Petroleum and Coal

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Mono Ethylene Glycol Optimization and Recovery in Egyptian Deep Marine Gas Plant

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Received March 10, 2023; Accepted July 3, 2023

Abstract

This research will look at hydrate inhibition, mainly by mono-ethylene-glycol and how this differently affects other areas, and how recovered again. The aim of this study will highlight the current mono-ethylene-glycol requirement in deep marine gas plant, the wells that still require mono-ethylene-glycol, and the others that do not, along with the volumes needed for inhibition. This search will also provide information of the future requirement for mono-ethylene-glycol in deep marine gas plant, and what options are available to reduce the quantity of MEG required to be injected safely without any impact on production. As it was injected about 14 cubic meter of mono ethylene glycol into the wells, the potential saving from this optimization by using HYSIS program is 3.65 Million dollar / year. Due to the rapidly decline on most wells and increasing aqueous received, the concentration of MEG in aqueous received from wells was lower than the on spec condition of existing MEG recovery unit. So, different scenarios were proposed starting from minimum concentration of MEG, required to operate MEG recovery unit and ending with the maximum concentration. HYSYS simulation program was used to estimate the saved cost of operating the MEG recovery unit at minimum and maximum concentrations which are 35,377,688 $ / year and 409,188,219 $ / year respectively.

Keywords: *Natural gas hydrates; Hydrate inhibition; MEG optimization; MEG recovery unit; HYSYS.*

1. Introduction

In the natural gas industry, hydrate formation is a well-known problem, which requires close attention and follow-up. It may cause slower gas flow and finally block the gas pipe flow and stop the production. It may also damage equipment and create safety issues and extra cost [1]. To prevent this from occurring hydrate inhibitors are used. This is the most common way of preventing hydrate formation. Hydrate inhibitor injects into the well stream and travels with the gas and condensate to the production facility where mixture separated and regeneration [2] this will take a closer look at the natural gas hydrate inhibitor MEG and the hydrate inhibition process. It will illustrate the regeneration of MEG and clarify losses that occur through this process. Finally, it will describe some of the environmental impact and look at what the future holds [2-3].

A natural gas hydrate is a crystalline solid which resembles ice physical form, where the water acts like a cage trapping the guest-molecule inside. Such a trapped guest-molecule is shown in Figure 1 where the cage is the red structure. The guest molecules are often gas or liquid, and can cause severe blockages and damage in gas pipelines. This can lead to slower gas streams, stops in production and great economical losses [4-6].

Hydrates form under certain conditions typically found in gas pipelines, and can cause severe problems in the gas industry. A generic hydrate formation curve is shown in Figure 2 It shows how hydrate formation is dependent on temperature and pressure. To the right of the curve no hydrates will be present; for natural gas. This is usually over 20°C and below 10 bars, curves need, however to be developed based upon gas properties.

Relevant for the actual gas along with possible free water content. There must also be lower molecular weight gas molecules present (methane, ethane, propane, isobutene, CO_2, H_2S). The figure shows a pipeline section starting at the wellhead where the gas by flowing up to the surface cools down and moves into the hydrate formation zone. At the same time the pressure drops and temperature rises which moves the gas out of the hydrate formation area again [7-8].

