Government Fiscal Strategies under Low Oil Prices and Climate Change

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Pedro van Meurs

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1. Introduction

The climate change debate and in particular the moderately successful 2015 Paris Conference has created a new worldwide framework for resolving climate change issues. In order to make the implementation of COP 21 a success, it is now necessary to transform the goals and lofty ideals into practical and effective upstream petroleum fiscal policies.

At the same time the world is facing a period of extra-ordinary low oil prices. Some of the current fiscal systems are designed to capture windfall profits under high oil prices. However, what is now necessary is to develop broader based strategies whereby fiscal terms are effective under low as well as high oil and gas prices. This document deals with these matters.

First the climate change issues will be reviewed and subsequently the low oil price issues. Thereafter, recommendations will be made with respect to the required changes in existing upstream petroleum policies and fiscal terms. Two examples will be provided of a royalty based system and a production sharing system based on these recommendations.

2. Climate Change

During the 2015 Paris COP 21 Conference a "Framework Convention of Climate Change" was adopted and enshrined in the Paris Agreement on December 11, 2015. Article 2 (1)(a) of this Agreement sets out the agreed goal as follows:

(a) Holding the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius, above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change.

There is no specific agreement as to how this goal should be achieved.

Of course, the easiest way to achieve the goal would be if technological progress towards carbon capture and storage techniques based on capturing CO2 directly from the atmosphere would become cheap enough to function as offsets from significant carbon taxes, say $ 120 per ton CO2 equivalent.

Nevertheless, I am skeptical that technological progress will proceed far enough to result in economic methods to capture CO2 from the atmosphere and turn it into alternative fuels, reinject the CO2 in suitable reservoirs or convert CO2 back to carbon.

Carbon capture and storage projects, where carbon is captured anyway as part of the process, such as CO2 removal from natural gas during production, conditioning or processing, may become economic against certain levels of carbon taxes or could simply become a regulatory requirement. However, the volumes involved are small compared to total emissions.

In the absence of large scale economic carbon capture and storage, it is prudent to consider the petroleum demand scenarios required to achieve the Paris Agreement goals and the alternative scenarios that would apply if the implementation is only a modest success or a complete failure.

It should be noted that forecasting oil and gas demand and supply trends as well as the related price developments is subject to significant error. Over the last 50 years we have been notoriously wrong about making these predictions.

Important currently unforeseen new technical and economic developments could occur. For instance, it could be that cheaper renewable energy supplies will develop during the coming decades and will constrain oil and gas demand and supply more rapidly than the projections in this paper. An interesting report compiled by Bloomberg New Energy Finance, is that by 2040 as much as 35% of new cars could be electric vehicles, reducing oil product demand by about 3 billion barrels per year.

Of course, major changes in economic development, such as long lasting recessions, or political developments, such as major wars, could also significantly alter the forecasts.

It may also be possible that further scientific evidence may indicate that modest annual increases in CO2 content over 450 ppm may be environmentally acceptable.

Therefore, many different forecasts are possible instead of the scenarios to be presented in this chapter. The following scenarios are therefore meant to be a framework for policy decisions, not attempts to make an actual forecast of petroleum demand for this century.

2.1 Oil Scenarios

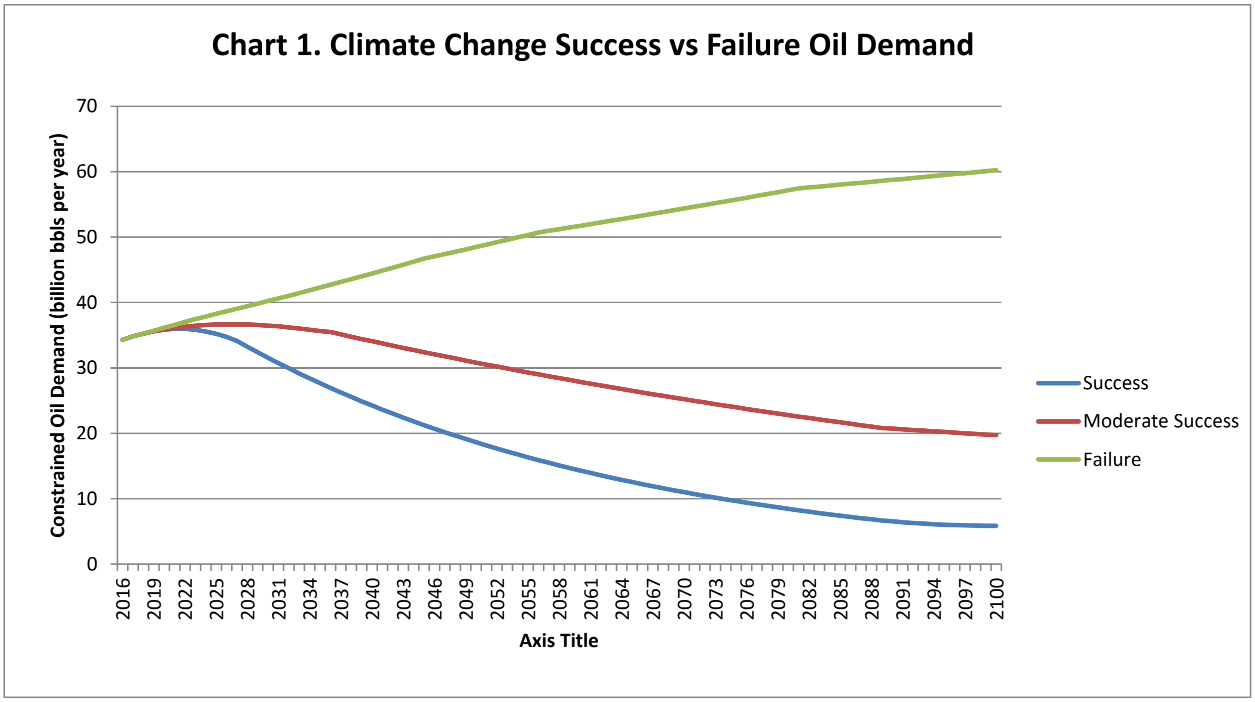
Chart 1 provides the Success Scenario in order to maintain the 450 ppm objective, extended to the year 2100, as well as a Failure Scenario and a Modest Success Scenario.

Success Scenario. In Chapter 8 of the World Energy Outlook 2012 of the International Energy Agency ("IEA") a detailed analysis is done as to how the Paris Agreement objective can be achieved. This is called the 450 Scenario, because it seeks to limit the amount of CO2 in the atmosphere to 450 ppm, which is believed to be consistent with the 2 degrees Celsius objective.

The IEA does not provide for detailed forecasts of constrained oil demand beyond 2035. However, the forecast for 2035 is that the world oil demand has to be well below current demand in that year.

Further reductions in fossil fuel use are required beyond 2035. In fact, the Paris Agreement in Article 14 provides for a regular "global stocktake" starting in 2023 and every 5 years thereafter. In other words there is no time limit on the Convention unless the Parties decide otherwise in the future. Logically, the world would have to continue to reduce the use of fossil fuels. A target would be to phase out the fossil fuels by 2100 as formulated during G7 meeting in June 2015.

Of course, oil and gas will always be required as feedstock for petrochemical and chemical industries. It is also likely that it will be very difficult economically or technically for certain industries to phase out petroleum product consumption entirely. Therefore, it is assumed in Chart 1 that by 2100 petroleum consumption would still be 16 million barrels per day.

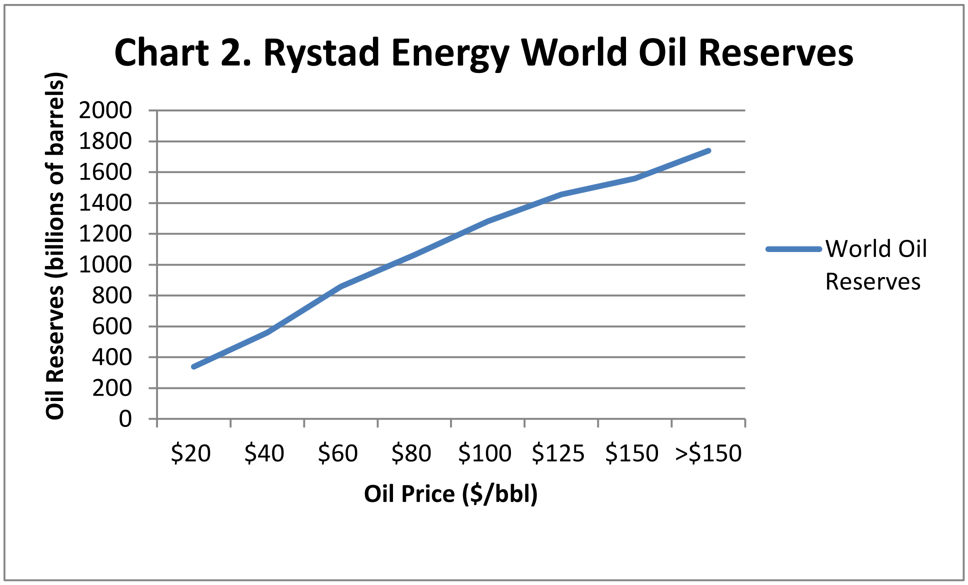


Under the Success Scenario, the cumulative oil consumption until the year 2100 is 1520 billion barrels.

The BP Statistical Review of World Energy, June 2015, provides oil reserve statistics which indicate that the world had at the end of 2014 in total 1700 billion barrels of proved oil reserves. BP defines these "proved reserves" as "quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions".

Since the oil price in 2014 was about $ 100 per barrel, this would represent an estimate at that price level. (BP indicates that this definition is not necessarily the SEC definition). The total BP oil reserves include 167 billion barrels of Alberta oil sands and 220 billion barrels in the Venezuela Orinoco heavy oil belt.

An interesting set of data was published in the Economist obtained from Rystad Energy. This showed the economically recoverable proved oil reserves from existing fields at various price levels. This information indicates that Rystad Energy estimates the world oil reserves at 1455 billion barrels at a price of $ 125 per barrel.



This means that for an oil price range of $ 100 to $ 125 per barrel, we have in principle already found most or all the oil that we can afford to burn during this century under the Success Scenario.

Failure Scenario. Chart 1 also contains the failure scenario. This is based on continuing growth of oil demand, although it is assumed that the growth rate will slow down. In other words the implementation of the Paris Agreement would be a complete failure. This scenario would require 4225 billion barrels of oil. This volume is significantly over current proved reserves and reasonable expectations of what can be further recovered from existing reservoirs, possible new petroleum discoveries to be made and new developments of shale oil projects. Such a scenario would probably require tapping currently uneconomic petroleum resources on a large scale, such as the Green River oil shale in Utah.

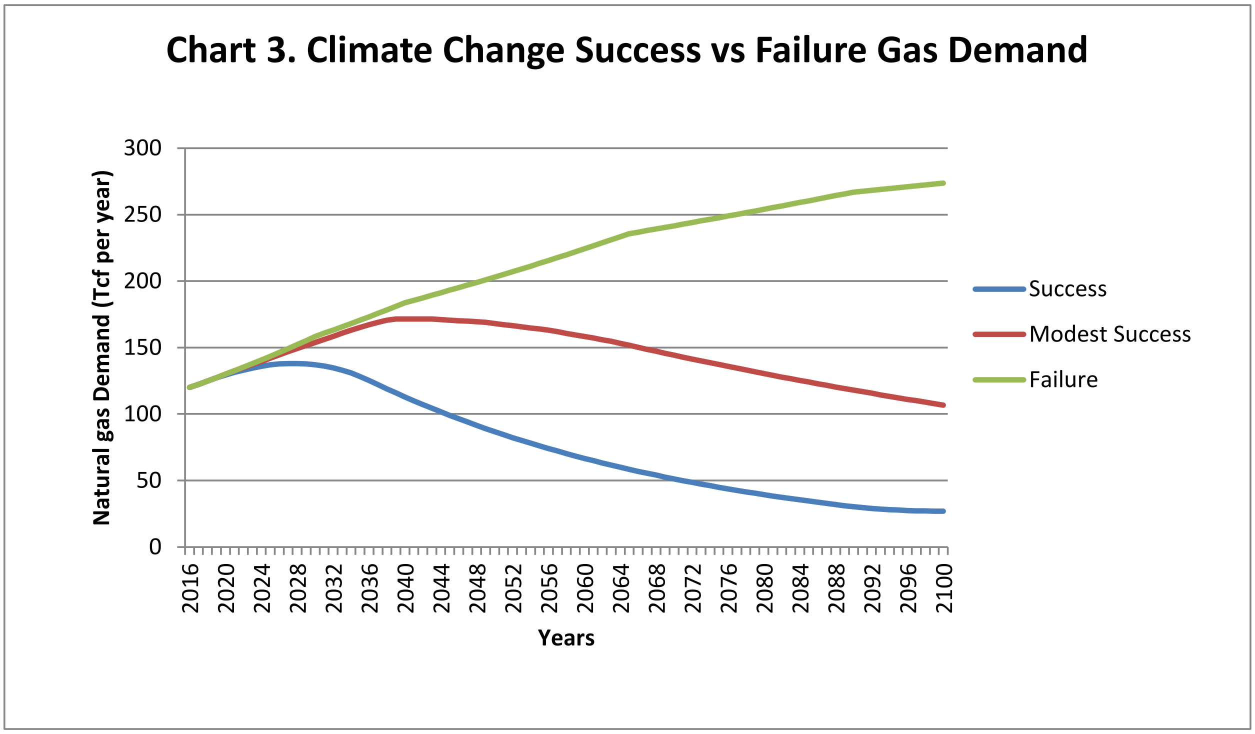
Modest Success Scenario. The Modest Success Scenario of Chart 1 assumes that oil demand will continue to increase modestly in the next decade and that by 2040 demand will return to 2016 levels and will start to decline after 2040 by about 1% per year. This scenario requires 2428 billion barrels of oil.

This could probably be supplied from current proved reserves, improvements in recovery from discovered reserves, new conventional discoveries and development of reasonably economic shale oil during this century at a level of less than $ 150 per barrel.

2.2 Natural Gas Scenarios

Chart 3 illustrates the Success Scenario, Modest Success Scenario and Failure Scenario for natural gas.

Success Scenario. With respect to natural gas, the IEA expects that natural gas consumption will continue to increase for this decade in the 450 Scenario, in particular where gas would replace coal. Thereafter gas consumption would decline. Chart 3 illustrates the Success Scenario if we assume that demand will level out at about 25 Tcf per year by the year 2100 due to chemical uses and industrial uses in which it is difficult to replace natural gas economically or technically.



The cumulative demand would require 6616 Tcf. The same BP statistics indicate a proved reserve for natural gas of 6606 Trillion cubic feet. Presumably this is based on various different gas prices around the world.

This seems to indicate that also for natural gas we have already found whatever we can afford to burn under the Success Scenario.

Failure Scenario. This scenario assumes continued increased in gas demand, although it is assumed that the growth rate will slow down. This scenario would require 18,003 Tcf of gas. This is well beyond what can be supplied based on current proved reserves, increased recovery from existing reservoirs, new conventional discoveries and new shale gas projects. It would require a massive development of coal bed methane and gas hydrates.

Modest Success Scenario. The Modest Success Scenario assumes that natural gas demand will continue to grow, in particular because gas would be used as a transition fuel to replace coal in power generation. Gas demand would start to decline by 2040 and by 2088 it would reach the 2016 demand level. It would continue to decline afterwards. The required volume would be 12,269 Tcf of gas. In order to supply this gas possible significant production of coal bed methane is required in addition to the proved reserves, enhanced recovery of existing reservoirs, and new shale gas developments. Of course, the use of natural gas as a transition fuel is constrained by the fact that carbon inefficient gas resources may in the end result in the same emissions of CO2 as coal burning and therefore natural gas can only replace coal to a certain degree from a CO2 emission perspective, where the production and transport of this gas is carbon efficient.

2.3 Review of the Success Scenario

It should be noted that the proved oil and gas reserves published by BP are to a significant extent still undeveloped. This means that these reserves still need to be developed through the drilling of development wells and installation of platforms, pipelines and other petroleum infrastructure. This will require very large investments on the part of the petroleum industry. In fact, it is likely that the future oil and gas developments will still require in excess of $ 3 trillion in order to supply the Success Scenario during this century. The continued existence of a healthy, profitable and efficient petroleum industry therefore has to be the basis of government petroleum policies.

The fact that we have already found all the petroleum that we can afford to burn, would lead to the interesting observation that we might not need to explore anymore for new petroleum reserves.

Although this may be true from a worldwide volumetric point of view, the dynamics of the petroleum industry will be that exploration will continue as long as it is profitable to do so. Governments will continue to promote exploration in order to benefit from the government revenues and economic growth as a result of the development and production of oil and gas fields that will be discovered.

At the same time a number of governments will continue to promote new unconventional petroleum projects, such as shale oil, shale gas, coal bed methane and gas hydrates, which will also add to the proved reserves.

In other words, the main purpose of new exploration and unconventional resource development is to create a future reserve base that is more attractive than the existing base on a worldwide basis, in terms of costs, higher government take to governments, less negative impact on environment, enhanced local content, increased national or jurisdictional economic growth and the creation of supply conditions which moderate oil and gas prices.

During the coming decades, important proved petroleum reserve additions will be the result of technological progress with respect to improved oil and gas recovery techniques from existing reservoirs.

As long as oil and gas prices remain low, it is likely that worldwide proved reserve additions will be modest on a yearly basis. However, assuming that oil and gas prices bounce back to higher levels, it is not inconceivable that during the next 20 years as much as 400 billion barrels will be added to the proved reserves of oil and as much as 1200 Tcf to the proved natural gas reserves.

Under this scenario, the available world proved reserves for the Success Scenario for oil and gas in 2036 would be far in excess of the requirements for the remaining constrained demand curves from then onwards until 2100.

In other words, if the world is successful in achieving the Success Scenario and at the same time maintains an effective petroleum industry which is actively exploring and developing additional reserves, it appears that a structural long term over-supply situation for oil and for gas will be emerging over the next 20 years, which may result in downward pressure on the oil and gas prices.

The combination of these two policies should encourage an effective and orderly transition from the use of petroleum fuels to renewable resources. The transition should as much as possible be driven by economic decisions in the context of substantive carbon taxes and the resulting oil and gas prices. In addition, a transparent fiscal and regulatory framework is required.

3. New Price Environment

3.1 Oil Price Developments during the last 43 years

The drop in oil prices during 2016 to less than $ 30 per barrel has created a new design framework from a fiscal perspective.

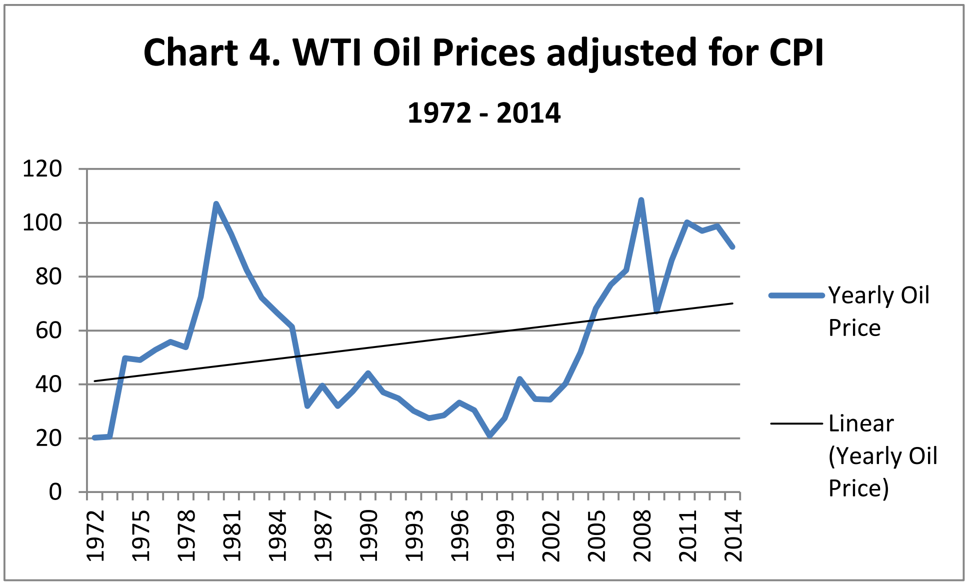
Up to the year 2013 the discussions about future oil prices and supplies focused on the concern to supply an ever increasing world economy with oil. Opinions were expressed for the so-called "peak oil" scenario, where the supply of oil would be restricted by a variety of petroleum policies of producing nations. This would lead to supply shortages and consequently high oil prices in the distant future.

By 2014 it became increasingly obvious that unconventional oil and gas resources were going to play a very significant role. The concept was that high prices would sustain significant unconventional oil developments and that therefore the peak oil scenario was not likely.

During 2015 when oil prices were around $ 60 per barrel, the general outlook was that this would a short period of low oil prices and that prices would go back up within one or two years. In other words the long term sustainable oil price was continued to be perceived somewhere in the range of $ 80 to $ 100 per barrel.

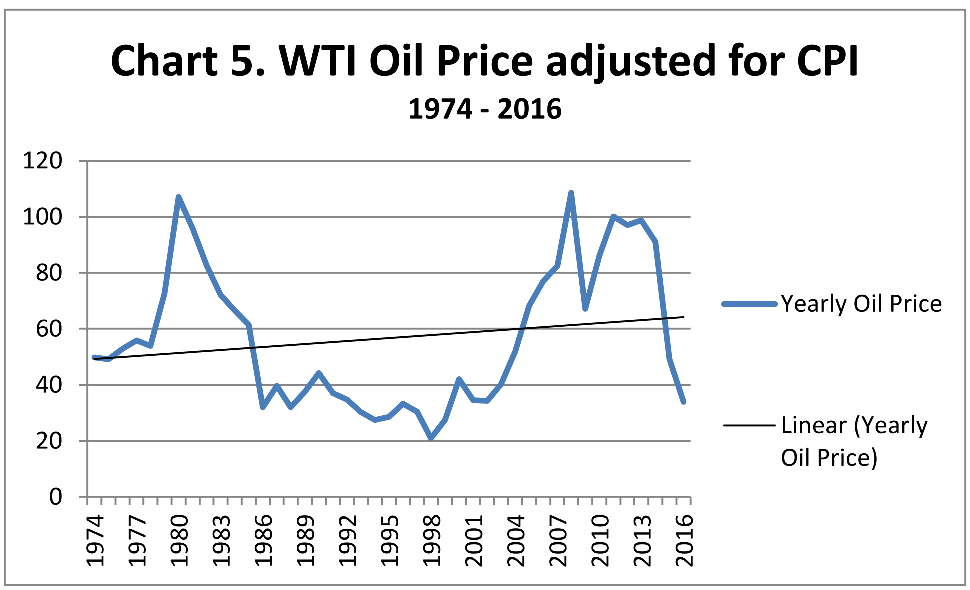
Chart 4 reflects the information at the start of 2015 and shows the yearly average WTI Oil prices adjusted back in time for headline CPI as processed from data of MACROTRENDS, which were in turn based on data of the Energy Information Administration (USA).

It also shows a simple linear trend between 1972 and 2014. This trend would make the prediction of a long term price in the range of $ 80 to $ 90 per barrels for the next two decades reasonable.



The 2016 drop now makes it more likely that the low oil prices will be a longer term event. In other words, February 2016, starts to look more like February 1986 than February 2009.

Chart 5 shows the same information from 1974 to 2016 assuming an average price of about $ 34 per barrel for 2016.



Based on the extra data for 2015 and 2016, the trend is now much different. At best $ 65 to $ 70 per barrel is now a good average prediction for the next two decades.

A longer period of low oil prices can now be expected to follow the eight year period of high oil prices. This fundamentally changes the long term outlook for oil prices and in particular for definition of fiscal policies regarding oil and gas.

Regardless of whether the Success, Failure or Modest Success scenario is being realized the proved reserves are ample to supply any of these scenarios during the next 30 years. Therefore, there does no longer seem to be a justification for making forecasts of high oil prices and impending oil supply constraints a basis for fiscal policies.

The average oil price during the 1974 – 2016 period (assuming $ 34 for 2016) is $ 56.67 per barrel.

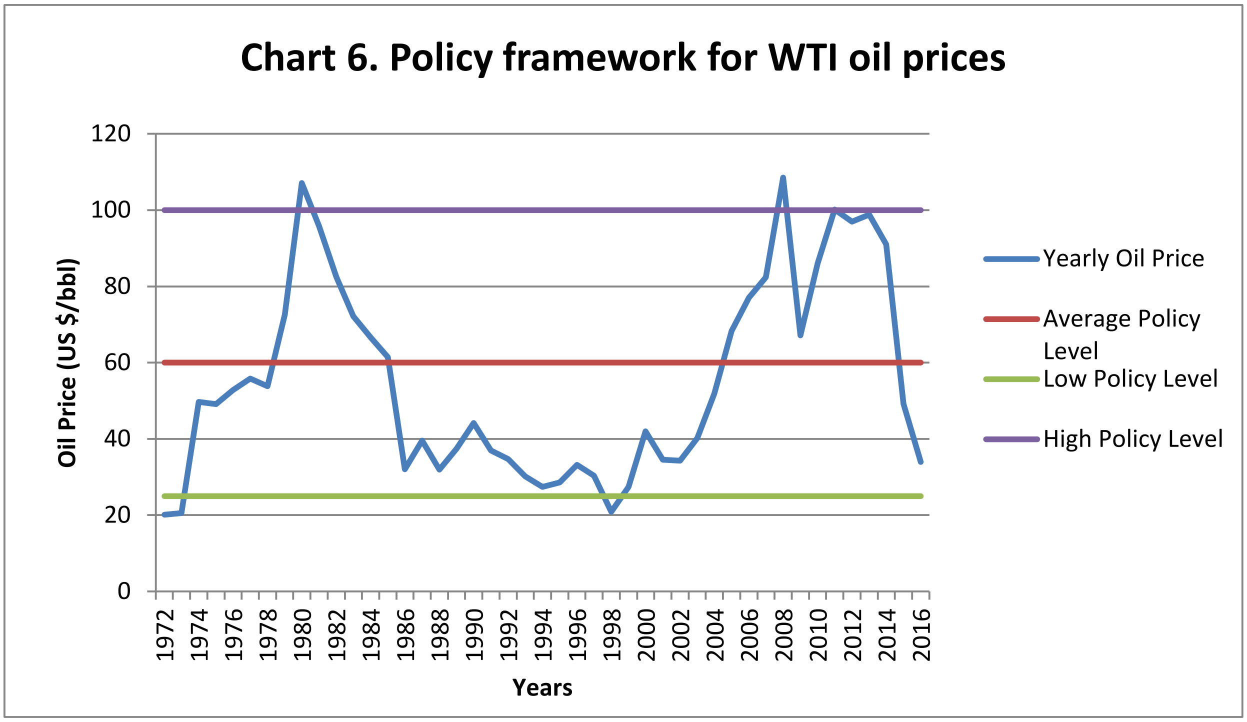
3.2 <u>“Pivot Price” concept for New Fiscal Policies</u>

Chart 6 displays a prudent basis for a new petroleum fiscal policy formulation. It is important for governments to decide on the “pivot price”, which is the price below which the petroleum industry is assisted by government (in a relative way) and above which the government recovers lost government income under low price. In order to be conservative, governments should preferably select this “pivot” point low enough to have a reasonable probability of replenishing “lost” revenues during periods of high prices.

Based on the price variation of the last 43 years, the “pivot price” can be assumed to be $ 60 per barrel adjusted yearly for inflation. The upper policy limit would be $ 100 per barrel and the lower policy limit $ 25 per barrel. In other words the fiscal policy would be based on the conservative assumption that it is probable that oil prices will vary between this high and this low during most of the years in the coming decades.

If nations want to promote the very considerable investments that still need to be made in the supply of new oil and gas, the fiscal policies should result in providing robust economics at an oil price of $ 60 per barrel adjusted for inflation. Economically marginal oil and gas reserves at $ 60 per barrel would cost about $ 25 per barrel in terms of capital and operating costs. This $ 25 per barrel also corresponds to the low price policy level.

Therefore, if governments want to avoid “boom and bust” cycles, governments should not promote through the fiscal terms high cost petroleum developments during periods of high oil prices. In fact fiscal terms should discourage petroleum developments costing in excess of $ 25 per barrel based on a “pivot price” of US $ 60 per barrel.



Of course, depending on the actual developments of oil and gas supply and demand, these policy targets could be adjusted over time.

It should be emphasized that not promoting "expensive" resources is a policy to be achieved through the fiscal terms. It is not suggested that investors should be prevented from the development of expensive resources where such investors believe that such development is economically acceptable and commercial.

4. New Petroleum Fiscal Policy Framework

4.1 Climate Change Policy Framework

Assuming that it is the objective of the government to support the Paris Agreement in a substantive manner, a variety of new or enhanced petroleum fiscal policies can be introduced. In general, the use of renewable resources should become less expensive to consumers and the burning of fossil fuels should become more expensive.

The suggested policies are the following:

1. Introduce carbon taxes and increase these taxes over time to meet the Paris objectives;
2. Eliminate subsidies and other policies resulting in artificially low cost natural gas and petroleum products which in turn stimulate excessive consumption;
3. Promote a healthy and effective petroleum industry with robust fiscal terms at the $ 60 target level for those reserves and prospects which are inherently economic at that price level and the corresponding regional price levels for gas;
4. Promote gas development in order to serve as a transition fuel for power generation in order to replace coal;
5. Reduce emphasis on most fiscal stability provisions; and
6. Promote a regulatory framework that is consistent with the climate change objectives.

4.2 Low Oil Price Policy Framework

An important new objective as a result of the low oil prices is to moderate boom and bust cycles in the petroleum industry. To date fiscal terms are not designed for this purpose. In order to implement such new policies, a significant redesign of a variety of petroleum fiscal features is required.

The suggested policies are the following:

1. Create price progressive fiscal terms for the entire target price range;
2. Ensure a minimum government take for the resource owners;
3. Discourage excessive unsustainable investment levels during high oil and gas prices;
4. Restructure fiscal terms to improve alignment between governments and the petroleum industry;
5. Eliminate gold plating;
6. Modify the role of state participation from a broad to a narrow mandate; and
7. Promote a regulatory framework that permits investors to survive periods of low oil and gas prices.

4.3 Consequences

The consequence for important petroleum producing jurisdictions of implementing the Paris Agreement is that it becomes imperative to follow policies that promote diversification of their economies in order to reduce the dependence on oil and gas production.

The consequence of new low price policies is to strengthen possible sovereign wealth funds and lessen the dependence on oil and gas revenues for government budgets.

5. Current status of government take structure

Before entering into a detailed discussion of policy changes, it may be useful to investigate the current status of the structure of government take and why this structure is not adequate for the new framework that is emerging.

5.1 World Overview of Government Take Structures.

The landmark study World Rating of Oil and Gas Terms[1] provides a comprehensive economic and fiscal evaluation of 580 different sets of fiscal terms in 156 countries and different logistical environments. It provides an unprecedented insight into the various strategies that governments use to maximize their share of the petroleum resource wealth. Following is a review of the results of this study.

World Regions. Upstream petroleum fiscal systems are very different from country to country. What is interesting is that different parts of the world seem to adopt different styles of wealth sharing. In order to study this matter in more detail 580 fiscal systems in different logistical environments were divided in five groups, as follows:

- Concession, license or lease systems in:
  - The United States (excluding Alaska) – 83 systems
  - The Developed Countries (excluding the US, but including Alaska) – 177 systems
  - The Developing Countries - 116 systems
- Production sharing contracts, risk service contracts and profit sharing contracts in:
  - Africa south of the Sahara – 65 systems
  - Other Developing and Developed Countries – 139 systems.

Resource Wealth Sharing Strategies. In maximizing their share of the resource wealth, governments use two strategies:

- Maximizing the direct revenues retained by governments; and, in some cases,
- Participating in the petroleum operations through state companies.

[1] *World Rating of Oil and Gas Terms: Volume 1 and Volume 6* provide detailed fiscal descriptions and investor analysis and favorability ratings of 580 fiscal systems in different logistical environments applicable in 156 countries. The study is produced jointly by Van Meurs Corporation, IHS and Rodgers Oil & Gas Consulting, with the assistance of Barrows Company and Ernst & Young. www.petrocash.com

The share the government receives of the resource wealth is called “government take”. The government take is the percentage that the government receives of the "divisible income". The divisible income is simply defined as the gross revenues less all capital and operating expenditures. Based on the above two strategies one can define the total government take as follows:

Total Government Take = Government Income Take + Government Participation Take

The three factors that determine the amount of the resource wealth related to an oil or gas field are: (1) the volume of petroleum that is produced from the field, (2) the price of the petroleum and (3) the exploration, development and production costs. The total resource wealth is larger the higher the volume, the higher the price and the lower the costs.

The total government take could be:

- **Progressive** –the take goes up with higher volumes or prices or with lower costs
- **Neutral** –the take stays the same for different levels of volume, prices or costs.
- **Regressive** –the take goes down with higher volumes or prices or with lower costs.

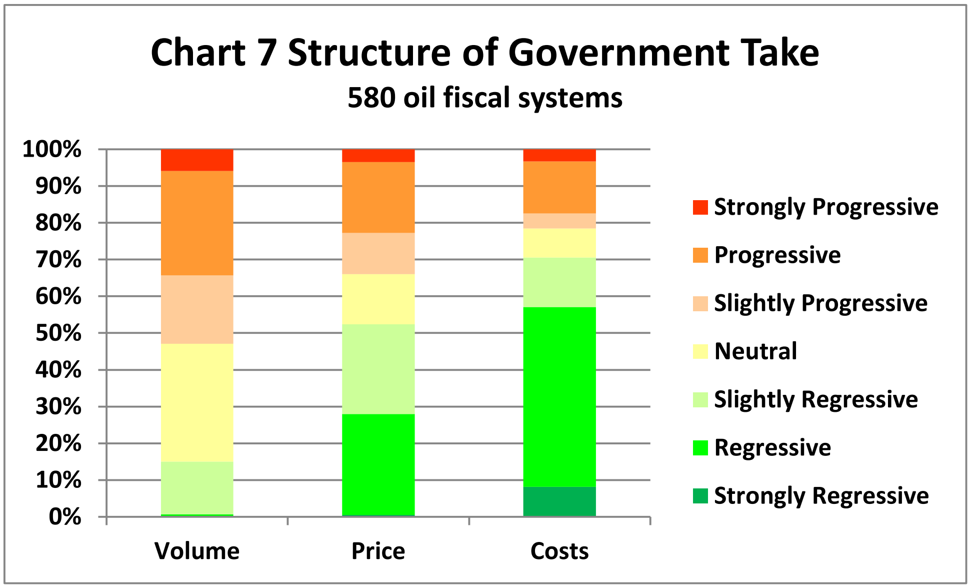
Each component of the fiscal system can be defined based on these concepts. For instance, royalties or profit oil with sliding scales based on daily production are volume progressive, but price and cost regressive. Corporate income tax is typically neutral with respect to volume, price and costs.

