The use of gross split contract scheme in economic analysis of shale gas field at meliat formation in Tarakan Basin.

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Abstract. Due to the low supply and increasing demand for natural gas in Indonesia, the government has decided to develop other resources such as shale gas. The Meliat formation in the Tarakan Basin has a shale-gas potential for which 3.8 TCF is technically recoverable with 25.1 TCF risked in place. This study examines the economic impact of the gross split contract scheme on the development of this shale-gas field. Our model leverages three flow-rate profiles, comprising a low-production profile wells having an initial production (qi) of 50 mmcf/mo, a medium-production profile wells of qi = 125 mmcf/mo and a high-production profile wells of qi = 200 mmcf/mo. We used US models and the nearest field in the Tarakan Basin as a benchmark in making investment costs for development. Sensitivity analysis was conducted for the production profile, drilling costs and wellhead gas prices. Gross split contracts have a net present value (NPV) > 0 and an individual rate of return >10% on medium and high-production profile wells. The analysis showed that the production profile is the most substantial factor that is affected by the NPV increase. As a result, the indicator of NPV reaching positive is when the gas price sets at $9.24/MMBTU for medium-production profile wells and $6.43/MMBTU for high-production profile wells.

1. Introduction

Indonesia spots the world’s fourth-largest population of 265,015,000 people [1]. The country faces a situation wherein the amount of domestic gas supply and demand is in a deficit condition, compounding yearly. As portrayed in 2018, the gas supply was 7,732 MMSCFD, which faced a 9,494-MMSCFD demand [2]. The projected supply in 2030 is expected to be 3,338 MMSCFD, whereas the needs are expected to reach 11,144 MMSCFD. This difference of supply and demand will have tripled in this scenario. However, it could be reduced by leveraging new conventional natural gas reserves and non-conventional gas resources, such as those that contain shale gas [3].

Indonesia contains non-conventional gas reserves in the form of potential coal-bed methane (CBM) and shale gas. Indonesia’s shale-gas potential is estimated at 574 TCF, which is greater than the CBM potential of 453.3 TCF and natural gas at 334 TCF [4]. Based on geological data, shale-gas reserves are located in Indonesia’s major sedimentary basins in the islands of Sumatra, Java, Kalimantan and Papua.
[5].

Shale gas comprises natural gas trapped in shale formations, which does or did contain large amounts of organic material required for the consistency of oils and natural gases. Shale has a nanoscopic permeability. Thus, the contained gas cannot be collected by using conventional drilling methods. Hence, in order to create extensive artificial fissures around the drill site, horizontal drilling and hydraulic fracturing must be used [6].

The government issued the Minister of Energy and Mineral Resources Regulation No. 5 of 2012 concerning procedures for establishing and developing non-conventional oil and gas working areas [7]. The first such contract in Indonesia was let for the Sumbagut MNK Working Area on 31 January 2013 to PT Pertamina Hulu Energi, using a production-sharing contract (PSC) cooperation agreement [8]. However, it did not pertain to shale gas. Consequently, even with the addition of new regulations, there are still no contracts in Indonesia for harvesting shale gas.

Specifically, for shale gas, a gross split cooperation contract scheme was established by the Minister of Energy and Mineral Resources Regulation No. 8 of [9]. In this regulation, the government offered a gross split scheme comprising variable and progressive components for oil and gas field development. This kind of contract is based on the PSC but adds the principle of gross production sharing without a mechanism of returning operating costs. This scheme is a substitute for the PSC used with ongoing cooperation contracts, aiming to improve the investment climate by accelerating licensing and government approval while delaying the full submission of budgeting and activity processes, hopefully expediting the discovery and production of reserves [2].

The Meliat formation in the Tarakan Basin holds considerable promise for shale-gas exploitation. This basin has an area of 19,450 km², located in the north-east position of north Kalimantan Province, Indonesia [10]. The Meliat formation has shale-gas resources that can be technically produced at 5 TCF from a gas-in-place risk of 35 TCF [11]. This examines the economic development of this field by leveraging a non-conventional oil and gas gross split cooperation contract.

2. Data and Methods

We began this research with a literature study about shale-gas consistencies, well characteristics and shale-gas reserves in Indonesia [12]. Furtherly, we examined the applicable laws and contract schemes regarding the development of non-conventional oil and gas fields. US standards were used as a benchmark in order to calculate our production and economic profiles. We used the Arps hyperbolic reduction curve equation with constants, $q_i$, $b$ and $D_i$, which are based on the Barnett field production profile of the US. We used three production flow scenarios: a low-production scenario of 50 mmcf/mo, a medium-production scenario of 125 mmcf/mo and a high-production scenario of 200 mmcf/mo. Parameters $b$ and $D_i$ were assumed to be the same for all scenarios: 0.9 and 0.13, respectively.

