ESCANABA ELECTRIC DEPARTMENT

Escanaba Power Supply Alternatives

FINAL REPORT

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Power System
Engineering Inc.

ESCANABA POWER SUPPLY ALTERNATIVES

For

Escanaba Electric Department
Escanaba, Michigan

FINAL REPORT

Respectfully submitted,
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Section 1 - Introduction

This report is the second in a series of reports that will comprise the Escanaba Electric Department (EED) Power Supply Study. The first report provided the load forecast, which identifies the power supply requirements that EED must plan for. In meeting those requirements, EED must choose among numerous options. There are multiple technologies and fuels available for generation of electricity with dramatically different cost characteristics. Ideal peaking units have low investment costs and high operating costs while the ideal baseload units have the opposite cost structure. The options to participate in units being planned by others differ widely depending on the expected changes in future transmission access to the UP. The size of units and the cost of fuels also may differ depending on the locations of new generation. The UP has many relatively small utilities that are seeking long-term power supply resources providing numerous possible alliances to consider in weighing build versus buy alternatives. Sizes and timing of units also will have an important impact on the effective choices available to EED.

Thus, there are potentially numerous options for EED to consider. PSE has recently issued a request for proposals (RFP) to a broad range of potential power suppliers to the UP with very disappointing results. It appears that near-term options are very limited. The case for concerted power supply development is apparent but will require multilateral efforts that do not fit conveniently within the intended scope and schedule of this study.

The purpose of this report is to present the dimensions of available choices to EED and to confirm the alternatives that should be included in the evaluation stage of the power supply study.

Section 2 - Report Outline

The load forecast report defines the expected growth in total energy requirements and peak demands for EED through 2023. That report did not address the EED load shape, introduced here as part of the needs definition in Section 3.

Existing resources are reviewed in Section 4 and compared to future requirements to identify the need for additional resources. Both generation and transmission resources have an important bearing on the menu available to EED. Generic unit costs for new generation at various locations are developed in Section 5 to guide the formulation of cost-effective alternatives for EED.

This report assumes that EED will want to determine the least-cost reliable power supply option for consideration. The mix of technologies and fuels used to supply EED loads is the key determinant of the cost of supply. An optimum mix analysis helps to define the theoretic least-cost option, which helps to focus the search for effective solutions. The optimum mix analysis is presented in Section 6.

Based on the suggestive results of the mix analysis, Section 7 then proposes specific alternatives to evaluate. The results of our recent RFPs for supply to the UP are summarized as background for deciding on the value of another RFP. The list of proposed alternatives reflects our generic analyses and current understanding of the UP power market. PSE wishes to confirm the list of alternatives with EED before proceeding to more detailed evaluation. This is intended to assure that the list of options includes all those of interest to EED. This will also be the basis for EED decisions on how to proceed with options that may require ongoing joint planning efforts with other UP utilities that are not likely to be concluded within the time frame of this study. .

Following EED review of this report, PSE proposes to meet with EED for discussion of the results to date and to seek EED confirmation of the plans for study completion. Power supply planning often evolves and it is important to keep the power supply plan aligned with the current findings from this study and other developments in the UP power market.

Section 3 - Power Supply Needs

The EED load forecast is summarized in Figure 1 and Table 1. While summer and winter peaks were balanced in the late 1990's, in the last three years the summer peak has been dominant. This trend is expected to continue based on common developments in the Upper Midwest. The summer load factor is expected to continue falling gradually but the 2013 result (54.7 %) is similar to the average figure from the past three years. Thus, little change is anticipated in the EED load shape over the next decade. Growth of about 7.6 MW is forecast by 2013 and about 13.8 MW by 2023.

Figure 1 EED Seasonal Peak Demands

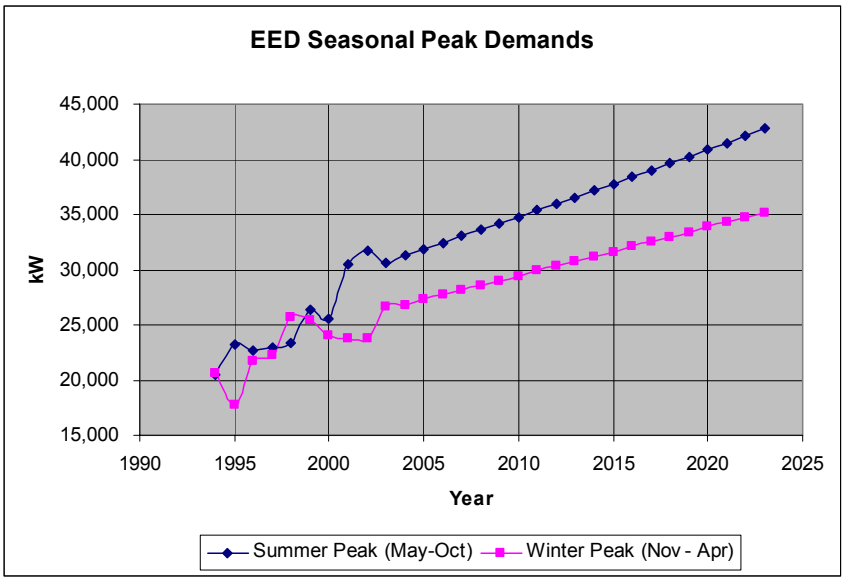
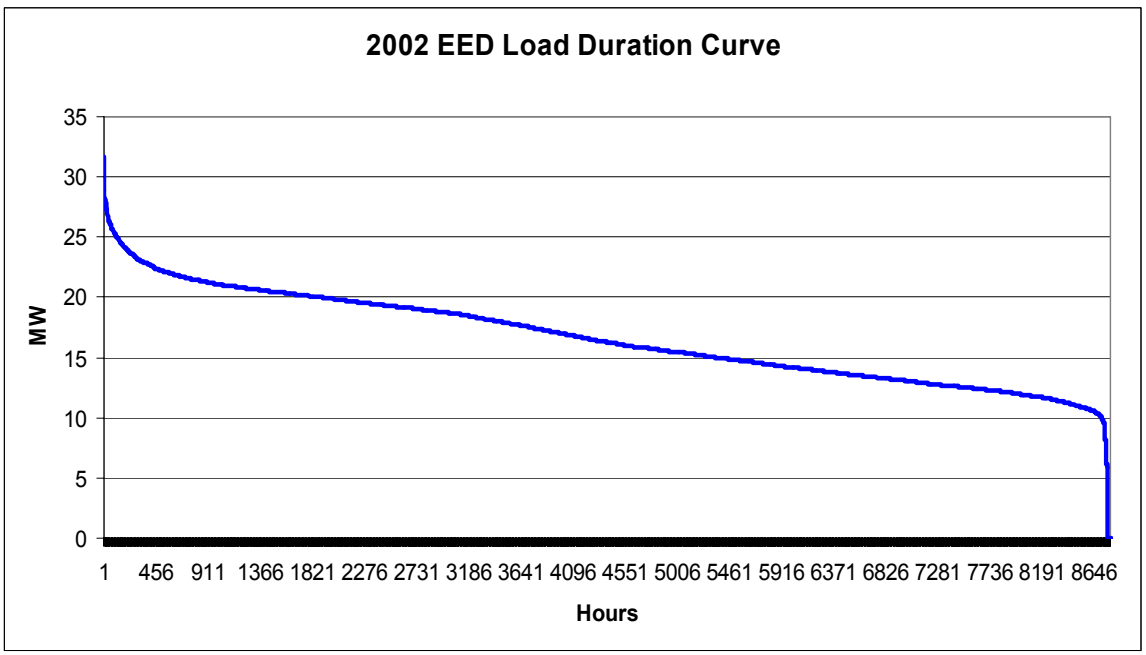


Table 1 Load Forecast Summary[1]

Year	Winter	Summer	Annual	Total Energy	Annual LF
1999	25,400	26,400	26,400	137,962	59.7%
2000	24,100	25,500	25,500	137,134	61.4%
2001	23,800	30,500	30,500	145,395	54.4%
2002	23,700	31,725	31,725	144,074	51.8%
2003	26,685	30,582	30,582	152,036	56.8%
2008	30,167	35,217	35,217	171,631	55.6%
2013	32,337	38,150	38,150	182,753	54.7%
2018	34,546	41,199	41,199	193,910	53.7%
2023	36,790	44,365	44,365	205,072	52.8%
Includes Expected Increases for Walmart and EMP in 2004					

Hourly load data for calendar years 2000 through 2002 have been tabulated to develop the EED historic load shape. The load shape has been very stable over that period so that the 2002 load shape shown in Figure 2 is considered to be representative for the planning horizon. The EED record peak of 31,725 occurred in 2002. The minimum load was 5.9 MW but there were only 26 hours with loads below 9 MW. There were 196 hours with loads above the 24.0 MW capacity of the two EED coal units. The total energy requirement represented here is about 146 GWh, which differs slightly from Table 1 due to the different time periods considered[2].

Figure 2 EED Load Shape



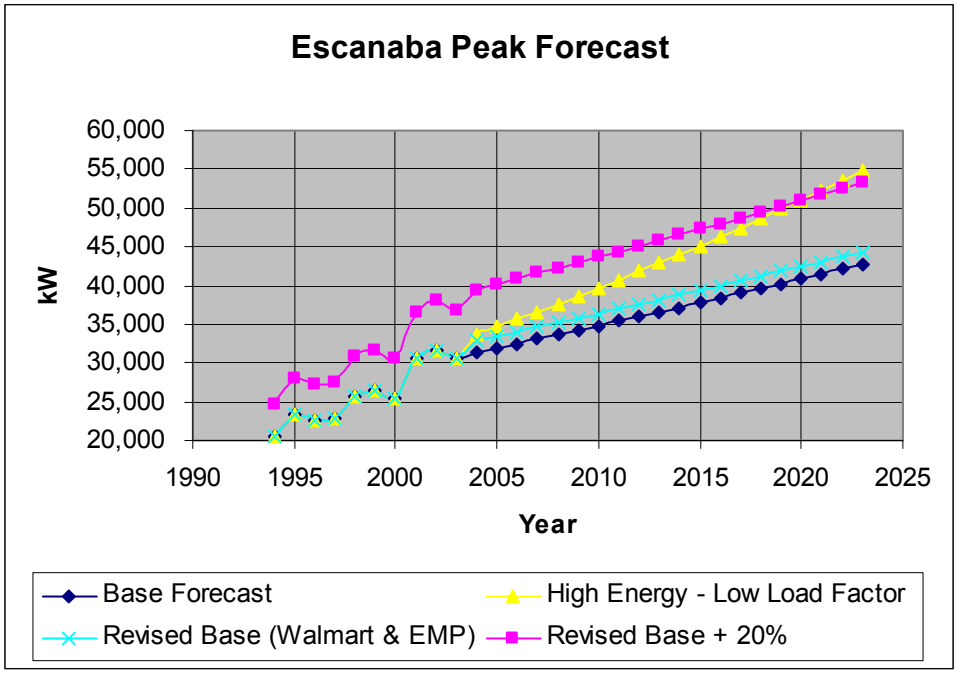
In planning for reliable power supply, utilities must recognize both the uncertainty of the base load forecast and the possibility of forced outages of some generators at the time of system peak. To be reasonably sure that the load can be served, utilities carry reserve

[1] The seasons reported here are based on MAPP definitions. Summer is defined as the months of May through October of year n. Winter is defined as November of year (n-1) through April of year n.

[2] The load shape data is for the calendar year.

capacity. For an isolated utility, the historic practice was to have excess generation equal to the size of their largest unit so that load could be met under a first contingency outage. For EED, that would require reserve capacity equal to the 18.0 MW of the existing combustion turbine (CT). Against a current load of about 30 MW, that would constitute a 60% reserve margin, which is very large and very costly. Utilities that are connected to an integrated grid can expect to rely on each other to cover load during periods of occasional outage of some units. Sophisticated loss-of-load studies have been prepared to assess the necessary reserves for the various reliability regions. Typically, such studies show that reserves ranging from 15% to 22% provide reasonable expectations of reliable service. Historically, EED has been able to rely on other suppliers to cover outages but transmission access to the UP is very limited and the future generation in the area is currently unclear. Figure 3 shows both load forecast uncertainty and EED capacity requirements assuming a 20% reserve margin. The 20% reserve margin would be sufficient to cover the high load forecast through 2020. Thus, it appears reasonable for EED to plan for load plus 20% reserves. This reserve margin would not cover the base load forecast with one of the two coal units on forced outage.

