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Optimal and Coordinated Functioning of Oil and Gas Wells

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Abstract: Typical production objectives in the lift gas assisted oil wells include stable and optimal production that meets demands on oil and gas. The attainment of these objectives in a typical production facility involving depletion of oil and gas, from a diversity of reservoirs that have different pressures, compositions, gas to oil ratios and natural flows. The objectives are also bound by constraints on compression and its costs, specifications on the export gas for pressure, volume and composition as per different customer end demands. While optimal allocation of the limited lift gas is desirable, an enterprise-wide, coordinated view of the production from the diverse gas or oil reservoirs would facilitate greater flexibility towards meeting the customer demands in an optimal manner. In this paper, we consider a smaller prototype of a production facility involving a low pressure, medium pressure and high pressure gas reservoirs, which also exhibit varying compositions, gas to oil ratios and natural flows. We propose a formulation that promotes co-ordination between these diverse reservoirs so as to honor the constraints on export gas or liquid pressures, compositions or natural flows. The results have been verified on a prototype of a three well production facility using a simulation model adapted from Jahanshahi *et al*. (2012).

Keywords: Optimization, Lift Gas Assisted Oil Wells, Co-ordinated production, Upstream oil and gas

1. INTRODUCTION

In oil and gas production, as reservoir pressures decline over time, oil and gas fields lose the ability to produce oil naturally. Artificial lift techniques are required to enhance oil and gas production. Gas lift is one such mechanism, in which formation gas from the wells is compressed and injected at the bottom of well tubing. This reduces the density of the multiphase mixture in the well, creating a favourable pressure distribution for the oil to flow from the reservoir into the wells.

However, the use of lift gas causes fluctuations in the oil flow rate from a well resulting in well instability which needs to be controlled to prevent damage to downstream equipments. Each well shows a typical behaviour of oil output with the injected flow rate, which is characterized by the Gas Lift Performance Curve (GLPC). The lift gas available is limited due to capacity constraints and hence, must be used judiciously. Usually, the formation gas leaving the wells is compressed, recycled and used as lift gas. The power available offshore for this compression may be limited too. There are also gas nominations for pressure, composition and demand volumes on the formation gas exported from the field. For example, the reservoir contains oil, water, methane and carbon dioxide gas and the carbon-dioxide content in the export gas must be checked depending on customers' requirements. These issues mentioned above can be addressed by using optimization tools to allocate the available lift gas to different wells and to meet the various production and customer-side constraints.

There has been significant research in the area of optimal allocation of lift gas to wells. Alarcon *et al*. (2007) implement a nonlinear optimization technique to find the optimal gas injection rates to a set of twelve wells. Kanu *et al*. (1981) propose an economical approach for allocation of both limited and unlimited supply of lift gas. Nishikiori *et al.* (1989) use a quasi-newton non- linear optimization technique coupled with gradient projection method. The method is capable of accommodating restrictions on gas injection rates. Foss *et al*. (2009) present a method for real-time optimal allocation of gas from an external source wherein they employ a decentralized structure to improve computational efficiency and transparency of a solution.

The aforementioned approaches solve for optimal allocation of gas constrained by limited lift-gas availability or by using lift gas from an external source. In lift-gas assisted oil fields, there are constraints on the maximum compression power that need to honored. Furthermore, an associated gas reserve is posed with additional constraints related to priorities on gas versus oil export, minimum liquid or gas production, especially for an on-site refinery or gas processing complex.

†*Based on M.Tech. thesis work at IIT Bombay (2013)*

Enterprise-wide decision making requires that reserves exhibiting a diversity of behaviour related to pressures, natural flows, compositions and gas to oil ratios be operated in a coordinated manner with due consideration given to the final export gas pressure, quality and flow rate. When such decisions are made at an enterprise-wide level, opportunities such as blending of gas from different wells offer better ways of depleting the reservoirs while meeting specifications on the gas nominations. Such co-ordinated decisions could also help align with a longer term strategy of preserving relatively favourable gas reserves. For example, specifications on heating value and landing pressures are different when an enterprise sends export gas to a LNG processing facility than when it sends export gas to a fertilizer complex. These additional constraints may compel the need to explore possibilities to meet end-customer specifications through blending. In this paper, we propose a realistic enterprise-wide formulation of the optimization problem that helps to explore these opportunities. The proposed algorithm has been evaluated on a prototype of three well production facility using a simulation model adopted from Jahanshahi *et al*. (2012).

