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The Ado about Gas Pricing

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Abstract

The intent of this paper is to demonstrate that there is a progressive increase in Govt Take as the gas price increases and hence while fixing the natural gas price, a host Government needs to take cognizance of the exploratory efforts expended by an Operator and the focus should be on import parity price.

In a PSC environment where the Government takes a part of the economic rent in the form of Government Take, a substantial part of each dollar increase in price goes back to the Government. Over the last nine NELP rounds in India, the competition for exploration blocks especially in Basins like KG Basin has increased, with an exponential increase in Govt Take. The Cost Recovery Ceiling (CRC) and Profit Oil Tranches have become more skewed towards the Government, which could thus leave many gas fields stranded / undeveloped under a lower price regime.

An analysis of three cases one each in Onshore (150 BCF), Shallow Water (750 BCF) and Deepwater (2 TCF) environments was carried out with two variants of fiscal parameters (i) normal parameters viz., CRC at 100% and PFO tranches ranging between 90% to 20% for Investment Multiples (IM) of ≤ 1.5 to ≥ 3.5 and (ii) stringent parameters for the Contractor viz., CRC at 40% and PFO tranches ranging between 50% to 10% for IMs of ≤ 1.5 to ≥ 3.5.

The results indicate that a price of the order of US $ 6, 10 and 7 / MMBTU would be required to allow the fields to be developed in Onland (150 BCF), Shallow Water (750 BCF) and Deepwater (2 TCF) respectively under stringent parameters.

The effect of every one dollar increase in price has been analysed in terms of distribution of Additional Economic Rent (AER) between the Contractor and the Govt. In the Deepwater case, Govt share in the AER of US $ 2 Billion generated with an increase of one dollar in price say from US $ 8 / MMBTU to US $ 9 / MMBTU, is 73.76% or US $ 1475.22 MM, with the Contractor entitled to only 26.24% or US $ 524.78 MM, under stringent fiscal parameters. Once the threshold profitability of the Contractor is achieved, the Govt take progressively increases to levels of 90% of the AER with each dollar increase in price. The effect is similar in all the other analysed cases as well, which is largely due to the way the Indian PSC works.

It is thus concluded that the gas pricing mechanism in an energy importing country needs be viewed holistically. The gas pricing mechanism needs to (i) allow development of gas fields so that no

reserves is left stranded (ii) facilitate field growth and (ii) provide incentive for commitment of risk money for further exploration. It can also be concluded that increase in gas price till a threshold level does not yield windfall profits to Contractor and that the Govt's economic rent philosophy remains protected.

Introduction

Oil can be transported and stored at a lower cost than other fossil fuels due to its liquid form and high energy density. In contrast, both transportation and storage of gas is expensive because of its fugitive form and low energy intensity. As the consumption of natural gas increases, the debate around gas pricing gets more intense. At times of rising oil prices, some proposals are made for de-coupling gas prices from oil prices and move towards free floating gas price model. Also, the prices across various regions in the globe vary widely; the regional differences can be attributed to several factors like geography, demand, resource endowments.

It is conceded that gas pricing is a complex subject especially in an energy importing country like India saddled with many forms of subsidies. Till the time the end users especially of fertilisers and power, can afford to buy energy in a free market situation, the debate on subsidies would continue. The intent of this paper is not to delve into how the gas price is to be fixed or to analyse the technicalities and propose a gas pricing policy but to limit itself in attempting to provide a perspective from upstream industry point of view.

NELP in India

In a PSC environment where the Government takes a part of the value of the produce in the form of Government Take, it can be deduced that a substantial part of each dollar increase in price goes back to the Government.

The New Exploration Licensing Policy has given a tremendous impetus to exploration in India. PSCs have been signed for more than 240 blocks and substantial reserves have been added under NELP.

Over several rounds of NELP in the past in India, the competition for exploration blocks especially in Category I Basins like KG Basin and Offshore with a high perceived prospectivity has increased, with an exponential increase in Govt Take. The Cost Recovery limit and Profit Oil Tranches have become more skewed towards the Government. A review of the bids submitted by various operators for blocks especially from NELP-VI onward indicates that the biddable parameters under Cost Recovery and Profit Oil are very heavily skewed towards the Government, due to intense competition for blocks. There is also a substantial risk money commitment in the form of Minimum Work Programme (MWP) commitment. Under these circumstances many gas fields could be left stranded / undeveloped under a lower price regime.

It can be demonstrated that there is a progressive increase in Govt Take as the gas price increases and hence while fixing the natural gas price a host Government needs to take cognizance of the exploratory efforts expended by an Operator and the focus should be on import parity price.

