MEMORANDUM

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| *TO*: | Jamie Piziali (EPA Headquarters) and John King (EPA Region I) |
| *FROM*: | John Sunda, Tetra Tech |
| *DATE:* | August 22, 2012 |

*SUBJECT*: Merrimack Station NPDES Permit Response to Comments Related to Secondary Environmental Factors

Tetra Tech was requested to provide technical support addressing public comments submitted in response to draft NPDES Permit for Merrimack Station (Permit #NH0001465) (Merrimack). Tetra Tech was specifically asked to address those comments related to the secondary environmental factors associated with the installation of cooling towers to comply with Merrimack Station's Draft Permit 316(a) and 316(b) requirements.

## I. Documents Reviewed

As indicated in the direction from EPA Region 1, most of the specific comments to be addressed are contained in the document:

- "Response to Environmental Protection Agency's Draft NPDES Permit, PSNH Merrimack Station, Units 1 & 2, Bow, New Hampshire, Enercon Services, Inc. February 2012" hereafter referred to as "Enercon 2012."

In order to evaluate most of the technical documentation submitted by Enercon and referenced in this analysis, Tetra Tech also referred to a document that it had previously reviewed under a separate task:

- "Response To United States Environmental Protection Agency CWA § 308 Letter PSNH Merrimack Station Units 1 & 2 Bow, New Hampshire, Enercon Services, Inc. and Normandeau Associates, Inc. November 2007"hereafter referred to as "Enercon 2007."

Lastly, Tetra Tech was also tasked with reviewing several other sets of stakeholder comments to ensure that no additional significant comments on secondary environmental factors were submitted. Tetra Tech reviewed the documents below and concurred with EPA Region 1 that there were no new substantive comments contained within them.

- Comments of the Utility Water Action Group (UWAG) on Proposed NPDES Permit for the Merrimack Station in Bow, New Hampshire, NPDES Permit NH0001465. UWAG, February 28, 2012
- Comments of Public Service Company of New Hampshire (PSNH) on EPA's Draft National Pollutant Discharge Elimination System Permit No. NH 0001465 for Merrimack Station. PSNH, February 28, 2012
- Preliminary Economic Analysis of Cooling Water Intake Alternatives at Merrimack Station. NERA, February 2012
- Comments on the Draft 316(b) Requirements in "Clean Water Act NPDES Permit Determinations for Thermal Discharge and Cooling Water Intake Structures at Merrimack Station in Bow, New Hampshire-Permit Number NH0001465. The Electric Power Research Institute, Inc. (EPRI), February 27, 2012.

## II. Secondary Environmental Factors

The remainder of this memo is dedicated to a review of the secondary environmental factors discussed in Enercon 2012, including Tetra Tech's assessment of Enercon's analysis and conclusions. The factors to be discussed are: evaporation from the cooling towers, cost considerations, air emissions, effects of the cooling tower plume, power generation losses, circulating water and blowdown water quality, and noise.

### A. Evaporation from Cooling Towers

Enercon 2012 discusses two main issues related to evaporative losses due to the operation of cooling towers: evaporative losses to the receiving stream and consumption of water as part of cooling tower drift.

<u>Evaporative Losses and Effects on the Receiving Stream</u>

Merrimack currently employs Power Spray Modules (PSM) as a way to mitigate thermal discharges. On Page 16 of Enercon 2012, the authors state that the primary mechanism by which the PSMs cool water is convection, and not evaporation. PSMs rely on convection and wind to transport air though the system which limits the amount of air/water interaction and thus the performance of the PSMs but just like in cooling towers, heat is transferred to the air via both evaporation and conduction to the air (also referred to as sensible heat). They provide no scientific basis for the assertion that the PSMs rely primarily on convection; both PSMs and wet cooling towers rely upon the same principle of mechanically inducing an increase in the surface area of contact between heated cooling water and ambient air through formation of suspended water droplets. It is likely that the mix of evaporation versus conduction for the PSMs will be similar to that of a cooling tower and will be dependent on meteorological conditions, particularly the relative humidity. However, since cooling towers are designed to produce a much greater air flow to maximize air/water surface area and duration for both evaporation and conduction, Enercon is correct in their assertion that cooling towers will evaporate more water than the PSMs, as well as more water than is evaporated from the surface of Hooksett Pool due to the temperature increase from the once-through cooling water discharge. But this conclusion is not surprising; the purpose of the wet cooling towers is to maximize the transfer of heat to the ambient air, thereby reducing the discharge of heat to the river. Using a wet cooling tower as part of a closed-cycle cooling system (as opposed to a helper tower) provides the added benefit of reducing intake flow volumes as well.

In support of their assertion that evaporation may have an impact on water resources during drought periods, Enercon notes that in 2007, several power plants in the Southeastern United States had to either shut down or reduce operation due to water shortages (USDOE 2009). However, the problem at these facilities was not related to evaporation and consumption but rather the cited report indicates that the reason for the shut down and reduced operation of these plants was due to circumstances where the river levels became too low for the intakes to operate properly.[1] Additionally, at these plants, the combination of low river water flow and high temperature limited the capacity of the river to accept the discharge of the heat load of the once-through discharge without exceeding thermal water quality limits. Thus, the reason these plants were required to reduce operations was actually due to the use of once-through cooling and had nothing to do with water consumption. In fact, two facilities located in the Southeastern United States owned by Georgia Power, McDonough and Yates, have responded to these water quality and quantity concerns by converting from once-through to closed-cycle as part of plant repowering projects. If water consumption by the cooling towers were a significant issue, then closed-cycle cooling would not have been the selected remedy.

