



**Report to the
Global CCS Institute**

**Steam Turbine Generator
Configuration and Sizing Considering
the Impacts of Carbon Capture System
Availability**

Final Report March 2011

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Abstract

The Tenaska Trailblazer Energy Center (Trailblazer or Project), is a supercritical, pulverized coal fired electric generating station under development in Nolan County, Texas, United States, approximately nine miles east of Sweetwater, Texas. Plant nominal capacity is expected to be 760 MW when operating in full power generation mode with no carbon capture.

Trailblazer is expected to be the first, new-build, coal-fired, power plant in the United States to incorporate a commercial-scale carbon dioxide (CO₂) capture plant into the initial design. The Project will be designed to capture 85 to 90 percent of the CO₂ that otherwise would be emitted into the atmosphere.

In June 2009, Tenaska signed a Memorandum of Understanding (MOU) with Fluor Enterprises, Inc. (Fluor) to work together to define the scope of the Project and to develop and negotiate an Engineering, Procurement and Construction (EPC) contract for the pulverized coal power plant and the carbon capture plant.

The steam turbine configuration and sizing is a critical study that sets a part of the design basis for the plant and has major implications for plant operating modes, part load operation, overall operability and ultimately the profitability of the plant given the markets for power and CO₂ in Texas. The study was based on the assumption that the plant would operate in a base load (full load) condition for the vast majority of all operating hours. Partial load operating scenarios were not considered in the economic evaluation. The fundamental outcome of the study is that of steam turbine sizing. Since the carbon capture process utilizes approximately 30 percent of the steam energy generated in the boiler a key question is should the steam turbine be sized for 70 percent flow left when the carbon capture plant is running, or the full steam flow to generate more power when the carbon capture plant is off-line? This does not impact the boiler or fuel side of the facility but will have an impact on steam turbine, condenser, air cooling equipment and various large pump sizing. It is the first time a study like this has been done by Fluor and Tenaska for a full-scale coal fired plant. Tenaska is not aware of any previous full-scale steam turbine configuration and sizing studies by others.

Tenaska worked with six major steam turbine generator (STG) manufacturers to develop steam/water cycles for the Project that would allow either the simultaneous generation of power and provision of steam for the flue gas carbon capture process, or operation power generation only mode with no steam to the carbon capture process.

This report presents the findings on a comparison of two STG sizing options, which were considered in this study. In Option 1 (the Big Turbine Option), the STG is designed to normally run with 30 percent of the main steam flow directed to the carbon capture facility (CC ON), but is designed with a low pressure (LP) turbine large enough to accommodate the full condensing steam flow operation at 100 percent boiler heat input (full power generating mode at 760 MW) when no steam is being sent to the carbon capture plant (CC OFF). In Option 2 (the Small Turbine Option), the turbine, the generator and all of the auxiliary systems are sized for CC ON, which means there would no increase in electrical output in

CC OFF mode. In both steam turbine sizing options, the operation of the exact same boiler will be at the same full boiler duty. The only difference is that when the plant is operating in CC OFF mode, the Big Turbine Option will be able to utilize the full load flow of steam to generate power, whereas the Small Turbine Option will require a reduction in boiler load to operate. This is because the Small Turbine Option is designed for the lower condensing flow associated with the high extraction steam flow for the CC ON condition, so the unit's full condensing flow and output is limited to 70 percent of that which could be achieved with the full boiler heat duty in CC OFF mode. The Small Turbine Option's optimization for the CC ON condition was expected to increase the turbine's LP efficiency in the normal CC ON condition, and reduce the plant's capital cost due to smaller LP turbines, generator, condenser, air cooling equipment, and various large pump requirements. The economic evaluation for this study was based on an operating mode with CC ON for 95 percent of the total plant operating hours during a 30-year period.

After studying the costs and benefits associated with both options, Tenaska concluded that the Big Turbine Option was superior to the Small Turbine Option, as the cost evaluation did not appear to provide enough cost reduction or CC ON performance benefit to offset the large reduction in plant output capacity with the CC OFF. If the Project were initially configured with the Small Turbine Option, a future switch to maximum electricity production capability would require major plant modifications and several months of outage time.

This is the fourth in a series of knowledge sharing reports on Carbon Capture and Storage (CCS), developed by Tenaska for the Global CCS Institute.

Key Lessons

While the Small Turbine option was estimated to provide some capital cost savings, these savings were within the variation of costs from steam turbine suppliers. This was due to the fact that the Small Turbine option is not a common turbine design. It is anticipated that the carbon capture plant, being the "first of a kind" design at this scale, will not have the same availability as the more mature pulverized coal power plant. The additional electrical output provided by the Large Steam Turbine option during such periods of capture plant unavailability nearly cancels the potential savings on capital costs of the Small Turbine option. In view of the uncertainties associated with a "first of a kind" plant, it was deemed prudent to select the Large Turbine option.

Steam Turbine Generator Sizing Study

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1.0 Introduction

1.1 Overview

The Tenaska Trailblazer Energy Center (Trailblazer or Project) is a supercritical pulverized coal electric generating station under development in Nolan County, Texas, United States, approximately nine miles east of Sweetwater, Texas at an elevation of 2000 feet. Plant nominal capacity is expected to be 760 MW when operating in full power generation mode with CC OFF. Trailblazer is expected to be the first new-build pulverized coal-fueled power plant in the United States to incorporate a commercial-scale CO₂ capture plant into the initial design. The Project is being designed to capture 85 to 90 percent of the CO₂ that otherwise would be emitted into the atmosphere. CO₂ from the Project will be sold into the Permian Basin CO₂ market, where it will be used for EOR and ultimately permanently stored underground. Geologic storage of CO₂ will be considered should it become economically attractive.

Sub-bituminous coal will be delivered to the Project from the Powder River Basin in Wyoming via the Union Pacific (UP) and/or Burlington Northern Santa Fe (BNSF) railroads. The Project site is bordered on the north by the UP railroad and on the south by the BNSF railroad.

The Project will interconnect to the Electric Reliability Council of Texas (ERCOT) 345 kV electrical system, most likely at a substation about three miles from the Project site.

