CENTER FOR ENERGY ECONOMICS

Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin

Economics & Technology of the Crude Oil, Natural Gas and LNG Value Chains

November 29-30, 2007

McCombs School of Business: Energy Finance Program

Outline Day 1

- Introduction
  - Overview of energy value chains - oil and gas systems in overall context
  - Key issues impacting global energy and trade flows – National Petroleum Council Global Oil and Gas Study
  - National Oil Companies
  - Commodity vs physical markets
- Upstream issues
  - Trends - North America, worldwide
  - Identification of key risks, uncertainties
  - Upstream investment decision considerations
  - Heavy oil resource case study - technology and optimization

Outline Day 2

- Midstream/downstream commercialization
  - Trends - North America, worldwide (oil v gas)
  - Pipeline economics and cost model
  - Refining economics and issues
  - LNG value chain
  - Gas and power business models
- Conclusions
  - Business integration models and asset/enterprise valuation

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The Link Between Energy Value Chain Economics, Finance and Frameworks

Upstream Oil and Gas

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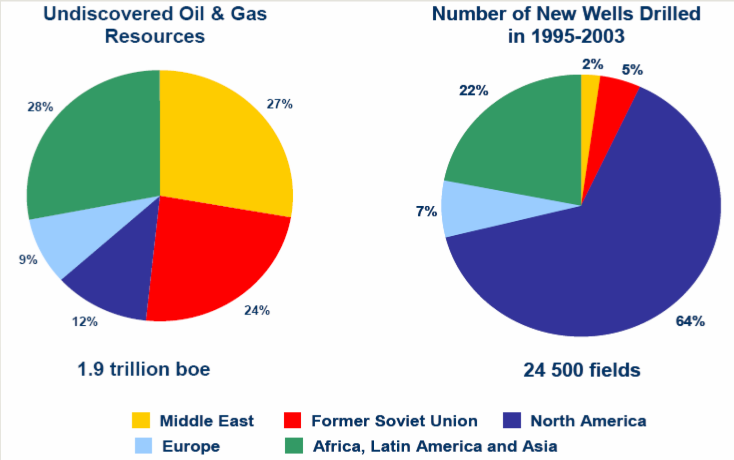
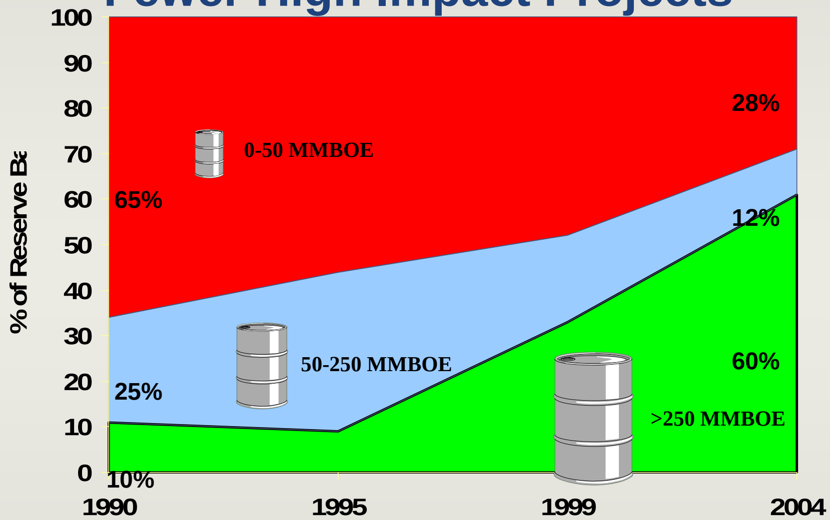
Global E&P Activity



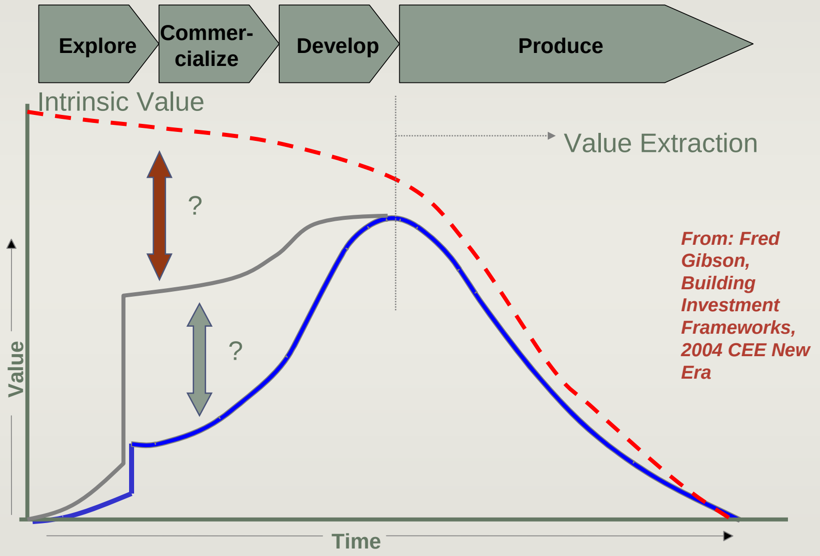
Source: World Energy Outlook 2004, International Energy Agency

Change in Strategic Focus: Fewer High Impact Projects



From: Fred Gibson, Building Investment Frameworks, 2004 CEE New Era

Where is Value Created?



Upstream Evaluation is Complex

- The inability to determine with certainty the geological characteristics of a project area ➔ probability analysis.
- Political factors have significant bearing on the outcome.
- A considerable amount of data needs to be collected and analyzed.

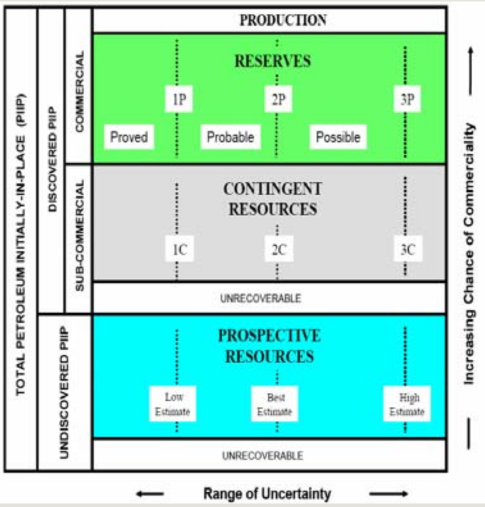
Exploration Costs

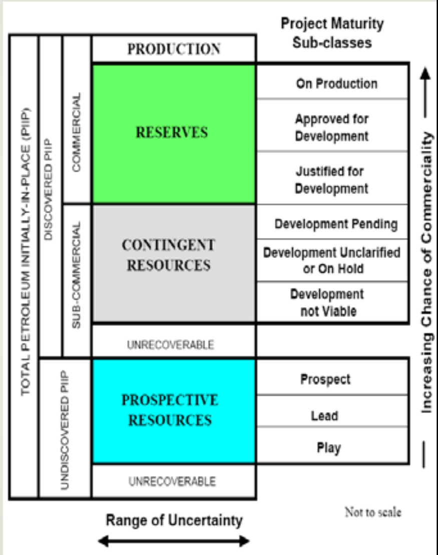
- Topographical, geographical and geophysical (G&G) studies, rights of access to properties to conduct these studies and salaries and other expenses of people involved in these studies.
- Costs of carrying and retaining undeveloped properties, such as rentals, taxes, legal costs and maintenance of the land and lease records.
- Dry hole contributions and bottom hole contributions.
- Costs of drilling and equipping exploratory wells.
- Costs of drilling exploratory-type stratigraphic test wells.