The rest of the paper is structured as follows. In Section 2, we discuss the schematic of an oil well-pad, the phenomenon of well instability and the significance of gas lift performance curves. In the next section, we formulate the objective function for optimization along with constraints. Thereafter, we present the simulation results for both oil wells and gas wells in Section 4.

2. OIL AND GAS PRODUCTION

There are in general multiple wells in an oil field. The multiphase mixture leaving these wells mixes in different manifolds or a single manifold from where it is directed towards the separation unit. Figure 1 shows a prototype of an oil or gas well production facility having three platforms with representative wells belonging to low pressure, medium pressure and high pressure reservoirs. The three wells considered are assumed to have different gas to oil ratios whose values are provided in Table 1.The multiphase mixture from the wells is blended together in the manifold as shown. For simplicity, only a single manifold is assumed in our work; however, the formulation proposed here can be generalized to the case where the facility has different manifolds to accommodate and export gas flows, for example with significantly differing sour gas content. The two phase mixture is sent to two separators wherein a reduction in pressure causes the dissolved gases to separate out. The gas is then compressed in two stages and sent to a drying unit. Water needs to be removed to avoid the risk of condensation in gas pipelines. The dried gas is then compressed again and used either for lift-purposes or for export from the field. The manifold pressure is externally controlled to be lower than the pressures of the incoming streams to avoid backflow in the pipelines.

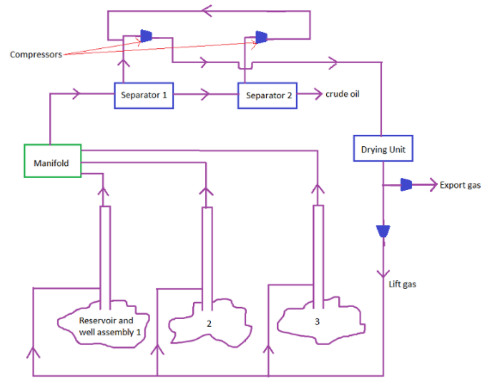

Figure 1. Prototype of an oil well-pad

The schematic of an artificially-assisted oil well is shown in Figure 2. The gas injection choke opening (denoted by *g*) controls the lift gas injection flow rate into the well casing. The production choke opening (denoted by *u*) controls the flow rate of oil and gas leaving the well. As discussed earlier, the oil flow from a well depends on the lift gas injection rate. The Gas Lift Performance Curve is non-linear in general and unique to each well. The oil outflow increases on increasing the lift-gas inflow up to a certain point called 'Technical Optimum' beyond which the oil outflow drops gradually. For any well, more oil would be produced on increasing the production choke opening and hence, the GLPC shifts upwards on increasing the value of *u*. As shown by Mukhtyar *et al. (2013)*, improved opportunities for optimization exist through coordinated manipulation of *u* and g. Hence, both *u* and *g* of each of the wells are taken as the decision variables in the optimization formulation proposed here. Furthermore, the GLPC being a steady state characterization operates on time scales slower than the well instability. These different time scales are merged (as shown in Mukhtyar *et al*. (2013) by formulating an objective function which maximizes production and at the same time eliminates well instability.

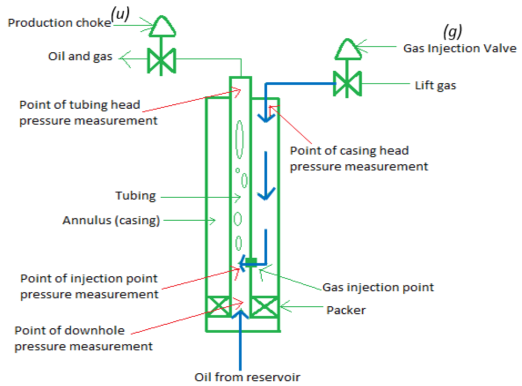

Figure 2. Schematic of a lift-gas assisted oil well

As discussed earlier, well instability results in decreased average production and hence needs to be controlled. The instability is characterized by an instability index (as shown in Mukhtyar *et al. (2013)*) which is the mean squared sum of deviations from the mean flow over a finite time period.

$$I = \frac{\sum_{j=1}^{n}\left(w_{j,o} - \overline{w_o}\right)^2}{n} \qquad (1)$$

where, $w_{j,o}$ is the oil production at the j^{th} instant, $\overline{w_o}$ is the mean oil production over the time horizon over which the index is being calculated, and n is the number of instants at which flow rates are computed. The time period for oscillations is generally 1 to 3 hours. Hence, the instability index I can be calculated over a time period of 1 day.