A profit oil sliding scale based on the IRR or an R-factor is price and cost progressive, but volume neutral. Bonuses, rentals and fixed royalties are regressive with respect to volume, price and costs.

How the total fiscal system behaves depends on the mixture of the various fiscal components. For instance, a system consisting of a fixed royalty and corporate income tax will be regressive.

A significant insight can be obtained in the various government strategies by analyzing separately the behavior of the total government take with respect to volume, price and costs.

Chart 7 provides an overview of all 580 fiscal systems in terms of progressivity as published in the World Rating of Oil and Gas Terms.



It can be seen how of the 580 fiscal systems 52% are volume progressive, 34% are price progressive and 22% are cost progressive.

Volume progressivity

The volume progressivity was evaluated by comparing two cases:

- A 500 million barrel case at a price of $ 80 per barrel and a cost of $ 20 per barrel
- A 50 million barrel case at a price of $ 80 per barrel and a cost of $ 20 per barrel

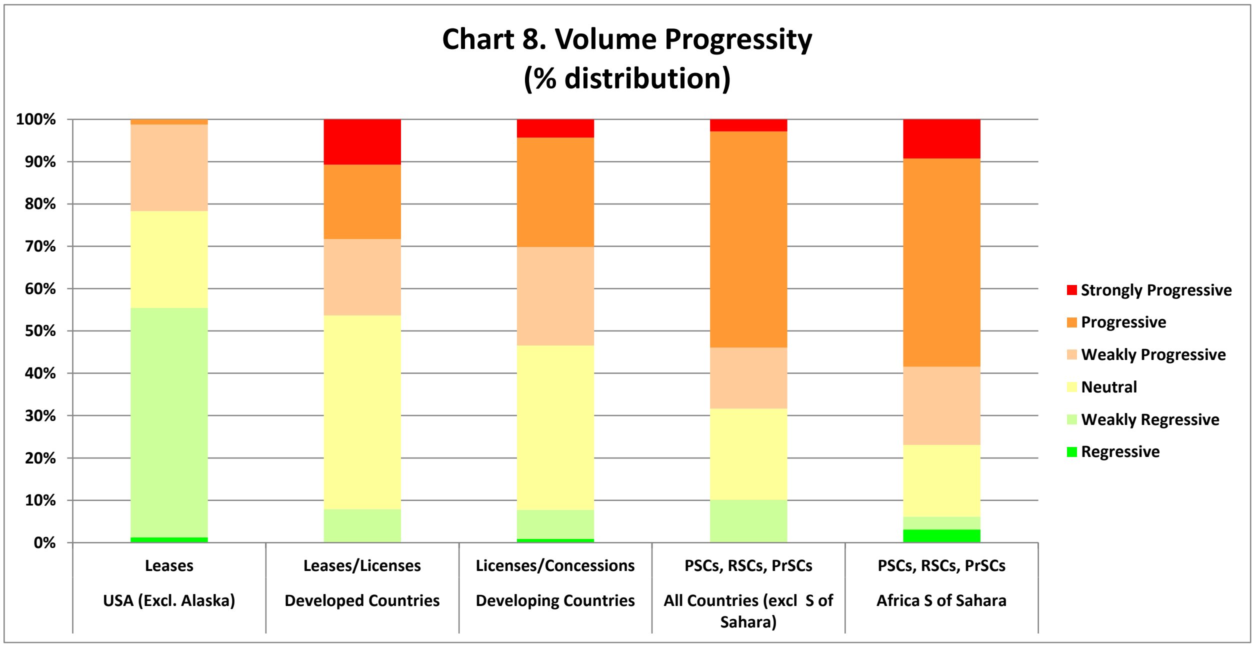
The total government take of the 50 million barrel case is subtracted from the 500 million barrel case. If the system is volume progressive, the result will be positive. If the result is negative the fiscal system is regressive. For analytical purposes, if the difference is less than 0.5% positive or negative the system is considered “neutral”.

For North America, where fiscal terms are determined well by well, a 500,000 barrel well is compared with a 50,000 barrel well.

In total 52% of the 580 fiscal systems are progressive. This means that level of production is a very important determinant in structuring fiscal systems. Volume progressivity is typically created through sliding scale royalties and profit oil based on daily or cumulative production.

Volume regressivity is created through bonuses and rentals and other payments of fixed amounts.

Chart 8 shows how different the five regions in the world are in terms of volume progressivity. In the United States only a few states follow this concept, while most PSCs in Africa south of the Sahara are volume progressive.



Price progressivity

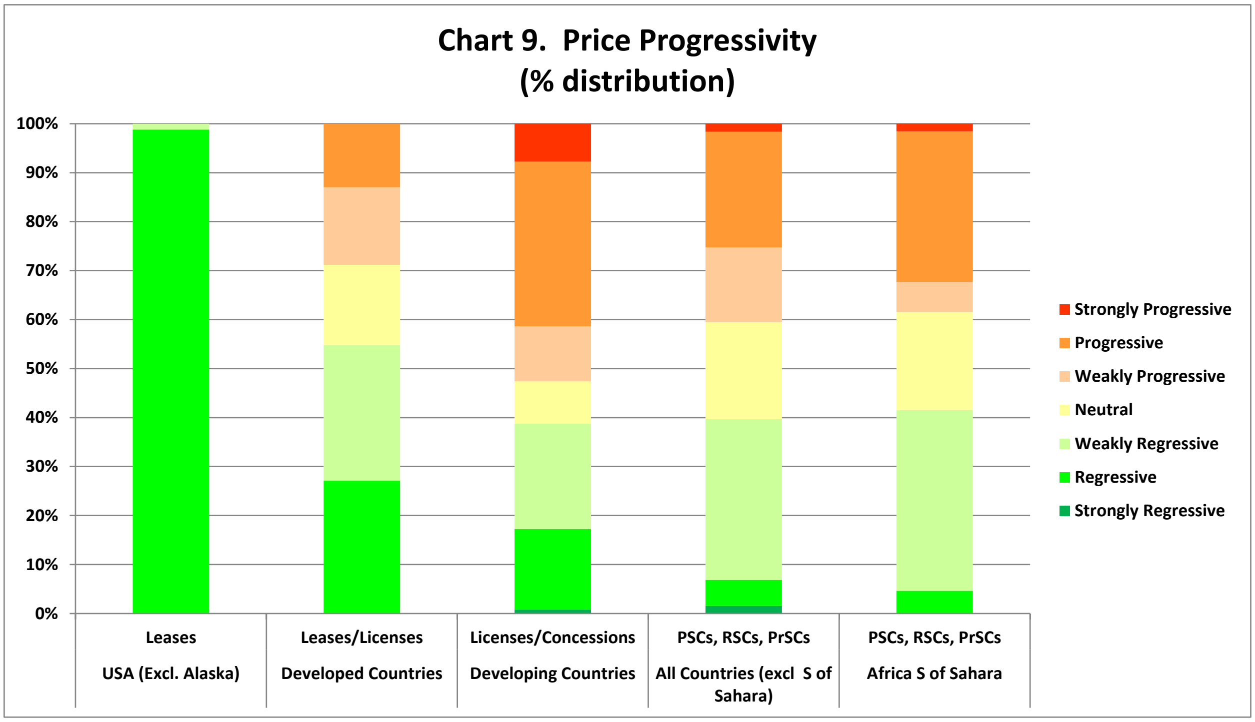
The price progressivity is determined by taking the 100 million barrel field (or 100 k well in North America) at $ 20 costs per barrel and subtracting the total government take at $ 80 per barrel from the total government take at $ 160 per barrel. A positive result indicates price progressivity for the high price ranges as were still expected during the preparation of World Rating of Oil and Gas Terms.

Only 34% of the 580 fiscal systems are progressive with price for this price range. It is interesting to note that despite the enormous price variation that has occurred over the last decade, only about a third of the fiscal systems feature price progressivity.

Price progressivity is primarily created through windfall profits taxes, IRR or R-factor sliding scales, and price progressive royalties, profit oil scales or taxes. Also risk service contracts with fixed service fees are strongly price progressive. Interestingly, licenses and concession in developing countries have the strongest price progressivity.

It is important to note that Chart 9 only applies to price progressivity between $ 80 and $ 160 per barrel, as was a scenario in 2012. This chart does not give information about the price progressivity between $ 30 and $ 60 per barrel, for instance.

A more detailed review of price progressivity will be provided in sub-chapter 5.2.



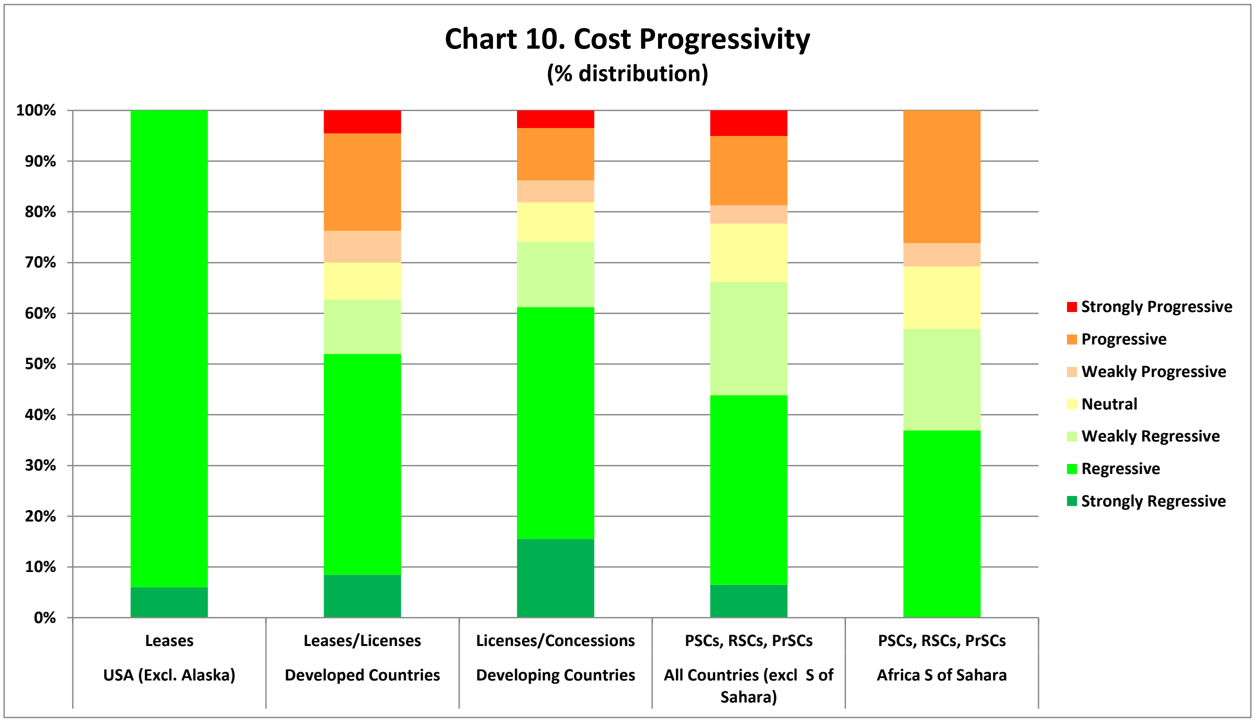
Cost progressivity

The cost progressivity is measured by taking a 100 million barrel field (or 100 k well) at an oil price of $ 80 per barrel and subtracting the government take of a $ 30 per barrel cost case from the government take of the $ 10 per barrel case. Again if the result is positive the system is progressive.

Only 22% of the 580 fiscal systems are cost progressive. This means that on a worldwide basis efficient oil companies are typically rewarded with a lower total government take.

Cost progressivity is primarily created through fiscal systems with sliding scales based on IRR or R-factors, or through uplifts, such as the uplift on the hydrocarbon tax in Norway.

Chart 10 shows the regional variation in the matter of cost progressivity. The United States (excluding Alaska) does not feature cost progressivity. A number of the developed countries and jurisdictions with concessions and licenses feature cost progressivity, such as for Australia and several provinces in Canada.



5.2 <u>Detailed Analysis of Price Progressivity</u>

As indicated on Chart 7 only 34% of the fiscal systems that were analyzed had price progressive systems. However, these price progressive systems were mainly aimed at capturing windfall profits under high prices.

The following charts show examples how price and government take are related in the various countries and jurisdictions. They are based on a 100 million barrel field with a cost of $ 20 per barrel.

Chart 11 illustrates price regressive systems. The cause for the price regressivity is different in different nations. In the United States and Brazil it is caused by using mainly fixed royalties. In some of the production sharing countries, such as Egypt and Equatorial Guinea it is caused by the cost oil limits. In Indonesia the slight price regressivity is caused by the bonuses and significant other yearly contributions.

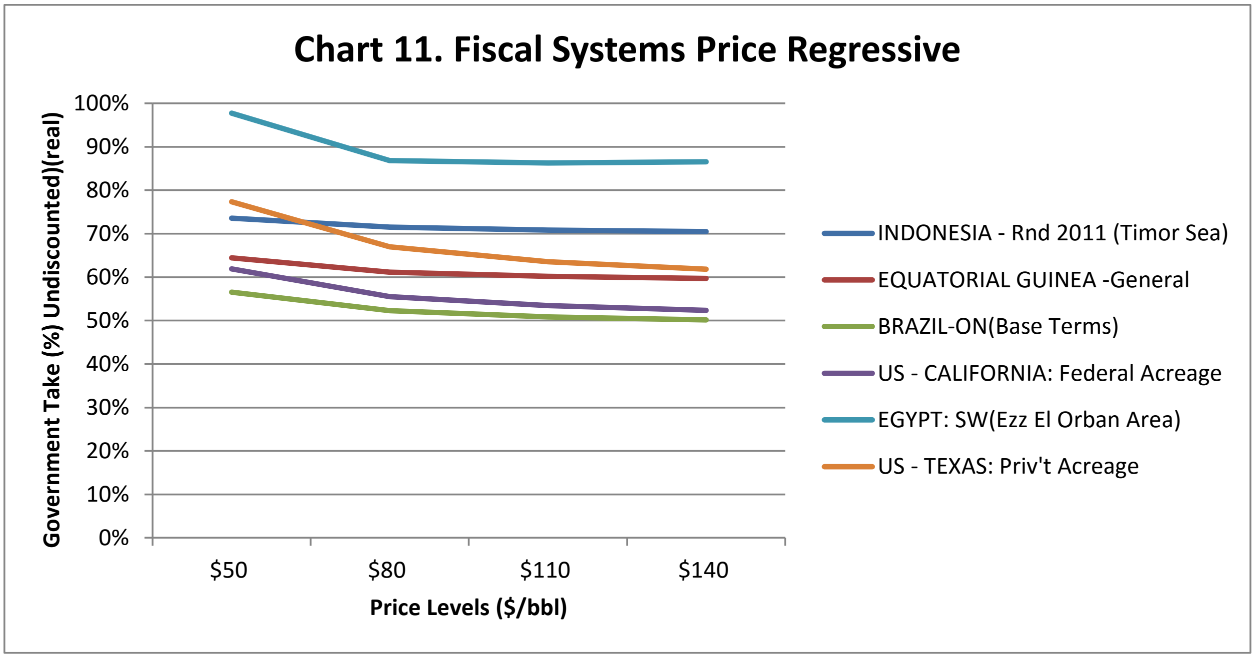


Chart 12 shows a number of examples of price neutral systems. These are systems primarily relying of corporate income tax such as Spain, South Africa and PNG, or a constant percentage profit oil share such as the Philippines. In Nigeria the system is neutral because the effect of royalties and uplifts on costs is cancelling each other out. Liberia only has a volume progressive sliding scale in the production sharing contract, which is not affected by price.

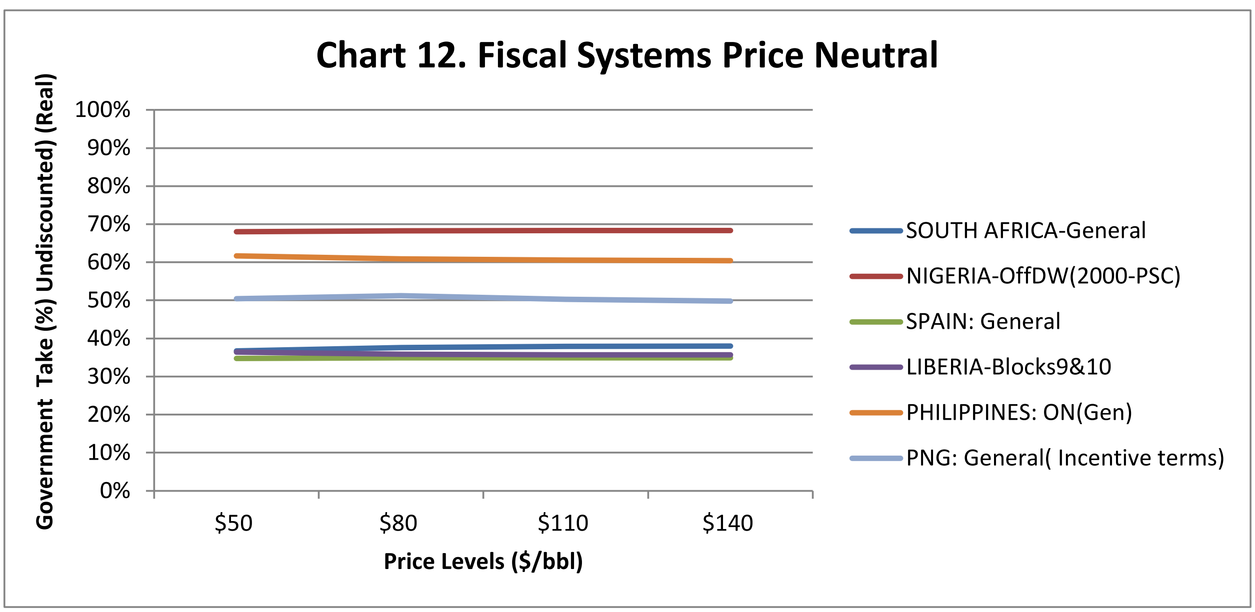
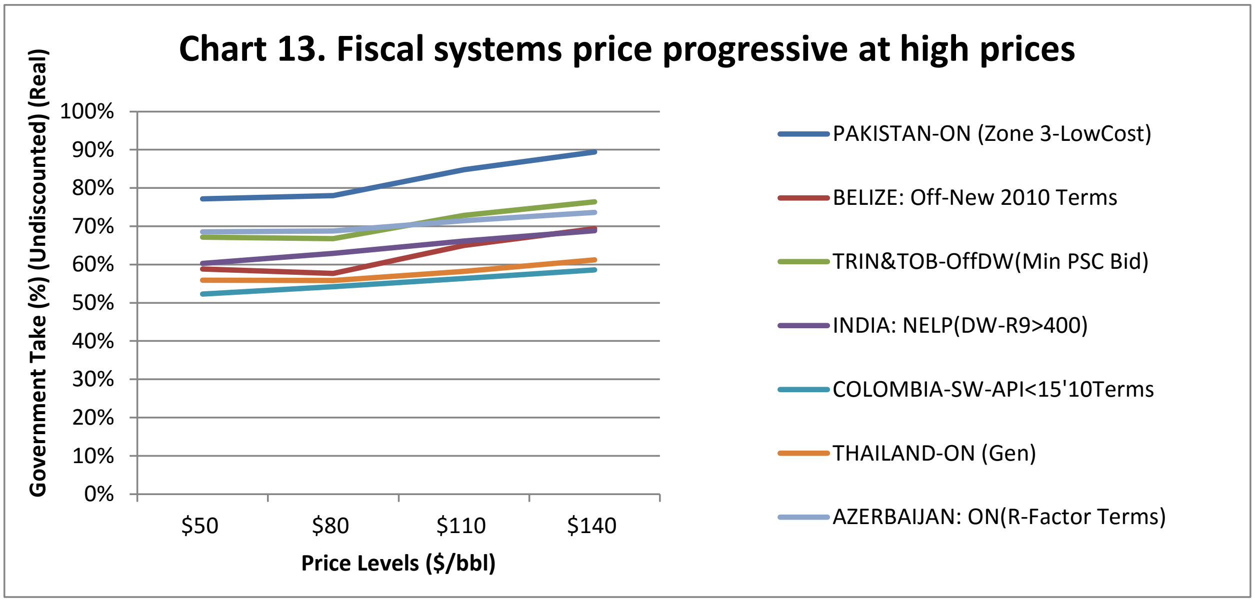
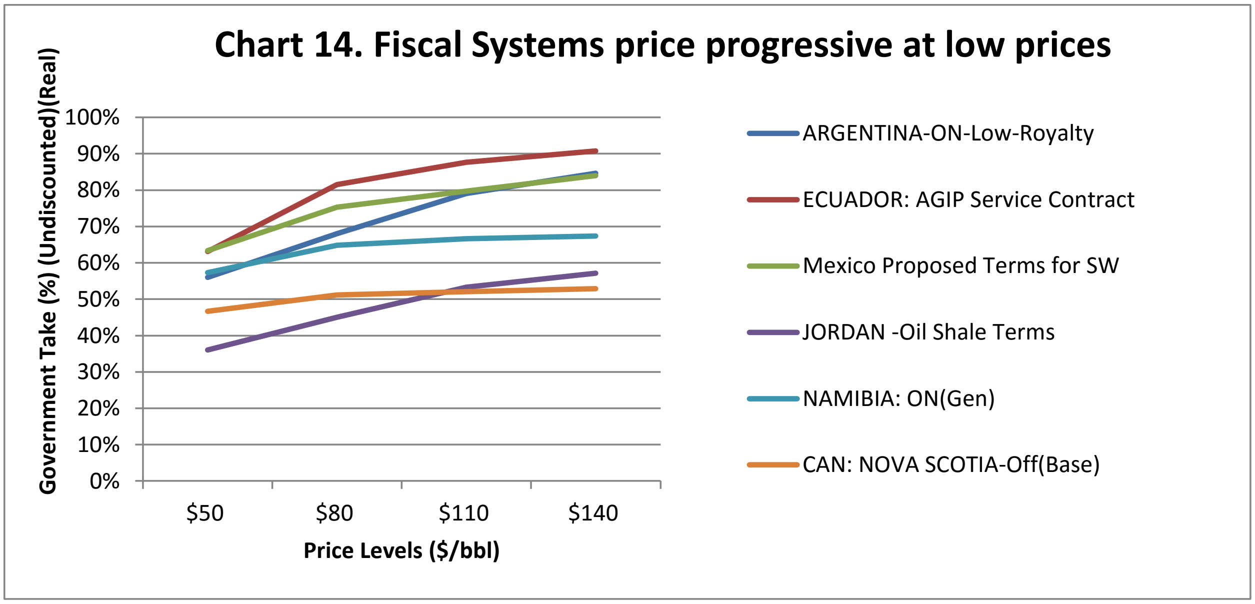


Chart 13 illustrates how certain jurisdictions designed fiscal terms whereby an extra government take is captured under high prices. This can be done through a wide variety of features. Pakistan and Trinidad and Tobago have price progressivity incorporated in their profit oil sliding scales. Belize and Columbia have special windfall profit type features. Thailand has a price sensitive profit share, called Special Remuneration benefit (‘SRB”). India and Azerbaijan have R-factor based features.



There are not too many countries with price progressivity under low prices. Argentina has a price sensitive export tax. Mexico has a price sensitive royalty and an IRR based profit share for shallow water. Namibia and Nova Scotia have IRR based systems. Jordan, for its oil shales, has a price sensitive royalty and an R-factor based profit share.

Interestingly, service contracts with a fixed fee for the contractor (not subject to price variation) will create strong price progressivity in case of low prices as is the example for Ecuador. The State rapidly loses under these conditions.



The systems that are price progressive are so for very different reasons and the degree of price progressivity is very different for the various price levels.

It will be very obvious from this discussion is that the world is very poorly prepared for switching to a more comprehensive price progressivity concept in order to manage the booms and busts in the petroleum industry and to secure a fair share for governments under a wide range of prices.

6. Detailed Recommendations with respect to Climate Change Policies

Following is a detailed discussion of the recommendations with respect to the Climate Change Policy Implementation.

6.1 Introduce carbon taxes.

As stated earlier in the Success Scenario, still huge investments have to be made to produce the available resources of oil and gas. It is important that such new production and enhanced production and the burning of oil products and gas is economic in the climate change context.

For this reason, as a first step it is clear that the cost of carbon emissions has to be included in the cost of producing oil and gas. This means the introduction of credible carbon taxes. The World Bank Report "State and Trends of Carbon Pricing" (September 2015) (99533) indicates that carbon taxes in the range of US $ 80 to US $ 120 per ton of CO_2 equivalent are required in order to achieve the goal of limiting temperature increases to 2 degrees Celsius. Therefore, it can be recommended to preferably start carbon taxes at the US $ 30 to US $ 60 per ton CO_2 equivalent range and gradually increase these taxes to higher levels, in principle up to US $ 120 per ton CO_2 equivalent.

This will eliminate the petroleum resources that are carbon-inefficient from future supplies. It will incentivize the petroleum industry to reduce emissions.

So far, the introduction of carbon taxes has been slow. However, the use is very gradually expanding. Table 1 below gives the current status of these taxes, derived from "Climate and carbon – Aligning prices and policies", OECD Environment Policy Paper, October 2013, No 1.

Table 1. Existing/Future Carbon taxes (per ton CO2 equivalent)		
Country/Jurisdiction	Year	Amount
British Columbia	2008	CAD 30
Chile	2014	USD 5
Costa Rica	1999	3.50%
Denmark	1992	USD 31
Finland	1990	EUR 35
France	2014	EUR 7
Iceland	2010	USD 10
Ireland	2010	EUR 20
Japan	2012	USD 2
Mexico	2012	MEX 10 - 50
Norway	1991	USD 4 - 69
Portugal	2014	EURO 5
South Africa	2016	Rand 120
Sweden	1991	USD 168
Switzerland	2008	USD 68
United Kingdom (floor price)	2013	USD 15.75

The Climate Leadership Team of British Columbia (October 2015) developed a detailed report on the future of carbon taxes in this province. The current tax is Can \$ 30 per ton. It is proposed to start increasing this tax with Can \$ 10 per ton per year in 2018 through 2050. However, increases will be reviewed every 5 years in order to determine whether the industries of British Columbia remain competitive and therefore it is likely that increases will be halted well before reaching such high levels.

The goal of the province is the reduce greenhouse gas emissions by 40% of 2007 levels by 2030 and 80% of these levels by 2050.

British Columbia introduced the Can \$ 30 tax in 2008 and as a result the fuel use dropped by 16% while the economy grew 9.2% to 2013. The tax is revenue neutral this means that any income from the carbon tax is offset with lower other taxes, in particular corporate and personal income tax. The Team recommends reducing the provincial sales tax in the coming years.

An important observation that can be made from the example of British Columbia is that economic growth and limiting greenhouse gas emissions are not mutually exclusive goals. It is possible to maintain economic growth while limiting greenhouse gas emissions, with the right fiscal policies and a revenue neutral approach.

6.2 Eliminate subsidies

IMF, the World Bank and a host of other advisors, including myself, have been advocating regularly the elimination of subsidies to consume petroleum and elimination of other fiscal terms which have the effect of lowering domestic prices for oil and gas.

It is time to get serious on these matters if nations want to be proactive in the implementation of the Paris Agreement. The current low oil prices and the need to reduce government deficits in major oil producing countries, may incentivize these policies.

This means:

1. Elimination of actual subsidies to consumers for natural gas and petroleum products,
2. Elimination of domestic market or domestic supply obligations
3. Reduction of regulatory price controls and establishment of market based gas prices and product prices, where possible, and
4. Elimination of export duties.

A remarkably large number of countries are still subsidizing the consumption of natural gas and oil products. This includes Venezuela, Saudi Arabia, Kuwait, Iran, Russia, Indonesia, etc. Such subsidies are counter-productive and should be eliminated.

A number of countries have domestic market or domestic supply obligations to supply crude oil and/or natural gas for reduced prices. This includes Indonesia, Malaysia, Nigeria, Egypt and other countries. Such obligations should be eliminated and where applicable, replaced with other fiscal features.

Natural gas in many countries still is being provided for artificially low regulated prices for the domestic market. This includes countries such as Algeria, Nigeria, Angola, Russia and the previously mentioned OPEC countries. Often the argument is that the gas is associated gas and therefore should be "free" to government and consumers in the first place. Although regulation of natural gas prices may continue to be necessary in some countries, policies should be established to make the supply of such gas profitable to investors and therefore encourage further supplies of gas to the domestic markets, in particular where gas can replace coal.

With respect to gas importing countries, such as Thailand, domestic gas prices should gradually be made competitive with imported LNG.

Export duties are applied in Russia, Argentina, China, Malaysia and Vietnam, often with the purpose of controlling or reducing oil and natural gas prices domestically. Again such duties should preferably be phased out. It is understood that in some cases, such as in Russia, the export duties are such an important component of the fiscal petroleum income that the phase out has to be done gradually and carefully.

6.3 Promote a healthy and effective petroleum industry

On the assumption that a government wants to implement the Paris Agreement and pursue a Success Scenario, new oil reserves do not need to be explored because the world is running out of oil. The nation would want to pursue exploration in order to discover fields that result in profitable operations for the petroleum industry and attractive revenues for government.

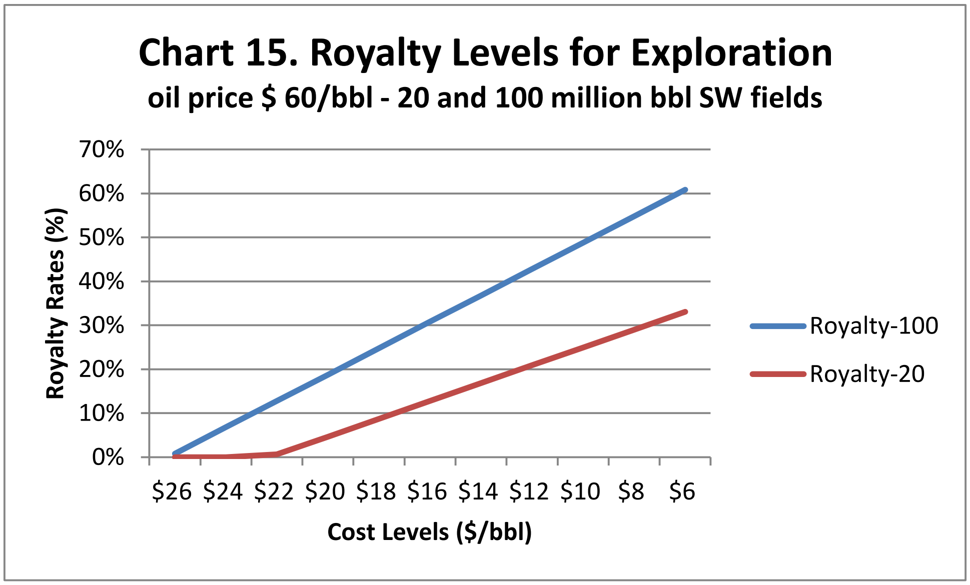
These objectives have to be achieved based on the $ 60 policy "pivot price" (escalated for inflation). Of course, the level of what could be considered attractive revenues depends on the characteristics of the resource base. These characteristics are:

- The size of conventional fields or unconventional projects and costs levels,
- The nature of the project, such as exploration or development of oil and gas fields, or large integrated projects, such as LNG projects,
- The level of exploratory or project risk,
- The logistical environment and related time lines of the project, such as onshore, shallow water and deep water, and
- Whether investment decisions are made well by well, as onshore North America, or on a field or project basis.

Following is an analysis of what a typical framework could be for exploration in shallow water. It is based on two separate exploration targets both with a probability of success of 30%, for a 20 and 100 million exploration target. It is assumed that the country has already a corporate income tax of 30% and wants to implement a royalty system.

The question is now what the royalty level should be at the $ 60 "pivot price" level.

Chart 15 shows the levels of royalties for various cost levels calibrated on the assumption that a Risked Real Profit to Investment Ratio discounted at 10% ("Risked PIR10") of 0.3 is acceptable to investors. The risked cash flow is created by combining 70% of the dry hole cash flow with 30% of the discovery cash flow for the target field size.

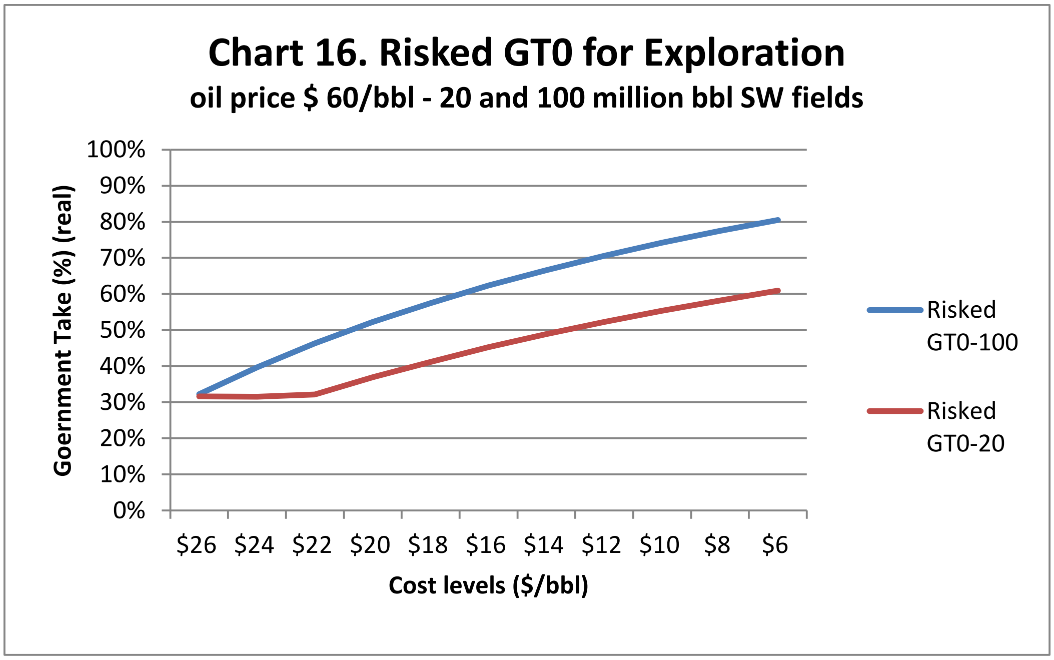


As is very clear the level of royalty that can be charged depends very much on the size of the exploration target and the levels of development capital costs and operating costs that are expected. Furthermore, the level would depend on the geological risk.

