Manual for the
Open Upstream Gas and LNG Model

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1. Introduction and purpose of the model

a. Purpose of a model in general

A financial/fiscal model provides forecasted returns of a project to the investor and government. These estimates are based on fiscal, market, technical and corporate input variables, many of which are forward looking assumptions. Investors use financial models to determine whether to go ahead with a particular investment. Governments use models to compare their fiscal regimes with their peer countries and to assess how much revenue will flow into the state coffers from a particular project. A model is fundamental to help answer the following questions:

- What is the fairness of the current and potential deals?
- What is the equitability of the fiscal regime for investors and the government?
- What is the trade-off between “quick money” through front-loaded payments such as a signature bonus as compared to charging back-loaded payment such as a higher profit tax?
- What is the efficiency of tax incentives?
- What impact do tax regime changes have on the financial flows to both parties?
- How does the fiscal regime compare with others?
- How do changes in the ownership and commercial structure affect the financial flows to both parties?
- What are expected revenue flows from extractive industry projects and what long-term public investment policies can be funded and planned?
- How do revenue flows alter if market factors (for example, changes in prices or costs) or technical factors change?

To support project negotiations, it is crucial for governments to use fiscal models to assess the impact of the negotiated fiscal terms on the returns to the investor and the revenues to the government. Ideally the company and government share their respective models to ensure fiscal negotiations are undertaken on a common understanding. It may be, for example, that the parties use different assumptions regarding future prices, costs, new discoveries or feedstock sources to a plant, etc; which may lead to an impasse in negotiations given that the government revenues and investor returns are highly affected by these assumptions. By agreeing on the underlying assumptions and ways of calculating the financial flows, both parties can negotiate on the same basis.

We note however that in agreeing on assumptions the government should recognize that the companies usually have more experience and information. So a comprehensive description and discussion of the assumptions is a vital step to assure a balanced understanding and identification of risks to the government.

Given that civil society groups normally do not have access to fiscal models, the use of an independent ‘open’ model such as this one may be the only alternative for assessing project returns and government revenues. They key challenge becomes gaining access to the main assumptions that are necessary in order to perform such a modeling exercise.
b. **Purpose of the upstream and LNG model**

This model has been developed for training purposes. It models the gas value chain from the upstream project to the use of gas under the form of LPG, LNG or as feedstock for local industrial or power generation uses. It allows users to assess the different LNG structures that can be considered when producing LNG: the tolling structure, the Independent Plant Owner/Buyer Model and the Related Party Plant Owner/Buyer Model. It provides various fiscal regime options for the upstream and mid-stream sectors to understand the impacts of changes on the government take and the private sector returns. It also allows for users to add additional upstream fields to the LNG project and understand what impact this has on the LNG economics when the processing facilities are shared.

c. **Use of the upstream and LNG model for different parties**

Various interested parties use project economics models for sometimes related, but often different purposes.

**Upstream Investors** – Usually international oil companies and national oil companies are investing in developing the upstream gas discoveries. They use models to reasonably ensure they will achieve an adequate return on their investments relative to the expected range of geologic, operational, and political and market risks that they take on. If they are required to “Carry” state oil company investments, they also want to assess the likelihood that those carries can be repaid under a variety of scenarios.

**Investors in the LNG Plant** – Usually these are international oil companies and national oil companies and often may include international gas buyers, construction companies or local utility companies. They are interested in assessing the economic viability of their investments under a range of operational and market risks and evaluating the reliability of gas supply.

**Governments and National oil companies** – Want to ensure the projects are economically viable and continue to attract investors, but at the same time achieve the maximum financial benefits for the country given that their natural resources represent a finite asset that depletes over time.

Governments need to plan how much revenue can be expected into the government treasury, the timing of those receipts and the volatility over the life of the project. National oil companies may need to evaluate whether their share of the project investment has sufficient returns to be financed by lenders.

**Financial sector** – Private banks and multi-laterals lending directly to the project investors utilize project economics to assess the underlying ability of the borrowers to repay their project loans and quantify the risk factors that could cause delays or defaults in payment. Financial institutions making general purpose loans to the country or to local businesses will be interested in knowing how much additional revenues the government will be collecting, which may assist in repaying loans. Credit rating agencies use economic models to forecast sources of government and country wealth to assist in their assessments and developing their ratings.
Civil Society – Want to know that the deal between the government and the private investors is reasonable and that it achieves the maximum returns for the country while still encouraging new investment. The model also serves as a means of independently evaluating what should be coming into the government treasury in any period and comparing that to actual reported revenues.

Gas Buyers – International LNG buyers or local utility companies want to assess the basic viability and reliability of the projects and whether they can continue to operate and supply them with gas under a variety of future market conditions.

2. Explanation of the different structures

a. Natural Gas compared to Crude Oil Projects
Natural gas projects are different than oil projects, because of the following factors:

- Natural gas cannot be easily stored and costs of transportation (pipeline and tankers) and treating (separation of liquids and liquefaction and regasification) are much higher than for oil. Each segment of transportation and treating of natural gas entails very different costs, technologies and risks compared to the upstream extraction.
- Greater economies of scale are often required for LNG plants to be economically and operationally viable; consequently the gas to be supplied to an LNG plant often comes from several different blocks, each with different investors.
- Markets for gas are smaller and more segmented than for oil.

b. Gas Project Segments, Ownership Structures, Risks and Finances
Because of the above variations in risks and technical processes various segments of gas projects often take a different legal and ownership form. Activities and investments in the natural gas “value chain” are quite often split between different entities or groups of investors and not undertaken by the same group of investors. Commercial interests, tax and fiscal treatment may vary by segment.

Upstream – The ownership and legal structure are usually determined by the government who decides which parties are awarded the rights to explore and exploit the oil and gas reserves in a particular block. Usually this is a group of companies comprising an unincorporated joint venture (JV), oftentimes including the national oil company. There may be more than one block that produces gas in a region and each of those blocks will have a different set of owners/investors. Due to the high risks of not finding exploration success or reserves being uneconomic, successful upstream projects often earn higher rates of returns than the other segments of the value chain, e.g. 15% or higher.

Gas Gathering Pipeline(s) – The gas produced in the upstream sector must be transported to shore to be processed. If only one block uses this pipeline, often the upstream block partners may also build and own the gas pipeline either through the same JV or via a different company that they form. If more than one block uses the gas pipeline, then there may be a separate company with the same or different ownership that charges a tariff to the upstream producers.
to use it (see line 95 in the ‘Assumptions & Results’ sheet in the model). Unless it is part of the upstream JV, the gas pipeline does not take ownership of the natural gas – it is considered to be a shipper only. It is common to have most of the upstream partners also be partners in the gas pipeline. But it is important to note that this pipeline is a strategic asset and has the potential to be monopolized because any one set of owners may decide to restrict its use or charge very high tariffs to any new blocks that want to use it. Consequently, many countries regulate these pipelines or take ownership through the government to ensure that its capacity remains open and reasonably priced to any new producers. Since pipelines have relatively low technical and commercial risk, they often earn only medium level of return – typically in the range of 8-12%.

