Evaluation of Gas Turbine Performance Improvement Alternatives For Indonesia Power

in cooperation with the
Indonesian Institute of Sciences (LIPI) Technical Implementation Unit

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1.0 EXECUTIVE SUMMARY

A study was conducted to compare various alternative gas turbine power enhancements for the gas turbines located in Indonesia. The Pesanggaran site in Bali, Indonesia, which has four (4) simple cycle gas turbines was chosen as a sample site to perform the comparison, an Alstom Atlantique PG5341 rated at 21.35MW installed in 1985, a GE MS500L rated at 20.10 MW installed in 1993, and two (2) Westinghouse CW-251B11 rated at 42.07 MW each. Turbines 1 and 2 were rated at 30C (86F) and units 3 and 4 (Westinghouse) were rated 27C (80.6F) and 83% relative humidity. or, The Pesanggaran site is located basically at sea level.

Six (6) technologies were review and compared at nine (9) different conditions at the request of the representatives from the Indonesian Institute of Sciences. The nine comparisons were

1. Evaporative Cooling
2. Fogging
3. Inlet Chilling to 13^0C (55.4^0F)
4. Inlet Chilling to 15^0C (59^0F)
5. Inlet Chilling to 17^0C ($62,6^0$F)
6. 1% Wet Compression
7. 2% Wet Compression
8. Dry Air Injection
9. Humid Air Injection

Due to consistently high relative humidity of 83%, alternatives 1 and 2 offer no real benefit to gas turbines installed in the area. Inlet chilling (3, 4, & 5) was found to be very capital intensive and based on the remaining life of the equipment, not good investments. While the technology of wet compression (6 & 7) offered the most power enhancement, they require the internal compressor components to be coated and have a higher risk of compressor damage and accelerated maintenance that can be extremely risky. Again, the limited remaining life of the assets may not be a worth the significant capital investment, along with a demineralized water plant addition to provide the demineralized water.

The analysis showed that dry air injection offered the best alternative for the Pesanggaran simple cycle gas turbines. The benefits of dry air injection include (a) short downtime to install, (b) low capital cost per kW, (c) introduces no additional contaminants into the gas turbine (d) has the portability to relocate the system on any other, or future gas turbine(s) that might be installed at the site. Humid Air injection would be considerably more expensive to introduce a steam source at the site, along with high pressure steam piping to move the steam to the each gas turbine package, as well as the additional cost of demineralized water to make up the steam (humid air addition) that gets exhausted to the stack.

2.0 DISCUSSION

2.1 Introduction

Indonesia Power ("IP") supplied approximately 9.2 GW of the 30 GW of capacity needed in the Java-Bali system of Indonesia during 2012 (Power, 2012). Approximately 0.7 GW of this installed capacity is composed of simple cycle gas turbines with a capacity factor of approximately 19% and availability of 90% while approximately 2.7 GW of this installed base is gas turbine combined cycle with a capacity factor of approximately 39%. Not all of the gas turbine installed capacity is capable of being realized due to the prevailing warm weather conditions in Indonesia and age of the original equipment. The country is only approximately 65% electrified, with plans to increase electrification to 93% by 2025 (Rose, August 2010). In the interests of better utilizing the existing gas turbine resource base, Indonesia Power desires to evaluate gas turbine power output improvement options that can be applied to the fleet of existing gas turbine assets. As a government owned utility, the Indonesia power market is a regulated market. While efficiency is important to reduce costs, capacity increase at the least cost is the primary goal.

The "test case" utilized in this analysis is the Bali Generation Business Unit (Pesanggaran plant) located in southern Bali, on the east portion of Denpensar, Bali. It is one of three generation plants owned and operated by PT Indonesia Power. The other Bali stations are Gilimanuk Gas Power Generation on the West end of Bali Island, and Pemaron Gas Turbine Power Plants (GTPP) located at Northern Beach of Bali. Bali is one of the larger islands of Indonesia, located immediately to the East of the island of Java. Bali's installed capacity is approximately 433 MW. Supplemental power is provided to Bali from Java via an underwater cable. Currently the load peaks on Bali during the early and late evening when the tourist hotels demand the most electricity. The Pesanggaran facility contains four operating gas turbines as well as reciprocating engines. A new Wartsila diesel engine based plant totaling approximately 200 MW is also under construction at the site. Table 1 summarizes the four gas turbines, manufacturer, year installed, design capacity and design ambient conditions located at the Pesanggaran site.

Table 2-1: Pesanggaran Gas Turbine Installation Summary

	OEM	Model	COD	Design Capacity [MW]	Design Conditions
Unit 1	Alstom-Atlantique	PG5341	1985	21.35 (base) 23.05 (peak)	30C, n.s. % rh[1], 1.013B
Unit 2	GE	MS500L	1993	20.10 (base) 23.05 (peak	30C, n.s. % rh[2],
Unit 3	Westinghouse	CW-251-B11	1994	42.07	27C, 83 % rh, 1013 mbar, 0.8 pf
Unit 4	Westinghouse	CW-251-B11	1994	42.07	

[1] A relative humidity was not specified in the design documents
[2] A relative humidity was not specified in the design documents

For each gas turbine at the Pesanggaran Station, Table 2 shows the most recent plant performance test report date and time, test results and ambient temperature. The gas turbine performance tests reported by IP were not corrected to the design ambient conditions of temperature, barometric pressure and humidity. Since a gas turbine's power and heat rate are affected by these conditions, to properly compare test results, performance must be corrected to a consistent set of ambient conditions, usually the initial design conditions. The manufacturer normally provides these correction curves with the gas turbine manuals. The plant library data was reviewed but only the performance correction curves for GT2 were located, which were mostly illegible.

2.2 USE of GT Pro Software

GT Pro, a power cycle thermodynamic computer modeling software program, was utilized to conduct the performance evaluation of the various alternatives. In order to determine the baseline power production, a gas turbine of the same type is simulated using the GTPro power plant modeling software at the design conditions, if known, for inlet temperature, humidity and barometric pressure. The gas turbine is then run at an "off-design" case, i.e. at the ambient temperature for that unit's latest plant performance test results. Only the temperature correction was applied as the ambient conditions of humidity and barometric pressure were not recorded during the plant tests and were not available in any of the site recorded data. The ratio of the performance test result divided by the GTPro predicted new and clean (N&C) gross power output indicates the shortfall in gas turbine performance since new. Subtracting this ratio from 1.0 yields the apparent degradation. The study could be refined in the future to include the effects of barometric pressure and humidity. IP Staff personnel were attempting to retrieve test conditions for these parameters, as well as confirm temperature, from the Airport weather services which is located only a few kilometers away. Note that all of the devices used to measure power, temperature and fuel flow at the plant have an inherent uncertainty which has not been analyzed, so an uncertainty analysis is not available.