Figure 3 Load Plus Reserves Forecast



Section 4 - Existing Resources

EED currently owns two coal-fired units with nameplate capacities of 12,500 kW. These units began commercial operation in 1958 and are currently operated by the Upper Peninsula Power Company (UPPCO) under contract to Escanaba. Effective net capacity has been conservatively estimated at 24,000 kW. Since 1982, Escanaba has had a contract purchase from UPPCO covering 10,000 kW. That contract was revised to reduce the June through August obligations to 5,000 kW from 2001 through 2004. The contract has now been terminated as of the end of April 2005. Finally, EED purchased an

18,000 kW refurbished combustion turbine in 2002 that is now available for service despite some remaining combustion problems.

John Irving, a Registered Professional Engineer with over 30 years experience in design, construction, startup and operation of utility power plants, visited the Escanaba plant to inspect facilities, interview operating staff, and obtain data needed to assess current operation and expected future operation of these units. His findings are summarized here.

4.1 General Unit Descriptions

The Escanaba Generating Station consists of two coal-fired generating units and an oil-fired combustion turbine generator. The site is located just north of the city of Escanaba, Michigan on the shore of Lake Michigan.

The identical coal-fired units, designed by Black and Veatch, began commercial operation in 1958. Each includes a top supported two-drum boiler supplied by Babcock and Wilcox. The units are rated for 125,000 lbs per hour of steam at 600 psig and 825° F. Steam temperature control is accomplished by balancing boiler over-fire air. The boiler may be operated at 140,000 lbs per hour of steam flow for up to two hours. The coal is burned on a Detroit Stoker traveling grate. Each boiler has an economizer for preheating feedwater to the boiler, but does not have an air preheater. At rated capacity, boiler performance data states the efficiency of the boilers at 84.3%.

The boilers are balanced draft units, each with a single forced draft fan providing combustion air from the ground floor elevation, and a single induced draft fan located between the mechanical collectors and the electrostatic precipitators. Flue gas cleaning consists of centrifugal mechanical collectors followed by a three field electrostatic precipitator.

Steam from the boiler in each unit is piped to a turbine generator that was supplied by Allis Chalmers. The nameplate rating of the generators is 12,500 kW gross. Steam is extracted to four feedwater heaters. The turbine exhausts to a surface condenser utilizing circulating water from Lake Michigan.

The combustion turbine is a General Electric Frame 5 unit that was manufactured in 1968. The unit was originally installed in New Hampshire and then relocated to Ecuador. The air-cooled generator is rated at 21,176 kVA at .85 power factor, which equates to 18 MW gross output. Prior to being shipped to Escanaba in 2002, the purchase contract required the unit to be completely overhauled. It is uncertain how many operating hours were on the unit prior to purchase by Escanaba, but since that time the turbine has operated for 420 hours and been started 132 times as of August 2003. The unit is equipped with an evaporative cooler for the combustion air to improve capacity and efficiency in hot weather, and water injection for capacity enhancement as well as NOx reduction. A 100,000-gallon tank for number 2 fuel oil is located adjacent to the combustion turbine.

There have been numerous operational problems with the combustion turbine, but most of them have been resolved. A combustion problem remains but it is expected that this will soon be resolved. The unit has been available commercially at Escanaba since March 2003. The combustion turbine provides black start capability for the coal units as well as additional capacity for Escanaba Electric.

4.2 Operation

The coal-fired units operate continuously whenever they are available. Typically during the day they are operating at high loads, as much as 13 MW gross for each unit. Considering the station service requirements of 500 kW for each unit, the net output is as high as 12.5 MW. The current State of Michigan Operating Permit references a nameplate rating of 12.5 MW. For the planning purposes of this report, full load output is assumed as 12.0 MW net per unit.

During the night, the units are typically ramped down in load to allow economy purchases of energy at costs lower than self-generation costs. The minimum load for each unit is 4.0 MW gross. Operating the units at minimum load during the off-peak hours as opposed to shutting them down and restarting has probably helped the availability of the units.

The historical equivalent availability of the coal-fired units at Escanaba has been excellent, as summarized in Table 2.

Table 2 Coal Unit Availability and Capacity Factor

	Year	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	10 Yr Average
Equivalent Availability	Unit 1	89.5	83.1	92.6	93.5	91.7	91.7	94.6	82.6	95.4	91.7	90.6
	Unit 2	93.7	94.6	93.5	93.5	93.7	91.9	84.4	92.3	95.7	100.0	93.3
Station Capacity Factor		50.5	50.1	52.7	46.5	47.3	47.9	50.3	54.7	54.8	49.1	50.6

These statistics are considerably better than average. The North American Electric Reliability Council (NERC) data indicates that the average equivalent availability for coal-fired generators between 1 and 99 MW for the period 1997 through 2001 was only 86.3%. The NERC data for coal-fired generators between 1 and 99 MW for the ten-year period from 1992 through 2001 experienced an average equivalent availability of 86.1%.

The average capacity factor for the two coal units for the past 5 years is 51.8%. As can be seen by the availability data above, this is due primarily to deliberate decisions to purchase economy power, not limitations in the reliability of the plant.

At the Escanaba Plant, 80% of the total outage hours in the last 10 years for Unit 1 have been planned outages and inspections. At Unit 2, 89% of the total forced outage hours for the last 10 years have been attributable to planned outages and inspections. This indicates good preventative maintenance and planning on the part of plant staff, which greatly minimizes unplanned outages for the utility.

UPPCO, under contract to the City of Escanaba, has operated the station since 1958. UPPCO has recently been acquired by the Wisconsin Public Service Corporation. This change has not resulted in any change of personnel at the station, and may well bring additional technical and support resources to the station at Escanaba. The plant is operated and maintained by a staff of 26 people.

The operating personnel work 8-hour shifts. The International Brotherhood of Electrical Workers Union Local 510 represents all personnel except for the Station Supervisor and the Station Superintendent. All of the personnel interviewed during the plant visit were very knowledgeable about their job and obviously took a great amount of pride in the station. It is very difficult to keep a coal-fired plant clean, but the housekeeping in this station is excellent. The relations among plant staff are excellent and professional. The plant appears to have a well functioning Safety Program, which is administered by the Station Supervisor. The safety records reviewed for the past few years have a low incidence of accidents.

4.3 Maintenance

Each unit is scheduled for one overhaul annually. One unit is typically scheduled in the spring and the other in the fall, when system loads and power costs are at a minimum. Every seven years, each unit has a major overhaul. Although Allis Chalmers stopped making turbine generators many years ago, Siemens Westinghouse provides service and parts for these units. During a major overhaul, the turbine rotors are crated and shipped to the factory for inspection and repair as required.

4.4 Fuel

Units 1&2 are solely fueled by coal at Escanaba. There is no auxiliary fuel capability. Startup is accomplished by using waste wood on the boiler grates. Given the infrequency of plant startups, this works quite adequately.

Annually, plant staff requests proposals for potential coal suppliers. Coal is requested to be sized 4”x 0”. The coal typically has a calorific value of 12,500 BTU/lb., and must contain less than 1.5% sulfur in accordance with the current operating permit. Coal is transported by ship and stored on the land immediately northeast of the plant. There is adequate draft next to the coal pile so that the ship can unload directly to the storage pile. Generally, the plant purchases sufficient coal to operate the plant for one year. Annual coal requirements vary between 60,000 tons and 80,000 tons. Coal is loaded into a dump truck from the storage pile using a front-end loader and transported to the infeed hopper at the station.

Coal costs are the largest single cost item for the plant, averaging between 45%-60% of the total annual cost. Historically, coal costs have been fairly stable compared to other fuels. There are still fluctuations based primarily on price spikes or shortages of other fuels. Table 3 provides a comparison of coal prices and quantities for the past five years.

Table 3 Historic Coal Purchases and Costs

Coal Purchases at Escanaba Generating Station					
Year	1999	2000	2001	2002	2003
Tons Purchased	71,224	62,091	67,917	74,900	80,000**
Price per Ton, delivered	$43.61	$44.09	$65.36	$45.20	$44.66
Price per MBTU*	$1.74	$1.76	$2.61	$1.81	$1.79

*Based on 12,500 BTU/lb
** Up to 80,000 tons

4.5 Spare Parts

The coal plant maintains an inventory of consumables, gaskets, seals and parts that wear out on a regular basis. Some of the original equipment manufacturers for the Escanaba Plant are no longer in business to supply spare parts. Fortunately, the plant Maintenance Department has expertise and tools to manufacture many parts when necessary and there are excellent machine shops available in the Escanaba area. The original design of the plant allowed for adequate redundancy.

The original pneumatic control system, which would have been a major problem for spare parts, was replaced with a digital control system (DCS) as part of the capital improvement program. The turbine generator manufacturer, Allis Chalmers, has not manufactured turbine generators for many years. Siemens Westinghouse has taken over the responsibility for service and parts and has the technical expertise and design drawings necessary.

4.6 Capital Improvements

The coal plant has a successful ongoing capital improvement program. Examples of this in the past are the pneumatic control replacement. There have been many upgrades to the ash handling system as well. Recently, the original coal stokers on one unit were replaced with stokers manufactured by Alstom. This improvement allows that unit to operate at full load with one of the four stokers out of service, further improving availability. Future capital improvements include new stokers for Unit 2, overfire air combustion modifications, replacement front-end loaders and coal and ash trucks, and continuous emission monitors over the next 3-4 years. Annual capital improvement costs vary between $100,000 to $500,000, depending on the magnitude of projects planned.

4.7 Permit Requirements

The Escanaba generating units operate under a permit issued by the State of Michigan. The permit is presently due for renewal, and a draft permit has been issued by the State. The proposed permit does not have any onerous conditions and probably is very similar to previous permits with a few exceptions. For example, it includes the combustion turbine and there are limitations for the fuel oil of 0.2% sulfur, and 2.0 million gallons per year consumption based on a rolling 12-month period. The combustion turbine shall not exceed a 10% stack opacity based on a six-minute average excluding startup, shutdown, and “initial shakedown” periods.

The coal units are limited to 1.5% sulfur coal, and a stack opacity of 20% based on a six-minute average except for one six-minute average of not more than 27% opacity. This seems achievable for the existing units. During my visit, the opacity was typically below 1%.

Discussions with State of Michigan air regulators did not reveal any known changes in the future for permit requirements other than NESHAP Regulations (National Emission Standards for Hazardous Air Pollutants. The Environmental Protection Agency is proposing NESHAP regulations, which could pertain to the Escanaba Generating Units. These regulations pertain to emissions of:

- Arsenic
- Cadmium
- Chromium
- Hydrogen Fluoride
- Lead
- Manganese
- Mercury
- Nickel

Plant staff is very aware of the proposed regulations and are working with other similar generators at this point. If the proposed regulations are adopted, it is not clear if Escanaba would be affected. According to the proposed rules, a plant would be eligible if the potential emissions of any of the above pollutants can exceed 10 tons per year, or if the aggregate of all the above pollutants exceeds 25 tons per year. These emissions can vary widely from plant to plant and from different coal sources. Specific testing at Escanaba would be required to see if the plants there are eligible. If the plant is subject to the proposed regulations, it can either limit the particulate matter (PM) emissions to .07 lbs/MMBTU or reduce the emissions of selected metals to .001 lbs/MMBTU and reduce HCl emissions to .09 lbs/MMBTU and reduce mercury emissions to .00007 lbs/MMBTU. It is quite possible that the existing controls at Escanaba Station limit particulate emissions to less than .07 lbs/MMBTU. It is also quite possible the emissions of the 9 pollutants are low enough not to trigger eligibility. The rules may change again before enacted or be delayed.

