ECONOMIC ANALYSIS OF THE ALASKA STRANDED GAS FISCAL CONTRACT

April 17, 2006
Pedro van Meurs

EXECUTIVE SUMMARY

This report compares the economics of three different fiscal options open to Alaska with respect to the Alaska Gas Project:

- **The current gas fiscal terms on the North Slope ("Status Quo")**
- **The proposed Alaska Stranded Gas Fiscal Contract ("ASGFC"), and**
- **The ASGFC enhanced with PPT credits on the GTP and lateral lines ("A+GTP")**

The Alaska Gas Project is a highly unique and unusual project from an economic perspective.

A successful Alaska Gas Project would provide the Sponsors and other producers with the largest bookable reserve in the world in a single project. Given the fact that even the major oil companies have difficulty maintaining adequate reserve/production ratios, this is a huge benefit to them.

Under current gas prices the undiscounted net cash flow ("NCF") of the project to the producers is the largest in the world. In constant 2006 $ dollar terms at $ 6.50 per MMBtu in Chicago a project that would terminate in Alberta would generate a total net cash flow of $ 121.6 billion to the producers under the Status Quo fiscal terms. This is a phenomenal amount of cash (the model assumes only a 30 year cash flow).

Even at a low price of $ 3.50 per MMBtu (or $ 22 per barrel WTI) the net cash flow would still be $ 50.7 billion. This would still be one of the highest net cash flows in the world.

The huge cash flow is due to the enormous size of the project.

However, it is also the result of the relatively low operating costs of the project. Most of the gas will be derived from Prudhoe Bay were incremental gas production costs will be nil. The operating costs of the midstream are low. The operating costs for the project are therefore only $ 0.34 per MMBtu.

Under current gas prices of $ 6.50 per MMBtu, the Net Present Value discounted at 10% ("NPV10") of the project is huge. Under Status Quo fiscal terms the NPV10 would be $ 12.7 billion in real 2006 $. This is among the highest NPV10 values in the world for a single project.

Given these spectacular economics, why is the Alaska Gas Project not going forward on the basis of the current fiscal terms on a normal commercial basis?

Why do we need a stranded gas contract?

The last three decades have proven that oil and gas price predictions are notoriously unreliable. In the late 70's an energy crisis was predicted with oil prices going up to very high levels. Then prices crashed in the mid 1980's. Only three years ago, the average long term oil price forecast was $ 25 per barrel, but they now exceed $ 60 per barrel. There is a significant possibility that oil and gas prices may be substantially lower again at some time in the future.

Therefore, a very large project with a very long lead time, requiring $ 20 billion or more, needs to be evaluated on the basis of a variety of possible scenarios of gas prices and costs.

In this study the following forecasts for the Chicago gas prices (2006 $) were used as representative of the currently prevailing conditions of major oil company views about the future:

- **A low forecast of $ 3.50 per MMBtu (the "stress price")**
- **An average forecast of $ 5.50 per MMBtu, and**
- **A high forecast of $ 8.50 per MMBtu**

Currently, major oil companies use low price forecasts of $ 20 - $ 25 per WTI in order to test the economics of investment projects. This corresponds with the low forecast of $ 3.50 per MMBtu in Chicago. Therefore, extensive analysis was done on the Alaska Gas Project based on this stress price.

Also cost sensitivity was done based on 90% to 150% of capital and operating costs.

Furthermore, economics was done for a project ending in Alberta and in Chicago.

At this time it appears that a share of the gas can be delivered to Alberta without need for further pipelines based on an estimated take-away capacity of 2 Bcf/day in 2015. For the remaining gas, take-away capacity needs to be secured in order to deliver the gas to the Chicago area. This means the actual economics of the project will be somewhere between the Alberta and Chicago economics. Profitability indicators for a project ending in Chicago are lower than a project ending in Alberta. This is because of the much higher midstream investment that is required.

Seven profitability indicators were used to evaluate the Alaska Gas Project from the perspective of the investors:

- **The internal rate of return (“IRR”)**
- **The net present value discounted at 10% (“NPV10”)**
- **The profitability ratio discounted at 10% (“PFR10”)**
- **The undiscounted net cash flow (“NCF”)**
- **The NPV10 per barrel equivalent (“NPV10/BOE”)**
- **The NPV10 over undiscounted capital expenditures (“NPV10/Capex”), and**
- **The NCF per barrel equivalent (“NCF/BOE”)**

The importance of each of these profitability indicators is explained in more detail in the main report.

PFC Energy did a study on 60 competing oil and gas projects around the world requiring a capital investment of more than one billion dollars.

Based on this study each profitability indicator (in real 2006 $) was calibrated in such a manner that each target represented a value whereby 20% of the projects were less attractive and 80% of the projects were more attractive.

A project is unattractive when many of the indicators are below the targets or when some of the indicators are substantially below the targets. It should be noted that these targets only apply to the stress price of $ 3.50 per MMBtu in Chicago. At higher prices companies would select higher targets.

The following table illustrates the target values and whether the target values are being achieved. Values in “bold” mean that the target is not being achieved.

Minimum Criteria and the Alaska Gas Project in real 2006 $
At $ 3.50 stress price - no cost overruns

		Target	**Status Quo Alberta**	**Status Quo Chicago**	**ASGFC Alberta**	**ASGFC Chicago**	**A+GTP Alberta**	**A+GTP Chicago**
IRR	(%)	13%	**11.8%**	**10.5%**	13.5%	**11.9%**	14.0%	**12.2%**
NPV10	($ million)	2500	**1685**	**664**	2786	**2209**	3098	2520
PFR10	($/$)	1.15	1.18	**1.05**	1.35	1.19	1.39	1.21
NCF	($ billion)	20	50.8	62.5	50.2	60.5	50.7	61.0
NPV10/BOE	($/barrel eq)	0.33	**0.23**	**0.09**	0.38	**0.30**	0.42	0.34
NPV10/Capex	($/$)	0.12	**0.09**	**0.02**	0.17	**0.10**	0.19	**0.11**
NCF/BOE	($/barrel eq)	2.50	6.90	8.49	6.83	8.22	6.90	8.29

The table illustrates how under the Status Quo option and the low price of $ 3.50 per MMBtu the Alaska Gas Project would not be viable. Many profitability indicators are below the targets and the IRR and NPV10 are well below minimum requirements, in particular for the Chicago Project. It is therefore highly unlikely that investors would go forward with this project under Status Quo fiscal terms.

The main focus of the stranded gas contract is to improve significantly the economics under the stress price.

This is mainly being achieved by taking the royalty and production tax gas in kind and assuming directly the shipping and marketing obligations of the gas. In order to balance this commitment the State participates directly in the midstream project for 20%.

The ASGFC option would result in acceptable profitability indicators for Alberta Project. The Chicago Project would be a very weak project with a very low IRR and modest NPV10. Economics somewhere between the Alberta and Chicago Projects create a viable project. Therefore, the ASGFC option results in acceptable conditions at the stress price.

By providing additionally the PPT credits on the GTP and lateral lines the profitability indicators improve enough to make also the Chicago Project more attractive. Therefore, the ASGFC+GTP option would create economics under the stress price that are well in excess of minimum requirements.

What about cost overruns?

The table below shows the same table as above but now with a 10% cost overrun for capital and operating expenditures.

Minimum Criteria and the Alaska Gas Project in real 2006 $
At $ 3.50 stress price - 10% cost overruns

		Target	**Status Quo Alberta**	**Status Quo Chicago**	**ASGFC Alberta**	**ASGFC Chicago**	**A+GTP Alberta**	**A+GTP Chicago**
IRR	(%)	13%	**10.9%**	**9.6%**	**12.5%**	**11.0%**	13.0%	**11.3%**
NPV10	($ million)	2500	**924**	**-519**	**2128**	**1171**	**2471**	**1514**
PFR10	($/$)	1.15	**1.09**	**0.97**	1.25	**1.09**	1.29	**1.12**
NCF	($ billion)	20	49.7	60.8	49.0	58.6	49.6	59.1
NPV10/BOE	($/barrel eq)	0.33	**0.13**	**-0.07**	**0.29**	**0.16**	0.34	**0.21**
NPV10/Capex	($/$)	0.12	**0.05**	**-0.02**	0.12	**0.05**	0.14	**0.06**
NCF/BOE	($/barrel eq)	2.50	6.76	8.27	6.67	7.96	6.74	8.03

Under the stress price and a 10% cost overrun both the Status Quo and ASGFC options are unattractive. The ASGFC+GTP option is very marginal.

This indicates that cost overruns are a very serious risk.

This also illustrates that even with a stranded gas contract it remains essential for the investors to lower costs and take extensive preparatory steps in order to avoid such cost overruns.

What is also clear from the table is that under these conditions the main attraction of the project is the very large net cash flow and the attractive NCF/BOE results.

The profitability "anchor" of the Alaska Gas Project is therefore the attractive net cash flow.

However, this makes fiscal stability essential. Investors have to be able to count absolutely on the attractive net cash flow in order to pull the project through under possible dismal downside conditions.

What are the benefits to Alaska of the proposed stranded gas contract?

From a fiscal perspective the main benefit for Alaska is the massive new Alaska income for the State and Municipal governments from this project.

The following two table shows the Total Alaska Income of the State and Municipalities for the three fiscal options for the Alberta Project and Chicago Project. The total income includes for the ASGFC and ASGFC+GTP options the return of the State on its investment in the pipeline.

TOTAL ALASKA INCOME (before financing)

Alberta Project	Real 2000 $ ($ million)		
	Status Quo	ASGFC	A+GTP
$2.50	13433	13288	12501
$3.50	24250	24124	23337
$4.50	35307	35189	34402
$5.50	46213	46103	45315
$6.50	57192	57089	56302
$7.50	68153	68058	67271
$8.50	79064	78976	78189

TOTAL ALASKA INCOME (before financing)

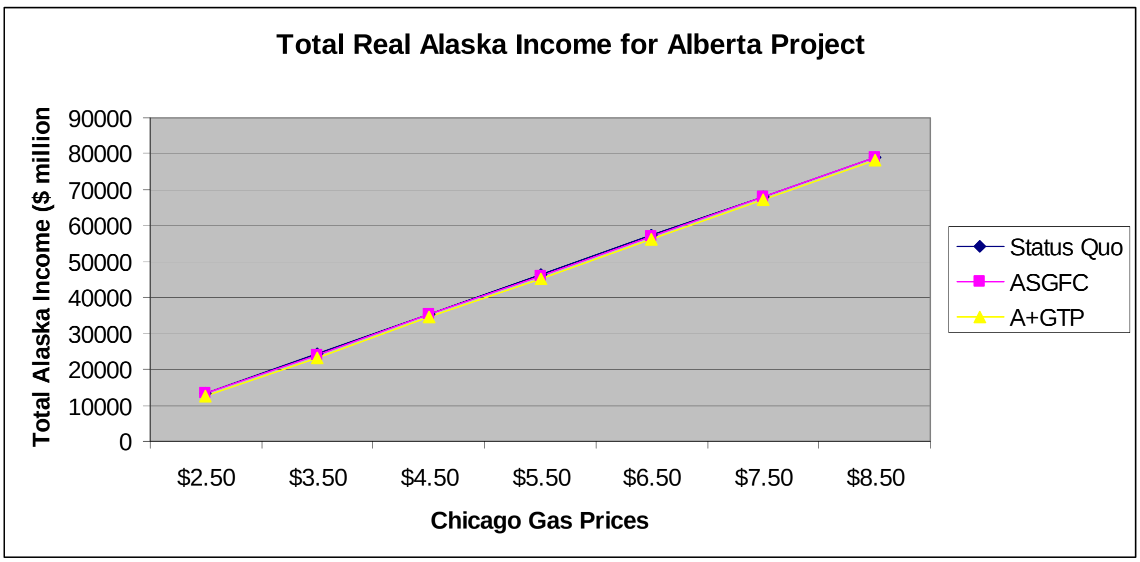
Chicago Project	Real 2000 $ ($ million)		
	Status Quo	ASGFC	A+GTP
$2.50	15472	17034	16247
$3.50	26302	27872	27085
$4.50	37390	38967	38180
$5.50	48300	49885	49098
$6.50	59289	60881	60094
$7.50	70255	71855	71068
$8.50	81166	82773	81986

These tables are on a before financing basis. The cost of interest payments on debt in real terms under the Alberta project is about $ 1 billion and on the Chicago project $ 1.5 billion. On an after financing basis these costs need to be deducted.

The differences between the Status Quo and the ASGFC are the following:

- **The State gains income on its investments in the midstream and the midstream municipalities gain some income as a result of the change of the property tax to a c/MMBtu basis.**
- **The State looses marketing costs of the gas, the Upstream Cost Allowance and the State share of property taxes outside municipal boundaries along the pipeline right of way.**

The end result is only minor differences between the three options, as can also be seen from the Chart below. Of course, with the PPT credit there is a loss due to this credit, which is small in the total context.

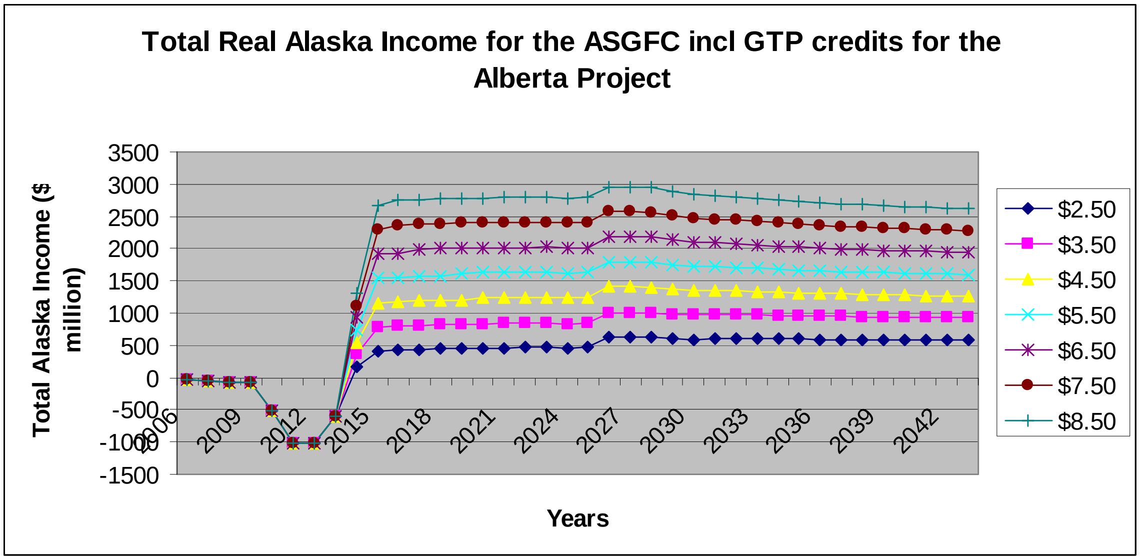


The following chart shows the income under the ASGFC+GTP option on a yearly basis.

Even at a price of only $ 2.50 per MMBtu (in constant 2006 $) the State of Alaska will still gain considerable income in real terms.

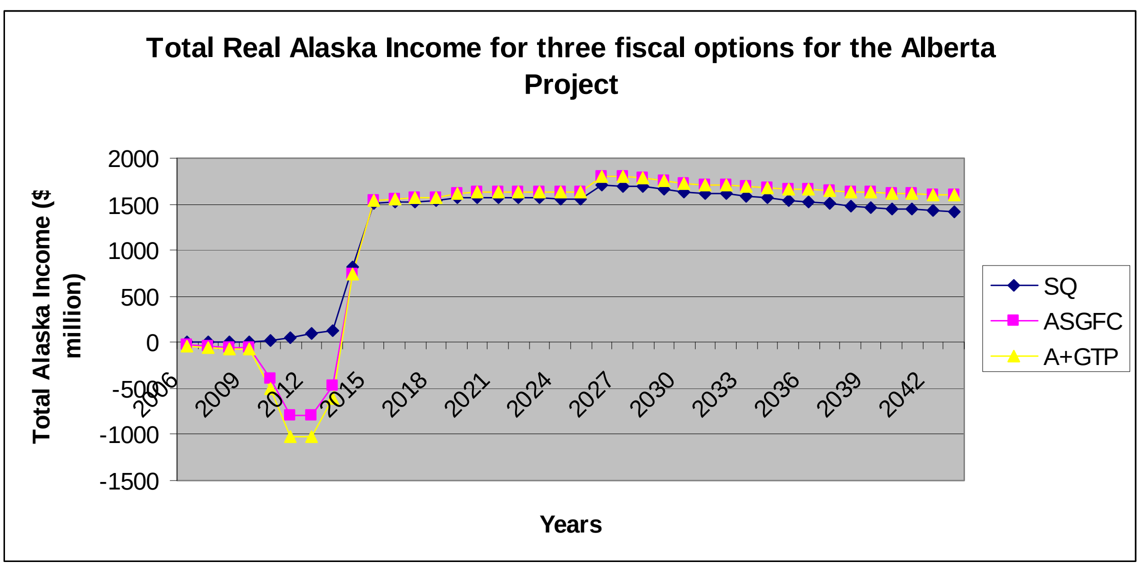
The Alaska income per year is about as follows in real terms:

- **At low prices: $ 1 billion per year**
- **At average prices: $ 1.7 billion per year, and**
- **A high prices $ 2.7 billion per year.**



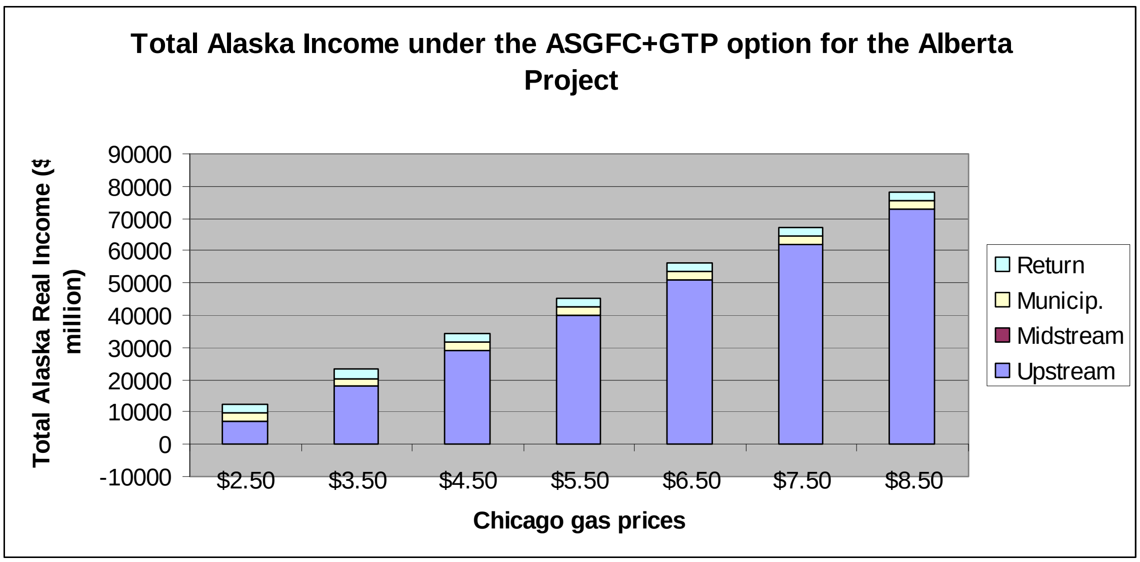
The following chart shows the year by year differences between the fiscal options.

The difference with the Status Quo is that during the construction period the State will co-invest in the construction of the midstream. During the subsequent years the State receives slightly higher income than would otherwise be the case under the Status Quo.



The risk distribution of the Total Alaska Income is favourable. At low Chicago gas prices, the property taxes received by the municipalities and the investment income by the State from the midstream investments remain unaltered. This illustrates how this income provides a "safety net" during low gas prices.

At the same time, however, the PPT credits on the GTP and lateral lines are about equal to the midstream income in corporate income tax that the State would otherwise receive and therefore the midstream income is essentially nil.



Are the terms of the Alaska Stranded Gas Fiscal Contract competitive?

Despite the high income for the State, the question can be raised whether this is a competitive deal from an international perspective and whether maybe not more could be obtained.

The table below illustrates the total government take (Federal and Alaska) from the project. At the average price forecast of $ 5.50 per MMBtu, the government take is about 51%.