Table 2-2: Gas Turbine Performance Summary

GT	Last Capacity Test Date	Test Results [MW]	Aux Loads [kW]	SFC [l/kWh]	Test Conditions [°C]	N&C Capacity at Test Temperature [MW]	Apparent Degradation [%]
1	17DEC201	17.8	TBD	0.453	TBD	21.35	TBD
2	15JAN2014 19:00-20:00	16.30	220	0.422	30C	20.10	23.6%
3	06JAN2014 19:00-20:00	39.80	161	0.339	30C	40.77	2.4%
4	19JAN2014 19:00-20:00	35.40	98	0.404	30C	40.77	13.2%

2.3 Gas Turbine Overview

The basic gas turbine operating cycle is also called the Brayton Cycle and is depicted below. It consists of a compression stage, a heat addition (combustion) stage, and an expansion stage (turbine). The turbine (expander) thrust (power) is a function of mass flow. Air entering the compressor at point 1 is compressed to some higher pressure. No heat is added; however, compression raises the air temperature so that the air at the discharge of the compressor is at a higher temperature and pressure. Upon leaving the compressor, air enters the combustion system at point 2, where fuel is injected and combustion occurs. The combustion process occurs at essentially constant pressure. Although high local temperatures are reached within the primary combustion zone (approaching stoichiometric conditions), the combustion system is designed to provide mixing, burning, dilution and cooling. Thus, by the time the combustion mixture leaves the combustion system and enters the turbine at point 3, it is at a mixed average temperature. In the turbine section of the gas turbine, the energy of the hot gases is converted into work. Some of the work developed by the turbine is used to drive the compressor, and the remainder is available for useful work at the output flange of the gas turbine. Typically, more than 50% of the work developed by the turbine section(s) is used to power the axial flow compressor. In the ideal cycle (a) the compression is performed adiabatically (no heat transfer), (b) the combustion is performed with no change in pressure (isobaric) and (c) the expansion occurs adiabatically as well. In reality friction and heat loss/gain results in less than ideal performance.

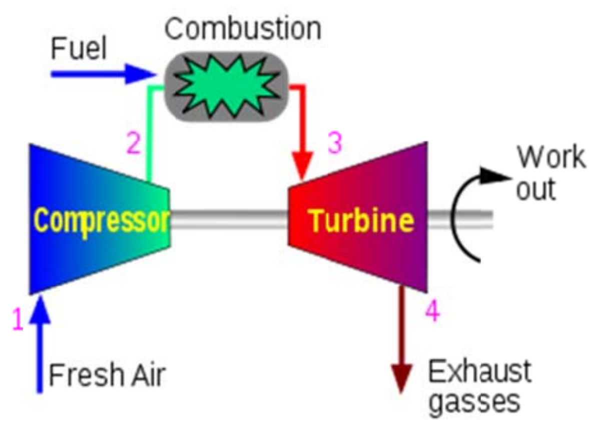

Figure 2-1: Gas turbine Cycle Schematic

2.3.1 Factors that Affect Gas Turbine Performance

Gas turbines catalog performance is normally rated at International Standards Organization (ISO) conditions of 59F (15 C), 14.7 psig (1.013Bar) and 60% relative humidity. Since the gas turbine is essentially a constant volume air-breathing machine, its performance varies by anything that affects the density and/or mass flow of the air intake to the compressor. Figure 2-2 shows how ambient temperature affects the output, heat rate, heat consumption, and exhaust flow of a single-shaft MS7001 (Frank J. Brooks, 2000). When the gas turbine inlet temperature increases, the air is less dense, this results in reduced turbine output. Each gas turbine model has its own temperature-effect performance curves, driven by the Brayton cycle parameters, hardware efficiencies and air mass flow.

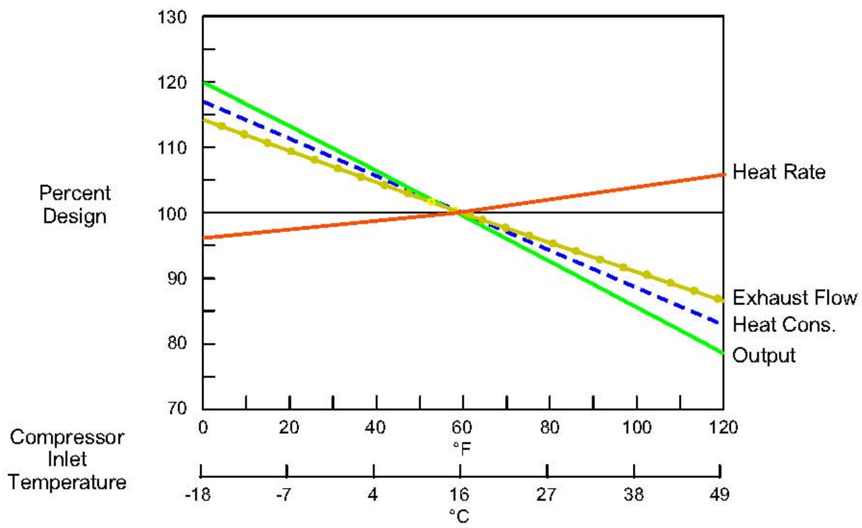

Figure 2-2: Effect of Ambient Temperature on MS7000EA Gas Turbine Performance (typical)

Correction for altitude or barometric pressure is more straightforward. The air density reduces as the site elevation increases. While the resulting airflow and output decrease proportionately, the heat rate and other cycle parameters are not affected. A standard altitude/inlet pressure correction curve is presented in Figure 2-3. The reduced performance due to inlet pressure drop can also be estimated using the same curve.

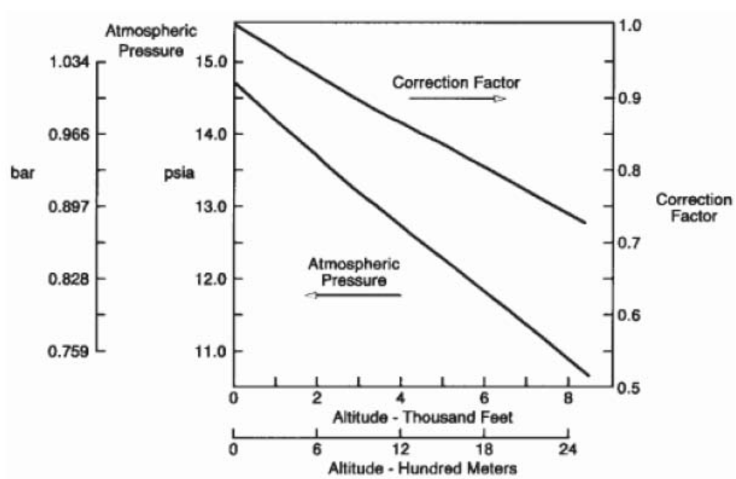

Figure 2-3: Altitude/Inlet Pressure Effect on Gas Turbine Performance for MS7000EA (typical)

Similarly, humid air, which is less dense than dry air, also affects output and heat rate, as shown in Figure 2-4.

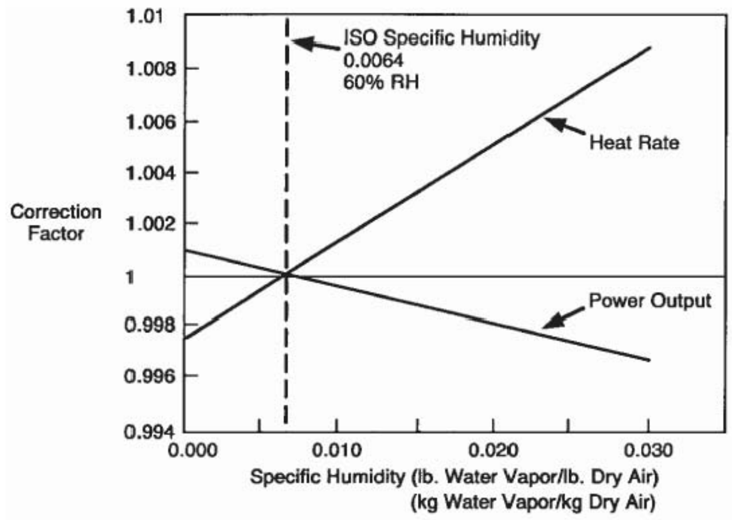

Figure 2-4: Typical Effects of Humidity on GT Performance

In the past, this effect was thought to be too small to be considered. However, with the increasing size of gas turbines and the utilization of humidity to bias water and steam injection for NOx control, this effect has greater significance.

