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Evaluation of the Results of the Tongonan-1 CO_2 Gas Injection Project, Leyte, Philippines

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ABSTRACT

The Tongonan-1 CO_2 Gas Injection Project aims to reduce gas emissions from the geothermal power station by injecting the gases to the reservoir through mixing with the separated Tongonan brine prior to injection. Silica deposition in the brine line could also be inhibited due to lowering of the brine pH after gas mixing.

The brine has a pH of 6.1 to 6.2 and an SSI of 1.10. Injection of 0.36 to 0.60 TPH of non-condensable gases resulted in a brine pH lowering to 5.2-5.6, with a notable increase in dissolved gases of 20 ppm CO_2 and 5.5 ppm H_2S. Inspection of the test spools showed that deposition of amorphous silica, calcite and anhydrite in the gas - treated brine line was insignificant. Ultrasonic thickness gauging in the injection set-up showed that thinning was insignificant indicating that corrosion was minimal.

Although the tests showed the feasibility of injecting gases to the reservoir, coupled with modifying the brine pH to minimize silica polymerization, conditions during the test were not ideal due to operational constraints. For one, the amount of gas injected was low (0.60 TPH), or only 16% of the amount of waste gases (3.78 TPH) available from one of three turbine units. Also, the brine requirement (598 TPH) to dissolve the injected gases was high, making it difficult to operate the system. These concerns will limit the feasibility of CO_2 injection in industrial applications, especially in fields with a limited amount of brine.

1. INTRODUCTION

The Tongonan-1 CO_2 Gas Injection Project is a pilot test trial aimed at disposing part of the non- condensable gases (NCG) from the Tongonan-1 Geothermal Power Plant back to the geothermal reservoir by mixing the waste NCG into the separated brine prior to injection into the wellbore. The primary objectives are: (1) to demonstrate the technical and economic viability of gas injection back to the reservoir in order to reduce gas emissions from geothermal power stations; and (2) to improve the injectability of silica saturated brines through pH modification upon addition of the gases into the brine.

The project was approved in late 1995 as part of the Global Environmental Facility (GEF) funded projects in order to promote industrial projects with reduced CO_2 emissions to the atmosphere. However, it went through a series of re-design stage particularly due to the declining amount of available brine from the Tongonan-1 sector. The gas compressor was re-sized several times until it was decided to fix the gas compressor size to the minimum amount of brine required for injection. The gas compressor was also designed for use later as additional gas extractor for the Malitbog Bottoming Cycle Plant.

The project was first commissioned in November 10, 2000. The NCG from Tongonan-1 Power Plant Unit No. 3 Gas Extraction System was compressed to elevated pressure and injected to the branchline of injection well 1R8D. However, during the injection process, the wellhead pressure of well 1R8D was fluctuating and very unstable due to the very tight condition of the well. Thus, gas injection was aborted and the test was temporarily suspended to allow the work-over of the injection well. On February 2001, a strong typhoon hit the project site resulting to landslides that damaged part of the brine piping and CO_2 gas injection line. The system was restored completely last December 2001 and sufficient amount of brine from South Sambaloran sector was diverted to Tongonan-1 for use in the gas injection project and provide re-charge to the Tongonan reservoir. In January to end of February 2002, the Gas Injection System was re-commissioned thrice, each encountering operational problems that triggered suspension of gas injection. It was finally continuously operated for 11 days from May 14-24, 2002, until it was decided to finally shutdown the Gas Injection System and end the test trials after encountering again increasing wellhead pressures in well 1R8D that was affecting the operation of the Tongonan-1 Fluid Collection and Recycling System (FCRS).

2. FIELD ARRANGEMENT AND SET-UP

2.1 CO_2 Gas Injection Process Flow

The Tongonan-1 112.5 MW Geothermal Power Plant (TGP-1) is composed of 3 x 37.5 MW Turbine-Generator Units. Each unit has a separate condenser and gas extraction system. After expanding in the turbine, steam will be condensed at the condenser and the non-condensable gases (NCG) will be extracted by the gas extraction system. The TGP-1 gas extraction system consists of two stages of steam gas ejectors (Fig.1). The waste NCG is primarily CO_2 and H_2S and 1.05 kg/s (3.78 TPH) is ejected from Unit #3. At pressure slightly above atmospheric, part of the ejected NCG from Unit #3 second stage drain separator is diverted to the CO_2 gas compressor. The waste gas is then compressed and its pressure increased to about 100 psig before injecting into well 1R8D.