If the government would want to adopt level of a flat 15% royalty for all field sizes and cost levels, the 100 million barrel target could not cost more than $ 21/bbl and the 20 million target $ 15/bbl in order to achieve the Risked PIR10 of 0.3.

As is clear, the government can maximize their revenues by making the royalty level also a function of the costs and the level of production. This ensures higher government revenues under more favorable circumstances. A more detailed discussion of these matters is to be found in the following chapters.

Chart 16 illustrates the corresponding Risked Undiscounted Government Take (“Risked GT0”) government take assuming the 30% corporate income tax.



Currently, the arithmetic average un-risked GT0 in the world at a price level of $ 60 per barrel is approximately 63%.

The above example is merely an indicative example and different examples with higher or lower resulting royalty rates can be calibrated.

Nevertheless, those jurisdictions that wish to encourage petroleum exploration and development of unconventional resource may wish to lower their GT0 and Risked GT0 by improving fiscal terms at the $ 60 per barrel "pivot price".

6.4 <u>Promote gas development in order to replace coal.</u>

Until about a decade ago, gas prices in most important gas markets in the world followed oil prices on an energy equivalent basis, since gas was primarily competing with oil and was a substitute for oil. During the last decade gas supplies have expanded and natural gas is now driven in the North American and North West European markets by gas-gas competition. This has resulted in gas prices now being considerable less than oil prices on an energy equivalent basis. Yet, many fiscal systems continue to provide for the same or similar fiscal terms for gas as for oil. This no longer makes sense if governments want to promote gas production relative to oil.

The CO_2 emissions associated with the burning of a million Btu are the following:

- 98 kg for coal
- 77 kg for oil
- 58 kg for natural gas

This means that replacing the coal with natural gas in power generation could be a transition method to reduce CO_2 emissions. It should be noted that the benefits that natural gas may have for this purpose are limited, since also certain natural gas production, liquefaction and transportation practices could also result in significant CO_2 and methane emissions. Assuming the gas value chain would be subject to carbon taxes and only carbon-efficient gas production is promoted, gas could play a role as a "transition fuel" by substituting gas for coal in order to reduce CO_2 emissions from coal fired power plants.

Therefore, promoting natural gas as a transition fuel may make sense under certain circumstances. Such a promotion is in particular relevant in jurisdiction where there are significant opportunities to replace coal for power generation.

A large number of jurisdictions are already applying "Gas-Favorable" terms. Table 2 provides a listing.

Some jurisdictions could enhance their efforts. For instance, the Canadian provinces could do more in this respect. Although Alberta has gas-favorable terms for shale gas and coal bed methane, for conventional oil and gas Alberta is doing the opposite. The minimum royalty for oil is 0% and for gas is 5%.

Other jurisdictions have no gas-favorable terms at all, such as the United States and Brazil, and could take important steps in this direction.

Table 2. Jurisdictions with Gas-Favourable Fiscal Terms			
Argentina	Egypt	Mali	Sierra Leone
Australia	Ethiopia	Morocco	South Sudan
Belize	France	Nicaragua	Sudan
Benin	Ghana	Niger	Tanzania
Brunei	Guatemala	Nigeria	Thailand
Cambodia	India	Oman	Trinidad & Tobago
Cameroon	Indonesia	Pakistan	Tunisia
Canada - Alberta	Iraq - Kurdistan	Papua New Guinea	USA-Arkansas
Canada - British Columbia	Kazakhstan	Paraguay	USA-Louisiana
Canada - Nfld. & Lab. (Proposed)	Kyrgyzstan	Poland	USA-Michigan
Canada - Nova Scotia	Laos	Portugal	USA-North Dakota
Central African Republic	Latvia	Qatar	Venezuela
Chad	Liberia	Russia	Vietnam
China	Libya	Sao Tome & Principe	Zambia
Colombia	Madagascar	Saudi Arabia	
Cote de I'voire	Malaysia	Senegal	

The following specific Gas-Favorable fiscal policies can be recommended:

1. Have lower royalties for gas than for oil. Where royalties are price sensitive ensure that for a particular price level per MMBtu the gas royalties are less than the oil royalties. In case royalties are based on volume based sliding scales, the energy equivalent production levels of gas for a certain level of royalties should be higher than for oil;
2. Apply lower severance taxes, production taxes or mineral extraction taxes to gas compared to oil;
3. Have lower profit gas shares for gas than for oil in production sharing contracts;
4. Where windfall profit taxes are being applied to oil, do not apply these taxes to natural gas or apply a lower rate for gas; and
5. Where R-factors are being used for royalties, taxes, profit oil and gas shares, profit shares, taxes or other features, design the R-factors separately for oil and for gas and make the R-factors for gas more attractive.

Apart from fiscal provisions, there are a number of regulatory or contractual provisions that governments can use to promote gas, to be discussed further in sub-chapter 6.6.

6.5 <u>Reduce emphasis on fiscal stability provisions.</u>

A general policy change that can be recommended is to reduce the emphasis on fiscal stability in some countries. The world has to create an effective transition out of fossil fuels. This means that governments need flexibility to adjust fiscal terms from time to time. Fiscal stability provisions should not undermine Climate Change policies.

In many nations there would be no restrictions in the petroleum agreements to introduce carbon taxes and the make adjustments in corporate or personal income taxes or other taxes, if the government wants to achieve revenue neutrality. These are the countries in Europe, North America, most Latin American nations and some other countries.

For instance, the model concession of ANP of Brazil states specifically in clause 25.1:

The Concessionaire shall be subject to the tax regime at the federal, state and municipal levels, being obligated to comply with their terms, timing and conditions defined by the applicable Brazilian legislation.

The Chinese Shell Contract (1996) for the Gulf of Bohai states in clause 20.1:

Each company comprising the Contractor shall pay taxes to the Government of the People's Republic of China subject to the tax laws and regulations of the People's Republic of China.

However, a number of other nations provide for fiscal stability by stating in the contract that the contractor will not be subject to any taxes other than provided for in the Agreement. For instance the Shah Deniz agreement in Azerbaijan states in clause 12.1 (a):

Other than Profit Tax obligations described in this Article 12, the Contractor Parties shall not be subject to any Taxes of any nature whatsoever arising from or related, directly or indirectly, to Hydrocarbon Activities.

A similar clause 26.7 in the Gabon Contract with Vanco states:

Apart from the bonuses established in Articles 28.1 and 28.2, the taxes, imposts and royalties established in Article 26.1, the duties and taxes collected by the Customs Administration, established in Article 34, the contribution to the Hydrocarbon Support Fund, established in Article 21.7, the contribution established in Article 39 and, with the exception of the property tax on structures due under common law on residential buildings, the Contractor is exempted, in connection with the Petroleum Operations, from any other taxes, royalties, duties, imposts and contributions.

Such clauses are a clear impediment to introduce carbon taxes and to make consequential changes in other possible taxes. It cannot be recommended to have such wide ranging clauses in future contracts. As a minimum these clauses should be adjusted to contemplate the possible future introduction of carbon taxes, without altering other fiscal provisions in the contract.

Equally restrictive provisions are clauses where the host government, the regulator or the national oil company promises to pay taxes on behalf of the contractor.

For instance, clause 5.3.7 in the Indonesian PSC obligates BPMIGAS (the previous regulator) as follows:

Except with respect to CONTRACTOR's obligation to pay the income tax and the final tax on profits after tax deduction as set forth in paragraph 5.2.18 of this Section V, assume and discharge all other Indonesian taxes of CONTRACTOR including value added tax, transfer tax, import and export duties on materials, equipment and supplies brought into Indonesia by CONTRACTOR, its contractors and Subcontractors; exaction's in respect of property, capital, net worth, operations, remittance or transactions including any tax or levy on or in connection with operations performed hereunder by CONTRACTOR.

It cannot be recommended to have such wide ranging clauses in future contracts. Also in this case carbon taxes should be specifically excluded from such obligations. The whole purpose of introducing carbon taxes is to change the behavior of the investor. Having the regulator pay such taxes will not affect the contractor and its efforts to reduce greenhouse gases during operations.

Some contracts have stabilization provisions in the contract, whereby it is recognized that the government may change laws and regulations, but the stabilization provisions require the parties to amend the contract to restore the balance.

Sometimes these provisions are rather broad, as for instance in clause 40(3) of the Kenya Model Contract:

If after the effective date of this contract the economic benefits of a party are substantially affected by the promulgation of new laws and regulations, or of any amendments to the applicable laws and regulations of Kenya, the parties shall agree to make the necessary adjustments to the relevant provisions of this contract, observing the principle of the mutual economic benefits of the parties.

With such a clause it is unclear how the contract would have to be amended in case of imposition of new carbon taxes. Presumably the share of profit oil/profit gas to the State may be reduced. Such a change would alter the contractor's behavior with respect to carbon emissions. Nevertheless, it is a rather complex and unnecessary process.

It is far better to exclude specifically carbon taxes or any taxes of general application, as is the case Article 20.2 in the Model R/C contract of Malaysia, which states:

The terms of this Contract have been negotiated and agreed having due regard to the terms of the Petroleum (Income Tax) Act, 1967 as amended by the Petroleum (Income Tax) Amendment Act, 1976, export duty and levies required to be made by Contractors and all subsequent amendments thereto in force on the Effective Date.

If, at any time or from time to time there should be changes in the aforesaid or the introduction of any legislation, regulations or order which imposes taxes, duties and levies peculiar to the petroleum industry ***and not of general application****, the effect of which would be to increase or decrease materially the liability of Contractors to pay petroleum income tax or such other taxes, duties or levies, PETRONAS and Contractors shall meet and formulate a mutually acceptable arrangement to restore the Parties substantially to the same economic position as of the Effective Date of this Contract.*

As a general principle in the future negotiations of petroleum contracts, it needs to be established that future fiscal changes in order to address greenhouse gas emissions are a reasonably foreseeable event. Therefore, the risk that such fiscal change may occur should be borne by the investor. It should not be an obligation of government to protect investors from the consequences of climate change policies.

6.6 Promote a regulatory framework consistent with Climate Change policies

There are a number of regulatory issues that would need to be addressed in a new Climate Change policy. Following is a discussion of some of these issues.

Flaring and Carbon Capture and Storage of produced greenhouse gases. Many governments have already introduced prohibition or restrictions of flaring of natural gas and related gas mixtures. The purpose of these restrictions is to ensure that natural gas is not wasted and is re-injected for future consumption. Reinjection is often back into the same reservoirs that the gas was produced from.

However, a different issue is that frequently natural gas will contain a few percent or considerable volumes of CO2 and other possible gases such as H2S. Such CO2 has to be removed from the natural gas in order to create pipeline quality gas. The removal of this CO2 can take place during the production of the gas, in special conditioning plants or in gas processing plants. In other words the CO2 has to be “captured” in order to create natural gas of acceptable specifications. This is an inherent cost of the production of gas with such impurities.

In the context of Climate Change policies it cannot be accepted that such CO2 would subsequently be released in the atmosphere. It can now be recommended that such CO2 be re-injected and stored in reservoirs containing brine with an adequate seal to ensure that the CO2 does not escape back in the atmosphere. Apart from CO2 also other possible gases that need removal from the natural gas can be stored in this manner jointly with the CO2, such as H2S. The reservoirs in which the CO2 would be injected will be different from the reservoirs that the natural gas was derived from. This therefore implies a considerable additional cost.

Obviously, any CO_2 vented in the atmosphere as a result of these processes should be subject to a carbon tax. Therefore, depending on the level of tax, such separate sequestration of CO_2 may be economic compared with the alternative tax. Of course, for very small volumes such storage would not be a viable proposition and the respective tax would be paid. However, over certain minimum volumes, regulations or contractual provisions should now provide for the fact that CO_2 need to be sequestered regardless of whether it is economic to do so and the cost of such storage would become an element in the cost of producing the petroleum. These provisions would not apply to the sequestration of possible CO_2 created as a result of the burning of petroleum or petroleum products during petroleum operations.

For the purpose of petroleum legislation, license contracts or production sharing contracts, the definition of "petroleum operations" should now include the carbon capture and storage of greenhouse gasses and other impurities associated with the production of petroleum. Also a well injecting CO_2 and other greenhouse gasses for the purpose of sequestration should be classified as a "development well".

The expenses should be a deductible/recoverable expense for fiscal purposes.

Significant Discoveries. As was discussed in sub-chapter 2.3 under the new Climate Change framework, the main purpose of new exploration and unconventional resource development is to create a future reserve base that is more attractive than the existing base on a worldwide basis. At the same time, the anticipated decline of oil and gas production under the Success Scenario in the coming decades, make it no longer necessary to take a short term approach to oil and gas development from a government point of view. It is now more beneficial to take a longer term approach, since there is no longer an urgent need to secure future petroleum supplies.

Under the traditional petroleum laws, concessions, licenses, license contracts and production sharing contracts, petroleum operations have to be carried out in a relatively tight time frame. For instance, there might be an exploration period of, for instance, 7 years, divided in two or three sub-phases. Upon discovery of petroleum, an appraisal program can be proposed, which is typically not longer than 2 years. Upon the completion of the appraisal program, the holder or contractor has to make a commercial declaration and present a development plan, otherwise the concession, license or contract terminates for the discoveries that have not been declared commercial. The underlying concept of these provisions is that it is in the interest of the jurisdiction to develop the resources as fast as possible. The fast development of the petroleum resources was necessary to secure the economic future of the nation and benefit as soon as possible from the revenues and economic activity created as a result.

The process is to (1) declare a commercial discovery, or (2) not declare a commercial discovery and relinquish the area and field. However, we are moving towards a phase in the petroleum industry where most regions of the world are now in a rather mature stage of development and production. New discoveries are small and marginal. New unconventional developments are typically high cost. Under the Success Scenario it is not necessarily logical to invest heavily in new midstream infrastructure, such as new pipelines, new refineries, gas processing plants or liquefaction plants in order to promote strong increases in oil and gas production.

It is more logical to use the existing infrastructure more effectively and extend the life of this infrastructure as much as possible and only build new infrastructure where necessary.

Therefore, the petroleum policy would change from boosting petroleum production as fast as possible to bringing new petroleum reserves on line as economically as possible from a longer term perspective, benefitting as much as possible from infrastructure already in place and developing local markets in the case of gas.

This can be achieved by introducing the concept of a "significant discovery". This concept already exists in a number of countries, such as Canada and Bangladesh. This means that upon completion of the appraisal program, the company would be able to declare the following:

(1) A commercial discovery. This would obligate the company to submit a development plan in a pre-determined time frame, or
(2) Not a commercial or significant discovery. This would oblige the company to relinquish the respective production or development area and in case no other discoveries have been declared commercial or significant, terminate the concession, license or contract, or
(3) A significant discovery. Where a significant volume of oil or gas has been discovered, but not commercially attractive, the holder or contractor would be able to retain the respective discovery area for a specified period where the discovery has the potential to become commercial:
    a. Together with other discoveries as a result of exploration operations or appraisal operations in other areas in or outside the concession, license or contract, or
    b. Once capacity becomes available in existing infrastructure or infrastructure to be expanded or new infrastructure to be created, or
    c. In the case of natural gas:
        i. once local demand is sufficient to merit the development of the field including as a result of the replacement of coal in local power plants, or
        ii. export markets become available as a result of new LNG or other export contracts.

The period during which the significant discovery can be retained would depend on an assessment of the above conditions, but a maximum period, such as 10 years, may be established. Prior to or upon the termination of this retention period, the holder or contractor would have to declare whether or not the field is commercial. The ability to declare a significant discovery would lower the commercial risk of the exploration or unconventional pilot projects. It would also permit a more systematic and orderly transition to renewable resources.

Concession, License or Contract Term. Under the constrained demand of the Success Scenario, oil production would commence to decline within 10 years and gas production within 20 years. This means that concessions, licenses or contracts entered into in the coming years, will face this framework.

The term of typical leases on wells in North America is as long as such lease is producing oil or gas in paying quantities. In the case of licenses in Canada and Europe, the licenses are typically renewed until all commercial production is exhausted. Renewals are usually under prevailing terms and conditions or under terms and conditions as decided by the Minister in charge of Petroleum.

However, license and production sharing contracts have a finite term, usually between 20 and 40 years, which sometimes can be renewed once or twice for limited periods of time, such as 5 or 10 years. The typical average total duration is about 32 years, while the maximum term is typically not longer than 50 years. Once a contract is finally terminated, some nations permit the negotiation of a new contract or special contract extension.

This overall scheme for contracts is no longer consistent with the Climate Change concepts. As long as it was considered in the interest of the nation to achieve as rapidly as possible the highest level of production, limiting the contract term was a strong incentive for producers to precisely achieve this.

However, in the new environment achieving this goal is less important than before. It is more in the interest of governments to try to increase the recovery factors from reservoirs with continuously improving technologies, without pre-conceived ideas about of field production duration. Encouraging secondary and tertiary recovery will extend time lines and encourage incremental investments based on existing and new facilities and advanced technologies. Often, such projects result in high levels of local content. This permits nations to benefit as long as possible from their remaining reserves. This is a more effective focus in the framework of Climate Change policies.

It can therefore be recommended that modern license and production sharing contracts adopt the concept that the duration of the contract should correspond with the commercial production life of the field or project and that renewals will be granted as long as commercial production is being maintained. Such renewals can be on prevailing or specially determined fiscal and commercial terms and conditions. The advantage of this approach is that the contractors will have a vested interest in achieving the maximum economic recovery from the reservoirs and will be automatically responsible for abandonment.

Development Plan approval. It will be obvious that a new element in development plan approval procedures will be the obligation on the holder or contractor to submit detailed information on the estimates of greenhouse gases that will be burned or vented as a result of the operations and how such emissions can be minimized, preferably using renewable energy. Also ongoing monitoring of greenhouse gas emissions needs to be a requirement under the petroleum operations to be approved.

7. Detailed Recommendations with respect to Low Oil and Gas Price Fiscal Policies

Following is a detailed discussion of the recommendations with respect to the Low Oil and Gas Price Fiscal Policy Implementation.

7.1 Create price progressive fiscal terms for the entire target price range.

The new oil price environment requires a new design of the relationship between oil and gas prices and fiscal terms.

As was discussed in Chapter 5, so far only a limited number of countries and jurisdictions have implemented fiscal systems that are price progressive. In countries that have such systems the prime objective is to avoid a windfall for the petroleum industry under high prices.

The new pricing policy framework contemplates oil prices moving between $ 25 and $ 100 per barrel based on a "pivot price" of $ 60 per barrel, escalated for inflation. It is not in the interest of any nation to create excessive "boom and bust" conditions as a result of the petroleum fiscal terms. This means that during periods of high oil prices huge investments are made in new oil and gas developments that are not sustainable during periods of low prices.

When the boom takes place, costs go up significantly due to lack of available supplies and services. During the bust there are significant layoffs of personnel and curtailment of investments and operations.

Creating stop-go-stop-go conditions under excessive boom and bust scenarios is not in the interest of government. During the boom governments are facing often excessive cost increases, not just for petroleum industry activities but for the economy in general, while during the bust it is the government that will largely have to deal with the resulting unemployment.

With actual prices that could vary between $ 25 and $ 100 per barrel, or over a wider range, it is not possible to avoid "boom and bust" sequences, but the fiscal terms could moderate the effects. This means that during periods of high oil prices, excessive investment in unsustainable projects should be discouraged with a high government take, while during periods of low oil price petroleum operations should be supported with a low government take. This will permit a more orderly and more profitable transition from fossil fuels to renewable resources.

Of course, a more significant variation in government take between periods of high and low oil prices, will put an increased strain on government budgets. It is therefore important that during periods of high oil prices a high government take is being applied in order to compensate for budget losses during low oil prices.

Also these petroleum fiscal policies have to be supported by policies to make budgets of petroleum producing nations less dependent on petroleum revenues through diversification of the economy and to create more effective sovereign wealth funds during periods of high oil prices.

There is a wide variety of possible fiscal features that can be used to create increased price progressivity over the entire range of $ 25 to $ 100 per barrel and similar gas price ranges, with the main emphasis to moderate "boom and bust" situations. Some of these features are new concepts. These features are:

1. Gross revenue based concepts, based directly on price or gross revenues,
2. Direct payment amounts based on a price sensitive scale,
3. Price sensitive profit oil/gas systems,
4. Price sensitive profit based systems,
5. R-factor systems,
6. IRR based systems,
7. Combinations of price sensitive royalties and profit shares,
8. A variety of Risk Service Contracts

Following is a discussion of these concepts.

Gross Revenue based Concepts

There several fiscal features based on gross revenues that can be used to implement such price progressivity. These are:

- Royalties based on sliding scales which vary with oil or gas prices,
- Price sensitive severance or production taxes,
- Windfall profit taxes or similar levies, based on a percentage of the difference between a market price and a base price. The percentage can be fixed or a sliding scale,
- The supplemental petroleum tax of Trinidad and Tobago, and
- Export duties based on the level of the oil or gas prices

Following is a discussion of a number of examples.

Mexican royalty. An interesting recent and very adequate example is the price sensitive royalty adopted in Mexico.

Article 24 of the Hydrocarbon Revenue Law establishes separate royalties for crude oil, condensates, associated natural gas and non-associated natural gas.

For crude oil the royalty rate is 7.5% when the contract crude oil price is less than US $ 48 per barrel. Over this price level, the royalty rate is established by the following formula:

Rate = [(0.125 * contract crude oil price) + 1.5]%

In other words if the oil price is $ 100 the royalty rate is 14%. Interestingly, there is no cap on the formula which means that at an oil price of $ 788 per barrel the royalty rate is 100%. However, it appears that under current low oil prices we can live with this problem.

For condensates, the rate is 5% under a contract price of $ 60 per barrel. Over this price level, the royalty rate is established by the following formula:

Rate = [(0.125 * contract condensate price) - 2.5]%

In other words if the price is $ 100 per barrel the rate is 10%.

For non-associated natural gas when the contract gas price is higher or equal than $ 5.50 per MMBtu and for associated natural gas at any price level, the rate is simply determined as:

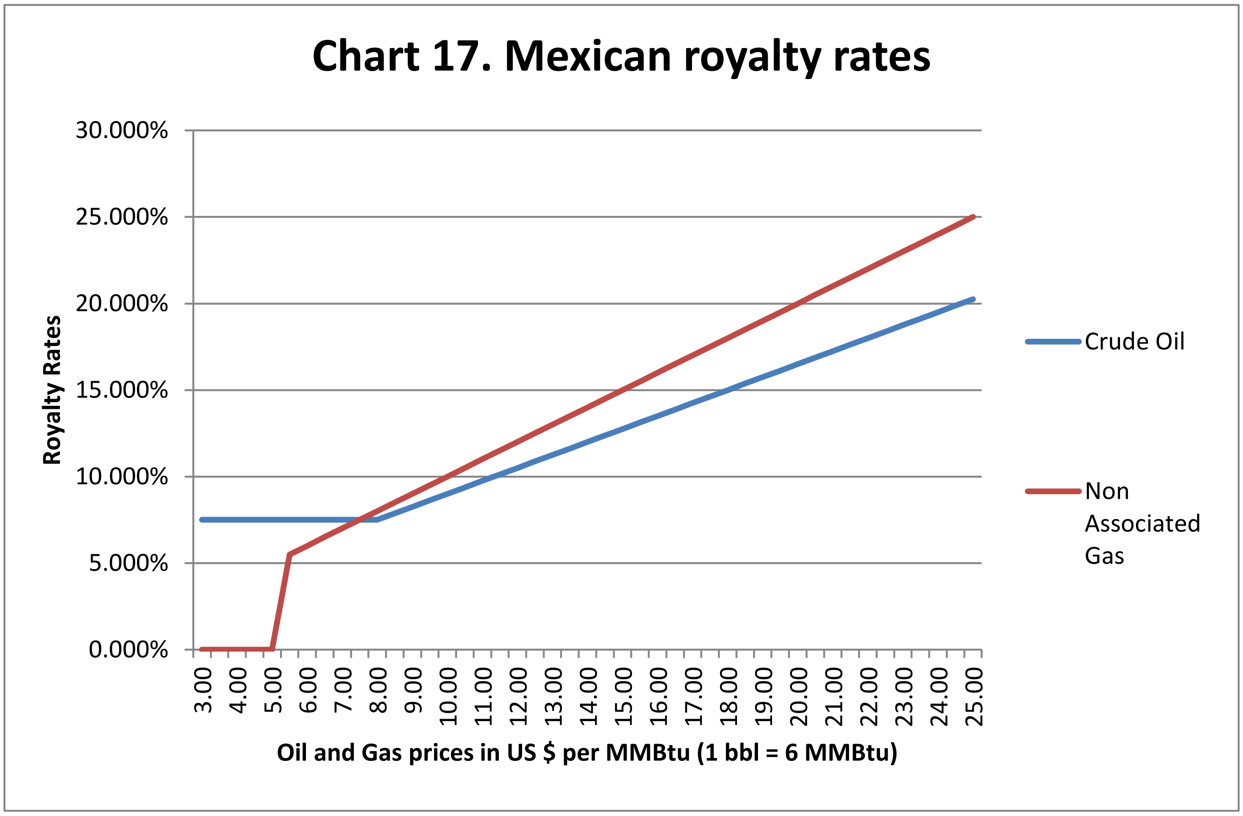
Rate = contract natural gas price /100

For non-associated gas the royalty rate is 0% when the contract gas price is less than $ 5.00 per MMBtu. Between $ 5 and $ 5.50 the scale moves up from 0% to 5.5%.

The contract prices are determined at the measurement point.

The price levels are adjusted for the US Consumer Price Index.

Chart 17 illustrates the royalties applicable to crude oil and non-associated gas. The price sensitive royalties are indicated per MMBtu equivalent (1 barrel = 6 MMBtu).



The adjustment with the US Consumer Price index will ensure that investment conditions for oil or non-associated gas fields do not deteriorate merely as a result of price escalation due to inflationary pressures. It encourages investors to take a long term approach. This will be in particular important for deep water conditions where production may not even start within 10 years after the signing of the contract.

A point of criticism that I have is that under royalty systems the resource owner should always levy a reasonable minimum royalty, such as 5%. This means that the minimum non-associated gas royalty could have been 5% at $ 5 per MMBtu and in this case there would have been no need to separate between associated and non-associated gas. This would have made the system simpler.

As part of an overall climate change policy, it makes sense to promote gas as a transition fuel. In this context, the oil royalties per MMBtu could have been higher than the non-associated gas royalties.

If governments want to adopt policies to moderate “boom and bust”, the royalties should increase much stronger with price.

Alberta Conventional Royalties. For conventional oil and gas wells, the Alberta royalty formula consists of a percentage for well productivity and for price. The Alberta royalty formula is as follows:

R% = Rp% + Rv%

The total royalty rate (R%) consists of the addition of the results of the price sensitive royalty scale (Rp%) and the well productivity sensitive royalty scale (Rv%). For low oil prices and well productivities the scales can result in negative amounts. Alberta has also a maximum holiday rate of 5% on the earlier of one year or the first 50,000 barrels. This is a modern and effective concept. However, the three year period for shale gas wells and coalbed methane is excessive and could be reduced to two years.

Jurisdictions with existing price progressive royalties, such as Alberta, could make such features more pronounced. The concept is that governments should assist when times are tough as a result of low oil prices, but reap the corresponding benefits when prices are high.

Colombia Windfall Profits Tax. Colombia has a rather effective "High Price Levy" based on a threshold price. This threshold price depends on the gravity of the oil. It is a lower price for a higher API level. These prices are indexed for inflation. The High Price Levy moves based on a sliding scale which is a multiple of the threshold price, up to 5 times this price. The rate moves from 30% to 50%.

For gas the levy is based on the distance to export.

Similar concepts are being used in the Malaysian Wind Fall Profit feature, the Chinese Oil Gain Levy, the Trinidad Supplemental Petroleum Tax and similar taxes in other countries.

In order to make price sensitive concepts effective, it is important to index price levels with inflation. Malaysia has an index system, while China and Trinidad and Tobago do not.

Russian Export Duty. The Russian export duty is price sensitive. However, it can be recommended to gradually phase out this duty and replace it with fiscal terms directly related to the resources.

Direct Payment Amounts

Russian Mineral Extraction Tax. The Russian Mineral Extraction Tax is based on an amount of rubles per ton for oil and per 1000 m3 for gas. This MET is price sensitive. Recently Russia modified the MET to ensure that there is always a minimum payment amount. As the export duty is being phased out, the MET needs to be strengthened to maintain government revenues.

Price Sensitive Production Sharing

Trinidad and Tobago PSC. Trinidad and Tobago has a special profit oil/gas table in the contract with a combination of a sliding scale for level of production and price. Over the maximum price, Trinidad and Tobago applies a windfall profit feature. This concept will be used in our example analysis in sub-chapter 8.3. This table is an effective way to create both volume and price progressivity.

Egypt and Brazil have similar type systems. In the case of the Pre-Salt PSC the table is based on well productivity and price.

Oman PSC – Price Sensitive Cost Oil. Oman in some contracts has a price sensitive cost oil limit. This is a concept that could be useful in other countries.

Price Sensitive Profit Based Systems

Norway. The 51% hydrocarbon tax in Norway contains an uplift of 22% taken over 4 years. This is effective to stimulate new investments under average and high oil prices. It is an indirectly price progressive system. Nevertheless, the effectiveness under low oil prices is nil as soon as the uplift has been fully applied. It can be recommended that Norway changes the system by applying an uplift of, say, 16% to both development capital expenses and operating expenses. This will assist companies in surviving low oil prices.

UK. The UK has a surtax of 20% with an uplift of 65% for development capital expenses. Also in the UK it can be recommended to make the uplift a lesser percentage and apply it to capital development expenses and operating expenses.

R-factor Systems

All R-factor systems are price sensitive by their very nature.

Thai SRB. Thailand has a Special Remuneration Benefit ("SRB") for government. The system is based on an R-factor which consists of the gross revenues divided by the meters drilled. In other words the system is sensitive to price and well productivity. The sliding scale goes from 0% to 75% and is based on a profit share. The profit share is calculated with an uplift. Conceptually, the SRB is an effective system. The SRB is not based on cumulative values and is therefore effective during low oil and gas prices. However, based on the last two decades of history, the SRB could be adjusted in order to generate more revenues under favorable conditions. Also, as will be discussed in sub-chapter 7.4 the SRB could be made more robust.

Peru R-factor. The Peru R-factor is applied to royalties and based on the ratio of cumulative gross revenues divided by total costs (which includes prior royalty payments). The R-factor is very robust. However, the cumulative nature does not make it an effective mechanism during periods of low oil prices, since the R-factor will only modestly decline (if at all).

Azerbaijan R-factor. The R-factor is based on contractor cumulative investment recovery plus profit oil divided by cumulative investment. This R-factor is too sensitive and creates serious gold plating issues as will be discussed in sub-chapter 7.4.

Mexico Deep Water R-factor. The Mexico system for deep water has an additional royalty based on an R-factor. The R-factor is an innovative formula, as follows:

R = cumulative (gross revenues – royalties – rentals – surface taxes)/cumulative total costs

The R-factor is then applied to a formula which contains a variable called "Operating Result Coefficient" ("CRO"). The CRO is determined separately for each trimester, but not on a cumulative basis.

The CRO is defined as:

CRO = (Gross Revenues – royalties – rentals – surface taxes – costs)/(gross revenues).

In other words the CRO is really the before tax net cash flow divided by the gross revenues. If the CRO is negative for any trimester the CRO is set to zero. During periods of low oil prices, the CRO will be low. In other words the CRO is directly affected by the oil, condensate and natural gas prices. Towards the end of the field life and close to abandonment the CRO will also be low since costs per barrel equivalent will be high. During periods of re-investment, which create a negative cash flow for such semester, the CRO is zero.

The R-factor scale is defined as follows:

$R < 2$	Additional Percentage is 0%
$2 < R < 4$	Additional Percentage is ((R – 2)*25*CRO)%
$4 < R$	Additional Percentage is (50*CRO)%.

This Mexican Deep Water R-factor has various advantages over most other R-factors. These are:

- The R-factor is immediately responsive to price variation, since the CRO is not cumulative. If the CRO is zero, the R-factor results in zero additional percentage regardless of the level of the R-factor.

- The additional percentage declines towards the end of the field life when costs relative to revenues are expected to go up. This R-factor therefore maximizes the recovery of the reserves.

- The additional percentage is automatically less if investments are made in costly further field developments.

The problem with many R-factors, other than the Mexican deep water terms, is that there is not a strong drop in the royalty or profit share percentages when the price drops, due to the fact that most R-factors are based on cumulative profits or revenues, not trimestral profits or revenues. Also at the end of the field life, most R-factors are high and therefore impede the full recovery of the reserves. Investments in enhanced recovery or other costly undertakings often do not have a significant impact on the R-factor later in the life of the field.

The only problem with the proposed Mexican R-factor is that in case very significant re-investments are made, for instance, as a result of installing a new platform in the field or developing a new field in the same contract area, the negative trimestral cash flow that would result is not carried forward. This could impede such investments.

Algeria R-factor. The Algerian R-factor is based on discounted values and is as a result subject to serious gold plating. It can be recommended to make the R-factor more robust.

Nigeria-2005 PSC. The Nigerian R-factor is also subject to gold plating. It is based on a linear scale, rather than a "jumping" scale.

IRR Systems

Almost all IRR based systems applicable to profits or production shares feature gold plating and can therefore not be recommended. A discussion of gold plating is contained in sub-chapter 7.5. In that sub-chapter the recent Mexican shallow water terms will be reviewed.

