

Day 1: Results of World Rating of Oil and Gas Terms

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Presentation for Alaska Legislature

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Introductory Comment

The objective of Governor Parnell is to achieve a TAPS throughput of 1 million barrels per day.

Can this objective be achieved from State of Alaska resources? **Yes**

How?

This will be demonstrated during the coming two days.

World Rating of Oil and Gas Terms

The 2011 ratings of fiscal terms will cover 6 volumes.

Three volumes have been completed:

- **North American wells and shale plays**
- **Deep water and certain basins**
- **Arctic**

Three volumes still to be completed:

- **Shallow water and certain basins**
- **Onshore fields and shale plays**
- **Summary**

First results of shallow water oil already done.

Discussion of reports

In discussing the reports, emphasis is placed on the relevance of the reports for providing background for the development of Alaska oil and gas policies.

The results of the reports will be discussed in the following order:

1. Shallow water report (oil)
2. Arctic report (oil)
3. North American onshore report
4. Deep Water report
5. Arctic report (gas)

Session 1

Session 1 will concentrate on a comparative analysis of Alaska government take for light oil using the:

- **Shallow Water Oil results, and**
- **Arctic Oil results.**

Session 1

Shallow water results (oil)

The Shallow Water results for oil have been compiled. The survey deals with 124 countries and 191 fiscal terms. Alaska terms are featured for the Cook Inlet. It is assumed that for this area general terms will be applicable from 2022 onwards.

The Shallow Water report permits the most detailed comparative analysis of the relative position of Alaska due to the large number of fiscal systems involved.

Session 1

Base Case Field

The Base Case for Oil used for rating has the following characteristics:

- 100 million barrels cumulative production
- Maximum production 51,100 bopd
- Field life – 17 years
- \$ 20 per barrel costs (\$ 15 capital expenditures, \$ 5 operating expenditures)
- Oil price - \$ 80 per barrel

Shallow water exporters (Oil)

Rating of Alaska in terms of investor favorability out of 191 fiscal systems:

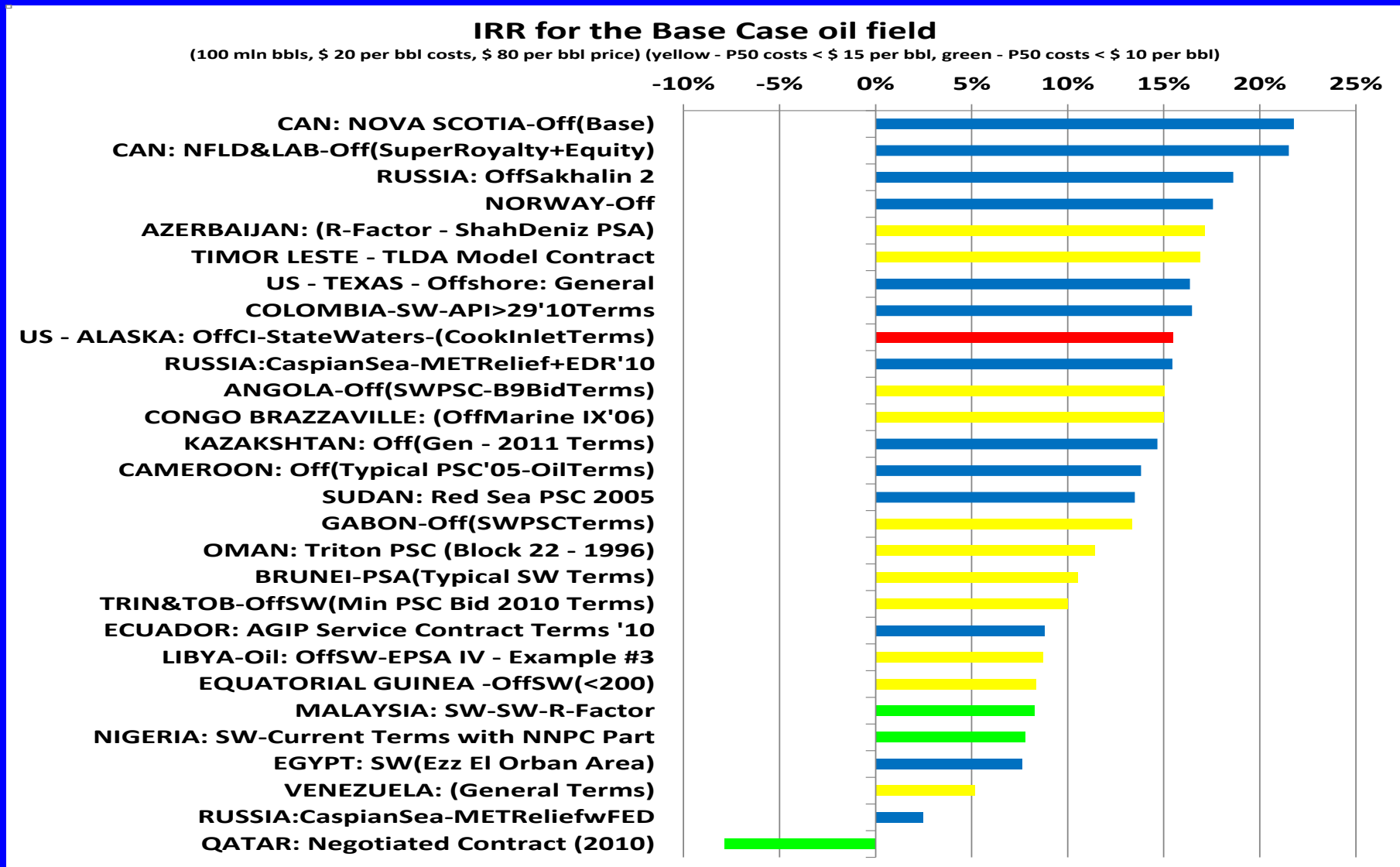
- 129 – rate of return
- 128 – net present value discounted at 10%
- 130 - undiscounted government take
- 128 – 10% discounted government take

Session 1

Shallow water results (oil)

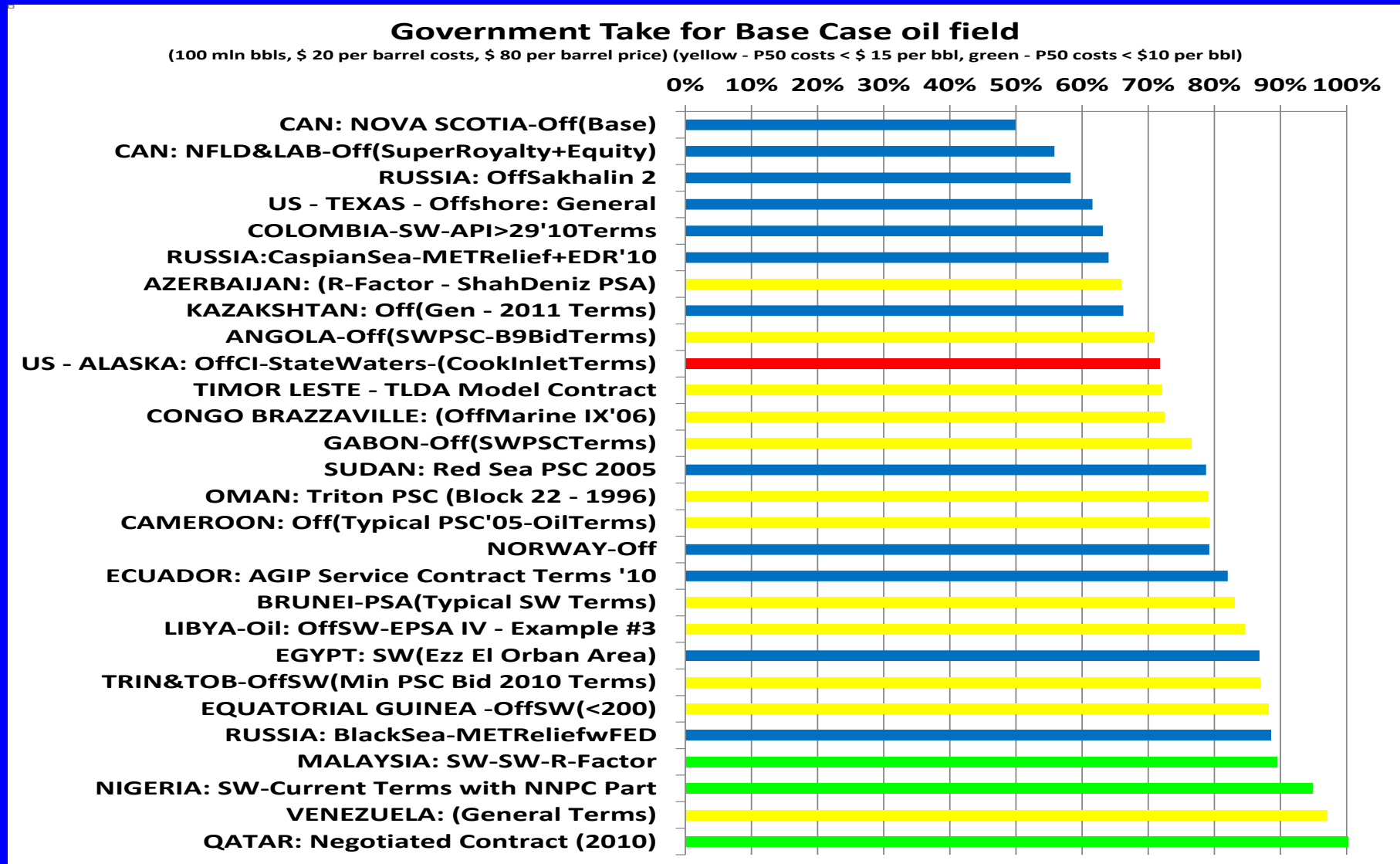
The Shallow Water results also permit a comparison with the largest “peer group”. The largest peer group for Alaska are the exporting jurisdictions. The following charts provide the results for a selection of 28 exporters of oil.

Shallow water exporters (Oil)



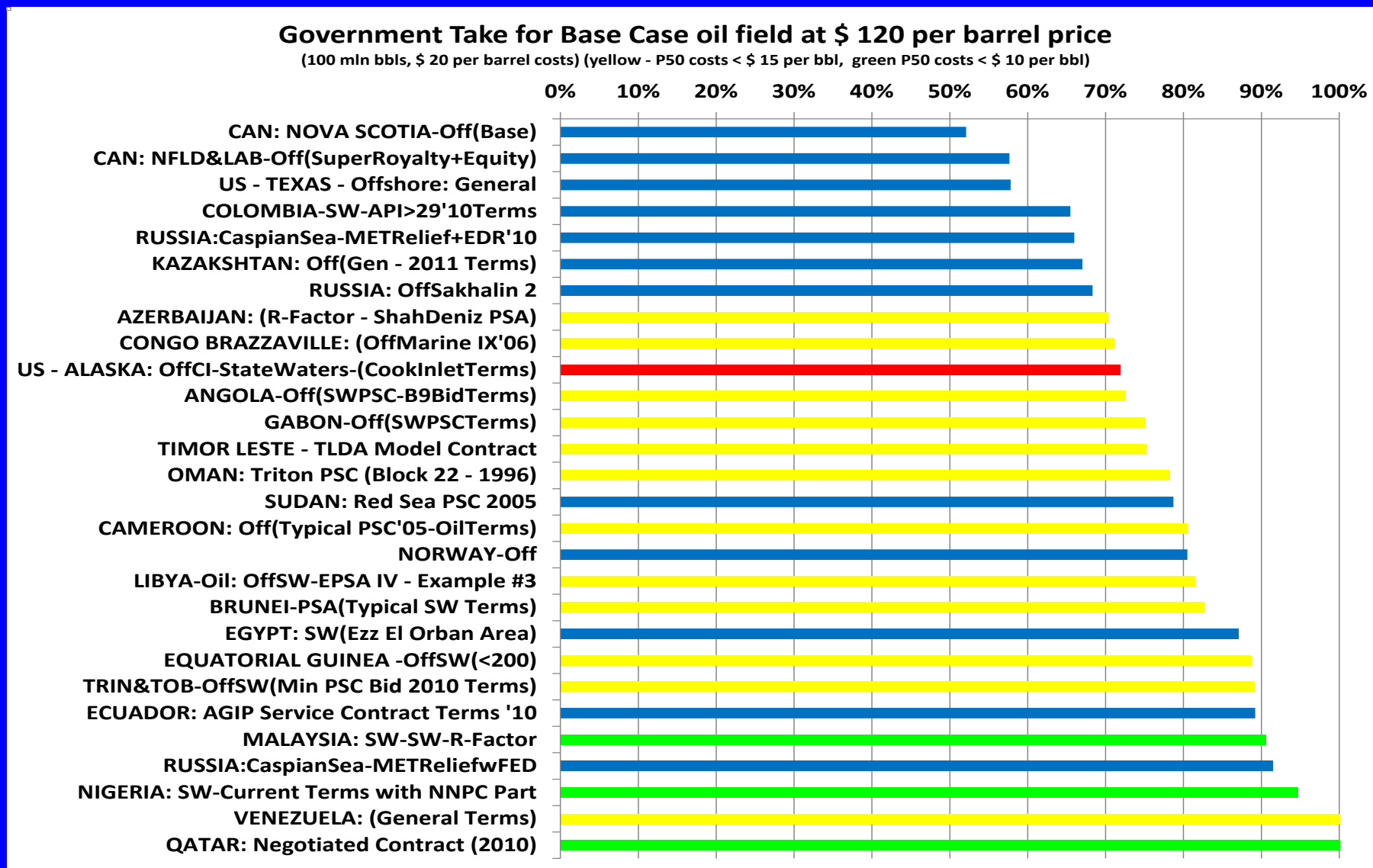
IRR: Alaska terms rate # 9 out of 28 exporters.

Shallow water exporters (Oil) - \$ 80



Undiscounted Government Take: Alaska terms rate # 10 out of 28 exporters.

Shallow water exporters (Oil) - \$ 120



Undiscounted Government Take at \$ 120 per barrel: Alaska terms also rate # 10 out of 28 exporters.

Shallow water results

The government take of Alaska in the \$ 80 to \$ 120 price range is lower than for the majority of the other exporters. However, most of these exporters would have lower costs than Alaska.

For existing operations it therefore appears that a government take of about 70% - 75% is reasonable, may be slightly on the high side.

Session 1

Arctic

The Arctic study deals with:

- **Arctic offshore and onshore oil fields (generic)**
- **Arctic offshore and onshore gas fields (generic)**

Both oil fields and gas fields are adjusted for net back pricing due to transportation. Gas fields also take differences in gas markets into account.

Arctic study contains comments on ACES and the House Bill proposals. These comments will be discussed on Wednesday. This session will concentrate on the Arctic framework.