Field Size Analysis

A detailed analysis of three cases one each in Onshore (reserves, 150 BCF), Shallow Water (reserves, 750 BCF) and Deepwater (reserves, 2 TCF) environments was carried out with two variants of fiscal parameters (i) a normal set of parameters viz., Cost Recovery at 100% and the PFO tranches ranging between 90% to 20% for Investment Multiples (IM) of ≤ 1.5 to ≥ 3.5 and (ii) a stringent set of parameters for the Contractor viz., CR at 40% and the PFO tranches ranging between 50% to 10% for IMs of ≤ 1.5 to ≥ 3.5. For each case standalone development concept was considered and yearwise investment (Capex and Opex) and production profile was estimated. The effect of every one dollar increase in price has been analysed in terms of additional economic rent (AER) and the Contractor share and Govt share thereof. Detailed sensitivity analysis on price and production has also been carried out to understand and assess the price range that would make the field sizes commercially viable.

Onland Case: Field Size 150 BCF

The analysis indicates that an Internal Rate of Return (IRR) of 14% is achieved at a price of around US $ 4.5 / MMBTU under normal fiscal parameters while a price of more than US $ 6 / MMBTU would be required under stringent fiscal parameters. The Additional Economic Rent (AER) of US $ 150 MM generated by an increase in price by one dollar say from US $ 7 to US $ 8 / MMBTU is shared between the Government and the Contractor in the ratio of 69.68% : 30.32%, with US $ 104.53 MM going to the Govt as Govt Take (under normal parameters).

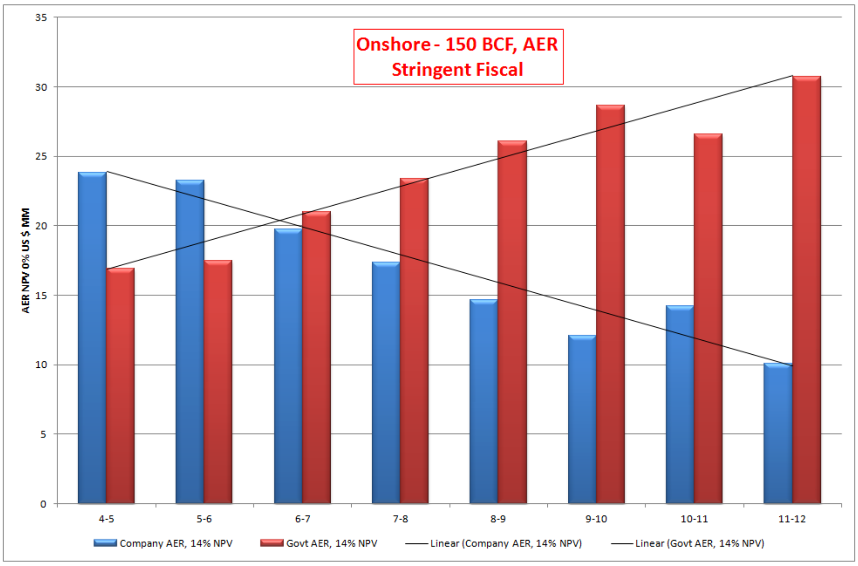

Fig-1: The distribution of the AER @ 14% NPV is demonstrated in Figure-1. It can be observed that the Government Take in the additional AER progressively increases.

Shallow Water Case: Field Size 750 BCF

The analysis indicates that an Internal Rate of Return (IRR) of 14% is achieved at a price of around US $ 7.5 / MMBTU under normal fiscal parameters while a price of more than US $ 10 / MMBTU would be required under stringent fiscal parameters. The Additional Economic Rent (AER) of US $ 750 MM generated by an increase in price by one dollar say from US $ 8 to US $ 9 / MMBTU is shared between the Government and the Contractor in the ratio of 70.14%: 29.86%, with US $ 526.07MM going to the Govt as Govt Take.

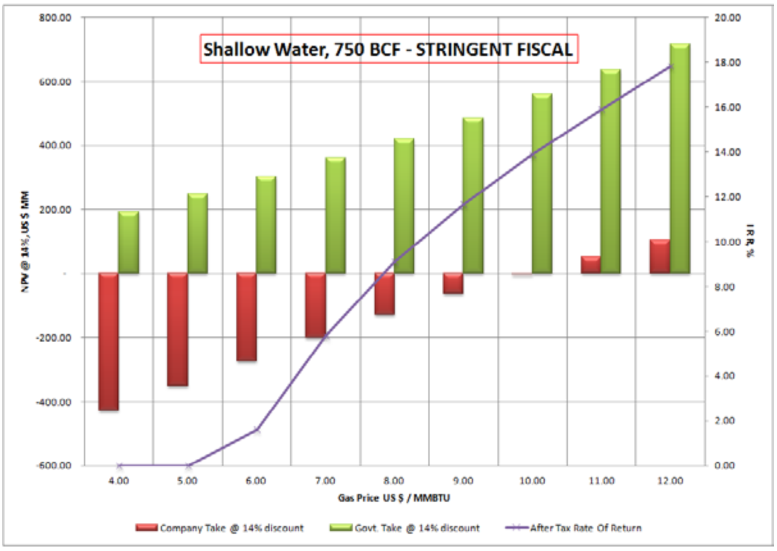

Fig: 2: The Field would not be developed as the commerciality is achieved above a price of US $ 9 – 10 / MMBTU.