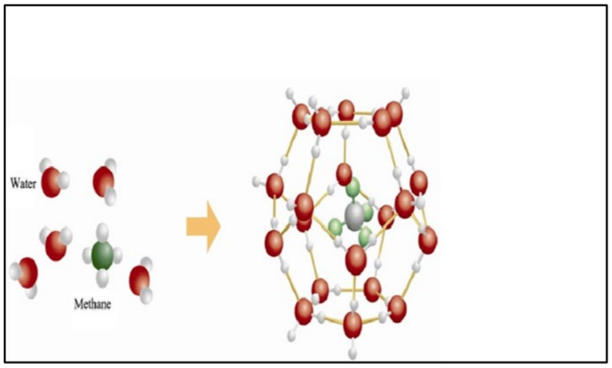

Figure 1. Gas hydrate formation

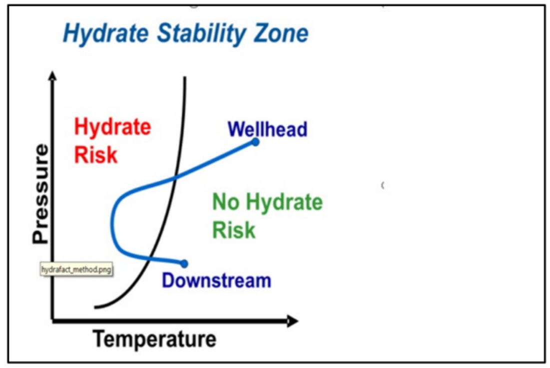

Figure 2. Area for hydrate formation

2. Deep marine gas plant current and optimization

2.1. Historical of gas production

Existing plant consists of separation, compression and dehydration then the de-hydrated gas pass to the national grid via the gas metering station. Separation stages to remove the water and condensate and these process consist of slug catchers and high-pressure separators. Due to the low arrival pressure of the natural gas feed to the plant, gas compressors are used to increase the pressure from 17.0 bar to 83.0 bar via two stages of compressors, main compressor increase the pressure from 17.0 bar up to 56.0 bar and then the booster compressor increase the pressure from 56.0 bar up to 83.0 bar. After that, the water disposal from separation concentrated with high percentage of MEG coming from the wells.

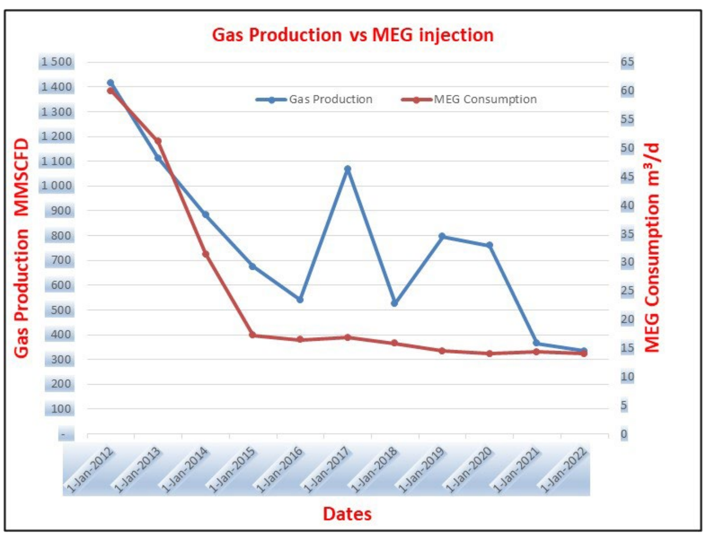

Figure 3. Actual case of deep marine gas plant MEG reduction

In this research optimum quantity of MEG had been determined and simulated by using (HYSYS) simulation program and followed by economic study using (HYSYS) to investigate the best method to recover the MEG by using existing MEG recovery unit. This deep marine gas plant from the biggest company of production natural gas which reach on 2006 to 2100 MMSCFD, but due to reservoir conditions changing rapidly from most of wells the gas reduced to now approximately 300 MMSCFD, as show in Figure 3.During this period, the gas decreased and increased several time according to new discovery of new fields. Now the current production is approximately 300 MMSCFD and total MEG injection is 14 cubic meter per day.

2.2. Current deep marine gas plant MEG requirement

The MEG injected into Deep Marine Gas Plant is approximately 14 m^3/d. as showing in Table 1 below provides an approximate volume of MEG being injected into each of the three systems, Field -1, Field-2 and Field-3. The table also provides data on the calculated volume of chemical mixture (MEG/CI) sitting in the MEG lines and the time it would take at current injection rates for any mixture to reach the injection points from onshore.

