Exhibit 2

Northern Michigan University

Facilities Department
Facilities Specialist/Planner
1401 Presque Isle Avenue
Marquette, MI 49855-5301
906 227-2025
FAX: 906 227-2467

February 5, 2007

RECEIVED
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AIR QUALITY DIV.

Michigan Dept of Environmental Quality
Attn: Ms. Mary Ann Dolehanty, Supervisor
AQD – Thermal Process Unit
P.O. Box 30260
Lansing, MI 48909

SUBJECT: Permit to Install Application for a New Circulating Fluidized Bed Boiler
Northern Michigan University – Ripley Heating Plant

Dear Ms. Dolehanty:

Enclosed is a Permit to Install Application for the proposed installation of a new solid fuel-fired circulating fluidized bed (CFB) boiler at the Northern Michigan University (NMU) – Ripley Heating Plant. In support of the Governor's 21st Century Energy Plan, this project will be designed to allow operation on Renewable Resources (specifically wood chips) up to 100% of the total heat input, with the capability to operate on sub-bituminous coal, and natural gas if the Renewable Resource fuel is unavailable or not economically feasible. The application requests that all fuels be allowed up to a possible 100% of the total heat input into the boiler. It is anticipated that NMU may blend these solid fuels as needed, to support the heat input required with the Renewable Resource fuel given preference whenever feasible. Natural gas is only intended to be used for startup, shutdown, and backup purposes.

NMU recently received PTI 126-05 for two (2) new oil/gas fired boilers. Since NMU is proposing to install the new solid fuel boiler within the contemporaneous period, we have included these boilers in the analysis for the new CFB. Based on our analysis, the facility will continue to comply with all applicable standards. In addition, we have provided correspondence from the U.S. Fish & Wildlife Service regarding the impacts to endangered species.

We authorize Mr. Jeffrey P. Jaros of NTH Consultants, Ltd., to serve as our agent in responding to your questions concerning this application and to negotiate the conditions for the revised permit. Should you have any questions concerning the application, please contact Mr. Jaros at (517) 484-6900.

Sincerely yours,
NORTHERN MICHIGAN UNIVERSITY

Michael G. Hellman,
Facilities Specialist/Planner

MGH:kag

cc: Jeff Jaros, NTH Consultants, Ltd.
Randy Russell, P.E., Cummins & Barnard, Inc.
Carl S. Pace, Assoc. VP Facilities & Business Services – NMU
Kathy Richards, Director of Engineering & Planning – NMU
Robert Ryan, Project Manager - NMU

Permit to Install Application
For
A Circulating Fluidized Bed (CFB) Boiler

at

Northern Michigan University

Marquette, Michigan

[SRN: M3792]

February 5, 2007

Prepared By:
NTH Consultants, Ltd.
608 S. Washington Avenue
Lansing, MI 48933
(517) 484-6900
NTH Project No. 16-060504

Northern Michigan University

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MICHIGAN DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR QUALITY DIVISION

PERMIT TO INSTALL APPLICATION

For authority to install, construct, reconstruct, relocate, or modify process, fuel-burning or refuse burning equipment and/or control equipment. Permits to install are required by administrative rules pursuant to Section 5505 of 1994 PA 451, as amended.

FOR DEQ USE
APPLICATION NUMBER

Please type or print clearly. The "Application Instructions" and "Information Required for an Administratively Complete Permit to Install Application" are available on the AQD Permit Web Page at http://www.deq.state.mi.us/aps, or contact the Air Quality Division at 517-373-7023.

1. FACILITY CODES: State Registration Number (SRN) and North American Industry Classification System (NAICS)
   SRN: M 3 7 9 2 NAICS: 2 2 1 1 1 2

2. APPLICANT NAME: (Business License Name of Corporation, Partnership, Individual Owner, Government Agency)
   Northern Michigan University - Ripley Heating Plant

3. APPLICANT ADDRESS: (Number and Street)
   1401 Presque Isle Avenue
   MAIL CODE:

   CITY: (City, Village or Township)
   Marquette
   STATE: **MI**
   ZIP CODE: **49855**

4. EQUIPMENT OR PROCESS LOCATION: (Number and Street – if different than Item 3)

   CITY: (City, Village or Township)
   ZIP CODE:
   COUNTY: **Marquette**

5. GENERAL NATURE OF BUSINESS:
   Combined Heat and Power

6. EQUIPMENT OR PROCESS DESCRIPTION: (A Description MUST Be Provided Here. Include Emission Unit IDs. Attach additional sheets if necessary.)
   Northern Michigan University is proposing to install a new 185/205 MMBtu (7 MW) circulating fluidized bed (CFB) boiler capable of firing solid fuels, including coal and wood. In 2005, NMU received PTI 126-05 to install two (2) new fuel oil/natural gas fired boilers to replace 2 existing boilers that were decommissioned and reviewed. Since this project is within the contemporaneous period, NMU is submitting the enclosed application to include both the new solid fuel CFB and two new oil/gas boilers.