The estimated combined quantity of consumed water at Merrimack through of evaporation and drift of 3,325 gpm is equivalent to 7.4 cfs. To provide context for this volume as it relates to the Merrimack River during drought periods, USGS data was examined for a gauging station downstream on the Merrimack River. The year with the lowest mean annual flow lowest during the past 20 years was 2002. During 2002, the mean annual flow was 3,254 cfs at the USGS gauging station on the Merrimack River near Goffs Falls, below Manchester, NH about 16 miles downstream. The lowest daily flow during that year was 538 cfs on August 13, 14 and 17, 2002 (USGS 2013). Thus, the estimated volume of consumed water represents roughly 0.2% of the mean annual flow and only 1.4% of the minimum daily flow in the Merrimack River during the lowest flow year during the last 20 years.

<u>Consumption Via Cooling Tower Drift</u>

In Enercon 2012, two different estimates for the amount of drift that could occur are presented. In the text on page 17, they provide an estimated volume of drift of 57,000 gpd equal to roughly 40 gpm for both Units 1 and 2 based on a cited drift rate of 0.02%. But in Figure 4, they present a schematic showing a total volume of drift of only 2 gpm (0.6 for Unit 1 and 1.4 for Unit 2) which is equivalent to the drift rate of 0.001% which coincides with the specifications in the SPX

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[1] Intake pumps require a minimum water depth in order to prevent air entrainment and cavitation.

tower design specs contained in Enercon 2007.[2] The cited drift rate of 0.02% is not unreasonable for a cooling tower that is not equipped with drift eliminators. However, new high efficiency drift eliminators are capable of drift rates as low as 0.0005% and the specified drift rate of 0.001% is a reasonable value to use in estimating the performance of a new high efficiency drift eliminator. Clearly the engineering design of the proposed closed-cycle system in Enercon 2007 includes high efficiency drift eliminators. Even using the larger estimated drift volume of 40 gpm (without the drift eliminator), this represents about 1% of the total consumption volume associated with cooling tower evaporation estimated by Enercon. When high efficiency drift eliminators are factored in this value becomes 0.06% of total consumption. The drift rate is insignificant from a water consumption perspective and the primary reason facilities install high efficiency drift eliminators, as Enercon 2007 indicates is planned at Merrimack , is not to minimize consumption but rather to minimize potential impacts related to drift including deposition of mineral content, equipment corrosion, and icing. These impacts are discussed further below.

## B. Cost Considerations

Enercon's primary concern in Enercon 2012 is that the costs estimates originally presented in Enercon 2007 are preliminary and uncertain in nature and cannot be relied upon to perform a BTA assessment. They also state that the 2007 cost estimate does not include consideration of site changes related to the presence of new interferences associated with the subsequent construction of the wet flue gas desulphurization (FGD) system. They contend that any estimate equivalent to a "class 4" or "feasibility phase" level of detail (per USCOE ER 1110-2-1302 - Enercon 2012 reference 6.29) is too uncertain and thus is unsuitable for EPA to use in determining the economic feasibility of closed-cycle cooling as BTA. While it is reasonable to conclude that Enercon's assessment that the 2007 cost estimate is roughly equivalent to a "feasibility phase" estimate[3] and is subject to a relatively higher degree of uncertainty than a more definitive estimate, it should be pointed out that EPA BTA determination is not an analysis that is dependent on the use of precise costs. It is a determination that examines the relative costs and benefits of the technology being assessed and as long as the feasibility phase cost estimate is a reasonable assessment of the expected costs based on the known factors and sound engineering practice, it should be sufficient.

Enercon contends that the 2007 cost estimate cannot be relied upon to reflect an estimate of the actual costs since it cannot incorporate unforeseen issues related to unforeseen difficulties that may arise as the project design is refined and individual component costs are more fully incorporated. They argue that the contingency multipliers provided in the 2007 Enercon response and discussed in the draft permit are not intended to cover these unforeseen issues that can arise during implementation of large projects as the project plans are fleshed out from the conceptual design stage and the detailed design stage. That assertion is incorrect, as contingent costs derived

[2] Note that Enercon continues to base the design of their proposed closed-cycle system on the 14-cell plume abated tower design presented in Enercon 2007 and has not suggested any changes to the fundamental design of the system in Enercon 2012.

[3] The US COE cost estimation guidance establishes four phases of construction estimation (in order of increasing complexity and accuracy): "reconnaissance phase," "feasibility phase," "preconstruction engineering and design (PED) phase," and "construction phase." Reconnaissance phase is the least well defined and is considered as an order-of-magnitude estimate used for screening purposes and would not be suitable for use in a BTA evaluation.

using contingency factors are indeed intended to provide a reasonable accounting for unexpected events in the project life cycle (Kawasaki). If not, then all such cost estimates would be of little use. Cost engineering is as much an art as a science and in situations where there are many unknown factors that may affect the costs, then the cost engineer may select a higher contingency factor based on experience and guidance. However, Enercon has not presented a convincing argument that a larger contingency factor is warranted (see Tetra Tech 2012). Enercon's argument that the cost estimate used by EPA should include consideration of the site changes since 2007 with regard to the new FGD is valid. However, this impact is expected to be relatively small. As described in Tetra Tech 2012, the new FGD unit is expected to have a cost impact on only a portion of the return cold water piping and will likely increase total project costs by several percent. The changes to the site condition regarding the presence of the new FGD system is a new condition, but not an unknown factor. If Enercon truly believes that this new condition will have a significant impact on the previous cost estimate for the closed-cycle system, then they should be capable of providing a more definitive description of expected modifications to the conceptual design and relative costs.