In the event that these emissions have to be reduced, additional equipment or operating limitations may be necessary. Plant staff has received budget-pricing indicating that a spray dryer could be purchased to reduce these pollutants to an acceptable level for under $3,000,000.

4.8 Current Operating Costs

Operating costs for the two coal units for the period from 1998 to 2002 are summarized in Table 4.

Table 4 Coal Plant Historic Operating Costs

Calendar Year	1998	1999	2000	2001	2002	Average
Operation and Maintenance	$1,612,682	$2,109,915	$3,035,196	$1,934,281	$1,862,846	$2,110,984
Fuel	$2,773,786	$2,964,232	$3,038,371	$4,007,665	$3,768,356	$3,310,482
Other Fixed A&G Costs	$721,052	$687,723	$704,000	$630,167	$630,000	$674,588
Total	$5,107,520	$5,761,870	$6,777,567	$6,572,113	$6,261,202	$6,096,054
Net Power Generated, MWh	100,728	105,721	115,024	119,473	103,321	108,853
Total Cost/MWh	$50.71	$54.50	$58.92	$55.01	$60.60	$56.00
Fixed Cost, $/kW-year	$97.24	$116.57	$155.80	$106.85	$103.87	$116.07
Energy Cost, $/MWh	$27.54	$28.04	$26.42	$33.54	$36.47	$30.41

The costs for the past five years are quite consistent. Every seven years, it is necessary to do a major overhaul on the turbine generator. Major overhauls for this review period were done in 2002 for Unit 2 and in 2000 for Unit 1. There were major price increases in energy costs in 2001, which resulted in increased coal costs, as shown in the previous section on coal.

Currently, Escanaba Station is operated at a minimum load of 4.0 MW gross per unit. During the on-peak hours, the unit is typically operated at higher loads depending on energy prices and availability. In this mode, the cost of operation, maintenance and A&G are essentially a fixed cost. The variable cost is basically the cost of the fuel and the ash disposal. In the event that this mode of operation changed, this would have to be re-evaluated.

It is difficult to assess the operational reliability of the combustion turbine at Escanaba, as the unit was just recently declared commercial at this location. There is little data available regarding the operating history prior to being located in Escanaba. The contract for procuring this combustion turbine required that the unit be renewed to original equipment specifications. The generator was rewound, the Detroit Diesel starting motor was overhauled, and the Frame 5 combustion turbine itself was overhauled.

NERC data should provide a good indication of what to expect based on historical information. The category for gas turbines in the 1-19 MW range includes a database from operating 180 units. The average size is 17 MW compared to the 16-MW unit at Escanaba and has an average age of 34.5 years compared to the Escanaba unit that is 35 years old.

The average equivalent availability factor for units in this database was 91.67% for the period from 1997 to 2001. The average capacity factor was 1.5%.

Frame 5 combustion turbines of this vintage typically have a heat rate of 15,600 BTU/kWh according to the manufacturer. A recently rebuilt machine should have a heat rate in this range, but preliminary data from Escanaba indicate a higher heat rate for this machine. Fuel oil costs this year averaged about $1.00/gallon. At a fuel calorific content

of 138,000 BTU per gallon, this equates to a fuel cost of $7.24/MBTU. At a 16,000-BTU/kWh heat rate, the resulting energy cost would be $116/MWh.

Plant staff anticipates that this combustion turbine will operate approximately 100-200 hours per year. Most of the machine has been recently overhauled. If the machine rebuild was done properly, the availability of the Escanaba gas turbine should be higher than the NERC averages above, providing the utilization is relatively low. If this unit has to run continuously for extended periods of time, the equivalent availability will be lower and the maintenance costs will be higher. There are still some combustion related problems to resolve, but these should be completed shortly.

For purposes of this study, the annual fixed cost for this unit has been roughly estimated at 20% above the comparable figure for a new CT, which is $17.51 per kW-year.

4.9 Future Operation

Based on the current level of care and commitment at the Escanaba Generating Station, Mr. Irving believes that the plant has a high probability of operating reliably for the next 10 years. This is based on an external visual inspection, a review of plant records and interviews with key plant personnel. Projections beyond ten years are not possible based on this level of examination and this view does not exclude the possibility of a major failure within the next decade. This opinion could be reinforced by conducting a boiler tube-testing program to determine the thickness of boiler tubes in various areas of the boiler. Thickness testing in the past has been limited primarily to the lower furnace area.

The other area where the projected reliability could be confirmed relates to the turbine generator. A failure of the turbine generator is uncommon for coal-fired units in the 1-99 MW size range but the consequences if there is one are devastating.

It would be advisable to have Siemens Westinghouse perform a Remaining Life Assessment Study on one of the Escanaba units. This work must be done during a major overhaul. Detailed metallurgical replicas are taken at key locations in the turbine generator and the material grain structure is analyzed. Major overhauls are not scheduled for the Escanaba Units until 2007 and 2009 currently. Given the identical design of both units at Escanaba and similar operating history, it is probably adequate to do the life assessment study on only one unit.

It would also be prudent to research where other similar units exist. Given the age of these units, it is likely that identical turbine generator units have discontinued operating and may be a source for spare parts. The lead-time for a replacement turbine rotor, should one fail, would be approximately one year as well as being quite expensive.

Plant staff seems to be doing an excellent job of prudently ensuring the plant will continue to operate reliably. Indications are that this has been the case for the 45-year life of the unit to date. There are some measures that could be taken to further ensure the reliability of the units over the next ten years.

Steam temperature control is accomplished by balancing the over-fire air in the boiler. When changing load, there will be temperature excursions of the steam. The rotating stages in the steam turbine are pressed onto the shaft. Temperature excursions in similar units have resulted in the rotating stages coming loose and failing. While there is no evidence that this has happened in the Escanaba units, the last major overhaul inspection reports on both turbines indicated some axial movement on the first four blade stages. We suggest continuous recording of the main steam temperature of both units. This can easily be done with the new digital control systems that were installed recently at the Escanaba Plant.

The Allis Chalmers Instruction Book recommends limiting temperature excursions from the 825° F design temperature to no more than 25° F for no more than 400 hours per month. It also recommends that the design temperature not be exceeded by 50° F for more than 80 hours per month. Monitoring these temperatures would verify actual temperatures and make operators more aware of these limitations.

The recent turbine inspection indicated erosion in the last stage blading. This is certainly not surprising considering the age of the blades, but additional erosion should be minimized. Last stage blade erosion occurs at an increased rate when operating the turbine at low exhaust pressures and low loads. Under these conditions, the change of state from steam to water moves further toward the high-pressure end of the turbine, resulting in water droplets at the lower stages. These water droplets erode the blading. Given the low load operation of these turbines virtually every night, and the low temperatures of Lake Michigan water in the winter, this could be a factor. We suggest contacting the engineering staff at Siemens Westinghouse to determine what a minimum backpressure should be for these units at low load.

The existing method of preventative maintenance has obviously worked well for years, but there are tools today to improve this. Computerized Preventative Maintenance Systems (PMS) are available for nominal costs that greatly facilitate ensuring all the various lubrication and inspections are done on a timely basis. One example of this is a product called MP-3. We understand that plant staff would have access to a PMS system through WPSC.

The most difficult part of getting a system like this operational is all the research that is required to gather the maintenance requirements for each piece of equipment in the station. Once the research is complete, the system will systematically print out the PMS needs based on calendar days or hours of operations. The Digital Control System should also allow plant staff to monitor operating hours of plant equipment for optimal loading of redundant equipment.

Periodic analyses are conducted on the turbine generator lubricating oil currently. It is advisable to also do periodic oil analyses on lubricating oil for key fans and pumps at the station.

4.10 Existing Resource Summary

For long-term capacity planning, the UPPCO contract that expires in 2005 can be ignored, leaving EED with 24.0 MW of coal-fired capacity and 18.0 MW of oil-fired combustion turbine capacity. It is expected that these resources can continue to operate reliably for another 10 years although a 45-year-old coal plant is operating well beyond its expected life. This study assumes that continued operation of the both the coal units and the combustion turbine will be possible at costs comparable to recent historic experience except for price escalation. Decisions on continued operation of these units should be made based on their economic competitiveness with other options that may be available rather than on any clear belief about a time at which the plant will experience a fatal failure. All power supply decisions involve risks that should be evaluated in addition to costs in selecting the most appropriate plan.

4.11 Existing Resource Vs Requirements

Figures 4 and 5 provide the most useful planning context for assessment of the existing resource portfolio. Figure 4 shows that continued operation of the existing EED generation will be sufficient to cover the high load forecast through 2011 and would provide 20% reserves above the base forecast until 2008. Since some new plant alternatives will have a lead-time of at least five years, it is clear that EED should be deciding now on a supply plan that will cover future needs. Decisions at a later date could foreclose cost-effective options. Figure 5 focuses on the size of the capacity additions needed to provide different levels of coverage of expected loads. If EED wished to have redundant capacity adequate to compensate for a forced outage of one of the coal units, new capacity would be required in 2005. This study assumes that EED wishes to plan for a 20% reserve margin with the recognition that this presumes adequate transmission access and regional generation capacity to provide for coverage from other area resources in the event of forced outages.

Figure 4 Need Vs Existing Resources

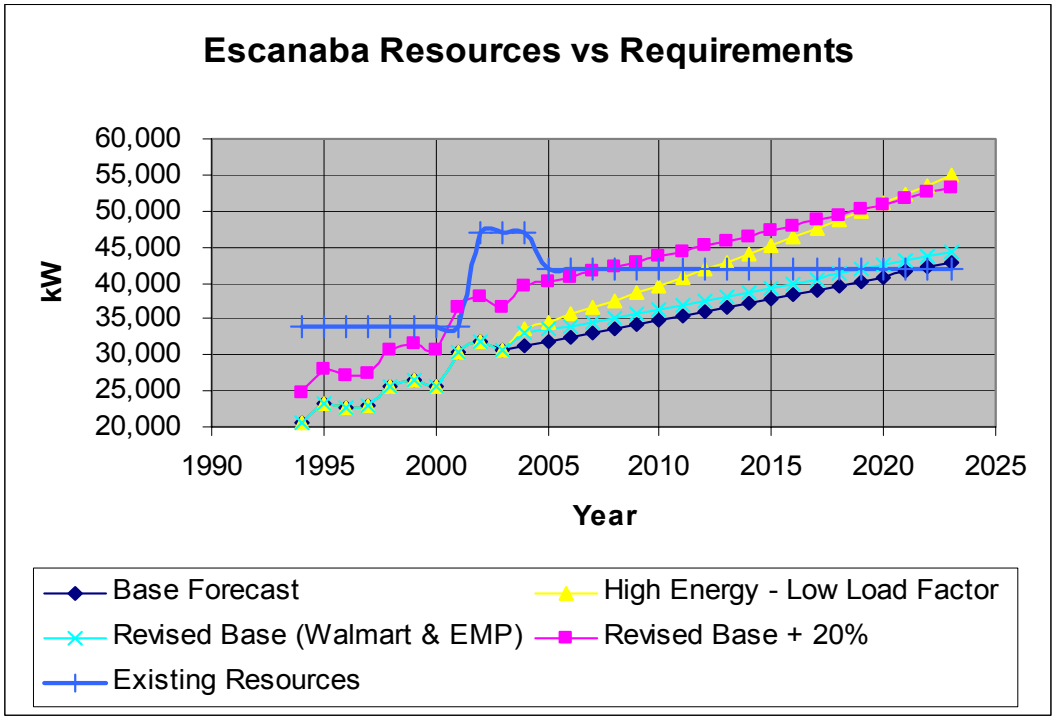
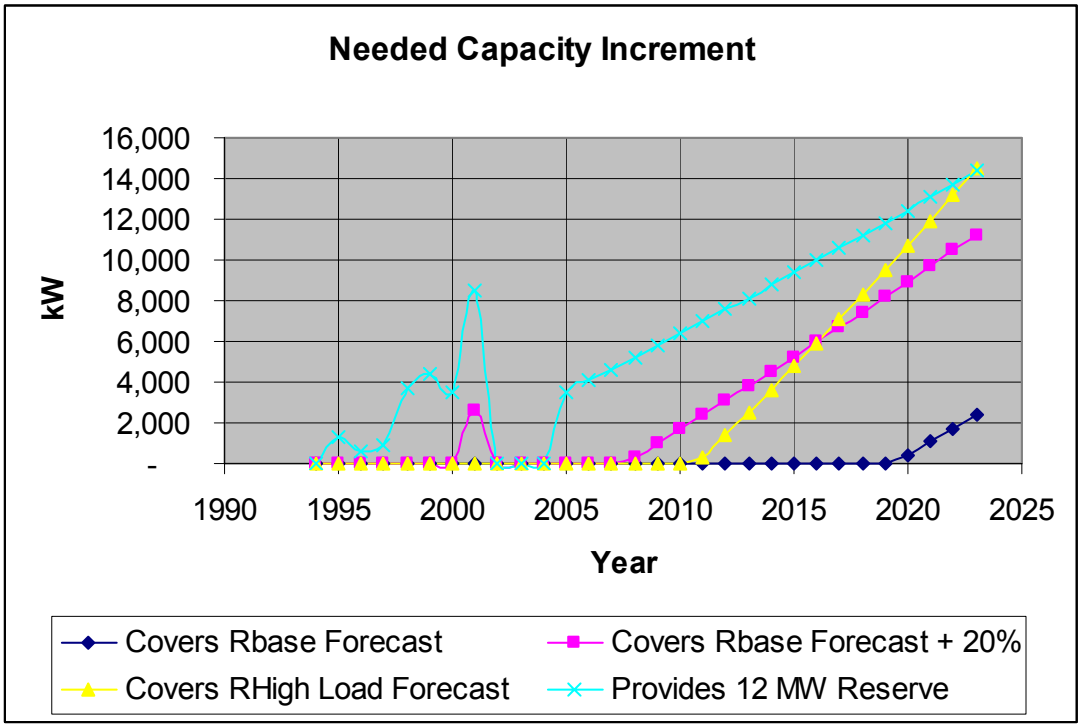