7. REASON FOR APPLICATION: (Check all that apply.)
   - ☒ INSTALLATION / CONSTRUCTION OF NEW EQUIPMENT OR PROCESS
   - ☐ RECONSTRUCTION / MODIFICATION / RELOCATION OF EXISTING EQUIPMENT OR PROCESS – DATE INSTALLED:
   - ☐ OTHER – DESCRIBE

8. IF THE EQUIPMENT OR PROCESS THAT WILL BE COVERED BY THIS PERMIT TO INSTALL (PTI) IS CURRENTLY COVERED BY ANY ACTIVE PERMITS, LIST THE PTI NUMBER(S): **126-05**

9. DOES THIS FACILITY HAVE AN EXISTING RENEWABLE OPERATING PERMIT (ROP)? ☒ NOT APPLICABLE ☐ PENDING APPLICATION ☐ YES
   PENDING APPLICATION OR ROP NUMBER **MI-ROP-B2357-2006**

10. AUTHORIZED EMPLOYEE: **Michael Hellman**
    TITLE: **Facilities Planner**
    PHONE NUMBER: (Include Area Code) **906-227-2120**
    SIGNATURE: Michael Hellman
    DATE: **February 1, 2007**
    E-MAIL ADDRESS: **mhellman@nmu.edu**

11. CONTACT: (If different than Authorized Employee. The person to contact with questions regarding this application) **Jeffrey P. Jaros**
    PHONE NUMBER: (Include Area Code) **517-484-6900**
    CONTACT AFFILIATION: **NTH Consultants, Ltd.**
    E-MAIL ADDRESS: **jjaros@nthconsultants.com**

12. IS THE CONTACT PERSON AUTHORIZED TO NEGOTIATE THE TERMS AND CONDITIONS OF THE PERMIT TO INSTALL? ☒ YES ☐ NO

FOR DEQ USE ONLY - DO NOT WRITE BELOW

DATE OF RECEIPT OF ALL INFORMATION REQUIRED BY RULE 203:	
DATE PERMIT TO INSTALL APPROVED:	SIGNATURE:
DATE APPLICATION VOIDED:	SIGNATURE:
DATE APPLICATION DENIED:	SIGNATURE:

A PERMIT CERTIFICATE WILL BE ISSUED UPON APPROVAL OF A PERMIT TO INSTALL

EQP 5615E (Rev. 09/2004)

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APPENDICES

1.0 INTRODUCTION

Northern Michigan University (NMU) is submitting the attached permit to install application for the construction of a circulating fluidized bed (CFB) boiler capable of firing coal and wood. The CFB boiler will have a maximum heat input capacity of 185 million Btu per hour (MMBtu/hr) for 100 percent coal firing and 205 MMBtu/hr for 100 percent wood firing. The existing NMU power plant consists of three (3) 84 MMBtu/hr natural gas/No. 2 oil fired boilers, covered by Permit No. 126-05. The facility is located at 1401 Presque Isle Avenue, Marquette, Michigan [SRN: M3792].

NMU is currently not considered a major source because its potential to emit of any criteria pollutant is limited to 99.9 tons per year (tpy) by federally enforceable conditions in Permit No. 126-05. The existing facility is also not a major source of hazardous air pollutants (HAP) because it does not have the potential to emit 10 tpy of any single HAP, or 25 tpy of any combination of HAPs. The facility, however, will become a major source as defined in Michigan Rule 211(1)(a) upon initial startup of the CFB boiler, as the CFB boiler has the potential to emit 100 tpy or more of any criteria pollutant. NMU will remain a minor source of HAPs after issuance of this permit, as NMU requests federally enforceable permit conditions limiting the facility's potential emissions to less than 10 tpy for a single HAP, and less than 25 tpy of all HAPs combined.