The gas results will be discussed in session 4

Arctic onshore and offshore (Generic)

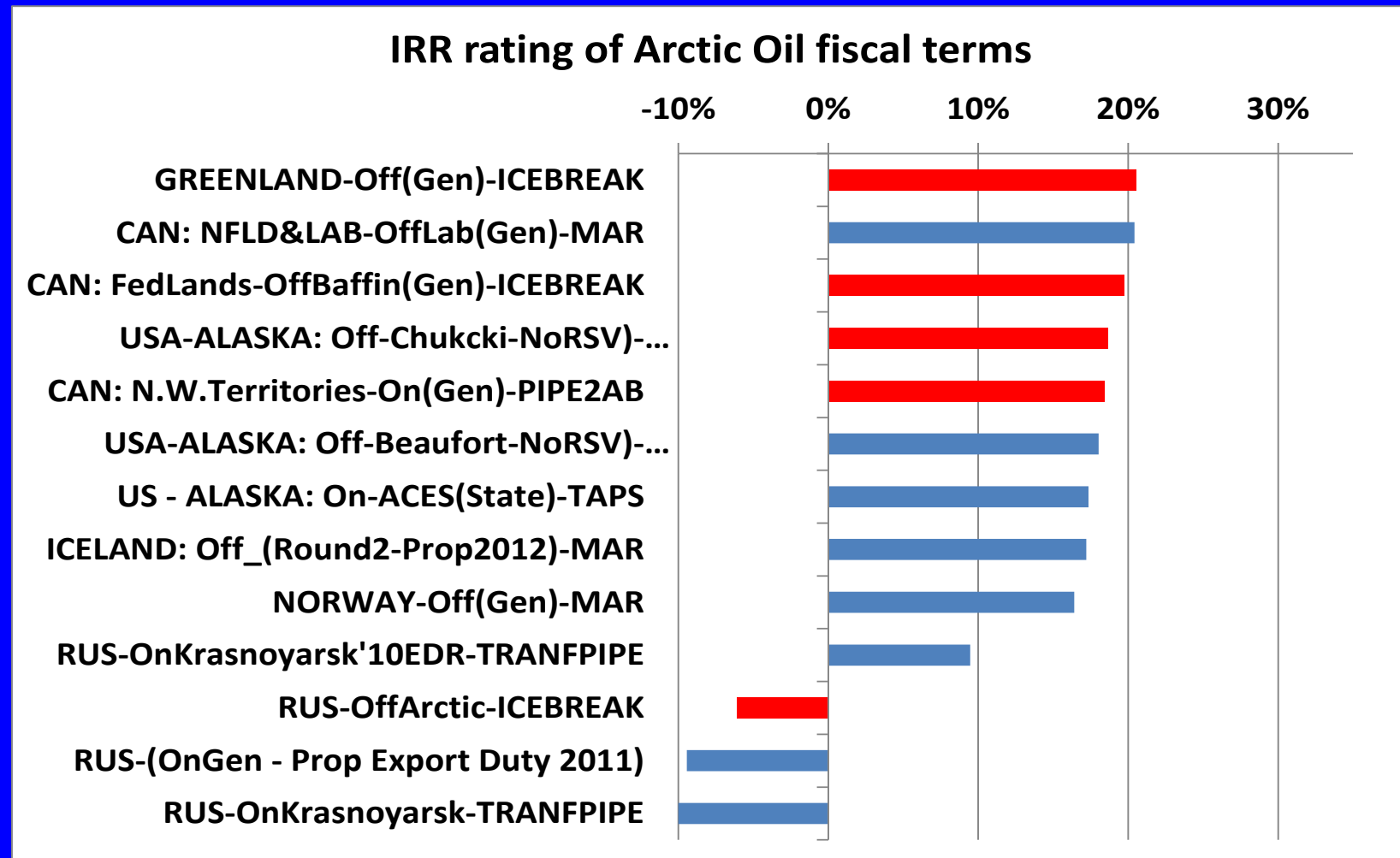
Deep water rating based on standard fields:

- **For oil: 500 mln barrel at \$ 25 per barrel and \$ 80 costs (range 50 million – 5 billion, \$ 50 - \$ 12 costs).**

Investment scenarios:

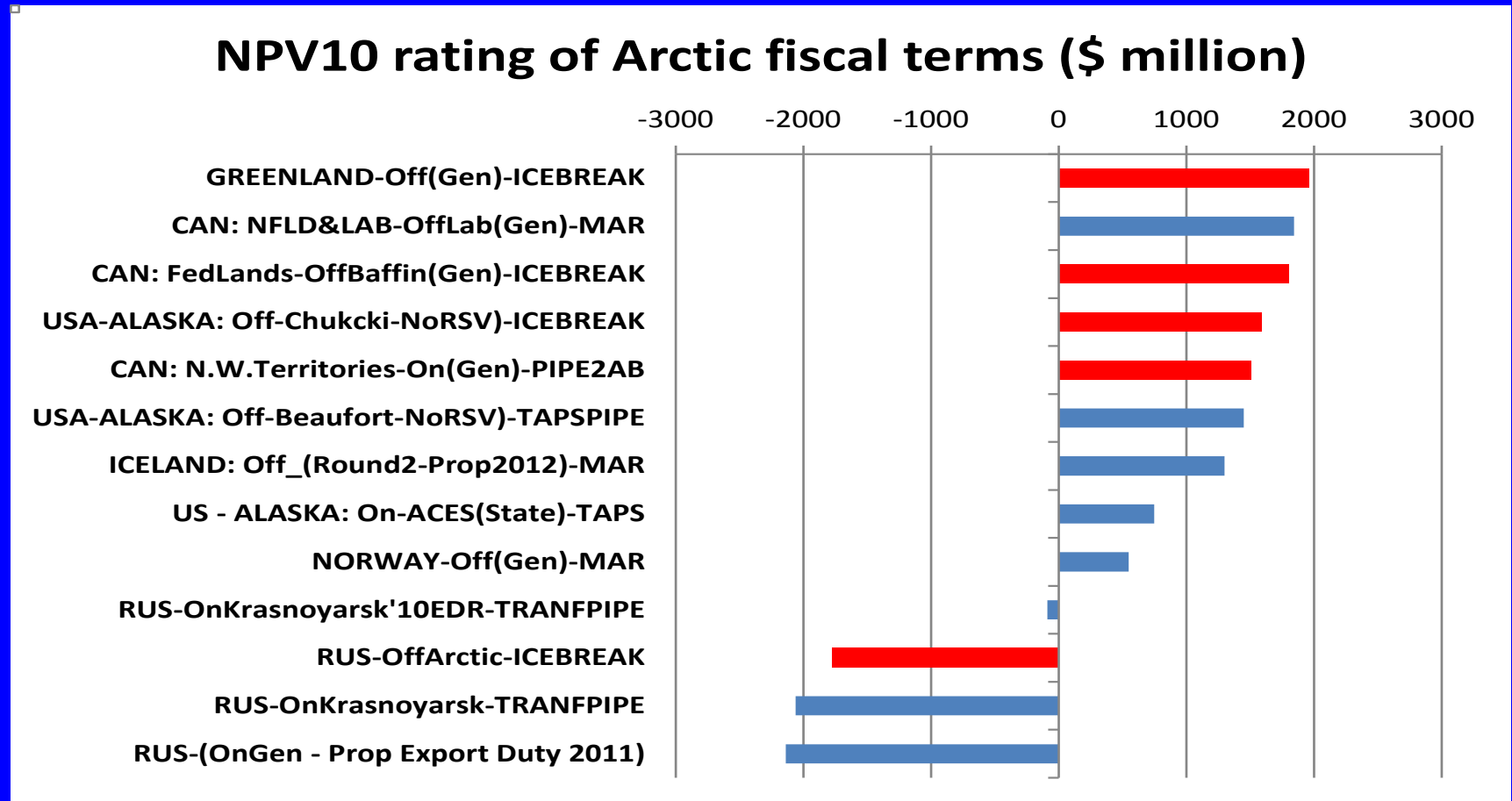
- **stand alone**
- **country incremental**

Arctic (Oil)



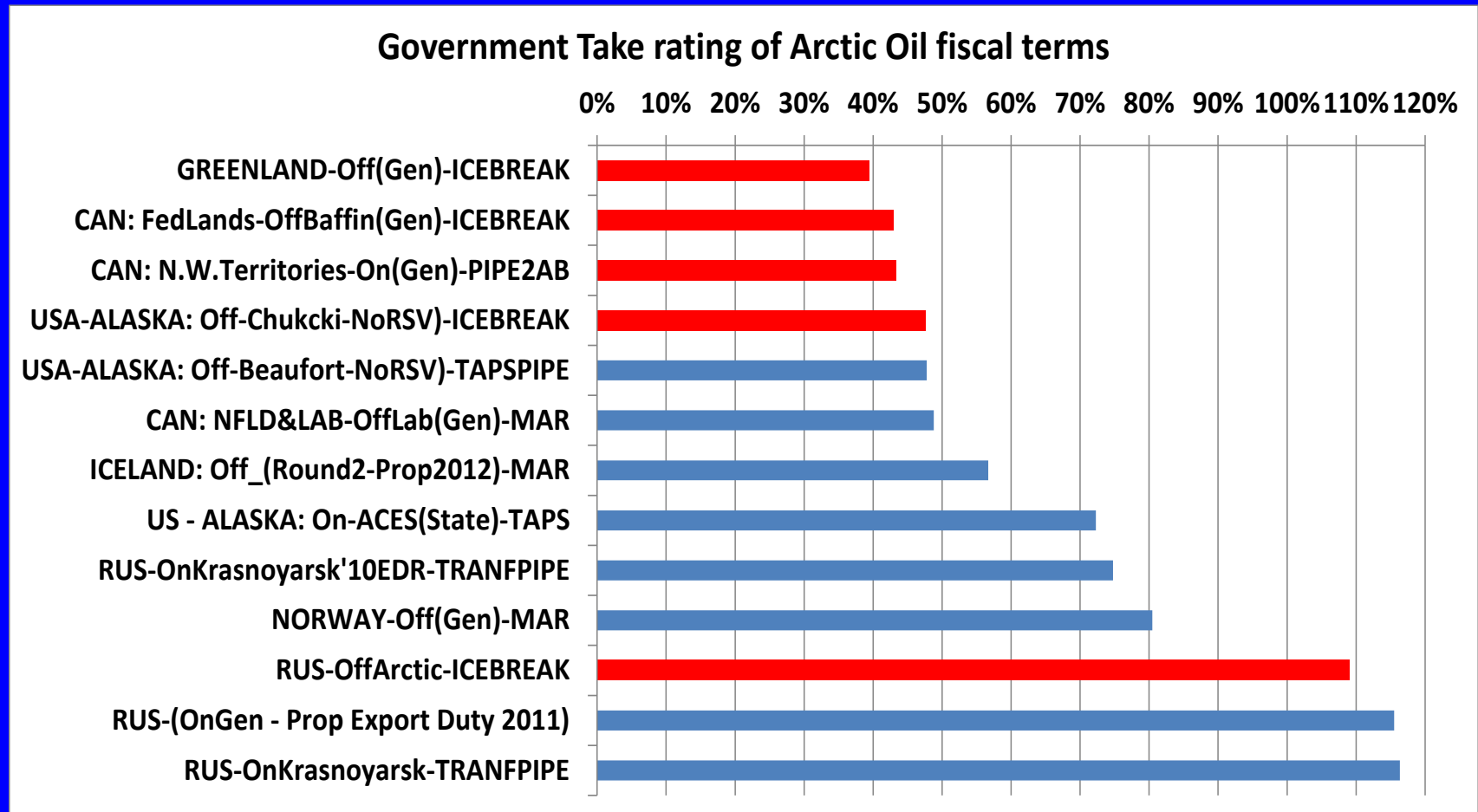
Jurisdictions trying to promote new Arctic infrastructure (red) have often more favorable terms than jurisdictions with existing infrastructure (blue). Alaska ACES IRR compares favorably with other Arctic jurisdictions. Russia still very tough under high cost and slow development conditions.

Arctic (Oil)



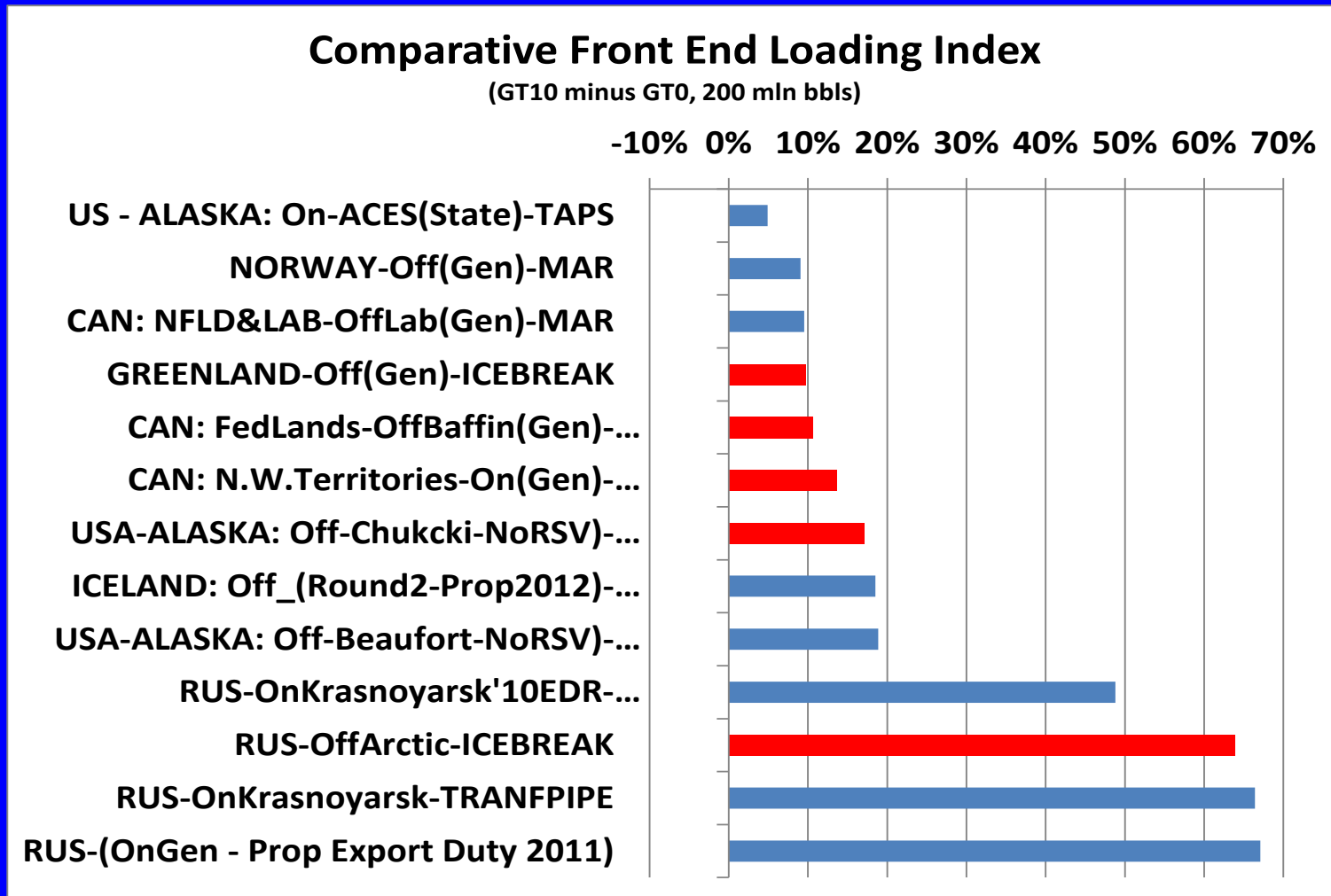
Alaska ACES NPV10 seems OK compared to other jurisdictions, but is somewhat meager. Note how Federal Beaufort and Chukchi acreage is attractive. Russia still very tough.

Arctic (Oil)



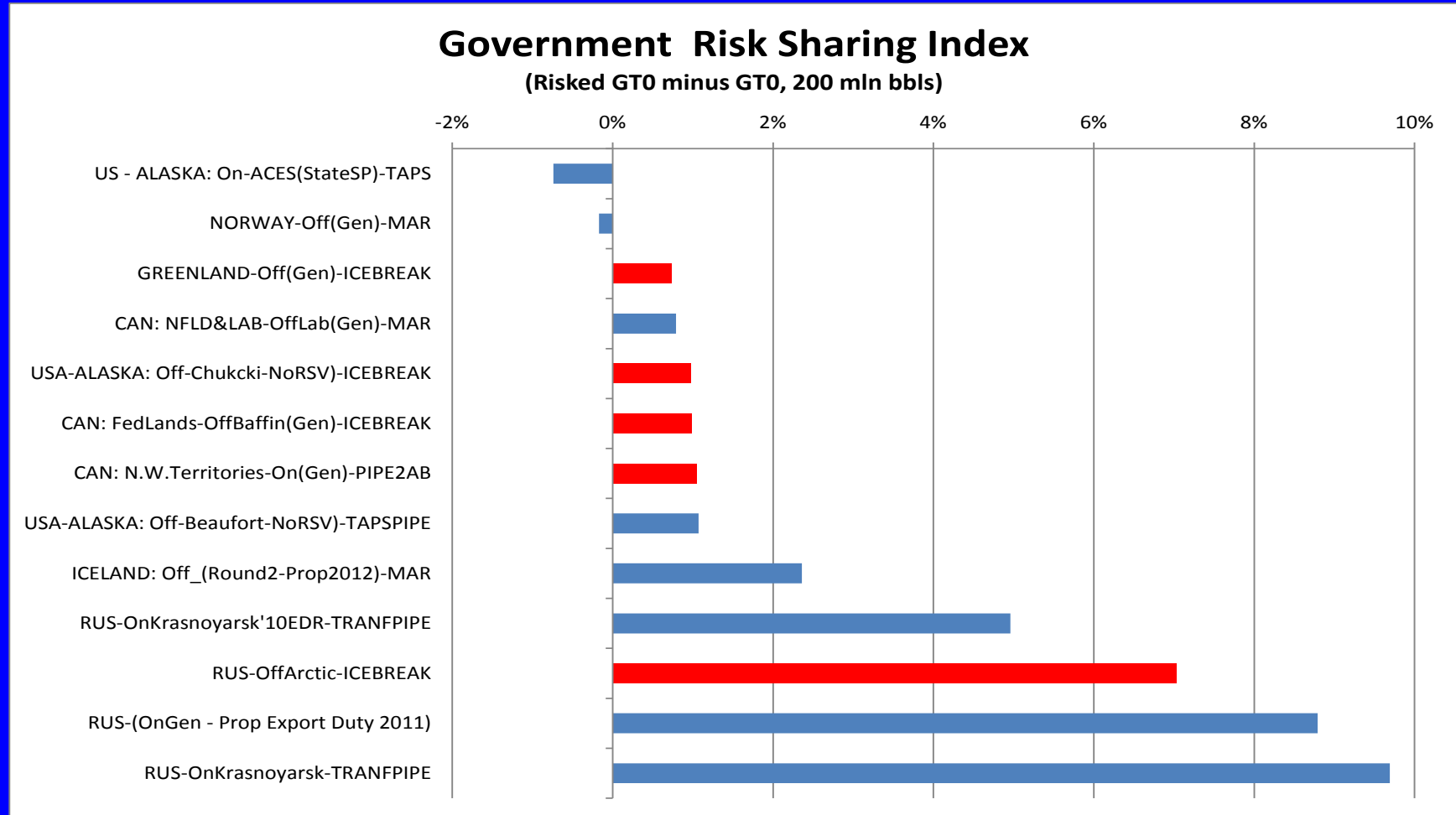
Alaska ACES government take is attractive from a government point of view and approximately at the right level for existing operations for investors. Interestingly new Russian terms compare with Alaska and Norway government take.