**LPG Extraction** – Depending on the “richness” (carbon content) of the natural gas produced, it may be more economic to extract and separately sell the liquids from the natural gas stream as Liquefied Petroleum Gas (Butane, Propane, etc.) prior to the liquefaction process. The investment to extract liquids from the gas stream can be made by the upstream group or may be made by the LNG plant owners. This model (Cell C14 in the ‘Assumptions & Results’ sheet) provides the option of evaluating either LPG investor alternative, or no LPG extraction at all if the gas stream is not considered to be “wet”. LPG extraction revenues typically would only be received by the LNG plant owners if the plant owners took title to the gas stream, which is not the case in a normal tolling scenario (see Table 2).

**LNG Plant** – These plants often require production from several different blocks in order to be economic and entail very different technical and commercial risks than upstream investments. In addition there can be clear commercial conflicts of interest between upstream suppliers of gas and the LNG plant as the buyer of gas and reseller of LNG. Because of these factors it is most common that the LNG investors are a completely separate group than the upstream investors, although it is not uncommon to include some of the upstream investors in the LNG group as well. Typically the LNG plant commercial structure is one of three options:

1. **Tolling Plant Model** – The LNG plant investors pay the capital and operating costs of the plant, but the ownership of the produced gas remains with the upstream producers. The LNG plant owners charge a negotiated fee per unit of gas processed as their source of revenues (Line 97 of the ‘Assumptions & Results’ sheet in the model). After paying for the processing of gas into LNG, the upstream owners market and sell the gas into the export market.

2. **Independent Plant Owner/Buyer Model** - Separate LNG plant owners are the buyers of the unprocessed gas. Under this structure, a separate group of LNG plant investors pays the capital and operating costs of the LNG plant, and those LNG investors purchase and take title of the gas on an arms-length basis from the upstream owners as it enters the plant “gate” from the gas pipeline. The LNG investors then sell the LNG into the export market.

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1 Angola is a case in point: As part of the overall deal the upstream blocks were required to pay all capital costs of the gas pipelines, and could include them in their PSA cost recovery. Upon completion of construction, the full ownership was transferred to Sonangol, the State owned company. All of the LNG partners were part of the management of the pipeline and shared the operating costs, but ultimate control and ownership was passed to the State as it was viewed as a strategic asset necessary to enable new fields to be able to access the LNG plant.
3. **Related Party Plant Owner/Buyer Model** - Upstream investors own and operate the LNG plant. This is similar to the model option above, but the ownership of the LNG plant is the same as the upstream ownership group. Due to separate tax regimes that typically treat upstream activities differently than an LNG plant, there is usually a requirement to establish a transfer price (Line 4 of the ‘Assumptions & Results’ sheet in the model) from the upstream to the related parties in LNG plant. The Government would normally be the arbiter of what constitutes a fair transfer price for tax purposes.

The model permits the assessment of the three structures. The Independent Plant Owner/Buyer Model and the Related Party Plant Owner/Buyer Model structures are evaluated in the worksheets called “LNG equity” and “Consolidated LNG equity”. The model would require the same items of input and would utilize the same computation. **The difference between these two structures would be that one would use an arms-length market price and the other would use an agreed transfer price.** Even though the ownership structure may be different, the fiscal and economic result should be the same. Users of the model can assess the impact on investor returns and government revenues under different transfer price scenarios (in the sensitivity analysis section of the ‘Assumptions & Results’ sheet).

The tolling plant structure is evaluated in the worksheets called “LNG Tolling” and “Consolidated LNG Tolling” sheets.

There can be variations in all of these forms, so the substance of the structure must be scrutinized to ensure the right option is selected in the model, not to mention in reviewing the actual proposals given by the investor.

**LNG Tankers** – There are several options for ownership and control of the high cost specialized refrigerated LNG tankers. In many cases LNG buyers own or charter hire and manage these LNG tankers (Line 8 of the ‘Assumptions & Results’ sheet in the model); and the LNG is sold on an free on board (FOB) basis from the LNG plant (Line 7 of the ‘Assumptions & Results’ sheet in the model). In other cases the LNG sellers themselves may own or charter hire the LNG vessels; and in those cases the LNG may be sold on a Delivered ex-Ship (DES) basis price as determined at market at the regasification receiving terminal country (Line 9 of the ‘Assumptions & Results’ sheet in the model). There are often variations whereby the LNG owners may own or charter hire some vessels and sell those cargoes on a DES basis, but will sell the remainder of the LNG to buyers on a FOB basis under an arrangement where the buyers arrange and pay the costs of their own LNG vessels. The model allows users to either choose the FOB or DES method. If the project uses a mix of both methods, the user must compute the average price and average tanker costs outside the model before inputting in any one year.

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2 For the purpose of the model, no distinction is made between a sale to an unrelated or a related party. There is only 1) the final export price of the LNG, and 2) the price that the LNG plant owners pay to the upstream owners to acquire the gas (“transfer price”). The methods for determining either of those prices can vary considerably (depending on such factors as the cost and scope and number of trains of the LNG plant, whether the gas is wet or dry, the distance and cost to transport the gas to the plant, and what market the LNG is being sold into). To derive the transfer price, a simplistic percentage formula is used, irrespective of whether the LNG owners were related to the upstream owners. It would always be up to the government to continually review or try to adjust any prices proposed between related parties during the life of the plant.
c. Fiscal Arrangements by Segment

- The upstream sector fiscal terms are determined by the PSA or legislation regarding taxes and royalties. The information required for the input into the model can be obtained from those documents.
- The gas pipeline costs usually are either considered part of the upstream costs for fiscal purposes, or if a separate entity, would typically be part of the country’s corporate income tax regime.
- The LNG plant is usually part of the country’s corporate income tax regime, but in many cases the plant owners negotiate fiscal terms that could include features such as:
  - Permitting some capital costs from LNG to be taken as deductions against the upstream fiscal regime. Typically, this would only be possible in situations where the LNG equity investors are the same as the upstream investors.
  - A specified period of tax holidays or tax exemptions
  - Special levy imposed if gas prices rise above a certain level and the LNG plant investors are the sellers of the LNG.
  - When the LNG plant is owned by the same group of investors as the upstream, there is usually an “arms-length” type of transfer pricing required for the gas in order to determine the tax and fiscal treatment and split between the upstream fiscal regime and the downstream.

Tables 1, 2, 3 below, summarize the above explanations.