TOTAL GOVERNMENT TAKE

Alberta Project		Real 2000 $	
	Status Quo	ASGFC	A+GTP
$2.50	52.4%	53.1%	52.2%
$3.50	51.4%	51.8%	51.3%
$4.50	51.2%	51.4%	51.1%
$5.50	51.0%	51.2%	50.9%
$6.50	50.9%	51.1%	50.8%
$7.50	50.8%	51.0%	50.8%
$8.50	50.8%	50.9%	50.7%

This is a very competitive government take compared to other long distance gas exporters aimed at the Lower 48 US market. At this point in time large volumes of stranded gas are being developed and marketed as LNG and in some cases based on long distance pipelines. Other governments now typically have a government take for long distance export gas that is about ten percentage points less than for oil.

Alaska compares favourably in this competitive environment.

The Alaska take share of this overall government take is about 23% as can be seen from the table below.

TOTAL ALASKA TAKE

Alberta Project		Real 2000 $	
	Status Quo	ASGFC	A+GTP
$2.50	23.6%	23.5%	22.1%
$3.50	23.2%	23.1%	22.4%
$4.50	23.2%	23.2%	22.6%
$5.50	23.1%	23.1%	22.7%
$6.50	23.1%	23.1%	22.8%
$7.50	23.1%	23.1%	22.8%
$8.50	23.1%	23.1%	22.8%

TABLE OF CONTENTS

1. INTRODUCTION

This report contains an economic analysis of the Alaska Stranded Gas Fiscal Contract ("ASGFC"). The purpose of the analysis is to provide the necessary information for public debate and discussion. During the negotiations, on an ongoing basis, economic analysis was done of various proposals and concepts.

Various models were used: the DOR model, primarily developed by Roger Marks, the DNR model, primarily developed by William Nebesky and the PVM model, developed by myself (Pedro Van Meurs). At several points in time the models were tested based on the same inputs in order to ensure that the three models provided generally the same results. This proved to be the case and therefore, this provides an assurance that the results of all three models are reliable. The PVM model is a gas only model. It does not take into consideration the investments in oil production, oil revenues and oil losses in Prudhoe Bay. The DNR and DOR models are both oil and gas models. The DNR model is more complex than the DOR model.

Initially as lead negotiator and subsequently as senior economic consultant to Alaska, I used primarily the PVM model for decision making and therefore I use this model also for this economic report.

In this report first the PVM model will be discussed. Then the report will define and review the Status Quo. Finally, it will discuss economics of the ASGFC from the perspective of the State and the producers.

2. PVM Model.

2.1. Model Structure

The PVM model is a gas only model. It does not include revenues from oil or condensates. Nor does it include the oil losses in Prudhoe Bay as a result of the production of the gas. At the same time oil related capital and operating expenditures are not included. With respect to Point Thomson, it was assumed that 75% of the capital and operating expenditures would be attributable to gas.

The PVM model is a relatively simple cash flow model based on Excel. A cash flow is prepared of each project component. The model is set up to permit two options for the project:

- A project delivering gas to Chicago ("Chicago Project"), and
- A project delivering gas to AECO Alberta ("Alberta Project").

The project components for the Chicago Project are the following:

- Upstream
- Point Thomson Feeder
- Gas Treatment Plant
- Alaska Mainline
- Canada Mainline and Extraction Plant
- Lower 48 pipeline.

The project components for the Alberta Project are:

- Upstream
- Point Thomson Feeder
- Gas Treatment Plant
- Alaska Mainline
- Yukon Border – Alberta Border Mainline
- Alberta Hub.

With a toggle the model can be switched from the Chicago to the Alberta Project.

There are separate sheets to determine the tariffs, property taxes and State/Provincial and Federal Income taxes for each of the downstream components.

The tariffs are calculated separately for the State of Alaska and the producers, as if the structure was an undivided joint venture. Since the State would not pay income tax on the components in the United States, the tariffs are slightly different. At this time there is no agreement with the Sponsors as to how to share the tariff revenues in the LLC's and therefore the State versus Sponsor differences in tariff income were maintained in the model.

For the Upstream cash flow the "well head value" is calculated as follows:

- Under the Chicago Project: the Chicago price, less the tariffs for the Lower 48, Canadian Mainline, Alaska Mainline and GTP and for the Point Thomson gas also the Point Thomson Feeder.
- Under the Alberta Project: the Chicago price, less the Alberta-Chicago gas price differential, less the Alberta Hub costs, less the tariffs for the Yukon-Alberta border mainline, the Alaska mainline, the GTP and for Point Thomson gas also the Point Thomson Feeder.

Therefore under either option the input variable is the Chicago gas price in $/MMBtu.

The model is a total producer model and it therefore does not distinguish between gas from the Sponsors and other possible gas being produced and transported.

The cash flow is starting year 2006. First gas transport is assumed to occur in 2014. Therefore an 8 year period is used for the preparatory studies, regulatory processes and construction of the pipeline. The cash flows terminate in 2043 for a total production period of 30 years.

2.2. Model Inputs

The main economic input variables are the following:

- Chicago gas price
- AECO-Chicago differential
- Alberta Hub Entry Fee
- Total Capital Cost of the Chicago Project
- Capital Costs of Point Thomson Feeder
- Capital Costs of Upstream activities
- Breakdown percentages of capital costs the Chicago or Alberta Projects
- Operating Costs as a percentage of component capital costs
- Cost sensitivity factor (to do cost sensitivity analysis) for initial investments
- Btu/Mcf ratio
- Year by Year Gas Production Levels for Prudhoe Bay, Point Thomson, Other gas production on State leases and Other gas production on Federal Leases.
- Capex and Opex cost escalation
- Price escalation
- CPI inflator
- Cost of GTP and pipeline debt in Canada and USA
- Cost of GTP and pipeline equity in Canada and USA
- Debt/Equity ratios in Canada and USA.
- Production duration switch (either 22 years or 30 years).
- All fiscal variables (royalty rates, tax rates, etc, depending on case to be run)

2.3. Model Outputs

The main model outputs are:

- Total Alaska Revenues broken down as: upstream revenues, municipality revenues, State midstream tax income and state midstream cash flow (in case of midstream ownership).
- Federal and Other Revenues, which includes US and Canadian Federal Governments, Provincial Governments and Lower 48 State Governments.
- Producer Revenues
- Total Divisible Income
- Producer IRR, NPV @10% and Profitability Ratio @10%.

2.4. Model Base Case Assumptions

The model base case assumptions were structured in such a way that they do not contain any confidential data. This permits the PVM model to be released as a non-confidential model.

Following are the main economic assumptions.

- *Chicago gas price.* This was the main model variable, typically analysis was done from $ 2.50 to $ 8.50 per MMBtu.
- *AECO-Chicago differential.* The differential is assumed to be $ 0.82 per MMBtu. However, in 2026 it is assumed that the differential will reduce in half due to the fact that depreciation under tariff structures is being fully recovered.
- *Alberta Hub Entry Fee.* Was assumed to be $ 0.18 per MMBtu.
- *Total Capital Cost of the Chicago Project.* Project was assumed to cost $ 20 billion in $ 2003.
- *Capital Costs of Point Thomson Feeder.* Assumed to be $ 250 million in $ 2003.
- *Capital Costs of Upstream activities.* It was assumed that initially $ 1500 million capital costs can be attributed to gas under the Point Thomson development. It is also assumed that from 2024 onwards producers have to invest $ 200 million per year in order to bring sufficient gas on stream to keep the main pipeline full for the duration of the cash flow.
- *Breakdown percentages of capital costs the Chicago or Alberta project.* It was assumed that the breakdown would be as follows: Conditioning plant - 12%, Mainline in Alaska - 25%, Mainline in Canada incl Extraction Plant – 50%, Pipeline in Lower 48 – 13%. In turn the Canadian component for a bullet line would be broken down as follows: Yukon – Alberta border – 50%, Bullet line in Alberta – 24%, Liquid Extraction – 7%, Alberta – US border – 19%.

- *Year by year capital expenditure distribution for each component*
  The year by year distribution of each component was assumed to be the same as follows:
    - 2006 – 1%
    - 2007 – 1.5%
    - 2008 – 2%
    - 2009 – 2.5%
    - 2010 - 15%
    - 2011 – 30%
    - 2012 – 30%
    - 2013 – 18%
- *Operating Costs as a percentage of component capital costs.* The following operating costs as percentage of capital costs were used: Conditioning – 2.5% all other – 1.5%.
- *Cost sensitivity factor (to do cost sensitivity analysis.* Typically analysis was done between 90% and 150%. This does not apply to the $ 200 million per year in order to maintain production.
- *Btu/Mcf ratio.* 1.08 MMBtu/Mcf
- *Year by Year Gas Production Levels for Prudhoe Bay, Point Thomson, Other gas production on State leases and Other gas production on Federal Leases.* It was assumed that at the exit of the GTP the volume of gas would be 4.3 Bcf per day. Due to energy use, the actual volumes sold in the Alberta and US markets were assumed to be 4.1 Bcf per day. It was assumed that initially Prudhoe Bay would produce 67% of this volume and Point Thomson the rest. It was assumed that Prudhoe Bay would decline 8% per year after 2028 and Point Thomson 9% per year after 2029. The pipeline would continue to operate at the 4.1 Bcf per day level, with 50% of the shortfall production supplied from State leases and 50% of the shortfall production from Federal leases.
- *Capex and Opex cost escalation:* 2%
- *Price escalation:* 2%
- *CPI inflator:* 2%
- *Cost of GTP and pipeline debt in Canada and USA:* 5.5%
- *Cost of GTP and pipeline equity in Canada and USA:* 14% in US and 12% in Canada.
- *Debt/Equity ratios in Canada and USA: 80/20.*

2.5. Model Operation Modes

The model can be operated in the nominal and real modes:

- *Nominal* - by entering the escalation factors for costs and prices and entering the CPI inflator. Furthermore the cost of debt and equity for tariff purposes can be set on a nominal basis.
- *Real* - by setting the escalation factors and CPI inflator at 0%. Also the cost of debt and equity for tariff purposes would now be the nominal rate less the CPI rate. For instance, an interest rate of 5.5% while there would be 2% inflation, would be 3.5% in real terms.

This is a somewhat simplified method. A more thorough method would be to first escalate all cash flows and then discount them with the inflation discount rate. This would provide for a somewhat higher real tax rate. Also this would provide for a declining tariff.

However, it was easier to compare the model with other results by following the short cut procedure. This procedure provide for a flatter levellized lower tariff as will be illustrated later in Chart 5.24. Therefore, the real profitability indicators are slightly higher than would have been the result on the basis of the alternative method.

The model can also be operated as:

- *Before Financing* - This mode assumes that no financing takes place at all on the midstream components. The model in the “before financing” mode nevertheless calculates the tariffs based on the debt and equity assumptions that have been indicated. In other words the tariff remains the same in the before and after financing mode. In the “before financing” mode, the model does not calculate the financial interest in the midstream cash flows. In other words the model operates as if tariffs were approved by the regulatory entities based on certain debt/equity assumptions, but that in effect the investor would use 100% equity to finance the midstream components. Because there is no interest calculated the corporate income tax is higher since interest would otherwise be a deduction.
- *After Financing* - This mode assumes financing for all the midstream components. In this mode the tariffs are the same as under “before financing”, however, the individual cash flows of each midstream component now include financing and the corresponding interest as well as the loan and the loan repayment. In the “after financing” mode corporate income tax is less because interest is now a deduction for corporate income tax purposes.

3. STATUS QUO definition

An important issue during various discussions was the matter of the ‘Status Quo” for gas on the North Slope. The view of the Status Quo was decided between DNR and DOR in an agreement reached on September 28, 2004. This report uses this agreement, with a subsequent modification on Point Thomson royalties as well as small modifications required in order implement the non-confidential version of the PVM model.

The “Status Quo” would be further modified with the PPT legislation. However, during the negotiating process the Status Quo was measured as per the September 28 agreement and in this report therefore, this is the target for comparative analysis.

3.1. Status Quo as Benchmark

Prior to discussing the Status Quo as a benchmark, it is important to make two preliminary comments.

Status Quo for gas is not necessarily a valid benchmark

The so-called “Status Quo” for gas is simply the fiscal system developed for oil, but applied to gas on the North Slope. In other words the same fiscal terms are applied to both oil and gas.

It should be noted that internationally many jurisdictions with stranded gas and relatively low netbacks have opted to develop fiscal terms which are more attractive to the investors for gas than for oil. The government take for gas is less than for oil. The North Slope gas is clearly gas with a low net back such as many other jurisdictions.

It was precisely for this reason that the Stranded Gas Development Act was developed. It was realized that North Slope gas could not be developed under a fiscal system that is identical for oil and for gas. Therefore, the government was given permission to negotiate special contracts for approval by the Legislature.

A detailed gas competitiveness study will be carried out and a separate report will be provided on this matter. However, it may be useful to sketch out on a preliminary basis what other nations have done to make gas that has to be transported over long distances economic.

Following is a review of these concepts for important long distance gas exporting countries:

Australia. Australia developed its first LNG projects on the North West Shelf on the basis of a flat 12.5% royalty and 30% tax, while for oil there is a 40% PRRT (similar to the PPT).

Indonesia. Indonesia developed its LNG exports on the basis of production sharing terms with more favourable production splits for gas than for oil. Sometimes gas contracts have a government take that is 30 percentage points less than oil contracts. Furthermore, Indonesia provided initially government supported financing for liquefaction plants (backed up by Japan).

Malaysia. This country also has more favourable production sharing terms for gas than for oil. Gas terms typically are 10 percentage points less than for oil. Gas is exported as LNG.

Qatar. Qatar has very high government takes for oil and condensates in the 80 – 90% range, but a generous fiscal system applicable to gas. Profits are centered in the midstream through a low gas feed price and on these profits only a 35% corporate income tax is applicable. Most gas is exported as LNG.

Oman. Has approximately the same concept as Qatar with a low feed gas price and a joint venture arrangement for LNG exports. Terms for oil are in the 80 – 90% range.

Libya. Libya in their Exploration and Production Sharing Agreements (EPSA) has a much more favourable sharing for gas than for oil. Much of the gas of Libya is exported as LNG.

Trinidad&Tobago. This country has much lower terms for gas than for oil. Oil is subject to the SPT which is like a price sensitive severance tax. Gas is not subject to this tax at all. Oil is subject to a 10 – 12.5% royalty. Gas is subject only to a 2 cents per MMBtu royalty. Even at low prices the government take is about 10 percentage points less for gas than for oil. At high prices this difference increases. T&T proved to be very aggressive in establishing LNG exports.

Venezuela. Under the 2002 hydrocarbon law, oil is subject to a 30% royalty and a obligatory state participation. Gas for LNG exports is only subject to a 20% royalty. Venezuela has not yet started its LNG project.

Therefore, many nations have already concluded that one cannot economically develop and market gas and transport it over long distances on the basis of a fiscal system that is identical for oil and for gas.

There no proof that the Status Quo for gas is actually a viable and competitive fiscal system.

This makes measuring the ASGFC relative to the Status Quo for gas a somewhat meaningless exercise.

Nevertheless, the Status Quo will serve for many Legislators as an important benchmark.

The comparison with the Status Quo is therefore made in order to provide a benchmark, not because this comparison is inherently valid for the purpose of determining whether the proposed stranded gas contract is attractive or not to the State.

Status Quo is not subject to fiscal stability

Another point that must be made is that the Status Quo for gas does not include provisions for fiscal stability. The Government of Alaska has the unilateral right to increase or decrease taxes. Therefore, the Government could adjust these terms prior to or during the life of the project. Also even with no change in legislation, the Government has today considerable flexibility to adjust government take through regulations.

The Status Quo is therefore merely a snapshot of the current status of the legislation frozen in time.

3.2. Description of the Status Quo.

Following is a description of the Status Quo.

Royalty rates

The Prudhoe Bay royalty rate is 12.5%. The only area of difference is Point Thomson.

The latest State position on the PTU royalties is that the average royalty can be estimated as 14.5%. However, depending on the mapping of the ultimate outline of the field, this royalty may turn out to be higher or lower, the probability that the number is higher is more likely.

It was assumed that the average royalty rate of State leases would be 13%, since currently some of the fields that may contribute gas to the line have higher rates than 12.5%.

At was assumed that from all Federal Leases the State would receive half the royalty. This was assumed to be 6.25%.

It should be noted that both for new State leases the royalty rates may be much higher if oil and gas prices continue to be high in the future. The State may simply set higher royalty rates during bidding rounds.

Net Profit Share in Point Thomson

The Net Profit Share in Point Thomson was simplified in order to avoid the use of confidential data. It was assumed that the share would be equal to 2.2% on the total value of the Point Thomson production after achieving payout.

The payout time varies with the price of gas. At $ 2.50 per MMBtu in Chicago there would be no NPS.

At $ 3.50 per MMBtu the NPS would "click in" in 2030, at $ 4.50 in 2020, at $ 5.50 at 2019, at $ 6.50 in 2017 and at $ 7.50 and higher in 2016 (two years after the start of production).

Severance Taxes

In order to avoid the use of confidential data the severance tax rates for Prudhoe Bay and Point Thomson were simplified.

It was assumed that in Prudhoe Bay the severance tax rate in 2014 would be 7% and that afterwards this rate would decline linearly with 0.08% percentage points each year until 5.48% in 2033. Thereafter the rate would decline linearly with 0.5% percentage points each year. The most recent report in DOR suggests that this rate schedule may be somewhat high.

It was assumed that for Point Thomson the severance tax rate in 2014 would be 9.9% and this rate would stay constant for a decade. Then it would decline linearly by 0.09% percentage points each year.

The September 28, 2004 agreement establishes that the State's position is that with respect to the other fields a reasonable rate would be 7%.

It should be noted that the severance tax rates are notoriously difficult to estimate. In particular, the rates for gas depend on many factors, such as the oil production (since the rates vary with the well count) and the number of wells. The number of wells depends on possible production acceleration programs as well as abandonment programs that the companies implement.

For Yet To Find fields it is anyone's guess what the production tax rates would be. The 7% was "picked" because it was about the weighted average between Prudhoe Bay and Point Thomson.

Upstream Property Tax

Currently on average the upstream property tax for oil is $ 0.50 per barrel. It is assumed that for Status Quo purposes this rate would have been escalated with CPI. This is somewhat debatable since the $ 0.50 per barrel arrangement was only a three year arrangement and the actual per barrel amounts would have to be negotiated periodically.

The State believes that in addition one should consider a property tax component for gas. The State's estimates this component as $ 0.02 per Mcf escalated over time. For Status Quo purposes it was also estimated that this amount would escalate with CPI.

The State's position with respect to gas is to an important degree based on the fact that the extension of the lifetime of the Prudhoe Bay facilities would normally lead to an up-valuation of the property tax.

Field Cost Allowance for Royalties

The State recognizes that there is a Field Cost Allowance of $ 0.224 per Mcf on Prudhoe Bay.

The State claims that this allowance does not apply to other leases.

I reviewed the State position with Wilson Condon and he feels that the Exxon Settlement Agreement is rather specific that the Field Cost Allowance does not apply to Point Thomson. The other Settlement Agreements are a toss-up. With respect to leases entered into after 1978, the State has a very good case that the Field Cost Allowance would not apply.

Processing Fee for Royalties

The Status Quo assumes that the State would have to assume processing costs for gas with respect to Prudhoe Bay, but not for other fields.

Processing Fee for Tax Gas

The State claims that a reasonable processing fee would be $ 0.02 per Mcf nominal.

Current processing fees are higher. However, it is the State's view is that under the provisions of the statute it is reasonable to assume that the processing fees would be recalculated in case the gas project would come along. Currently, the processing fees are based on the NGL's the MI and the Fuel and Sales Gas. The gas volumes are very low. It is a reasonable interpretation of the statute that the processing fees would be re-determined based on the new gas throughput volumes and that the regulations would be adjusted accordingly.

Midstream Property Tax

The State calculates the asset value for property tax calculations on the basis of the Replacement Cost New Less Depreciation (RCNLD) system.

The State's view was recently supported by the State Assessment Review Board and therefore seems a strong position. However, the matter is not a clear cut case.

Property taxes are simply based on 2% each year of this value.

"*Higher Of" Value*

DNR has determined the values given up by agreeing to a RIK as 2% of the sales price of the gas.   This includes matters such as being able to pick the "higher of" market value and the value of RIK/RIV switching.

Debt/Equity Split on Pipeline Financing

The Debt/Equity split on financing the project is not strictly a fiscal matter. However, a higher equity assumption increases the pipeline tariff and thereby reduces all the fiscal values which are based on the net back. In this respect it has an important impact on the Status Quo value to the State.

4. Alaska Stranded Gas Fiscal Contract terms

4.1. Summary of ASGFC terms

Following is a summary of the ASGFC terms that were used in the analysis of the contract.

Term. The term of the contract is up to 10 years for construction and 35 years for production-transportation of gas for a maximum period of 45 years.

