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Assessment of Clean Development Mechanism Potential on the Combine Cycle Gas Turbine Power Plant Development in Java-Madura-Bali Power System

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Abstract—Ratification of UNFCCC and Kyoto Protocol by the Government of Indonesia trough Law Number 6/1994 and Law Number 17/2004 give the opportunity to Indonesia to participate with the world effort in solving the climate change problems caused by global warming. This is also in line with the results of the Paris World Climate Summit (UNFCCC COP21) in which Indonesia has committed to reducing GHG emissions by 2030 by 29% on its own, and up to 41% with international assistance and co-operation keeping the earth's average temperature rise below 2%. The form of that participation is by being involved on the Clean Development Mechanism (CDM) in energy sector trough the development of combine cycle power plant in Java-Madura-Bali (JAMALI) power system. The objective of this research is to determine the feasibility and financial impacts of applying low-carbon projects of combine cycle gas turbine power plant to be proposed as a CDM project by Independent Power Producer. The analysis resulted of a 145 MWel combined cycle power plant (CCPP) with the contract period of the Power Purchace agreement over 20 years, in the base case without CDM finance, the equity IRR of the project is 10.16% without considering the additional revenue from the registration of the project as CDM project. Upon considering the additional revenue from registration of the project as CDM project the IRR would be 13.31%, which is close to the equity benchmark IRR of 13.22%, which can be achieved under the upside scenarios when including CDM financing. The benchmark rate used for this indicator is the Investment Rate published by the Indonesian central bank (Bank Indonesia). The average investment rate for the most recent three years 13.22%.

Keywords—Clean Development Mechanism, Combine Cycle Power Plant.

I. INTRODUCTION

Indonesia is facing a crisis in electric power supply, as demand is growing by 8% a year as against production growth of only 3% per year. For the most recent 11 years, the share of newly built similar power plants (public and private) in the JAMALI grid accounted for less than 14% for gas-based plants, against over 86% for coal-based plants. Moreover, between 2002 and 2006 the share of electricity generated from gas based power plants in the JAMALI grid (public and private) decreased to 27%, whilst the share of generation accounted for by oil and coal increased by 41.3% and 34.5% respectively. Indonesia is the second largest exporter of coal in the world. In light of abundant availability of cheap coal and to reduce dependence on fuel oil, the Indonesian government has undertaken a “Crash Program”. This program involves the construction of 24 new coal fired power plants units with a total capacity of 8,192 MWel. In Java, 10 units of PLTU with a total capacity of 7,140 MWel will be built (plants will have a capacity of 300 MWel to 660 MWel). The current trend in Indonesia is clearly focused on the construction of coal based power plants. Mainly due to the government’s plan to encourage coal based power projects it is likely that the share of power generation fired by natural gas will decline. Therefore, we consider that this evidence supports the fact that the project activity is not common practice in Indonesia.

While Indonesia resource-rich archipelagic nation is the world’s fourth-largest producer of coal and a top coal exporter. Indonesia is also Southeast Asia’s biggest gas supplier, with exports accounting for roughly 45% of its production. Globally, Indonesia is the tenth-largest gas producer and the seventh-largest exporter of liquefied natural gas (LNG). Indonesia’s natural gas reserves in 2005 were 5261.27 billion cubic meter (bcm). About 2755.23 bcm is proven and 2506.04 bcm is probable reserves, with the proven reserve having been increased since then. Around 50% of the natural gas produced is processed into liquefied natural gas (LNG) for export whilst the rest is consumed domestically by industries and some for electricity production. It is anticipated that domestic utilisation will increase, but current pricing dictates that use for gas-based power production is not economically attractive in the absence of economic incentives and when compared to power plants using the country’s inexpensive and large coal supplies. Indonesia’s current annual production is only between 2-3% of proven reserves and between 1-2% of proven and probable reserves. A report by Business Monitor International forecasts that Indonesian natural gas production will increase to 100 bcm by 2020, with domestic usage increasing to over 50 bcm per year by that time. The project is sourcing its gas from a new source that is not currently used, but this forecast also indicates that there will be plentiful new supply from Indonesia's large resources and the project only requires around 0.2bcm per year, which accounts for only 0.3% of current production, 0.2% of future production, or 0.8% of the forecast increase in production. In summary there is clearly sufficient gas available within the country in the future to comfortably satisfy the existing capacity of gas based power production and the project. The above information clearly substantiates that Indonesia has sufficient proven and probable resource to meet the local energy requirements.