Additional Data Needed Before Commerciality

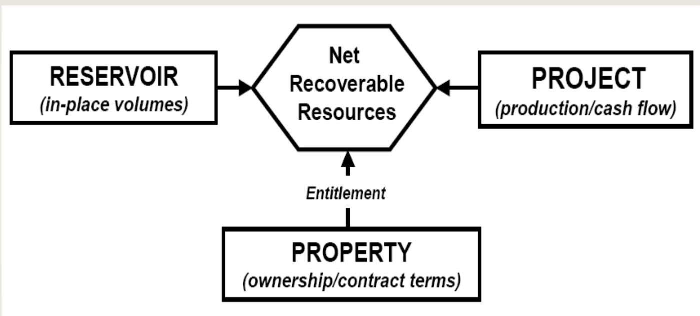
- initial reservoir pressure and temperature,
- formation properties,
- fluid properties,
- short-term flow tests to estimate the potential rate and reservoir extent,
- geological sample data and depth reference points for modification of pre-drilling data.

Hydrocarbon Classification Framework





Resource Evaluation



Reserves are just an estimate

- If reservoir conditions are good, estimate will be more likely to be real:
  - If the pressure in the formation is higher than the pressure in the well, it will push the oil and gas up the well bores.
  - An aquifer, which expands in size as production continues, will act as a piston and push the fluids up.
  - A gas cap, which expands as production continues can push the oil out of the pores toward the well.
  - If the reservoir has enough vertical permeability, gas rises and oil falls because of density differences. This separation of oil and gas enhances oil recovery.

Reserves are just an estimate, II

- If reservoir conditions are bad, estimate will be less likely to be real (and more expensive to prove):
  - Significant capillary forces in tight sections of the formation, where permeability and porosity are low, reduce the flow of oil and gas.
  - Low permeability and porosity mean that the rock is tight and cannot produce at commercial rates.
  - Limitedness of the area of flow around the well bore can also lower the rate of production.
  - If oil is high in viscosity, it will not flow as easily.
  - The farther oil needs to flow to reach the well, that is, the deeper the objective, the greater will be the resistance to flow.

Enhanced Recovery May Be Needed

- Water flooding (secondary recovery) - injection of water under pressure to maintain pressure.
- Tertiary recovery – injection of chemical solutions (detergents), carbon dioxide or other substances.
- Associated gas produced along with oil may be reinjected into the reservoir.
- A steam flood may reduce viscosity and hence increase the rate of flow.
- Part of the oil can be burned in the reservoir to lower viscosity and help produce the rest of oil.
- “Fracing” involves pumping fluids into the producing zones under extremely high pressures in order to increase, widen and connect the naturally occurring fracture system.

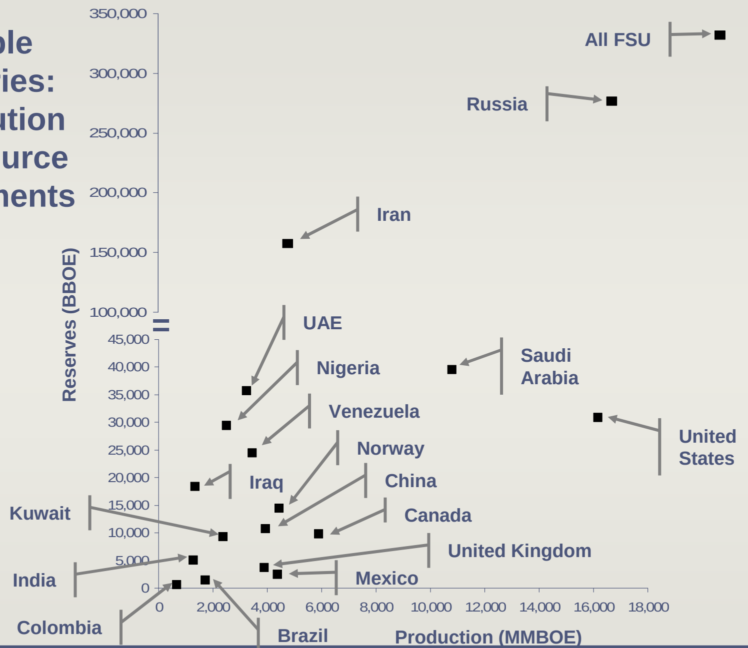
Enhanced Recovery is not free

- The decision to employ these methods depends on the expected increase in production rate.
- It is difficult to accurately estimate enhanced recovery performance of each method.
- The success of each method changes from field to field.
- A careful evaluation of options in each individual situation is necessary.

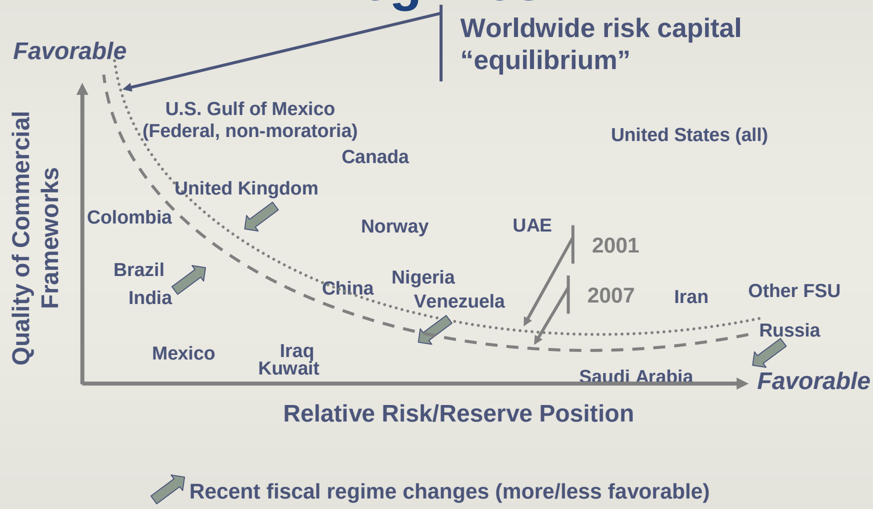
International Upstream Investment

- The financial issue of how costs are recovered and profits divided.
- Division of profits is commonly referred as contractor take and government take.
- The objective of a host government is to maximize wealth from its natural resources by encouraging appropriate levels of exploration and development activity by private companies ➔ governments must design fiscal systems.