Participation. The State has the right to participate in all downstream components of the project for 20%, including the Point Thomson Feeder line, Gas Treatment Plant, Mainline in Alaska, Mainline in Canada, the Liquid Extraction Plant and the pipeline in the lower 48 States.

Royalties in Kind. The State will take all fixed royalties in kind. The royalties for Prudhoe Bay and other fields are whatever they are today. For Point Thomson the royalty still has to be finalized. For new leases the State can fix royalties as the State decides.

Tax Gas in Kind. For all production the State will take the production tax on gas in kind at a flat rate of 7.25%, net of royalties. The tax gas in kind is a production tax in value converted to an amount in kind.

State Gas. The State is responsible for the shipping commitments and marketing of the Royalties in Kind and Tax Gas in Kind. The State will pay an Upstream Cost Allowance of $ 0.224 per Mcf for all State Gas to the Sponsors.

Upstream property tax. There is an upstream property tax on oil of about $ 0.50 per barrel escalated by 70% of CPI. Furthermore, there is an upstream allowance on gas of 2.1 cents per Mcf, escalated at 80% of the CPI.

Midstream property tax. The midstream property taxes are 1 cent per MMBtu for the GTP and 2.4 cents per MMBtu for the main pipeline. This property tax is escalated with CPI.

Impact fund. There will be an impact fund of $ 125 million to be distributed to impacted communities.

State Corporate Income Tax. No change to the current tax of 9.4%.

4.2. Economic interpretation of ASGFC terms and other factors.

Term. The model is for a total of 38 years, consisting of 8 years construction and 30 years production. Therefore, the last 7 years under the ASGFC are not captured.

Participation. It was assumed that the State would participate for 20% in all components.

Royalties in Kind. The royalty on Point Thomson was assumed to be 14.5%. No allowances other than the UCA were assumed.

Tax Gas in Kind. No allowances other than the UCA were assumed.

State Gas. It was assumed that the gas marketing activities would cost the State 5.5 cents per Mcf or 5.94 cents per MMBtu, escalated by CPI. This is a very conservative and high number. The total marketing costs in nominal terms would be $ 771 million over the 30 year period.

Upstream property tax. There is an upstream property tax on oil of about $ 0.50 per barrel was not included in the PVM model, since this is a gas only model.

Midstream property tax. These taxes were fully included.

Impact fund. The impact funds were distributed over 5 construction years.

State Corporate Income Tax. For the upstream it was assumed that the actual tax rate would be 4.7% due to the allocation process of world wide taxes to Alaska. The tax rate for midstream income was assumed to be 9.4%. It was assumed that the State of Alaska would be tax free with respect to its investments in the USA.

Federal tax rates. It was assumed that the US federal tax rate would be 35%. A 15% us Federal tax credit is included in the calculation of the GTP. The Canadian total tax rate is assumed to be 36.2%.

State Corporate Income Tax Rates. It was assumed that the blended State corporate income tax would be 8%.

Non-Alaska Property taxes. It was assumed that in Canada the property tax would be 1% without depreciation of the capital base. The property tax for the lower 48 States was assumed to be 3% with a depreciating capital base.

4.3. PPT

In addition to the basic ASGFC analysis, another case was developed with the inclusion of the PPT effects. The effects were measured on the basis of a system with 20% tax and 20% credits.

The PPT effects are the following:

- Capital Investments in the Upstream are subject to deduction of capital expenditures, which based on a 20% tax rate would result in a 20% loss carry forward credit, this applies to Point Thomson and also the $ 200 million yearly investment required in order to maintain production.
- Capital Investments in the Upstream are subject to the 20% tax credit.
- Operating Costs in the Upstream are subject to deduction of operating expenditures, which based on a 20% tax rate would result in a 20% loss carry forward credit
- A special credit of 35% is contemplated in for the GTP and lateral lines, only with respect to the capital expenditures.

All these credits were taken as a reduction of the State gas income. It should be noted that the amount of these upstream capital and operating costs reflects only the portion that would be attributable to gas. This is consistent with the PVM gas only model.

It should be strongly emphasized, however, that the PPT deductions were already taken into account in presenting the PPT on "oil" to the Legislature, except for the PPT credits on the lateral gas lines and the GTP. All PPT revenues on oil were net of the consequences of the total capital and operating expenditures on Point Thomson as well as other possible condensate fields.

Therefore, for the Legislative decision on the approval or not of the ASGFC, these deductions should not again be taken into account. Only the PPT credits on the GTP and lateral lines are a new feature and should be considered.

Therefore all analysis will be done based on three options ("fiscal options"):

- **Status Quo,**
- **the Alaska Stranded Gas Fiscal Contract ("ASGFC"), and**
- **the ASGFC with the PPT credits on the GTP and lateral lines ("ASGFC+GTP" or "A+GTP") .**

5. Economic analysis of the Alaska Stranded Gas Fiscal Contract – State of Alaska perspective

The economic analysis of the ASGFC will be done based on nominal as well as real data. Nominal data provide the estimates of the amounts that may actually be received from year to year. However, the value of this income is properly described by real data when time sequences are being considered of long duration.

Under the nominal analysis the results will also be evaluated on a before and after financing basis.

The economic analysis will also be carried out based on two options:

- 100% of the gas is delivered to a liquid market in Alberta ("Alberta Project"), and
- 100% of the gas is delivered in Chicago ("Chicago Project").

5.1. State of Alaska Income – Nominal Results

5.1.1. Project ending in Alberta.

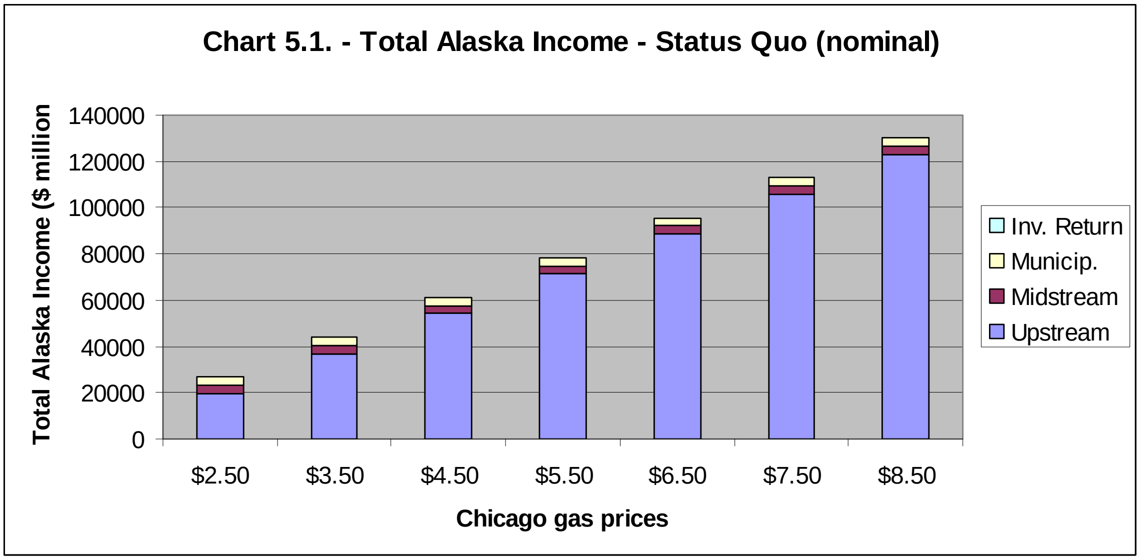
First the nominal results for a project ending in Alberta will be evaluated in detail.

5.1.1.1. Status Quo before financing

Table 5.1 and Chart 5.1 provide the overview of the income of the State of Alaska under Status Quo conditions.

Table 5.1. Alaska nominal income - Status Quo

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	19576	3536	3547	26659	0	26659
$3.50	36714	3536	3547	43797	0	43797
$4.50	54140	3536	3547	61223	0	61223
$5.50	71301	3536	3547	78384	0	78384
$6.50	88554	3536	3547	95637	0	95637
$7.50	105780	3536	3547	112864	0	112864
$8.50	122945	3536	3547	130028	0	130028



Under the Status Quo, there is no investment income and therefore this component is zero. The municipal property taxes include only the component of the property taxes that will go to the municipalities. The State component of property taxes is included in either the upstream or midstream income, depending on the base for property tax. The State component consists of any difference between the municipal tax and 20 mills, as well as the State property tax on main line sections that do not cross municipal lands.

It can be seen how the upstream income to the State is very sensitive to the gas prices in Chicago, as can be expected, since this income consists largely of royalties, production taxes and state corporate income tax, which are all sensitive to the net back prices.

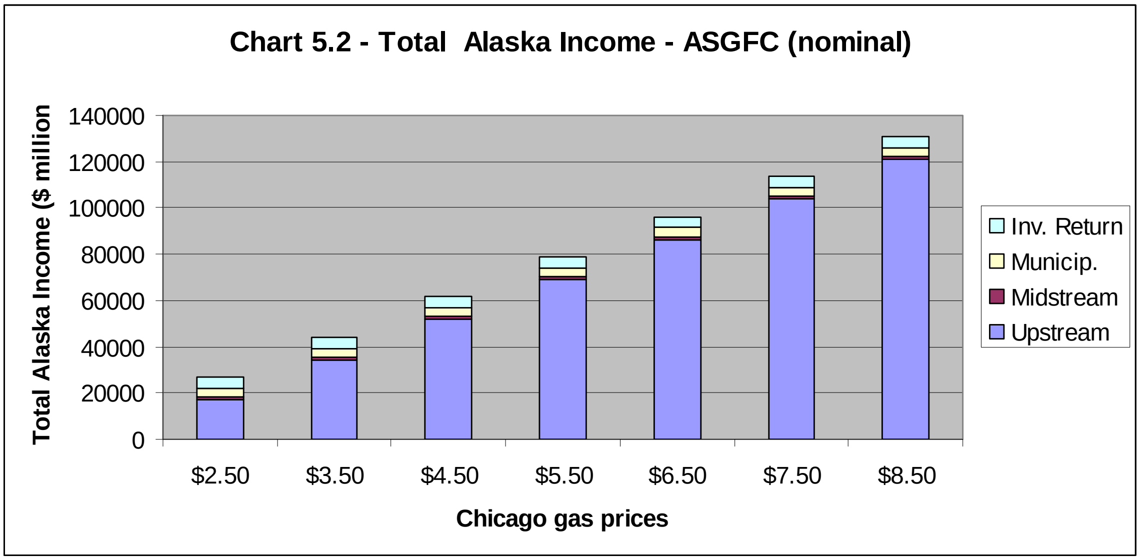
The State midstream corporate income tax is stable irrespective of price, since it is based on tariff income. Also the municipal property taxes are stable under different gas prices.

5.1.1.2. ASGFC before financing

Tables 5.2 and Chart 5.2 provide the income under the Alaska Stranded Gas Fiscal Contract ("ASGFC").

Table 5.2. Alaska nominal income - ASGFC

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	17107	1156	3920	22183	4685	26868
$3.50	34327	1156	3920	39403	4685	44088
$4.50	51835	1156	3920	56911	4685	61596
$5.50	69078	1156	3920	74154	4685	78840
$6.50	86413	1156	3920	91489	4685	96174
$7.50	103721	1156	3920	108797	4685	113483
$8.50	120967	1156	3920	126043	4685	130729



As can be seen from the table and the Chart, the total Alaska Income remains slightly higher than the Status Quo.

5.1.1.3. Status Quo and ASGFC comparison before financing

The differences between the Status Quo and the ASGFC can be studied for a price level of $ 3.50 in Chicago in Table 5.3

Table 5.3. Status Quo and ASGFC

	Status Quo	ASGFC
Upstream gas Muni	1474	1094
Midstream Muni	2073	2826
Midstream return	0	4685
State Midstream	3536	1156
Royalties	20575	20620
Prod Tax	9972	10980
UCA	0	-2908
Marketing Costs	0	-771
PTU	340	340
Upstream State CIT	5826	6066
Total	43796	44088

As can be seen from this table, there are the following differences:

- The upstream gas property tax is less, due to the lower CPI escalation
- The midstream property taxes to the municipalities are more because of the switch to c/MMBtu with a better long term profile.
- There is midstream investor income for the State of Alaska from its 20% participation, which is part of the Status Quo.
- The midstream State of Alaska income is less because there is no midstream State of Alaska property tax on lands outside municipalities
- The value of royalties is more due to higher net back value which is caused by lower tariff due to lower property taxes and no property taxes during construction. This true despite the allocation of the specific values for the benefits of royalty in value as discussed above. Also certain allowances do not apply.
- The value of production taxes is higher due to higher net back value and generally a higher percentage production tax on average.
- Upstream Cost Allowance does not exist under the Status Quo for all fields and therefore this is a negative factor.
- Relatively high gas marketing costs were included in the ASGFC for comparison and therefore this negative factor may be excessive.
- There is no change in the PTU in cash.
- The upstream State corporate income tax is slightly higher due to higher net back and UCA payments to companies and other factors.

It should be noted that in this comparison the return on midstream investment by the State is calculated on a “before financing” basis, in other words as if the entire financing by the State is done on an equity basis.

5.1.1.4. Status Quo and ASGFC comparison after financing

On an after financing basis, the Total Alaska Income will be less for the following reasons:

- The State would have to pay about $ 1.9 billion in interest payments assuming 80% financing at a rate of 5.5% interest. There would also be financing during construction for the State's share of the midstream facilities.
- The financing by the State of the Canadian portion will be a tax deduction for Canadian Federal Income tax and therefore this amount would be less.
- The financing by the private companies also results in less midstream corporate income tax for the State.

It should be noted that the tax effect on the midstream corporate income tax also occurs under the Status Quo conditions. Therefore both cases result in less Total Alaska Income on an after financing basis. However, the income under the ASGFC becomes much less as can be seen from the following two tables.

Table 5.4. Alaska nominal income - after financing - Status Quo

	Upstream	Midstrean	Municip.	Subtotal	Inv. Retur	Total
$2.50	19515	2958	3547	26020	0	26020
$3.50	36653	2958	3547	43158	0	43158
$4.50	54079	2958	3547	60584	0	60584
$5.50	71241	2958	3547	77746	0	77746
$6.50	88493	2958	3547	94999	0	94999
$7.50	105720	2958	3547	112225	0	112225
$8.50	122884	2958	3547	129390	0	129390

Table 5.5. Alaska nominal income - after financing - ASGFC

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	17046	694	3920	21660	2743	24403
$3.50	34266	694	3920	38880	2743	41623
$4.50	51774	694	3920	56388	2743	59130
$5.50	69018	694	3920	73631	2743	76374
$6.50	86352	694	3920	90966	2743	93708
$7.50	103661	694	3920	108274	2743	111017
$8.50	120907	694	3920	125521	2743	128263

In total the income under the ASGFC on an after financing basis is about $ 1.6 billion less for a price of $ 3.50 per MMBtu in Chicago.

5.1.1.5. ASGFC and PPT deduction and credits before financing.

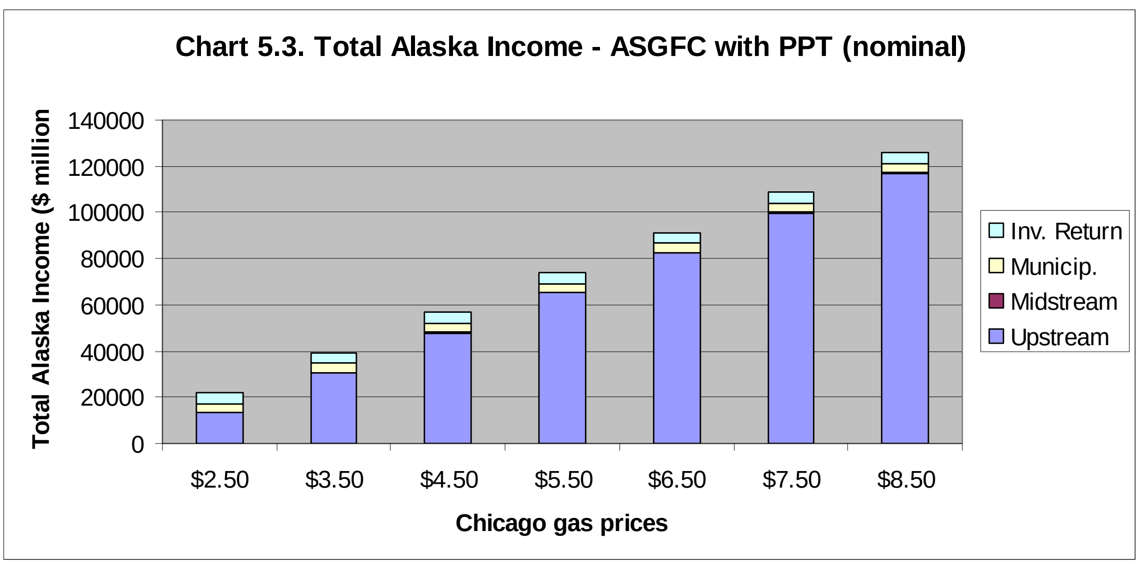
As was discussed earlier in Section 4.3 of this report, most PPT deductions and credits were already taken into consideration when discussing the PPT on oil in the Legislature and should therefore not be deducted again for Legislative analysis. Only the PPT credits of 35% on the lateral gas lines and GTP are new features.

Nevertheless, for illustration purposes all PPT deductions and credits are hereby taken into consideration again.

With the PPT deductions and credits the ASGFC would generate less. Table 5.6 provides the overview of the ASGFC + PPT proposal.

Table 5.6. Alaska nominal income - before financing - ASGFC with PPT credits

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	13200	282	3920	17401	4685	22086
$3.50	30420	282	3920	34621	4685	39306
$4.50	47928	282	3920	52129	4685	56814
$5.50	65171	282	3920	69372	4685	74058
$6.50	82505	282	3920	86707	4685	91392
$7.50	99814	282	3920	104015	4685	108701
$8.50	117060	282	3920	121262	4685	125947



The difference between the ASGFC with and without PPT is as follows:

Table 5.7. Total PTT Credits

	Rate	Upstream	Midstream	Total
Opex Credits	**20%**	**428**		**428**
Point Thomson Credits	**40%**	**703**		**703**
Yet to Find Credits	**40%**	**2776**		**2776**
PT Feeder Credits	**35%**		**83**	**83**
GTP Credits	**35%**		**792**	**792**
Total		**3907**	**875**	**4782**

In Table 5.7, Opex Credits refers to the reduction in PPT that will be obtained as a result of the deduction of gas upstream operating costs primarily in Point Thomson and Yet to Find.

The Point Thomson credits consist of the 20% credit that can be obtained as a result of the deduction of capital expenditures on Point Thomson (In the PVM model only the capital expenditures attributable to gas are included). Furthermore there is the 20% investment credit on Point Thomson.

The same applies to the Yet-to-Find or Other fields that will be developed in order to keep the gas line at full capacity. As can be seen, this is the largest amount and it is large as a result of the 2% escalation. These capital expenditures are scheduled to start in 2024. At this time, the amount of capital required is estimated as $ 200 million per year in 2006 $.

Finally, there are the special credits on the PT Feeder line and the GTP at 35% of these amounts as per oil stability provisions of the ASGFC. The total is $ 875 million. These are the new credits to be considered for the Legislative approval process.

Table 5.8 indicates that prior to the PPT credits the ASGFC provided a slightly higher Total Alaska Income than the Status Quo. At $ 3.50 per MMBtu it is $ 292 million more, on a before financing basis. After the PPT credits the stranded gas contract provides for less Total Alaska Income. In the case of $ 3.50 per MMBtu in Chicago, $ 4490 million less over the cash flow period. The difference consists of the credits listed in Table 5.7.