2.3.2 Inlet and Exhaust Losses

Inserting air filtration, silencing, evaporative coolers or chilling coils into the inlet or adding heat recovery devices in the exhaust ductwork causes permanent pressure losses in the system. The effects of these pressure losses are unique to each gas turbine design. Table 2-1 below shows typical inlet and outlet pressure losses for a GE Frame 7EA. These pressure losses occur regardless of whether the performance enhancement is operational or not, for example part load conditions.

Table 2-3: Typical Effect of Inlet & Exhaust Losses on Performance (MS7000EA)

	4 inch H2O (10mBar) inlet Loss	4 inch H2O (10mBar) outlet Loss
Power Output Reduction	1.42%	0.42%
Heat Rate Increase	0.45%	0.42%
Exhaust Temperature increase	1.9F (1.1C)	1.9F (1.1C)

2.3.3 Gas Turbine Performance Degradation

All turbo-machinery experience losses in performance with time. Gas turbine performance degradation can be classified as either recoverable or non-recoverable loss. Recoverable loss is usually associated with compressor fouling and can be partially rectified by water washing or, more thoroughly, by mechanically cleaning the compressor blades and vanes after opening the unit. Non-recoverable loss is due primarily to increased turbine and compressor clearances and changes in surface finish and airfoil contour. Because this loss is caused by reduction in component efficiencies, it cannot be recovered by operational procedures, external maintenance or compressor cleaning, but only through replacement of affected parts at recommended inspection intervals.

2.4 Gas Turbine Power Improvement Alternatives

Various gas turbine performance enhancements exist that attempt to negate or minimize the negative performance impact of hot ambient conditions. Some options have secondary maintenance, operations, performance and support equipment requirements which are described below.

2.4.1 **Evaporative cooling**

Evaporative cooling is a passive process. In an evaporative cooling system a wet media is installed in the cross-section of the gas turbine filter house. The media is kept wet using high quality water, such as that from a reverse osmosis unit. The air entering the filter house passes over the saturated media, and the water contained in the media evaporates into the air stream on its way to the gas turbine. The extent of the evaporation is inversely proportional to the percent humidity in the air stream.

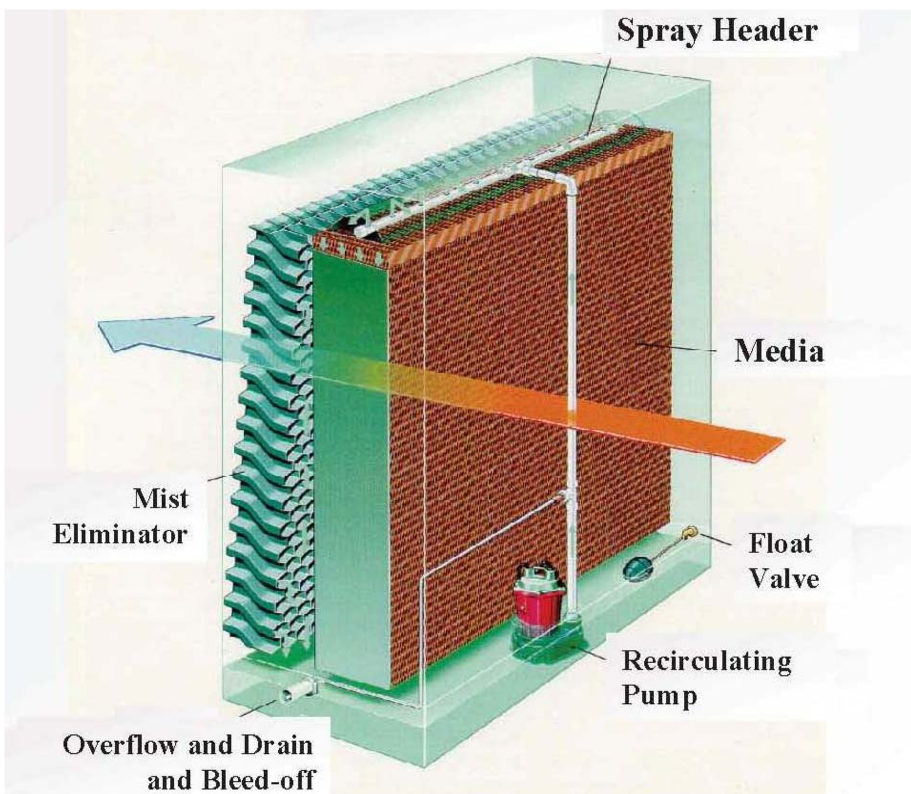

Figure 2-5: Evaporative Cooling Components

The lower the humidity the more easy it is for the water to evaporate. The heat to vaporize the water is taken from the ambient air, leaving the air stream cooler. Cooler air results in more dense air, which corresponds to more mass flow, which results in greater output in gas turbines (recall power is function of mass flow). The higher the humidity, the harder it is for the water to evaporate. However to arrive at 100% saturation technically requires an infinite contact time with the saturated media. The evaporative cooling effectiveness is the percentage of water expected to be evaporated divided the water needed to achieve saturation. A typical effectiveness is 85% to 95%. In the climate of Indonesia, the humidity is high, averaging 83% -. With this humidity the dry bulb depression achievable using evaporative cooling is very low, approximately 4^0F at the design condition of 90^0F /85% relative humidity.

Evaporate cooling is inexpensive in a new installation as it requires only the cooling media section to be added to the inlet filter house and a water circulation pump. In a retrofit, the installation requires the modification of the inlet filter house to accommodate the evaporative cooling media. This requires re-engineering, and service interruption. The application of evaporative cooling system is well suited for climates with low humidity. A drawback of the system is when the ambient humidity is close or at saturation (raining) the system is totally ineffective at improving gas turbine performance.

Another important consideration is the permanently added pressure drop addition to the inlet filter house. If at any time the operation of the evaporative cooler is not warranted, the air will still flow over the permanently installed media, and impose a pressure drop at all times, even during part load operation. Evaporative cooling systems require a few minutes to achieve 100% saturation of the inlet media.

2.4.2 Fogging

Fogging is an active form of an evaporative cooling system. With fogging pressurized water is sprayed into the air stream in ultra-fine droplets of approximately 10 microns in size. The amount of water spray is typically more than 100% of that needed to achieve saturation. The excess water compensates for the residence time so that 100% effectiveness can be achieved. Fogging has the same attributes and limitations as evaporative cooling but virtually no additional inlet pressure drop since wet media is not used. A small amount of parasitic load is required to create the pressure water (2000 psig/138 bar). Since water is forced into the air stream, demineralized water is recommended as normal water would enable deposits to enter the gas turbine which would harm the turbine internal components. While the overspray conditions of fogging are more likely to approach saturation, the extra water can present problems, especially in retrofit installations. The extra water will drain on the inside walls, collect dirt which will get sucked into the gas turbine fouling the gas turbine. Since fogging systems are water droplets, the water must be demineralizer water or they stand to damage the compressor with dissolved minerals. Fogging systems can be online very quickly.

2.4.3 Wet Compression

In an application using wet compression, demineralized pressurized water is injected close to the inlet of the gas turbine and/or in various stages of the gas turbine compressor. The water nozzles create an ultra-fine droplet size water mist.

