Final Report

Economic and Technical Feasibility of Modifying the Minnesota Valley Power Plant to Utilize Whole Trees as the Primary Fuel Source

Submitted to XCEL ENERGY

by

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Executive Summary

Conversion of the Xcel Energy Minnesota Valley Generating Plant, located in Granite Falls, MN, to a renewable energy power plant is proposed. This 44 MW pulverized coal power plant, that went into operation in 1953, currently operates infrequently. The project is to repower the Minnesota Valley plant to a 77 MW peak capacity Whole Tree Energy™ Combined Cycle (WTECC) power plant using farm grown trees as the fuel. With a capacity factor of 80%, this retrofitted power plant will deliver 504,000 MWh per year. The retrofit project was also evaluated without the combustion turbine.

The retrofitted WTECC power plant will generate 53 MW peak power from the existing steam turbine-generator and 24 MW from a new combustion turbine-generator with an increase in net total plant efficiency from 30% to 34%. Exhaust from the combustion turbine heats the boiler feedwater, and the economizer and feedwater heaters are bypassed. Exhaust from the boiler heats the combustion air and the air used to dry the fuel.

The fuel is provided by harvesting 7800 acres per year of hybrid poplar trees on 40 to 80 acre plots of leased farmland within a 50 mile radius of Granite Falls. These fast growing trees yield a biomass fuel of 25 dry tons per acre after five growing seasons. The dedicated cropland required for the tree farms is 39,000 acres or 1% of the cropland within the 50 mile radius. Special planting and harvesting equipment are being developed to improve tree farming. Harvested trees are delivered whole (not chipped) to a drying dome at the power plant site where they are dried for one month using waste heat from the boiler.

The trees are conveyed from the drying dome in whole form and fed into the boiler as tree segments. A water-cooled fixed grate, a dump grate below, and extensive overfire air are added to the boiler. The whole tree segments burn in a 9 ft deep fuel bed where the lowest layer near the grate is wood char, and in the upper layers of the fuel bed the wood is gasified at high temperature. Some char and ash falls through the grate and is burned on a dump grate. Volatiles are burned with the overfire air in the upper part of the boiler.

The fuel supply of farm grown hybrid poplar trees will have very positive impact on air quality, wildlife diversity, soil characteristics and water runoff. The power plant itself is clean burning with much less ash than a coal plant. Closed-loop biomass power plants are a practical green power solution to combat global warming.

The direct capital cost for the WTECC retrofit is $48.6 million and $29.9 million for the WTE steam cycle only retrofit. The cost of farm grown wood fuel delivered to the plant is $2.81/million Btu, and the assumed cost of natural gas is $3.83/million Btu. The total annual cost is $30.4 million for the WTECC retrofit and $19.3 million for the WTE steam cycle only retrofit. The Bus Bar cost of electricity for the WTECC retrofit is 48.4 mills/kWh and 46.0 mills/kWh for the WTE steam cycle only retrofit in $2003.

The Whole Tree Energy™ Combined Cycle retrofit has been scheduled for 36 months, however an accelerated schedule would allow for delivery of commercial power in 24 months. The fuel supply will require 5 years from project start to harvest, and the first 2-3 years of operation will use existing wood resources in Minnesota.

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Project Contributors

This project was supported by the Xcel Renewable Energy Development Fund under Contract No. RDF 2001 BB06. Managers of this project at Xcel were Rick Halet and John Donatell. Dave Ostlie and Ken Ragland of Energy Performance Systems, Mike Gilbertson of Inventure, and Rich Andresen of Tee Array Consulting carried out this project. Mark Holmberg, Doru Posteuca, Frank Qie, Tony Witkowski and others at Utility Engineering participated in a subcontract regarding some of the power plant design aspects of the project. Lynn Wright from Oak Ridge National Laboratory assisted with the environmental impact assessment of growing short rotation woody crops in Minnesota. Bill Berguson of the Natural Resource Research Institute, Ernie Schmidt of the Minnesota DNR, and Don Remenschnider of the Wisconsin DNR provided input on the fuel supply. Dale Claridge and Libby Henderson of Wenck & Associates consulted on the water and air permits. Minnesota Valley power plant operators Sean Skogrand and Don Berends were most helpful in running power plant tests and providing design and operation details.

1. Existing Minnesota Valley Power Plant

The Xcel Energy Minnesota Valley Generating Plant is located in Granite Falls, MN, in the southwestern part of the state. The plant has one operating pulverized coal fired boiler (Boiler #4) and one operational steam turbine-generator (Unit 3). This equipment went into operation in 1953 and is rated at 44 MW. Currently the plant does not run on a regular basis. The plant also has three retired boilers and two retired steam turbines.

The Minnesota Valley plant can receive coal by train or truck. The coal is transferred from the coal yard to a bunker in the powerhouse via a crusher building and a conveyor. The coal travels from the bunker to three pulverizers and is blown into the boiler by six burners located on the west side of the boiler. The two-drum boiler has a working pressure of 1500 psig and produces up to 425,000 lb/hr of superheated steam at 950°F. The steam cycle has four feedwater heaters and a deaerating heater but no reheat.

The once-through cooling system takes water from the Minnesota River for the condenser, and the water is returned to the river via an outlet structure downstream. Ash from the boiler is sent to settling ponds located east of the powerhouse. The exhaust from the boiler flows through an electrostatic precipitator prior to going to the 350 ft stack.

In June 2002 the Minnesota Valley plant was run on coal at peak load for four hours and test data was obtained. The net power generated was 46 MW and the net plant efficiency was 31.0% with a corresponding heat rate of 11,179 Btu/kWh. Further details of the performance test are given in the next section of the report.

Natural gas is available at the plant to provide up to a 13 MW load. The Great Plains gas pipeline just across the river has sufficient capacity to supply a full load but a different metering arrangement at the town-border station across the river is needed to do so.

For the retrofit the rail spur that runs into the coal yard would need to be removed to make way for the drying dome. Since Xcel owns the spur, no problem is anticipated with its removal. US highway 212 provides excellent access to the plant. Highway 212 has two lanes going east and one lane going west. A turning lane going west onto power plant property may be desirable. Many excellent state and county highways serve the area.

The vintage and condition of the transformers were not determined. In the 1960's the power plant apparently generated 75 MW when the two older units were operated along with the current 44 MW unit.

Additional listing and description of the existing power plant equipment are given in Appendix 1.

2. Repowering and Retrofitting the Minnesota Valley Power Plant

Repowering Configuration

The basic operating conditions of the retrofit combined cycle power plant are summarized in Figure 2.1. A flow diagram for the retrofit plant is shown in Figure 2.2. The steam cycle (WTE) portion of the retrofit plant has a full load net power output of 48 MW at full load. For design purposes a capacity factor of 80% is assumed. To improve efficiency and increase output, a 24 MW combustion turbine (GTD1) is added as shown. Two new heat exchangers (HX2 and HX4), located in the same enclosure, are added to utilize the exhaust from combustion turbine to preheat the boiler feedwater. During combined-cycle operations the retrofit power plant bypasses the existing feedwater heaters (FWH1, FWH2, FWH3, and FWH4) and the existing economizer (ECON1).

Figure 2.1 WTE Combined Cycle Plant Full Load Operating Conditions

Factor	Units	Specification	Source
Total net power, WTE Combined Cycle	MW	72	From GateCycle model
Capacity factor	%	80	Design specification
Net annual output	MWh	505,000	Calculation
Net power plant efficiency	%	33.7	From GateCycle model
Net power plant heat rate	Btu/kWh	10,130	From GateCycle model
Wood feed rate	dry lb/hr	70,900	From GateCycle model
Natural gas flow rate	lb/hr	10,646	Calculation

In the combined cycle mode the feedwater flows from the condenser (CND1); to the first heat exchanger (HX4); to the deaerator (DA1); to the second heat exchanger (HX2); and to the boiler drum (DRUM1). Steam flows out of the boiler (FB1); through the steam turbine (ST1 and ST2); and on to the condenser (CND1). Flue gas from the boiler flows around the economizer (ECON1, which is bypassed); to existing the air heater (HX1); to a new heat exchanger (HX3), that heats air for the drying dome; and to the electrostatic precipitator (ESP) and exhaust stack. In Figure 2.3 the symbols SP are slitters that direct the flow depending on the mode of operation (combined cycle or existing configuration) and the symbol M refers to a mixer which joins two flows. When modeling the existing configuration, SP4 directs all the feedwater flow to the feedwater heaters; the extractions from the steam turbine (ST) are activated; ECON1 is activated; and GTD1, HX2 and HX4 are shut down. In addition, when modeling the URGE test, HX3 was bypassed since that feedwater heater was down.

Computer Modeling Results

Computer modeling of the existing and repowered plant was done using GateCycle, version 5.4 (GE Energy and Industrial Services, Inc.). The GateCycle program is a PC-based software program that performs detailed, steady-state design analyses of thermal power systems using a Windows 2000 operating system. A specific GateCycle model is built up from a palette of component equipment (equipment icons) that are connected to make a flow network. Mass and energy balance calculations are done for each link of the network.

Figure 2.3 summarizes the main results from the modeling. For the Minnesota Valley plant, the steam flow rate at the turbine inlet is rated at 425,000 lb/hr maximum for a 4 hr period and 385,000 lb/hr for long duration. The steam pressures were set at the conditions of the URGE test: 1315 psia at ST1 inlet, 1435 psia at DRUM1 and 1665 psia at PUMP4, and the steam temperature at ST1 inlet was set at 957°F. Pressure drop in the links and heat exchangers was not modeled at this time. The isentropic efficiency of the steam turbine was set at 82% based on a good match between the model and the URGE test data. The condenser pressure was set at 1.5 psia (115°F). The deaerator was operated at 50.6 psia for the combined cycle cases. Blowdown from the drum was assumed to be 2,000 lb/hr for wood fuel and 5,000 lb/hr when using coal (Note: during the URGE test, the blowdown was zero). Air for the drying dome was set at 132°F and the drying air flow rate was set at 45 times the wood feed rate based on previous dying tests.

The gas turbine was modeled using the parameters of the LM2500, which is built into GateCycle. The net power of the gas turbine (GT1) was adjusted to yield a feedwater temperature to the drum of 460°F for the full load case. Note that the drum saturation temperature is 590°F at 1434 psia, and the feedwater temperature out of the economizer (ECON1) reached 432°F during the URGE test with the high pressure feedwater heater down. In the model the fuel input to the boiler was adjusted until the desired steam flow rate was obtained. Other assumptions used in the modeling are given in Figure 2.3.

In the combined cycle maximum load case the gas turbine generates 24.3 MW and the steam turbine 53.3 MW for a total output of 77.6 MW at a net plant efficiency of 33.3% (net plant heat rate of 10,239 But/kWh). At 385,000 lb/hr of steam, the net power output is 72.0 MW at essentially the same efficiency. The steam cycle efficiency and power output are higher in the combined cycle case than for the existing case because the feedwater is heated by the gas turbine exhaust rather than with extracted steam. The net steam plant efficiency for the combined cycle case was 34.3%, whereas for the existing configuration the net efficiency is 29.2%. The steam flow to the condenser is 21% higher for the maximum output (77.6 MW) combined cycle case and 14% higher for the 72 MW combined cycle case compared to the URGE test. For the URGE test (using low moisture, low sulfur, bituminous coal) the measured net plant efficiency was 30.5%, which is slightly higher than the wood case (29.2) due to the higher moisture in the wood (23% versus 5.6% moisture for the test coal).

The new feedwater heat exchangers HX2 and HX4 have a surface area (calculated in GateCycle) of 32,500 ft^2 and 55,800 ft^2, respectively. The new heat exchanger for the drying dome (HX3) has a calculated surface area of 35,000 ft^2. The existing combustion air heater (HX1) has a surface area or 70,900 $ft^{2,}$ and the existing economizer (ECON1) has a surface area of 6,650 ft^2.

Figure 2.2 Minnesota Valley WTE™ Retrofit Steam and Air Flow Diagram

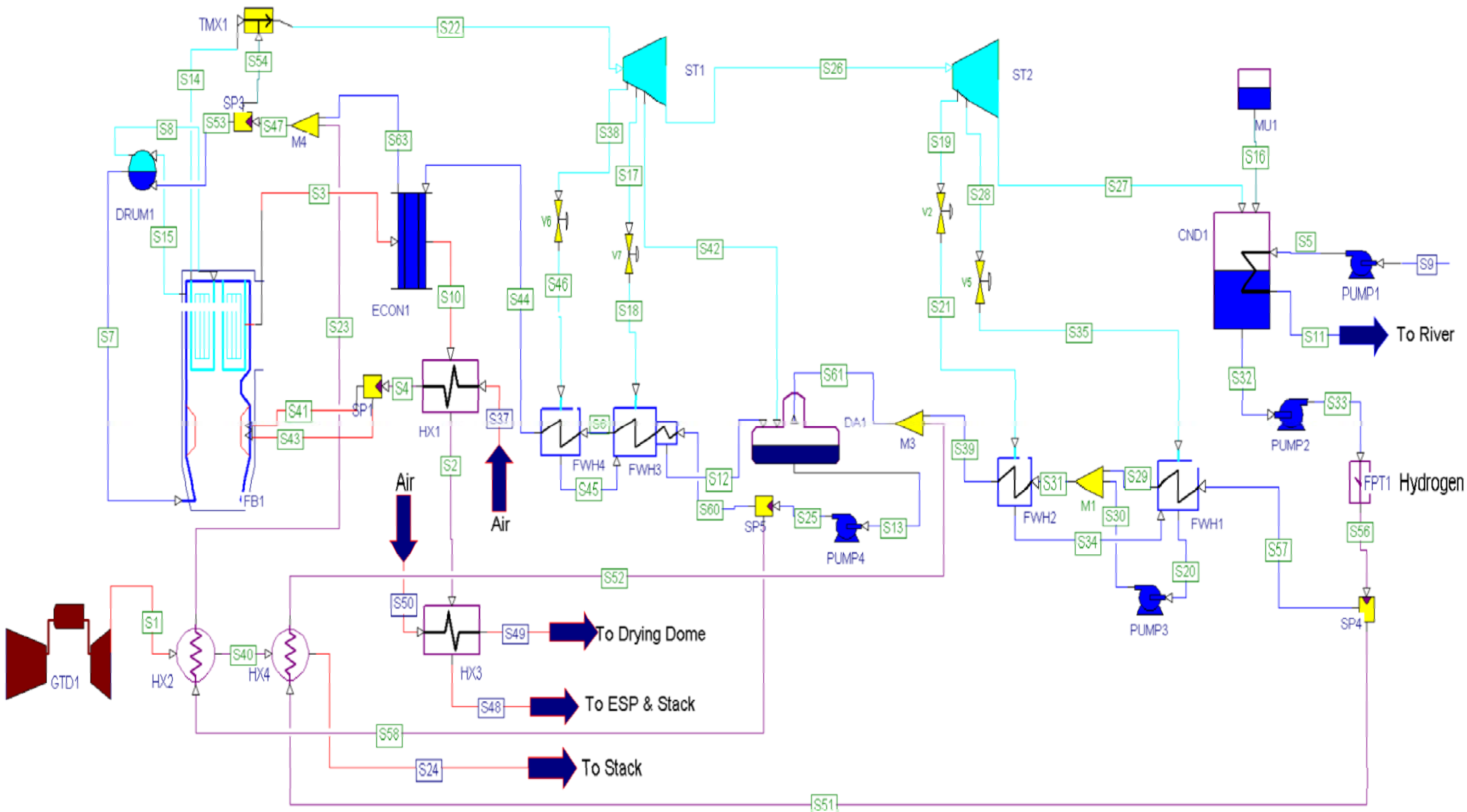


Figure 2.3 Summary of Modeling Results for Minnesota Valley Power Retrofit

	WTE™ Combined Cycle			Coal Operations	
Parameter	**WTE-CC** (Peak Steam)	**WTE-CC** (Full Load)	**WTE Only**	**Coal Only**	**Coal Urge Test**
Steam flow to ST, lb/hr	425,000	385,000	385,000	385,000	397,860(2)
Total net power, MW	77.6	72.0	43.1	42.4	46.3
ST net power, MW	53.3	47.7	43.1	42.4	46.3
GT net power, MW	24.3	24.3	-	-	-
Net plant efficiency, %	33.3	33.7	29.2	30.0	31.0
Net plant heat rate, Btu/kWh	10,239	10,130	11,701	11,366	11,179
Net steam plant efficiency, %	33.7	34.3	29.2	30.0	30.5
Net steam cycle efficiency, %	42.9	43.3	37.9	37.5	37.7 (3)
Net GT efficiency, %	31.8	31.8	-	-	-
Boiler efficiency, %	80.4	81.1	82.1	86.2	88.7 (3)
Steam extraction to DA, lb/hr	21,500	15,000	14,370	14,710	19,070**
FW temperature to boiler, °F	461	477	430	448	429
Solid fuel feed rate, lb/hr(ar)	80,600	70,900	75,370	50,520	40,440
Boiler air flow rate, lb/hr	416,000	366,000	398,000	413,500	413,630 (3)
Boiler air preheat, °F	720	720	604	580	590
Flue gas flow rate, lb/hr	496,600	436,900	473,730	461,730	450,020 (3)
Nat. Gas flow rate, lb/hr	10,646	10,646	-	-	-
Steam flow to condenser, lb/hr	403,500	370,000	286,000	285,500	319,240 (3)
Circulating water temp rise,°F	28.5	26.3	20.2	20.2	22.5
Drying air flow rate, 1000 lb/hr	2,800	2,500	2,600	-	-

Notes:

(1) Best fit to URGE data using model; test data readings were 435,000 lb steam/hr and 385,000 lb water/hr, which indicates instrumentation error in one or both readings.
(2) All efficiencies, including GT efficiency, based on HHV.
(3) Model calculation.

Nomenclature:

WTE-CC = Whole Tree Energy Combined Cycle, feedwater heaters & economizer bypassed
WTE only = Whole Tree Energy without GT, active feedwater heaters & economizer
Coal only = sub-bituminous coal without GT or HX3, active FW heaters & economizer
Coal test = URGE test data using low moisture, low sulfur bituminous coal without GT or HX3, with high pressure FW heater bypassed, other FW heaters & economizer active
GT = gas turbine
ST = steam turbine
FW = feedwater
DA=deaerator

HHV = higher heating value
HX – heat exchanger
ar = as-received basis

Key Assumptions:

Gas Turbine type LM2500 (General Electric Co.)
Ambient conditions, 50°F, 14.23 psia (890 ft elevation), 60% relative humidity
Steam conditions at turbine inlet, 957°F, 1315 psia
Steam turbine efficiency, 82%
Steam condenser pressure, 1.5 psia
Circulating water to condenser, 13 million lb/hr
Auxiliary and balance of plant power, 5% (excluding FW pumps)
HHV: wood 6700 Btu/lb; URGE test coal 12,564 Btu/lb; coal (Decker subbituminous) 9540 Btu/lb (all fuels as-received basis)
Wood proximate analysis: 0.15 fixed carbon, 0.613 volatile matter, 0.007 ash, 0.23 water
Wood ultimate analysis: 0.500 carbon, 0.060 hydrogen, 0.440 oxygen (dry ash free basis)
Coal (URGE test) proximate analysis: moisture 0.0575, ash 0.0949, sulfur 0.0071.
Coal (URGE test) ultimate analysis (assumed): 0.78 carbon, 0.053 hydrogen, 0.14 oxygen, 0.02 nitrogen, 0.0007 sulfur (dry ash free basis)
Coal (Decker subbituminous) proximate analysis: 0.4137 fixed carbon, 0.3125 volatile matter, 0.0398 ash, 0.234 water
Coal (Decker subbituminous) ultimate analysis: 0.76 carbon, 0.053 hydrogen, 0.1724 oxygen, 0.01 nitrogen, 0.0046 sulfur (dry ash free basis)
Excess air for combustion, 15%
Natural Gas higher heating value, 23,880 Btu/lb
Air to drying dome 45*dry wood feed rate, air heated to 132°F
Blowdown is 2000 lb/hr from drum for wood and 5000 lb/hr for coal; makeup at condenser is from a demineralizer; URGE test had zero blowdown.

Startup Times and Ramp Rates

For the WTE™ plant, the startup time prior to load ramp includes the cumulative time it takes to rebuild the main fuel bed, start the bed burning, and bring the boiler to a minimum operating temperature (Figure 2.4). Rebuilding the main fuel bed requires injecting multiple batches of trees onto the main grate. How long this step takes depends on the cycle time of the fuel feed system. After the bed reaches some minimum size for startup (estimated at 30 dry tons), the bed is ignited using gas burners under the main grate. A short time is needed before the bed is fully ignited and able to generate significant heat. Once the bed is reacting, the entire mass of the furnace and boiler needs time to heat up to a minimum temperature before power can be efficiently produced. The time for this step should be comparable to the coal-fired power plant. In either case, normal operating procedure for the Minnesota Valley plant is to heat soak at an output of 2.5/3.0 MW for 20-30 minutes before building to desired output.

Ramp rate measures how long it takes to bring a plant from a low load to a higher load level. For the Minnesota Valley plant, the rule-of-thumb has been to bring the plant up at about 1 MW/min from 2.5/3.0 MW to full load. The recommended ramp rate of 1 MW/min is based on turbine operating limitations rather than potential heat output of the fuel.

Figure 2.4 Startup Time Estimate for WTE™ Plant

Factor	Units	Value	Comments
Ram fueling cycle	minutes	2	Design specification
Minimum fuel load for startup	dry tons	30	Design specification
Fuel batch size	dry tons	6	Calculation
Number of batches required		5	Calculation
Total fuel loading time	minutes	10	Calculation
Time to ignite fuel	minutes	3	Estimate based on testing
Time to heat boiler/ turbine to minimum dispatch level	minutes	20-30	Data from Minnesota Valley plant
Total cold startup time	minutes	33-43	Calculated

Assumes cold start with no fuel in main burn pile.

Boiler Retrofit

The Riley-Stoker Corp Boiler # 4 was placed in service in November 1953 and was originally rated at approximately 45 MW when firing with Western Kentucky coal (boiler serial number 2895; YPR-22 plus WW boiler; two drum; working pressure 1500 psig; heating surface-water walls, 12,584 ft^2; convective heating surface, 2450 ft^2; furnace volume 30,400 ft^3; water cooled furnace envelope 6500 ft^2 steam capacity 385,000 lb/hr; one hour peak capacity 425,000 lb/hr). The boiler was converted in 1974 to burn low sulfur sub-bituminous Western coal, resulting in a boiler derate to approximately 40 MW. Currently, the plant #4 boiler is maintained for use in emergencies but requires advanced trucking of large quantities of coal to the site. In June 2002, a four-hour URGE test of the Minnesota Valley plant generated 46 MW of capacity with bituminous coal.

Converting the boiler for WTE™ requires significant internal and external modifications. Utility Engineering, Inc. had a subcontract to detail the modifications, and their report is found in Appendix 10. As part of this subcontract Babcock Borsig Power, Inc, manufacturer of the original equipment, reviewed the proposed boiler modifications, provided a cost estimate, and explained their design concerns (contained in Appendix 10).

With the WTE™ system, combustion is divided into three distinct stages. In the first stage, the deep-bed of whole tree segments is supported by the fixed water-cooled grate. The fuel near the grate is primarily carbon char that is exposed to air, and the char temperature is very high (> 3000°F). In the upper two-thirds of the bed oxygen is no longer present and the wood gasifies under sub-stoiciometric conditions. Because of the drying and devolatilization of the wood, the solids temperature is expected to be 2000 to 2100°F and the gas temperature decreases towards the solids temperature near the top of the bed. In the second stage, volatiles released from the bed are combusted in the volume above the bed at temperatures of 2700°F or so with the addition of overfire air. In the third stage, char from the bottom of the deep bed falls through the grate and is burned on a smaller lower grate

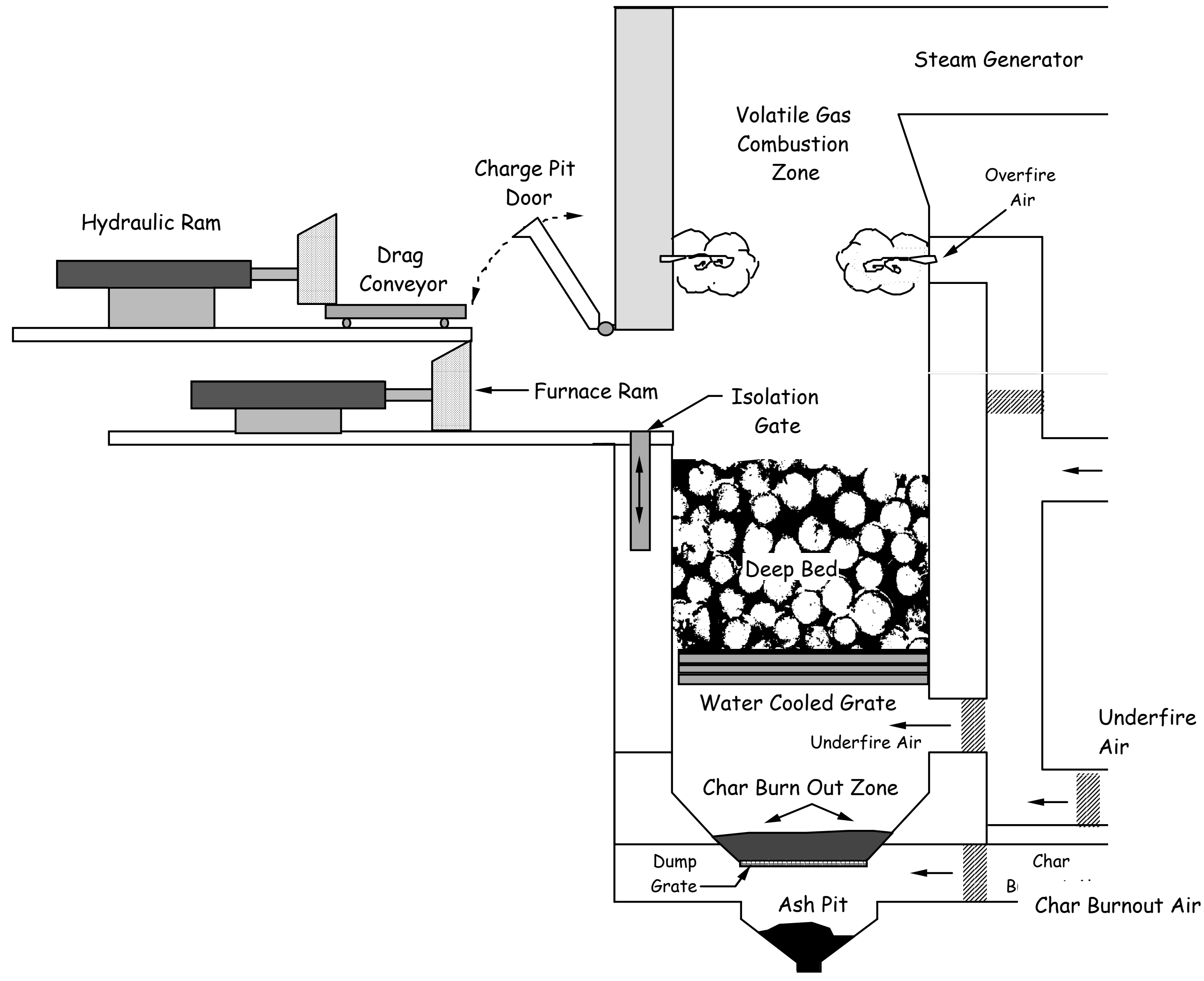
Converting boiler #4 to WTE™ will require modifications to the existing waterwalls and exterior structure to accommodate the new fuel feed system, combustion grate and char burnout grate. Openings in the boiler wall will also be added for new overfire air nozzles, underfire air ports and new instrumentation ports. The existing coal injection ports will be removed.

Additional modifications to boiler auxiliary equipment have been identified in conjunction with modifications to the boiler. The wood drying system uses boiler flue gas waste heat extracted by a new condensing heat exchanger. Two new large capacity blowers provide fresh air to the condensing heat exchanger and subsequent ductwork to the drying dome. The existing forced draft fan ductwork requires rerouting to allow for an adequate air supply of overfire and underfire air. An additional fan is required for the air-cooled char burnout grate. A new induced draft fan and ductwork are needed for the condensing heat exchanger. In addition, a CO_2 blanketing system is needed for fire protection.

Modifications to Boiler for New Fuel Feed System

The WTE™ fuel feed system uses a pair of rams as shown in Figure 2.5 and Figure 2.6 to first load the charging pit and then to feed the fuel load into the boiler. At the appropriate time in the fuel loading cycle, the charge pit isolation gate opens allowing the charge pit ram to push each batch of trees into the furnace on top of the fuel bed. The charge pit ram retracts and the furnace isolation gate closes in preparation for the next batch of fuel. When closed, the door maintains an air and heat seal around its perimeter to maintain efficient furnace operation. During plant operation, the charge pit door and the charge pit isolation gate are never open at the same time. The charge pit isolation door allows batches of trees 24 feet in length (nearly the width of the furnace inside the water wall) to be pushed onto the deep bed. Each load will weigh up to 6 dry tons (For more information on the fuel feed system see Fuel Handling section).

Figure 2.5 WTE™ Fuel Feed System



In order to feed large batches of wood fuel into the boiler, a 24 ft x 8 ft opening will be made in the front wall. The bottom edge of the fuel feed opening will be at elevation 928 ft. The opening will require the removal of up to 192 square feet of boiler wall and water wall area in front of this opening (see Water Wall Modification section below). While this opening in the side of the boiler is larger than typically used, large isolation gates and rams faces have been used in mass burn boilers. The opening is 1.5% of the water wall surface, and this amount of heat transfer will be more than made up by heat transfer to the water cooled grate.

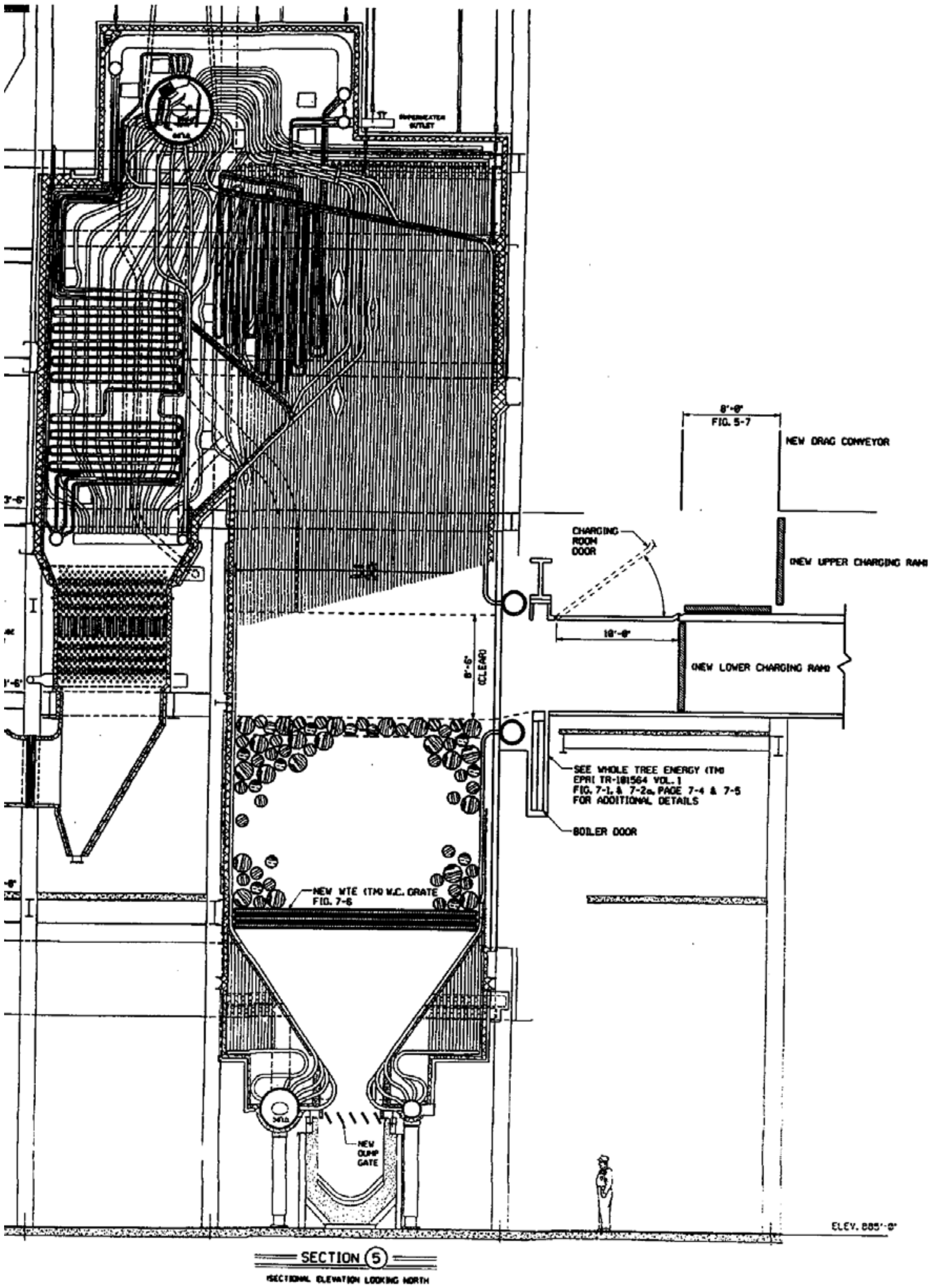
The charge box structure will tie into this new opening providing leak resistant charge pit for loading fuel directly into the boiler. The existing external structural members forming the skin of the existing boiler will require the addition of new structural framing to support the upper and lower portions of the wall and integrate the charge pit structure, the isolation gate and furnace ram mechanisms. Clearance for the new water wall headers - required to bridge the fuel feed opening - will also need to be considered in the final design. Demolition of the existing coal storage and crushing systems will be required to provide clearance for the fuel drag conveyor and the fuel feed rams.

The face of the charge pit isolation gate is lined with high temperature, high reflectivity refractory material that withstands exposure to the 2200°F reducing conditions at the top of the fuel bed. The normal fuel charging time is about 1 min. The face of the charge pit ram will see furnace temperature only for about 10 s after the fuel charge has been pushed into the furnace and the isolation gate is closing. Otherwise the fuel charge with 23% moisture acts as a shield for the ram face. There is no requirement for sealing the ram face because the charge pit is isolated during the charge cycle, however, seals around the piston and guide interface with the rear bulkhead of the charge pit are needed. The temperatures and stresses experienced in the charge pit will vary by section and during each fuel feed cycle. The charge pit ram will be built using a combination of high temperature insulation, refractory materials, cast alloy tile, high temperature gasketing materials and water-cooled steel jacketing. Heat transfer analysis including cooling of the charge pit are to be a part of the detailed design process.

Another design consideration to ensure reliable, fail-safe operations is avoiding the possibility of a fuel jam or misfeed caused by branches or debris stuck in the charge pit doors or ram systems. The charge pit door will be designed with a built-in sheer along its edge to cut any branches blocking its from closing. Although the preliminary sketches show the charge pit isolation door closing vertically from the bottom to the top of the charge pit, it may prove easier to seal the door and maintain a smooth obstruction free surface by having the door close down from the top. Details such as this will be worked out during the detailed design phase.

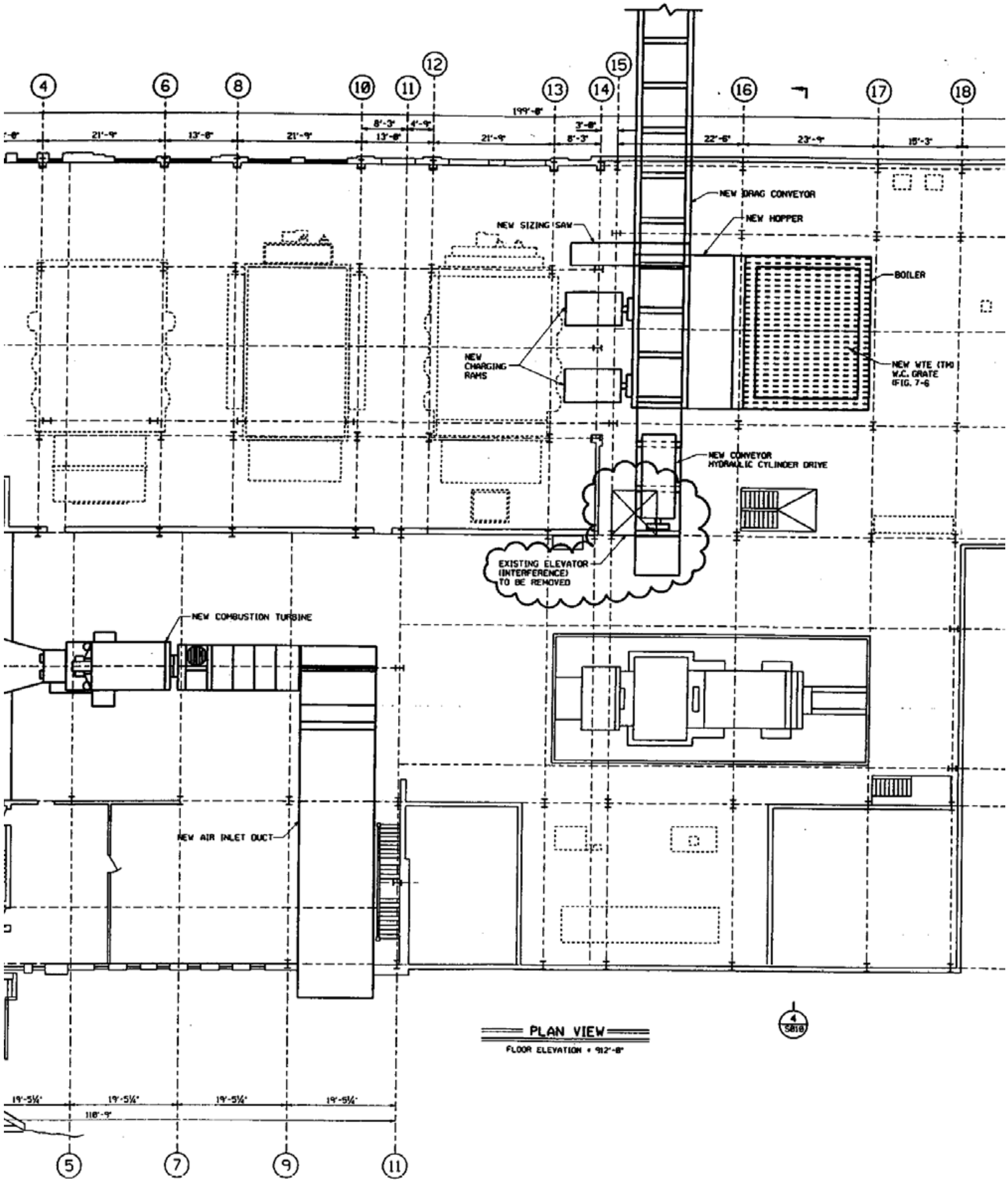
Most of the modifications and components required to accommodate the new fuel feed system will be site-built. Examples include fabricating and insulating the charge pit box, reinsulating the opening in the boiler wall and adding new structural support members. Some components such as the rams, charge pit door and charge pit isolation door will likely be fabricated off-site by various contractors. While the boiler modifications are a technical challenge, they will use existing technologies and materials commonly used in the power industry. Other views of the feed system are shown in Figures 2.7 and 2.8.

Figure 2.6 Boiler Elevation Showing Fuel Feed System



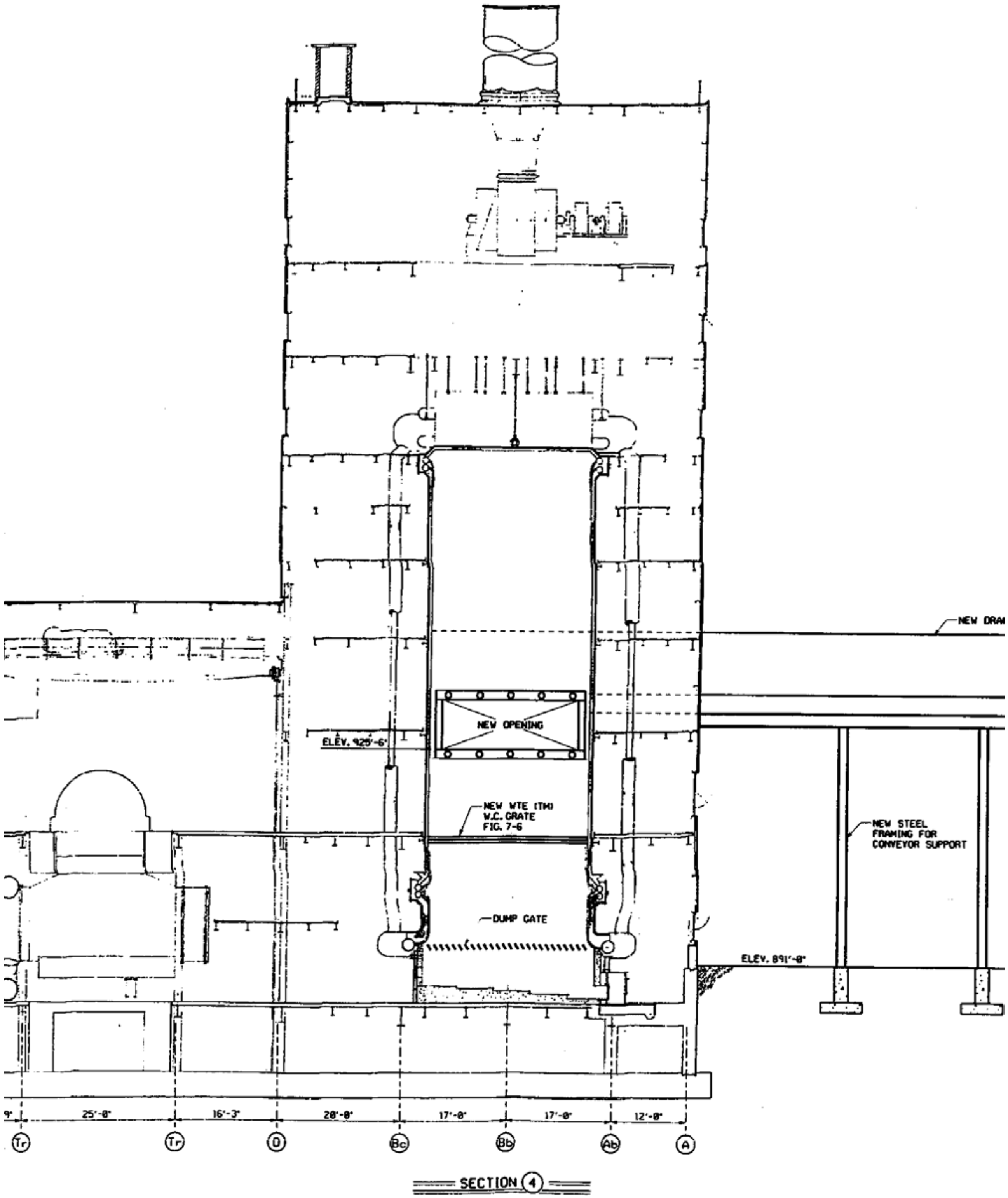
UE drawings D010783-006S009 Sectional Elevation Looking South, in Appendix 10.

Figure 2.7 Boiler Plan View Showing Fuel Feed System



UE drawings D010783-006S007 Heat Recovery Unit, in Appendix 10.

Figure 2.8 Boiler Elevation Showing Fuel Feed Opening



UE drawings D010783-006S008 Section 4 Looking West, in Appendix 10.

Water Wall Modifications

Currently, several openings in the water wall provide access for coal injectors, firing air ducting, gas and oil burners and instrumentation ports. Converting the existing boiler to burn whole trees will require changes to the water wall to provide openings for additional overfire air ports and the wood fuel feed system. Other minor modifications may be required for new instrumentation and viewing ports.

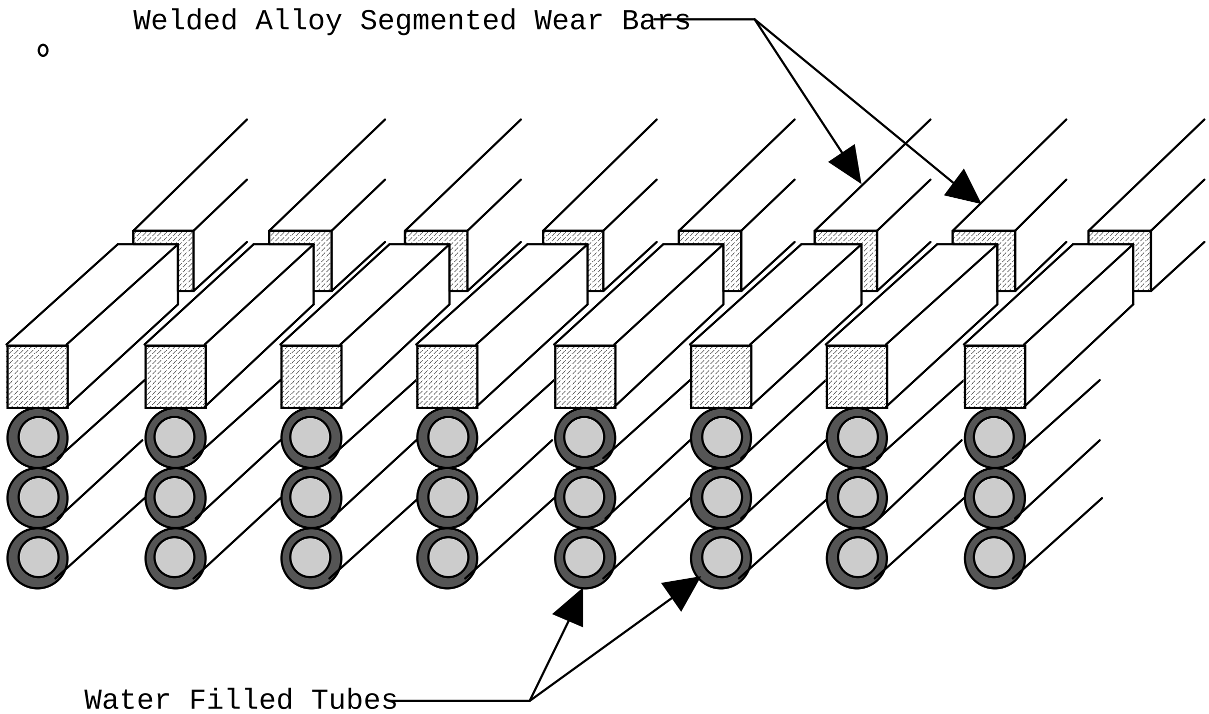
The overfire air ports will be situated above the top elevation of the new fuel feed opening. The exact number and size of these ports will be determined during the detailed design stage. The overfire ports will be designed to maintain even mixing of air and volatile compounds to ensure complete combustion while minimizing nitrogen oxide formation.

For the new fuel feed port a system of headers will be designed and fabricated to direct the water-wall piping around the opening on the back wall of the furnace and reconnect with a matching header system above the opening. The lower header and piping will need to be protected from potential damage as each load of trees is injected into the furnace. Minor modifications to the water wall will be needed to accommodate the structural supports for the new combustion grate. These modifications will use standard components. As part of the boiler performance analysis, the impact of these changes in the existing water wall be analyzed and considered in the final design.

Grate for Fuel Bed

A fixed, water-cooled combustion grate approximately 24 ft long x 20 ft wide will be fabricated and mounted about 12 ft below the fuel feed system opening at an elevation of 910.0 ft (Figure 2.6). The grate will consist of a network of 3 in. diameter heavy-walled tubes mounted in parallel sets of three tubes welded together vertically with each set on 9 in. centers (Figure 2.9). The openings in the grate between the tubes allow particles of char to drop down to a secondary char burnout grate below and allow underfire air to flow evenly up through the main burn bed. The grate tubing will run from front to back of the boiler perpendicular to the orientation of the pile of trees in fuel bed. Segmented high temperature alloy wear bars are welded longitudinally along the top tube of each set to provide a wear surface to protect the combustion grate from damage. All the grate tube sections will be headered together at both ends and connected to the main feedwater to provide continuous cooling water to the grate. The grate will be designed to withstand the a 70 ton load of fuel and to absorb the intermittent forces generated from up to 6 dry tons of trees fed from above during each fuel charge cycle. The grate design needs to take into account that the temperature just above the grate where the air meets the carbon char will be in excess of 3000°F. The grate is to be sloped slightly and made vertically adjustable by using spool pieces in each corner.

Figure 2.9 Water Cooled Fuel Bed Grate



Char Burnout Grate
A new dump grate for holding unburned char and ash will need to be installed below the main grate. The dump grate will be approximately 5 ft wide and extend the width of the furnace. This grate will be mounted at an elevation of about 892.0 ft in the lower portion of the boiler about 17 ft below the main grate and just above the ash sluice pit. The char grate will consist of movable slats that remain closed except for a brief intermittent dump of ash into the existing ash pit. The char burnout grate will be air cooled with small holes that provide the char burnout air.

Other Boiler Modifications
Other required boiler modifications include:

- Remove existing coal burner equipment and ports.
- Pressure part water wall modifications to eliminate the existing coal burner openings:
  -Upper row of three burners ~ elevation 929'-6"will be replaced with straight tubing
  -Lower row of three burners ~ elevation 916'-6" will be removed and no new tubes are required due to the new fuel chute being added in this location.
- Add instrumentation water wall openings.
- New furnace observation doors will also be added at the appropriate locations requiring openings in the furnace wall and minor modifications to existing water wall piping.

Boiler Performance
Converting the boiler from pulverized coal firing to deep fixed bed combustion rises the issue that the heat transfer profile in the boiler may change. However, since the deep fixed bed combustion system can operate over a wide range of air flows, bed heights and underfire/overfire air ratios, necessary adjustments can be made during initial startup tests. During these tests the best set of operating conditions to maintain desired superheat temperatures and steam loads will be determined. The boiler

contractor needs to evaluate the past deep fixed bed combustion test data and modeling information obtained to date and participate in the startup tests.

The primary grate area is 480 $ft^2$and the design heat input for maximum power from the steam turbine is 540 million Btu/hr, or 1.1 million Btu/hr- ft^2. Previous field tests and modeling have shown that this heat release rate is readily achievable with a deep fixed bed of whole trees with a 6 ft to 9 ft deep bed with under-grate air velocities of 3 ft/s to 4 ft/s. A deeper bed and higher air velocities will give a greater heat release rate. Underfire-to-overfire air ratios of near one are expected but the design should allow for a ratio of 0.75 to 2.0 with stoichiometries of 0.55 to 0. 65 at the top of the fuel bed. The distance from the top of the bed to the nose of the boiler is 34 ft so that the residence time is 2-3 s, which allows sufficient time to complete combustion.

In addition to the boiler retrofit requirements noted above, the boiler contractor should complete a comprehensive boiler assessment and design study. The study will provide the following information:

- Assessment of the condition of the boiler;
- Assessment of the capability of the retrofitted boiler to make full load;
- Design of boiler retrofit modifications to insure good boiler circulation without hot spots;
- Specification of sootblowers changes, if any;
- Design of ducting for adequate combustion air flows;
- Design of overfire air system.

The overfire air nozzle design must provide for complete burnout of the gasified fuel above the bed at low excess air while maintaining the lowest possible nitrogen oxide emissions. During startup tests the overfire air system will need to be tuned to best operating conditions in relation to the fuel bed height, underfire air flow rate, air preheat, and steam load. The overfire system needs to accommodate a range of operating conditions.

Flue Gas Flows

The GateCycle model of the WTE combined cycle was used to determine the total air flow rate and wood feed rate required to meet the steam load. At the high steam flow rate of 425,000 lb/hr with an excess air of 15%, the flow rate of under-grate air is 208,000 lb/hr and using a 50/50 split, the over-bed air flow rate is also 208,000 lb/hr. The flow rate of combustion products is 496,600 lb/hr. Using estimated temperatures at the top of the fuel bed and top of the furnace, the gas velocities in the furnace are calculated as shown in Figure 2.10. The furnace volume allows for a wide range of bed depths, air flows and heat release rates.

Figure 2.10 Gas Flows in Boiler with WTE Combined Cycle

Factor	Peak Steam	Full Load
Steam flow rate, lb/hr	425,000	385,000
Wood feed rate, lb/hr	80,600	70,900
Heat release per unit area, Btu/hr/ft^2	1,000,000	890,000
Under-grate air flow, lb/hr	208,000	183,000
Under grate air temperature,°F	720	720
Under-grate air velocity, ft/s	3.3	2.9
Temperature at top of bed,°F	2200	2200
Gas flow at top of bed, lb/hr	288,600	253,900
Gas velocity at top of bed, ft/s	10.3	9.1
Temperature at top of furnace, °F	2100	2100
Gas flow at top of furnace, lb/hr	496,600	436,900
Gas velocity at top of furnace, ft/s	17.0	15.0

The existing forced draft fan is a Buffalo Forge No. 12 "SLD" fan capable of moving 135,000 cfm at 12.6 in. water gauge pressure, which is satisfactory for the anticipated air flows. An internal visual inspection of this FD fan in 1991 indicated that this fan was in good condition. The existing induced draft fan is a Buffalo Forge No. 15.5 "SHLD" fan capable of moving 215,000 cfm at 13.5 in. water gauge pressure. Maintenance records show that the fan blading was replaced in 1976, and a 1991 inspection indicated the fan was in good condition but inlet swirl vanes were badly eroded. The flow rate is adequate but the fan may need to be replaced.