Combination Systems

Alberta Oil Sands. The Alberta oil sands feature a combination of a base royalty and a net profit share. Both are price sensitive in the range of $ 55 to $ 120 for West Texas Intermediate. The price levels are not adjusted for inflation. The base royalty slides between 1% and 9% and the net profit share between 25% and 40%. The producer pays the highest of the two values. The net profit share is calculated by applying the long term bond rate to the carry forwards in the cash flow. This ensures that the net profit share is not being paid unless the investor has made a before tax IRR equal to the long term bond rate. Once payout is achieved the net profit share clicks in. If payout is achieved and subsequently new investments are made the long term bond rate can be applied again until the subsequent payout.

As indicated with respect to the Alberta oil sands the concept of using nominal oil prices without inflation adjustment for the price based sliding scale for the base royalties does not provide for effective price progressivity. Even with modest inflation rate assumptions the real price for oil will become rather low within one or two decades, this reduces interest in investments and requires the use of royalty rates that are less than otherwise would be possible.

It can be recommended to revise the oil sands scale taking into account inflation adjustment and adjust the royalty percentages in such a way that royalty revenues are maintained under high prices (and improved using the minimum 5%) but become more competitive and effective under low prices from a long term real economic perspective.

Risk Service Contracts

Under the current risk service contracts, contractors are paid a fee that is fixed and usually not subject to a price related sliding scale. This means that 100% of the benefit of higher prices goes to government, but government also absorbs 100% of the reduced revenues in case of low prices. This means some service contracts rather attractive under low prices for investors and unattractive for governments.

A number of Risk Service Contracts typically do not provide for the correct incentives to ensure efficiency on the part of the operators. Therefore it can be recommended to phase these contracts out.

Iraq. The Iraq Technical Services Contract provides for the fact that contractors recover (often rather immediately) 100% of the costs. This creates gold plating conditions, since contractors do not have a vested interest to reduce costs. It also creates unnecessary cost control problems.

Ecuador. This contract provides for a total fee per barrel that covers costs and a profit margin. So this type of contract provides an incentive to be cost effective. However, profits do not increase when oil prices increase and therefore there is no incentive to invest more under higher prices.

7.2 Ensure a minimum government take for the resource owners.

On the assumption that the world will have sufficient oil and gas supplies to provide the Success Scenario or the Moderate Success Scenario, it is in the collective interest to produce the most profitable part of these resources first. Therefore, resource owners should receive reasonable minimum payments for the production of their resource.

Overall Minimum Government Take. A reasonable minimum can be calculated as consisting of the government take that would result from a 30% corporate income tax, a $ 60 per ton of CO_2 equivalent carbon tax and a 5% royalty. For oil this would result in about 45% un-risked real government take at a price of $ 30 per barrel and a cost of $ 20 per barrel and in about 35% un-risked real government take at a price of $ 100 per barrel and a cost of $ 10 per barrel.

For production sharing a similar un-risked real government take can be recommended as a minimum. The government take in this case does not only depend on price and costs but also on the cost limit.

Carbon Taxes. The introduction of carbon taxes would automatically create some minimum government take.

The upstream petroleum industry is a significant user of energy. The "own use" in a typical oil or gas field is approximately equal to 3% of the amount of the production. Most of the energy use in oil fields is associated gas. Levying a carbon tax of $ 120 per ton CO_2 equivalent would therefore add US $ 1.25 per barrel of oil in terms of fiscal cash costs and $ 0.21 per Mcf of gas.

Royalties. With respect to countries that use royalties, policies providing for very low royalties, such as only 1%, or even negative resource income due to excessive incentives should be eliminated. It should be noted that reducing the royalty from 5% to 1% does not really provide a meaningful competitive advantage. Also if a project needs a royalty reduction to 1% than such project is too weak economically to justify as an investment.

For instance, minimum gross revenue based royalties in Alberta, such as 0% for conventional oil and 1% for oil sands should be increased. The same applies to base royalties in Newfoundland and Labrador, Nova Scotia, some of the terms in British Columbia and Federal terms in the Arctic areas.

For instance, it can be recommended that Alberta establishes minimum levels of 5% for oil and gas royalties. Excessive incentives lowering the effective royalty rate below 5% should be eliminated. An example of an incentive that can be eliminated in Alberta are the credits under the Natural Gas Deep Drilling Program, since the royalty is already reduced for deeper wells through the general formula. However, this formula could be revised to become more effective.

As indicated earlier Mexico should have a minimum royalty of 5% for non-associated gas, rather than the 0% royalty below $ 5 per MMBtu

The 2% royalty of the Faroe Islands could be increased to 5%. The same applies to the royalty in Papua New Guinea.

Originally, the Mineral Extraction Tax in Russia could go down to zero for very low oil prices and under some other conditions. Russia has now established a minimum MET.

South Africa has a royalty that slides between 0.5% and 5% based on a profitability indicator. This could be simplified by having simply a 5% royalty.

There are a number of countries with sliding scale royalties which start at less than 5%. Such scales could be adjusted to a minimum 5%.

Production Sharing. If production sharing contracts feature a royalty separately payable from a production share, the above 5% can be recommended as a minimum. As will also be recommended in more detail, it can be recommended to break out the corporate income tax from production sharing and a 30% rate can be assumed. Also carbon taxes as discussed above should be applied. If these features are included a sliding scale production sharing could start at 0%. Otherwise a minimum profit oil/gas share has to be determined based on the above mentioned government take.

Except for the Bokhitar PSC in Tajikistan, all PSCs in the world are consistent with the above mentioned minimum un-risked real government take.

7.3 Discourage unsustainable investment levels during high oil and gas prices.

Price Incentive Index. The concept of moderating a "boom and bust" cycle in the petroleum industry requires strong increases in government take during high oil prices in order to discourage excessive investment and to replenish the government treasury in order to compensate for the losses during the low oil prices.

However, the design of fiscal systems with strong price progressivity has its limits. When the progressivity is too strong, the marginal government take will increase quickly and could exceed 100%. This issue can be demonstrated with the Price Incentive Index.

Charts 18, 19 and 20 display a conceptual analysis of four levels of price sensitive royalties, all based on the same slope. The royalties are all based on a simple linear formula starting from the minimum level. The minimum levels are 5%, 15%, 25% and 35%. The slope is determined by taking 40% of the price, minus 7%, plus 3%, plus 13% and plus 23% for the four royalty levels. It is assumed that the minimum royalty is applicable when the oil price is $ 30 or less. Chart 18 shows these royalty levels.

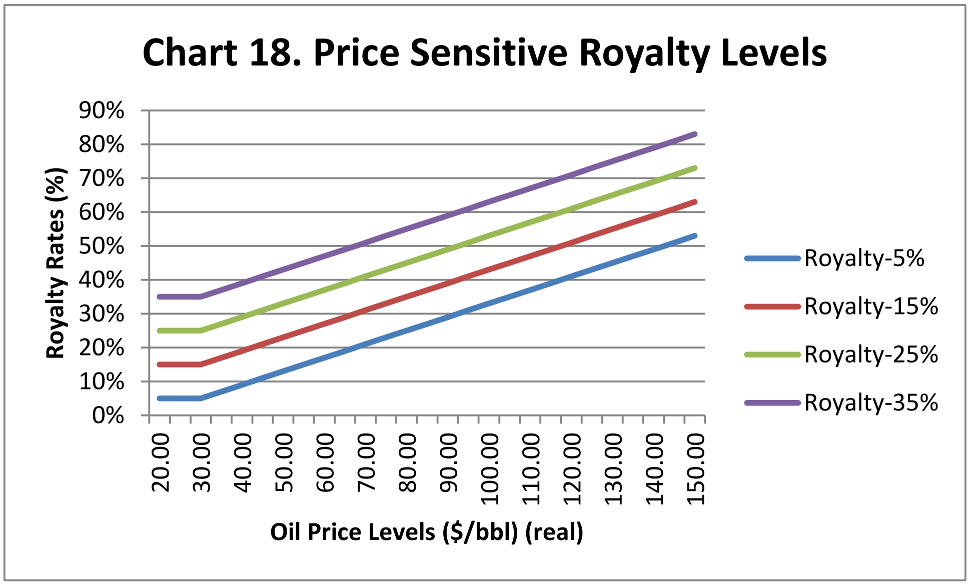


Chart 19 displays the resulting government take, assuming that the only other fiscal feature is 30% corporate income tax. As can be seen a simple price sensitive royalty and corporate income tax could cover a wide range of government take levels.

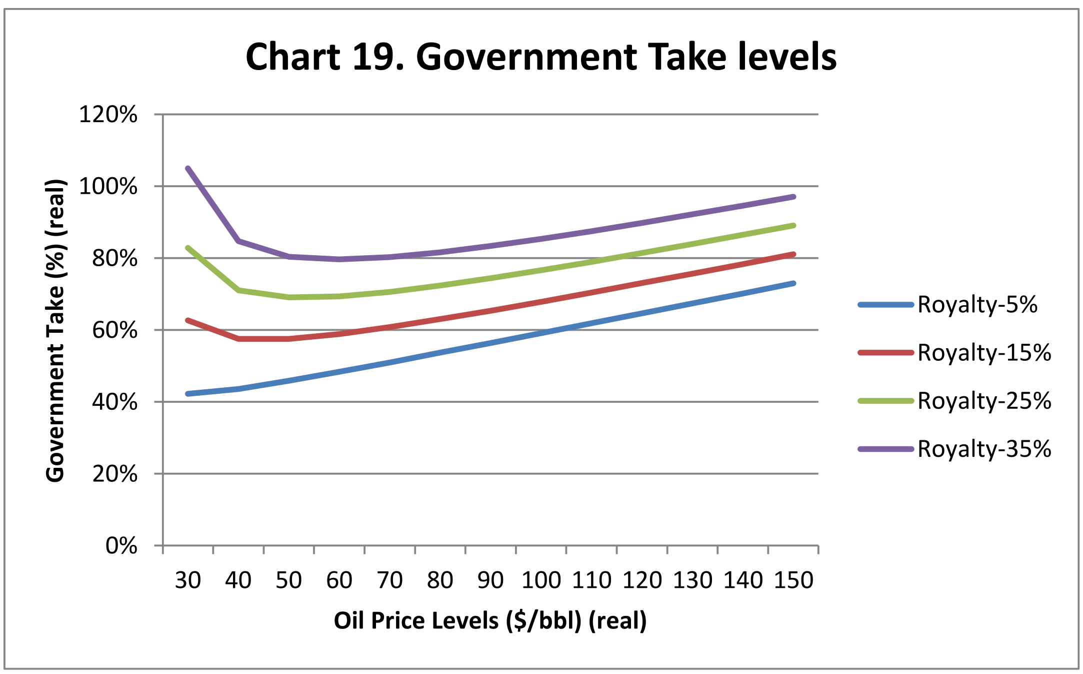
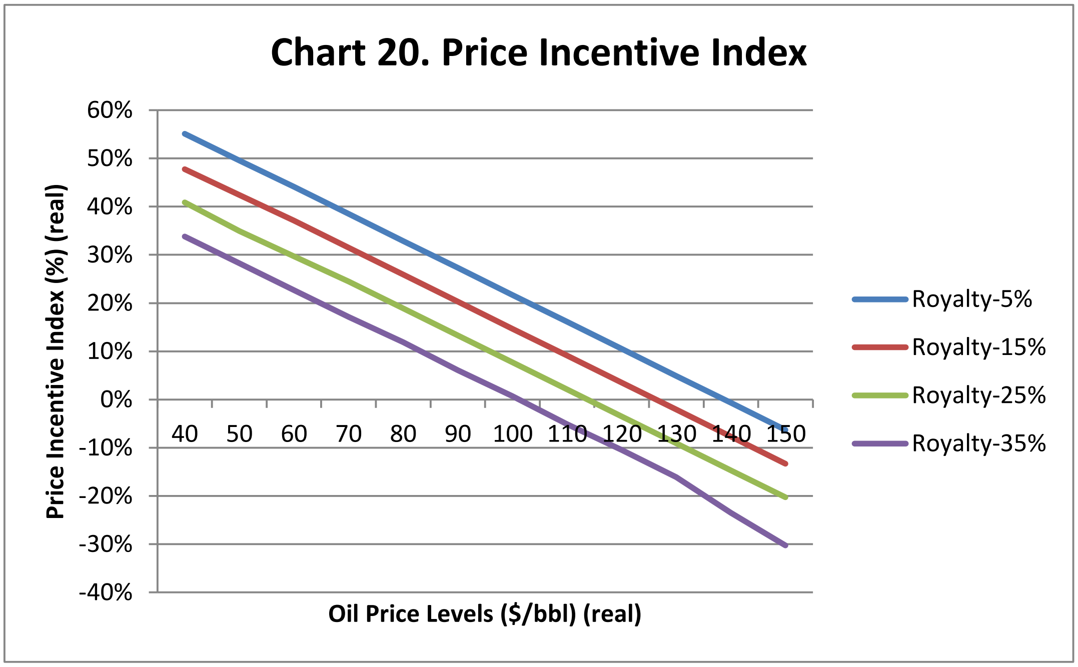


Chart 20 displays the Price Incentive Index. This is the index that indicates how much a producer can keep of the increased revenues if the producer manages to get an extra dollar for the sale of his oil. For instance, if the index is 40%, the producer retains $ 0.40 of every one dollar gained.



In a rational market system, the fiscal terms should encourage the producer to seek the highest possible prices for oil and gas. This means the Price Incentive Index should always be positive and preferably not drop below 10%. Chart 20 shows how the Price Incentive Index becomes negative at approximately the following oil price levels: $ 138, $ 126, $ 114 and $ 102 per barrel.

This means that a simple linear formula with a single slope does not create rational results under high price levels. If the government wants to employ a strongly price progressive system, the formula has to contain several slopes with the slopes becoming less steep under higher prices. As discussed in Sub-Chapter 7.1 Alberta has actually currently such a system applicable to individual wells. Conceptually this system is highly effective with high royalties under high prices. As indicated in this report, some adjustments can be recommended in the royalty rates, but the Alberta concept is superior to other royalty systems under high prices.

Interestingly, the Royalty Review Advisory Panel appointed by the Alberta Government has recently recommended to phase out this effective system and replace it with a system similar to the Alberta oil sands, but applicable to individual wells. This is a counter-productive and bizarre recommendation. The Panel calls this system "modern". This is puzzling because surplus profit based systems applicable to oil and gas fields have existed in the world already for more than 60 years.

Following is a set of examples of multi-slope royalties, in this case three different slopes.

Chart 21 illustrates the different levels of royalties for shallow water exploration. The low royalty is aimed at exploring relative high cost small fields. In our example a 20 million barrel target at $ 20 per barrel capital and operating costs. The average royalty is aimed at larger lesser costs targets. A 50 million target at $ 15 per barrel costs was used. The high royalty is aimed at large targets at low costs. A 100 million target at $ 10 per barrel costs was selected.

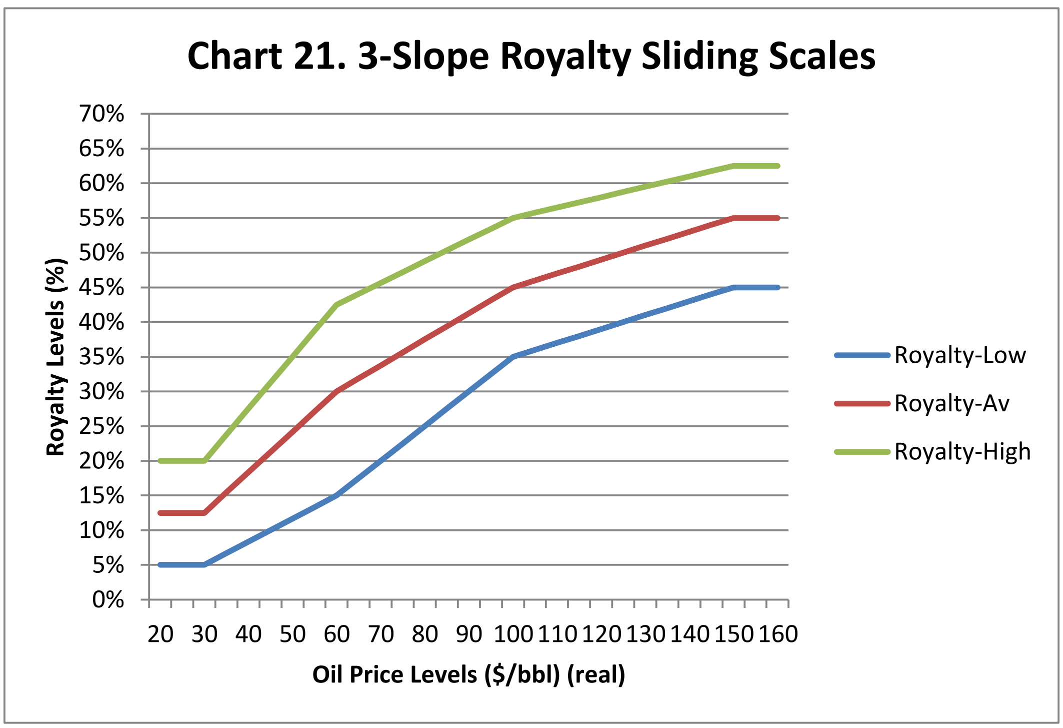


Chart 22 shows the Risked GT0 (risked undiscounted government take) based on real price and cost data. This chart illustrates how a very simple royalty tax system with a royalty based on a 3-Slope price sensitive system can cover a wide range of risked government take conditions.

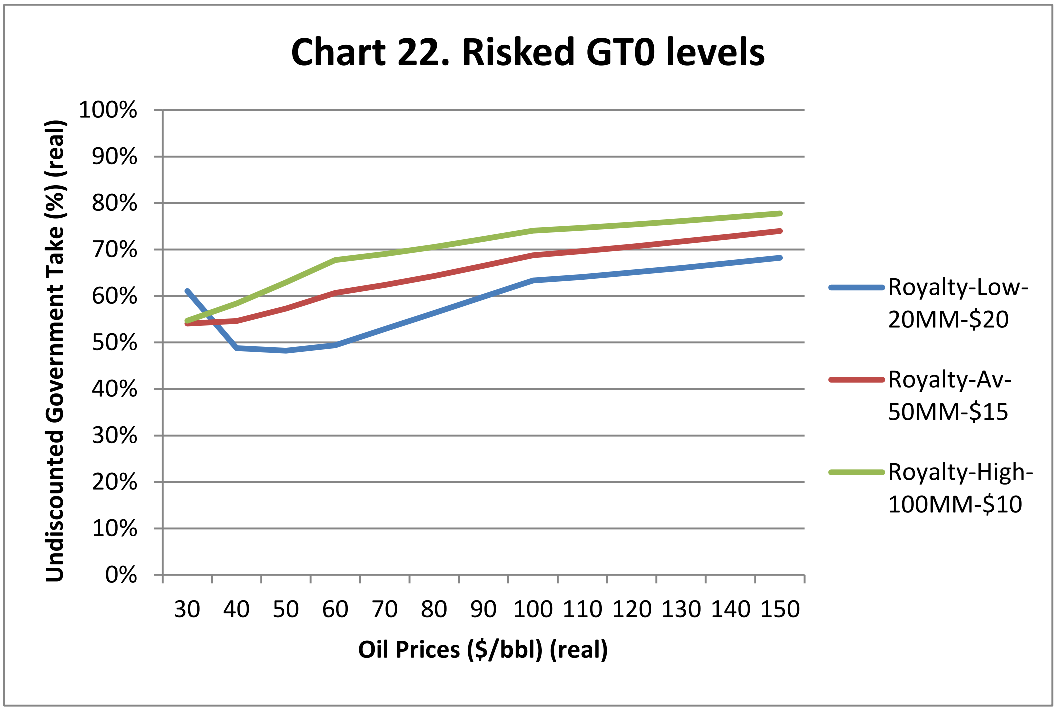
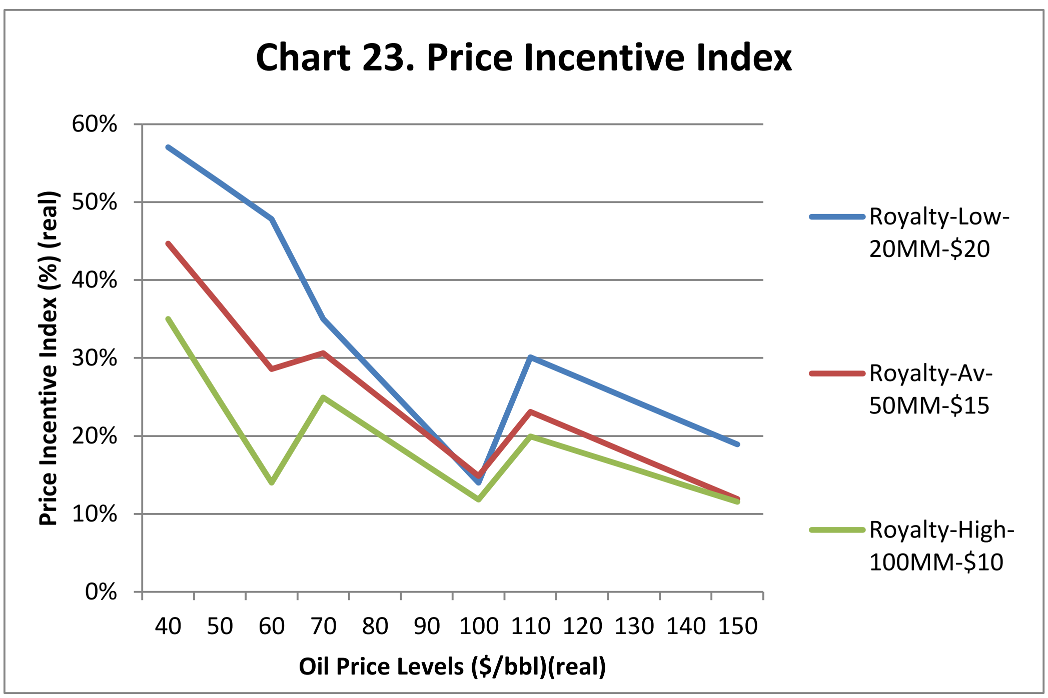


Chart 23 illustrates the Price Incentive Index. As can be seen the index is always higher than 10% and consequently this is a viable system from a royalty design point of view.



As is illustrated by this example, using a multi-slope price sensitive royalty will permit the use of relatively high royalties under high prices. This in turn will moderate the level of investment during the "boom". At the same time it will replenish the treasury in order to compensate for the period of low prices with low levels of royalties.

Of course instead of royalties other fiscal features can also be used to achieve these goals, as discussed in Sub-Chapter 7.1.

As will be discussed in Chapter 8, also more sophisticated royalty systems can be employed which also involve volume and cost progressivity.

7.4 <u>Restructure fiscal terms to improve alignment</u>

As stated in Chapter 2, even if the Success Scenario is being realized very large investments still have to be made in order to supply the oil and gas and create the related midstream infrastructure.

As will be demonstrated in this sub-chapter in many respects the fiscal structures being used today do not provide for an optimal alignment between governments and the petroleum industry. A better alignment can assist the petroleum industry during periods of low oil prices while improving government take at government discount rates.

<u>Wide variety of fiscal terms</u>

Over the last 15 years, the fiscal terms for oil and gas in the world have become increasingly diverse and complex. Therefore it is more difficult to determine which fiscal features are effective in creating a competitive system for investment and which are not.

Of course, an important factor is the overall government take. Countries with a poor resource base often have a low government take in the 20 – 35% range. Countries with a rich resource base can have a high government take in the 80 – 98% range. The level of government take is therefore an important indicator of the attractiveness of the fiscal terms.

However, there is an enormous variation in government take for the same level of profitability. As an example, for a particular shallow water field based on certain price and cost assumptions, the internal rate of return is the same at 28% in the Bahamas and the Netherlands. Yet the government take in the Bahamas is 17% and in the Netherlands 68%. The reason for this significant difference is related to the structure of the fiscal terms. In the Bahamas the system consists primarily of royalties and in the Netherlands the system is based on participation and profit sharing with special allowances which encourage investment. It is therefore important to analyze not just the level but also the structure of the government take.

Discount Rate

In order for government to decide on fiscal policy, it is important to establish the discount rate that would be used. As an example, Norway reviewed this matter in detail in its government report NOU 2012:16.

This report came to the conclusion that for cost-benefit analysis of ordinary government projects with a time line during the next 40 years the real risk free discount rate should be 2.5% and that a risk premium of 1.5% should be applied for a total risk-adjusted rate of 4%.

It should be noted that the Norwegian rate is low compared to what rates would be in other countries. It is likely that some other developed economies and significant oil and gas producing nations would use somewhat higher rates. Emerging economies would use substantially higher rates but most likely not exceeding 10%. Some of the low-income developing countries may use higher rates.

Given this framework, the analysis will be done using an real undiscounted government take ("GT0") as well as a real 10% discounted government take ("GT10") on the assumption that for most nations the actual rate will be somewhere in between.

For government investment in projects that compete with private capital, such as state participation in oil and gas projects, the same rates as used by the corresponding private enterprises should be used for cost-benefit analysis.

Investor scenarios

The attractiveness of the fiscal terms depends very much on the investor scenario. Three main scenarios can be distinguished:

- "stand alone" where an investor makes the very first investment in a country.
- "country incremental" where an investor has already established significant production and profits in the country and where further investments are made.
- "contract incremental" or "field incremental" where the investor has already established significant production and profits in a contract area and where further investments are made in the same area or the same field.

Different fiscal features react differently under the various circumstances. For instance, when an investor enters for the first time in a country, exploration expenditures will have to be carried forward for corporate income tax purposes. When an investor has already significant operations in the country, exploration expenditures can often be deducted from ongoing taxable income.

In the case of production sharing contracts, exploration expenditures from one contract area cannot be recovered from another contract area. If the contract permits consolidation at the contract level, however, such expenditures can sometimes be recovered from other fields in the same contract.

At the same time the impact depends very much on whether the fiscal terms apply to risked economics of an exploration venture or un-risked development economics.

The alignment issue will be studied using a 100 million barrel shallow water field at a price of $ 80 per barrel and a cost of $ 20 per barrel. For the risked cases, a relative high risk scenario is used with a low 20% probability of success during exploration, which means an 80% change of a dry hole.

The analysis will focus in particular on the Front End Loading Index ("FLI"). The FLI is calculated by subtracting the GT0 from the GT10. The larger the difference the stronger the front end loading of a fiscal system. The higher the FLI the more unfavorable the government take is structured for an investor.

<u>Stand Alone Unrisked</u>

The "stand alone" scenario applies to an investor which invests for the first time in a new country. "Un-risked" means that the investment relates primarily to the development of oil fields. The un-risked exploration costs are part of the cash flow. In other words the scenario relates to the economics of an exploratory success.

From a Stand Alone Un-risked perspective a fiscal system is more aligned when the system is less front end loaded.

It is possible to analyze the various fiscal features on their impact on the FLI. Table 3 provides an overview twenty two different ways of creating a 20% undiscounted un-risked government take on a stand-alone basis, using different fiscal concepts for the Base Case.

The lowest FLI, in fact 0%, is a 20% government participation in the venture, whereby the government participates as any other investor from the first day of the petroleum arrangement. Under stand-alone conditions this is therefore the least front end loaded concept. In this case the government and petroleum industry objectives are fully aligned. The IRR of the fiscal terms with a 20% government participation is the same as no government take at all.

The highest FLI is associated with a signature bonus of $ 1200 million. This creates also 20% government take, but the entire government income occurs on the first day of the venture. In other words this is the most front end loaded concept. This results in a complete mis-alignment and creates an unnecessary low profitability.

In between these two concepts there is an entire range of increasing values for the FLI. As can be noted, relatively favorable are profit oil scheme based on increasing the rate of profit oil with higher levels of cumulative production. This automatically provides a low fiscal burden early in the cash flow and a higher fiscal burden later on. Another favorable feature is an Additional Profits Tax based on a IRR sliding scale, with higher levels of tax under higher levels of profitability.

A carried interest is also relatively favorable, because the government party will contribute its share of the development costs.

Other favorable features are a "steep" R-factor which starts low and end up high under high R-factor values, royalties based on cumulative production, or corporate income tax or production sharing featuring uplifts or tax credits.

Unfavorable features are corporate income tax with slow depreciation and depreciation of assets based on asset life, production sharing with a low cost limit, flat royalties or royalties based on a sliding scale of daily production, rentals and bonuses.

Table 3. Twenty two different ways to create a 20% undiscounted government take - Base Case -Stand Alone - Unrisked

(ranking in order of the Front End Loading Index ("FLI")) (real)

		GT0 (%)	GT10 (%)	FLI (%)	IRR (%)	NPV10 ($ mln)	PIR10 (ratio)	Payout (years)
	No Government Payments	0.0%	0.0%	0.0%	30.1%	1423	1.68	10.24
1	20% state participation from day 1	20.0%	20.0%	0.0%	30.1%	1138	1.68	10.24
2	Profit oil cum SS, 5% to 30 mln bbls, 15% to 60, over 60 mln 29%, 50% cost limit	20.0%	20.6%	0.6%	27.9%	1129	1.33	10.29
3	"Steep" APT 2% up to 15% IRR, 12% up to 25% IRR, 26.95% over 25% IRR	20.0%	20.7%	0.7%	28.0%	1129	1.33	10.25
4	19.65% carry from approval of development plan	20.0%	20.9%	0.9%	29.1%	1125	1.61	10.28
5	"Steep" R-factor; 2% up to 1, 7% up to 2, 23.92% over 2; (cum rev/cum costs)	20.0%	21.5%	1.5%	27.8%	1117	1.32	10.26
6	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln	20.0%	21.9%	1.9%	27.5%	1111	1.31	10.34
7	21.45% CIT, 40% uplift on all capex, depr 100% write offs, depr as incurred	20.0%	22.3%	2.3%	27.5%	1105	1.31	10.26
8	21.45% Profit Oil, 40% uplift on all capex, 100% cost limit, costs expensed	20.0%	22.3%	2.3%	27.5%	1105	1.31	10.26
9	"Flat" APT 15% up to 15% IRR, 18% up to 25% IRR, 22.02% over 25% IRR	20.0%	22.4%	2.4%	27.4%	1104	1.30	10.28
10	"Flat" R-factor; 13% up to 1, 16% up to 2, 21.0% over 2; (cum rev/cum costs)	20.0%	22.6%	2.6%	27.4%	1101	1.30	10.28
11	19.75% CIT, depr 100% write offs; depr as incurred;	20.0%	23.2%	3.2%	27.2%	1093	1.29	10.29
12	19.75% Profit Oil, cost limit 100%, costs expensed	20.0%	23.2%	3.2%	27.2%	1093	1.29	10.29
13	19.70% CIT, depr 20% SL; depr as incurred;	20.0%	23.3%	3.3%	27.1%	1092	1.29	10.33
14	19.64% Profit Oil, 50% cost limit, costs expensed	20.0%	23.8%	3.8%	26.8%	1084	1.28	10.44
15	19.62% CIT, depr 20% SL, depr asset life	20.0%	24.0%	4.0%	26.8%	1082	1.28	10.47
16	19.52% Profit Oil, 30% cost limit, costs expensed	20.0%	24.6%	4.6%	26.4%	1072	1.27	10.54
17	15% royalty	20.0%	25.4%	5.4%	26.2%	1062	1.25	10.57
18	Prof Oil daily prod SS to 10000 bbls/day 5%, to 25,000 33% over 48.5%, 50% cost limit	20.0%	26.1%	6.1%	26.2%	1052	1.24	10.34
19	Dailly Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over	20.0%	27.3%	7.3%	25.7%	1034	1.22	10.63
20	$ 60.2 mln/year nominal rentals	20.0%	36.7%	16.7%	19.5%	900	1.06	10.97
21	$ 200 mln bonus; $ 1175 mln production bonus at 10,000 bopd	20.0%	46.9%	26.9%	17.3%	756	0.89	11.69
22	$ 1200 mln bonus	20.0%	84.4%	64.4%	11.2%	223	0.26	11.69

Governments can therefore make their fiscal systems more competitive – for any level of undiscounted government take - by using fiscal features which are favorable in terms of front end loading. Governments make their fiscal systems less competitive by using highly front end loaded features.

Stand Alone Risked

As stated above, the "stand alone" scenario applies to an investor which invests for the first time in a new country. "Risked" means that the investment relates primarily to the exploration of an oil prospect.

The Stand Alone Risked scenario has different alignment rules compared to the Stand Alone Un-risked scenario.

Table 4 illustrates the same fiscal features that were reviewed in Table 3.1.4.2-1 on a risked basis. The table can be divided into three broad groups:

- The Risked GT0 is equal to the Unrisked GT0 at 20% (the green area to the right)
- The Risked GT0 is 20.8%, while the Unrisked GT0 is 20% (the yellow area to the right), and
- The Risked GT0 is higher than 20.8%, while the Unrisked GT0 is 20% (the red area to the right).