II. METHOD

Method in this study used the UNFCCC CDM methodologies appropriate for large-scale CDM project activities, ie approved baseline methodology AM0029, version 03:"Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas". In the selection of calculation methods of emission factors supporting data that can be used as reference consists of two types: ex ante and ex post. The ex ante data is determined by the submission of the Project Design Document (PDD) to the CDM-Executive board while the ex post data is determined by the time when the project starts connecting to the system. This research is not intended to be submitted to CDM-Executive board so that the data year used is adjusted to the availability of data. In this study there is also no project implemented so that the type of data the selected is ex ante so that the required data is the electricity data for the most recent three years available. Detail each calculation explain in list below :In line with the methodology, the emission reductions are calculated as explained below :

$$\mathbf{ER_y = BE_y - PE_y - LE_y} \qquad (1)$$

Where:

ERy : Emissions reductions in year y (t CO2e)
BEy : Emissions in the baseline scenario in year y (t CO2e)
PEy : Emissions in the project scenario in year y (t CO2e)
LEy : Leakage in year y (t CO2e)

- Baseline Emissions:

Baseline emissions are calculated by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO2 emission factor ($EF_{BL,CO2,}y$), as follows:
Baseline Emissions (tCO2e) :

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y} \qquad (2)$$

Wherein:

BEy : Baseline emissions in year *y* (tCO2e / yr)
$EG_{PJ,y}$: Electricity generation in the project plant during the year *y* in MWh.
$EF_{BL,CO2,y}$: Baseline emission factor for the grid in year *y* (tCO2/MWh)

- Project Emissions:

The project activity is on-site combustion of natural gas to generate electricity. The CO2 emissions from electricity generation (PEy) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} \qquad (3)$$

FCf,y : is the total volume of natural gas or other fuel 'f' combusted in the project plant or other startup fuel (m3 or similar) in year(s) 'y'
COEFf,y : is the CO2 emission coefficient (tCO2/m3 or similar) in year(s) for each fuel and is obtained as:

$$COEF_{NG,y} = NCV_{NG,y} \,.\, EFc_{o2,NG,y} \,.\, OXID_{NG} \qquad (4)$$

Where:

NCVf,y : is the net calorific value (energy content) per volume unit of natural gas in year 'y' (GJ/m3) as determined from the fuel supplier, wherever possible, otherwise from local or national data;
EFCO2,f,y: is the CO2 emission factor per unit of energy of natural gas in year 'y' (tCO2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data;
OXIDf : is the oxidation factor of natural gas.

$$PE_y = FC_{NG,y} \,.\, COEF_{NG,y} + FC_{HSD,y} \,.\, COEF_{HSD,y} \qquad (5)$$

- Leakage

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH4 emissions and CO2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered.

- Fugitive CH4 emissions associated with fuel extraction, processing, liquefaction, transportation,re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity.
- In the case LNG is used in the project plant: CO2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \qquad (6)$$

Where:

LEy : Leakage emissions during the year y in tCO2e
$LE_{CH4,y}$: Leakage emissions due to fugitive upstream CH4 emissions in the year y in t CO2e

$LEL_{NG,CO2,y}$: Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in t CO2e.

In the project activity there will be no LNG consumption, hence $LE_{LNG,CO2,y}$ will be zero.

- Fugitive Methane Emissions

For the purpose of estimating fugitive CH4 emissions, project participants should multiply the quantity of natural gas consumed by the project in year y with an emission factor for fugitive CH4 emissions ($EFNG,upstream,CH4$) from natural gas consumption and subtract the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH4,y} = (FC_y . NCV_y . EF_{NG,upstream,Ch4} – EG_{PJ,y} . EF_{BL,upstream,CH4}) . GWP_{CH4} \quad (7)$$

Where:

$LE_{CH4,y}$: Leakage emissions due to fugitive upstream CH4 emissions in the year y in t CO2e.

FCy : Quantity of natural gas combusted in the project plant during the year *y* in m3.

$NCV_{NG,y}$: Average net calorific value of the natural gas combusted during the year *y* in GJ/m3.

$EF_{NG,upstream,CH4}$:Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, regasification and compression into a transmission or distribution system, in t CH4 per GJ fuel supplied to final consumers

$EG_{PJ,y}$: Electricity generation in the project plant during the year in MWh.

$EF_{BL,upstream,CH4}$: Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH4 per MWh electricity generation in the project plant, as defined below.