Feedwater Heating Equipment

In the current plant two low pressure (#31 and #32) and two high pressure (#34 and #35) Foster Wheeler feedwater heaters use turbine extraction steam to heat the boiler feedwater. One of the high pressure feedwater heaters (#35) is out of service and needs to be replaced and the others may need tube replacements. During combined cycle operation, these feedwater heaters are bypassed and feedwater is heated using a new heat recovery heat exchanger mounted inline with the combustion turbine exhaust. This heat exchanger will be mounted where the machine shop floor is currently (Figure 2.11). The new feedwater heat exchanger has two compartments (HX2 and HX4) with an estimated surface area (calculated in the GateCycle model) of 32,500 ft^2 and 55,800 ft^2, respectively. The performance of these heat exchangers is shown in Figure 2.12.

Figure 2.11 New Heat Recovery Feedwater Heater - Plan View

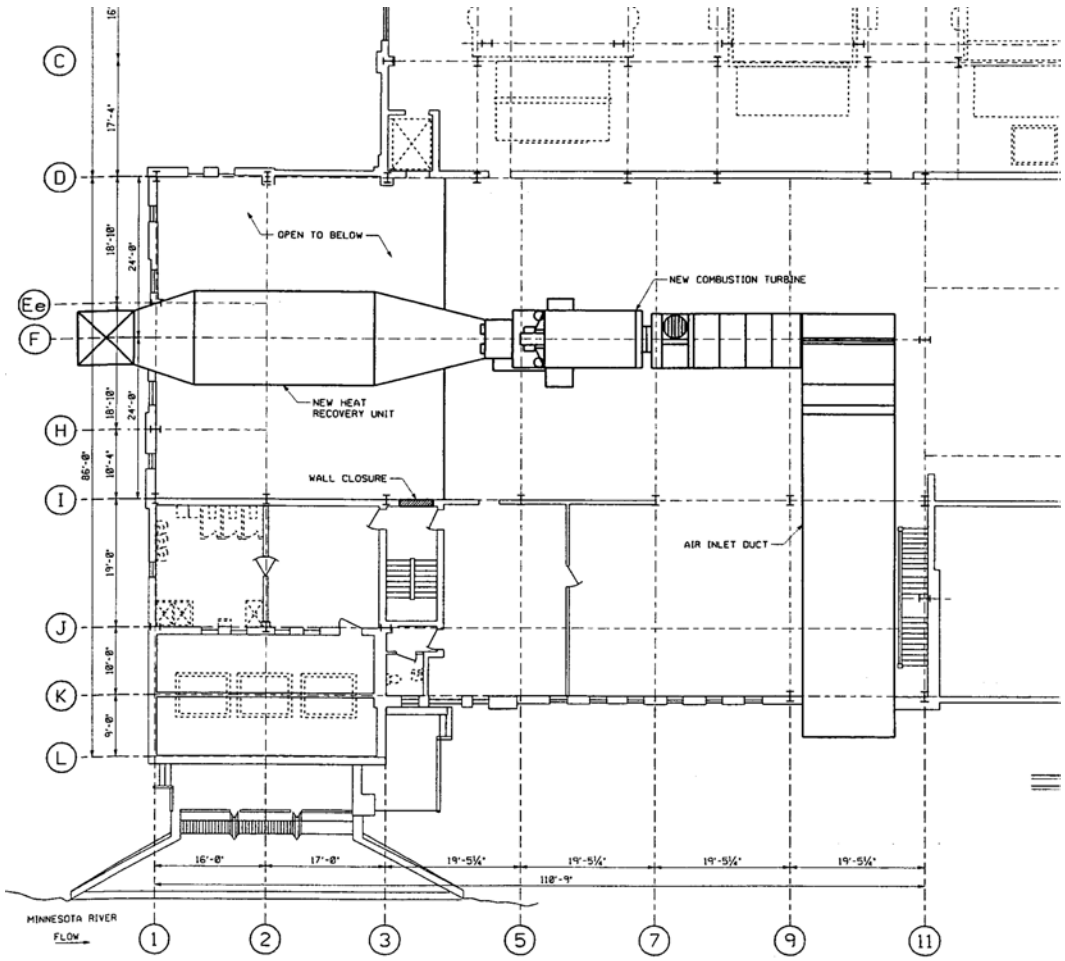


Figure 2.12 New Heat Recovery Feedwater Heater - Operating Conditions

Variable	Section HX2	Section HX4
Direction of gas flow	Horizontal	Horizontal
No. of Gas Passes	One	One
Gas flow, lb/hr	586,000	586,000
Gas inlet temperature, °F	980	464
Gas outlet temperature, °F	464	155
Direction of water flow	Horizontal	Horizontal
No. of passes	One	One
Feed water flow, lb/hr	427,000	406,000
Water inlet temperature, °F	284	121
Water outlet temperature, °F	461	232
Heat transferred, MMBtu/hr	80	45
Estimated delivered cost	$780,000	

Existing Combustion Air Heat Exchanger
The existing combustion air heater (HX1) is a Ljungstrom rotary regenerative heater Model 22-V-56 with a heating surface area of 70,900 ft^2. The original rated air pressure drop is 4.1 in. water and the gas pressure drop is 2.8 in. water at a rated air flow rate of 425,500 lb/hr and rated gas flow of 490,000 lb/hr (Figure 2.13). The condition of the air heater was considered good in 1991. The existing air heater will be used in the retrofit WTE™ plant to provide 416,000 lb/hr of air at up to 720°F for overfire and underfire combustion air.

Figure 2.13 Combustion Air Heater Peformance

Variable	Urge Test Data	WTE Combined Cycle
Gas flow, lb/hr	449,000	496,000
Gas inlet temperature, °F	700	870
Gas outlet temperature, °F	336	363
Total air flow, lb/hr	413,000 (1)	416,000
Underfire air flow	-	208,000
Overfire air flow	-	208,000
Air inlet temperature, °F	108	50
Air outlet temperature, °F	589	720
Heat transferred, MBtu/hr (1)	50.0 (1)	68.7

(1) Calculated by GateCycle Model

New Condensing Heat Exchanger
In order to generate warm air for drying the fuel, a new condensing heat exchanger is added to extract waste heat from the flue gas exiting the combustion air heat exchanger. A condensing heat exchanger

is used because there is no sulfuric acid in the flue gas when burning wood. Approximately 2.8 million lb/hr of drying air heated to 132°F and ducted to the drying dome. The performance of the drying air heat exchanger is summarized in Figure 2.14. See the Fuel Handling section for further information.

Figure 2.14 New Condensing Heat Exchanger for Drying Air

Variable	Quantity
No. of Gas Passes	One
Gas flow, lb/hr	496,000
Gas inlet temperature, °F	363
Gas outlet temperature, °F	115
No. of air passes	One
Air flow, lb/hr	2,800,000
Air inlet temperature, °F	50
Air outlet temperature, °F	132
Heat transferred, MBtu/hr	55.4

3. Fuel Handling, Drying and Feeding

Background
The tree drying/handling facility consists of an air supported fabric dome, a drying air distribution system, a tower crane tree handling system, and an integrated firewater storage system. A separate drag conveyor system is designed to transport a continuous pile of whole trees from inside the drying dome to the dual-ram fuel feed system at the furnace.

The design fuel feed requirements are 35 dry ton/hr for full load operations and 40 tons/hr at short term (4 hr) peak load. The trees are fed into the boiler from the fuel drying building on a first in-first out basis. In a typical cycle, the crane picks up a load of green trees from a waiting whole tree hauling truck, raise the load to pile height and swing the load to the current position of the transition zone between green and dried trees. The load of green wood will then be dropped at the leading edge of the green trees and the crane will swing across the transition zone and pick up a load of dried trees to be fed onto the drag conveyor. Again, the load will be raised to pile height and swing back to the loading zone to be dropped into the fuel feed hopper over the drag conveyor. The loading/unloading area will be located immediately next to the fuel feed hopper. Simulation of the fuel handling cycle has shown this configuration to be the most efficient in terms of crane cycle times.

Whole green trees are dried from their typical 40% to 50% moisture down to less than 25% moisture in the drying dome using warm dry air (130°F) for a period of one month. This improves boiler efficiency and decreases emissions from burning wood. The fabric drying dome is supported by air pressure from the drying air supply during the normal tree-drying operation. An independent, motor-driven, air supply system equipped with a back-up diesel generator will be used to keep the dome inflated during emergency and plant shut-down periods. The tree drying facility integrates tree unloading, storage, drying and a fuel handling.

Drying Dome
The drying dome is 410 ft in diameter and 145 ft high to accommodate a 300 ft diameter by 70 ft tall stack of trees (Figure 3.1). The entire enclosed space can be used for storage since internal support columns are not required. The trees are randomly stacked in a donut shaped pile with a center open space of 50 ft in diameter to provide space for the central crane tower. The dome will be situated approximately where the coal storage yard is currently located (Figure 3.2). The existing coal storage and handling facilities will be removed during the demolition phase of the project.

The size of the dome is dependent on the volume of trees to be stored and dried. In previous testing, EPS has determined that drying trees from 50% green moisture content to 23% as fired takes about 30 days. At a design fuel feed rate of about 54,593 dry lb/hr (524 dry tons/day at 80% capacity factor), about 15,700 dry tons of fuel needs to be stored in the drying dome (Figure 3.3).

The dome will be made from double-layer of a strong plastic/fabric film called ESIFILM (from Environmental Structures, Inc.). The special plastic fabric is commonly used in large air-supported structures such as sports domes, temporary construction buildings, and emergency shelters. This film is strong, light, translucent, and resistant to damage from ultraviolet radiation. The film is also designed to meet standard fire codes for flame resistance. Galvanized 3/8-inch aircraft cable are embedded in seams every 4 ft allowing the entire dome to be folded up and erected in one piece on site. The load bearing steel cables also provide structural strength while maintaining the shape of the dome. Low pressure air separates the inner and outer layers of the double-wall cover. This slightly pressurized dead air space acts as an insulation layer.

The translucent film lets natural daylight into the enclosure eliminating the need for auxiliary lighting during the day. Lights can be mounted on outside poles illuminating the cover at night for shadow-free inside light without internal obstructions. At the top of the dome, a large circular opening is designed to exhaust the warm, saturated air from the building to the atmosphere. This vent will be adjustable to retain a positive pressure inside the drying building at all times.

The domes 1288 ft long perimeter will include various access doors and exits. One 14 ft by 14 ft truck entrance door, two revolving personnel entrance doors and several exit doors will be located around the perimeter of the drying building. The truck entrance door will not require an airlock given the high airflow into the building from the air distribution system.

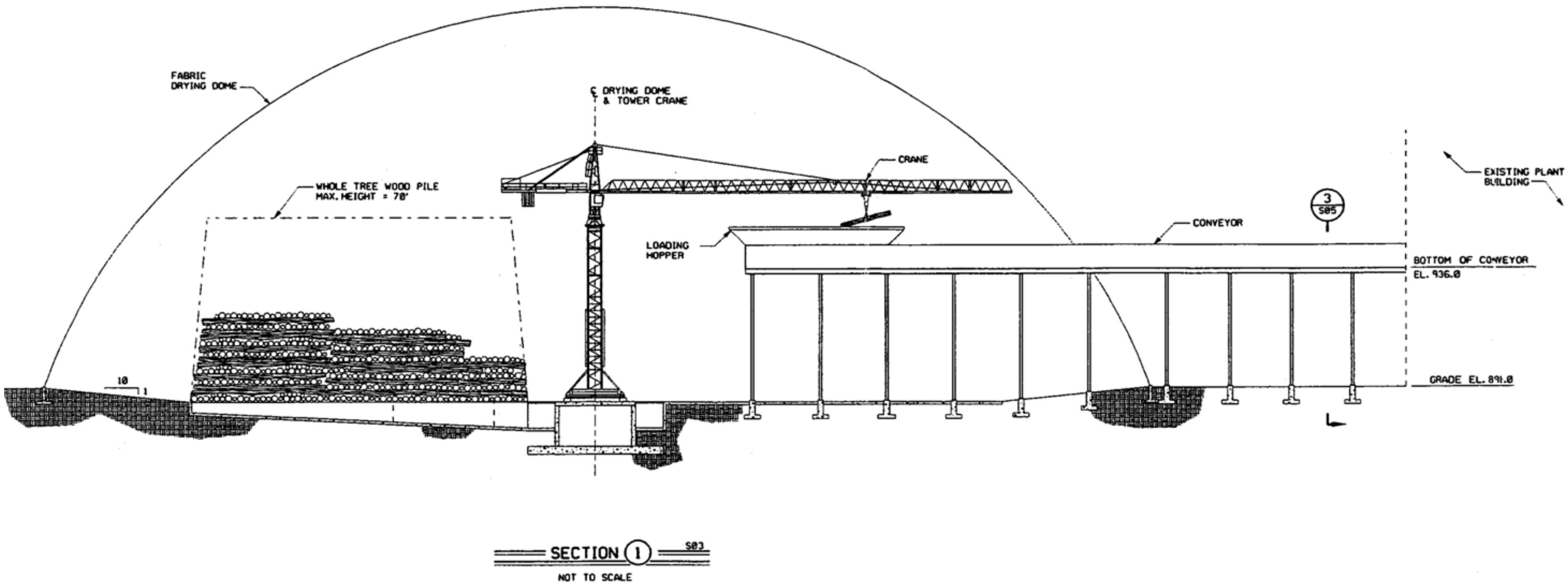
The mechanical system required to inflate the dome will consist of two 250 hp drying air circulation blowers, several small backup fans, and two emergency stand-by generators. Only two small fans are needed to maintain the normal interior pressure once the building is inflated (and the vent is closed). The backup fans are used to stabilize the building in high wind conditions or in case of a system failure and will pressurize the dome to 1.5 in. water.

The structure will be designed to withstand the appropriate wind and snow loads typical for the Granite Falls area. Normal wind pressures require an inside air pressure of only 0.4 to 0.5 inches of water to support the structure. As wind velocity rises through gale force winds, internal pressure is increased using an automatic pressure control system. The drying building, as designed for the Minnesota Valley project, will have the design capability to withstand 100+ mile per hour winds. Since the drying building will be heated to 110 to120°F continuously, snow load will not build up. An automatic control system will maintain a constant interior air pressure by automatically adjusting to all expected atmospheric conditions such as storms, high winds, snow loads, or air losses at the doors.

The drying building will require only minor maintenance on a regular basis to maintain its integrity for many years. There are no windows to wash or replace. The structure needs no painting. In the case of minor damage to the dome of the drying building, repairs are simple and inexpensive. Damage to the exterior envelope due to trees falling off the pile or accidentally puncturing the sides is not expected to be a problem since there will be a tree-free zone 100 ft wide between the perimeter wall and the edge of the tree pile, and in prior stacking tests whole trees were stacked 100 ft high (in a square stack) without any problem with trees falling off or the pile tipping over. Even if the dome were to get accidentally punctured, the drying building will not deflate and the tear can be easily repaired on-site.

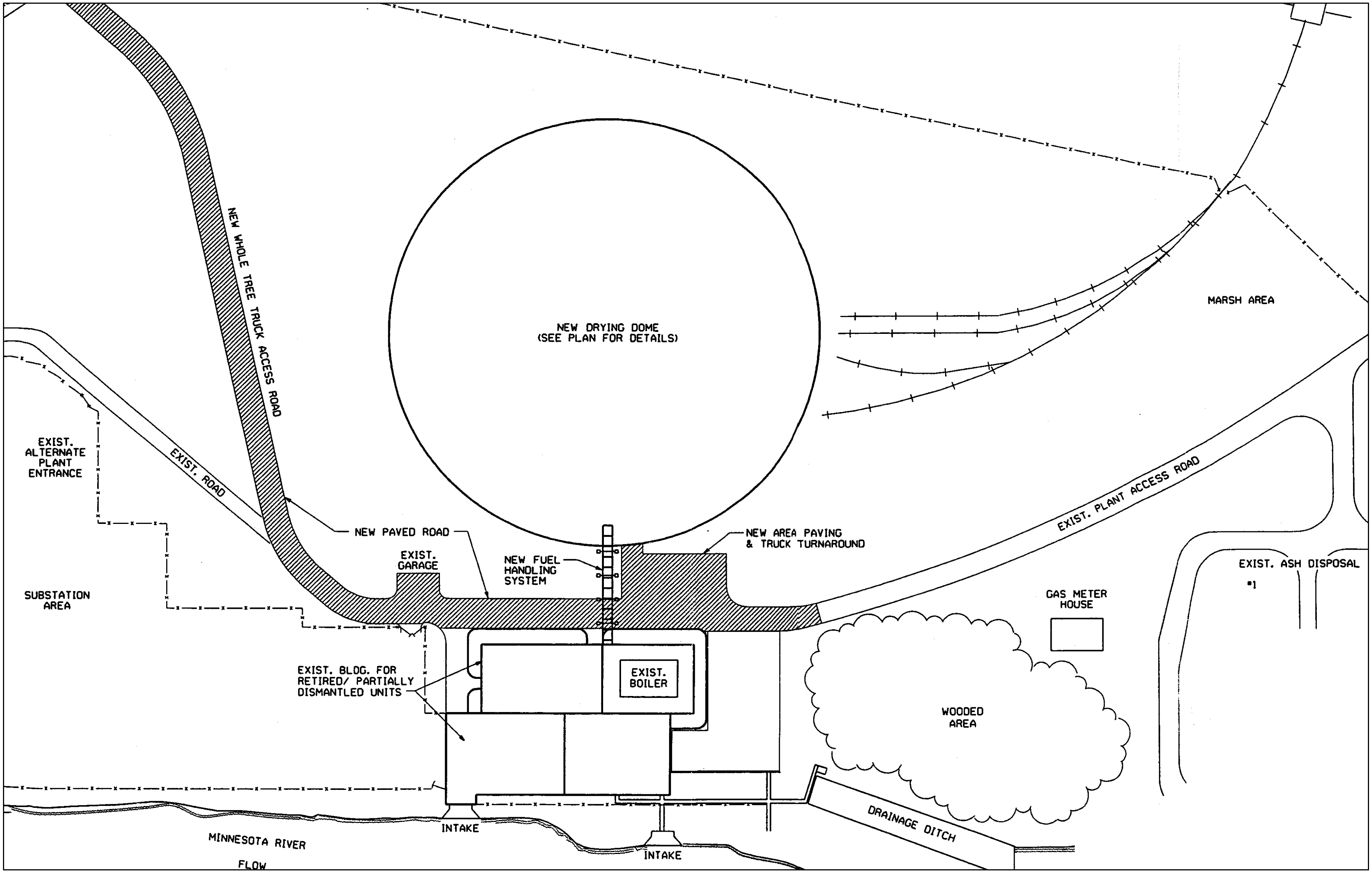
The cost of the entire drying building including the fabric dome, the anchor wall, the mechanical systems and the site preparation is expected to be about $9.9 million. This includes the cost of the fabric dome, the anchor system and the mechanical system. Construction of the dome enclosure can be completed before the radial walls, crane and other equipment to facilitate an above freezing indoor environment.

Figure 3.1 Drying Dome Elevation



UE drawings D010783-006S004 Drying Dome and Conveyer Section in Appendix 10.

Figure 3.2 General Site Plan



See UE drawings D010783-006S002 General Site Plan in Appendix 10.

Figure 3.3 Drying Dome Specifications

Description	WTE™ Plant
Diameter, ft	410
Center height, ft	145
Volume, million cu ft	11.7
Cover area, sq ft	198,100
Perimeter length, ft	1,288
Plan area, sq ft	132,025
Maximum whole tree storage capacity, dry tons (70 foot high pile at 9 dry lbs/cu ft)	19,750
Air flow during normal operations, million lb/hr	2.8

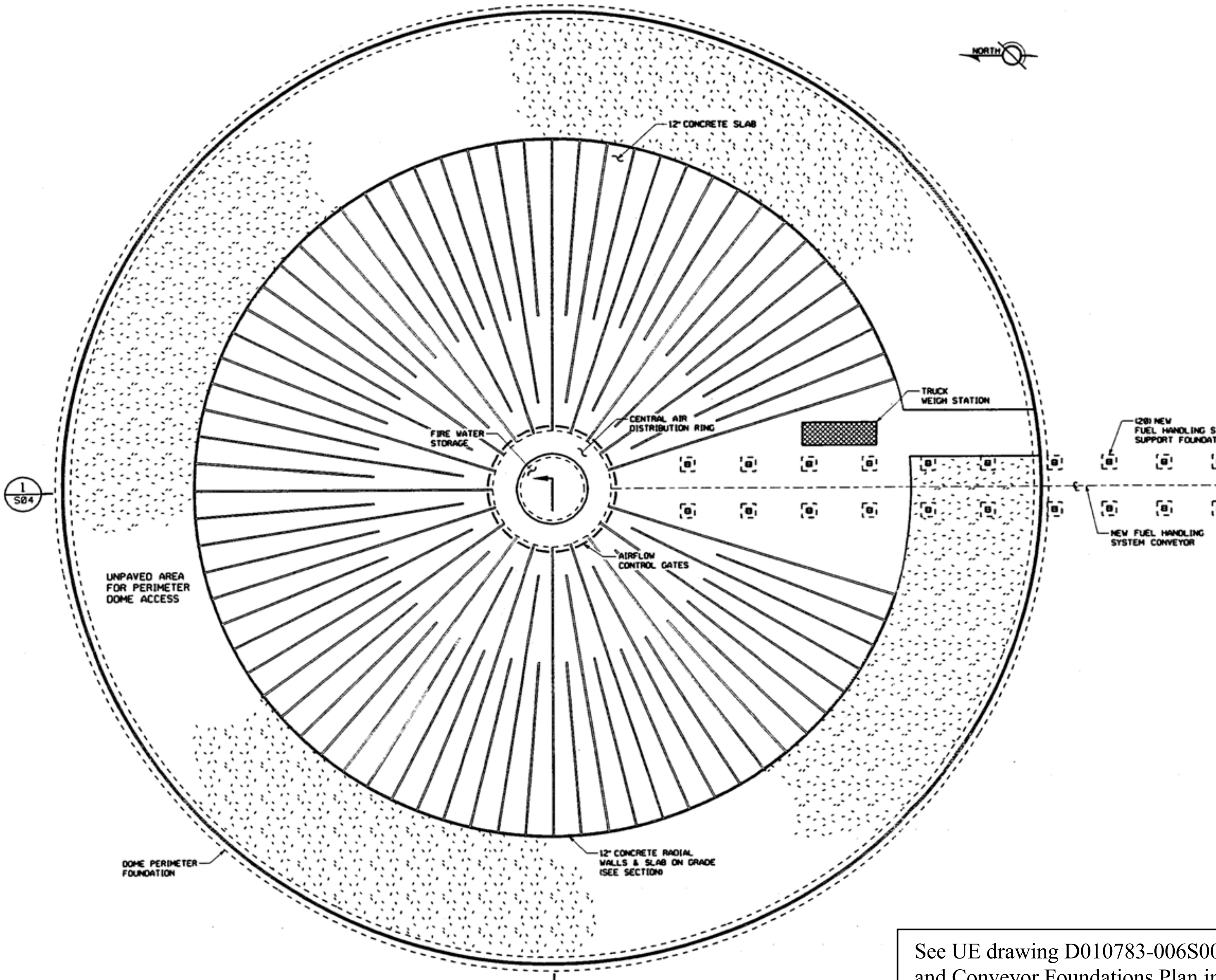
Drying Air Distribution System

A large duct transports warm dry air from the condensing heat exchanger underground to the center ring air manifold inside the drying building. A network of radial walls distribute the drying air under various sections of the pile (Figure 3.4). The long radial walls extend out 120 ft from the central manifold to the edge of the pile at approximately 4.8° intervals. At about 50 ft from the manifold, a second shorter set of radial walls are spaced at 9.6° intervals and offset from the long walls by 2.4°. This second set of walls reduces the overall distance that the first layer of trees has to span from to 12 ft at the outside edge of the distribution system. All of the channel walls will slope up from a depth of about 8 ft at the manifold to 3.5 ft at the outside edge. Openings in the manifold wall centered between each radial channel allow warm air to circulate. The air distribution system will deliver about 2.8 million Btu/hr 130°F air to the wood pile under design conditions.

The air distribution ducts will be below grade such that the bottom of the whole tree pile (and top of the radial walls) is flush with ground level surrounding the pile. The walls will be constructed using standard poured concrete reinforced with steel rebar (Figure 3.5). Cross supports will help strengthen and stabilize the walls. The walls of the air distribution system will be formed and poured at the same time as the footing and foundation wall is constructed for the drying building structure.

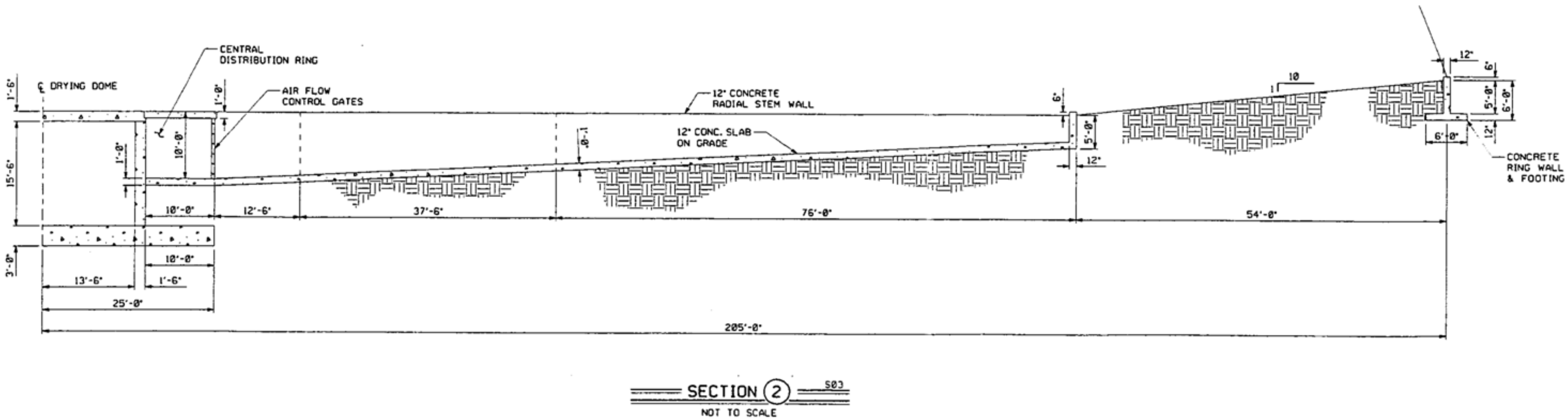
A system of simple automatic baffles at the manifold end of each air channel will be used to automatically control the flow of air through various sections of the pile. Less air is required to remove the excess moisture from the drier wood while significantly higher volumes are required for the wettest wood. Air flow rates will vary from the wettest section of the pile to the driest section. The first layer of trees will be placed perpendicular to the channels to create a stable "floor" for stacking the main pile.

Figure 3.4 Plan View Air Distribution Channels



See UE drawing D010783-006S003 Drying Dome and Conveyor Foundations Plan in Appendix 12

Figure 3.5 Cross-Section of Air Distribution Channels



See UE drawings D010783-006S005 Drying Dome and Conveyer Sections in Appendix 10.

Tower Crane and Grapple
Unloading the tree-hauling trucks and stacking and unstacking the tree pile will be accomplished by a large capacity tower crane/grapple system located in the center of the drying building (Figure 3.1). EPS recommends the use of a Liebherr Model 1800C tower crane or equivalent (Appendix 2). The Model 1800C can lift 30+ tons at the normal working radius of about 150 ft. The total rated horsepower of the crane is about 550 hp (2x200 hp for hoist, 6x20 hp for swing and 30 hp for trolley). The option of purchasing and installing used equipment should be considered for the crane and grapple system.

The crane foundation structure is designed to contain a 65,000 gallon concrete firewater storage tank for a deluge fire-control system. The boom of the crane will have a reach of about 150 ft from the center of the tower to the maximum outward grapple position. A large EPS-designed 25 ton grapple designed to efficiently pick up and move piles of whole trees will be mounted on the boom to unload green trees from the trucks and to place dried fuel on the drag conveyor. The grapple will have three to four opposed tines and 360.8° rotation capability. In order to allow for clearance for the grapple, the boom needs to be mounted at least 20-30 ft above the maximum pile height or at approximately 100 ft above ground level. An air-conditioned cab for the operator will be located on the boom at the top of the tower offering a clear view of the entire tree pile and the truck loading/unloading area.

The tower crane will be operated 24 hours/day during normal operation. Fuel will arrive at the drying building in the form of whole trees loaded on standard wood hauling trailers and custom whole-tree hauling trailers. The deliveries will take place continuously over a 10 to 12 hour day, 5 days per week. Four crane operators will be required for three 8 hr shifts per day. Personnel required to operate and maintain the conveyor system and for building cleanup will include one rover, one front-end loader operator (for cleanup and miscellaneous tasks), and one person for general maintenance.

An area outside the drying building may be set aside to store loaded and empty trailers to allow for quicker turnaround time for the delivery trucks and to smooth the flow of traffic to the unloading crane. During gaps in the delivery schedule, loaded trailers stockpiled outside the drying building could be brought into the drying building and unloaded. The unloaded trailers would then be returned to the parking area and be available for use by a driver at some later time.

Drag Conveyor
The wood fuel handling system is based on proprietary EPS design and includes a hydraulically operated ratcheting drag conveyor, fuel feed rams extending across the boiler front wall, a sizing saw and seal doors. This new equipment will replace the existing coal conveyors, feeders, pulverizers and accessories. The existing building structure requires modification for the conveyor. The existing coal burners, piping, ducting and coal bunker structure will be removed.

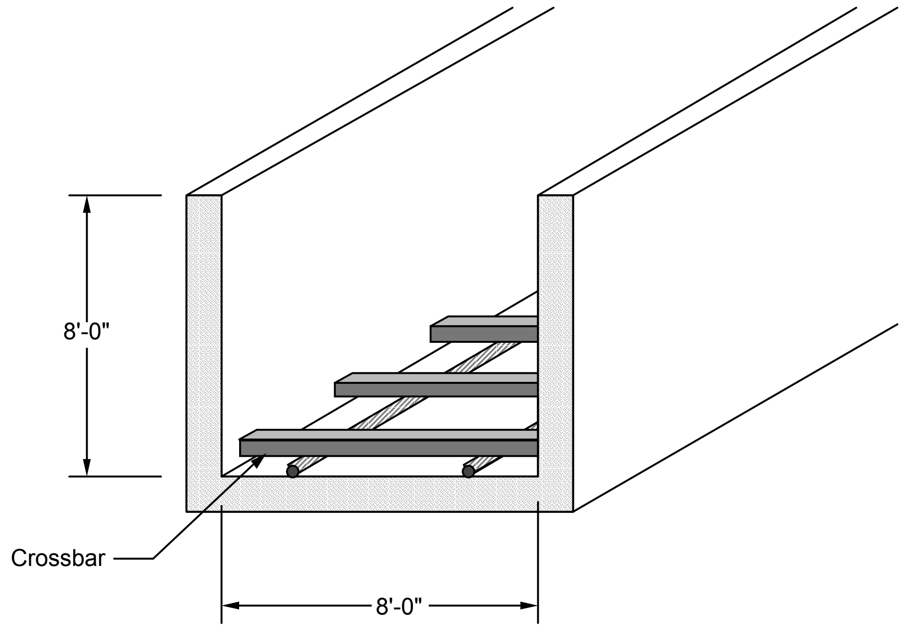
The drag conveyor will extend approximately 245 ft from inside the drying building to the edge of the powerhouse and continues another 75 ft inside the building past the fuel charge pit in font of the boiler. The drag conveyor consists of regularly spaced steel 8 in. by 12 in. rectangular tube slats with welded wear plates on the bottom attached near each end to two continuous loop of 2-1/2 in. steel braided-wire cables (Figure 3.6). The conveyor is 8 ft wide and originates inside the drying building at the fuel loading hopper. The loading hopper is 65 ft long and 20 ft wide at the top level. The sides of the hopper taper in to make a lower channel 8 ft wide with 8 ft high vertical sidewalls. The drag conveyor rides along the bottom of this channel; the channel has groves in the bottom for the cables (not shown in Figure 3.6). A load of trees is dropped into the hopper and slides down into the bottom channel where the drag conveyor latches onto a pile of trees and transports them into the drying building. The duty cycle of the conveyor is such that the conveyor is mostly at rest.

From the loading hopper, the conveyor moves through the sidewall of the drying building to the side wall of the powerhouse and continues to the fuel feed area at the boiler. The conveyor regularly delivers loads of wood to the fuel feed ram and then continues over a large conveyor drive wheel before returning back to the fuel loading hopper to complete a continuous loop.

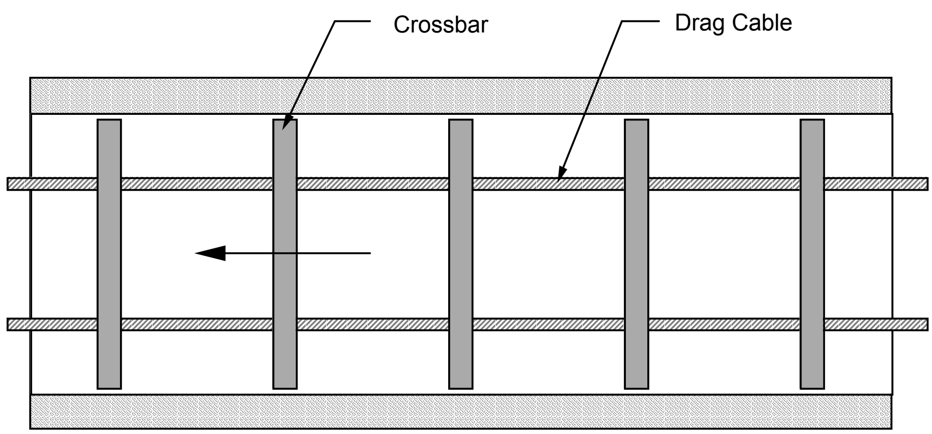
The drag conveyor is continuously loaded with fuel. A fully loaded conveyor at the retrofit Minnesota Valley plant holds approximately 2 hours of fuel for full-load boiler operation. The bulk density is less for the pile on the conveyor and in the combustor as compared to the large tree pile (7.5 dry lb/ft^3 compared to 9 lb/ft^3 of the large pile). The conveyor cycles on and off as needed to deliver fuel to the boiler. Since a fuel load is added to the boiler at approximately 4 minute intervals with each "on" cycle lasting less than one minute, the conveyor duty cycle will be less than 20%.

The conveyor system is supported at approximately 25 ft intervals. Each support consists of a 45 ft steel frame, braced in the east-west direction and resting on concrete foundations (Figure 3.7). Steel support beams run north-south connecting the tops of each frame and the existing building. The drag conveyor will enter the boiler building through a 9 ft by 12 ft opening cut through the north side of the building (Figure 3.8). Inside the building the conveyor is supported by steel frames resting on the existing building floor. The new hopper and ram systems are supported off of the existing floor structure.

Figure 3.6 Drag Conveyor Detail

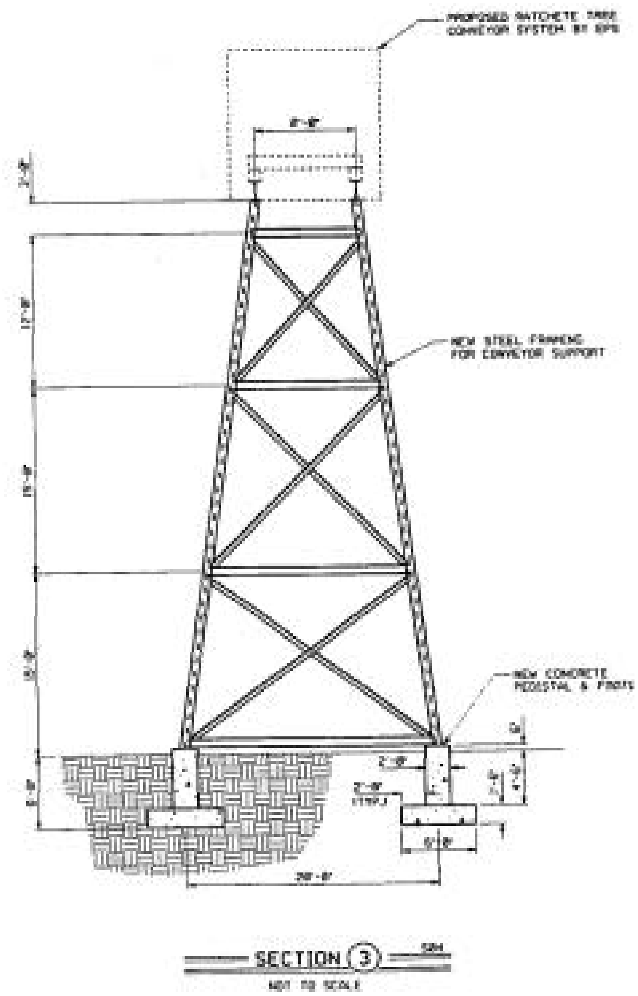


Cross Section - Rachet Drag Type Conveyor



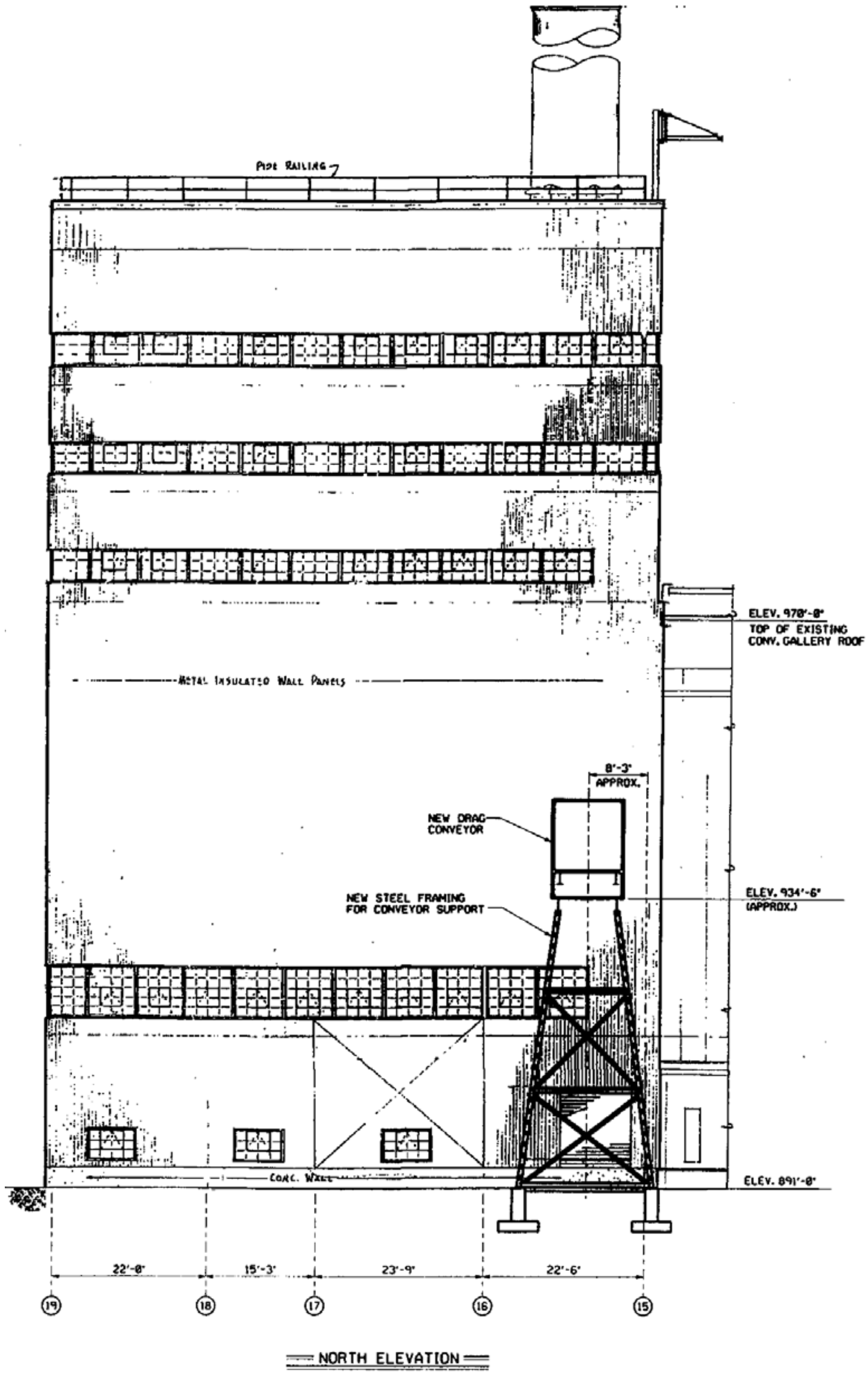
Top View - Continuous Drag Conveyer Section

Figure 3.7 Structural Support for Drag Conveyor



UE drawings D010783-006S005 Drying Dome and Conveyer Section in Appendix 10.

Figure 3.8 Opening in Boiler Building for Drag Conveyor



UE drawings D010783-006S010 North Building Elevation in Appendix 10.

Sizing Saw and Ram Feed System
After the drag conveyor advances the continuous pile of whole trees towards the furnace, a large cutoff saw cuts through the line of trees creating a separate batch of trees approximately 24 ft long by less than 8 ft tall and 8 ft wide (Figure 3.9 and Figure 3.10). Each batch of trees is then pushed off the drag conveyor by a hydraulically driven ram into the main charge pit. The charge pit isolation gate remains closed and sealed against hot gases at this point. The charge pit door closes shearing off any protruding branches. At the appropriate time in the fuel loading cycle, the furnace isolation gate opens and a second ram pushs the batch of trees into the furnace on top of the main fuel bed. The charge pit ram retracts and the furnace isolation gate closes in preparation for the next batch of fuel. A sawdust collection system is also part of this system.

The ram feed system is unique to the WTE™ system. The isolation door will be about 24 ft long and 9 ft tall to allow clearance for a full batch of fuel. The furnace-side face will see continuous temperatures of up to 2500°F during normal operations. When closed, the door will maintain an air and heat seal around its entire perimeter to maintain efficient furnace operation. The door will need to be protected from wear and damage from the fuel. As the charge pit ram pushes a load into the furnace, the face will momentarily see the high temperatures inside the furnace. Although the ram feed system will require innovative design, the primary systems and components use standard materials and off-the-shelf technology. Preliminary cost estimates by Utility Engineers (based on EPS design specifications) total $1.23 million for the ram feed system and cutoff saw combined.

The cut-off saw will be custom designed for this application but all the components and materials are readily available and proven in other industrial operations. The main challenge will be designing the saw components for long term reliability and minimal maintenance. The sawdust recovery collection system also uses standard components and off-the-shelf technology. Similar systems are used in most wood products and wood processing facilities.

Figure 3.9 Ram Feed System

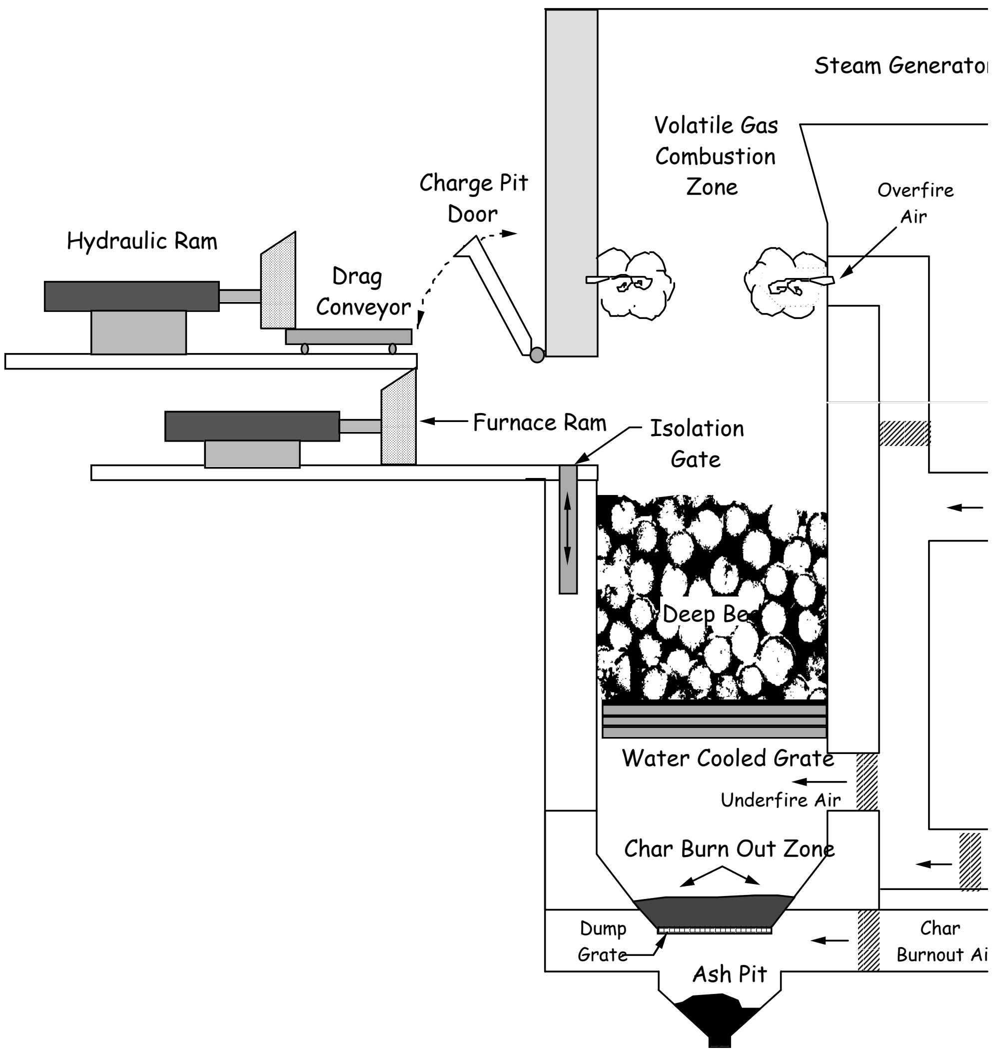
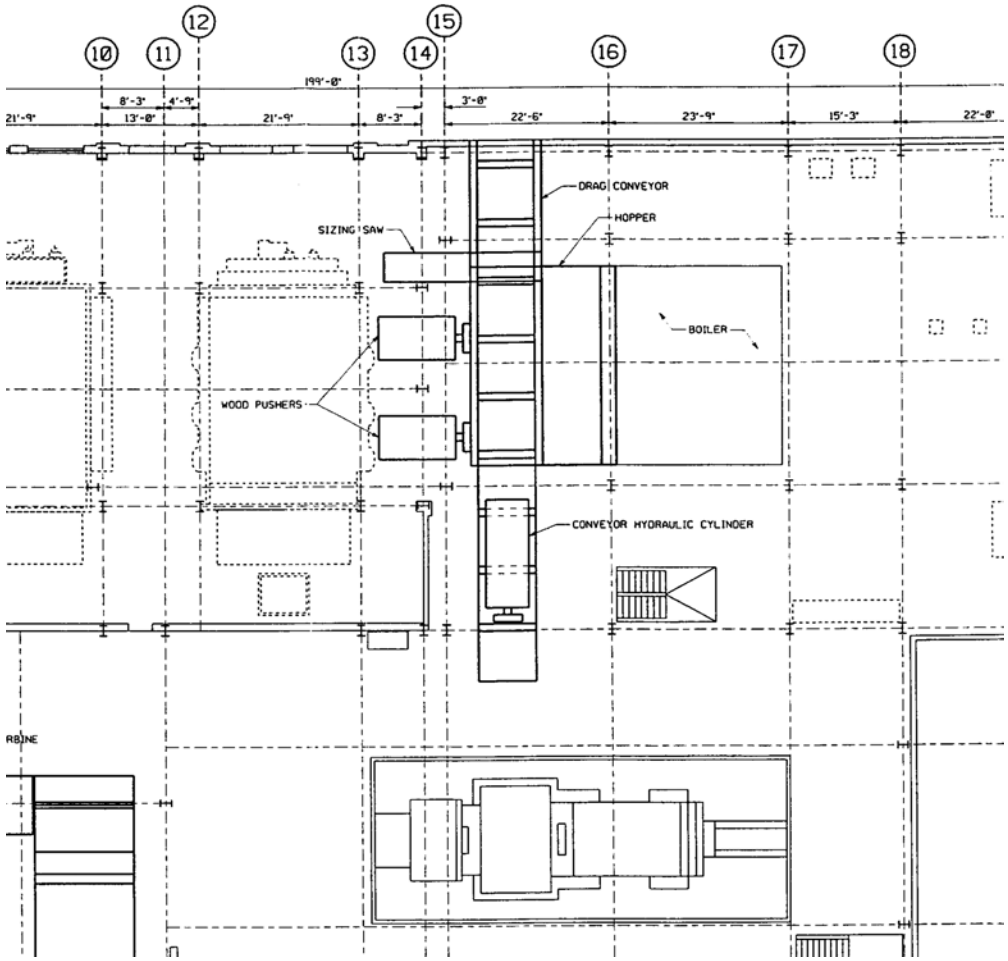


Figure 3.10 Ram Feed System - Plan View



Fuel Handling Roadway

Trucks carrying whole trees arrive from an off-site location at the northwest plant entrance. A new two-lane, 24 ft wide, access road is required to accommodate the traffic from the fuel trucks. Trucks enter the drying area through a dome opening and travel down a 50 ft access to a weigh station. Once the fuel is unloaded, the trucks back out of the drying dome, turn around in a designated area, and leave the plant by way of the new access road. The new access roadways and weigh station are estimated to cost $84,000 and $190,000 respectively. Exterior demolition of existing coal handling facilities including railroad tracks, coal conveyors, coal crusher etc is budgeted at $661,000.

Dome Electrical Description

The retrofit will require the addition of major new electrical equipment including the dome drying air and backup inflation fans, crane hoist and drive motors, drag conveyor and rams hydraulic pump motors for the furnace feed system, and the cutoff saw drive motor. Many smaller motors will also be added. A complete listing of 480V loads for this system is not available, and preliminary one-line diagrams below the 480V switchgear level were not identified.

In order to provide power to the new equipment needed for the fuel related systems new 2400V and 480 V switchgear will be added. A 480 V feed to the drying dome from the 480 V switchgear will be added to feed a motor control center with starters for drying dome fans. A 480V feed to the dome facility from newly installed 480V switchgear will feed a motor control center with starters and distribution feeders as required. Electrical distribution and control equipment (shown on UE D010783LSIE100 in Appenxix 12) for operation of the fuel handling and boiler systems are supplied from a 480V feed from the proposed 480V switchgear.

4. Fuel Supply

Whole Tree Energy (WTE™) integrates the production of biomass with its use as a power plant fuel. WTE is a patented technology for firing 100% wood fuel in new or converted power plants. The technology includes advances in planting, weed control, harvesting and handling, storage, drying, and staged combustion. Trees are grown for fuel, harvested and utilized in "whole-tree" form rather than as woodchips. The WTE process can also use wood fuel from a variety of other sources such as forest residue and wood waste.

The fuel will supply consist of hybrid poplar and cottonwood trees grown as farm crops within 50 miles of the power plant. These short rotation tree crops are grown on plots averaging 80 acres that are integrated with the existing land use patterns. As will be shown in this chapter, the Granite Falls region is an appropriate area for this alternative farm crop (Figure 4.1).

The retrofit power plant will require 191,300 dry tons (7800 acres) of whole tree biomass annually to meet the design specifications summarized in Figure 4.2. If the plant is operated at a different capacity factor or power level, the amount of wood fuel required will change proportionally. Counties within a 50 mile radius of Granite Falls where the fuel will be grown include Yellow Medicine, Lac Qui Parle, Lincoln, Lyon, Redwood, Renville, Kandiyohi, Chippewa, and Swift (Figure 4.3).

SRWC Fuel

The proposed biomass fuel for the Minnesota Valley retrofit is short rotation woody crops (SRWC). These tree crops, which have been developed specifically for biomass fuel, include varieties of hybrid poplar, willow and cottonwood. They have been carefully selected to be fast growing, drought and pest resistant. The trees grow tall and straight with relatively small branches. When grown in good soil on 6 ft centers the fields can be harvested after five growing seasons with an average yield of 25 dry tons per acre. The five year growing cycle will require 39,000 acres of dedicated SRWC.