The Project owner is Tenaska Trailblazer Partners, LLC. Tenaska Trailblazer Partners, LLC is owned 65 percent by affiliates of Tenaska, Inc. and 35 percent by an affiliate of Arch Coal, Inc. (Arch Coal). Tenaska, Inc. and Tenaska Trailblazer Partners, LLC are referred to collectively as ‘Tenaska’ in this report.

In February 2008, the site was procured, an air permit application was filed with the Texas Commission on Environmental Quality (TCEQ), an electric interconnection request was filed with ERCOT, and the Project was announced to the public. Tenaska engaged Burns & McDonnell to serve as Owner’s Engineer in November 2008. In June 2009, Tenaska signed a Memorandum of Understanding (MOU) with Fluor to work together to define the scope of the Project and related work and to develop and negotiate an Engineering, Procurement and Construction (EPC) contract for the pulverized coal power plant and the carbon capture plant. In July 2010, Tenaska and Fluor executed a contract for Fluor to perform the Front-End Engineering Design (FEED) study for the carbon capture plant and to be the presumptive carbon capture technology provider for the Project. In December 2010, the Project received a final air permit from the TCEQ. See <http://www.tenaskatrailblazer.com> for more information about the Project.

The report to the Global CCS Institute titled *Development of the Tenaska Trailblazer Energy Center* dated August 2010, provides a history of the Project, the rationale behind the site selection and technology selection, and identifies key challenges that the Project faces. The report to the Global CCS Institute titled *CO₂ Technology Evaluation, Methodology and Criteria*, dated September 2010, describes the process undertaken by Tenaska to identify and

select the preferred vendor to perform the carbon capture Front End Engineering Design for the Project. See <http://www.globalccsinstitute.com> for more information about the Global CCS Institute.

1.2 Developer Overview

Since its founding in 1987, Tenaska has successfully developed and constructed 15 power generation facilities, totaling more than 9,000 MW of output. Today, Tenaska operates eight power generation facilities totaling 6,700 MW that it owns in partnership with other companies. Tenaska also provides energy risk management services and is involved in asset acquisition and management, power marketing, fuel supply, natural gas exploration, production and transportation systems, biofuels marketing and electric transmission development.

Tenaska Capital Management, an affiliate, provides management services for standalone private equity funds, with almost \$5 billion USD in assets. Assets include nine power plants and multiple natural gas midstream assets, including gas storage, gathering and processing facilities. In 2009, Tenaska and its affiliates managed approximately 34,000 MW of assets on behalf of a variety of customers and private equity investors.

Another affiliate, Tenaska Marketing Ventures (TMV), is regarded as one of the top 10 natural gas marketers in North America, and provides natural gas commodity, volume management, hedging and asset management products and services. In 2009, TMV was ranked No. 1 in the USA in natural gas pipeline capacity trading, according to Boston-based CapacityCenter.com, which monitors and collects capacity and operational information on all interstate pipelines. Customers responding to Mastio & Company's 'Value and Loyalty Benchmarking' survey in 2009 ranked TMV No. 1 in the nation among major marketers for value and loyalty.

Another affiliate, Tenaska Power Services Co. (TPS), specializes in electric power marketing and asset management for utilities and non-utility generators, and is one of the largest marketers of electric power in the United States. TPS has developed a significant presence in the wind industry, and currently schedules about 20 percent of the wind generation in ERCOT.

In 2009, Tenaska had gross operating revenues of \$7.9 billion USD and assets of approximately \$2.8 billion USD. In 2009, *Forbes* magazine ranked Tenaska as 16th among the largest privately-held United States companies, based on 2008 revenues.

See <http://www.tenaska.com> for more information about Tenaska.

1.3 Partner Overview

In March 2010, Arch Coal acquired a 35 percent share of Tenaska Trailblazer Partners, LLC from affiliates of Tenaska. St. Louis-based Arch Coal is the second largest United States coal producer, with revenues of \$2.6 billion USD in 2009. Through its national network of mines, Arch Coal supplies cleaner-burning, low-sulfur coal to United States power producers to fuel roughly 8 percent of the nation's electricity. The company also ships coal to domestic

and international steel manufacturers as well as international power producers.

In total, Arch Coal contributes about 16 percent of the United States' coal supply from 11 mining complexes in Wyoming, Utah, Colorado, West Virginia, Kentucky and Virginia.

Arch Coal controls a domestic reserve base totaling 4.7 billion tons. Of that total, 88 percent is low in sulfur and nearly 83 percent meets the most stringent requirements of the Clean Air Act without the application of expensive scrubbing technology.

In addition to becoming a valued partner, Arch Coal also will provide low-sulfur Powder River Basin coal to the Project under a 20-year coal supply agreement.

See <http://www.archcoal.com> for more information about Arch Coal.

1.4 Contractor Overview

Fluor Enterprises, an affiliate of Fluor Corporation (collectively, Fluor), is the presumptive EPC contractor for the Project. Fluor is one of the world's largest publicly owned engineering, procurement, construction, maintenance, and project management companies. Fluor has more than 36,000 global employees, and maintains offices in more than 30 countries across six continents. Fluor ranks No. 111 on the Fortune 500 list of America's largest corporations. *Engineering News-Record* magazine ranks Fluor No. 1 on its Top 100 Design-Build Firms list and No. 2 on its Top 400 Contractors list. See <http://www.fluor.com> for more information.

Burns & McDonnell is the owners' engineer for the Project. Burns & McDonnell is a full-service engineering, architecture, construction, environmental and consulting solutions firm. Its staff of more than 3,000 represents virtually all design disciplines. Burns & McDonnell plans, designs, permits, constructs and manages facilities all over the world. In 2010 *Engineering News-Record* ranked Burns & McDonnell number 22 in design firms and number eight in power plant design firms. See <http://www.burnsmcd.com> for more information.

2.0 Executive Summary

The Project is a supercritical, pulverized coal fired electric generating station under development in Nolan County, Texas, United States, approximately nine miles east of Sweetwater, Texas. Plant nominal capacity is expected to be 760 MW when operating in full power generation mode with CC OFF.