Figure 5 Capacity Increments



Section 5 - Generic Costs

5.1 Estimation Methodology

There are two fundamental strategies for developing cost estimates for future power supply. In power markets with significant excess capacity and adequate transmission availability, the classic approach has been to issue a Request for Proposals (RFP) that specifies the exact capacity and energy sought for particular time frames. Generator owners with excess capacity to sell were often eager to market a mix of their resources to improve the profitability of their underutilized portfolio. This process would not always yield exactly what was sought but generally one would expect to receive multiple acceptable proposals. The process of selection was then a matter of careful evaluation and negotiation to obtain the most favorable arrangement.

The second basic approach is to develop indicative costs to construct the needed new resources at the time that they are needed. Utilities can either build to cover just their own needs or can build a larger plant with the intent to market some of the capacity or energy to others. This approach also provides essential benchmarking to determine what is prudent to pay if resources are purchased from others. This approach can be developed quite easily if the units that would be built are a common size in a location where many similar plants have been recently built. In that case, one can exploit available data from comparable plants to reasonably estimate the cost of a proposed new facility to serve its load. However, when the needed capacity is much smaller than the typical plant size and specific sites are considered, more detailed design studies may be required to get more representative cost figures. In this case, generic costs can be used to screen options but this will not necessarily define an actionable option at a known cost. The manifestation of the desired build option will require consideration of the specific site, size and financing that will be used to construct a new plant.

For this study, both the RFP and the generic costing approach have been used to develop cost estimates sufficient to define alternatives that EED may wish to pursue. This section presents the cost data that have been assembled to characterize the future generation options. The cost of new generation from various technologies will depend on:

- Required investment
- Size of the unit
- Interest during construction
- Financing
- Life of the unit
- Site
- Transmission availability
- Fuel

Generic investment costs are available from DOE's Annual Energy Outlook for:

- 600 MW pulverized coal-fired units (CFs) with scrubbers

- 250 MW conventional and 400 MW advanced combined-cycle units (CCs) fired with gas and/or oil
- 160 MW conventional and 230 MW advanced combustion turbines (CTs) fired with gas and/or oil
- 1000 MW advanced nuclear units (NUCS)

These costs are provided on a per kW basis for standard size units where there is sufficient data to provide statistically sound cost experience. Generally costs per kW will increase as the unit size decreases since there are some fixed costs that do not depend on unit size. Obviously, the typical unit sizes are not proportionate to EED's needs or the combined needs in the UP. However, this kind of data is useful in assessing the hypothetical cost of participation in a larger unit either in the UP with sales or elsewhere with sales to the UP. The data can also be used for benchmarking to test the attractiveness of specific offers that may be obtained from an RFP process and to judge the likely limits to market prices.

Since the time required for construction of a new CT can be as short as one or two years while CFs can require from 4 to 6 years, interest during construction (IDC) can add significantly to the basic investment costs when calculating the total needed investment. IDC recognizes that a power plant developer will likely need to make periodic payments to the contractors as the project proceeds. Assuming that loans are used to make these payments, typical financing will require payment of interest on those loans even though principle payments may be deferred until the project comes on line. Given the different levels of investment and the different time periods for construction, addition of IDC to the analysis will definitely influence the selection of the least-cost option.

New generation available to EED could be built as merchant plants or by investor-owned utilities, or by a group of municipal utilities or by a group of cooperatives. A group of relatively small municipal utilities would often use a joint action agency to spearhead the development while cooperatives typically form a generation and transmission (G&T) cooperative for this purpose. Each of these entities would typically have quite different financing packages in terms of debt versus equity. IOUs and merchant developers would also be subject to income taxes, which will also raise the financing costs of the project.

The nominal life of the unit used for planning studies is twenty years for CTs and CCs and 30 years for CFs. Thus the CFs may be financed over a longer period than the other options resulting in a lower annual cost per dollar of investment.

Given the lengthy list of factors that can influence costs, it is easy to see that a very large number of possibilities could theoretically be of interest to EED in planning their future power supply. An efficient pruning methodology is required to sort through the possible options and to reduce the list to those that merit further evaluation. This study uses a combination of generic cost comparisons and our recent RFP to prune possible options. It is anticipated that discussion with EED and the Electric Advisory Council (EAC) will reduce the menu to something like six to eight options for more detailed evaluation.

The specific sites for units can influence costs depending on permitting in different states, the investment needed to connect the site to the transmission grid, access to cooling water, distances and mode of travel to ash disposal sites, etc. The first unit on a given site will normally cost more per kW than subsequent units because some of the fuel handling, storage, and disposal facilities may be shared between multiple units. Units located in the UP might be much smaller than units located elsewhere in the Midwest based on the power market that they are intended to serve.

Finally, the fuel delivery networks can vary widely for different locations resulting in very different delivered costs for the same fuels. Some sites may have access to natural gas while others may not.

5.2 Levelized Costs

The generic costs have all been developed for hypothetical units that would come on line in 2003 to provide a common basis for comparison[3]. Estimates for units coming on line in the future can then be obtained by escalation of these base figures.

Obviously, both fixed and variable O&M costs and fuel costs will vary for each type of plant in each year as unit maintenance costs and especially fuel prices escalate. At the screening stage, we attempt to recognize the performance and cost of each type of unit over its complete life cycle. To do this, we use levelized costs[4]. Levelized costs are fixed annual payments over the life of the project that have the same present worth as the escalating series it represents. This is similar in concept to a budget billing arrangement that many utilities offer their customers. On budget billing, the customer pays the same amount each month of the year rather than a bill that depends on his varied usage pattern over the year. Levelized costs can be thought of as typical annual costs over the life of the project. They will be higher than first year costs but lower than the annual costs in the final year of the project life. The period of analysis for screening is twenty years, which represents the nominal life of CC and CT units.

5.3 Fixed Costs

Fixed costs consist of:

- Annual capital costs based on assumed financing structures for merchant plants, IOU plants, and plants built by municipal or cooperative utilities.
- Annual fixed O&M costs which are those expenditures that are required on a regular basis independent of the hours of use of the unit.

Annual capital costs are fixed percentages of the total capitalized value of the plant at the time of commissioning and do not change over time. Debt service payments are

[3] This actually biases the comparisons against the existing resources. In the detailed evaluation stage, the timing of the units will be established before cost comparisons are developed.

[4] Levelized costs are calculated by escalating costs year by year, finding the present worth of that series based on the appropriate discount rate for the project owner, and then finding the equivalent set of fixed annual payments with the same present worth. Note that the same set of future costs will have a different levelized cost depending on the project owner since the discount rates vary by muni, IOU, and merchant plant owners.

established based on the amount and terms of the investment financed with debt. After tax returns and income tax, rates on profits for taxable entities are assumed to remain fixed at current levels over the life of the project. Fixed O&M costs have been assumed to escalate at an annual rate of 3.0% over the life of the project.

Table 5 summarizes the fixed costs for a 600 MW pulverized CF, a 250 MW conventional gas-fired CC, and a 160 MW combustion turbine based on DOE estimates published in the 2003 Annual Energy Outlook.

Table 5 Generic Fixed Costs by Technology and Owner

New Generation Generic Fixed Costs For 2003 Vintage Plants				Conventional	Conventional	New Coal
Item	Factor	Units		Combustion Turbine	Combined Cycle	W/ Scrubber
Order Year				2002	2001	1999
Completion Year				2003	2003	2003
Base Overnight Construction Costs		2001 $ $/kW	$	389.00	$ 510.00	$ 1,079.00
Contingency Factor		Multiplier		1.05	1.05	1.07
Base Including Contingency		2001 $ $/kW	$	408.45	$ 535.50	$ 1,154.53
Escalation to Completion Year	3.0%	Multiplier		1.0609	1.0609	1.0609
Installed Costs		Completion Year $/kW	$	433.32	$ 568.11	$ 1,224.84
Interest During Construction	6.0%	Multiplier		1.03	1.06	1.12
Total Installed Cost		Completion Year $/kW	$	446.13	$ 602.20	$ 1,376.23
Expected Life		Years		20	20	30
Annual capital recovery factor	Merchant	Multiplier		0.1339	0.1339	0.1241
Annual capital recovery factor	IOU	Multiplier		0.1239	0.1239	0.1132
Annual capital recovery factor	Muni/Coop	Multiplier		0.0872	0.0872	0.0726
Annual Capital Cost	Merchant	Completion Year $/kW/yr	$	59.73	$ 80.62	$ 170.85
Annual Capital Cost	IOU	Completion Year $/kW/yr	$	55.29	$ 74.63	$ 155.82
Annual Capital Cost	Muni/Coop	Completion Year $/kW/yr	$	38.90	$ 52.50	$ 99.98
Fixed O&M		2001 $/kW/yr	$	10.22	$ 12.26	$ 24.52
Escalation to Completion Year		Multiplier		1.0609	1.0609	1.0609
Annual Fixed O&M		Completion Year $/kW/yr	$	10.84	$ 13.01	$ 26.01
Levelized Fixed O&M	Merchant		$	14.68	$ 17.61	$ 36.93
Levelized Fixed O&M	IOU		$	14.66	$ 17.58	$ 37.15
Levelized Fixed O&M	Muni/Coop		$	14.59	$ 17.50	$ 38.55
Total Levelized Annual Fixed Costs	Merchant		$	74.41	$ 98.23	$ 207.78
Total Levelized Annual Fixed Costs	IOU		$	69.95	$ 92.22	$ 192.97
Total Levelized Annual Fixed Costs	Muni/Coop		$	53.49	$ 70.01	$ 138.54

The wide variation of fixed costs across technologies and across types of owners is readily apparent. Both the annual capital costs and the levelized fixed O&M costs are centrally dependent on the weighted cost of capital for the owners. Table 6 summarizes the financing assumptions that have been used to support the fixed cost estimates. For this study, the ranges of possible costs have been evaluated based on IOU or Muni/Coop owners. IOUs are assumed to finance projects with a combination of debt and equity while Municipal utilities are assumed to rely entirely on debt finance. The difference of

4.8% in the weighted cost of capital between IOUs and Municipal systems has a substantial impact on the cost comparisons. Obviously, particular projects for particular owners could have different financing plans and parameters but these are intended to reasonably represent the alternatives.