Sample Countries: Distribution of Resource Endowments



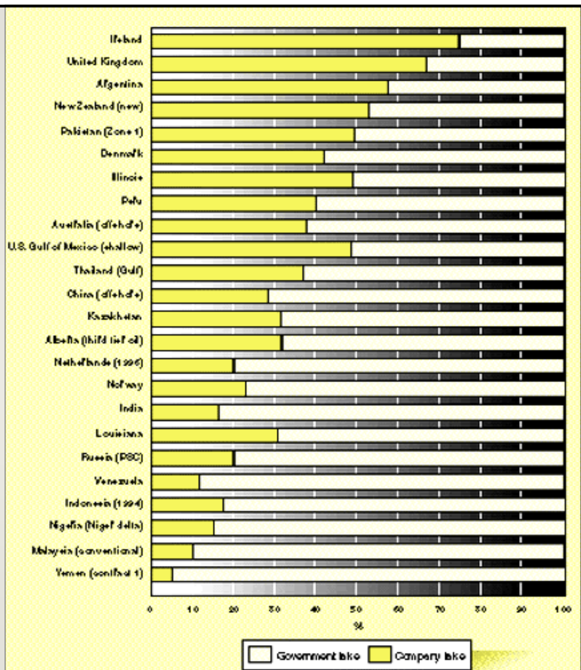
Sample Countries: Upstream Regimes



*Source: Foss, 2005. *Approximations, only. Based on Foss, et.al., 1998.*

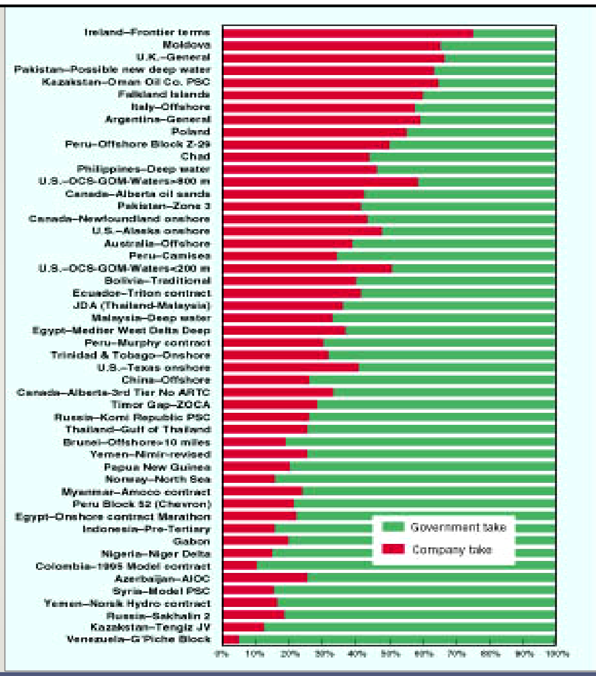
How 24 Fiscal Systems Compare

Source: Governments cut takes to compete as world acreage demand falls, Oil & Gas Journal, April 24, 1995 by Pedro Van Meurs.



Undiscounted Government Take in 50 Selected Fiscal Systems

Source: Government takes decline as nations diversify terms to attract investment, Oil & Gas Journal, May 26, 1997 by Pedro Van Meurs.



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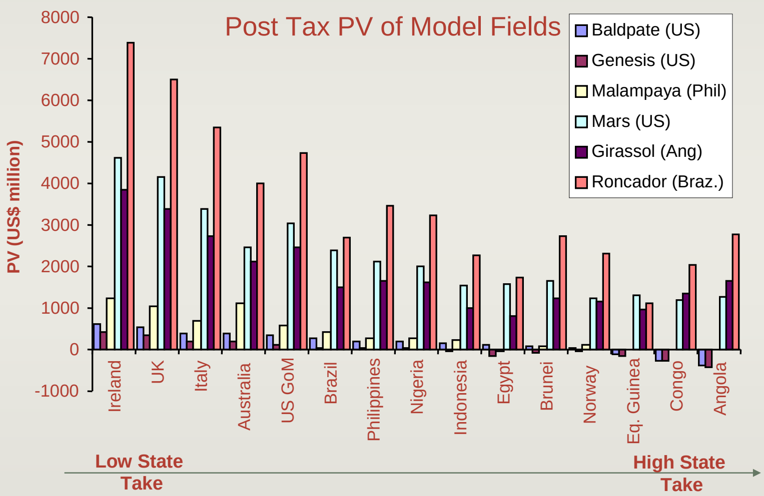
Value of Specific Deepwater Fields Under Various Fiscal Country Models



Source: Wood MacKenzie Global Deepwater Markets November 2000

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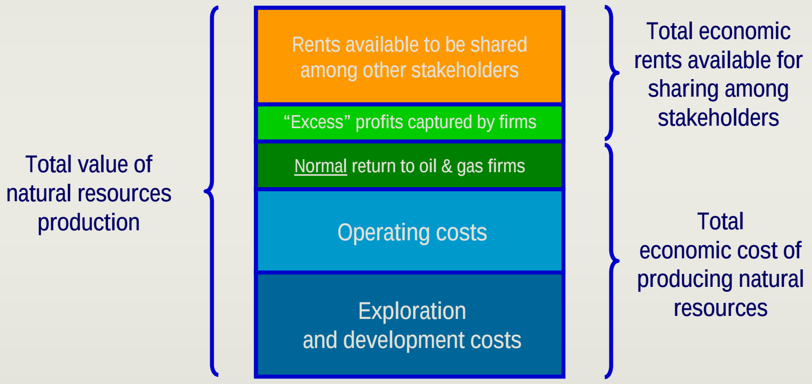
Oil & gas often generates substantial economic rents…because value often greatly exceeds cost of production



From: Paul Boothe, Fiscal Instruments in Oil & Gas Regimes, UN Workshop on Oil & Gas in Iraq, 2006

Oil & gas rents flow to many different stakeholders…in a wide variety of ways

To the owners of the resource

- Royalties
- Equity stakes
- Production sharing
- Sale / auction of exploration, development and production rights
- Black market sales / smuggling

To governments

- Taxes on production from privately owned oil & gas
- Revenues devolved/shared by other levels of government
- Export taxes
- "Excess profit" taxes
- Specific targeting of resource sector by corporate, property, sales or other general taxes
- Sale/auction of pollution permits
- Carbon tax

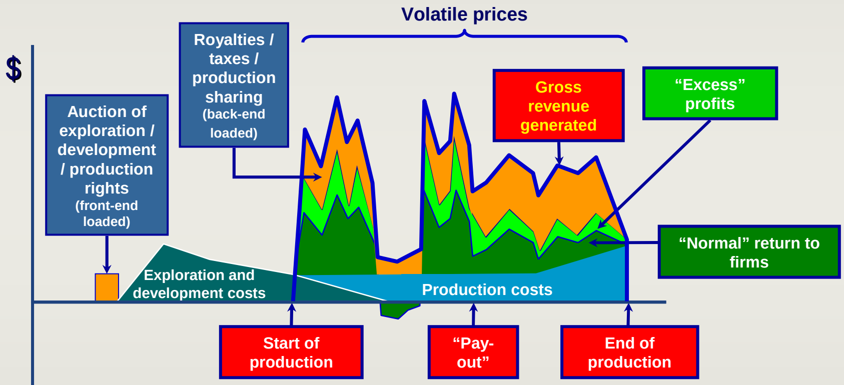
To private citizens

- Above-average wage rates or corporate profits in resource sector
- Subsidized prices for end use of oil & gas (e.g. as fuel) by residents
- Theft / black market sales
- Graft and corruption of public officials (regulatory officials, managers of state assets, etc.)

From: Paul Boothe, Fiscal Instruments in Oil & Gas Regimes, UN Workshop on Oil & Gas in Iraq, 2006

Combinations of fiscal instruments work best

Illustration of “front-end” bids and “back-end” royalties/taxes



From: Paul Boothe, Fiscal Instruments in Oil & Gas Regimes, UN Workshop on Oil & Gas in Iraq, 2006

Combinations of fiscal instruments work best

	Argentina	Australia	Brazil	Canada	Indonesia	Malaysia	Mexico	Nigeria	Norway	Russia	Saudi Arabia	UAE	USA	Venezuela
Profits from state / SOC oil & gas production			+ + +		+ + ?	+ + ?	+ + +	+ + ?	+ + +	+ + ?	+ + +			+ + +
State / SOC equity stakes (e.g. joint ventures)	?	?	+	+	?	+ + ?		+ + ?	+ +	?	+	+ + +		+
Royalties / production sharing (pre-“payout”)	?	+ ?	?	+	+ ?	?		+ ?	?	?			+ ?	?
Royalties / production sharing (post-“payout”)	?	+ + + ?	?	+ + +	+ + + ?	?		+ + + ?	?	?			+ + + ?	?
Price-sensitive royalties / production shares	?	?	?	+ + ?	?	?		?	?	?			+ + ?	?
Sale / auction of rights (at front-end)	?	+ + ?	+	+ +	?	?		?	?	?			+ + ?	?
Service contracts for exploration / development	?	?			?	?	+ ?	+ ?	?	?				+
Oil & gas-specific taxes	?	?	+ ?		?	?		?	+ +	?			?	+
General taxes (including “excess profits taxes”)	?	?	?	+ ?	?	?		?	?	?			+ + ?	?