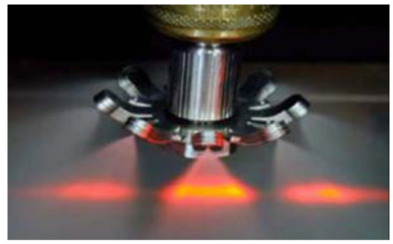

Figure 2-6: Typical wet compression nozzle that creates ultra-fine water droplets

At the inlet some of the water evaporates quickly cooling the inlet air similar to evaporative cooling or fogging. The water injected above that needed to achieve saturation is drawn into the compressor blade path and evaporates during the various stages of compression. Wet compression has the advantage of providing the effect of interstage cooling as water evaporates in each stage. Evaporation of the water droplets in the compressor blade path causes the air temperature to drop and thereby reduces the power consumption of the compressor because less energy is required to compress cool air compared to warm air with the same mass. This translates into a decrease in turbine work because one-half to two-thirds of a turbine's output is typically used to drive the compressor. The result is more turbine power for the generation of electricity and improved gas turbine efficiency.

Water that does not completely evaporate impinges on the compressor blades and can easily cause pitting and premature damage to the compressor blades, particularly the leading edges. When an early stage of a compressor fails, the broken pieces go downstream resulting in a multi-million dollar repair bill and at least 8 – 12 weeks out of service. Therefore proper applications require the compressor blades and stators to be coated to protect the surfaces for the steam and water impact. Siemens uses an Advanced Compressor Coating on gas turbine hardware to minimize the damage of wet compression (Crampsie, March-April 2012). Considerable downtime would be required to coat the compressor components. The compressor rotor and stator components would have to be shipped off site to an authorized service shop to apply the advanced coating. This would results in a few weeks of downtime. Alternatively this work could be conducted during a scheduled major overhaul.

Wet compression systems can be on line very quickly.

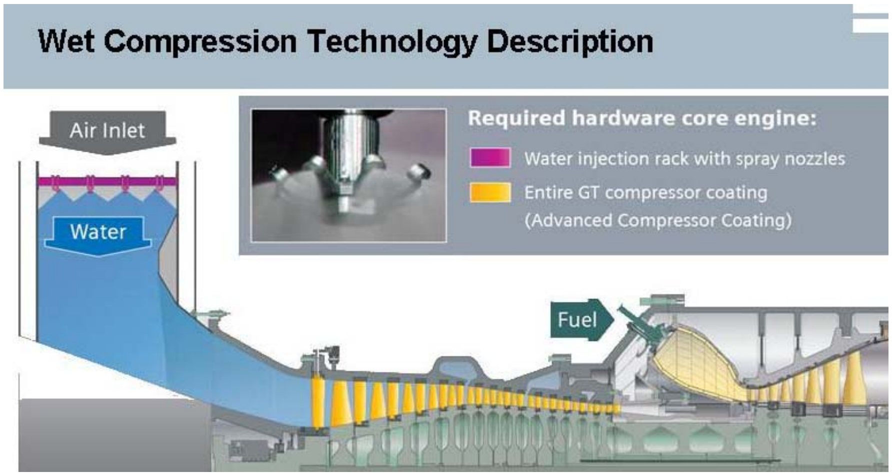

Figure 2-7: Wet Compression depiction with 100% coating of the compressor components (Al-Sati, 2014)

Maintenance is also critical. As water nozzles foul, the droplet size increases which result in water droplets impacting the compressor blades.

Figure 2-8: Typical wet compression demin pump skid with VFD

The wet compression system consists of a skid mounted water pump with variable frequency drive, using demineralized water supplied from a water treatment facility. The pump discharge is connected to a compressor inlet spray system. The gas turbine control logic is adjusted to accommodate the wet compression operating limits and integrated with the balance of plant logic. Installation and commissioning of a wet compression system usually requires an outage of 2-4 weeks as well as a full site survey (Crampsie, March-April 2012). The installation cost of a demineralized water system, demineralized plant operation (water, chemicals and labor) and maintenance cost also need to be included in a system evaluation.

2.4.4 Inlet Chilling

With inlet chilling a cooling coil is installed in the cross section of the gas turbine inlet filter plenum. Cold water (generated from a chilled water source) is pumped through the coil as the gas turbine inlet air flows over the coil. The advantages of inlet chilling system is the ability to reduce the inlet of the gas turbine to a desired temperature, generally ISO conditions or slightly lower during all times of operation. A source of the chilled water is required. The chilling system can be an electric driven chiller(s) or absorption chiller(s). The chilling system will require a way to reject heat, which, in most cases is a wet cooling tower. The wet cooling tower uses the vaporization of water to the atmosphere to take away the heat of the cycle driver and the cooling effect. A disadvantage to inlet chilling is the permanent pressure drop in the inlet filter house that will permanently reduce the GT output year round, regardless of the whether the inlet chilling system is operational, or not, even during part load operation. Inlet chilling system are generally very slow at responding, due to the thermal inertia of the warm water sitting in the piping before startup. One method to avoid this is to add a very small chiller to run 100% of the time to simply keep the chilled water piping system cold.

Figure 2-9: Typical turbine air chilling system with water cooling tower mounted above the chiller & pump house (Turbine Air Systems)

2.4.5 Steam Injection

In this system steam is injected at the combustor. The pressure of the steam must be high enough to match the compressor discharge pressure. A source of the steam is required, usually from the HRSG or steam turbine extraction of a combined cycle plant. The steam is 100% lost to the atmosphere as it proceeds through the turbine and up the stack. Therefore use of steam injection requires a demineralizer system adequate to provide for the makeup water volume. Steam (as with air) controls the flame temperature and results in lower NOx emissions. Steam injection normally is only attractive when (a) it is being generated in a combined cycle or HRSG (b) free steam is available, or (c) required for emissions control. The introduction of water or steam in the blade path of the gas turbine will impact the chemistry of turbine components to various degrees. Depending on the source of the steam, steam injection can be slow in reaching full benefit, sometime as much as 1 hour. Steam injected is not considered at the Pesanggaran site because there is no steam capability.

2.4.6 Air Injection

Air injection has a separate, stand-alone, air compressor designed to match the gas turbine’s compressor discharge conditions. The system can either be a humid air injection (HAI) or dry air injection (DAI) system. In general DAI provides greater cycle efficiency.. The DAI system uses atmospheric air less the moisture that condenses in the compressor intercooler. The intercooler substantially improves the compressor and reduces the compressor size requirements. Dry air introduces no additional chemistry concerns as with water or steam injection, and therefore the life of the gas turbine components is not impacted whatsoever. The DAI system can respond quickly to power demands, coming on line in less than a few minutes. DAI systems are external to a gas turbine package and the compressed air is single line to each gas turbine. Therefore a DAI system for multiple gas turbines at the same site can be provided from one, DAI system "manifold". The DAI System manifold can then take advantage of economies of scale, for example using five (5) DAI air compressors serving four (4) gas turbines, with one air compressor serving as a backup to any of the other four compressors. Also since they are external to the package, the DAI System can be applied to any future replacement gas turbines, or relocated to another gas turbine installation if the Pesanggaran site becomes no longer viable.