In Minnesota hybrid poplar is the most common SRWC. There are currently over 20,000 acres of hybrid poplar planted in Minnesota, which is approximately 20 percent of the poplar planted nation wide. Most of these acres were planted under one of the following programs:

- Poplar breeding and research led by the USDA North Central Research Station of the Forest Service, and the University of Minnesota, began in the 1970's, which developed many of the clones that are used today.
- A biomass energy consortium established in 1986 by Energy Performance Systems including the USDA Forest Service, EPRI and the US DOE. A 10 year, 13 site, four-state program that conducted screening trials to identify the best clones for energy production and resulted in selecting the poplar vairety NM-6.
- The Oklee Project, managed by the Agriculture Utilization and Research Institute and the University of Minnesota – Crookston, planted 3,000 acres near Oklee, Minnesota north of Crookston. This project included cost-share payments from the Conservation Reserve Program (CRP) and long-term contracts with Minnesota Power.
- The MN Wood Energy Scaleup Project, started in 1993 and coordinated by WesMinn RC&D and the US DOE, has planted over 1,800 acres on CRP land within a 50 mile radius of Alexandria, MN;
- Private individuals planted hybrid poplar under the CRP program in the early to mid 1990s when it was easier to get hybrid poplar enrolled. One landowner has over 1,500 acres of hybrid poplar planted on CRP land and many others have smaller plantings;

- Champion International (now International Paper) is actively purchasing land in the Todd County area and planting poplar for the purpose of utilizing the wood in its paper plant in Sartell, MN. International Paper has approximately 9,000 acres planted as of the summer of 2000, and plans to plant 2000+ acres per year for the foreseeable future.

Figure 4.1 Minnesota Land Use

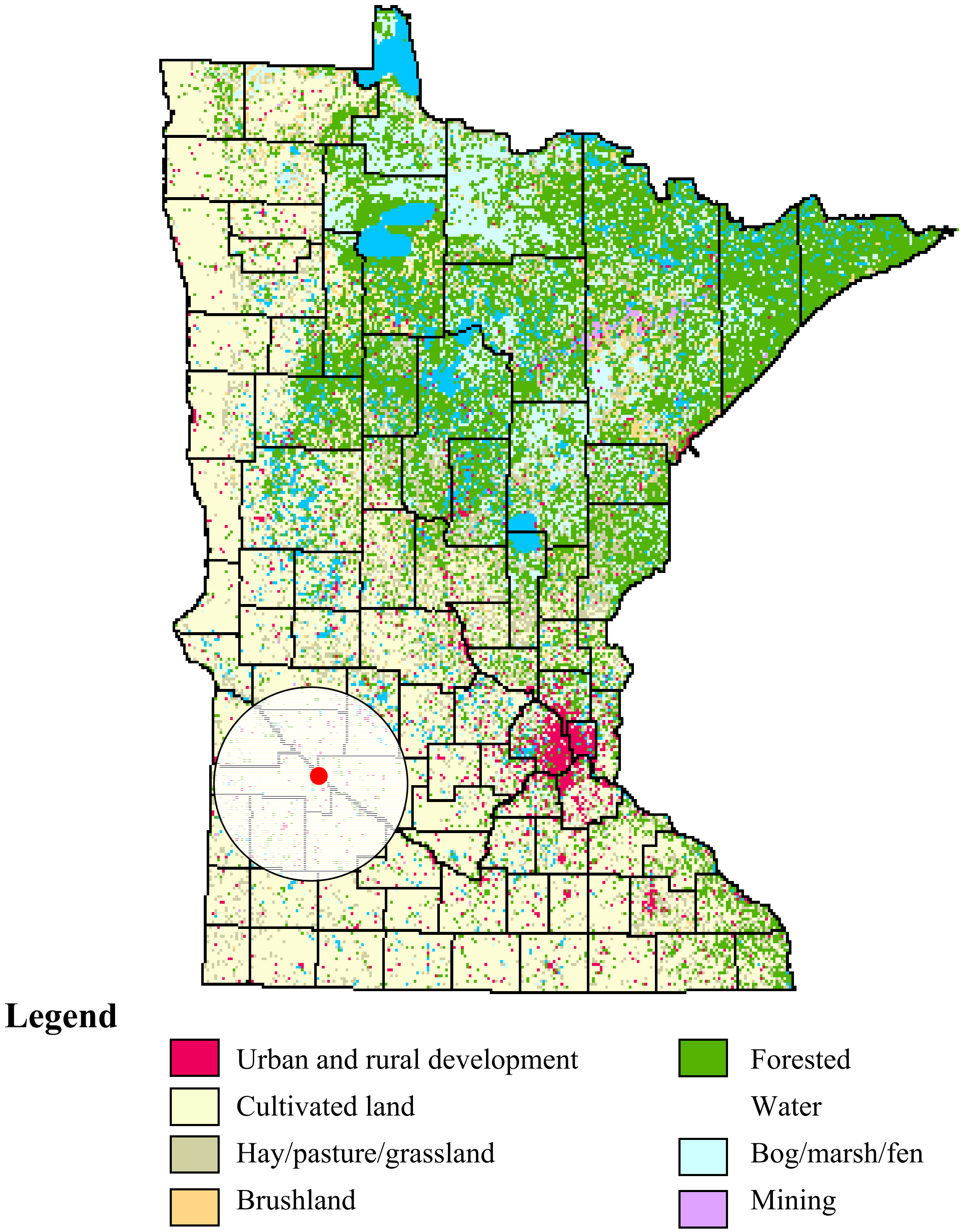
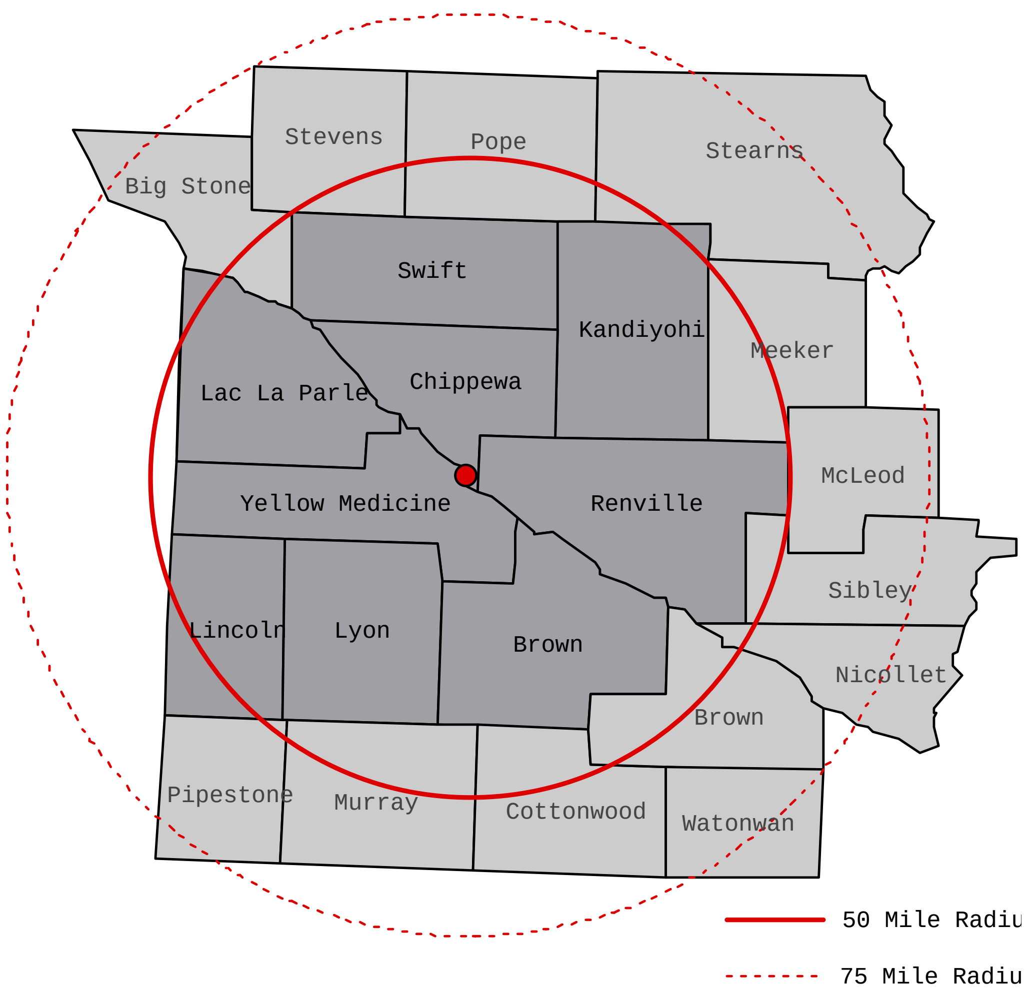


Figure 4.2 Fuel Supply Assumptions

Key Parameters	Units	Values	Source
Net power, WTE steam turbine*	kW	47.7	From GateCycle model
Capacity factor	%	80	Design specification
Net steam plant efficiency	%	34.3	From GateCycle model
Net plant heat rate	Btu/kWh	10,130	From GateCycle model
Wood higher heating value	Btu/lb dry	8,700	From test results
Total fuel energy required	10^{12} Btu/yr	3.38	Calculation
Fuel heat content	MBtu/dry ton	17.4	Calculation
Wood flow rate	Dry lb/hr	54,593	From fuel supply model
Annual fuel requirements	Dry tons	191,294	From fuel supply model
Wastewood usage	Dry tons	Not included	Variable

*Assumes operation of plant as a combined cycle system with combustion turbine.

Figure 4.3 Counties in Fuel Supply Area



Current Land Use in the 9 County Region

A vast majority of the land in the procurement area surrounding Granite Falls is currently farmland. Of the 4.4 million acres of land area in the 9 counties 84% is cropland, 5% is in CRP, and 1.0% is wetland (Figure 4.4). Currently 97% of cropland is planted in either corn or soybeans (Figure 4.5). There are 8,091 farms in the procurement area averaging 459 acres in size (Figure 4.6). To get an idea of the relative scope of this project, if an average farmer were to choose to rent all of his land to grow SRWCs, less than 20 average size farms per year in the 9 county procurement area would need to commit to the program, or less that 1% of the land in the 9 counties.

Figure 4.4 Land Usage by County

Counties	CRP Acres	Crop Acres	Wetland Acres	Total Acres	Percent CRP	Percent Crop	Percent Wetland
Chippewa	7,803	326,753	2,503	376,398	2%	87%	1%
Kandiyohi	37,399	377,217	18,396	551,868	7%	68%	3%
Laq Qui Parle	38,289	410,605	6,704	498,318	8%	82%	1%
Lincoln	60,874	278,286	2,450	351,290	17%	79%	1%
Lyon	22,068	387,941	2,795	462,076	5%	84%	1%
Redwood	17,730	510,636	1,198	564,182	3%	91%	0%
Renville	5,102	575,165	1,483	631,725	1%	91%	0%
Swift	22,658	400,602	8,283	481,444	5%	83%	2%
Yellow Medicine	27,710	424,068	2,330	488,656	6%	87%	0%
Total (50 Mi Radius)	239,633	3,691,273	46,142	4,405,957	5%	84%	1%

Figure 4.5 Average Annual Acreage Planted by County, 1995-2000

County	Small Grains(1)	Corn	Wheat	Soybeans	Total
Chippewa	1,117	135,367	4,967	135,683	277,133
Kandiyohi	6,183	142,967	5,700	115,583	270,433
Laq Qui Parle	533	146,100	19,450	183,333	349,417
Lincoln	3,483	86,467	9,283	95,133	194,367
Lyon	3,167	175,450	4,850	171,900	355,367
Redwood	3,383	227,167	2,833	233,767	467,150
Renville	2,467	237,067	6,217	244,400	490,150
Swift	2,017	155,350	10,967	158,733	327,067
Yellow Medicine	1,150	173,700	11,233	187,500	373,583
Total Acres	23,500	1,479,633	75,500	1,526,033	3,104,667
Percent of Total	1%	48%	2%	49%	

1. Mostly oats

Figure 4.6 Regional Farm Facts

County	Farms (Number)	Land in Farms (Acres)	Average Size of Farm (Acres)	Total Cropland (Acres)
Chippewa	618	318,472	515	297,971
Kandiyohi	1,131	378,831	335	326,925
Laq Qui Parle	790	397,519	503	361,544
Lincoln	724	269,646	372	233,699
Lyon	931	403,001	433	365,967
Redwood	1,168	508,129	435	472,615
Renville	1,114	601,103	540	567,231
Swift	739	388,215	525	352,100
Yellow Medicine	876	415,269	474	380,068
Total	8,091	3,680,185	459	3,358,120

Source: 1997 Agriculture Census Data

Site Selection
Selecting the farm sites suitable for SRWC development depends on location, soil quality, slope, availability, and cost.

Location
Distance from the power plant and ease of access to the fields are the main location factors. All else being equal, sites closer to the Minnesota Valley plant are more valuable due to lower transportation costs. In practice, the farm developers may choose to pay more for rent to get higher quality land closer to the plant to balance the lower transportation cost. Or they may offer slightly higher rents for land closer in to save money and time on transportation. For the purposes of this study, all the cropland within a 50-mile radius (approximately the 9 counties listed above) is considered within an economic range for SRWC's. The entire region is crisscrossed with hundreds of local, township and country and state roads providing relatively direct access to all the farms in the region.

Soil Quality
Poplars and other SRWC grow best on good agricultural soils, but can also be grown on soils that are marginal for traditional crops (Figure 4.7). Generally, better quality soil will produce greater yields earlier in the rotation. The best SRWC growth occurs on sites with a large rooting volume and good aeration, water, and nutrient availability. Soil pH should be above 5.5 and below 8.0. SRWC have been grown successfully on soils ranging in texture from sandy loam to silt or clay loams. Soils with higher clay content tend to have lower production in the first few years. Although SRWC grow on poorly drained soils, they do not grow at economically acceptable rates under these conditions.

The best soils for SRWC are loams, silt loams and clay loams, which are the predominant soils in the 9 county region. The soils in the Minnesota River basin and in the floodplains of its tributaries are deep alluvial soils deposited when much of the area was covered by water while the glaciers were melting. Most of the upland soils are mollisols formed under prairie grasses, and are very fertile. Detailed information on soils can be found in the USDA Soil Survey for each County.

The Crop Equivalency Rating (CER) of potential plots is a key measure of soil quality. In general, any cropland with a CER between 50 and 100 is considered adequate for growing SRWC. In the procurement region, over 3.5 million acres or 81% of all land area fits this criteria (Figure 4.8). This probably represents most of the current land classified as cropland in the region. Land with lower CER ratings tend to be too wet, too rocky, too steep or prone to erosion to be used for productively growing trees (or any other type of crop for that matter). Most of the cropland in the procurement area is high quality and is expected to support relatively high levels of productivity for selected SRWC hybrids.

Figure 4.7 Suitable Soil Characteristics

Soil Characteristic	Suitable	Unsuitable
Texture	Loams, sandy loams, loamy sands, clay loams and silt loams	Coarse sand, clay soils
Structure	Well developed to single grain structure	Massive or lacking structure
Drainage	Imperfectly to moderately well drained	Excessively well or very poorly drained
PH	5.5 to 8.0	Below 5.5 or above 8.0
Depth	18 inches of more	Less than 18 inches
Slope	Less than 12%	Avoid greater than 12%

Figure 4.8 CER by County

	Chippewa	Kandiyohi	Lac Qui Parle	Lincoln (1)	Lyon	Redwood	Renville	Swift	Yellow Medicine	Total
CER Range										
Known Acres										
under 10	4,090	19,120	28,389	*3,741*	4,880	9,340	19,623	20,890	4,000	114,073
10 - 20	3,750	6,555	0	*3,320*	4,330	1,650	0	13,840	5,910	39,355
20 - 30	10,985	42,280	16,074	*4,891*	6,380	19,760	3,697	14,410	6,780	125,257
30 - 40	4,500	19,000	21,680	*6,739*	8,790	23,145	10,422	37,700	10,620	142,596
40 - 50	48,875	40,585	87,984	*17,522*	22,855	4,275	54,277	37,040	14,650	328,063
50 - 60	54,510	29,050	207,983	*30,901*	40,305	35,630	96,022	126,470	26,670	647,541
60 - 70	186,795	103,190	126,349	*105,094*	137,079	258,125	186,371	162,975	296,740	1,562,718
70 - 80	54,055	183,395	0	*174,873*	228,095	111,850	127,428	56,635	116,150	1,052,481
80 - 90	0	48,970	0	-	0	90,435	129,575	0	0	268,980
90 - 100	0	0	0	-	0	0	0	0	0	0
No CER calculated	6,315	59,625	632	*4,209*	5,490	2,890	4,685	8,440	3,300	95,586
Total	373,875	551,770	489,091	351,290	458,204	557,100	632,100	478,400	484,820	4,376,650
Weighted Average CE	63.2	62	52.3		67.7	66.9	65.8	55.3	66.1	

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1. Estimated based on Lyon County ratios
2. Total over CER 50 3,531,719
3. Percent over 50 81%

Minnesota Land Economics, University of Min

CER: Crop Equivalency Rating

Slope

The slope of the land affects the potential for erosion and ease planting and harvesting SRWC. Slope over 12% is too difficult or too expensive to use for SRWC. Erosion on steep slopes could be a significant problem in the first two years of plantation development before the crown closes in. The cost of land prep and planting would likely be higher. The main consideration, though, is harvesting; slopes over 12% are difficult to harvest using rapid harvesting equipment and would require slower, more labor intensive techniques. Preference should be given to plots with slopes under 12%.

Figure 4.9 Acreage with Potential Slope Limitations

County	Slope 12%+
Chippewa	4,500
Kandiyohi	20,500
Laq Qui Parle	4,500
Lincoln	19,300
Lyon	15,700
Redwood	10,068
Renville	8,849
Swift	NA
Yellow Medicine	7,814
Total	**91,231**

NA: Data not available.

Except in areas near rivers and other waterways, most of the land in the procurement area is relatively flat. According to county soil surveys, only about 91,000 acres in the area have slopes over 12% (not including Swift County). A significant portion of these acres are not currently being farmed due to erosion problems or may already be part of the CRP set-aside program and therefore not included in the total cropland acreage statistics. For the purposes of this study, all the acres currently classified as cropland will be considered potential farmland for SRWC.

Availability

Most of the land expected to be offered for growing SRWC will be land that is being rented to grow crops. In Minnesota, approximately 55% of all acres farmed are rented (13 million acres of 26 million acres of cropland). This number is increasing each year as the average age of farmers continues to increase. (Over 54% of the nation's farmland landlords are over 65 years old.) Assuming this ratio holds true for the cropland in the 9 county procurement area, of the 3.4 million acres of existing cropland, about 1.87 million acres are rented each year. Additional acreage will also become available each year as current farm owners decide to retire from active farming and offer their land for rent. Some farmers may decide to rent a portion of their acreage for growing trees as a way to downsize their operations. Growing SRWC on the land may be an appealing way to rent the land long term without the work and risk of crop sharing arrangements and ongoing planting and harvesting activities. Renting 7,800 acres per year for 5 years during the farm development phase should not create a significant management challenge given the total number of acres currently in rent each year.

Cost

The most important factor in selecting land for growing SRWCs is the land rental cost compared to the land quality. In the analysis of fuel supply costs land rent of \$100-\$120 per acre is felt to be cost competitive (without additional support such as CRP payment or CO_2 rebates, etc). Rental prices depend on a number of factors including soil quality, moisture, location, historical productivity and crop prices. High quality soil with proven productivity is worth more than lower quality soils. Land closer to Granite Falls will be worth more to the project than land farther away because of the differential cost of transportation. The Soil Rental Rate (SRR) can be used as a reasonable measure of how much land might be available for a certain rental rate in the procurement area (Figure 4.10). Higher quality land will have a higher SRR. Using SRR as a guide, a vast majority of the acreage available in the procurement area has an SRR under $120. The average SRR for the 9 county region is $87. Land rents can vary from year to year depending on crop prices, demand for rental land and other factors. In the long run though, the land rental price needs to be low enough so a farmer renting the land has a reasonable chance to produce a profit growing the crop of choice. In recent years, in some areas, land rental prices have gotten too high to justify the risk and they have begun to stabilize and decline to more reasonable levels. With the number of acres of cropland available in the procurement area, it is a reasonable expectation to rent sufficient acres of good quality land within the cost limits above to be able to produce economically viable wood fuel.

Figure 4.10 Land Rental Rates, 2001

SRR Range Known Acres	Chippewa	Kandiyohi	Lac Qui Parle	Lincoln	Lyon	Redwood	Renville	Swift	Yellow Medicine	Total	Percent
under $10	0	0	0	0	0	0	0	0	0	0	0%
10 - 20	0	0	0	0	0	0	0	0	0	0	0%
20 - 30	0	0	0	0	0	0	0	0	0	0	0%
30 - 40	0	0	0	0	0	0	0	0	0	0	0%
40 - 50	0	0	0	7,513	0	0	0	0	0	7,513	0%
50 - 60	0	108,670	36,889	85,696	0	0	0	0	32,250	263,505	6%
60 - 70	8,990	15,245	23,288	139,002	62,700	27,410	0	14,360	30,680	321,675	8%
70 - 80	11,700	46,235	194,282	102,697	45,040	16,825	31,546	46,430	96,650	591,405	14%
80 - 90	15,530	211,455	60,598	0	201,265	53,220	14,957	204,230	235,030	996,285	24%
90 - 100	136,865	112,890	138,084	0	24,250	266,660	317,926	153,850	82,900	1,233,425	29%
100 - 110	198,490	0	0	0	102,899	189,670	151,331	51,090	0	693,480	16%
110 - 120	0	0	0	0	0	0	112,760	0	0	112,760	3%
120 - 130	0	0	0	0	0	0	0	0	0	0	0%
130 - 140	0	0	0	0	0	0	0	0	0	0	0%
Total	371,575	494,495	453,141	334,908	436,154	553,785	628,520	469,960	477,510	4,220,048	100%
	$ 99	$ 82	$ 82	$ 66	$ 87	$ 96	$ 102	$ 89	$ 83	$ 87	

The SRR is used by the USDA to determine payments for long-term Cons
Reserve Program entries. The soil rental rates weight the average cr
rate in each county by the relative productivity of each soil listed
deemed more productive (and hence more costly) are associated with h
The cropland rental rates themselves are re-determined periodically
USDA, based upon recommendations from county USDA offices.

Minnesota Land Economics, University of Minnesota

SSR: Soil Rental Rate.

Fuel Supply Development Plan

The retrofit power plant will require approximately 39,000 acres of tree crops to run at full capacity (Figure 4.11). This will require planting 7,800 acres per year for 5 years during the development stage. A representative SRWC farm development plan is laid out over a 20 year period in Appendix 5. The trees are harvested after 5 years growing seasons and grow back from the stumps for another harvest in five years.

The fuel development process starts with recruiting interested landowners willing to rent some or all of their land for a contract term of at least 10 years. EPS or an affiliate fuel supply management company will process applications, review soil reports, negotiate rates and contract for each plot. At an average of 80 acres per "tree farm", about 98 contracts will need to be signed annually during the first 5 years. The farm managers will be responsible for marketing the program, recruiting farmers, selecting the sites, negotiating the rental contracts, and growing the plantations.

Once the land is identified, preparations for planting can begin. Depending on the land, land prep activities will include application of herbicides, fertilization if necessary, and minimal tilling in some instances. Soil tests and site surveys will determine the requirements for each plot.

Tree planting is done within a 4-6 week period in late spring when the soil temperature reaches 50°F. Hybrid poplar is established by inserting a 10 inch long cutting - called a slip - into the ground leaving the top inch above ground. These slips are 0.375 in. to 1.25 in. diameter and are dormant sticks (no roots). Slips are commercially available from select nurseries in Minnesota and Wisconsin. The main variety will be hybrid poplar NM6 (Nigra x Maximawitzii 6). The quantity of slips needed to establish the fuel supply is contracted for in advance to ensure that adequate quantities are available. Slips are harvested from nursery stool beds (two year old trees) during the winter, and cut to length and stored frozen until shipment.

To maximize productivity slips are planted in a 5.3 ft by 5.3 ft spacing pattern at a density of 1,500 slips per acre. EPS has developed a high-speed 4-row slip planter that is pulled by a tractor. Four people sit on the planter and feed the slips into hoppers, and the slips are inserted into the soil by a mechanical ram as the tractor moves along at four miles per hour. Plans are to increase this to a six row planter to further reduce the slip planting cost and time required compared to the traditional hand planting method. Further details on the fuel development plan are given in Appendix 5.

Weed control is necessary until the shade created by canopy closure suppresses weed growth early in the third growing season. During the first couple of growing seasons, timely herbicide applications and shallow cultivation are required to control weeds.

After five growing seasons the trees are 6-8 in. diameter and 30-35 ft tall. At this size the growth slows given the tight spacing, and the trees yield an average of 25 dry tons per acre harvested. A special harvesting machine is being developed by EPS. It is mounted on four powered rubber tracks and moves forward continuously along a row cutting trees at the base and accumulating them towards the rear of the harvester. At the end of the row the whole trees are loaded onto a trailer. This machine will reduce SRWC harvesting costs compared to traditional forestry methods. Harvesting will continue throughout the year (Appendix 5).

After harvest the stumps re-grow (coppice) to produce new shoots of vigorous growth. Another option is to kill the stump and replant using a new, better hybrid. Promising new species are being tested each year and some will no doubt be superior to today's best clones.

Figure 4.11 SRWC Assumptions

Farm Fuel Assumptions	**Units**	**Values**	**Comments**
Typical Farm Acreage	acre	80	Estimated
Square Feet Per Acre	sq ft/acre	43560	Calculation
Total Square Feet Per Field	sq. ft./field	3,484,800	Calculation
Spacing (Row to Row)	ft	5.3	Average
Spacing (Plant to Plant)	ft	5.3	Average
Slip Density Per Acre	slips/acre	1,551	Calculation
Slip Density Per Field	slips/field	124,058	Calculation
Rotation Age	year	5	Design specification
Growth Per Year/Acre	dry ton/yr	4.9	Average expected growth rate for selected hybrids
Harvest Yield At Maturity	ton/acre	24.5	Calculation
80% Capacity Factor			
Annual Fuel Required (Dry)	ton/year	191,300	Calculation
Annual Development	acre/yr	7,800	Calculation
Total Dedicated Land	acre	39,040	Calculation r
Number of 80 acre Fields/yr	fields/yr	98	Calculation

CRP Potential for SRWC

Not included in the above analysis is land currently set-aside as CRP acreage. Until the mid-1990's, poplar was rated as an attractive cover crop for planting on CRP program acres. Since the late 1990's, a change in CRP cover crop rating criteria has made it much more difficult to utilize poplar as a cover crop on CRP land. Future revisions of CRP eligibility ratings, as sought by hybrid poplar proponents, could result in a more favorable outlook for planting of woody crops on CRP acres.

There are currently about 240,000 CRP acres in the procurement area. The fuel supply needs of the proposed plant could be met with just a fraction of existing CRP acres planted in SRWC. In this scenario, the landowner would receive payments from both the CRP program and rental payments for growing SRWC. Naturally, if a potential grower is eligible for cost-share payments from an outside source, the profitability of growing poplar increases dramatically. Many landowners that currently have plantations of poplar are involved in some sort of cost-share program. Currently, CRP guidelines, as interpreted in the state of Minnesota, do not allow this type of arrangement. However the USDA has shows a willingness, in principal, to test the planting and harvesting of energy crops (grasses and trees) on CRP land as evidenced by their selection in 2001 of six projects around the country where CRP land could be used. A proposed hybrid poplar site in Minnesota was among those selected, but some of the conditions imposed reflected a lack of understanding of practicalities associated with getting a bioenergy project started. However, given the increasing interest by USDA in bioenergy (e.g., the recent Farm Bill), and the fact that some of the 6 sites were able to negotiate variances in some of the conditions, it may be possible to negotiate terms more appropriate to establishing hybrid poplar or willows on CRP land in the future. For the purposes of this analysis, no CRP acres are included.

Existing Acreage of SRWC

Another potential source of wood biomass is existing SRWC plantations in the region surrounding Granite Falls. Within a 75 mile radius of the Granite Falls site (mainly Swift, Chippewa, Meeker, Kandiyohi, and Yellow Medicine counties, see Figure 4.3) there are 5,100 acres of hybrid trees of various types that have been planted and maintained over the past 10 years as part of various experimental programs to test the productivity of different hybrids. Most of these plantations have reached harvestable maturity and could be a potential source of biomass for a WTE plant. Harvesting these plots would allow testing of various harvesting techniques and equipment like EPS's Whole Tree Harvester. Wood from existing SRWC plantations is not included in this analysis; however, if available this wood could be used in the WTE plant.

Economic Impact of SRWCs

Rural communities throughout south central Minnesota that are heavily dependent on agriculture are experiencing serious challenges as a result of low commodity prices. These communities would benefit from having land leased at a steady rate with an alternate crop. The jobs and new business development linked to the conversion of the Minnesota Valley plant would bring welcome long term economic benefits to the area. In addition to the power plant itself, the establishment of many acres of SRWC would likely result in the creation of small businesses to manage and harvest the plantations, transport wood to the power plant and grow planting stock (Table 4.12).

Figure 4.12 SRWC Economic Impacts

Category	Economic Impact
Land use	● 2-4 fulltime jobs in plantation management ● Annual land rental payments to landowners ● Alternative to renting land for annual crops
Land prep and planting	● 10-20 seasonal jobs to prep land,, and operate planting machines
Annual maintenance	● 2-3 seasonal jobs to monitor plots and maintain as needed
Harvesting SRWC	● 4-6 fulltime jobs operating harvesting machinery year-round
Transporting SWRC	● 8-12 fulltime jobs operating tree hauling trucks year round
Power plant operations	● 10-15 fulltime jobs in plant operations and maintenance

Initial Wood Fuel Supply

During the first 2-3 years of operations, the WTE™ plant at Granite Falls will need to use various sources of wood while the SRWC fuel supply is being developed. Since wood resources within a 50 mile radius of Granite Falls are minimal (see Appendix 7), it is necessary to go up to 120 miles north to procure the wood fuel supply. In a 120 mile radius of Granite Falls there are 1.08 million acres of timberland in Minnesota (Figure 4.13). The total volume of *merchantable* growing stock is approximately 1088 million cu. ft. Adding in the estimated non-growing stock on these acres brings the total biomass available to 1600 million cu. ft. This results in an average of 1,460 cu. ft/acre or 23 dry tons/acre on timberland in the 120 mile radius. The average is 36 ton/acre on timberland in the 15 counties 50 to 120 miles north of Granite Falls.

Total annual wood removal in this procurement radius for year 2001 is estimated to be 14.5 million cu. ft (or about 14,400 acres). If non-growing stock is included, 21.1 million cu. ft or 328,000 dry tons of woody biomass are harvested each year. About 31% of this total is not used for commercial purposes resulting in a gross biomass residue available of 103,400 dry tons. Some of this material is too expensive or too difficult to collect. If only 50% is collectable, 51,700 dry tons of wood would be currently available to fuel the WTE plant in the interim period (and could be used as an auxiliary fuel during normal operations). Much of this material would be available at low or no cost for stumpage/harvesting. The primary cost would be transportation to the power plant.

During the interim period, the WTE plant will use wood available from multiple sources including wastewood, forest residue, existing SRWC plantations and harvests of existing standing biomass. The WTE plant will require about 191,300 dry tons of biomass fuel annually to operate at full load at an 80% capacity factor. One potential scenario for the interim fuel supply is summarized in Figure 4.14. Expanding the potential procurement area out to 120 miles opens up many more sources of wastewood including portions of the Twin Cities and suburbs, Rochester, St. Cloud etc. It is conservatively estimated that about 30,000 dry tons of fuel would be available from wastewood sources. Existing residue adds 51,700 dry tons (see calculations above). Small independent operators could add significant quantities of residue and wastewood. Some of the existing SRWC plantations in the 120 mile radius are 10+ years old and could be harvested to supply a portion of the fuel required for the retrofit plant. Conservatively, approximately 1000 acres/yr could be harvested for the interim fuel supply. This scenario results in a need to harvest about 75,000 dry tons from existing timberland acreage in the region. This represents only 0.3% of the total biomass resources available in the 120 mile procurement area. Assuming that the sawtimber quality wood is sold to local lumber mills, the number of acres harvested each year would be 3,900 or only 0.4% of timberland acres in the area (see Appendix 8). This wood supply plan for the first several years of operation before the tree farms are mature is summarized in Figure 4.14.

Figure 4.13 Potential Interim Fuel Supply Resources in 120 Miles Radius

Total Biomass	Units	Value	Notes
Total volume of merchantable growing stock	million cu ft	1,088	FIA website data search for 120 mile radius - MN
Ratio of non-growing stock to growing stock		0.45	See Ratios sheet - from 1992 MN harvest information
Additional non-growing stock biomass	million cu ft	492	Total growing stock times ratio of non-growing stock/growing stock
Total timberland biomass	million cu ft	1,579	Calculation
Acres of timberland in region	acres	1,082,000	FIA website data search for 15 county area - 1990 data updated 1996
Average merchantable growing stock	cu ft/acre	1,005	Calculation - total volume/total acres
Non-growing stock (limbwood, cull, saplings, dead and slash)	cu ft/acre	454	Calculation
Total biomass	cu ft/acre	1,460	Calculation
	dry ton/acre	23	Calculation - 36 ton/acre in 15 county area to north
Assumptions			
Conversion (cu. ft to dry lb)	lb/cu.ft.	31.2	Project Planning Handbook, www.nationalcarbonoffsetcoalition.org.
Total Existing Removals			
Existing annual growing stock removals	million cu ft	12.1	Source: North Central FIA web site query for 15 counties
Multiplier for estimated Year 2001 removals	Ratio	1.2	Represents increased harvest from 1990 to 2001 in Minnesota
Estimated growing stock removals 2001	million cu ft	14.52	Calculation
Additional non-growing stock biomass	million cu ft	6.6	Calculation
Total biomass removed (includes all residue)	million cu ft	21.1	Calculation
	dry ton	328,860	Calculation
Proportion of total biomass not used for products	%	31%	See Ratio sheet - assumes ratios from 1992 data apply to 2001 estimate
Biomass residue potentially available	million cu ft	6.6	Calculation
	dry ton	103,396	Includes logging residue and logging slash from growing and non-growing stock
Amount of residue collectible for WTE plant		50%	Estimate - some residue will be too difficult or expensive to collect
Net residue available for interim fuel supply	million cubic feet	3.3	Annual amount of residue from current harvests in area that could be used to fuel WTE plant during interim period
	dry ton	**51,698**	Note: Most of residue is in the 15 counties north of the 50 mile radius

Figure 4.14 Interim Fuel Supply Summary

Sources of Wood Fuel	Units	Value	Notes
Total annual interim fuel supply required	dry ton	191,294	Amount needed to fuel plant annually at 80% capacity factor
Sources of Interim Fuel			
Wastewood within 120 mile radius	dry ton	30,000	Includes storm damage, municipal trimmings, industrial wastewood etc.
Residue- existing harvests within 120 miles	dry ton	51,698	Estimate of amount of existing residue available in 120 mile radius
			(50% of total amount currently produced)
Small loads from independents	dry ton	10,000	Individuals and independents delivering wood from small plots, farms etc.
Harvest of existing SRWC plantations	dry ton	25,000	1000 acres/yr times average 25 dry tons per acre (Density may be higher on older, "overage" plantations)
Harvest of standing biomass	dry ton	74,596	Biomass needed from harvest of existing timberland biomass
Total biomass available in 120 mile radius	dry ton	24,637,354	Estimate of existing timberland biomass in 120 mile radius.
Percent of total biomass required for interim fuel		0.3%	Annual requirement for 2-3 years
Calculation of Annual Acreage Required			
Net amount of standing biomass needed	dry ton	74,596	See above calculation
Estimated total biomass per acre	dry ton/acre	36	Estimate for average on forestland in more productive acres in northern 15 counties
Percent of total biomass that is sawtimber quality		47%	Subtract sawtimber from total biomass
Net amount of useable biomass per acre	dry ton/acre	19	Net biomass available per acre assuming all sawtimber quality wood is sold
Number of acres to be harvested for WTE plant	acre	3,929	Assumes sawtimber quality wood is sold to lumber mills
Total timberland acres in 120 mile radius	acre	1,082,000	
Percent of timberland acres to be harvested	%	0.4%	

5. Air Emissions Control and Water Resources

Particulate Control
Particulates consists of bottom ash and flyash, both of which contain inorganic minerals and unburned carbon char. Because of the unique three-stage combustion system, and the use of dried wood with high temperature preheated air, the unburned carbon carryover is expected to be low. Since the dedicated wood crop has one-tenth the amount of ash as coal, the total ash collected and particulate emitted will be much less than when burning coal.

The WTE™ three-stage combustor (Figure 5.1) consists of a deep fixed bed of whole tree segments supported by a water cooled grate, an overfire section, and second char burnout grate under the main grate. Air preheated up to 720°F flows under the main grate and up through the fuel bed. Fuel is fed to the top of the bed. In general, drying of the fuel occurs in the top part of the bed, gasification in the middle part of the bed and char burn in the lower part of the bed. The oxygen is consumed in the lower part of the bed so that the upper part of the bed is a reducing zone. Some char may fall through the grate and is collected on the lower grate where it burns out with additional air. Air jets strategically located above the deep bed burn the gasified products to complete combustion as the heat is transferred to the water walls of the boiler.

Wood contains less than 1 % ash, whereas the ash content of coal can range from 4 %to 16 % by weight. With the inherent advantages of WTE and with the existing electrostatic precipitator, only about 5 tons of ash by-product will be generated daily from the baseload operation of the WTE™.

Flue gas flows from the steam generator through combustion air heater and to the drying air heat exchanger (Figure 5.2). The moisture in flue gas is condensed in the drying air heat exchanger where some particulate is removed with the condensate. The flue gas then flows to the electrostatic precipitator (ESP) where more of the particulate is removed. The Minnesota Valley ESP was installed in the 1978 and has a rated collection efficiency of 97% when using coal. It was last repaired in 1982. Fluegas from the ESP is discharged to the 350 ft tall stack, which is rolled steel plate lined with Gunnite sprayed over steel mesh.

Wood ash does not contain significant amounts of sodium, chlorine, or sulfur, but it does contain calcium, potassium and phosphorus so that the particle resistivity is not significantly different from coal. The char content of the ash is expected to be very low due to good combustion practice with dried fuel in the three-stage combustor. Thus the ESP efficiency should not be degraded by switching to wood. The US EPA AP-42 handbook (Table 1.6-1) indicates that ESPs operating with wood fuels have a collection efficiency of 90-99% with an average particulate emissions rate of 0.054 lb/million Btu and PM-10 emissions of 0.04 lb/million Btu. For the WTE retrofit less than 0.0282 lb/MBtu (or about 47 tons per year at design capacity) of particulates are expected to emitted with the flue gas (Figure 5.3) assuming no carbon carryover and with an ESP efficiency of 97%. An ESP collection efficiency of only 91% would still meet the new source particulate emission standard of 0.10 lb/MBtu. Thus although there may be a small amount of unburned carbon in the fly ash that might be collected less efficiently than the inorganic ash, the existing ESP should be adequate and replacement of the ESP with a fabric filter baghouse is not necessary. A final stage could be added to the precipitator if the collection efficiency were found to be less than expected.

Figure 5.1. Schematic of WTE™ Power Plant

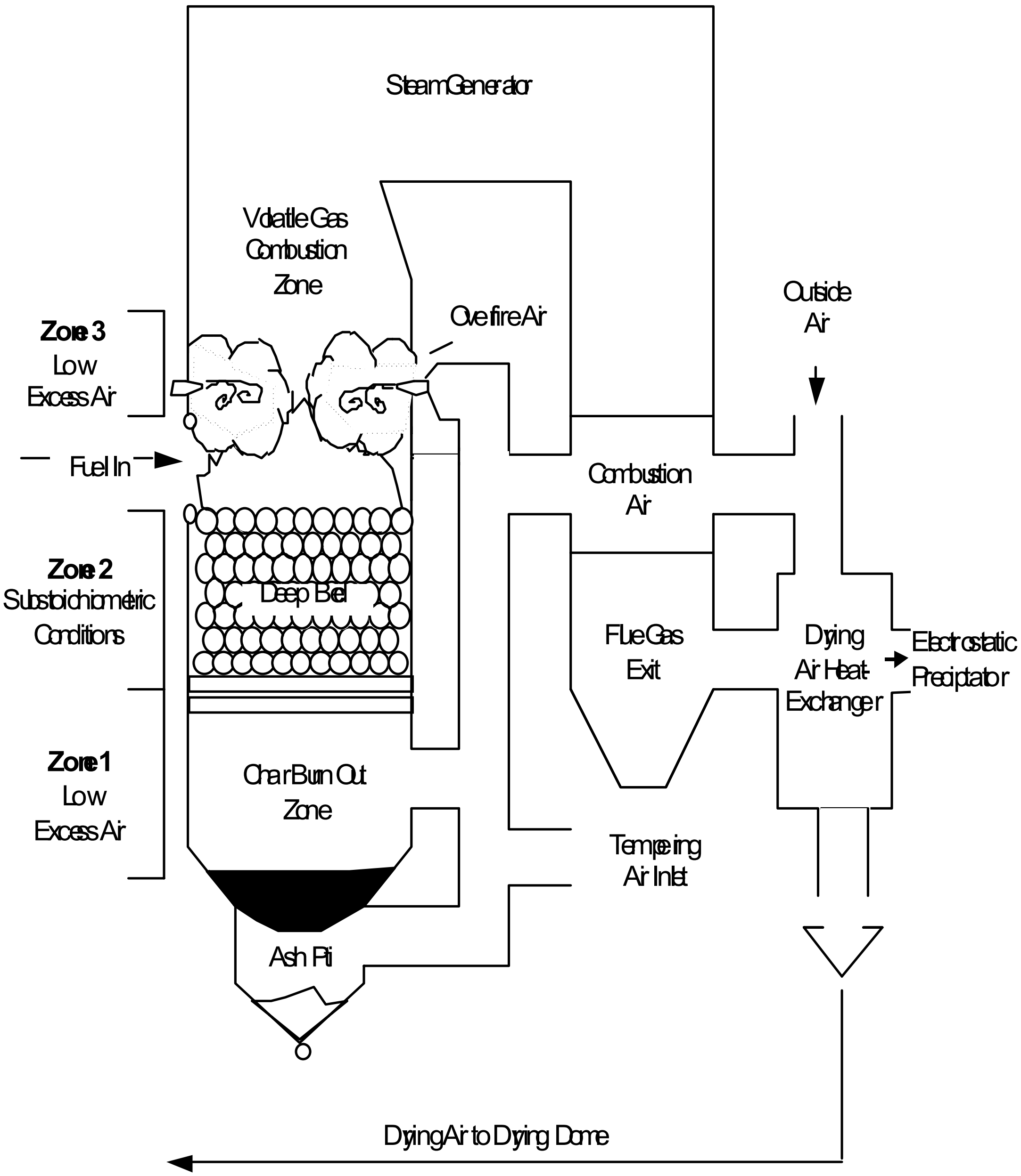
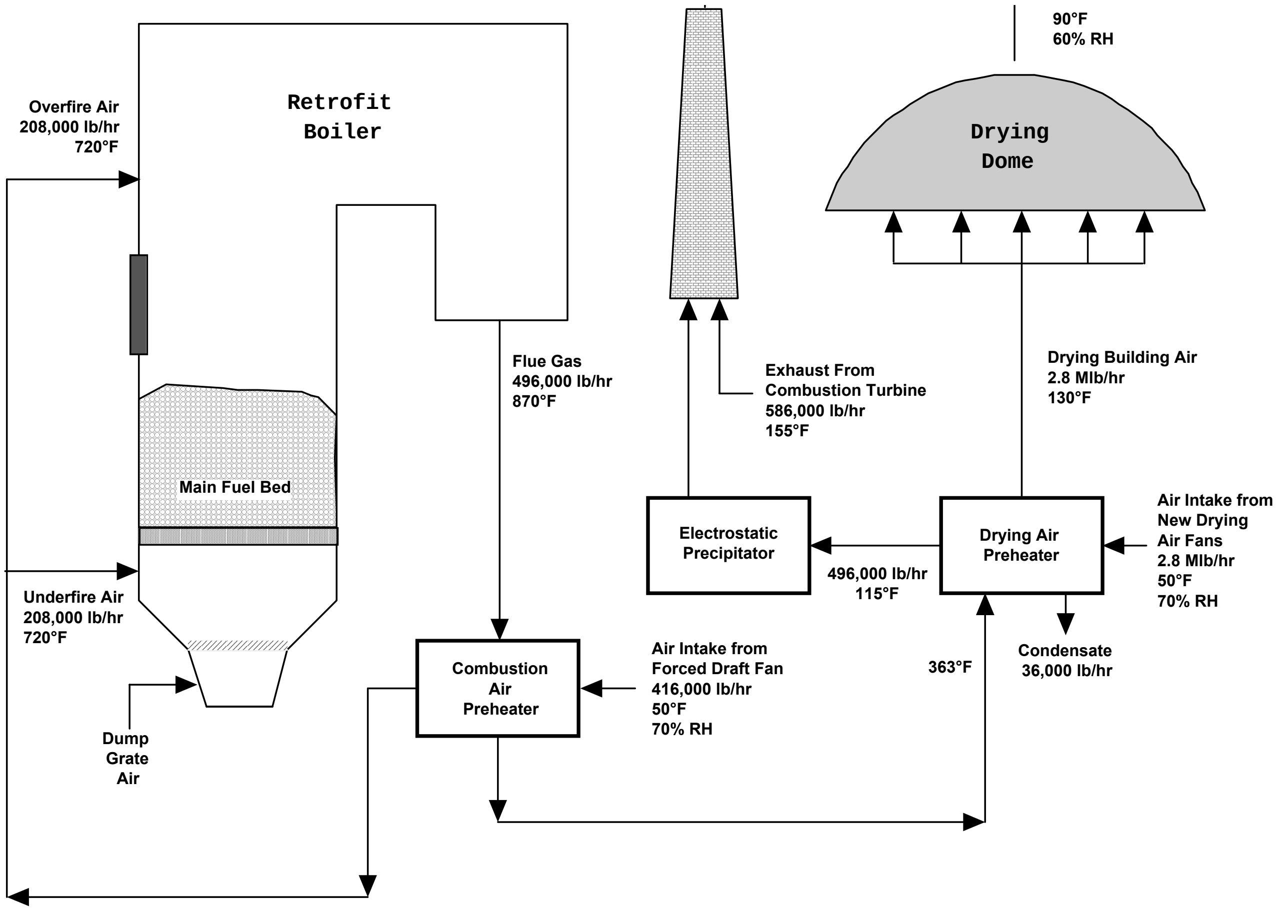


Figure 5.2 Air & Fluegas Flow Diagram



Ash Handling and Recycling

Bottom ash will be collected using the existing ash sluice system at the Minnesota Valley plant (the ash dump grate may need rework for use with wood fuel). An ash pelletizing system will be added to capture the ash from the precipitator and compress it into an easier to handle form for recycling as fertilizer or disposal.

The pelletized ash produced from the operation of the WTE™ plant may be used as a slow release fertilizer on the tree plantations. Unlike coal ash, ash produced by the direct combustion of wood is not acidic, contains only minute amounts of heavy metals, and is rich in calcium, potassium, phosphorous and magnesium. Land spreading of WTE™ ash likely not be regulated by the MPCA. If the ash cannot be used as a fertilizer, current permits would allow for disposal in existing ash ponds at the Sherco plant in Monticello.

Figure 5.3 Annual Ash Production

Parameter	Units	Value	Notes
Total ash content of wood, as received	%	0.7%	From various sources
Volume of wood required, as received	tons/year	248,400	From Gatecycle model
Total ash present in fuel	tons	1,739	Calculation
Portion of ash in flue gas at furnace exit	%	90%	Estimated from experience
Efficiency of collection	%	97.0%	Expected efficiency of electrostatic precipitator
Fly ash collected	tons/year	1,518	Calculation
Bottom ash collected	tons/year/	174	Calculation
Total ash collected	tons/year	1,692	Calculation
Ash in stack exhaust gas	tons/year	47	Calculation
	lbs/MBtu	0.0282	Calculation

Nitrogen Oxide Emissions
During the combustion of a fuel, oxides of nitrogen can be formed in two ways: thermal oxidation of nitrogen in air and oxidation of fuel-bound nitrogen. Wood typically contains little fuel-bound nitrogen (less than 0.1% vs. coal at 1-2%). Thermal NOx formed under high (>1,600 °F) combustion temperatures in boilers is controlled by staged combustion and controlled overfire air in the WTE™ system. The WTE technology employs deep fixed bed combustion under substoichiometric conditions to liberate volatiles contained within the wood fuel. NO that is formed in the oxidizing portion of the bed near the grate is reduced in the upper part of the fuel bed. Overfire air is added gradually to complete the burnout. In 1986 tests of the WTE technology by the Northern States Power Company in a converted 10 MW coal-fired unit demonstrated the ability of the WTE™ technology to achieve high temperatures, high efficiency and low NOx emissions. During the tests the NOx emission factor was found to be between 0.031 and 0.056 lb/MBtu with an average of 0.043 lb/MBtu. The actual NOx emissions for the retrofit plant will not be known until the plant is operating but it is expected to be acceptably low. The combustion turbine will have state of the art low NOx burners and emit about 9 lb/hr or 0.035 lb/MBtu based on similar units.

Carbon monoxide and VOC's
Carbon monoxide and volatile organic compounds (VOC's) that are formed in the gasification part of the deep fuel bed are oxidixed in the overfire air section of the boiler. Careful design of the overfire air section, the use of dried wood and a residence time of 2-3 s will consume the CO and VOC's that are formed in a manner similar to reburn technology. The combustion turbine is estimated to emit approximately 16 lb/hr of CO and 4 lb/hr of VOC's based on similar units.

River Water Authorization
Minnesota River water is used by power plant for condenser cooling, makeup water, ash sluicing, and potable water. Each of these uses is discussed below and the impact of converting to WTE is assessed.

The Minnesota Valley Plant is authorized by existing permits to annually use up to 13.7 billion gallons of water from the river. The plant has 9 pumps with a total pumping capacity of 53,000 gpm (this includes the large pumps that originally served the old steam generators that are not being used). During 1995 when the plant had 153 starts and ran up to 16 hours per day, the Annual Water Appropriation Report totaled 2.8 billion gallons. During 1994, the plant ran 210 days and reported using 3.8 billion gallons. Before that the plant typically ran 210 days per year for 16 hours per day. In recent years the plant has been run on an emergency use basis and to maintain the operating condition of the equipment.

Circulating Water
The primary use of river water at the Minnesota Valley Plant is for once-through cooling of the steam condenser. The two main circulating water pumps are rated at 26,000 gpm at full capacity. The trash screens (two Rex traveling water screens).were rebuilt in 1994. During the power plant tests last June the hotwell the temperature was 221°F and the pressure was 3.7 in. Hg, which is higher than the original design conditions. The circulating water temperature rose from 73°F to 93°F, a 20 degree rise which is consistent with past experience. During the retrofit process the circulating pumps should be inspected for wear. For the WTE retrofit case with the feedwater heaters bypassed the circulating water temperature rise would be about 25°F.

Changing the plant operation from limited use to operating 7,000 hours per year would use 10.9 billion gallons per year of river water, which is well within the permitted use of 13.7 billion gallons. However, the significant change in usage may require testing of the river water in the near downstream of the plant during different times of the year.

Boiler Makeup Water
The primary uses for makeup water are the hogger (condensor air evactor) and sootblowing. The need for sootblowing and hand lancing is expected to be reduced for wood burning based on previous testing and experience burning wood. Makeup water used for the hogger is expected to stay the same.

Historically, boiler makeup water was produced from Minnesota River water treated with hydrated lime and soda ash in a mixing vessel and pumped to a 1250 gal/hr Permutit hot lime soda water softner. When in use, the evaporator produced between 1,000 and 1,100 gpm for up to 6 hours per shift. Continuous blowdown to the evaporator was also a normal part of the operation (continuous blowdown will not be needed for WTE operations). This equipment was adequate in 1995. In recent years when operation was run strictly for emergency and for testing, water for makeup was trucked from the Angus Anson Plant. When the boiler is drained, the water is stored in surge tanks for reuse.

The existing equipment at the plant is expected to be adequate for providing boiler makeup water in the retrofitted plant. Compared to a coal plant operated at the same capacity factor, the WTE plant is expected to require less boiler makeup water primarily due to the lessened need for soot blowing and blowdown. New plants typically use well water and demineralizers to provide boiler makeup water. This is an option that could be considered for the retrofit plant.

Ash Sluicing
Fly ash is collected from economizer and electrostatic precipitator hoppers through a hydroveyor and sluiced to ash settling ponds east of the plant. Bottom ash is sluiced directly to ash pond. A separate pump that provides unfiltered river water to sluice the ash, and discharge from the ponds flows back to the river. Coal ash was periodically dredged out and trucked to the Sherco ash site. With wood ash less sluice water is needed because there is much less ash than with coal. Ash pelletizing equipment will be installed, and the ash pellets will be used on the tree farms.

Potable Water
There is currently no potable water in the plant. Water for showers, sinks and toilets comes from the river and is sand filtered, softened and passes thru an ultraviolet "cleaner". Bottled water is used for drinking. This approach is probably adequate for the retrofit WTE plant. The increased staffing level needed to operate the plant continuously would require additional bottled water.