Table 6 Generic Financing Assumptions by Type of Owner

Financing Structure/Cost by Owner		Merchant	IOU	Coop/Muni
Financing	Equity	40.0%	60.0%	0.0%
Financing	Debt	60.0%	40.0%	100.0%
Interest Rate		6.0%	6.0%	6.0%
Target ROE After Tax		15.0%	10.0%	0.0%
Marginal Tax Rate		40.0%	40.0%	0.0%
Interest		3.6%	2.4%	6.0%
After Tax Return As % of Investment		6.0%	6.0%	0.0%
Taxes on Return		2.4%	2.4%	0.0%
Weighted Cost of Capital		12.0%	10.8%	6.0%

In addition to the DOE standard unit data, it will be important to recognize the differential costs that may apply in the UP due to the smaller unit sizes and the possibility of additional transmission that could be needed to connect a new unit to the grid. For a new CF, we have some data for 60 MW units built in 1992. This suggests that the unit investment costs for such units can be as high as 50% above the DOE standard units. The heat rates are also much higher, at about 11,500 BTU/kWh rather than 9,000 BTU/kWh. The CT and CC units are more scalable and do not require nearly as large an adjustment as the CF. For this report, we have simply assumed a 40% investment cost premium for a 60 MW CF unit and a 10% premium for CTs and CCs in the UP.

5.4 Fuel Prices and Variable Costs

DOE provides national forecasts of the delivered cost of fuels to electric utilities in both its Annual Energy Outlook (AEO 2003) and in its Short Term Energy Outlook (STO). The fuel price forecasts are expressed in 2001 dollars but a forecast of the GDP Deflator is also provided which allows conversion to nominal prices that are appropriate for this study. The STO and AEO forecasts frequently diverge significantly over the next one or two years. The STO reflects current market conditions more closely while the AEO forecasts are driven by long-term market equilibrium logic. Where there were major differences between the STO and the AEO, the STO forecasts were used for the near term and the AEO forecasts for the long term. The only fuel requiring this adjustment was natural gas.

Of course, national average fuel prices will not apply to the UP. For UP-specific fuel prices we have simply used current costs for Escanaba purchases of coal and fuel oil and have applied the national escalators to get the Escanaba forecast. The coal price in Escanaba is about 50% above the national average.

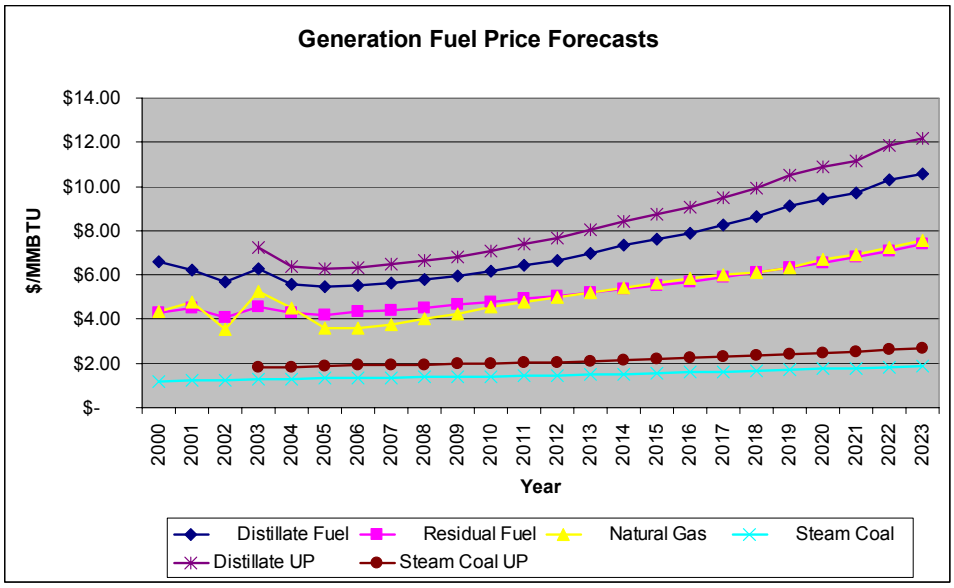
Table 7 and Figure 6 provide the fuel price forecasts used for this study. Clearly gas and fuel oil prices are expected to increase more rapidly than coal. The premium paid for fuel

in the UP is also evident in the graph. The levelized prices shown in the Table are the most relevant for the subsequent analyses in this study.

Table 7 Delivered Fuel Prices in $/MMBTU

Muni/Coop	Location	2003 Price	20 Year Levelized
Residual Fuel	National	$ 4.53	$ 5.34
Distillate	National	$ 6.29	$ 7.19
Natural Gas	National	$ 5.23	$ 5.23
Steam Coal	National	$ 1.27	$ 1.55
Distillate	UP	$ 7.24	$ 8.27
Steam Coal	UP	$ 1.80	$ 2.19
IOU	**Location**	**2003 Price**	**20 Year Levelized**
Residual Fuel	National	$ 4.53	$ 5.39
Distillate	National	$ 6.29	$ 7.20
Natural Gas	National	$ 5.23	$ 5.26
Steam Coal	National	$ 1.27	$ 1.58
Distillate	UP	$ 7.24	$ 8.28
Steam Coal	UP	$ 1.80	$ 2.23

Figure 6 Fuel Price Forecasts



The final cost component is variable O&M. This includes non-fuel materials and labor that are generally regarded as proportional to the hours of use of the generation stations. For coal plants, ash disposal is an important part of variable O&M. The 2003 variable O&M figures for the generic new plants have been taken from DOE data. The estimates for the existing EED CF plant are based on analysis of a recent history of plant accounting data. Table 8 summarizes both the 2003 data and the levelized figures based on 3.0% annual escalation. This analysis does not recognize any differences between O&M costs in the UP versus other locations. There are minor differences in the levelized figures based on the differences in discount rates that typify IOUs and municipal utilities.

Table 8 Variable O&M Costs

Technology	Location	2003 Var O&M $/MWh Out	Levelized Var O&M $/MWh Out
Existing EED Coal Plant	Escanaba	$6.18	$8.32
Existing EED CT	Escanaba	$4.09	$5.50
New Coal Plant IOU	UP60	$3.07	$4.38
New Coal Plant Muni Coop	UP60	$3.07	$4.55
New Combined Cycle IOU	UP	$2.04	$2.76
New CT IOU	UP	$4.09	$5.53
New Combined Cycle Muni Coop	UP	$2.04	$2.75
New CT Coop Muni	UP	$4.09	$5.50
New Coal Plant IOU	Region	$3.07	$4.38
New Coal Plant Muni/Coop	Region	$3.07	$4.55
New Combined Cycle IOU	Region	$2.04	$2.76
New Combined Cycle IOU	Region	$2.04	$2.76
New Combined Cycle Muni Coop	Region	$2.04	$2.75
New Combined Cycle Muni Coop	Region	$2.04	$2.75
New CT IOU	Region	$4.09	$5.53
New CT IOU	Region	$4.09	$5.53
New CT Muni/Coop	Region	$4.09	$5.50

5.5 Generic Cost Summary

It is often useful to have the most critical cost estimates summarized in a single table like that presented as Table 9. Both fixed and variable costs are included. The costs presented in this table provide the direct inputs used for the optimum mix analysis that is developed in Section 6.

Table 9 Summary of Costs by Technology

Technology	Location	Annual Capital $/kW-yr	Levelized Fixed O&M $/kw-yr	Total Annual Fixed Costs $/kw-yr	Net Heat Rate BTU/kWh	Fuel	Levelized Fuel Price $/MBTU	Levelized Fuel Cost $/MWh Out	Levelized Var O&M $/MWh Out	Total Variable $/MWh Out
Existing EED Coal Plant	Escanaba	$ -	$144.15	$ 144.15	15,000	Coal	$ 2.19	$ 32.80	$ 8.32	$ 41.11
Existing EED CT	Escanaba	$ -	$ 17.51	$ 17.51	16,000	Fuel Oil	$ 8.27	$ 132.30	$ 5.50	$ 137.81
New Coal Plant IOU	UP60	$ 218.15	$ 37.15	$ 255.30	11,500	Coal	$ 2.23	$ 25.66	$ 4.38	$ 30.04
New Coal Plant Muni Coop	UP60	$ 139.97	$ 38.55	$ 178.53	11,500	Coal	$ 2.19	$ 25.14	$ 4.55	$ 29.70
New Combined Cycle IOU	UP	$ 82.10	$ 17.58	$ 99.68	7,500	Fuel Oil	$ 8.28	$ 62.13	$ 2.76	$ 64.89
New CT IOU	UP	$ 82.10	$ 14.66	$ 96.75	10,939	Fuel Oil	$ 8.28	$ 90.62	$ 5.53	$ 96.15
New Combined Cycle Muni Coop	UP	$ 57.75	$ 17.50	$ 75.26	7,500	Fuel Oil	$ 8.27	$ 62.02	$ 2.75	$ 64.76
New CT Coop Muni	UP	$ 42.79	$ 14.59	$ 57.38	10,939	Fuel Oil	$ 8.27	$ 90.46	$ 5.50	$ 95.96
New Coal Plant IOU	Region	$ 155.82	$ 37.15	$ 192.97	9,000	Coal	$ 1.58	$ 14.20	$ 4.38	$ 18.58
New Coal Plant Muni/Coop	Region	$ 99.98	$ 38.55	$ 138.54	9,000	Coal	$ 1.55	$ 13.91	$ 4.55	$ 18.46
New Combined Cycle IOU	Region	$ 74.63	$ 17.58	$ 92.22	7,500	Gas	$ 5.26	$ 39.46	$ 2.76	$ 42.22
New Combined Cycle IOU	Region	$ 74.63	$ 17.58	$ 92.22	7,500	Fuel Oil	$ 7.20	$ 54.00	$ 2.76	$ 56.76
New Combined Cycle Muni Coop	Region	$ 52.50	$ 17.50	$ 70.01	7,500	Gas	$ 5.26	$ 39.46	$ 2.75	$ 42.21
New Combined Cycle Muni Coop	Region	$ 52.50	$ 17.50	$ 70.01	7,500	Fuel Oil	$ 7.19	$ 53.90	$ 2.75	$ 56.65
New CT IOU	Region	$ 55.29	$ 14.66	$ 69.95	10,939	Gas	$ 5.26	$ 57.56	$ 5.53	$ 63.08
New CT IOU	Region	$ 55.29	$ 14.66	$ 69.95	10,939	Fuel Oil	$ 7.19	$ 78.62	$ 5.53	$ 84.15
New CT Muni/Coop	Region	$ 38.90	$ 14.59	$ 53.49	10,939	Gas	$ 5.26	$ 57.56	$ 5.50	$ 63.06
New CT Muni/Coop	Region	$ 38.90	$ 14.59	$ 53.49	10,939	Fuel Oil	$ 7.20	$ 78.76	$ 5.50	$ 84.27

Section 6 - Optimum Mix Analysis

6.1 General

The generic cost estimates in Section 5 provide unit fixed and variable costs for a variety of technologies, fuels, locations, sizes, and owners of new generating plants. To discover the least-cost capacity expansion plan for EED, these generic units must be combined in the most effective way. This section provides an optimum mix analysis that will show which combinations of plants are likely to be cost effective and how much of each type of plant EED should pursue. Those insights then guide what should be sought if new RFPs are to be issued and provide needed benchmarks for evaluation of contract purchases that may be available to EED.