GWP_{CH4} : Global warming potential of methane valid for the relevant commitment period.

The emission factor for upstream fugitive CH4 emissions occurring in the absence of the project activity ($EFBL,_{upstream,CH4}$) should be calculated consistent with the baseline emission factor ($EF_{BL,CO2}$) used in equation (1) above, as follows:

The default values used in the project activity are as follows:

- Emission factor for fugitive CH4 upstream emissions for coal as 0.8 tCH4/kt coal as suggested in AM0029 for surface mining (assumed all the coal comes from in Indonesia)
- Emission factor for fugitive CH4 upstream emissions for Oil including production, transport,refining and storage 4.1 tCH4/PJ
- Emission factor for fugitive CH4 upstream emissions for Natural Gas, assuming the total for“Rest of the world” 296 tCH4/PJ

$$EF_{BL,upstream,CH_4} = 0.5 \cdot \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH_4}}{\sum_j EG_j} + 0.5 \cdot \frac{\sum_i FF_{i,k} \cdot EF_{k,upstream,CH_4}}{\sum_i EG_i} \quad (8)$$

$EF_{BL,upstream,CH4}$: Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH4 per MWh electricity generation in the project plant

j : Plants included in the build margin

$FF_{j,k}$: Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin

$EF_{k,upstream CH4}$:Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in tCH4 per MJ fuel produced

EG_j :Electricity generation in the plant j included in the build margin in MWh/a

$FF_{i,k}$: Quantity of fuel type k (a coal or oil type) combusted in power plant i included in the operating margin

EG_i :Electricity generation in the plant i included in the operating margin in MWh/a

III. RESULT AND DISCUSSION

A. Data Collection.

- *Grid Emission Factors*

The Operating Margin data for the most recent three years and Build Margin data for the Jawa Madura Bali (JAMALI) Grid based on database in Directorate General of Electricity and Energy Utilization and approved by Ministry of Environment of Indonesia are as follows:

Total GHG emission in 2014, 2015, 2016 (tCO2)	243,312,048
Total net electricity produced in 2014, 2015, 2016 (MWh)	288,316,859
Average Operating Margin for the most recent three years (tCO2/MWh)	0.844

Table 1. Average Operating Margin

Total GHG emission in 2016 (tCO2)	27,161,539
Total net electricity produced in 2016 (MWh)	28,937,555
Average Build Margin for the most recent three years (tCO2/MWh)	0.937

Table2. Build Margin

Build Margin (tCO2/MWh) (50%)	0.937
Average Operating Margin (tCO2/MWh) (50%)	0.844
Combined Margin (tCO2/MWh)	0.891

Table 3. Combined Margin

According to AM0029, this determination will be made once at the validation stage based on an ex ante assessment and once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, they will be estimated ex post, as described in Tool to calculate emission factor for an electricity system.

Emission factors determined using the three options are summarized in the Table below:

Options	Emission Factor (tCO2e/MWh)
Option 1 : Build Margin for JAMALI Grid	0.937
Option 2 : Combined Margin for JAMALI Grid	0.891
Option 3 : Emission factor of coal based power plant	1.070

Table 4. Summary Emission Factors

Year	Power Plant	Gross electricity generated and delivered to the grid (Mwh)	Net electricity generated and deliveres to the grid (Mwh)	Quantity of fuel consumed (kton)	Net calorific value of coal (TJ/kt coal)	Operational efficiency (net)
2015	Paiton 1	9,116,000	8,730,393	4,437	24	29.5%
	Paiton 2	9,109,000	8,723,689	4,273	24	30.6%
	KDL	2,230	2,136	0,8	24	38.3%
	Cilacap	1,937,000	1,855,065	764.1	24	36.4%
	Tanjung Jati B	3,869,000	3,705,341	1,525	24	36.4%
	PJB	4,929,000	4,720,503	2,753	24	25.7%
	Indonesia Power	23,875,480	22,865,547	13,165	24	26%

Average Operational efficiency (grosss) : 33.2%
Average Operational efficiency (Nett0) : 31.8%

Table 5. Energy Efficiency of Coal Fired Power Plant

Parameter	Default value	Unit	Source
EFcoal,upstream, CH4	0.8	tCH4 /kt coal	Table 2 of AM0029: Default emission factors for fugitive CH4 upstream emissions
EFoil,upstream,CH4	4.1	tCH4 / PJ	Table 2 of AM0029: Default emission factors for fugitive CH4 upstream emissions
EFNG,upstream, CH4	296	tCH4 / PJ	Table 2 of AM0029: Default emission factors for fugitive CH4 upstream emissions