3. OPTIMIZATION FORMULATION

We begin by first defining the objective function for determining the optimum operation of the well assembly. Our objective could be either of (i) Meeting the customer demands on gas (subject to perhaps a minimum required oil production), or (ii) Maximizing the overall oil production from the well assembly. Accordingly, the objective function to be maximized can be formulated as shown below.

$$Max_U \left\{ w_o \sum_{i=1}^{n} Q_{o,i} + w_e \sum_{i=1}^{n}\left(Q_{gout,i} - Q_{gin,i}\right) - w_c \sum_{i=1}^{n} Q_{gout,i} - w_I \sum_{i=1}^{n} I_i \right\} \qquad (2)$$

In the above, $Q_{o,i}$ and $Q_{gout,i}$ are respectively the flow rates of oil and gas from the i^{th} well. $Q_{gin,i}$ is the flow rate of lift gas entering the casing of the i^{th} well. For a flexible representation of the objectives, w_e can be altered to reflect the importance of export gas in the overall objective function depending on the demand of export gas relative to oil. w_c can be altered depending on the cost of compression of the formation gas produced by the wells. I_i is the instability index calculated for the i^{th} well using equation 1. w_I can be changed depending on the importance of operating the well in a stable regime. A large value of w_I could be chosen so that the instability indices of all the wells are low enough to ensure well stability. The relative importance of oil or gas production can be taken into account by altering the value of w_o which can be taken as 1 when we consider oil wells and our primary objective is to produce more oil. It can be taken as 0 when we consider gas wells and our primary objective is to get more export gas from the gas field. *n* is the total number of wells.

The decision space U is the vector given below where u_i and g_i are respectively the production choke opening and gas injection choke opening for the i^{th} well.

$$U = \left[u_1, g_1, u_2, g_2, ..u_i, g_i, ..\right] \qquad (3)$$

The objective function for optimization is bound by the following constraints.

i. The model based on the first principles is given by the following equations and binds the optimization formulation.

$$\frac{dx_{1,i}}{dt} = Q_{gin,i} - Q_{ginj,i} \qquad (4)$$

$$\frac{dx_{2,i}}{dt} = Q_{ginj,i} + Q_{gres,i} - Q_{gout,i} \qquad (5)$$

$$\frac{dx_{3,i}}{dt} = Q_{ores,i} - Q_{o,i} \qquad (6)$$

In the above equations, $x_{1,i}$, $x_{2,i}$ and $x_{3,i}$ are respectively the mass of gas in the casing, the mass of gas in the tubing and the mass of oil in the tubing of the i^{th} well. $Q_{ores,i}$ and $Q_{gres,i}$ are the average flow rates of oil and gas respectively from the reservoirs into the tubing. $Q_{ginj,i}$ is the flow rate of the gas from the tubing into the casing. The flow rates on the right hand side of the equations are computed using the well model given by Mukhtyar *et al*. (2013).

ii. The total lift gas supply to the wells may be limited due to economic constraints. This imposes an upper bound denoted by $Q_{gin,MAX}$ on the total lift gas that can be used by all the wells.

$$\sum_{i=1}^{n} Q_{gin,i} \le Q_{gin,MAX} \qquad (7)$$

iii. Since no external supply of lift-gas is assumed in our work, the total flow rate of formation gas leaving the wells must be greater than or equal to the total lift gas used.

$$\sum_{i=1}^{n} Q_{gin,i} \le \sum_{i=1}^{n} Q_{gout,i} \qquad (8)$$

iv. In the case of gas wells, there can be an upper bound on the oil flow rate from the field due to handling capacity. Also, there can be a lower bound on the oil flow rate in order to maintain supply to the customers.

$$Q_{o,MIN} \le \sum_{i=1}^{n} Q_{o,i} \le Q_{o,MAX} \qquad (9)$$

v. Since gas from the wells is mixed in a single manifold, there is an upper bound on the carbon dioxide content in the final export gas. The volume percentage of carbon dioxide in the export gas denoted by C_{export} depends on the volume percentage of carbon dioxide in the i^{th} reservoir (denoted by C_i) and the flow rate of gas from each well. Using mass balance, the function relating these quantities can be found.

$$C_{export} = f\left(C_1, Q_{gout,1}, C_2, Q_{gout,2}, .., C_n, Q_{gout,n}\right) \qquad (10)$$

$$C_{export} \le C_{max} \qquad (11)$$

vi.