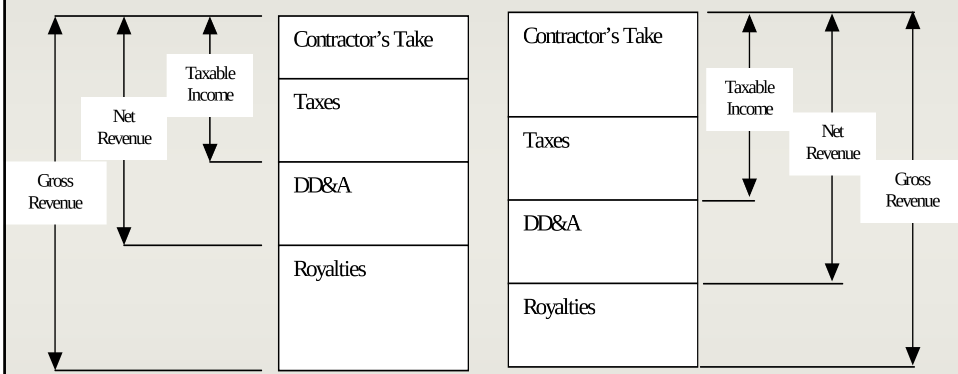
Contribution to revenues:
+ Minor
++ Major
+++ Dominant

From: Paul Boothe, Fiscal Instruments in Oil & Gas Regimes, UN Workshop on Oil & Gas in Iraq, 2006

Types of Fiscal Systems

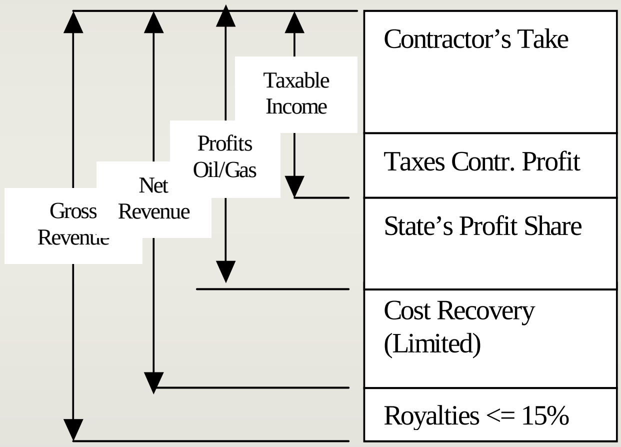
- Petroleum Fiscal Arrangement
  - Concessionary Systems
  - Contractual Systems
    - Production Sharing Contract PSC
    - Service Contracts SC

Concessions



Royalties are the first, and usually the major, take for a government

Production Sharing Contracts



Basic Features of PSCs

- Title of hydrocarbons remains with the state.
- State maintains management control and contractor is responsible for execution of petroleum operations according to contract.
- Contractor is required to submit annual work programs and budgets for scrutiny and approval of a state institution, usually the national company.
- The contract is based on production sharing and not profit-sharing basis.

Basic Features of PSCs (cont'd)

- Contractor provides all financing and technology required for operations and bears the risks.
- During contract term, after allowance for up to a specified % of annual production for recovery of costs, remaining production is split between contractor and state.
- Equipment purchased and imported by contractor become property of the state. Service company equipment and leased equipment are exempt.

PSC Structure

	National Legislation	*Contract Negotiation*
Operational Aspects	Government participation Ownership transfer Arbitration Insurance	Work commitment Relinquishment Commerciality
Revenue or Production Sharing Elements	Royalties Taxation Depreciation rates Investment credits Domestic obligation Ringfencing	Bonus payments Cost recovery limits Production sharing

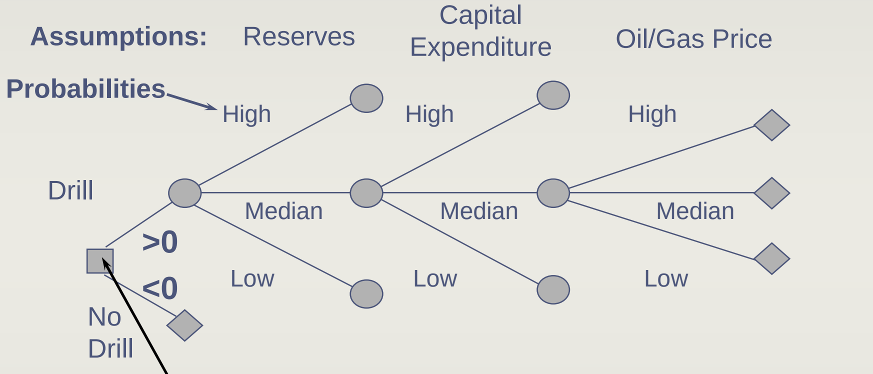
An Oil PSC Model

- Cash Flow = Net Revenues – Intangible Expenses – Tangible Expenses – O&M Expenses – Bonuses – Total Profit Oil + Contractor's Profit Oil – Income Tax

Evaluation Criteria

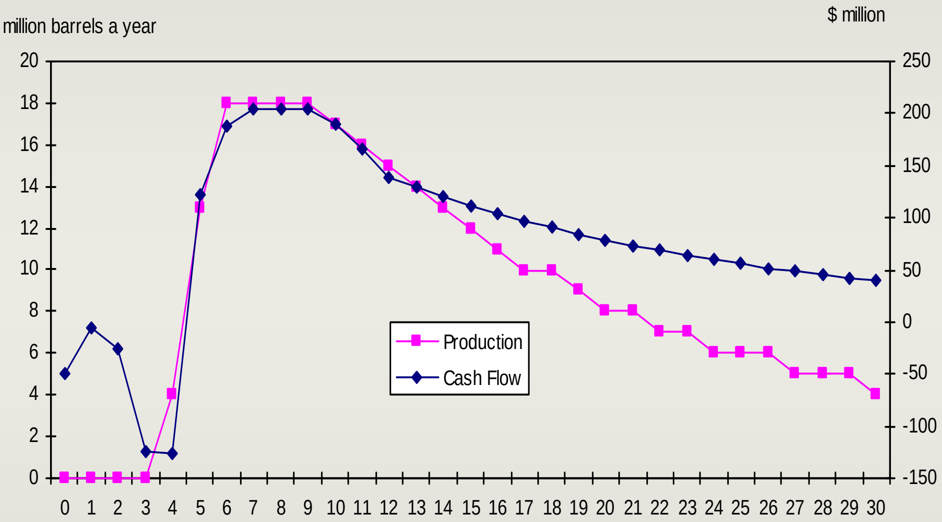
- NPV
- IRR
- PWP - the time it takes to recover an investment in terms of present value dollars.
- PWI - the ratio of the present value of cash inflows to the present value of the cash outflows.

A Simple Decision Analysis Framework



At the "decision node," if the expected NPV>0 at the required discount rate, then the choice is to drill. The ENPV is the sum of the probabilities times the values for all branches of the tree.

