



South Africa, June 29, 2006

Response to request for review

Rosslyn Brewery Fuel-Switching Project

Dear Members of the CDM Executive Board,

We would like to provide an initial response to the requests for review raised by four Board members concerning DNV's request for registration of the Rosslyn Brewery Fuel-Switching Project.

The reasons for the request of the Board members and our respective explanations are shown below:

1. Since the methodology does not provide for the switch to biogas, there is no provision for calculating leakage during its production. It has been assumed that the efficiency of natural gas and the biogas used would be identical. For this to be true, the biogas would need to be cleaned and scrubbed and the concentration of methane would need to be increased to that of natural gas. To do this, energy would be consumed. The treatment of the same needs to be explained. A deviation should have been requested to the Executive Board before the project submission.

The non-combustible constituents in the biogas would slightly reduce overall boiler room efficiency. The boiler manufacturer indicated that there is usually a 0.5% boiler efficiency difference when firing a boiler with a fuel at 35 MJ/m³ and with a fuel at 18 MJ/m³. Given the biogas is expected to have a calorific value of about 24 MJ/m³ and that the total volume of biogas relative to the total fuel consumed is less than 10%, when this dual fuel boiler is combined with two boilers firing natural gas only, the decrease in the overall boiler room efficiency is expected to be less than 0.05%. Thus, it would be reasonable to consider that the effect of the biogas on the global efficiency of the boiler room is minimal.

Regarding the treatment of biogas, it would only require scrubbing if the hydrogen sulfide concentration exceeded 1,000 ppm, in order to eliminate corrosion of the transfer piping and boiler biogas burner. Since in this case the hydrogen sulfide concentration in the biogas is negligible, there is no need to scrub the gas. In effect, the only thing that would be done regarding the biogas is to install a small blower (3 to 5 kW motor) to transfer the biogas from the digester to the boiler, and to get it through the boiler's biogas burner.

According to the PDD submitted for registration, the project would reduce electricity consumption (by about 350 kW) since the steam generated by the current coal boilers requires more electrical energy than the steam generated by the new natural gas boilers. This reduction in electricity consumption is substantially higher than the electricity consumption from the small blower required to transport the biogas. As a conservative assumption, the emission reduction from the avoided coal fuel combustion at the power plants connected to the grid is not considered for this project activity.

Consequently, there is no need to consider any leakage related to biogas treatment, because the biogas is not treated before entering into the boiler room, and thus, a deviation should not have been requested to the Executive Board before the project submission.

In addition, according to the PDD submitted for registration, the overall efficiency of the boiler room using natural gas and biogas will be measured as a function of the load factor following project implementation. Thus, only measured values of the boiler room overall efficiency will be used in the calculation of emission reductions.

2. The claiming of CERs for positive leakage in fugitive emissions is not conservative, because it cannot be assured that the coal will not be used somewhere else, and it does not include the fugitive emissions associated with the production, distribution and transportation of natural gas.

The methodology used in this project activity (AM0008) clearly states the following:

Fugitive CH₄ emissions from fuel production and CO₂ emissions from fuel transportation are categorized as leakage. Emissions from fuel production/transportation is counted only if the fuel is produced/transported in a non-Annex I country.

The leakage LE_y is expressed as

$$LE_y = [Q_NG_y * FE_NG_CH_4 - \sum_i (Q_F_{i,y} * FE_F_i_CH_4)] * GWP_CH_4 \\ + [\sum_j (Q_TF_{j,y} * EF_TF_j) - \sum_k (Q_TF_{k,y} * EF_TF_k)]$$

where FE_NG_CH₄ and FE_F_i_CH₄ are the IPCC default CH₄ emission factor of natural gas and fuel i associated with fugitive emissions. In case that the effect of methane leaked from pipeline cannot be neglected, it should be included in this term (although it is not a function of Q_NG_y in the IPCC Guidelines).

In addition, the PDD submitted for registration, page 31, clearly states the following:

Fugitive methane emissions from coal mining and natural gas production, processing, pipeline, and distribution, and CO₂ emissions from coal transportation are considered as leakage.

Fugitive methane emissions from coal mining operations are calculated using a default emission factor given by the IPCC Guidelines for National Greenhouse Gas Inventories Volume 3, Reference Manual (1996). The IPCC does not give a specific emission factor for coal mining in South Africa, where the coal consumed in Rosslyn Brewery comes from. However, page 1.105 provides a range of estimates for methane emissions from coal mining underground from 10 to 25 m³ of methane per tonne of coal, along with a methane density of 0.67 kg/m³ at 1 atm and 20 °C. An average value of 17.5 m³/t coal (0.0117 tCH₄/t coal) is assumed.

Since measured data on natural gas production, processing and pipeline leakage are not available, standard estimates are used, as suggested in IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual (1996). Table 1-64, p. 1.131, indicates values corresponding to the “Rest of the world”, region where Mozambique and South Africa would fall: 39.59 to 96.00 tonnes of methane per PJ of natural gas for its production and 116.00 to 340.00 tonnes of methane per PJ of natural gas for its processing, pipeline and distribution.

Average values of 70.00 tCH₄/PJ (0.00007 tCH₄/GJ) for natural gas production and 230.00 tCH₄/PJ (0.00023 tCH₄/GJ) for natural gas processing, pipeline and distribution are assumed. Thus, for natural gas production, processing, pipeline and distribution, the methane emission factor considered is 0.0003 tCH₄/GJ of natural gas consumption.