Arctic (Oil)



Alaska ACES government take is relatively well balanced compared to other Arctic jurisdictions in terms of the time distribution of the government take.

Arctic (Oil)



Under Alaska ACES the Alaska government is one of the few governments which shares disproportionately in the geological risk, indicating very strong support for exploration. In fact, with South Africa, Alaska rates the highest in the world in this respect.

Arctic Oil results

The government take of about 70%-75% for Alaska for the Base Case field is reasonable compared to the other exporters for existing operations. It is maybe slightly on the high side.

Alaska also offers a favorable time distribution of the government take and very favorable sharing of geological risk.

Session 1

Alaska Policy Issue

(for discussion tomorrow)

The reports establish a government take range of 70%-75% as reasonable for existing operations compared to other exporting jurisdictions.

Both House Bill proposals lower the government take below 65% for existing as well as for new operations.

Although some improvements could be made in the existing terms, the results of the report raise the question whether a significant lowering of government take for existing operations is necessary.

Session 2

Session two will deal with the following issues from the North American Well report:

- **The style of competitive government takes**
- **The future of the North American gas market**
- **Government take for shale oil.**
- **Government take for heavy oil.**

North American Wells

The North American Well report deals with:

- **Conventional oil wells (generic)**
- **Conventional gas wells (generic)**
- **Shale oil wells (per play)**
- **Shale gas wells (per play)**

Rating criteria

The rating criteria are:

- Internal Rate of Return (“IRR”)
- Net Present Value discounted at 10% (“NPV10”)
- Profit to Investment Ratio discounted at 10% (“PIR10”)
- Undiscounted Government Take (“GT0”)
- 10% Discounted Government Take (“GT10”)

North American Wells

Fiscal terms

Fiscal terms vary greatly between Canada and the United States.

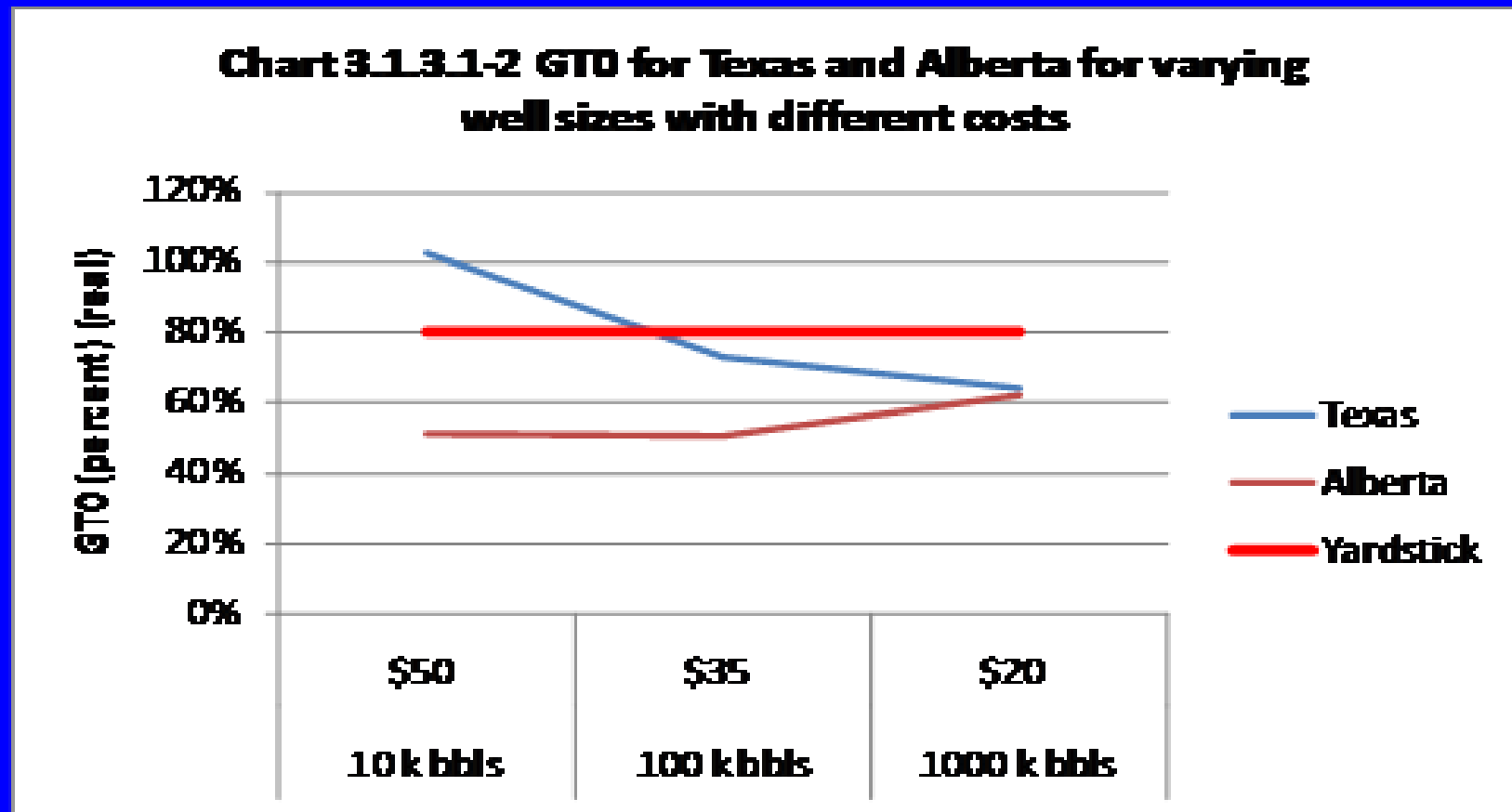
In Canada the fiscal systems consist of:

- **Royalties, based usually on formulas**
- **Federal and provincial corporate income tax**

In the United States the fiscal systems consist of:

- **Royalties, usually a fixed percentage**
- **Federal and often state corporate income tax**
- **Severance (production) taxes**
- **Property taxes**

North American Wells (Oil)



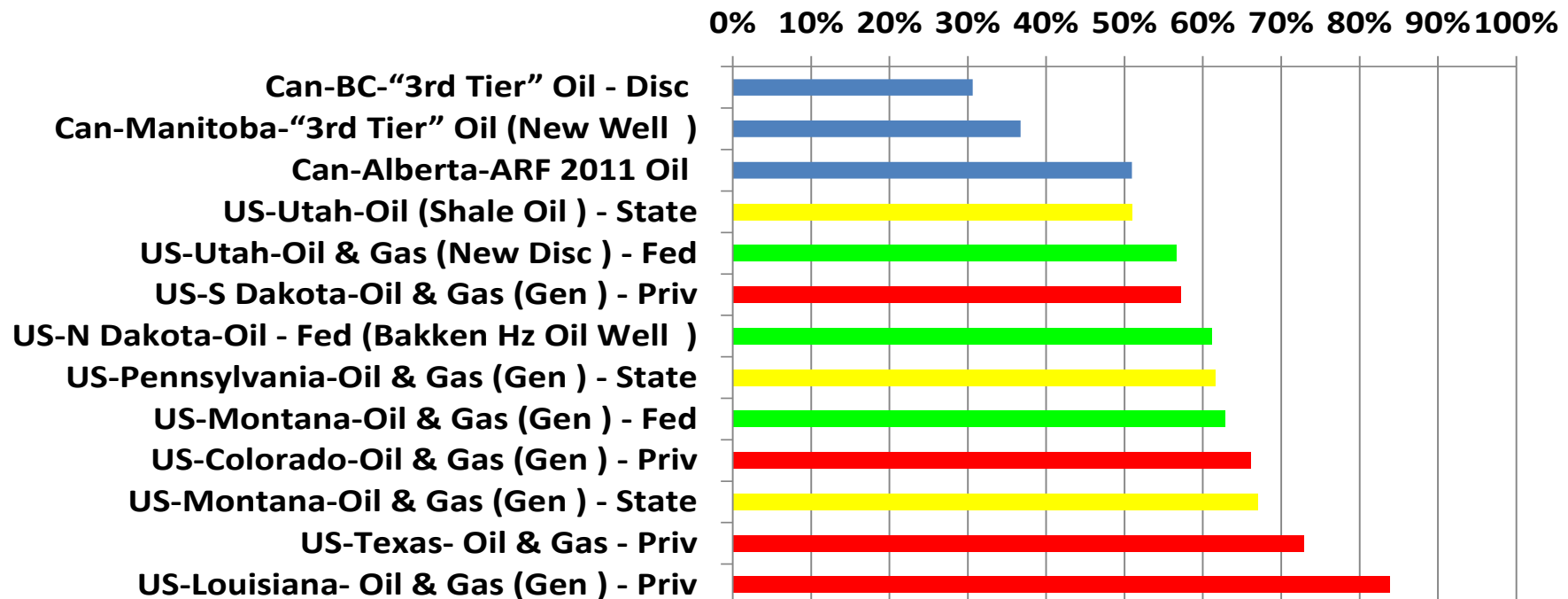
In Canada the government take usually goes up and in the United States the government take goes down with higher level of production per well or with higher prices (or both).

North America Wells (Oil)

Typical Well: 100,000 barrels, \$ 35 costs, \$ 80 price

Government Take on Oil Wells in North America

Government take (%)(real)



The government take on oil wells varies between 30% and 83% in North America and depends very much on the resource owner: Canadian provinces (blue), US Federal lands (green), US State lands (yellow) and US private lands (red)

North American Wells

Fiscal terms

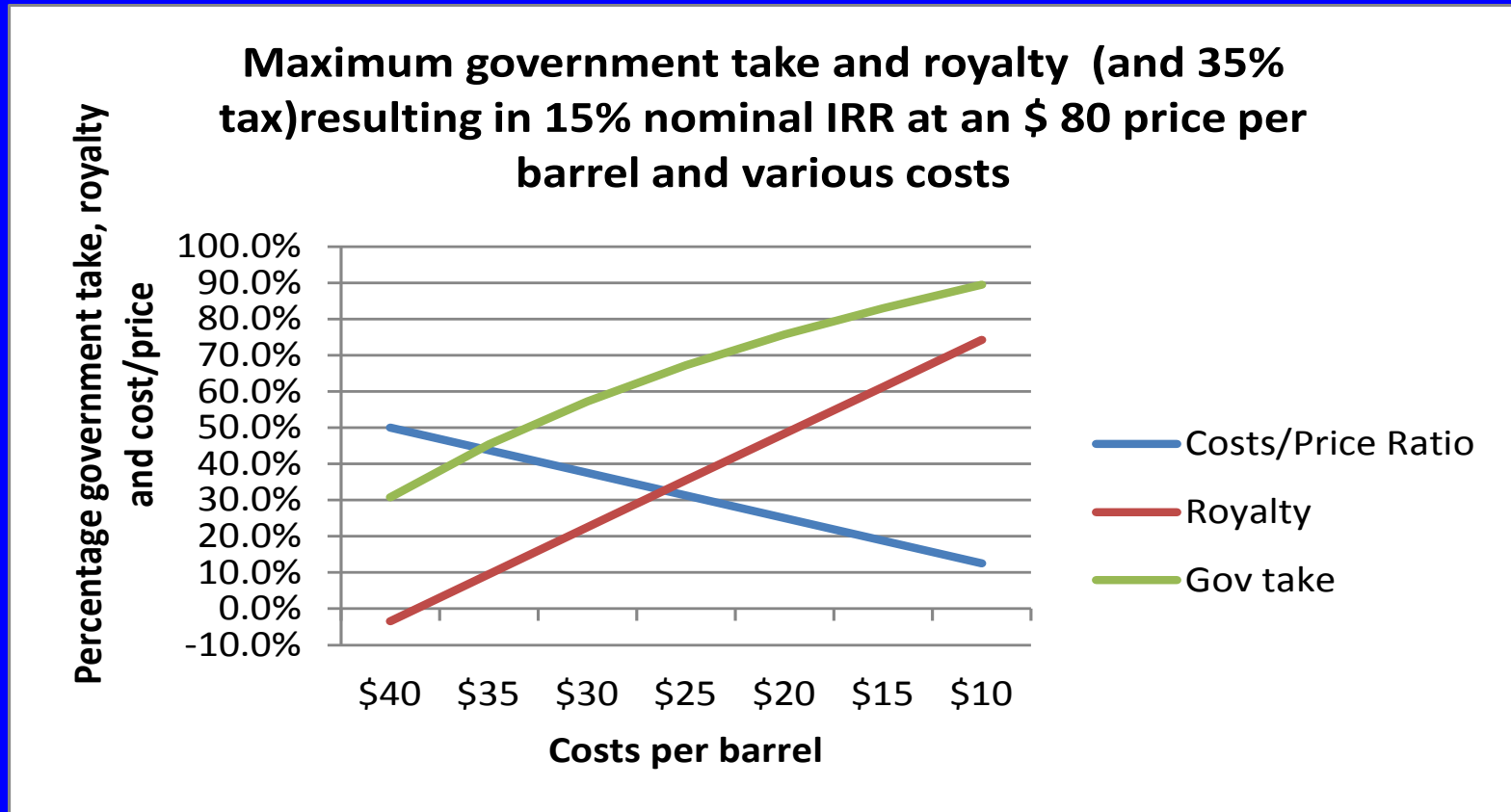
Since 1997 Canada has lowered government take considerably, while the government take in the United States stayed the same.

The combined federal- provincial tax rate in Canada declined from about 45% to 25%.

Due to declining conventional oil production, the major Canadian oil producing provinces promoted strongly new activity with more attractive royalties formulas which compete over a wider cost range.

North American Wells (Oil)

Cost/Price Ratio



In Alberta the royalty for oil can vary between 0% and 40% depending on volume and price levels. This means Alberta competes effectively in the cost range of \$ 20 to \$ 40 per barrel. Creating attractive economics over a wide cost range promotes activity.