Table 5.8. Total Alaska Income Differences

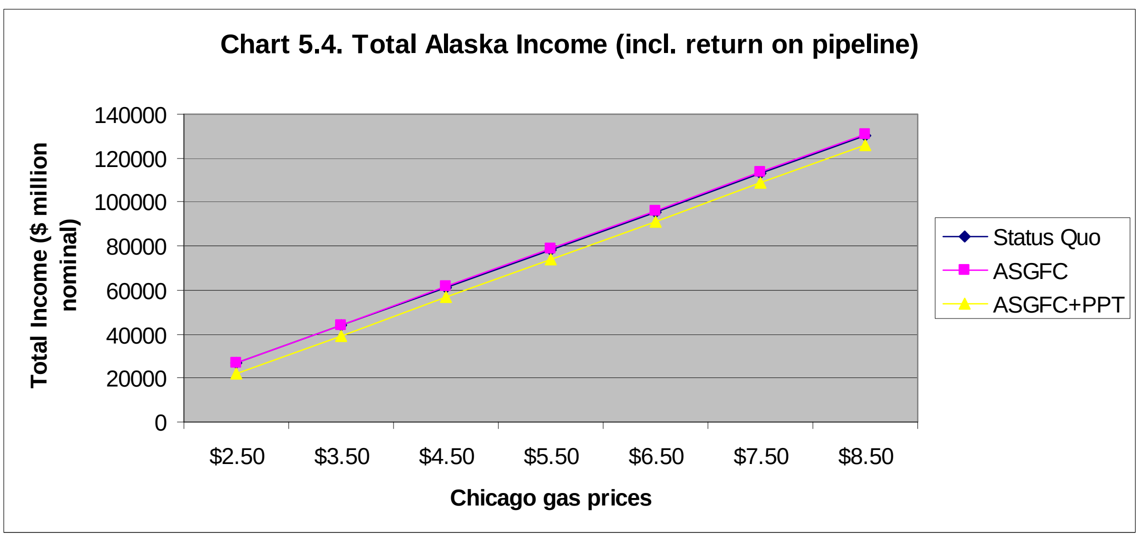
	ASGFC	ASGFC+PPT
$2.50	209	-4572
$3.50	292	-4490
$4.50	373	-4409
$5.50	455	-4327
$6.50	537	-4245
$7.50	619	-4163
$8.50	701	-4081

5.1.1.6. Total Alaska Income analysis for the three cases

The three cases can be evaluated taking with and without the State's return on midstream income.

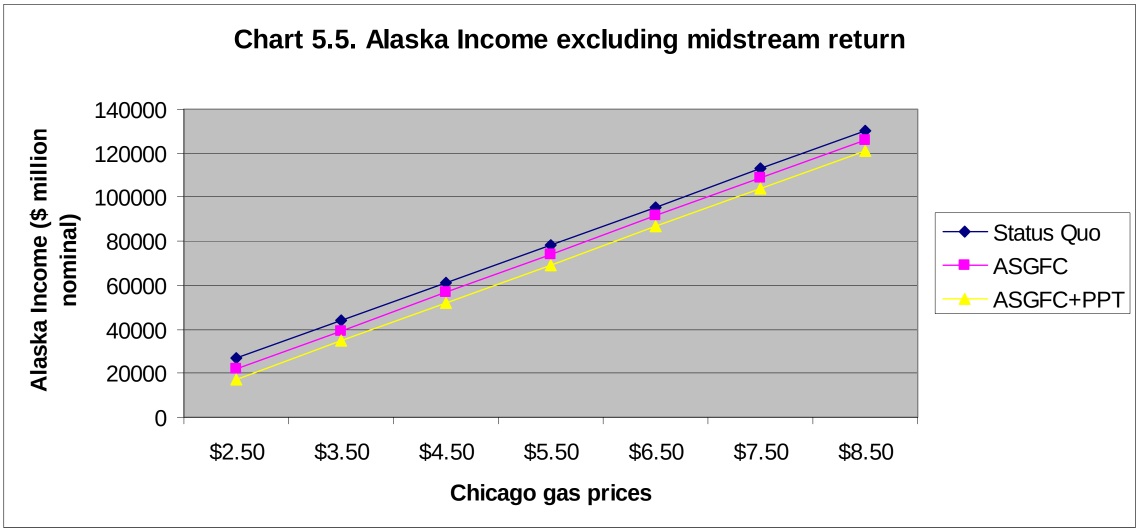
The following charts show the before financing income.

Chart 5.4 illustrates that Total Alaska Income including the State's return on the midstream investments.



As can be seen from the Chart, the ASGFC prior to the PPT credits is slightly above the Status Quo. The PPT credits bring the total income below the Status Quo. At low prices this difference is significant in relative terms, at average and high prices it is not.

Chart 5.5 illustrates the Total Alaska Income excluding the State's return on the midstream investments.



The Chart 5.5 illustrates how the Total Alaska Income would be less across the price range. The difference is considerable at low and average prices in relative terms. At high prices the relative difference is less important.

The two charts raise the issue as to what the most appropriate way is to evaluate these results.

An argument can be made that the “pure” State income should be separated from the State income that is a result of a direct State investment. This argument is based on the fact that the State’s investment income would be optional. It could be argued that under any circumstance the State can participate in a venture of this type. It is the investment by the State that earns the income. Since the income is “earned” it should not be counted as part of the overall State take. Under this argument the State participates from the beginning of the venture as any other participant. The State is not being carried and assumes full risk for its share of the investment. This would be a valid approach for analysis in many similar arrangements in the world.

Under the specific circumstances of the proposed stranded gas contract, this argument is not correct.

As will be described in a separate report, without improvement in downside economics, the establishment of fiscal stability and risk sharing, the Alaska Gas Project may be delayed considerably or may not be viable. Therefore, the participation by Alaska is integral to the stranded gas contract.

The risk sharing and improvement in downside economics are realized through taking the gas in kind. As a result of taking the gas in kind, and taking the corresponding shipping and marketing risks, the Sponsors agreed to an equivalent participation in by the State in the midstream projects for 20% because this is essential in order to make the shipping feasible for the State.

It would not make any sense for the State to take the shippers and marketers risk without a corresponding interest in the midstream facilities in order to directly compensate for payments to be made by the State in corresponding investor income. This is the only way to create the same risk balance for the State as for the Sponsors as far as the gas in kind shipping marketing and transportation is concerned.

The payments by the State for the shipment of the gas in kind were netted out in determining the net value of the gas in kind to the State. Only the net income of the State after deduction of capital and operating costs was considered as part of the State's benefit.

The investment by the State is secured by overall LLC income earned by all four parties in the venture jointly.

The income from State participation in the project is not optional income. It is an integral part of the contract.

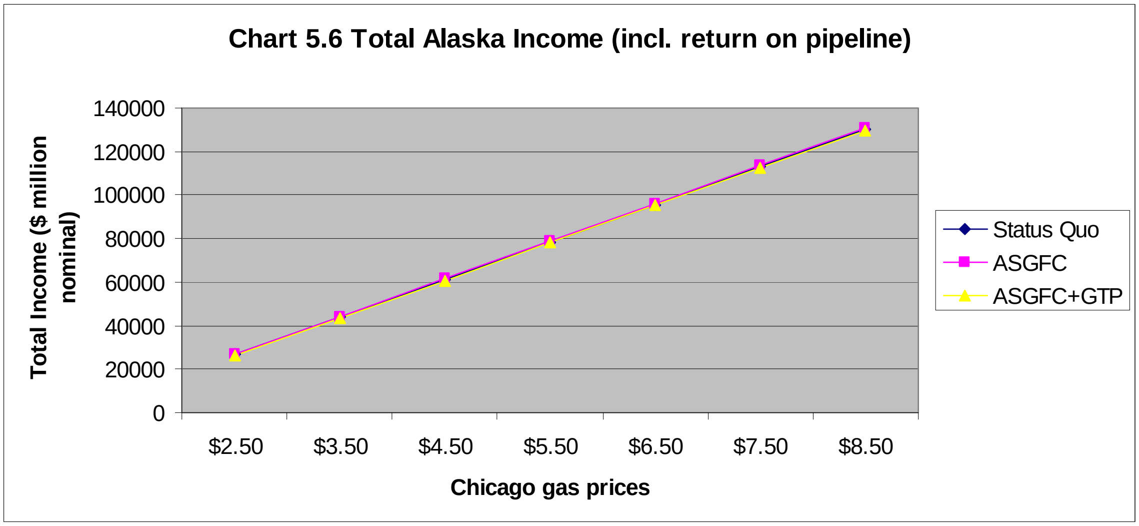
The alternative is the Status Quo. Under a hypothetical Status Quo scenario the Sponsors would go forward with the project on a fully commercial basis. They would have no incentive to offer the State a 20% interest in the project.

It can therefore be concluded that the net revenues for the State from this participation are an integral benefit for the State inherent in the specific structure of the gas contract. Therefore the correct way to analyze the Total Alaska Income is with the return on investment included, but with a total new GTP and lateral line credit of $ 825 million excluded.

The following table and Chart 5.6 illustrate the comparison between the ASGFC, ASGFC+GTP and the Status Quo on this basis.

Table 5.9 Status Quo - ASGFC comparison

	Status Quo	ASGFC less credits
$2.50	26659	26043
$3.50	43797	43263
$4.50	61223	60771
$5.50	78384	78015
$6.50	95637	95349
$7.50	112864	112658
$8.50	130028	129904



As can be observed there is no relevant difference between the two cases in terms of Total Alaska Income.

5.1.1.7. Distribution of Divisible Income

Status Quo

Tables 5.10 and 5.11 provide the distribution of the divisible income for the Status Quo.

Table 5.10 Income distribution under Status Quo

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	26659	34384	61043	56998	118041
$3.50	43797	55411	99208	94709	193917
$4.50	61223	76337	137559	132233	269792
$5.50	78384	97355	175739	169928	345667
$6.50	95637	118341	213978	207564	421543
$7.50	112864	139337	252201	245217	497418
$8.50	130028	160354	290382	282911	573293

Table 5.11 Take distribution under the Status Quo

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	22.6%	29.1%	51.7%	48.3%	100.0%
$3.50	22.6%	28.6%	51.2%	48.8%	100.0%
$4.50	22.7%	28.3%	51.0%	49.0%	100.0%
$5.50	22.7%	28.2%	50.8%	49.2%	100.0%
$6.50	22.7%	28.1%	50.8%	49.2%	100.0%
$7.50	22.7%	28.0%	50.7%	49.3%	100.0%
$8.50	22.7%	28.0%	50.7%	49.3%	100.0%

The two tables show how Federal Governments in Canada and the United States take most of the government take related to the Alaska Gas Project. This take is in the form of federal corporate income tax and property taxes.

The internal distribution of the Total Alaska take is detailed in Table 5.12.

Table 5.12 Internal Take distribution under the Status Quo for Total Alaska Income Only

	Royalties	Sev Tax	Upstr CIT	Total Upstream	Midstream	Munis	Total
$2.50	9.5%	4.6%	2.5%	16.6%	3.0%	3.0%	22.6%
$3.50	10.6%	5.3%	3.0%	18.9%	1.8%	1.8%	22.6%
$4.50	11.1%	5.8%	3.2%	20.1%	1.3%	1.3%	22.7%
$5.50	11.4%	5.9%	3.3%	20.6%	1.0%	1.0%	22.7%
$6.50	11.6%	6.0%	3.4%	21.0%	0.8%	0.8%	22.7%
$7.50	11.7%	6.1%	3.5%	21.3%	0.7%	0.7%	22.7%
$8.50	11.8%	6.2%	3.5%	21.4%	0.6%	0.6%	22.7%

As can be seen from this table, the royalties, severance tax and upstream corporate income tax all are somewhat progressive. This seems contradictory to the concept that these features are usually considered regressive or neutral features.

The reason for this government take behaviour is that the government take is measured on the basis of the divisible income based on AECO prices. With higher AECO prices, the midstream component of the project stays identical in value. However, the upstream component increases rapidly in value. Since the royalties, severance taxes and corporate income taxes are all based on percentages of the gross or net upstream income, these components increase their share of the total divisible income as measured based on the AECO price in Alberta.

In other words under the Status Quo, Alaska receives a flat government take of the share of the divisible income based on AECO prices and involving the total project to Alberta.

Therefore, despite the regressive nature of the upstream components, the total government take of the project as a whole act as a neutral fiscal system.

It is also for this reason that the total system acts slightly regressively for the federal and other income despite the fact that the corporate income tax is typically a neutral fiscal feature.

ASGFC

Tables 5.13 and 5.14 provide the information for the ASGFC without the GTP credits.

Table 5.13 Income distribution under ASGFC

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	26868	34709	61578	55863	117441
$3.50	44088	55707	99796	93520	193316
$4.50	61596	76604	138201	130991	269191
$5.50	78840	97594	176434	168633	345066
$6.50	96174	118552	214726	206216	420942
$7.50	113483	139519	253001	243816	496817
$8.50	130729	160507	291236	281456	572692

Table 5.14 Take distribution under ASGFC

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	22.9%	29.6%	52.4%	47.6%	100.0%
$3.50	22.8%	28.8%	51.6%	48.4%	100.0%
$4.50	22.9%	28.5%	51.3%	48.7%	100.0%
$5.50	22.8%	28.3%	51.1%	48.9%	100.0%
$6.50	22.8%	28.2%	51.0%	49.0%	100.0%
$7.50	22.8%	28.1%	50.9%	49.1%	100.0%
$8.50	22.8%	28.0%	50.9%	49.1%	100.0%

As can be seen from Table 5.14, the ASGFC does not change the fact that Alaska has a flat government take system as measured based on AECO prices. The government take is a small fraction higher.

In other words the ASGFC does not change the overall economic characteristics of the Total Alaska Income.

ASGFC + GTP

Tables 5.15 and 5.16 provide the information for the ASGFC with the GTP credits included.

Table 5.15 Income distribution under ASGFC +GTP

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	25994	35015	61009	56431	117441
$3.50	43214	56013	99227	94089	193316
$4.50	60721	76910	137632	131559	269191
$5.50	77965	97900	175865	169201	345066
$6.50	95299	118858	214157	206784	420942
$7.50	112608	139825	252433	244384	496817
$8.50	129854	160813	290668	282025	572692

Table 5.16 Take distribution under ASGFC +GTP

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	22.1%	29.8%	51.9%	48.1%	100.0%
$3.50	22.4%	29.0%	51.3%	48.7%	100.0%
$4.50	22.6%	28.6%	51.1%	48.9%	100.0%
$5.50	22.6%	28.4%	51.0%	49.0%	100.0%
$6.50	22.6%	28.2%	50.9%	49.1%	100.0%
$7.50	22.7%	28.1%	50.8%	49.2%	100.0%
$8.50	22.7%	28.1%	50.8%	49.2%	100.0%

The GTP credit has the maximum effect under low price conditions. Therefore, the Alaska income becomes slightly progressive.

The Producers and the US Federal Government share the benefits from this credit. The lower PPT results in more taxable income for US corporate income tax purposes and this results in more federal tax as can be seen when comparing Tables 5.13 and 5.15. However, most of the benefit goes, of course, to the Producers.

Summary

The following two charts provide an overview of the government take information.

Chart 5.7 shows how the total government take is slightly regressive. The overall government take of the gas project ending in Alberta would be about 51%.

The differences between the three cases are minimal from a government take point of view.

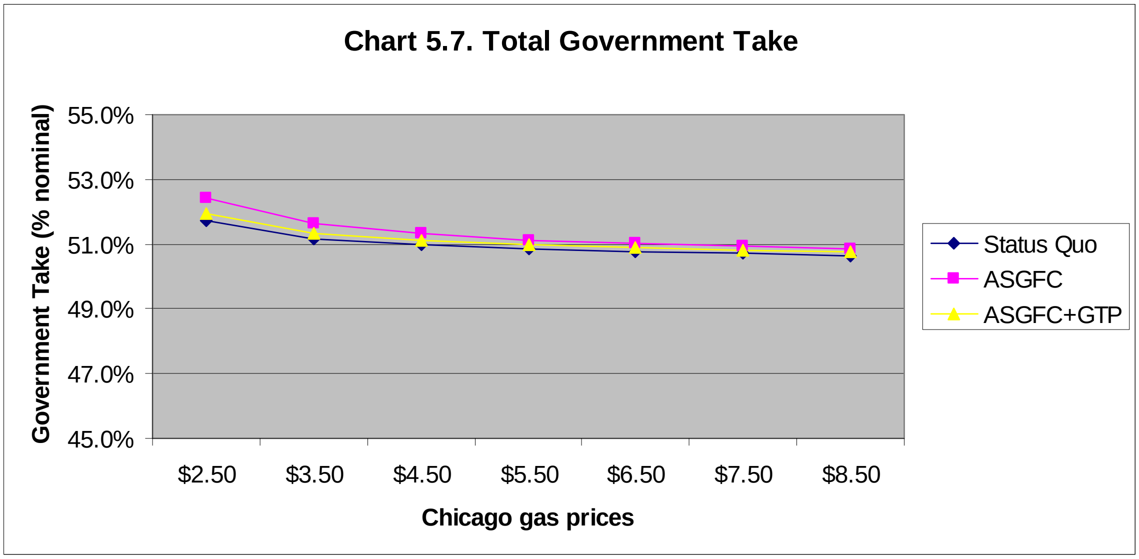
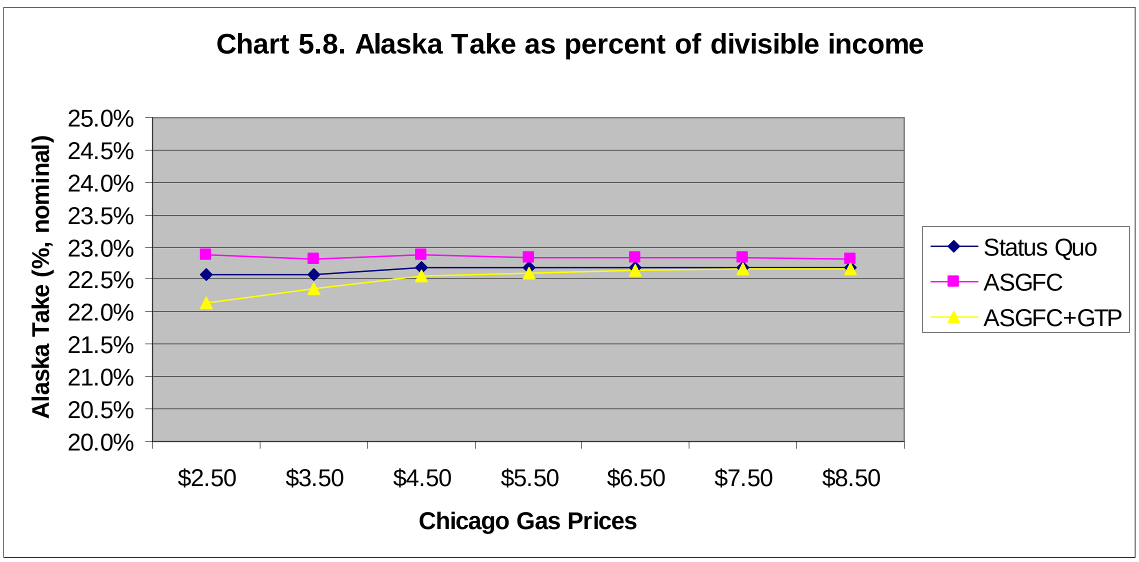


Chart 5.8 shows how the overall Alaska take is between 22 and 23%. The GTP credit lowers the Alaska take slightly at low prices. This creates a slightly progressive system. Overall both the Status Quo and the ASGFC are flat fiscal systems from a government take perspective.



5.1.1.8. Year by Year analysis

It is important and illustrative to do a year by year analysis of the three options.

Status Quo

Chart 5.9 provides the data on the nominal Total Alaska Income from the gas project under Status Quo conditions.

The Chart illustrates an important point, which is that even at a low gas price of $ 2.50 per MMBtu in Chicago, Total Alaska Income from the project will still be about a $ 1 billion per year beyond 2026. This is caused by two factors:

- the fact that the differential between Alberta and Chicago is expected to diminish by 2026 because of elimination of depreciation provisions in Canadian tariffs, and
- the transport tariff stays constant in nominal terms while the Chicago gas price escalates by 2% per year for any price level assumed in the economic model.

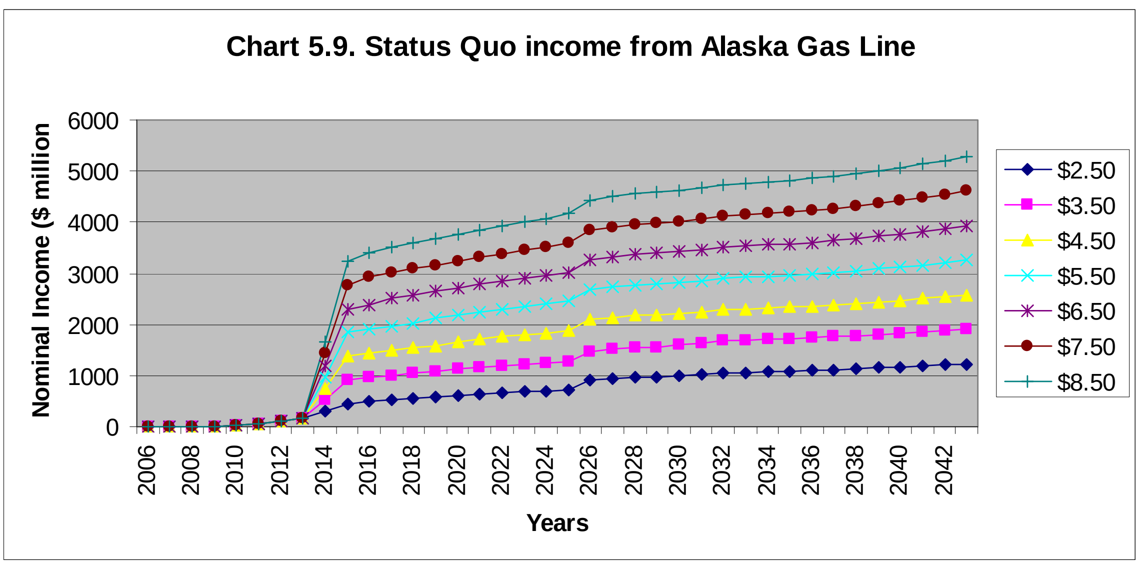


Chart 5.9 shows clearly how Alaska income will reach very high levels per year under high gas prices in constant 2006 $.