<u>Remark 1:</u> As stated earlier, we consider here for simplicity that the produced gases from the three wells evacuate into a single manifold. However, if the carbon dioxide content in the reservoir streams differ by a significant order of magnitude, then multiple manifolds are used and the formulation can easily be extended to the case of multiple manifolds. (Bandi and Gudi, 2014).It is important to note that the optimization formulation in such a case will involve routing of gas through different manifolds and can result into a mixed integer programming problem.

vii. In order to ensure lift-gas supply to all wells, the gas injection choke opening must be positive. From an operational viewpoint, a small lower bound on g is imposed. Also, an optimal value of g higher than the 'technical optimum' on the GLPC of a well is impractical. Hence, we impose an upper bound on g.

$$g_{\min} \le g \le g_{\max} \quad \forall\ i = 1 \text{ to } n \qquad (12)$$

viii. Usually, the oil and gas being produced from the well are accompanied by sand. The fraction of sand in the extracted mixture, however, must not exceed a certain limit to prevent damage to equipments. This translates into an upper bound on the value of production choke opening. At the same time, we need to ensure a non-zero production and hence u must be positive. From an operational viewpoint, it translates to a lower bound on u.

$$u_{\min} \le u \le u_{\max} \quad \forall\ i = 1 \text{ to } n \qquad (13)$$

The nonlinear constrained programming problem has been solved using an interior-point algorithm implemented by optimization solver *fmincon* of MATLAB. The results after every iteration were recorded to confirm the optimality of the final solution in all the cases.

4. OPTIMIZATION RESULTS

We consider three oil or gas reservoirs with varying pressures, compositions and gas to oil ratios, as shown in Table 1 and Table 2. A detailed list of the values of all the parameters of the wells can be found in Appendix II and III. The gas to oil ratio (GOR) for a well is defined as the ratio of the volume of gas to the volume of the oil in the reservoir. We consider two cases, one for optimal lift gas allocation to oil wells and another to gas wells.

Table 1. Assumed properties of oil wells

	Well 1	Well 2	Well 3
Reservoir pressure (in bar)	140	160	180
Gas to oil ratio (GOR)	2.9e-2	3e-2	3.3e-2
Carbon-dioxide content (in volume percent)	0.6	0.7	1.2

Table 2. Assumed properties of gas wells

	Well 1	Well 2	Well 3
Reservoir pressure (in bar)	140	160	180
Gas to oil ratio (GOR)	2.9e-2	3e-2	3.3e-2
Carbon-dioxide content (in volume percent)	0.6	0.7	1.2

*4.1 Optimal gas allocation to lift-assisted **oil** wells*

We first solve for optimal allocation of gas to oil wells with a primary objective of extracting more oil. Since we consider oil wells, we take w_o to be 1. At first, we consider no constraints on cost of compression and demand for export gas (i.e, w_e = w_c =0). In order to ensure stable operation of wells, w_I could be taken to be a large value, say 100. In all the cases presented in the sequel, instability was not encountered due to the sufficiently high weight given to the corresponding term in the objective function. There are no constraints on the availability of lift gas or on the carbon-dioxide content in the final export gas. Furthermore, the lower bound on u could be taken as 0.1 for all the wells. The upper bound on u could be taken as 0.6 for low pressure and medium pressure wells. However, since the onset of instability is seen at a relatively low choke opening for high pressure wells, an upper bound of 0.5 is chosen for the third well. Similarly, the lower and upper bound on g could be taken as 0.2 and 0.9 respectively for all the three wells. The values of the decision variables converge after certain number of iterations as can be seen in Figures 3.

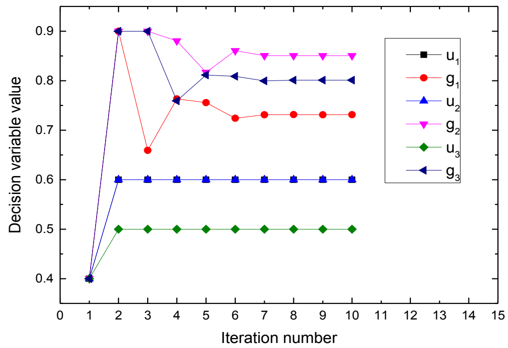

Figure 3. Convergence of decision variables

Table 3. Unlimited Lift gas supply

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Oil from well (in kg/s)	Optimal set of (u, g)
1	4.30	4.30	17.47	(0.6, 0.73)
2	4.78	4.78	20.19	(0.6, 0.85)
3	4.48	4.48	21.74	(0.5, 0.80)
Total	13.56	13.56	59.40	

The optimal solution for this case is given in Table 3. Since there is no restriction on the availability of lift gas, each well receives lift-gas at an injection rate that corresponds to the technical optimum on the GLPC, as can be seen in Figure 5. As at a given lift gas injection flow rate, more oil is produced for a wider opening of the production choke, the optimal value of the production choke opening is equal to the upper bound on u for all wells. The instability indices are low enough to prevent fluctuations in oil flow.