North American Wells (Oil)

Cost/Price Ratio

To put the Alberta competitive strategy in the Alaska context, it would be equal to:

-- Alaska having a 41% government take for high cost and marginal resources, applying only corporate income tax, zero ACES and zero royalties, while

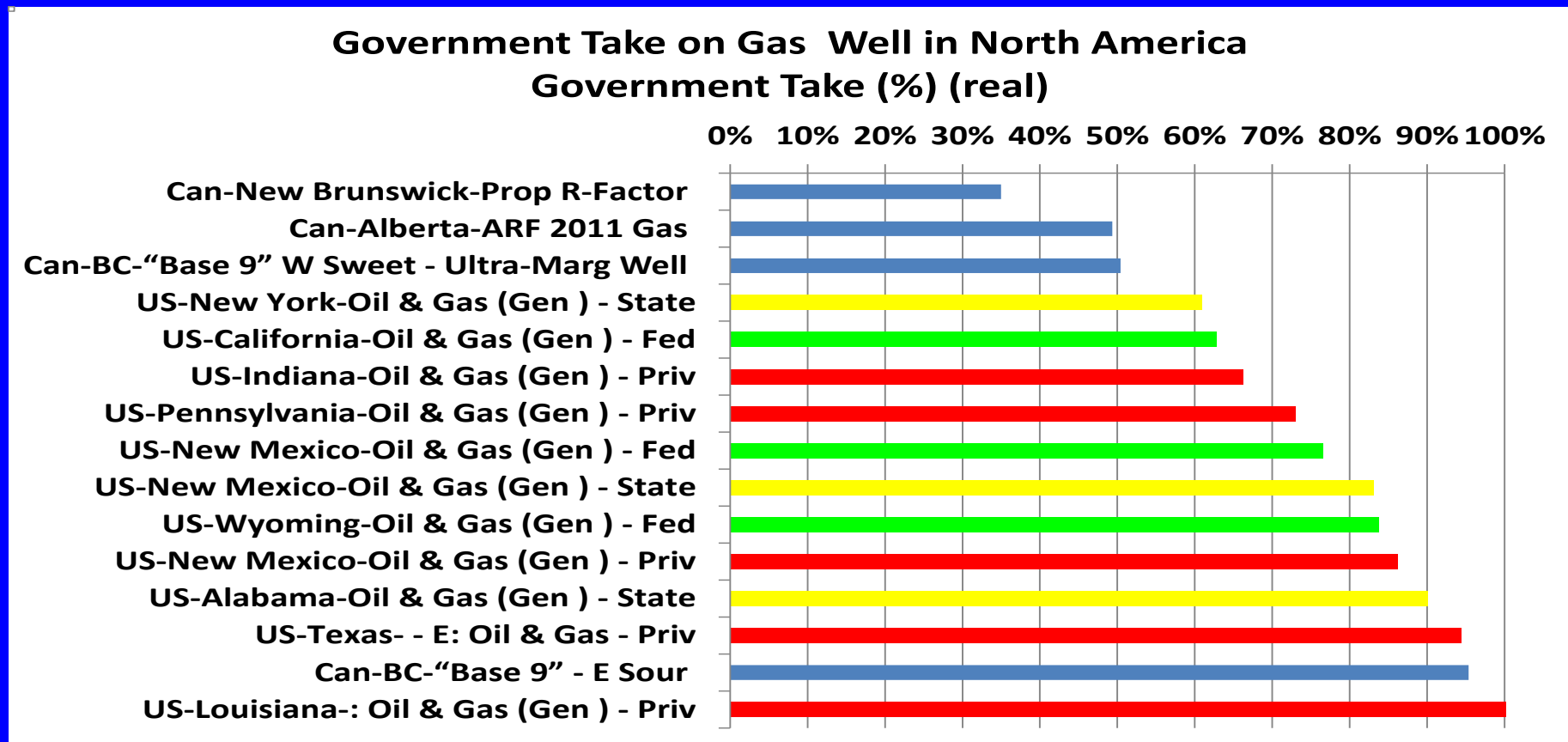
-- having a 72% government take for low cost resources, applying corporate income tax, current ACES and 12.5 % royalty.

In other words “being competitive” does not necessarily mean having a specific level of government take; it means having a competitive government take range for a wide range of cost levels.

A competitive “government take range” strategy results in more investment than a competitive “government take level” strategy.

North American Wells (Gas)

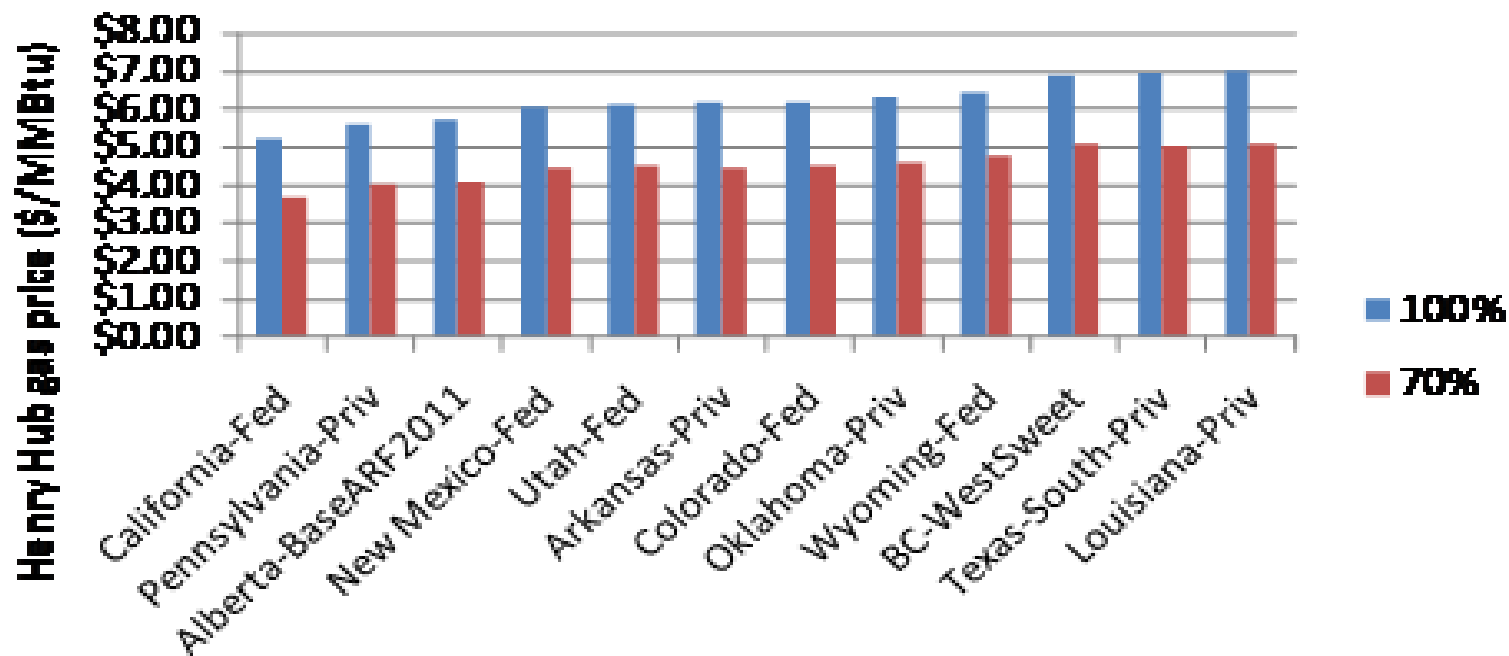
Typical Well: 1 Bcf, \$ 2.90 per Mcf costs, Henry Hub price \$ 5.00.



The Government Take ranges at this cost between 35% and 100% (which means wells have to be lower costs in Louisiana). Government Take depends on resource ownership : Canadian provinces (blue), US Federal (green) US States (yellow) and US Private (red). British Columbia has a wide range of government take levels.

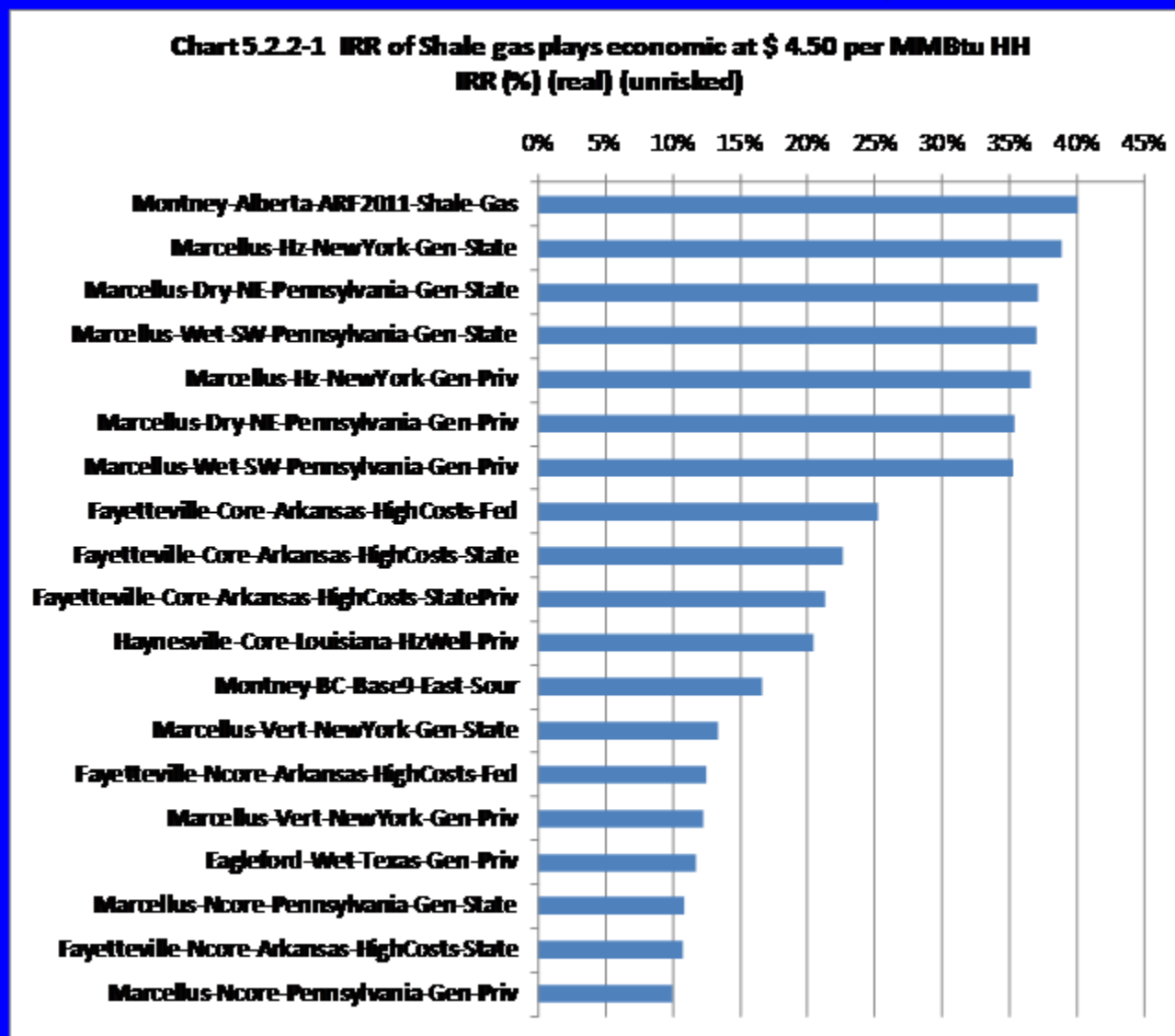
North American Wells (Gas)

Chart 3.2.3.1-2 Break even price at \$ 2.90 and \$ 2.03 per Mcf in the major gas producing areas



At about \$ 2 per Mcf costs most North American basins show attractive economics at \$ 4.50 per MMBtu Henry Hub. At about \$ 3 per Mcf costs all basins are economic at \$ 7 per MMBtu. This indicates strong conventional gas supply conditions in this price range.

North American Wells (Shale Gas)



Significant shale gas plays are economic at \$ 4.50 Henry Hub.

North American Wells (Shale Gas)

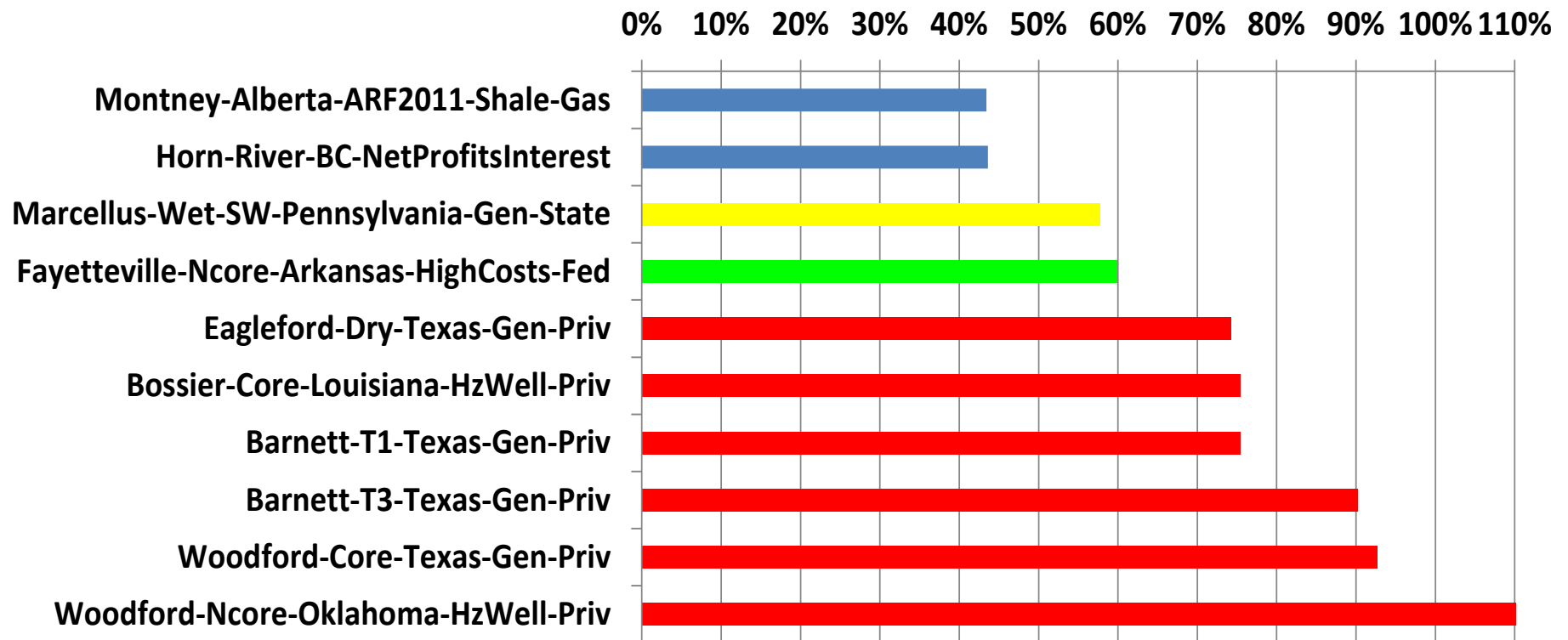
Table 5.2.3-2 Break-even price analysis of Shale Gas Plays (Risked)

Economic				\$ 3.50 HH	\$ 4.00 HH	\$ 4.50 HH	\$ 5.00 HH	\$ 5.50 HH	\$ 6.00 HH	\$ 6.50 HH
Uneconomic										
ARF 2011 Gas – Shale Gas	Can	Alberta	Montney							
Oil & Gas (Gen) - State	US	Pennsylvania	Marcellus - SWPA - Wet							
Oil & Gas (Gen) - State	US	New York	Marcellus - Hz							
Oil & Gas (Gen) - Priv	US	Pennsylvania	Marcellus - SWPA - Wet							
Oil & Gas (Gen) - Priv	US	New York	Marcellus - Hz							
Oil & Gas (Gen) - State	US	Pennsylvania	Marcellus - NEPA - Dry							
Oil & Gas (Gen) - Priv	US	Pennsylvania	Marcellus - NEPA - Dry							
Gas (High Cost) - Fed	US	Arkansas	Fayetteville - Core							
"Base 9" - East Sweet	Can	BC	Montney							
Gas (High Cost) - State	US	Arkansas	Fayetteville - Core							
Oil & Gas - Priv	US	Texas	Eagleford - Wet							
Gas (High Cost) - State Priv	US	Arkansas	Fayetteville - Core							
Oil & Gas (Gen) - State	US	New York	Marcellus - Vertical							
Oil & Gas (Gen) - Priv	US	New York	Marcellus - Vertical							
Oil & Gas - Priv	US	Texas	Barnett - T1							
Oil & Gas (Gen) - Priv	US	W Virginia	Marcellus - Dry							
Oil & Gas (Gen) - State	US	Pennsylvania	Marcellus - Non-core							
Oil & Gas (Gen) - Priv	US	Indiana	New Albany - Hz							
Oil & Gas (Gen) - Priv	US	Pennsylvania	Marcellus - Non-core							
"4th Tier" Gas	Can	Saskatchewan	Colorado							
Oil & Gas (Gen) - Priv	US	Illinois	New Albany - Hz							
Oil & Gas - Priv	US	Texas	Eagleford - Dry							
Oil & Gas - Priv	US	Texas	Bossier - Core							
Oil & Gas - Priv	US	Texas	Barnett - T2							
Gas (High Cost) - Fed	US	Arkansas	Fayetteville - Non-core							
Oil & Gas (Hz Well) - Priv	US	Louisiana	Bossier - Core							
Gas (High Cost) - State	US	Arkansas	Fayetteville - Non-core							
Oil & Gas (Gen) - State	US	Pennsylvania	Marcellus - CPA - Dry							
Gas (High Cost) - State Priv	US	Arkansas	Fayetteville - Non-core							
Oil & Gas (Gen) - Priv	US	Pennsylvania	Marcellus - CPA - Dry							
Oil & Gas (Hz Well) - Priv	US	Louisiana	Haynesville - Core							
Oil & Gas (Hz Well) - Priv	US	Oklahoma	Woodford - Core							
Oil & Gas - Priv	US	Texas	Bossier - Non-core							
Oil & Gas - Priv	US	Texas	Barnett - T3							
Oil & Gas - Priv	US	Texas	Woodford - Core							
Oil & Gas (Gen) - Priv	US	W Virginia	Marcellus - Non-core							
Oil & Gas (Gen) - Priv	US	Indiana	New Albany - Vertical							
Oil & Gas (Gen) - Priv	US	Illinois	New Albany - Vertical							
Oil & Gas (Hz Well) - Priv	US	Oklahoma	Woodford - Non-core							
Oil & Gas - Gen	Can	Quebec	Utica							
Oil & Gas - Priv	US	Texas	Haynesville - Non-core							
Oil & Gas (Hz Well) - Priv	US	Louisiana	Bossier - Non-core							
Oil & Gas (Gen) - Fed	US	Michigan	Antrim							
Oil & Gas - Net Profits Interest	Can	BC	Horn River							
Oil & Gas - Priv	US	Texas	Woodford - Non-core							
ARF 2011 Gas – Hz Gas Wells	Can	Alberta	Colorado							
Oil & Gas (Gen) - Priv	US	Michigan	Antrim							
Oil & Gas (Gen) - State	US	Michigan	Antrim							
Oil & Gas (Hz Well) - Priv	US	Louisiana	Haynesville - Non-core							

Most shale gas plays are economic at \$ 6.50 Henry Hub.