Table 1. Current MEG data in deep marine gas plant

MEG System	Approx. injection rate (m^3/day)	Calculated volume occupied in MEG system (m^3) (Total) From simulation	Calculated volume occupied in MEG system (m^3) (based on flowing wells only) From simulation	Time for new mix fluid to reach injection point *(@ current injection rate)
Field -1	1.3	913	826	635 days
Field -2	6.0	1201	1139	190 days
Field -3	6.7	910	812	121 days

2.3. MEG optimization

The majority of Deep Marine Gas plant wells do not require MEG for hydrate inhibition due to unexpected shut-in of wells and natural decline in reservoir conditions. Today MEG is being injected mainly as a carrier for corrosion inhibitor for the majority of wells as CI cannot be injected into the pipeline system any other way in deep marine gas plant. This research will be highlight on the current MEG requirement in deep marine gas plant, the wells that still require MEG, and the ones that do not, along with the volumes needed for inhibition. This research will also provide info on the future requirement for MEG in deep marine gas plant and what options are available to reduce the volumes injected safely without impacting production.

2.4. Future MEG requirement

2.4.1. Field -1

MEG in this field is currently injected by pressurizing the system to 75 bara at the Subsea distribution assembly from onshore and allowing the MEG to disperse into the well flow lines via the glycol control unit' which are set at minimum. When the pressure drops to 70 bara the system is re-packed to 75 bara, on average it takes about 5 days for the pressure to drop from 75 to 70 bara, with average MEG injected in this period around 6.5m^3, equating to about 1.3 m^3/d. At current injection rate of 1.3 m^3/d, and this quantities was injected as a carrier for corrosion inhibitor (CI).

Although in house calculations from simulation based on forecast data with composition, dada of each well show MEG is still required at this time. The salt content has not been taken into account, as no software in operations is available to do this calculation. Salt helps further inhibit the fluid from hydrates.

To prove salt helps inhibit the fluid against hydrates, a live test was carried out on well -54, the one well flow line calculations show MEG is required for hydrate inhibition. The glycol control unit was reduced to minimum setting and flow line conditions monitored for over a week. No increase in pressure drop along the flow line was seen to occur, meaning MEG is not required for this well flow line at today's condition, thus not required for future.

2.4.2 Field -2

Today, 6 wells (well-17, well-49, well-51, well-57, well-59 and well-60) require MEG injection for hydrate inhibition, for these six wells calculation were carried out using simulation program based on forecast data with composition dada of each well without salt show well-51 will not require MEG injection after 190 days (the time it would take any fluid to reach the injection point at current injection rate) as the future operating condition is shown to be outside of the hydrate curve.

Table 2 shows the wells in Field-2 still requiring MEG for hydrate inhibition, and the approximate period when MEG will no longer be required without accounting for salts.

Table 2. Approximate MEG required in Field-2

Well	Current MEG requirement, (m^3/day)	After 6 months (2023)	After 1 year (2024)
Well-17	0.5	Yes	Yes
Well-49	0.5	Yes	Yes
Well-51	0.1	No	No
Well-57	2	Yes	Yes
Well-59	1	Yes	Yes
Well-60	2	Yes	Yes

MEG with CI is continuously being injected into Field-2 at a rate of approximately 6.0 m^3/d without having to pack the system up .To prove the concept of salt helping inhibit, well-51 Glycol control unit has been reduced to minimum setting as a trial. The result of monitoring for over a week show no change to the flow line conditions, meaning this well flow line no longer requires MEG for hydrate inhibition as shown in Figure 4 the well out of hydrate zone. Another trial for another well (well 59) the results show the well still on hydrate zone as shown in Figure 5.

2.4.3. Field -3

MEG is required for 7 well flow lines currently in the Field-3 system. Calculations from simulation based on forecast data with composition dada of each well without salt show in 121 days (the time it would take any fluid to reach the injection point at current injection rate), this will drop to 6 wells, as Well-37 will not require any MEG. Live trials on Well-37 have been conducted to prove salt helps inhibit. Over a week of monitoring, no change in flow line conditions were seen, meaning Well-37 no longer requires MEG for hydrate inhibition at today's condition as shown in Figure 6.