Table 6. Default Emission Factors for Fugitive CH4 Upstream Emissions

Data/Parameter	$NCV_{NG,y}$
Data Unit	GJ/m^3
Source of data to be used	Fuel supplier data
Value of data applied for the purpose of calculating expected emission reduction	0.03654

Table 7. Net Calorific Value of Natural Gas

Data / Parameter:	*NCV* y of HSD, IDO and MFO
Data unit:	GJ/ kiloliter fuel
Description:	Net calorific value per volume unit.
Source of data used:	The source of data comes from the data given by Indonesian Directorate General of Electricity and Energy Utilization. The same data is used to calculate the official JAMALI Grid.

Table 8. Net Calorific Value of HSD, IDO and MFO

Data / Parameter:	EFCO2, Coal
Data unit:	Kg CO2e/TJ
Description:	CO2 emission factor of coal combustion
Source of data used	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Table 2.2 page 2.16 (Other-Bituminous Coal - CO2 - Default value)
Value applied:	94,600

Table 9. CO2 Emission Factor of Coal Combustion

Data / Parameter:	*EF, CO2 NG*
Data unit:	kg CO2e/TJ
Description:	CO2 Emission Factor of Natural Gas
Source of data to be used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Table 2.2 page 2.16 (Natural Gas - CO2 - Default value)
Value of data applied for the purpose of calculating expected emission reductions in section B.6	56,100
Description of	Default values for Carbon Emission Factor of Natural Gas as 2006 IPCC

Table 10. CO2 Emission Factor of Natural Gas

Data / Parameter:	EF *NG, upstream CH4*
Description:	Emission factor for upstream fugitive methane emissions of Natural Gas from production, transportation, distribution
Source of data used:	Available from methodology AM0029 Table 2 page 9
Value applied:	296
Data / Parameter:	*EF oil , upstream CH4*
Data unit:	tCH4/PJ
Description:	Emission factor for upstream fugitive methane emissions of oil from production, transportation, distribution
Source of data used:	Available from methodology AM0029 Table 2 page 9
Value applied:	4.1

Tabel 11.Emission Factor for Upstream Fugitive Methane Emissions of Natural Gas From Production, Transportation, Distribution

Data / Parameter:	*EF Coal upstream CH4*
Data unit:	tCH4/kt Coal
Description:	Emission factor for upstream fugitive methane emissions of coal from production, transportation, distribution
Source of data used:	Available from methodology AM0029 Table 2 page 9
Value applied:	0.8

Tabel 12. Emission Factor for Upstream Fugitive Methane Emissions of Coal From Production, Transportation, Distribution

Data / Parameter:	*OXID NG*
Data unit:	-
Description:	Oxidation Factor of Natural Gas
Source of data to be used:	Volume 2 (Energy) - Chapter 1- Table 1.4 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied	1

Tabel 13. Oxidation Factor of Natural Gas

Data / Parameter:	**GWP (CH4)**
Data unit:	-
Description:	Global warming potential of methane
Source of data used:	Established by Kyoto Protocol
Value applied:	21

Table 14. Global Warming Potential of Methane

B. Calculation of Emission reductions .

As per methodology AM0029 Version 03, the baseline emissions, project emissions, leakage emissions and emission reductions by the project activity is calculated as follows

- *Baseline Emissions*

Baseline Emissions (tCO2e) :

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y}$$

Where:

$EG_{PJ,y}$= Annual expected net electricity generated in the project activity (MWh)= Gross electricity generated – Auxiliary power consumption= 8640*0,85*(2*37,97+50) - 8640*0,85*(2*1,4+1,8) = 891,070 MWh 8640 hours/year, the remaining 5 days the plant will be shut down for maintenance services.

AM0029 advises to address the baseline uncertainties in a conservative manner by choosing the $EF_{BL,CO2,y}$ as the lowest emission factor among the following three options:

- Option 1: The build margin, calculated according to "Tool to calculate emission factor for an electricity system"; and
- Option 2: The combined margin, calculated according to "Tool to calculate emission factor for an electricity system", using a 50/50 OM/BM weight.
- Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated as follows:

$$EF_{BL,CO_2}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$

where,

$COEF_{BL}$: the fuel emission coefficient (tCO2*e*/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used

η_{BL} : the energy efficiency of the technology, as estimated in the baseline scenario analysis above.