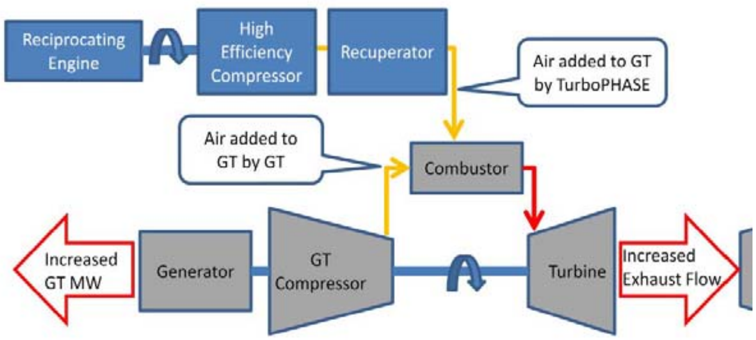

Figure 2-10: Air injection schematic

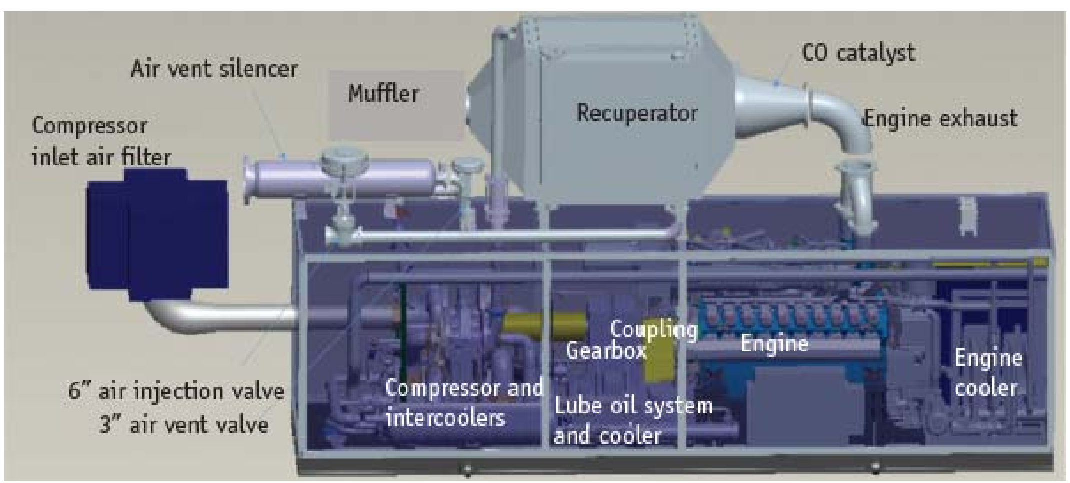

Figure 2-11: Typical Air Injection System (Turbo PHASE)™ provided by PowerPHASE

The HAI system is essentially a combination of high pressure steam injection diluted with dry air injection. HAI can provide greater output than DAI, but at less efficiency. HAI is most common in a combined cycle where steam is already being produced. HAI has the added cost of demineralized water make-up, water chemistry, steam piping, and of course make up water cost. HAI introduces the potential concerns for water/steam chemistry impacting the life of the gas turbine components. HAI systems can take a while to be fully functional, depending on the source of the high pressure water vapor.

Manufacturer's published general limitations on excess air or steam flow is 5%. However on older gas turbines, the surge margins are generally more conservative and therefore higher DAI and HAI mass flows are likely possible.

2.5 Evaluation of Alternatives for Indonesia

2.5.1 Evaluation Methodology

GT Pro software, under license from ThermoFlow of Massachusetts, was utilized to develop comparative performance and cost estimates for the each of the above technologies on the family of Bali gas turbines installed at Pesanggaran.

The following methodology was employed:

1) The first step is to replicate the New and Clean (N&C) performance of the each gas turbine at the design ambient conditions when the unit was installed using the GTPro computer performance modelling software. Site specific conditions are entered such as generator voltage, line voltage, site specific fuel composition, GT starter mechanism, and others. For the case of GT3, this value is 42.07 MW at 27C (80.6F). Using 4 inches inlet pressure drop and 4 inches outlet pressure drop the GTPro performance calculates 41.743 MW output which is close enough.

2) Using GTPro, the model arrived at in step (1) is run at the ambient conditions of the most recent gas performance test provided by the plant. For GT3, this was 30C (86F) on 06JAN2014. Unfortunately, the plant only records the ambient temperature and does not record the atmospheric pressure or humidity, both of which also affect the gas turbine performance, albeit in a secondary effect. Therefore any off-design performance impacts due to barometric pressure and humidity could not be corrected for. Historically, the Plant does not correct for the off-design conditions of temperature, atmospheric pressure or humidity when conducting any of the performance tests. While the pressure and humidity have less influence on power and heat rate, all performance test results should be corrected for all three parameters. In the N&C case, the predicted performance is at 30C is 40.768 MW.

3) By comparing the corrected performance in step (2) divided by the performance in step (1), a degradation factor is determined. For GT3, the test value was 39.8 MW indicating a degradation of 2.4%. The calculated degradation is then permanently applied to the GTPro Model which establishes a performance baseline to which to compare each performance enhancement being considered.

4) Using the GTPro capital cost estimating segment of the computer program (PEACE), an estimate of the cost to install the gas turbine in current year dollars is determined. It was agreed to use the default cost multipliers for Indonesia provided in GTPro for commodities, equipment, labor and materials. The cost ("PEACE") factors are listed in the table below. The costs of the baseline GT determined establishes the new and clean cost to install the gas turbine without any options, as constructed. The baseline cost prediction in GTPro is $US 33,379k for GT3.

Table 2-4: GT Pro Cost Factors Recommended for Indonesia

Category	Factor for Indonesia
Specialized Equipment	1.05
Other Equipment	0.75
Commodities	0.65
Labor	0.54

5) Each GT will then be modelled in GTPro with each of the enhancements under consideration. For each enhancement, the parameters of (a) Power Output, (b) Fuel Consumption and (c) total installed cost of the GT are recorded. The respective values are compared to the baseline GT (a) Power Output with apparent degradation, (b) fuel consumption and (c) total installed cost. The difference between the respective parameters is the estimated first cost to install the enhancement ***if new***. Some initial costs require additional adjustments not modelled in GTPro including demineralized water plant, compressor coatings, source of steam or air injection which must be added. The initial cost will be slightly higher since GTPro is comparing total plant cost, not calculating the incremental cost for a retrofit. Since all of the installations considered are retrofits, an adjustment cost to mobilize, demobilize, demolishment etc. of 10% has been added to each enhancement option. Other less tangible aspects of the alternatives are also shown. These include
   a. Lead time: the time from purchase order to receipt of equipment for installation at the project site.
   b. Installation time: the time the installing contractor will on the site to install the equipment
   c. Downtime: the time the gas turbine must be off-line and unavailable for dispatch to complete the installation.
   d. Foot print: the land area required to install a typical system. This does not include interconnecting piping routes which may be installed overhead or underground.
   e. O&M Costs: the additional O&M water costs estimated to support the system

3.0 RESULTS

3.1 Systems evaluated

Based on the aforementioned information and procedure outlined, the following are the results of the GTPro simulations conducted based on the test data and calculations described in Table 1-2. For Unit 3, the evaluation procedure was conducted at the Pesanggaran site office with the representatives from Indonesia Institute of Sciences Technical Implementation Unit for Instrumentation Development, Mr. Hilman Syaeful Alam M.Eng, and Mr. Imam Djunaedi. Unit 1 test information was not provided with the test temperature. Once the ambient temperature conditions are known, the table will be provided for Unit 1.

Each unit was checked for generation constraints to ensure it can accommodate additional capacity. Below is a table which compiles the manufacturer's data for the main components of the system that would be used to deliver the incremental power, namely the gas turbine, the load gear, the electric generator and the transformer. For each application, further study would require confirmation that the electrical bus, 11kV bus, circuit breaker and HV cables are sufficiently sized to handle the extra power. Based on this research, none of the technologies evaluated pose a threat to exceeding any of the major equipment ratings on any of the gas turbines installed.