2.2 Gas Compressor Set-Up

The gas compressor used is a Liquid Ring Vacuum Pump (LRVP) that uses a sealing fluid that acts as a piston to compress the gases. This 200 Hp compressor can handle 520 kg/hr (0.52 TPH) of NCG which is 91.4 mole% CO_2. It requires a cooling system that includes a heat exchanger, cooling tower and cooling water pumps (Fig.2). The seal water (38 gpm) compresses the gases and also serves as a coolant absorbing heat from the gases. To avoid flashing of the seal fluid, its temperature is maintained at 27°C through the heat exchanger. Then, 138 gpm of cooling water from the cooling tower will absorb the heat from the seal water. Since the seal fluid comes in contact with the gases, part of it becomes entrained into the gas, thus, a separator is provided at the compressor discharge. In case the gas discharge pressure increases to more than the desired setting, a by-pass valve is provided to relieve excess gas back to the suction line. Conversely, if the discharge pressure falls during injection, the by-pass valve is then closed.

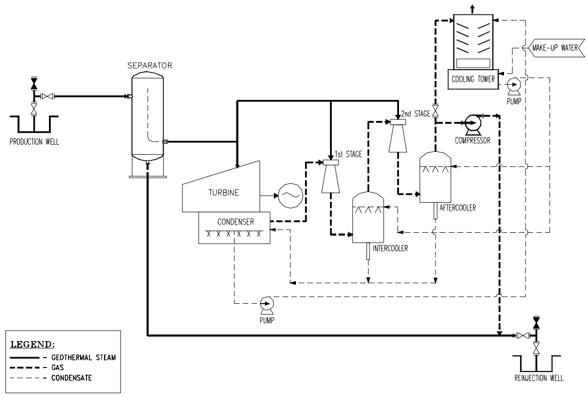

Figure 1: The CO_2 gas injection project process flow diagram.

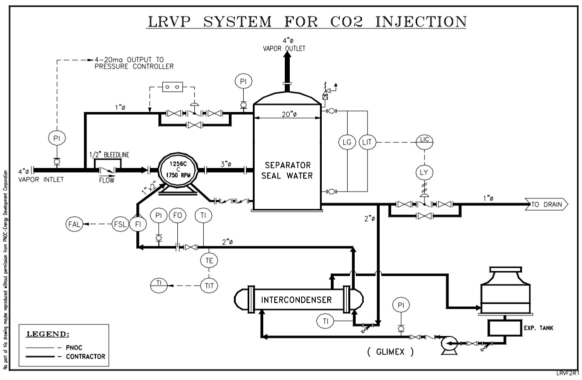

Figure 2: The CO_2 gas injection project gas compressor system.

Figure 3: The CO_2 injection piping set-up near well 1R8D branchline.

2.3 Gas Injection Point and W1R8D Set-Up

Compressed gas at 100 psig is injected into the 10” brine line of well 1R8D (Fig.3). The separated brine from the flash vessels of Tongonan and South Sambaloran is at 165°C and 166 kg/s brine is injected to W1R8D at wellhead pressure of 5.0 kscg (0.50 MPag). At the injection point, brine line pressure is at 0.60 MPag and the compressed gas pressure is maintained at 0.65 MPag. With the 160 kg/s brine flow, the calculated amount of gas (CO_2) necessary to modify brine pH from baseline of 6.1-6.2 to pH 5.0-5.5 is 0.14 kg/sec (0.50 TPH). To evaluate the effectiveness of brine pH modification on preventing silica scaling, deposition spools were installed upstream and downstream of the injection point.

3. RESULTS AND DISCUSSIONS

3.1 Baseline Brine and Gas Chemistry

Shown in Table 1 is the baseline chemistry of the mixed Tongonan-1 (~17 kg/s) and South Sambaloran (149 kg/s) brines injected in well 1R8D. The baseline brine pH calculated at line condition (157^{o}C) is at 6.1-6.2. The brine pH at the actual brine line condition was simulated by back-calculating the brine fluid chemistry, based from the analyzed water and gas chemistry, to the actual line temperature (157^{o}C) and pressure (0.5 MPag). *Watchworks* was used to back-calculate the brine chemistry at line condition. The brine is slightly supersaturated with respect to silica at saturation index of 1.09-1.11. Baseline dissolved gases, particularly CO_2 and H_2S, which were later used to monitor amount of gas dissolved in the brine, were at 32-34 ppm and 1.4-1.9 ppm, respectively. Baseline dissolved iron, also used to monitor corrosion during gas injection, was at 0.4-1.0 ppm.