As a major source of new source review regulated air contaminants, the CFB boiler will be subject to the federal Prevention of Significant Deterioration (PSD) regulations at 40 CFR Part 52.21. The CFB boiler will also be subject to the federal New Source Performance Standards (NSPS) for Industrial-Commercial-Institutional Steam Generating Units at 40 CFR Part 60, Subparts A and Db. As NMU will be a minor, or area, source of HAPs after issuance of the permit, the facility's boilers will not be subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, Institutional Boilers and Process Heaters, 40 CFR Parts A and DDDDD. In addition to the federal air quality requirements, the CFB boiler will be subject to the Michigan air toxics requirements under Rules 224-232.

The process description and boiler specifications are provided in Section 2.0. A regulatory analysis is provided in Section 3.0, and provides a summary of pertinent federal and state air

quality requirements that are applicable to the proposed CFB boiler and the NMU facility. Emission estimates for this application are provided in Section 4.0, and include estimates for criteria pollutants, hazardous air pollutants (HAP), and toxic air contaminants (TAC) from the new CFB boiler. The best available control technology (BACT) analysis has been conducted for particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO) and is presented in Section 5.0, and also includes Michigan's requirements for BACT for VOC and toxic air contaminants. Section 6.0 presents an air quality modeling analysis that demonstrates compliance with state and federal ambient air quality standards. Additional impact analyses as required by the PSD rules [40 CFR 52.21(o)] are provided in Section 7.0. A site map is provided in Appendix A, and additional permit to install application supporting information is attached as Appendices B through G.

2.0 PROCESS DESCRIPTION

NMU is proposing to install and operate a cogeneration (combined heat and power (CHP)) 185 MMBtu/hr coal/wood/natural gas fired circulating fluidized bed (CFB) boiler that will include a 10 MW gross electrical output generator, and be capable of producing 120,000 pounds of steam per hour. The new boiler will be located next to NMU's existing Ripley Heating Plant, which is located on the north end of NMU's campus.

2.1 CIRCULATING FLUIDIZED BED BOILER AND STEAM TURBINE

The CFB technology that will be employed by NMU is a non-reheat steam generator that will provide steam to an electrical turbine generator, and supply steam for the NMU campus. At this time, NMU has not decided upon the vendor for this equipment. There will also be a new wet-dry mechanical draft-cooling tower to accommodate additional heat rejection from the system.

The new CFB plant cycle consists of a turbine generator with four (4) feedwater heaters, including a deaerator to remove dissolved gases from the process feedwater. Dissolved gases, including oxygen and carbon dioxide, increase the corrosiveness of the water by lowering pH levels, which leads to boiler tube failures. The nominal steam flow of the CFB generator will be 120,000 pounds per hour at average ambient conditions. The boiler will be designed to accommodate bituminous and subbituminous Powder River Basin (PRB) coals, virgin wood, and natural gas. Natural gas will be used primarily for boiler startup, and any other times when solid fuel firing may not be available; i.e., as a back-up fuel source and for initial startup. Coal will come from either the Marquette Board of Light & Power, or the nearby WE Energy Presque Isle Power Plant. Virgin wood fuel will be supplied from independent wood suppliers and natural gas will be pipeline quality gas from NMU's supplier of natural gas.

Coal and limestone sorbent are fed into the bottom of the CFB at a molar ratio of calcium to sulfur of approximately 4:1. Primary and secondary air for combustion is forced into the furnace approximately one-third from the bottom of the boiler. Flue gas exiting the boiler passes through a mechanical collector (cyclone) and the removed particulate (unburned carbon or loss on ignition) is recycled back into the bottom of the furnace. Bottom ash from the combustion of fuels empties through the bottom of the CFB and is removed. Once the flue gas passes through

the cyclone it enters the convection pass, superheater and economizer surfaces where heat is transferred to water tubes to produce steam. Finally, the flue gas passes through the SNCR and fabric filter at an estimated maximum rate of 108,700 actual cubic feet per minute (ACFM), which is while firing 100% wood fuel. The plot plan for the campus, showing the location of the new boiler and stack, is included in Appendix A.

Steam produced from the CFB boiler will be used to feed the steam turbine to produce electricity, and will supply steam for use on the campus; mostly for on-site campus heating, hot water for bathrooms, and for laundry equipment.