Costs for a cooling tower retrofit can vary considerably from site to site even for similarly designed systems. However, when estimating costs for a system where the detailed design has not yet been well defined, it can be useful to compare costs for project of similar design and scope. To get an indication as to whether the Enercon 2007 capital cost estimate based on the originally chosen contingency factors is reasonable, costs for a completed project of similar design and scope were examined. In 2008, Georgia Power completed the retrofit of a plume abated closed-cycle cooling system at their McDonough-Atkinson plant in Smryna, Georgia. The following data and description was obtained from a report for an EPA site visit conducted at the Georgia Pacific McDonough Plant (USEPA 2009). This project consisted of two 10-cell inline plume abated cooling towers for existing generating units with a design once-through flow of 393 mgd (roughly 1.4 times design flow of 287 MGD for Merrimack). Similarly, the relative size of the two 10-cell cooling towers are also roughly 1.4 times larger.[4] The McDonough cooling tower project involved numerous site-related difficulties including space constraints since the towers are sandwiched between transmission lines, buildings, the switchyard, and a railroad. New pumps were installed and due to concerns with existing infrastructure, much of the piping was routed above ground along the river. In order to accommodate the towers, the adjacent Atkinson plant was demolished and maintenance buildings were moved. Also, because of the age of the facility, McDonough-Atkinson had no blue prints or information on existing underground piping which presented a substantial challenge during retrofit. The pump and fan energy requirements were greater than the capacity of the facility's station service system, requiring the construction of a separate transmission line from the transmission yard routed across the river and down to the new pump station. This description of the McDonough-Atkinson closed-cycle retrofit project suggest that it likely involved more challenges and potential difficulties than are present at Merrimack Station which has a relatively unfettered tower location with the only apparent difficulties being related to the routing of the cold water return piping in the vicinity of the intakes and the new FGD unit. The McDonough-Atkinson project was completed in 2008 for a total cost of $96 million. Interestingly, this cost figure is also roughly 1.4 times the Enercon estimate of $68 million for the closed-cycle retrofit at Merrimack. The fact that the relative size of the project and costs were almost identical is a good indication that the Enercon 2007 estimate

[4] Most large cooling tower cells are similar in size (50 ft by 50 ft) and 20 cells is 1.4 times 14 cells.

(which is based on the contingency factors selected by the cost engineers) is reasonable and comparable to the actual costs of a completed project of similar size and scope.

## C. Air Emissions

Enercon asserts that a significant amount of additional air pollution will be emitted to compensate for the energy penalty associated with converting from once-through to closed-cycle cooling. There are two primary categories of air emissions: stack emissions and cooling tower emissions.

### Stack Emissions

This type of emissions may occur as a result of burning additional fuel in the onsite Units 1 and 2 when the units are operating at less than full capacity or at offsite generating units which would be required whenever Units 1 and 2 are already operating at full capacity or when they must derate generation to prevent equipment damage. They note that these increased emissions will be the result of:

- Increased Station parasitic losses resulting from the cooling tower's electricity demands.
- Reduced efficiency of the turbine and condenser as a result of warmer condenser water.
- Increased coal consumption to make up for newly incurred operational efficiency.

It is important to note that Enercon's estimate of the operational efficiency losses is primarily based on the requirement to derate power production to protect equipment rather than an efficiency loss. As noted in the discussion above, a considerable portion of the Unit 2 operational efficiency losses is the result of the requirement to maintain the condenser backpressure at or below 2 inches Hg. By definition, this reduction does not result in extra power generated, but rather, power that cannot be generated that is shifted to a different unit and thus represents emissions moved to another unit, not an increase in emissions. In many cases, this shifted generation will be produced offsite and as discussed above potentially may be generated by units that produce less pollution. However, Enercon is correct that the auxiliary power requirements will potentially result in an increase in emissions which based on the revised values in Table 3 should not exceed 0.8% on an annual basis with some portion emitted offsite.

As noted by Region 1, Merrimack has recently installed an FGD system to address air pollutant emissions. This technology will greatly reduce the total emissions of mercury, SOx, and particulates from the facility; the increases in emissions described above that would result from conversion to closed-cycle cooling would be very small relative to the total reduction of emissions achieved at the facility.

### Emissions from Cooling Tower Drift

Enercon suggests that while the facility is not in a non-attainment area for PM10 or PM 2.5, the potential emissions associated with drift may still be a concern. The cooling tower design specified by Enercon 2007 includes high efficiency drift eliminators which (as discussed above) are estimated to produce a total of 2 gpm (2,880 gpd) of drift. The TDS of cooling tower recirculating water is typically used as a surrogate for estimating particulate air emissions. The TDS in the recirculation water is a function of the make-up water TDS and the operating cycles of concentration. River water monitoring data from downstream locations near the in Massachusetts border suggests that the typical TDS levels in the Merrimack River range from about 50 to 100 mg/l (Merrimack River Watershed Council 2010). The design cycles of concentration for the cooling tower is 5, which is fairly high and should be considered the maximum since the facility will more likely operate at a lower rather than higher cycles of concentration. This means that the TDS of the recirculating water would be, at most, approximately 250 to 500 mg/l. The corresponding emission rate for airborne solid particulates is 6 to 12 lbs per day. It is current practice for EPA to assume that all tower particulates are emitted as PM2.5 but in reality a portion will be PM10 and a portion will be PM2.5. Regardless, this is an insignificant amount that falls well below the de minimis threshold for this pollutant under the National Ambient Air Quality Standards (NAAQS) and does not warrant further consideration. Emissions of solid particulates via drift is a much greater concern for closed-cycle systems that use brackish or saltwater as makeup source since TDS concentrations in the recirculating water (and the corresponding emissions) can be hundreds of times greater.