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Footnote: Note that the model allows to use two types of profit sharing arrangements – R-Factor based and production-based
<table>
<thead>
<tr>
<th>Gas Projects - Aspects by Segment</th>
<th>Upstream</th>
<th>Gas Pipeline</th>
<th>LNG Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ownership</td>
<td>Granted by License Award by Government</td>
<td>Can be part of upstream, or Different</td>
<td>Separate from upstream</td>
</tr>
<tr>
<td>Participation by NOC</td>
<td>Commonly the case</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>Legal Form</td>
<td>Typically unincorporated JV</td>
<td>Part of upstream JV, or Investors purchases Shares in a separate Company</td>
<td>Shares Company (Investors that can be the same as in the upstream purchase shares in a separate LNG Company)</td>
</tr>
<tr>
<td>Source of Revenues</td>
<td>Sales of Natural Gas to LNG plant, or Sales of LNG to Export Buyers</td>
<td>Tariffs from upstream, or Part of upstream Costs</td>
<td>Tolls from upstream, or Sale of LNG to Export Buyers</td>
</tr>
<tr>
<td>Main Risks</td>
<td>Geologic, Market (gas prices) Successful exploration, Completion, and Operational</td>
<td>Completion, and Operational only (Maintaining full capacity)</td>
<td>Completion, Operational (Maintaining full capacity), and Market (gas prices) (if not a Tolling plant only)</td>
</tr>
<tr>
<td>Fiscal Regime</td>
<td>PSA, or upstream Royalty/Petroleum Tax Regime</td>
<td>Part of upstream Fiscal Regime, or Corporate Tax</td>
<td>Corporate Tax, often with special incentives or taxes</td>
</tr>
<tr>
<td>Rates of Return (typical range)</td>
<td>15% +</td>
<td>7-13%</td>
<td>11-16%</td>
</tr>
</tbody>
</table>
Table 2: Overview of where the title to gas and LNG passes under the different ownership structures

<table>
<thead>
<tr>
<th>Ownership Structure</th>
<th>LNG Plant Investors</th>
<th>Upstream</th>
<th>Gas Pipeline</th>
<th>LNG Tankers/Export Buyers</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Independent Plant Owner/Buyer:</strong></td>
<td>LNG Plant Investors purchase gas from <strong>Upstream</strong>. Title passes to different LNG Plant Investors.</td>
<td>Upstream Gas Producers</td>
<td>Gas Pipeline</td>
<td>LNG Plant (separate investors than upstream)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ownership Structure</th>
<th>LNG Plant Investors</th>
<th>Upstream</th>
<th>Gas Pipeline</th>
<th>LNG Tankers/Export Buyers</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Related Party Plant Owner/Buyer:</strong></td>
<td>LNG Plant Investors purchase gas from <strong>Upstream</strong>. Title passes to LNG Plant Investors who are the same owners as Upstream, but a different legal entity.</td>
<td>Upstream Gas Producers</td>
<td>Gas Pipeline</td>
<td>LNG Plant (same investors, but separate legal entity)</td>
</tr>
</tbody>
</table>

**Tolling Structure:** **Upstream** retains title to Gas/LNG until point of export; LNG Plant Investors just receive a toll.

![Diagram showing the flow of gas ownership](image)

◆ = Point where title is passed
Table 3: Overview of which segment is bearing the risk factor according to the commercial structure

<table>
<thead>
<tr>
<th>Risk Factor:</th>
<th>Tolling Structure</th>
<th>Equity Structure – LNG Plant owners are same as upstream</th>
<th>Equity Structure – LNG Plant owners are separate</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNG market price risks</td>
<td>Upstream bears full risk</td>
<td>LNG plant investors bear full risk</td>
<td>LNG plant investors bear full risk unless transfer price from upstream is linked to market price</td>
</tr>
<tr>
<td>Gas transfer price to plant</td>
<td>Not applicable since gas is not sold to plant</td>
<td>Upstream owners want as low as possible</td>
<td>Upstream owners want as high as possible and plant owners as low possible – which will get the parties to a true arm’s length price</td>
</tr>
<tr>
<td>Upstream production and reserves risks</td>
<td>Both upstream and LNG investors bear risk unless there is a send-or-pay clause to protect plant investors</td>
<td>Both upstream and LNG investors bear risk, but could entail a shift due to different fiscal regimes.</td>
<td>Both upstream and LNG investors bear risk unless there is a take-or-pay clause to protect plant investors</td>
</tr>
<tr>
<td>LNG plant operability and downtime risks</td>
<td>Both upstream and LNG investors bear risk unless there is a take-or-pay clause to protect upstream investors</td>
<td>Both upstream and LNG investors bear risk</td>
<td>Both upstream and LNG investors bear risk unless there is a take-or-pay clause to protect upstream investors</td>
</tr>
<tr>
<td>LNG plant capital cost risks</td>
<td>LNG plant investors take full risk, unless tolling tariff formula is linked to costs</td>
<td>LNG plant investors bear full risk</td>
<td>LNG plant investors bear full risk</td>
</tr>
<tr>
<td>LNG evaporation product loss</td>
<td>Upstream bears full cost</td>
<td>LNG plant investors bear full cost</td>
<td>LNG plant investors bear full cost</td>
</tr>
<tr>
<td>Upstream capital cost risks</td>
<td>Upstream bears full risk</td>
<td>Upstream bears full risk</td>
<td>Upstream bears full risk</td>
</tr>
</tbody>
</table>
3. Using the model

a. Structure

The model is composed of 15 worksheets, which are linked by formulas. Table 4 provides an overview of the function of each worksheet. The worksheets are color coded, with the blue worksheet (‘Assumptions & Results’ sheet) being the place where users may input all variables and can observe the compiled results. This is also where the sensitivity analysis is presented. Users will spend most of the time in this worksheet. The red worksheets provide the user with the upstream project economics and government revenues for 3 fields. The green worksheet provides the user with the pipeline project economics and government revenues. The orange worksheets provide the user with the LNG project economics and government revenues for the LNG project under the three most common structures explained in section 2b. The black worksheets consolidate the upstream, pipeline and LNG project economics under the three structures.