Table 3-1: Equipment Ratings to Enable GT Uprates

		UNIT 1		UNIT 2		UNIT 3	UNIT 4
		base	peak	base	peak		
GAS TURBINE	MW	21.35	23.05	20.1	23.05	42.07	42.07
LOAD GEAR	MW	27		31.5		80.46	80.46
ELECTRIC GENERATOR	MVA	37	37	28.358	30.4	61.375	61.375
BUS 1		(a)	(a)	(a)	(a)	(a)	(a)
BREAKER		(a)	(a)	(a)	(a)	(a)	(a)
BUS 2		(a)	(a)	(a)	(a)	(a)	(a)
TRANSFORMER (Manufacturer)	MVA	27 (Alstom)		27 (Hunday)		60 (Hunday)	60 (Hunday)
		(a) Not confirmed					

Evaporative Cooling: Installing an in-line evaporative cooling media would require significant downtime, and because of the prevalent humidity in the region, it does not produce much incremental power. A major drawback is (a) permanent pressure drop of the evaporative cooling media (even during part load GT operation) and (b) output is inversely proportional to the humidity, which is high in the country.

Fogging System: As with the evaporative cooling system, installing a fogging system would require significant downtime, and because of the prevalent humidity in the region, it does not produce much incremental power. Fogging also requires the use of demineralized water, an added cost for its production, storage and piping. The Plant provided the cost to generate demineralized water in its current plant as is 576.07 Rupias/liter.

Chilling System: Three cases are evaluated for inlet chilling systems, chilling to 13^{0}C, 15^{0}C and 17^{0}C gas turbine inlet temperature. The resulting air conditioning system load for the respective system is shown. The system would use package chilling systems with "roof mounted" water cooling towers to reject the heat. No redundancy of equipment is included. The cooling tower makeup requirements are also provided.

Wet Compression System: Two cases are modeled, 1% and 2 % wet compression. In addition to the skid cost for wet compression, the cost of a demineralized water plant, storage tanks for raw and demin water for 0.5 days of operation, plus the estimated cost to coat the compressor is added to the implementation cost. The demineralized water required for each wet compression systems is provided. Considerable downtime would be required to coat the compressor components, which would have to be shipped off-site to an authorized service shop to add the advanced coating. This would results in a few weeks of downtime. Alternatively this work could be conducted during a scheduled major overhaul.

Dry Air Injection (DAI): The dry air injection is modelled based on 5% of ISO air flow conditions, e.g. 0.05 x 374.6 lb/sec = 18.73 lb/sec of air injection for G3/G4. The air is assumed to be available from the skid at 220 psig and 600 F. Greater flow can be achieved with the older gas turbines which were design with more conservative stall margins.

Humid Air Injection (HAI): A performance was evaluated assuming 10% of the dry air flow used above in DAI is provided with steam at similar conditions. The performance improvement is shown in the last column. Since there is no steam system at the site, heat recovery steam generator (HRSG) or steam turbine to extract steam from, a 90% efficient (LHV) boiler is assumed to be used as a source of the steam flow. The air flow is taken as 90% of the DAI compressor module heat input for providing the air flow. Additional parasitics for the new boiler was also added. As can be seen while the power boost is greater for HAI than DAI, the incremental heat rate is not as attractive as dry air. The incremental cost estimate for a boiler, installation, steam piping, makeup water piping and fuel piping is included in the capital cost along with 90% of the DAI cost for the air system. Other sites that have gas turbines in combined cycle may be able to avoid the cost of the boiler. However note, steam removed from a steam turbine (closed cycle) to be injected into a gas turbine (open cycle) adds additional make-up water cost to the steam turbine’s closed system.

3.2 Unit 1: GT1-Alstom Atlantique PG5341

Performance test data pending for comparison purposes.

Figure 3-1: Pesanggaran Unit 1, Alstom Atlantique PG 5341

3.3 Unit 2: GE MS5001

Figure 3-2: Pesanggaran Unit #2, GE MS5000

Below is a summary table comparing the various GT enhancement technologies to the Unit 2 gas turbine.

Table 3-2: GT2 Performance Enhancement Comparison

No	Parameter	Units	Evap Cooling	Fogging	Chilling, to 13 C	Chilling, to 15 C	Chilling, to 17 C	water/wet compression	water/wet compression	Dry Air Injection	Humid Air Injection
1	Cost New	k.USD	22,656	22,577	25,224	24,958	24,700	23,040	23,295	22,253	22,253
	Demin Plant/RO	k.USD	35	75				405	492	n/a	175
	Compressor component recoating	k.USD						700	700	n/a	n/a
2	Cost Base Plant	k.USD	22,232	22,232	22,232	22,232	22,232	22,232	22,232	22,232	22,232
3	**Technology Estimated Cost, USD**	**k.USD**	**505**	**462**	**3,291**	**2,999**	**2,715**	**2,104**	**2,481**	**1,171**	**1,629**
	(includes 10% for retrofit vs. new premium)										
4	New Power	kW	16,548	16,615	18,579	18,271	17,991	18,648	20,420	18,365	18,430
5	Base Power	kW	16,300	16,300	16,300	16,300	16,300	16,300	16,300	16,300	16,300
6	New Parasitic	kW	7	9	1,311	1,140	966	34	99	20	40
7	**Additional Net Power Output**	**kW**	**241**	**306**	**968**	**831**	**725**	**2,314**	**4,022**	**2,045**	**2,090**
8	**Capacity cost**	**USD/kWh**	**$ 2,094**	**$ 1,511**	**$ 3,399**	**$ 3,608**	**$ 3,742**	**$ 910**	**$ 617**	**$ 573**	**$ 779**
9	Lead time, month	months	12	6	12	12	12	16	16	6-8	10-12
10	Installation Time, days	weeks	6-8	4-6	5-7	5-7	5-7	12-16	12-16	6-8	10-12
11	Down time, days	days	12-16	6	15-20	15-20	15-20	14-28	14-28	2-3	2-3
	New GT Fuel Consump. [LHV]	kBTUY/hr	224,509	225,024	241,720	239,291	236,869	241,197	284,236	227,846	228,103
	Non-GT Fuel consump [LHV]	kBTUY/hr			-					16,719	20,903
	Base Fuel Consump. [LHV]	kBTUY/hr	221,898	221,898	221,898	221,898	221,898	221,898	221,898	221,898	221,898
12	Incremental Fuel Cons, Btu/hr [LHV]	kBTUY/hr	2,611	3,126	19,822	17,393	14,971	19,299	62,338	22,667	27,108
13	**Incremental heat rate, Btu/kWh [LHV]**	**BTU/kWh**	**10,830**	**10,222**	**20,469**	**20,930**	**20,638**	**8,342**	**15,501**	**11,084**	**12,970**
	Specific Fuel Consump. [asssumes 19,500 btu/lb]	**litre/kWh**	**0.300**	**0.283**	**0.568**	**0.580**	**0.572**	**0.231**	**0.430**	**0.307**	**0.360**
14	Additional O/M cost, USD/kWh	US$/kWh	-	0.068	-	-	-	0.091	0.099	-	0.048
	Demin Water Cost (Rp 576.07/liter)										
15	Water needs	lbs/sec	0.2546	0.2659	6.654	5.838	5.18	2.672	5.078	0	1.273
16	Cooling Capacity	AC Tons	n/a	n/a	1627	1435	1233	n/a	n/a	n/a	n/a
17	Permanent Land requirement	ft2	70	500	124	100	90	1649	2401	285	713
	Permanent Land requirement	m2	7	48	12	10	9	159	231	27	69

When operated for a hypothetical 2,000 hours/year, the incremental power, fuel and demineralized water costs are tabulated below.