Trailblazer is expected to be the first new-build, coal-fired power plant in the United States to incorporate a commercial-scale CO₂ capture plant into the initial design. The Project will be designed to capture 85 to 90 percent of the CO₂ that otherwise would be emitted into the atmosphere. CO₂ from the Project will be sold into the Permian Basin CO₂ market in West Texas, where it will be used in Enhanced Oil Recovery (EOR) and ultimately stored permanently underground. The electricity generated will be sold into the Electric Reliability Council of Texas (ERCOT) market.

In June 2009, Tenaska signed a MOU with Fluor to work together to define the scope of the Project and to develop and negotiate an EPC contract for the pulverized coal power plant and the carbon capture plant.

Steam turbine configuration and sizing is a critical decision that sets part of the design basis for the plant and has major implications for plant operating modes, part load operation, overall operability and the ultimate profitability of the plant given the markets for power and CO₂ in Texas. Since the carbon capture process utilizes approximately 30 percent of the steam energy generated in the boiler, it must be decided whether the steam turbine should be sized so that it can take advantage of the full steam flow which is available when the carbon capture plant is off-line or whether it should be sized to accommodate only the 70 percent steam flow available when the carbon capture plant is running. This does not impact the boiler or fuel side of the facility but will have an impact on the steam turbine, condenser, air cooling equipment and various large pump sizing. It is the first time a study like this has been done by Fluor or Tenaska for a full-scale coal fired plant. Tenaska is not aware of any previous full-scale steam turbine configuration and sizing studies by others.

The Project's thermal cycle requires the STG to operate both with and without a large quantity of steam being sent to the carbon capture process. The study assumed that the plant would operate with the carbon capture process running 95 percent of the time and without the carbon capture process running 5 percent of the time. Tenaska and Fluor worked with six major STG manufacturers to develop steam/water cycles for the Project that would allow either the simultaneous generation of power and provision of steam for the flue gas carbon capture process (CC ON) or operation in power generation only mode with no steam to the carbon capture process (CC OFF).

Two STG sizing options were considered in this study.

- Under the Big Turbine Option, the STG is designed to normally run with CC ON, but is also capable of full condensing operation at 100 percent boiler heat input with CC OFF. The LP turbine size is based on 55 percent of the steam flow with CC ON or 100 percent with CC OFF.

- Under the Small Turbine Option, the STG is sized for full boiler duty with CC ON, but the STG's steam flow and electrical output with CC OFF (full condensing mode) is limited to 70 percent of the boiler heat duty in order to reduce plant capital cost related to the air cooled condenser, electric generator and related equipment.

The Big Turbine Option facility can produce almost 200 MW more electric power with CC OFF than with CC ON. This is because all of the steam that would otherwise be sent to the carbon capture facility can be usefully converted in the larger-sized steam turbine. The Small Turbine Option facility produces about 60 MW less electric power with CC OFF than with CC ON, because the steam flow going into the high pressure (HP) and intermediate pressure (IP) turbines must be reduced 30 percent because of the LP turbine's lower maximum flow rate when no CC process steam being extracted.

The performance and cost evaluation of the two options indicates that there is no significant economic advantage for the Small Turbine Option. The calculated Small Turbine Option cost benefit of \$5 million USD was based on the facility operating with CC ON 95 percent of the time and with CC OFF 5 percent of the time. The Big Turbine Option is recommended since the Small Turbine Option cost evaluation did not appear to provide enough cost reduction or CC ON performance benefit to offset the large reduction in plant output capacity with the CC OFF. The cost difference would become even less of a factor if decreased availability factors were applied to the carbon capture facility. For example, carbon capture equipment availability during the first few years of operation could be lower due to equipment and process start up shake out. The Big Turbine Option design also provides flexibility to optimize generation output during short-term peak periods of elevated power demand or forced outages on the CC plant. The total installed plant cost per output (\$USD/kW) for the Big Turbine Option's increased capacity is attractive, even considering short-term CC OFF operation. This is due to the fact that the steam turbine and generator set would be rated at approximately 800 MW. The specific plant cost would be calculated as the installed cost divided by the rated output.

Building the plant with full or near-full condensing capability will allow the facility to operate efficiently in the full CO₂ capture mode, a reduced/partial CO₂ capture mode, or in the full power generating mode with no CO₂ capture plant operation without any added limitations or impacts to the facility's reliability. Overall plant operation was not a part of the scope of this study due to limited turbine vendor information at this time. However, unit start-up, shutdown and load following capability are not anticipated to be impacted.

Key Lessons

The Small Turbine Option (steam turbine and air cooled condenser) is expected to have a lower capital cost than that the Large Turbine Option. Early estimates indicate a potential difference of as much as \$22 million USD. However, this figure was in the range of differences in costs for the Small Turbine Option, which is not a common design. The Large Turbine Option provides maximum flexibility in the event of the anticipated difference in availability for the carbon capture plant, when compared to the more mature pulverized coal plant. The additional generation afforded by the Large Turbine Option nearly compensates for the difference in capital cost. In view of the uncertainties associated with a “first of a kind” plant, it was deemed prudent to select the Large Turbine option.

3.0 Purpose and Goals

This report discusses how Tenaska studied the various conditions and configurations under which the Project will operate, and determined the steam turbine generator configuration to best accommodate the anticipated range of operating conditions.

Factors such as ambient conditions and steam requirements of the carbon capture plant are important in the determination of the best steam turbine configuration for the facility. The study evaluated the life cycle economics of plant capacity and steam usage with the carbon capture system in and out of service.

The study assumptions were:

- Ambient and site conditions for plant capacity guarantees (see Exhibit 2);
- Operation and dispatch profiles;
 - On (CC ON) 95 percent of the time and off (CC OFF) 5 percent of the time
 - Base loaded operation
- Operation at part load is assumed to be limited to a very small number of hours per year. Best base load efficiency is the primary criteria for STG selection;
- Fluor Econamine Plus would be the CC system supplier;
- Carbon capture process steam pressure at the steam turbine interface at 70 psia (4.8 bar); and
- Condensate return from carbon capture would return to the cycle at the deaerating (#5) feedwater heater.