Another trail carried out for well-24 the results shown the well in hydrate zone as shown in Figure 7 .Trials will be carried out for the remainder of Field-3 wells in Table 3 in the coming period to determine if they require MEG or not.

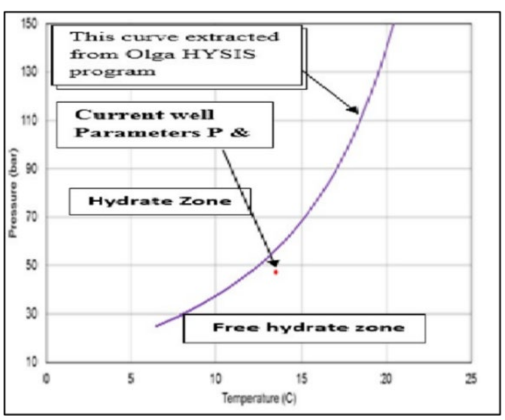

Figure 4. Hydrate curve for Well-51 free hydrate zone

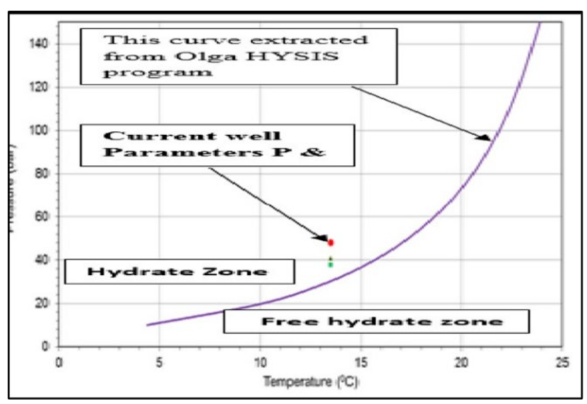

Figure 5. Hydrate curve for Well 59 inside hydrate zone

Table 3. Approximate required in Field-3 Wells

Well	Current MEG requirement, (m^3/day)	After 6 months (2023)	After 1 year (2024)
Well-24	1	Yes	Yes
Well-26	1	Yes	No
Well-27	0.5	Yes	No
Well-35	1	Yes	Yes
Well-37	0.1	No	No
Well-45	1	Yes	Yes
Well-61	**2.2**	**Yes**	**Yes**

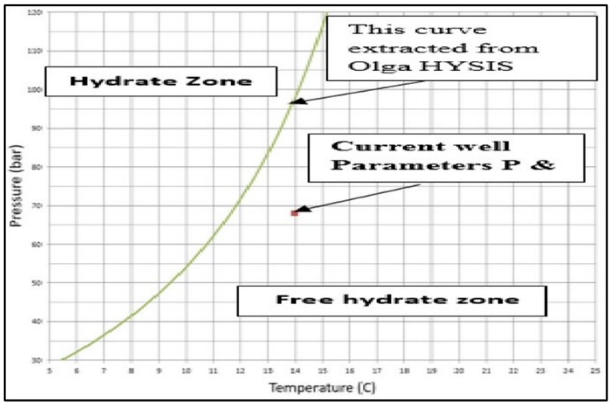

Figure 6. Hydrate curve for Well 37 free hydrate zone

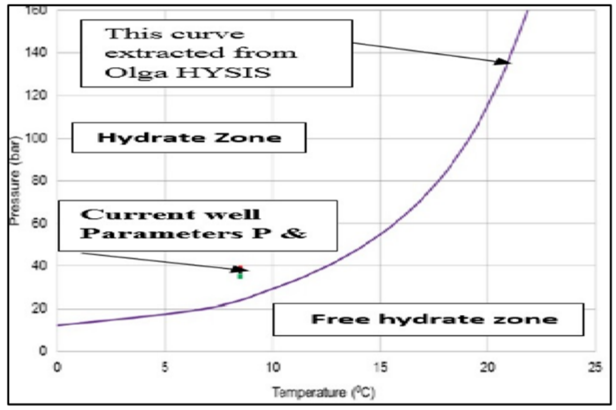

Figure 7. Hydrate curve for Well 24 inside hydrate zone.