Table 3-3: GT2 Operating Cost Comparison, 2,000 hrs./year

Assumptions										
Fuel Cost	[US$/gal]	$ 2.75								
Fuel Oil Heating Value	[BTU/gal HHV	132,000								
LHV/HHV ratio		0.96								
Annual hours of operation	[hours/year]	2,000								
Parameter	**Units**	**Evap Cooling**	**Fogging**	**Chilling, to 13 C**	**Chilling, to 15 C**	**Chilling, to 17 C**	**1% water/wet compression**	**2% water/wet compression**	**Dry Air Injection**	**Humid Air Injection**
Electric Energy Generated	[kWh]	482,200	611,600	1,936,800	1,662,000	1,450,800	4,627,200	8,043,000	4,090,000	4,180,000
Fuel Cost	[US$]	$113,325	$ 135,677	$ 860,330	$ 754,905	$ 649,783	$ 837,630	$ 2,705,642	$ 983,799	$ 1,176,548
Demin water Cost	[US$]	$ -	$ 41,776	$ -	$ -	$ -	$ 419,798	$ 797,805	$ -	$ 200,001
Operating Cost	**[US$]**	**$113,325**	**$ 177,453**	**$ 860,330**	**$ 754,905**	**$ 649,783**	**$ 1,257,428**	**$ 3,503,447**	**$ 983,799**	**$ 1,376,549**
average power cost	**[$/kW]**	**$ 0.235**	**$ 0.290**	**$ 0.444**	**$ 0.454**	**$ 0.448**	**$ 0.272**	**$ 0.436**	**$ 0.241**	**$ 0.329**

3.4 Unit 3: Westinghouse 251-B11

Figure 3-3: Pesanggaran Unit 3& 4 (typical)

Below is a summary table comparing the various GT enhancement technologies to the Unit 3 gas turbine. The apparent degradation of Unit 3 based on the last performance test of 39.8 MW (06JAN2014) is 2.4%. The ambient test conditions indicated 30C. This degradation is better than expected.

Table 3-4: GT3 Performance Enhancement Comparison

No	Parameter	Units	Evap Cooling	Fogging	Chilling, to 13 C	Chilling, to 15 C	Chilling, to 17 C	1% water/wet compression	2% water/wet compression	Dry Air Injection	Humid Air Injection[b]
1	GT Cost New w/Enhancement	k.USD	33,905	33,793	36,788	36,385	35,990	34,426	34,761	36,041	36,225
	Demin/RO Plant		50	100				276	412	n/a	250
	Compressor component recoating							750	750	n/a	n/a
2	Cost Base Plant w/o enhancement	k.USD	33,379	33,379	33,379	33,379	33,379	33,379	33,379	33,379	33,379
3	**Technology Estimated Cost, USD**	**k.USD**	**634**	**565**	**3,750**	**3,307**	**2,872**	**2,280**	**2,798**	**2,662**	**3,096**
	(includes 10% for retrofit vs. new premium)										
4	New Power	kW	41,316	41,522	44,830	44,179	43,498	46,219	50,244	45,413	45,553
5	Base Power	kW	40,743	40,743	40,743	40,743	40,743	40,743	40,743	40,743	40,743
6	New Parasitic	kW	10	16	1,394	940	894	53	92	20	40
7	**Additional Net Power Output**	**kW**	**563**	**763**	**2,693**	**2,496**	**1,861**	**5,423**	**9,409**	**4,650**	**4,770**
8	**Capacity cost**	**USD/kWh**	**$ 1,125**	**$ 741**	**$ 1,392**	**$ 1,325**	**$ 1,543**	**$ 420**	**$ 297**	**$ 573**	**$ 649**
9	Lead time, month	months	12	6	12	12	12	16	16	6-8	10-12
10	Installation Time	weeks	6-8	4-6	5-7	5-7	5-7	12-16	12-16	6-8	10-12
11	Down time, days	days	12-16	6	15-20	15-20	15-20	14-28	14-28	2-3	2-3
	New GT Fuel Consump. [LHV]	kBTUY/hr	455,563	456,981	481,008	476,365	471,316	489,995	520,587	467,084	467,855
	Non-GT Fuel consump [LHV]	kBTUY/hr								24,599	30,755
	Base Fuel Consump. [LHV]	kBTUY/hr	451,042	451,042	451,042	451,042	451,042	451,042	451,042	451,042	451,042
12	Incremental Fuel Consumption [LHV]	kBTUY/hr	4,521	5,939	29,966	25,323	20,274	38,953	69,545	40,641	47,568
13	**Incremental heat rate [LHV]**	**BTU/kWh**	**8,026**	**7,784**	**11,126**	**10,145**	**10,894**	**7,183**	**7,391**	**8,740**	**9,972**
	Specific Fuel Consumption [asssumes 19,500 btu/lb]	**litre/kWh**	**0.223**	**0.216**	**0.309**	**0.281**	**0.302**	**0.199**	**0.205**	**0.242**	**0.277**
14	Additional O/M water cost	US$/kWh	-	0.037	-	-	-	0.057	0.063	-	0.031
	Demin Water Cost (Rp 576.07/liter)										
15	Water needs	lbs/sec	0.33	0.363	7.2	5.9	4.73	3.952	7.54	n/a	1.873
16	Cooling Capacity	AC Tons	n/a	n/a	1780	1410	1060	n/a	n/a	n/a	n/a
17	Permanent Land requirement	ft2	80	600	144	108	91	1940	2825	297	742.5
	Permanent Land requirement	m2	8	58	14	10	9	187	272	29	71

When operated for a hypothetical 2,000 hours/year, the incremental power, fuel and demineralized water costs are tabulated below.

Table 3-5: GT3-Operating Cost Comparison, 2,000 hours/yr.

Assumptions										
Fuel Cost	[US$/gal]	$ 2.75								
Fuel Oil Heating Value	[BTU/gal HHV]	132,000								
LHV/HHV ratio		0.96								
Annual hours of operation	[hours/year]	2,000								
Parameter	**Units**	**Evap Cooling**	**Fogging**	**Chilling, to 13 C**	**Chilling, to 15 C**	**Chilling, to 17 C**	**1% water/wet compression**	**2% water/wet compression**	**Dry Air Injection**	**Humid Air Injection**
Electric Energy Generated	[kWh]	1,126,600	1,526,000	5,386,800	4,992,000	3,722,000	10,845,800	18,818,200	9,300,000	9,540,000
Fuel Cost	[US$]	$ 196,224	$ 257,769	$1,300,608	$1,099,089	$ 879,948	$ 1,690,668	$ 3,018,446	$1,763,921	$2,064,569
Demin water Cost	[US$]	$ -	$ 57,031	$ -	$ -	$ -	$ 620,899	$ 1,184,609	$ -	$ 294,267
Operating Cost	**[US$]**	**$ 196,224**	**$ 314,800**	**$1,300,608**	**$1,099,089**	**$ 879,948**	**$ 2,311,567**	**$ 4,203,056**	**$1,763,921**	**$2,358,836**
average power cost	**[$/kW]**	**$ 0.174**	**$ 0.206**	**$ 0.241**	**$ 0.220**	**$ 0.236**	**$ 0.213**	**$ 0.223**	**$ 0.190**	**$ 0.247**

3.5 Unit 4, Westinghouse 251-B11

The apparent degradation of Unit 4 based on the last performance test of 35.4 MW (19JAN2014) is 13.2%. The ambient test conditions indicated 30C. This degradation is high than expected and the cause should be investigated.