Sewage System
A septic tank to capture sewage and other drainage from the plant is located east of the plant near the discharge channel. It is pumped as needed. There is a question of whether it may be leaking.
The septic tank may need to be tested and brought up to current standards. More frequent pumping would be required based on higher usage.

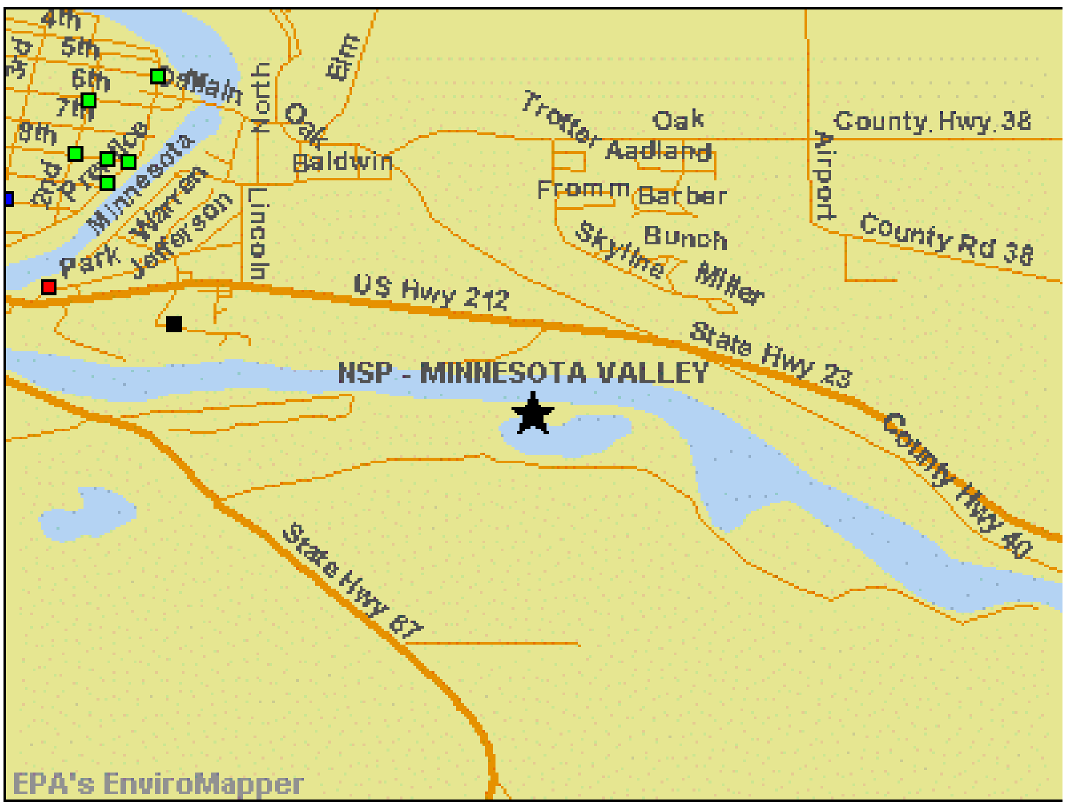
Other Water Uses
A small amount of water is used for cooling equipment such as motor and equipment bearings. Separate pumps draw this water from the river supply into the plant where it is filtered and used for cooling. The amount used is negligible but will increase with the WTE retrofit because the plant will likely be operated at a higher capacity than in recent years. For the combustion turbine no open cycle water will be consumed or discharged.

6. Permits

Background
This section summarizes the issues and permit requirements related to converting the existing coal-fired furnace at the Minnesota Valley plant to a WTE™ combined cycle unit. A WTE™ plant is subject to similar regulations and procedures as like-sized coal-fired facilities. As part of this activity, the requirements for site and facility permits including water usage, air emissions, ash handling, plant operations and plant expansion were reviewed.

The Minnesota Valley power plant is located outside of Granite Falls, MN between Hwy 212 and the Minnesota River (Figure 6.1). Since the plant is currently used infrequently as a coal-fired peaking plant and has been used in the past as a base-load plant, permits covering the existing plant are in force. The retrofit plant can be grandfathered-in on some on these permits and needs updated permits to operate as a combined-cycle WTE power plant.

Figure 6.1 Minnesota Valley Plant Location



The retrofit project consists of a) modification of the existing boiler to WTE configuration including removal of coal burners and pulverizers, addition of a wood feed system and conversion to a fixed bed; and b) addition of a 24 MW gas turbine. Heat from the turbine exhaust will be used to heat the boiler feedwater. The boiler will have a peak heat input of 540 million Btu/hr and a power output of 53 MW; and the 24 MW gas turbine will have a heat input of 254 million Btu.

The general permitting tasks needed prior to initiating WTE™ modifications at Minnesota Valley are:

1. *Meet with state regulators to review plans for facility restart. (Obtain Certificate of Need if required).*
2. *Conduct environmental walk downs to identify any problems with hazardous or toxic waste prior to conducting modifications.*
3. *Conduct environmental review (land, air, water, ash by-product) in support of potential Environmental Assessment Worksheet preparation.*
4. *Submit Power Plant Siting plan to Environmental Quality Board*
5. *Develop monitoring plan and install monitoring equipment.6. Prepare air quality permit (Prevention of Significant Deterioration - PSD, New Source Performance Standards - NSPS etc.)*
7. *State review, public comments, modify as needed and issue air permit.*
8. *Amend and submit National Pollutant Discharge Elimination System (NPDES) permit application.*
9. *State review application and issue NPDES permit, Water Appropriation etc.*
10. *Prepare and submit ash by-product recycling plan.*
11. *State review and approval of ash recycling plan.*
12. *Construction permits, local building permits, fuel supply permitting issues.*

The permitting process may take 12-24 months to complete before construction activities can start. We assume ambient air quality is not required. The retrofit plant will have to re-qualify for various site, air and water permits, as discussed below. Some permits are likely to be grandfathered in like the water usage permits while others will require new or updated permits. Most regulations in this area, whether state or federal, are administered by state agencies, particularly the Minnesota Pollution Control Agency. Local approval may also be required, in some circumstances.

Water Permits

Key permits related to water usage and disposal for the retrofit plant include:

- MN DNR: Water Appropriation Authorization
- NPDES: National Pollutant Discharge Elimination System
- SWCC : Stormwater runoff requirements and testing.
- SPCC: Spill Prevention Control & Countermeasure

<u>Water Appropriations Permit:</u>
A Water Appropriations Permit from the Minnesota Department of Natural Resources is required for all users withdrawing more than 10,000 gallons of water per day or 1 million gallons per year. All permitted water users are required to submit annual reports of water use.

The Minnesota Valley plant has an active and current Water Appropriations Permit (#764356). The permit authorizes the annual use of up to 13.7 billion gallons of water from the river. The permit covers 9 pumps/intake pipes with a total capacity of 53,000 gpm. Most of the volume of water is used for non-contact cooling water for the condenser and for cooling other plant equipment - most of which is returned to the river. Some of the water is used for sluicing ash (contacts ash) to the settling ponds. Boiler blowdown water and makeup water also use processed river water.

During 1995, when they ran 153 days in 1995 and ran up to 16 hours per day, the plants Annual Water Appropriation Report totaled 2.8 billion gallons. In the past 5 years the maximum usage has been only 363 million gallons per year in 1998. The retrofit WTE plant will use approximately 10.9 billion gallons per year at full load (and 80% capacity factor) - well within the permitted range for the plant today. Most of this water will be circulated through the condensers and returned to the river directly at about 26ºF warmer than the normal river water temperature. With the existing permit, the river temperature at the end of the mixing zone - 3600 feet down river is limited to a temperature rise of no more than 5ºF above the inlet temperature. (*Note:* In the summer months, with low river flow, the high river temperature may cause poor performance of the steam turbine and require load reductions to stay within the mixing zone limit.

The Water Appropriations Permit is expected to be extended for use by the new retrofit plant.

<u>NPDES Permit</u>
As authorized by the Clean Water Act, the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. In Minnesota, the NPDES permit program is administered by the Minnesota Pollution Control Agency (MPCA). Ongoing monitoring is required to characterize waste streams and receiving waters, evaluate wastewater treatment efficiency, and determine compliance with permit conditions.

The Minnesota Valley plant has an NPDES permit in force currently that will need to be updated to reflect the retrofit plant conditions and requirements. (Note: New NPDES standards are pending and may be in effect by May, 2003).The current permit has effluent limits for boron, selenium, and mercury. Converting the plant from coal to wood will reduce the potential for effluent discharges. The retrofit plant may need a well to provide potable water and a demineralizer for boiler makeup and NOx control. The existing permit should be easily modified to reflect the impact of the fuel changes and the addition of a well, if needed.

<u>Stormwater Discharges</u>
The conversion of the Minnesota Valley plant from coal to wood will significantly reduce the potential for runoff of harmful pollutants. The wood fuel will be stored under a large dome, and the runoff from the dome roof will be managed to avoid erosion. The retrofit plant will not be storing any toxic materials or chemicals that would have potential contact with stormwater.

Included in the NPDES permit process are regulations covering stormwater runoff during construction activities. Storm water runoff from construction activities can have a significant impact on water quality, contributing sediment and other pollutants exposed at construction sites. The NPDES permit application must be submitted at least 7 days before construction is to begin. The MPCA is authorized to implement the NPDES program for stormwater in Minnesota.

As of March 10, 2003, all small construction activities (disturbing one to five acres) must apply for permit coverage. The retrofit project at Minnesota Valley will likely be classified as a small project since all of the construction activity will take place on the existing plant site. The primary activities include demolition of existing coal handling facilities, road construction, excavation and construction of drying dome. Modifications to the existing water intake system may also be required (see below)., Development of a storm water pollution prevention plan and implementation of soil erosion and sedimentation practices (best management practices) are part of the permit application and site management process.

The NPDEC permit to cover construction activities is expected to be relatively straightforward. Information required for submission of the permit request will include preliminary construction plans, site surveys/maps, a storm water prevention plan and a project schedule.

Sewage Treatment

The Minnesota Valley Plant does not have a sewage treatment systems. A septic tank-subsurface disposal system serves the powerhouse, and is in service. The existing system should be carefully inspected and evaluated.

Cooling Water Intake Structures

The Minnesota Valley plant has an existing cooling water intake system. The proposed WTE™ plant would use the existing intake piping and filtering structures. While the existing cooling water intake meets existing EPA regulations, new rules have been proposed and are in the process of review that may effect the proposed project. The new rule will apply to certain existing power producing facilities that employ a cooling water intake structure and that withdraw 50 million gallons per day (MGD) or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the U.S. for cooling purposes. The proposed WTE™ plant will use 13 million gallons per hour at full capacity. Section 316(b) of the Clean Water Act requires EPA to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The proposed regulation is designed to protect fish, shellfish, and other aquatic life from being killed or injured by cooling water intake structures. The proposed national requirements would be implemented through National Pollutant Discharge Elimination System (NPDES) permits,

The proposed requirements will vary according to the environmental sensitivity of the water source, the percentage of the source waterbody withdrawn, and facility utilization rate. It expected that existing facilities like Minnesota Valley will have several ways to meet the requirements including retrofit, exemption (if cost is too high) and remediation.

Spill Prevention, Control and Countermeasure Requirements

An SPCC plan must be prepared by all facilities subject to regulation. This plan is to help prevent any discharge of oil into navigable waters or adjoining shorelines. Before a facility is subject to the SPCC rule, it must meet three criteria:

- it must be non-transportation-related;
- it must have an aggregate above-ground storage capacity greater than 1,320 gallons or a completely buried storage capacity greater than 42,000 gallons; and
- there must be a reasonable expectation of a discharge into or upon navigable waters of the United States or ad-joining shorelines.

In the past, oil has been used to ignite the furnace during startup. In the retrofit plant, natural gas will be used for igniting the main fuel pile during startup. On-site oil storage for the retrofit plant may not be necessary or may be limited to less than the 1,320 gallon threshold requiring an SPCC plan.

Air Emissions Permits

Background

The existing Minnesota Valley plant is currently operated infrequently for emergency and testing purposes only. In 2001, the plant was on-line only for URGE, Relative Assurance Test Audit and other testing requirements. The plant has not operated at significant load in the past 10+ years. Because of the existing plant's age, it is grandfathered in to most existing air quality rules and would not need to meet the air emissions requirements for new or modified rules if it were to continue operating as a coal plant (assuming significant modifications were not required to upgrade the plant for continuous operations). The new retrofit plant would be operated as a base load plant and will add additional capacity. Since major modifications will be required to retrofit the plant to burn wood and add the combustion turbine, air emissions requirements will need to be re-considered.

New Source Review & New Source Performance Standards

The EPA has developed New Source Performance Standards (NSPS) (contained in 40 CFR Part 60) that apply to specific categories of sources and emission units. The NSPS require a new or modified emission source to be less polluting than older sources. The NSPS standards apply to the six criteria pollutants (nitrogen oxides (NOx), sulfur dioxide (SO2), Ozone/Volatile Organic Compounds (VOCs), particulate matter (PM) and particulate matter less than 10 microns in size (PM10), carbon monoxide (CO), and lead (Pb)).

NSPS applies to specific units (i.e. not whole facilities). For a new boiler that burns wood the Federal NSPS 40 CFR Part 60, Subpart Db applies. That is, PM emissions shall not exceed 0.10 lb/million Btu and stack opacity shall not exceed 20 percent (6 minute average) except for one 6 minute period per hour of not more than 27 % opacity. There are no stricter standards in Minnesota state rules. Because of the inherently low inorganic matter in wood, it is anticipated that the retrofitted boiler with existing electrostatic precipitator will meet the new source particulate emission regulations. Note that the NOx requirement of subpart Db will be met by limiting natural gas combustion to below specified annual capacity levels. The applicability of Subpart Da, for utility steam generating units, will have to be assessed as well. If natural gas is used for startup, it is possible that Subpart Da may apply instead of Db.

For the combustion turbine, 40 CFR Part 60, Subparts GG apply. NO_X emissions in percent by volume (at 15% oxygen and on a dry basis) shall not exceed 0.0150*14.4/HR, where HR is the turbine heat rate in kJ/Wh and is based on the lower heating value. The expected turbine heat rate is 9215 Btu/kWh = 9.71 kJ/Wh (1 Btu = 1.054 kJ) so that the NO_X emission limit is 0.0022 % = 22 ppm. If the fuel-bound nitrogen is greater than 0.015% by weight an additional allowance is made according to section 60.332(a)(3). As needed, the combustion turbine emissions can be controlled for NOx using selective catalytic reduction (SCR) with ammonia injection, for CO with catalytic oxidation, and for PM-10 with good combustion practice.

New Source Review (NSR) - Prevention of Significant Deterioration

The Prevention of Significant Deterioration (PSD) program applies to construction of new major facilities and major modifications to existing major facilities located in attainment areas. The program considers the emissions of all units at the facility combined for determination of major sources and major modifications designations.

This project is a major modification of an existing major facility with a fossil-fuel fired capacity of greater than 250 million Btu/hour and potential emissions of greater than 250 tons per year of at least one criteria pollutant. The boiler is existing and will be modified as noted previously. Therefore the potential to emit of the stationary source (including the gas turbine) must be compared to the maximum past actual consecutive 2 years of emissions out of the last 10 years. This value, given that past actual emissions are low due to limited operations, is very low so that the threshold levels (significant' PSD levels) listed in Figure 6.2 are the criteria. Calculations indicate that the retrofitted power plant will exceed the threshold for NO_X, CO, PM and PM-10 unless controlled. Exceedance of the lead and sulfur dioxide thresholds is not expected because there is essentially no lead or sulfur in the biomass or natural gas.

Figure 6.2 Significant Net Emissions Increase Values for PSD

Pollutant	Threshold (ton/yr)
Nitrogen oxides, NO_X	40
Sulfur dioxide, SO_2	40
Volatile organic compounds, VOC	40
Total particulate, PM	25
Particulate less than 10 microns, PM-10	15
Carbon monoxide, CO	100
Lead, Pb	0.6

There are two applicable listings for this project. First - "fossil fuel-fired boilers (or combination thereof) totaling more than 250 million Btu/hour heat input". If natural gas, a fossil fuel, is used to startup the boiler, this may keep the facility applicability under this item. If however, natural gas is not used for startup, this category will not apply. The second possible listing, "fossil fuel-fired steam electric plants of more than 250 million Btu/hr" apparently does not apply because the 24 MW gas turbine input is less that 250 million Btu/hr. In any event PSD regulations are applicable.

The result of PSD applicability is the need to conduct a Best Available Control Technology (BACT) analysis and the need to conduct ambient air quality analyses. For the boiler, we expect that the existing electrostatic precipitator, and use of good combustion practices will meet BACT. For the turbine, we expect that the use of low NOx burner technology and good operating practices will meet BACT requirements.

<u>Other Issues</u>
The Minnesota Pollution Control Agency (MPCA) typically requires air toxics reviews as part of any environmental review process; for this retrofit project this is expected to be straightforward.

Control of fugitive particulates, visible air emissions, and odor control requirements should not change from current practice. A permit for the drying dome should not be required because the water vapor emissions will be insufficient to cause visible fog. Since low temperature drying is used (130°F or less) and because whole trees rather than chips are being dried, there is no self heating of the pile and no organic emissions from the drying dome are anticipated. Monitoring, testing and reporting requirements should be similar to current operations.

Air Permitting Process
In Minnesota, New Source Review requirements are managed by the Minnesota Pollution Control Agency. Air quality permits are required to operate existing air emission facilities and to begin construction on new or modified facilities. In Minnesota one permit is issued covering both construction and operation in cases where construction or modification occurs; no separate construction permit is issued in Minnesota. A permit will need to be obtained from the MPCA to address applicable NSPS and PSD requirements prior to beginning construction of the modifications. The air permit issued by the MPCA will establish limits on the amount of certain pollutants that can be emitted from the facility. The permit will contain conditions regarding monitoring of emissions and reporting.

Power Plant Siting
Depending primarily on the size of the facility, either an Environmental Assessment Worksheet (EAW) or an Environmental Impact Statement (EIS) would be prepared on a new facility. An EIS is required for a facility greater than 50 MW. For a facility between 25 MW and 50 MW, the Environmental Quality Board is required to prepare an EAW. For small facilities between 5 and 25 megawatts, the local unit of government where the facility is located has discretion on whether to prepare an EAW. For facilities that burn natural gas or are less than 80 MW, proposers may opt to pursue permitting with local officials. New power plants between 5 MW and 25 MW are subject to discretionary review.

The retrofit project at the Minnesota Valley plant should only need to work with local officials with respect to power plant siting issues. The conversion of the existing coal plant to burn wood would will not require a siting permit since this is an existing plant. The addition of a 24 MW of gas-fired combustion turbine may be considered a "new facility" but the small size allows the permitting process to be completed with local officials in Granite Falls. As part of this process, an environmental assessment worksheet may be required. (Although, given the small size of the combustion turbine, it is likely that an EIS will not be required).

Other Permits

Local Permits
General permits from Granite Falls covering normal construction project activities such as site plan review, zoning, electrical, and plumbing will also be required before construction can begin. Chippewa County may also become involved if any changes in county access roads are required as part of this project.

Certificate of Need
Prior to the issuance of a site permit, a certificate of need from the Minnesota Public Utilities Commission is normally required for a proposed large plant. (Minn. Stat. § 216B.243). Because the WTE portion of the plant is retrofitting an existing plant to use a renewable resource, no certificate of need should be required. The combustion turbine portion is not considered a large source so a certificate of need should not be required for this part either. In any case, if a certificate of need is required, there is sufficient data to support the need for additional electric generating capacity based on renewable energy sources.

Hazardous Waste
A walk-down of the existing plant and surrounding area should be conducted prior to construction activities to determine compliance with hazardous waste regulations.

Fuel Supply Permits
Although no permits are required to grow trees for fuel, several types of permits related to managing the fuel supply may need to be obtained including:

- Herbicide control permit may be necessary.
- Permit to use wood ash pellets for nutrient addition may be required (see below).
- Permit to haul wide/long loads of trees (in lieu of individual move permits)
- Permit to move harvester (in lieu of individual move permits)

Obtaining these permits is expected to be straightforward. The fuel supply development team and/or the project operator would manage this process as needed.

Ash Disposal on Tree Farm Fields
At full load the retrofit plant will produce about 1,500 tons per year of fly ash and 175 tons per year of bottom ash. The bottom ash will be ground and mixed with the fly ash in a pug mill and pelletized into 1 in. diameter by 2 in. long pellets. The pellets will be trucked to the tree farms and spread on the fields once during the five year growing period at the rate of roughly one pellet per 25 ft^2. This will require 67 truck hauls per year with a 25 ton load. The ash pellets will be stored on a short term basis in the drying dome for later delivery the fields.

Wood ash is a valuable soil amendment and replacement for commercial lime and fertilizer. Wood ash contains potash and phosphate essential for plant growth. Wood ash is very low in heavy metals. The ash is pelletized for slow release to the soil.

7. Environmental Impact

The first section reviews the differential impact of plant operations on the air, water and land resources surrounding the plant. The second section reviews the differential impact of using locally grown wood for fuel compared to coal shipped in from out-of-state mines.

Power Plant Operations

Operating a power plant has an environmental impact on the nearby air, water and land resources. Air impacts include emissions from the flue gas such as particulates, sulfur dioxide, nitrogen oxides and carbon dioxide. Water impacts include temperature rise, contamination, and construction and stormwater runoff. Land impacts from plant operations include construction effects, ash and waste disposal and increased truck traffic. Limits on these environmental effects are set by federal, state and local regulations.

The operating conditions of the WTE™ Combined Cycle power plant are compared to a plant operating on sub-bituminous coal in Figure 7.1. Wood and coal have very different characteristics as fuel sources (Figure 7.2). The constituent components of each fuel has a significant impact on the type and amount of each emission. The air emission profile of the WTE™ unit is expected to be quite different from that of a conventional pulverized-coal boiler not equipped with the latest environmental control devices. As an example, wood is naturally lower in ash and sulfur making it much easier and cheaper to meet current environmental regulations when burned in a modern, high- efficiency furnace. Operation of the WTE™ retrofit unit at Minnesota Valley would meet or exceed all applicable air emissions standards.

The expected levels of emissions from a WTE™ or coal plant at Minnesota Valley are summarized in the following section. The expected emissions levels for WTE were calculated using the estimated fuel requirements, output from the Gatecycle model and emissions data from large-scale testing of the WTE™ system completed by NSP in earlier testing. Coal emissions were estimated from output from the Gatecycle model and comparable coal plants operating today.

Figure 7.1 Plant Operating Conditions for WTE™ Combined Cycle Vs. Coal

Characteristic	Units	WTE CC	Coal
Net power output	MW	72.0	42.4
Auxiliary power requirements	MW	2.6	3.0
Net plant heat rate	Btu/kWh	10,130	11,366
Capacity factor	%	80%	80%
Net generation	MWh	504,580	297,140
Net plant efficiency	%	33.7	30.0
Steamflow into turbine	lb/hr	385,000	385,000
Boiler blowdown,	lb/hr	2,000	5,000
Soot blowing,	lb/hr	Not modeled	Not modeled
Makeup water	lb/hr	2,000	5,000
Net steam power output	MW	47.7	42.4
Boiler efficiency,	%	81.1	86.2
Higher heating value, dry	Btu/lb	8,700	12,450
Fuel feed rate, as fired Natural gas	lb/hr lb/hr	70,900 10,646	50,520
Fuel flow rate, dry Natural gas	lb/hr	54,590 10,646	38,698
Annual fuel, dry Annual natural gas	tons	191,300 37,300	135,600

Wood @ 23% moisture and sub-bituminous coal @ 23.4% moisture
Based on higher heating value of fuel

Figure 7.2 Fuel Properties of Wood, Natural Gas and Coal

Ultimate Analysis (dry)	Wood	Natural Gas	Coal**
Carbon	51.0	69.3	72.0
Hydrogen	6.5	22.7	5.0
Oxygen	41.8	0.0	16.4
Ash	0.7	0.0	5.2
Sulfur (expected)	<0.00035	0.0	0.44
Nitrogen (expected)	<0.1	8.0*	0.95
Total	100.0	100.0	100.00
Proximate Analysis (dry)			
Volatiles	80.0	100.0	40.8
Fixed carbon	19.3	0.0	54.0
Ash	0.7	0.0	5.2
Total	100.0	100.0	100.0
Fuel Higher Heating Value (dry), Btu/lb	8,700	23,800	12,450
Fuel Higher Heating Value (as-burned), Btu/lb	6,700	23,800	9,450

N_2 gas, not organic nitrogen
** Decker, MT sub-bituminous coal

Ash and Particulates
One advantage of wood is it's naturally low ash content. The ash content, especially in short rotation trees grown specifically for the WTE plant, should average less than 0.7% by weight. This compares to sub-bituminous coal at 4% or more. Lower ash results in significantly less ash and lower particulate emissions.

At design capacity, the total ash production for Minnesota Valley will be about 1,692 tons annually (Figure 7.3). This averages less than 5 tons per day or less than one truckload. Approximately 10% (174 tons/yr) of the ash collected will be bottom ash and the other 90% (1,518 tons/yr) will be removed by the existing electrostatic precipitator. Total particulate emissions from the stack are expected to be less than 47 tons per year. The combustion turbine will not add to the ash and particulate emissions for the retrofit plant. As modeled, a comparable coal plant at Minnesota Valley will produce 5,470 tons/year of ash and 167 tons/yr of particulate emissions without the addition of extra pollution control equipment (see Appendix 3 for detailed calculations).

A secondary advantage is that the wood ash has very low levels of heavy metals and other contaminants so is can generally be used as a fertilizer either on the fuel plantations or other farmland. Unlike coal ash, ash produced by the direct combustion of wood is not acidic, contains only minute amounts of heavy metals, and is rich in calcium, potassium, phosphorous and magnesium. Ash produced from the operation of the WTE™ at Minnesota Valley would either be given to local landowners to be used as a fertilizer or returned to the wood harvesting area to recycle its valuable nutrients back to the soil. An ash pelletizing system is included as part of the project budget. Coal ash must be stored indefinitely in specially designed settling ponds because of its high levels of contaminants.

Sulfur Dioxide Emissions

Emissions of SOx from the WTE™ plant will be extremely low because there is almost no sulfur in wood. The typical sulfur content is 0.01% or less while coal is 0.5% or more. At full capacity, the sulfur dioxide emissions are about 14.2 lb/hr or 49.6 ton/yr which is less than 0.030 lb/MBtu. The SOx emissions from a comparable coal plant will be 372 lb/hr (1302 ton/yr) or almost 1 lb/MBtu - about 26 times higher than WTE™. The current standard for SO_2 is 0.1 lb/MBtu. To meet current pollution control standards for SO_2, a coal plant will require the addition of expensive flue gas desulfurization equipment. Installation of SO_2 environmental control technologies would not be necessary with the WTE™ technology.

Nitrogen Oxide Emissions

During the combustion of a fuel, oxides of nitrogen can be formed in two ways: thermal oxidation of nitrogen in air and oxidation of fuel-bound nitrogen. Wood contains little fuel-bound nitrogen (less than 0.1% vs. coal at 1-2%). Thermal NOx formed under high (>1,600 °F) combustion temperatures typical in boilers is controlled by staged combustion and low excess air in the WTE™ system. The WTE technology employs deep fixed bed combustion under substoichiometric conditions to liberate volatiles contained within the wood fuel. NO that is formed in the oxidizing portion of the bed near the grate is reduced in the upper part of the fuel bed. Overfire air is added gradually to complete the burnout. In 1986 tests of the WTE technology by the Northern States Power Company in a converted 10 MW coal-fired unit demonstrated the ability of the WTE™ technology to achieve high temperatures, high efficiency and low NOx emissions (Figure 7.4). During the tests the NOx emission factor was found to be between 0.031 and 0.056 lb/MBtu with an average of 0.043 lb/MBtu. The actual NOx emissions for the retrofit plant will not be known until the plant is operating but they should be acceptably low. The combustion turbine will have state of the art low NOx burners and emit about 9 lb/hr based on similar units.

Carbon monoxide and VOC’s

Carbon monoxide and volatile organic compounds (VOC's) that are formed in the gasification part of the deep fuel bed are oxidixed in the overfire air section of the boiler. Careful design of the overfire air section, the use of dried wood and a residence time of 2-3 s will consume the CO and VOC’s that are formed. The combustion turbine is estimated to emit approximately 16 lb/hr of CO and 4 lb/hr of VOC's based on similar units.

Carbon Dioxide

The combustion of any material containing carbon (e.g., coal, wood, etc.) produces carbon dioxide, the most prevalent manmade greenhouse gas. Although wood combustion introduces similar amounts of CO_2 into the atmosphere compared to coal, wood is CO_2 neutral because the CO_2 released is reabsorbed by new biomass growth. Dedicated biomass crops are termed ‘closed loop biomass’ because new biomass growth starts right after harvest. The WTE retrofit will recycle 54,500 lb/hr of CO_2. The combustion turbine, which uses natural gas, will emit 16,000 lb/hr of CO_2.

Figure 7.3 Projected Air Emissions for Minnesota Valley WTE™ Combined Cycle

Parameter	Units	Combined Cycle WTE	Combined Cycle Nat. Gas	Sub-Bituminous Coal
Steam flow rate	lb/hr	385,000		385,000
Fuel feed rate, as received	lb/hr	70,900	10,646	50,520
Ash collected	lb/hr	483	0.0	1951
	ton/yr	1,692	0.0	6,836
	lb/MBtu	0.89	0.0	4.05
Particulate emissions,	lb/hr	13.4	0.0	59.7
	ton/yr	47	0.0	209 (2)
	lb/MBtu	0.028	0.0	0.125
Sulfur dioxide	lb/hr	14.2	0.0	464
	ton/yr	49.6	0.0	1,627 (3)
	lb/MBtu	0.030	0.0	1.0
Carbon dioxide, net	lb/hr	0 (1)	19,110	101,297
	ton/yr	0 (1)	66,500	354,945
	lb/MBtu	0 (1)		210
Nitrogen oxide	lb/MBtu	0.043 (4)		

(1) Emissions of CO_2 will be about 98,600 lb/hr, 345,000 tons/yr or 208 lb/MBtu but the tree plantations will be sequestering an equal amount for a net CO_2 contribution of approximately zero.
(2) Does not include bag house. A coal plant would require a bag house to minimize particulate emissions.
(3) Does not include desulfuring equipment that would be required for a coal plant.
(4) From test results of WTE technology in modified 10 MW boiler.
(5) The gas-fired combustion turbine will add primarily CO_2 and some NOx as part of the WTE™ combined cycle.
(6) ESP collection efficiency is 97%, no carbon in ash, and all ash is flyash.
(7) All sulfur in fuel goes to sulfur dioxide.

Figure 7.4 Results From a 72-Hour Test Run in a Modified 10 MW Coal-Fired Boiler

Regulated Emission	Test Measurement (lb/MBtu)
Sulfur Dioxide	0.0004
Nitrogen Oxide	0.043
Particulates	0.87[b]

a. Old standards. New standards for SOx and NOx are 0.8 lb/MBtu and 0.4 lb/MBtu respectively.
b. Boiler was not equipped with a particulate collection system during test.
Source: PACE Laboratories, "Results of the Particulates and Oxides of Sulfur and Nitrogen Emissions Engineering Tests on the Number 3 Boiler at the NSP Facility Located in Ashland, Wisconsin.", August and October, 1986

Construction Impacts
Most of the physical modifications to the existing site would be within the confines of the powerhouse. However, some structures outside the powerhouse would need to be moved, upgraded, or dismantled. New structures (such as the combined wood storage/drying dome and the rerouting of a service road) would require construction in previously undisturbed areas at the site. For a coal plant, upgrades to the existing coal unloading/crushing and storage facilities would be needed in addition to new construction such as a bag house and flue gas desulfuring facilities. In either case, these construction-related impacts will be temporary and can be effectively managed using normal site management techniques.

Other Impacts
On site noise from both construction and operation of the WTE™ unit would increase from present levels since the plant is currently inactive. Operation of heavy equipment during construction, and fuel delivery trucks and unloading equipment during operation would be responsible for the majority of the increase. During normal operation, the noise level generated by a retrofit WTE would be comparable to a similar coal plant. Noise from operating the crane and other fuel handling equipment will be no more than noise from the outdoor coal handling equipment. There may be an increase in the frequency of noise in the local area from the truck traffic delivering wood fuel to the plant but this is expected to be within acceptable levels for the area surrounding the plant site. Noise from operation of the gas turbine may be an issue that needs to be addressed during the detailed design stage. Otherwise, noise from power plant operations will be comparable. Noise is not expected to be a significant environmental issue.

Impact on Water Resources
Water required for cooling and circulating water, which makes up the bulk of a plant's water requirement, for the WTE™ retrofit unit is expected similar to the coal-fired operations. The WTE™ retrofit uses less boiler make up water, due to a decreased need for soot blowing operations. No differences between WTE and coal are expected in potable water usage. The operation of power generating options at the Minnesota Valley site may be subject to unit deaerating or temporary suspension of plant operations during the hottest portions of the summer or periods where river flow

rates are low in order to avoid exceeding thermal discharge limits to the Minnesota River. Otherwise, no significant difference in environmental impacts to the local water resource are expected from the operation of the WTE™ compared to coal at Minnesota Valley.

Environmental Impact of Growing the Fuel Supply

The procurement area includes all suitable and available land within a 9 county area around Granite Falls. The entire project area is within the Minnesota River Watershed, which is primarily an agricultural area. Figure 7.5 presents a map of current land use in the region around the Minnesota Valley plant location. As noted, most of the vegetation in the procurement area for the Minnesota Valley project consists of row crops such as corn, soybeans, oats and other small grains. Native/natural vegetation is limited to steep slopes, riparian areas and flood plains that flood so often that row crops production is not economically viable. Forested areas are focused around streams, wetlands and floodplains and consist of deciduous softwood species such as cottonwood, box elder, American elm and silver maple. The drier sites support hardwood species such as red oak, white oak, and red and sugar maple. Wetlands areas are dominated a variety of grasses, thistle, rushes and sedges.

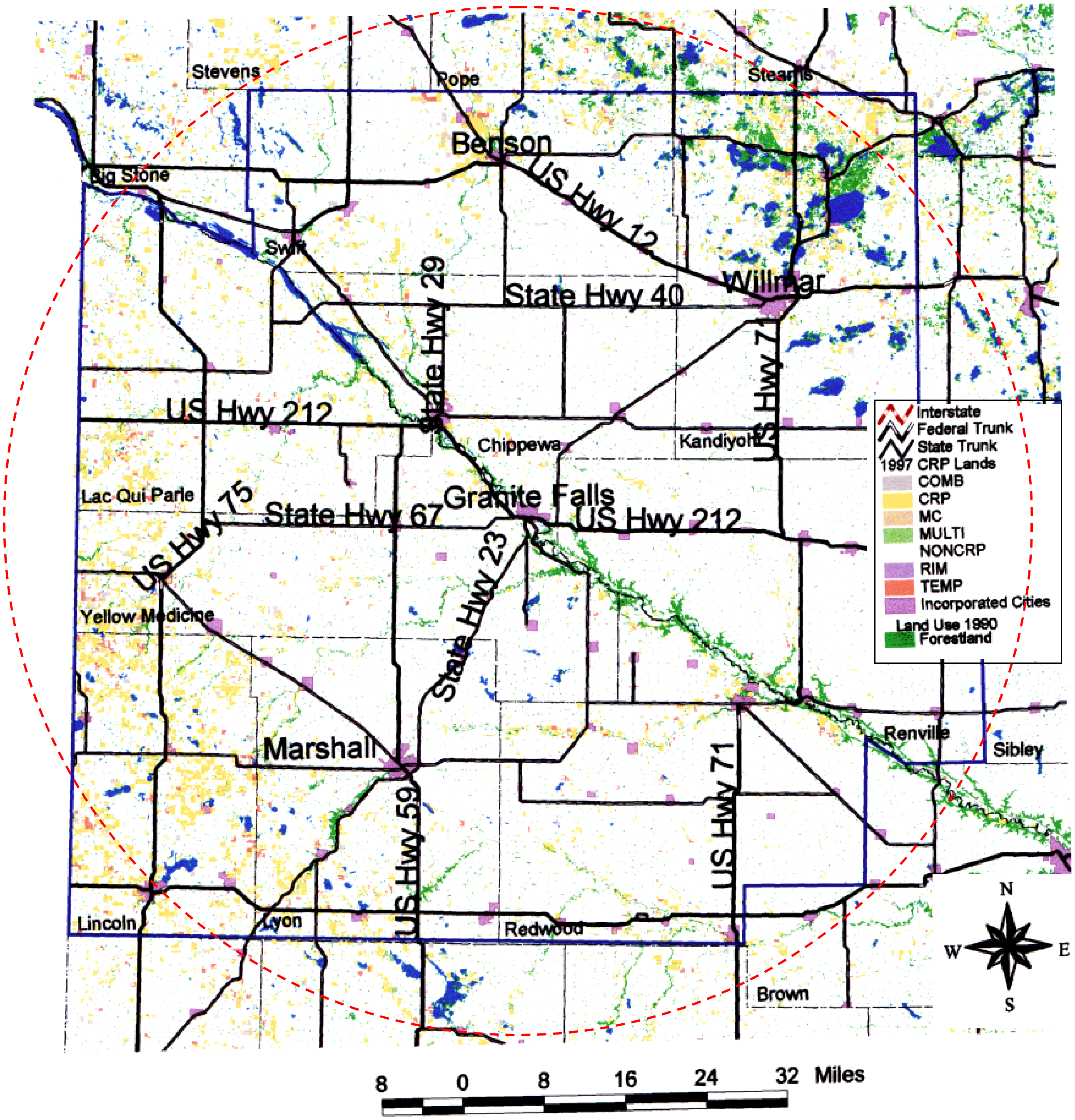
Many factors interact to determine the environmental impact of SRWC’s, including crop species and management; site characteristics (soils, climate, previous land use), and amount of land in production. Some of the typical environmental effects of growing SRWC's on agricultural land are discussed in the following paragraphs and summarized in Figure 7.6.

Wildlife

Because the vast majority of the acres converted to SRWC for this project will be replacing existing cropland, the project will not decrease species diversity on the field level, and will actually increase diversity in and around each farm location. Numerous studies have shown an increase in mammalian and avian abundance in poplar plantations. Therefore, when hybrid poplar is planted in the place of another agricultural crop, very little adverse environmental impact is expected.

Because of the rural nature of the procurement area, wildlife is common where suitable habitat is present. However, because of the intensive annual cultivation of most of the land, wildlife is limited to species that thrive in this habitat. Examples include upland grass songbirds, pheasant and deer in the upland fields, and river bottom areas support turkey, mink, beaver, muskrat, fox, songbirds and waterfowl.

Figure 7.5 Land Use Map - 50-Mile Radius of Granite Falls



Source: MN DNR Database

Endangered or threatened species that are known to be present within the Minnesota River Basin include the burrowing owl; the chestnut collared longspur, the king rail, the Blandings turtle, the five-lined skink and the western hog-nosed snake. No net impact of planting SRWC's is expected on these species compared to annual planting of existing row crops.

SRWC plantings represent an improvement over traditional agriculture as habitat for some types of forest birds and small mammals. In Minnesota clonal trials, diversity of birds and small mammals was greater (in hybrid poplar stands) than that found in fields of row crops. Poplar plantations can potentially provide habitat for songbirds, game birds, raptors, deer and rodents. However, research on wildlife abundance and diversity has shown that the ecological value of SRWC plantings is very sensitive to its landscape context, as well as its age and management activities. Habitat diversity must be explicitly designed into the plantation, for example, by mixing clones, if maximizing its value to wildlife is an objective.

Since hybrid poplar provides permanent cover, rather than annual cover that is plowed down in the fall and spring to plant crops, it provides a source of winter cover during harsh Minnesota winters for deer, pheasants, game birds, and other wintering wildlife. Winter cover is very important in this area because without protection, many game birds, such as pheasants, wild game animals such as deer, will not survive.

Figure 7.6 SRWC Environmental Impacts

SRWC	Environmental Impact
Wildlife Impact	● Increased diversity in species with the conversion of cropland to woodland. ● Increase winter cover.
Air Impact	● Use of SRWC is a true closed carbon cycle system reducing net CO_2 emissions to zero. ● Significantly lower emissions of SO_2, NOx and particulates compared to coal. ● 1/10 of the ash production of a comparable coal plant.
Soil Impact	● Significantly less herbicide, pesticide and fertilizer usage with little to none used during years 3-5 of each rotation after initial 2 year plantation establishment period compared to corn and soybeans. ● Improved long term erosion resistance from runoff and wind. ● Improved water-holding capability.
Water Quality	● Reduced erosion in years after establishment. ● Lower levels of pesticide and herbicide contaminated runoff. ● Less nitrate and phosphate runoff

Air Quality Impact

Short term, SRWC reduces wind blown dust and wind erosion by acting as a windbreak. Long term, the key benefit of SRWC to air quality is a net reduction in atmospheric CO_2. When burning a dedicated biomass crop, the CO_2 that is added to the atmosphere is offset by uptake of CO_2 as the new biomass grows. On the other hand when fossil fuels are burned, CO_2 from millions of years ago is added to the atmosphere. Since wood is approximately 50% carbon on a dry basis, SRWC crops sequester about 2.5 tons/acre/yr of carbon in above ground biomass. In addition, 40% of hardwood biomass is below ground in the roots so that 1 ton/acre/yr of carbon is sequestered in the roots. Thus there is a net reduction in atmospheric CO_2.

The amount of carbon sequestered does not give the whole story in terms of climate impact. A long-term study in Michigan that compared the Global Warming Potentials (GWPs) of several different annual crop tillage systems, perennial alfalfa, a poplar plantation, and unmanaged successional woodlands of varying ages, found that the poplar plantation had by far the lowest GWP (105 g/m2/year CO2 equivalents) of all the managed systems. This stemmed in large part from the relatively low soil N availability in the plantation that resulted in lower N_2O emissions. Because N_2O has much higher atmospheric warming potential than CO_2, small differences in N_2O emissions make large differences in GWP. Lower rates of N fertilization and tighter N cycling, compared to annual crops, ensure that N releases to the atmosphere, as well as the groundwater, will be lower in SRWC systems.

Switching from coal to dedicated biomass eliminates CO_2 input to the atmosphere. In addition the extensive root system creates long-term accumulation of carbon in the soil even as the aboveground portion is periodically harvested. SRWC hardwoods are acknowledged to be among the best feasible carbon sinks. Furthermore the soil chemistry of SRWC is such that emissions from the soil of another global warming gas, N_2O, is reduced compared to annual crops.

Water Quality Impact

Water quality and evenness of flow improves with establishment of tree crops on agricultural land. The largest impacts of tree plantations on water quality may be when they are located in or near riparian zones. There is an extensive literature documenting the nutrient and sediment filtering functions of forested riparian zones. Vegetated riparian zones trap sediment and slow down water flow both aboveground and in the soils. The plants may then take up nutrients from the groundwater and immobilize them either in wood (long-term) or leaves (short-term). In addition, the slower movement of water and the often-saturated condition of the soils in the riparian zones allow anoxic conditions to develop, which favors denitrifying bacteria. These convert nitrate and nitrite to nitric or nitrous oxide (NO, N_2O), which escapes into the atmosphere.

Non-point source pollution by agricultural runoff is the major source of contamination for the Minnesota River. The main causes of excessive plant growth and its negative effects in lakes and streams are excessively high levels of nutrients, particularly nitrogen (N) as nitrate (NO_3) and phosphorous (P) as phosphate (PO_4). NO_3-N is highly soluble and typically moves through the soil with groundwater, eventually reaching the water table. On the other hand, PO_4,-P binds readily to clay or organic soil particles and moves only when the soil particles move, i.e. when erosion is occurring. SRWC can help remove NO_3-N from the groundwater (and reduce the amount added to the soil in the first place), and helps keep PO_4-P from reaching streams by prevent or slowing erosion.

Numerous studies have established the effectiveness of hybrid poplars for the remediation of surface-applied municipal wastewater, including the immobilization of heavy metals and pesticides. Hybrid poplar plantations are also being used as secondary recipients of treated municipal wastewater in several towns in Oregon and Washington.

An advantage of trees over grasses for nutrient uptake is that tree roots can exploit deeper layers of soil. Year-round reduction from 20-150 to 2-3 mg NO_3-N/L in near-surface ground water under deep-planted hybrid poplars has been demonstrated. This nutrient removal function can be beneficial not only in riparian zones but anywhere in proximity to more heavily fertilized conventional crops.

Soil Quality Impact

As described earlier, the soils within the procurement area are primarily loams, silt loams and clay loams. The soils in the Minnesota River basin and floodplains of its tributaries are deep alluvial soils deposited when much of the area was covered by water while the glaciers were melting. Most of the upland soils are mollisols formed under prairie grasses, and are very fertile.

Of greatest concern is the impact of planting energy crops on erodible soil during the period the crops are first being established. Initial erosion levels, depending on soils and slope, may be quite high, but may be expected to decline significantly following establishment. Erosion rates might be reduced as much as 90 percent under established biomass crops in comparison to conventionally cultivated row crops. After establishment, limited or no further cultivation of the soil is usually required which significantly decreases the risk of erosion. Most row crops are cultivated multiple times annually leading to increased potential for erosion.

In addition to less cultivation, rates of fertilizer and herbicide application are lower than those typically used for row crops. For example, annualized rates of herbicide applications were 11% of those applied to corn and 20% of those applied to soybeans (Figure 7.7). The Minnesota Valley project will result in poplar replacing traditional row crops. Although poplar is a crop, and will require some level of chemical uses and soil cultivation, the overall environmental impacts are expected to be much less than were associated with the crop it replaced. Figure 7.7 compares fertilizer and chemical use and estimated erosion rates for different crops. The overall affect SRWCs have on soils is very positive because the roots build organic matter and here is less soil disturbance over the life of the crop which results in less soil erosion and runoff.

Figure 7.7 Comparison of SRWC and Row Crops

		Fertilizers			
Crop	Erosion (ton/acre/yr)	Nitrogen (lb/acre/yr)	Phosphorus (lb/acre/yr)	Potassium (lb/acre/yr)	Herbicide (lb/acre/yr)
Corn	10	120	24	71	2.7
Soybeans	18	9	31	62	1.6
HECs*	0.1	27	45	80	0.22
SRWCs	0.9	11	5	14	0.35

Source: Wright, L.L., and W.G. Hohenstein (eds.). 1992. Biomass energy production in the United States: Opportunities and constraints. U.S. Department of Energy and U.S. Environmental Protection Agency. Draft, August 1992. Adapted from Office of Technology Assessment, U.S. Congress. 1993. Potential environmental impacts of bioenergy crop production: Background paper. Washington, D.C.: U.S. Government Printing Office.
*HEC: Herbaceous Energy Crop (e.g., Switchgrass).

Startup

During the first 2-3 years of plant operations, the WTE™ retrofit plant will be fueled using a combination of wastewood, wood residue and wood harvested from forest stands. The number of acres harvested will depend on the productivity of the available plots, the proportion of the harvest suitable for WTE™ and the availability of wastewood and wood residue. Harvested plots will range in size from 10 acres to 100 acres primarily in forested lands to the north of the Minnesota Valley plant. Much of the forested land in the region is privately owned. The current harvest in this region for sawtimber, pulpwood and fuel wood. Harvesting stands for WTE™ will likely use the same feller/buncher/skidder techniques used currently in typical logging operations. The main difference will be that the whole tree will be used versus just the main sawlog or pulpwood bole. Depending on the type of land being harvested, the forest may be allowed to regenerate naturally, be converted to another use (i.e. farmland or housing) or be replanted (state forestland).

8. Project Costs

The operating and maintenance costs, fuel supply costs, and capital costs for the repowered plant are summarized in this section. Operating costs are based on typical costs for a similar size and age coal plant adjusted for a WTE™ plant. The fuel costs were developed from data specific to the area around the Minnesota Valley plant and were compiled on a mills/kWh basis. The wood fuel needed was based on 47.7 MW for the steam cycle operating 7008 hours per year (80 percent capacity factor) for a total of 334,280 MWh/ year. The combustion turbine adds 24.3 MW of capacity for a annual power output of 170,290 MWh/yr. Total plant output is 504, 600 MWh per year based on a power output of 72 MW. Inputs for fuel usage were calculated based on the heat content of each fuel, the net steam cycle efficiency of the plant of 43.3 % and the net combustion turbine efficiency of 31.8%. Fuel costs were estimated using EPS's fuel supply development model using trees planted on farmland within a 50 mile radius of the Minnesota Valley plant. Capital costs were estimated by Utility Engineering and EPS based on preliminary layout drawings for the WTE™ retrofit. Basic design specifications for the combined cycle and the Whole Tree Energy retrofit without the combustion turbine are summarized in Figure 8.1.

Figure 8.1 Operating Conditions for Retrofit Power Plant

Factor	Units	WTE-CC Peak Output	WTE-CC Base Load	WTE Base Load
Total net power	MW	77.6	72.0	43.1
Net steam turbine power	MW	53.3	47.7	43.1
Capacity factor	%	-	80	80
Net annual output	MWh	-	504,576	302,045
Net power plant efficiency	%	33.3	33.7	29.2
Net power plant heat rate	Btu/kWh	10,239	10,130	11,701
Wood feed rate, as-received	lb/hr	80,600	70,900	75,370
Natural gas flow rate	lb/hr	10,646	10,646	-------

Note: Values from Figure 2.3

Plant Operating and Maintenance Costs

The operation and maintenance costs include all non-fuel activities such as operating labor, materials and tools for plant maintenance on both routine and emergency basis. Estimated annual O&M costs for the WTE™ plant are $2.0 million plus an additional $200,000 for the combustion turbine portion for a total of $2.2 million or 4.41 mills/kWh (Figure 8.2). The largest portion of O&M costs is $1.45 million for labor costs. Given the simplicity of the WTE™ technology, the average annual operating costs are expected to be comparable to or less than a similar sized coal plant - primarily because a WTE plant does not require complex pollution control equipment and because wood produces less ash. A WTE plant also does not require as many consumables like lime and limestone as a coal plant. EPS expects total employment will be about 28 full time equivalent positions with 6 persons per shift times 4 shifts (including weekend shifts) plus an additional 4 people on day shift for general maintenance.

Labor costs were estimated using census data for utility operations, internal data and past experience. Maintenance costs were estimated from experience and adjusted for the age and general condition of the plant. These costs do not include labor cost associated with developing and harvesting the fuel supply - those costs are included in the overall fuel cost estimate (see Fuel Cost section below).

Figure 8.2 Estimated Operating Costs ($2003)

Fixed Costs	Units	WTE™ Plant	Combustion Turbine	Total
O&M Labor jobs	Number	25	3	28
Labor hours/yr (2080 hr/yr/person)	hr/yr	52,000	6,240	58,240
Average labor cost (including benefits)	$/hr	$25	$25	$25
Operating labor cost	$/yr	$1,300,000	$156,000	$1,456,000
Total Fixed Costs	$/yr	$1,300,000	$156,000	$1,456,000
Variable Costs				
Overtime, contract labor, supplies	$/yr	$700,000	$50,000	$750,000
Bottom and fly ash disposal	$/yr	$17,000	$0	$17,000
Total Variable Costs	$/yr	$717,000	$50,000	$767,000
Total Non-Fuel O&M Cost	$/yr	$2,017,000	$206,000	$2,223,000
	mills/kWh			4.41

Farm-Grown Trees
The primary long-term fuel supply for the retrofit WTE plant is assumed to be farm-grown trees. The fuel cost estimate is based on 39,000 acres of short rotation woody crops (SRWC) planted on farmland within a 50 mile radius of the Minnesota Valley plant (see Fuel Supply for more information). The net fuel cost for farm-grown trees includes the cost of land rent, land prep, planting, yearly maintenance, harvesting and transportation to the plant. Although the actual plant will likely use a proportion of wastewood and forest residue, these alternative fuel sources were not included in this cost analysis. Assumptions used to estimate the cost of farm-grown fuel supply are summarized in Figure 8.3. For detailed calculations, see Appendices 6 and 7.

Land Rent: In order to produce sufficient fuel to feed the retrofit WTE plant, the fuel supply development team must obtain long term rental agreements for about 7,800 acres of existing farmland per year for five years within a 50 mile radius. A total of 39,000 acres are needed to provide a continuous supply of farm-grown trees to the plant. There are millions of acres of suitable land in the procurement area. The average rent is assumed to be $104 per acre.

Prep and Planting Cost: Prep and planting costs including tilling, planting and the application of herbicides, pesticides and fertilizer as needed. These cost are assumed to occur in the first two years of each farms development cycle. Normally, first year prep and planting costs are estimated to be $227 per acre. This is based on detailed modeling by EPS and experience with SRWC plantation development. Second year costs average $66 per acre. These costs are typical for farms started in Year 2 through Year 5. In modeling the Minnesota Valley project, a planting and prep cost of $536 per acre for Year 1 farms - $309 more per acre than normal is used. The increased cost is due to an estimated cost of $0.30 per slip for hothouse produced slips compared to a normal cost of $0.10 per slip for nursery-grown stock. The farm development process would be delayed a year if the project were to wait for sufficient nursery grown stock to be produced for Year 1 planting. Construction of the retrofit plant could still start on time - another year of fuel from existing forestland would need to be added to the fuel supply plan. Lower cost nursery stock will be available for planting all farms started in Year 2.