Table 4. Twenty two different ways to create a 20% risked undiscounted government take - Base Case -Stand Alone - Risked

(ranking in order of the Risked Front End Loading Index ("FLI")) (real) (risked 1:5)

		GT0 (%)	Risked GT0 (%)	Risked GT10 (%)	Risked FLI (%)	Risked IRR (%)	EMV10 ($ mln)	Risked PIR10 (ratio)	Risked Payout (years)
	No Government Payments	0.0%	0.0%	0.0%	0.0%	22.7%	243	1.15	10.53
1	20% state participation from day 1	20.0%	20.0%	20.0%	0.0%	22.7%	194	1.15	10.53
2	Profit oil cum SS, 5% to 30 mln bbls, 15% to 60, over 60 mln 29%, 50% cost limit	20.0%	20.8%	24.2%	4.2%	20.7%	184	0.87	10.58
3	"Steep" APT 2% up to 15% IRR, 12% up to 25% IRR, 26.95% over 25% IRR	20.0%	20.8%	24.2%	4.2%	20.8%	184	0.87	10.54
4	19.65% carry from approval of development plan	20.0%	20.8%	24.5%	4.5%	21.1%	183	1.01	10.63
5	"Steep" R-factor; 2% up to 1, 7% up to 2, 23.92% over 2; (cum rev/cum costs)	20.0%	20.8%	25.2%	5.2%	20.6%	182	0.86	10.56
6	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln	20.0%	20.8%	25.7%	5.7%	20.5%	181	0.86	10.64
7	21.45% CIT, 40% uplift on all capex, depr 100% write offs, depr as incurred	20.0%	20.8%	26.2%	6.2%	20.4%	179	0.85	10.56
8	21.45% Gov Profit Oil, 40% uplift on all capex, 100% cost limit, costs expensed	20.0%	20.8%	26.2%	6.2%	20.4%	179	0.85	10.56
9	"Flat" APT 15% up to 15% IRR, 18% up to 25% IRR, 22.02% over 25% IRR	20.0%	20.8%	26.2%	6.2%	20.4%	179	0.85	10.61
10	"Flat" R-factor; 13% up to 1, 16% up to 2, 21.0% over 2; (cum rev/cum costs)	20.0%	20.8%	26.5%	6.5%	20.3%	178	0.85	10.61
11	19.75% CIT, depr 100% write offs; depr as incurred;	20.0%	20.8%	27.1%	7.1%	20.2%	177	0.84	10.64
12	19.75% Gov Profit Oil, cost limit 100%, costs expensed	20.0%	20.8%	27.1%	7.1%	20.2%	177	0.84	10.64
13	19.70% CIT, depr 20% SL; depr as incurred;	20.0%	20.8%	27.3%	7.3%	20.2%	177	0.84	10.67
14	19.64% Gov Profit Oil, 50% cost limit, costs expensed	20.0%	20.8%	27.9%	7.9%	20.0%	175	0.83	10.76
15	19.62% CIT, depr 20% SL, depr asset life	20.0%	20.8%	28.1%	8.1%	20.0%	175	0.83	10.8
16	19.52% Gov Profit Oil, 30% cost limit, costs expensed	20.0%	20.8%	28.9%	8.9%	19.8%	173	0.82	10.87
17	15% royalty	20.0%	20.8%	29.7%	9.7%	19.7%	171	0.81	10.91
18	Prof Oil daily prod SS to 10000 bbls/day 5%, to 25,000 33% over 48.5%, 50% cost limit	20.0%	20.8%	30.5%	10.5%	19.6%	169	0.80	10.81
19	Dailly Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over	20.0%	20.8%	32.0%	12.0%	19.3%	165	0.78	10.98
20	$ 60.2 mln/year nominal rentals	20.0%	33.1%	96.3%	76.3%	10.3%	9	0.04	12.17
21	$ 200 mln bonus; $ 1175 mln production bonus at 10,000 bopd	20.0%	34.7%	120.9%	100.9%	8.6%	-51	-0.24	12.94
22	$ 1200 mln bonus	20.0%	104.1%	494.2%	474.2%	-0.3%	-957	-4.53	999

Table 5 illustrates the Risked GT0 calculation in case there is zero burden during the exploration phase. In other words, no payments to government during exploration, only 20% government take in case of a discovery. Due to the additional exploration costs the payments to government now weigh more on the risked divisible income, as a result the risked undiscounted government take is 20.82%. This is the average case.

Table 5 Risked GT0 calculation

	Unrisked ($ mln)	Risked ($ mln)
Gross Revenues	8000.0	1600.0
Exploration Capex	55.0	55.0
Exploration Abandonment		3.2
Appraisal and Development Capex	1445.0	289.0
Opex	500.0	100
Divisible Income	6000.0	1152.8
Government Revenues	1200.0	240
Government Take	20.00%	20.82%

If the government shares in the geological risk, by participating in the exploration the risked undiscounted government take and the un-risked government take are both 20%.

If the government charges bonuses and rentals during exploration the Risked GT0 becomes much higher than 20.8% because these payments are made during the exploration phase and also need to be paid in case of a dry hole. This creates an unfavorable Stand Alone Risked environment.

Country Incremental Unrisked

The Country Incremental Un-risked scenario applies to an investor which has already one or more producing oil or gas fields in the country and invests in the development of a new oil field in a separate license or contract area in the same country. The un-risked exploration costs are part of the cash flow. In other words the scenario relates to the economics of an exploratory success.

Table 6 shows again the comparison of twenty two fiscal features ranked in accordance with their front end loading index ("FLI"). In order to properly compare with the Stand Alone scenario, the values were left identical. These were the value required to achieve a 20% undiscounted government take on a Stand Alone basis.

This new table now shows significant differences with Table 4. The differences relate to the corporate income tax. As will be discussed in more detail below full alignments is achieved for a consolidated corporate income tax, which expensing of all capital costs and deductions of capital costs when incurred.

These factors have a significant impact on the FLI as can be seen in Table 6. Consolidated taxation with a 40% uplift and 100% write offs now rates as the most favorable. It has actually a rate of return that is higher than the "no government take" case. Also the GT0 and GT10 are now less than 20%.

For the 19.75% tax case, the undiscounted and 10% discounted government take are now also 19.75%, because the consolidated tax results in a situation where the government through the tax systems shares in 19.75% of all costs and 19.75% of all revenues.

Even if capital expenditures have to be depreciated over time, the fiscal feature becomes more attractive as long as the depreciation can be taken when costs are incurred. As can be seen, there is now improvement in economics relative to the Stand Alone case if depreciation can only be taken when the assets come in active use.

Table 6. Twenty two different ways to create a 20% (stand alone) GT0 - Base Case -Country Incremental - Unrisked

(ranking in order of the Front End Loading Index ("FLI")) (real)

		GT0-SO (%)	GT0-CI (%)	GT10 (%)	FLI (%)	IRR (%)	NPV10 ($ mln)	PIR10 (ratio)	Payout (years)
1	21.45% CIT, 40% uplift on all capex, depr 100% write offs, depr as incurred	20.0%	19.6%	17.0%	-3.0%	32.2%	1181	1.39	10.07
2	19.75% CIT, depr 100% write offs; depr as incurred;	20.0%	19.75%	19.75%	-0.25%	30.1%	1142	1.35	10.24
	No Government Payments	0.0%	0.0%	0.0%	0.0%	30.1%	1423	1.68	10.24
3	20% state participation from day 1	20.0%	20.0%	20.0%	0.0%	30.1%	1138	1.68	10.24
4	Profit oil cum SS, 5% to 30 mln bbls, 15% to 60, over 60 mln 29%, 50% cost limit	20.0%	20.0%	20.6%	0.6%	27.9%	1129	1.33	10.29
5	"Steep" APT 2% up to 15% IRR, 12% up to 25% IRR, 26.95% over 25% IRR	20.0%	20.0%	20.7%	0.7%	28.0%	1129	1.33	10.25
6	19.65% carry from approval of development plan	20.0%	20.0%	20.9%	0.9%	29.1%	1125	1.61	10.28
7	"Steep" R-factor; 2% up to 1, 7% up to 2, 23.92% over 2; (cum rev/cum costs)	20.0%	20.0%	21.5%	1.5%	27.8%	1117	1.32	10.26
8	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln	20.0%	20.0%	21.9%	1.9%	27.5%	1111	1.31	10.34
9	19.70% CIT, depr 20% SL; depr as incurred;	20.0%	19.9%	21.9%	1.9%	28.1%	1111	1.31	10.32
10	21.45% Gov Profit Oil, 40% uplift on all capex, 100% cost limit, costs expensed	20.0%	20.0%	22.3%	2.3%	27.5%	1105	1.31	10.26
11	"Flat" APT 15% up to 15% IRR, 18% up to 25% IRR, 22.02% over 25% IRR	20.0%	20.0%	22.4%	2.4%	27.4%	1104	1.30	10.28
12	"Flat" R-factor; 13% up to 1, 16% up to 2, 21.0% over 2; (cum rev/cum costs)	20.0%	20.0%	22.6%	2.6%	27.4%	1101	1.30	10.28
13	19.75% Gov Profit Oil, cost limit 100%, costs expensed	20.0%	20.0%	23.2%	3.2%	27.2%	1093	1.29	10.29
14	19.64% Gov Profit Oil, 50% cost limit, costs expensed	20.0%	20.0%	23.8%	3.8%	26.8%	1084	1.28	10.44
15	19.62% CIT, depr 20% SL, depr asset life	20.0%	20.0%	24.0%	4.0%	26.8%	1082	1.28	10.47
16	19.52% Gov Profit Oil, 30% cost limit, costs expensed	20.0%	20.0%	24.6%	4.6%	26.4%	1072	1.27	10.54
17	15% royalty	20.0%	20.0%	25.4%	5.4%	26.2%	1062	1.25	10.57
18	Prof Oil daily prod SS to 10000 bbls/day 5%, to 25,000 33% over 48.5%, 50% cost limit	20.0%	20.0%	26.1%	6.1%	26.2%	1052	1.24	10.34
19	Daily Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over	20.0%	20.0%	27.3%	7.3%	25.7%	1034	1.22	10.63
20	$ 60.2 mln/year nominal rentals	20.0%	20.0%	36.7%	16.7%	19.5%	900	1.06	10.97
21	$ 200 mln bonus; $ 1175 mln production bonus at 10,000 bopd	20.0%	20.0%	46.9%	26.9%	17.3%	756	0.89	11.69
22	$ 1200 mln bonus	20.0%	20.0%	84.4%	64.4%	11.2%	223	0.26	11.69

Country Incremental Risked

The Country Incremental Risked scenario applies to an investor which has already one or more producing oil or gas fields in the country and re-invests in the exploration of a new license or contract area.

Table 7 provides the overview of the results for the fiscal features on a risked basis. As can be noted three features now have a risked GT0 that is less than 20.8% (colored green on the right hand side of the table). These features strongly support risk taking. What is interesting that the tax structure with the uplift provides a very strong incentive for exploration even if the uplift is not on exploration expenditures. The reason is that the uplift creates an environment in which the tax rate applied to the exploration costs (resulting in tax reductions) is higher than the average tax rate which is levied on the income.

This means that the government is taking disproportionate risk during exploration through the tax system (the tax deduction rate is for exploration is higher than the tax income rate).

However, even a fully consolidated tax system with 100% write offs for exploration is a strong incentive to explore, since the 19.75% tax rate also results in a Risked GT10 of 19.75%.

It should also be noted that even if depreciation of 20% on a straight line basis is required, including for exploration expenditures, the tax system is still more favorable for exploration than the other fiscal features (except for participation from day 1) as long as deductions can start from the day the costs are incurred. This is because the fact that in any case exploration costs can be deducted from the start of exploration, rather than having to wait until the start of production.

Table 7. Twenty two different ways to create a 20% (stand alone, unrisked) GT0 - Base Case -Country Incremental - Risked

(ranking in order of the Risked Front End Loading Index ("FLI")) (real) (risked 1:5)

		GT0-SO (%)	Risked GT0-CI (%)	Risked GT10 (%)	Risked FLI (%)	Risked IRR (%)	EMV10 ($ mln)	Risked PIR10 (ratio)	Risked Payout (years)
1	21.45% CIT, 40% uplift on all capex, depr 100% write offs, depr as incurred	20.0%	19.5%	16.2%	-3.8%	23.8%	203	0.96	10.36
2	19.75% CIT, depr 100% write offs; depr as incurred;	20.0%	19.75%	19.75%	-0.25%	22.7%	195	0.92	10.53
	No Government Payments	0.0%	0.0%	0.0%	0.0%	22.7%	243	1.15	10.53
3	20% state participation from day 1	20.0%	20.0%	20.0%	0.0%	22.7%	194	1.15	10.53
4	19.70% CIT, depr 20% SL; depr as incurred;	20.0%	20.8%	23.0%	3.0%	21.4%	187	0.89	10.60
5	Profit oil cum SS, 5% to 30 mln bbls, 15% to 60, over 60 mln 29%, 50% cost limit	20.0%	20.8%	24.2%	4.2%	20.7%	184	0.87	10.58
6	"Steep" APT 2% up to 15% IRR, 12% up to 25% IRR, 26.95% over 25% IRR	20.0%	20.8%	24.2%	4.2%	20.8%	184	0.87	10.54
7	19.65% carry from approval of development plan	20.0%	20.8%	24.5%	4.5%	21.1%	183	1.01	10.63
8	"Steep" R-factor; 2% up to 1, 7% up to 2, 23.92% over 2; (cum rev/cum costs)	20.0%	20.8%	25.2%	5.2%	20.6%	182	0.86	10.56
9	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln	20.0%	20.8%	25.7%	5.7%	20.5%	181	0.86	10.64
10	21.45% Gov Profit Oil, 40% uplift on all capex, 100% cost limit, costs expensed	20.0%	20.8%	26.2%	6.2%	20.4%	179	0.85	10.56
11	"Flat" APT 15% up to 15% IRR, 18% up to 25% IRR, 22.02% over 25% IRR	20.0%	20.8%	26.2%	6.2%	20.4%	179	0.85	10.61
12	"Flat" R-factor; 13% up to 1, 16% up to 2, 21.0% over 2; (cum rev/cum costs)	20.0%	20.8%	26.5%	6.5%	20.3%	178	0.85	10.61
13	19.62% CIT, depr 20% SL, depr asset life	20.0%	20.1%	26.8%	6.8%	20.2%	178	0.84	10.77
14	19.75% Gov Profit Oil, cost limit 100%, costs expensed	20.0%	20.8%	27.1%	7.1%	20.2%	177	0.84	10.64
15	19.64% Gov Profit Oil, 50% cost limit, costs expensed	20.0%	20.8%	27.9%	7.9%	20.0%	175	0.83	10.76
16	19.52% Gov Profit Oil, 30% cost limit, costs expensed	20.0%	20.8%	28.9%	8.9%	19.8%	173	0.82	10.87
17	15% royalty	20.0%	20.8%	29.7%	9.7%	19.7%	171	0.81	10.91
18	Prof Oil daily prod SS to 10000 bbls/day 5%, to 25,000 33% over 48.5%, 50% cost limit	20.0%	20.8%	30.5%	10.5%	19.6%	169	0.80	10.81
19	Dailly Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over	20.0%	20.8%	32.0%	12.0%	19.3%	165	0.78	10.98
20	$ 60.2 mln/year nominal rentals	20.0%	33.1%	96.3%	76.3%	10.3%	9	0.04	12.17
21	$ 200 mln bonus; $ 1175 mln production bonus at 10,000 bopd	20.0%	34.7%	120.9%	100.9%	8.6%	-51	-0.24	12.94
22	$ 1200 mln bonus	20.0%	104.1%	494.2%	474.2%	-0.3%	-957	-4.53	999

Contract Incremental Unrisked

The Contract Incremental Un-risked scenario applies to an investor which has already one or more producing oil or gas fields in the contract area or ring fenced concession area and re-invests in the development of a new oil field in the same concession or contract area. The un-risked exploration costs are part of the cash flow. In other words the scenario relates to the economics of an exploratory success.

Table 8 illustrates the analysis twenty four fiscal features. In this case sliding scale royalties are evaluated on the basis of a contract or concession area where royalties are consolidated based on the production of the total area as well as a case where royalties are ring fenced field by field.

The table indicates how on a contract incremental basis the order to the front end loading index (FLI) is very different from the un-risked country incremental table 6.

There are a large number of very important differences which create a rather different ranking of fiscal systems.

Firstly, signature bonuses on a contract incremental basis are no longer applicable. They have already been paid when the contract was signed. So if a further exploration prospect in the block is being evaluated, the bonus no longer applies. As a result, the contract incremental profitability is considerably enhanced by the fact that the bonus is now a sunk costs. Consequently, the bonus is now the most favorable feature with the most favorable FLI differential.

A similar situation is applicable to rentals paid during exploration. Rentals are often paid per exploration acreage and therefore a further exploration well in the same concession or contract area does not increase the rentals. In our example it was assumed that rentals were also payable during development and production. In this case rentals are often charged per production area, so rentals can be expected to increase during the development and production phase. Nevertheless, the overall government take on rentals is now much less than the 20% on an undiscounted stand-alone basis because the fact that no additional rentals are payable during exploration.

As can be noted, R-factor systems now rate very favorable. The reason is that most PSCs have an R-factor that is calculated over the total production, revenues and costs of the contract area. In other words R-factors are consolidated within the contract area. This creates an unusual dynamic. Firstly, the new investment will benefit by being able to deduct the costs and the applicable profit oil rate at the time the costs are incurred will be applied. This means that state shares in the development costs through a reduction of the profit oil.

However, at the same time, the new investments in the contract area usually lower the contract wide R-factor. This is applicable to the existing production. In other words as a result of the re-investment in the contract area the various benchmarks on the existing production are deferred.

Sometimes the R-factor returns below a benchmark that was already passed. Therefore, the contractor will typically pay less profit oil on the ongoing existing production during the period of re-investment and shortly thereafter. This effect is similar to a very strong uplift on the new investment. The relative impact on the contract consolidated R-factor depends on the typical cost levels of the ongoing production and the new production.

Under certain specific conditions the R-factor could result in less favorable incremental situations. This could be case for sensitive R-factors (for instance an R-factor whereby only cumulative capital expenditures are the denominator). Under these conditions sometimes, the resulting R-factor may jump to higher levels over time as a result of the new investment.

Production sharing which is consolidated over the contract area now also performs in general much different. In fact 19.75% profit oil share has now the same economic impact as a 19.75% corporate income tax as long as the cost limit is 100% or very high, since the profit oil will be $ 0.1975 less for every dollar expended during the incremental exploration and development phase.

Most APT or other IRR based sliding scales in the world are ring fenced per field. There are three fiscal systems (Azerbaijan ROR contract, Sakhalin 2 and Timor Leste) which have IRR based sliding scales which are consolidated for the contract area. For these fiscal systems the contract incremental economics typically deteriorate, since it is more difficult to "go back" on an IRR scale than on an R-factor scale. This means that the contract incremental investment typically reaches quickly a higher step or higher level of IRR.

Production sharing and royalties which are consolidated by concession or contract area with sliding scales based on daily or cumulative production deteriorate in economics under the contract incremental scenario, because the existing production now pushes the rates higher up in the scales.

Table 8. Twenty four different ways to create a 20% (stand alone) GT0 - Base Case -Contract Incremental - Unrisked

(ranking in order of the Front End Loading Index ("FLI")) (real)

		GT0-SO (%)	GT0-NI (%)	GT10 (%)	FLI (%)	IRR (%)	NPV10 ($ mln)	PIR10 (ratio)	Payout (years)
1	$ 1200 mln bonus	20.0%	0.0%	0.0%	-20.0%	30.1%	1423	1.68	10.24
2	"Steep" R-factor; 2% up to 1, 7% up to 2, 23.92% over 2; (cum rev/cum costs)	20.0%	14.6%	5.5%	-14.5%	37.8%	1344	1.50	9.68
3	"Flat" R-factor; 13% up to 1, 16% up to 2, 21.0% over 2; (cum rev/cum costs)	20.0%	15.1%	7.9%	-12.1%	36.8%	1310	1.55	9.79
4	21.45% CIT, 40% uplift on all capex, depr 100% write offs, depr as incurred	20.0%	19.6%	17.0%	-3.0%	32.2%	1181	1.39	10.07
5	21.45% Gov Profit Oil, 40% uplift on all capex, 100% cost limit, costs expensed	20.0%	19.6%	17.0%	-3.0%	32.3%	1181	1.39	10.07
6	$ 60.2 mln/year nominal rentals	20.0%	15.2%	19.7%	-0.3%	26.1%	1143	1.35	10.60
7	19.75% CIT, depr 100% write offs; depr as incurred;	20.0%	19.75%	19.75%	-0.25%	30.1%	1142	1.35	10.24
8	19.75% Gov Profit Oil, cost limit 100%, costs expensed	20.0%	19.75%	19.75%	-0.25%	30.1%	1142	1.35	10.24
	No Government Payments	0.0%	0.0%	0.0%	0.0%	30.1%	1423	1.68	10.24
9	20% state participation from day 1	20.0%	20.0%	20.0%	0.0%	30.1%	1138	1.68	10.24
10	Profit oil cum SS, 5% to 30 mln bbls, 15% to 60, over 60 mln 29%, 50% cost limit	20.0%	21.9%	22.7%	2.7%	27.9%	1100	1.30	10.25
11	"Steep" APT 2% up to 15% IRR, 12% up to 25% IRR, 26.95% over 25% IRR	20.0%	20.0%	20.7%	0.7%	28.0%	1129	1.33	10.25
12	19.65% carry from approval of development plan	20.0%	20.0%	20.9%	0.9%	29.1%	1125	1.61	10.28
13	19.64% Gov Profit Oil, 50% cost limit, costs expensed	20.0%	19.8%	21.2%	1.2%	26.8%	1121	1.32	10.25
14	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln; ringf	20.0%	20.0%	21.9%	1.9%	27.5%	1111	1.31	10.34
16	19.70% CIT, depr 20% SL; depr as incurred;	20.0%	19.9%	21.9%	1.9%	28.1%	1111	1.31	10.32
17	19.52% Gov Profit Oil, 30% cost limit, costs expensed	20.0%	19.8%	22.1%	2.1%	27.6%	1108	1.31	10.26
18	"Flat" APT 15% up to 15% IRR, 18% up to 25% IRR, 22.02% over 25% IRR	20.0%	20.0%	22.4%	2.4%	27.4%	1104	1.30	10.28
19	19.62% CIT, depr 20% SL, depr asset life	20.0%	20.0%	24.0%	4.0%	26.8%	1082	1.28	10.47
15	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln	20.0%	22.3%	25.2%	5.2%	26.9%	1064	1.26	10.37
20	15% royalty	20.0%	20.0%	25.4%	5.4%	26.2%	1062	1.25	10.57
21	Daily Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over; ringf	20.0%	20.0%	27.3%	7.3%	25.7%	1034	1.22	10.63
22	$ 200 mln bonus; $ 1175 mln production bonus at 10,000 bopd	20.0%	16.7%	32.8%	12.8%	22.2%	955	1.13	11.45
23	Daily Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over	20.0%	26.9%	36.1%	16.1%	24.2%	909	1.07	10.78
24	Prof Oil daily prod SS to 10000 bbls/day 5%, to 25,000 33% over 48.5%, 50% cost limit	20.0%	31.2%	39.6%	19.6%	24.3%	860	1.02	10.62

Contract Incremental Risked

The Contract Incremental Risked scenario applies to an investor which has already one or more producing oil or gas fields in the contract or concession area and re-invests in the exploration of a new prospect in the same license or contract area.

The analysis of the individual features is provided in Table 9. This table is similar to Table 8, but now for the Risked front end loading index (Risked FLI)

What is remarkable about this table is that now a large number of fiscal features now have a Risked GT0 which is less than 20.8% (colored "green" on the left hand side of the table). This means that on a contract incremental basis a remarkable number of fiscal features supports further exploration in the same contract or concession area. This includes corporate income tax and production sharing (other than based on daily or cumulative scales based on production), bonuses, rentals and participation from day 1.

On a risked basis royalties and production sharing based on daily or cumulative production that are consolidated for the concession or contract area result in a deterioration of the rating.

Of course, if royalties or production sharing have production based sliding scales on a field by field basis, than there is no deteriorating in profitability.

Table 9. Twenty four different ways to create a 20% (stand alone, unrisked) GT0 - Base Case -Contract Incremental - Risked

(ranking in order of the Risked Front End Loading Index ("FLI")) (real) (risked 1:5)

		GT0-SO (%)	Risked GT0-NI (%)	Risked GT10 (%)	Risked FLI (%)	Risked IRR (%)	EMV10 ($ mln)	Risked PIR10 (ratio)	Risked Payout (years)
1	$ 1200 mln bonus	20.0%	0.0%	0.0%	-20.0%	22.7%	243	1.15	10.53
2	"Steep" R-factor; 2% up to 1, 7% up to 2, 23.92% over 2; (cum rev/cum costs)	20.0%	13.7%	1.2%	-18.8%	28.2%	243	1.15	9.87
3	"Flat" R-factor; 13% up to 1, 16% up to 2, 21.0% over 2; (cum rev/cum costs)	20.0%	14.2%	2.7%	-17.3%	27.6%	236	1.12	10.01
4	21.45% CIT, 40% uplift on all capex, depr 100% write offs, depr as incurred	20.0%	19.5%	16.2%	-3.8%	23.8%	203	0.96	10.36
5	21.45% Gov Profit Oil, 40% uplift on all capex, 100% cost limit, costs expensed	20.0%	19.5%	16.2%	-3.8%	23.8%	203	0.96	10.36
6	19.75% CIT, depr 100% write offs; depr as incurred;	20.0%	19.75%	19.75%	-0.25%	22.7%	195	0.92	10.53
7	19.75% Gov Profit Oil, cost limit 100%, costs expensed	20.0%	19.75%	19.75%	-0.25%	22.7%	195	0.92	10.53
	No Government Payments	0.0%	0.0%	0.0%	0.0%	22.7%	243	1.15	10.53
8	20% state participation from day 1	20.0%	20.0%	20.0%	0.0%	22.7%	194	1.15	10.53
9	$ 60.2 mln/year nominal rentals	20.0%	15.6%	21.8%	1.8%	21.6%	201	1.02	10.80
10	19.70% CIT, depr 20% SL; depr as incurred;	20.0%	20.8%	23.0%	3.0%	21.4%	187	0.89	10.60
11	19.64% Gov Profit Oil, 50% cost limit, costs expensed	20.0%	20.3%	23.5%	3.5%	21.3%	186	0.88	10.58
12	"Steep" APT 2% up to 15% IRR, 12% up to 25% IRR, 26.95% over 25% IRR	20.0%	20.8%	24.2%	4.2%	20.8%	184	0.87	10.54
13	19.65% carry from approval of development plan	20.0%	20.8%	24.5%	4.5%	21.1%	183	1.01	10.63
14	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln; ringf	20.0%	20.8%	25.7%	5.7%	20.5%	181	0.86	10.64
15	19.52% Gov Profit Oil, 30% cost limit, costs expensed	20.0%	20.5%	25.9%	5.9%	20.5%	180	0.85	10.62
16	Profit oil cum SS, 5% to 30 mln bbls, 15% to 60, over 60 mln 29%, 50% cost limit	20.0%	22.7%	26.2%	6.2%	20.7%	179	0.85	10.55
17	"Flat" APT 15% up to 15% IRR, 18% up to 25% IRR, 22.02% over 25% IRR	20.0%	20.8%	26.2%	6.2%	20.4%	179	0.85	10.61
18	19.62% CIT, depr 20% SL, depr asset life	20.0%	20.1%	26.8%	6.8%	20.2%	178	0.84	10.77
19	Cum SS Royalty; 5% upp to 30 mnl bbls; 15% up to 60 mln; 22.5% over 60 mln	20.0%	23.3%	29.6%	9.6%	20.0%	171	0.81	10.69
20	15% royalty	20.0%	20.8%	29.7%	9.7%	19.7%	171	0.81	10.91
21	Daily Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over; ringfenced	20.0%	20.8%	32.0%	12.0%	19.3%	165	0.78	10.98
22	$ 200 mln bonus; $ 1175 mln production bonus at 10,000 bopd	20.0%	17.4%	38.5%	18.5%	17.4%	149	0.71	11.74
23	Daily Prod SS Royalty, 5% to 10,000 bopd, 23% to 23,000 and 35% over	20.0%	28.0%	42.3%	22.3%	18.1%	140	0.66	11.16
24	Prof Oil daily prod SS to 10000 bbls/day 5%, to 25,000 33% over 48.5%, 50% cost limit	20.0%	32.4%	46.1%	26.1%	11.0%	131	0.62	11.04

Alignment Overview

Based on the above analysis it is possible to provide an overview as to how the alignment between governments and the petroleum industry can be improved. As a result, it will facilitate the continuation of operations during periods of low oil prices.

In general, the alignment improvement can be created by governments through:

- Less front end loading, and
- Increased geological and technical risk sharing

These steps are in addition to the creation of a wider range of price progressivity as discussed in Sub-Chapter 7.1.

It should be noted that the following suggestions for improvement of alignment are aimed at jurisdictions that would have a real risk adjusted discount rate of less than 10% and have a reasonably varied and significant oil and gas resource base.

Countries with a high discount rate and a small resource base should seek an adequate level of front end loading and avoid sharing resource risk.

Most fiscal systems of countries with a low discount rate and large resource base are too front end loaded to ensure that profitable resources are being developed effectively. Less front end loading should be promoted in many countries. For instance, the United States is excessively front end loaded.

Following is a discussion for a variety of the main fiscal features.

Signature bonuses. High signature bonuses cause significant alignment problems and strongly discourage exploration and should therefore be avoided. Nevertheless, with respect to the award of new acreage bonuses could be an effective bidding parameter. If very high bonuses are being received during bid rounds it is an indication that the government take is too low and could be increased.

Production bonuses. Production bonuses are a highly cost and price regressive feature, do not cause alignment and do not serve a useful function in the fiscal system and should therefore not be used.

Rentals. Yearly rentals per square kilometer, hectare or acre could be useful in providing a modest encouragement to relinquish acreage which the petroleum company does not intend to use. Nevertheless they create lack of alignment and discourage exploration. Rentals should therefore be used in moderation.

Royalties. Royalties are a widely used feature in petroleum fiscal systems. The main advantage of royalties is that they do not require cost control and are usually relatively easy to collect. Royalties also provide a guaranteed income to the resource owner as long as there is oil and gas production.
The main disadvantages of royalties is that they are price and cost regressive and front end loaded and therefore create a significant degree of lack of alignment. As discussed in sub-chapter 7.3 royalties could be made price progressive through sliding scales. Royalties could also be made volume progressive through production based sliding scales. With the help of R-factors, royalties can even be made cost progressive.

Where volume progressive sliding scales based on daily or cumulative production are being used and these scales are being determined per contract area, alignment can be slightly improved by calculating such royalties ringfenced per field or exploitation area instead.

Alignment in terms of front end loading can be significantly improved through the use of royalties which increase with cumulative production and start at relatively low levels. Nevertheless, a high level of royalties later in the life of the field could hasten abandonment and therefore reduce the recovery factor of the oil or gas unnecessarily.

A better form of alignment with respect to royalties is to provide for an initial time period during which royalties are low, say 5%, or even 0%. This time period could be one or two years from the start of the production of a well (in North America) or 2 to 6 years from the start of the production of a field or unconventional project. Examples are the current Alberta royalty system and the Pakistan offshore royalties.

A somewhat more complex but effective way to increase alignment is to determine all or part of the royalties based on an R-factor of the style proposed for the Mexican deep water bid round, as discussed in sub-chapter 7.1.

Severance and Production Taxes. The same comments that apply to royalties can be applied to severance and production taxes.

Windfall Profit Taxes or Features. Windfall profit taxes or features are based on a fixed or sliding scale percentage of the difference between the market price and a lower base price multiplied by the production. This is similar to price sensitive royalties. Most windfall profit features in the world are aimed at capturing extra revenues for government under high prices, such as the Special Oil Gain Levy in China or the windfall profit tax in Venezuela and Kenya.

As discussed under the royalties and sub-chapter 7.1, it can be recommended amend these concepts for the full price range of $ 25 to $ 100 per barrel and provide for stronger rates at high prices.

Mineral Extraction Tax. The Mineral Extraction Tax in Russia is already price sensitive and Russia has amended to tax to ensure that Russia always receives a minimum amount.

Corporate Income Tax. Corporate Income Tax is a very important feature to create alignment under country incremental, contract incremental or field incremental scenarios.

Under a regime where the corporate income tax can be consolidated at the national level, an investor will be able to deduct exploration and development costs from ongoing existing revenues. The degree to which this is beneficial depends on the detailed rules of the tax laws.

Two factors have an important impact on the consolidated profitability:

- What the depreciation schedule is for capital expenditures, and
- Whether depreciation can be taken:
    - when costs are incurred, which means that deductions can be taken against the income of existing producing fields, or
    - when the asset comes in active use, which means when the oil field starts to produce. This in turn means that the depreciation cannot be taken against existing production and the investor has to wait until the field comes into production.

The most favorable system is when under a consolidated tax regime all costs can be 100% written off as incurred for tax purposes.

The least attractive system is when slow depreciation is required (for instance, 10% straight line depreciation) and when depreciation can only be taken when the asset comes in active use under a ringfenced tax system per field or contract area.

The system can be made more favorable with uplifts, tax credits or allowances. Uplifts create a degree of price and cost progressivity. Allowances can be used to create cost, price and volume progressivity. For instance, a small field allowance can be created providing a deduction of say $ 5 per barrel for the first 10 million barrels in shallow water. Nevertheless, it can typically be recommended not to use corporate income tax to create cost, price or volume progressivity and leave corporate income tax neutral with price, costs and volume at least for the GT0. In general, the less distorting features the corporate income tax system has the better.

It can be recommended to replace special corporate income tax regimes for the petroleum industry, such as in Thailand, with the regular normal corporate income tax. It can also be recommended to improve consolidation with other sectors where corporate income tax is ring fenced for the upstream petroleum industry, such as in Mexico.

It should be noted that most production sharing contracts are severely misaligned with respect to corporate income tax. Alignment can be significantly improved by paying corporate income tax separately on a consolidated basis, such as is for instance the case for the Pre-Salt PSCs in Brazil.

The following practices cannot be recommended from an alignment perspective:

(1) To include corporate income tax in the profit oil/gas share and have the national oil company pay the taxes on behalf of the contractor, as is for instance the case in Egypt.
(2) Ring fence corporate income tax per contract area or field area, as is the case for instance in Indonesia, Angola or Nigeria.

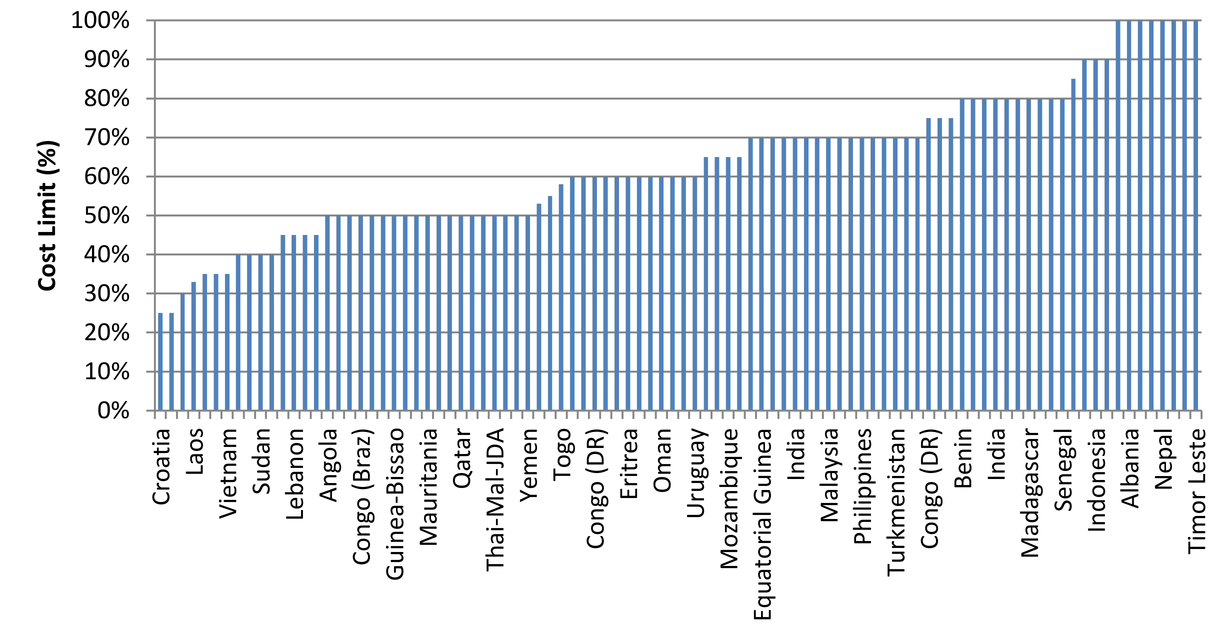
Of course, countries which include corporate income tax in profit oil/gas or ring fence corporate income tax per contract or field area have important arguments for this practice, such as ease of administration, guarantees of government income, avoidance of corruption or to achieve front end loading.