2.5. Optimum MEG injection on deep marine gas plant

Based on the expected results of the simulation program, and because of low pressure rate of reservoir wells, the amount of water associated with gas production increased, as shown in the Figure 8 and the injection MEG was reduced to approximately 6 cubic meters for all wells as shown in Figure 9. The optimum percentage not effect on the production, also does not effect of using MEG as a carrier of corrosion. From simulation and actual trial done in producing well injections can be reduced in each field as the following:-
total MEG injection for all wells to 6.3 m^3/d.
Filed -1 MEG Injection can be reduced to 0.8 m^3 /d
Filed -2 MEG Injection can be reduced to 3.9 m^3 /d
Filed -3 MEG Injection ca be reduced to 1.4 m3 /d

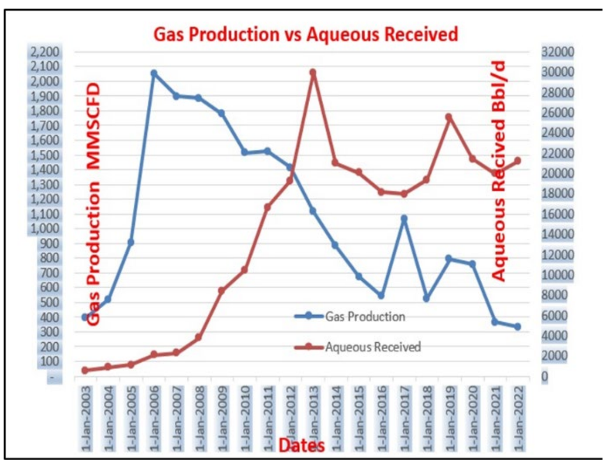

Figure 8. Gas production vs aqueous received

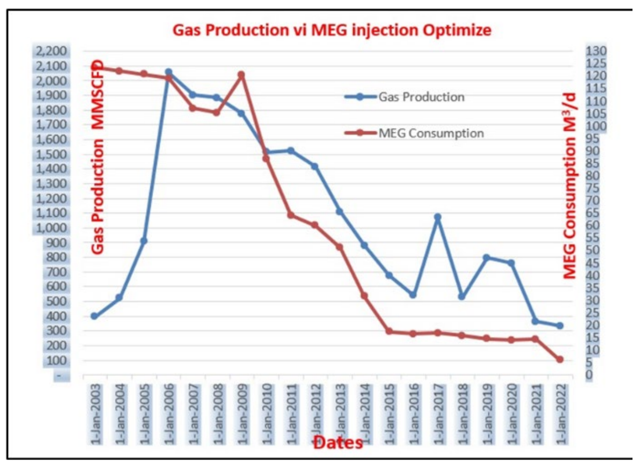

Figure 9. Gas production vs MEG injection

3. Cost estimation

3.1. Operating cost calculation for the fuel

MEG recovery units consume 1 MMSCFD of natural gas via one day which equal 365 MMSCFD in one year, cost of one MM BTU is 8.0 dollars [9].
Fuel gas cost = (365,000,000*1070*8) / 1,000,000 = 3,124,400 $ per year;
where: 1070 is the BTU per cubic feet of the natural gas; 8 $ is the price of MMBTU of natural gas.

3.2. Maintenance and spare parts cost

Maintenance cost, spare parts and material used for rehabilitation and operating of the MRU are around 3,500,000 $/ year. This figure resulted from data obtained from suppliers and manufacturers. Total cost for fuel and spare parts: Cost = 3,124,400+3,500,000 = 6,624,400 $ per one year. Total maintenance manpower who worked to put MRU unit again in service was 7000 Man-Hours. Minimum manpower required to operate the MEG unit as the following member as showing in Table 4

Table 4. Manpower required

	Personnel job definition	Required manpower
A	Production engineer	1
B	Panel operator	1
C	Field operators	2

These 4 persons are essential per each shift, which accordingly means 16 persons (8 persons Day / Night and their back to back) should be excluded from shift man power to keep unit running properly for 24 hrs all year.