The study was designed to determine:

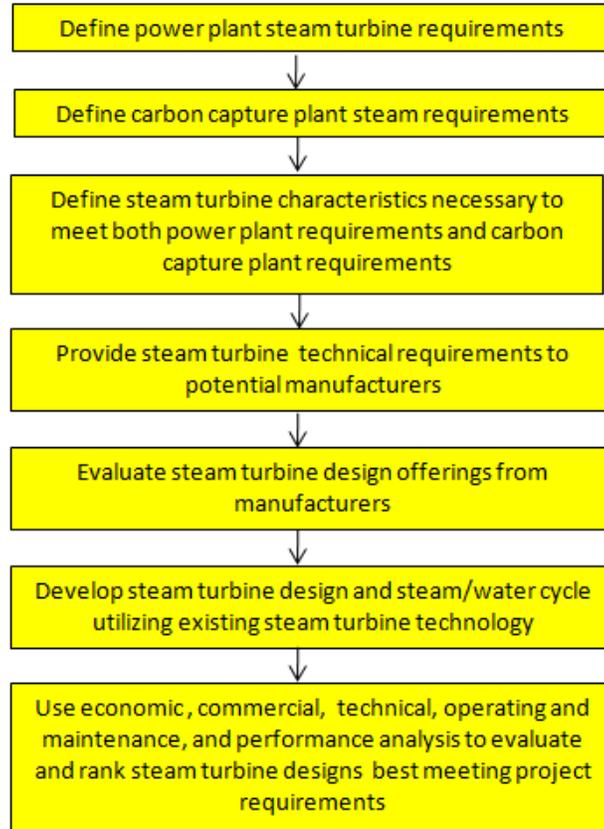
- Heat balances for guaranteed ambient conditions and selected options;
- Process steam requirements and impacts on steam turbine generator design; and
- Recommended steam turbine generator design to meet the operation profiles.

The study did not address the following:

- Heat integration between the carbon capture plant and the coal fired steam cycle (to be reviewed after more information is available from the CC process) and
- Detailed operational evaluation for part load operation, load ramping rates, equipment upsets and trips, etc. (more information from vendors and carbon capture process needed).

Figure 1 below illustrates the steps Tenaska used to select the preferred steam turbine generator design.

FIGURE 1 – Process used to select steam turbine size



4.0 Steam Turbine Evaluation

4.1 Overview

Tenaska and Fluor worked with six major STG manufacturers to develop steam/water cycles for the Project that can simultaneously generate power and provide steam for CC ON and CC OFF configurations.

The Project's thermal cycle is complex, as it requires the STG to be capable of operating both with and without sending a large quantity of steam to the carbon capture process. Fluor worked with the STG manufacturers to determine the turbine equipment that is commercially available to meet the Project's needs, and considered the range of STG options in the steam/water cycle optimization. Tenaska prefers to utilize existing turbine technology rather than a custom turbine designed for this application due to cost and schedule implications. The turbine suppliers are well informed about the Trailblazer project and stand ready to provide firm proposals.

Firm bids for the STGs were not solicited during this study phase, as the overall cost of the STG equipment was not as important to the study as the difference in cost between the two turbine sizing options. The turbine suppliers did provide guidelines on the cost differences that were used in the cost/benefit analysis of the two turbine options studied. The six STG suppliers queried all confirmed that they were able to bid equipment for this project for either of the two options. The specifics of the STG suppliers' designs are proprietary, so only general statements can be made in this report about the equipment limitations that were used in the cycle design to ensure that all six suppliers could provide bids for this project.

4.2 Technical Description of the Steam Turbines Evaluated

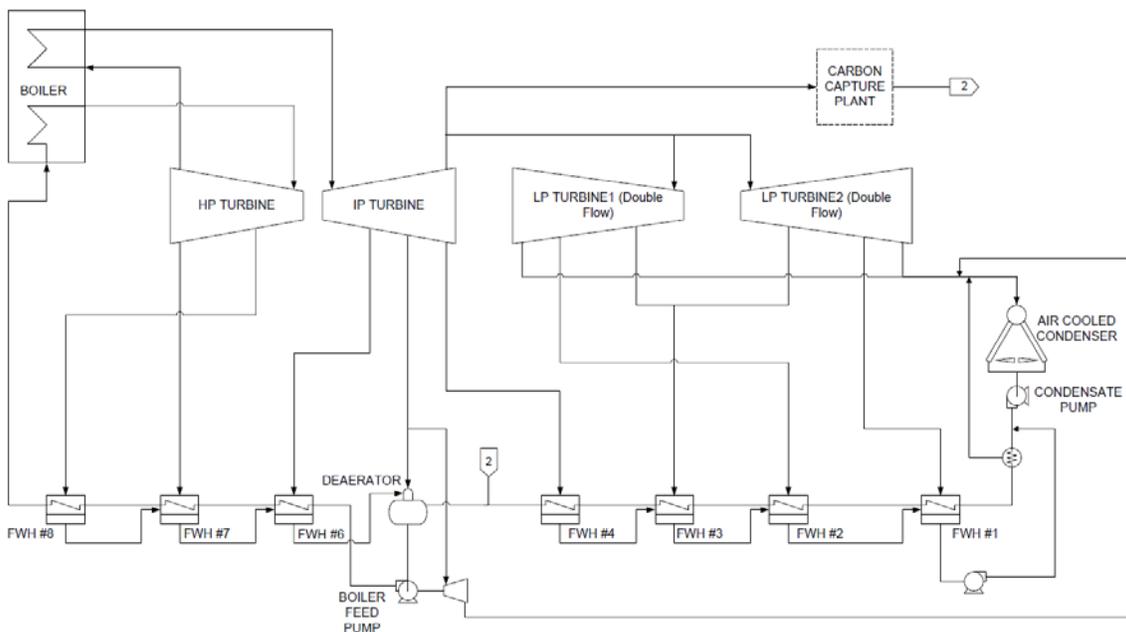
Figure 2 illustrates the steam/water cycle used for the steam turbine sizing study. The steam turbine consists of four sections, all in line on one shaft that drives the generator. Superheated, supercritical steam from the boiler at 3,690 psia (254.4 bar) and 1,085 °F (585 °C) enters the HP section where it expands before exiting and being returned to the boiler for reheating. In the boiler reheater section, the steam is superheated again to 1,085°F (585 °C) and is sent to the IP section. After expansion in the IP section, the steam flow is divided equally and sent to two identical LP sections. The LP sections exhaust into an air cooled condenser, where the steam is condensed. The condensate is pumped through a series of eight regenerative feedwater heaters and recycled back to the boiler. Relatively small quantities of steam extracted from the steam turbine are used for heating the feedwater to progressively higher temperatures in the feedwater heaters. The fifth feedwater heater is a direct contact, deaerating heater that removes non-condensable gases from the feedwater. Condensate pumps deliver condensate from the air cooled condenser hotwell through the first four feedwater heaters to the deaerating heater. Boiler feedwater pumps deliver condensate from the deaerating heater storage tank through the last three feedwater heaters to the boiler. The boiler feedwater pumps are steam turbine driven.