Where, $EF_{BL,CO2,y}$ is calculated in a conservative manner and should use the lowest emission factor among the three options mentioned above. Among the three options above, the lowest emission factor selected is Build Margin emission factor of 0.8417 tCO2e/MWh. As per the Tool to calculate emission factor for an electricity system, the combined margin emission factor is calculated as combination of operating margin (OM) and build margin (BM) emission factors. According to AM0029, the weighting of OM and BM is 50/50.

$$EF_{CM,y} = EF_{OM,y} \cdot w_{OM} \times EF_{BM,y} \times w_{BM}$$

Where: $w_{OM} + w_{BM} = 1$

The operating margin (OM) emission factor is 0.844 tCO2/MWh (the source of data comes from the data given by Indonesian Directorate General of Electricity and Energy Utilization. The same data is used to calculate the official JAMALI Grid.).

$$EF_{CM,y} = EF_{OM,y} \cdot w_{OM} \times EF_{BM,y} \times w_{BM}$$

$$EF_{CM,y} = 0.5*0.844 + 0.5*0.937$$

Applying a 50/50 weight to the values for operating margin and build margin emission factors provided in the Indonesian Directorate General of Electricity and Energy Utilization. database, the Combined Margin emission factor calculated is 0.891 tCO2/MWh

$$EF_{BL,CO2,y}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$

Based on the IPCC default value for coal emission coefficient ($COEF_{BL}$), the value used for the emission factor calculation is 0.0946 tCO2/GJ) is 31.8%29. And the value of the energy efficiency (η_{BL}) is 31.8%

$$EF_{BLCO2,y} = \frac{0.0946(tCO2/GJ)*3.6(GJ/MWh)}{31.8\%}$$

$$EF_{BLCO2,y} = 1.070 tCO2e/MWh$$

And baseline emission factor value is:

$EF_{BL,CO2,y}$= 0.891 tCO2e/MWh

Therefore baseline emission is:

BE y=891,070 * 0.891

BE y= 793,944 tCO2e

- Project Emissions

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y}$$

$PEy = FC_{NG,y} \cdot COEF_{NG,y} + FC_{HSD,y} \cdot COEF_{HSD,y}$

And

$COEF_{NG,y} = NCV_{NG,y} \cdot EFco_{2,NG,y} \cdot OXID_{NG}$

$COEF_{NG,y} = 0.03654 * 0.0561 * 1$

$COEF_{NG,y}$ = 0.00205 $tCO2/m^3$

$PEy = FC_{NG,y} \cdot COEF_{NG,y} + FC_{HSD,y} \cdot COEF_{HSD,y}$

For Ex-ante project emission calculation , FC_{HSDy}, has been considered nil.

Then

$PEy = FC_{NG,y} \cdot COEF_{NG,y}$

PEy = 208,759,413 * 0.00205

PEy = 427,934 tCO2e

- Leakage

Leakage emissions due to fugitive upstream CH4 emissions

$LE_{CH4,y} = (FC_y \cdot NCV_y \cdot EF_{NG,upstream,Ch4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}) \cdot GWP_{CH4}$

$LE_{CH4,y}$ = [208,759,413 * 0.03654 * 0.000296 – 891,121 * 0.000473]* 21

$LE_{CH4,y}$ = 38,566 tCO2e

- Emissions Reductions

$ER_y = BE_y - PE_y - LE_y$

ER_y = 793,944 - 427,934 - 38,566

ER_y = 327,443 tCO2e

Summary of the ex-ante estimation of emission reductions for all years of the crediting period has been presented in the table below.

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Year	Estimation of project activity emission (tonnes of CO2e)	Estimation of baseline emissions (tonnes of CO2e)	Estimation of leakage (tonnes of CO2e)	Estimation on of overall emission reductions (tonnes of CO2e)
2018	142,645	264,648	12,855	109,148
2019	427,935	793,944	38,566	327,443
2020	427,935	793,944	38,566	327,443
2021	427,935	793,944	38,566	327,443
2022	427,935	793,944	38,566	327,443
2023	427,935	793,944	38,566	327,443
2024	427,935	793,944	38,566	327,443
2025	427,935	793,944	38,566	327,443
2026	427,935	793,944	38,566	327,443
2027	427,935	793,944	38,566	
Total (tonnes CO2 equivalent)	4,279,347	7,939,437	385,656	3,274,435

Table 15. Emission Reductions for All Years of the Crediting Period

C. Calculation and Comparison of Financial Indicators

A financial model was prepared by the project company to evaluate the investment. The financial model on which the investment was based is considered the base case. However, this is an optimistic scenario in which the company assumes that it is able to sell power in excess of its contracted agreements. Simple cost analysis is not appropriate as there are revenues to the project. Investment comparison is not appropriate as this is the project company's first Independent Power Producer investment and will not consider other investments in the same technology (gas-fired power generation) until they see the level of success (or failure) of this project. Therefore, benchmark analysis is more appropriate in this case. The proposed project activity is determined for the selected financial indicator.