Current gas prices exceed the $ 6.50 per MMBtu level. If this price levels would be maintained in constant 2006 $, revenues would increase from about $ 2.5 billion per year to eventually $ 4 billion per year.

The increasing revenues to Alaska on a year by year basis, is an important issue. A way of looking at this is that the transportation tariff in real terms declines. Chart 5.10 illustrates the total differential between Chicago and the North Slope "wellhead" in real terms.

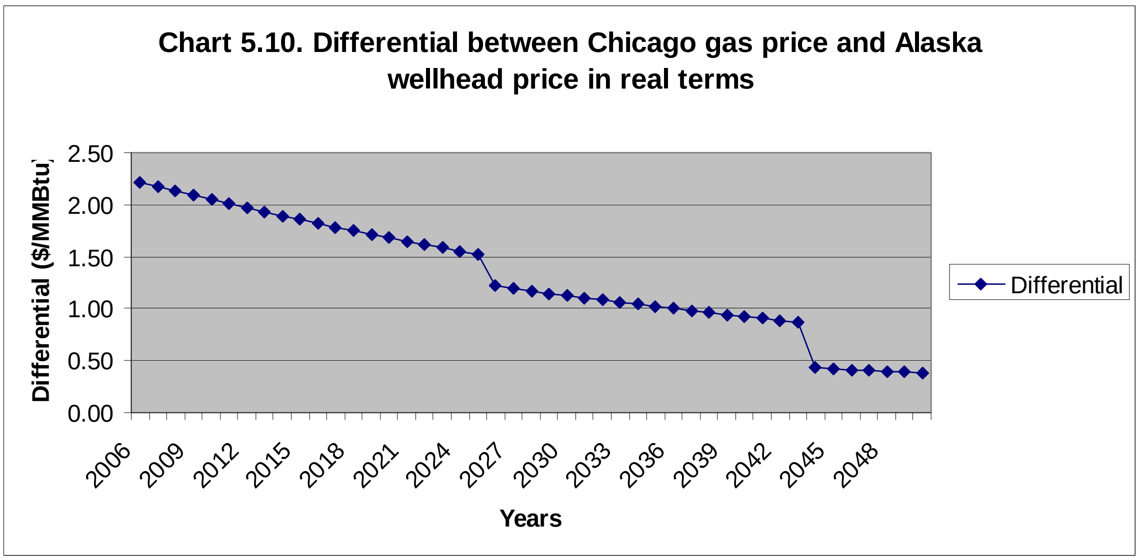


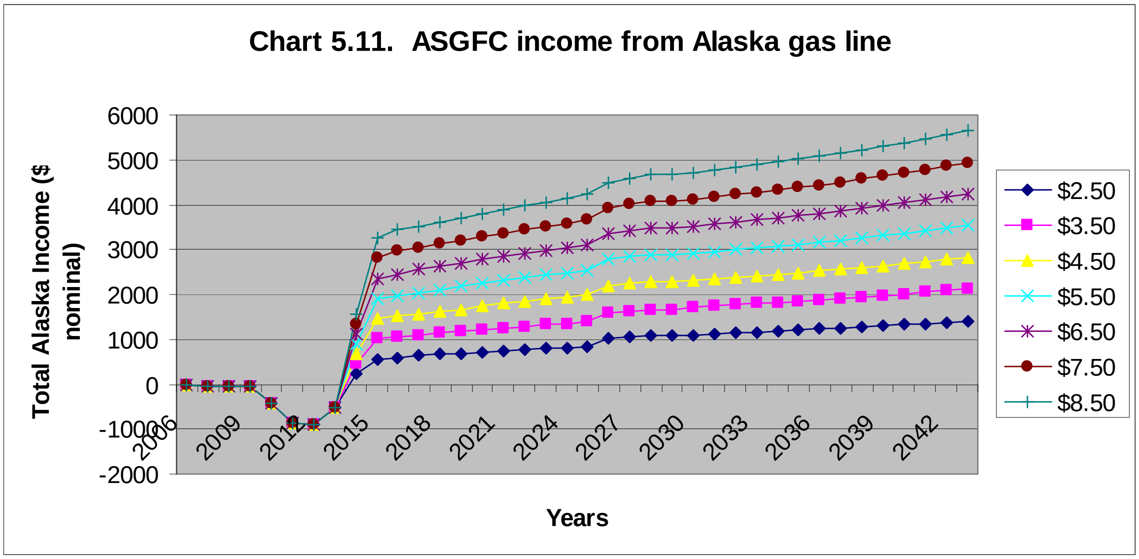
Chart 5.10 shows the drop in real terms of the price differential in 2006 $ based on a 2% escalation of the gas price in Chicago. The drop in 2026 is for the reasons explained above. The drop in 2045 is because the depreciation provisions on the Alaska gas project would run out. Of course, the price differential is only relevant when the gas line comes into operation. It should be noted that in order to calculate the tariffs, the capital and operating costs were escalated and capital costs were built up with interest and equity during construction.

Therefore, irrespective of the Chicago gas price level, the price differential will drop in real terms. In other words, it will become cheaper to transport Alaska gas in real terms over time on the assumption that a certain level of inflation will continue.

The anticipated gradual increase of the value of the Alaska North Slope gas production, for any assumed constant price level, is therefore a very important economic issue.

ASGFC

Chart 5.11 shows the same year by year Total Alaska Revenues.



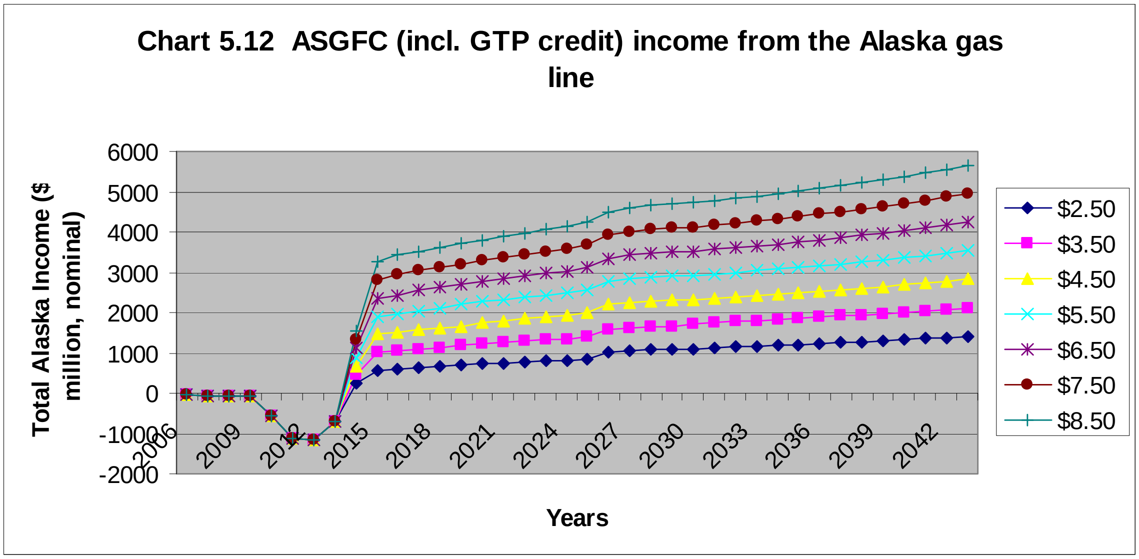
As can be seen immediately, the important difference between Chart 5.9 and 5.11 is that prior to the start of the revenues, there is a negative cash flow for Alaska. This relates to the investment in the 20% share in the Alaska Gas Project by the State. This negative cash flow is on a before financing basis. On the basis of a 80/20 debt/equity financing package the negative cash flow would be substantially less.

After wards the revenues per year to the State are slightly higher because of the return on the investment.

ASGFC+GTP

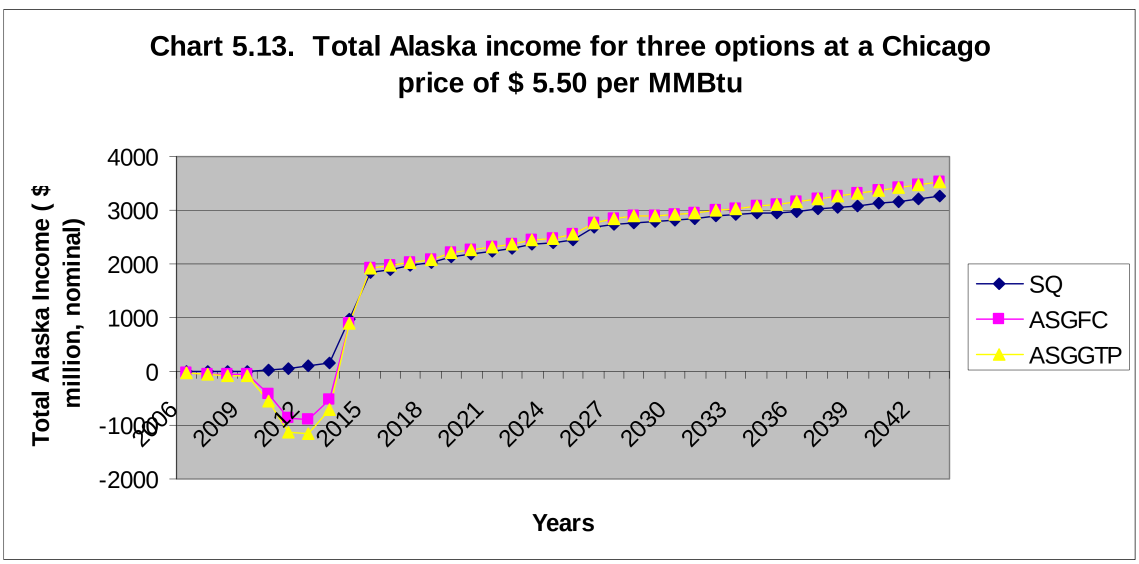
Chart 5.12 shows same Total Alaska Income on a year by year basis with the GTP credits included.

In this case the negative cash flow becomes more negative. Otherwise, there is little change in the cash flow.



Differentials

Chart 5.13 shows the three options for a price level of $ 5.50 per MMBtu in Chicago.

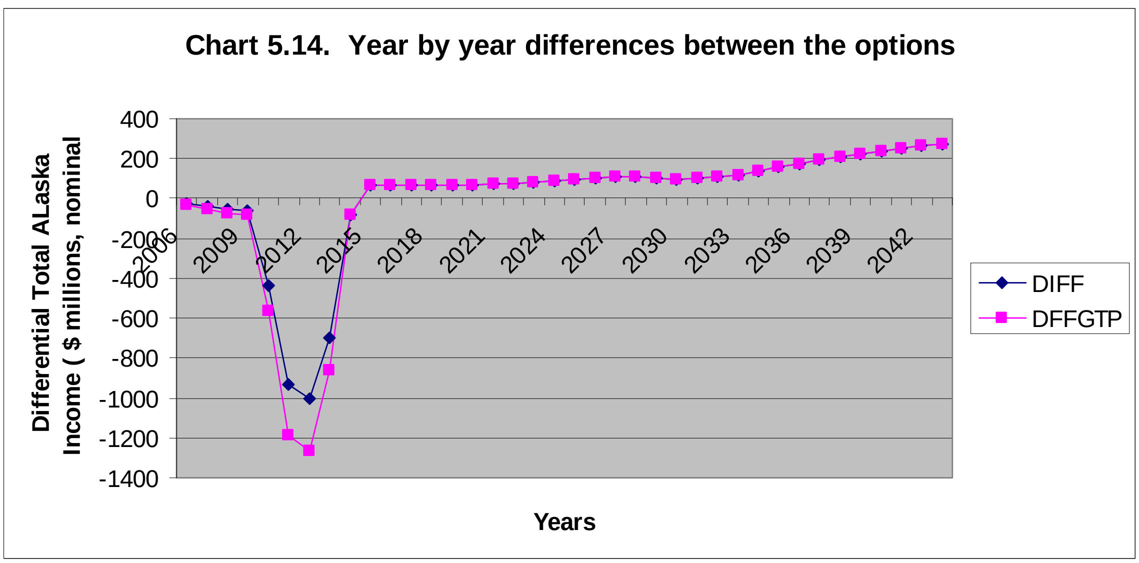


This Chart clearly shows the different structure of the packages. It shows that during the investment phase the ASGFC results in negative cash flows, while the Status Quo does not. After wards, the ASGFC brings in slightly more Alaska Income every year.

Chart 5.14 illustrates the differences between the three options. “DIFF” is the difference of the ASGFC less the Status Quo. “DFFGTP” is the difference of the ASGFC with the GTP and lateral line credits less the Status Quo.

This graph shows how the ASGFC with and without the credits is more back end loaded than the Status Quo. One of the objectives of the Stranded Gas Development Act was to design contracts with more back end loaded fiscal systems in order to make the gas project more competitive.

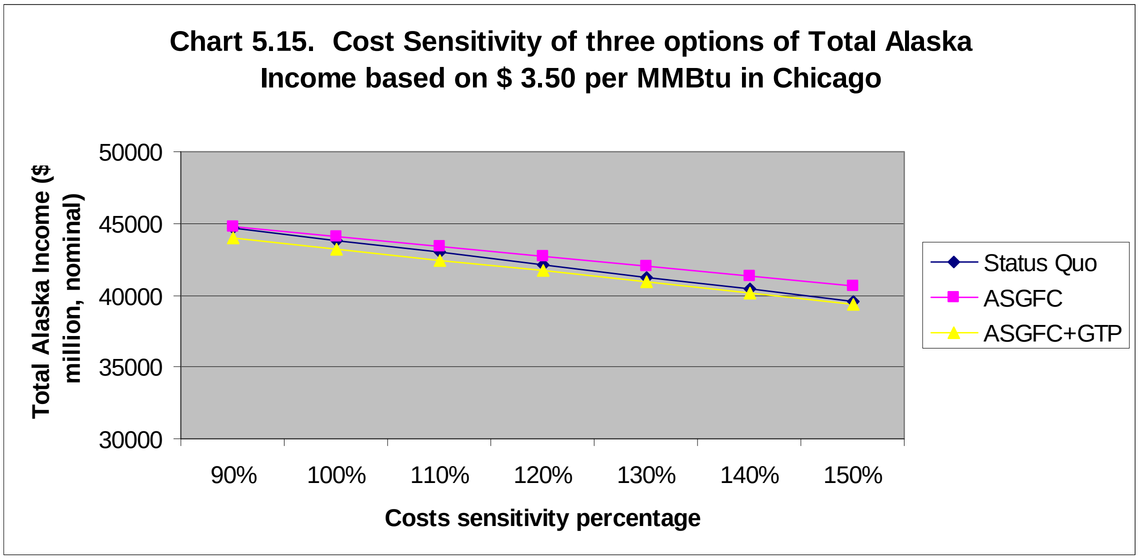
In the early years during the investment phase, the State participates in the venture. During the later years the ASGFC results in general in more income, in particular in the later years.



5.1.1.9. Cost Sensitivity

One of the major risks associated with the Alaska Gas Project is cost overruns. This risk is important for the State as well as the Sponsors.

Chart 5.15 illustrates the Total Alaska Income for a price of $ 3.50 in Chicago. This Chart illustrates the cost sensitivity range of 90% to 150% of all capital and operating costs, with the exceptions discussed above.



As can be expected, the Alaska Total Income goes down very significantly with higher costs. A 50% cost overrun means under the Status Quo a $ 5 billion loss of income.

Cost overruns can be mitigated through careful preparation for the project. It is for this reason that the Work Commitment section of the ASGFC should permit sufficient latitude for project execution in order to ensure that cost overruns are kept to a minimum.

What can also be observed from Chart 5.15 is that the ASGFC is more resistant to cost overruns than the Status Quo. ASGFC becomes almost $ 600 million more beneficial relative to the Status Quo. The ASGFC+GTP option becomes $ 350 more beneficial on a relative basis, although this option will stay slightly under the Status Quo options.

The reason, of course, for this improvement is that it is assumed in the Economic Model that higher capital and operating costs means higher tariffs and since the State participates in the midstream, the State benefits along with the Sponsors from the higher tariffs.

Under the State participation options therefore the State is less exposed to cost overruns from an income point of view.

As can be seen the effect on the ASGFC+GTP is less relative "beneficial" because cost overruns also means a higher PPT tax credit on the GTP and lateral lines.

Chart 5.16 illustrates the total government take. As can be expected, the total government take is slightly regressive with respect to higher costs. This is because the divisible income is less with higher costs.

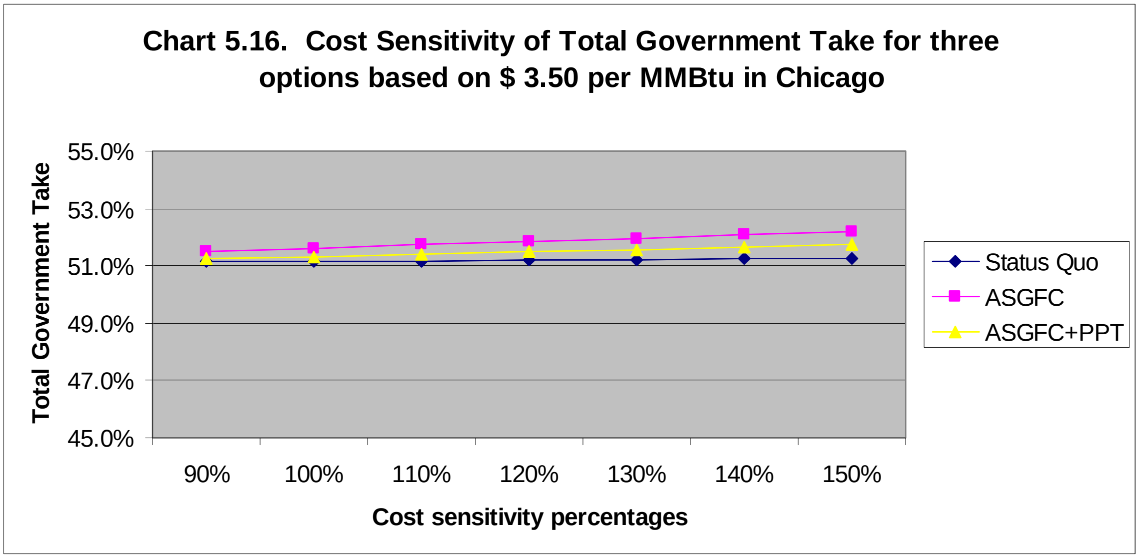
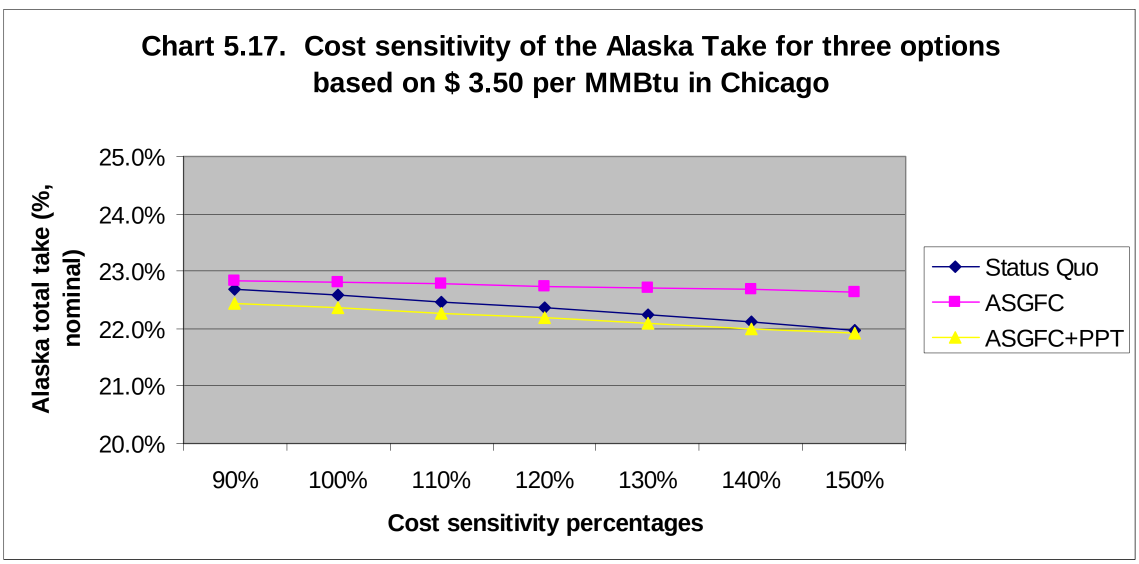


Chart 5.17 displays the Alaska take.



