas Rev B

Table F-4
Case 2: Cash Flow Summary and Present Worth

CT Project Risk Analyzer
Annual Cash Flow Summary and Present Worth

		Cost Account	User Cost Adjustment	Annualized Cost	Present Worth Sum	Total Cost Over Project Life
Fixed O&M Cost Categories						
Operations Base Labor (Direct)		Fixed	100%	$665,000	$5,803,894	$28,067,675
Operations Overtime and Bonus (Direct)		Fixed	100%	$133,000	$1,160,779	$5,613,535
Operations Labor Benefits (Indirect)		Fixed	100%	$232,750	$2,031,363	$9,823,686
Maintenance Base Labor (Direct)		Fixed	100%	$300,000	$2,618,298	$12,662,109
Maintenance Overtime and Bonus (Direct)		Fixed	100%	$60,000	$523,660	$2,532,422
Maintenance Labor Benefits (Indirect)		Fixed	100%	$105,000	$916,404	$4,431,738
Home Office/Employee Support (Indirect)		Fixed	100%	$341,000	$2,976,132	$14,392,597
Annual Plant O&M Services and Materials		Fixed	100%	$172,000	$1,501,158	$7,259,609
Non-operating Purchased House Power*		Fixed	100%	$19,171	$167,318	$809,149
	Subtotal			$2,027,921	$17,699,005	$85,592,520
Variable O&M Cost Categories						
Catalyst Replacement		Variable	102%	$70,600	$616,176	$2,979,830
Other Consumables		Variable	102%	$760,780	$6,639,828	$32,110,259
Disposal Charges		Variable	102%	$10,955	$95,610	$462,370
Scheduled Maintenance (OEM Recommended)						
CT Combustor Inspection/Overhaul -	Parts/Mat'l	Variable	110%	$658,193	$5,744,488	$26,112,038
	Labor	Variable	110%	$123,838	$1,080,813	$5,067,206
CT Hot Gas Path Inspection/Overhaul -	Parts/Mat'l	Variable	105%	$1,142,369	$9,970,208	$54,925,936
	Labor	Variable	105%	$117,174	$1,022,659	$5,452,177
CT Major Inspection/Overhaul -	Parts/Mat'l	Variable	105%	$1,509,013	$13,170,153	$82,511,126
	Labor	Variable	105%	$164,403	$1,434,853	$8,423,802
HRSG Inspect/Refurbish -	Parts/Mat'l	Variable	105%	$141,750	$1,237,146	$5,982,846

	Labor	Variable	105%	$44,100	$384,890	$1,861,330
Steam Turbine/Gen. Inspect/Refurbish -	Parts/Mat'l	Variable	100%	$198,957	$1,736,427	$9,771,249
	Labor	Variable	100%	$28,060	$244,899	$1,326,151
BOP Inspection/Overhaul -	Parts/Mat'l	Variable	105%	$136,500	$1,191,326	$5,761,260
	Labor	Variable	105%	$34,125	$297,831	$1,440,315
Unplanned Maintenance (Allowance)						
CT Unplanned Maintenance		Variable	105%	$90,300	$788,108	$3,811,295
HRSG/ST/Gen/BOP Unplanned Maint.		Variable	105%	$67,515	$589,248	$2,849,608
	Subtotal			$5,298,632	$46,244,663	$250,848,799
<u>Total Operating and Maintenance Costs</u>			O&M Cash Flow Summary:	$7,326,553	$63,943,668	$336,441,318
			Fixed O&M Costs:	$2,027,921	$17,699,005	
			Variable O&M Costs:	$5,298,632	$46,244,663	
<u>Business Interruption Costs</u>						
Net Loss Due to Unplanned Outages - No Insurance				$190,890	$1,666,022	$7,765,981

<u>Economic Basis</u>	
Average Inflation/Escalation rate	2.0%
PW Discount Rate	12.0%
Plant Economic Life, Years	30

* Non-operating auxiliary load assigned as "fixed". Auxiliary load during operation not included in total O&M costs

** Convention: costs are defined at the beginning of each year,
i.e. the PW of costs occurring within the base year is the same as actual costs

Case: Dual Fuel Case 2 DualFuel 92Gas Rev B

Case 3a: Dual Fuel, Natural Gas 50%, Distillate 50%

Table F-5
Case 3a: Operating and Maintenance Cost Summary

CT Project
Risk Analyzer
Operating and Maintenance Cost Summary

Basis						
	Combustion Turbine Manufacturer		General Electric		(GE)	
	CT Model		GE 7 FA			
	Number of CT's		1			
	Cycle Type		Combined Cycle/Cogen			
	Duty Cycle - Mission		Baseload: 40-95% Service Factor			
	Plant Net Output, MWe rating		274.7			
	Capacity Factor		85.0%			
	Present Worth Discount Rate		12.0%			
	Base Year		2001			
	Plant Economic Life, Years		30			
Operating Costs		Annualized Cost*	% of Total	Present Worth*	Cost Account	
	Direct Labor (base, OT, bonus)	$864,000	11.3%	$7,541,000	Fixed	
	Benefits (Indirect)	$252,000	3.3%	$2,199,000	Fixed	
	Home Office/Support (Indirect)	$354,000	4.6%	$3,090,000	Fixed	
	Catalyst Replacement	$72,700	1.0%	$634,000	Variable	
	Other Consumables	$851,300	11.1%	$7,430,000	Variable	
	Disposal Charges	$11,300	0.1%	$98,000	Variable	
	Purchased House Power**	$19,600	0.3%	$171,000	Fixed	
	Subtotal	$2,424,900		$21,163,000		
Maintenance Costs						
	Direct Labor (base, OT, bonus)	$360,000	4.7%	$3,142,000	Fixed	