Since the initial planting and prep costs are investments in developing a long-term fuel supply for the power plant, the annual costs are capitalized over the life of each farm (20 years) and then added to the annual fuel supply cost (see Appendix 9). Although some acreage may be replanted after harvest with new and improved clones, for the purposes of this analysis the increased productivity of the new clones is assumed to be counter balanced by the additional planting and prep costs, so the farms are assumed to be planted only once over their 20 year life cycle with no change in productivity.

Harvesting Cost: The harvesting cost for farm-grown wood assumes the use of one or more high productivity harvesters being developed by EPS. The high-speed harvester is designed to combine several logging functions into one machine. The harvester is a large, rubber-tracked machine designed to continuously travel down each row of trees at relatively high speed. Each tree is cut off, guided into an accumulation area and batch-dumped onto a trailer towed behind the harvester. The harvester eliminates many of the inefficiencies of normal feller/buncher/skidder type harvesting operations and significantly lowers harvesting costs. The harvesters would be leased, and the cost including lease costs, fuel, operators and support crew is expected to average about $101 per acre. The first unit is scheduled to be demonstrated in spring of 2004.

Transportation Cost: Trees harvested from each farm will be directly loaded onto a trailer by a high productivity harvester. Contract truckers will leave empty trailers near the end of the tree rows to be harvested and pick up loaded trailers. The average distance from field to plant is estimated to be 25 miles. The estimated cost per loaded mile is $1.70. Each truck can haul about 14 dry tons per load, which is a 27 ton load of green trees. Hauling costs to the Minnesota Valley plant for farm grown trees is expected to average about $3.06/dry ton.

Figure 8.3 Fuel Supply Assumptions

Power Plant Assumptions	***Units***	
Steam Turbine Net Power	kW	47.7
Cap. Factor	%	80.0
Net Annual Output	MWh	334,000
Plant Heat Rate (Combined Cycle)	Btu/kWh	10,239
Fuel Heat Content (dry)	Btu/lb	8,700
Estimated Wood Flow Rate, dry	lb/hr	54,593
Annual Fuel Required (Dry)	tons/year	191,294
Farm Fuel Assumptions	**Units**	
Typical Acreage per Farm	acre	80
Slip Density Per Acre	slips/acre	1,551
Total Slips Required	slips	12,107,964
Rotation Age	years	5
Growth Per Year/Acre	dry ton/yr	4.9
Harvest Yield At Maturity	dry ton/acre	24.5
Plant Fuel Req't -Acres/yr (1)	acres/yr	7,808
Plant Fuel Req't -Lifetime	acre	39,040
Farm Cost Assumptions	**Units**	
Annual Rent on Land	$/yr/acre	$104
First Yr Prep/Planting Cost (2)	$/acre	$227
Second Yr Costs	$/acre	$66
Harvesting Cost	$/acre	$101
Transportation Cost	$/ton	$3.06
Fuel Cost (3)	$/ton	$48.91

Note: Certain costs have been capitalized but not levelized over the typical 20-year life of a farm
(1) Assumes plant is entirely fueled using grown trees - no wastewood is assumed.
(2) Land prep, planting, and certain startup marketing costs for first five years of each farm are capitalized.
(3) See proforma financials in Appendix 9.

Total Farm-Grown Fuel Cost: The average farm grown fuel cost delivered to the retrofit WTE plant is $48.91/ton or about $2.81/MBtu. Fuel costs have not been levelized as part of this study and the impact of inflation and escalation are not considered.

Natural Gas - Combustion Turbine
The proposed WTE retrofit of the Minnesota Valley plant includes a natural gas-fired combustion turbine as part of the combined cycle system. The existing natural gas service to the plant will only require minor modifications to supply the new combustion turbine. The combustion turbine is assumed to operate in parallel with the WTE plant at an 80% capacity factor. (During combined cycle operation, the WTE plant operates at a higher efficiency and requires less wood fuel). For the purposes

of this study, the price for natural gas was assumed to be the average of 2002 prices for Minnesota utilities. Natural gas prices are estimated from US Energy Information Agency web site data (http://www.eia.doe. gov/emeu/states/ngprices/ngprices_mn.html). The average cost of natural gas is estimated to be $3.83/MBtu with a higher heating value of 23,880 Btu/lb. (Natural gas prices have been volatile in recent years with significant annual increases from historical averages although prices are expected to stabilize going forward). Given the plant operating assumptions shown in Figure 8.4, the total annual cost for wood fuel is $9.3 million and natural gas is estimated to cost $ 6.8 million per year.

Figure 8.4 Fuel Costs

Costs	Units	WTE™ Plant	Combustion Turbine	Total
Fuel required	ton/year	191,294	37,304	
Fuel cost (1)	$/ton	$48.91		
	$/MBtu	$2.81	$3.83	
Fuel Higher Heating Value	Btu/lb	8,700	23,880	
Total Annual Fuel Cost	$/yr	$9,335,715	$6,828,946	$16,500,000
	mills/kWh		40.10	32.08
Fixed O&M	mills/kWh	4.30	0.93	2.88
Variable O&M plus Fuel	mills/kWh	30.10	40.89	33.60
Total O&M plus Fuel	mills/kWh			36.48

Average of first 3 years of second harvests - year 10,11and 12.

Existing Forest Resources

The need for existing forest resources and wastewood will depend on the actual development schedule for the retrofit project. Assuming construction starts simultaneous with development of the farm-grown fuel supply, a gap of about 2-3 years (5-6 years for fuel supply development less 2-3 years for plant construction) would need to be filled with other wood resources such as existing forestland resources in the procurement area. Forest resources are available in the area although the procurement area will have to extend north up to 120 miles to reach sufficient quantities to fuel the plant. The fuel supply manager will contract for harvesting rights to private and public lands in the procurement area and hire independent loggers and truckers to harvest and deliver the trees to the Minnesota Valley plant.

In the procurement area for the proposed WTE plant, the pulpwood stumpage cost ranged from $11/cord to $60/cord in 2002. This is the stumpage cost (cost for right to harvest trees on private or public land) - harvesting cost and transportation cost to plant location vary depending on the type of harvest (thinning vs. clearcut) and the distance to the plant location. The cost for each of these elements depends on many factors including competition, type and value of wood, fuel costs, distance to plant, etc. It also only applies to the main bole or sawtimber portion of relatively healthy merchantable trees. WTE can use all of the resource on the site which will lower the net cost per ton about 45% (by adding additional biomass beyond just the merchantable portion of the tree).

Stumpage costs vary significantly by primary type of tree, location and size of plot. Parcels with a high proportion of sawtimber generally have higher stumpage costs than primarily pulpwood parcels. A WTE plant can utilize just about any type of wood, if the price is right, including hardwoods, softwoods, damaged trees, and even dead and dying trees. Based on current trends and competitive factors, EPS believes sufficient acreage can be obtained at an average stumpage cost of $30 per dry ton as measured by normal merchantable pulpwood prices. (Note: any sawtimber quality logs harvested from a site would likely be sold to a sawmill at a much higher price. The net stumpage price for the total biomass, including what normally would be considered residue such as trimmings, branches, and dead and dying is expected to average about $16.44 /dry ton (Figure 8.5).

Figure 8.5 Stumpage Cost Calculation for Existing Timberland Resources

	Units	120 Mile Radius	Comments
Estimated stumpage value of wood per acre	$/acre	$470	MN Finance and Commerce - 44,000 public acres @ $20.7 million in rev.
Estimated average stumpage cost - merchantable wood	$/ton	$30.00	Calculation
Proportion non-growing stock		0.45	
Net cost for all biomass available	$/ton	$16.44	Calculation - does not include sawtimber revenue

Note: Stumpage costs vary significantly depending on species of wood, quality, location, demand etc. For instance, in 2001, stumpage prices for sawtimber ranged from $30.46/Mbf for cedar to $170.13/Mbf for white pine. Polewood varies similarly. At $100/Mbf, sawtimber is about $33/dry ton for the merchantable portion of the wood. Stumpage costs for residue varies from free to $5/cord or only about $2.25 per ton - in many cases skidded to a landing area near the harvesting site ready for loading.

The average harvesting cost for wood in the procurement area is about $14-$21 per dry ton. Normal logging equipment such as feller/bunchers and skidders would be used by contract loggers to harvest the fuel supply. Unlike when trees are used for pulpwood or sawtimber, the trees will not be trimmed as part of the harvesting process. The whole trees will be loaded onto the log hauling trailers. The feasibility of this process has been proven in previous large scale testing of the WTE technology. Minor trimming may be necessary to limit the load length to permit requirements. High quality sawlogs will be segregated and sold separately at market value. The WTE plant will be able to use all of the biomass available including whole trees, dead and dying trees and damaged wood.

The fuel supply manager will contract with local truckers to transport the whole trees on log hauling trailer from each site to the Minnesota Valley plant. Each trailer is assumed to haul about 14 dry tons of whole trees per load. The average one-way trip to the plant is estimated to be 100 miles. The cost per loaded mile is estimated at $1.70 for a net cost for hauling of about $12.23 per ton.

The total delivered cost for standing biomass resources for the retrofit WTE plant is expected to average $43 per dry ton ($2.47/MBtu) for the 2-3 years needed while the farm-grown trees mature to harvestable size (Figure 8.6).

Figure 8.6 Cost Calculation for Existing Timberland Resources

Parameter	Units	Value	Notes
Stumpage Costs			
Gross stumpage cost for resource, range	$/ton	$10-$40	Typical prices paid for non-sawlog quality logs
Expected net cost in 120 mile procurement area	$/ton	$16.44	EPS estimate - net cost all biomass not including revenue from sale of sawtimber
Harvesting cost			
Net whole tree harvesting cost	$/ton	$15.00	Using normal feller/buncher/skidder
			No branch removal
Transportation cost			
Mileage to plant	miles	100	Average one-way distance from plot to plant
Delivery cost	$/mile	$1.70	Average for long haul distance - loaded mile
Total transportation cost per load	$/load	$170.00	Mileage times delivery cost
Average load capacity, dry	ton/load	13.9	Estimated from experience and testing
Net transportation cost	$/ton	$12.23	Calculation
Total Cost			
Total Standing Biomass Cost	$/ton	$43.67	Estimate

Capital Cost Summary

Capital costs for the retrofit Minnesota Valley plant are summarized in Figure 8.7 and detailed in Appendices 7 and 11. The total estimated cost for retrofitting the Minnesota Valley is $55 million or $764/kW ($2003). This includes the new combustion turbine, drying dome, fuel conveyor, fuel feed system, boiler modifications, engineering and permitting needed to convert the existing coal-fired plant to a WTE combined cycle plant. If the combustion turbine and associated costs are eliminated (WTE only case) then the capital costs are $33.9 million or $787/kWh.

Data for this analysis was provided by several sources including previous published data, vendor estimates, EPS internal data, and other expert sources. Utility Engineers served as subcontractor in developing part of the preliminary design and capital equipment estimates. The capital costs were divided into four major categories. Contingencies of 25% were added to each category total; the project contingencies are set high to cap the costs for development as the first WTE™ plant.

Boiler Modifications: The boiler modifications, including the new water-cooled grate, char burnout grate, and various boiler modifications will cost $12.86 million. This estimate includes all materials including firebrick, insulation, equipment, demolition and installation. Costs included in this total are $1.5 million for the new condensing heat exchanger and $225,000 for drying air fans and motors, with labor and materials for drying air and combustion air ductwork making up the bulk of the remaining investment.

Tree Drying Dome: The drying building and air distribution system is estimated to cost $9.9 million. This includes the drying building dome material, the anchor wall system, the building mechanical systems, the central air vent, lighting system, weigh station, and the truck and personnel doors. The concrete under-pile air distribution system (balance of plant cost) is also included in this estimate. A tower crane and grapple system represents $2.15 million of the total.

Fuel Handling System: The fuel feed conveyor and rams, sizing saws, dust collection system are major components of the fuel handling system, which is estimated to cost $7.75 million. This includes the cost of the concrete work and other balance of plant items. Other major costs include $2.65 million for the crane, crane tower, and foundation. Appropriate contingency factors and estimates of indirect costs have been included in the estimates for total plant cost.

Combustion Turbine: Adding a 24 MW combustion turbine to the Minnesota Valley plant adds $18.8 million to the direct costs for the retrofit plant. The combustion turbine and new heat recovery feedwater heater represent the largest portion of added cost at $10.8 million to the overall capital cost. The combined cycle system increases the efficiency of the overall plant, decreases wood fuel requirements and increases the output of the plant. Other major costs associated with adding the combustion turbine include $1.0 million for upgrades to the natural gas supply system, and $1.2 million for related electrical upgrades with the remaining costs related to demolition, new ducting, and balance of plant.

Sales taxes of $1.6 million were estimated assuming a 6.5% tax rate on 50% of total estimated costs (including the 25% contingency built into the estimates). The capital cost estimates include equipment, labor and materials needed to complete the retrofit. Engineering and construction management adds another $4.5 million. (Additional engineering costs for modifying the boiler are built into the cost estimate for boiler modifications). Permitting and other indirect costs add $750,000. An estimate of $3.0 million for allowance for funds used during construction (AFUDC) is based on a 3 year project schedule with 12%, 61% and 27% of total capital costs occurring in Year 1, Year 2 and Year 3, respectively with an assumed interest rate of 5.5% (see Appendix 6).

The total investment required for the WTE Combined Cycle retrofit is estimated to be $59.0 million (2003$) or $820/kW. Using a fixed charge rate of 20.3% results in an annual capital cost of $12.0 million or 23.8 mills/kWh. Note that this cost does not include capitalized cost related to the development of the fuel supply because those costs are allocated separately and applied to total fuel cost. If the combustion turbine and associated costs are eliminated (WTE only case) then the annual cost of capital is $7.8 million or 24.4 mills/kWh (Figure 8.7).

Figure 8.7 Capital Cost Summary of Retrofit

Item	WTE-CC	WTE only
Direct Costs (Material and Installation)		
Boiler modification cost	$12,300,000	$12,300,000
Tree drying facility cost	$9,849,334	$9,849,334
Fuel handling and balance of plant cost	$7,754,250	$7,754,250
Combustion turbine and heat recovery feedwater heaters	$18,712,063	------
Subtotal Directs Cost (1)	$48,615,647	$29,903,584
Indirect Costs		
Sales tax (2) at 6.5%	$1,580,000	$972,000
Engineering and construction management	$4,000,000	$2,500,000
Permitting	$250,000	$200,000
Other indirect costs	$500,000	$300,000
Subtotal Indirect Cost	$6,330,000	$3,972,000
Total Retrofit Construction Cost (3)	$54,945.655	$33,875,584
Allowance for funds used during construction (AFUDC)	$4,079,591	$2,515,261
Total Investment (not including escalation)	**$59,025,301**	**$36,390,845**
Cost per unit of capacity, $/kW	$820	$844
Fixed charge rate, %	20.3%	20.3%
Fixed capital charges	$11,993,941	$7,387,341
Capital cost per unit of electricity, mills/kWh	23.77	24.45

(1) Represents the direct costs of only the items within the scope of this study. 25% contingency included in direct cost estimates.
(2) Applied to 50% of total capital costs - remaining assumed to be non-taxed or installation costs.
(3) Does not include estimates for escalation or inflation. Does not include capitalized fuel supply development costs (planting, prep etc.) - these are included in net fuel costs

Annual Total Cost Summary
The total annual cost for the retrofitted WTE Minnesota Valley combined cycle power plant (WTE-CC) is $30.4 million, and the annual cost of the WTE only (no combined cycle) is $19.3 million (Figure 8.8).

There is a Federal tax credit for closed-loop biomass under the Renewable Electricity Production Credit (REPC), which is a per kilowatt-hour tax credit for electricity generated by qualified energy resources - defined as wind, closed-loop biomass, or poultry waste. Available during the first 10 years of operation, the REPC provides a 1.5 cents per kWh credit adjusted annually for inflation. The adjusted credit amount for 2003 is 1.8 cents per kWh. Enacted as part of the Energy Policy Act of 1992 (U.S. Code Citation: 26 USC 45), the credit, which had expired at the end of 2001, was extended in March 2002 as part of H.R. 3090, Job Creation and Worker Assistance Act of 2002. The credit is set to expire on 12/31/03. It is reasonable to assume that this tax credit will be extended and adjusted for inflation. This credit has been extended regularly since 1992 and the emphasis for CO_2 abatement continues to grow.

After taking a tax credit of 18 mills/kWh for the biomass portion, the cost of electric power production is 48.4 mills/kWh for the WTE-CC plant and 46.0 mills/kWh for the WTE steam cycle plant.

The cost calculations in Figure 8.8 do not include estimates of escalation or inflation. The costs are not levelized, and the annual levelized cost for the existing plant assets is also not included. No investment tax credit was assumed. A 25% contingency is included in the capital costs. More refined cost calculations should be made as the project moves forward.

Figure 8.8 Total Annual Costs ($2003)

Item	WTE-CC	WTE only
Operations and maintenance cost	$2,223,000	$2,017,000
Fuel cost	$16,185,000	$9,921,997
Capital cost	$11,994,000	$7,387,341
Total Annual Cost	**$30,402,000**	**$19,326,338**
Production cost, mills/kWh	60.32	63.98
Biomass tax credit at 18 mills/kWh	11.92	18.00
Bus Bar cost of power, mills/kWh	**48.4**	**46.0**

If the Minnesota Valley power plant were run on Western sub-bituminous coal (summarized in Figure 2.3, higher heating value of 9,540 Btu/lb, 42.4 MW, 50,520 lb/hr) that costs $1.40/million Btu delivered by rail and unloaded at the Minnesota Valley power plant, then the annual fuel cost would be $4.7 million. If the operations and maintenance costs are assumed to be $2.5 million/yr and assuming there is no capital cost, then the cost of power would be 24.2 mills/kWh. However some additional expenses would be incurred in base load operation of the plant on coal for inspection and repair/replacement of plant equipment. The status of the existing permits would need to be established as well as the adequacy of the electrostatic precipitator for continued use with coal. Because of the particulate, nitrogen oxides, sulfur dioxide and mercury emissions, it is questionable if this current unit could be permitted for base load coal-fired operation.

9. Project Schedule

The Whole Tree Energy™ combined cycle retrofit of the Minnesota Valley power plant is scheduled for 36 months in this section. An accelerated schedule would allow for delivery of commercial power in 24 months. Engineering and design will require 10 months (some of which will take place simultaneous with other activities), permitting 12 months (overlaps with engineering and design activities) site prep and demolition 3 months, and construction 12-18 months. Startup operations will require about 2 months before the plant can go online at full capacity.

Key elements of the retrofit project include the drying dome, grapple crane, combustion turbine, the fuel feed system, and boiler modifications. The fuel supply involves establishing 7800 acres of short rotation woody crops per year for five growing seasons on farmland within 50 miles of Granite Falls. The power plant will use existing wood resources and waste wood during the first several years of operations while the fuel supply matures.

The project schedule is presented in Figures 9.1 to 9.4.

Figure 9.1 Schedule for WTE™ Retrofit of the Minnesota Valley Plant

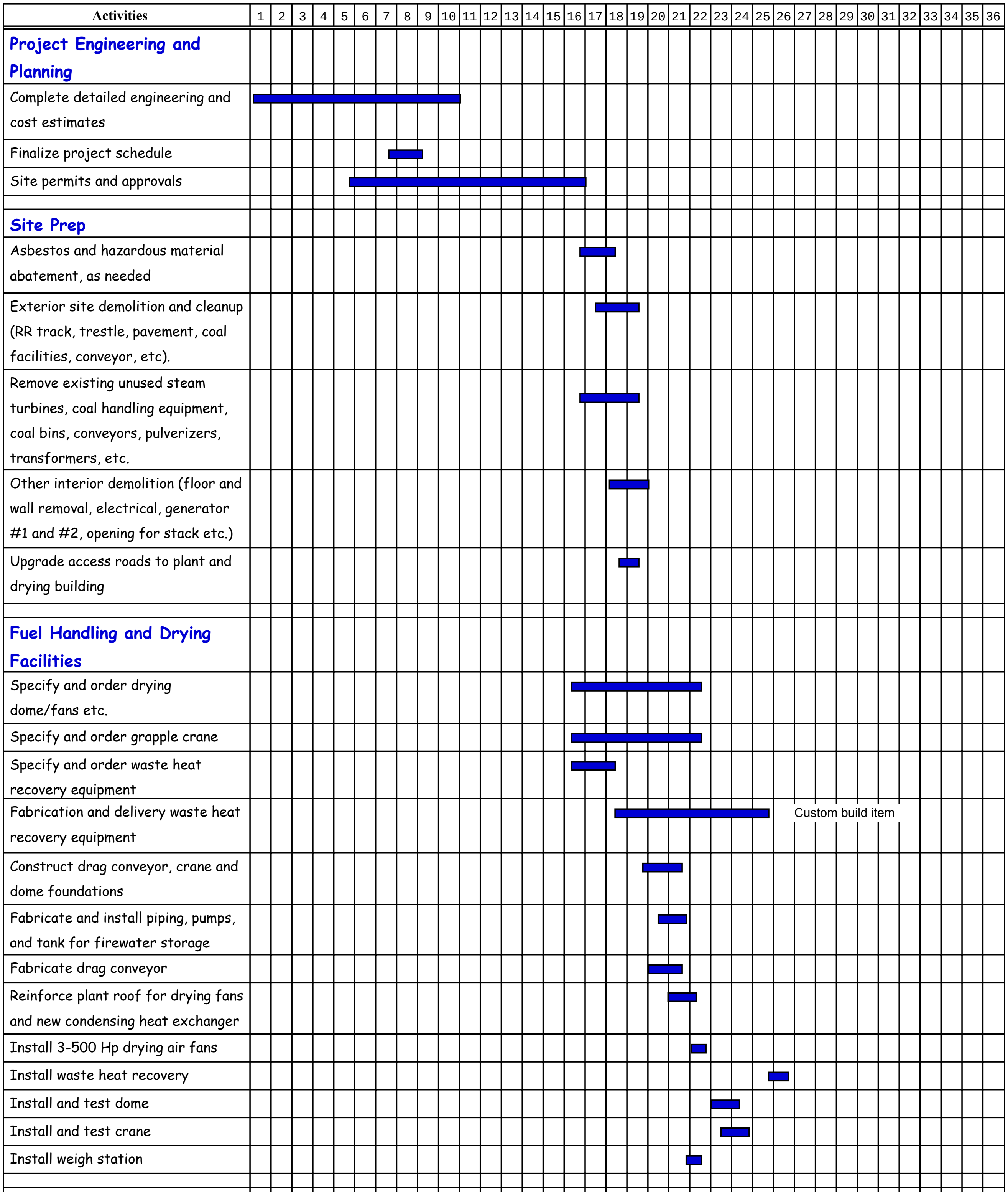


Figure 9.1 Schedule for WTE™ Retrofit of the Minnesota Valley Plant, cont.

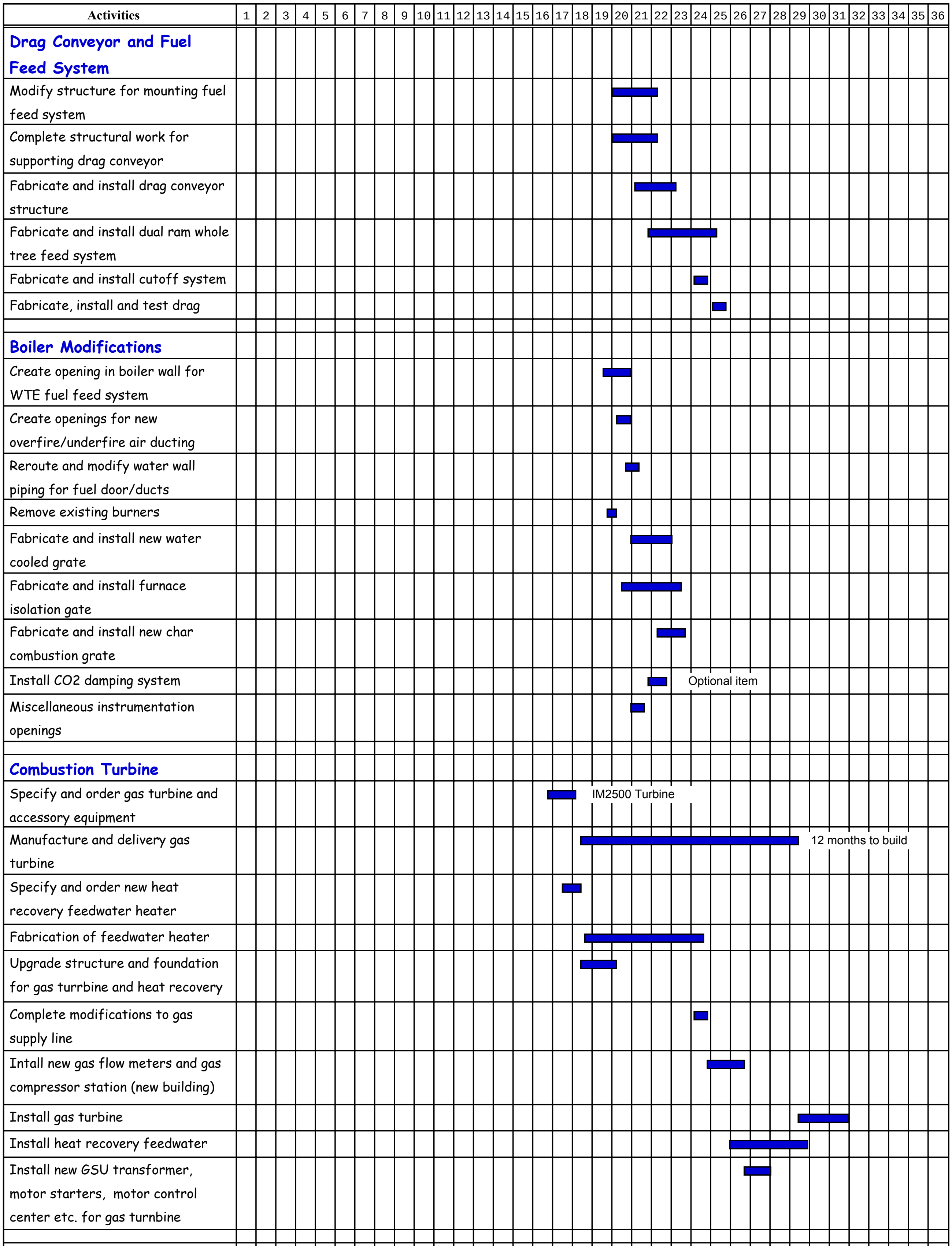


Figure 9.1 Schedule for WTE™ Retrofit of the Minnesota Valley Plant, cont.

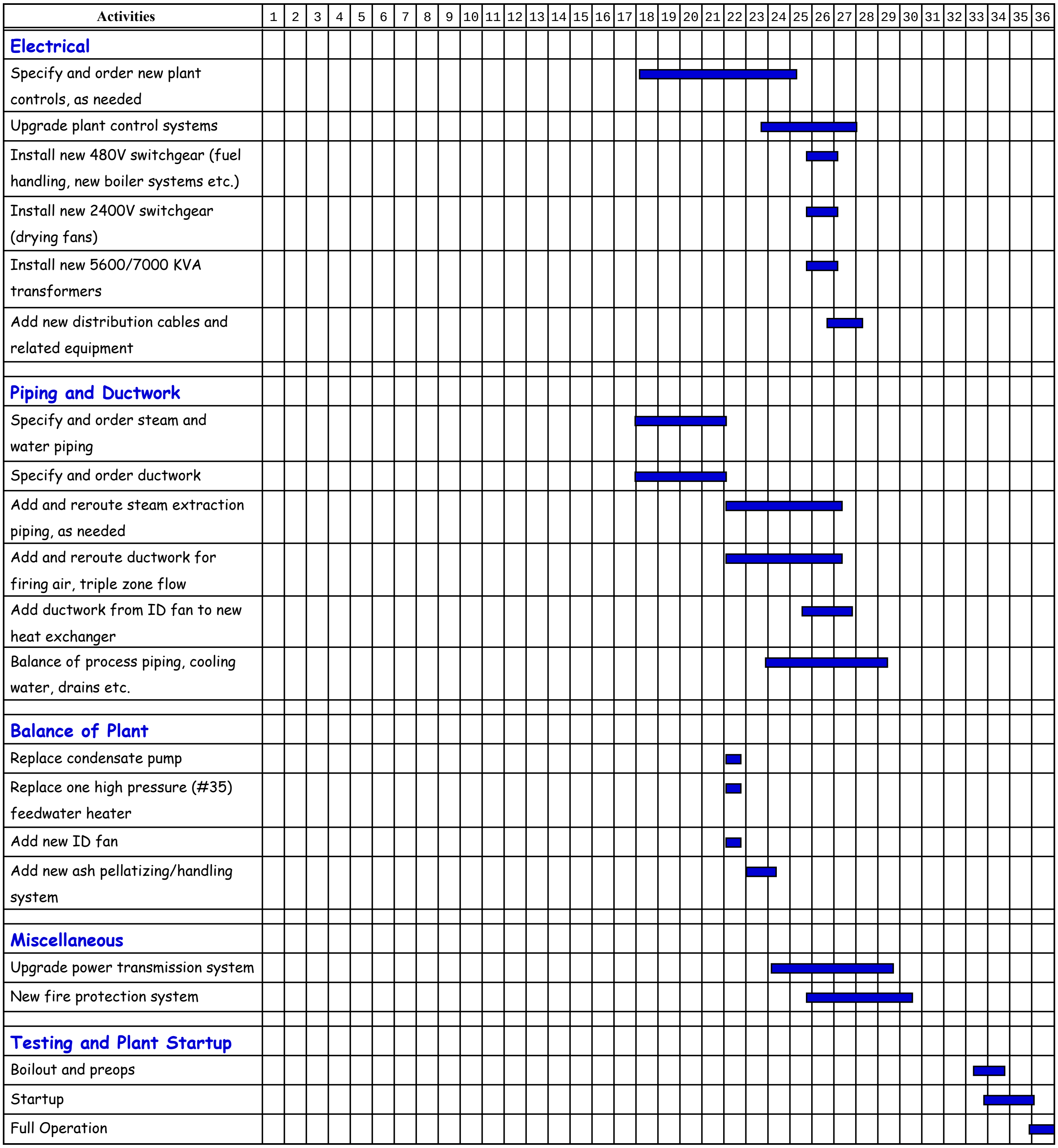


Figure 9.2 Poplar Slip Supply Development Schedule

NM-6 Hybrid Slip Production Plan

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Ostlie Nursery Production (Existing Beds)						
Total stools	200,000	200,000	200,000	200,000	200,000	200,000
Total number of slips per stool per season (1)	13	12.5	12.5	12.5	12.5	12.5
Number of slips from existing beds	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000
Ostlie Nursery Production (New Beds)						
Total stools in new beds	200,000	225,000	225,000	225,000	225,000	225,000
Total number of slips per stool per season (1)	3	12.5	12.5	12.5	12.5	12.5
Number of slips from new beds	600,000	2,575,000	2,812,500	2,812,500	2,812,500	2,812,500
Other Supplier Production (Existing Beds)						
Total stools in potential suppliers beds	250,000	250,000	250,000	250,000	250,000	250,000
Total number of slips per stool per season (1)	13	12.5	12.5	12.5	12.5	12.5
Number of slips from stool bed #2	3,250,000	3,125,000	3,125,000	3,125,000	3,125,000	3,125,000
Other Supplier Production (New Beds)						
Total stools new stool beds	225,000	375,000	375,000	375,000	375,000	375,000
Total number of slips per stool per season (1)	3	12.5	12.5	12.5	12.5	12.5
Number of slips from stool bed #2	675,000	3,262,500	4,687,500	4,687,500	4,687,500	4,687,500
Greenhouse/Hothouse Production						
Total 1.0" slips planted in greenhouses	1,000,000	0	0	0	0	0
Total number of slips per stool per cycle (1)	3	3	3	3	3	3
Growing cycles per year	2	2	0	0	0	0
Number of slips from greenhouse production	6,000,000	0	0	0	0	0
Total slips produced	13,025,000	11,462,500	13,125,000	13,125,000	13,125,000	13,125,000

Overall Slip Inventory

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Beginning inventory of slips (Jan 1)	0	0	742,036	96,573	100,000	100,000
Slips purchased from Ostlie Nursery	250,000	3,100,000	5,075,000	5,312,500	5,312,500	5,312,500
Slips purchased from other sources	300,000	3,925,000	6,387,500	6,798,891	6,795,464	6,795,464
Slips from greenhouse production	0	6,000,000	0	0	0	0
Total slips available for planting	550,000	13,025,000	12,204,536	12,207,964	12,207,964	12,207,964
Less: Number of slips used in additional stool beds	425,000	175,000	0	0	0	0
Less: Number of slips used in greenhouse planting (2)	125,000	0	0	0	0	0
Total slips available for fuel supply planting	0	12,850,000	12,204,536	12,207,964	12,207,964	12,207,964
Number of slips used for farm planting	0	12,107,964	12,107,964	12,107,964	12,107,964	12,107,964
Net slips in inventory	**0**	**742,036**	**96,573**	**100,000**	**100,000**	**100,000**

Definitions:
Stool bed: Roots and stump left over in nursery after harvesting whips.
Whip: 8'-10' long annual growth from stool bed or planted slip
Slip: 10" long piece of whip

Slips per Established Stool =

Whips/Stool X	Slips/Whip	Total
2.5	5.0	12.5

(1) Note: New stool beds only produce one whip in first season.

(2) Each 10" slip is assumed to produce 8 - 1" slips for greenhouse planting.

Figure 9.3 Tree Farm Development Schedule

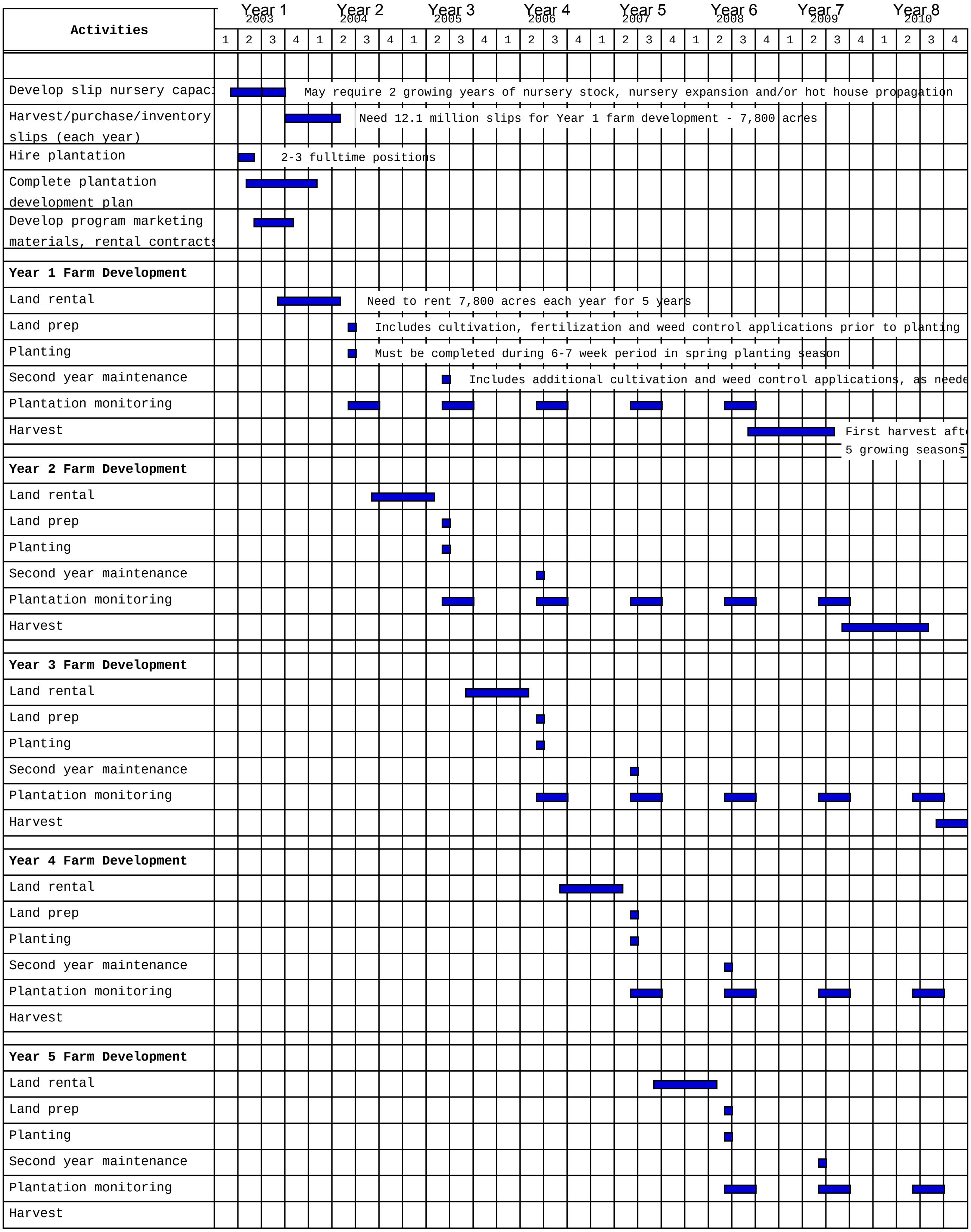


Figure 9.4 Fuel Supply Development Schedule

Fuel Supply Plan 1

Plant Fuel Usage Schedule		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
Plant Usage Factor (% of contract rate)	%	NA	NA	NA	0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Fuel Required to Operate Plant	1000's Dry Tons	0	0	0	0	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191
Wastewood Usage %	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Wastewood Usage	1000's Dry Tons	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Farm Grown Fuel Requirements	1000's Dry Tons	0	0	0	0	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191

Wastewood Inventory Schedule		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
Wastewood Beginning Inventory	1000's Dry Tons	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Purchases of Wastewood		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wastewood Used in Plant		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Inventory of Wastewood		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Typical Farm Planting/Harvesting Schedule	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
Year 1 Farms	P	G	G	G	H	G	G	G	G	H	G	G	G	G	H	G	G	G	G	H	G
Year 2 Farms		P	G	G	G	H	G	G	G	G	H	G	G	G	G	H	G	G	G	G	H
Year 3 Farms			P	G	G	G	H	G	G	G	G	H	G	G	G	G	H	G	G	G	G
Year 4 Farms				P	G	G	G	H	G	G	G	G	H	G	G	G	G	H	G	G	G
Year 5 Farms					P	G	G	G	H	G	G	G	G	H	G	G	G	G	H	G	G
Year 6 Farms						NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

*P=Plant, G=Grow, H=Harvest

Number of Acres Planted Each Year		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
Year 1 Farms Development	acres	7,808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 2 Farms Development		0	7,808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 3 Farms Development		0	0	7,808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 4 Farms Development		0	0	0	7,808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 5 Farms Development		0	0	0	0	7,808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 6 Farms Development		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Acres		7,808	7,808	7,808	7,808	7,808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Acreage		7,808	15,616	23,424	31,232	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040	39,040

Number of Slips Planted Each Year		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
Year 1 Farms Development	1000's of slips	12,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 2 Farms Development		0	12,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 3 Farms Development		0	0	12,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 4 Farms Development		0	0	0	12,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 5 Farms Development		0	0	0	0	12,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 6 Farms Development		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Slips			12,108	12,108	12,108	12,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Number of Farms Started Each Year		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
Year 1 Farms Development	# of 80 acre farms	98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 2 Farms Development		0	98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 3 Farms Development		0	0	98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 4 Farms Development		0	0	0	98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 5 Farms Development		0	0	0	0	98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Year 6 Farms Development		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Farms Started			98	98	98	98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Farms Harvested Per Year		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
Year 1 Farms Harvested	# of 80 acre farms					98	0	0	0	0	98	0	0	0	0	98	0	0	0	0	98	0
Year 2 Farms Harvested							98	0	0	0	0	98	0	0	0	0	98	0	0	0	0	98
Year 3 Farms Harvested								98	0	0	0	0	98	0	0	0	0	98	0	0	0	0
Year 4 Farms Harvested									98	0	0	0	0	98	0	0	0	0	98	0	0	0
Year 5 Farms Harvested										98	0	0	0	0	98	0	0	0	0	98	0	0
Year 6 Farms Harvested											0	0	0	0	0	0	0	0	0	0	0	0
Total Annual Harvest			0	0	0	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98

Figure 9.4 Fuel Supply Development Schedule, Cont.

Typical Annual Farm Development Schedule — Year 1 thru Year 4 Farm

Year 1 Farms Summary

Year of Farm			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Number of Acres			7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808
Number of Farms			98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Fuel Inventory Per Acre	dry tons per acre		4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5
Fuel Inventory Per Farm	dry tons per farm		392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176	1568	1960
Total Fuel Inventory	dry tons		38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294
		$/acre																				
Rent	$1,000's/Yr	$104	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812
First Yr Prep/Planting Costs*	$1,000's	$227	$1,769	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Second Yr Prep/Planting Costs*	$1,000's	$66	$0	$516	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting Cost	$1,000's	$32	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253
Total Cost Per Year	$1,000's		$2,581	$1,328	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812	$812	$812	$1,065

Year 2 Farms Summary

Year of Farm				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Number of Acres				7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808
Number of Farms				98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Fuel Inventory Per Acre	dry tons per acre			4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6
Fuel Inventory Per Farm	dry tons per farm			392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176	1568
Total Fuel Inventory	dry tons			38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035
		$/acre																				
Rent	$1,000's/Yr	$104	$0	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812
First Yr Prep/Planting Costs*	$1,000's	$227	$0	$1,769	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Second Yr Prep/Planting Costs*	$1,000's	$66	$0	$0	$516	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting Cost	$1,000's	$32	$0	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0	$0	$0
Total Cost Per Year	$1,000's		$0	$2,581	$1,328	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812	$812	$812

Year 3 Farms Summary

Year of Farm					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Number of Acres					7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808
Number of Farms					98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Fuel Inventory Per Acre	dry tons per acre				4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7
Fuel Inventory Per Farm	dry tons per farm				392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176
Total Fuel Inventory	dry tons				38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776
		$/acre																				
Rent	$1,000's/Yr	$104	$0	$0	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812
First Yr Prep/Planting Costs*	$1,000's	$227	$0	$0	$1,769	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Second Yr Prep/Planting Costs*	$1,000's	$66	$0	$0	$0	$516	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting Cost	$1,000's	$32	$0	$0	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0	$0
Total Cost Per Year	$1,000's		$0	$0	$2,581	$1,328	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812	$812

Year 4 Farms Summary

Year of Farm						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Number of Acres						7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808	7,808
Number of Farms						98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Fuel Inventory Per Acre	dry tons per acre					4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8
Fuel Inventory Per Farm	dry tons per farm					392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176	1568	1960	392	784
Total Fuel Inventory	dry tons					38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518	114,776	153,035	191,294	38,259	76,518
		$/acre																				
Rent	$1,000's/Yr	$104	$0	$0	$0	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812	$812
First Yr Prep/Planting Costs*	$1,000's	$227	$0	$0	$0	$1,769	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Second Yr Prep/Planting Costs*	$1,000's	$66	$0	$0	$0	$0	$516	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting Cost	$1,000's	$32	$0	$0	$0	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0	$0	$0	$253	$0	$0
Total Cost Per Year	$1,000's		$0	$0	$0	$2,581	$1,328	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812	$812	$812	$1,065	$812	$812

Figure 9.4 Fuel Supply Development Schedule, Cont.

Typical Annual Farm Development Schedule																						Year 5 thru Year 6 Farm
Year 5 Farms Summary																						
Year of Farm							1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Number of Acres							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Farms							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Inventory Per Acre	dry tons per acre						4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9	9.8	14.7	19.6	24.5	4.9
Fuel Inventory Per Farm	dry tons per farm						392	784	1176	1568	1960	392	784	1176	1568	1960	392	784	1176	1568	1960	392
Total Fuel Inventory	dry tons						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		$/acre																				
Rent	$1,000's/Yr	$104	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
First Yr Prep/Planting Costs*	$1,000's	$227	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Second Yr Prep/Planting Costs*	$1,000's	$66	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting Cost	$1,000's	$32	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost Per Year	$1,000's		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Year 6 Farms Summary																						
								1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Inventory Per Acre								0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Farms								0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Inventory Per Acre	dry tons per acre							4.9	9.8	14.7	19.6	24.5	29.4	34.3	39.2	44.1	49.0	53.9	58.8	63.7	68.6	73.5
Fuel Inventory Per Farm	dry tons per farm							392	784	1176	1568	1960	2352	2744	3136	3528	3920	4312	4704	5096	5488	5880
Total Fuel Inventory	dry tons							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		$/acre																				
Rent	$1,000's/Yr	$104	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
First Yr Prep/Planting Costs*	$1,000's	$227	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Second Yr Prep/Planting Costs*	$1,000's	$66	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting Cost	$1,000's	$32	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost Per Year	$1,000's		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel Inventory - All Farms			38,259	114,776	229,553	382,588	535,623	497,364	459,105	420,847	382,588	535,623	497,364	459,105	420,847	382,588	535,623	497,364	459,105	420,847	382,588	535,623

10. Selected References on Whole Tree Energy[TM]

1. EPRI (1993*) Whole Tree Energy[TM] Design, Volume 1: Engineering Evaluation*, TR-101564v.1, Electric Power Research Institute.

2. EPRI (1993) *Whole Tree Energy[TM] Design, Volume 2: Program to Test Key Elements of WTE*, TR-101564v.2, Electric Power Research Institute.

3. EPRI (1993) *Whole Tree Energy[TM] Design, Volume 3: 100 MW Design,* TR-101564v.3, Electric Power Research Institute.

4. EPRI (1995) *100 MW Whole Tree Energy[TM] Power Plant Feasibility Study, TR 104819,* Electric Power Research Institute.

5. Lamarre, L. (1994 Jan-Feb) Electricity From Whole Trees*, EPRI Journal*, pp. 16-24.

6. Ostlie, L. D. & Ragland, K. W., (1998) High Efficiency Bioenergy Steam Power Plant, in *Bioenergy'98*, pp. 772-781.

7. Bryden, K. M. & Ragland, K. W. (1996) Numerical Modeling of a Deep, Fixed Bed Combustor, *Energy and Fuels*, American Chemical Society, 10, 269-275**.**

8. Ragland, K. W., Ostlie, L. D. & Berg, D. A. (2001) Whole Tree Energy Power Plant*, Progress In Thermochemical Biomass Conversion*, International Energy Agency, pp. 812-823.

9. Water Appropriations Permit information can be found at http://www.dnr.state.mn.us/ waters/programs/water_mgt_section/appropriations/ index.html or by calling 651-297-2835.

10. NPDES permit information, see http://www.pca.state.mn.us/water/ permits/index.html or contact the MPCA's Customer Assistance Center at 651-296-7162.

11. Stormwater discharge permit information can be found at http://www.pca.state.mn.us/water/stormwater.html.

12. Power plant siting information can be found at the Environmental Quality Board's website, http://www.mnplan.state.mn.us/eqb/ pwrplant.html).

13. Information on hybrid poplar yields in Minnesota: http://bioenergy.ornl.gov/bfdpmain.html

14. General information on hybrid poplars: The Poplar Council of the Unites States, 251 Bessey Hall, Iowa State University, Ames, IA 50011-1021.

APPENDICES

Appendix 1. Existing Minnesota Valley Power Plant Equipment

Boiler: Riley Stoker Corp.; built in 1952; serial number 2895; YPR-22 plus WW boiler; two drum; working pressure 1500 psig; heating surface-water walls, 20,420 ft2; convective heating surface, 2450 ft2; furnace volume 30,400 ft3; water cooled furnace envelope 6500 ft2 steam capacity 385,000 lb/hr; four hour peak capacity 425,000 lb/hr at 1350 psig, 950°F; three Riley pulverizers; six burners; original rating 7.24 lb steam/kWh at 44,000 kW generator output (power factor 0.935), 7.22 lb steam/kWh at 40,000 kW generator output (power factor 0.85); coal feed rate 42,400 lb/hr at 385,000 lb steam/hr (HHV=12,300 as fired), 47,200 lb/hr at 425,000 lb steam/hr; 10 boiler sootblowers, 2 economizer sootblowers and 1 air preheater sootblower. Screen tubes are used. The boiler has made full load on natural gas.

Superheater: heating surface 34,890 ft2, operating outlet pressure 1350 psig; operating temperature 950 F. Steam pressure drop 67 psig at 385,000 lb/hr and 81 psig at 425,000 lb/hr. The lower 18 inches of the superheater loops were replaced in 1990; had a number of leaks between 1984 and 1990, major areas of tube leakage were replaced in 1990.

Economizer: heating surface 6650 ft2; water pressure drop 15 psi.

Air preheater: Ljungstrom rotary, regenerative (model 22-V-56); heating surface 70,900 ft2; air pressure drop 4.1; draft loss 2.8 in. water; total static pressure at heater inlet 8.1 in. water; total static suction at heater exit 6.7 in. water; air flow rate 425,500 lb/hr; gas flow rate 490,000 lb/hr. Condition – good in 1991.

Steam Turbine-Generator: General Electric (Contract GE-67362, shipped Jan. 1953); 40,000 kW, 44,000 kW maximum, 3600 rpm, tandem compound double flow condensing with steam at 1250 psig, 950 F, 1.5 in Hg abs.; extraction at 5th stage, 8th stage, 13th stage, 16th stage and 19th stage; steam moisture entering last stage under normal operating conditions not to exceed 9.5%; 40,000 kW, power factor 0.85, two poles, three phase, 60 cycle, 13,800 V, 1968 A, wye connections, hydrogen cooled generator. Overhauled in 1991.

Feedwater heaters: two low pressure and two high pressure, Foster Wheeler. One high pressure FWH is out of operation at this time. All FWH could need tube replacement.

Deaerating Heater: Elliott direct contact, spray type vertical DA mounted on 1750 ft3 storage tank.

Feedwater pumps: two Worthington barrel type pumps (Model 6” WLS-2)

Drain pump: low pressure Ingersoll-Rand No. 2 Class SFL single stage, horizontal centrifugal

Condensate pump: Allis Chalmers model 6x6 2CL centrifugal pump, 600 gpm (could have a NPSH problem)

Condenser: two pass surface condenser, 30,000 ft2, re-tubed in 1990; two 13,000 gpm circulating wate pumps.

Forced draft fan: Buffalo forge No. 12 'SLD", 135,000 cfm at 12.6 in. water. Condition good in 1991.

Induced draft fan: Buffalo forge No. 12 'SHLD", 215,000 cfm flue gas at 13.5 in. water, 350 F; condition good in 1991.

Electrostatic precipitator: UOP, 1978, collection efficiency 97%.

Stack: 350 ft tall; rolled steel plate lined with Gunnite sprayed over steel mesh. Last repaired in 1982.

Coal handling, feeding and pulverizing equipment: to be removed.

Makeup water treatment system: makeup water from Minnesota River is treated with hydrated lime and soda ash in mixing vessel and pumped to a 1250 gal/hr Permutit hot lime soda water softener.

Evaporator: no longer in use but used extracted steam to vaporize incoming makeup water and direct to deaerator.

Traveling water screens: two Rex screens; redone in 1994.

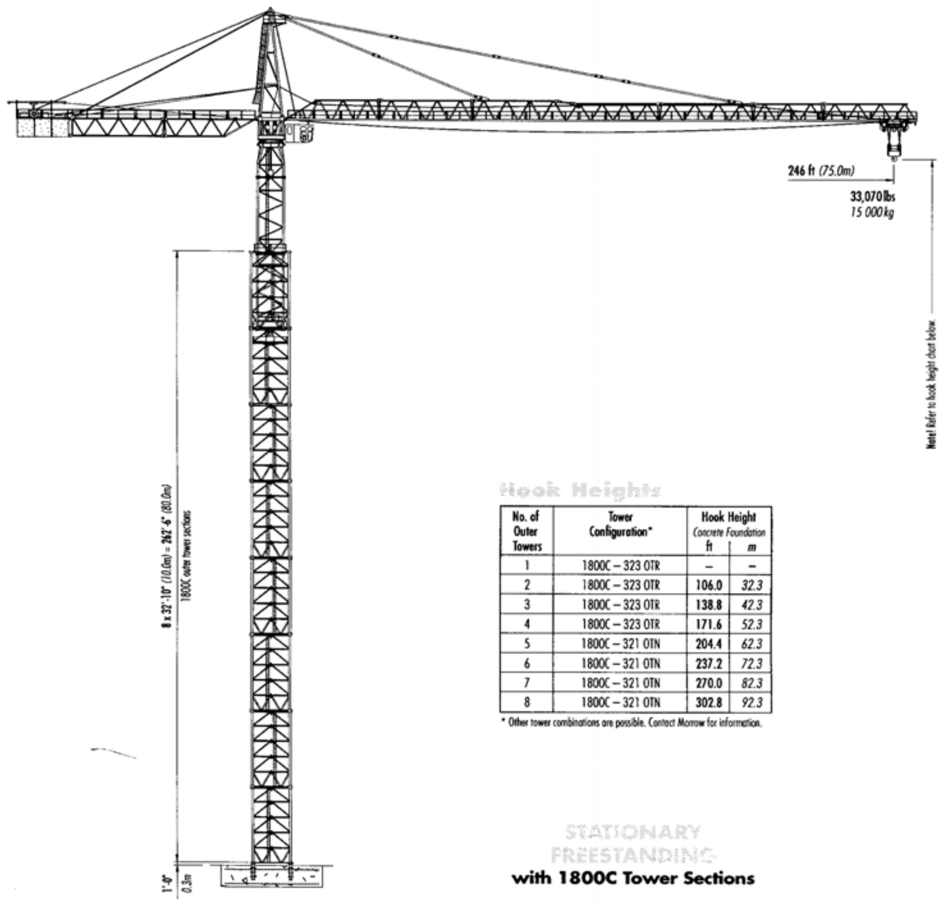
Ash handling system: currently fly ash is collected from economizer and electrostatic precipitator hoppers through hydroveyor and sluiced to ash ponds; bottom ash sluiced to ash pond. Amount of ash from wood will be 10% that of coal and ash to be pelletized and but back on fields as fertilizer.