As can be seen, the Status Quo is actually progressive with costs when the divisible income is measured based on AECO prices. This is because the overall Alaska share becomes less with higher transport costs. In other words, under the Status Quo the Alaska total government take declines with higher costs.

This is a negative aspect of the Status Quo fiscal terms. It is also one of the reasons why the Status Quo terms do not align the interests of Alaska and the Sponsors very well. The interests are conflictive.

Under the ASGFC the Alaska government take is more or less flat. Under the ASGFC+GTP option, the Alaska take is slightly regressive. The interests of the State of Alaska and the Sponsors are more aligned. In case of cost overruns, the State will benefit from higher tariff income, just as the Sponsors will benefit from higher tariff income (subject to such limitations as may exist on pass through of cost overruns).

Therefore a Stranded Gas Contract aligns the interests of the Sponsors and the State better with respect to cost overruns. The State and the Sponsors are to a degree "in the same boat".

This is an aspect that lower the risk perception on the part of the investors.

5.1.1.10. Fiscal Sensitivity

The economics of the Alaska Gas Project is very sensitive to changes in fiscal terms. It is for this reason that fiscal stability is absolutely required. The sensitivity of the economics of the Alaska Gas Project will be analyzed in a separate report.

5.1.2. Project ending in Chicago

In many respects the economics of the Project to Chicago is similar in its overall characteristics to the Project to Alberta. Therefore in this section only the analysis of the main issues will be repeated.

An important aspect of the Chicago project is that the Alberta – Chicago price differential of $ 0.82 cents per MMBtu, reduced to $ 0.41 cents per MMBtu does not apply . The entire distance between the North Slope and Chicago is subject to a transportation tariff.

This therefore creates an important difference between the two cases.

Following are the tariffs that are the result of the economic analysis on a nominal basis. These tariffs include the GTP and to the extend of the Point Thomson production the PT Feeder Line.

Table 5.17. Tariffs on a nominal basis for the three options

		Status Quo	ASGFC	ASGFC+GTP
Alberta	Producers	$1.455	$1.397	$1.397
	State	n/a	$1.409	$1.409
Chicago	Producers	$2.089	$2.031	$2.031
	State	n/a	$2.049	$2.049

Slightly different tariffs were calculated for the Producers and the State. This is due to the fact that the State is not taxable on the portions in the US. Interestingly, because of the nature of the rate base calculation this results in a slightly higher tariff. How the tariff revenues will be allocated among the partners in the light of different tax treatments is still a matter of the LLC discussions.

The tariffs for the Status Quo are higher because of the fact that higher property taxes are included in these tariffs.

Also, it was assumed that Federal tax credits on the GTP for federal income tax and State tax credits for the GTP for the PPT would not impact on the tariffs.

5.1.2.1. Status Quo

Table 5.18 and Chart 5.18 provide the Total Alaska Income information for the Status Quo.

Table 5.18. Alaska nominal income (Chicago project) - Status Quo

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	18995	3536	3547	26078	0	26078
$3.50	36116	3536	3547	43199	0	43199
$4.50	53545	3536	3547	60628	0	60628
$5.50	70708	3536	3547	77792	0	77792
$6.50	87965	3536	3547	95048	0	95048
$7.50	105194	3536	3547	112277	0	112277
$8.50	122358	3536	3547	129442	0	129442

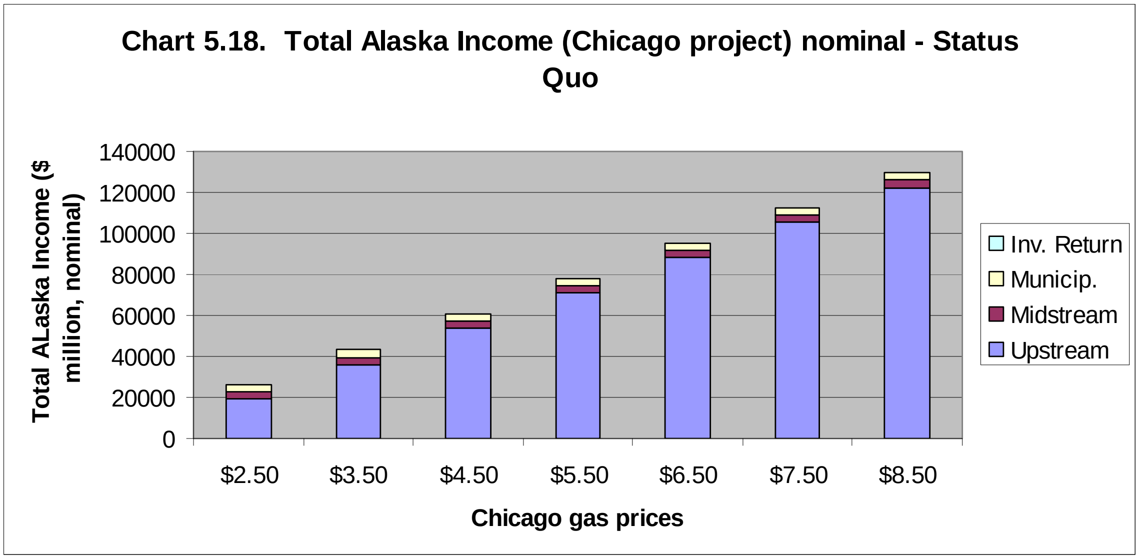


Table 5.19 shows the differential between the Alberta less the Chicago project.

Table 5.19. Differential between Alaska and Chicago project - Status Quo

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	-581	0	0	-581	0	-581
$3.50	-597	0	0	-597	0	-597
$4.50	-595	0	0	-595	0	-595
$5.50	-593	0	0	-593	0	-593
$6.50	-589	0	0	-589	0	-589
$7.50	-586	0	0	-586	0	-586
$8.50	-586	0	0	-586	0	-586

As can be seen the only difference between the Alaska less the Chicago project is that the undiscounted upstream revenues for the Chicago project are less. This is due to the fact that the all distance tariffs to Chicago are less attractive over time than terminating the project in Alberta and benefiting from the tariff reduction after 2026.

5.1.2.2. ASGFC

Table 5.20 and Chart 5.19 provide the Total Alaska revenues under the ASGFC.

Table 5.20. Alaska nominal income (Chicago Project) - ASGFC

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	16433	1156	3920	21509	7483	28992
$3.50	33636	1156	3920	38712	7483	46195
$4.50	51146	1156	3920	56222	7483	63706
$5.50	68392	1156	3920	73468	7483	80951
$6.50	85731	1156	3920	90807	7483	98290
$7.50	103041	1156	3920	108117	7483	115600
$8.50	120287	1156	3920	125363	7483	132847

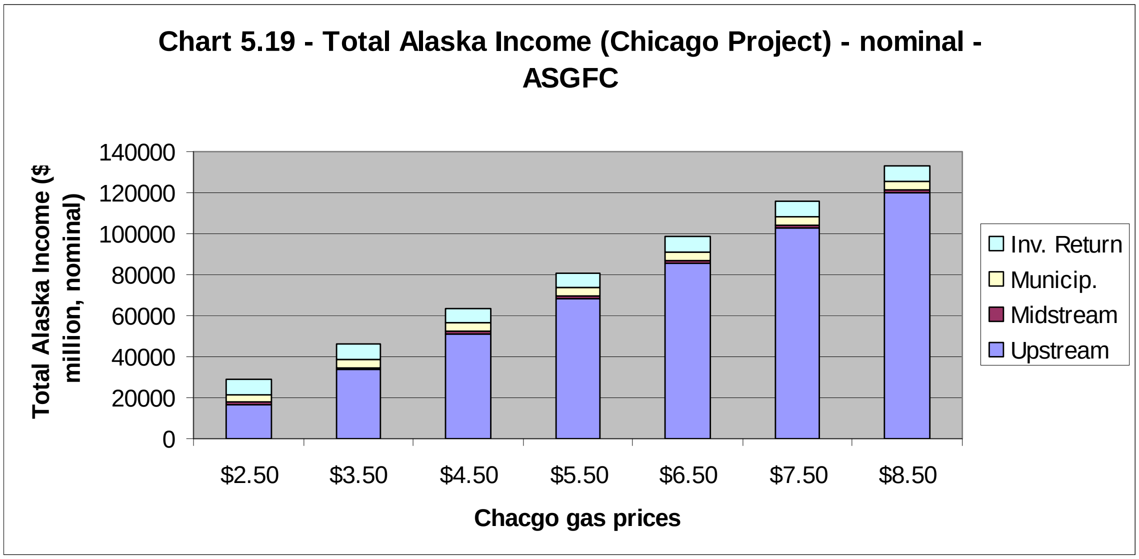


Table 5.21 provides for the differential between the Alberta less the Chicago project.

Table 5.21. Differential between Alaska and Chicago project - ASGFC

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	-674	0	0	-674	2798	2124
$3.50	-691	0	0	-691	2798	2107
$4.50	-688	0	0	-688	2798	2109
$5.50	-686	0	0	-686	2798	2111
$6.50	-682	0	0	-682	2798	2116
$7.50	-680	0	0	-680	2798	2118
$8.50	-680	0	0	-680	2798	2118

Also in this case the undiscounted upstream income is somewhat less because of the less attractive price and transport differential over time.

However, now the Return on Investment before financing for the State is considerably more, $ 2.8 billion more.

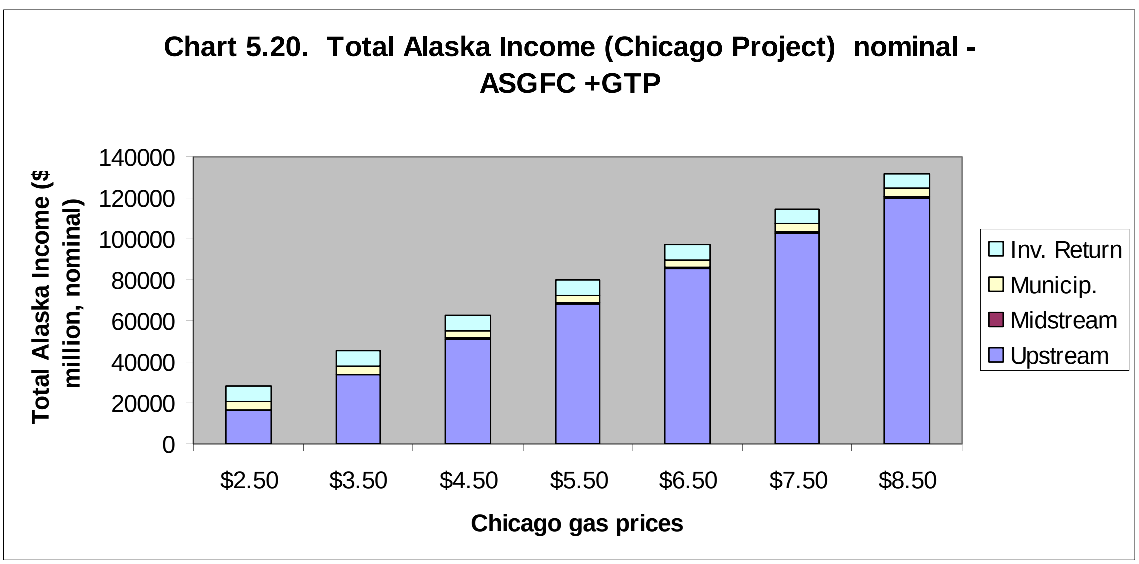
Consequently, Total Alaska Income is considerably more than the Status Quo if it were necessary to pursue a project to Chicago because of market conditions in North America.

5.1.2.3. ASGFC + GTP

Table 5.22 and Chart 5.20 provide for the Total Alaska Income for the ASGFC with tax credits for the GTP and lateral lines. These data show the same revenues as for the ASGFC, except that the midstream revenues are $ 875 million less because of the credits.

Table 5.22. Alaska nominal income (Chicago project) - ASGFC with GTP

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	16433	282	3920	20634	7483	28117
$3.50	33636	282	3920	37837	7483	45320
$4.50	51146	282	3920	55348	7483	62831
$5.50	68392	282	3920	72593	7483	80076
$6.50	85731	282	3920	89932	7483	97415
$7.50	103041	282	3920	107243	7483	114726
$8.50	120287	282	3920	124489	7483	131972



5.1.2.4. Total Alaska Income analysis for the three cases

Table 5.23 shows the comparison among the three options.

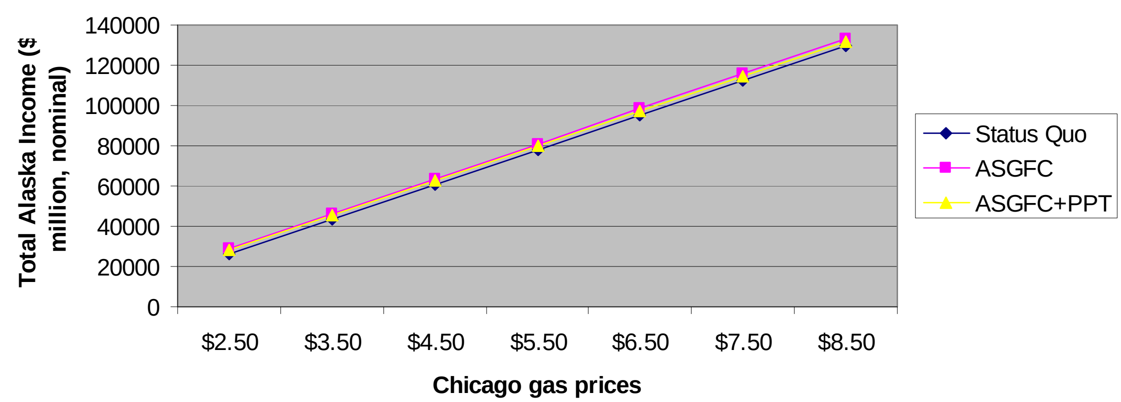
Table 5.23 Comparison of Total Alaska Income ($ million, nominal)

	Status Quo	ASGFC	ASGFC+GTP
$2.50	26078	28992	28117
$3.50	43199	46195	45320
$4.50	60628	63706	62831
$5.50	77792	80951	80076
$6.50	95048	98290	97415
$7.50	112277	115600	114726
$8.50	129442	132847	131972

It can be seen from the above tables and from Chart 5.21 how the ASGFC terms are $ 2.9 to $ 3.4 billion higher than the Status Quo, while the ASGFC+GTP terms are $ 2.0 to $ 2.5 billion higher, depending on the level of price. The difference increases with price.

Chart 5.21 shows the comparison among the three options in chart form.

Chart 5.21. Total Alaska Income (Chicago Project) - nominal - for the three options.



Because of the 20% right of the State to participate in the entire midstream venture to Chicago, the income to the State, before financing, by definition is higher under the Chicago Project than the Alberta Project.

5.1.2.5. Distribution of Divisible Income

Tables 5.24 through 5.29 show the same distribution tables of the divisible income as were displayed for the Alberta Project.

Table 5.24 Income distribution (Chicago Project) under Status Quo

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	26078	45256	71334	67113	138447
$3.50	43199	66288	109488	104835	214322
$4.50	60628	87213	147841	142357	290198
$5.50	77792	108231	186022	180051	366073
$6.50	95048	129216	224264	217684	441948
$7.50	112277	150210	262488	255336	517824
$8.50	129442	171228	300669	293029	593699

Table 5.25 Take distribution (Chicago Project) under the Status Quo

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	18.8%	32.7%	51.5%	48.5%	100.0%
$3.50	20.2%	30.9%	51.1%	48.9%	100.0%
$4.50	20.9%	30.1%	50.9%	49.1%	100.0%
$5.50	21.3%	29.6%	50.8%	49.2%	100.0%
$6.50	21.5%	29.2%	50.7%	49.3%	100.0%
$7.50	21.7%	29.0%	50.7%	49.3%	100.0%
$8.50	21.8%	28.8%	50.6%	49.4%	100.0%

Table 5.26 Income distribution (Chicago Project) under ASGFC

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	28992	45187	74179	63671	137850
$3.50	46195	66190	112385	101340	213725
$4.50	63706	87087	150792	138808	289600
$5.50	80951	108076	189027	176449	365476
$6.50	98290	129032	227322	214029	441351
$7.50	115600	149998	265598	251628	517226
$8.50	132847	170987	303833	289268	593102

Table 5.27 Take distribution (Chicago Project) under ASGFC

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	21.0%	32.8%	53.8%	46.2%	100.0%
$3.50	21.6%	31.0%	52.6%	47.4%	100.0%
$4.50	22.0%	30.1%	52.1%	47.9%	100.0%
$5.50	22.1%	29.6%	51.7%	48.3%	100.0%
$6.50	22.3%	29.2%	51.5%	48.5%	100.0%
$7.50	22.4%	29.0%	51.4%	48.6%	100.0%
$8.50	22.4%	28.8%	51.2%	48.8%	100.0%

Table 5.28 Income distribution (Chicago Project) under ASGFC+GTP

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	28117	45493	73610	64240	137850
$3.50	45320	66497	111817	101908	213725
$4.50	62831	87393	150224	139377	289600
$5.50	80076	108382	188458	177018	365476
$6.50	97415	129338	226753	214598	441351
$7.50	114726	150304	265030	252197	517226
$8.50	131972	171293	303265	289837	593102

Table 5.29 Take distribution (Chicago Project) under ASGFC+GTP

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	20.4%	33.0%	53.4%	46.6%	100.0%
$3.50	21.2%	31.1%	52.3%	47.7%	100.0%
$4.50	21.7%	30.2%	51.9%	48.1%	100.0%
$5.50	21.9%	29.7%	51.6%	48.4%	100.0%
$6.50	22.1%	29.3%	51.4%	48.6%	100.0%
$7.50	22.2%	29.1%	51.2%	48.8%	100.0%
$8.50	22.3%	28.9%	51.1%	48.9%	100.0%

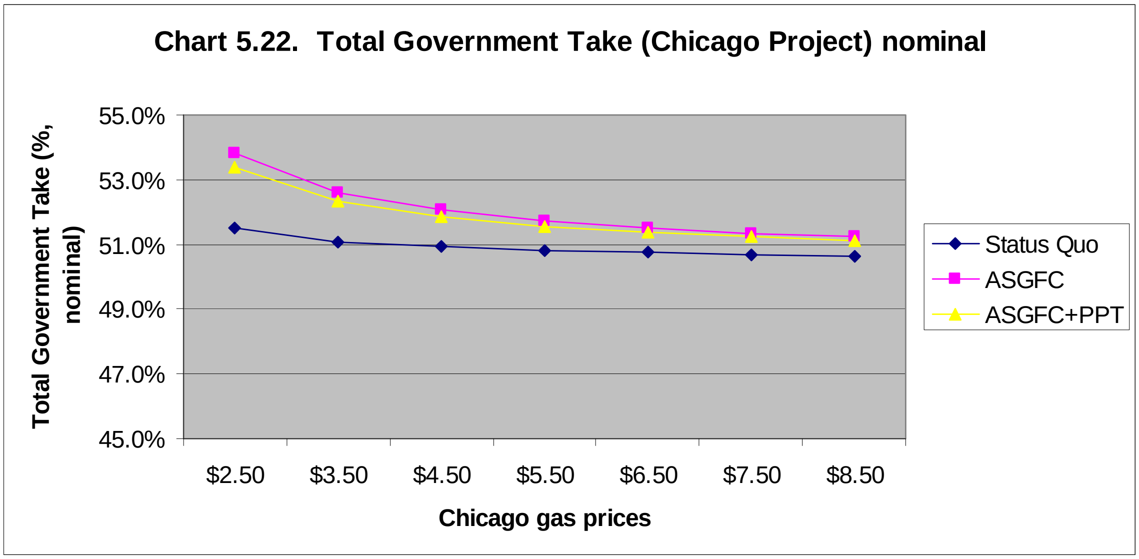
In comparing these tables with Tables 5.10 through 5.16, two important changes can be observed:

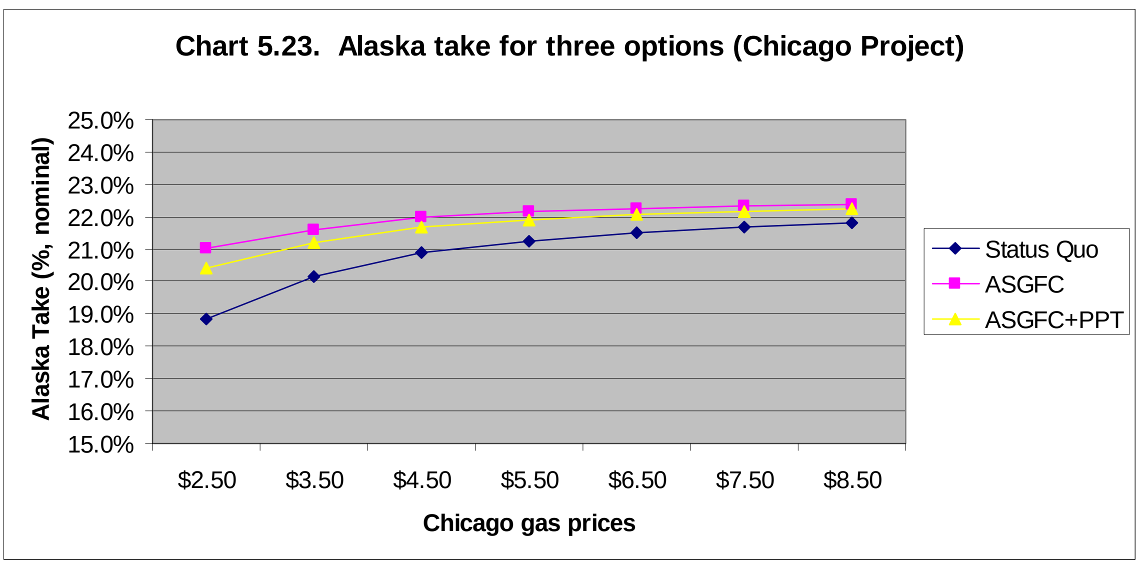
- The Alaska total take is somewhat less for all three options, and
- The Alaska total take is progressive for all three options.