North American Wells (Shale Gas)

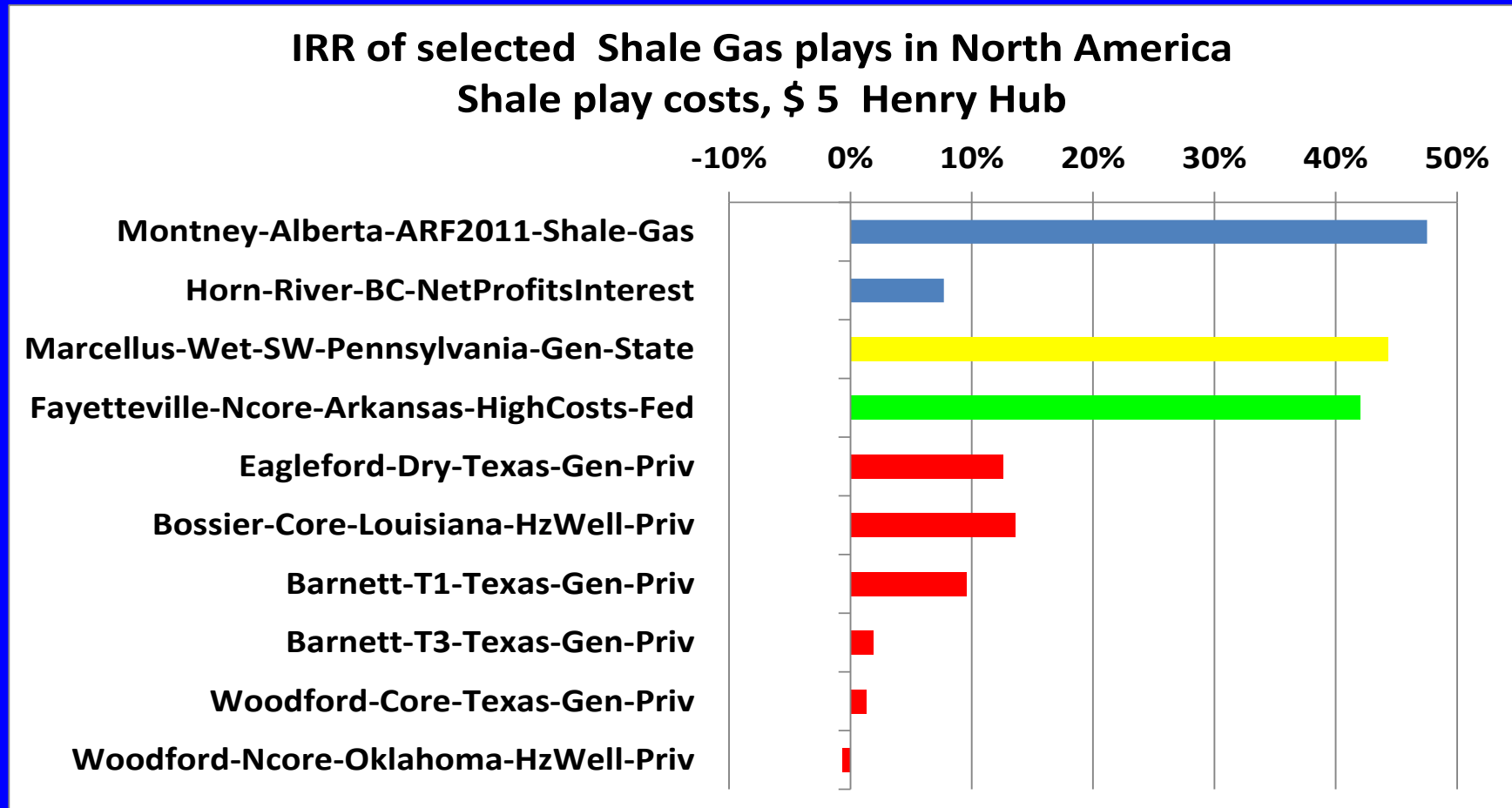
Government Take on Shale Gas in North America
Shale Plays based on costs for each play , price \$ 5 Henry Hub



The government take ranges enormously for shale gas plays in North America. Canada offers favorable terms for shale gas.

North American Wells (Shale Gas)

IRR (%) Unrisked



On some US private lands, high royalties make shale gas uneconomic. British Columbia has made shale gas economic under difficult price conditions with a net profit sharing royalty. Alberta Montney is more profitable than the Pennsylvania Marcellus due to a competitive government take of 44%.

North American Gas

The study identifies that significant conventional and shale gas resources are economic at \$ 4.50 per MMBtu Henry Hub.

Very large conventional and shale gas supplies are available in the Canadian provinces and the lower 48 states for a price range of \$ 6.50 to \$ 7.00 Henry Hub.

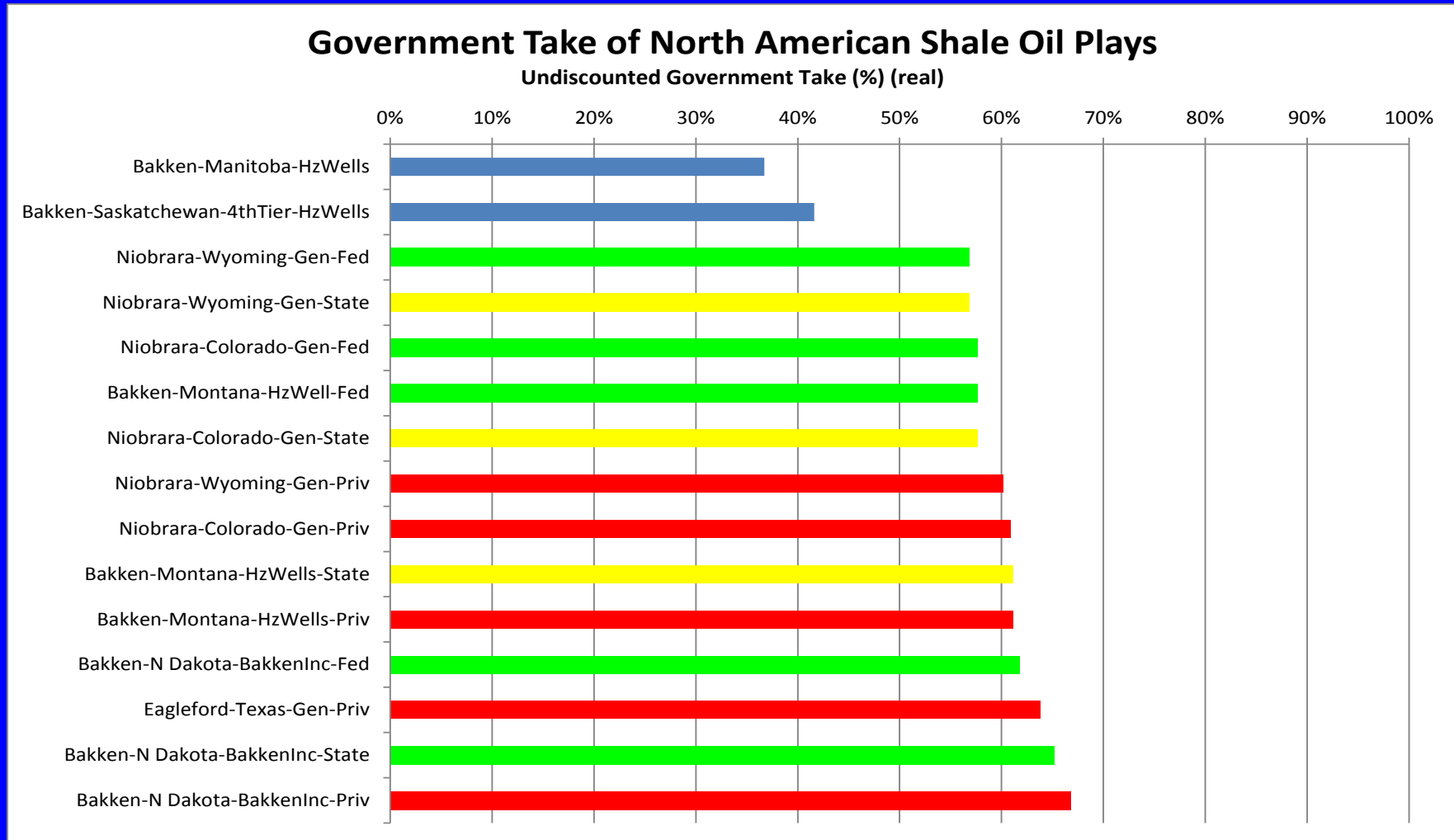
This indicates that in the next 10 years or so, it is unlikely that North American gas prices will move to much higher gas price levels.

In case supplies would be insufficient at these price levels, it is economic to import LNG and significant LNG import capacity is already available and large supply sources are available.

This indicates that it may be difficult for the Alaska gas line project to compete in this market in the next 10 or 20 years. The main opportunity would be an Alaska gas line under high gas prices with significant LNG exports from the Lower 48 states.

North American Wells (Shale Oil)

Government Take (%) Unrisked



Shale Oil plays in the United States are typically subject to a government take of about 60% and in Canada 40%.

Shale Oil

Alaska may have significant shale oil potential.

Great Bear Petroleum LLC has identified three major source rock formations which could yield prolific shale oil production.

In order to determine whether shale oil can indeed be produced from these formations extensive pilot projects are necessary to verify whether formations can be properly fracked and whether production levels would be adequate.

Given the fact that the formations are relatively deep, operating conditions are severe and infrastructure is lacking, the costs per barrel would very likely be higher than in Canada and the Lower 48 States.

It is unlikely that large capital investments can be attracted unless the government take is in the 45 – 55% range at current prices. However, even at this government take range the probability that this will materialize by 2022 is modest.

Heavy Oil

Alaska has significant heavy oil potential, probably in excess of 5 billion barrels. Alaska heavy oils range from 10 to 22 degrees API.

For Alberta oil sands, at 10 degrees API, government takes are in the range of 43% - 55% depending on the oil price.

In order to compete the government take for 10 degree heavy oil in Alaska may have to be similar to Alberta. Heavy oils in the 15 – 22 degrees API range could have higher government takes.

North America Well Report

Conclusions for Alaska

North America Well Report conclusions for Alaska:

- **Gas market conditions in North America make an Alaska gas line to Alberta highly unlikely**
- **Canadian provinces offer a formula approach for royalties. They therefore compete over a wider cost range.**
- **The government take for Alaska shale oil will have to be in the 45-55% range in order to attract major investment.**
- **The government take for ultra-heavy oil in Alaska would have to be similar to oil sands in order to be able to compete, while heavy oil could have a higher government take.**

Session 2

Alaska policy issues

Policy issues for review on Wednesday:

Should Alaska promote increased activity by creating more flexible fiscal terms which permit Alaska to compete over a wider cost range?

Should Alaska promote shale oil and ultra-heavy oil development with a government take in the 45-55% range under current prices and heavy oils at somewhat higher levels of government take?

Session 3

Deep Water Oil

This session will deal with the following issues from the Deep Water report:

- **Downward adjustment of oil government take by nations with declining oil production**
- **Resource wealth sharing**
- **Back end loading of fiscal terms**
- **Role of direct state participation in increasing government take**

Deep Water

The Deep water study deals with:

- **Deep water oil fields (generic)**
- **Deep water gas fields, adjusted for regional gas price scenarios (generic)**
- **Deep water oil and gas basin analysis**

Deep Water (Generic)

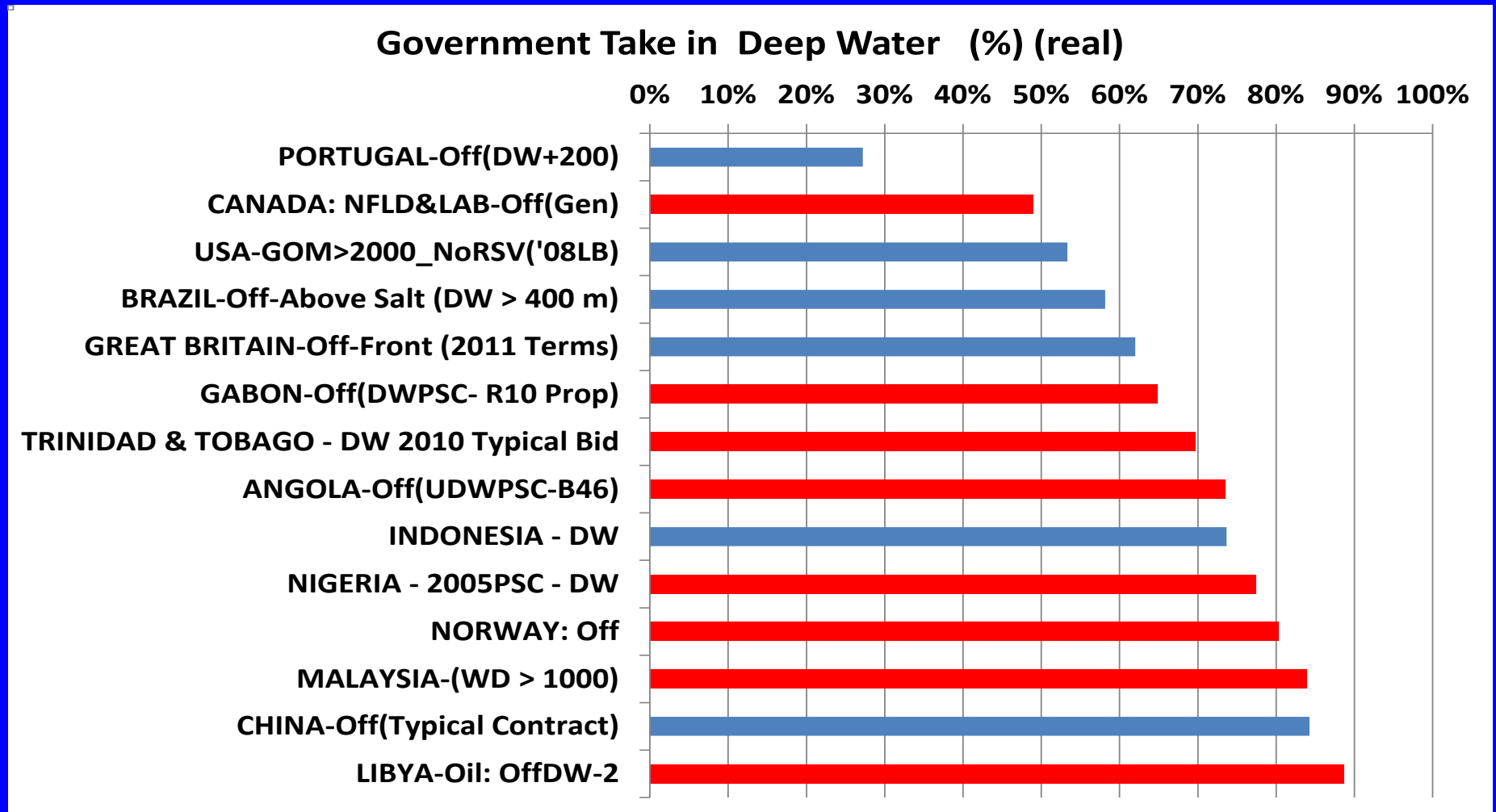
Deep water rating based on standard fields:

- For oil: 500 mln barrel at \$ 25 per barrel and \$ 80 costs (range 50 million – 5 billion, \$ 49 - \$ 13 costs).