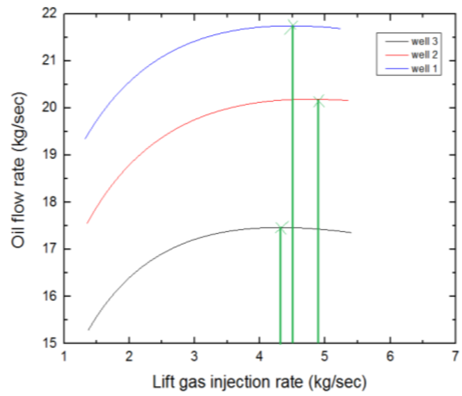

Figure 4. Optimal injection flowrates on the GLPC

Next, we look at a case when the availability of lift gas is limited. Since the total lift gas used in the previous example is 13.57 kg/sec, we could set the upper bound on availability of lift gas at 10 kg/sec. The optimal solution is shown in Table 4.

Table 4. Limited lift gas supply

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Oil from well (in kg/s)	Optimal set of (u, g)
1	3.19	3.19	17.28	(0.6, 0.50)
2	3.49	3.50	19.98	(0.6, 0.57)
3	3.32	3.30	21.56	(0.5, 0.55)
Total	10	9.99	58.82	

Next we account for cost of compression and prioritize the demand of export gas, respectively by choosing w_c = 1 and w_e = 10. As in the previous example, the upper bound on availability of lift gas is kept at 10 kg/sec. The optimal solution has been summarized in Table 5. From the previous example, we see that the order of magnitude of formation gas leaving the field is 10^{-2} while that of total formation gas that needs to be compressed is 10^{+1}, which drives the optimizer to penalize cost of compression by a larger extent. As a result of this, the total lift-gas used is 6.98 kg/sec, which is lower than the maximum availability of 10 kg/sec. Also, the wells produce significantly lower amount of formation gas. The export gas leaving the field is 0.02 kg/sec. The introduction of the above mentioned additional constraints reduces oil production from 58.82 kg/sec to 56.88 kg/sec (i.e. by 1387 barrels per day).

Table 5. Compression and its costs

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Oil from well (in kg/s)	Optimal set of (u, g)
1	2.26	2.26	16.69	(0.6, 0.34)
2	2.42	2.43	19.30	(0.6, 0.37)
3	2.30	2.31	20.90	(0.5, 0.36)
Total	6.98	7.00	56.89	

We now impose an additional constraint on the carbon dioxide content in the export gas. The volume percentage of carbon dioxide in the export gas in the previous example is 0.78% and hence we could limit it to 0.7%. The optimal solution has been summarized in Table 6. This constraint is satisfied with the volume percentage of carbon dioxide in the export gas being equal to 0.7%. Since the third well has the highest volume percentage of carbon dioxide (1.2%), the lift gas allocated to it is the least possible, i.e., *g* hits its lower bound of 0.2. The gas allocated to the first well increases significantly as it has lower volume percentage of carbon dioxide (0.6%). The total lift gas used is still less than 10 kg/sec due to high cost of compression. The oil production reduces from 56.89 kg/sec to 56.10 kg/sec (i.e. by 564 barrels per day).

Table 6. Restricted carbon-dioxide content

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Oil from well (in kg/s)	Optimal set of (u, g)
1	4.38	4.38	17.46	(0.6, 0.74)
2	2.42	2.43	19.30	(0.6, 0.37)
3	1.33	1.33	19.34	(0.5, 0.2)
Total	8.13	8.14	56.10	

In all of the above cases, we note that most of the formation gas from the wells is used for lift purpose and very little is available for export. This is because the wells have low gas to oil ratios, and in order to obtain more export gas, we need to increase the gas to oil ratios for the wells, i.e., shift from oil wells to gas wells.