Oil PSC Production & Cash Flow

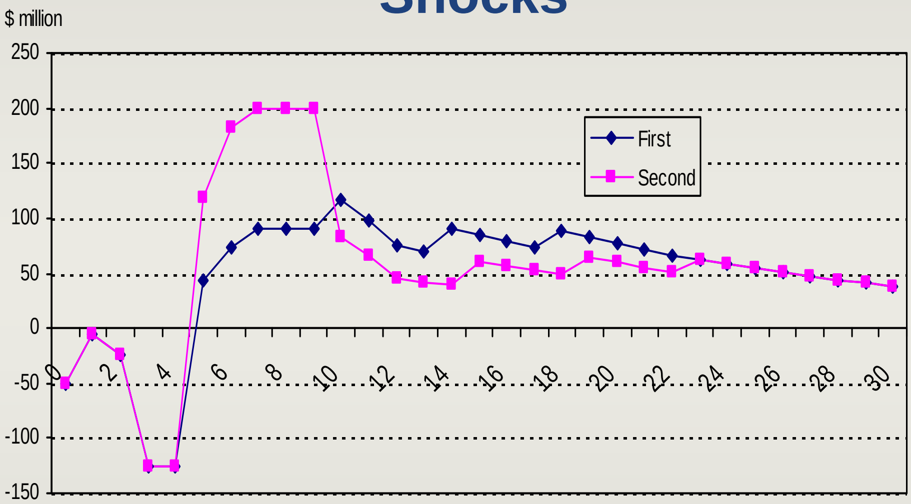


Oil PSC Model Results

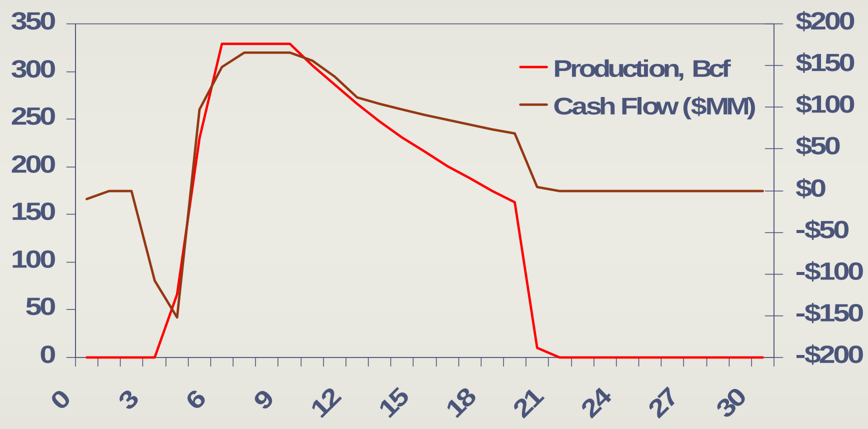
Reserves (mmbbls)	319
O&M cost ($/bbl)	2.00
Fiscal Terms:	
Royalty	12.5%
Signing Bonus (millions USD)	$50
Contractor profit share	65%
Cost recovery limit (usually 80-100%)	80%
Income Tax	30%
Oil Price (bbl)	$25.00
Discount Rate	10%
Production Profile:	
No of producing wells	25
Plateau rate (bbls/day)	50,000
Annual plateau production (mmbbls)	18.3
Project Life	30
Decline rate (3% to 7%)	7%

NPV @	10%	596
NPV @	5%	1,147
NPV @	12%	463
NPV @	15%	317
IRR		32.25%
Total negative cash flow		(331)
Total Investment		365
Profit to Investment Ratio PIR		6.49
Discounted PIR		1.47
Payout time (in years)		8
Investment Efficiency		2.33

Scenario Analysis – Oil PSC, Price Shocks



Gas PSC Model



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Gas PSC Model Results

Reserves (bcf)	3,900
O&M cost ($/mscf)	0.10
Fiscal Terms:	
Royalty	10.0%
Signing Bonus (millions USD)	$10
Contractor profit share	75%
Cost recovery limit (usually 80-100%)	80%
Income Tax	30%
Gas Price ($/MMbtu)	$1.00
Discount Rate	10.00%
Production Profile:	
No of producing wells	18
Plateau rate (mmscfd)	900,000
Annual plateau production (bcf)	328.5
Project Life	19
Decline rate (3% to 7%)	7%

NPV @	10.00%	461
NPV @	5%	812
NPV @	12%	369
NPV @	15%	265
IRR		39.26%
Total negative cash flow		(270)
Total Investment		298
Profit to Investment Ratio PIR		4.96
Discounted PIR		1.32
Payout time (in years)		8
Investment Efficiency		2.36

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Case Study: Extra-heavy oil resource

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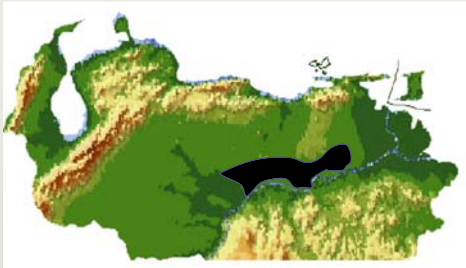
Outline

- Background
- Evolution of fiscal regime
- Fiscal Regimes
  – Royalty-Tax
    - Accelerated depreciation
  – Equity participation
- Uncertainty
- Final comment

The Faja

- The Faja is one of the largest oil deposits in the Western Hemisphere and is now economically viable, over 70 years after its discovery.
- Hydrocarbon ranges from 5 to 12 API and 125m to 1600m of depth.
- Why did production finally take off?



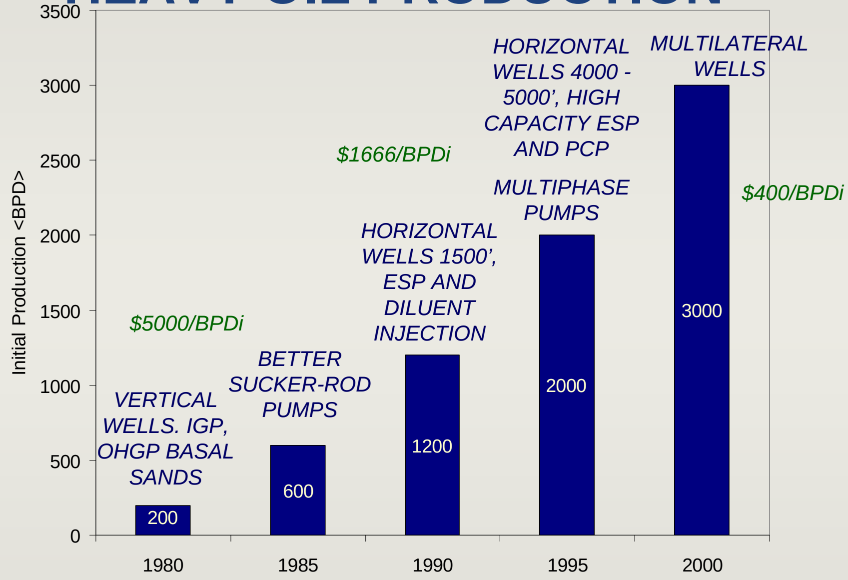
Development of Unconventional Resources

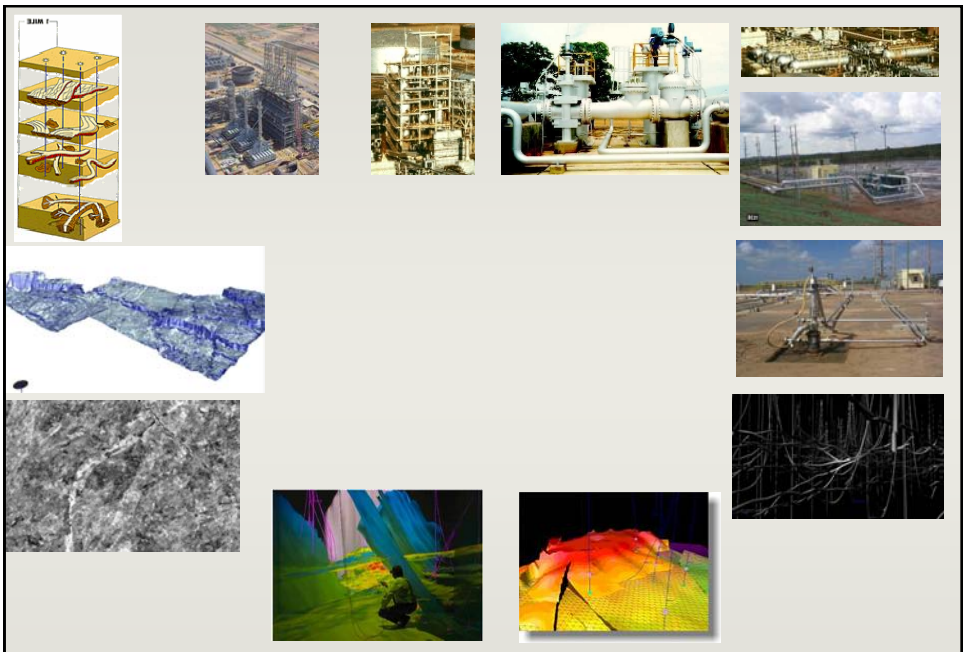
- Geostatistical and production uncertainty
  - Where should wells be located?
  - How much will wells cost to build?
  - How will they perform?
  - For how long?
  - How much oil? Gas? Water? Sand?
- And let us not forget
  - For how much will the oil be sold?
    - Historically blended with lighter crude oil.