Field-development contracts in the Meliat formation are assumed to last for 30 years with durations of 10 years are held for exploration while others 20 years are for exploitation. In increasing the number of wells and gas production, drilling activities will be going on until 15 years forward. The number of rigs will be limited to five, each with three months of drilling duration, considering the logistical factors (e.g., rig availability). So, it can be estimated that there could be up to 20 wells in 1-year production.

The estimated investment costs comprise Capex and Opex. Capex affects the development of shale-gas fields, including exploration and development, geological and geophysical work, seismic studies, exploratory drilling and field development (e.g., well drilling, well completion and facility construction). These costs include acquisition, data processing, data analysis and interpretation costs. In 2007, acquisition costs for forest areas were $5,000,000 per 100 km², costs for data processing were $500/km² for 3D seismic analyses and personnel and interpretation costs were $500,000 [13]. Costs for 2017 are adjusted to the IHS Markit Upstream Capital Cost Index [14]. In 2017, PT. X, a company that drilled production well in Bunyu area at Tarakan Basin, costs $3,481,570.19 for vertical drilling. But, the standard price of drilling in the USA cause drilling horizontal wells could cost 1.5–2.5 times more expensive than drilling wells vertically [15]. Based on references that mentioned above, it can be concluded that if a vertical well in Tarakan is drilled horizontally, it would cost at around $5,222,355.29
to $8,703,925.48. It is almost similar to the estimated budget of a service company in the field of completion, PT.Y. They estimated that the completion in hydraulic fracture for horizontal wells would cost at $4,126,000.00.

Constructing the facility also has a prime role in drilling wells. Therefore, it must include in the budget. In constructing a facility, three aspects that needed to include at cost budgeting. They are the construction cost, equipment cost, and pipeline installation cost. According to Sitawati, Azwar, Nugroho and Ardianto [16], the construction of a gas-processing facility must have 14 MMSCFD. It is required to install a trimethylene glycol (TEG) that costs $12,000,000. Then, the dehydration unit at an Onshore Receiving Facility (ORF) must have 40 MMSCFD plus fees that cost $5,000,000. While pipeline-cost estimates use Seddon’s equation [17].

Production costs were adjusted using the 6/10 rule. 2017 cost was adjusted using the Chemical Engineering Plant Cost Index (CEPCI). The Operating cost for developing the shale-gas field is assumed to be $1/MMBTU. This assumption is based on the management Opex of the Eagle Ford field in the US [18], which has the same wet-gas-type reservoir as the Meliat formation [19].

In a gross split contract scheme, the split of initial profit share (split base) is 52% for the state and 48% for the contractor. Then, the profit-sharing amount determined based on the initial revenue-sharing adjusted to the variable and progressive components. For shale-gas fields, gross splits are calculated from the base splits adjusted to variable and intensifying components.

We also performed sensitivity analysis on costs of shale-gas production, drilling and selling to determine the effects of the given variables on economic indicators (i.e. net present value (NPV), internal rate of return (IRR), profitability index (PI) and payback period) for several economic scenarios.

3. Result and Discussion
The development of the shale-gas field comprises three stages, beginning with preproduction, followed by production, gas processing and transmission [12]. During the exploration stage, workers obtain geological, geophysical and seismic data. Then, they could determine the drilling location. Once the location is determined, vertical drilling carrying out until it reaches a depth of 1,000–4,000 m in the Meliat formation. Furthermore, Drilling is continued horizontally at a lateral length of 914 m. As a result, In the 11th contract year, or by the end of the first year of exploitation, shale-gas production will have begun and revenue will be generated (figure 1).

During the 20-year exploitation and production in the Meliat formation, wells that have low-production profiles will produce 1.17 BCF in cumulative well production and 310 BCF from 25.1 TCF risked gas-in-place in cumulative field production. Meanwhile, wells that have medium-production profiles will produce 2.94 BCF in well cumulative production and 776 BCF in field cumulative production. Whereas high-profile production wells will produce 4.71 BCF in cumulative well production and 1,242 BCF, or 4.94% risked gas-in-place in cumulative field production.
Cumulative production at one production well (figure 2) will increase significantly until the 4th year. Then, the rate of production will have a downward trend. Therefore, it needs to add production wells. The addition of 20 production wells per year will be able to sustain a constant increase to maintain the cumulative field production rate (figure 3) or to increase the cumulative field production significantly (figure 4). Drilling will not be going on between the 16th and 20th years, and the flow rate of field production will have a direct impact on decreasing the gradient of shale-gas field production.
Figure 2. Cumulative Gas Production (1 Well).