2.2 COAL & WOOD HANDLING

Bulk deliveries of coal and wood will be received via trucks. The trucks delivering the bulk solid fuels will be unloaded inside dedicated areas that have a 3-sided enclosure to reduce wind effects and will minimize fugitive emissions. The site has the capacity to store up to a 3-day supply of coal and wood in dedicated silos controlled by vent filters. Unloading of the solid fuels will be done in a fashion to minimize fugitive emissions.

Coal and wood fuels will be supplied to the CFB boiler from the silos. Coal received will already be sized correctly, so that there will be no coal processing performed on-site. Wood will be received chipped, and there will not be wood chipping performed on-site. Coal and wood fuels will be delivered to the CFB boiler inside enclosed transfer equipment. The fuel silos can hold an approximate 3-day supply of fuel, which will allow boiler operation through weekends and holidays. Finally, from the fuel silos, fuel is gravity fed onto a screw conveyor system that feeds the CFB for combustion.

2.2.1 Fugitive Emissions

Emissions of particulate as a result of coal/wood handling and storing are expected from 3 sources; truck unloading and receiving, fuel, ash, and limestone storage silos, and the conveyance of solid fuels and limestone to the CFB boiler. On average, NMU will receive a shipment every day, except on weekends. A typical shipment will consist of 40 tons of coal and/or 40 tons of wood. The annual maximum delivery of each fuel would equate to approximately 68,669 tons of bituminous coal, 95,329 tons of PRB coal, and 199,533 tons of wood. However, due to reduced

capacity factors as a result of startup, shutdown, and maintenance activities, the shipments will be lower.

The coal and wood will be unloaded directly from the delivery trucks into 3-sided enclosures to minimize fugitive emissions. Transfer from the silos to the boiler will be done in enclosed conveyance systems. Dust from coal or wood transfer points will be controlled with fabric filters. Once the coal and wood is received, it will be stored in dedicated silos, and each silo will be controlled with a vent filter.

2.3 ASH HANDLING & STORAGE

Ash removed from the CFB will be stored in a dedicated silo with vent filter. Ash will be loaded out of the ash silo periodically, and placed in covered trucks for final disposal off-site of the NMU campus. The final plans for this activity have not yet been finalized.

2.4 LIMESTONE HANDLING & STORAGE

Limestone will be received via trucks and pneumatically transferred to a silo with a vent filter. Limestone will then be removed from the silo on an as-needed basis for co-firing into the bed of the CFB boiler.

2.5 ALTERNATIVE TECHNOLOGY REVIEW

The control technology analysis presented in Section 5 does not include a detailed technical evaluation of other potential fossil-fueled power generation technologies for this project such as Integrated Gasification Combined Cycle (IGCC) or Pulverized Coal boilers (PC). These are other power plant design technologies that are not appropriate and rejected for the reasons identified in this Alternative Technology Review. There are sound reasons for not including the analysis of these technologies into the BACT analysis included with this application. Primarily, there are no IGCC units that are cogeneration or combined heat and power units.

Second, as stated in the U.S. Environmental Protection Agency's (EPA's) New Source Review (NSR) Manual, "Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator have not been required by EPA as

part of a BACT analysis to consider building a natural gas-fired electric turbine, although the turbine may be inherently less polluting per unit product (in this case electricity)." (NSR Manual Page B.13). While the NSR Manual notes that there may be instances where, in a permit authority's judgment, alternative production processes may be required to be analyzed, this does not apply to cases where such a process would fundamentally change the project design, as would the case of IGCC or super critical pulverized coal (SCPC) boilers. EPA's Environmental Appeals Board has consistently upheld state permitting agency decisions to not require consideration of fundamentally different designs as part of the BACT analysis (In the Matter of Pennsauken County 2 E.A.D. 667 [1998] [firing municipal waste in a power plant rather than in the proposed MSW combustor]; In the Matter of Hawaiian Commercial & Sugar Co., 4 E.A.D. 95 [1992] [combined cycle or oil fired plant rather than CFB boiler fired with coal, fuel oil, or bagasse]; In re: Kendall New Century Development, 2003 EPA APP. LEXIS 26 [constructing a facility with larger units or operating as a combined cycle plant rather than a smaller simple cycle peaking unit as proposed]).