Optimum mix analysis consists of two steps. In the first step, diagrams are prepared that show the cost of operating each alternative technology different numbers of hours ranging from 0 to 8,760 hours per year. This provides a simple visual method of identifying the appropriate number of hours to operate each technology to cover the expected EED load. Baseload technologies have high fixed costs but relatively low variable costs. Thus, they need to run many hours per year to make the cost per kWh competitive. The more hours of run time, the lower the fixed costs per kWh. Peaking units provide capacity at very attractive costs but are very expensive to run. Therefore, it is not desirable to run them very many hours. These intuitive notions are easily seen in the first stage diagrams, which provide useful guidance to EED in defining the alternatives of primary interest.

The second stage of the optimum mix analysis combines the hours of desired run time for each type of unit with the EED load duration curve to determine how much energy should come from each source and how much capacity of each source is needed for least cost generation.

To simplify the graphic analysis, the 18 alternatives defined in Section 5 have been grouped into categories defined by assumed ownership and location of the new units. The groups are:

- New units built by munis or coops in the UP
- New units built by IOUs in the UP
- New units built by munis or coops in the region but outside the UP
- New units built by IOUs in the region but outside the UP

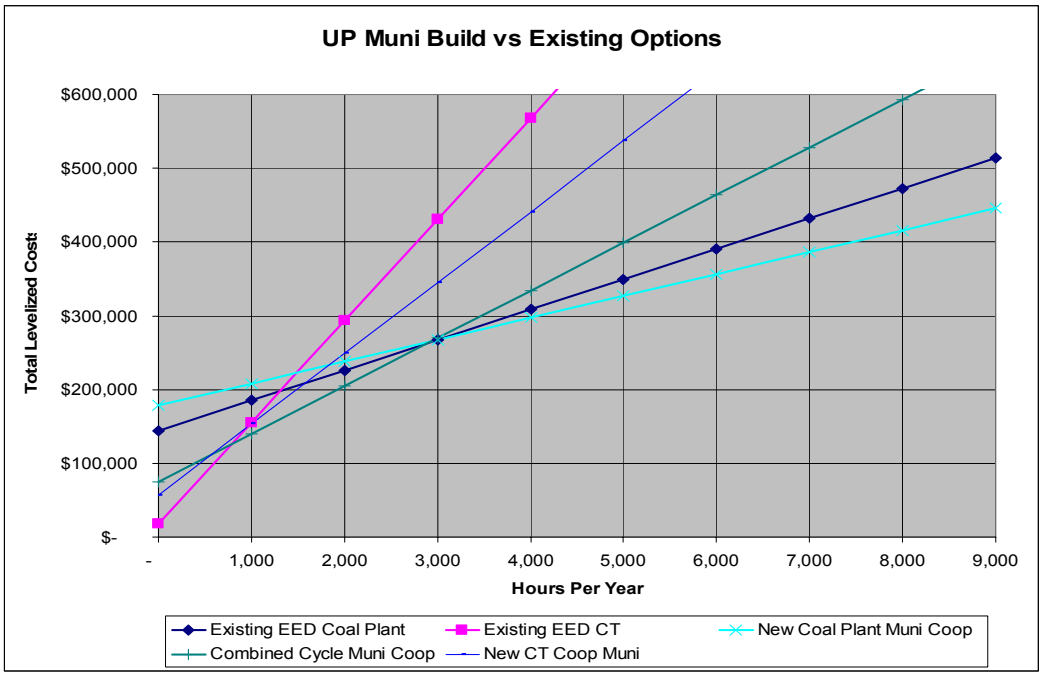
The latter two groups would require transmission upgrades that are not yet committed or costed by the American Transmission Company (ATC).

6.2 Optimum Hours by Technology

Section 5 provided total $/kW-year and $/MWh for numerous possible alternatives using levelized costs that would be representative of a typical year. If the unit does not run in a given year, the fixed costs must still be paid. The $/MWh figures remain fixed in this

analysis regardless of the number of hours run. Thus, the annual cost of operating any given unit can be plotted as a straight line against the number of hours that the unit is run. The lowest line in the diagram represents the least-cost option for that number of hours. Figure 7 provides an example that compares the options that involve construction of new generation in the UP by a municipal utility or a group of municipal utilities and/or cooperatives.

Figure 7 Muni-Build in the UP Alternatives



The following conclusions are immediately apparent:

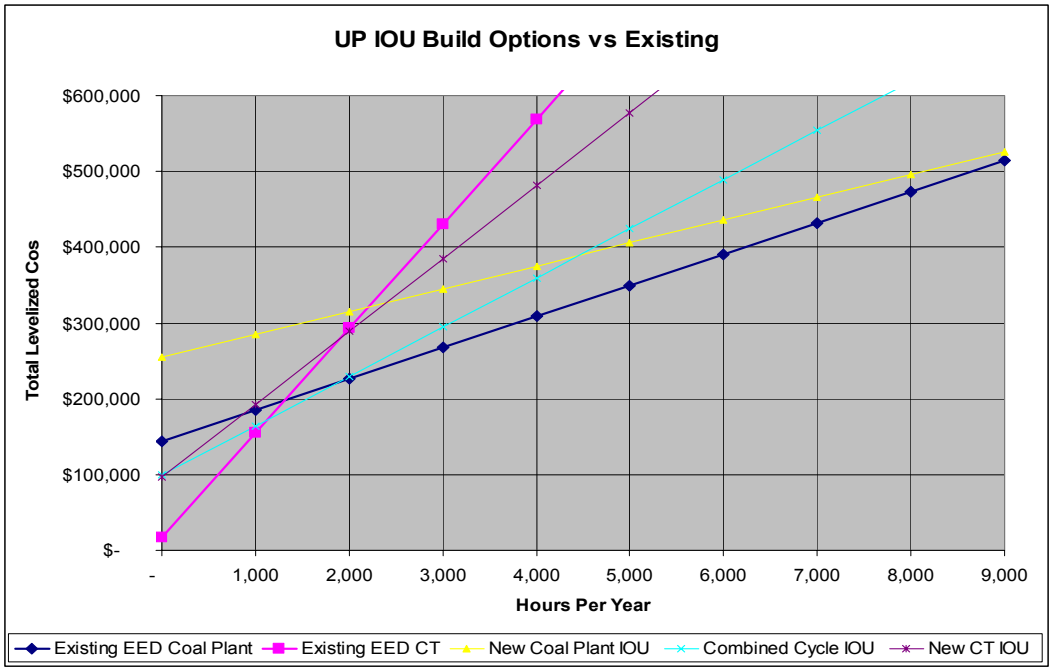
- The existing EED CT is the most attractive option when operation is limited to about 700 hours per year. This is true despite the fact that it burns rather expensive fuel oil. It would certainly be worth exploring whether it would pay to connect the site to gas supply for this level of operation.
- There is no apparent reason to pursue a new CT in the UP.
- From 700 to about 3,000 hours, the lowest cost of these options would be a new CC unit burning fuel oil.
- The CC role would clearly expand if it were built at a site with gas access. In practice, a dual fuel unit would be preferred to guard against excessive price volatility.
- If no CC unit were available, the existing EED CF would be useful to cover some of the intermediate load.
- The preferred option for baseload would be participation in a new 60 MW CF built by an alliance of municipal and cooperative interests.

- If no muni CF unit can be agreed upon, the existing EED CF would provide baseload power as long as there are no major failures or cost variances from those that have been assumed.

The alternatives to pursue based on these comparisons would be new CF and CC units in the UP owned by a group of municipal utilities. The amount of capacity of each type that EED would seek will be determined in the second stage of the mix analysis. The size chosen will need to consider the needs of all parties that might wish to consider such units. The possibility of off-system sales of capacity and energy should also be explored although this set of alternatives does not include transmission upgrades that might be required to make such sales possible.

Municipal and cooperative systems in the UP are relatively small and may not be able to coalesce on the timing, size, type, and location of new generation projects. In that case, WPS/UPPCO might be interested in developing new generation. Based on the IOU financing assumptions that we have used, Figure 8 compares existing EED resources with new IOU generation.

Figure 8 IOU Build in the UP Alternatives



In this case the results are quite different:

- The minor role shown for the CC can be ignored at very low cost.
- In general IOU build options do not appear to compete with existing EED resources.
- For units operating 7,000 hours per year the difference between new and existing resources is not so large. Thus, if new IOU capacity is needed to

replace one or two of the EED CFs, the cost implications are not too severe.

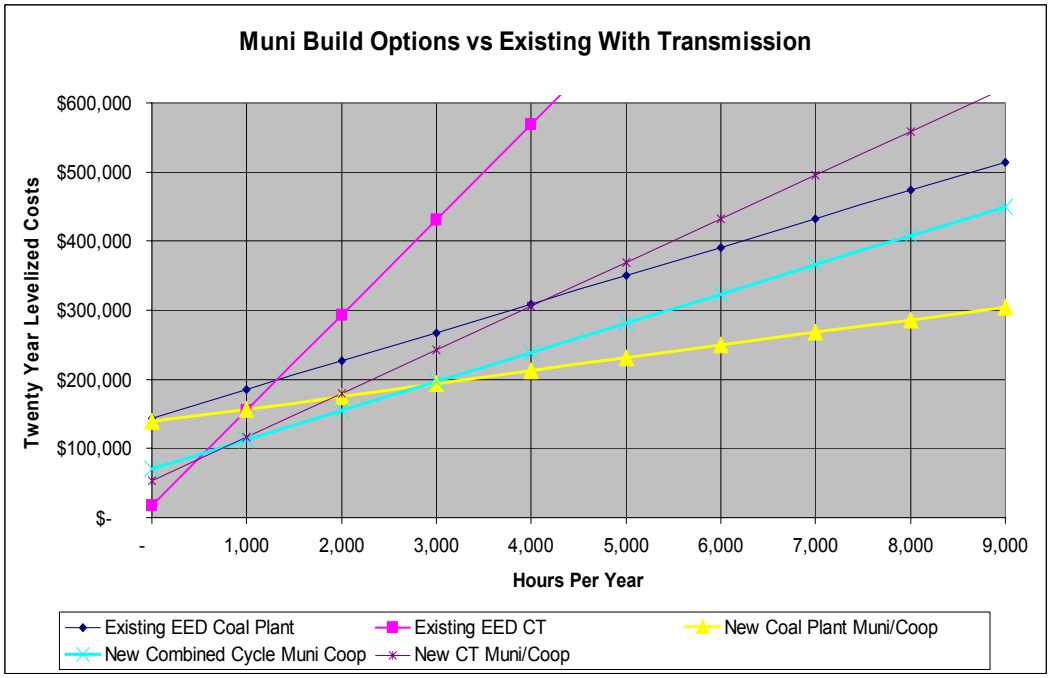
- If EED participates soon in a new IOU CF and retires the existing EED CF, a new IOU CC becomes quite attractive.
- The existing EED CT would ideally be used approximately 1,000 to 1,200 hours per year for this potential resource mix.

From this set of comparisons, it appears reasonable to pursue contingent participation in a 60 MW CF in the UP and/or a CC. The CF participation would be tied to planning for retirement of the existing EED CFs. As long as those units continue to operate as assumed here, they would offer lower costs than the new IOU CFs in the UP. The CC has been evaluated based on fuel oil and would be more attractive based on gas firing. Dual fuel options offer the best risk mitigation strategy for this technology. To play a significant role, the IOU CC in the UP would need to run primarily on gas.

Figures 7 and 8 suggest solutions if smaller new units were built in the UP with higher heat rates and fuel costs. Access to DOE scale units with fuel prices near national average figures would likely require improved transmission access to the UP. The costs and likelihood of such transmission upgrades cannot be determined absent additional studies by ATC or others to determine what could be done and a cost and schedule to complete those improvements. Even then, transmission projects are notoriously difficult to permit and implement on a predictable timeline. The approach used here is to identify what EED would seek from new units outside the UP assuming that transmission were available. This will determine what EED could afford to pay for transmission to break-even with the best UP options.