Table 1. Tongonan baseline brine chemistry.

Parameter	Jan 16, 2002	Jan 24, 2002
pH	6.10	6.20
SiO_2 (ppm)	703	719
Cl (ppm)	9,838	10,001
SSI	1.09 (157^{o}C) Line Temp	1.11 (157^{o}C) Line Temp
H_2S (ppm)	1.91	1.39
CO_2 (ppm)	31.8	34.5
SO_4 (ppm)	28.1	27.0
HCO_3 (ppm)	14.2	18.9
NH_3 (ppm)	0.46	0.71
Fe (ppm)	0.39	1.03

The chemistry of the gas ejected from TGP-1 Unit #3 gas extractor system is shown in Table 2. It is composed mostly of CO_2 and H_2S, at 91.424 and 4.585 mole%, respectively. Of the 1.05 kg/s (3.78 TPH) waste NCG available from Unit #3, about 0.167 kg/s (0.60 TPH), or about 16% maximum was used in the CO_2 gas injection trials. Since the waste gas was extracted from the condenser handling re-circulated cooling water from the cooling towers, the gas composition shows contamination with air (O_2 and N_2).

Table 2. Tongonan power plant Unit #3 ejected gas chemistry.

Parameter	Composition (in mole %)
CO_2	91.424
H_2S	4.585
NH_3	0.856
O_2	0.647
Ar	0.0
N_2	2.434
H_2	0.054
CH_4	0.0
He	0.0

3.2 CO2 Gas Injection Periods

The CO_2 gas injection test trial was re-commenced last January 24, 2002. Three short duration injection attempts were conducted, each aborted by operational problems that required shutdown of the CO_2 gas compressor. It was then shutdown on March 01, 2002 for evaluation and correction of operational problems that were encountered during the initial injection attempts. On May 14, 2002, it was then re-commissioned for a final injection attempt and was able to operate for 11 days without operational problems, until the wellhead pressure of well 1R8D was already increasing from 5.0 to 5.5 MPag (Fig.4) and beginning to affect the water level of the Flash Vessel of the Tongonan-1 Fluid Collection and Disposal System. On May 24, 2002, it was finally decided to shutdown the gas compressor and terminate the test trials. Listed below are the CO_2 gas injection periods and the problems encountered during gas injection:

Test 1 : Jan 24 (1757H) to Jan 29 (1237H) : 4 days 19 hrs

- shutdown due to erratic Level Control Valve in SS#1
- frequent clogging of sampling line to on-line pH set-up

Test 2 : Feb 07 (1500H) to Feb 08 (1255H) : 22 hrs

- shutdown due to cut-out of water supply to compressor (dam maintenance)

Test 3 : Feb 22 (1043H) to Mar 01 (1450H) : 7 days 4 hrs

- shutdown due to problems in gas injection (low gas flow rate, clogging of compressor inlet strainer)
- unreliable on-line pH reading (not getting fresh sample)

Test 4 : May 14 (0700H) to May 24 (2400H) : 10 days 17 hrs

- continuous monitoring of injection and brine parameters
- shutdown due to increasing wellhead pressure in well 1R8D

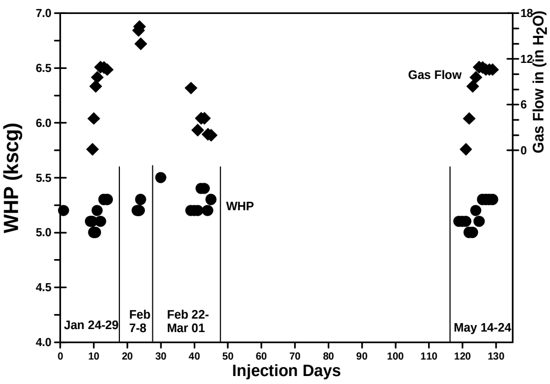

Figure 4: Well 1R8D wellhead pressure versus gas injection flow rate.