This steam turbine configuration is described in the power generation industry as a tandem

compound reheat turbine operating at supercritical inlet conditions of 3,690 psia (254.4 bar) /1,080°F (582 °C) superheat/1,080°F (582 °C) reheat, with eight stages of regenerative feedwater heating with the top stage above reheat pressure. The use of reheat steam and regenerative feedwater heating allows the plant to operate nearer to the ideal Rankine cycle, improving cycle and plant efficiency.

Fluor specified that STG suppliers extract CC process steam from the IP turbine exhaust at 70 psia (4.8 bar) required by the CC system when the CC system is fully operating and the STG is at base load. Exhibit 1 shows net plant output for a range of operating conditions. Exhibit 2 shows the cycle design parameters provided to the STG manufacturers. Maximum backpressure was set at 5.8 in HgA (14.7 cm HgA) at the maximum condensing case based on the site hot day design condition. The study evaluated the Big Turbine Option and the Small Turbine Option (see Section 4.4 below) operation at base load and part load conditions, but assumed the Project will operate primarily at base load. It is typical for newer coal plants to operate as base load facilities in the United States primarily due to their low energy production cost and efficiency rating at this condition.

FIGURE 2 – STEAM/WATER CYCLE



4.3 Steam Turbine Designs Evaluated

Each STG manufacturer applied one of two turbine designs based on their standard practice as follows:

Low Crossover Pressure - Some manufacturers utilize LP crossover throttle valves to regulate the CC extraction steam pressure. These suppliers have a relatively low (75 – 100 psia or 5.2 - 6.9 bar) maximum LP turbine inlet pressure limit, so they use larger LP inlet nozzle areas to set the maximum LP inlet pressure at the maximum condensing flow condition and then throttle the LP flow to maintain the required 70 psia (4.8 bar) extraction

pressure with CC ON, when approximately 45 percent less steam enters the LP turbines. If the inlet steam was not throttled during the CC ON operation, the extraction pressure would not be sufficient to operate the carbon capture amine solvent regeneration system. An LP crossover extraction valve can adjust the extraction pressure, which allows for more efficient operation in part-loaded conditions, eliminating the need for more complex steam let-down stations and allowing the operator to fine tune the extraction pressure while meeting the CC system requirements. Adjustability of the extraction pressure during operation may be a benefit to the CC process and could further optimize cycle performance. Using LP crossover throttle valves does have a disadvantage of pressure drop across the throttle valve at base load operation. With CC OFF, the low crossover pressure turbines can open their LP crossover throttle valves, as no extraction pressure control is required with CC OFF. So, during the CC OFF operation, the low crossover pressure turbines' efficiencies improve.

High Crossover Pressure – Other STG suppliers have higher LP turbine inlet pressure capability, so they set the LP inlet nozzle areas to provide the 70 psia (4.8 bar) extraction pressure with CC ON at full boiler load and then let the LP inlet pressure increase with increased LP turbine inlet flow with CC OFF. No LP throttle valve is used to adjust extraction steam pressure for this design, which gives it better CC ON plant performance than the Low Crossover Pressure STGs. These suppliers cannot make adjustments to their extraction pressures once the equipment is built, except by disassembling the equipment and installing alternate blade-path parts. The facility's heat rate will suffer when operating at part load with hot reheat process steam extraction. Part load heat rate has not been evaluated in this study because plant is specified to be based loaded with operation at part load deemed insignificant with respect to the design basis and life of the plant.

STG Sizing Options Eliminated from Consideration - This study considered steam cycles operating in the range of 70 percent to 100 percent boiler heat input with CC OFF. In accordance with the table shown in Exhibit 1, the maximum power generating capacity at average ambient conditions and with CC OFF is 804¹ MW for the Big Turbine Option at 100 percent boiler heat input and 550 MW for the Small Turbine Option at 70 percent boiler heat input. With the Small Turbine Option, operation with the carbon capture system off would require operation of the boiler at a reduced heat input. Boiler heat input below 70 percent was not considered since no further reduction in LP throttling in the CC ON condition would be realized. No boiler efficiency losses were assumed for this case. Exhibit 1 provides a comparison of the net plant output of the Project for the Big Turbine Option and the Small Turbine Option at hot and average ambient temperatures and at varying CC plant operating modes.

4.4 Steam Turbine Sizing Options

4.4.1 Option 1 – Big Turbine Option

In the Big Turbine Option, the STG is designed to normally run with CC ON, but the larger

¹ The 804 MW referenced by the steam turbine output for average ambient temperature in Exhibit 1 does not reflect the selected conditions for the plant rating of 760 MW and is used here for reference purposes.

LP turbine is also capable of full condensing operation at 100 percent boiler heat input with CC OFF. This option has the potential to produce the highest maximum plant electrical output of all options in the CC ON mode using the High Crossover Pressure technology, as discussed in more detail below. This arrangement requires the largest air cooled condenser. The Big Turbine Option facility can produce almost 200 MW more electric power with CC OFF versus with CC ON (see Exhibit 1). For purposes of the study it was assumed that the plant would be operated with CC OFF 5 percent of the time due primarily to CC plant outages.