Nevertheless, faced with the current low oil and gas prices, some countries which have confidence in their ability to administer a corporate income tax, may wish to re-think the relation between corporate income tax and production sharing and create more alignment through by breaking out corporate income tax as a separate consolidated tax under the general tax laws.

Production Sharing – Cost Oil/Gas. Under low oil and gas prices an important issue with respect to production sharing contracts is that the cost oil/cost gas limits are usually defined as a fixed percentage. For instance, if the cost limit is 40% and the oil price is $ 100 per barrel, $ 40 per barrel is available for cost recovery. However, if the oil price is $ 25 per barrel, only $ 10 is available. This means that during low oil and gas prices, it is not possible in many cases to properly recover costs. This means costs will be carried forward to future years for recovery in the future. If oil and gas prices stay low for a long period of time, costs may not be recovered at all before the end of the contract and may “fall of the table” at the end of the contract.

Typical international costs limits are displayed in Chart 24. Currently the average cost limit is about 60%.

Chart 24. International Cost Limits



The lower the cost limit the stronger the front end loading under the contract and the less the alignment as can be seen from the above tables in this sub-chapter. An obvious solution is to increase the cost limit, say from 40% to 80%. However, this may create overly generous conditions under high oil prices.

An effective way to deal with low oil and gas prices and align interests is therefore is to make the cost limit sensitive to price. For instance, a linear function can be designed between an 80% cost limit at $ 30 per barrel reducing to a cost limit of 30% at $ 100 per barrel. The concept of a price sensitive cost limit exists in some contracts offshore Oman. The price levels can be adjusted for inflation. Of course, this concept puts the price risk largely on the shoulders of government.

Another possible solution is to include a “deemed interest” or “minimum return” feature in the cost oil/gas of say 0.3% per month, with the amount being carried forward in each month uplifted with this percentage. This will ensure that the burden of carrying forward considerable costs during periods of low oil prices is partially paid for in the future, if prices return to higher levels. It should be noted that the interest rate of such a deemed interest feature has to be rather low in order to avoid gold plating effects, to be described in the next sub-chapter. The amount could also be based on the long term bond rate. In this case the price risk remains largely with the investors.

Another feature that can moderately help improve the alignment is to fully expense all cost oil/gas items rather than depreciating capital costs as is done in some contracts. For instance, Egypt depreciates capital costs.

A feature that could significantly improve the alignment is a step down of the cost oil/gas limit after a number of years. Brazil has in principle such a feature, although not clearly defined. For instance, the cost limit could be 80% during the first 5 years after the start of commercial production and step down to 50% thereafter.

Production Sharing – Profit Oil/Gas. There is a wide range of features that can be used with respect to Profit Oil/Gas in order to improve alignment and reduce front end loading.

The main features are:

(1) Sliding scales based on cumulative production, as in Nigeria,
(2) Sliding scales based on R-factors, as in Azerbaijan,
(3) Sliding scales based on IRR benchmarks, as in Angola, and
(4) A time sensitive feature, whereby the Profit Oil/Gas increase after a number of years or step wise, as in Madagascar.

In Nigeria the cumulative production feature is linked to the production from the contract area. This creates lack of alignment, since this makes it uneconomic to improve recovery factors or produce small high cost marginal fields late in the life of the contract. Therefore, such features should be per field or exploitation area.

There is a wide variety of R-factors. A discussion of which will be entered into in more detail below. In order to avoid gold plating R-factors have to be rather robust as will be discussed in the next sub-chapter. However, well designed R-factors could be a suitable feature in production sharing contracts.

Systems based on IRR benchmarks result almost always in severe gold plating problems and therefore this concept is not recommended.

Time sensitive features are usually not employed in production sharing contracts, but time sensitivity is actually the simplest way to create less front end loading and therefore more alignment. This is an area that governments may wish to review more as a possible solution to improved alignment.

Profit Oil/Gas sliding scales can create volume, price and cost progressivity.

Volume progressivity can be created with cumulative or daily production sliding scales, holidays on domestic supply obligations or time related scales whereby the percentage Profit Oil/Gas increases with time.

Price Progressivity can be created through price sensitive scales, as used in Trinidad and Tobago (in combination with daily production scales) and Brazil (in combination with well productivity scales). It can also be created by combining a windfall profit style feature with Production Sharing as is being done in Malaysia. Also price caps can be used as done in Pakistan.

Cost progressivity can be created through uplifts as used in Angola, deemed interest features as discussed above and excess cost oil provisions as used in Egypt with excess cost oil having a higher share (or 100%) to government.

Cost and price progressivity can be combined in profit progressive systems based on R-factors, IRR benchmarks or payout features.

Cost, price and volume progressivity can be created through combinations of sliding scales as used in Libya.

State Participation. A Petoro style state participation as is employed in Norway provides for the perfect alignment between government and the petroleum industry. Under this concept the State participates from the first day of the license or contract and incurs all geological, technical and economic risks in the same way as the private as a result the IRR and Profit to Investment Ratio are not affected. This feature can be studied in detail in the above tables.

For this feature to work, a large resource base is required. The critical factor is that the resource base has to be large enough to permit several exploration wells per year to be drilled, in order to ensure that the many dry holes that will be drilled are being offset by sufficient discoveries. In this way the government spreads the risk over many ventures and taking the related geological risk becomes acceptable. At the same time the feature requires considerable initial investment by government and therefore the feature can be recommended for developed countries, large petroleum producing countries and emerging economies.

For low income countries or countries with a small resource base resulting in only the occasional exploration well being drilled, the Petoro style participation cannot be recommended and state participation has to be structured on the basis of a carried interest. This necessarily creates less alignment. In sub-chapter 7.6 the matter of state participation will be discussed in more detail.

Surtaxes and Profit Based Systems. Norway and the United Kingdom have adopted a surtax system whereby in addition to corporate income tax a further tax is being charged which is also consolidated. In the case of Norway the corporate income tax is 27% and the Hydrocarbon Tax is 51%. There is an uplift on all development capital with respect to the Hydrocarbon Tax of 22% spread out over 4 years. In the case of the UK, the base corporate income tax is 30% and the surtax is 20%. With respect to the surtax there is an uplift of 65% on all development capital costs from the start of production.

In the context of climate change policies and low oil prices, these systems could be amended. The main emphasis should not only be on promoting investment with uplifts. It is also important to support petroleum operations under low oil prices. Therefore, a lowering of the uplift on development capital and establishing an uplift on operating costs would be a better balance.

Alaska and the Netherlands have also consolidated profit based systems. The Netherlands also uses uplifts.

Several profit based systems are ring fenced. Brazil, for instance, has the special participation which is volume progressive.

The advantage of profit based systems is that they avoid cost regressivity and are usually less front end loaded or not front end loaded. The disadvantage is that relying primarily on profits based systems requires sophisticated cost verification, which in many nations is a problem.

IRR based systems. Some nations have special additional profits taxes based on IRR benchmarks. Examples are Ghana and Namibia. Australia has the petroleum resource rent tax. Other countries have sliding scale profit oil/gas based on IRR benchmarks, such as for Sakhalin (Russia), Angola, the AIOC agreement in Azerbaijan and the recent shallow water terms for PSCs in Mexico.

Alberta applies a Net Profits Share based on the long term bond rate for the oil sands fiscal terms, which is like an IRR system.

Other than Alberta and Australia under some conditions, the vast majority of IRR based systems have serious gold plating problems and therefore it can be recommended to phase these systems out.

R-factor systems. R-factor systems are fiscal features based on profitability as calculated by a ratio. Essentially, all countries in the world have very different R-factor definitions. In fact, there are more than 20 mathematically different R-factors in the world.

With respect to R-factors there are basically the different types as to the relevance for low oil prices and fiscal design:

(1) R-factors based on cumulative calculations, which is the majority of the R-factors, and these in turn can be classified as:
   a. R-factors based on discounted values, as is the case in Algeria, and
   b. R-factors based on undiscounted values.

(2) R-factors mainly based on yearly, trimestral or monthly profitability data or other variables. The Thai SRB and the recently proposed deep water terms in Mexico are examples.

Furthermore, R-factors can be classified as:

(1) Relatively robust, not resulting in gold plating, such as the Peru R-factor applied to royalties, the recent R-factor used in Poland and the Mexican proposed deep water terms, and
(2) Too sensitive, resulting in gold plating. These include the R-factors of India, Azerbaijan and the Thai SRB.

The Algerian system features severe gold plating due to the high discount rates which are being used.

It can be recommended to change the Algerian system and the R-factors that are too sensitive in more robust concepts. An interesting mechanism to increase the robustness of the system is to combine the R-factor with another feature that is already price sensitive, as Mexico is doing with the price sensitive royalty and the R-factor based additional royalty.

Import Duties. In order to promote international trade, it can be recommended to phase out import duties as part of international free trade agreements.

Export Duties. In order to support the climate change objectives as discussed in sub-chapter 6.2, it can be recommended to phase out export duties.

Property Taxes. Where property taxes are collected by the local municipalities or communities, they are a valuable tool to distribute resource wealth to near the petroleum operations.

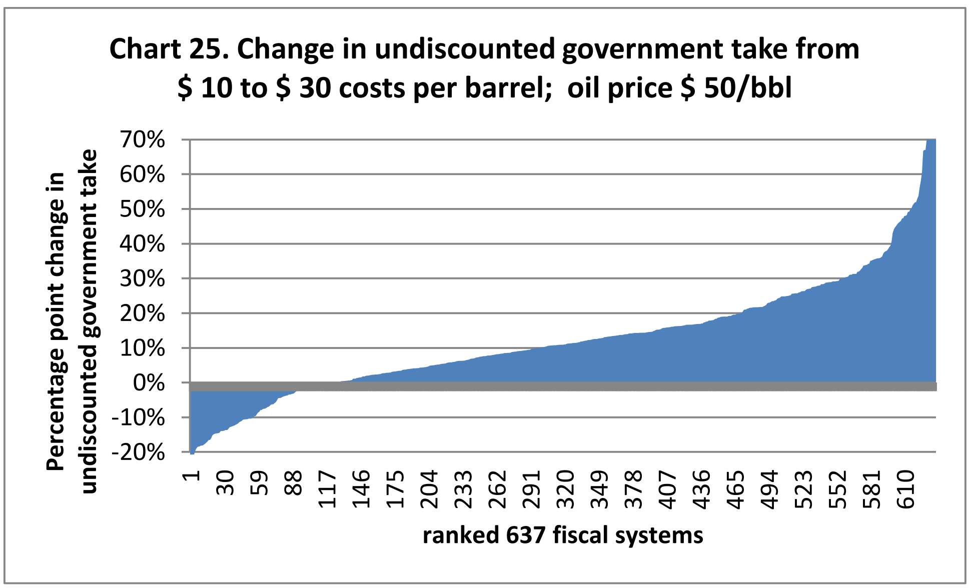
Risk Service Contracts. Risk service contracts usually create a poor alignment between government and the petroleum industry and often provide for misguided incentives to carry out petroleum operations in an inefficient manner. As a result, it can be generally recommended to phase out these types of contracts.

In fact, Mexico is in the process of doing so. Iran has also abandoned the so-called buy-back contracts. Kuwait never implemented proposed risk service contracts.

Interestingly, the Technical Services Agreements in Iraq and the risk service contracts in Ecuador are favorable for investors under low oil prices, since they provide for fees that are fixed irrespective of the oil and gas prices. The Iraq contract is rather inefficient since the cost recovery permitted under the contract does not provide an incentive to be seek the lowest possible costs per barrel. Also the lack of price sensitivity does not provide for the right inducements under low oil prices. The Ecuador contract could result in the bizarre situation that the fee to the contractor could actually be higher than the oil price.

Cost regressivity. In order to ensure that the most profitable oil and gas resources are being produced in this world, excessive cost regressivity should be avoided. Truly profitable petroleum resources should not be prevented from being produced through excessively high fixed royalties or very low cost limits in production sharing contracts or similar excessively cost regressive features.

Excessive cost regressivity is rather wide spread in the world. This can be evaluated from the Chart 25, which is based on 637 fiscal systems. The chart shows the increase in un-risked undiscounted real government take, if costs increase from $ 10 to $ 30 per barrel under a $ 50 per barrel oil price. A high positive value indicates strong cost regressivity. About 50 fiscal regimes show excessive cost regressivity.



Bid processes should not be aimed primarily at maximizing royalty type structures or profit shares. This creates over-bidding and results in under-development of potentially profitable resources, as is likely going to be the case in Mexico. Bid processes should preferably be aimed at other variables or maximizing royalties and profit shares in combination with other variables.

7.5 Eliminate gold plating

"Gold plating" means that an incremental investment would result in a lowering of the payments to Government with an amount that is higher than the amount of the incremental investment. For example, an incremental investment of $100 million in a set of further development wells would result in a reduction of $200 million in payments to Government. This would make the investment in the wells profitable regardless of the merits of this investment. In other words, it is an invitation to squander money.

Gold plating is caused with cost progressive features based on

(1) IRR based scales,
(2) R-factor scales which are too sensitive or based on discounted values, or
(3) high uplifts combined with high tax rates.

It can generally be recommended not to apply IRR-based scales. Almost all of them result in gold plating. The exception in this case is the Alberta system applicable to oil sands which uses a long term bond rate escalator to determine payout, after which a net profits share clicks in. A number of R-factor systems also create gold plating as explained in sub-chapter 7.4.

Modest R-factors and uplifts could work well to create cost progressivity, in particular in combination with the earlier mentioned windfall profits taxes, volume based scales or well productivity based scales.

The effects of gold plating are more severe if the benchmark rates are higher than the hurdle rate and the profit differential is very large.

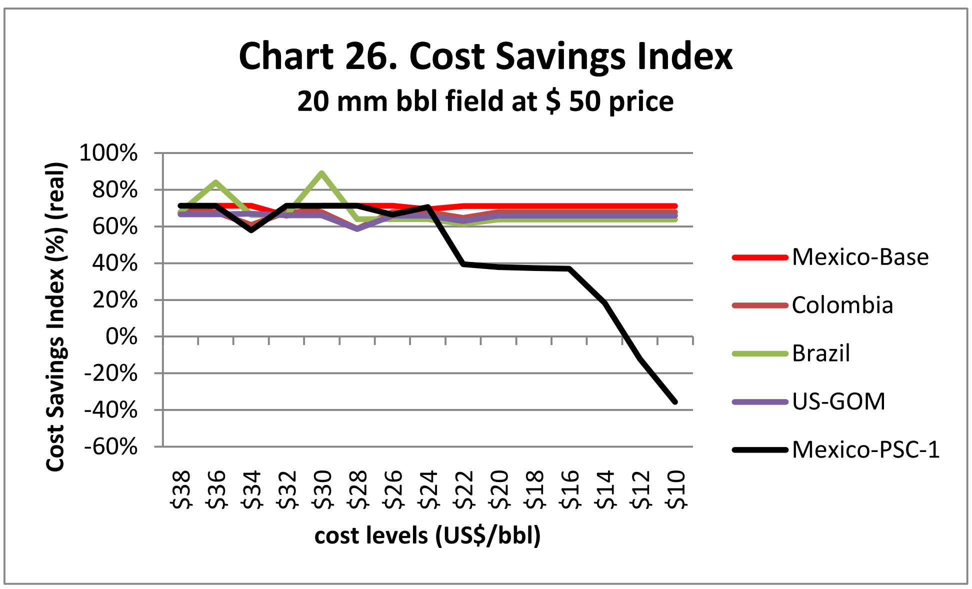
As an example, the recent Mexican shallow water PSC features gold plating. This is because the benchmark rates of 25% and 40% are clearly over industry hurdle rates. The reduction of the profit share by 75% is extreme by international standards.

The proposed terms therefore result in more severe gold plating than in most countries with such problems. The system will also lead contractors to propose excessive costs and will make proper cost control extremely difficult or impossible. This in turn will place difficult burdens on CNH to review and approve development plans. SHCP will have difficulties in cost control.

Cost Savings Index. One of the methods to measure gold plating is to study the cost savings index. The cost savings index measures how much an investor retains when saving a dollar of cost. In other words, if the cost savings index is 60%, the investor retains $0.60 when costs are reduced by a dollar. If the cost savings index is below 20% the system becomes very difficult to administer from a cost control concept, since the contractor has little incentive to minimize costs. A negative cost savings index indicates gold plating, which means that the investor has no incentive to save and in fact has an incentive to increase costs.

Chart 26 shows a gold plating analysis of the Mexican shallow water PSC, assuming an oil price of $ 50 per barrel and costs ranging from $ 40 per barrel to $ 10 per barrel. The chart shows how gold plating effects become rather serious when costs are less than $ 16 per barrel. At higher prices the gold plating "clicks in" at higher levels of costs.

The Mexico Base terms (which means the basic terms contained in the Hydrocarbon Revenue Law) are not subject to gold plating.

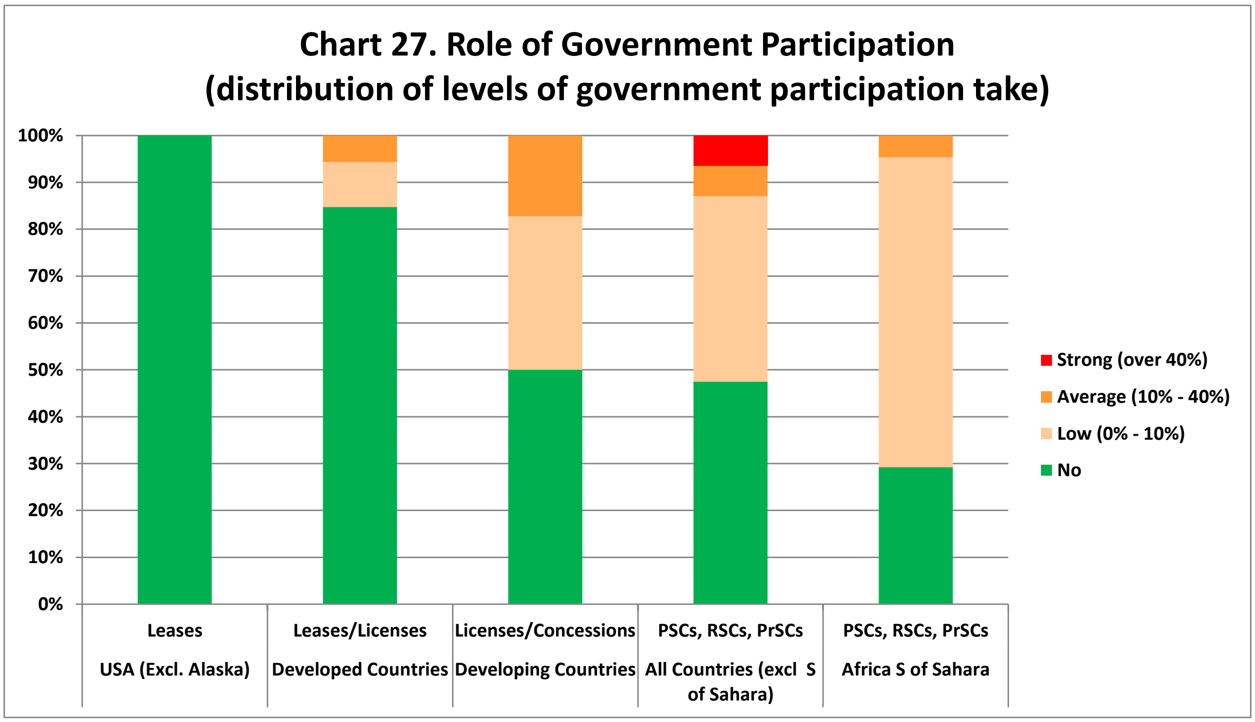


7.6 Modify the role of state participation from a broad to a narrow mandate.

Participation by a state owned corporation is rather common in petroleum fiscal systems. In the landmark study reported earlier[2] of 580 fiscal systems in the world in 160 countries, 35% of the fiscal systems had state participation.

The importance of the state participation in the total fiscal picture can be measured by the percentage government take that state participation represents. In total 26% of the fiscal systems had a modest level of state participation of less than 10%, while 9% had a higher level.

Chart 27 illustrates how government participation take is distributed around the world.



[2] *World Rating of Oil and Gas Terms: Volume 1 and Volume 6* provide detailed fiscal descriptions and investor analysis and favorability ratings of 580 fiscal systems in different logistical environments applicable in 156 countries. The study is produced jointly by Van Meurs Corporation, IHS and Rodgers Oil & Gas Consulting, with the assistance of Barrows Company and Ernst & Young. www.petrocash.com

Most government participation takes place in developing countries. Nevertheless, 15% of the 177 fiscal systems of developed countries (outside the United States) feature state participation. This includes fiscal systems in Norway, Denmark, Newfoundland and Labrador, Greenland, the Netherlands, Greece, Latvia, Ukraine and Russia.

The Netherlands was the first developed country to include state participation in the fiscal terms. This came about as a result of the discovery of the giant Groningen gas field which resulted in the closure of the Dutch state coal mines. The state participation was part of the required restructuring. Norway has effectively used state participation to expand the role of Norwegian state companies. As a result Statoil is now a major international company. Statoil, however, was partially privatized. State participation in new licenses was taken over by a new Norwegian state company called Petoro.

During the late 1970's, as a result of the energy crisis, there was considerable interest in the developed world in the promotion of state owned companies. It was seen as a vital component of balancing public versus private interests in the petroleum industry. The 1975, the UK created BNOC and Canada created Petro-Canada.

In the developing world, many state companies were created as a result of nationalizations: Mexico (1938), China (1950), Brazil (1954), Iran (1955) and Indonesia (1957). At the start of the energy crisis in 1975 also Venezuela, Saudi Arabia and Kuwait nationalized their petroleum industries.

During the last two decades, the pendulum has swung the other way. Many state companies were fully or partially privatized (Statoil, Petro-Canada, BNOC, the Chinese state companies, Petrobras, YPF, Ecopetrol, Gazprom, PTT, etc.). The reason was that the perceived public role did not materialize or did not prove to be necessary and in some cases the state companies under-performed commercially, lacked transparency or needed capital. The recent announcement of Saudi-Arabia that the country is considering selling off a 5% share of Saudi Aramco to the private sector is a continuation of this trend. Currently, some of the remaining state companies are seriously under-performing from a commercial point of view (Pemex, PDVSA, NNPC, Sonangol). It is mainly for this reason, that Mexico has changed the constitution and is now opening the country for private investment. Nigeria is considering private participation in NNPC.

Based on the experience of the last two decades, it cannot be recommended to establish new state owned companies in competition with the private industry and fulfilling a wide range of policy objectives, such as being a "window" on the oil industry, engaging in projects that the private companies are not interested in, dealing with other state companies around the world, establishing an international presence, creating large headquarter operations, etc.

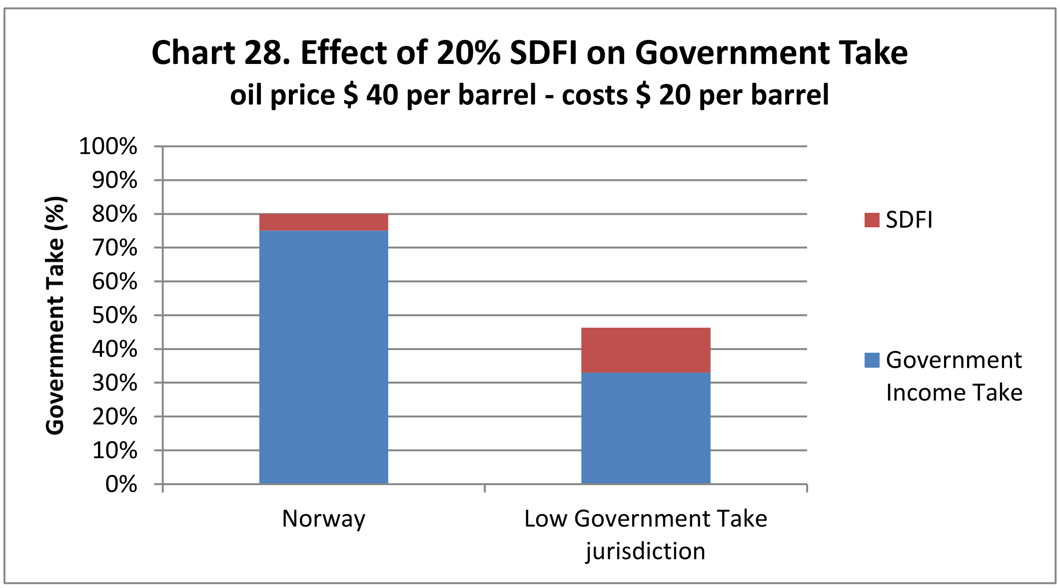
In the context of new climate change policies it does not make sense to commit major government funding to expand oil and gas activities in the country. Where possible government funding is available it should be dedicated to promoting renewable resources instead.

However, in sub-chapter 7.4 it was identified that a Norway Petoro type state participation is a highly effective way to align government and petroleum industry objectives and to increase the government take in a manner that does not affect the economic performance of the private participants.

The success of Petoro in Norway and EBN in the Netherlands is largely due to a rather limited mandate. The mandate is simple: to participate in licenses issued by government as a minority fully at-risk partner, with the main goal to create an additional cash flow for government.

On their website Petoro claims to have contributed 1600 billion Norwegian Kroner cash flow to the Norwegian treasury since 2001 (about 300 billion US $ based on exchange rates during this period). This participation is called in Norway the State Direct Financial Interest ("SDFI"). Petoro typically participates for 20%. It should be noted that the Petoro cash flow is in addition to the corporate income tax and hydrocarbon tax, which after uplifts typically result in an overall government take of 75%. In other words it increased the Norwegian revenues by 6.7%.

What is important is that in jurisdictions with a low government income tax, a similar SDFI of 20% would have a very significant impact. Chart 28 illustrates this matter.



The chart represents a jurisdiction with a government income take of 33%. This means the corporate take to the private investor is 67%. If the jurisdiction would participate with an SDFI of 20%, this would represent a 13.4% extra government take (20% of 67%). Therefore, an SDFI applied by such jurisdiction would have the potential to significantly increase revenues without negatively affecting the profitability of the private petroleum industry.

For this reason there are quite a number of jurisdictions where the SDFI concept may be attractive. As indicated before, such jurisdictions would have to have a significant resource base in order to justify taking the geological risk and have sufficient financial strength. The province of Newfoundland and Labrador has already a provincial participation. Other provinces in Canada, such as Nova Scotia, British Columbia and Alberta might benefit from this concept. The US Federal Government could offer the various US coastal states to participate in the offshore developments this way. The UK could make Scotland an offer to participate in this way in the Scottish section of the offshore. Mexico could re-direct PEMEX to participate in this manner in the new bid rounds. Colombia, Peru and Argentina may improve their government take in this way. Australia could consider this. Thailand could reform its system including such an SDFI.

It should be noted that in many of these jurisdictions state participation is not necessarily popular. Therefore, for political reasons such options may not be considered. Nevertheless, from an economic point of view there is a rationale for it.

7.7 Regulatory provisions to permit companies to survive periods of low oil and gas prices.

There are a number of regulatory issues that can also support companies to survive periods of low oil prices.

Significant Discoveries. The “Significant Discovery” concept already discussed in sub-chapter 6.6 can also be used in order to assist companies to survive periods of low oil and gas prices. In this case the ability to declare a significant discovery rather than a commercial discovery would be based on current low prices, with the possibility that under higher prices, the operations may be economic and a commercial declaration can be made.

It would seem unfair that companies that explored actively for the last seven years and made discoveries would be denied the benefit of such discoveries as a result of the current low oil or gas prices. The ability to declare a “significant” discovery would permit a company to keep the discovery on hold and avoid having to make large investments until the price situation improves.

Development Plan in Phases. Many contracts or regulatory provisions require the presentation of a “development plan”. It is often perceived that this constitutes a single large plan that would deal with the entire development of the field. Modifications can then be made to this plan in future years.

A significant misconception is that the great importance of incremental investments in oil and gas fields is misunderstood. Often, it is believed that an oil or gas field is like the investment in a building. You have to construct the building and once it is operational all you have to do is to maintain the building properly and make some occasional adjustments. This is not the way how an oil or gas field operates.

A typical field goes through many phases. Typically, production starts on the basis of primary recovery, which means the wells produce based on the pressure contained in the reservoirs or are produced based on well pumps. Subsequently, often an infill drilling and extension drilling phase occurs where more wells are drilled at favorable locations in order to enhance recovery and accelerate production. Afterwards a secondary recovery phase may start where water or gas or both are being injected in the reservoirs in order to maintain reservoir pressure and increase the recovery factors.

Finally, a tertiary recovery phase may start to further increase the recovery from the reservoirs through injection of naphta, steam, polymers or CO2 or other procedures. As new technologies develop such as horizontal drilling and advanced fracking procedures, such technologies are also applied to increase recovery or lower costs of production.

In other words, real oil or gas fields are subject to ongoing regular further incremental investments. The purpose of these investments is to increase the recovery from the reservoirs.

Therefore, it makes sense to establish procedures in the regulations and contracts to submit development plans in phases. The first development plan would have a detailed description of the first phase and a general description of further phases to be carried out in the future. The company would commit to carry out the first phase. The company would have a general responsibility to achieve the "maximum economic recovery" for the field or unconventional project as described in more detail below. After the approval of the first phase, the submission of the next phase would at the initiative of the company. However, the government would have the ability to require a submission for a next phase where it is of the view that the company is not complying with the obligation to achieve a maximum economic recovery for the field or project.

The specific ability under regulations or a contract to submit a development plan in phases and make the necessary investment commitments step by step, would assist the petroleum industry to survive periods or low oil and gas prices.

For instance, a company could submit a plan for the drilling and production of reservoirs with highly productive shallow wells during the period of low oil prices. Once oil prices increase, a further plan can be presented to drill and produce deeper less productive wells. This procedure would also permit the development of "hot spots" in unconventional projects first, before drilling and fracking less attractive formations.

For governments to feel comfortable with permitting a development plan in phases, the commitment to the maximum economic recovery obligation on the part of the holders or contractors has to be more specific than is typical at this time.

MER: Maximum Efficient Rate and Maximum Economic Recovery. Two concepts of MER are typically used in the petroleum industry: Maximum Efficient Rate and Maximum Economic Recovery. Both concepts will be discussed.

Maximum Efficient Rate. The "Maximum Efficient Rate" is usually defined as follows (as from the Libya contract):

means the maximum rate, according to Good Oilfield Practices, at which oil or gas can be produced without excessive decrease of reservoir pressure or loss of reservoir energy.

In other words the concept is used to make sure companies do not aggressively over-produce the reservoirs and thereby lower the recovery that should be obtained. This is largely a technical concept.

It should be noted that the "Maximum Effective Rate" from a technical point of view makes only sense if it is applied on a well by well basis. In a field each well should produce at not more than the maximum effective rate. For instance, it would not be good international petroleum industry practice to produce half the wells at excessively high rates and other wells at very low rates in order to achieve on average a maximum effective rate for the field as a whole.

As an example, the Section 6830 of the California Public Resources Code describes this as follows:

6830. All oil and gas leases issued by the commission for lands under its jurisdiction as set forth in Chapters 3 and 4 of Part 1 and in Chapter 3 of Part 2 of Division 6 of this code shall contain a reservation to the commission of the right to determine the spacing of wells and the rate of drilling and rate of production of such wells so as to prevent the waste of oil and gas and promote the maximum economic recovery of oil and gas from, and the conservation of reservoir energy in, each zone or separate underground source of supply of oil or gas covered in whole or in part by leases issued under this chapter.

One of the earlier model contracts with Ecopetrol in Colombia described the MER for the field as follows in Clause 12.1:

12.1 The Operator shall, with the approval of the Executive Committee, determine semi annually or as necessary, a Maximum Efficiency Rate (MER) for each Commercial Field. This Maximum Efficiency Rate (MER) shall be the sum of the Maximum Efficiency Rate (MER) of each producing well, as based on the determining technical factors of the reservoirs. Estimated production shall be decreased as necessary to compensate for actual or anticipated operating conditions, such as wells under repairs which are not producing, capacity limitations in collection lines, in pumps, separators, tanks, pipelines and other facilities.

Since the Maximum Efficient Rate is a well by well concept, it should not be applied to the field or contract production as a whole, other than as provided for in the Colombia example. Nor should there be a requirement to produce at this rate. For instance, clauses such as Clause 6.3 in Equatorial Guinea model should be avoided:

> *6.3 CONTRACTOR shall produce Crude Oil from the Contract Area at the Maximum Efficient Rate.*

In other words if the Maximum Efficient Rate concept is used in the regulations or a contract it should clarify that this rate applies to each well and that the production from each well **cannot be higher** than this rate.

Maximum Economic Recovery. Another "MER" concept that is often used is "Maximum Economic Recovery". This is an economic concept and it means that companies should maximize the recovery of oil and gas from the reservoirs based on economic conditions.

Very interestingly, as far as I have been able to identify there is no international definition of "Maximum Economic Recovery".

Despite the fact that "Maximum Economic Recovery" is an undefined term, it is widely used. Following are some examples of how "Maximum Economic Recovery" is used.

For instance, a requirement under the Colombia ANH model contract is to provide yearly:

A forecast of the annual production of Hydrocarbons and their sensitivities, using the optimum rate of production allowing the maximum economic recovery of reserves to be achieved.