Table 3-6 GT4 Performance Enhancement Summary

No	Parameter	Units	Evap Cooling	Fogging	Chilling, to 13 C	Chilling, to 15 C	Chilling, to 17 C	1% water/wet compression	2% water/wet compression	Dry Air Injection	Humid Air Injection
1	Cost New	k.USD	33,878	33,760	36,698	36,326	35,986	34,367	34,699	35,719	33,385
	Demin Plant	k.USD	50	100				441	660	n/a	250
	Compressor component recoating	k.USD						750	750	n/a	n/a
2	Cost Base Plant	k.USD	33,347	33,347	33,347	33,347	33,347	33,347	33,347	33,347	33,347
3	**Technology Estimated Cost, USD**	**k.USD**	**639**	**564**	**3,686**	**3,277**	**2,903**	**2,432**	**3,038**	**2,372**	**2,835**
	(includes 10% for retrofit vs. new premium)										
4	New Power	kW	36,722	36,977	39,825	39,304	38,758	41,154	44,739	40,413	40,527
5	Base Power	kW	36,249	36,249	36,249	36,249	36,249	36,249	36,249	36,249	36,249
6	New Parasitic	kW	10	13	1,358	1,130	934	53	92	20	40
7	**Additional Net Power Output**	**kW**	**463**	**715**	**2,218**	**1,925**	**1,575**	**4,852**	**8,399**	**4,144**	**4,238**
8	**Capacity cost**	**USD/kWh**	**$ 1,380**	**$ 789**	**$ 1,662**	**$ 1,702**	**$ 1,843**	**$ 501**	**$ 362**	**$ 573**	**$ 669**
9	Lead time, month	months	12	6	12	12	12	16	16	6-8	10-12
10	Installation Time, days	weeks	6-8	4-6	5-7	5-7	5-7	12-16	12-16	6-8	10-12
11	Down time, days	days	12-16	6	15-20	15-20	15-20	14-28	14-28	2-3	2-3
	New GT Fuel Consump. [LHV]	kBTUY/hr	417,773	419,410	439,202	435,575	431,636	447,981	474,658	424,825	425,427
	Non-GT Fuel consump [LHV]	kBTUY/hr			-					24,599	30,755
	Base Fuel Consump. [LHV]	kBTUY/hr	414,077	414,077	414,077	414,077	414,077	414,077	414,077	414,077	414,077
12	Incremental Fuel Cons, Btu/hr [LHV]	kBTUY/hr	3,696	5,333	25,125	21,498	17,559	33,904	60,581	35,347	42,105
13	**Incremental heat rate [LHV]**	**BTU/kWh**	**7,983**	**7,460**	**11,327**	**11,167**	**11,148**	**6,988**	**7,213**	**8,530**	**9,935**
	Specific Fuel Consumption [asssumes 19,500 btu/lb]	**litre/kWh**	**0.221**	**0.207**	**0.314**	**0.310**	**0.309**	**0.194**	**0.200**	**0.237**	**0.275**
14	Additional O/M cost, USD/kWh	US$/kWh	-	0.040	-	-	-	0.064	0.071	-	0.035
	Demin Water Cost (Rp 576.07/liter)										
15	Water needs	lbs/sec	0.349	0.3624	7.083	5.983	4.856	3.953	7.544	0	1.873
16	Cooling Capacity	AC Tons	n/a	n/a	1796	1524	1235	n/a	n/a	n/a	n/a
17	Permanent Land requirement	ft2	80	600	144	108	91	1940	2825	297	742.5
	Permanent Land requirement	m2	8	58	14	10	9	187	272	29	71

When operated for a hypothetical 2,000 hours/year, the incremental power, fuel and demineralized water costs are tabulated below.

Table 3-7: GT4 Operating Cost Comparison

Parameter	Units	Evap Cooling	Fogging	Chilling, to 13 C	Chilling, to 15 C	Chilling, to 17 C	1% water/wet compression	2% water/wet compression	Dry Air Injection	Humid Air Injection
Assumptions										
Fuel Cost	[US$/gal]	$ 2.75								
Fuel Oil Heating Value	[BTU/gal HHV]	132,000								
LHV/HHV ratio		0.96								
Annual hours of operation	[hours/year]	2,000								
Electric Energy Generated	[kWh]	926,000	1,429,800	4,436,200	3,850,200	3,150,200	9,704,000	16,797,000	8,288,000	8,476,000
Fuel Cost	[US$]	$ 160,417	$ 231,467	$1,090,495	$ 933,073	$ 762,109	$ 1,471,528	$ 2,629,384	$ 1,534,146	$1,827,459
Demin water Cost	[US$]	$ -	$ 56,937	$ -	$ -	$ -	$ 621,056	$ 1,185,238	$ -	$ 294,267
Operating Cost	**[US$]**	**$ 160,417**	**$ 288,404**	**$1,090,495**	**$ 933,073**	**$ 762,109**	**$ 2,092,584**	**$ 3,814,622**	**$ 1,534,146**	**$2,121,726**
average power cost	**[$/kW]**	**$ 0.173**	**$ 0.202**	**$ 0.246**	**$ 0.242**	**$ 0.242**	**$ 0.216**	**$ 0.227**	**$ 0.185**	**$ 0.250**

4.0 CONCLUSIONS

From the discussions of the various gas turbine performance enhancements options, certain systems can be dismissed from consideration due to the humid climate of Indonesia, namely evaporative cooling and fogging systems. Of the remaining systems, the inlet cooling system is by far the most expensive and can also be dismissed due to the infrequent hours of operation of the gas turbines, the significant downtime to install the chilling coils, and large capital investment for these turbines with few remaining plant life years.

The wet compression alternative requires gas turbine specific installation of compressor coatings, nozzles, and demin water usage. Again, because the gas turbines are relatively old, the additional cost is significant to invest in these units. The most significant cost of wet compression, application of protective coatings, is not portable to other gas turbines and must be applied to each individual gas turbine.

This leaves DAI (Dry Air Injection) and HAI (Humid Air Injection). Currently there is no steam source of approximately 10 bar pressure at the Pesanggaran facility to utilize HAI. Therefore the cost to install a heat recovery device to use the steam intermittently is not profitable. While other gas turbine sites may have steam available, if steam is being removed from a steam turbine it is merely displacing the power created in the steam turbine with power created in the gas turbine. The steam chemistry would also need to be reviewed carefully to minimize the effects on the gas turbine components.

It is apparent that the most cost effective, ($/kW) and least effect on O&M is dry air injection. The dry air injection

- Has the least down time
- Has one of the lowest capital cost per kW
- introduces no additional contaminants into the gas turbine
- Has the portability to relocate the system on any other or future gas turbine(s) that might be installed at the site

In the GTPro model only 5% incremental air flow was evaluated. Due to the vintage of the gas turbines at Pesanggaran, the stall margins are much more conservative, and therefore it is highly likely additional performance can be achieved by exceeding the 5% flow threshold.

5.0 RECOMMENDATIONS

For each of the 4 gas turbines evaluated, the dry air injection presents the least cost alternative to performance enhancements of gas turbines install at the Pesanggaran Station in Bali. The dry air injection

- Has the least down time
- Has one of the lowest capital cost per kW
- introduces no additional contaminants into the gas turbine
- Has the portability to relocate the system on any other, or future gas turbine(s) that might be installed at the site or in the IP system
- Requires no water use
- Can be brought on line extremely quickly
- Can be manifolded to serve multiple gas turbines achieving economies of scale, and can easily be fitted with a system redundancy with an extra module that can serve any of the four gas turbines.

Other sites in Indonesia may have other parameters which may alter the DAI recommendation.

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ATTACHMENT A-1

Unit 1 Performance Figures

ATTACHMENT A-2

Unit 2 Performance Figures

ATTACHMENT A-3

Unit 3 Performance Figures

ATTACHMENT A-4

Unit 4 Performance Figures