Table 4: Worksheets of the model

<table>
<thead>
<tr>
<th>Name of worksheet</th>
<th>Description of variables in worksheet</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumptions &amp; Results</td>
<td>Assumptions are inputted and key results are presented graphically</td>
</tr>
<tr>
<td>Field 1 Depr</td>
<td>Depreciation schedule of the capital expenditure of Field 1</td>
</tr>
<tr>
<td>Field 1 Fiscal</td>
<td>Computation of the fiscal terms paid by upstream gas investors of Field 1</td>
</tr>
<tr>
<td>Field 1 Investor</td>
<td>Calculation of the financial return of the investor and of the government take for Field 1</td>
</tr>
<tr>
<td>Field 2 Depr</td>
<td>Depreciation schedule of the capital expenditure of Field 2</td>
</tr>
<tr>
<td>Field 2 Fiscal</td>
<td>Computation of the fiscal terms paid upstream gas investor of Field 2</td>
</tr>
<tr>
<td>Field 2 Investor</td>
<td>Calculation of the financial return of the investor and of the government take for Field 2</td>
</tr>
<tr>
<td>Field 3 Depr</td>
<td>Depreciation schedule of the capital expenditure of Field 3</td>
</tr>
<tr>
<td>Field 3 Fiscal</td>
<td>Computation of the fiscal terms paid by upstream gas investor in Field 3</td>
</tr>
<tr>
<td>Field 3 Investor</td>
<td>Calculation of the financial return of the investor and of the government take for Field 3</td>
</tr>
<tr>
<td>Gas PL</td>
<td>Economics, financial returns and government take of the gas pipeline</td>
</tr>
<tr>
<td>LNG Equity</td>
<td>Computation of LNG project economics of Equity/buyer structure, whereby LNG owners take title to gas from upstream and sell to 3rd parties (irrespective of whether the LNG plant owners are the upstream operators)</td>
</tr>
<tr>
<td>LNG Tolling</td>
<td>Computation of LNG project economics of tolling structure, whereby the LNG plant does not take title to gas and the gas owners pay a toll (i.e: a fee) for processing purposes</td>
</tr>
<tr>
<td>Consolidated LNG Equity</td>
<td>Consolidation of the economics of all 3 elements of the projects (upstream, pipeline and LNG facility) under the LNG Equity model</td>
</tr>
<tr>
<td>Consolidated LNG Tolling</td>
<td>Consolidation of the economics of all 3 elements of the projects (upstream, pipeline and LNG facility) under the LNG-Tolling structure</td>
</tr>
</tbody>
</table>
The cells in the model are also color coded to facilitate the navigation of the model. Table 5 explains each color coded cell used in the model.

### Table 5: Color-coding of cells in the model

<table>
<thead>
<tr>
<th>Color</th>
<th>Description of color coding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Light blue</td>
<td>Input variables that can be changed by the user. Price, production, cost and fiscal inputs should all be edited in the ‘Assumptions and Results’ worksheet. The structure to be analyzed can be chosen in cell C156 of that tab.</td>
</tr>
<tr>
<td>Light green</td>
<td>Section dividers</td>
</tr>
<tr>
<td>Yellow</td>
<td>Checks that allow the user to see whether errors have occurred in the model. This color has also been used to highlight which model structure is activated and therefore which results are valid and invalid</td>
</tr>
<tr>
<td>Red</td>
<td>Key results</td>
</tr>
<tr>
<td>White</td>
<td>Fields that are linked by a formula in the model and should not be changed by inexperienced modelers, as changing them may result in the model not functioning properly</td>
</tr>
<tr>
<td>Red font</td>
<td>Explanatory notes within the model</td>
</tr>
</tbody>
</table>

*It is important to note that the user needs to pick the commercial structure that he/she wants to analyze in Cell C156 in the ‘Assumptions and Results’ worksheet. If the user wants to assess the tolling structure, then “1” should be inserted in cell C155. If the user wants to assess the equity structure, “2” should be inserted.*

### b. Calculations and Outputs

**Understanding how the model is linked**

As explained above, the white fields (the majority of the fields in the model) are linked by formulas and should only be edited by more experienced modelers, given that changing the formulas might break the model and lead to wrong results. To understand how a particular field is linked within the model, the “trace precedents” and “trace dependents” functions in Excel can be used. These will provide insights into what cells are calculating the field and what other cells are affected by the field.

**Checking for errors**

As explained above, the yellow background cells provide the user with feedback on whether there are mistakes in the model and which results are valid and invalid based on the structure that has been chosen. This should help the user to make sure that the correct worksheets are used for the structure that is being analyzed. For example, if the user selects the tolling structure in the assumptions page, then only the ‘LNG Tolling’ and the ‘LNG Tolling Consolidation’ worksheets are VALID and the ‘LNG Equity’ and ‘LNG Equity Consolidation’ worksheets INVALID. This will be flagged in the top left corner of these four worksheets. There are several other cross-checks in the model. If the word INVALID (or NOT APPLICABLE in the chart area of the Assumptions &Results sheet) appears in any spreadsheet the user should check for structure chosen in cell C156 and/or any errors in the input data or formulas.
Checking and understanding the results

- **Checking that project and investor returns are reasonable** – Users should check the net present value (NPV) and internal rate of return (IRR) for each of the segment of the project. Both the NPV and IRR indicators take into account the time-value of money. A higher discount rate used for the NPV calculation means that later cash flows are discounted at a higher rate (i.e. that later cash flows are worth less). The IRR is the discount rate at which NPV=0. Table 1 of this guide provides a rough reference as to what range of returns (IRR) are required for each segment (these rates are only ballpark figures and need to be risk adjusted). All of the segments need to be commercially viable in order for the whole project to go ahead and attract investors. If the results show that the individual segments are earning much lower or much higher rates of return, it may be a sign that the assumptions need to be reviewed, that the project is not economic and/or that the fiscal system is too onerous. If the rates of return are high, the commercial terms may be unduly skewed to the investors with the government being able to increase taxes and still attracting investors.

- **Checking that the Government Take (GT) is reasonable** - Another factor to look at is the GT, which is defined as all payments going to the government (royalties, Government’s share of production under a PSA, income taxes, etc) divided by the pre-tax project cash flows. Given the higher returns on the upstream segment, GT tends to be higher there than for the pipeline and LNG segment. Apart from reviewing the GT for the individual projects, the consolidated GT should also be reviewed to assess whether subsidies, incentives or fiscal reliefs granted in one or more segments (necessary to reach the NPV and IRR to make those segments attractive for investors) are worth it on a consolidated basis.

- **Checking the interpretation of the fiscal terms, assessing the impacts of different structures and potential for profit shifting** - When deciding on the commercial and legal ownership structure for the project it is important to understand how the fiscal terms are interpreted, as different interpretations may have a large impact on the revenue flows. For instance, when considering a tolling structure the upstream investors may find that treating the tolling costs as simple operating cost subject to cost recovery may create a disadvantage by displacing or deferring recovery of costs from the other upstream operations and capital spending. When compared to other commercial or legal structures, such as the equity option of selling the gas to the LNG plant, the investor economics are negatively affected. In this type of case, the upstream operators may seek an interpretation of the PSA that would allow them equivalency with the other ownership options. In this example, a means of achieving that parity would be to “netback” the final LNG FOB price by netting out the tolling costs. These interpretations can be very technical and not easy to follow, but can be critical to the financial returns to investors and to the Government.

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4 Cells C38 and C39 of the ‘investor’ worksheets for field 1,2,3; cells C37 and C38 of the ‘Gas PL’ worksheet; cells C44 and C45 of the ‘LNG equity’ worksheet, cells C33 and C34 of the ‘LNG Tolling’ worksheet; cells C31 and C32 of the ‘Consolidated LNG equity’ worksheet; and cells C29 and C30 of the ‘Consolidated Tolling’ worksheet.