Electrical and Controls Equipment: see 1992 retention report.

Appendix 2. Crane Specifications

LIEBHERR 1800 C

TOWER CRANE



Hook Heights

No. of Outer Towers	Tower Configuration*	Hook Height Concrete Foundation ft	m
1	1800C – 323 OTR	–	–
2	1800C – 323 OTR	106.0	32.3
3	1800C – 323 OTR	138.8	42.3
4	1800C – 323 OTR	171.6	52.3
5	1800C – 321 OTN	204.4	62.3
6	1800C – 321 OTN	237.2	72.3
7	1800C – 321 OTN	270.0	82.3
8	1800C – 321 OTN	302.8	92.3

* Other tower combinations are possible. Contact Morrow for information.

STATIONARY
FREESTANDING
with 1800C Tower Sections

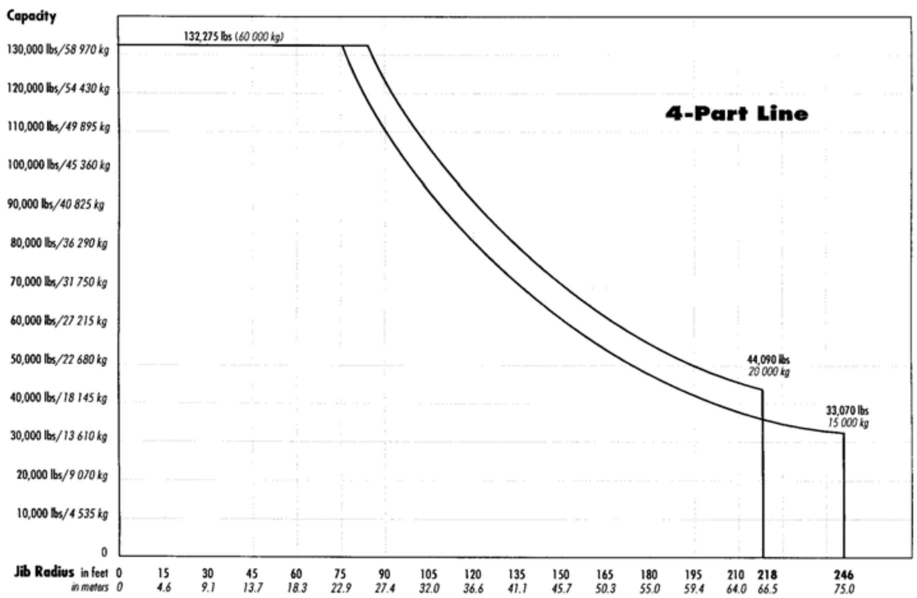
Morrow Equipment

Radius and Capacities

LIEBHERR Tower Crane Model 1800 C

4-Part Line

Hook Radius	4-Part Line Max Capacity – Radius	ft m	55 16.8	70 21.3	95 29.0	110 33.5	125 38.1	140 42.7	155 47.2	170 51.8	185 56.4	200 61.0	210 64.0	**218** 66.5	225 68.6	235 71.6	**246** 75.0
246 ft 75.0m	132,275 lbs – 75.1 ft 60 000 kg – 22.9m	lbs kg	132,275 60 000	132,275 60 000	105,000 47 630	90,000 40 825	78,500 35 610	68,200 30 935	59,000 26 760	51,500 23 360	45,000 20 410	40,200 18 235	37,500 17 010	36,350 16 490	35,100 15 920	34,000 15 420	**33,070** **15 000**
218 ft 66.5m	132,275 lbs – 84.0 ft 60 000 kg – 25.6m	lbs kg	132,275 60 000	132,275 60 000	116,000 52,615	101,000 45 815	87,500 39 690	76,500 34 700	67,500 30 620	59,000 26 760	52,500 23 815	48,000 21 770	45,500 20 640	**44,090** **20 000**			



Morrow Equipment Co., L.L.C.

Appendix 3. Air Emissions Spreadsheets

General Plant Operating Parameters			
		WTE-CC	**WTE-CC**
Parameter	**Units**	**(Max. Steam)**	**(Normal)**
Steam flow to ST	lb/hr	425,000	385,000
Capacity factor		NA	80%
Total net power	MW	77.6	72
ST net power	MW	53.3	47.7
GT net power	MW	24.3	24.3
Net plant efficiency	%	33.3	33.7
Net plant heat rate	Btu/kWh	10,239	10,130
Net steam plant efficiency	%	33.7	34.3
Net steam cycle efficiency	%	42.9	43.3
Net GT efficiency	%	31.8	31.8
Boiler efficiency	%	80.4	81.1
Solid fuel feed rate, as received (23%)	lb/hr	80,600	70,900
Solid fuel feed rate, dry	lb/hr	62,062	54,593
Solid fuel feed rate, dry	ton/hr	31	27
Annual solid fuel feed rate, dry	ton/year	NA	191,294
Fuel energy input	Mbtu/hr	540	475
Wood fuel heat content, dry	Btu/lb	8,700	8,700
Ash Emissions			
		Maximum	**Normal**
Parameter	**Units**	**Output**	**Output**
Total ash content of wood	%	0.7%	0.7%
Volume of wood required, as received	lb/hr	80,600	70,900
Volume of wood required, dry	lb/hr	62,062	54,593
Fuel energy input	Mbtu/hr	540	475
Total ash present in fuel	lb/hr	564	496
	tons/year	NA	1,739
Portion of ash in flue gas at furnace exit	%	90%	90%
Fly ash generated	lb/hr	508	447
	tons/year	NA	1,565
Efficiency of collection	%	97.0%	97.0%
Fly ash collected	lb/hr	493	433
	tons/year	NA	1,518
Bottom ash generated	lb/hr	56	50
	tons/year/	NA	174
Total ash collected	lb/hr	549	483
	tons/year	NA	1,692
Ash in stack exhaust gases	lb/hr	15.2	13.4
	tons/year	NA	47
	lbs/Mbtu	0.0282	0.0282

Method 2: Carbon Dioxide Emissions - Wood

Parameter	Units	Maximum Output	Normal Output	Notes
Carbon in fuel, dry basis	%	50%	50%	Multiple sources
Fuel feed rate, as received	lb/hr	80,600	70,900	Gatecycle model
Fuel feed rate, dry		61,740	54,309	
Total carbon	lb/hr	30,870	27,155	Calculation
Proportion sequestered (in ash)	%	1%	1%	Assumed similar to coal
Net carbon emissions	lb/hr	30,561	26,883	
Moles carbon		2,547	2,240	Calculation
Moles oxygen needed		5,094	4,481	Calculation
Molecular weigh carbon	lb/lb mole	12	12	Periodic table
Molecular weight oxygen	lb/lb mole	16	16	Periodic table
Carbon dioxide emissions	lb/hr	112,057	98,572	Calculation
	ton/hr	NA	345,395	Calculation
	lbs/MBtu	208	208	

Sulfur Dioxide Emissions - Wood

Parameter	Units	Maximum Output	Normal Output	Notes
Sulfur in fuel, as received	%	0.01%	0.01%	Multiple sources
Fuel feed rate, as received	lb/hr	80,600	70,900	Gatecycle model
Total sulfur	lb/hr	8.1	7.1	Calculation
Moles sulfur		0.25	0.22	Calculation
Moles oxygen needed		0.50	0.44	Calculation
Molecular weigh sulfur	lb/lb mole	32.066	32.066	Periodic table
Molecular weight oxygen	lb/lb mole	16	16	Periodic table
Sulfur dioxide	lb/hr	16.1	14.2	Calculation
	ton/yr	NA	49.6	Calculation
	lb/MBtu	0.030	0.030	Calculation

Assumes all sulfur in fuel is converted to SO2 and that there is no desulfuring unit on plant.

General Plant Operating Parameters - Coal

Parameter	Units	Coal Only	Urge Test Coal	Notes
Steam flow to ST	lb/hr	385,000	397,860	From Gatecycle model
Capacity factor		80%	80%	Design
Total net power	MW	42.4	46.3	From Gatecycle model
ST net power	MW	42.4	46.3	From Gatecycle model
GT net power	MW	-	-	From Gatecycle model
Net plant efficiency	%	30	31	From Gatecycle model
Net plant heat rate	Btu/kWh	11366	11179	From Gatecycle model
Net steam plant efficiency	%	30	30.5	From Gatecycle model
Net steam cycle efficiency	%	37.5	37.7	From Gatecycle model
Net GT efficiency	%	-	-	From Gatecycle model
Boiler efficiency	%	86.2	88.7	From Gatecycle model
Solid fuel feed rate, as received	lb/hr	50,520	40,440	From Gatecycle model
Solid fuel feed rate, dry	lb/hr	-	-	Calculation
Solid fuel feed rate, dry	ton/hr	-	-	Calculation
Annual solid fuel feed rate, as received	ton/year	177,022	NA	Calculation
Fuel energy input	MBtu/hr	482	386	Calculation
Coal fuel heat content	Btu/lb	9,540	9,540	From various sources

Ash Emissions - Coal

Parameter	Units	Coal Only	Urge Test Coal	Notes
Total ash content of coal, as received	%	3.98%	3.98%	From various sources
Volume of coal required, as received	lb/hr	50,520	40,440	From Gatecycle Model
Volume of coal required, dry	lb/hr	-	-	From Gatecycle Model
Fuel energy input	MBtu/hr	482	386	Calculation
Total ash present in fuel	lb/hr	2,011	1,610	Calculation
	tons/year	7,045	5,640	Calculation
Portion of ash in flue gas at furnace exit	%	99%	99%	Energy Information Agency
Fly ash generated	lb/hr	1,991	1,593	Calculation
	tons/year	6,975	5,583	Calculation
Efficiency of collection	%	97.0%	97.0%	Expected efficiency of electrostatic precipitator
Fly ash collected	lb/hr	1,931	1,546	Calculation
	tons/year	6,766	5,416	Calculation
Bottom ash generated	lb/hr	20	16	Calculation
	tons/year/	70	56	Calculation
Total ash collected	lb/hr	1,951	1,562	Calculation
	tons/year	6,836	5,472	Calculation
		4.05	4.05	
Ash in stack exhaust gases	lb/hr	59.7	47.8	Calculation
	tons/year	209	167	Calculation
	lbs/MBtu	0.1239	0.1239	Calculation

Method 1: Carbon Dioxide Emissions - Coal

Parameter	Units	Coal Only	Urge Test Coal	Notes
Fuel feed rate	lb/hr	50,520	40,440	Gatecycle model
	MBtu/hr	482	386	Calculation
Carbon coefficient for coal	lbs C/MBtu	57.90	57.90	Energy Information Agency
Total carbon	lbs/hr	27,906	22,338	Calculation
Proportion sequestered (in ash)	%	1%	1%	Energy Information Agency
Carbon sequestered	lbs/hr	279	223	Calculation
Net carbon emissions	lb/hr	27,626	22,114	Calculation
Conversion of carbon to CO2	lb mole C/lb mole CO2	3.67	3.67	44/12 ratio of moles CO2 to moles ca
Total carbon dioxide emissions	lb/hr	**101,297**	**81,086**	Calculation
	lb/MBtu	210	210	

Method 2: Carbon Dioxide Emissions - Coal

Parameter	Units	Coal Only	Urge Test Coal	Notes
Carbon in fuel, dry basis	%	75%	75%	Multiple sources
Fuel feed rate, as received	lb/hr	50,520	40,440	Gatecycle model
Fuel feed rate, dry		38,698	30,977	
Total carbon	lb/hr	29,024	23,233	Calculation
Proportion sequestered (in ash)	%	1%	1%	Energy Information Agency
Net carbon emissions	lb/hr	28,734	23,000	
Moles carbon		2,394	1,917	Calculation
Moles oxygen needed		4,789	3,833	Calculation
Molecular weigh carbon	lb/lb mole	12	12	Periodic table
Molecular weight oxygen	lb/lb mole	16	16	Periodic table
Carbon dioxide emissions	lb/hr	105,356	84,335	Calculation
	ton/yr	369,168	295,510	Calculation
	lbs/MBtu	219	219	

Appendix 4. Fuel Cost Summary

Fuel Cost Summary - Farm Grown Biomass

Parameter	Units	Value	Notes
Establishment, Maintenance and Harvesting Costs			
Cost for farm-grown biomass at farm	$/ton	$45.85	See Proforma Financials sheet for details.
	$/ton		
Transportation cost			
Mileage to plant	Miles	25	Average one-way distance from plot to plant
Delivery cost	$/mile	$1.70	Average for long haul distance - loaded mile
Tota l transportation cost per load	$/load	$42.50	Mileage times delivery cost
Average load capacity, dry	ton/load	13.9	Estimated from experience and testing
Net transportation cost	$/ton	$3.06	Calculation
Total Standing Biomass Cost	$/ton	$48.91	Calculation - see note.
	$/MBtu	$2.81	Calculation

Notes:
Does not include impact of tax credits for closed-loop biomass.

2002 Natural Gas Prices - Minnesota

Month		$/1000 cu ft
Oct		4.52
Sep		4.82
Aug		3.91
Jul		3.28
Jun		3.53
May		3.66
Apr		3.96
Mar		2.55
Feb		4.16
Jan		3.94
	$/1000 cu ft	3.833
	cu ft/MBtu	1000
		3.833

US Energy Information Agency

Appendix 5. Fuel Supply Development Plan

Fuel Supply Development Plan			Planting Calculation					
Typical Planting Crew								
Planter Operators		6	Seasonal contract workers					
Tractor Driver		1	Seasonal contract workers - acts as field supervisor					
Supervisor/farm manager		1	Fulltime - manages up to			5	crews	
Total		8						
Equipment Required Per Planting Crew								
Tractor (track type)		1	Rented for duration of the planting season					
Automatic planters		6	Built for project use					
Other Equipment and Personnel Required to Support Crews								
Pickup truck		1	For supervisor and crew transport, refueling and supplies					
Trailer (low boy type)		1	Tractor/planter transport - rented or purchased used					
Semi-tractor		1	For tractor/planter transport and delivering slips to field					
Refrigerated trailer		1	For delivery of the frozen slips to the field					
Driver for refrigerated trailer and transport trailer		1	Contract fulltime for planting season					
Available Planting Time Per Season								
Average daily operating time	hrs	6.0	Estimated from experience					
Average daily down time (1)	hrs	4.0	Estimated from experience					
Total time in field per day	hrs	10.0	Calculation					
Total planting days per year	days	21	Estimated from experience					
Availablitity percentage		90%	Estimate (some weather delays and scheduling conflicts)					
Average planting days per year		18.9						
(1) Down time includes time for employee breaks, reloading slip inventory, turnaround time, maintenance and fueling.								
Typical Planting Productivity Estimates Per Crew								
Average speed of tractor	mph	4.0	Estimated speed during normal field operation					
Distance between trees	ft	5.3	As per planting specifications					
No. of slips planted per second per planter	slips	1.11	Calculation					
No. of planting machines per tractor	planters	6	Planned number					
No of slips planted per tractor per second	slips	6.6	Calculation					
No. of slips planted per tractor per day	slips	143,457	Calculation					
Slips per acre	slips	1,551	Calculation					
No. of acres planted per day per tractor	acres	**92.5**	Calculation					
No. of acres planted per crew per season	acres	1,748	Calculation					
No. of 80 acre farms planted per crew per season	farms	22	Calculation					
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	
No. of acres required per year by fuel supply plan	acres	7,808	7,808	7,808	7,808	7,808	0	
No. of planting crews required each season	crews	4.5	4.5	4.5	4.5	4.5	0.0	
Slip Delivery Requirements Per Crew								
Number of slips per box	slips	1,000	Estimated from experience					
Boxes per pallet	boxes	18	Estimated from experience					
Slips per pallet	slips	18,000	Calculation					
Boxes needed per day per planting team	boxes	143.5	Calculation					
Pallets needed per day per planting team	pallets	8.0	Calculation					

Fuel Supply Development Plan			Harvestings and Hauling Calculation			
Harvesting Assumptions						
Total time in field per day	hrs	10.0	Estimate			
Less:						
Downtime for each trailer loading	hrs	0.17	Calculation	(min=	10	)
Other daily down time (1)	hrs	2.0	For transport, refueling, maintenance etc.			
Average daily operating time	hrs	7.8	Estimate			
Harvester capacity per hour	dry tons	100	Calculations from DOE researc			
Tons per tree	tons	0.016	Calculation			
Tons/acre	tons	24.5	Calculation			
Trees per hour	trees	6330	Calculation			
Tons per row	tons	7.9	Calculation			
Tons per farm	tons	1960	Calculation			
Tons per day	tons	783	Calculation			
Acres harvested per day	acres	32	Calculation			244.205
Farms harvested per day	farms	0.40	Calculation			
Harvester lease cost	$/yr	$200,000	EPS Estimate			
Harvesting crew		4	Full time equivalent			
Salary	$/yr	$35,000	Includes benefits			
Miscellaneous costs	$/yr	$100,000	Fuel, maintenance etc.			.05% of capital 750000
Acres harvested per year	acres/yr	7808				
Total harvesting cost	$	$440,000	Calculation			
Harvesting cost	$/ton	$2.30	Calculation			
	$/MBtu	$0.03	Calculation			
	$/acre	$56	Calculation			
Hauling Assumptions						
Load capacity per hauling trailer	dry tons	13.9	Results from large scale testing			
Truckloads required per day to plant		38	Calculation			
Truckloads per year		13,762				
Average distance from field to plant	miles	40	Estimate - averagesurface road distance			
Average on-road truck speed	mph	50	Estimate			
Time to drop trailer and pick up full load	minutes	30	Estimate			
Travel time from field to plant	minutes	48	Calculation			
Time to unload trailer at plant	minutes	10	Estimate			
Time to return to field	minutes	48	Calculation			
Total time for round-trip	minutes	136	Calculation			
Average daily load hauling time available	hrs	10				
Average downtime	hrs	0.5	Breaks, lunch, refueling, maintenance etc			
Time available for hauling	hrs	9.5				
No. of loads hauled per truck per day		4.2	Calculation			
No. of trucks required to supply plant		9.0	Calculation			
No. of trailers required		18	Will need	2	trailers for each truc	
Hauling cost	$/mile	$1.70				
Cost per truckload delivered to plant	$/load	$68.00	Roundtrip from plantation to plant and back			
	$/ton	$4.89				
Total harvesting and hauling cost	$/ton	$7.19	Calculation			
	$/acre	$176	Calculation			

Fuel Supply Development Plan				Establishment Costs
Establishment Cost (2003 $ Per Acre)				
First Year - First Farm with Hot House Slips		**Unit Cost**	**Units**	**Total**
Slips	$0.10	30.0¢	1551	$465
Planting	$0.02	2.2¢	1551	$35
Rent		$104.00	1	$104
Cultivation and Weed Control		$36.06	1	$36
Total				$640
First Year (Nursery Slips)		**Unit Cost**	**Units**	**Total**
Slips		10.1¢	1551	$156
Planting		2.2¢	1551	$35
Rent		$104.00	1	$104
Cultivation and Weed Control		$36.06	1	$36
Total				$331
Second Year		**Unit Cost**	**Units**	**Total**
Rent		$104.00	1	$104
Cultivation and Weed Control		$36.06	1	$36
Fertilizer		$30.00	1	$30
Total				$170
Third Year		**Unit Cost**	**Units**	**Total**
Rent		$104.00	1	$104
Fourth Year		**Unit Cost**	**Units**	**Total**
Rent		$104.00	1	$104
Fifth Year		**Unit Cost**	**Units**	**Total**
Rent		$104.00	1	$104
Note:				
All of these fuel supply development expenses are capitalized.				
Slips produced in greenhouses will cost $0.25-$0.35 each for the first years farms planted.				

Appendix 6. Capital Cost Summary

Minnesota Valley Plant WTE Conversion
Capital Cost Summary

Item			Cost	Notes
Direct Costs (Material and Installation)				
Boiler modification cost			$12,300,000	Babcock preliminary estimate
Tree drying facility cost			$9,849,334	UE preliminary estimate
Fuel handling and balance of plant cost			$7,754,250	UE preliminary estimate
Combustion turbine and heat recovery feedwater heater			$18,712,063	UE preliminary estimate
Subtotal Directs Cost (1)			**$48,615,647**	Includes *25%* contingency on all direct costs
Indirect Costs				
Sales tax (2)	6.5%		$1,580,009	Assumes 50% of capital costs taxable items
Engineering and construction management			$4,500,000	
Permitting			$250,000	
Other indirects			$500,000	
Subtotal Indirects Cost			$6,330,009	
Total Retrofit Construction Cost (3)			**$54,945,655**	Calculation
Estimated AFDUC	5.5%	Net interest	**$3,022,011**	See calculation below - not adjusted for inflation or escalation
Total Investment			**$57,967,666**	
$/kW			$805	For modifications only - book value of existing plant not included.
Fixed charge rate			20.3%	See calculation below
Fixed capital charges	$/yr		$11,779,030	Calculation
	mills/kWh		23.34	Calculation

(1) Represents the direct costs of only the items within the scope of this study
25% contingency included in direct costs
(2) Applied to 50% of total capital costs - remaining assumed to be non-taxed or installation costs.
(3) Does not include estimates for escalation, AFDUC, inflation etc.
Does not include capitalized fuel supply development costs (planting, prep, etc.) - these are allocated to net fuel costs.

Fixed Charge Rate for Capital Costs

Component		Value			Notes
Interest/required return on investment		9.0%			See calculation below
Depreciation		5.0%			Straight line for 20 year life
Interim replacements		0.4%			Allowance for capital equipment replacements
Property insurance		1.0%			
Income taxes (effective)		4.9%			Combined rate: See calculation below
Total Fixed Charge Rate		20.3%			
Calculations					
Interest/return on investment	Proportion	Rate		Value	
Debt	50%	6%		3.0%	
Equity	50%	12%		6.0%	
				9.0%	Interest/return on investment
Income tax charge	41%	times req'd ROI	12%	4.9%	Effective tax on profit
Income tax rates					
Federal		35%			
State		6%			
Combined		41%			

AFDUC Calculation

	2004	2005	2006
Cost allocation over project time line	12%	61%	27%
Amount financed	$6,593,479	$33,516,850	$14,835,327
Years of interest	2.5	1.5	0.5
Total interest	$362,641	$1,843,427	$815,943
Cumulative total AFDUC estimate			**$3,022,011**

Interest expense 5.5%

Appendix 7. Wood Fuel Resources Within 50 Mile Radius of Granite Falls

Of the 4.3 million acres of land area within the 9 counties only about 1.5 percent is forestland totaling about 63,000 acres (Figure A7.1). (Note that there are actually 5.0 million acres in a 50-mile radius but since the available data is summarized by county, complete county areas were used for this analysis). On a county by county basis, the proportion of forestland ranges from 0% in Lincoln County to about 4.5% in Kandiyohi County. The forestland - mostly hardwoods such as oak, hickory, maple and elm - is divided into several ownership classes including federal (4,300 acres/7%), state (1,500 acres/2%), farmer/rancher owned (34,700 acres/56%), corporate (1,800 acres/5%), and private individual owned (18,100 acres/29%), (Figure A7.2). There are only about 52,800 acres of forestland owned by farmers and private individuals. Much of this forestland borders wetlands, lakes and rivers.

Figure A7.1 Forestland by County, Acres

County	All Land	Total Forest	Percent Forest	Percent of All Forest in Region	Non-Forestland	Percent Non-Forestland
Chippewa	373,800	9,400	2.5%	14.9%	364,400	97.5%
Kandiyohi	501,600	22,500	4.5%	35.7%	479,100	95.5%
Lac Qui Parle	493,900	7,000	1.4%	11.1%	486,900	98.6%
Lincoln	344,600	0	0.0%	0.0%	344,600	100.0%
Lyon	457,100	2,400	0.5%	3.8%	454,700	99.5%
Redwood	564,200	9,400	1.7%	14.9%	554,800	98.3%
Renville	629,900	6,900	1.1%	10.9%	623,000	98.9%
Swift	475,700	2,200	0.5%	3.5%	473,500	99.5%
Yellow Medicine	485,400	3,300	0.7%	5.2%	482,100	99.3%
All counties	4,326,200	63,100	1.5%	100.0%	4,263,100	98.5%

- Source North Central FIA : St. Paul, MN

Figure A7.2 Forestland Ownership by County, 1000's Acres

County	All Owners	Miscellaneous Federal	State Owned	Farmer/ Rancher	Private Corporation	Private Individual
Chippewa	9.4	0	0	5.9	2	1.5
Kandiyohi	21.1	3.1	1.5	7.7	0	8.8
Lac Qui Parle	7	1.2	0	5.8	0	0
Lincoln	0	0	0	0	0	0
Lyon	2.4	0	0	1.2	0	1.2
Redwood	9.4	0	0	3.9	0	5.5
Renville	6.9	0	0	5.8	1.1	0
Swift	2.2	0	0	2.2	0	0
Yellow Medicine	3.3	0	0	2.2	0	1.1
All counties	61.7	4.3	1.5	34.7	3.1	18.1

- No timberland in national forest, BLM, tribal trust, county/municipal, or forest Industry ownership classes
- Numbers in rows and columns may not add to totals due to rounding.
- The data are derived by sampling and are subject to statistical error.
- Source North Central FIA : St. Paul, MN

Current Forestland Harvests

Because of the relatively small amount of forestland in the procurement area, minimal logging currently takes place. Only about 356 thousand board feet are harvested annually (Figure A7.3). For comparison purposes, this translates into only 3,100 green tons (roughly 1,550 dry tons at 50% moisture) of biomass, while the WTE plant requires 191,300 dry tons of wood fuel annually. Because of the small amount of forestland in the region, standing biomass is not expected to be a significant source of fuel and is not included in the fuel supply forecast.

Figure A7.3 Current Sawlog Harvest in Procurement Area

County	Harvest (MBF)	Harvest (Green Tons)
Kandiyohi	70	613
Lincoln	105	919
Lyon	8.7	76
Redwood	77.5	678
Renville	5.3	46
Yellow Medicine	90	788
50 Mile Radius	356.5	3,119
Other Nearby Counties		
Meeker	61.7	540
Stearns	1351.8	11,828
Total	1770	18,607

Note: One thousand board feet of hardwood sawtimber (Doyle) = 17,500 pounds (range:15,000-19,000 lbs.) or 8.75 tons

Forest Residue

Forest residues include underutilized logging residues like branches and crowns, imperfect commercial trees, dead wood, and other non-commercial trees. Because of their typical sparseness and remote location, these residues are usually more expensive to recover than urban and mill residues. In Minnesota, between 30% and 50% (by weight) of the biomass removed from a forest during logging operations is left behind in the form of branches, trimmings, dead trees and crowns. These resources could be used in a WTE power plant if economically available. Since there is very limited harvesting of trees in the Minnesota Valley procurement area, the amount of logging residue available is inconsequential. Using the above numbers, harvesting 1,550 dry tons of sawlogs would leave behind between 460 dry tons (30%) and 775 dry tons (50%) of branches, stems and other residue. It is so widely scattered, though, that the cost of collecting would most likely outweigh any value as a potential fuel source. If available at low cost, the material could be used in a WTE plant but none is included in the fuel supply assumptions for the Minnesota Valley project. EPS expects some of this material to be collected and delivered to the plant by independent operators once the plant is operating and demand for the resource creates an opportunity. In order to fuel the WTE plant for the first 2-3 years of operations, the procurement area will need to be expanded out to 120 miles - mostly to the north - to reach areas with more forest resources and wood-using industries (See 120 Mile Procurement Area).

Sawmill and Wood Products Residue

Another potential source of wood fuel for the Minnesota Valley plant is residue created from sawmills typically in the form of slabs, shavings and sawdust. Unlike in other parts of Minnesota, the southeastern region lacks wood manufacturing facilities and therefore produces very little sawmill and other types of wood residue. In a survey of sawmills in 2001, only 1,052 green tons of mixed residue was produced in the 9 county procurement area for the plant (Figure A7.4). Another 2,293 green tons were produced in Meeker and Stearns County, which are within 75 miles of Granite Falls. Much of this resource is already being used for other purposes such as animal litter and bedding (sawdust and shavings), landscaping (wood chips) and firewood (slabs). The value of these residues depends on the end use. Only about 646 green tons are not currently being utilized. Since the plant will need about 60 dry tons per hour of wood during normal operations, the available sawmill residue would hardly supply enough fuel for one day of operations.

Figure A7.4 Sawmill Residue by Type and County

	Slabs/Edgings		Sawdust/Shavings		Total Amount of Residue	
County	**Total**	**Amt Not Used**	**Total**	**Amt Not Used**	**Total**	**Amt Not Used**
Kandiyohi	229	0	16	0	245	0
Lincoln	573	458	234	12	807	470
Meeker	287	0	117	0	404	0
Stearns	1341	141	548	35	1889	176
	2430	599	915	47	3345	646

Based on 2001 Sawmill Survey
No bark or bark mixed with edgings/chips reported

Other Waste Wood Sources

There are many other potential sources of wastewood including debris from the river due to erosion and flooding, storm damaged trees, diseased trees, residential and utility trimmings, construction and demolition debris and residue from discarded wood products such as used pallets and crates. While each of these sources may be relatively small, the total amount can be significant in a larger urban environment. In many communities, this material is either burned, mulched or landfilled. All of this material could be burned in a WTE plant to produce electricity.

Research by Oak Ridge National Laboratories and other organizations have tried to estimate the amount of this material that might be available in urban areas of different sizes and locations. While none of the communities in a 50 mile radius of Granite Falls comes close to the size of communities surveyed in the ORNL study, the estimates generated give at least a rough, top-end estimate of the amount of "urban" residue that could be available annually. On average, a typical urban area produces about 1/3 of a ton (moisture content varies) per person annually. This is dependent on many factors including the existence of wood products and other types of manufacturers, the amount of construction activity and the type of housing. For the small rural communities surrounding the Minnesota Valley plant, this estimate will likely be higher than what is actually available. With a total population of about 62,000 in city and township areas with populations over 1,000 (50-mile radius), the amount of wood residue available could be up to 20,000 tons annually (including the sawmill residue above). Expanding the procurement area to 75 miles would increase the "urban" population to 240,400 (cities and townships with populations over 1,000) and the estimated amount of wood to 80,000 wet tons (approximately 48,000 dry tons at an average moisture content of 40%). While this seems like a significant amount, the cost and logistics of collecting and transporting most of this residue from dozens of different cities would be prohibitive given current conditions. Obviously, if a natural disaster such as a tornado or flood generated a large one-time source of wastewood (such as the St. Peter tornadoes), or if material is already collected and available (utility trimmings), the material could be collected and burned in the proposed WTE plant - a much better use than being burned or landfilled. For the purposes of this analysis, though, no "urban" waste is included in the fuel supply estimates.

Figure A7.5 Cities in Procurement Area

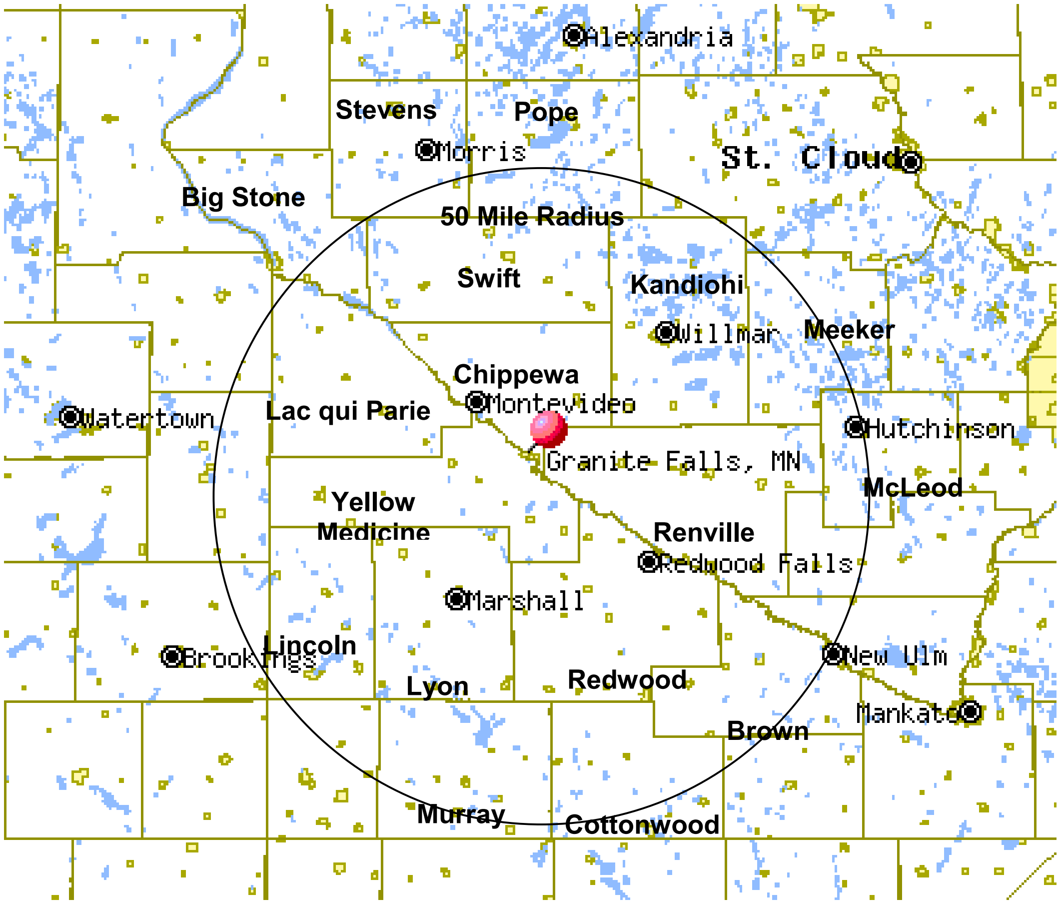


Figure A7.6 Cities in Fuel Supply Procurement Area

County	City or Township	2000
Chippewa	Montevideo	5,346
Chippewa	Clara City	1,393
Chippewa	Granite Falls (part)	1,045
Kandiyohi	Dovre township	1,968
Kandiyohi	Green Lake township	1,473
Kandiyohi	New London township	3,057
Kandiyohi	Willmar	18,351
Lyon	Marshall	12,735
Redwood	Redwood Falls (part)	5,459
Renville	Olivia	2,570
Swift	Appleton	2,871
Swift	Benson	3,376
Yellow Medicine	Granite Falls	2,025
	Total "Urban" Population	61,669

Appendix 8. Existing Wood Resources in 120 Mile Radius of Granite Falls

Estimated Biomass Resources in 120 Mile Radius (Including Residue)

	Units	15 Counties North of 50 Mi Radius	All Forestland in 120 Mile Radius Minnesota	Notes
Total Biomass				
Total volume of merchantable growing stock	million cu ft	745	1,088	FIA website data search for 13 county area - 1990 data updated 1996
Ratio of non-growing stock to growing stock		0.45	0.45	See Ratios sheet - from 1992 MN harvest information
Additional non-growing stock biomass	million cu ft	337	492	Total growing stock times ratio of non-growing stock/growing stock
Total timberland biomass	million cu ft	1,081	1,579	Calculation
Acres of timberland in region	acres	468,100	1,082,000	FIA website data search for 15 county area - 1990 data updated 1996
Average growing stock	cu ft/acre	1,591	1,005	Calculation - total volume/total acres
	dry ton/acre	25	16	Calculation
Non-growing stock (limbwood, cull, saplings, deac	cu ft/acre	719	454	Calculation
and logging slash)	dry ton/acre	11.2	7.1	Calculation
Total biomass	cu ft/acre	2,310	1,460	Calculation
	dry ton/acre	36	23	Calculation
Assumptions				
Conversion (cu. ft to dry lb)	lb/cu.ft.	31.2	31.2	Project Planning Handbook, www.nationalcarbonoffsetcoalition.org.
Total Removals				
Existing annual growing stock removals	million cubic feet	10.3	12.1	Source: North Central FIA web site query for 15 counties
Multiplier for estimated Year 2001 removals	Ratio	1.2	1.2	Represents increased harvest from 1990 to 2001 in Minnesota
Estimated growing stock removals 2001	million cubic feet	12.4	14.52	Calculation
Additional non-growing stock biomass	million cubic feet	5.6	6.6	Calculation
Total biomass removed (includes all residue)	million cubic feet	17.9	21.1	Calculation
	million lb	559.9	657.7	Calculation
	dry ton	279,939	328,860	Calculation
Proportion of total biomass not used for products	%	31%	31%	See Ratio sheet - assumes ratios from 1992 data apply to 2001 estimate
Biomass residue potentially available	million cubic feet	5.6	6.6	Calculation
	million lb	176.0	206.8	
	dry ton	88,015	103,396	Includes logging residue and logging slash from growing and non-growing sto
Amount of residue collectible for WTE plant		50%	50%	Estimate - some residue will be too difficult or expensive to collect
Net residue available for interim fuel supply	million cubic feet	2.8	3.3	Annual amount of residue from current harvests in area that could be used
	million lb	88	103	to fuel WTE plant during interim period before fuel supply is ready to harvest
	dry ton	**44,007**	**51,698**	Note: Most of residue is in the 15 counties north of the 50 mile radius
Average growing stock per acre	cu ft/acre	1,591	1,005	
	dry ton/acre	25	16	Note: Southern timberland much less productive than northern timberland
Estimated number of acres harvested, 2001	acres	7,768	14,443	Estimate based on above assumptions

Interim Fuel Supply Scenario for WTE Plant

Sources of Wood Fuel	Units	Value	Notes
Total annual interim fuel supply required	dry ton	191,294	Amount needed to fuel plant annually at 80% capacity factor
Sources of Interim Fuel			
Wastewood within 120 mile radius	dry ton	30,000	Includes storm damage, municipal trimmings, industrial wastewood etc.
Residue- existing harvests within 120 miles	dry ton	51,698	Estimate of amount of existing residue available in 120 mile radius (50% of total amount currently produced)
Small loads from independents	dry ton	10,000	Individuals and independents delivering wood from small plots, farms etc.
Harvest of existing SRWC plantations	dry ton	25,000	1000 acres/yr times average 25 dry tons per acre (Density may be higher on older, "overage" plantations)
Harvest of standing biomass	dry ton	74,596	Biomass needed from harvest of existing timberland biomass
Total biomass available in 120 mile radius	dry ton	24,637,354	Estimate of existing timberland biomass in 120 mile radiu
Percent of total biomass required for interim fuel		0.3%	Annual requirement for 2-3 years
Calculation of Annual Acreage Required			
Net amount of standing biomass needed	dry ton	74,596	See above calculation
Estimated total biomass per acre	dry ton/acre	36	Estimate for average on forestland in more productive acres in northern 15 counties - most likely harvesting area.
Percent of total biomass that is sawtimber quality		47%	Substract sawtimber from total biomass
Net amount of useable biomass per acre	dry ton/acre	19	Net biomass available per acre assuming all sawtimber quality wood is sold
Number of acres to be harvested for WTE plant	acre	3,929	Assumes sawtimber quality wood is sold to lumber mills Note: Less acres for existing demands will need to be harvested if the sawtimber from these acres is sold reducing the total number of acres needed to meet existing demands and the new temporary demand from WTE
Total timberland acres in 120 mile radius	acre	1,082,000	
Percent of timberland acres to be harvested	%	0.4%	

Assumptions

Amount required for retrofit plant	dry ton/yr	191,294	From Gatecycle model

Interim supply needed for 2-3 period after plant is constructed and before SRWC supply is ready for harvest.

Stumpage Cost Calculation for Existing Timberland Resources

Estimated stumpage value of wood per acre	$/acre	$	470	$	470	MN Finance and Commerce - 44,000 public acres @ $20.7 million in rev.
Estimated average stumpage cost - merchantable	$/ton	$	18.95	$	30.00	Calculation
Proportion non-growing stock			0.45		0.45	
Net cost for all biomass available	$/ton	$	10.39	$	16.44	Calculation - does not include subtraction for sawtimber revenue

Note: Stumpage costs vary significantly depending on species of wood, quality, location, demand etc. For instance, in 2001, stumpage prices for s
from $30.46/Mbf for cedar to $170.13/Mbf for white pine. Polewood varies similarly.
At $100/Mbf, sawtimber is about $33/dry ton for the merchantable portion of the wood.

Stumpage costs for residue varies from free to $5/cord or only about $2.25 per ton - in many cases skidded to a landing area near the harvesting si

Appendix 9. Fuel Supply Plan Proforma

Cash Flow Assumptions

5/13/0

Working Capital Assumptions(In Days)	Startup	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Accounts Receivable	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60

Fixed Asset Purchases (In Dollars)	Startup	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Buildings	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Building/Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Machinery & Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Office Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Automobiles	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fixed Asset Purchases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Financing (In Dollars)	Startup	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Sale of Stock	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash Dividends Declared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Proceeds from Short Term Loans	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Repayment of Short Term Loans	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Proceeds from Long Term Loans	$250,000	$5,000,000	$5,100,000	$6,100,000	$7,400,000	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Repayment of Long Term Loans	$0	$0	$0	$0	$0	$0	$857,000	$908,420	$962,925	$1,020,701	$1,081,943	$1,146,859	$1,215,671	$1,288,611	$1,365,928	$1,447,883	$1,534,756	$1,626,842	$1,724,452	$1,827,920	$1,937,5
Cumulative debt		$5,250,000	$10,350,000	$16,450,000	$23,850,000	$31,550,000	$30,693,000	$29,784,580	$28,821,655	$27,800,954	$26,719,011	$25,572,152	$24,356,481	$23,067,870	$21,701,942	$20,254,059	$18,719,302	$17,092,460	$15,368,008	$13,540,088	$11,602,4

Other Balance Sheet Accounts (In $)	Startup	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Purchase of Investments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sale of Investments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Notes Receivable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Collection of Notes Receivable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Other Current Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reduction of Other Current Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Other Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reduction of Other Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Other Payables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Decrease in Other Payables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Accrued Liabilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Decrease in Accrued Liabilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Income Statement

5/13/03

		Startup	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Sales											
Whole Tree Fuel	(1)	$0	$0	$0	$0	$0	$3,508,330	$8,770,824	$8,770,824	$8,770,824	$8,770,824
Total Sales		$0	$0	$0	$0	$0	$3,508,330	$8,770,824	$8,770,824	$8,770,824	$8,770,824
Farm Development Costs											
First Year Planting/Prep Costs		$0	$4,184,402	$1,768,978	$1,768,978	$1,768,978	$1,768,978	$0	$0	$0	$0
Second Year Prep Costs		$0	$0	$515,814	$515,814	$515,814	$515,814	$515,814	$0	$0	$0
Total Farm Development Costs	(2)	$0	$4,184,402	$2,284,792	$2,284,792	$2,284,792	$2,284,792	$515,814	$0	$0	$0
Other Farm Development Costs											
Farm Management		$106,700	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500
Marketing/Land Acquisition		$95,000	$80,000	$69,000	$64,000	$64,000	$58,000	$11,000	$11,000	$11,000	$11,000
Rent		$0	$812,023	$1,624,046	$2,436,069	$3,248,092	$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115
Total Other Farm Development Cost	(2)	$201,700	$1,249,523	$2,050,546	$2,857,569	$3,669,592	$4,475,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615
Total Cost		$201,700	$5,433,925	$4,335,338	$5,142,361	$5,954,384	$6,760,407	$4,944,429	$4,428,615	$4,428,615	$4,428,615
Gross Profit		($201,700)	($5,433,925)	($4,335,338)	($5,142,361)	($5,954,384)	($3,252,077)	$3,826,395	$4,342,209	$4,342,209	$4,342,209
Misc. Operating Expenses											
Crop Insurance	(3)	$0	$39,040	$78,079	$117,119	$156,158	$195,198	$195,198	$195,198	$195,198	$195,198
Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting		$0	$0	$0	$0	$0	$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826
Miscellaneous		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Costs		$0	$39,040	$78,079	$117,119	$156,158	$1,571,024	$1,571,024	$1,571,024	$1,571,024	$1,571,024
Total Operating Expenses		$0	$39,040	$78,079	$117,119	$156,158	$1,571,024	$1,571,024	$1,571,024	$1,571,024	$1,571,024
Income From Operations		($201,700)	($5,472,965)	($4,413,417)	($5,259,480)	($6,110,542)	($4,823,101)	$2,255,371	$2,771,185	$2,771,185	$2,771,185
Interest Income		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest Expense	(4)	$15,000	$315,000	$621,000	$987,000	$1,431,000	$1,893,000	$1,893,000	$1,841,580	$1,787,075	$1,729,299
Income before Taxes		($216,700)	($5,787,965)	($5,034,417)	($6,246,480)	($7,541,542)	($6,716,101)	$362,371	$929,605	$984,110	$1,041,886
Taxes on Income	(5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Income After Taxes		($216,700)	($5,787,965)	($5,034,417)	($6,246,480)	($7,541,542)	($6,716,101)	$362,371	$929,605	$984,110	$1,041,886

		Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Sales												
Whole Tree Fuel	(1)	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824
Total Sales		$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824	$8,770,824
Farm Development Costs												
First Year Planting/Prep Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Second Year Prep Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Farm Development Costs	(2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Farm Development Costs												
Farm Management		$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500	$357,500
Marketing/Land Acquisition		$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000
Rent		$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115	$4,060,115
Total Other Farm Development Cost	(2)	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615
Total Cost		$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615	$4,428,615
Gross Profit		$4,342,209	$4,342,209	$4,342,209	$4,342,209	$4,342,209	$4,342,209	$4,342,209	$4,342,209	$4,342,209	$4,342,209	$4,342,209
Misc. Operating Expenses												
Crop Insurance	(3)	$195,198	$195,198	$195,198	$195,198	$195,198	$195,198	$195,198	$195,198	$195,198	$195,198	$195,198
Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Harvesting		$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826	$1,375,826
Miscellaneous		$0	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9
Total Other Costs		$1,571,024	$1,571,024	$1,571,025	$1,571,026	$1,571,027	$1,571,028	$1,571,029	$1,571,030	$1,571,031	$1,571,032	$1,571,033
Total Operating Expenses		$1,571,024	$1,571,024	$1,571,025	$1,571,026	$1,571,027	$1,571,028	$1,571,029	$1,571,030	$1,571,031	$1,571,032	$1,571,033
Income From Operations		$2,771,185	$2,771,185	$2,771,184	$2,771,183	$2,771,182	$2,771,181	$2,771,180	$2,771,179	$2,771,178	$2,771,177	$2,771,176
Interest Income		$0	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9
Interest Expense	(4)	$1,668,057	$1,603,141	$1,534,329	$1,461,389	$1,384,072	$1,302,117	$1,215,244	$1,123,158	$1,025,548	$922,080	$812,405
Income before Taxes		$1,103,128	$1,168,045	$1,236,856	$1,309,796	$1,387,113	$1,469,069	$1,555,942	$1,648,027	$1,745,638	$1,849,105	$1,958,780
Taxes on Income	(5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Income After Taxes		$1,103,128	$1,168,045	$1,236,856	$1,309,796	$1,387,113	$1,469,069	$1,555,942	$1,648,027	$1,745,638	$1,849,105	$1,958,780

Balance Sheet

5/13/03

Assets		Startup	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Current Assets																						
Cash		$73,956	$146,083	$31,076	$17,258	$9,199	$1,029,477	$92,153	$28,546	$49,731	$70,916	$92,101	$113,287	$134,472	$155,657	$176,842	$198,028	$219,214	$240,399	$261,585	$282,769	$303,954
Investments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accounts Receivable		$0	$0	$0	$0	$0	$96,119	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297	$240,297
Notes Receivable		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Inventory		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Current Assets		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Current Assets		$73,956	$146,083	$31,076	$17,258	$9,199	$1,125,595	$332,449	$268,843	$290,028	$311,213	$332,398	$353,583	$374,769	$395,954	$417,139	$438,325	$459,510	$480,695	$501,881	$523,066	$544,251
Plant & Equipment																						
Land		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Buildings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Building/Leasehold Improvements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Machinery & Equipment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Office Equipment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Automobiles		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Plant & Equipment	(6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Self Generating/Regenerating As	(7)	$0	$755,666	$2,266,999	$4,533,997	$7,556,662	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993
Total Assets		$73,956	$901,749	$2,298,075	$4,551,256	$7,565,861	$12,460,588	$11,667,442	$11,603,836	$11,625,021	$11,646,206	$11,667,391	$11,688,577	$11,709,762	$11,730,947	$11,752,132	$11,773,318	$11,794,503	$11,815,689	$11,836,874	$11,858,059	$11,879,244
Liabilities & Owners' Equity																						
Current Liabilities																						
Short Term Debt		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accounts Payable		$33,156	$893,248	$712,658	$845,320	$978,803	$1,111,300	$812,783	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991
Other Payables		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accrued Liabilities		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Current Liabilities		$33,156	$893,248	$712,658	$845,320	$978,803	$1,111,300	$812,783	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991	$727,991
Long Term Debt	(8)	$250,000	$5,250,000	$10,350,000	$16,450,000	$23,850,000	$31,550,000	$30,693,000	$29,784,580	$28,821,655	$27,800,954	$26,719,011	$25,572,152	$24,356,481	$23,067,870	$21,701,942	$20,254,059	$18,719,303	$17,092,461	$15,368,009	$13,540,089	$11,602,494
Total Liabilities		$283,156	$6,143,248	$11,062,658	$17,295,320	$24,828,803	$32,661,300	$31,505,783	$30,512,571	$29,549,646	$28,528,945	$27,447,002	$26,300,143	$25,084,472	$23,795,861	$22,429,933	$20,982,050	$19,447,294	$17,820,452	$16,096,000	$14,268,080	$12,330,485
Owner/Stockholder Equity																						
Common Stock		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Retained Earnings		($209,200)	($5,997,165)	($11,031,582)	($17,278,062)	($24,819,604)	($31,535,705)	($31,173,334)	($30,243,728)	($29,259,618)	($28,217,732)	($27,114,604)	($25,946,560)	($24,709,703)	($23,399,907)	($22,012,794)	($20,543,725)	($18,987,784)	($17,339,757)	($15,594,119)	($13,745,014)	($11,786,234
Reserve: Plantation growth reva	(9)	$0	$755,666	$2,266,999	$4,533,997	$7,556,662	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993	$11,334,993
Dividends Payable		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Owners' Equity		($209,200)	($5,241,499)	($8,764,583)	($12,744,064)	($17,262,942)	($20,200,712)	($19,838,341)	($18,908,735)	($17,924,625)	($16,882,739)	($15,779,611)	($14,611,566)	($13,374,710)	($12,064,914)	($10,677,801)	($9,208,732)	($7,652,791)	($6,004,763)	($4,259,126)	($2,410,021)	($451,241
Total Liabilities & Equity		$73,956	$901,749	$2,298,075	$4,551,256	$7,565,861	$12,460,588	$11,667,442	$11,603,836	$11,625,021	$11,646,206	$11,667,391	$11,688,577	$11,709,762	$11,730,947	$11,752,132	$11,773,318	$11,794,503	$11,815,689	$11,836,874	$11,858,059	$11,879,244

Cash Flows

5/13/03

Sources of Cash:	Startup	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Operations during the year:																					
Net Income After Taxes	($216,700)	($5,787,965)	($5,034,417)	($6,246,480)	($7,541,542)	($6,716,101)	$362,371	$929,605	$984,110	$1,041,886	$1,103,128	$1,168,045	$1,236,856	$1,309,796	$1,387,113	$1,469,069	$1,555,942	$1,648,027	$1,745,638	$1,849,105	$1,958,780
Add items not decreasing cash																					
Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Accounts Payable	$33,156	$860,092	($180,590)	$132,662	$133,483	$132,497	($298,517)	($84,792)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Other Payables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Accrued Liabilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deduct items not increasing cash																					
Increase in Accounts Receivable	$0	$0	$0	$0	$0	$96,119	$144,178	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash from Operations	($183,544)	($4,927,873)	($5,215,007)	($6,113,818)	($7,408,059)	($6,679,723)	($80,324)	$844,813	$984,110	$1,041,886	$1,103,128	$1,168,045	$1,236,856	$1,309,796	$1,387,113	$1,469,069	$1,555,942	$1,648,027	$1,745,638	$1,849,105	$1,958,780
Financing & Other:																					
Sale of Stock	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Proceeds from Short Term Loans	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Proceeds from Long Term Loans $31,550,000	$250,000	$5,000,000	$5,100,000	$6,100,000	$7,400,000	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sale of Investments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Collection of Notes Receivable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reduction of Other Current Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reduction of Other Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash from Operations & Financing	$66,456	$72,127	($115,007)	($13,818)	($8,059)	$1,020,277	($80,324)	$844,813	$984,110	$1,041,886	$1,103,128	$1,168,045	$1,236,856	$1,309,796	$1,387,113	$1,469,069	$1,555,942	$1,648,027	$1,745,638	$1,849,105	$1,958,780
Applications of Cash:																					
Payment of Dividends	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Purchases of Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Repayment of Short Term Loans	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Repayment of Long Term Loans	$0	$0	$0	$0	$0	$0	$857,000	$908,420	$962,925	$1,020,701	$1,081,943	$1,146,859	$1,215,671	$1,288,611	$1,365,928	$1,447,883	$1,534,756	$1,626,842	$1,724,452	$1,827,920	$1,937,595
Purchase of Investments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Notes Receivable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Other Current Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase in Other Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Increase/(Decrease) in Cash	$66,456	$72,127	($115,007)	($13,818)	($8,059)	$1,020,277	($937,324)	($63,607)	$21,185	$21,185	$21,185	$21,186	$21,185	$21,185	$21,185	$21,186	$21,186	$21,185	$21,186	$21,185	$21,185
Change in Cash Balance																					
Ending Cash Balance	$73,956	$146,083	$31,076	$17,258	$9,199	$1,029,477	$92,153	$28,546	$49,731	$70,916	$92,101	$113,287	$134,472	$155,657	$176,842	$198,028	$219,214	$240,399	$261,585	$282,769	$303,954
Beginning Cash Balance	$0	$73,956	$146,083	$31,076	$17,258	$9,199	$1,029,477	$92,153	$28,546	$49,731	$70,916	$92,101	$113,287	$134,472	$155,657	$176,842	$198,028	$219,214	$240,399	$261,585	$282,769
Increase/(Decrease) in Cash	$73,956	$72,127	($115,007)	($13,818)	($8,059)	$1,020,277	($937,324)	($63,607)	$21,185	$21,185	$21,185	$21,186	$21,185	$21,185	$21,185	$21,186	$21,186	$21,185	$21,186	$21,185	$21,185

Long Term Debt Amortization Schedule

5/28/03

		Prestart	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
Long term debt		$250,000	$5,250,000	$10,350,000	$16,450,000	$23,850,000	$31,550,000	$30,693,000	$29,784,580	$28,821,655	$27,800,954	$26,719,011	$25,572,152	$24,356,481
Interest	6%	$15,000	$315,000	$621,000	$987,000	$1,431,000	$1,893,000	$1,841,580	$1,787,075	$1,729,299	$1,668,057	$1,603,141	$1,534,329	$1,461,389
Amortization schedule														
Beginning Balance								$31,550,000	$30,693,000	$29,784,580	$28,821,655	$27,800,954	$26,719,011	$25,572,152
Principal								$857,000	$908,420	$962,925	$1,020,701	$1,081,943	$1,146,859	$1,215,671
Interest								$1,893,000	$1,841,580	$1,787,075	$1,729,299	$1,668,057	$1,603,141	$1,534,329
Payment								$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000
Ending Balance								$30,693,000	$29,784,580	$28,821,655	$27,800,954	$26,719,011	$25,572,152	$24,356,481

Long Term Debt Amortization Schedule

5/28/03

	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
Long term debt	$23,067,870	$21,701,942	$20,254,059	$18,719,302	$17,092,460	$15,368,008	$13,540,088	$11,602,494	$9,548,643	$7,371,562	$5,063,856	$2,617,687	$24,748
Interest	$1,384,072	$1,302,117	$1,215,244	$1,123,158	$1,025,548	$922,080	$812,405	$696,150	$572,919	$442,294	$303,831	$157,061	$1,485
Amortization schedule													
Beginning Balance	$24,356,481	$23,067,870	$21,701,942	$20,254,059	$18,719,302	$17,092,460	$15,368,008	$13,540,088	$11,602,494	$9,548,643	$7,371,562	$5,063,856	$2,617,687
Principal	$1,288,611	$1,365,928	$1,447,883	$1,534,756	$1,626,842	$1,724,452	$1,827,920	$1,937,595	$2,053,850	$2,177,081	$2,307,706	$2,446,169	$2,592,939
Interest	$1,461,389	$1,384,072	$1,302,117	$1,215,244	$1,123,158	$1,025,548	$922,080	$812,405	$696,150	$572,919	$442,294	$303,831	$157,061
Payment	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000
Ending Balance	$23,067,870	$21,701,942	$20,254,059	$18,719,302	$17,092,460	$15,368,008	$13,540,088	$11,602,494	$9,548,643	$7,371,562	$5,063,856	$2,617,687	$24,748

Self Generating Asset Calculation

5/13/03

	Units	Value	Notes
First 3 years establishment costs	$	$15,113,324	Also includes startup year
Number of harvests from each plot		4	Estimate
Amount harvested each time	dry ton	191,294	Gatecycle data
Total harvested over 20 years	dry ton	765,175	Calculation
Average cost basis for asset	$/dry ton	$19.75	Calculation - no inflation or interest included

Assumptions:

(1) Price whole tree fuel at farm $45.85 per dry ton $2.64 per Mbtu (not including transportation costs).
(1) First harvest begins at end of growing season in Year 5 - model assumes 40% of acreage is harvested and sold for fuel in Year 5.
(2) Farm development costs are amortized over life of farms.
(3) Crop insurance estimated at $4.00 per acre per year
(4) Interest on long term debt is 6%
(5) No taxes are calculated - tax loss carry-forwards are assumed to balance any net income.
(6) All equipment is assumed to be leased. Cost is included in farm management costs.
(7) Self generating assets are the trees planted on the farms. Asset valued at extimated development cost per ton times the annual increase in growing stock

(9) Balancing entry for self generating assets.