4.4.2 Option 2 – Small Turbine Option

In the Small Turbine Option, the STG is sized for full boiler duty with CC ON, but the LP turbine flow with CC OFF (full condensing mode) is limited to 70 percent of the boiler heat duty in order to reduce plant capital cost related to the LP steam turbines, air cooled condenser, pumps, electric generator and related electrical equipment. The Small Turbine Option with reduced LP flow passing capacity runs in CC ON mode closer to its LP blade design condition, so that it is more efficient. The result is a net higher output and lower heat rate with the CC ON than with the Big Turbine Option (see Exhibit 1). The 70 percent boiler flow in full condensing operation is where the low crossover pressure turbine suppliers could design their LP elements without the need for LP crossover throttling and still operate at full boiler flow with CC ON at the required CC steam extraction pressure. Since there was no LP throttling needed for the low crossover pressure turbines designed for less than 70 percent maximum boiler flow with CC OFF, reducing the unit sizing further did not afford any further improvement in efficiency but started to decrease the CC ON output capability, so no CC OFF capacities less than 70 percent of full boiler flow were investigated. Sizing the LP turbine for lower maximum flow also allows the turbine suppliers with a low LP inlet pressure limit to operate at the CC ON condition without having to throttle the steam entering the LP turbine. With CC OFF, the net electric output of the Small Turbine facility is approximately 60 MW less than with CC ON. This is due to having to reduce overall boiler steam flow by 30 percent to the HP and IP turbines to match the smaller LP turbine maximum flow rate when no CC process steam being extracted.

4.5 Assumptions Used

The evaluation used STG supplier performance data based on a heat input to the steam/water cycle of 6,310 million Btu/hr (6,655 GJ/hr) and a maximum fuel heat input of 7,285 million Btu/hr HHV (7,685 GJ/hr) into the boiler, which matched the performance of the preliminary boiler design corrected for the Trailblazer elevation. Subsequent changes to the boiler capability are assumed to not affect the selection of the best sizing option, as the outputs of all vendors' options would change proportionally with the boiler heat input.

Space for the larger air-cooled condenser associated with the Big Turbine Option was not considered to be a critical evaluation criteria.

The evaluation assumed that the STG suppliers applied similar budgetary bid margins to their thermal performance. The performance data received is budgetary, so it was assumed that further optimization may be realized later during a firm offer preparation.

The effects of performance degradation with time have not been considered. As turbines age, their heat rates generally increase by approximately two to four percent, about half of that being recoverable during major overhauls. All of the turbine options are assumed to degrade in a similar fashion.

Part load heat rate was not considered. High crossover pressure technology, without the use of LP crossover extraction throttle valves, will only be efficient at base load conditions, as switching over to hot reheat steam to meet the required extraction pressure at part load would be required to maintain the targeted 90 percent carbon capture rate. During the firm bid phase, the ST suppliers can be requested to provide options for the LP crossover throttle valves to determine the control valve cost/performance impacts.

Plant net outputs and heat rates were based on auxiliary loads estimated by Fluor.

Generator cost estimates were not solicited for this plant sizing evaluation. A \$2 million USD reduction in capital cost was applied to the Small Turbine Option to account for a smaller generator and related equipment. A \$20 million USD reduction in air cooled condenser cost was assumed for the Small Turbine Option based on vendor input. The potential \$22 million savings is within the cost variance of the steam turbine and air cooled equipment estimates, although the comparative differences should materialize between the Big Turbine Option and the Small Turbine Option.

Steam/water cycle heat input varied slightly between suppliers, but the differences were small enough that vendor heat balances were not recalculated.

4.6 Power Industry Trends

The large LP steam extraction that is required for this application is most closely associated with district heating applications, which are commonly applied in northern Europe and in South Korea. Butterfly type low pressure turbine crossover pipe throttle valves are used to maintain the required extraction pressure under varying steam demands. Builders of power plants with district heating extraction capabilities build the plants with full condensing/full electric output capability to give them maximum flexibility in their operating capabilities to meet changing market opportunities for steam and power.

The absence of demand in the power industry for limited output turbines means that the cost of these units per unit of steam supply (in comparison to conventional output turbines) is relatively high. This has a negative impact on the cost of the Small Turbine Option relative to the Big Turbine option.

5.0 Conclusions

5.1 Overview

The performance and cost evaluation of the Big and Small Turbine Options indicates that there is no significant economic advantage for the Small Turbine Option. The small economic benefit associated with the Small Turbine Option is based on the power plant operating with CC ON 95 percent of the time. This result is due to the large increase in baseline Big Turbine Option generation capacity during the 5 percent of the time the power plant operates with CC OFF. Over the life of the facility, the Big Turbine Option revenues nearly offset the increased initial equipment cost. The Big Turbine Option revenue estimates were based on the small and big turbine differential capacity with CC OFF (approximately 250 MW) multiplied by a net power sale revenue (\$/MWhr) multiplied by approximately 400 hour/year multiplied by 30 years, discounted appropriately. This reduces the Small Turbine Option benefit to an estimated \$5 million USD over the life of the facility. It should be noted that the assumption for net power sale revenue significantly impacts the results. Although the evaluation summary indicates a potential Small Turbine Option benefit of an estimated \$5 million USD, one should consider that the performance data provided by the steam turbine suppliers is budgetary in nature and that the price variation between suppliers will likely be in the range of \$20 million USD. The calculated difference between the Big and Small Turbine Options is within the uncertainty of the analysis.

Tenaska has selected the Big Turbine Option, since the Small Turbine Option cost evaluation did not appear to provide enough cost reduction or CC ON performance benefit to offset the large reduction in plant output capacity with the CC OFF.

Building the plant with full or near-full condensing capability will allow the facility to operate in the CO₂ capture mode as well as in the full power generating mode when the carbon capture plant or the export pipeline is unavailable due to forced outages or scheduled maintenance.

If the plant is initially configured with the Small Turbine Option, a future switch to maximum electricity production capability would require a new turbine generator, modified generator foundation, upgraded plant electrical auxiliaries, upgraded switchyard and upgraded plant cooling system at a cost of tens of millions of dollars as well as several months of outage time to make the changes. Constraining the full output capacity of the plant with the Small Turbine Option does not seem to be a good approach given the ever changing power generation market conditions.