5 This is what this model does in Lines 4-5 of the ‘Field X Fiscal’ sheets.
Another interpretation example comes from countries where the government allows the investors to interpret the PSA in such a way to permit some of the LNG capital costs to be considered “upstream” in nature and thereby become part of PSA Cost Recovery. Since effective Government Take is generally higher in the upstream, this has the impact of improving the investor’s rate of return by reducing profit gas and taxes. This can be a legitimate means of incentivizing LNG investment, but must be recognized as being, in effect, a subsidy by the government. This latter type of interpretation would normally not be considered unless the project structure was the Related Party Plant Owner/Buyer Model where the upstream investors were the same as the LNG plan investors. The model provides options to allow for the pipeline and LNG expenditures to be deducted from the upstream project.⁶

Furthermore, the model also allows for the transfer price from the upstream to the LNG project to be adjusted. If the transfer price is reduced, the upstream project will appear less economic, while the LNG project appears more economic. This impact should be viewed with caution as a reduction of the transfer price will also result in a fall in overall government revenues given that the LNG segment is taxed at a lower rate than the upstream segment. If upstream owners also own the LNG plant they will have a natural benefit and incentive to shift revenues to a lower tax regime, which means less for the government.

• **Understanding the timing of government revenues.** As noted above, early returns to the investor will increase the IRR and NPV of the project. Given the high levels of capital expenditure required for oil and gas projects, it is common for countries to allow for cost recovery and depreciation in the fiscal terms. This will result in government revenue flows being delayed. The consolidated worksheets provide the government and civil society with an indication of when revenues from the various segments should be expected, which may help governments in fiscal planning and manage expectations of civil society.

• **Checking the competitiveness of the fiscal terms.** In order to test the competitiveness of the fiscal terms, it may be worthwhile running a “benchmarking” evaluation of similar projects in the same country or in another country (See sources of data and assumptions section of where data for similar projects may be found).

• **Understanding the sensitivity analysis.** It is important to test the resilience of the results under a range of circumstances. This exercise is called “sensitivity analysis”. While the results for the investors and for the government may look reasonable in the base case, it is important to ensure that these results hold under modified assumptions. For example, it should be tested that the investor IRR and NPV indicators do not completely collapse when the gas prices moderately fall and that government take increases with a rise in gas prices. If either is the case, it is likely that there will be pressures for the contract to be renegotiated when commodity prices change. This

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⁶ The model gives this possibility in lines 61-65 and 77-85 of the ‘Assumptions & Results’ sheet.
model provides for sensitivity analyses from line 237 in the ‘Assumptions and Results’ worksheet. Apart from price changes, the sensitivity analysis tests the impacts of varying assumptions regarding the production, capital expenditure, tolling fees and delay in production start.

- The sensitivity analyses are calculated using the ‘data table’ function in Excel, which cannot be traced by the ‘trace precedents’ function. If a particular result in the sensitivity analysis is surprising and the user is unfamiliar with the ‘data table’ function, it is recommended to re-run the model with the revised assumptions to better understand the results.

- To test the sensitivity of lower production volumes and production start delays, the model includes additional input variables for the upstream gas field 1, which have not been replicated for fields 2 and 3. This is for illustrative purposes. The same sensitivities should be performed for these two other fields once more information is available.
4. Assumptions and input variables

Input assumptions have a significant impact on the modeled results. If the input assumptions are wrong, the results will also be wrong. Therefore a careful review needs to be undertaken of the available information. The most significant input assumptions and data are as follows:

**Forecast prices** – LNG prices typically are agreed with individual buyers under a contract formula. These formulae can vary, but typical methods include:

- Directly linked to a published natural gas index price at a large natural gas market, e.g. Henry Hub (see further explanation below).
- Directly linked to a published crude oil index price for a widely traded crude type, e.g. Brent. This type of price would also require an adjustment to recognize the different energy content, processing requirements and standard of measurement of oil versus natural gas.
- An agreed blended mix of the above two basic methods.

These prices are usually on a DES basis (at the market) and may be further adjusted to an FOB basis to recognize transportation costs to reach such reference markets, energy or BTU content of the gas, and whether the contract is short or longer term in nature.

Generally LNG and natural gas that is produced and sold from any country is priced based on international markets. Those markets are divided into three regional markets: 1) North America, where the pricing point is called “Henry Hub” and is the primary price for natural gas futures contracts traded on the New York Mercantile Exchange and the over-the-counter (OTC) swaps traded on the Intercontinental Exchange (ICE); 2) Asia where the pricing benchmark is called Japan Customs –cleared Crude (JCC), which is the average price of crude of the second largest Asian importer and is a commonly used index in long term LNG contracts in Japan, Korea and Taiwan; and 3) Europe where the trading point is called the National Balancing Point, which is the virtual trading location for the sale and purchase and exchange of UK natural gas and is the pricing and delivery point for the ICE Futures Europe natural gas contract. LNG pricing references and benchmarks are still evolving.

For instance, the crude-price linked methodology was widely used in older long term LNG contracts and still influences how LNG is priced. Newer sales contracts are more frequently referencing natural gas or LNG price hub indices as benchmarks.

Markets are affected by general growth in energy consuming economies and its effect on demand for energy, ease of substitution of one type of fuel for another, and competing LNG projects in other parts of the world. Often it may be best to use as a base case a generally recognized forecast of prices, such as those from the World Bank (see [http://www.worldbank.org/en/research/commodity-markets](http://www.worldbank.org/en/research/commodity-markets)). All that we know about any price forecast is that it will be wrong, so testing a range of sensitivity cases for prices is essential to better understand the risks and upsides and how they may affect the key results.
Production forecasts – Not only are upstream production rates and reserves needed to run the model, it is also important to note that for natural gas projects there is always a certain amount of “product loss” as the natural gas may be used as a fuel in running machinery or equipment, plus in the process of being cooled to a liquid form or being warmed back into a gaseous form and stored usually entails a certain amount of evaporation. Keep in mind that full upstream production capacity will always constrained by the LNG plant designed capacity to take the gas and by any LNG plant downtime for maintenance or emergency shut-ins. Consequently, upstream production forecasts must take this into account. The model includes input for these factors.7

With respect to product loss due to evaporation or running machinery, in the Tolling model the upstream gas owners bear the impact of any product loss or evaporation during the LNG plant processing as they would still pay the toll based on product going into the plant and still retain ownership of the gas.8 In the Equity model the LNG plant owners bear the economic impact of the product loss since they took title to the gas at the LNG plant gate9 (see Table 3).