## D. Effect of Plume: Icing, Fogging, and Other Vapor Plume Issues

Plume-induced fogging and icing conditions typically would occur when ambient conditions include fog, rain, or snow. Plume abatement technology is included in the planned cooling tower design at Merrimack (as described in Enercon 2007) for the express purpose of minimizing visible vapor plume, fog formation, and icing. Plume abatement technology will minimize the emissions of wet saturated air originating from the cooling tower and under optimum conditions, a plume reduction of 95 to 99 percent can be achieved. Enercon claims that even with plume abatement technology, that during less than optimum conditions, such as during certain time during the winter, plume abatement may be less effective and there may be some periods where a plume persists. This is true, but the magnitude and duration of these effects is likely to be small and within an acceptable range. Without conducting a site-specific modeling exercise, the precise impacts are difficult to estimate, but the analysis below gauges the effects on a relative scale and on a qualitative level.

In order to get a feel for the relative magnitude of fogging and icing that might occur as a result of operation of a multi-cell plume abated cooling tower, the results of a modeling effort for the Manchester Street Station in Providence, Rhode Island was examined(CH2MHill 2009). This effort utilized a version of the CALPUFF model modified to account for plume abatement. The tower modeled was an 8 cell plume abated cooling tower serving three generating units with a combined steam capacity of 264 MW which is roughly 60% of size of Merrimack Units 1 and 2 and corresponding tower and thus, the magnitude of comparable effects at Merrimack may be similar but proportionally greater. Additionally, it should be recognized that the meteorological conditions are different in Providence, but given the more maritime nature of the Manchester Street location, that location should have a greater incidence of high humidity (i.e., fog inducing) conditions. Therefore Manchester Street should be more likely than less likely to produce fogging than a similar tower design at Merrimack. The modeling for Manchester Street predicted that fogging and icing would occur for a total of 24 hours per year dispersed over 6 days during the winter and each fogging event was expected to cause icing. The maximum distance of an event was 800 m (2,640 ft) but this was of a relatively short duration of about one hr. The maximum distance for total duration not exceeding 3 hours was about 1,700 ft. In other words, for 21 hours of the 24 hours, the total estimated fogging and icing occurred at distances less than 1,700 ft downwind. The majority of the fogging and icing (19 hours) occurred less than 1,100 ft downwind of the tower. The model predicted that, at Manchester Street, the majority of fogging would occur south of the tower and very little fogging was predicted north of the tower. While the duration, distance, and direction of the induced fogging may be different for Merrimack, it seems reasonable to conclude that the effect of fogging is not widespread but rather is to a limited area downwind during the events.

For additional perspective, the items below provide further information on why plume effects raised by Enercon are unlikely to be a problem at Merrimack. At Merrimack, the cooling tower will be located on the northern end of the island in the middle of the discharge canal. In general, there are very few nearby buildings or infrastructure that could potentially be impacted. The nearest homes are over 4,200 ft to the east on the opposite side of the Merrimack River.

- Enercon expressed concern that driving on nearby roads and highways could be significantly impacted, with the possibility of 'black ice' formation during the winter months. The only roadways within a distance that likely would be impacted are the local road (River Road) and the adjacent site access road both of which are located about 550 to 650 ft from the proposed tower at their closest location. The roadways are relatively level with no sharp turns with little through traffic. These areas would only be impacted by fogging or icing for brief periods during the winter and only if the wind direction is from the east during the event.
- Enercon expressed concern that ice accumulation on electrical equipment within the Station may bridge gaps in outdoor electrical equipment that are required to be clear. The switchyard, however, is located approximately 900 ft northwest of the proposed tower location and thus is not likely to be affect by icing for any significant duration.
- Enercon expressed concern that visibility could be significantly reduced in areas surrounding the Station, which could pose a safety concern. As demonstrated in the Manchester Street modeling effort, it is likely that any fogging that would occur would be for relatively short duration.
- Enercon expressed concern that the potential exists for increased corrosion of Station equipment resulting from plume presence over a period of time. Most station equipment is located more than 600 ft from the tower and would only be enveloped in fog for brief periods, if at all.
- Enercon expressed concern that mineral or impurity content of the entrained moisture could damage vegetation in the vicinity of the station. The source of such deposition would be the drift, which as noted above would be limited to at most 6 to 12 lbs per day. Such a small amount of solid material dispersed over a relatively large area downwind is very unlikely to have a perceptible effect.

Enercon has noted that EPA failed to utilize or request use of any models, such as SACTI (Seasonal Annual Cooling Tower Impacts), to more precisely quantify the icing/fogging effects of a cooling tower before issuing the draft permit. As described above, modeling at another site in the region suggested that the effect is minimal and there appears to be no specific concerns for this site. If Enercon believed that icing or fogging may present significant safety or operational issue, then it is Tetra Tech's professional opinion that they should have performed an analysis that demonstrated that plume abatement technology would not effectively minimize this problem or that site-specific conditions present exceptional considerations rather than make broad unsubstantiated assertions.