Impact of Fiscal Regime

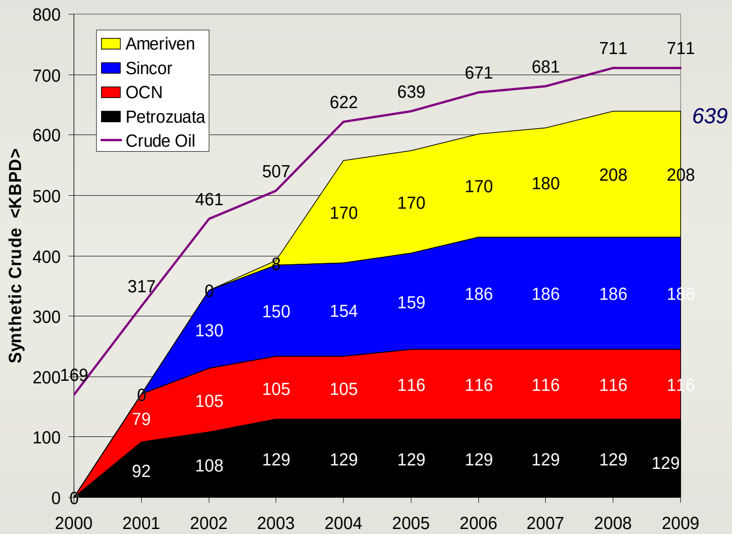
- 1976
  - Royalty Relief: No
  - Long run royalty: 16.67%
  - Taxes: 66.7%
  - Private participation: No
- 1990's
  - Royalty Relief: 1%
  - Long run royalty: 16.67%
  - Taxes: 34%
  - Private participation: 50%
- Price Level
  - $8-$20 per barrel