Figure 3. Gas production profile (1 field).
The wet gas produced will have a methane content >82% and it will require dehydration to meet pipeline specifications. It will have flowed from the wellhead through the production header to the gas scrubber. Afterward, it will enter the TEG dehydration package (i.e. TEG contractor, TEG regeneration, reboiler and column). Then, the dehydrated gas will be sent through the 50-km pipeline to the delivery point.

The cost of geology, geophysics and seismic in 2007 for an area of 500 km$^2$ will have been $25,750,000.00, including acquisition, processing and data analysis and interpretation costs. Costs from 2017 are adjusting to the IHS Market Upstream Capital Cost Index to $40,633,027.52. Drilling one well will cost at around $5,222,355.29 to $8,703,925.48. So, the initial calculation for one horizontal well drilling is it will cost $5,222,355.29 or 1.5 times more than the vertical drilling price, while the cost of completion for hydraulic fracturing will be $4,126,000.

The estimated cost of constructing a gas-processing facility and of installing a TEG dehydration unit (14-MMSCFD capacity) in 2014 is $12,000,000. Thus, it will require $5,000,000 to install a TEG dehydration unit at the ORF (40-MMSCFD capacity) (Sitawati et al., 2012). Then, the cost will adjust to the capacity using the rule of the 6/10 equation. Costs from 2017 are adjusted using the CEPCI cost index.

The transmission pipes used in horizontal drilling will differ in three sizes. First, pipelines that are used for low production wells are 16-inch diameter. Second, medium high production will have 20-inch diameter pipelines. Last, High production wells will have 22-inch diameter pipelines. These pipelines will be installed 50 km away to the point of delivery. As a result, gas can flow to the LNG plant in Bontang through these pipelines. To see more details, Table 1 presents the estimated investment costs for various production flow paces.

The calculation of Capex costs also considers tangibles and intangibles. Typically, Intangible drilling costs are at around 65 to 80 percents of total costs [20]. Which is, operating costs are assumed to be $1 per MMBTU. Opex fees will incur an escalation fee of 3% per year. The Economic analysis extends to
The 3rd International Conference on Smart City Innovation  IOP Publishing  
IOP Conf. Series: Earth and Environmental Science 673 (2021) 012011  doi:10.1088/1755-1315/673/1/012011

low, medium and high-production profiles with gas prices at the delivery point of $10 and horizontal drilling costs 1.5 times the cost of vertical drilling. This scenario is called the analysis condition or basic condition. In the analysis, gas prices escalate 1.3% per year [21], and the costs of Capex and Opex are assumed to escalate by 3%.

**Table 1.** Investment costs for various production flow paces.

|                              | Low flow rate | Medium flow rate | High flow rate |
|------------------------------|---------------|------------------|----------------|
| Peak production (MMSCFD)     | 140           | 223              | 327            |
| Pipeline diameter (in)       | 16            | 20               | 22             |
| Pipeline cost (M$)           | 49,93         | 56,20            | 59,34          |
| Facility construction cost (M$) | 47,99         | 65,20            | 79,78          |
| TEG dehydration unit cost (M$) | 10,65         | 14,47            | 17,71          |
| Total cost                   | 108,57        | 135,87           | 156,83         |

The economic analysis that used in this research is a gross split scheme in which the development of shale gas with medium and high-production profile well provides positive NPV value, IRR above 10% per year and PI above 1. So, the development of the shale-gas field in those production profiles will give benefits to the contractor. On the opposite, the low-production profile well that has IRR less than 10% with negative NPV value and PI below 1, will make it even almost impossible to develop. To see more details, the economic analysis of gross split contract calculations for the analysis conditions showed in Table 2.