## E. Power Generation Losses

The following is an evaluation of Enercon's estimates of power generation losses (energy penalty) associated with conversion from once-through to closed-cycle cooling. Power generation losses associated with closed-cycle cooling can result in lost revenue due to power no longer available for sale, additional costs associated with burning extra fuel to compensate for lost generation (plus added air emissions associated with consumption of extra fuel), and replacement power generated in another unit onsite or at offsite facilities. Table 1 summarizes the estimated power generation losses presented in Enercon 2007 that are associated with auxiliary power requirements (aka parasitic load) of the cooling tower fans and added booster circulating pumps, plus the operational efficiency losses (heat rate penalty). The operational efficiency losses were estimated for both annual average and maximum summer conditions. The discussion below is divided into two categories: auxiliary power losses and operational efficiency losses.

**Table 1. Power Generation Losses Associated with Closed-Cycle Cooling Reported by Enercon 2007**

| | 120 | 350 | | | | 478 MW |
|---|---|---|---|---|---|---|
| | Power Requirement (MW) | | | Percent of Generating Capacity | | |
| | Unit 1 | Unit 2 | Units 1 & 2 | Unit 1 | Unit 2 | Units 1 & 2 |
| **Fan Motor Energy** | 0.6 | 1.5 | 2.1 | 0.5% | 0.4% | 0.4% |
| **Pump Motor Energy** | 1.0 | 3.7 | 4.6 - 1.8 | 0.8% | 1.0% | 1.0% — 0.4 % |
| **Pump & Fan Motor Energy** | 1.6 | 5.1 | 6.7 | 1.3% | 1.5% | 1.4% |
| **Operational Efficiency Losses (Average)** | 0.2 | 2.8 | 3.0 | 0.2% | 0.8% | 0.6% |
| **Operational Efficiency Losses (Maximum)** | 1.0 | 13.1 | 14.1 | 0.8% | 3.7% | 3.0% |
| **Combined Penalty (Average)** | 1.8 | 7.9 | 9.7 | 1.5% | 2.3% | 2.1% |
| **Combined Penalty (Maximum)** | 2.6 | 18.2 | 20.8 | 2.1% | 5.2% | 4.4% |
| | | | → 18.0 | | | → 3.8% |

Red based on error described on next page

Auxiliary Power Requirements

An engineering review of the pump and fan energy requirements show that the estimates presented in Table 1 for fan power are consistent with the cooling tower design parameters and the design parameters are reasonable for a system of this size. However, the power requirements represent the maximum requirement when all fans are operating continuously at full speed and the estimated operating costs assume continuous operation throughout the year. This, however, does not reflect actual operation. While the towers may be equipped with either single or dual speed fans, the vendor (SPX) recommends dual or multi-speed fan motors in their tower specifications because they reduce operating costs. In fact, SPX considers dual-speed fans as the minimum level of control for cooling towers used in cold climates with variable speed drives providing the best control. Reducing the operation of the fans[5] can be an important operational

[5] Fan operation can be decreased by reducing their speed, cycling them on and off, or shutting down individual towers and bypassing a portion of the flow.

measure for controlling ice formation and subcooling when air temperatures are below freezing during winter months. Annual estimates of power requirements (and costs) for cooling tower fans should take into consideration reduced fan operation during winter months along with reductions when units are not operating. The annual fan energy and related cost estimates in Enercon 2007 do not appear to take this into consideration and thus are likely overestimated.

A review of the estimated pumping power requirements also revealed an error that resulted in an apparent double counting of energy requirements for the two booster pumps specified for each unit (four total). An independent calculation of the hydraulic pump energy requirement for pumping 199,000 gpm of water against a pumping head of 36 ft resulted in a power requirement of 1,808 Hp. This value is equivalent to the pumps' specs provided by a pump vendor in "Attachment 1, Section 2: Circulating Water Pumps, b) New Boosters – Sulzer" and it is clear that the vendor specs provide the total requirements for both pumps rather than for each of two pumps. To obtain the pump motor requirements the hydraulic Hp value must be adjusted to account for the pump and motor efficiencies. Table 2 presents the vendor pumps specs (hydraulic Hp, Brake Hp, pump efficiency) along with the corresponding estimate of the pump motor requirements based on an assumed motor efficiency of 90%. It is clear from the roughly two times difference between the calculated pump energy values in Table 2 and the pump Hp and power requirements presented by Enercon,[6] that the vendor specs were mistakenly assumed to be reported on a per pump basis. Thus, Enercon's pump energy requirements are overestimated by well over 100%. Calculations for pump motor energy requirements are relatively simple and it is not clear why Enercon's total value exceeds the expected 100% difference associated with the obvious error. The impact of this error on the estimated total power generation loss is summarized in Table 3 below.