5.2 Comparison of Options

Budgetary performance was requested for the Big and Small Turbine Options from six STG suppliers. Based on evaluated performance with carbon capture plant operating 95 percent of the time and offline 5 percent of the time at the annual average ambient conditions, the Small Turbine Option showed a potential benefit of \$5 million USD over the life of the plant.

The comparison was made between the capital cost savings of a smaller generator, air cooled

condenser and less expensive piping and valves versus the performance penalty due to higher heat rate and lower net electrical output of the Small Turbine Option.

The study did not investigate the overall plant economy of scale between the two options. However, the total installed cost of the Big Turbine Option on a dollar per net kilowatt basis is approximately 10 percent less than that of the Small Turbine Option, making the Big Turbine Option more economically attractive.

5.2.1 Maintenance Costs

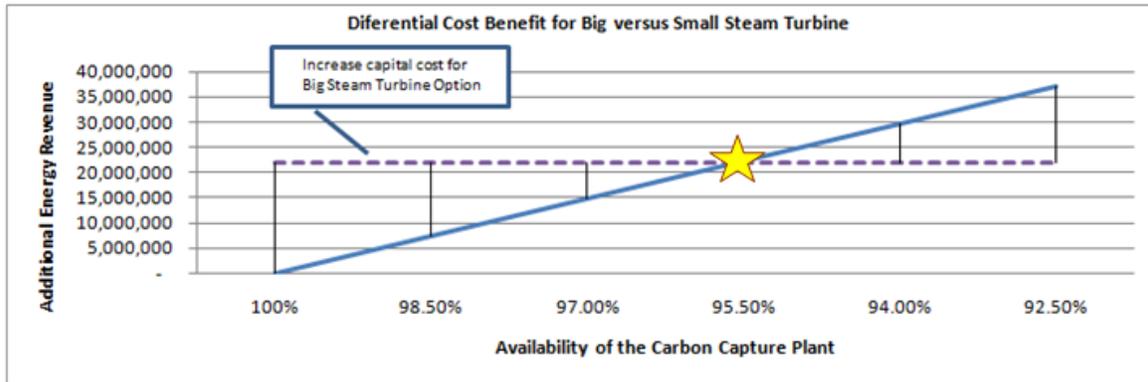
STG maintenance costs were not considered in the evaluation of the options because there is very little difference in the equipment used. The LP turbine elements are very similar, with only some differences in blade sizes. The boiler, pumps, high pressure turbine element, and intermediate pressure turbine elements are full sized for all options. Some reduction in air cooled condenser fan replacement and cleaning costs would be expected for the Small Turbine Option, but the difference of these costs compared to the evaluated performance and capital cost differences was considered small and would be within the uncertainty of the evaluation calculation.

Extraction control valve maintenance cost for suppliers who employ the LP crossover throttle valves were not included in this evaluation.

5.2.2 Economic Evaluation Factors - Sensitivity Analysis

The Small Turbine Option breaks even with the Big Turbine Option when cost evaluation factors are weighted at 94 percent for carbon capture plant online and 6 percent carbon capture plant off line. This situation could occur if carbon capture plant forced outage rates are higher than envisaged, which is a situation that is more likely to occur early in the operating life of the facility. Figure 3 shows a graph of the value of the added generation vs. the potential unavailability of the carbon capture plant (ie. CC OFF time). If the plant were able to operate at all times with the CC ON, then there would be a calculated benefit for the small turbine option. As the difference in availability between the capture plant and the power plant increases, the revenues from additional generation afforded by the large turbine option will eventually equal or exceed the estimated capital cost savings of the small turbine option. Given the uncertainty involved in any “first of a kind” plant, it was deemed prudent to select the large turbine option.

FIGURE 3 – Differential Cost Benefit for Big Versus Small Steam Turbine



6.0 Key Lessons

Trailblazer is expected to be the first new-build pulverized coal power plant in the United States to incorporate a commercial-scale CO₂ capture plant into the initial design. This study:

- confirmed that the steam requirements of a CO₂ capture plant can be met with currently available technology;
- confirmed that the STG can operate both with and without sending a large quantity of steam to the carbon capture process;
- confirmed that net plant output is least negatively impacted by the use of full or near-full steam turbine and condensing capacity (Big Turbine Option);
- quantified the impact of a CO₂ capture plant on power plant output(Exhibit 1);
- determined that building the plant with a full or near-full sized steam turbine and condensing capability will allow the facility to operate in the carbon dioxide capture mode as well as the full power generating mode without making any equipment changes;
- determined that there is no significant economic advantage for building the plant with less than full or near-full steam turbine and condensing capability; and
- determined that the total installed plant cost per kilowatt (\$/kW) based on net capacity with the CC system off is less with a larger-sized turbine.

These considerations led to the selection of the Big Turbine Option as the most prudent selection, given the level of uncertainties associated with a “first of a kind” plant.

The considerations and processes presented in this report may assist other projects as they evaluate the same or similar issues.

7.0 Acronyms and Citations

Acronym/Abbreviation/Frequently Used Terms

°C	Degrees Centigrade
°F	Degrees Fahrenheit
Arch Coal	Arch Coal, Inc.
BarA	Bar pressure absolute
BFP	Boiler Feed Pump
BFPT	Boiler Feed Pump Turbine
Big Turbine Option	First of two options reviewed. The steam turbine generator is designed to normally run with the carbon capture on, but is designed with a low pressure turbine large enough for full condensing operation at 100 percent boiler input with carbon capture off.
BNSF	Burlington Northern Santa Fe Railway
CC	Carbon Capture
CC OFF	Carbon Capture plant not operating
CC ON	Carbon Capture plant operating
CCS	Carbon Capture and Storage
Cm HgA	Centimeters of mercury absolute
CO ₂	Carbon Dioxide
CRH	Cold Reheat
DA	Deaerator
DCA	Drain Cooler Approach
EOR	Enhanced Oil Recovery
EP	Engineer/Procure
EPC	Engineering, Procurement and Construction
ERCOT	Electric Reliability Council of Texas
FEED	Front-End Engineering Design
Fluor	Collectively, Fluor Corporation and its affiliate Fluor Enterprises, presumptive EPC contractor
FWH	Feedwater Heater