Domestic supply of gas – Since natural gas and LPG can be used relatively cheaply and easily domestically for electrical power generation or direct industrial or consumer purposes, most LNG projects contain some requirement for natural gas or LPG to be supplied to local markets. The negotiation of the volumes to be dedicated for this purpose, the determination of the sales price and the tax treatment can become critical issues to investors and the government. The challenge is that the amount actually utilized in the domestic market may build or vary annually as the gas markets are being developed whereas investors are locked-in in long-term gas contracts with gas buyers. The model permits a range of assumptions to be incorporated.10

Capital costs forecasts – Since capital costs occur in the very beginning of a project they have a much greater impact on discounted value indicators. In addition, cost overruns have a disproportionate impact on host governments due to the interplay of government take factors and the more restricted options for financing typically available to government. Also, several studies indicate that most companies tend to greatly underestimate the capital costs on megaprojects. These factors taken together mean that testing capital cost sensitivity analyses, especially testing for large overruns, are especially important for any host government or national oil company (the model allows this in the sensitivity analysis section of the ‘Assumptions & Results’ sheet). For more information on why such analysis is crucial, see:

http://www.spe.org/ogf/print/archives/2012/02/02_12_08_Feat_Cost_Est.pdf
http://www.costandvalue.org/download/?id=2047
http://www.ogdeestimating.com/services/field-development/type-of-estimate

7 See ‘Assumptions & Results’ sheet, lines 24 and 25
8 See ‘Field X Investor’ sheet, line 12
9 See ‘LNG Equity’ sheet, line 13
10 See ‘Assumptions & Results’ sheet, lines 10-11 and 26-28
**Fiscal terms and taxes** – As explained above, this information should be available from published petroleum and tax laws of the country, plus any agreements, such as Production Sharing Agreements,\(^\text{11}\) between the government and the upstream investors. Oftentimes, the details of the LNG fiscal terms are not agreed until right before the Final Investment Decision is made.

**Units of measurement** – Extreme care must be taken when entering data into an economics model to ensure that the units of measure are known and are made consistent within the model, and that conversions are performed where necessary. The following industry convention should be taken into account:

1. Natural gas production, gas reserves and pipeline capacity are typically measured in units of volume, such as Thousands of Standard Cubic Feet (MCF) or Thousands of Cubic Meters (MCM). When referring to gas reserves it is common to use a measurement of Trillion of Cubic Feet (TCF).
2. LNG Plant capacity and LNG Tanker capacity are commonly measured in units of weight, typically in Metric Tons (MT) since they are producing or transporting gas in a liquid form.
3. Condensate (liquids present in wet gas fields) is commonly measured in Barrels, while LPG may be measured in Barrels or Metric Tons.
4. In many cases capacity is measured as an amount PER DAY while in other situations volumes are referred to as an amount PER ANNUM.
5. In some cases where there is a high liquids content in the natural gas stream the gas may be measured or referenced in units relating to its energy content, typically Thousands of British Thermal Units (MBTU) or in some cases as Gigajoules.
6. Most natural gas and LNG sales prices are quoted and paid in U.S. Dollars. A commonly referenced unit in price quotes for natural gas is Dollars per MCF and may be converted to a price per MT for LNG.
7. Most tariffs or tolls are referenced in U.S. dollars. Pipeline tariffs are usually a price per MCF. LNG Tolling tariffs may be a price per MCF or in many cases a price per MT.
8. Also, attention must be paid to the “thousands” conventions. In the petroleum industry, “M” typically is used to refer to one-thousand and “MM” refers to one-million (or a thousand thousands). The economics model itself usually refers to input and output amounts expressed in millions, or MM.

The below tables can help users with conversions where necessary:

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\(^\text{11}\) See resourcecontracts.org for a database of publicly available contracts.
Table 6: General Conversion Factors for Energy

<table>
<thead>
<tr>
<th>From:</th>
<th>To:</th>
<th>TJ</th>
<th>Gcal</th>
<th>Mtoe</th>
<th>MBtu</th>
<th>GWh</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>multiply by:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TJ</td>
<td>1</td>
<td>238.8</td>
<td>2.388E-5</td>
<td>947.8</td>
<td>0.2778</td>
<td></td>
</tr>
<tr>
<td>Gcal</td>
<td>4.1868E-4</td>
<td>1</td>
<td>10E-7</td>
<td>3.968</td>
<td>1.163E-3</td>
<td></td>
</tr>
<tr>
<td>Mtoe</td>
<td>4.1868E-4</td>
<td>10E-7</td>
<td>1</td>
<td>3.968E-7</td>
<td>11630</td>
<td></td>
</tr>
<tr>
<td>MBtu</td>
<td>1.0551E-4</td>
<td>0.252</td>
<td>2.52E-8</td>
<td>1</td>
<td>2.931E-4</td>
<td></td>
</tr>
<tr>
<td>GWh</td>
<td>3.6</td>
<td>860</td>
<td>8.6E-3</td>
<td>3412</td>
<td>1</td>
<td></td>
</tr>
</tbody>
</table>

Source: GAIL

Table 7: Additional Useful Conversion Factors

<table>
<thead>
<tr>
<th></th>
<th>= 1 cubic metre @ 1 atmosphere pressure and 15.56 °C</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Cubic Metre</td>
<td>= 35.31 Cubic feet</td>
</tr>
<tr>
<td>1 BCM (Billon Cubic Metre) / Year of gas (consumption or production)</td>
<td>= 2.74 MMSCMD 365 Days a Year</td>
</tr>
<tr>
<td>1 TCF (Trillion Cubic Feet) of Gas Reserve</td>
<td>= 3.88 MMSCMD 100% Recoverable for 20 years @ 365 days / Annum)</td>
</tr>
<tr>
<td>1 MMTPA of LNG</td>
<td>= 3.60 MMSCMD Mol.Weight of 18 @ 365 days / Annum)</td>
</tr>
<tr>
<td>1 MT of LNG</td>
<td>= 1314 SCM Mol.Weight of 18</td>
</tr>
<tr>
<td>Gross Calorific Value (GCV)</td>
<td>= 10000 Kcal/SCM</td>
</tr>
<tr>
<td>Net Calorific Value (NCV)</td>
<td>= 90% of GCV</td>
</tr>
<tr>
<td>1 Million BTU (MMBTU)</td>
<td>= 25.2 SCM @10000 Kcal/SCM; 1 MMBTU= 252,000 Kcal)</td>
</tr>
<tr>
<td>Specific Gravity of Gas</td>
<td>= 0.62 Molecular Weight of Dry Air=28.964 gm/mole)</td>
</tr>
<tr>
<td>Density of Gas</td>
<td>= 0.76 Kg/SCM Mol.Weight of Gas 18 gm/mol</td>
</tr>
<tr>
<td>Gas required for 1 MW of Power generation</td>
<td>= 4541 SCM per Day Station Heat Rate (SHR); ~ 1720 Kcal/Kwh-NCV (50% Thermal Efficiency); N.Gas GCV-@10000 Kcal/SCM</td>
</tr>
<tr>
<td>Power Generation from 1 MMSCMD Gas</td>
<td>= 220 MWH Station Heat Rate (SHR); ~ 1720 Kcal/Kwh-NCV (50% Thermal Efficiency); N.Gas GCV-@10000 Kcal/SCM</td>
</tr>
</tbody>
</table>

Source: GAIL

When using conversion tables to convert from gas volume measures (such as CF or CM) to gas energy measures (such as BTU or gigajoules) it must be recognized that the degree of liquid content in the gas stream can affect those conversion factors. In the same way when converting

12 http://www.gailonline.com/final_site/energyconversionmatrix.html
from liquid volume measures (such as barrels or MCF) to weight measures (such as metric tons) the specific gravity of the liquids will affect that conversion. These ranges are usually relatively small, but can create differences from the conversions used by a company or government in their models.