HEAVY OIL PRODUCTION

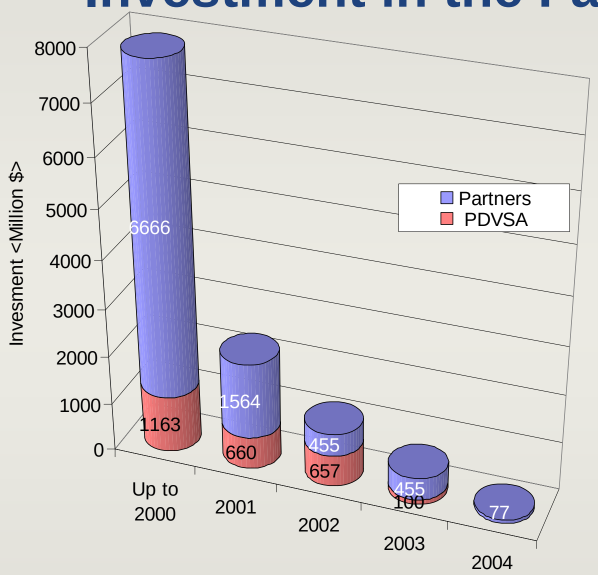




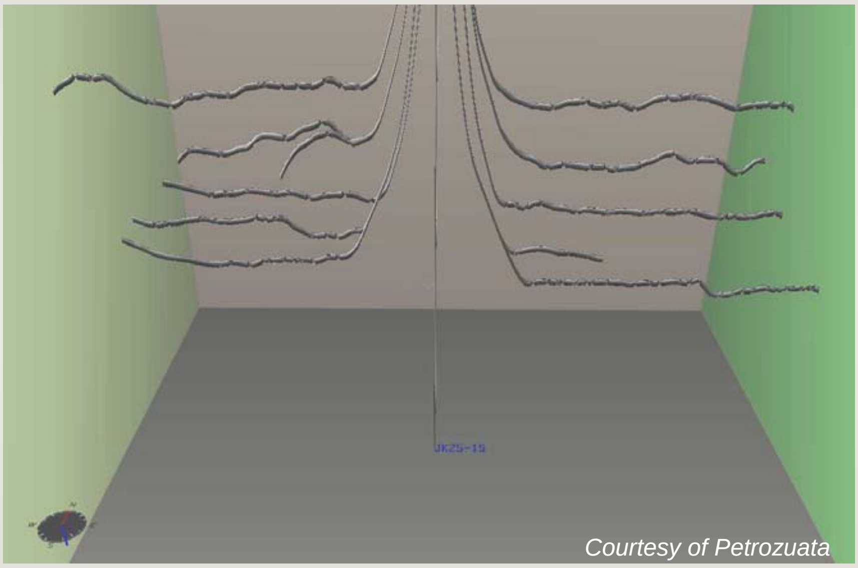
Original Production Plan of the Faja



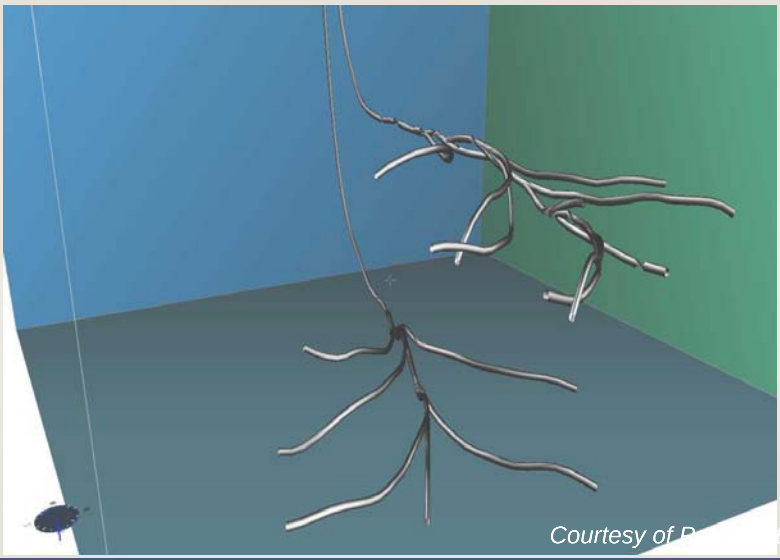
Investment in the Faja



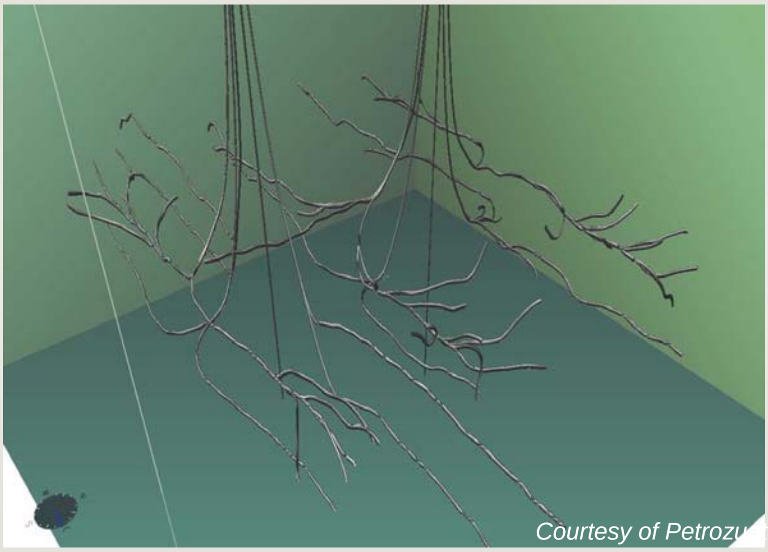
HORIZONTAL WELLS



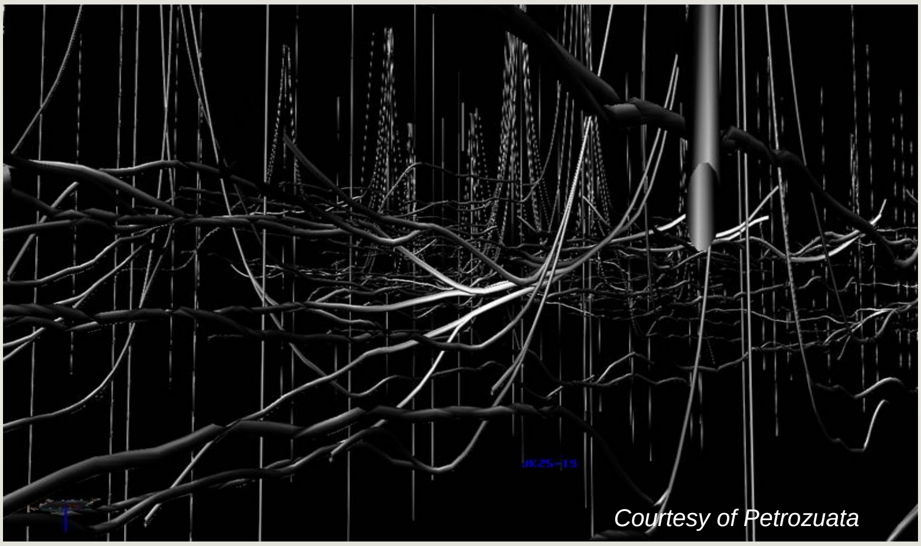
LATERAL FISHBONES



COMPLEX MULTILATERALS



WELLS OF PETROZUATA

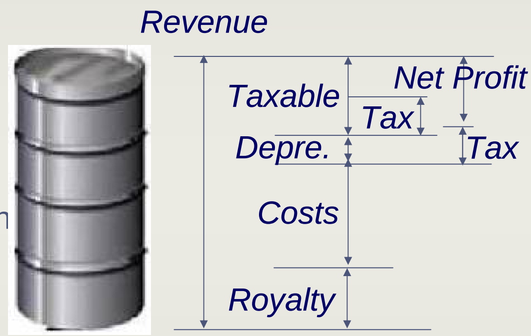


Focus on Petroleum Fiscal Regimes

- Tax royalty agreements
  - Joint Ventures
- Contractual
  - Production Sharing Agreements
    - All costs are usually covered by investor
    - Facilities and hydrocarbons are owned by the host government
    - Payment for service is through a portion of production
    - Cost recovery can be limited at a portion of the total revenue (possibility of carryover)
  - Service Contracts

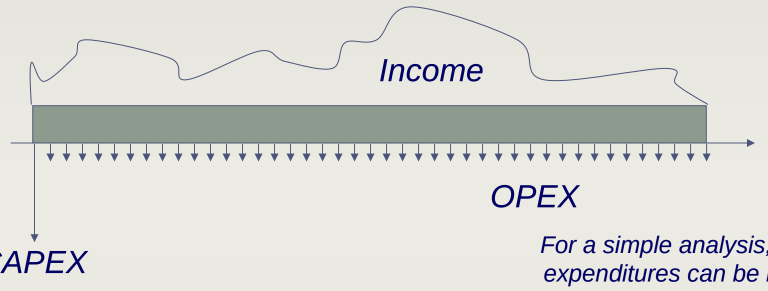
Tax – Royalty with depreciation schedule

- In the simple case
  - Company pays royalty
  - Company pays taxes on profits after considering depreciation



*Cash Flow=(Revenue – Royalty – OPEX – Dep.) * (1 - tax) + Dep.*

Simplified Discounted Cash Flow Model

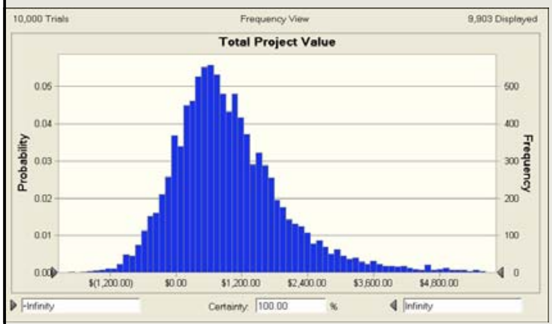


For a simple analysis, capital expenditures can be lumped at the beginning of the project period, operation expenditures are incurred as production comes online, and depending on prices, the income changes over time

Data Input

- Investment Data
- Operating Cost Data
- Price Data
- Years to the date for start of exports

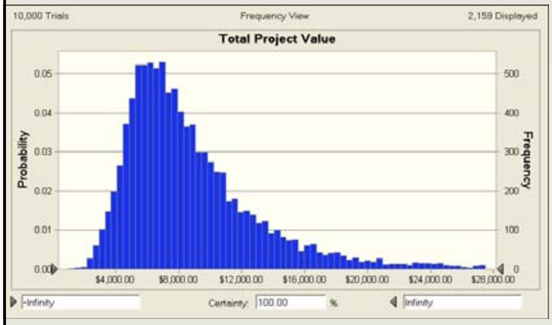
Expected Project Value 1998



P50 $815.12

Expected Project Value 1998

Expected Project Value 2006 (1998 $)

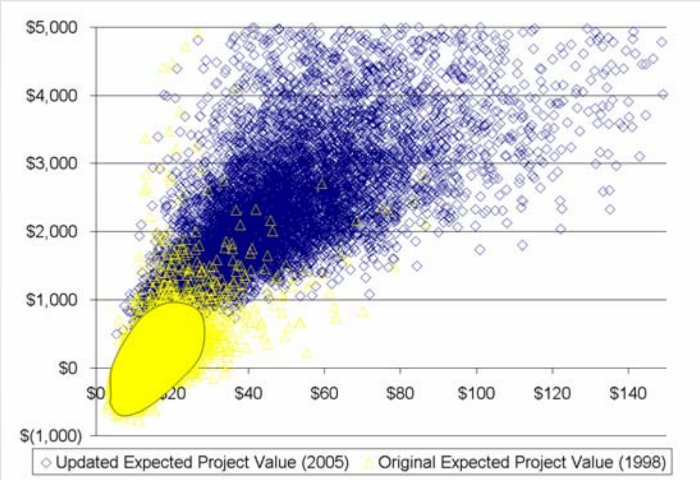


P50 $7,786.79

Considers price evolution between 1998 and 2006.