Investment scenarios:

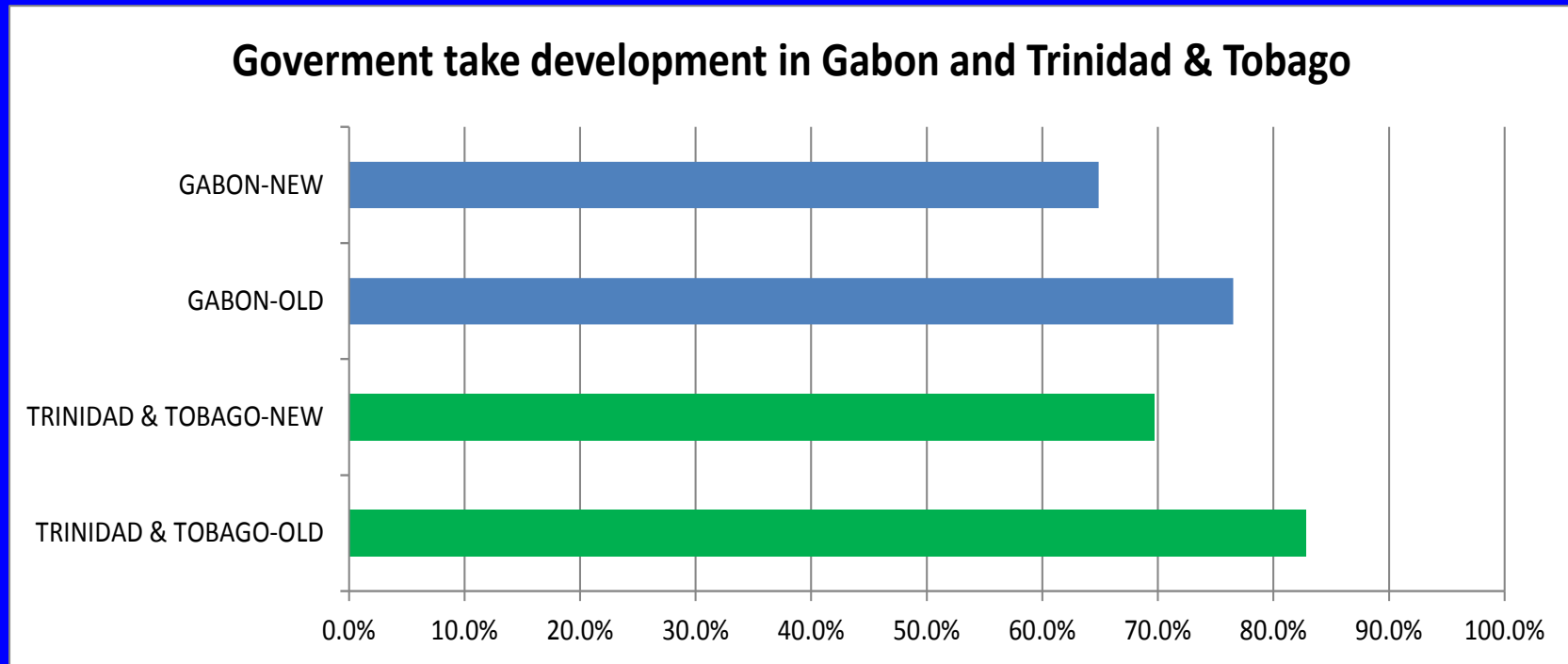
- stand alone
- country incremental
- contract incremental

Deep Water (Oil)



In deep water importing nations (blue) have typically better terms than exporting nations (red). However, a some importing nations have tough terms.

Deep Water (Oil)



Gabon and Trinidad and Tobago are exporters with a declining oil production and have recently reduced their terms by about 12 percentage points.

Deep Water (Oil)

An important “peer group” for Alaska would be exporting jurisdictions with a declining conventional oil production.

There are not many jurisdictions in this group, but examples are Alberta, Gabon, Trinidad & Tobago, Malaysia.

Both Gabon and Trinidad applied about a 12 percent drop in order to attract new investment in an effort to offset declining production.

Both in Gabon and Trinidad this only applies to new blocks. Terms and conditions on old blocs remain unchanged.

This means that both countries go higher on the cost/price ratio curve. Trinidad and Tobago has already been successful with this policy. Gabon still has to have a new bidding round on these terms.

Alberta with their 2011 terms applied a similar strategy.

Deep Water (Oil)

Sharing of resource wealth

There are 9 main types of resource wealth sharing for PSC fiscal systems:

- Progressive means a higher government take with higher volumes or prices or lower costs
- Neutral means the government take stays the same
- Regressive means a lower government take with higher volumes or prices or lower costs

	Volume	Price	Costs
Progressive	X	X	X
Neutral	X	X	X
Regressive	X	X	X

Deep Water (Oil)

Sharing of resource wealth

Table 3.2.2.4-1 GT0 behavior in relation to production, price and costs
Concessions - Country Incremental

P	Progressive		
N	Neutral		
R	Regressive		
Country	Volume	Price	Costs
Argentina	N	P	R
Australia	N	P	P
Brazil	P	R	R
Canada-Newfoundland	N	P	P
Canada-Nova Scotia	N	P	P
Colombia	P	P	R
Faroe Island	R	P	P
Ghana	R	P	P
Morocco	P	R	R
New Zealand	N	R	R
Norway	N	P	P
Papua New Guinea	N	N	N
Thailand	P	P	P
Turkey	N	R	R
United Kingdom	N	N	N
United States -GOM	N	R	R

Fiscal structures in terms of progressivity are still very different for concessions

Deep Water (Oil)

Sharing of resource wealth

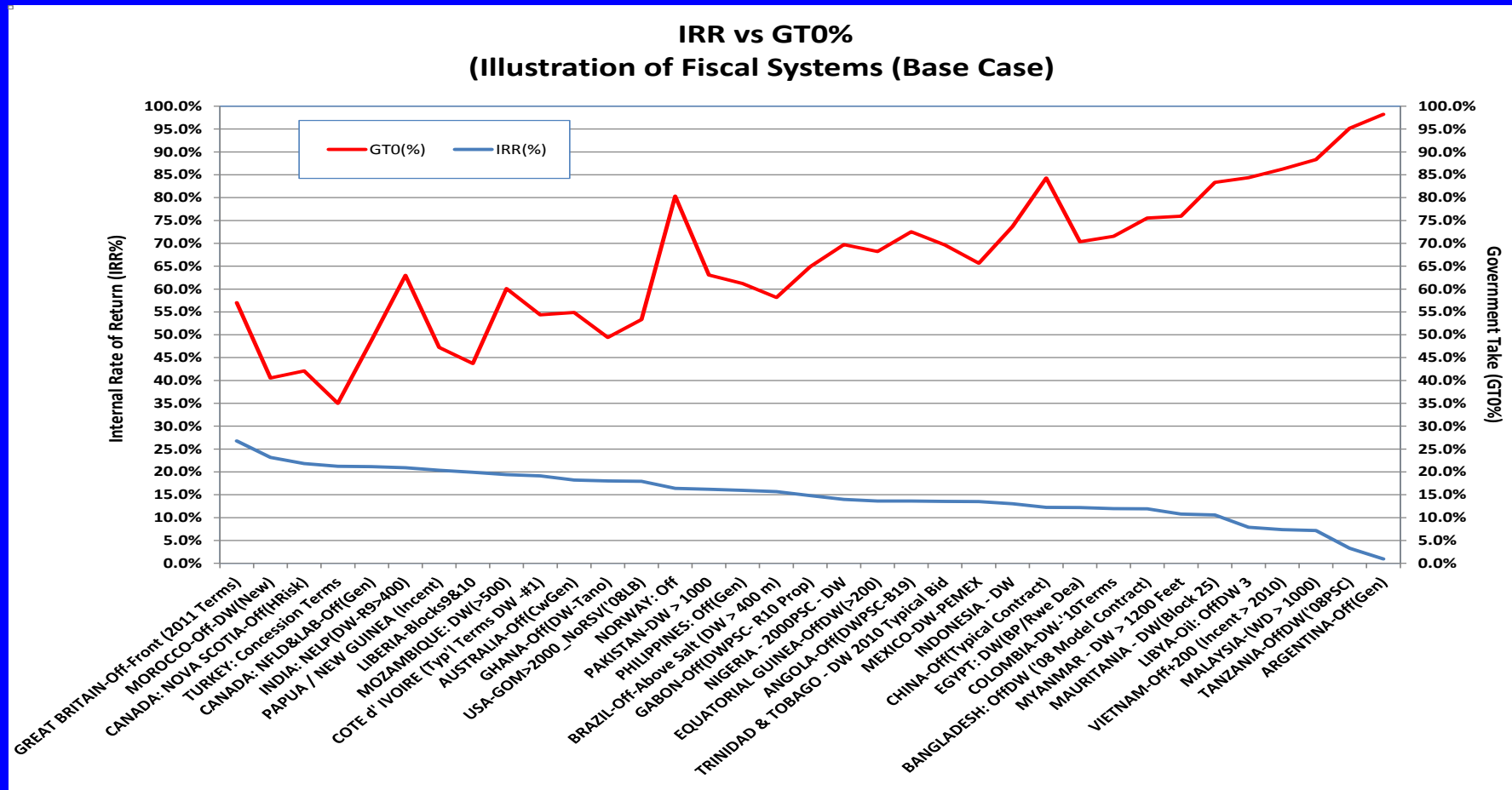
The Alaska ACES system is:

- **Neutral on Volume**
 - The Alaska system does not have strong volume progressive features
- **Progressive on Price**
 - The Alaska system has strong price progressive features
- **Neutral on Costs**
 - The cost progressive tax credits are offset by the effect of regressive royalties.

Because the Alaska ACES system is relatively neutral on costs, the development of high cost resources such as heavy oil and shale oil will not be stimulated. In other words Alaska is not going very high on the cost/price ratio curve. New features are required to stimulate heavy oil and shale oil.

Deep Water (Oil)

Timing of government take



There is a remarkable diversity in government take for the same level of internal rate of return due to the difference in back end loading versus front end loading and policies with respect to state participation

Deep Water (Oil)

Timing of government take

Two rather different styles of fiscal packages exist in deep water:

- **High government take strategy (on a relative basis):** Norway, UK, Denmark, Newfoundland & Labrador, NE British Columbia, India, China.
 - **Back end loading** through uplifts, tax credits, tax or royalty holidays, cumulative profit based formulas
 - **Direct State participation**
- **Low government take strategy (on a relative basis):** US Gulf, Egypt, Libya, Brazil, Trinidad & Tobago
 - Front end loading through emphasis on royalties and production sharing with cost limits.

Deep Water (Oil)

Timing of government take

FRONT END LOADING:

- **Signature bonuses**
- **Royalties**
- CIT ring fenced or consolidated with slow depreciation
- **Property Taxes**
- PSC with cost limit

NEUTRAL:

- **CIT consolidated with fast depreciation or 100% write offs**
- PSC – No cost limit
- JV with limited or no carry

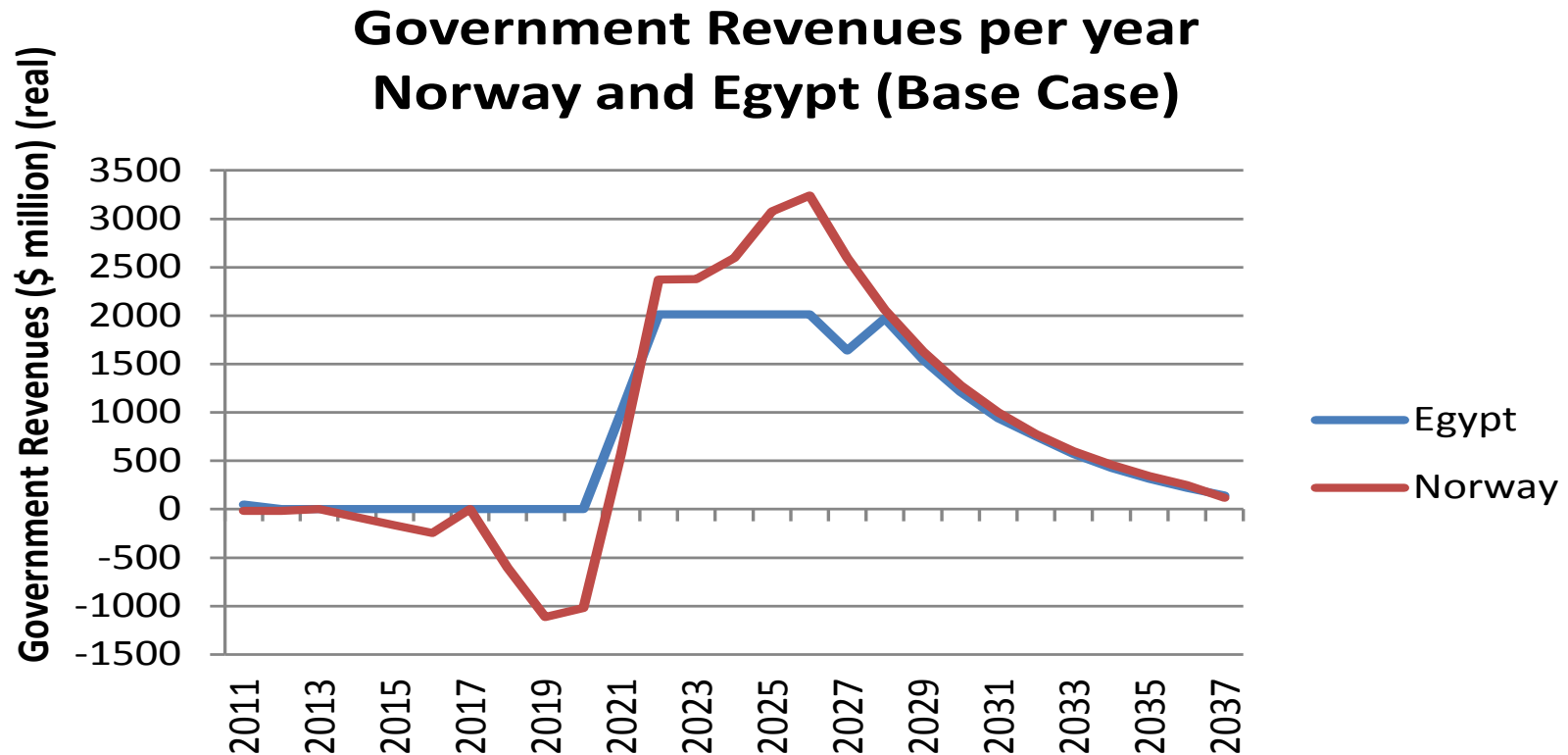
BACK END LOADED:

- PRRT, APT and other IRR or R-factor based taxes
- **Tax Credits and Uplifts for CIT, PPT, HT**

Features applicable in Alaska in red

Deep Water (Oil)

Timing of government take



Tax consolidation and special tax consolidation combined with uplift or tax credits are strong instruments to create back end loading.

Deep Water (Oil)

Timing of government take

Relatively rich nations (high income per capital relatively solid financial position), with a relatively low discount rate, can afford to use back end loading to attract investment.

With the introduction of tax credits under the production tax Alaska became more back end loaded.

However, Alaska could go further along this path in order to stimulate high cost resources.

Deep Water (Oil)

Direct State Participation

Some jurisdictions add significantly to their government take through direct state participation. This is participation from day 1 in a license or lease, just as any partner in joint operating agreement.

Examples:

- Norway – 20%**
- Denmark – 20%**
- Newfoundland & Labrador – 10%**

Deep Water (Oil)

Direct State Participation

Alaska has already a system with back end loaded features such as the PPT with the tax credits.

Nevertheless, for the development of heavy oil, shale oil and natural gas, it may be beneficial to create stronger incentives apart from a lower government take by making the system more back end loaded.

In principle, this could be done by exchanging the royalty for a direct state participation share, for instance a 12.5% royalty for a 25% participation share. The state company would then be responsible for making the contribution to the Alaska Permanent Fund.

This would be a powerful way to stimulate shale oil, heavy oil and natural gas development while maintaining a high government take and a high IRR at the same time.

Session 3

Alaska Policy Issues

Policy issues for Wednesday:

Should Alaska encourage the development of new and often more expensive light oil production through a drop in government take of about 10 percentage points for new developments only? This level of government take would be similar to HB110 for new investments and to HB17.

Should Alaska promote the development of shale oil, heavy oil and natural gas, through replacement of royalties by direct state participation?