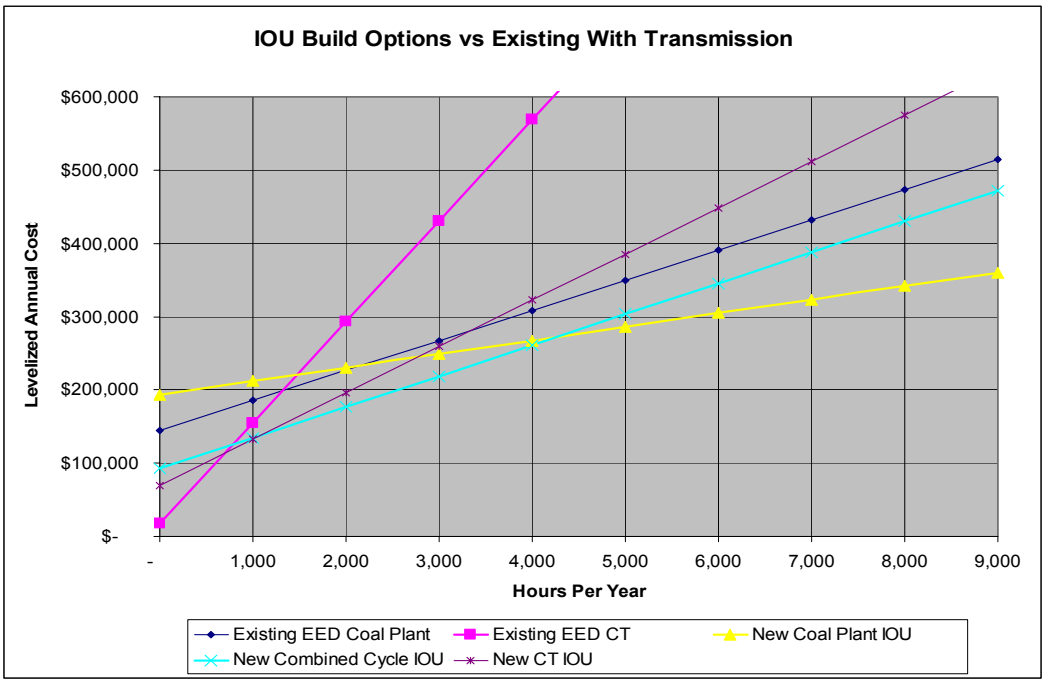
Figures 9 and 10 present the comparisons assuming municipal/coop units and IOU units respectively.

Figure 9 Municipal Options Outside the UP



Participation in new municipal plants would ideally involve some CC capacity for intermediate load and new CF for baseload. In this case generation from the existing EED CT would be limited to about 500 hours per year. If CC participation is not available, access to a new CT would increase total peaker generation to about 1,900 hours per year. The alternatives to pursue initially would be new CC and new CF. Pursuit of additional peaking would make sense only if the CC were not available on the terms indicated here. Of course, pursuit of these options will require pursuit of transmission improvements as well. It is interesting to note that the energy costs for the existing EED CF are very similar to those of a new gas-fired CC (the slopes of the lines are nearly the same). The fuel price advantage for coal in the UP is about offset by the higher efficiency of new CC units. Of course, the gas price is likely to be much more volatile than the coal price.

Figure 10 IOU Options Outside the UP



Although the cost of the same new units financed by IOUs would be higher, Figure 10 shows that the same type of units would be preferred from IOUS as from municipal systems. The lowest cost mix would include new CC and CF capacity and energy to supplement the existing EED CT. A new CT would be important only if CC participation could not be arranged.

The results of the first stage of the optimum mix analysis can be easily summarized as follows:

- New CC and CF units in the UP will most likely offer the most concrete options to consider because of the difficulty of developing firm plans and costs for transmission upgrades.
- New CTs would only be of interest in the event that CC units are not possible for some reason.
- If the new UP CC and CF units were financed on municipal terms, they could compete with the existing EED CF. If they are financed on IOU terms, the new units would only be pursued in the context of eventual retirement of the EED CF.
- Without firm costs for new transmission, we cannot determine how new plants outside the UP will compete with the UP options.
- Ignoring transmission, the types of units of interest are the same – CCs and CFs.

While the optimum mix points to CC units for intermediate service and CF for baseload in all cases, the specific amounts of capacity of each type will differ across the cases.

Determining the MW sought of each type is the object of the second stage of the mix analysis.

It should also be noted that these curves indicate the least-cost mix but do not allow calculation of the power costs associated with any particular solution. These curves are based solely on unit costs per kW-year and per MWh. To derive power costs, we must combine these curves with the EED load duration curve. That determines the quantities of energy produced by each source and the quantities of capacity of each type that EED should pursue. The key input from the first stage analysis to the second stage is the number of hours each of the technologies should operate to achieve the lowest cost. Table 10 summarizes the crossover points between the least cost technologies for each of the scenarios portrayed in Figures 7 through 10. The last case shows the least cost split between the existing EED units assuming that these are the only resources and that they can adequately cover peak loads plus reserve requirements. The other cases substitute CC production for both CF and CT production to reach the least cost solution.

Table 10 Crossover Points and Operating Hours by Technology

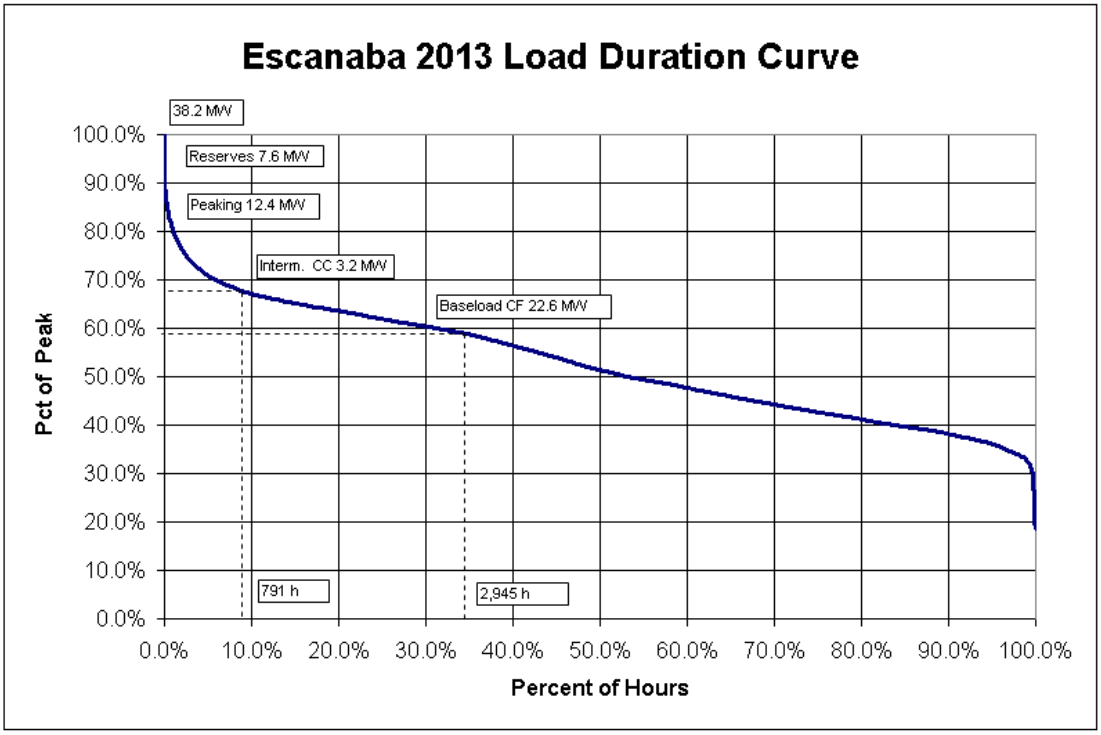
	Crossover Hours		
	ECT - NCC	ECT - NCF	NCC-NCF
UP Munis	791	1,489	2,945
Region Munis	549	1,014	2,886
Region IOUS	782	1,472	4,262
	ECT - ECF		
UP IOUS	1,310		

ECT = Existing EED Combustion Turbine
ECF = Existing EED Coal Plant
NCC = New Combined Cycle
NCF = New Coal Fired Unit

6.3 EED Least-Cost Capacity Requirements

If EED pursues a strategy based on new units in the UP that are jointly developed with other municipal or cooperative systems, Table 10 showed 791 hours and 2,945 hours as the division points between the EED CT and new CCs and new CFs respectively. Figure 11 translates these division points into the desired capacity of each resource. The load curve in Figure 11 is the EED 2002 load curve shown in Figure 2 converted to percentage terms. This simplifies applications for future years when actual loads are different than they were in 2002. Since new plants have long lead times, EED needs to develop plans that would meet their needs 5 to 10 years from now. For this illustration, 2013 has been selected. The load forecast shows that EED's peak demand in 2013 will be about 38.2 MW and that annual energy requirements will be 182,753 MWh. With 20% reserves, the total capacity needed will be 45.8 MW.

Figure 11 New UP Muni Units – EED Capacity and Energy



The 791 hour division point between peaking and a new CC unit represents 9.0% (791/8760) of the hours in the year. The load curve shows the load corresponding to 791 hours is 67.6% of the peak or 25.8 MW. Thus, the peaking capacity to cover load is 38.2-25.8 = 12.4 MW. In addition, peaking capacity would be used to cover the reserve requirement, which suggests that the total peaking requirement would be about 20 MW. The 18.0 MW EED CT would probably be sufficient since it would provide almost 15% reserves. Beyond 2013, however, additional peaking would be required. The load curve also shows that loads will exceed 59.3% of the peak 33.6% of the time, which corresponds to 2,945 hours. Peaking capacity plus new CC capacity will then need to cover 38.2-22.6 = 15.6 MW. The required amount of firm CC capacity would be 15.6 – 12.4 = 3.2 MW[5]. The remaining capacity of 22.6 MW would come from new baseload units. To summarize, the least cost capacity mix to cover EED's expected loads in 2013 would be:

- 20.0 MW of peaking
- 3.2 MW of new CC
- 22.6 MW of new CF

[5] The analysis illustrated here is normally adjusted for forced and planned outages of the units. That can be done by derating the net capacity of the units to reflect availability. For that reason, the capacity requirements illustrated here are understated. This is sufficient for screening but the final plan evaluations will need to include this refinement.

If the new CC runs on lower cost gas, its role will expand and the CC capacity will increase while the desired baseload capacity decreases[6].

A first reasonable strategy for EED to pursue would be to test the interest of municipal and cooperative utilities in the UP to determine whether they have a collective interest in developing new baseload and/or combined cycle generation in the time frame of interest to EED. This type of development would often be pursued through a joint action agency.

This process can be repeated for any scenario of interest but the most interesting additional case might be to determine what happens in 2013 if EED were only operating its current CT and CF resources. The crossover point is then 1,310 hours, which is 14.95 percent of the hours in the year. EED is expected to have loads in excess of 24.9 MW or 65.2% of the peak about 15% of the time in 2013. Thus, the desired peaking capacity would be 38.2 – 24.9 = 13.3 MW to cover load plus 7.6 MW for reserves. Total peaking desired will then be 20.9 MW. Baseload requirements will be 24.9 MW. Allowing for outages, the total baseload requirement would be in the range of 28 to 30 MW.

In this context, a second reasonable strategy would be for EED to develop plans to add three 15 MW baseload units over the planning horizon. The timing of these units would be tied to the retirement plans for the existing CF units. This would provide a "go-it-alone" option in case the collaborative effort does not materialize.

Section 7 - Proposed Alternatives and Next Steps

7.1 General

Section 6 identified the mix and amounts of generation of various types that EED should seek under various assumptions about the likely developers and locations of that capacity. The search for that capacity would normally define the next step in the study as an RFP broadcast widely that seeks the type of capacity desired. PSE has very recently completed an RFP on the behalf of the Upper Peninsula Transmission Dependent Utilities (UPTDU) group. The sobering results of that RFP are summarized here in general terms to help define the preferred next steps for EED.

The results of our forecast of needs and the mix analysis combined with our current reading of the UP power market provides the basis for recommending specific alternatives for EED to consider. Following EED concurrence with the menu of alternatives to pursue, the next phase of the power supply study will involve attempts to obtain or stimulate concrete development plans for consideration. The next steps in that process are described in the closing part of this section.