5. Mozambique example
For illustrative purposes, the input values in the model are based on publicly available information on the Rovuma basin LNG project in Northern Mozambique. However no quantitative conclusions can be drawn from this analysis given that the data is still very preliminary and there were a number of data gaps. Furthermore, some of the numbers have been adapted to better show the impact of the different project structures. The second upstream field has been included to illustrate the impact of additional volumes on the LNG economics and has the same characteristics as the first upstream field.

a. Assumptions and references

Fiscal Terms
• Upstream Fiscal Terms are based on Block 1 PSA from 2006, with some exception. Bonus amounts indicated in the PSA and withholding tax are not included.
• A $1 Billion unrecovered exploration cost is included (out of $2 Billion total unrecovered exploration costs), based on the Standard Bank report.\textsuperscript{13} It was assumed that some of that amount is not recoverable as they would be outside the ring fence.
• For the gas pipeline segment the standard corporate income tax of 32% with no tax relief or investment uplift (such as was provided for the Pande Temare project) is used (Petroleum Law No 27/2014).
• For the LNG segment the standard corporate income tax of 32% with no tax relief or investment uplift is used (Petroleum Law No 27/2014).

Technical and Commercial Inputs
• The LNG production volumes are estimated based on four LNG trains at 6 million tonnes per annum each. This is equivalent to a total LNG plant output of approximately 1,062 million cubic feet per day (MMCFD). The upstream production is assumed to be 1650 MMCFD per field before taking account for LNG production losses of LNG plant downtime.
• It is assumed that two upstream projects are supplying the LNG plant. Figures for both fields are the same.
• The pipeline construction has been scheduled to conclude one year before start of operations to allow for line testing, inspections and potential modification prior operation.
• Based on the reviewed material, the model uses the tolling structure as the base case.
• The capital cost and timing of expenditure figures are based on educated guesses and adapted to provide reasonable return rates for the different segments of the project. Excluding the financing cost and capitalized interest, these figures are relatively close to the Standard Bank report estimates.

\textsuperscript{13} Standard Bank (2014) Mozambique LNG: Macroeconomic Study
• No LPG or Condensate production is assumed. There may be some condensate produced by the upstream projects, which would increase the profitability.
• 2% domestic gas sales are assumed. This would have to be adjusted when the Government’s requirement for domestic sale becomes clearer.
• Due to data gaps regarding the LNG tolling rates and operating costs, these figures are based on educated guesses. The tolling rate will involve a commercial negotiation.
• Under the LNG tolling arrangement it is assumed that the gas price to be used under the PSA terms are to be interpreted as the FOB Export price less the LNG toll itself. This impacts the cost recovery cap. It may be argued that a "Wellhead" type of price for gas is really NET of the toll that would need to be incurred prior to be able to sell the gas (even though the wellhead concept is not used in the PSA per se). A commercial reason is that companies may not be willing to agree to an interpretation of the PSA whereby paying a toll to a third party to process/liquefy the gas would put them in a worse situation than selling the gas directly to a plant owner at the same netback price strictly due to the mechanics of how the Cost Recovery cap functions.

The main documents reviewed for the purpose of this model include:
• 2006 PSA Block 1\textsuperscript{14}
• Mozambique’s Petroleum Law No 27/2014
• Standard Bank (2014) Mozambique LNG: Macroeconomic Study

\textit{b. Asking the right questions regarding the assumptions and Interpreting the results}

\textbf{Fiscal Terms}
The Fiscal Terms are based on an existing PSA and existing tax laws in Mozambique, but do include an assumed “agreed interpretation” regarding the netback of tolling. Some questions that might be asked are:
• Will these terms continue for 30+ years even if costs and markets and production vary?
• Are there any other “interpretations” that end up being agreed (or not agreed) with the government that were not modeled that might create a different result?

\textbf{Commercial Assumptions}
• Is a constant FOB export price of $8.50 per MCF realistic in today’s market, or what is anticipated for the life of the project? If price assumptions are changed, what impact might that have on costs, tariffs or other input assumptions?
• Is an assumed domestic gas price of $2.50 consistent with other terms and assumptions?

\textsuperscript{14} http://www.resourcecontracts.org/contract/ocds-591adf-MZ0646925511RC/view
• Does a LNG toll of $4.00 reasonable and commercially viable to all parties? Will it change over time if world markets change or new projects come into the plant as feedstock?
• Does this LNG toll option yield significantly different results than utilizing an LNG equity option? If so, what caused the difference and does that cause any concern?

Technical Assumptions
The economics assume recoverable reserves of 34 TCF.
• Are there sufficient reserves already discovered in this area to provide this level of production to constantly feed into the LNG plan on an uninterruptable basis, that is, more than 34 TCF in reserves in order to cover unexpected shut-ins or some fields performing at less than expectations? Are the investors and the government relying too much on the hope that additional reserves will be discovered in the future?
• Are reserves so high that it indicates that it might be less than efficient to build only a 4-Train LNG plant?

Total capital costs for all project sectors were $28 billion, including $16.8 billion for the LNG plant.
• Are estimated capital costs too low? Some single train LNG plants have costs more than what was assumed for this 4-Train plant. A high proportion of energy sector “megaprojects” overrun their original budgets by a sizable percentage.
• Are costs too high and consequently understate the real returns to investors?
• Are there any benchmarks to compare costs?
• Have the appropriate range of sensitivity analyses been run and evaluated?

No Condensate or LPG has been included.
• If indeed there would be some condensate or LPG extracted from the gas stream both the capital costs and the resultant net revenues would be higher and project economic results would likely improve.\textsuperscript{15} What would these look like and what fiscal terms (upstream or LNG) would be applied?