According to the methodology, fugitive methane emissions from the two fuels, coal and natural gas, should be considered in the leakage calculation. As shown above, the procedure required by the methodology regarding leakage from fugitive emissions is strictly applied in the PDD and, consequently, there are no reasons to consider that the calculation is not conservative.

Moreover, taking into account that ACM0009 Version 02 (Table 2, page 9) proposes default emission factors for fugitive CH₄ upstream, these values could be compared with the values considered in the PDD. It is concluded that the fugitive methane emission factors of natural gas and coal considered in the PDD are much more conservative than those proposed in ACM0009. The fugitive methane emission factor from coal mining operations proposed in ACM0009 is 13.4 kg CH₄/t coal, while the one used in the PDD is 11.7 kg CH₄/t coal. On the other hand, the fugitive methane emission factor for natural gas production, processing, pipeline and distribution proposed in ACM0009 is 0.296 kg CH₄/GJ, while the one used in the PDD is 0.300 kg CH₄/GJ. It clearly shows that in the two cases the values considered in the PDD leads to less emission reductions.

3. The PDD has to be updated according to the Validation Report findings.

According to Table 3 of the Final Validation Report, **all** the corrections required by DNV were included in the PDD, and **all** the clarifications and documentation required by DNV were provided before the project was submitted for registration.

For more details, please see Table 3 of the Final Validation Report.

4. As the beer production will increase, the baseline scenario was not clear in terms of which boiler they were expecting to use and it is not clear that the project activity does not increase the capacity of the thermal output during the crediting period. It is not clear how the changes in the specific energy consumption per unit of output has been adjusted for changes in projected capacity utilization. This need to be explained.

The PDD submitted for registration, page 7, states the following:

The boiler room of the industrial facility has seven coal-fired boilers. The boilers #1 to #3 are connected to one common chimney, and the boilers #4 to #7 are connected to a second common chimney. The plant currently operates three to four of the boilers #4 to #7 as required to meet peak steam production. However, according to the projected beer production increase for the next years, in the absence of the project, Rosslyn would have had to use more than four of the existing coal boilers.

The specifications of the current boilers are shown in the table below.

Table 2: Technical characteristics of equipment

Technical characteristics of the boilers #1 to #7	
Manufacturer	John Thompson Afripac mk3
Year of manufacture	1982 (boilers #1 to #3) 1984 (boilers# 4 to #7)
Fuel used	Coal
Capacity	20 tonnes/hour of steam
Primary air fans	Quantity: 2 Motor size: 11 kW; 380 V; 3 phases
Induced air fan	Quantity: 1 Motor size: 55 kW; 380 V; 3 phases
Coal grate drive motors	Quantity: 2 Motor size: 0.55 kW; 380 V; 3 phases
Coal feed valves	Quantity: 2 motorized coal feed valves Motor size: 0.37 kW; 380V; 3 phases

The project is based on fuel switching from coal to natural gas and biogas, and involves the installation of new boilers, which are likely to be sourced from a European country, contributing to technology transfer to South Africa. The capacity of the new boilers will be in the range of 25 to 35 tonnes/hour of steam each. Rosslyn Brewery would initially install three or four new boilers (depending on the size selected) and later would install an additional one as required by projected plant steam requirements, but under no circumstance would the total installed capacity of the boiler room exceed the current capacity of 140 tonnes/hour of steam.

As shown above, there are 7 coal boilers with a capacity of 20 tonnes/hour each, totaling a capacity of 140 tonnes/hour for the boiler room. Following project implementation, initially there will be 4 natural gas boilers of 25 tonnes/hour each or 3 boilers of 35 tonnes/hour each. Later, as required by projected plant steam requirements, there will be a total of 5 boilers of 25 tonnes/hour each or 4 boilers of 35 tonnes/hour each. As a result, following project implementation, the boiler room will have a total capacity of 125 tonnes/hour (5 boilers of 25 tonnes/hour each) or 140 tonnes/hour (4 boilers of 35 tonnes/hour each). Consequently, the PDD submitted for registration clearly shows that the project activity does not increase the capacity of the thermal output during the crediting period.

On the other hand, the PDD shows that, in the baseline scenario, more than four of the seven existing coal boilers would be used. As the capacity of the thermal output will not be increased by the project activity, it is clear that the existing capacity of the boiler room would satisfy the higher steam demand during the crediting period.



Regarding the specific energy consumption per unit of output, the steam generated by the boiler room is used solely for brewing processes: that is to say, brewing, cellars (CIP), and packaging (pasteurizers, bottle washers, crate washer, CIP, etc.). None of it is used for space heating. As there are a number of brewhouses, fermentation & storage vessels, and packaging lines, whenever production requirement drops below the plant's maximum output capacity, a specific brewhouse, and/or packaging line is shut off. Thus, the operating brewhouse(s) and packaging lines will still be operated at full capacity as management makes all efforts to optimize the brewery production efficiency. In effect, plant management would rather operate fewer days per week to produce the required volume of product rather than operate at less than full capacity on the brewhouses and packaging lines it operates. Consequently, the specific steam energy consumption per unit of beer produced remains constant and will remain constant even during the future production increase.

According to the PDD submitted for registration, fuel consumption at the boiler room during the crediting period is estimated according to the annual volumes of beer production foreseen by the company. However, this is only used for the ex-ante calculation of emission reductions. Following project implementation, natural gas and biogas consumption at the boiler room will be monitored in Rosslyn Brewery plant, and the measured values will be used for the ex-post calculation of emission reductions.

We hope that the Board accepts the explanations above and decides not to carry out a review of the request for registration of the Rosslyn Brewery Fuel-Switching Project.

Yours sincerely,

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