3.3 Geochemical Evaluation

3.3.1 Brine Chemistry After Gas Injection

The brine pH, as analyzed in the laboratory (25^{o}C) from collected water samples, ranged from a baseline of 6.5-6.7 to 5.6-5.8 upon gas injection into the line (Fig.5). The analyzed water and gas chemistry was then used to back-calculate the brine pH to the actual line temperature (157^{o}C) and pressure (0.5 MPag) using *Watchworks*. The calculated brine pH at line condition ranged from a baseline of 6.1-6.2 to 5.2-5.6 upon injection of 0.14-0.16 kg/s of compressed NCG into the line (Fig.5). It was in the fourth injection attempt that a consistent brine pH below 5.5 was achieved.

The dissolved gases (CO_2 and H_2S) in the collected water samples are plotted in Figure 6. From a baseline of 32-34 ppm and 1.4-1.9 ppm, for CO_2 and H_2S, respectively, both dissolved gas parameters showed an increase in concentrations upon gas injection into the brine. Dissolved gas levels in the brine after gas injection now ranged from 48-52 ppm and 5.0-7.0 ppm, for CO_2 and H_2S, respectively. This indicates increase in dissolved gases of about 20 ppm CO_2 and 5.5 ppm H_2S. This does not include the injected gas that partitioned into the vapor phase during gas sample collection. Also, there were indications that part of the gas injected was not thoroughly mixed and dissolved in the brine. The indications include the increasing wellhead pressure in well 1R8D after gas injection, possibly resulting from gas pockets in the wellbore. Also, simulation results indicated lower brine pH (4.9-5.1) should have been achieved at the amount of compressed gas injected.

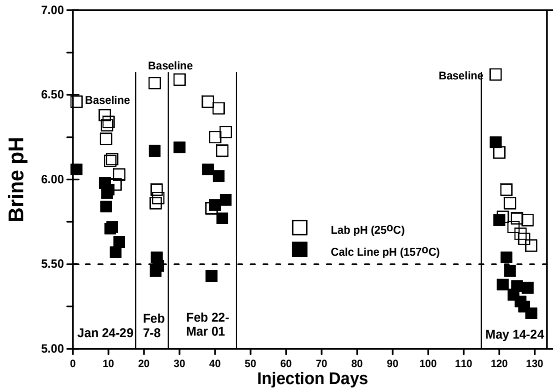

Figure 5: Resulting brine pH after gas injection (lab pH and calculated to line condition).

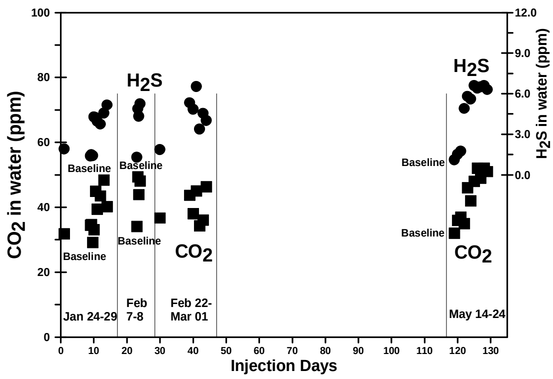

Figure 6: Dissolved gas (CO_2 and H_2S) concentrations after injection.

To evaluate the potential for mineral scale formation, the saturation indices of the scale forming minerals were calculated. Figure 7 (a, b and c) shows the saturation indices of common scales found in the brine lines. For amorphous silica (Fig. 7a), the mixed brine is slightly saturated prior to NCG injection. However, NCG injection to the mixed brine modifies the pH to 3.5-5.0 and this will prevent its precipitation. Lowering the pH reduces the precipitation potential of amorphous silica by one unit. Similar trend can be said for anhydrite (Fig. 7c). Reducing the pH from 6.2 to lower than 5.0, also decreases the precipitation potential of this mineral.

Calcite formation potential was also calculated to evaluate if CO_2 injection to the brine would induce its deposition due to possible excess CO_3^{-2} available. The plot (Fig. 7b) indicates that calcite will not form at the resulting brine pH (3.5-5.0) and at line temperature of 157°C. This is possibly due to the very small amount of CO_2 injected that will not exceed its solubility limit at the resulting line temperature.