Benefits (Indirect)	$105,000	1.4%	$916,000	Fixed
Annual O&M Services, Materials	$172,000	2.3%	$1,501,000	Fixed
Scheduled Maintenance Parts/Mat'ls***	$3,898,400	51.0%	$34,023,000	Variable
Scheduled Maintenance Labor ***	$523,000	6.8%	$4,564,000	Variable
Unplanned Maintenance	$159,000	2.1%	$1,387,000	Variable
Subtotal	$5,217,400		$45,533,000	
Grand Total	$7,642,300		$66,696,000	

Fixed and Variable Cost Summary	Annualized	Normalized
Fixed O&M	$2,126,600	$7.74 /kW-yr net
Variable (non-fuel) O&M	$5,515,500	$2.70 /MWh net (average)
Grand Total	$7,642,100	

* All costs in Base Year dollars over project life. See Cash Flow summary sheet for detailed accounts.
** For auxiliary loads during non-operation.
*** Annualized costs dependent on PW Discount Factor.

Case: Dual Fuel Case 3a DualFuel 50Gas Rev B

Table F-6
Case 3a: Cash Flow Summary and Present Worth

CT Project Risk Analyzer
Annual Cash Flow Summary and Present Worth

		Cost Account	User Cost Adjustment	Annualized Cost	Present Worth Sum	Total Cost Over Project Life
Fixed O&M Cost Categories						
Operations Base Labor (Direct)		Fixed	100%	$720,000	$6,283,915	$30,389,061
Operations Overtime and Bonus (Direct)		Fixed	100%	$144,000	$1,256,783	$6,077,812
Operations Labor Benefits (Indirect)		Fixed	100%	$252,000	$2,199,370	$10,636,171
Maintenance Base Labor (Direct)		Fixed	100%	$300,000	$2,618,298	$12,662,109
Maintenance Overtime and Bonus (Direct)		Fixed	100%	$60,000	$523,660	$2,532,422
Maintenance Labor Benefits (Indirect)		Fixed	100%	$105,000	$916,404	$4,431,738
Home Office/Employee Support (Indirect)		Fixed	100%	$354,000	$3,089,592	$14,941,288
Annual Plant O&M Services and Materials		Fixed	100%	$172,000	$1,501,158	$7,259,609
Non-operating Purchased House Power*		Fixed	100%	$19,643	$171,439	$829,079
	Subtotal			$2,126,643	$18,560,619	$89,759,290
Variable O&M Cost Categories						
Catalyst Replacement		Variable	105%	$72,677	$634,298	$3,067,472
Other Consumables		Variable	105%	$851,273	$7,429,621	$35,929,701
Disposal Charges		Variable	105%	$11,277	$98,422	$475,969
Scheduled Maintenance (OEM Recommended)						
CT Combustor Inspection/Overhaul -	Parts/Mat'l	Variable	110%	$670,876	$5,855,178	$26,823,496
	Labor	Variable	110%	$127,318	$1,111,185	$5,332,102
CT Hot Gas Path Inspection/Overhaul -	Parts/Mat'l	Variable	105%	$1,196,073	$10,438,920	$54,233,024
	Labor	Variable	105%	$120,964	$1,055,730	$5,393,624
CT Major Inspection/Overhaul -	Parts/Mat'l	Variable	105%	$1,554,195	$13,564,483	$81,759,728
	Labor	Variable	105%	$168,394	$1,469,682	$8,354,507
HRSG Inspect/Refurbish -	Parts/Mat'l	Variable	105%	$141,750	$1,237,146	$5,982,846

	Labor	Variable	105%	$44,100	$384,890	$1,861,330
Steam Turbine/Gen. Inspect/Refurbish -	Parts/Mat'l	Variable	100%	$198,957	$1,736,427	$9,771,249
	Labor	Variable	100%	$28,060	$244,899	$1,326,151
BOP Inspection/Overhaul -	Parts/Mat'l	Variable	105%	$136,500	$1,191,326	$5,761,260
	Labor	Variable	105%	$34,125	$297,831	$1,440,315
Unplanned Maintenance (Allowance)						
CT Unplanned Maintenance		Variable	105%	$90,300	$788,108	$3,811,295
HRSG/ST/Gen/BOP Unplanned Maint.		Variable	105%	$68,670	$599,328	$2,898,357
	Subtotal			$5,515,507	$48,137,474	$254,222,425
Total Operating and Maintenance Costs			O&M Cash Flow Summary:	$7,642,150	$66,698,092	$343,981,715
			Fixed O&M Costs:	$2,126,643	$18,560,619	
			Variable O&M Costs:	$5,515,507	$48,137,474	
Business Interruption Costs						
Net Loss Due to Unplanned Outages - No Insurance				$234,463	$2,046,313	$9,538,665

Economic Basis	
Average Inflation/Escalation rate	2.0%
PW Discount Rate	12.0%
Plant Economic Life, Years	30

* Non-operating auxiliary load assigned as "fixed". Auxiliary load during operation not included in total O&M costs

** Convention: costs are defined at the beginning of each year,
i.e. the PW of costs occurring within the base year is the same as actual costs

Case: Dual Fuel Case 3a DualFuel 50Gas Rev B

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Target:
New Combustion Turbine

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