This is the result of the fact that the divisible income of the project is now measured at Chicago. This means the divisible income is about $ 20 billion more. Because the divisible income is larger, the Alaska take is somewhat less.

Because an equal amount of about $ 20 billion is added to every gas price scenario, the Alaska system is now also progressive. Relative to the value of the gas in Chicago, Alaska receives a higher share of the total divisible income under higher prices. This is true for all three options.

Charts 5.22 and 5.23 show the total government take and the Alaska take for the Chicago Project.





The total government take has now become more regressive than for the Alberta Project. This is the result of the fact that now considerable property taxes and State corporate income taxes are included for the Lower 48 states.

As explained above, the Alaska take has now become more progressive. It can be seen how the ASGFC and the ASGFC+GTP terms are now well above the Status Quo terms as a result of the large return on investment for the State on the entire project (before financing).

5.1.3. Mixture of Alberta and Chicago economics

At this time it is not known what the exact mix will be between the Alberta and Chicago projects.

At this time the typical estimate is that about 2 Bcf/day capacity will be available on existing pipeline systems out of Alberta by about 2014.

This means it may not be necessary to built a full 4.3 Bcf/day pipeline system to Chicago. It is uncertain at this time as to whether or not significant long term shipping commitments would have to be made on available share pipeline capacity in order to secure transportation.

It may be that it would be prudent to secure capacity with long term shipping commitments. In this case the economics would have the character of the Chicago Project. It are the shipping commitments that determine the project economics, not whether actually new pipelines are being constructed.

It may also be that capacity out of Alberta can easily be contracted for on the basis of short term commitments on excess pipeline capacity that is amply available. In this case the Alberta Project would represent the overall project economics.

Given the need in Alberta for large additional volumes of gas as energy source for oil sands developments, a share of the gas may actually be sold in the Alberta Hub to Alberta customers.

Several factors could cause the need for long term take-away capacity and new pipeline construction from Alberta to be high. This may include, increases in gas discoveries and production from Alberta and adjacent areas such as the Southern NWT and NE British Columbia due to ongoing high gas prices. Also switches in oil sand technology towards the use of oil as an energy source rather than gas may result in more gas being available than anticipated for long distance marketing from Alberta.

In summary, at this time the projections of take-away capacity that can be contracted for on the basis of short term contracts is subject to a considerable margin of uncertainty.

For this reason it can be expected that actual Alaska revenues may fall somewhere between those of the Alberta project and the Chicago project.

Based on this general concept, it can be concluded that the Total Alaska income after the GTP credits have been deducted will be about equal to the Status Quo income.

5.2. State of Alaska Income – Real Results

Following is a discussion of the results in real $ 2006.

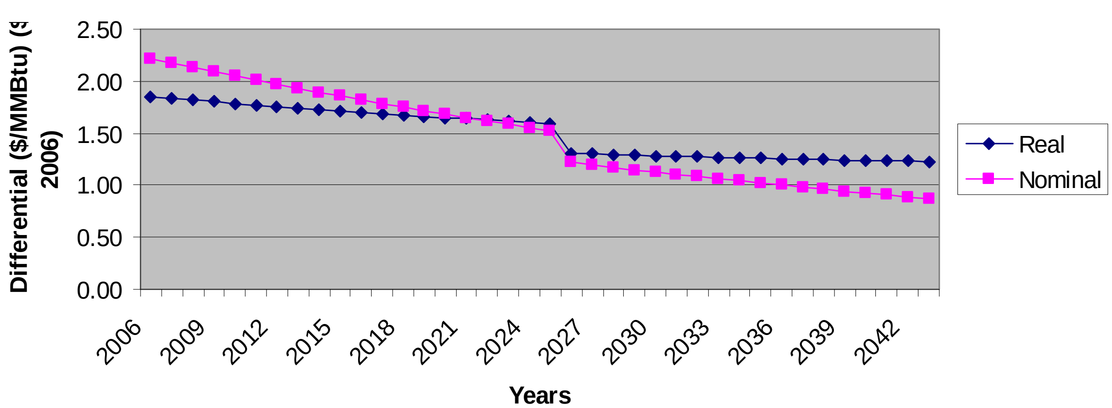
It should be noted that with the methodology used in this report for determining real values, the price differential between AECO and the North Slope well head price is somewhat flatter than would have resulted from a real analysis that was derived from nominal cash flows as is illustrated in Chart 5.24.

By using zero percent cost escalation and costs of financing and equity which are 2% less, the transportation tariff between the North Slope is lower on a levellized basis. Since the price differential between AECO and Chicago is expressed in nominal terms, this price differential declines if one uses $ 2006.

This methodology over-evaluates early upstream revenues and under-evaluates the late upstream revenues. This needs to be kept in mind when reviewing the data.

This is even more true for a Chicago Project since in this case the entire tariff is flat.

Chart 5.24. Differential between AECO and well head prices based on a Nominal and a Real analysis in Constant 2006 $



Since most of the issues have been discussed under the "nominal" section of this chapter, the "real" section will be primarily a review of the results. This is to provide information to those who prefer to review projects economics in constant dollar results.

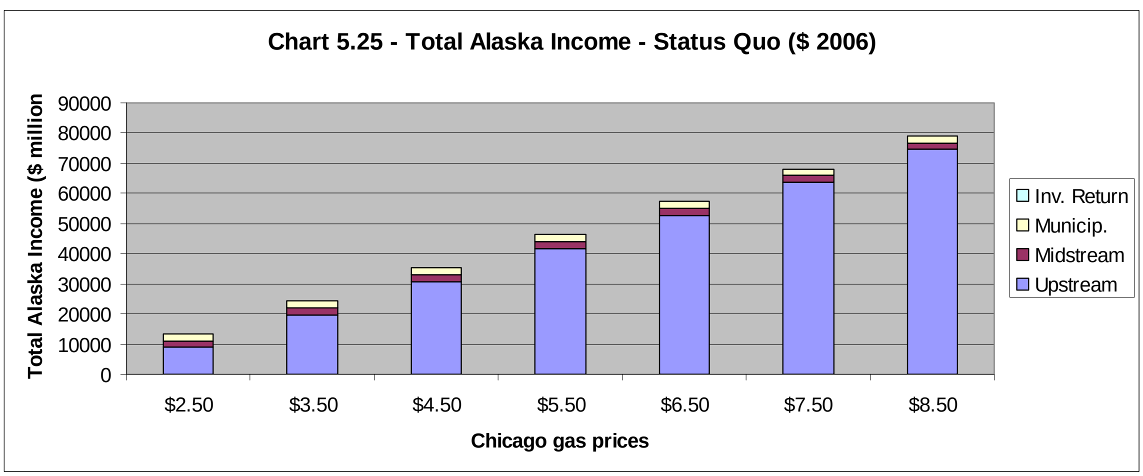
5.2.1. Project ending in Alberta.

Table 5.30 and Chart 5.25 illustrate the Alaska Income in $ 2006 for different price levels for the Status Quo.

5.2.1.1. Status Quo

Table 5.30. Alaska income - Status Quo - ($ 2006)

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	8912	2256	2265	13433	0	13433
$3.50	19729	2256	2265	24250	0	24250
$4.50	30786	2256	2265	35307	0	35307
$5.50	41692	2256	2265	46213	0	46213
$6.50	52671	2256	2265	57192	0	57192
$7.50	63632	2256	2265	68153	0	68153
$8.50	74543	2256	2265	79064	0	79064



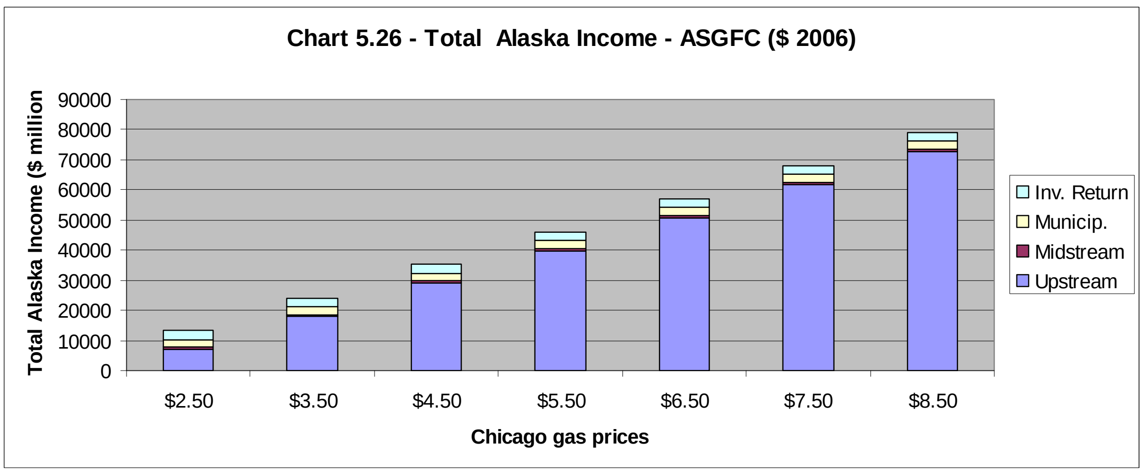
These data clearly illustrate that even in constant 2006 $ the size of the project is enormous. Under current price levels of $ 6.50 per MMBtu in Chicago it would lead to $ 57 billion in Total Alaska Income. Under reasonable typical long term average price forecasts of $ 5.50 per MMBtu in Chicago it would lead to $ 46 billion.

5.2.1.2. ASGFC

Table 5.31 and Chart 5.26 illustrate the Total Alaska Income for the ASGFC.

Table 5.31. Alaska income - ASGFC - ($ 2006)

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	7063	740	2564	10366	2922	13288
$3.50	17899	740	2564	21203	2922	24124
$4.50	28964	740	2564	32268	2922	35189
$5.50	39877	740	2564	43181	2922	46103
$6.50	50864	740	2564	54167	2922	57089
$7.50	61833	740	2564	65137	2922	68058
$8.50	72751	740	2564	76055	2922	78976



It can be seen how in real terms the ASGFC Total Alaska Income is about $ 100 million less than the Status Quo for every price level.

The redistribution of Total Alaska Income was already discussed in Section 5.1.1.3 of the report. In general State Midstream income is much less because the State's share of the property taxes has been eliminated except for the differential between the 20 mills and possible lower mill rates. Also the Upstream income is less primarily due to the UCA and the marketing costs associated with the gas in kind of the State. The midstream municipal income is slightly more and, of course, the State now earns a considerable before financing return from its investment.

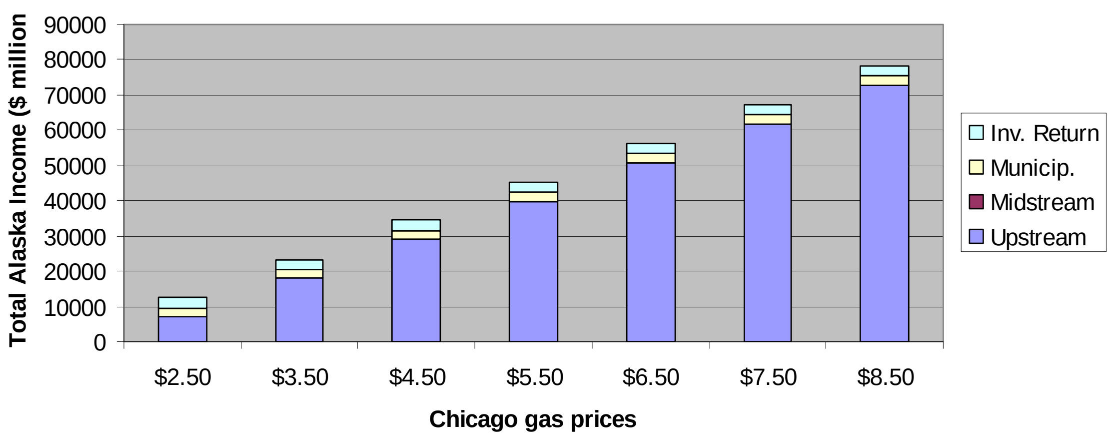
5.2.1.3. ASGFC +GTP

Table 5.32 and Chart 5.27 illustrate the difference with the GTP and lateral line credits.

Table 5.32. Alaska income - ASGFC +GTP - ($ 2006)

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	7063	-47	2564	9579	2922	12501
$3.50	17899	-47	2564	20415	2922	23337
$4.50	28964	-47	2564	31480	2922	34402
$5.50	39877	-47	2564	42393	2922	45315
$6.50	50864	-47	2564	53380	2922	56302
$7.50	61833	-47	2564	64349	2922	67271
$8.50	72751	-47	2564	75267	2922	78189

Chart 5.27 Total Alaska Income - ASGFC +GTP ($ 2006)

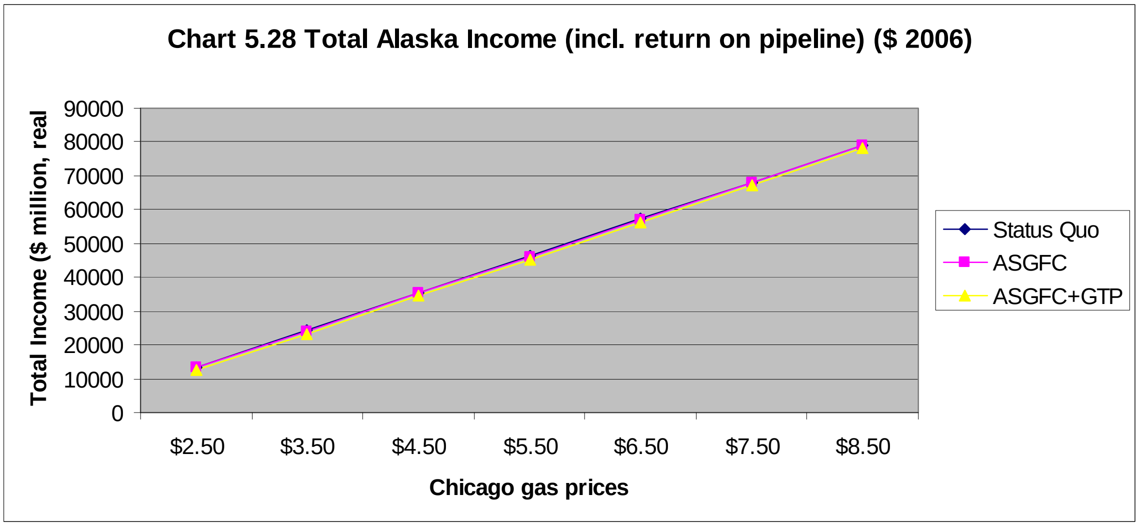


The only change in this table relative to Table 5.31 is the GTP and lateral line credit which lower the midstream income. Actually in this case this income becomes slightly negative. In other words the GTP and lateral line credits exceed the corporate income tax for the mid stream in constant dollar terms.

As a result, the Total Alaska Income is somewhat less than the Status Quo results.

5.2.1.4. Summary

Chart 5.28 shows the overall result.



As can be seen the differences are minimal for most of the price range. However, at very low prices, such as $ 2.50 per MMBtu in Chicago, the GTP tax credits become more important in a relative sense.

5.2.1.5. Distribution of Divisible Income

Tables 5.33 through 5.38 and Charts 5.29 and 5.30 show the distribution of the total government take and the Alaska government take.

Table 5.33. Income distribution under Status Quo ($ 2006)

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	13433	16395	29828	27082	56910
$3.50	24250	29547	53796	50792	104589
$4.50	35307	42614	77921	74346	152267
$5.50	46213	55735	101948	97998	199946
$6.50	57192	68830	126022	121602	247624
$7.50	68153	81931	150084	145218	295303
$8.50	79064	95050	174114	168867	342981

Table 5.34 Take distribution under the Status Quo ($ 2006)

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	23.6%	28.8%	52.4%	47.6%	100.0%
$3.50	23.2%	28.3%	51.4%	48.6%	100.0%
$4.50	23.2%	28.0%	51.2%	48.8%	100.0%
$5.50	23.1%	27.9%	51.0%	49.0%	100.0%
$6.50	23.1%	27.8%	50.9%	49.1%	100.0%
$7.50	23.1%	27.7%	50.8%	49.2%	100.0%
$8.50	23.1%	27.7%	50.8%	49.2%	100.0%

Table 5.35 Income distribution under ASGFC ($ 2006)

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	13288	16719	30007	26528	56535
$3.50	24124	29864	53988	50225	104213
$4.50	35189	42929	78118	73774	151892
$5.50	46103	56047	102149	97421	199570
$6.50	57089	69139	126228	121021	247249
$7.50	68058	82237	150296	144632	294927
$8.50	78976	95354	174330	168276	342606

Table 5.36 Take distribution under ASGFC ($ 2006)

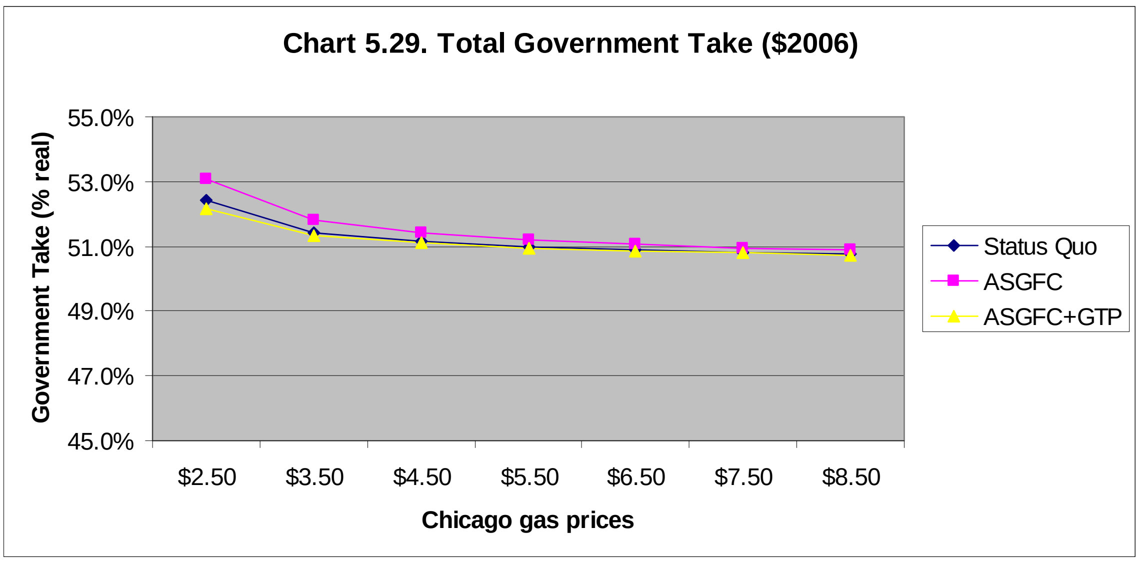
	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	23.5%	29.6%	53.1%	46.9%	100.0%
$3.50	23.1%	28.7%	51.8%	48.2%	100.0%
$4.50	23.2%	28.3%	51.4%	48.6%	100.0%
$5.50	23.1%	28.1%	51.2%	48.8%	100.0%
$6.50	23.1%	28.0%	51.1%	48.9%	100.0%
$7.50	23.1%	27.9%	51.0%	49.0%	100.0%
$8.50	23.1%	27.8%	50.9%	49.1%	100.0%