The process of review under the PSD requirements of the Clean Air Act (CAA) is focused on a single media (i.e., air quality) and must be kept in perspective with other governmental policy and permit reviews. Under the CAA the applicant must show that the proposed project will meet an emission limitation based upon the BACT and will not significantly impact air quality. However, the applicant must consider a myriad of other factors, including capital and operating costs, fuel diversification, availability, economic risks and costs to the applicant and electricity consumers, and ability to secure financing when designing its project proposal. These decisions may be influenced by state and federal agencies responsible for the energy policy and by local land use agencies concerned with the broad public health and welfare. But they are not germane to an evaluation under the CAA of the best available means to control, not redesign, the source proposed by the applicant. Note that the statute does not require an emission limitation based upon the "Best Available Design Technology." Therefore, NMU believes that MDEQ does not have the discretion to require treatment of alternative designs in the analysis of alternative control technologies that are germane to the satisfaction of BACT analysis requirements. This position has been reaffirmed by the position taken by U.S. EPA's Stephen Page, Director of the Office of Air Quality, Planning and Standards in his December 13, 2005, letter regarding the consideration of IGCC as an element of BACT or LAER when considering coal fueled power generation

projects. In Mr. Page's letter (copy attached), EPA clearly stated that IGCC is not to be considered an element of BACT or LAER, but rather an Alternative Technology.

NMU recognizes that there is public interest in alternative means of producing electricity. Therefore, it has included an assessment of the design alternatives of IGCC and PC for informational purposes and separate from the BACT analysis. The alternative technology analysis clearly demonstrates that IGCC and PC are fundamentally different source designs than proposed by NMU and for a variety of cost, availability, and other factors, were not appropriate designs for the proposed project. NMU proposes to construct, own and operate a solid fuel-fired cogeneration, or combined heat and power, facility to provide reliable and cost efficient electric power and steam for its campus.

During the initial planning stages of any cogeneration project, it is necessary to define the project objectives and criteria including, among other things: requisite electrical and steam generating capacity, capital and operating costs, reliability, availability, fuel price, fuel price volatility, fuel availability, site characteristics, safety factors and potential environmental impacts. Based on a review of technical, financial and practical considerations, NMU determined the appropriate design for the proposed power plant is a unit capable of firing a range of fuels. Based on a technical review of the potentially available solid fuel stream and electricity-generating configurations (e.g., Integrated Gasification Combined Cycle, Sub-Critical or Super-Critical Pulverized Coal), NMU concluded that the most appropriate fuel conversion technology for a project of this size is a CFB boiler.

CFB technology was selected based upon its satisfying the following project criteria:

1) CFB technology is readily available in single unit size of generating 7 to 10 MW of electricity and 120,000 pounds per hour of steam;
2) CFB technology is part of DOE's Clean Energy Program;
3) CFB technology has proven experience utilizing the range of fuels selected for this project;
4) CFB technology is highly cost competitive, both in terms of initial capital cost and operating and maintenance costs for a unit of this size;

5) CFB technology can be operated with a high level (i.e., ≥90 percent) of availability and reliability;
6) The commercial risk of CFB technology relating to capital cost, operating cost, environmental performance, reliability and availability is considered low;
7) CFB technology is well suited for the required electrical output needed; and
8) CFB has a solid record of demonstrated environmental performance.

The following paragraphs discuss alternate technologies for fuel conversion, which NMU does not consider appropriate for the needs of its campus.

2.5.1 Integrated Gasification Combined Cycle (IGCC)

IGCC is not structurally similar in design or capacity to CFB boilers or electrical generation of the size required to serve the needs of NMU. IGCC is not based on coal combustion but on coal gasification; the two processes are fundamentally different. IGCC is not a "control technology" such as baghouses, electrostatic precipitators (ESPs), SCR, etc. Instead, IGCC would constitute a redefinition of a coal-fired power plant. Furthermore, there are no IGCC units for cogeneration, or combined heat and power, needs.

IGCC power systems use a gasifier to convert coal (or other carbon-based solids) into a synthesis gas (syngas) consisting of a mixture of carbon monoxide (CO), hydrogen (H_2), carbon dioxide (CO_2) and traces of other gases. Syngas from the gasifier is filtered and scrubbed to reduce particulates, sulfur and other contaminants prior to being combusted in a gas-fired combustion turbine. Heat from the turbine exhaust gas is extracted in a heat recovery steam generator (HRSG) to produce steam to drive a steam turbine generator.