The model of Trinidad and Tobago states for instance, after a development plan has been approved:

the Contractor shall proceed promptly and diligently and in accordance with good international Petroleum industry practice to develop the Discovery, to install all necessary facilities, to commence Commercial Production and to produce the Field in a manner that will achieve maximum economic recovery of the reserves.

The UK Petroleum Production (Landward) Regulations of 1995 state in clause 6, related to the renewal of a license:

6. *Where this licence has continued in force by virtue of clause 5 of this licence for a total period of twenty years after the expiry of the second term, the Minister, on application being made to him in writing not later than three months before the expiry of such period, may agree with the Licensee that this licence shall continue in force thereafter for such further period as the Minister and the Licensee may agree in order to secure the maximum economic recovery of petroleum from the licensed area and subject to such modification of the terms and conditions of this licence (which modification may include making provision for any further extension of the term of this licence) as the Minister and the Licensee may then agree is appropriate.*

In a contract between the Malaysia-Thailand Joint Development Area with Petronas Carigali and Triton on Block A-18 it states with respect to the use of associated gas:

Subject to MTJA's approval, Contractors shall be given priority to use Associated Gas produced in the Contract Area for Petroleum Operations including re-injection for pressure maintenance or re-cycling operations to effect maximum economic recovery of Crude Oil

As a consequence of a new policy to adopt a more flexible approach to development plan implementation in the new price environment, it is necessary obtain a stronger commitment from holders or contractors to the goal of achieving a maximum economic recovery. However, this means that this concept needs to be defined. I would suggest the following definition as an example:

Maximum Economic Recovery – The highest possible recovery of petroleum from reservoirs and formations using development and production practices, which at the time such practices are applied are commercial under the prevailing economic conditions, and which consist of the optimal spacing of vertical and horizontal wells, the production of wells at not higher than the maximum effective rate, carrying out regular workovers, drilling of infill and extension wells, fracking of formations and implementing secondary and tertiary recovery schemes, using the most effective technologies existing when the practices are applied.

This definition applies to conventional as well as unconventional petroleum. The definition is also “future” based. This means over a 50 years life of a concession, license or contract, new technologies will come along that need to be applied in case such technologies are commercial.

8. <u>Integrated Petroleum Fiscal Examples</u>

8.1 <u>Summary of Petroleum Fiscal Recommendations</u>

Following is the summary of the petroleum fiscal recommendations contained in Chapters 6 and 7 of this report:

1. Introduce carbon taxes preferably initially in the $ 30 to $ 60 per ton CO2 equivalent range, increasing to US $ 120 per ton CO2 equivalent.
2. Eliminate of subsidies to consumers for natural gas, oil, condensates and petroleum products.
3. Phase out domestic market or domestic supply obligations and replace with market based pricing structures.
4. Eliminate or phase out export duties
5. Establish robust fiscal terms and a competitive government take at the $ 60 per barrel pivot oil price level and create price progressive systems over the entire $ 25 to $ 100 per barrel range.
6. Promote gas development with gas-favorable fiscal terms over established gas price ranges.
7. Reduce emphasis on fiscal stability provisions
8. Ensure a minimum government take for resource owners in addition to corporate income tax
9. Discourage excessive investment during high oil and gas prices with tougher price sensitive features, but ensure that the price incentive index always exceeds 10%.
10. Change policies to higher price progressivity, while also increasing volume progressivity and introduce cost progressivity or less regressivity, without creating gold plating, and depending on the absorption capacity of the country, provide for less front end loading and increased sharing of risks with the following steps:
    a. Moderate signature bonuses,
    b. Phase out production bonuses,
    c. Moderate rentals,
    d. Make royalties, severance and production taxes strongly price progressive as well as volume progressive and introduce where applicable also some cost progressivity or less regressivity and provide for a few years after the start of production for zero or lower royalties,
    e. Extend the range of progressivity of windfall profits taxes over the entire price range of $ 25 to $ 100 per barrel and corresponding gas prices,
    f. Ensure corporate income tax is consolidated for the entire jurisdiction, promote capital costs depreciation as incurred and apply accelerated depreciation or even 100% write offs of capital,

g. Break out corporate income tax as a separate consolidate feature where corporate income is included in or linked to the profit oil/gas shares in production sharing contracts and do not ring fence corporate income tax per contract area or field,
h. Establish price sensitive cost oil/gas limit formulas in production sharing contracts or simply increase cost limits, in particular where they are 50% or less and use a step down of the cost limit during the first 5 years of the commercial production,
i. Establish deemed interest features for carry forwards of cost oil/gas,
j. Create increased price progressivity for profit oil/gas over the entire price range and combine with volume and cost progressivity,
k. Reform state participation provisions to Petoro style participation where appropriate in financially strong countries with a significant resource base,
l. Change uplifts from applying only to capital costs to uplifts for capital as well as operating costs,
m. Phase out all IRR based systems, except for systems based on a rate of return not higher than the long term bond rate,
n. Reform R-factor systems based on discount rates and systems which are too sensitive to more robust systems,
o. Introduce R-factors based on yearly, trimestral or monthly profit features rather than cumulative features only,
p. Phase out import duties during international trade negotiations
q. Phase out risk service contracts

11. Avoid excessive cost regressivity.

8.2 <u>Integrated royalty based example</u>

In this sub-chapter an example will be provided as to how all the recommendations in sub-chapter 8.1 could be brought together in a single fiscal system based on a sliding scale royalty concept.

The system would consist of three components:

(1) The carbon tax,
(2) A sliding scale royalty, and
(3) Corporate income tax.

In order to illustrate the possible range of application of the example, three different levels of sliding royalties will be evaluated based on the shallow water examples already used in sub-chapter 7.3:

(1) A low royalty, on average over the life of the field 11.5%, calibrated on making exploration commercially attractive for a 20 million barrel target at a price of US $ 60 per barrel, with $ 20 per barrel development capital and operating costs and with a probability of success of 30%,
(2) An average royalty, on average over the life of the field 26.79%, calibrated on making exploration commercially attractive for a 50 million barrel target at a price of US $ 60 per barrel, with $ 15 per barrel development capital and operating costs and with a probability of success of 30%, and
(3) A high royalty, on average over the life of the field 44.11%, calibrated on making exploration commercially attractive for a 100 million barrel target at a price of US $ 60 per barrel, with $ 10 per barrel development capital and operating costs and with a probability of success of 30%.

The calibration results in basic terms. It is assumed that these terms serve as starting point for a bid round. Companies can then bid higher based on their view of the geological and technical factors and their profitability and risk analysis.

Carbon Tax. It is assumed that a $ 60 per ton CO2 equivalent will be levied. Table 10 illustrates how this results in a payment of $ 0.62 per barrel of oil. This is based on the assumption that associated natural gas will be used as fuel in the field and that the amount of fuel is equivalent to 3% of the oil production. This carbon tax is not subject to fiscal stability and could be increased in the future. No increase is assumed in the analysis.

Table 10. Carbon Tax Calculation per barrel

Emissions per MMBtu gas	**(kg)**	**58**
MMBtu per barrel		**6**
Emissions per barrel	**(kg)**	**348**
Carbon Tax per ton CO2 equivalent	**(US $)**	**60**
Carbon Tax per barrel burned	**(US $)**	**20.88**
Energy Use in the field	**(%)**	**3%**
Carbon tax per barrel produced	**(US $)**	**$ 0.6264**

Four Component Royalty. All the recommendations of sub-chapter 8.1 are used to create a sliding scale royalty. The sliding scale royalty consists of four components related to:

(1) Time,
(2) Price,
(3) Volume, and
(4) Costs.

The time component is introduced to make the royalty somewhat less front end loaded. The royalty is price progressive over the entire range from US $ 30 to US $ 150. The royalty is volume progressive over 10,000 bopd. Finally, the cost regressivity of the royalty is moderated with a Mexican style R-factor. The elements are listed in Table 11.

The time component consists of a royalty holiday, which overrides all the other royalty components and is based on a number of years after the start of commercial production. During the royalty holiday the minimum royalty applies, regardless of what the other royalty formulas result in.

Price progressivity is created with a three-slope sliding scale royalty component as discussed in sub-chapter 7.3. The price progressivity is designed in such a manner that it meets reasonably the Price Incentive Index as discussed in sub-chapter 7.3. For this reason the slope becomes less if the price becomes higher.

Volume progressivity is created with a traditional volume sliding scale. Up to 10,000 bopd the royalty is 0%. Thereafter, to the degree the volume is over 10,000 bopd the royalty is 10% up to a level of 30,000 bopd. Thereafter, to the volume is over 30,000 bopd the royalty is 20%.

The cost regressivity reduction is created by applying the Mexican R-factor system already discussed in sub-chapter 7.1. The R-factor is based on the same formulas and also relate to the R-factor levels of 2 and 4. Between these R-factor levels the royalty moves linearly and is adjusted for the Operating Result Coefficient ("CRO").

The minimum royalty is 5% and the maximum in any month is 80%.

Table 11. Four Component Royalty				
		Low	Average	High
Time				
Holiday Years	(Years)	4	3	2
Minimum Royalty	(%)	5.00%	12.50%	20.00%
Price				
Below and At $ 30	(%)	5.00%	15.00%	30.00%
At $ 60	(%)	30.00%	37.50%	45.00%
At $ 90	(%)	45.00%	47.50%	53.75%
Above and At $ 150	(%)	52.50%	55.00%	57.50%
Volume				
below 10,000 bopd	(%)	0.00%	0.00%	0.00%
Over 10,000 bopd	(%)	10.00%	10.00%	10.00%
over 30,000 bopd	(%)	20.00%	20.00%	20.00%
Costs				
Below R=2	(%)	0.00%	0.00%	0.00%
At R=2	(%)	10.00%	15.00%	25.00%
At R=4	(%)	20.00%	30.00%	50.00%
Over R=4	(%)	20.00%	30.00%	50.00%
Minimum royalty	5.00%			
Maximum royalty	80.00%			

Corporate Income Tax. It is assumed that the corporate income tax rate is a flat 30% and is consolidated at the national level for all economic sectors. Depreciation commences at the day the costs are incurred. For exploration and appraisal activities the capital expenses are expensed (written off 100%). For development expenditures, the depreciation rate is assumed to be 25% straight line. It is assumed that the loss carry forward is indefinite.

It is assumed that the investor has sufficient taxable income to deduct the depreciation and operating costs related to the project for tax purposes in any year.

Government take analysis. The Risked Undiscounted Government Take ("Risked GT0") is being evaluated for changes in price, volume and costs. The sliding scale royalties are compared with the fixed royalties at the rates of 11.5%, 26.79% and 44.11%.

Chart 29 illustrates the sensitivity of the Risked GT0 for three levels of royalties and the price range of $ 30 to $ 100 per barrel. This chart clearly shows the pivot price of $ 60 per barrel. Below this price the Risked GT0 is more favorable to the petroleum industry than the corresponding fixed royalty. This assists the petroleum industry during low prices. Above this level the terms are less favorable to the petroleum industry and the government can recuperate the prior lesser revenues.

The low royalty is relatively flat for price levels of $ 40 and higher. This is because the price regressive nature of the carbon tax is balanced by the price progressive royalty. For very low price the low royalty is regressive. The average and high royalty feature the price progressivity that can be expected from the sliding scale.

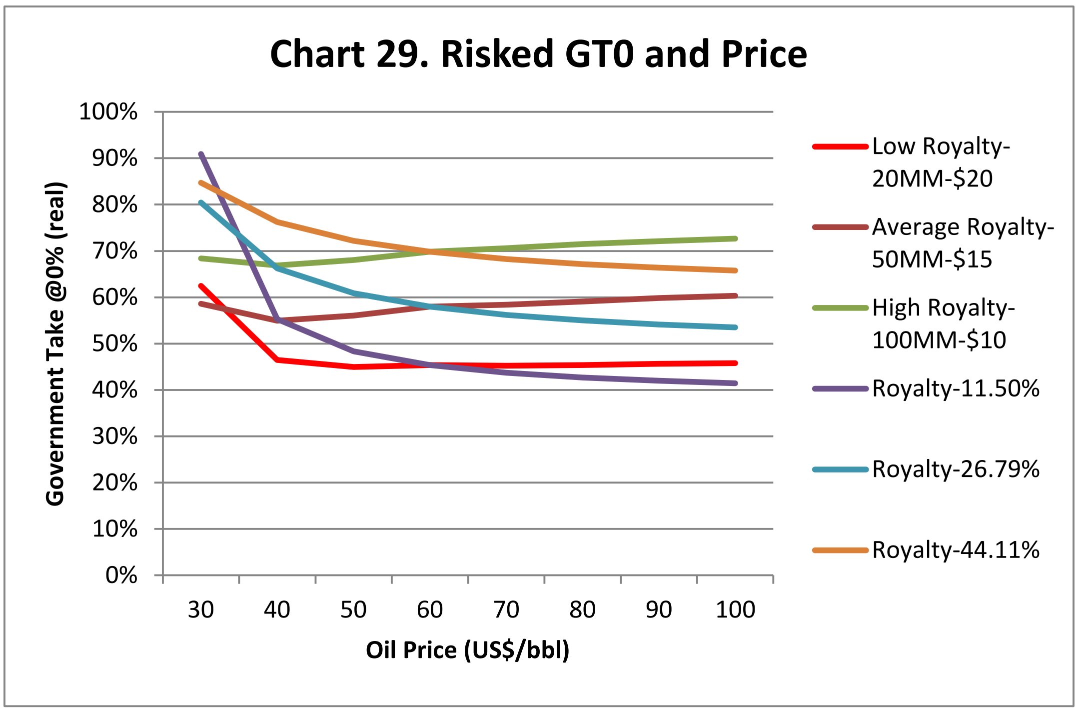


Chart 30 illustrates the strong volume progressivity. The volume progressivity is created by the volume based sliding scale, but also by the royalty holiday. The royalty holiday has a bigger effect on a small field than a large field, since the production life of a small field is shorter and therefore, the royalty in total is less. The volume progressivity is rather strong as a result and the government is therefore well protected in case of a large discovery.

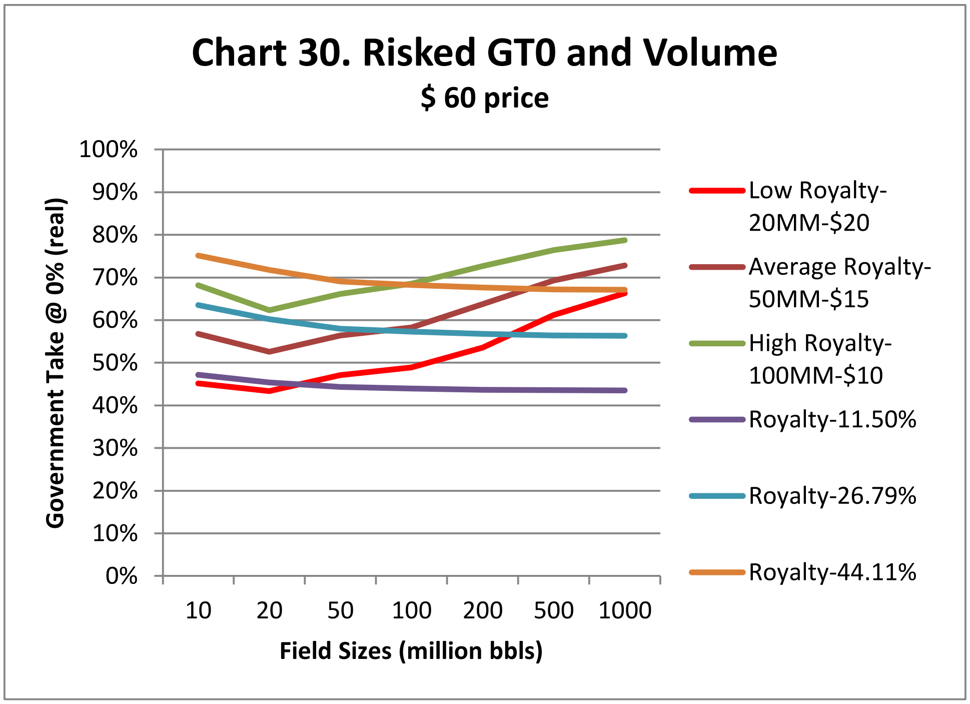
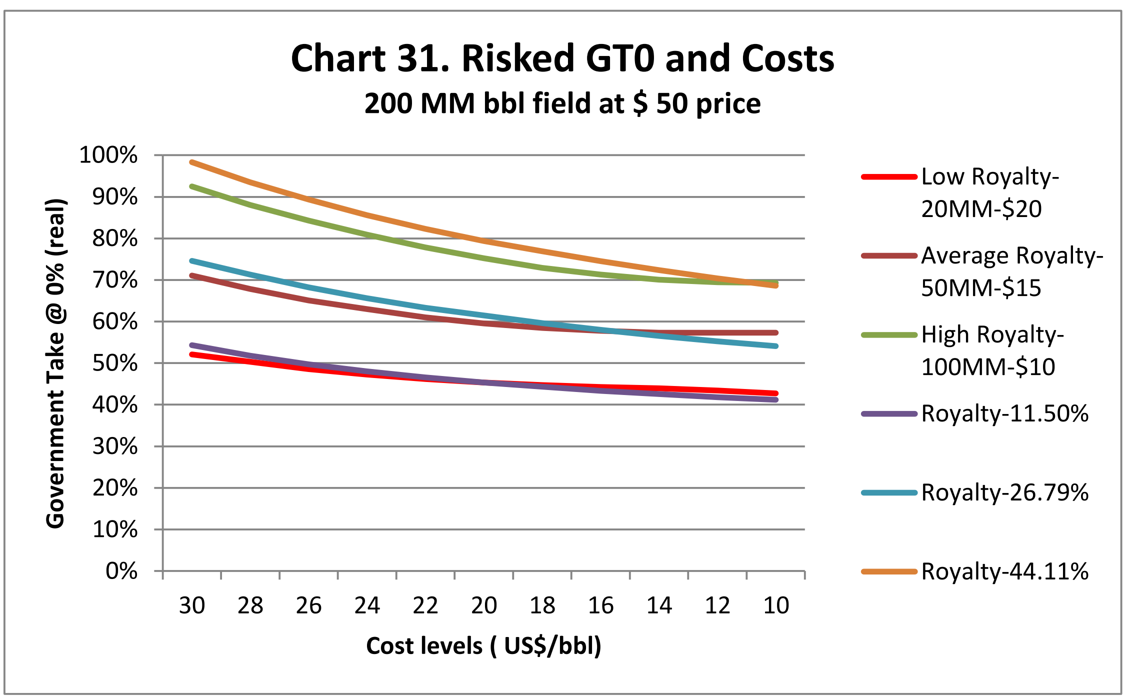
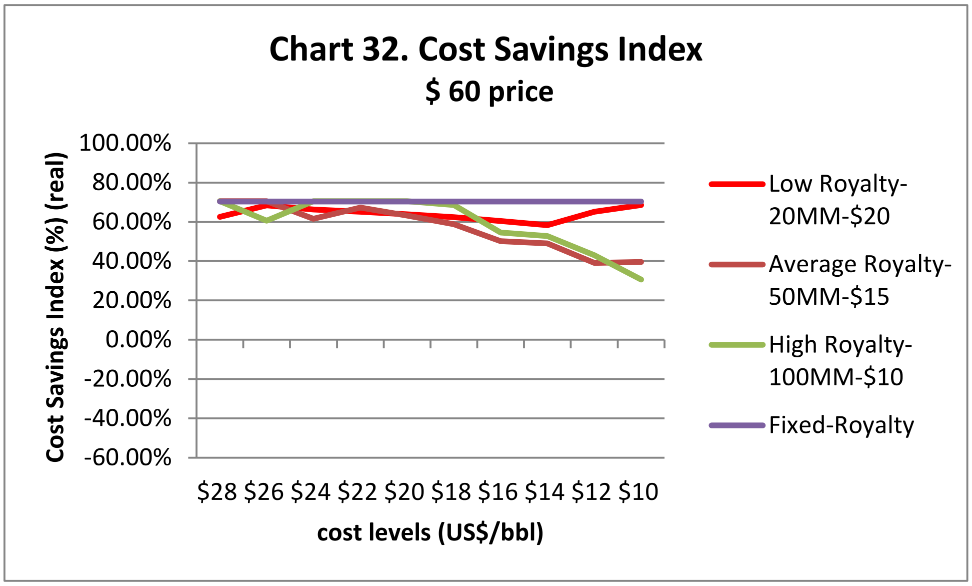


Chart 31 illustrates, how despite the important Mexican R-factor feature, in general the sliding scale royalty remains cost regressive. However, the regressivity is reduced. What is important is that the Mexican formula will assist in providing a lower royalty during temporary low price periods, as explained in sub-chapter 7.1.



Cost Savings Index. Chart 32 is the cost savings index analysis, which illustrates that the proposed R-factor in combination with the other sliding scales is fiscally healthy and does not result in gold plating.



Analysis of Profitability. Chart 33 illustrates the Risked IRR. It shows how below US $ 60 per barrel the proposed sliding scales improve the profitability considerably compared to the corresponding fixed royalties. This is due to the royalty holiday and the application of the Mexican R-factor. Therefore, this system will improve operating conditions for the petroleum industry during periods of low prices. The chart also shows how the Risked IRR is attractive at $ 60 per barrel. This means that companies doing profitability and risk analysis base on a long term price of $ 60 per barrel will find the terms attractive.

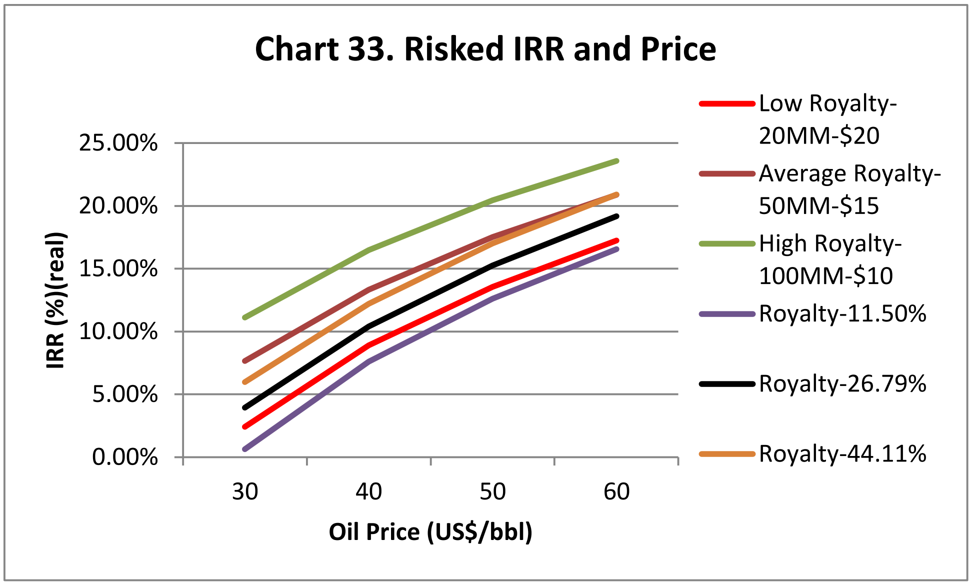
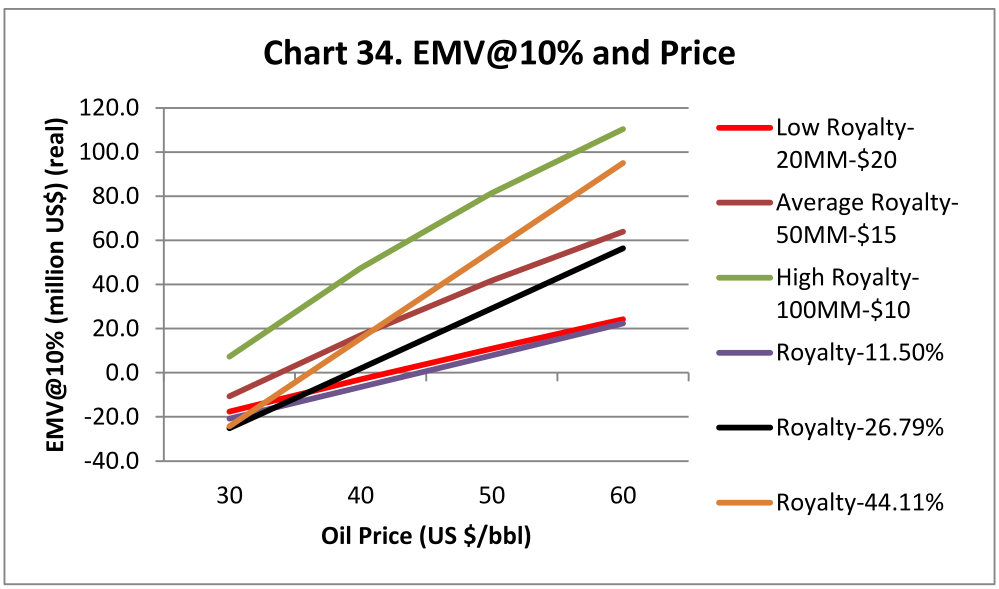


Chart 34 illustrates how the EMV10 is improved as a result of the proposed royalty changes, in particular for the average and high royalty. Also EMV10 values are attractive at the $ 60 price level.



Conclusion. The Four Component Royalty system has the potential from a petroleum industry perspective to make operating during low oil prices more attractive. The government would have a fair chance to recover from the lower government revenues during high prices.

In general the system provides superior protection to government that under highly profitable conditions the government gets a fair share. At the same time, however, this means that the system has less "upside" for the petroleum industry.

The fact that the system reacts effectively to a wide range of circumstances will create greater stability among the parties. Also a major advantage is that the system is relatively easy to administer.

Further refinements. A disadvantage of the system is the Mexican R-factor concept does not provide sufficient encouragement in this Four Component Royalty to strongly encourage contract and field incremental investments. The system could be improved further by incorporating certain allowances in the fiscal framework to achieve this goal.

Other refinement can be incorporated in the Four Component System by adding further components. For instance, the system could be made sensitive to the gravity of the oil. Also the system could be automatically adjusted for water depth, well depth and/or well productivity or other variables.

8.3 Integrated PSC based example

In this sub-chapter the recommendations of sub-chapter 8.1 will be brought together in a single fiscal system based on a production sharing concept.

The system would consist of three components:

(1) The carbon tax,
(2) A sliding scale production sharing arrangement, and
(3) Corporate income tax.

In order to illustrate the possible range of application of the example, three different levels of sliding scales will be evaluated based on the shallow water examples of sub-chapter 7.3. These examples are calibrated in the same manner as for the royalty examples.

(1) A low profit oil level, on average equivalent to a level of profit oil equivalent to 16% over the life of the field,
(2) An average profit oil level, on average equivalent to a level of profit oil equivalent to 34.5% over the life of the field, and
(3) A high profit oil level, on average equivalent to a level of profit oil of 53.5% over the life of the field.

Furthermore, the PSC terms were calibrated in such way that the results were as similar as possible to the royalty results, in order to be able to compare the use of royalties and production sharing. The minimum level of profit oil was calibrated against the results for the minimum royalty.

Also for the PSC terms, the calibration results in basic terms. It is assumed that these terms serve as starting point for a bid round.

Carbon Tax. It is assumed that a $ 60 per ton CO2 equivalent will be levied as for the royalty example.

Four Component Production Sharing. All the recommendations of sub-chapter 8.1 are used to create a sliding scale production sharing. As for the royalty sliding scale, the concept is based on four components related to:

(1) Time,
(2) Price,
(3) Volume, and
(4) Costs.

The time component is introduce to make the system somewhat less front end loaded. The royalty is price progressive over the entire range from US $ 30 to US $ 150. The production sharing feature is volume progressive over 10,000 bopd. Finally, the cost regressivity of the production sharing is moderated by a deemed interest.

The time component consists of a step down of the cost limit from 80% to 50% four years after the start of production for all three cases.

Volume and price progressivity are created by a volume-price table as indicated in Table 12. The volume scale is sliding. The price scale is "jumping". (The price level "99999" means "over $ 105 per barrel").

Table 12 Price-Volume Tables for PSC				
DAILY OIL	OIL PRICE: (US$/bbl)			
PRODUCTN	35.00	65.00	105.00	99999.00
(bbls/day)				
LOW				
10000	15.00%	16.00%	18.00%	20.00%
30000	20.00%	25.00%	35.00%	40.00%
9999999	55.00%	60.00%	65.00%	70.00%
AVERAGE				
10000	27.00%	32.00%	39.00%	45.00%
30000	40.00%	45.00%	47.00%	50.00%
9999999	65.00%	70.00%	72.00%	74.00%
HIGH				
10000	43.00%	49.00%	54.00%	60.00%
30000	50.00%	55.00%	59.00%	63.00%
9999999	72.00%	75.00%	77.00%	80.00%

The cost regressivity reduction is created by a deemed interest of 5% on the carry forward of unrecovered costs.

Corporate Income Tax. It is assumed to be the same as for the royalty example in sub-chapter 8.2.

Government take analysis. The Risked Undiscounted Government Take ("Risked GT0") is being evaluated for changes in price, volume and costs. The sliding scale profit oil concepts are compared with equivalent fixed profit oil levels of 16%, 34.5% and 53.5% and a flat cost limit of 50%.

Chart 35 illustrates the sensitivity of the Risked GT0 for three levels of royalties and the price range of $ 30 to $ 100 per barrel. This chart clearly also shows the pivot price of $ 60 per barrel.

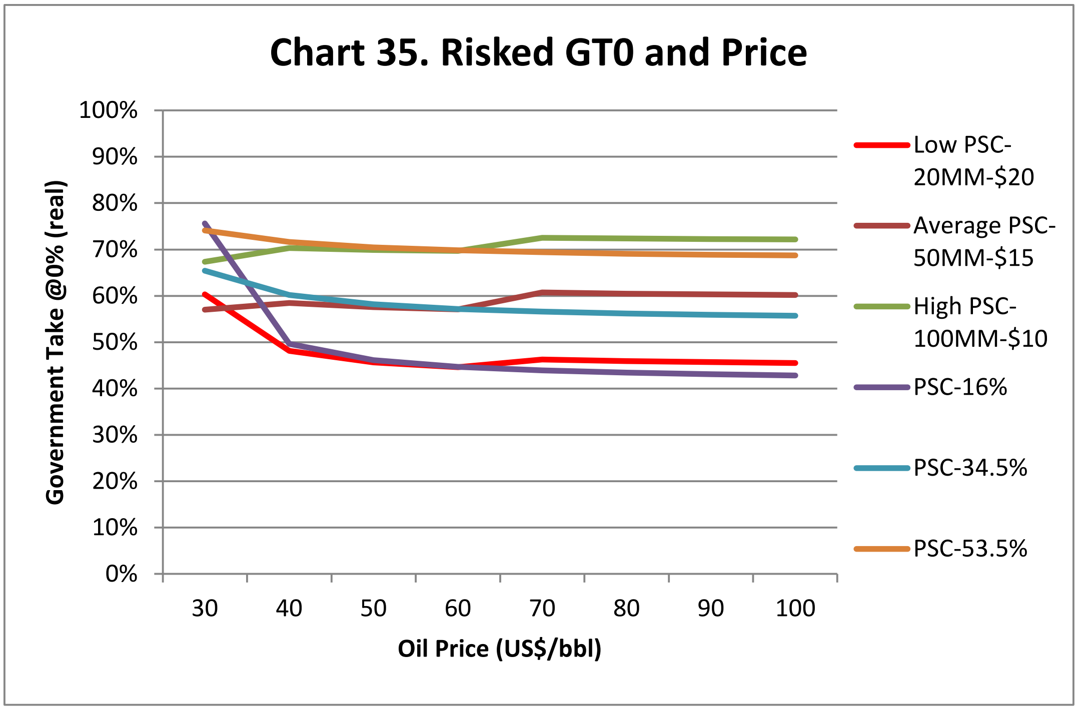


Chart 36 illustrates the strong volume progressivity created by the volume-price table. Also for the PSC, the government is therefore well protected in case of a large discovery.