Analyzing and Evaluating the Results
Below are a few selected key indicators from the base case:

<table>
<thead>
<tr>
<th>Selected Item</th>
<th>Upstream</th>
<th>Gas Pipeline</th>
<th>LNG Plant</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Costs, $Millions</td>
<td>5,290 * 2</td>
<td>1190</td>
<td>16,768</td>
<td>28,538</td>
</tr>
<tr>
<td>Gas Production</td>
<td>34 TCF</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV at 10%, $Millions</td>
<td>2,185</td>
<td>100</td>
<td>3,274</td>
<td>7,745</td>
</tr>
</tbody>
</table>

\textsuperscript{15} Part of the liquids can be sold on the same price terms as oil and be processed by the same facilities as oil. Some other liquids need additional processing that is a little more expensive in order to be sold. However they can still be relatively easily exported as liquids using a range of widely available vessels into quite a few open markets. Therefore high liquids content in a natural gas project significantly enhances its profitability and can enable producers to charge a lower price for gas. This can make the difference between a gas project being economically viable or not. When the liquids are liable to a high tax rate (e.g. oil tax rates), this economic benefit can be minimized for investors. Therefore, it is important to consider how condensate is treated under differentiated fiscal terms, as this can influence the pace of development of the gas industry (See : http://ccsi.columbia.edu/files/2014/03/Overview-APG-Utilization-Study-May-2014-CCSi1.pdf)
Some questions that might arise from these results:

- Are the relative IRRs for each project sector (e.g. upstream 15%, gas pipeline 11%, LNG plant 15%) reasonable compared to their risks and to other similar investments around the world or the region?
- Do the NPVs at 10% seem reasonable for each project sector relative to the size of the investment and the risk? Are these sufficient to attract the investment but at the same time not yielding too much of the rent?
- How do these IRRs or NPVs change using different assumptions? Check the sensitivity analysis to see whether these indicators collapse due to changes in the assumptions.
- The timing of cash flows is critical in determining NPV and IRR. Check the impact of a production delay of field 1 in the sensitivity analysis.
- Timing of cash flows is also important to the government in terms of the government treasury’s overall budgeting for inflows and spending or managing of sovereign wealth funds. It can also be instructive in evaluating the distribution between the government and the investors. Looking at the base case the first year of significant NET cash flows to investors is 2021 when they earn over $2 billion net, whereas the government does not reach $2 billion a year until 2026. The reality is that the Government does not receive much of their inflows until the last half of the project life, whereas the investors reach their net inflows right after production start.
- Overall percentage split of government take is another important indicator. In the upstream sector the government take is 50% of the total net cash flows, but is only 31-32% for the gas pipeline and LNG sector. This is a reflection of the fiscal and tax terms which are typically much higher in the upstream. But when these are compared to other similar projects with similar risks in other countries to evaluate, do they look to be competitive and consistent?
6. What the model does not include

1. Technical Input Data - The model does not create forecasts of production, costs or prices. These must be obtained from a reliable source such as one of the companies that are investing in the projects, the government or an assessment from an independent party such as an engineering firm, a consultant, a bank, or an international organization such as the World Bank. If completely reliable engineering detailed level data is not available, it becomes even more important to test the economic results by running scenarios with wide variation in the input data.

2. Exploration costs – This model focuses on the decisions to be made after a discovery has been made, so exploration costs are not included (only some of it as recoverable costs under the PSA are included). However, fiscal treatment of exploration costs could become a factor if past “sunk” exploration costs are permitted to break the “ring fence” to be used in cost recovery. At some point this may become a negotiating point in projects going forward and have an impact on the economics.

3. Full Decommissioning Costs Functionality – Decommissioning costs have been included as an upstream input item. However, this can be complex for a couple of reasons. One is that these costs are often required to be pre-funded by the upstream partners accordingly to a complex and sometimes arbitrary formula, and the related cost recovery or tax deductibility treatment can vary significantly. If the costs take place at the end of the field life then loss carryback provisions must be considered, which creates an added complexity. And decommissioning is not straightforward for fields that are feeding into an LNG plant. Often times an individual field may stop producing, yet its infrastructure may end up being used or leased for many years by other suppliers to the LNG plant as processing, compression stations, transportation, treating or even gas storage. This means the ultimate decommissioning from any one field may be delayed by years. Consequently, the model only includes provision for a very simple pay as you go cash basis funding and no loss carryback provisions for tax or production sharing.

4. Differentiation of investor equity shares - The model does not differentiate between the respective investor equity shares in the various segments. They are treated as one group for each segment. However, in many cases the government may have the option to take an equity share in any or all of the segments. In that case, attention must be paid to various factors and impacts, such as:
   • The amount of capital costs that would have to be financed by the government from its own sources or from lenders.
   • The returns that can be expected by the government (and its lenders) from its equity investment.
   • How much production or output will be available to the government to market or utilize for in country needs.
   • How these results are impacted by possible changes in the LNG market, transfer prices, tolls, project structure, recoverable reserves or cost overruns.
5. **Carry of the State’s interest** during exploration or development - This is a common option in PSA's especially as a means of the foreign investors “lending” to the state oil company; but there are many variations on how the repayments work and are quite complex to model. And in many cases the carry and repayment terms end up varying from the basic PSA requirements once a project involves LNG and the carry becomes part of a much larger government share financing discussion and negotiation. In most respects carrying or financing the state share becomes a separate financing negotiation and decision rather than an integral part of the basic gas value chain economics. But a carry often entails high costs to the government since a carry often requires the oil companies taking on certain additional risks. The terms of these carries must be carefully analyzed and modelled to determine their impact on the Government under a variety of assumptions and cost conditions.

6. **Financing** - Borrowing and financing can in some cases have an impact if interest on debt is permitted as a tax deduction. But a common analytical mistake is to focus on leveraged economics, so it is recommended that financing effects not be considered in a model in order to avoid confusing the impacts and compromising the analytical validity of the model. Financing is of course a huge factor in mega-projects such as LNG, especially the government share or for the smaller independent companies; but it must be clearly segregated as a separate type of analysis. If interest costs on loans from affiliated parties are permitted as tax deductions, great care must be taken to ensure they are not excessive. ([http://www.afr.com/business/energy/gas/chevron-claimed-gorgon-bonanza-would-pay-for-tax-for-cuts-for-everyone-20151116-gl0jo1](http://www.afr.com/business/energy/gas/chevron-claimed-gorgon-bonanza-would-pay-for-tax-for-cuts-for-everyone-20151116-gl0jo1))

7. **Withholding Tax on Dividends** – No provision has been made in the model since withholding tax in many cases is really just a minor timing difference on payment of corporate taxes. In other cases with tax treaties the companies get a full relief or credit for withholding taxes. In the event that the WHT in any place does not have these types of “relief” features and it becomes a real final tax, the model can cover this through utilizing the other tax components (surcharge or special tax) that have been set up in the model.

8. **Non Quantifiable Financial Results** – Economics models typically focus only on quantifiable financial results of a project. Most agreement and regulatory provisions do have financial impacts and these can be reflected. However, many other project agreements and petroleum regulations have consequences that cannot be easily modeled. Some of those include:
   - Control of project decisions, such as: approving projects going ahead, moving into the development phase, relinquishment, sales of interest, contracting and procurement.
   - Local content and local employment requirements and policies
   - Environmental regulations and standards,
   - Community engagement and consultation
   - Control and compliance of oilfield services contractors and their impact
   - The Sale and Purchase Agreement itself may protect the upstream and the LNG plant investors from a variety of market and operations disruptions through send-or-pay or take-or-pay clause.