Notes:

Model does not include the impact of potential tax benefits for using closed loop biomass, renewable energy sources or other types of benefits.

Minnesota Valley Generating Plant Conversion to Whole Tree Energy

Conceptual Design and Preliminary Cost Estimate

For Energy Performance Systems

UE Job Number: 010783
UE Project Manager: Mark Holmberg

November 2002

Revision 0

UTILITY ENGINEERING

Minnesota Valley Generating Plant
Conversion to Whole Tree Energy
Conceptual Design and Preliminary Cost Estimate

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D010783-S002	General Site Plan
D010783-S003	Drying Dome & Conveyor Foundations Plan
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D010783-S005	Drying Dome & Conveyor Sections
D010783-S006	CT, Heat Recovery Unit & Boiler Room Demolition Plan
D010783-S007	New CT, Heat Recovery Unit & Boiler Room Building Plan
D010783-E100	Preliminary One-Line Diagram

Minnesota Valley Generating Plant
Conversion to Whole Tree Energy
Conceptual Design and Preliminary Cost Estimate

Executive Summary

The Xcel Energy Minnesota Valley Generating Plant is located in Granite Falls, MN. The plant has one operational pulverized coal fired boiler and one operational steam turbine generator. This equipment went into operation in 1953 and is rated to produce 44 MW of electricity. The plant does not normally operate, but is URGE tested on an annual basis.

This conceptual design and preliminary cost estimate were developed to investigate the feasibility of converting the plant from coal to whole trees as a primary fuel. The wood handling, drying and burning method are based upon the Energy Performance System's Whole Tree Energy™ process.

Major portions of the existing plant are intended to be reused. Some of this equipment may need to be modified or replaced as detailed engineering design progresses. A detailed condition assessment to determine existing equipment condition and expected remaining life is recommended, but is not included in the scope of this study.

In addition to the conversion of the fuel handling and burning system, this study also investigated the addition of a combustion turbine at the site. A combustion turbine and heat recovery feedwater heater are additions to the plant that will increase peak plant output by approximately 20 MW and increase thermal cycle efficiency.

This study is preliminary and only addresses the particular items defined in the scope of work. The study does not attempt to address all the issues required to complete the conversion to the Whole Tree Energy™ process.

UTILITY ENGINEERING

Peter J. Schappa
Vice President and General Manager

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E-mail: Peter.J.Schappa@ue-corp.com

August 14, 2002

L. David Ostlie – CEO
Energy Performance Systems Inc.
7767 Elm Creek Blvd.
Maple Grove, MN 55369

Subject: Minnesota Valley Generating Plant
Conversion to Whole Tree Energy
Proposal for Preliminary Engineering

Mr. Ostlie,

We would like to thank you for the opportunity to become involved in the Whole Tree Energy Technology and to submit our proposal for preliminary engineering and estimating services.

Our proposal was developed based on information gathered from a plant site tour on August 7, 2002 and subsequent meetings with you, Ken Ragland, Rich Andresen, and MN Valley Plant Operators Don Berends and Sean Skogrand.

UE proposes to perform the following Scope of Work items, which were identified, in the meetings, as having the highest priority:

Whole Tree Energy Conversion with Combined Cycle CT

Scope of Work:

Civil/Structural:

1. Prepare preliminary site plan drawing to include existing plant and proposed tree handling equipment, drying dome, and demolition items.
2. Prepare preliminary dome layout, foundations, and cross section drawings.
3. Prepare preliminary CT and heat recovery arrangement drawings and foundation conceptual design.
4. Prepare preliminary support design for wood conveyor and charging hopper at boiler.
5. Prepare +/- 25% construction cost estimate for items 1-4 above.

Assumptions:

A. Dome layout and tree handling systems are based on EPS conceptual design.

Mechanical:

1. Prepare existing equipment list for #4 boiler and #3 STG.
2. Prepare preliminary list of equipment to be removed.
3. Prepare preliminary new equipment list based on EPS conceptual design.
4. Review CTG sizing (by EPS) and natural gas supply capability.
5. Determine preliminary boiler modifications required.
6. Determine preliminary balance of plant equipment modifications required.
7. Prepare +/- 25% construction cost estimate for items 2-6 above.

Assumptions:

A. EPS is to provide the overall plant heat and water balance.
B. Water treatment can be achieved with a standard demineralizer.
C. Water can be discharged into the river and the plant can operate under existing water permits.

Electrical & Controls:

1. Prepare preliminary 1-line diagram including proposed modifications to the existing station aux. system.
2. Prepare preliminary 1-line diagrams of the CTG outlet and additional modifications to the station aux. system.
3. Prepare +/- 25% construction cost estimates for items 1 & 2 above.
4. Prepare +/- 25 % construction cost estimate for replacement of the plant control system with a new DCS control system.

Assumptions:

A. The existing plant control system is assumed to be obsolete and not suitable for use with the new Whole Tree Energy Process and Combined Cycle CT equipment. This assumption can be investigated further during the detailed engineering phase.
B. Future total station auxiliary load will be equal to or less than the existing loads.
C. New 2400-volt switchgear can be tapped off the existing switchgear bus.
D. Existing station auxiliary transformer has sufficient capacity.

UE proposes to perform this Scope of Work on a time and expense basis in accordance with our attached billing rates for 2002. Our estimated cost for this work is $50,000 (not including expenses). Our billings will not exceed this amount unless authorized by EPS.

We currently have experienced staff available to immediately start work on this project.

Please contact Mark Holmberg (612 / 215-1337) if you have any questions or comments.

Sincerely,

Peter J. Schappa, V.P. and General Manager
Utility Engineering Corporation

PJS:ska

Enclosure

Cc: Mark H. Holmberg, Utility Engineering
Dick Ellis, Utility Engineering
File

Minnesota Valley Generating Plant
Conversion to Whole Tree Energy
Conceptual Design and Preliminary Cost Estimate

Project Report

Introduction

The Xcel Energy Minnesota Valley Generating Plant is located in Granite Falls, MN. The plant has one operational pulverized coal fired boiler (Boiler #4) and one operational steam turbine generator (Unit 3). This equipment went into operation in 1953. The plant is currently rated to produce 44 MW of electricity. The plant, however, does not run on a regular basis. The plant also has three retired boilers and two retired steam turbines.

This conceptual design and preliminary cost estimate was developed to investigate the feasibility of converting the Minnesota Valley Plant from coal as a primary fuel to whole trees as a primary fuel. The wood handling, drying and burning method are based upon the Energy Performance System's (EPS) Whole Tree Energy™ process.

Existing Plant Description

The Minnesota Valley plant can receive coal by train or truck. The coal is transferred from the coal yard to a bunker in the powerhouse via a crusher building and a conveyor. The coal travels from the bunker to three pulverizers and is then blown into the boiler by six burners located on the west side of the boiler.

The plant has a water softening system to produce cycle makeup water. The condensate is pumped through a series of feedwater heaters and a deaerator. The condensate then flows to the feed pumps, which supply high-pressure water to the boiler. The once-through cooling system takes water from the Minnesota River to cool the condenser. The used water is returned to the river via an outlet structure downstream. Ash from the boiler is sent to the settling ponds located to the east of the boiler building. The exhaust from the boiler is sent through an electrostatic precipitator prior to going to the stack.

Proposed Plant Conversion

The proposed conversion of the plant has four main areas:

1. Tree Drying Facility
2. Fuel Handling and Boiler Modifications
3. Combustion Turbine and Heat Recovery Feedwater Heater
4. Balance of Plant Equipment

The Tree Drying Facility and Fuel Handling and Boiler Modifications are required to convert the plant from coal to whole trees as a fuel. The Combustion Turbine and Heat Recovery Feedwater Heater are additions to the plant that will increase peak plant output by approximately 20 MW and increase thermal cycle efficiency. The Balance of Plant modifications are required due to the increased steam and water flow requirements for combined cycle operation.

Tree Drying Facility

System Description

The proposed tree drying facility consists of an air supported fabric dome, a tree drying air distribution system, a tower crane tree handling system and an integrated firewater storage system. The fabric dome is made of dual-ply fabric material reinforced with a steel cable system that is anchored to a perimeter concrete foundation. The proposed dome is 410 feet in diameter and 145 feet high to accommodate a 300-foot diameter by 70-foot tall drying tree pile. The required volume of the tree pile for the proposed power plant is based on an EPS design.

The drying air distribution system includes a central distribution ring and radial air tunnels for drying air distribution under the tree pile. The proposed air tunnel system layout and sizing is based on conceptual design information supplied by EPS. A controlled vent is to be installed at the top of the dome for moist drying air discharge. The fabric dome is supported by the drying air supply during the normal tree-drying operation. A motor driven air supply system equipped with a back-up diesel generator will be used for keeping the dome inflated during emergency and plant shut down periods.

The 25 ton capacity tower crane with a 150 foot boom range is located at the center of the tree pile and the dome. The tower crane is equipped with an EPS proprietary tree grapple system for tree handling. The crane foundation structure is designed to contain a 65,000 gallon concrete firewater storage tank.

Based on the requirements supplied by EPS, the preliminary conceptual design and layout of the Tree Drying facility is shown on UE drawings D010783-006S002 and D010783-006S003. The tree drying facility integrates a covered dome with whole tree unloading, storage, drying and a fuel handling system as indicated on the drawings.

Trucks carrying whole trees arrive from an off-site location at the northwest plant entrance. A new two-lane, 24-foot wide, access road is required to accommodate the traffic from the fuel trucks. Trucks enter the drying area through a dome opening and travel down a 50-foot access to a weigh station. Once the fuel is unloaded, the trucks back out of the drying dome, turn around in a designated area, and leave the plant by way of the new access road.

Electrical Description

Electrical Distribution and Control Equipment identified on preliminary one line drawing D010783-LSI100 for the Tree drying facility includes:

1. 2400V starters for three 500 HP Dome Heater Fans to supply heated air to the dome for drying of trees.
2. A 480V feed to the dome facility from newly installed 480V switchgear. This will feed a motor control center with starters and distribution feeders as required.

Assumptions

1. The layout and sizing of the drying air distribution system supplied by EPS is assumed to be feasible.
2. The volume of the drying tree pile is assumed to be adequate.
3. The shape of the tree stack is assumed to be nearly vertical as indicated by EPS.
4. Control of the air loss at the outlet of the truck loading entrance is assumed to be feasible in order to maintain the air support of the dome and drying efficiency of the fuel.
5. Tree drying process and capacity is assumed to be feasible to supply the plant at full load operation.
6. An access road with 12-foot lanes will be adequate to carry the fuel truck traffic.
7. Sanitary system in the dome is not considered.
8. The dome crane will be powered off the 480V MCC.

Areas of Concern / Additional Study

1. Fire protection and detection of the drying dome.
2. Safety of the work environment for operators.
3. Stability of tree pile under normal tree handling operations.
4. Water condensation in dome.
5. A complete listing of 480V loads for this system was not available, and preliminary one-line diagrams below the 480V switchgear level were not identified.
6. Costs associated with the installation of equipment powered from the 480V or 2400V switchgear have not been determined.

Fuel Handling and Boiler Modifications

System Description

The Whole Tree Fuel Handling System is based on proprietary EPS design and includes the hydraulically operated ratcheting drag conveyor, fuel feed rams extending across the boiler front wall, sizing saw and seal doors. This new equipment will replace the existing coal conveyors, feeders, pulverizers and accessories. Wood dust collection/containment and fire protection systems are required. The existing building structure requires modification. The existing burners, piping, ducting and coal bunker structure are to be removed as required for new equipment installation.

The conveyor system is supported at approximately 25-foot intervals. Each support consists of a 45-foot steel frame, braced in the east-west direction, resting on concrete foundations as shown on UE drawings D010783-006S004 and D010783-006S005. Steel support beams run north-south connecting the tops of each frame and the existing building. Inside the building the conveyor is supported by steel frames resting on the existing building floor. The new hopper and ram systems are supported off of the existing floor structure.

The Riley-Stoker Corp Boiler # 4 was placed in service in November 1953 and was originally rated at approximately 51 MW (see Ref. #4) for firing with Western Kentucky coal. The fuel was converted round 1974 to Western coal, resulting in a boiler derate to approximately 40 MW. Currently, the plant #4 boiler may be used for emergencies but requires advanced trucking of large quantities of coal. In June 2002, a four hour URGE test generated 44 MW of capacity.

Converting the boiler for Deep Fixed Bed Combustion requires extensive internal and external modifications. Babcock Borsig Power, Inc (Ref.#7), manufacturer of the original equipment, reviewed the proposed boiler modifications and provided a cost estimate. A letter describing their scope of work and design concerns is attached to this report.

Additional modifications to boiler auxiliary equipment have been identified in conjunction with modifications to the boiler. The Forced Draft Fan ductwork requires rerouting to allow for an adequate air supply of overfire and underfire air. An additional fan is required for the air-cooled char burnout grate. A new Induced Draft Fan and ductwork are needed for the condensing heat exchanger. In addition, a CO_2 blanketing system is needed for fire protection.

The Wood Drying Air System uses boiler flue gas waste heat supplied by a new condensing heat exchanger. Three new large capacity high efficiency Drying FD Fans (three at 33%) blow fresh air through the condensing heat exchanger and subsequent ductwork to the Drying Dome.

Electrical Description

Electrical Distribution and Control Equipment (shown on preliminary one line D010783-LSIE100) for operation of the fuel handling and boiler modification systems are supplied from a 480V feed from the proposed 480V switchgear.

Assumptions

1. The 8' x 8' cross section conveyor of EPS design will be capable of transporting the whole trees without hang-ups or jamming of the trees.
2. The existing building is able to withstand lateral and dynamic loads produced by the conveyor.
3. Control of the air loss at the outlet of Ratchet Drag Conveying System is assumed to be feasible in order to maintain air support of the dome.
4. The existing floor will be able to withstand the weight and forces induced by the ram system.
5. Existing boiler conversion is based on EPS proprietary Whole Tree Energy™ Process Design and Combined Cycle Plant Preliminary Heat and Water Balance.
6. The roof for the old end of the building (Boilers 1, 2, 3) will need structural modification to support the three new drying fans and condensing heat exchanger. An allowance for these improvements has been made in the cost sheets.
7. Rerouting the ductwork from the ID Fan to the new condensing heat exchanger will not require structural modifications to the boiler #4 building.

Areas of Concern / Additional Study

1. Density of the trees in the conveyor will require further verification.
2. Forces caused by the ratcheting drag conveyor require further analysis to determine the impact on new and existing structures.
3. Forces and sizes of the ram system require further investigation to determine the adequacy of the existing floor structure.
4. Babcock Borsig Power Inc. as a company still has reservation as to the viability of this technology and believes that there is significant work that still needs to be done to finalize a design that will meet all of the objectives for a successful project. To get to the next stage of designing components that will live in the environment that we will be subjecting this boiler to (in burning whole trees), an engineering study will be required. The engineering study may exceed a quarter of a million dollars.
5. By developing the boiler budget price, Babcock Borsig Power, Inc. will not warrantee or guarantee that the process is viability.
6. Concerning the performance of the boiler, if the system represented provides the flue gas weights and temperatures at the furnace exit that the coal-fired unit does, then the balance of the convective surface should work as it currently does. Also, in this budget Babcock Borsig Power, Inc. have not taken into account the current condition of the boiler. It is their understanding that a condition assessment will be performed under the next phase of the project and they would like to provide this service.

7. The air ducting layout for underfire, overfire, and char zone air needs additional study to verify new equipment performance and existing structural dimensional requirements.
8. The whole tree feed doors and mechanism layout needs to be reviewed to ensure no interference with feed opening headers, overfire air ducting, building structure and accessories.
9. The ability of the existing bottom ash sluice system to integrate with the ash pelletizing system needs to be verified.
10. A complete listing of 480V loads for this system is not available, and preliminary one-line diagrams below the 480V switchgear level were not identified.
11. Costs associated with the installation of equipment powered from the 480V or 2400V switchgear have not been determined.

Combustion Turbine and Heat Recovery Feedwater Heater

System Description

A new combustion turbine and heat recovery feedwater heater are to be installed in the southwest corner of the plant. The retired Unit 1 and Unit 2 steam turbine generators are to be removed from the plant to make room for the new equipment. The floor of the machine shop located on the western end of the building is to be removed to make room for the heat recovery unit, which fits inside the existing building. The preliminary layout of this equipment is shown on UE drawings D010783-006S007.

The combustion turbine is a General Electric LM2500, nominal 23 MW, 60 Hz machine. The turbine inlet air is supplied from a duct through the south wall of the building. This equipment package includes a 13.8 kV generator, dry low NOx burners, acoustic enclosure, inlet air filter, lube oil, hydraulic starter and fire protection system.

The heat recovery feedwater heater uses the exhaust from the combustion turbine to heat condensate water prior to going to the boiler feed pumps. When the heat recovery feedwater heater is in use, the existing feedwater heaters that take extraction steam from the steam turbine are bypassed. Dual operation of two existing boiler feedwater pumps is expected for the Combined Cycle bypassing requirements.

The existing natural gas supply line to the plant is to be reused to supply the fuel for the combustion turbine. New flow meters are to be installed to accommodate the additional gas flow. A new gas compressor station is required to boost the pressure of the natural gas for the combustion turbine. Two 100% compressors (700 horsepower) are to be located in a stand-alone building outside the plant to supply 200 MCF/hr of gas to the turbine.

The structural support systems for the proposed combustion turbine and heat recovery unit involve two retrofitted concrete foundations. The existing steam turbine foundations are to be extended up to the turbine floor as part of the combustion turbine foundation. These extensions are bridged with a concrete beam and slab system creating a structural platform on which the turbine will be located. The heat recovery unit foundation is a concrete structural platform supported on the west side of the existing turbine foundation extending to the existing west plant wall. The foundation of the heat recovery unit is also supported on several additional concrete columns that extend eight feet down to the existing ground floor.

Electrical Description

Electrical Distribution and Control Equipment identified on preliminary one line D010783-LSIE100 for operation of the new combustion turbine and heat recovery unit includes:

1. 13.8 KV Main Breaker
2. 15 KV Bus from the Generator to the new GSU transformer

3. 25 MVA GSU Transformer & Protective Relaying
4. (2) 2400V Full Voltage Non Reversing (FVNR) starters for (2) 700 HP Gas Compressors
5. 480V Distribution feeder(s) to Combustion Turbine 480V Motor Control Center(s)
6. Combustion Turbine 480V Motor Control Center(s)

Additional equipment not shown on the one line includes:

7. Balance of Plant Distribution for Lighting, Welding Receptacles, Heaters, Sump Pumps, etc. already located in the retired Units 1 and 2 area.
8. Protective Relaying for Generator.
9. Digital Control and Monitoring System for the Turbine – Generator

The new GSU transformer is to be located near the east end of the substation to allow for a shorter distance (and lower cost) installation of Bus from the Generator breaker. A new 115 KV overhead transmission line from the GSU transformer to the substation bus is required.

Newly installed 2400V Switchgear / Motor Control Center provides power for the Gas Compressors. 480V Power to the 480V MCC's will be provided from new 480V switchgear.

Balance of Plant Distribution equipment associated with retired Units 1 and 2 requires replacement. The existing equipment is from original construction in approximately 1930 and poses issues with safety and reliability. Distribution equipment requiring removal includes:

1. Six 333 KVA 13.8/480 Oil filled transformers
2. One 100 KVA, 480/120 Oil filled transformer
3. Two 25 KVA 480/120/240 Oil filled transformers
4. Three 240/120V Oil filled circuit breakers (Old End Basement)
5. Two 480V Oil filled circuit breakers (Sta. Aux Bus 1,2)
6. One Switchgear containing approximately 22, 480V air circuit breakers with oil dashpot trip units.

Upon removal of the above equipment, it is recommended that new switchboard(s) containing molded case breakers be installed in the area where the existing circuit breakers are located. The 480V circuits requiring re-feeding can be re-fed from the new switchboard(s). Power for the new 480V switchboard is supplied from new 480V switchgear.

Assumptions

1. Existing foundations for Unit 1 and Unit 2 steam turbine generators can be reused and augmented.
2. The existing ground floor foundation is capable of supporting the new heat recovery foundation.

3. Heat recovery feedwater heater can fit into machine shop space to avoid demolition of generator foundation and condenser.
4. The dry low-NOx burners in the combustion turbine will not require additional emissions control equipment.
5. Existing cooling water pumps can be used for cooling combustion turbine loads.
6. It is assumed for pricing purposes that the length of the bus required from the Generator main breaker to the GSU transformer is 120 feet.

Areas of Concern / Additional Study

1. The ability of the existing steam turbine to take the additional flow caused by eliminating steam extraction for feedwater heating needs to be investigated.
2. The proposed design of the foundation systems is conceptual and preliminary given the limited scope of this study. The feasibility of the proposed design need to be further evaluated.
3. Dynamic evaluation and analysis of the proposed structural support need to be addressed.
4. Existing Motor Starters re-fed from the new 480V switchboards may also require replacement due to age.
5. Existing molded case breakers in distribution panels should be replaced.
6. The new 115 kV overhead transmission line from the GSU transformer to the substation bus needs further investigation to determine costs.
7. It is not known if a 115 kV breaker is available and suitable for use.
8. A complete listing of 480V loads for the heat recovery system is not available, and preliminary one-line diagrams below the 480V switchgear level were not identified.
9. Costs associated with the installation of equipment powered from the 480V or 2400V switchgear have not been determined.

Balance of Plant Equipment

System Description

Major portions of the existing plant are intended to be reused. Some of this equipment may need to be modified or replaced depending on requirements of new plant operations. The performance of a detailed condition assessment of existing equipment to determine equipment condition or expected equipment life is recommended, but is not included in the scope of this study. A preliminary technical review of the existing plant equipment is described below.

The existing # 3 GE Steam Turbine – Generator is rated at 40 MW, 44 MW maximum, built in 1952 and overhauled in 1991 is intended to operate with 5 (five) steam extractions (four FW Heaters and one DA Heater) for the Simple Cycle operation and 2 (two) steam extractions (DA Heater) for Combined Cycle operation. Complete GE data and details regarding efficiencies, steam flow and maximum continuous rating is required during detailed engineering design. Rework of the extraction line drains for increased combined cycle flow is required to avoid turbine water damage.

The Main Condenser, a 30,000 sq. ft. two pass, built by Conseco and retubed during the 1990's by Moorhead Machinery is to operate with approximately 40% higher load during combined cycle operation. Preliminary thermal performance review for increased steam flow rates reveals operating requirements of increased circulating water flow and increased temperature differentials.

The existing single condensate pump rated at 600 gpm needs to be replaced with two pumps to provide improved plant reliability and meet the increased flow demand. The pump arrangement must be reworked to avoid potential cavitation damage.

Two low pressure (#31 & #32) and two high pressure (#34 & #35) Foster Wheeler Feed Water Heaters use turbine extraction steam to heat feed water. These existing feedwater heaters are required for simple cycle operation. HPFWH #35 needs to be replaced. The direct contact spray tray vertical Deaerator has a capacity of 325,000 pounds per hour (pph) and needs to be inspected to assess internal condition.

The Worthington Boiler Feedwater Pumps (two at 100%) are rated for 861 gpm, 3838 ft Total Head and 1030 brake horsepower (BHP) at 75% efficiency. Based on the approximate data head/flow curve, combined cycle dual pump operation is a viable option. Piping lines to the heat recovery feedwater heater are to be sized accordingly.

The two large (14,000 gpm x 27 ft TDH) once thru Circulating Water Pumps and related systems are to be reused for the larger temperature range operation. The two 1000 gpm Cooling Water Pumps replaced during the 1990's are to be used for Steam Turbine–Generator and auxiliaries heat removal.

The existing major equipment associated with the fresh air and flue gas system consists of an FD Fan, air preheater, electrostatic precipitator, ID Fan, associated ductwork and flue gas stack. The boiler fresh air ductwork requires modification for triple zone flow and increased air underfire / overfire ratio. Rework of the ductwork configuration from the electrostatic precipitator to the stack and a new larger ID fan are required due to the addition of the condensing heat exchanger.

A New Ash Pelletizing / Handling System is to be added to the existing equipment to process fly ash from the economizer and precipitator as well as boiler bottom sluice ash. The volume of ash generated by burning wood is significantly lower than the volume produce by burning coal.

A new Fire Protection System is to be provided for all new systems and related equipment.

Coal handling, storage, pulverizing, boiler burners and auxiliaries are to be removed. Areas of the coal yard and portions of the plant that require equipment removal and demolition work are shown in UE drawings D010783-006S001 and D010783-006S006.

Electrical Description

Electrical Distribution and Control Equipment changes for operation of the Balance of Plant equipment including re-powered unit 3 as shown on preliminary one-line D010783-LSI100 includes:

1. Replace (2) Existing station aux transformers (31, 32) rated 13.8 KV/2.4 KV, 4687 KVA with new units with a rating of 5600/7000 KVA. New transformers are to be oil filled and located in the same general area as the existing transformers.
2. Replace existing 2400V switchgear with (2) 1200A main breakers with new switchgear with (2) 2000A main breakers and medium voltage motor control center.
3. Install (2) new bus (5KV, 2000A) from 2.4 KV side of 5600/7000 KVA transformers to 2.4 KV switchgear.
4. Remove existing 750 KVA 2400V/480V transformer (301) and existing 480V switchgear, and replace it with a new 480V Double ended substation. The new transformers will be dry type base rated 1500 KVA, and located indoors.
5. Remove existing 2400V/120/240 KVA lighting transformer (31 LTG Bank) and replace it with a new dry type transformer fed from the 480V switchgear.
6. Install new DCS system.

Assumptions

1. Evaluation of balance of plant equipment is based on EPS proprietary Whole Tree Energy™ Process Design and Combined Cycle Plant Preliminary Heat and Water Balance.
2. Existing structure can be modified to reroute the ID Fan and Ductwork to Unit # 4 Stack thru the new Condensing Heat Exchanger.
3. Existing boiler feedwater pumps can be operated in parallel to meet the Combined Cycle increased head requirements.

4. Existing FD Fan - ID Fan Tandem Operation can be duplicated for the new conditions.
5. Existing Plant and Instrument Air Systems are to be reviewed and reused.
6. Actual condition of the existing reused equipment will need to be determined and appropriate reconditioning or replacement measures be taken to assure complete functionality and safety.
7. New equipment constructed to fit existing layout restraints.
8. Increased thermal effluent discharge heat load and temperature differential will be within MN.0000906 NPDES/SDS Permit Outfall 010 to river mixing zone allowable limits.
9. It is assumed that the 5KV, 2000A buses are each 40 feet in length for estimating purposes.
10. It is assumed that all areas where new electrical distribution equipment is being installed are classified as NFPA non-hazardous.

Areas of Concern / Additional Study

1. The original steam turbine generator rating and de-rating as described on SWEC report (reference 3) needs to be verified.
2. Plant HVAC needs to be evaluated for additional loads.
3. Renewal of effluent water discharge permit issued in 1999 needs to be investigated.
4. The generator winding insulation (stator, field, excitation) condition is not known, testing and study are required.
5. The existing 1952 vintage GSU3 transformer winding condition is not known and requires further testing and evaluation.
6. The condition of the existing insulation system for the cables (1952 vintage, direct buried) from the generator mains to GSU3 is not known and should be studied further. Similar cable systems at High Bridge and Black Dog required replacement.
7. Existing molded case breakers in panels should be considered for replacement
8. Lighting is primarily incandescent, and should be considered for upgrade to a lower maintenance, lower cost of operation system such as fluorescent or metal halide. It is likely that energy savings will allow for a relatively quick payback on investment in new lighting where the lighting has high hours of operation.
9. The existing excitation system (Amplidyne) and voltage regulation system should be replaced.
10. Protective relaying for the Generator and GSU transformer needs to be evaluated for possible replacement.
11. The generator neutral reactor appears to be oil filled, and should be replaced with either a dry type unit or fluid filled unit rated for indoor applications.
12. Status of the CEMS system needs to be investigated.
13. A complete listing of 480V loads for each system is not available, and preliminary one-line diagrams below the 480V switchgear level were not identified.
14. It may be advantageous to convert the 2400V distribution system to a 4160V distribution system. Reasons for this include:
    a. The majority of the existing motors were increased in horsepower.

   b. With 4160V distribution, new cables require less copper cross section.
   c. With 4160V distribution, 1200A switchgear mains are likely adequate.

15. If circulating water pumps 31 and 32 are replaced with higher horsepower motors, it may be advantageous to move them to the 480V system. Reasons for this include:
    a. 200 HP motors are likely less expensive at 480V than 2400V.
    b. 200 HP Motor Control is likely less expensive at 480V than 2400V.
16. The capability of the 1970's vintage electrostatic precipitators needs to be evaluated.
17. Costs associated with the installation of equipment powered from the 480V or 2400V switchgear have not been determined.

Minnesota Valley Generating Plant
Conversion to Whole Tree Energy
Conceptual Design and Preliminary Cost Estimate

Preliminary Cost Estimate

Introduction

The attached cost sheets list the estimated equipment and installation costs of major pieces of equipment required for the conversion of the Xcel Energy Minnesota Valley plant from burning coal to using Whole Tree Energy™ technology. These preliminary costs represent only the direct costs associated with this project. Indirect costs associated with engineering, permits, legal, financial, taxes, geo-technical investigations have not been included.

This cost estimate is preliminary and only addresses the particular items defined in the scope of work. The study does not attempt to address all the costs that would be incurred to complete the conversion of the plant.

The costs information came from a variety of sources including original equipment manufacturers, past project experience, previous Energy Performance System studies, and site specific construction estimates. The source of each line item is cited in the cost tables.

Assumptions

1. Costs for abatement of hazardous materials such as asbestos insulation, lead paint, and PCBs are not included in this estimate.
2. No handling or disposal of hazardous materials has been included in this estimate.
3. Demolition estimates include disposal of identified scrap materials.
4. Demolition estimates include removal of salvageable equipment. The estimate does not include transportation and resale of salvaged equipment.
5. Demolition estimates were priced for non-union labor.
6. Costs taken from previous EPS studies were escalated by 4% per year.

Minnesota Valley Plant Conversion
Preliminary Cost Estimate

Tree Drying Facility Cost	$9,851,000
Fuel Handling and Balance of Plant Cost	$7,754,000
Boiler Modification Cost	$12,863,000
Combustion Turbine and Heat Recovery Feedwater Heater	$18,764,000

Total Cost**	**$49,232,000**

** Represents the direct costs of only the items within the scope of this study

Tree Drying Facility Cost

Item	Unit	Qty.	Unit Cost	Extended Cost	Source
Drying Dome	S.F.	132,000	$12	$1,584,000	Environmental Structures Inc.
- Long life cover	inc.				
- Fans	inc.				
- Air lock door	inc.				
- Emergency back-up system	inc.				
Drying Dome Foundation	C.Y.	1,240	$365	$453,000	UE Preliminary Estimate
Fire Protection System	Each	1	$350,000	$350,000	EPS 50 MW Study
Drying facility floor & radial air distribution					
Floor pad	C.Y.	2,600	$315	$819,000	UE Preliminary Estimate
Large stem wall (19)	C.Y.	610	$415	$253,000	UE Preliminary Estimate
Medium stem wall (18)	C.Y.	500	$415	$208,000	UE Preliminary Estimate
Small stem wall (36)	C.Y.	580	$415	$241,000	UE Preliminary Estimate
Truck drive	C.Y.	40	$315	$13,000	UE Preliminary Estimate
Perimeter wall	C.Y.	170	$415	$71,000	UE Preliminary Estimate
Crane foundation	C.Y.	400	$450	$180,000	UE Preliminary Estimate
- 65,000 fire water storage tank	inc.				
Air tunnel cover slab	C.Y.	50	$450	$23,000	UE Preliminary Estimate
Soil excavation/Site preparation	C.Y.	64,000	$8.05	$515,000	UE Preliminary Estimate
Air Flow Control gates	Each	18	$5,000	$90,000	Allowance
Crane					
Crane - 1000m-ton with 150' boom	Each	1	$2,000,000	$2,000,000	Morrow Equipment Company
Crane grapple & controls	Each	2	$73,000	$146,000	EPS 50 MW Study
Weigh Station	Each	1	$190,000	$190,000	EPS 50 MW Study
Access Roadway & Unloading					
12" Base Course	S.Y.	3,750	$14.90	$56,000	UE Preliminary Estimate
3" Binder Course	S.Y.	3,750	$5.35	$20,000	UE Preliminary Estimate
1" Wear Course	S.Y.	3,750	$2.25	$8,000	UE Preliminary Estimate
Demolition					
Railroad Track	L.F.	1,800	$8.60	$15,000	UE Preliminary Estimate
Existing Pavement Removal	S.Y.	1,250	$6.25	$8,000	UE Preliminary Estimate
Coal Unloading System Building	Each	1	$92,000	$92,000	Fagen Inc. 10.25.02
Underground Tunnel/Conveyor	Each	1	$89,000	$89,000	Fagen Inc. 10.25.02
Retired Conveyor	Each	1	$89,000	$89,000	Fagen Inc. 10.25.02
Train Trestle & Assoc. Conveyors	Each	1	$52,000	$52,000	Fagen Inc. 10.25.02
Coal Crushing Facility / Up Ramp	Each	1	$45,000	$45,000	Fagen Inc. 10.25.02
Coal Reclaiming Hopper	Each	2	$18,000	$36,000	Fagen Inc. 10.25.02
Conveyor to Boiler 4	Each	1	$116,000	$116,000	Fagen Inc. 10.25.02
Bulldozer House	Each	1	$14,000	$14,000	Fagen Inc. 10.25.02
Misc. Coal Yard Foundations	Lot	1	$105,000	$105,000	Fagen Inc. 10.25.02
Item Total				$7,881,000	
		25% Contingency		$1,970,000	
		Sub-Total		**$9,851,000**	

Fuel Handling and Balance of Plant Cost

Item	Unit	Qty.	Unit Cost	Extended Cost	Source
Conveyor Support					
Foundation	C.Y.	56	$400	$22,000	UE Preliminary Estimate
Conveyor support frame					
- Columns	Lb.	28,000	$1.30	$36,000	UE Preliminary Estimate
- Struts	Lb.	14,260	$4.10	$58,000	UE Preliminary Estimate
- Bracing	Lb.	20,560	$4.10	$84,000	UE Preliminary Estimate
- Beams	Lb.	30,000	$1.40	$42,000	UE Preliminary Estimate
Fuel Loading Ram System Support	Lb.	17,000	$2.00	$34,000	UE Preliminary Estimate
Drag Conveyor	Feet	250	$900	$225,000	1994 EPRI 100 MW Study
Fuel Handling					
Sizing Saw & Ram Feed	Each	1	$1,225,000	$1,225,000	EPS 50 MW Study
Dust Collection	Each	1	$305,000	$305,000	EPS 50 MW Study
Balance of Plant					
Condensate Pumps	Each	2	$70,000	$140,000	UE Preliminary Estimate
Feedwater Heater #35 Replacement	Each	1	$80,000	$80,000	Yuba Heat Transfer 10.30.02
Ash Pelletizing System	Each	1	$125,000	$125,000	EPS 50 MW Study
Fire Protection System	Each	1	$150,000	$150,000	UE Preliminary Estimate
Electrical					
5600/7000 KVA Transformers	Each	2	$80,000	$160,000	ABB
2000A, 5KV Bus, 40 ft	Each	2	$12,000	$24,000	MP Husky
5KV Switchgear/MCC	Each	1	$281,000	$281,000	Cutler-Hammer
480V Switchgear/Transformers	Each	1	$200,000	$200,000	Cutler-Hammer
(2) Lighting Transformers	Lot	1	$15,000	$15,000	UE Preliminary Estimate
Distribution Panelboards	Each	2	$8,000	$16,000	UE Preliminary Estimate
Install Electrical	Lot	1	$728,000	$728,000	UE Preliminary Estimate
DCS System (Install, Materials)	Lot	1	$1,700,000	$1,700,000	UE Preliminary Estimate
Demolition					
Coal Pulverizer Chutes	Each	3	$5,000	$15,000	Fagen Inc. 10.25.02
Remove Bottom of Bunker	Each	1	$225,000	$225,000	Fagen Inc. 10.25.02
Wall Opening for Conveyor	Each	1	$35,000	$35,000	Fagen Inc. 10.25.02
Floor Removal	Each	1	$75,000	$75,000	Fagen Inc. 10.25.02
Electrical Demolition	Each	1	$203,000	$203,000	Fagen Inc. 10.25.02
Item Total				$6,203,000	
		25% Contingency		$1,551,000	
		Sub-Total		**$7,754,000**	

Boiler Modification Cost

Item	Unit	Qty.	Unit Cost	Extended Cost	Source
Boiler Modifications					
Materials for Modifications	Each	1	$2,900,000	$2,900,000	Babcock Borsig Power 11.19.02
Installation	Each	1	$2,900,000	$2,900,000	Babcock Borsig Power 11.19.02
Boiler Mfg. Engineering Study	inc.				
Remove Existing Burners	inc.				
Rework Front Wall Opening	inc.				
Rework Water Wall Piping	inc.				
Protection for Water Walls from Logs	inc.				
Add Header for Boiler Opening	inc.				
Water Cooled Burning Grate	inc.				
Char Grate	inc.				
Rework Bottom Ash Dump Grate	inc.				
Provide Char Air Opening and Duct	inc.				
Provide Instrument Openings	inc.				
Boiler Accessories					
Furnace Door System	Lot	1	$150,000	$150,000	Allowance
FD Ductwork Modification	Lot	1	$350,000	$350,000	EPS 50 MW Study
ID Fan & Motor	Each	1	$120,000	$120,000	UE Preliminary Estimate
ID Fan Replacement	Each	1	$99,000	$99,000	Fagen Inc. 10.25.02
Char Fan and Ductwork	Lot	1	$50,000	$50,000	Allowance
Fuel Grate Support Structure	Lot	1	$50,000	$50,000	Allowance
Building Structure Rework	Lot	1	$100,000	$100,000	Allowance
CO2 Blanketing System	Each	1	$12,000	$12,000	EPS 50 MW Study
Condensing Heat Exchanger	Each	1	$1,500,000	$1,500,000	UE Preliminary Estimate
Condensing Heat Exchanger Install	Each	1	$70,000	$70,000	UE Preliminary Estimate
Drying Fan & Motor	Each	3	$175,000	$525,000	UE Preliminary Estimate
Drying Fan Installation	Each	3	$50,000	$150,000	Fagen Inc. 10.25.02
Structural Support for Roof	Each	1	$250,000	$250,000	Allowance
Material & Install of Air Duct to Dome	Feet	400	$2,660	$1,064,000	Fagen Inc. 10.25.02
Item Total				$10,290,000	
		25% Contingency		$2,573,000	
		Sub-Total		**$12,863,000**	

Combustion Turbine and Heat Recovery Feedwater Heater Cost

Item	Unit	Qty.	Unit Cost	Extended Cost	Source
Combustion Turbine Generator					
Concrete Platform Foundation	C.Y.	220	$450	$99,000	UE Preliminary Estimate
Retrofit existing structure	Each	1	$20,000	$20,000	UE Preliminary Estimate
GE LM2500 Combustion Turbine	Each	1	$9,793,000	$9,793,000	GE Budget Price 10.7.02
CT Installation	Each	1	$250,000	$250,000	GE Budget Price 10.7.02
Air Inlet Duct	Each	1	$497,000	$497,000	Fagen Inc. 10.25.02
Water cooled option for generator	Each	1	$125,000	$125,000	GE Budget Price 10.7.02
DC Enclosure	Each	1	$5,000	$5,000	GE Budget Price 10.7.02
Heat Recovery Feedwater Heater					
Concrete Platform Foundation	C.Y.	120	$450	$54,000	UE Preliminary Estimate
Retrofit existing structure	each	1	$30,000	$30,000	UE Preliminary Estimate
HRFWH Equipment	Each	1	$780,000	$780,000	Deltak Budget Price 10.10.02
HRFWH Construction	Hrs	5000	$45	$225,000	Deltak Budget Price 10.10.02
Natural Gas Supply					
Gas Compressor - 700 hp	Each	2	$330,000	$660,000	SCFM Budget Price 10.14.02
Gas Compressor Building	Each	1	$200,000	$200,000	UE Preliminary Estimate
Compressor Installation	Hrs	1000	$45	$45,000	UE Preliminary Estimate
Upgrade Existing Line & New Meters	Each	1	$140,000	$140,000	1996 Great Plains Estimate
Balance of Plant					
Process Piping, Fuel Piping					
Cooling Water, Drains etc.					
5% Capital Costs (CT, HRFWH, GC)	%	5%	$11,233,000	$562,000	Allowance
Electrical					
13.8 kV Switchgear	Each	1	$182,000	$182,000	GE Budget Price 10.7.02
CT MCC's	Each	1	$45,000	$45,000	GE Budget Price 10.7.02
25 MVA GSU Transformer	Each	1	$300,000	$300,000	ABB, Waukesha
Bus (Generator to GSU), 120 ft	Each	1	$86,000	$86,000	Delta Unibus
Installation	Lot	1	$610,000	$610,000	UE Preliminary Estimate
Demolition					
Generator #1 & #2	Each	2	$58,000	$116,000	Fagen Inc. 10.25.02
Floor and Wall Demolition	Each	1	$130,000	$130,000	Fagen Inc. 10.25.02
Wall Opening for Stack	Each	1	$57,000	$57,000	Fagen Inc. 10.25.02
Item Total				$15,011,000	
		25% Contingency		$3,753,000	
		Sub-Total		**$18,764,000**	

November 19, 2002

Utility Engineering
901 Marquette Avenue
Suite 3200
Minneapolis, MN 55402

Attention: Mr. Duru Posteuca

Subject: Whole Tree Burning System for
The NSP Minnesota Valley Station
BBBP Contract No. B2052

Dear Mr. Posteuca;

We have prepared this budget price based on the scope outlined below. This budget price is a +/- 25% and is for the design and supply of the materials. The prepared budget price for the installation labor is the same as the material cost.

Babcock Borsig Power Inc. as a company still has reservation as to the viability of this technology and believes that there is significant work that still needs to be done to finalize a design that will meet all of the objectives for a successful project. To get to the next stage of designing components that will live in the environment that we will be subjecting this boiler to (in burning whole trees), an engineering study will be required. The engineering study may exceed a quarter of a million dollars.

Also by developing this budget price, we do not warrantee or guarantee that the process is viability.

As for the performance of the boiler, if the system represented provides the flue gas weights and temperatures at the furnace exit that the coal-fired unit does then the balance of the convective surface should work as it currently does. Also in this budget we have not taken into account the current condition of the boiler. It is our understanding that a condition assessment will be performed under the next phase of the project and we would like to provided you with this service.

In developing this price we have included the engineering, the materials, and start up services for the scope outlined below. The budget price for the scope outlined is **$2.9 million dollars for the materials with another $2.9 million for the installation labor.**

If you have any question regard what we have done please call me at 847-645- 9025.

Sincerely yours,

BABCOCK BORSIG POWER, INC.

John W. Scott
Central Regional Sales Manager

Northern States Power

Whole Tree Conversion Project
Granite Falls, Minnesota
Riley Original Cont. # 2052

11/16/02
K. Toupin
Northern States Power, Whole Tree Firing Proposal.doc

Project Objective:
Convert an existing pulverized coal fired boiler to whole tree log firing.

The following lists the Babcock Borsig Power (BPPI) Work Scope

1. Existing Coal Burner Equipment Removal
   BBPI Scope
   1.1 Pressure part water wall modifications to eliminate the burner openings
   - Upper row of three burners @ elevation 929'-6"will be replaced with straight tubing
   - Lower row of three burners @ elevation 916'-6" will be removed and no new tubes are required due to the new log fuel chute being added in this location.