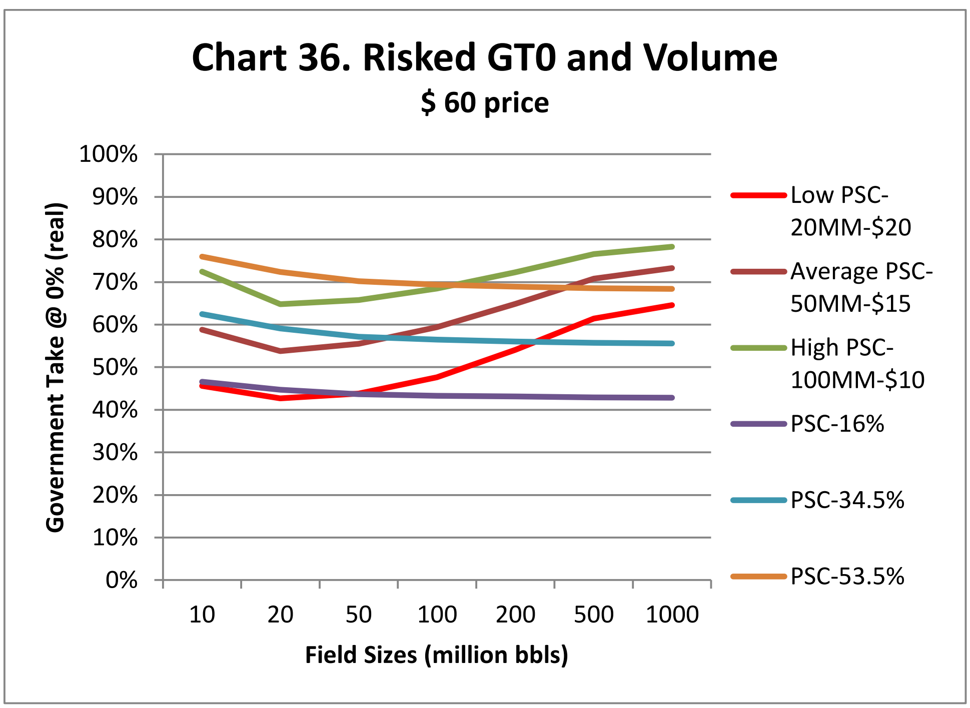
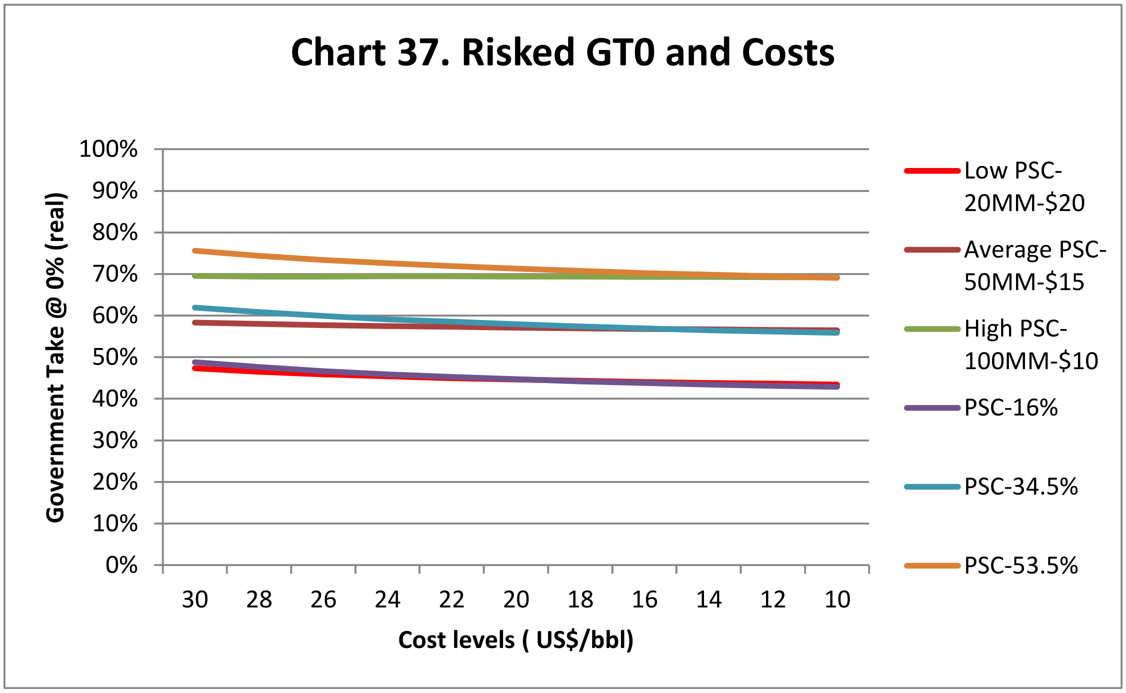


Chart 37 illustrates how the production sharing provisions combined with the deemed interest creates a rather flat Risked GT0.



The Cost Savings Index chart shows how the system does not create gold plating. Also the system is sound from a Price Incentive Index perspective.

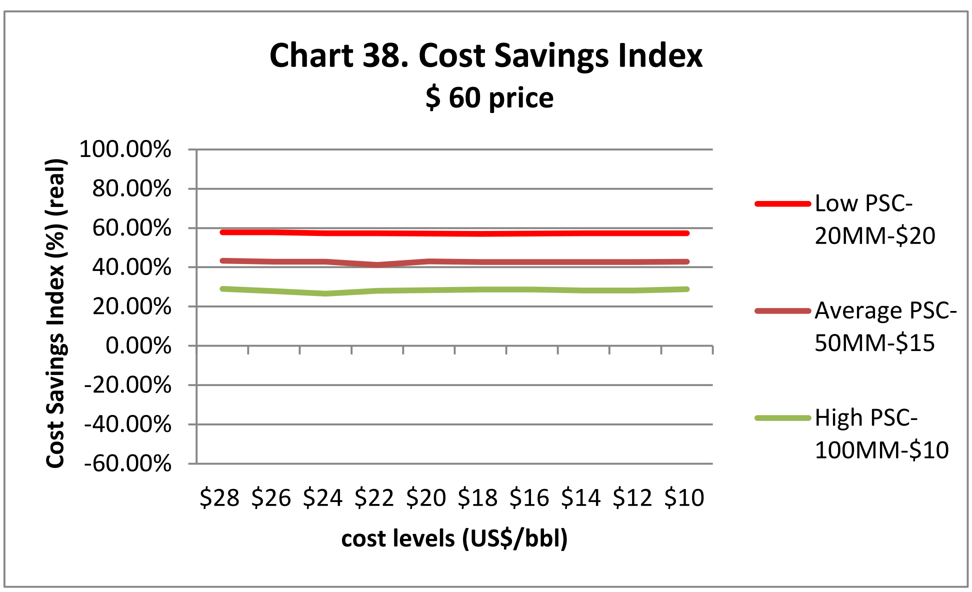


Chart 39 illustrates how the production sharing terms provide effective support at low price levels. A company targeting a long term price of US $ 60 per barrel will find the system attractive for exploration from a fiscal point of view.

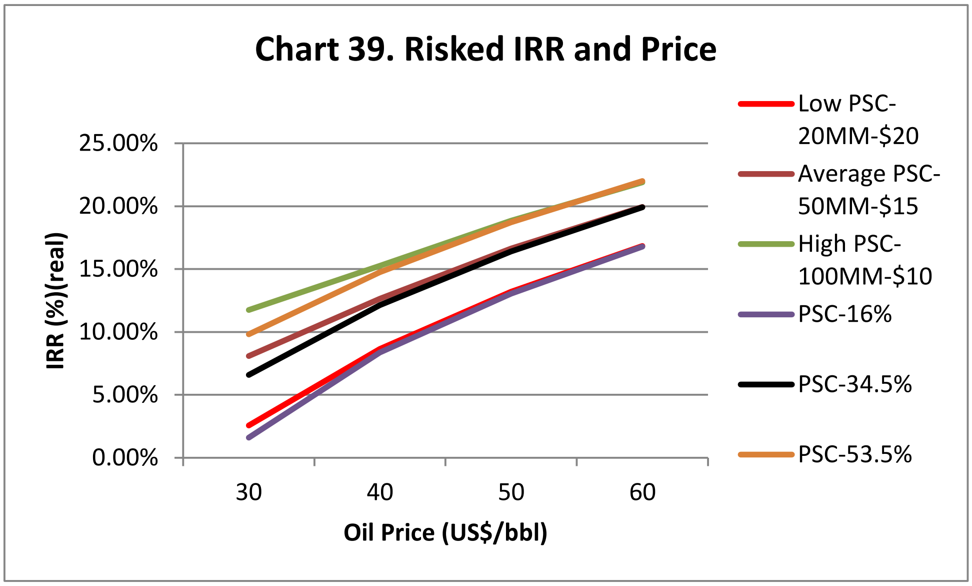
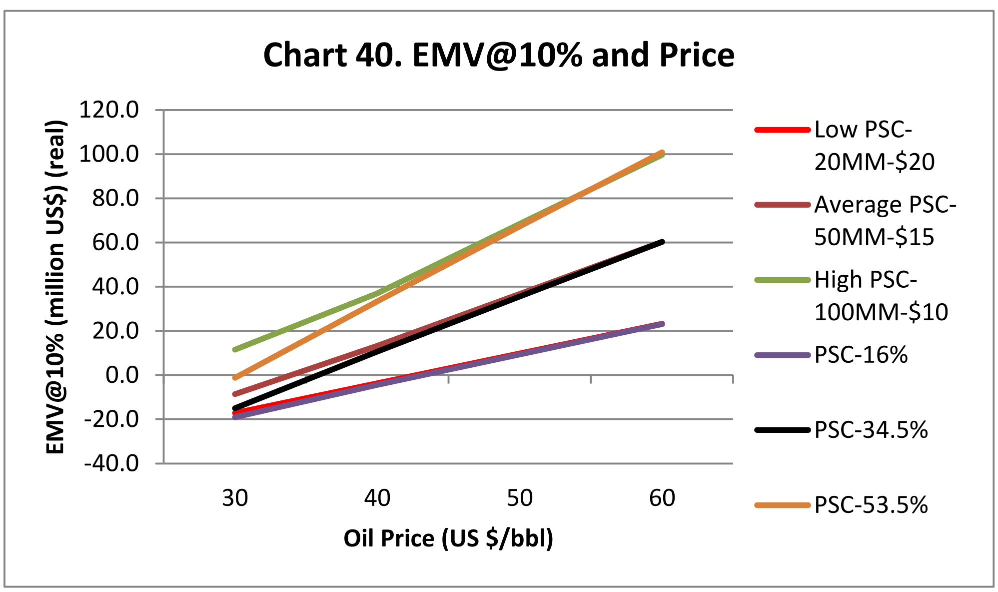


Chart 40 illustrates how also the EMV10 is acceptable at the $ 60 per barrel level, while support is provided at lower prices.



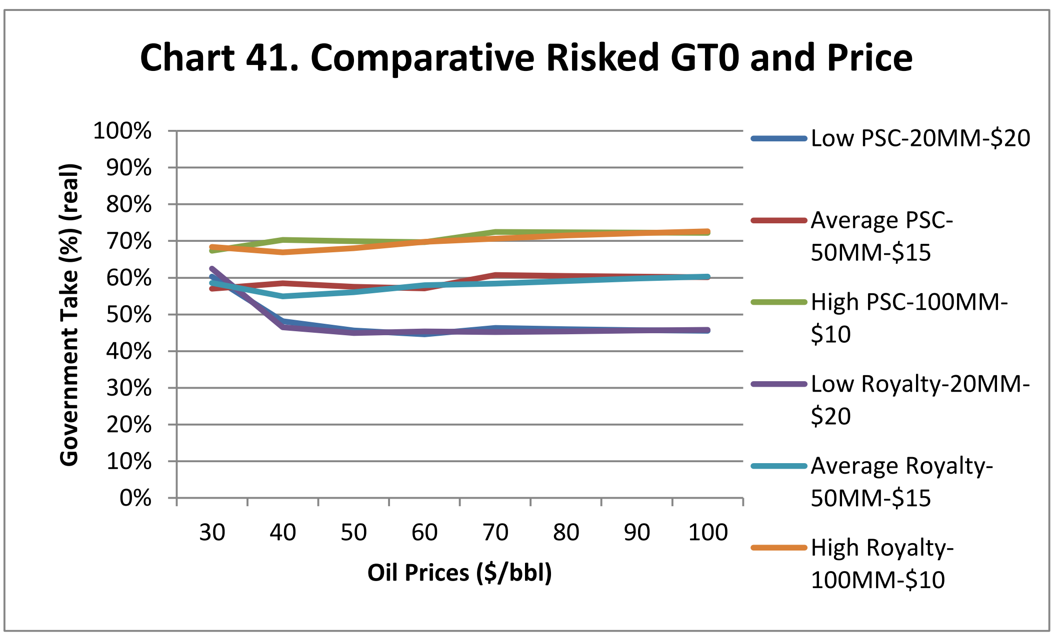
<u>Conclusion.</u> The conclusions for the Four Component Production Sharing system are the same as for the Four Component Royalties. It is an effective system to support the petroleum industry during low oil prices and created greater stability among the parties, while creating less upside for the petroleum industry.

Further refinements. The system could be refined further by introducing an R-factor type feature in order to encourage contract and field incremental investments. Instead of the deemed interest a single uplift can be used. Price progressivity can also be created by including a windfall profits type feature.

As for the royalties, the system could be made sensitive to the gravity of the oil and could be automatically adjusted for water depth, well depth and/or well productivity or other variables.

8.4 <u>Comparison of integrated examples</u>

As is clear from Charts 41 and 42, Four Component Royalties and Four Component Production Sharing can be calibrated in such a way that the systems provide for an identical government take of the entire price range of $ 30 to $ 100 per barrel and field size range of 10 to 1000 million barrels.



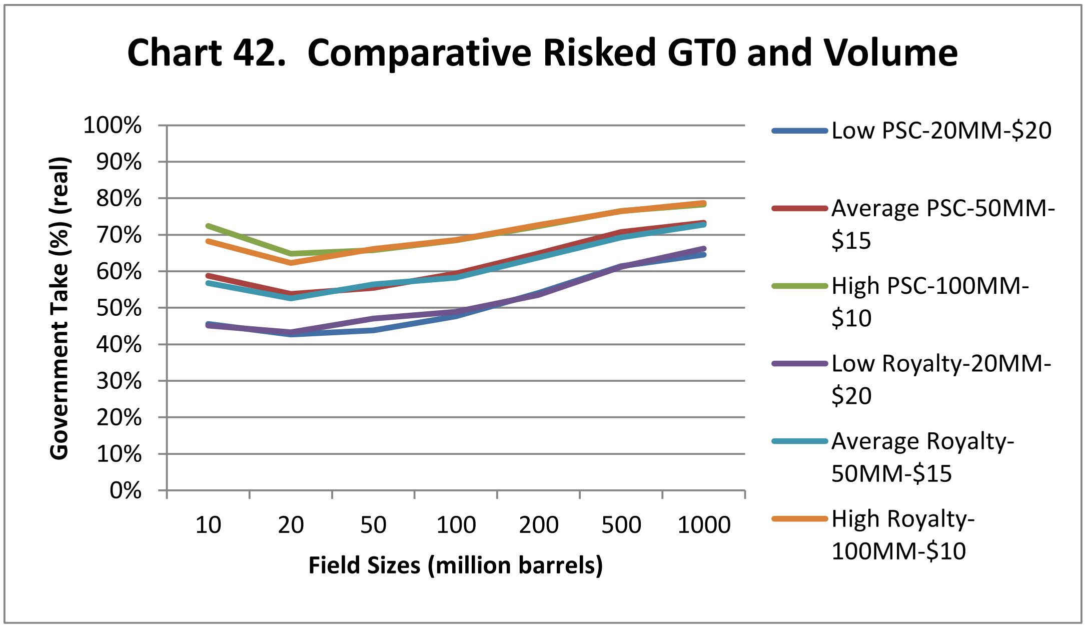


Chart 43 illustrates how Four Component Royalties are more cost regressive than Four Component Production Sharing. The reason is simple, because production sharing is profit based. This means that under higher than expected cost conditions, royalties are a more secure form of government income than production sharing. At the same time it means that higher than expected costs are a more important risk factor for the petroleum industry.

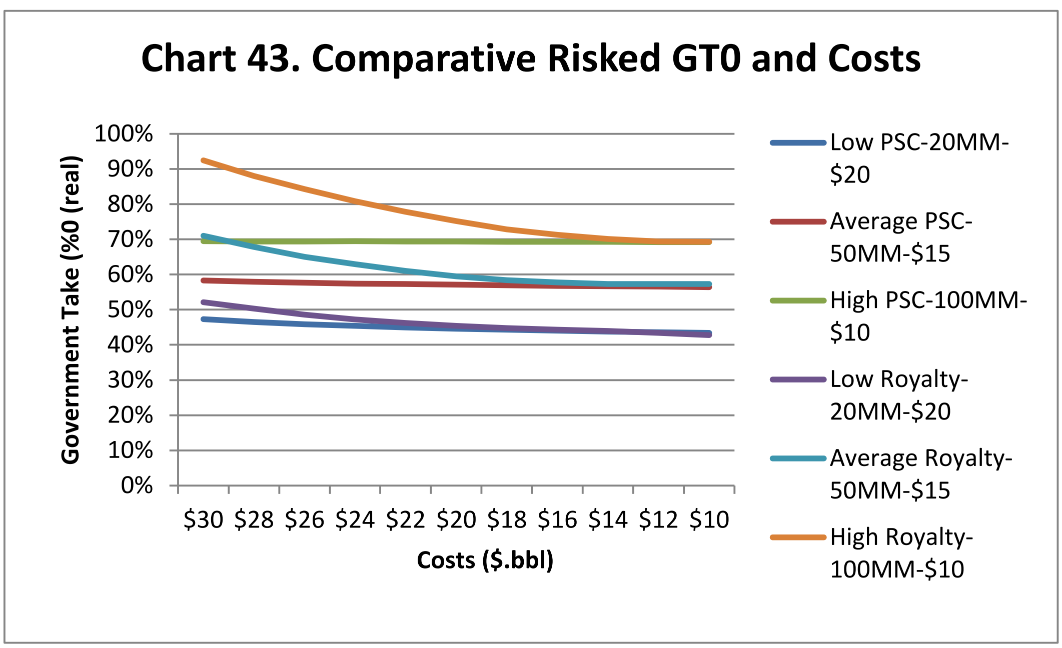
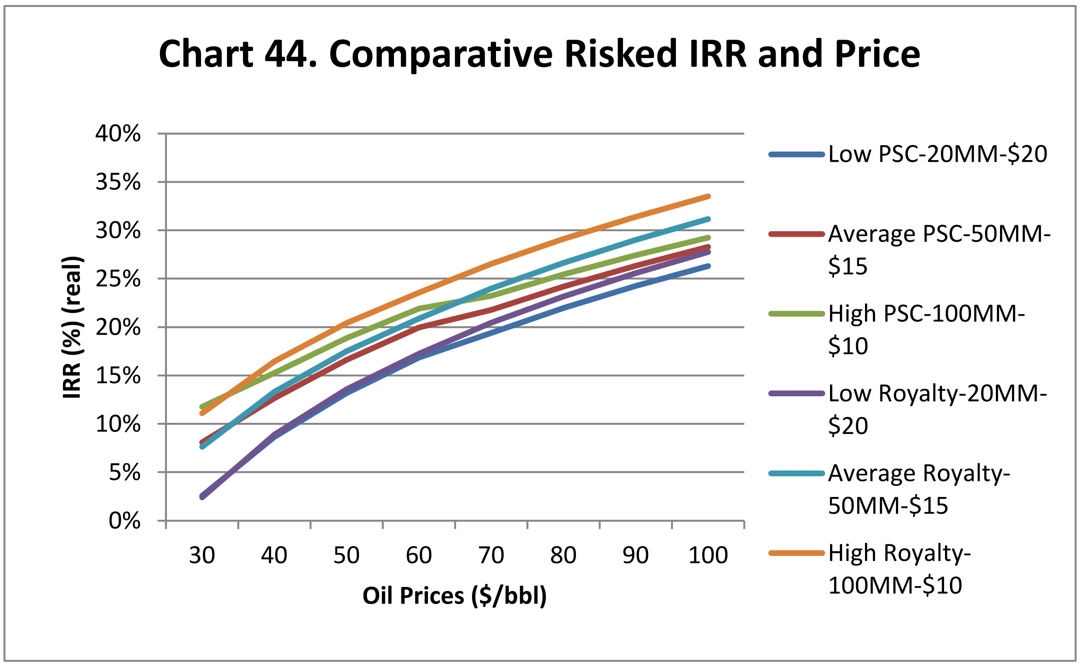
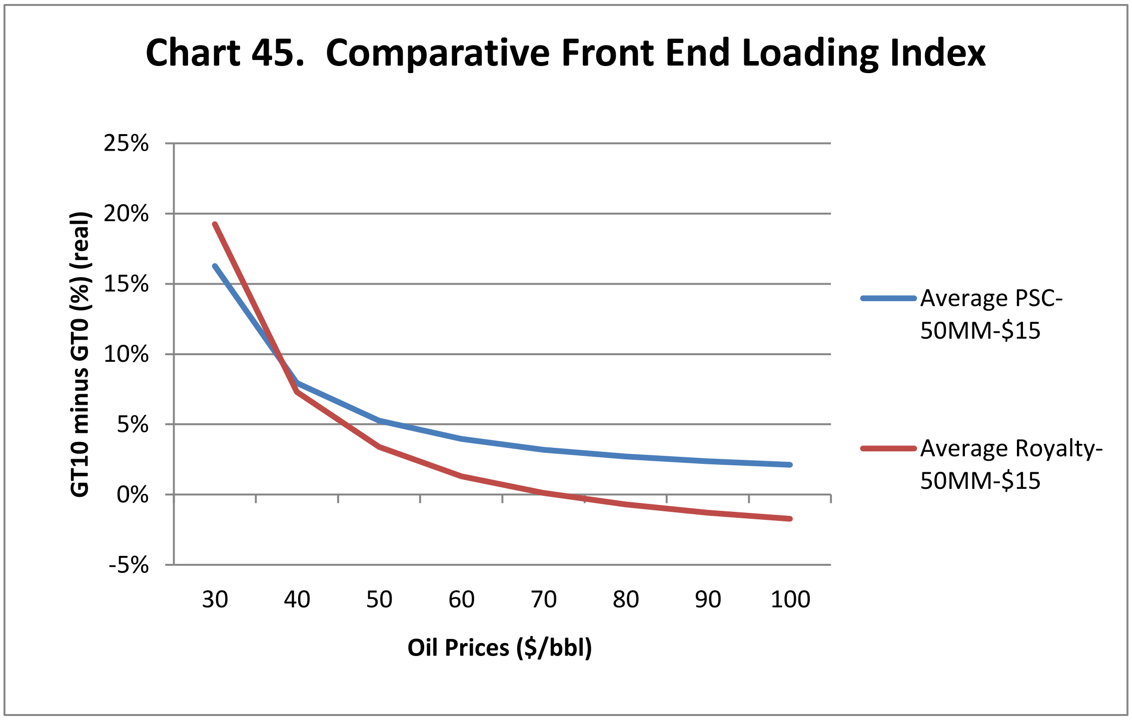


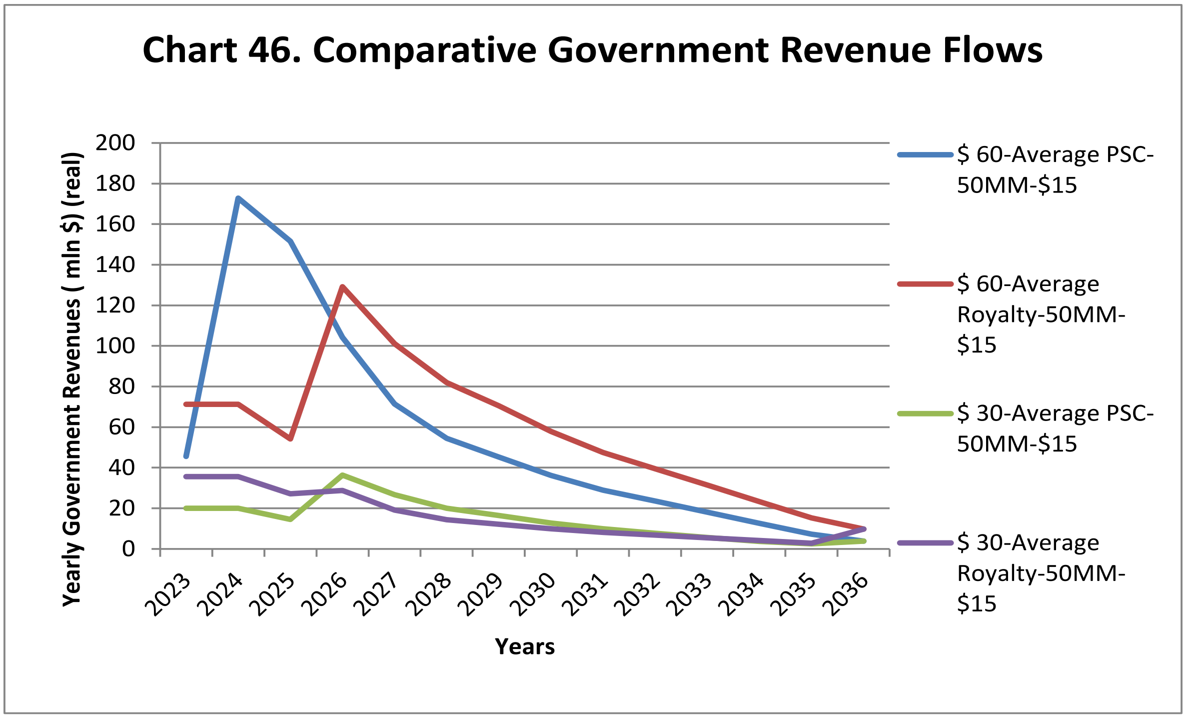
Chart 44 indicates how under high prices, Four Component Royalties with a holiday are more profitable than Four Component Production Sharing with a high initial cost limit. The reason is that Four Component Royalties are less front end loaded under higher prices as can be seen in Chart 45.

In fact it is remarkable that the royalty holiday creates actually a back end loaded system with a negative front end loading index under high prices. The inherent front end loaded nature of royalties can therefore be complete reversed with the holiday concept.

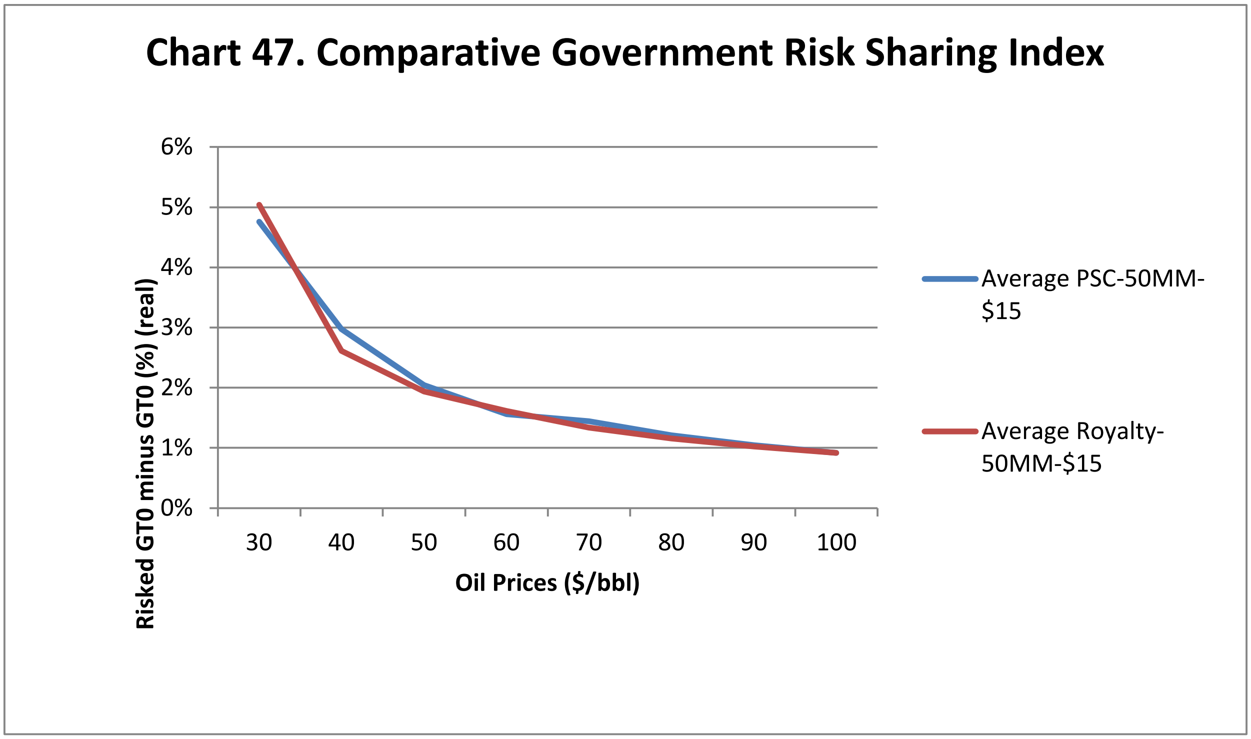




The reason is directly related to the shape of the government revenue flow as can be seen in Chart 46. Under high prices, the high cost limit does not provide as much assistance to investors as a royalty holiday. The reason is that costs are recovered quickly under high prices and this means that the payments to government increase regardless of the high cost limit. On the other hand, a royalty holiday is a guaranteed period of low payments to government. As can also be seen from Chart 46, at $ 30 per barrel the logic is reversed. In this case royalties are higher initially for the same overall government take as production sharing.



It can be seen from Chart 47 that the geological risk sharing on the part of government is the same for both systems, with respect to the first investment in the contract area. In both cases exploration costs can be deducted from consolidated taxable income under the same overall tax economics.



Conclusion. From the perspective of climate change and low oil prices, royalty based systems and production sharing systems could be equally effective. There is no reason to believe that production sharing will result in higher government revenues than royalties, as is sometimes argued. Both systems could be effective in supporting the petroleum industry under low oil prices and permit governments to establish a pivot point price below which the government supports the petroleum industry and above which the government recuperates the lost revenues.

Under both system a robust fiscal system can be developed that promotes cost efficiency and price effectiveness and provides for more alignment between governments and the petroleum industry than is currently the case in many fiscal systems with less front end loading and more geological and technical risk sharing.

The main difference is that production sharing can be designed in a way that is less cost regressive. However, royalties provide more secure income for governments and are easier to administer since cost control verification plays a less important role.

9. Consequences of Low Oil Price and Climate Change Policies

9.1 Petroleum Based Sovereign Wealth Funds

In providing more effective fiscal terms to deal with price volatility, governments will automatically assume a more difficult role in balancing the government budgets, since government petroleum revenues will be subject to wider swings. In this respect, what is the importance of sovereign wealth funds?

Sovereign Wealth Funds in the context of the petroleum industry are established for various reasons. These are:

1. To provide income to future generations from a "windfall" with respect to petroleum resources. The Alaska Permanent Fund is an example of this type. Alaska realized that the Prudhoe Bay fields would be a one-time event and that given the small population of Alaska, there would be considerable excess benefits for a limited period of time, which could be squandered. The Alaska Permanent Fund was established under the Alaska Constitution. This was its success, because strong safeguards for the fund are established and the fund pays dividends every year to all Alaskans from is excess profits. This fund has been extremely popular with the Alaska public ever since.
2. To protect the economy from the "Dutch Disease". This means overheating the economy due to large petroleum revenue generated inputs, which drive up the value of the currency and create inflation. Norway and in part Brazil have created a sovereign wealth fund for this reason. The Norwegian system has worked rather well.
3. To deal with "boom and bust" cycles. The fund is increased when oil prices are high and the fund is used when oil prices are low. This is typical for the funds established by Saudi Arabia, Kuwait, Qatar and the United Arab Emirates. The usefulness of these funds is dramatically demonstrated at this time for the Gulf countries.
4. To make regular contributions to the government budget. The Alberta Heritage Savings Trust Fund is primarily a fund which contributes to essential government programs from profits made from investments by the government.

As a result of the proposed policies in this paper, governments of major oil and gas producing countries should increasingly pay more attention to the creation of effective sovereign wealth funds.

9.2 Diversification

Given the fact that during the next two generations a start needs to be made for the phase out of oil and gas production for energy on a worldwide basis, it is absolutely imperative that large petroleum producing jurisdictions follow policies to promote diversification.

Basically there are three different types of diversification in this respect:

1. The promotion of industries that produce non-energy products from oil and gas,
2. The promotion of Climate Change industries, and
3. The promotion of any other activities not related to oil and gas.

Promotion of Non-Energy Products. The climate change policies do not require the reduction of petroleum production for the purpose of non-fossil fuel industries. Production of petro-chemical products and fertilizers will continue to expand over the coming decades, not restricted by climate change objectives. Large petroleum producing jurisdictions should implement policies to maintain oil and gas production for the purpose of creating non-fossil fuel industries. Natural gas could be used as feedstock to produce ammonia, methanol, petrochemical products, etc. Crude oil can be used to produce asphalt and after refining also lubricating oils, paint thinners and other chemical products.

Many natural gas producing jurisdictions are already actively promoting the use of natural gas for the production of non-energy products. Trinidad and Tobago, for instance, has been unusually successful in achieving this objective and is one of the main ammonia suppliers of the United States. In fact, due to dwindling gas reserves Trinidad and Tobago is now trying to re-direct their policies back to using gas primarily for energy purposes. However, other jurisdictions with very large gas and low cost gas resources, such as Saudi Arabia, Qatar, Iran and Nigeria, have policies to increase the use of this gas for the production of non-energy products. Now the embargo on Iran is withdrawn, this will be a major new investment opportunity. Alberta has also a large petro-chemical industry based on natural gas.

Promotion of Climate Change industries. Firstly, there is the direct production of renewable energy. Newfoundland and Labrador and Alberta have suitable locations for wind energy and some of these sites are already being exploited. Dubai and Abu Dhabi are already promoting large scale solar power for electricity generation. Norway intends to expand the use of its hydropower resources. There is a large range of renewable resource projects that can be undertaken in major oil and gas producing countries. Such industries could be expanded under suitable carbon taxes and with improved technology.

All oil and gas producing countries would have a competitive advantage in pursuing the combination of carbon capture and injection of CO2 in depleted petroleum reservoirs in order to remove CO2 emissions.

An Alberta company called Carbon Engineering is building in Squamish, BC an innovative plant whereby CO2 is directly sucked from the atmosphere to produce fossil fuels based on already known technologies. Further R&D and improvements in this process could result in significant opportunities.

If hydrogen becomes an important fuel in the future, the production of hydrogen would become a major industry. Coal and oil and gas resources can be used to produce hydrogen.

Further research and development is essential if oil and gas producing nations want to benefit from these types of industries.

Promotion of other industries. There is, of course, a limitless range of opportunities for other industries. The low oil prices and climate change policies are a wake-up call to start taking diversification seriously. Oman is promoting tourism. The Prime Minister or Norway recently stated that Norway has to look again at the fisheries industries; a 4.5 kg salmon once packaged and processed is worth more than a barrel of oil.

9.3 Value Added

As indicated, even under the Success Scenario, still very large investments have to be made in oil and gas development and production. In this context oil and gas producing nations could benefit from these resources to produce value added industries. Creating such value added industries will make the economy less dependent on the direct government revenues from oil and gas production.

In addition to promoting the production of non-energy products as discussed above, there are two main policies in this respect:

1. The promotion of midstream petroleum activities, such as upgrading, refining, gas processing, sulfur removal, LNG production, etc, and
2. The promotion of large scale energy use.

Promoting midstream activities. Many petroleum producing jurisdictions have policies to promote midstream activities. In many cases this is done through direct investment by state companies. Saudi Arabia has created large refining operations. Pemex of Mexico, NNPC of Nigeria and PDVSA of Venezuela have this official policy, but have largely failed at this. These countries are importing petroleum products.

Nevertheless, effective policies largely based on private investments have been successful in many countries. Fiscal and regulatory support could be effective in promoting midstream activities.

Promotion of Large Scale Energy Use. Oil and gas producing countries have a price advantage, since petroleum can be sold prior to its transportation to world markets. This means the netback prices are lower than the market prices in other countries.

It is for this reason that many large petroleum producing countries can also promote large energy using industries, such as large scale agricultural or industrial operations, electricity production for exports and fresh water from sea water plants, cement production, iron and steel production, and food processing. Most large oil and gas producing countries have already established such policies.