GJ/hr	Gigajoules per hour
in HgA	Inches of mercury absolute
mm HgA	millimeters of mercury absolute
HP	High Pressure
HRH	Hot Reheat
IP	Intermediate Pressure
kV	kilovolts
LHV	Lower Heating Value
LP	Low Pressure
MOU	Memorandum of Understanding
MW	Megawatt
Owners' Engineer	Burns & McDonnell
P	Pressure
Project	Tenaska Trailblazer Energy Center
psia	pound per square inch absolute
RH	Reheater
Small Turbine Option	Second of two options reviewed. The unit is optimized for the carbon capture on condition, with full condensing flow and output limited to 70 percent of that which could be achieved with the full boiler heat duty in the power generation only mode of operation.
ST	Steam Turbine
STG	Steam Turbine Generator
TCEQ	Texas Commission on Environmental Quality
Tenaska	Collectively, Tenaska, Inc., developer of the Trailblazer Energy Center, and Tenaska Trailblazer Partners, LLC, owner of the Trailblazer Energy Center
TMV	Tenaska Marketing Ventures
TPS	Tenaska Power Services Co.
Trailblazer	Tenaska Trailblazer Energy Center
TTD	Terminal Temperature Difference
UP	Union Pacific Railroad
VWO	Valves Wide Open

Exhibit 1 – Tenaska Trailblazer Estimated Dry Cooled Net Plant Output (MW)

This exhibit provides a comparison of the net plant output of the Project for the two Options (big turbine and small turbine) at hot and average ambient temperatures and at varying CC plant operating modes. The net plant output is shown in MW under the columns “High Crossover Pressure” and “Low Crossover Pressure”. This comparison also includes the steam turbine exhaust pressure since the plant is dry cooled. It should be noted that dry cooling has a significant impact on the results of this table. A wet cooled plant comparison was not completed for this effort. The column listing “Number Fans and Fan Speed” denotes the number of fans and the fan speed for the air cooled condenser at the operating mode stated. The CC plant is designed with twin CC trains, each capable of 50 percent turndown. For the purposes of this study, the one-half CC mode (CC ½) is from one train out of service or both trains operating at 50 percent. The STG exhaust pressure and the number of air cooled condenser fans are provided for information since the two Options (big turbine and small turbine) have different sizing of air cooled condensers.

	STG Exhaust Press in HgA	STG Exhaust Press cm HgA	Aux Load MW	High Crossover Pressure Turbine	Low Crossover Pressure Turbine	Number Fans and Fan Speed
Option 1 (Big Turbine)						
CC on Hot	3.84	9.75	178	546	539	100 full
CC on Avg.	1.98	5.03	156	603	597	100 half
CC ½ on Avg.	2.03	5.16	112	701	709	62 full/38 half
CC off Avg.	2.34	5.94	64	804	806	100 full
CC off Hot	5.8	14.73	65	737	740	100 full
LP Throttle Valve?				no	yes	
Option 2 (Small Turbine)						
CC on Hot	4.94	12.55	171	559	559	64 full
CC on Avg.	2.03	5.16	156	610	610	42 full/22 half
CC ½ on Avg.	2.5	6.35	108	697	697	64 full
CC off Avg.	2.18	5.54	43	550	550	64 full
CC off Hot	5.8	14.73	43	510	510	64 full
Extraction location				by Supplier	by Supplier	

CC = Carbon Capture
 Hot Ambient 99.6 degrees F (37.6 C) dry bulb/72.1 degrees F (22.3 C) wet bulb/13.67 psia (0.94 bar)
 Average ambient: 64.0 degrees F (17.8 C) dry bulb/56.0 degrees F (13.3 C) wet bulb/13.67 psia (0.94 bar)
 Plant Elevation: 2000 ft (610 m)

Exhibit 2 – List of Cycle Design Parameters Provided to Steam Turbine Suppliers

ST suppliers were given the preliminary heat and material balance data sheets as well as the following cycle design criteria to use for their budgetary heat balance diagrams:

CC= Carbon Capture

Hot ambient: 99.6 degrees °F (37.6 °C) dry bulb/72.1 degrees °F (22.3 °C) wet bulb/13.67 psia (0.94 bar)

Average ambient: 64.0 degrees °F (17.8 °C) dry bulb/56.0 degrees °F (13.3 °C) wet bulb/13.67 psia (0.94 bar)

Plant Elevation: 2000 ft (610 m)

	Design Case	
Extraction pressure drops:		
FWHs 1-4 (low pressure heaters)	5%	CC off, avg. ambient
DA (open direct contact)	7%	CC on, avg. ambient
BFPT	7%	CC on, avg. ambient
HP FWHs 6-8	3%	CC off, avg. ambient
Heater TTD's:		
FWHs 1-4	3 °F (1.7 °C)	CC off, avg. ambient
FWH 5 (open DA)	0 °F (0 °C)	all
FWH 6	-3 °F (-1.7 °C)	CC off, avg. ambient
FWH 7 (off of CRH)	0 °F (0 °C)	CC off, avg. ambient
FWH 8 (HP extraction)	-3 °F (-1.7 °C)	CC off, avg. ambient
RH pressure drop	8%	CC off, avg. ambient
FWH 1 drain is pumped forward to condensate line		
BFP outlet pressure	1.25 times HP turbine admission P	CC off, avg. ambient
Target HRH inlet pressure at IP turbine	748 psia (51.6 bar)	CC on, avg. ambient
DCA's (drain cooler approach temperatures)	10 °F (5.6 °C)	CC off, avg. ambient
Full arc admission, VWO all cases		
Condensate pump hydraulic efficiency	73% (CC off), 40% (CC on)	
Condensate pump motor efficiency	96%	CC off, avg. ambient
BFPT hydraulic efficiency	84%	CC off, avg. ambient
BFPT isentropic efficiency	82%	½ CC, avg. ambient
BFPT exhaust pressure drop	0.5 in HgA (1.27 cm HgA)	CC on, avg. ambient
Generator power factor	0.85 lagging	all cases