Deep Water Case: Field Size 2TCF

The analysis indicates that an Internal Rate of Return (IRR) of 14% is achieved at a price of around US $ 5 / MMBTU under normal fiscal parameters while a price of more than US $ 7 / MMBTU would be required under stringent fiscal parameters. The Additional Economic Rent (AER) of US $ 2000 MM generated by an increase in price by one dollar say from US $78 to US $ 8 / MMBTU is shared between the Government and the Contractor in the ratio of 67.33%: 32.67%, with US $ 1346.64 MM going to the Govt as Govt Take.

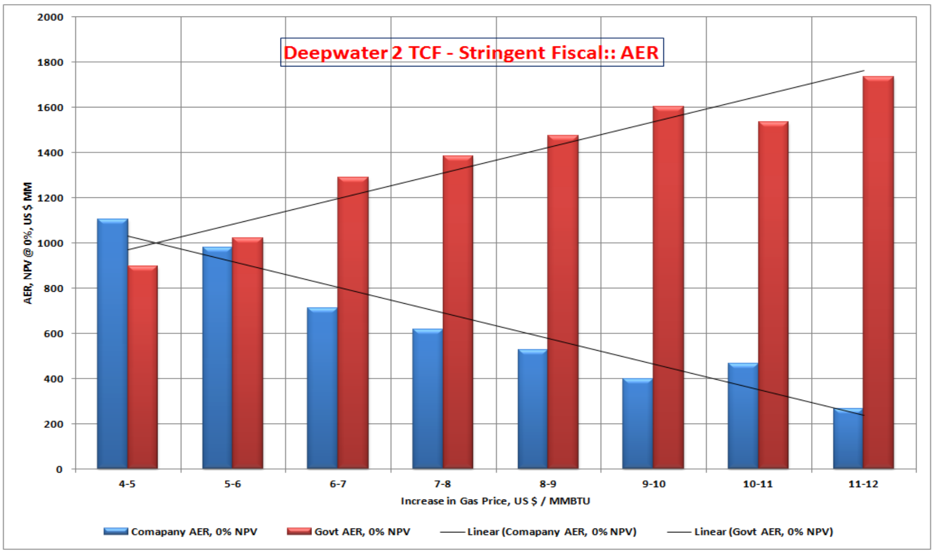

Fig-3: The distribution of AER under stringent fiscal parameters indicates a progressive increase in Govt Take.

Conclusions

A geoscientist is excited when the geological model is proved and new reserves are found but is normally removed from the economics of development. Even a marginal discovery provides a lead because it kindles the exploratory interest in the area and the probability of finding bigger structure / reserves gets better.

Development and production of gas reserves should be an automatic eventuality in case of exploratory success, without much debate, so that no reserve is left stranded especially in an energy importing country. Development of a field and further exploration in the area normally leads to field growth and economy of scale is achieved during production stage when new pools and satellite fields are brought on stream subsequently.

Unlike oil, the pricing of natural gas is related to several factors. Domestic gas prices stayed constant for last four years making exploration unviable at current input costs. Thus the debate around gas pricing needs to lead to a logical conclusion of development.

The three cases analysed in Onshore, Shallow Water and Deepwater demonstrate that under the Indian PSC, there would be a progressive increase in Govt Take for each dollar increase in the price of gas beyond a threshold price. The threshold break even prices for Onshore, Shallow Water and Deepwater for the considered field sizes are of the order of US $ 5 – 7 / MMBTU, US $ 7.5 – 10 / MMBTU and US $ 5-7 / MMBTU respectively. **An increase in Capex or a decrease in production by around 20% shall make these cases viable at a price of at least two dollars higher. An increase in the risk money also has an impact.**

It is also pertinent to mention that the probability of finding a single structure with substantial reserves especially in Category-I Basins, where the exploration density is quite high, is low. Cluster based development of relatively smaller fields is order of the day. Smaller, scattered fields would require higher capital expenditure investment for development and would consequently require higher prices.

It is thus concluded that the gas pricing mechanism in an energy importing country needs be viewed holistically. Keeping the aspects like (i) geological uncertainty (ii) the commitment by the Operator to invest risk money in the highly risky and uncertain business of hydrocarbon exploration (iii) rapidly changing capex and opex scenario etc., in view, a reasonable gas price which would allow development of marginal fields also is the requirement of the day.

The gas price needs to (i) allow development of gas reserves (ii) provide incentive for further exploration and facilitate an Operator to commit further risk money. It can also be concluded that increase in gas price till a threshold level does not yield windfall profits to Contractor and that the Govt’s economic rent philosophy is protected.