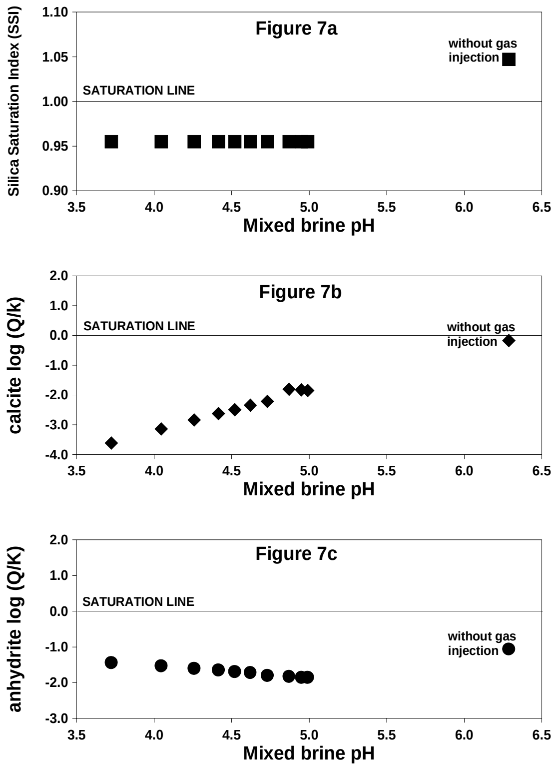

Figure 7: Saturation levels of different species at varied mixed brine pH.

3.3.2 Deposition Spools Documentation

The deposition spools were opened and inspected at the end of the test trials to actually document possible scale formation. Saturation index calculations indicated that amorphous silica, calcite and anhydrite are less likely to form. Its polymerization will be prevented by NCG injection into the brine. Upon inspection of the deposition spools, scale deposits of around 1-3 mm were noted in both the upstream and downstream deposition spools from gas injection point. These were scrapped and collected for petrologic analysis. Results shown in Table 3 indicate that the samples collected in the upstream deposition spool (without gas injection) were mostly amorphous silica, while those samples collected in the downstream deposition spool (with gas injection) were mostly corrosion products (i.e. iron oxides and sulfides). This demonstrates that gas injection to modify brine pH to 5.2-5.6 was able to prevent silica deposition in the downstream deposition spools. Calcite and anhydrite as predicted were not observed. The corrosion products collected in the downstream deposition spools may have come from the corrosion products (solids in steam) captured by the wash brine in the steam washing being conducted upstream in Tongonan-1 Separator Station #1.

3.3.3 Corrosion and UT Measurements

The potential for corrosion was evaluated primarily due to the fact that compressed gases were injected into the line and brine pH was being reduced to 5.0-5.5 levels. Dissolved iron was monitored during the injection trials and concentrations show that the dissolved iron in the brine was maintained within baseline of less than 1.0 ppm throughout the test (Fig.8). This indicates that minimal iron was being reacted or corroded in the pipeline.

Also, Ultrasonic Thickness (UT) gauging was conducted in the deposition spools and well 1R8D branchline, prior and after the conduct of the gas injection tests. Results show that no change in pipe thickness was observed during the duration of the CO_2 Gas Injection tests. This validated that pipe thinning was insignificant indicating that corrosion was negligible at brine pH of 5.2-5.6.

Table 3. Petrologic analyses of samples collected in the deposition spools.

Location	Petro Analyses
CO_2 Upstream Deposition Spool #1	Sample is made up of banded amorphous silica and corrosion products. 80% Amorphous silica – gray to brown, isotropic to slightly anisotropic, porous, dendritic, multilayered bands associated with corrosion products and embedded with impurities; average thickness of bands = ~1.5 mm 15% Corrosion products – hematized bands associated with silica; average thickness of bands = ~0.25 mm
CO_2 Upstream Deposition Spool #2	Loose fragments of corrosion products associated with amorphous clay and occasionally thinly enveloped by amorphous silica. 90% Corrosion products – hematized, banded fragments intimately associated with amorphous clay; some bands very thinly enveloped by silica; average size of fragments = ~0.5 mm 5% Amorphous silica – colorless to gray, isotropic to slightly anisotropic, thin lining on most corrosion product fragments; ave thickness of lining = ~0.04 mm 5% Amorphous clay – greenish to brownish masses intimately associated with corrosion products
CO_2 Downstream Deposition Spool #1	Sample is composed mostly of banded corrosion products (iron oxides and sulfides). 76% Pyrrhotite – porous bands associated with magnetite and impurities; some assuming dendritic patterns; ave thickness of bands = ~0.3 mm 20% Magnetite – porous bands associated with pyrrhotite; ave thickness of bands = ~0.5 mm 3% Impurities – fragments of chalcopyrite, chalcocite, magnetite and pyrite all associated with pyrrhotite bands; average size of framents = ~0.04 mm 1% Amorphous silica – one multilayered, isotropic to slightly anisotropic, grayish fragment embedded with opaque dendrites (pyrrhotite?)
CO_2 Downstream Deposition Spool #2	Sample is wholly composed of banded corrosion products. 75% Pyrrhotite – porous bands (ave thickness = ~0.5 mm) associated with magnetite; dendritic patterns observed 25% Magnetite – strongly hematized bands associated with pyrrhotite; ave thickness of bands = ~1.0 mm