*4.2 Optimal gas allocation to lift-assisted **gas** wells*

We now consider optimal gas allocation to gas wells which have relatively high gas to oil ratios (refer Table 2). Since our primary objective is to maximize the export gas supply, w_o could be set to 0. The lower and upper bound on *u* for all wells have been kept at 0.1 and 0.6 respectively. Similarly, the lower and upper bounds on *g* for all wells have been kept at 0.2 and 0.9 respectively.

At first, we do not consider any constraint on cost of compression (i.e, w_c =0). Since we are looking for an optimal solution in the stable regime, w_I could be taken as a large value, say 100. We assume there is an unlimited supply of lift gas and there is no constraint on the carbon dioxide content in the export gas as well. The optimal solution has been summarized in Table 7. The export gas supply from the field is 1.84 kg/sec. Since there is no restriction on the availability of lift gas, each well receives an amount of lift gas that produces maximum gas flow rate from the well. Instability indices are low enough to prevent fluctuations in the flow of gas produced.

Table 7. Unlimited lift gas supply

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Optimal set of (u, g)
1	3.63	4.20	(0.6, 0.59)
2	4.05	4.65	(0.6, 0.68)
3	4.39	5.04	(0.6, 0.77)
Total	12.05	13.89	

Next, we add cost of compression to the objective function by setting w_c to 0.01. The optimal solution for this scenario has been summarized in Table 8. Since the cost of compression has become relevant, there is a decrease in the amount of gas being produced by the wells and the total lift gas supply to the wells. The export gas supply reduces from 1.84 kg/sec to 1.82 kg/sec.

Table 8. Compression and its costs

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Optimal set of (u, g)
1	2.70	3.18	(0.6, 0.41)
2	2.90	3.49	(0.6, 0.45)
3	3.06	3.81	(0.6, 0.50)
Total	8.66	10.48	

Next we consider a case where in addition to the above constraints, we limit the availability of lift gas. Since the total lift gas used in the previous example is 8.66 kg/sec, we keep the maximum availability at 8 kg/sec. The results have been summarized in Table 9. The gas is allocated such that the export gas supply is maximum. However, due to limited availability of lift gas, the export gas supply decreases to 1.81 kg/sec.

Table 9. Limited lift gas supply

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Optimal set of (u, g)
1	2.51	2.07	(0.6, 0.38)
2	2.67	3.27	(0.6, 0.42)
3	2.80	3.45	(0.6, 0.45)
Total	7.98	9.79	

We now impose an additional constraint on the volume percentage of carbon dioxide in the export gas. The volume percentage of carbon dioxide in the export gas in the previous example is 0.8% and hence we now limit it to 0.7%. The optimal solution has been summarized in Table 10. The optimal allocation honors this constraint with volume percentage of carbon dioxide in the export gas at 0.7%. Again, since the third well has the highest volume percentage of carbon dioxide (1.2%), the lift gas allocated to it is the least possible, i.e., g hits the lower bound of 0.2. Furthermore, u which has always been at the upper bound in the previous cases, decreases to 0.15 in order to reduce gas production from the third well. In contrast, the gas allocated to the first well increases significantly as it has a lower volume percentage of carbon dioxide (0.6%). The total lift gas used is lower than 10 kg/sec due to high cost of compression. The oil production reduces from 56.89 kg/sec to 56.10 kg/sec (i.e. by 564 barrels per day).

Table 10. Restricted carbon dioxide content

Well	Lift gas supply (in kg/s)	Gas from well (in kg/s)	Optimal set of (u, g)
1	5.02	5.52	(0.6, 0.9)
2	1.72	2.29	(0.6, 0.25)
3	1.26	1.67	(0.15 , 0.2)
Total	8	9.47	

5. CONCLUSIONS

In this paper, we present a novel enterprise-wide optimization formulation for allocation of lift gas to a group of wells. The formulation is based on an approach that promotes coordinated production of oil and gas from different wells on the facility. We take into account more realistic constraints on compression and its costs, export gas nominations on pressure, volume and composition. In the presence of unlimited lift-gas supply, the optimal lift-gas allocated to each well corresponds to the technical optimum on its GLPC. We see that an increase in the compression costs reduces the amount of total lift gas being used to even below its maximum availability. Also, a restriction on the carbon dioxide content in the export gas results in a remarkably different gas allocation to wells. Further studies on this optimization approach including the consideration of water content in the multiphase mixture and the modelling of manifold pressure for its appropriate control are currently being pursued as a part of this research.

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