2. Log Fuel Chute
   BBPI Scope
   2.1 Pressure part modifications

3. Water Cooled Log Combustion Grate (EPS Design)
   BBPI Scope
   3.1 Pressure part modifications

4. Bottom Ash / Char Combustion Grate
   BBPI Scope
   4.1 Supply new Char Dump Grate
   - Air cooled dump grate

5. Water Wall Protection at the Log Combustion Grate
   BBPI Scope
   5.1 Supply cast alloy tile (similar to refuse combustion systems)

6. Combustion Air Duct Penetrations
   - Hot air to Log Grate
   - Cold air to Char grate

   BBPI Scope
   6.1 Pressure part modifications

7. Instrumentation WW Openings
   BBPI Scope
   7.1 Pressure part modifications

8. Over-fire Air WW Openings
   BBPI Scope
   8.1 Pressure part modifications

9. Furnace Observation Doors
   9.1 Pressure part modifications

10. Boiler Performance Analysis
    BBPI Scope
    10.1 Complete boiler performance engineering study
    - Superheater steam temperatures
    - Flue gas temperatures
    - Combustion air flows
    - Flue gas flows
    - Furnace retention time
    - Flue gas velocities
    - Heat release rates
    - Boiler efficiency
    - Fuel flow

11. Existing Boiler Physical Analysis with Recommended Modifications
    BBPI Scope
    11.1 Furnace sizing
    11.2 Tube bundle spacing
    11.3 Sootblower requirements
    11.4 Surface requirements (SH/Economizer)
    11.5 Maximum boiler load analysis

Northern States Power

Whole Tree Conversion Project
Granite Falls, Minnesota
Riley Original Cont. # 2052

11/20/02
K. Toupin
Northern States Power, Whole Tree Firing Concerns

Project Concerns:

1. <u>Furnace Height</u>
   Combustion system should be located as low as possible to increase the furnace retention time

2. <u>Isolation Grate Design</u>
   - Difficult design for reliability, too large
   - Evaluate a design similar to refuse units and straw fired units

3. <u>Fuel Distribution</u>
   Need uniform fuel depth

4. <u>Fuel Bed Formation & Consistency</u>

5. <u>Combustion Consistency w/Fuel Feed Intervals</u>

6. <u>Predicated Ex. Air is too low</u>
   Low ex. air operation requires:
   - Uniform fuel distribution
   - Uniform fuel bed consistency
   - Consistent fuel feed
   - Uniform combustion

7. <u>High Grate Heat Release are Unrealistic</u>
   - Calculations method?
   - Industry Practice
     $$\text{GHR} = (Fuel\,\frac{lbs}{hr})x(Fuel\,\frac{btu}{lb}) \,/\, (\text{Plan of Area ft}^2)$$

8. <u>High Under Grate Air Pressure Requirements</u>

9. <u>Ash Fusion Temp w/High Temperature Air</u>

10. <u>High Under Grate Air Temp</u>
    - Dumping grate reliability (char burn-out grate requires 80°F ambient air)
    - Use two air streams (one hot/one cold)

11. <u>Aux. Burner Requirements & Isolation</u> If required

Minnesota Valley Plant
Whole Tree Energy Conversion

Existing Equipment List

	Description	Existing Equipment	Existing Reuse	Existing Remove
Boiler				
	Boiler	x	x	
	Pulverized Coal Burners	x		x
	Drain System	x	x	
	Boiler Blowdown	x	x	
	Water Sampling	x	x	
	Blowdown Tank	x	x	
	Ignition Oil Tank	x	x	
	Ignition Oil Pumps	x	x	
	Natural Gas Ignition System	x	x	
Gas & Air Flow				
	Roof Ventilators	x	x	
	Fresh Air Duct & Dampers	x	x	
	Force Draft Fan	x	x	
	Flue Gas Duct & Dampers	x	x	
	Slag Screen	x	x	
	Induced Draft Fan Ductwork	x	x	
	Precipitator	x	x	
	Induced Draft Fan	x		x
	Stack Monitor	x	x	
	Stack	x	x	
Steam Turbine				
	Steam Turbine Generator	x	x	
	Chest & Valves	x	x	
	Gland Steam System	x	x	
	H2 Cooling System	x	x	
	Lube Oil Pump	x	x	
	Lube Oil Tank	x	x	
	Aux Oil Pump	x	x	
	Oil Storage Tank	x	x	
Condensate & Feed Water				
	Condenser	x	x	
	Condensate Pump #1	x		x
	25,000 Gal Dump Tank	x	x	
	Make-up Water Pump	x	x	
	LP Feedwater Heater # 31	x	x	
	LP Feedwater Heater # 32	x	x	
	HP Feedwater Heater # 34	x	x	
	HP Feedwater Heater # 35 (replace)	x	x	
	Heater Drains Pump	x	x	
	Evaporator	x	x	
	Steam Jet Air Ejector	x	x	
	Deaerator	x	x	
	Boiler Feed Water Pump	x	x	
	Seal Oil Tank	x	x	

Minnesota Valley Plant
Whole Tree Energy Conversion

Existing Equipment List

	Description	Existing Equipment	Existing Reuse	Existing Remove
Circulating / Cooling Water				
	Traveling Screens	x	x	
	Circulating Water Pumps	x	x	
	1,000 Gal Roof Tank	x	x	
	Back Wash Filters	x	x	
	Cooling Water Pumps	x	x	
	Filter Water Boost Pumps	x	x	
	Ash Sluice Water Pump	x	x	
	Oil cooler	x	x	
	Hydrovactor	x	x	
	Ash Sluice	x	x	
	Horizontal Ash Pump	x	x	
	Horizontal Bilge Pump	x	x	
	Ash / Bilge Sump	x	x	
	Sluice Pit Exhaust Fan	x	x	
Plant & Instrument Air				
	IntakeFilters	x	x	
	Instrument Air Compressor	x	x	
	Aftercoolers	x	x	
	Air Receivers	x	x	
	50HP compressor	x	x	
	25HP compressor	x	x	
Water Softener				
	Lime Softener	x	x	
	Evap Feed Pump	x	x	
	Feed Pot	x	x	
	Mix Pot	x	x	
	Chemical Mixer	x	x	
	Chem Mix Pump	x	x	
	Drain Sump	x	x	
Old Generators				
	Unit 1 Steam Turbine Generator	x		x
	Unit 2 Steam Turbine Generator	x		x
Coal Handling				
	Retired Coal Unloading Building	x		x
	Retired Underground Tunnel	x		x
	Retired Conveyor	x		x
	Coal Dumper Station	x		x
	Coal Rotating Conveyor	x		x
	Coal Crusher Building	x		x
	Conveyor to Boiler #4	x		x
	Coal Bunker	x		x
	Pulverizers	x		x

Minnesota Valley Plant
Whole Tree Energy Conversion

New Equipment List

	Qty	Description	Modify Equipment	New Equipment
Boiler				
	1	Boiler	x	
	1	Feed Doors		x
	1	Wood Grate		x
	1	Char Burnout Grate		x
	1	Char Air Fan		x
	1	CO2 Blanketing System		x
	1	Ash Pelletizing System		x
Gas & Air Flow				
	1	Overfire Air Ductwork	x	
	1	Underfire Air Ductwork	x	
	1	Under Grate Air Ductwork		x
	1	Larger Induced Draft Fan		x
	1	Condensing Heat Exchanger		x
	1	Ductwork for Condensing HX		x
Fuel Supply				
	1	Dome		x
	1	Emergency Inflation System		x
	1	Heating Air Duct		x
	1	Fire Protection		x
	1	Drag Conveyor		x
	1	Sizing Saw		x
	1	Ram Feed		x
	1	Dust Collection System		x
	1	Sump Pump		x
	1	Crane		x
	1	Weigh Scale		x
	3	Dome Air Fans		x
Gas Turbine				
	1	GE LM2500 Combustion Turbine		x
	1	TEWAC Generator		x
	1	Starting System		x
GT Aux. Systems				
	1	Lube Oil System		x
	1	Air Inlet Duct		x
	1	Gas Line		x
Heat Recovery Feedwater Heater				
	2	Condensate Pumps		x
	1	Heat Recovery FW Heater		x
	1	Drain System		x

Minnesota Valley Plant
Whole Tree Energy Conversion

New Equipment List

	Qty	Description	Modify Equipment	New Equipment
Natural Gas Supply				
	2	Gas Compressor		x
	1	Additional Gas Meter		x
Fire Protection System				x
	1	FireWater Electric Pump		x
	1	FireWater Deisel Pump		x
	1	FireWater Jockey Pump		x
Saw Dust Sys.				
	1	Saw Dust Disposal Sys.		x

Minnesota Valley Generating Plant
Conversion to Whole Tree Energy
Conceptual Design and Preliminary Cost Estimate

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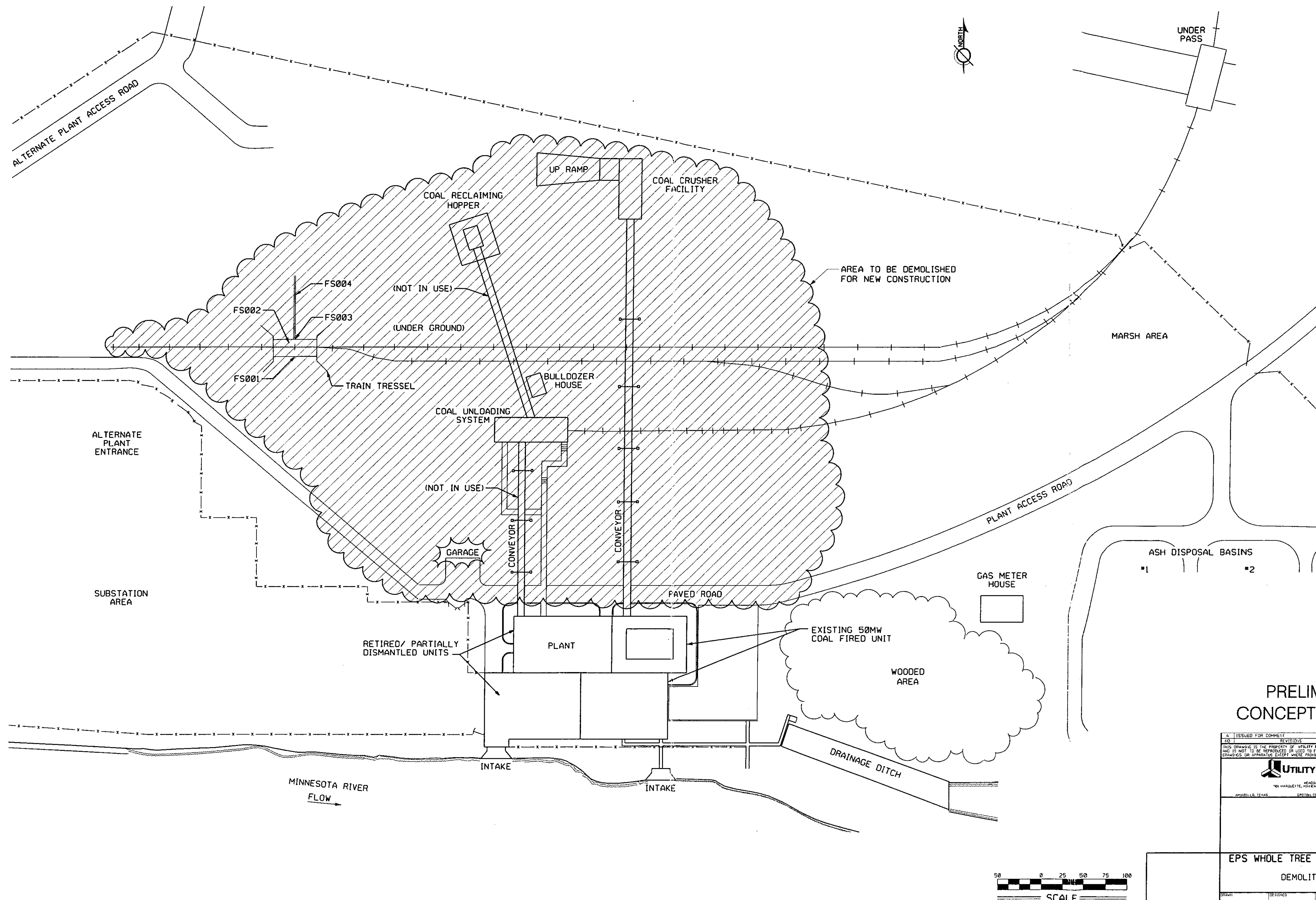
1. "Preliminary Modeling of Minnesota Valley Power Plant Conversion to Whole Tree Energy Combined Cycle," Draft, Energy Performance Systems, Inc. July 15, 2002
2. "Preliminary Assessment of the Infrastructure Required to Support Conversion to Whole Tree Energy Combined Cycle, Minnesota Valley Power Plant, Whole Tree Energy Conversion Feasibility Study," Energy Performance Systems, Inc. August 9, 2002
3. Whole Tree Energy ™ Design Volumes 1, 2 & 3, EPRI TR- 101564
4. SWEC J.O. No. 01261.03 Minnesota Valley Generating Station Unit No. 3 Capacity Retention Study, June 1990
5. 100-Mwe Whole Tree Energy ™ Power Plant Feasibility Study, EPRI TR-104819
6. "Whole Tree Firing Test Report," Northern States Power Bay Front Station Unit #3
7. "Whole Tree Burning System for the NSP Minnesota Valley Station BBBP Contract No. B2052," Letter from John W. Scott, Babcock Borsig Power, Inc. November 19, 2002.
8. "Babcock Borsig Power Work Scope" Letter from K. Toupin November 16, 2002
9. "Project Concerns," Letter from K. Toupin November 20, 2002



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EPS WHOLE TREE ENERGY PROJECT

DEMOLITION PLAN

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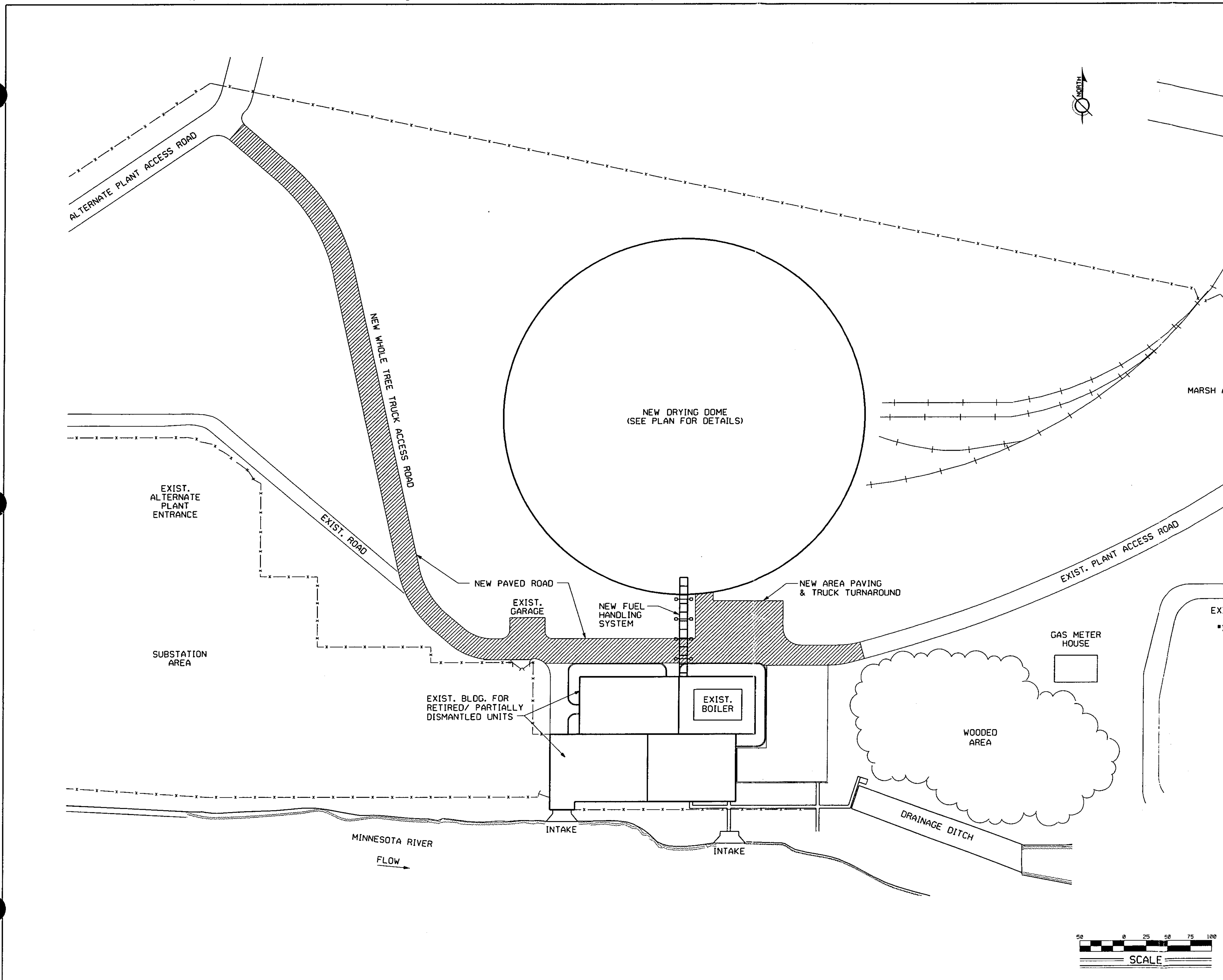

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GENERAL SITE PLAN

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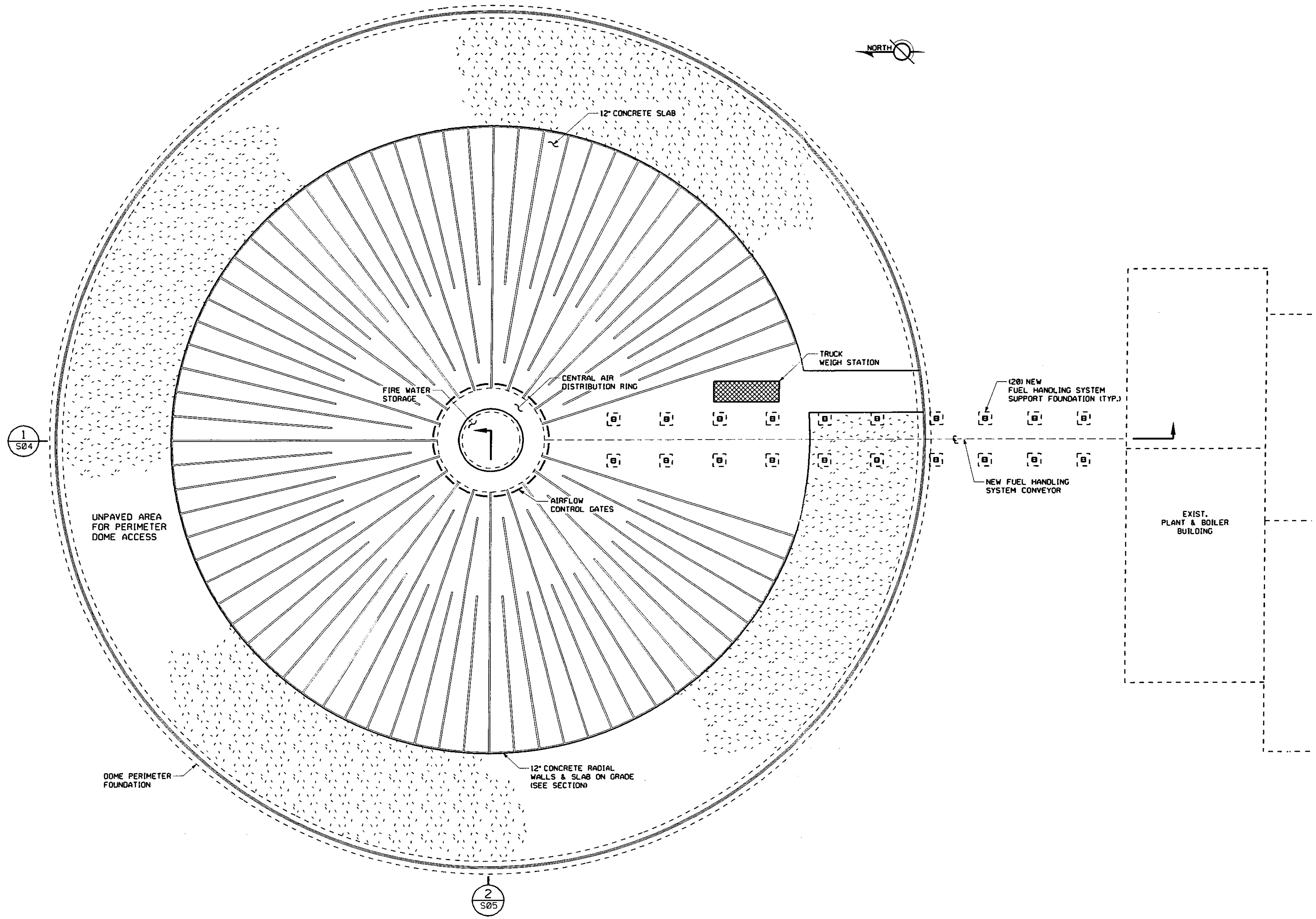

PLAN VIEW

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SCALE

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DRYING DOME &
CONVEYOR FOUNDATIONS
PLAN

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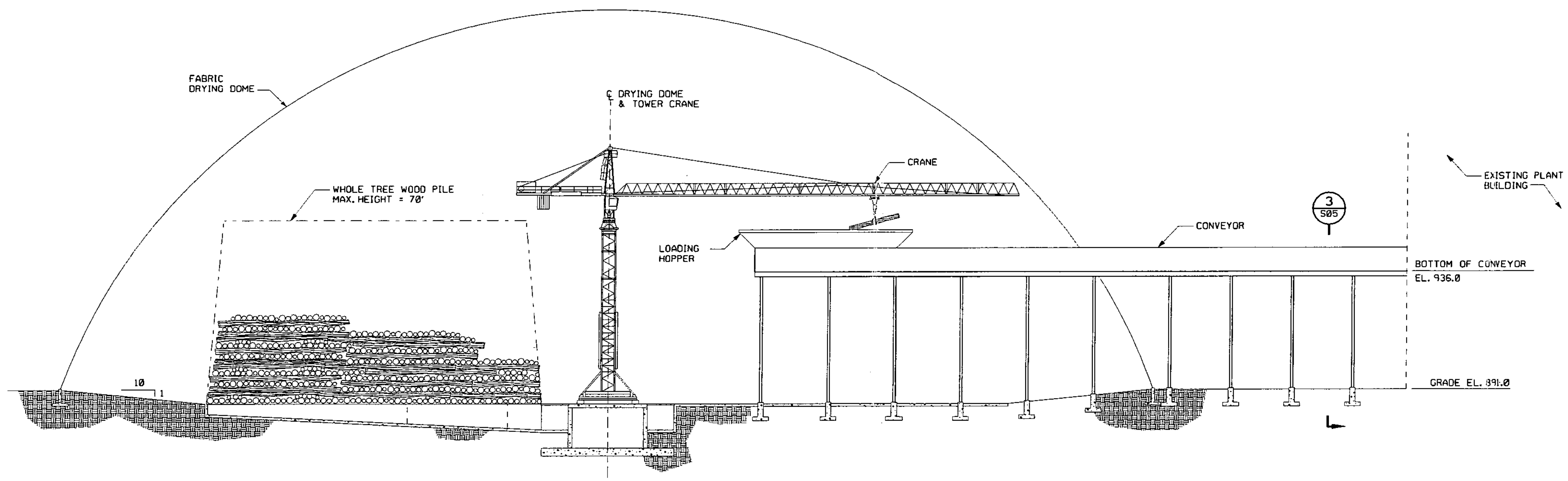

SECTION 1 S03

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DRYING DOME & CONVEYOR SECTION

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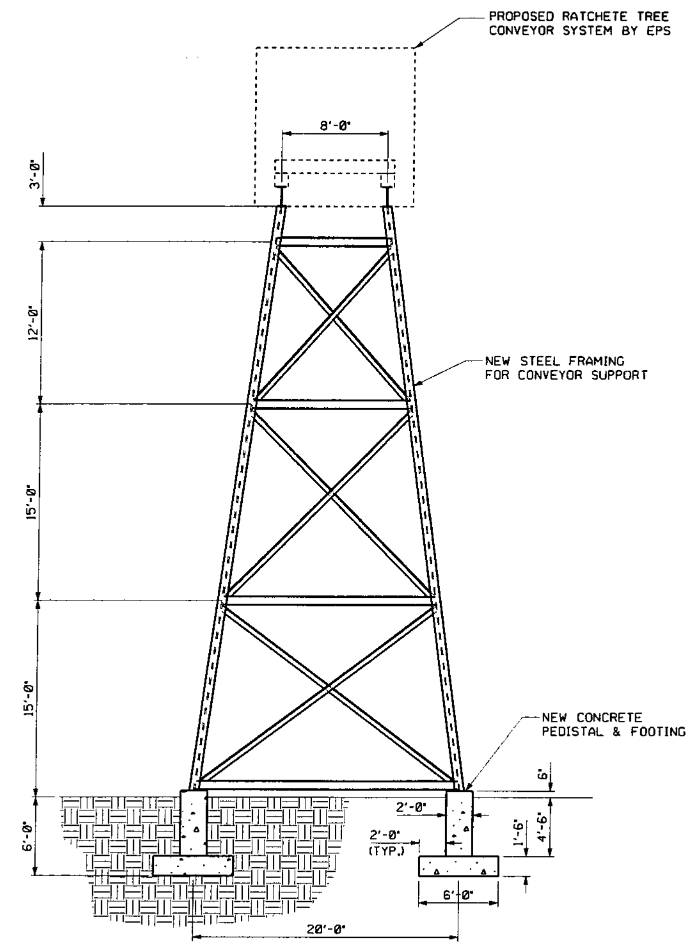

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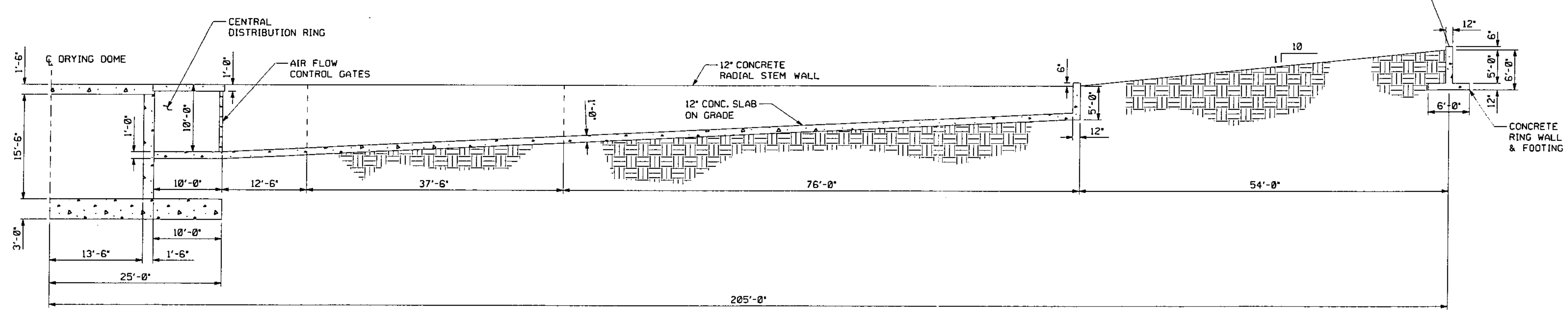

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DRYING DOME & CONVEYOR
SECTIONS

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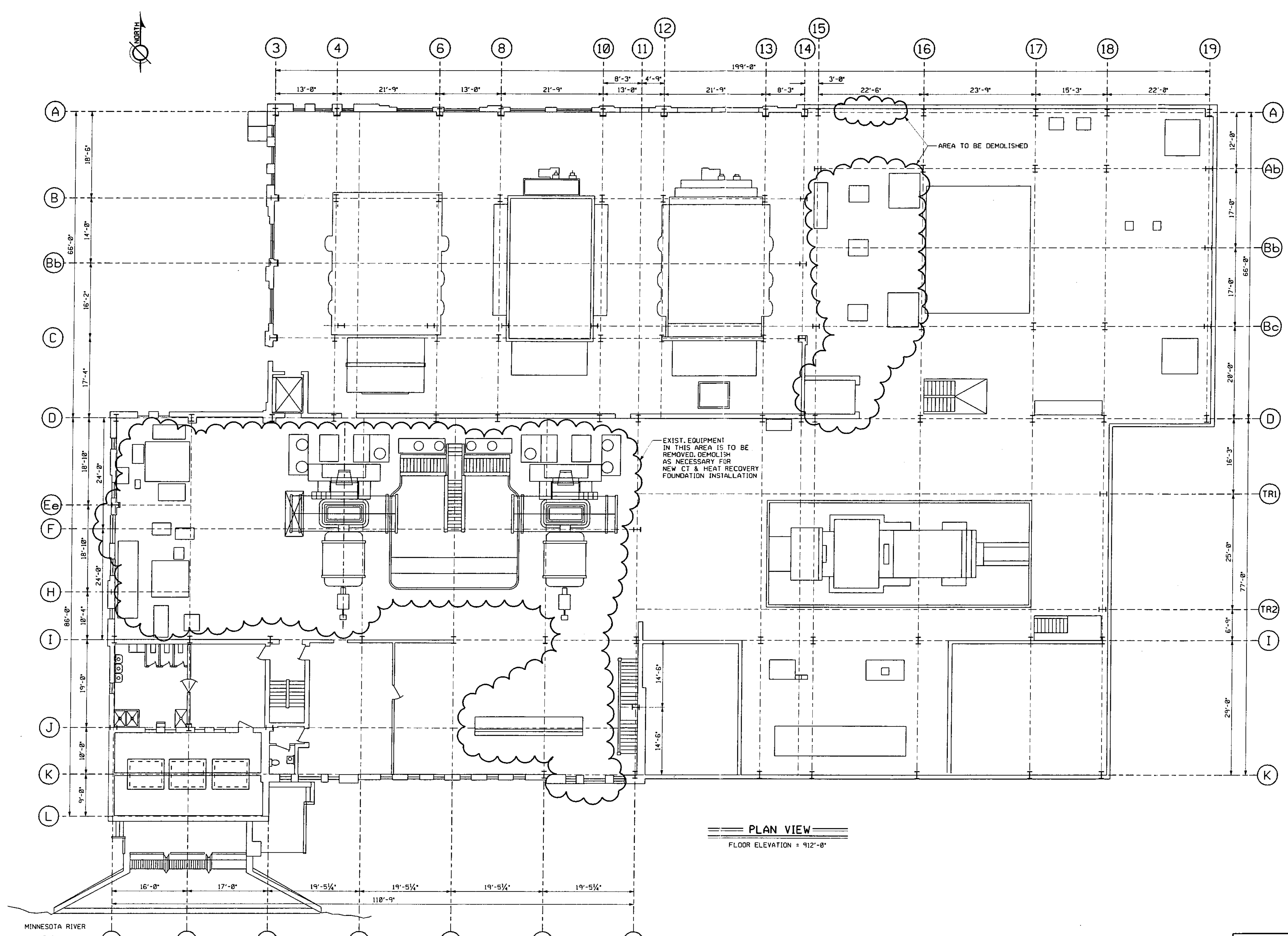

PLAN VIEW

FLOOR ELEVATION = 912'-0"

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EPS WHOLE TREE ENERGY PROJECT
CT. HEAT RECOVERY UNIT
& BOILER ROOM
DEMOLITION PLAN

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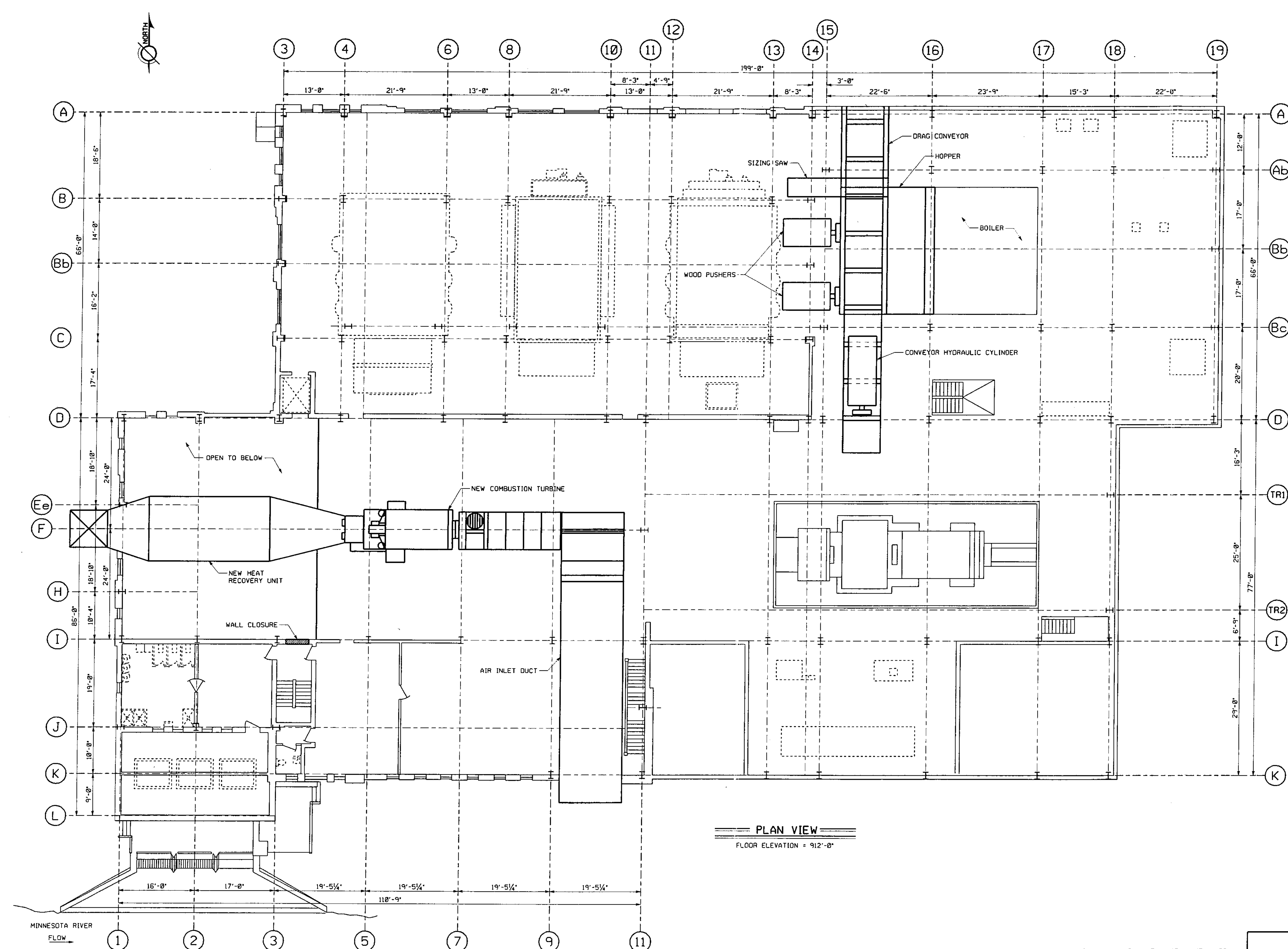

PLAN VIEW

FLOOR ELEVATION = 912'-0"

SCALE

1" = 20'-0"

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UTILITY ENGINEERING

AMARILLO, TEXAS

EPS WHOLE TREE ENERGY PROJECT
NEW CT, HEAT RECOVERY UNIT
& BOILER ROOM
BUILDING PLAN

D010783-006S007

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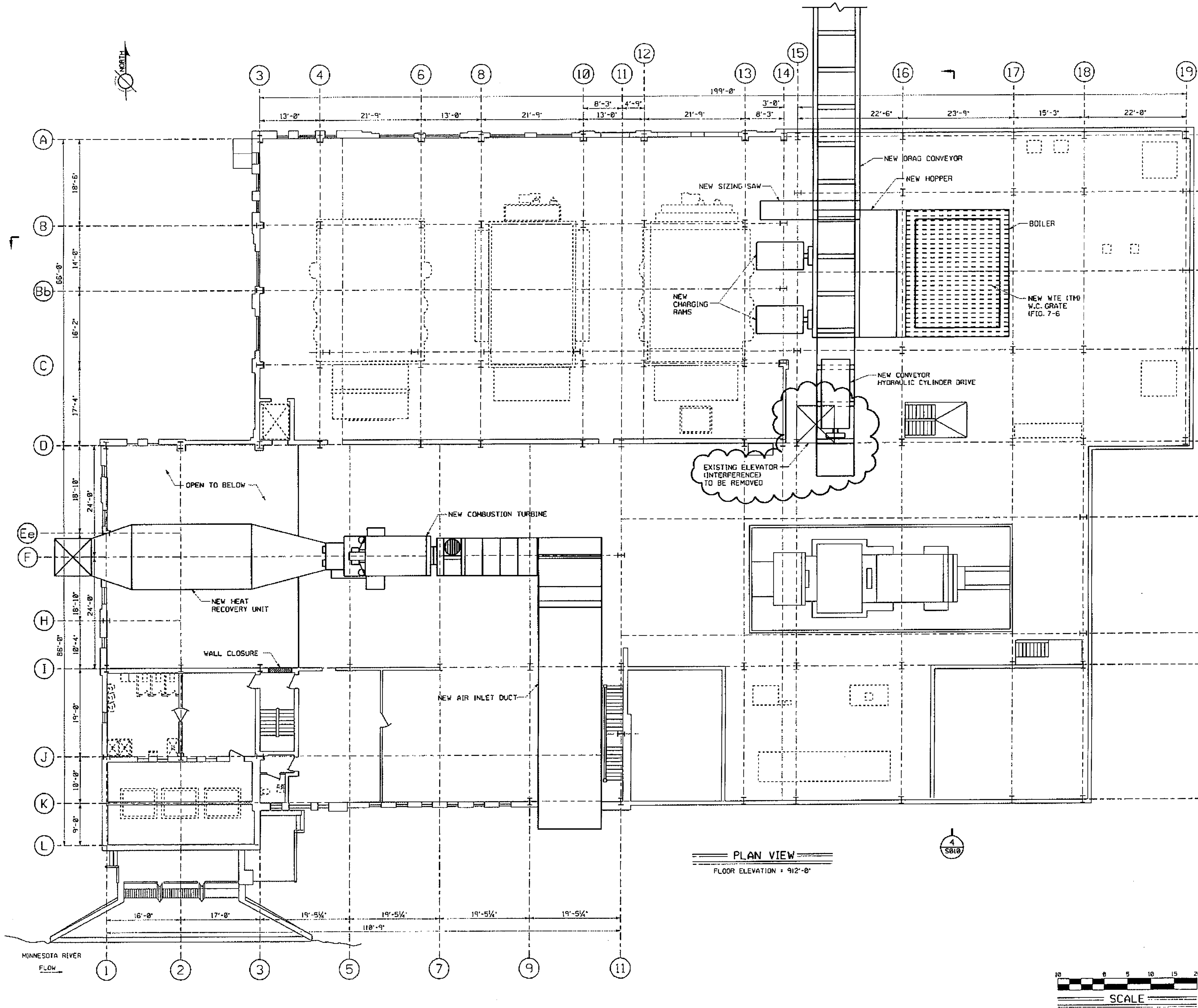

PLAN VIEW

FLOOR ELEVATION = 912'-0"

REFERENCE DRAWINGS

1. SECTION 4 - ELEVATION LOOKING WEST DWG. D010783-006S008
2. SECTION 5, SECTIONAL ELEVATION - LOOKING SOUTH. DWG. D010783-006S009
3. NORTH BUILDING ELEVATION, DWG. D010783-006S010

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B	ADDED SECTION CALLOUTS, W.C. GRATE & ELEVATOR INTERFERENCE					
A	ISSUED FOR COMMENT					

UTILITY ENGINEERING

EPS WHOLE TREE ENERGY PROJECT
NEW CT, HEAT RECOVERY UNIT
& BOILER ROOM
TURBINE FLOOR PLAN

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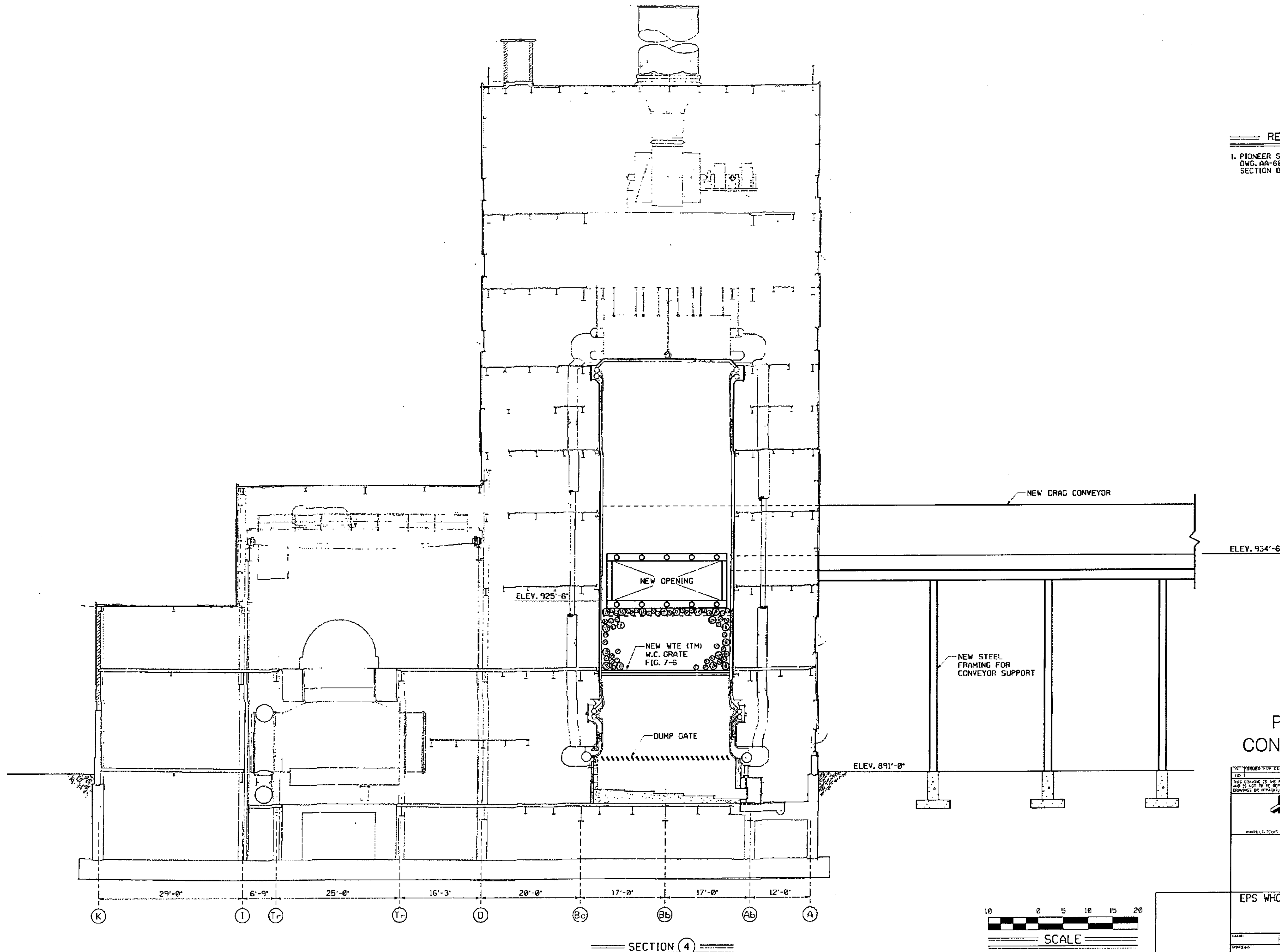

10 0 5 10 15 20
SCALE

REFERENCE DRAWINGS

1. PIONEER SERVICE & ENGINEERING COMPANY DWG. AA-60690-A, SECTION C-C, TYPICAL CROSS SECTION OF POWERHOUSE - ARCH.

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SECTION 4
LOOKING WEST

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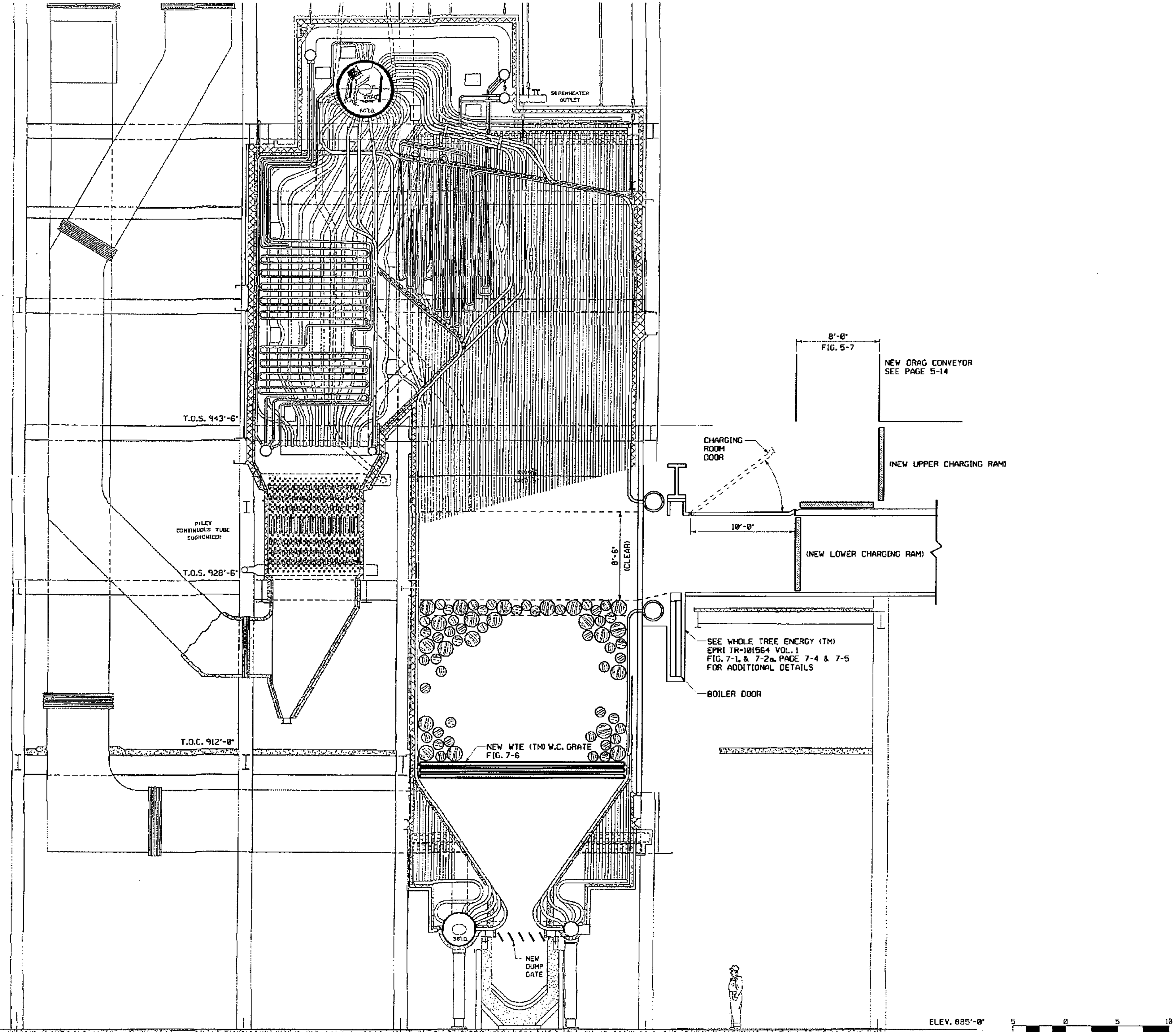

SECTION (5)

(SECTIONAL ELEVATION LOOKING NORTH)

REFERENCE DRAWINGS

1. SEE NORTHERN STATES POWER - MINNESOTA VALLEY STEAM PLANT, RILEY STEAM GENERATING UNIT, UE DRAWING # M010783 - 210M001 S01 RA

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SECTIONAL ELEVATION
LOOKING SOUTH
SECTION 5

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APPROVED | APPROVED

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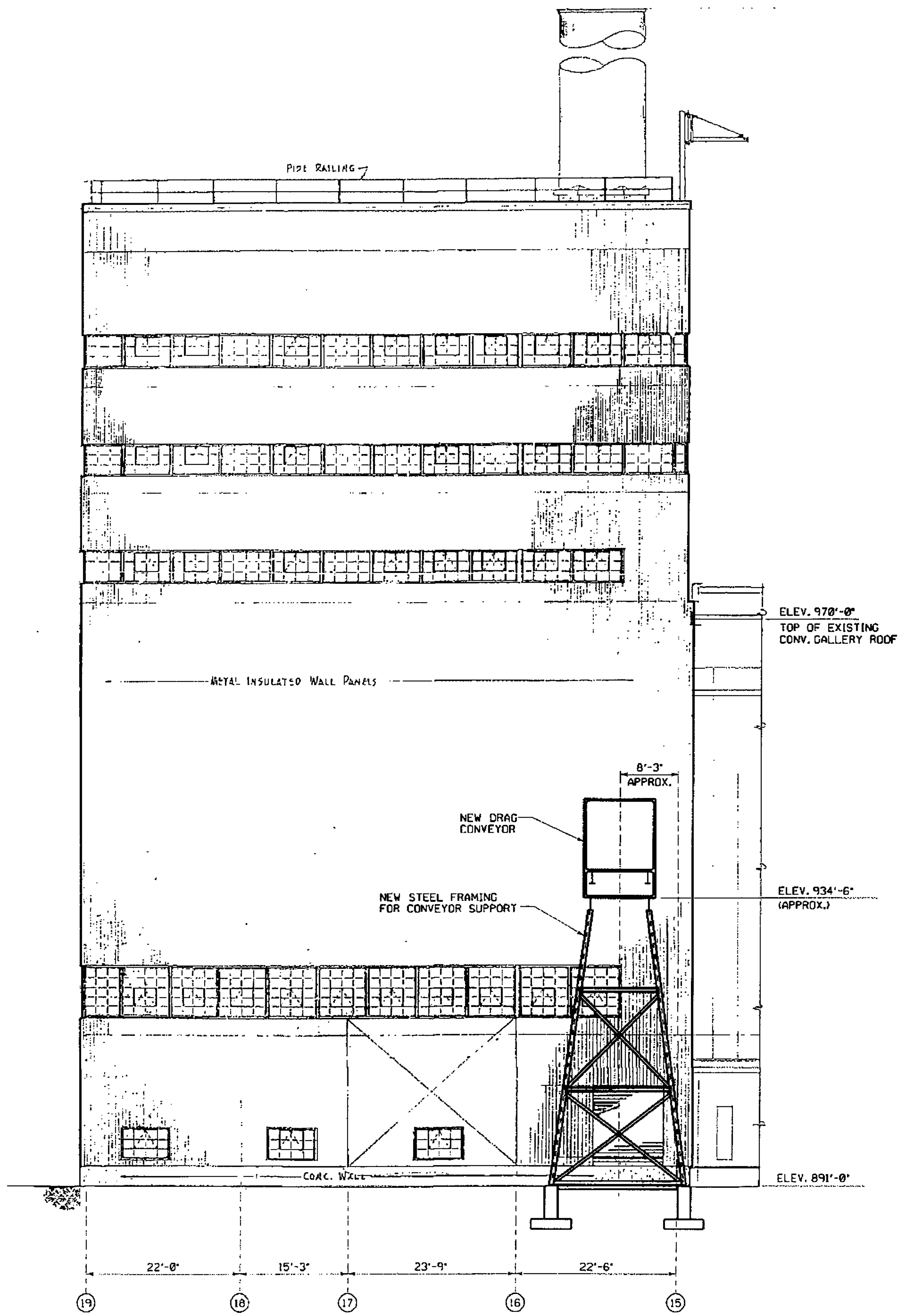

NORTH ELEVATION

10 0 5 10 15 20

SCALE

REFERENCE DRAWINGS

1. PIONEER SERVICE & ENGINEERING DWG. NO AA 604710 - NORTH & WEST ELEVATIONS & SEC. D-D.

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NORTH BUILDING ELEVATION

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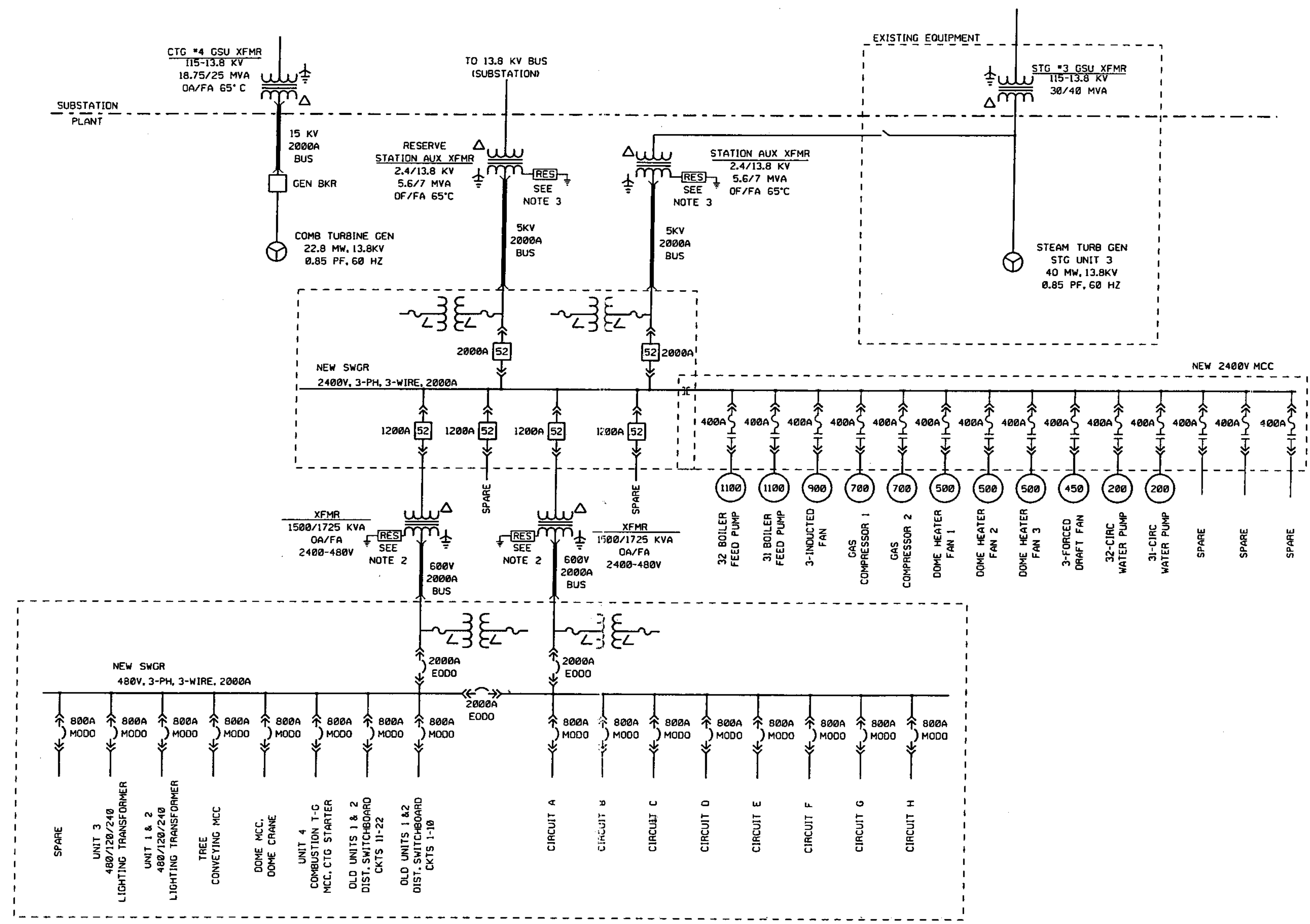

LEGEND

- INDICATES TRANSITION BETWEEN SWGR AND M

MODO - MANUALLY OPERATED DRAW OUT

EODO - ELECTRICALLY OPERATED DRAW OUT

GENERAL NOTES

1. MOTOR HORSEPOWER, XFMR RATINGS AND BUS AMPACITIES ARE PRELIMINARY VALUES AND ARE SUBJECT TO CHANGE.
2. HIGH RESISTANCE GROUNDING WITH PULSING SYSTEM.
3. HIGH RESISTANCE GROUND.

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ONE-LINE DIAGRAM

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