**Table 2.** Economic analysis of gross split contracts for condition analysis.

| Indicator                  | Low-Production Profile | Medium Profile Production | High-Profile Production |
|----------------------------|------------------------|---------------------------|-------------------------|
| NPV (MM$)                  | −1070.07               | 104.99                    | 819.33                  |
| IRR (%)                    | −15.4                  | 12.5                      | 28.8                    |
| PI                         | −2.33                  | 1.30                      | 3.22                    |
| Payback period (Years)     | N/A                    | 8.66                      | 4.07                    |
| Contractor take (M$)       | 2560.67                | 5855.23                   | 8160.75                 |
| Contractor take (%)        | 73                     | 67                        | 58                      |
| Government take (M$)       | 960.31                 | 2947.22                   | 5923.16                 |
| Government take (%)        | 27                     | 33                        | 42                      |
| Total (M$)                 | 3520.98                | 8802.45                   | 14083.92                |

Condition analysis applies a moderate production profile with drilling costs 1.5 times the cost of vertical drilling and gas prices of $10, escalated 1.3% per year. Sensitivity analysis is extended to the production profile, the cost of drilling and the selling price of gas at the delivery point. Sensitivity to the production profile uses an initial production flow rate of 50 mmcf/mo (−60%) and an initial production flow rate of 200 mmcf/mo (+60%) from the analysis conditions. The sensitivity of drilling costs uses two times the cost of drilling vertical wells (+33% analysis conditions) and 2.5 times the costs of vertical well drilling (+67% analysis conditions). Sensitivity to the selling price of gas at the delivery point uses gas prices of $6 (−40%), $8 (−20%), $12 (+20%) and $15 (+50%)/MMBTU.
With sensitivity applied to change the percentage of flow rates, drilling and gas prices, they will increase and positively affect NPV (figure 5), IRR (figure 6), PI (figure 7) and payback period (figure 8) in a gross split contract. Otherwise, increasing drilling costs have the opposite effect. Gas prices and production profiles give NPV values that are nearly the same when they are in the −25–5% range of percentage change. Meanwhile, the >5% percentage change in the production profile is more influential on the increase in NPV, IRR, PI and payback period, compared with changes in gas prices. However, gas prices become a more predominant factor when they change to <25%.

Figure 5. NPV sensitivity.

Figure 6. IRR sensitivity.
Based on the sensitivity analysis for the production profile, the economics of the project starting to generate at the medium-production profile. The calculation of the economic analysis in the medium-production profile with some gas prices showed in table 3.

Table 3. Economic analysis of gross split contracts for condition analysis.

| Indicator     | $6      | $8      | $10     | $12     | $15     |
|---------------|---------|---------|---------|---------|---------|
| NPV           | MMS     | $-749.74| $-222.52| 104.99  | 296.70  | 459.55  |
| IRR           | %       | $-7.35  | 5.16    | 12.48   | 17.13   | 21.18   |
| PI            |         | $-1.15  | 0.36    | 1.30    | 1.85    | 2.32    |
| Payback period| Years   | N/A     | 25.65   | 8.66    | 6.33    | 5.41    |
In the analysis condition, the gross split contract scheme provides positive economic indicators marked by positive NPV, IRR above 10% discount rate, PI above 1 and shorter payback period for medium and high-production profile wells. For medium-production products, the economical price of gas for sale is a price above $8 because it produces positive NPV, IRR > 10% and PI > 1. The economics of shale-gas field development are influenced, among other things, by the production flow rate, drilling costs and gas prices. Consequently, NPV must be considered before deciding to proceed with a project. If NPV > 0, then a project should be considered.

In the gross split contract scheme, the effect of gas prices on NPV in the low, medium and high-production profile wells showed in figure 9. Positive NPV is achieved on a high-production profile with gas selling at $6.43/MMBTU while on a moderate production profile with gas selling at $9.24/MMBTU.

4. Conclusion
The shale-gas field in the Meliat formation, Tarakan Basin, will produce a cumulative field production of 310 BCF with low-production profile wells. A well with a production profile currently providing a cumulative production of 776 BCF and a high-production profile well will produce 1,242 TCF shale gas from 25.1 TCF risked gas-in-place during the 20-year exploitation stage. A positive economic
indicator is achieving a moderate (NPV of $104.99 million with IRR 12.48%) and high ($819.33 million with IRR 28.83%) production profile. The low-production profile in the analysis condition has a negative NPV, an IRR of less than 10% and a PI of less than 1, which indicates that the development of shale gas is not feasible at that profile. It also can be said that the Production profile is the most influential factor for improving economic indicators. When gas produced under the moderate production profile field sells for $9.24/MMBTU or at $6.43/MMBTU for a high-production profile field, the result is that NPV has achieved positively.

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**Acknowledgments**

We acknowledge the financial support from The Directorate of Research and Community Service (DRPM) Universitas Indonesia through Grant Publikasi Terindeks Internasional (PUTI) Prosiding 2020 (Nomor: NKB-1158/UN2.RST/HKP.05.00/2020).