Session 4

Deep Water Gas and Arctic Gas

This session will deal with the following issues from the Deep Water and Arctic report:

- **Government takes for gas in the Pacific gas market.**
- **Government takes for gas in the Arctic**

Deep Water (Generic)

Deep water rating based on standard fields:

- For gas: base case: 12.5 Tcfe (10 Tcf with 500 mln bbls, \$ 2.60 per Mcfe costs) (range 2.5 Tcfe – 62.5 Tcfe). Gas rating based on gas prices for each country.

Investment scenarios:

- stand alone
- country incremental
- contract incremental

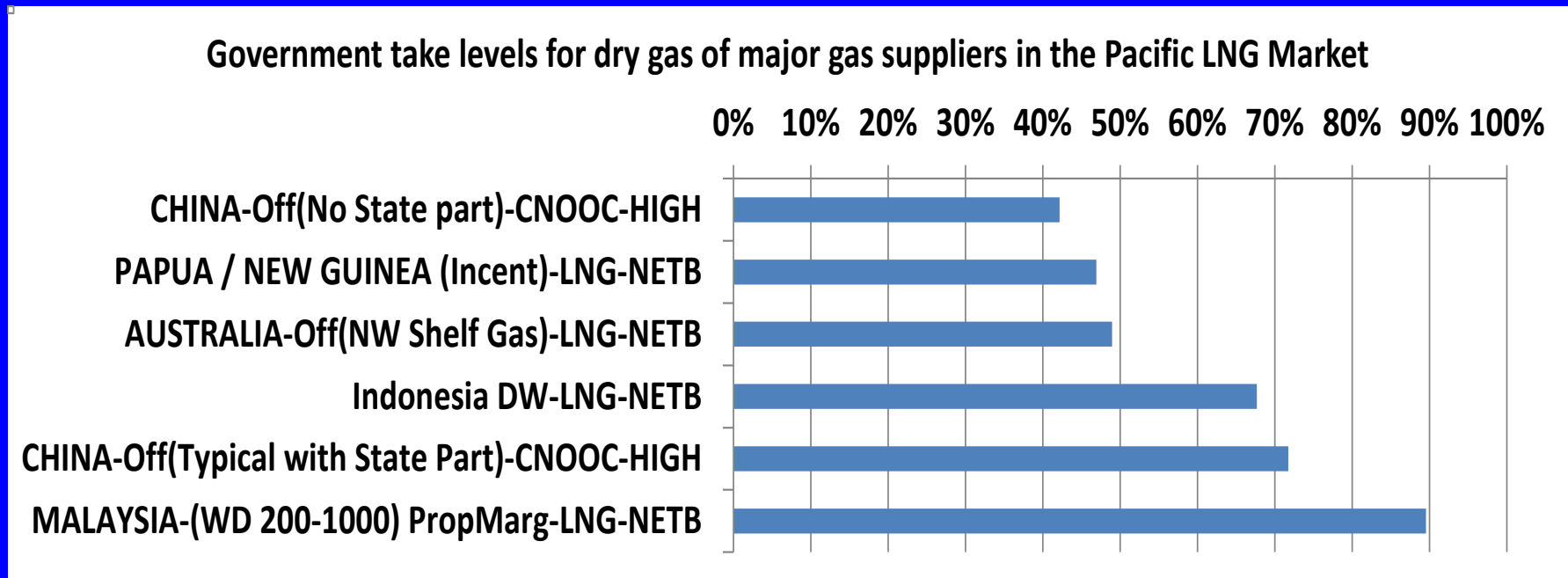
Deep Water (Gas)

Investor favorability

Investor favorability with respect to gas is determined by two main factors:

- **Level and structure of government take, and**
- **Gas pricing framework:**
 - Gas prices linked to crude oil or oil products: Japan, Asia LNG, Continental Europe, Brazil
 - Gas prices determined by gas-gas competition in a hub system: United States and Canada
 - Regulated gas prices: India, China, Egypt

Deep Water (Gas)



Current major new LNG suppliers in the Pacific LNG market are Australia and Papua New Guinea. Government take is less than 50% for dry gas.

Offshore and onshore conventional gas production in China is also significant. Chinese owned companies often benefit from a system where China does not participate on a carried basis, resulting in a government take of 42% for dry gas. In addition to the conventional gas resources, China has in situ 1300 Tcf of coal bed methane gas and 1100 Tcf of shale gas.

Arctic

The Arctic study deals with:

- **Arctic offshore and onshore oil fields (generic)**
- **Arctic offshore and onshore gas fields (generic)**

Both oil fields and gas fields are adjusted for net back pricing due to transportation. Gas fields also take differences in gas markets into account.

Arctic onshore and offshore (Generic)

Deep water rating based on standard fields:

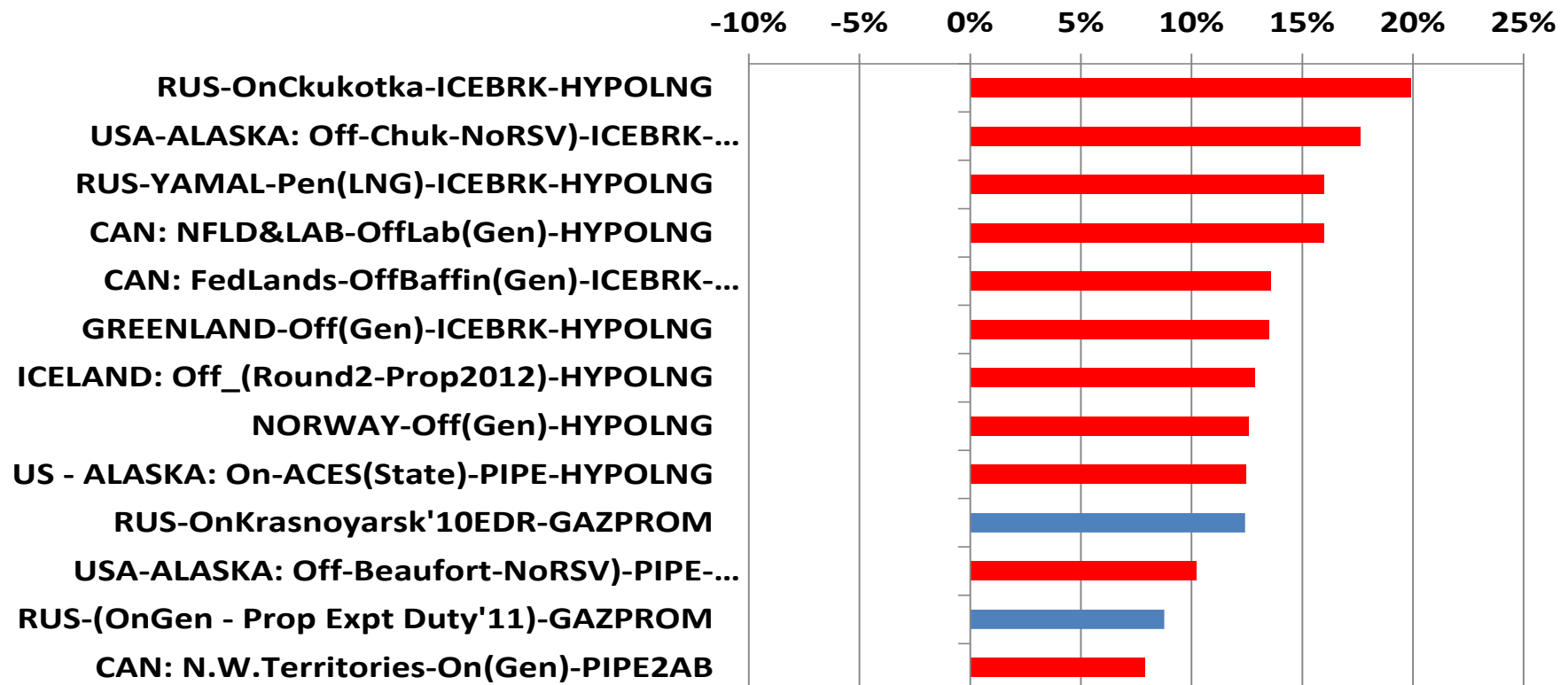
- **For gas: base case: 12.5 Tcfe (10 Tcf with 500 mln bbls, \$ 2.50 per Mcfe costs) (range 2.5 Tcfe – 62.5 Tcfe).**

Investment scenarios:

- **stand alone**
- **country incremental**

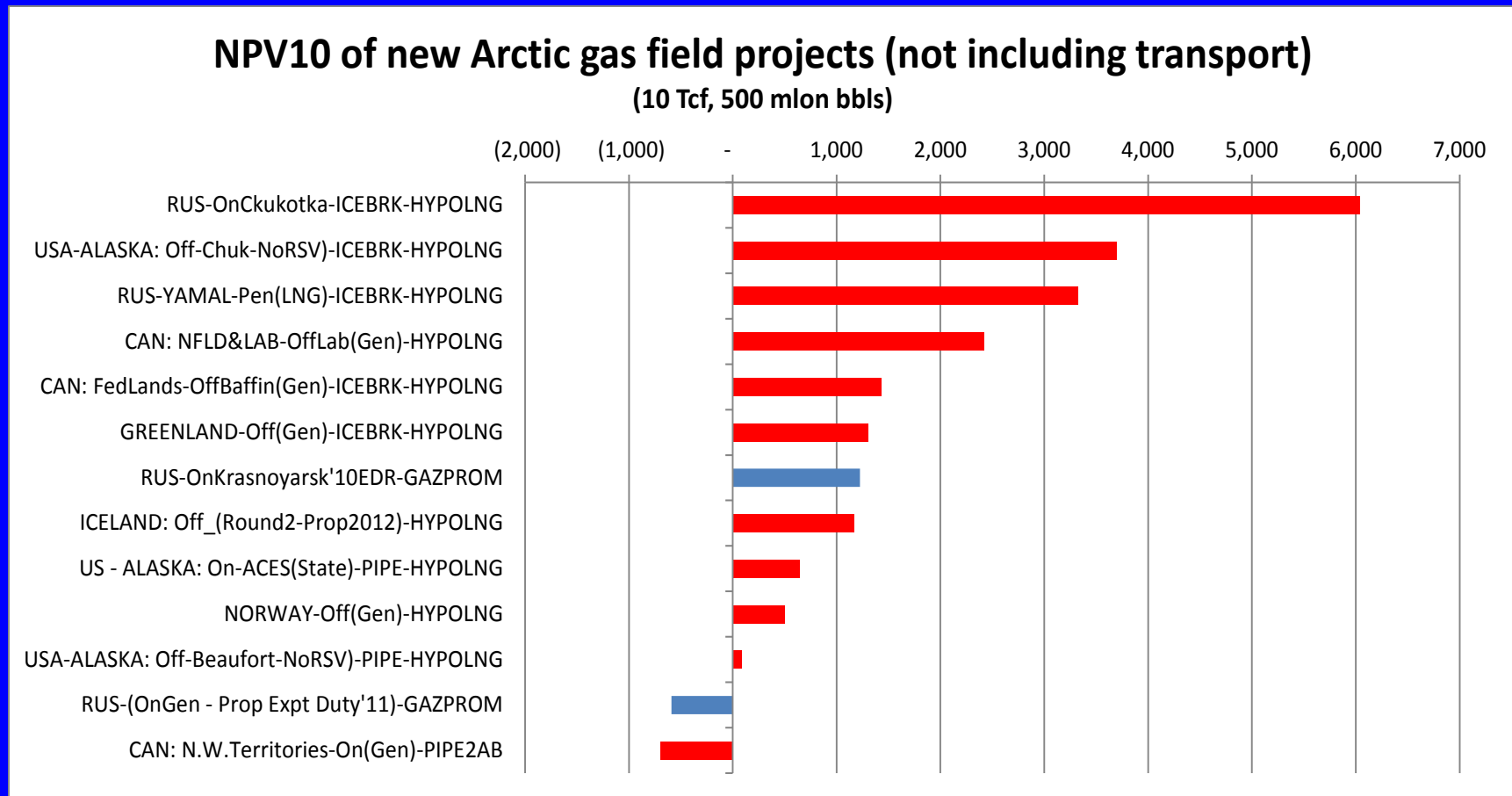
Arctic (Gas)

IRR of new Arctic gas field projects (not including transport) (10
Tcf with 500 mln condensates)



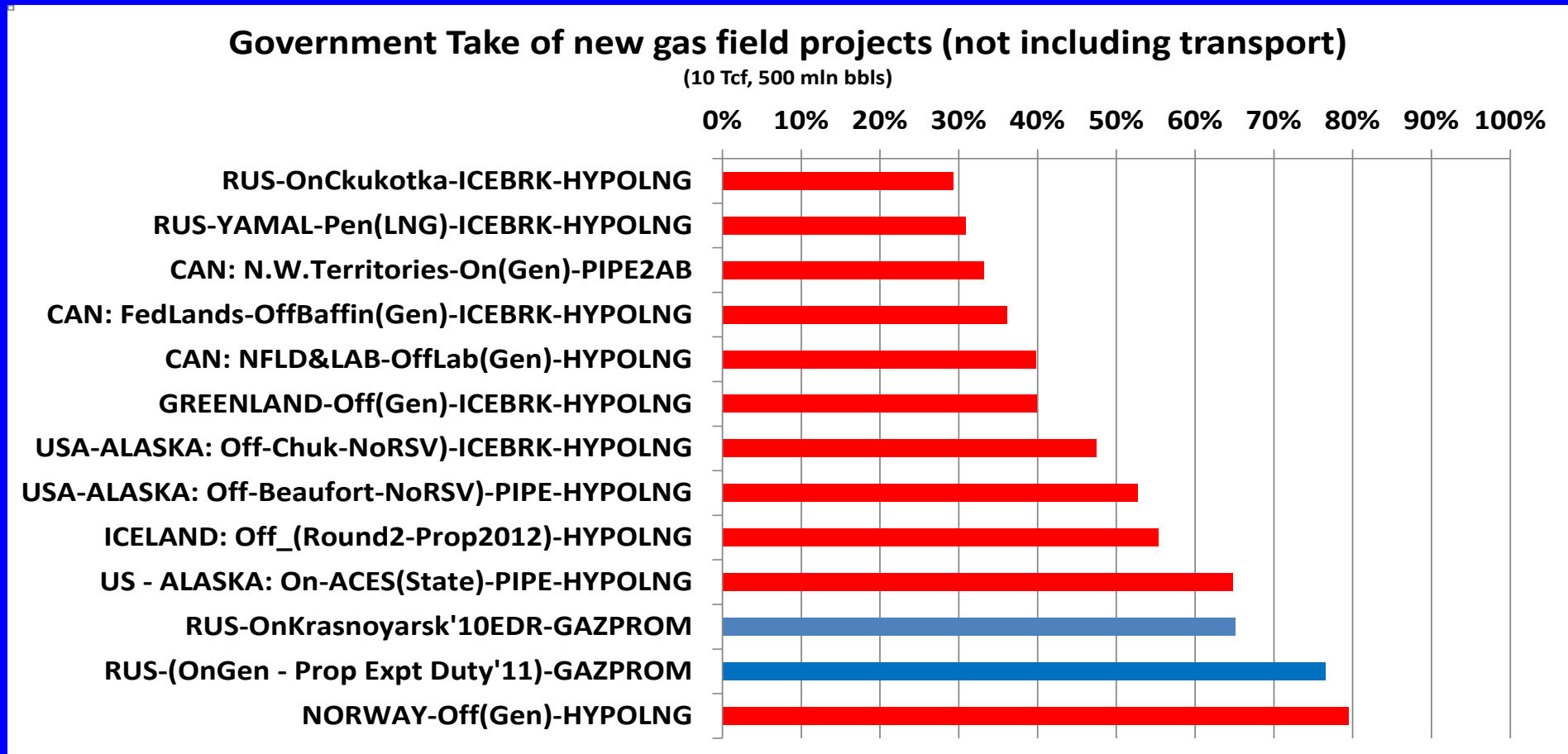
Alaska gas aimed at Pacific LNG does not compete well with other Arctic gas export opportunities. IRR is well below Yamal Peninsula project

Arctic (Gas)



Alaska gas aimed at Pacific LNG does competes poorly on an NPV10 basis with other Arctic LNG.

Arctic (Gas)



Alaska government take for gas aimed at Pacific LNG markets is about 25% to 30% too high compared to strong Russian competition.

Deep Water (Gas)

Compared to Arctic jurisdictions and other jurisdictions around the Pacific, Alaska has favorable and unfavorable features with respect to the Pacific LNG trade.

Favorable is the fact that the gas is produced as by-product to oil and is currently being re-injected. Production costs are therefore negligible.