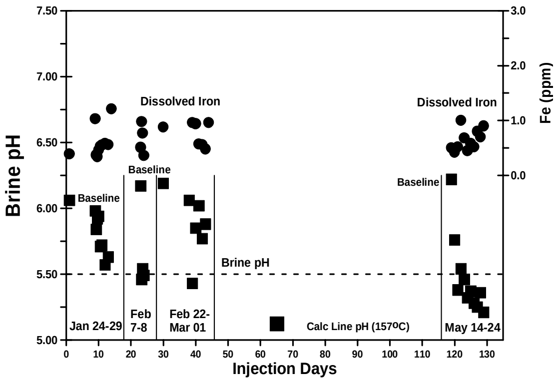

Figure 8: Dissolved iron versus brine pH (at line condition).

4. COST EVALUATION

4.1 Gas and Brine Flowrates

Based on the results of the pilot CO_2 Gas Injection test and the cost of the pilot project, the following were determined:

Brine To Gas Ratio = 9,992.39 kg/ m^3 of gas

Operating Cost Factor= 50.32 US $ per cubic meter of gas injected

Capital Cost Factor= 450.38 US $ per cubic meter of gas injected

Applying these data for non-Leyte Production Fields, the estimated total investment versus % Gas Abatement of the total gas produced from power plant is shown in Figure 9 for existing PNOC-EDC production fields (at various % NCG levels in steam supply).

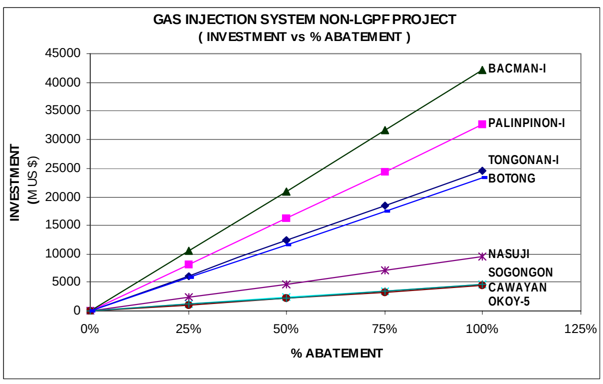

Figure 9: Investment vs. % Gas Abatement for existing PNOC-EDC producing fields.

4.2 Economic Viability of Gas Injection as Gas Abatement for Geothermal Power Plants

For purposes of comparison between a conventional chemical redox process versus gas injection in abating the H_2S gas from geothermal power stations, we calculated the total investment cost of the Tongonan-1 CO_2 Gas Injection pilot plant as shown in Table

Comparing this Budgetary Cost estimate of the Gas Injection method with the Conventional Chemical Redox Process by Lo-Cat, the results for existing PNOC-EDC producing field are shown in Table 5.

Table 4. Investment cost for Tongonan-1 CO_2 injection project.

Capital Cost:	**US $**
Gas Compressor	180,674
Piping and Valves	315,812
Electrical/ Instrumentation	147,673
Structural	2,280
Total	**646,439.00**
Operating Cost:	
Annual operating cost	72,221
Net Present Value	466.841
Term: 25 years	
Total Investment:	**1,113,280.00**
Note: 1. Peso exchange rate = US$ 1= PHP 50 2. Interest Rate = 15 % 3. Life = 25 years 4. Brine to Gas Ratio = 9,992.39 kg/m^3	

Table 5. Total investment in Redox method vs. Gas injection as gas abatement in PNOC-EDC plants.