**Table 2. Comparison of Calculated Pump Energy Requirements to Enercon Estimates**

| | Pump Specs | | | Calculated | Enercon Estimate[1] | |
|---|---|---|---|---|---|---|
| | Hydraulic Hp | Brake Hp | Pump Efficiency | Pump Motor (MW) | Pump Motor (MW) | Percent Difference |
| **Unit 1** | 535 | 622 | 86% | 0.52 | 0.96 | 86% |
| **Unit 2** | 1,270 | 1,547 | 82% | 1.28 | 3.65 | 185% |
| **Total** | 1,805 | 2,169 | | 1.80 | 4.61 | 156% |

[1] Same as reported in Table 1

Operational Efficiency Losses

Typical estimates of the operational efficiency losses are related mostly to the reduction in the steam pressure differential across the steam turbine that results from warmer cold water (condenser inlet) temperatures for closed-cycle versus once-through operation during warmer months. However, a review of the analysis in Enercon 2007 indicates that their estimate of the operational efficiency losses, particularly the estimate of the maximum rate, uses a different approach that appears to be based on lost power generation associated with the fact that the

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[6] Section 6.1.1.2 (Enercon 2007) states that two booster pumps would be needed for each unit and that "the new circulating water booster pumps would require an estimated 360 HP motor each (single speed) for Unit 1, and an estimated 1469 HP motor each (single speed) for Unit 2."

steam turbines have a maximum turbine exhaust backpressure that must not be exceeded in order to prevent equipment damage. The turbine exhaust pressure is a function of the cooling water temperature and during periods when the generating units are operating at or near capacity and the condenser inlet temperature exceeds a certain temperature, the steam load to the condenser must be reduced such that the maximum pressure is not exceeded. Since during periods of high wet bulb temperatures during the summer the cold water exiting the tower basin may exceed this temperature while the river water may be lower, the result is a reduction in the amount of power that can be produced when using a cooling tower. This forced reduction in generation is often referred to as a derate. This component is not, however, a reduction in turbine efficiency and while the effect is that this facility will lose revenue for power it is unable to generate, there should be less air emissions generated onsite associated with this derate component as compared to the typical method of estimating operational efficiency losses. And since replacement power must be generated offsite and may be generated using less polluting units (e.g., combustion turbines using natural gas), it is possible that, for this component, air emissions may be lower and that the overall increase in regional air emissions during summer months is primarily the result of the auxiliary power requirements and not the operational efficiency losses due to the derate estimated by Enercon. The magnitude of the derate is much greater for Unit 2 than Unit 1 because the turbine backpressure limit is 2.0 inches Hg for Unit 2 and 3 inches Hg for Unit 1. Another important aspect of this derate is the effect on estimated costs. Enercon estimated lost generation costs based on an estimate of the MWh lost due to the operational efficiency losses times the market value rate of $72/MWh. However, for the portion of power lost to the derate, the lost revenue cost to the facility should be based on the market rate minus the comparable cost of the fuel that was not burned.

The annual average operational efficiency loss values of 0.6% of capacity (0.2% for Unit 1 and 0.8% for Unit 2) calculated by Enercon (See Table 1) fall within the range of expected values for similar facilities. The estimated maximum operational efficiency loss of 13.1 MW (3.7%) for Unit 2 however seems excessive. As described in Enercon 2007 (see page 53), this estimate is primarily based on the fact that the reported maximum allowed turbine back pressure for Unit 2 is inches Hg. Since the vapor pressure of water is 2 inches Hg at a temperature of 102 °F, this means that whenever the condensing temperature in the condenser exceeds approximately 102 °F, the heat load to the condenser must be reduced resulting in a corresponding reduction in power output. While Enercon provides little detail regarding their operational efficiency loss calculations, according to the titles in the figures in Attachment 3, Section 2 it appears that they estimated this threshold is reached whenever the condenser inlet cooling water temperature exceeds 65.5 °F for Unit 2 and 74 °F for Unit 1. The estimate for the condenser inlet temperature that corresponds to a condensing temperature of 102 °F can be derived based on the condenser temperature range which is assumed to be 22.6 °F in the Enercon system design and the condenser terminal temperature difference (TTD) which is the difference between the condensing temperature and the condenser hot water outlet. The TTD is not reported and can vary based on the condenser design, condenser condition, and water flow rates and steam load. A typical TTD value is 6 °F (Burns and Micheletti 2002) but the design range may be as high as 12 °F (EPRI 2011). During operation, these values may be slightly higher as a result of tube plugging, fouling or air leakage.[7] Enercon did not report the TTD for Units 1 or 2 but based on

[7] Note that an important purpose of intake screens is to minimize blockage of the condenser tubes by debris in order to maintain the TDD close to its design value. The substantial reduction of the volume withdrawn from the river

their calculated thresholds of 65.5 °F and 74 °F, it appears their assumed TTD was 13 °F and 18 °F for Units 2 and 1, respectively. These values appear to be higher than expected but may be the result of condensers designed for relatively cold river water.

Table 3 presents the Enercon energy penalty estimates along with the estimates of the equivalent number of "typical US households" that were provided in the Enercon 2012. The estimated number of homes is based on annual average household power usage and appears to be a reasonable value. However, as noted above, Enercon overestimated pump energy requirements and Table 3 also includes the comparable revised values when the Enercon estimates are replaced with the calculated values from Table 2. Again, it should be noted that a large portion of the operational efficiency loss is associated with the need to derate due to the condenser operating limits and that this power is not lost (i.e., consumed as auxiliary power onsite or lost to reduced efficiency) but rather can't be produced and must be generated at another facility.