Gasification processes require an oxidant to react with the coal and maintain the temperature required for gasification. The oxidant reacts with coal to produce syngas. The typical air separation unit (ASU) cryogenically separates ambient air into its major constituents, oxygen (O_2) and nitrogen (N_2). Most of the O_2 is needed in the gasification plant for the production of syngas. A small percentage of the O_2 is used separately in a sulfuric acid plant. Most of the N_2 goes to the power plant's combustion turbine to dilute the fuel gas for NO_x abatement. This diluent N_2 also increases the combustion turbine's power production as it expands through the turbine.

The gasification process uses one-fifth to one-third of the theoretical oxygen (sub-stoiciometeric) to partially oxidize the combustible constituents of the feedstock. The major combustible products of gasification are CO and H_2, with a small fraction of the carbon completely oxidized to CO_2, and a small amount of methane (CH_4) may also be present.

The minor and trace components of coal are also transformed in the gasification reactor. Under the sub-stoiciometeric reducing conditions of gasification, most of the fuel's sulfur converts to hydrogen sulfide (H_2S), but some also converts to carbonyl sulfide (COS). Nitrogen bound in the fuel generally converts to gaseous nitrogen and ammonia (NH_3) and a small amount of hydrogen cyanide (HCN). Most of the chlorine in the fuel converts to hydrogen chloride (HCl) gas. Trace elements associated with both organic and inorganic components of the coal, such as mercury and arsenic, are released during gasification and partition between the ash fractions and gaseous emissions.

Syngas exiting a gasifier contains ash particulate that must be removed prior to combustion in the combustion turbine. Particulate matter can be removed by hot barrier filters (located upstream of the high-temperature heat recovery devices) or warm gas water scrubbers located downstream of the heat recovery system. Warm gas particulate removal by wet scrubbing is typically employed. In water scrubbers, the particulate is removed as slurry, which must be dewatered. Particulate-laden water is sent to a water-handling system, which separates the solids for recycle to the gasifier for disposal.

The gasifier's raw gas also contains COS and H_2S, both of which must be removed for the combustion turbine to achieve a low SO_2 limit. COS is not readily removed unless it is first converted to H_2S by hydrolysis. A hydrolysis unit reacts COS with water in the presence of a catalyst to form CO_2 and H_2S. The cooled syngas is then sent through an acid gas removal process to remove most of the H_2S and some of the CO_2.

Acid gas removal processes treat the syngas by contact with chemical or physical solvents to capture the H_2S. Amine solvents, such as methyldiethanolamine (MDEA), react to form a chemical bond between the acid gas and the solvent. The rich amine from the absorber is sent to a

stripper where it is stripped of acid gas. The amine can be recycled and the recovered acid gases sent to a sulfur recovery process for conversion into sulfuric acid or elemental sulfur.

The cleaned syngas is used to fuel a combustion turbine. The combustion turbine drives an electric generator and produces heat (exhaust) to generate steam in a heat recovery steam generator (HRSG) for a steam turbine. The low-Btu syngas produced by gasification requires modifications to the typical natural gas combustion turbine's burners.

IGCC Operations

There are currently three IGCC power generation plants operating in the United States designed specifically to generate electricity from gasified bituminous coal and/or petroleum coke - Polk Power Station, Wabash River Generation Station and Delaware Star Refinery Station. The U.S. Department of Energy's (DOE's) Clean Coal Technology (CCT) Demonstration Project co-funded the construction and initial operation of Tampa Electric's Polk Power Station and PSI Energy's Wabash River Generation Station. The rated outputs for these facilities are 250 MW, 262 MW and 180 MW for the Polk Power Station, Wabash River Generation Station and the Delaware Star Refinery Station, respectively. Based on available information, other plants have not been able to demonstrate syngas availability greater than 80 percent, and none of the plants identified herein has ever operated at an annual capacity factor higher than 77 percent, including periods when they operated on oil or natural gas with no attempt to use coal.

As stated previously, the plant proposed by NMU is to be a moderate capacity power generation facility. With the demonstrated limited availability and reliability of these existing IGCC plants, IGCC technology would not be technically and commercially feasible to satisfy the requirements of NMU's needs to supply its campus with electricity and steam. Additionally, IGCC technology has been developed around the use of 300 MW power generation blocks, which is far beyond the 10 MW capacity proposed for the project. The high capital cost of IGCC, which is a factor that the technology struggles with even at the 300 or 600 MW power increment, would be drastically exacerbated when scaled down to the 10 MW generation capacity needed by NMU.

The Public Service Commission of Wisconsin has determined that while "ICGG technology is still promising, [it] is still expensive and requires more maturation." (Public Service Commission