The benchmark rate used for returns comparison is investment loan rate as published by the Bank of Indonesia for the most recent three years, which stood at 13.22%. This is conservative in that project equity providers would expect to attach a risk premium to the bank financing rate in assessing projects. However, this is deemed appropriate in this situation in order to be conservative and as the major shareholder in Independent Power Producer also has a cost of equity of 13.22%. Assuming that the contract the project has a contract to sell power for 20 years only, at 70 % (or 889,140 MWh) of operational capacity. in the base case without CDM finance, the equity IRR of the project is 10.16% without considering the additional revenue from the registration of the project as CDM project. Upon considering the additional revenue from registration of the project as CDM project. the IRR would be 13.31%, which is close to the equity benchmark IRR of 14%, which can be achieved under the upside scenarios when including CDM financing.

#	Name of Case	IRR	IRR Change
1	Base Case	10.16%	-%
	CDM Finance vailable	13.31%	3.16%
	No CDM: Power production increases by 15%	11.32%	1.16%
	No CDM: Power production decreases 10%	9.25%	(0.90%)
	With CDM: Power production increases by 15%	15.16%	5.00%
	With CDM: Power production decreases 10%	11.88%	1.73%
	No CDM: Variable power Tariff increases by 20%	10.69%	0.54%
	No CDM: Variable power Tariff increases by 50%	11.48%	1.32%
	With CDM: Variable power Tariff increases by 20%	13.82%	3.66%
	With CDM: Variable power Tariff increases by 50%	14.56%	4.40%
	No CDM: Contract only 5 years, no excess power sold	2.00%	(8.15%)
	With CDM: Contract only 5 years, no excess power sold	2.83%	(7.32%)

Table 16. Summary Sensitivity analysis on IRR in relation to the change in electricity production and power tariff.

The sensitivity analysis on IRR is indicated in the table above assuming that the plant is fully completed for combined cycle operation by the year 2018. The investment returns evaluated could be summarized as:

- Base IRR without and with CDM finance: Assuming that the contract is 2025, the IRR would be 10.16% without CDM. With the finance available from CDM, the IRR would be 13.31%.
- In the best-case scenario, production of electricity from the plant would go up from current 70% to 85% and with CDM finance, the IRR would be 15.16%.
- In another best case scenario at 70% production wherein excess power tariff is valued at 100% of base power tariff instead of 50% (as per contract) and with CDM finance, the IRR would be 14.56%.
- In a downside situation wherein the company sells only the power it has contracted to sell in its 5-year contract (and no excess power), at 70% production the IRR drops to 2.83%, even with CDM finance (and 2.00% without).

This project faces a number of factors which reduce the returns in the base-case scenario, these present significant risks to the project developer. First, a 5-year Power Purchase Agreement is not typical for Independent Power Producers, because they face significant downside from the prospect of non-renewal, or renewal on less favorable terms. Secondly, the tariff rate paid for base power is low, and is not at the level which meets the expected level of power production; excess production above PPA amounts is sold at a significant discount to base-power production levels. Thirdly, the PPA does not guarantee that will be able to sell excess power produced, after the consideration of the discount.

IV. CONCLUSION

The analysis resulted of a 145 MWel combined cycle power plant (CCPP) with the contract period of the Power Purchase agreement over 20 years, in the base case without CDM finance, the equity IRR of the project is 10.16% without considering the additional revenue from the registration of the project as CDM project. Upon considering the additional revenue from registration of the project as CDM project the IRR would be 13.31%, which is close to the equity benchmark IRR of 13.22%, which can be achieved under the upside scenarios when including CDM financing. The benchmark rate used for this indicator is the Investment Rate published by the Indonesian central bank (Bank Indonesia). The average investment rate for the most recent three years 13.22%. The analysis resulted that development of combine cycle power plant in Java-Madura-Bali (JAMALI) power system is the most feasible to develop when including CDM financing.

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