**Table 3. Comparison of Enercon Penalty Estimates and Equivalent Number of Typical Homes to Revised Estimates Based on Correction to Pump Energy Requirements**

| | Enercon Estimates | | Revised Estimates | | |
|---|---|---|---|---|---|
| | MW | Equivalent Homes | MW | Percent of Generating Capacity | Equivalent Homes |
| **Fan Energy** | 2.1 | | 2.1 | 0.4% | |
| **Pump Energy** | 4.6 | | 1.8 | 0.4% | |
| **Pump & Fan Energy** | 6.7 | 5,500 | 3.9 | 0.8% | 3,200 |
| **Operational Efficiency Losses (Average)** | 3.0 | 2,440 | 3.0 | 0.6% | 2,500 |
| **Combined Penalty (Average)** | 9.7 | 7,940 | 6.9 | 1.5% | 5,600 |

In general, the data provided by the pump and tower vendor is sufficient to calculate the auxiliary power losses and with the exception of accounting for reduced fan energy requirement during winter months described above and shutdown periods the estimates should be fairly accurate. The calculation of lost generation that results from the turbine efficiency reduction is much more involved and inexact since it requires multiple calculations of the plant output throughout the year for both the original once-through cooling system and the retrofitted closed-cycle system to account for changes in cooling water temperature. This requires use of historical surface water temperatures for the once-through system and historical meteorological data concerning ambient wet bulb temperature. Meteorological data in combination with tower performance specifications (approach) obtained from the tower vendor can establish the expected closed-cycle cooling water temperature. Condenser performance data such as the TTD can then be used to establish the condensing (aka steam saturation) temperature which in turn establishes the turbine backpressure for any cooling water temperature. These values must then be combined with performance curves specific to each turbine to determine the changes in steam turbine output. Because each of the calculation components can be dynamic in nature, the derived values must be viewed as rough estimates. In general, the data available to Enercon should be sufficient to derive rough estimates of the lost generation. It is not clear from the description in Enercon

associated with closed-cycle cooling should reduce the occurrence of condenser plugging resulting in a potential reduction in the average TTD over a given time period.

2007 whether their calculation of turbine related losses included turbine efficiency loss or focused entirely on the required derate due to the turbine backpressure limitations.

## F. Cooling Tower Circulating Water and Blowdown Quality

Enercon expresses concern that the potential problem related to drift may require additional water treatment equipment to be installed in order for any cooling tower to be operated or permitted. Treatment could occur in two places: treatment of makeup water and treatment of blowdown. Given that the estimated cooling tower emission rates for air pollutants are insignificant (as described above), there should be no need for additional treatment equipment of the makeup water.

For blowdown, Enercon notes that recirculating water treatment chemicals as well as solids "air washed" from ambient air will be discharged along with the cooling tower blowdown and note that the level of effort that would be required to purify the cooling tower blowdown is unknown, but it could require significant effort. Chemical treatment of the circulating water is typically performed to control biofouling, scale, corrosion, and suspended solids. The concentration of pollutants in the blowdown and requirements for treatment chemicals is somewhat dependent of the operating cycles of concentration. As a cooling tower's water efficiency (percent reduction in intake flow) is increased by increasing the cycles of concentration, a point will be reached where treatment chemicals may become necessary, and the dosage will increase as the COC increases beyond that point.[8] This may also result in an increase in costs for more frequent monitoring of tower water quality and control of blowdown rates. However, the associated reduction in blowdown volume will also result in a reduction in the rate of chemical lost from the system. Treatment chemical vendors are able to evaluate the variation in chemical costs associated with these tradeoffs and recommend the optimum level that minimizes chemical and other operating costs while also minimizing risks. Operating at higher cycles of concentration may increase the concentration of contaminants contained in the makeup water as well as air washed solids. When operating at lower cycles of concentration blowdown rates are higher which results in lower concentrations of pollutants. If Enercon were to find that operating at a cycle of concentration lower than 5 would eliminate the need for certain treatment chemicals or prevent permit violations for the blowdown discharge, then this may be a reasonable adjustment to consider. The flow balance diagram presented in Figure 4 in Enercon 2012 indicates that their estimated flow reduction (assuming 199,000 gpm as the baseline) would be 97.9% at a cycle of concentration of 5. Table 4 presents calculated closed-cycle system flow balance estimates for various cycles of concentration.[9] A reduction in the cycles of concentration from 5 to 3 would change the flow reduction from 97.9% to 97.5%. This change would increase the makeup volume by 20% and the blowdown volume by 100% but would also nearly halve the concentration of pollutants in the blowdown. In order to operate at lower cycles of concentration, the draft permit flow limit and heat load for Outfall 3D would need to be relaxed. The effect of operating at higher cycles of concentration is further reductions in intake flow and heat load, but

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[8] For example, a general rule of thumb for most towers is that calcium hardness in the recirculating water should be limited to 350 to 450 ppm to prevent scale formation unless treatment chemicals are used.

[9] Assumed constants used in the Table 5 calculations were adjusted to mirror the estimate presented by Enercon in Figure 4 and were within a reasonable range of expected values.

is a small increment compared to the difference between once-though and closed-cycle operation.