Total required manpower =3840 man-hours= 4*2*24*2.5*365 =175200$.

where: average price for one hours is 2.5 $; 365 (one year) 24 (one day) 2 (two shift day and night); 4 (4 persons) minimum manpower. Cost of manpower approximately is 175,200 $ per year.

Total operating cost = 6,624,400+175,200 = 6,799,600 $ per year [10-12].

3.3. Cost estimation for minimum concentration

From HYSIS: simulation program version 12.1 [16]

- Total feed 3242 m^3/d with average MEG concentration from 4.52 %;
- Total recovered MEG quantity 124.5 m^3/d.

124.5 m^3 of MEG is provided with concentration 85% MEG i.e. 130.5 tons of pure MEG.

- One cubic meter = 1.0483017951 tone;
- The price of 1 ton of pure MEG referenced to last MEG tender is 900 $;
- Total Recovered MEG is 130.5 tons * 900 ($) = 0 .117462 MM$;
- Gross profit is 117462.216*365 = 42,873,708 $ per year.

Saved cost of disposing 130.5 m^3 of aqueous to Green Valley Oil Service Company which responsible for disposal and process all aqueous from wells.

Net Profit

- Total operating cost for MEG recovery unit = fuel gas cost + manpower cost + Maintenance and spare parts cost = 3,124,400 +175200 +3,500,000 = 6,799,600 $.
- Net saved cost= gross saved cost- Operating [13-15]
- Net saved cost= 42,873,708 - 6,799,600 = 36,074,108$.

3.3.1. Cost of delivery aqueous concentrated with MEG

Note that this amount of water is disposed of without benefit from it through service companies with cost, So is calculate only cost of transportation as benefit back to sister company as the following:

- Total aqueous received per day 2000 bpd about 318 m^3;
- The price of one cubic meter transferred is 6 USD;
- The total price per day is 6*318 =1908 USD per day;
- The total price per year 1908*365 = 696420 $ /year;

Net saved =36074108-696420 =35377688 $ /year.

4. Simulation scenarios proposed

Different scenarios were proposed starting from minimum concentration of MEG, required to operate MRU and ending with the maximum concentration of MEG which MRU withstand. By using HYSYS simulation program version 12.1, [16] and adding another stream from sister companies. The inlet, outlet and estimated net saved costs are summarized in Table 5.

Table 5. the proposed scenarios

MEG concentration %	Inlet feed m^3/d	Outlet feed m^3/d	Net saved cost $ /year
4.52	3242	124.5	35,377,688
40	3046	1064	358,910,616
50	3027	1160	391,969,865
60	3006	1210	409,188,219

5. Conclusions

Optimize the quantities of mono ethylene glycol (MEG) injection into deep marine wells after gas reduction safely without any losses on production and causing shutting of wells because hydrate. By using HYSIS simulation Program version 12.1 and running MRU with different concentrations of MEG starting from minimum value which unit can be operated and ending with the maximum value which existing MRU can withstand. The net saved cost around 35,377,688$ /year and 409,188,219 $. /year with minimum and maximum MEG concentration respectively. This increase the profits as the following:

- Maximize company profits by reduction of purchased fresh MEG, which is necessary for the daily MEG injection to keep all wells away from hydrate region.
- Achieving stability for the heating medium loop, which is necessary to keep hot stabilization of existing plant at required temperatures.
- Reduce amount of disposed aqueous with high MEG concentration.

Nomenclature & Abbreviations

CI	*Corrosion inhibitor*
MMSCFD	*Million standard cubic feet per day*
MEG	*Mono ethylene glycol*
MRU	*MEG Recovery unit*
m^3/d	*Cubic meter per day*
USD	*United State dollar*

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