Expected Project Value 2006 (1998 $)

Expected Value in 1998 vs 2006



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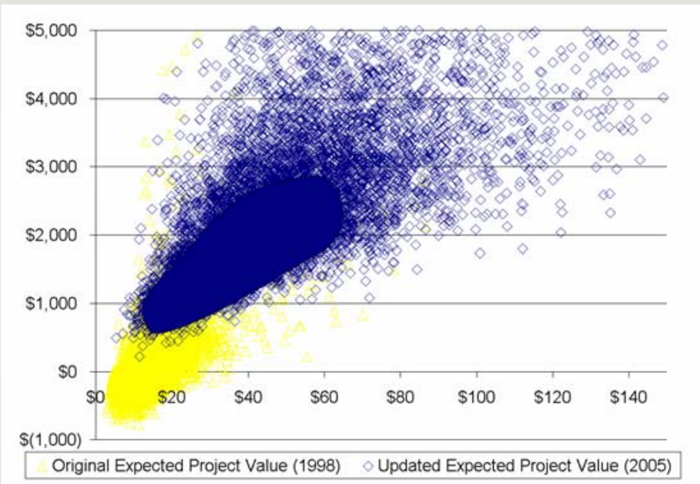

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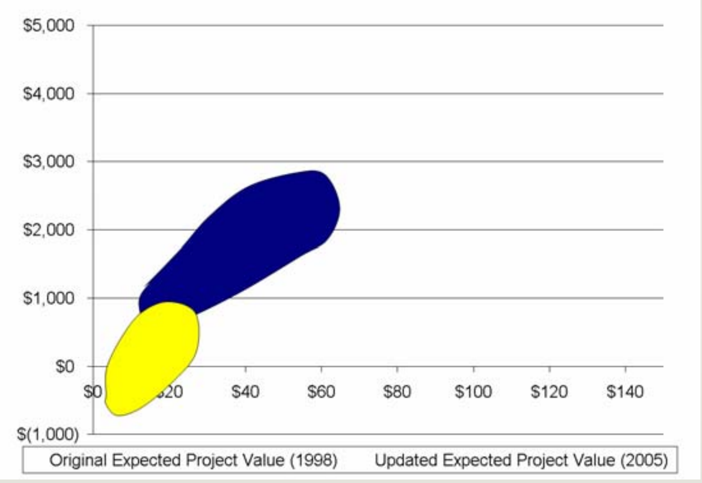
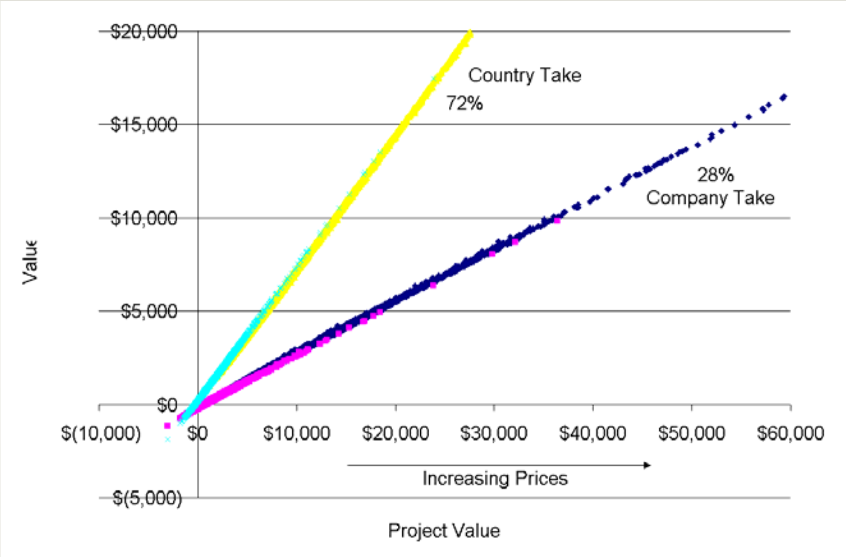
Expected Value in 1998 vs 2006



How was the value distributed?

- 1990's
  - Royalty Relief: 1%
  - Long run royalty: 16.67%
  - Taxes: 34%
  - Private participation: 50%

How was the value distributed?

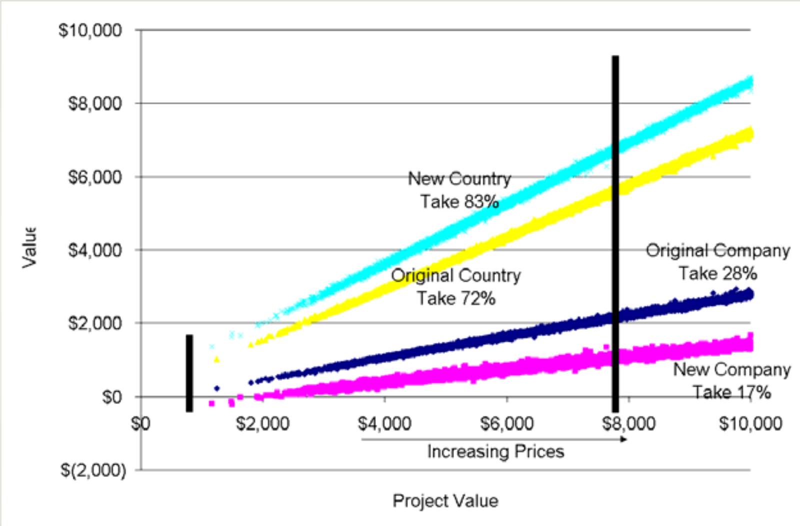


In 2006, the Government takes over

- 1990's
  - Royalty Relief: 1%
  - Long run royalty: 16.67%
  - Taxes: 34%
  - Private participation: 50%
- Price Level
  - $8 - $12 per barrel

- 2006
  - Royalty Relief: None
  - Royalty: 33%
  - Taxes: 50%
  - Private participation: 50%
- Price Level
  - $50-60 per barrel

How much value would a company lose?



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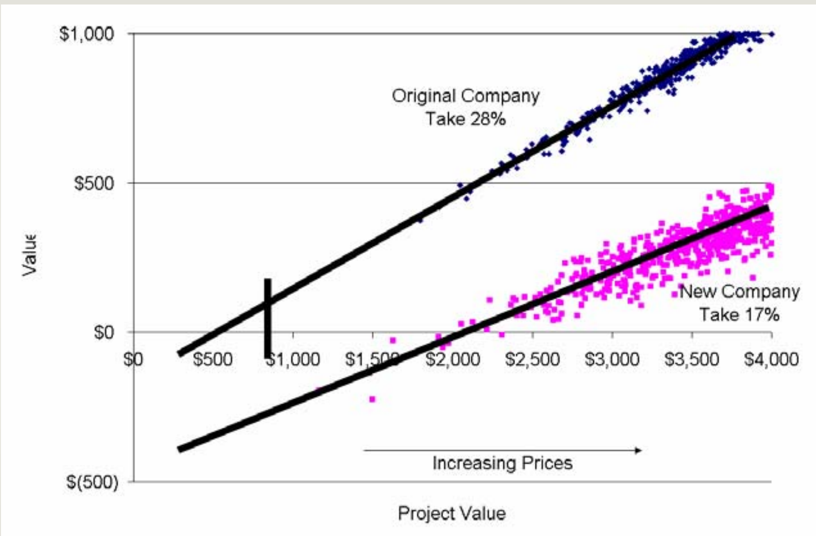
And what happens if prices go down?



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What is the status today?

- Incumbents did not add investments during transition of fiscal regime
- Two of the operating incumbents have been removed
- Add on investments still seem attractive
  - Lessons learned are in jeopardy of being lost
  - New operators versus Associations
- New projects will need market for Syncrude
  - Brasil will likely be the likely market for next project

Final Comments and Open Questions

- Technical uncertainty was resolved and initial projects demonstrated viability of the eastern Faja.
- The value of the Faja is mostly untapped and will likely not be tapped in the short term. And Alberta?
- Should royalty change once uncertainty is resolved? Low initial royalty and then one that captures extra rents? Wouldn't a corporate tax do the same?
- Production and upgrading, should they be taxed differently? Or are they effectively upstream?