Unfavorable features are that Alaska gas:

- Is mostly already stripped of its liquids,
- Is high in CO₂ content, and
- Exports by pipeline or ice-reinforced LNG tankers directly from Prudhoe Bay will be expensive.

Given the strong challenges of Russia, Australia, PNG and Chinese producers themselves, Alaska would have to offer a government take in the range of 45-55% (not including direct participation) in order to be competitive.

Session 4

Alaska Policy Issues

An Alaska policy issue for Wednesday:

Should Alaska offer a government take in the range of 45% – 55% under current prices for natural gas in order to make natural gas in the Pacific market competitive?

Session 5

Future Scenarios for Alaska

This session will deal with future scenarios for Alaska taking into account developments in:

- **The net back value of Alaska crude oil**
- **The Henry Hub gas price**
- **The JCC gas price**

FUTURE SCENARIOS FOR ALASKA

Any multi-billion dollar initiative to increase crude oil or liquid production substantially or to export significant volumes of gas will have a 10 year time line. The main opportunities are:

- **Heavy oil production**
- **Shale oil production**
- **Gas exports to North American markets**
- **Gas exports to East and South Asian markets**
- **GTL projects**

It is therefore important to review possible scenarios for the future of Alaska which could make some of these mega-projects economic and commercially viable.

FUTURE SCENARIOS FOR ALASKA

Future scenarios for Alaska are largely driven by price developments with respect to three indicators:

- **The netback value of Alaska crude**
- **The Henry Hub price**
- **The linkage of LNG contracts to the Japanese Crude Cocktail import price**

In this respect the anticipated price scenarios for the 2022 – 2042 period are important. Oil and gas price predictions have been consistently wrong. Therefore, it is a better policy tool to develop different scenarios and investigate the opportunities Alaska has under each of the scenarios.

The likelihood for investment in Alaska are furthermore determined by:

- **a variety of commercial conditions,**
- **the fiscal terms offered by Alaska,**
- **The fiscal stability offered in relation to these terms, and**
- **Developments in the US Federal corporate income tax rate**

FUTURE SCENARIOS FOR ALASKA

Alaska Crude Netback prices

Three different scenarios will be considered for the year 2022. All price levels are in real terms (corrected for inflation).

These scenarios are for Alaska Crude oil and the relative probability are:

- **HIGH** **Netback > \$ 120 per barrel** - 50%
- **AVERAGE** **\$ 80 < Netback < \$ 120 per barrel** – 30%
- **LOW** **\$ 80 per barrel > Netback** – 20%

Probability estimates are based on my assessments.

FUTURE SCENARIOS FOR ALASKA

Alaska Crude Netback prices

Increases/decreases in oil supply and demand (million bopd) estimated for 2022		
Policy change required		
Major new discoveries required		
SUPPLY	HIGH	LOW
North Am Shale Oil	2.0	0.5
Alberta Oil Sands	2.0	1.0
Brazil (below salt)	1.5	0.5
Mexico	1.0	-0.5
Venezuela heavy oil	1.5	0.0
Libya	0.5	0.0
Nigeria	0.5	-0.5
Angola(below salt)	1.0	0.0
Other Africa	1.5	0.5
Iraq	7.0	1.0
Kuwait	1.0	0.5
Saudi Arabia	4.0	2.0
Qatar	0.5	0.0
Iran	3.0	0.0
Russia	2.0	0.0
Kazakhstan	1.0	0.0
Int Shale Oil	1.0	0.0
Other Heavy Oil	1.0	0.0
TOTAL SUPPLY INCREASE	32.0	5.0

The future oil supply picture is highly uncertain. New oil supplies depend on the further developments in unconventional oil and new conventional discoveries. However a major factor is political developments in major oil producing countries

FUTURE SCENARIOS FOR ALASKA

Alaska Crude Netback prices

TOTAL SUPPLY INCREASE	32.0	5.0
Decline of Other Prod	-3.0	-8.0
NET AVAILABLE SUPPLY	29.0	-3.0
DEMAND CHANGE	-1.0	18.0
OVER/SHORT	30.0	-21.0

The uncertainties with respect to future oil supply are further compounded by considerable uncertainty about oil demand. Considerable oil shortages resulting in high oil prices as well as significant oversupply situations resulting in low oil prices can both be contemplated.

FUTURE SCENARIOS FOR ALASKA

Alaska Crude Netback prices

High – 50%

The HIGH scenario will require:

- **Strong ongoing demand for crude oil (1 – 2 million bbl/year increases)**
- **Ongoing constraints in crude oil supply.**

Strong ongoing demand for crude oil will occur when:

- **Asian and Latin American economies continue to grow strongly**
- **Transition to renewable energy is slow due to lack of technological progress**
- **Demand is not reduced as a result of low carbon taxes or strong restrictions in licenses for carbon trading.**

Ongoing supply constraints will occur when:

- **Political events will continue to constrain growth in oil production in countries such as Venezuela, Iran, Iraq, Libya, Nigeria, Russia, Kuwait and Mexico**
- **Technology improvements in oil sands and oil shale production are slow**

FUTURE SCENARIOS FOR ALASKA

Alaska Crude Netback prices

Average – 30%

The AVERAGE scenario will materialize with:

- **Modest ongoing demand for crude oil (0.5 – 1 million bbl/year increases)**
- **Modest constraints in crude oil supply.**

Modest ongoing demand for crude oil will occur when:

- **Growth in Asian and Latin American economies slows down**
- **Some technological discoveries result in important cost reductions for certain renewable energy supply sources**
- **Demand is gradually reduced as a result of carbon taxes and carbon trading due to increasing climate change concerns**

Modest supply constraints will occur when:

- **Some exporters will follow a rapid export growth path (for instance Libya, Iraq, Brazil, Russia ?)**
- **Technology improvements in oil sands and oil shale production continue to create lower costs per barrel**
- **Asian and Russian government takes are reduced**

FUTURE SCENARIOS FOR ALASKA

Alaska Crude Netback prices

Low – 20%

The LOW scenario will occur with:

- **No or very modest demand growth or even a demand decline.**
- **Ample crude oil supplies**

Very modest ongoing demand or a demand decline for crude oil will occur when:

- **The economy of China implodes and India paralyses.**
- **Strong technological development in renewable energy resulting in significant cost reductions occur.**
- **Demand is strongly reduced as a result of carbon taxes and carbon trading due to increasing climate change concerns**

Ample crude oil supplies will be available when:

- **Many oil exporters follow a rapid export growth path**
- **Technology improvements in oil sands and oil shale production continue to create strongly lower costs per barrel.**
- **West African, Asian and Russian government takes are reduced**

FUTURE SCENARIOS FOR ALASKA

Henry Hub gas prices

With respect to Henry Hub three scenarios are considered for the year 2022:

- HIGH HH > \$ 7.50 per MMBtu - 20%**
- AVERAGE \$ 5 .00 < HH < 7.50 per MMBtu – 50%**
- LOW \$ 5.00 per MMBtu > HH – 30%**

Probability estimates are based on my assessments.

FUTURE SCENARIOS FOR ALASKA

Henry Hub gas prices

High – 20%

The HIGH scenario will require:

- **Strong demand for gas in North America**
- **Constraints in gas supplies.**

Strong ongoing demand for gas will occur when:

- **The North American economy recovers from the current weak performance and regains a strong growth.**
- **Introduction of carbon trading or/and carbon taxes due to significant concerns about climate change, thereby reducing coal fired power generation.**
- **Weak performance of renewable power sector.**

Supply constraints will occur when:

- **Environmental concerns about shale gas, limit or curtail production.**
- **Technology improvements in gas production are slow.**
- **A significant share of the North American gas is exported as LNG because of more attractive gas markets abroad from Canada and the Lower 48 States.**

FUTURE SCENARIOS FOR ALASKA

Henry Hub gas prices

Average – 50%

The AVERAGE scenario will materialize with:

- **Modest ongoing demand for gas**
- **Modest growth of gas supplies.**

Modest ongoing demand for gas will occur when:

- **The North American economy maintains a modest economic growth path.**
- **Coal fired power generation continues to expand.**
- **Important growth occurs in the renewable energy supplies for power generation.**

Modest supply growth will occur when:

- **Relatively low cost gas resources are less than expected and supplies require higher prices.**
- **Only limited volumes of gas are exported as LNG.**
- **Technological development in gas production is less than expected**

FUTURE SCENARIOS FOR ALASKA

Henry Hub gas prices

Low – 30%

The LOW scenario will require:

- **Slow growth or decline in demand**
- **Ample gas supplies.**

Slow growth or a decline in demand will occur when:

- **North America experiences a second recession and economic growth remains slow.**
- **Coal fired power generation continues to expand.**
- **Technological breakthroughs make renewable energy, in particular residential renewable energy, economic.**

Ample gas supplies occur when:

- **Shale gas, coal bed methane and tight gas resource continue to expand production because of relatively low cost supplies.**
- **Advances in technology continue to reduce costs of gas production.**
- **Limited volumes are exported as LNG.**

FUTURE SCENARIOS FOR ALASKA

JCC linked gas prices prices

It is likely that by 2022, LNG import gas prices in Japan will still be based on a link with JCC. For the year 2022 this link is expressed as a percent of the JCC price. The following links can be estimated as follows:

- **HIGH** **JCC link > 14%** **- 40%**
- **AVERAGE** **8% < JCC link < 14% per MMBtu** **- 40%**
- **LOW** **8% > JCC link** **- 20%**

Probability estimates are based on my assessments.

FUTURE SCENARIOS FOR ALASKA

JCC gas prices – oil link

High – 20%

The HIGH scenario will require:

- **Strong demand for gas in East Asia**
- **Constraints in gas supplies.**

Strong ongoing demand for gas will occur when:

- **The East Asian economies continue on a strong growth path.**
- **Concerns about nuclear energy and policies**
- **Carbon trading schemes or carbon taxes lower coal power generation.**
- **Weak performance of renewable power sector.**

Supply constraints will occur when:

- **China fails to develop its large coal bed methane and shale gas resources**
- **Australian LNG supplies limited because of political issues.**
- **A wide variety of other LNG supplies and Russian pipeline gas supplies fail to materialize as a result of a variety of political and commercial issues.**

FUTURE SCENARIOS FOR ALASKA

JCC gas prices – oil link

Average – 40%

The AVERAGE scenario will require:

- **Average demand growth in East Asia**
- **Average gas supplies.**

Average ongoing demand for gas will occur when:

- **The gradual reduction in economic growth in East Asia**
- **Modest performance of renewable power sector.**

Average supply conditions will occur when:

- **China gradually expands its coal bed methane and shale gas production.**
- **Australia continues on its LNG export growth path**
- **Russian gas exports by pipeline to China materialize.**

FUTURE SCENARIOS FOR ALASKA

JCC gas prices – oil link

Low – 40%

The LOW scenario will require:

- **Slow growth or decline in gas demand in East Asia**
- **Ample gas supplies.**

Slow growth or a decline in demand will occur when:

- **The Chinese economy implodes or encounters significant growth difficulties.**
- **Coal fired power generation continues to expand.**
- **Technological breakthroughs make renewable energy economic in certain applications**

Ample gas supplies occur when:

- **Chinese coal bed methane and shale gas grow strongly**
- **Russian pipelines to China and Russian Arctic LNG projects for Asian markets materialize**
- **Malaysian and Indonesian LNG exports regain momentum through lower fiscal terms**
- **In addition to Australian LNG, LNG from some of the following new projects (Indian Ocean, Iraq, Iran, Qatar, South Atlantic) come on stream.**

FUTURE SCENARIOS FOR ALASKA

JCC linked gas prices - Valdez

The LNG import price in Japan will be the result of the combination of the crude price forecast and the forecast of the LNG link. It is likely that based on an LNG export line from Valdez producers would seek a \$ 4 per MMBtu netback on average. Assuming that the transport and liquefaction costs from the North Slope are about \$ 8 per MMBtu, the gas import price in Japan has to be \$ 12.00 per MMBtu or higher by 2022.

Following diagram illustrates how the probability of this occurring is about 36%.

Probability structure of Japanese LNG import price (\$/MMBtu)		20%	30%	50%
		80	100	120
40%	0.08	6.40	8.00	9.60
40%	0.11	8.80	11.00	13.20
20%	0.14	11.20	16.80	16.80

FUTURE SCENARIOS FOR ALASKA

JCC Net backs - 3 Bcf/day

Even with a probability of an attractive Japanese LNG import price of about 36%, by 2022, the probability that a large LNG export project will actually be build is low.

The reason is that in order to achieve a \$ 8 net back costs, the pipeline to Valdez or Kenai has to export large volumes, probably about 3 Bcf of gas. This means such a pipeline will need total purchase commitments for as much as 3 Bcf per day of gas for long periods. In the current LNG market where many suppliers are willing to offer much lower volumes for short periods it is unlikely that buyers are willing to make such large commitments.

Alaska would have to capture a market which is the equivalent of the entire growth in LNG demand in Japan, Korea and Taiwan at the exclusion of other suppliers. This is unrealistic.

The probability that a large diameter pipeline LNG project will materialize by 2022 is therefore very low.

FUTURE SCENARIOS FOR ALASKA

JCC netbacks – 1 Bcf/day

Based on LNG exports directly from Prudhoe Bay with icebreakers and ice-reinforced LNG tankers the transport and conditioning costs would likely be about \$ 6 per MMBtu. Therefore one needs an LNG import price in Japan of about \$ 10 per MMBtu. That this price level will be achieved by 2022 has about a 52% probability.

It is not yet known whether such a project is technically feasible in Prudhoe Bay, but Russia is carrying out similar LNG projects.

Alternatively the Alaska Government could heavily subsidize a much smaller pipeline project to Valdez or Kenai aimed at local consumption and limited LNG exports. Subsidy may be recovered under high price conditions.

The probability of being able to enter the market by 2022 with a 1 Bcf per day project is reasonable, but probably less than 50%.

FUTURE SCENARIOS FOR ALASKA

JCC netbacks – 1 Bcf/day

If Alaska decides that it is important to have a Alaska gas pipeline permitting 1 Bcf per day of exports from Kenai, the probability of capturing Asian LNG markets could be significantly enhanced with a strongly subsidized gas pipeline (and assuming a 45% - 55% government take on the gas).

In order to create a high probability for such a project, subsidies should permit producers to land gas for as low as \$ 8 per MMBtu in East Asia, with a \$ 2 per MMBtu netback on the North Slope. This means maximum gas transport costs on the line would have to be \$ 1 per MMBtu. This could be done through a cost recoverable subsidy. Alaska would fund the subsidy initially. The subsidy would be recovered through a share of a gas price windfall margin under high landed gas price conditions in East Asia. The probability that such a scheme would break even over about 20 years is probably 50/50.

FUTURE SCENARIOS FOR ALASKA

GTL conditions

There is a probability of about 20% that we would have the unusual combination of high oil prices and low JCC and HH gas prices.

This would be the best economic environment for GTL plants.

As long as the oil price is over \$ 120 per barrel and the feed gas price is \$ 3 per MMBtu or less, it may be possible to develop such a project economically.

It should be noted, however, that under these conditions GTL would be attractive anywhere in the world and there would be no particular reason to build a plant on the North Slope.

There is a low probability that such a project would be realized under these conditions.

FUTURE SCENARIOS FOR ALASKA

GTL conditions

However, Alaska could strongly stimulate GTL development in conjunction with modest LNG exports, since there would be sufficient gas on the North Slope.

Assuming crude oil prices would be high and JCC prices would be attractive, GTL on the North Slope would be a “natural” fit .

Alaska could stimulate such a development strongly with fiscal terms which are attractive to investors and pre-approval of an attractive low gas feed price.

Under these conditions there may be a 50/50 chance that such a project would be realized in the 2022 time frame

FUTURE SCENARIOS FOR ALASKA

Summary

Type of development start prior to 2022	Gov Take at \$ 100/bbl	Significant development probability
Existing Operatings	70 - 75%	Certain
Infill Wells	70 - 75%	Certain
New light oil fields	60 - 65%	Certain
Heavy Oil > 15 API	55 - 60%	Probable, depending on oil price
Heavy Oil <15 API	45 - 55%	Low
Shale Oil	45 - 55%	Fair, depending on pilot project
N Am gas Line	45 - 55%	Very Low
LNG - 3 Bcf single project	45 - 55%	Very Low
LNG - 1 Bcf by pipe	45 - 55%	Low
LNG - 1 Bcf by icebreaker	45 - 55%	Fair, if technically possible
LNG - 1 Bcf, pipe subsidized	45 - 55%	High
GTL - low gas price	45 - 55%	Low
GTL - high gas price	45 - 55%	Fair, with low feed price