**Table 4. Calculated Closed-cycle Cooling System Flow Balance Data for Different Cycles of Concentration for the Combined Unit 1 and 2 Cooling Tower Based on the Enercon 2007 Design**

| | Delta T | Circulat-ing water | Make-up Water | Blow-down | Evapora-tion | Drift | Cycles of Conc | Percent Red. | Blow-down |
|---|---|---|---|---|---|---|---|---|---|
| | deg F | gpm | gpm | Gpm | gpm | gpm | Xc/Xm | | MGD |
| Unit 1 | 22.6 | 59,000 | 2,960 | 1,973 | 987 | 0.6 | 1.5 | 95.0% | 2.8 |
| | 22.6 | 59,000 | 1,973 | 986 | 987 | 0.6 | 2.0 | 96.7% | 1.4 |
| | 22.6 | 59,000 | 1,480 | 493 | 987 | 0.6 | 3.0 | 97.5% | 0.7 |
| | 22.6 | 59,000 | 1,316 | 328 | 987 | 0.6 | 4.0 | 97.8% | 0.5 |
| | 22.6 | 59,000 | 1,233 | 246 | 987 | 0.6 | 5.0 | 97.9% | 0.4 |
| | 22.6 | 59,000 | 1,184 | 197 | 987 | 0.6 | 6.0 | 98.0% | 0.3 |
| | 22.6 | 59,000 | 1,096 | 109 | 987 | 0.6 | 10.0 | 98.1% | 0.2 |
| Unit 2 | 22.6 | 140,000 | 7,024 | 4,681 | 2,341 | 1.4 | 1.5 | 95.0% | 6.7 |
| | 22.6 | 140,000 | 4,683 | 2,340 | 2,341 | 1.4 | 2.0 | 96.7% | 3.4 |
| | 22.6 | 140,000 | 3,512 | 1,169 | 2,341 | 1.4 | 3.0 | 97.5% | 1.7 |
| | 22.6 | 140,000 | 3,122 | 779 | 2,341 | 1.4 | 4.0 | 97.8% | 1.1 |
| | 22.6 | 140,000 | 2,927 | 584 | 2,341 | 1.4 | 5.0 | 97.9% | 0.8 |
| | 22.6 | 140,000 | 2,810 | 467 | 2,341 | 1.4 | 6.0 | 98.0% | 0.7 |
| | 22.6 | 140,000 | 2,602 | 259 | 2,341 | 1.4 | 10.0 | 98.1% | 0.4 |
| Units 1 & 2 | 22.6 | 199,000 | 9,984 | 6,654 | 3,328 | 2.0 | 1.5 | 95.0% | 9.6 |
| | 22.6 | 199,000 | 6,656 | 3,326 | 3,328 | 2.0 | 2.0 | 96.7% | 4.8 |
| | 22.6 | 199,000 | 4,992 | 1,662 | 3,328 | 2.0 | 3.0 | 97.5% | 2.4 |
| | 22.6 | 199,000 | 4,437 | 1,107 | 3,328 | 2.0 | 4.0 | 97.8% | 1.6 |
| | 22.6 | 199,000 | 4,160 | 830 | 3,328 | 2.0 | 5.0 | 97.9% | 1.2 |
| | 22.6 | 199,000 | 3,994 | 664 | 3,328 | 2.0 | 6.0 | 98.0% | 1.0 |
| | 22.6 | 199,000 | 3,698 | 368 | 3,328 | 2.0 | 10.0 | 98.1% | 0.5 |

The draft permit contains discharge limits for the blowdown for flow, heat load, free available chlorine, chromium, zinc, and priority pollutants. Flow and heat load are addressed by the operation of the closed-cycle system and can be adjusted to match the system design. Free available chlorine would be used regardless of the cycles on concentration and can be easily dealt with by treating the blowdown or using intermittent dosing and then withholding blowdown until it is consumed. Also, a cycle of concentration of 5 which would result in a blowdown that has a five-fold concentration of pollutants contained in the make-up water, plus air washed solids, plus added treatment chemicals may not result in any concentrations that exceed the concentration-based limits for chromium, zinc, or priority pollutants. The limits for chromium and zinc are based on the Steam Electric Effluent Guidelines and were established primarily as a result of the fact that both chromium and zinc have been used as components in various cooling tower treatment chemicals in the past. Alternative chemical treatments that do not use chromium or zinc are available and therefore exceedance of these limits can be avoided.

However, establishing permit limits for flow and heat based on the vendor-specified cycles of concentration does limit the permittee's flexibility in selecting the optimal operating condition that balances the desire to minimize impact with regard to 316(a) & 316(b) with the potential impact of higher cycles of concentration. These impacts can include increased requirements for treatment chemical costs, increased potential operational problems (biofouling, scale, and solids), increased blowdown concentrations, and increased drift particulates.[10] Cycles of concentration is an operational parameter that is generally determined by controlling the blowdown rate. It can be adjusted at any time during tower operation and while it can have an effect on the quantity of intake flow and heat discharged, the differences in amount of intake flow and heat discharged that results from changing cycles of concentration between values above 3 are relatively small compared the reductions associated with converting from once-through to closed-cycle.[11] The operating cycles of concentration does not have any material effect on the design of the cooling system as long as the make-up and blowdown pumps and piping are sized to provide the corresponding range of flow volumes.

## G. Noise

Tetra Tech reviewed all of the public comments for comments related to noise and found no significant comments. One relevant comment was on page 14 of Enercon 2012 which stated "*Additionally, a cooling tower installation would cause an incremental increase in the noise pollution and visual impact of the Station, which could deter additional members of the public from using the river in areas close to the Station.*" By not discussing the issue further, Enercon appears to concede that noise is not a significant issue.

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[10] A lower cycle of concentration will result in lower TDS in the recirculating water, thus reducing the emission of drift particulates. Note that the McDonough plant cited as an example in the cost discussion reported operating at cycles of concentration of 3 to 4.

[11] Changing from a cycles of concentration of 5 to 3 will only change the overall closed-cycle flow reduction from 97.9% to 97.5%. The change in heat discharge compared to once-through would be nearly negligible since both cycles of concentration values would result in reductions >99%.

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