Project Location	**Total Investment, MM US $**		
	Redox Process	Gas *Injection*	% *Variance*
SNGPF	85.55	51.16	40 %
BGPF	66.65	28.03	58 %

This cost comparison has shown economic advantage on using the Gas Injection Method than the Conventional Redox Process Method in disposing waste NCG. The Operating Cost of the Gas Injection would be cheaper and also less manpower would be required compared with the Redox Process Method. On the technical viability of the CO_2 Gas Injection Project, there is a difficulty in the attainment of the liquid to gas flow rates. The brine requirement in order to safely inject the total waste gas produced is high and may not be attainable in the existing PNOC-EDC geothermal steam fields. On the average, the brine produce from the existing PNOC-EDC geothermal production fields range only from 150 to 700 kg/s. Most of the geothermal steam fields have also shown significant field drawdown and declining brine flows after years of exploitation.

For Philippine geothermal production fields other than in Leyte, the brine required in the gas injection system versus % Gas Abatement is shown in Figure 10. The figures shown in the plots reveal that for a 25 % and above Gas Abatement, the brine requirement is not attainable. However, below 25 % Gas Abatement and at NCG range from 0.5 % to 1.5 % the brine requirement maybe attainable.

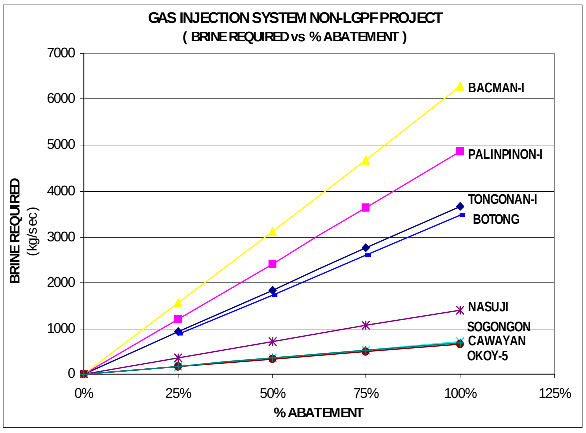

Figure 10: Brine requirement vs. Gas abatement for existing PNOC-EDC producing fields.

4.3 CO_2 Emission Reduction Credits

The potential CO_2 reduction credits that can be traded in the carbon market is calculated for the Tongonan-1 power plant at full gas injection for the equivalent 112.5 MW generation. The results for 7 years crediting period is summarized in Table 6.

Direct Emission (annual):

3 turbine units x 3.78 ton/hr gas x 91.424% CO_2 in the gas x 0.7 Load Factor x 8760 hr/yr = 63,573 tons CO_2

Indirect Emission (annual):

112.5 MW x 8760 hr/yr x 0.7 Load Factor x 0.61 ton CO_2/MWh (Emission Factor) = 420,809 tons CO_2 eq.

Table 6. Summary of emission reduction credits.

Period	CO_2 Reduction (tons)	Credits US$	Credits PHP
Annual	484,382	1,453,146	72,657,300
7 years crediting period	3,390,674	10,172,022	508,601,100

Note:
(1) Calculated at CER current price of US $3.00 (has potential to increase)
(2) US$ 1 = PHP 50

5. SUMMARY

The Tongonan-1 CO_2 Gas Injection Project completed its field trials last May 24, 2002. The testing accomplished intermittent injection of waste gas from NPC power plant to well 1R8D and proved successful continuous injection for eleven days. The brine pH at line condition was successfully modified to pH of 5.2–5.6 from a baseline of around 6.1-6.2. The project proved that gas injection is feasible at low gas and brine flow, however, it will not substantially reduce waste gas emission from geothermal power stations due to large brine flow requirements for total waste gas injection. Nevertheless, cost evaluation of waste gas injection versus other method of gas abatement (Lo Cat) concluded that it would be 40-60% lower in investment cost at low gas disposal flow.

The Gas Injection method is simple but may be difficult to operate and maintain as demonstrated during the testing. The observed decline in brine flows in the existing PNOC-EDC Geothermal Production Fields after years of exploitation resulted in the limited brine available for gas injection. This characteristic makes sizing of the equipment difficult to predict. This will limit the applicability of Gas Injection System for the Total Gas Abatement in a Geothermal Power Plant. However, Partial Gas Injections to reduce scaling along the cross-country brine line and re-injection well maybe attainable.

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