[6] It might be noted that Figure 11 also provides the basis for estimating the amount of percent of energy that would be taken from each resource to achieve least cost supply. Baseload energy is the area under the load curve up to 22.6 MW. If the baseload units have availability of 85%, about 26.5 MW of installed capacity would be necessary to provide the needed 22.6 MW. Then baseload would supply 94.4% of the energy with 4.2% coming from the CC and just 1.4% from the peaker.

7.2 PSE RFP

PSE is currently assisting five UP utilities (UPTDU-5) with evaluation of power supply options. UPTDU-5 includes the following co-ops and municipal systems:

- Ontonogan County Rural Electric
- Alger-Delta Cooperative
- City of Crystal Falls
- Village of Baraga
- Village of L'Anse

In late September 2003 PSE issued an RFP soliciting power supply proposals for this group to the following potential suppliers:

- Split Rock Energy (Split Rock)/Rainy River Energy Corporation (Rainy River)
- Wisconsin Public Service Corporation (WPS)
- Wisconsin Public Power Incorporated (WPPI)
- Xcel Energy (Xcel)
- Wolverine Power Supply Cooperative (Wolverine)
- Constellation Energy Group (Constellation)
- GEN~SYS Energy (GEN~SYS)
- Alliant Energy (Alliant)
- Wisconsin Electric (WE)
- Michigan Municipal Electric Association (MMEA)
- UPPCO (UPPCO)
- White Pine Refinery (White Pine)

Four recipients indicated their intent to respond but ultimately only three proposals were received. WE has just received approval for its plan to construct 1,800 MW of new CF at its Oak Creek site. Several Wisconsin utilities are considering participation in those units, which have reported investment costs in the range of those used in our analysis of the regional options. It is surprising that WE chose not to respond. Dairyland Power is also actively planning new capacity additions that would have capacity and energy marketed through GEN~SYS but they also chose not to respond. It is clear that the power market for UP utilities is very thin and quite possibly is being limited by the known deficiency of transmission capacity to allow firm delivery to the UP.

The first proposal offers output from a new 285 MW gas-fired combined cycle unit in Illinois. This would be unit power with the purchaser responsible for providing their own back-up when the plant is not running. Transmission would be required from both Exelon and ATC and would be the responsibility of the purchaser. The purchaser would be free to purchase from the market whenever that offers a lower cost alternative than this unit. If transmission could be secured, this unit would give EED access to a DOE scale CC unit but this is certainly not firm supply and the pricing will be tied to gas prices rather than on the firm basis that was sought.

The second response is more an indication of interest than a proposal since it is contingent on:

- The proponent's success in securing 65 MW of power that it is currently seeking in its own RFP.
- ATC completing transmission upgrades as defined in their 10-year plan.

Neither of these conditions can currently be firmed up and no pricing can be established without resolution of these issues. It appears that this proponent may be interested in new or repowered facilities in the UP and this would merit discussion.

The third proponent has 2X20 MW boilers and 3X20 MW steam generators in the UP. The boilers currently are configured for gas firing but could be converted to coal. The proponent is considering addition of a third 20 MW boiler that could be fired with wood. Depending on age and condition, refurbishing and/or fuel conversion of these units should easily be competitive with new construction. Expected efficiencies and fuel costs for the units are not known. Demand and energy prices have been quoted on a confidential basis. EED may wish to propose a purchase from this facility that is priced somewhat below the costs from the existing EED CF to see if there is room for negotiation.

7.3 Transmission Issues

It is not so surprising that potential power suppliers outside the UP are reluctant to provide firm transmission as part of their proposals. Unlike power market conditions over the last twenty years in the upper Midwest, there is now very little excess capacity available. Thus, the days of highly motivated sellers have disappeared. It is now a sellers market. Any supplier wishing to provide firm transmission to the UP is required to request transmission service from ATC. ATC will then conduct a three to five month transmission study to determine what improvements would be required and their likely cost. The applicant will be responsible for financing all improvements with the total investment cost then paid back by ATC at the time that the facilities are put into service. The user of the facilities will then pay based on ATC rates, which are now quoted in terms of dollars per kW-month. The current rate of $2.12 per kW-month for firm transmission translates to about 0.5 cents per kWh at a 55% load factor. Certainly future rates are likely to be higher if substantial new facilities are added to the rate base but speculation on what the rate will be without a specific application is not useful. Costs for constructing new transmission facilities will be blended into the transmission rate for all ATC customers.

7.4 Other Possible Alternatives

PSE has had brief discussions with Veirbicher Associates who have been working for two years with the Hannahville Indians to promote a new power plant on a site owned by the tribe. Preliminary discussions suggest that this project would require development thrust and financing from a utilities or a merchant developer with the tribe primarily interested in provision of the site and perhaps some simplified permitting. We do not

anticipate that an RFP to the tribe would yield a concrete proposal for supply from a specific unit built by others.

Meade Paper has a facility in the UP that is often mentioned as a possible site for cogeneration. Cogeneration is an attractive option from a cost perspective but the specific balance of heat/steam demands and the facility's electric demands are limiting factors. Optimized cogeneration is sized to balance electric and heat production against the loads of the host. If heat demands are substantially greater than electric demands, additional electricity could be produced at an attractive cost and then sold to EED. Cogeneration is complex to plan and many industrial concerns are not attracted to investing in power plants beyond what is needed to service their own needs. Dispatch is impacted by production schedules and the future of the plant would be tied to the future commercial success of the Meade operation at this site.

PSE is also currently assisting Gladstone with power supply evaluations. At this point Gladstone does not have firm plans that would provide supply to EED. Certainly Gladstone would be a potential participant in a new joint plant.

7.5 Conclusions and Open Issues

Based on the load forecasts, the evaluation of existing EED resources, the cost comparisons and mix analyses, and the responses to the RFP, PSE has reached the following conclusions:

1. EED currently has CT and CF resources that are well maintained and appear capable of reliable service for the next 10 years without predictable costs outside the range of recent experience.
2. The cost characteristics of these units would suggest that they would most effectively be used to cover peaking and intermediate loads.
3. EED is currently able to operate the existing units in this way primarily because of the arrangement with UPPCO that allows access to other resources whenever the price is below the cost of the EED CF. Effectively, this arrangement is providing baseload supply and allows the EED CF to cover intermediate loads.
4. The termination of the UPPCO contract in 2005 means that other resources should be considered to determine the least cost supply.
5. The EED power supply plan developed at this time should include at least contingent plans for retirement of the CF units. CC units are preferred for intermediate supply.
6. The EED CF will be an expensive source of baseload power relative to new plant options.
7. EED's peak load plus 20% reserves is expected to exceed the 42 MW of existing capacity in 2008 meaning that plans must be firmed up now if new construction of baseload units is envisaged.

8. EED's need for additional capacity will increase to about 11.5 MW by 2023 in addition to any capacity that would be required to replace existing resources that would be retired.
9. Cost characteristics of new capacity can be usefully distinguished in four scenarios that are defined by plant ownership and location inside or outside the UP.
10. Outside the UP, EED would have access to larger units with lower investment costs per kW, higher efficiencies, and lower delivered fuel costs. That advantage may or may not be offset by the necessary investment in transmission to provide such access.
11. Regardless of location, the financing assumptions used here suggest a significant investment cost advantage to municipal and cooperative plants relative to those built by IOUs or merchant developers.
12. All things considered, the most attractive of the four scenarios for EED appears to be pursuit of new capacity built in the UP by a group of municipal systems and/or cooperatives. A small joint action agency already exists and could possibly be expanded to finance the plant. Alternatively WPPI could be contacted to test interest in building a plant in the UP and adding UP municipal participants to their membership.
13. Given the absence of clear transmission costs and commitments and the anemic response to the PSE RFP, pursuit of options outside the UP should be very focused and only initiated based on some indication of likely interest. We do not see value in issuing a broad RFP for Escanaba again at this point without some reason to believe that the results will differ.
14. The alternatives to pursue for new plants in the UP would be a CF and a CC. The CF is the more critical of the two and would have the longer lead-time.
15. Screening analysis suggest that the EED CT could be called upon to run significantly more hours than the current plans for 200 hours per year. If that will be the case, the possibility of extending gas service to the plant should be examined.

7.6 Recommended Alternatives to Pursue

EED's menu of alternatives that merit more detailed evaluation can conveniently be grouped into the following strategies:

- Go It Alone – This strategy develops an independent power supply plan that does not require coordinated development or reliance on outside resources.
- Coalition of the Willing – This strategy aggressively pursues the formation of a group of UP utilities who wish to actively pursue development of new generation in the UP.
- Other UP – This strategy would focus on repowering or expanded development of existing UP generation.

- Trans Plus – This strategy commits to active pursuit of new resources outside the UP and the specific transmission upgrades necessary to provide firm delivery capability to the UP.

The first alternative to be considered in the Go it Alone strategy (GIA1) includes a twenty-year business as usual (BAU) alternative in which EED plans to continue operation of both the existing CF and CT units. EED will also need to add another 12 MW of new capacity to cover expected load growth. The new capacity would need to be in place by 2008. The second alternative (GIA2) in this strategy establishes a retirement date for the existing CF plant and adds new capacity to cover both replacement and load growth. We cannot fix a retirement date based on any projected deterioration of plant performance but prudence suggests that EED cannot wait for failure to occur before planning begins for replacement. We propose that GIA2 be comprised of addition of one new 15 MW CF by 2008 with a second 15 MW unit in 2013 and a third 15 MW unit in 2016. Retirements of the existing units could then be planned for 2008 and 2013. Evaluation of these options would provide EED with an independent course of action that would cover their needs over the next two decades with the preferred type of generation without concerns for uncertain evolution of the transmission grid. This will also define a maximum investment strategy to test the City's desire to follow an independent but clear course of development. A third possible variant (GIA3) would be to substitute a gas-fired CC for one of the CF units.

The Coalition of the Willing (COW) strategy is driven by the belief that new capacity in the UP is in the best interest of many interested parties and that larger units will have better unit costs and efficiencies than smaller units. The COW1 alternative would pursue development of a new CF with the size determined by the collective needs of the group that commits to the unit. It is anticipated that a unit in the 60 to 100 MW range may be sought. This type of coordinated development is not easily implemented but EED has an advantage based on the fact that other potential members have more immediate capacity needs than EED. The immediacy of need should keep others motivated to proceed as quickly as possible. The ideal coalition from a financing standpoint would be a municipal joint action agency. However, inclusion of UPPCO could bring power plant development expertise and leadership from WPS that may be useful. The important first step in pursuit of this alternative will be to establish a working group with a specified timeline for determining need and interest. PSE is facilitating a meeting of this sort at Marquette on November 18, 2003. Escanaba is invited and PSE can attend on EED's behalf if desired. The COW2 alternative would be to pursue a new CC plant in the UP while COW3 would promote one CF and one CC. Once needs are identified for this group, site selection and permitting studies would be needed to select the preferred locations for the plant or plants.

The Other UP (OTHERUP) strategy currently has two specific options that we are aware of. The first, OTHERUP1, would seek to negotiate a favorable contract for supply from the UP supplier with available steam generation units. The OTHERUP2 alternative would be to test Meade Paper's interest in development of cogeneration that could cover

EED's future needs. It is expected that the Hannahville option would most appropriately be addressed as part of the site selection studies.

The TransPlus alternatives would focus on identifying specific new supply sources and would require the ATC studies to determine the cost and timing for firm transmission to be available. TransPlus1 would again attempt to determine if participation in the WE CF at Oak Creek would be possible. If so, an ATC study would be requested to complete the costing of this alternative. Transplus2 would follow a similar course to test participation in new CC units being built in Illinois or Wisconsin.

It is important to emphasize that some of these alternatives require studies and calendar times that are outside the current scope of the PSE power supply study. This simply reflects the reality of the UP power market and the nature of EED's current resources and future needs. Given these developments, we feel it is critical to keep EED informed of our findings and to agree on the next steps and schedule for completion of the study.