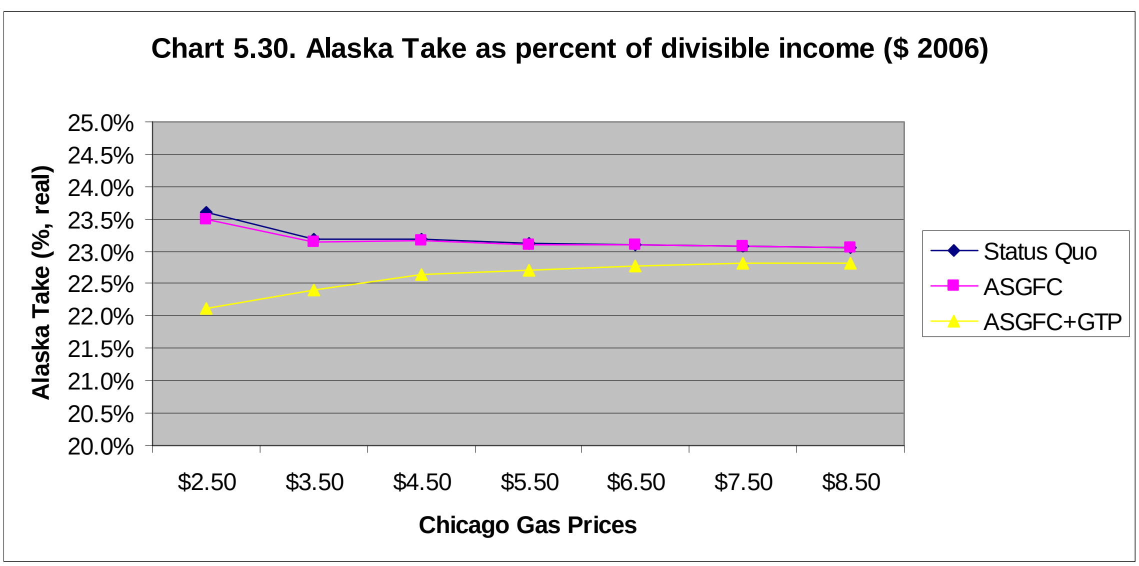
Table 5.37 Income distribution under ASGFC +GTP ($ 2006)

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	12501	16995	29495	27039	56535
$3.50	23337	30140	53477	50737	104213
$4.50	34402	43204	77606	74285	151892
$5.50	45315	56322	101638	97933	199570
$6.50	56302	69415	125716	121532	247249
$7.50	67271	82513	149784	145143	294927
$8.50	78189	95629	173818	168788	342606

Table 5.38. Take distribution under ASGFC +GTP ($ 2006)

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	22.1%	30.1%	52.2%	47.8%	100.0%
$3.50	22.4%	28.9%	51.3%	48.7%	100.0%
$4.50	22.6%	28.4%	51.1%	48.9%	100.0%
$5.50	22.7%	28.2%	50.9%	49.1%	100.0%
$6.50	22.8%	28.1%	50.8%	49.2%	100.0%
$7.50	22.8%	28.0%	50.8%	49.2%	100.0%
$8.50	22.8%	27.9%	50.7%	49.3%	100.0%





It can be seen from the constant 2006 $ tables and graphs that the overall pattern of government take distribution is not very different from the nominal tables and graphs provided earlier.

A number of noteworthy issues can be observed.   The total government take is for the low price scenarios slightly higher.   This is due to the overall front end loaded nature of the fiscal terms, in particular due to property taxes other US States.

The Alaska take is slightly higher for the Status Quo and the ASGFC options.   This is again due to the front end loaded nature of the Alaska system.

It can also be observed that the difference between the ASGFC and the ASGFC+GTP widens, because actually the ASGFC+GTP does not show an increase in government take.   The reason is that the credits on the GTP come early in the cash flow.   This incentive therefore offsets the front end loaded character of the Status Quo and the ASGFC. On a real 2006 $ basis this incentive at the front end has more weight than under the nominal cases.

5.2.1.6. Year by Year analysis

Charts 5.31 through 5.33 show the year by year analysis of the Total Alaska Income under the three different options.

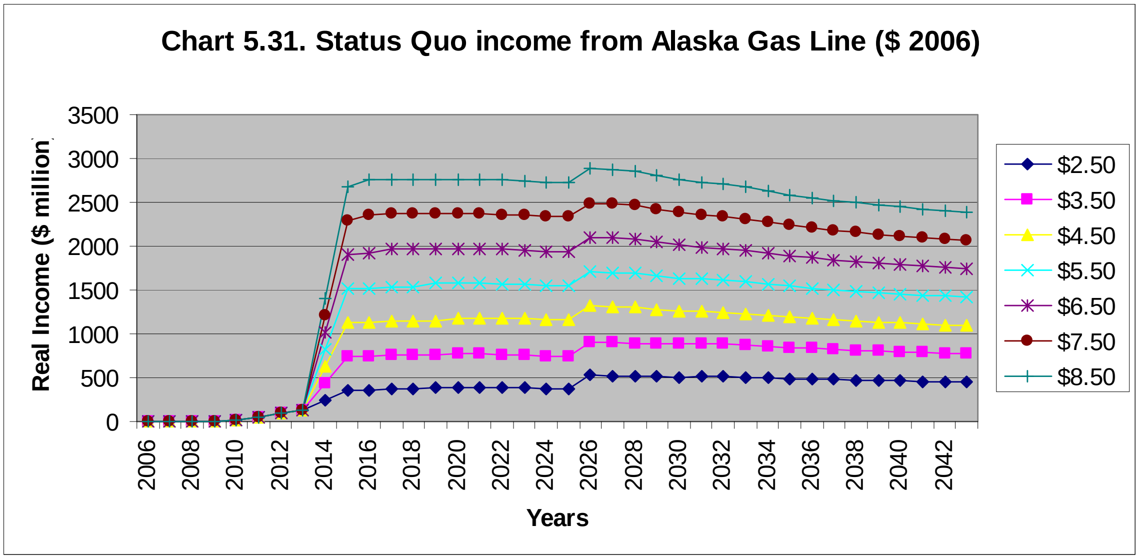


Chart 5.31. Status Quo income from Alaska Gas Line ($ 2006)
Real Income ($ million)
3500
3000
2500
2000
1500
1000
500
0
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Years
$2.50
$3.50
$4.50
$5.50
$6.50
$7.50
$8.50

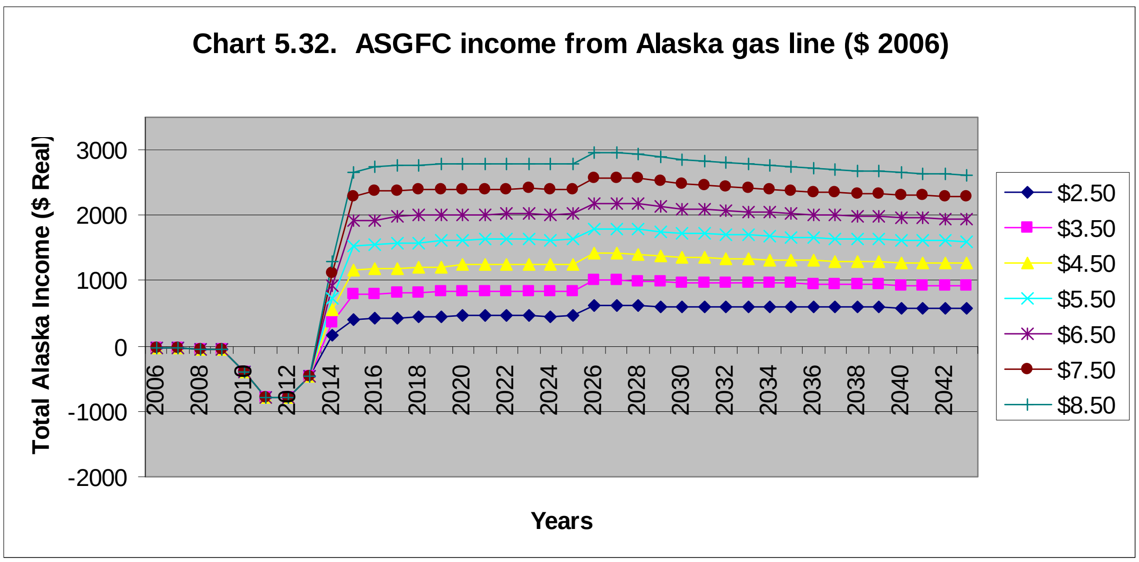
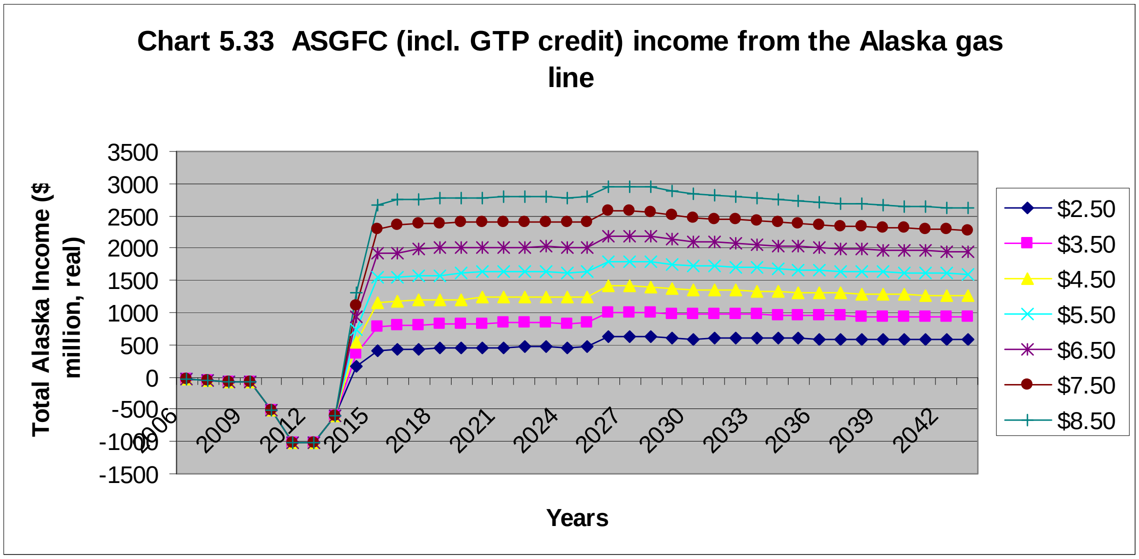


Chart 5.32. ASGFC income from Alaska gas line ($ 2006)
Total Alaska Income ($ Real)
3000
2000
1000
0
-1000
-2000
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Years
$2.50
$3.50
$4.50
$5.50
$6.50
$7.50
$8.50

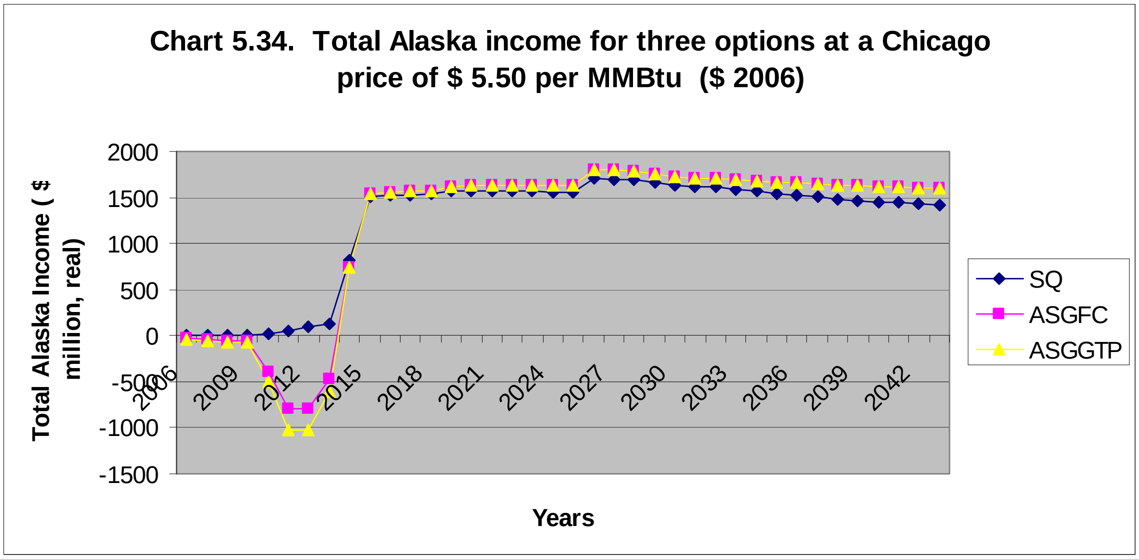


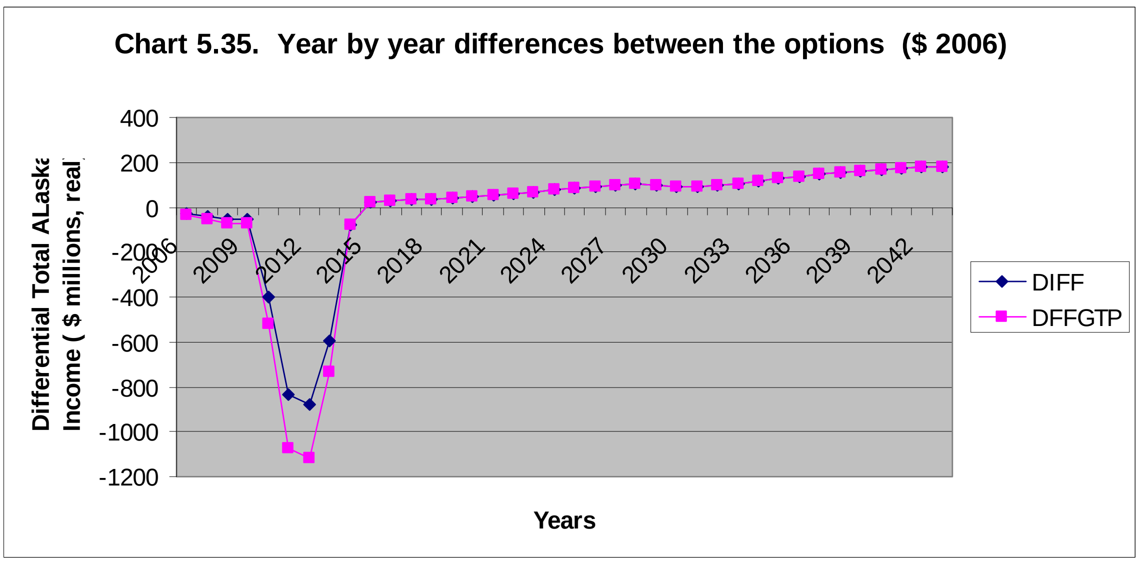
As can be seen, there is a slight decline in real terms in Total Alaska Income after 2026 in real 2006 $. This is due to two reasons: the average royalties and the tariff structure.

The average royalties become less over time because of the depletion of the Point Thomson gas production. Point Thomson has a higher royalty than the over fields. This affects both the Status Quo and the State gas under the ASGFC.

As was discussed at the beginning of this section 5.2., also the tariffs are slightly higher under the Constant 2006 $ option towards the later years. This results in less Alaska income. However, as was explained earlier, this is largely a result of the specific constant dollar methodology that was used. Based on the alternative methodology, the tariff would have declined and revenues would have been somewhat more.

Charts 5.34 and 5.35 provide a summary of the three options as well as the differentials.

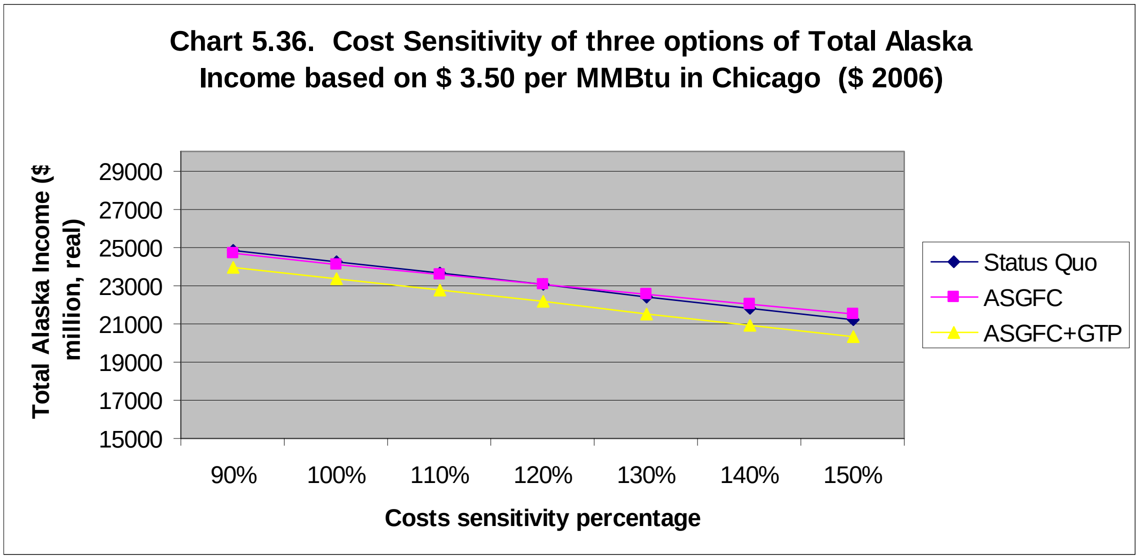




These graphs show the same overall pattern as under the nominal cases, except that the negative Total Alaska Income based on the before financing of the State share of the project is now relatively more important in the total economic picture.

5.2.1.7. Cost Sensitivity

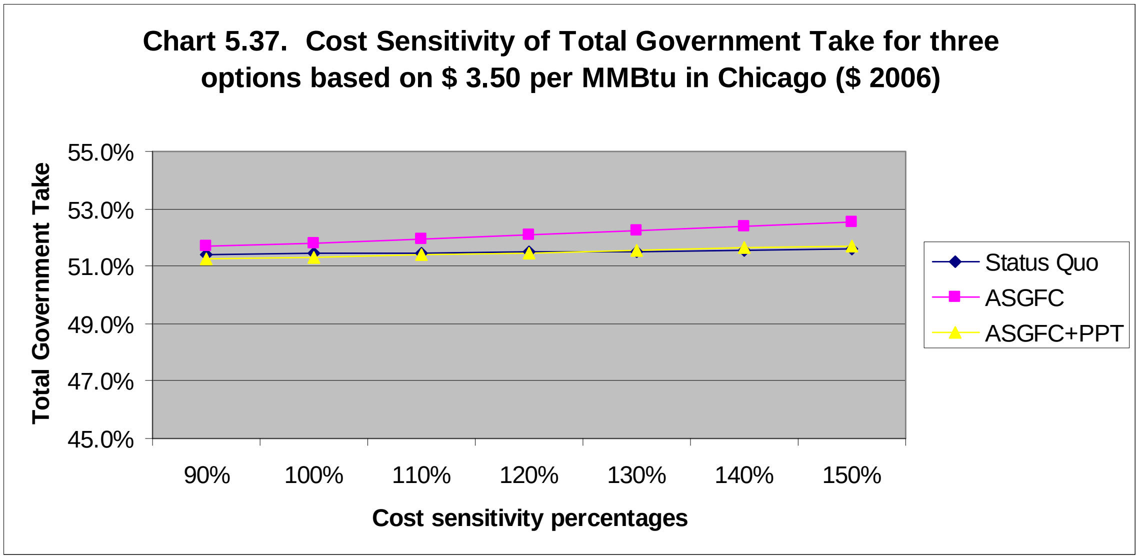
Chart 5.36 illustrates the cost sensitivity of the Total Alaska Income.

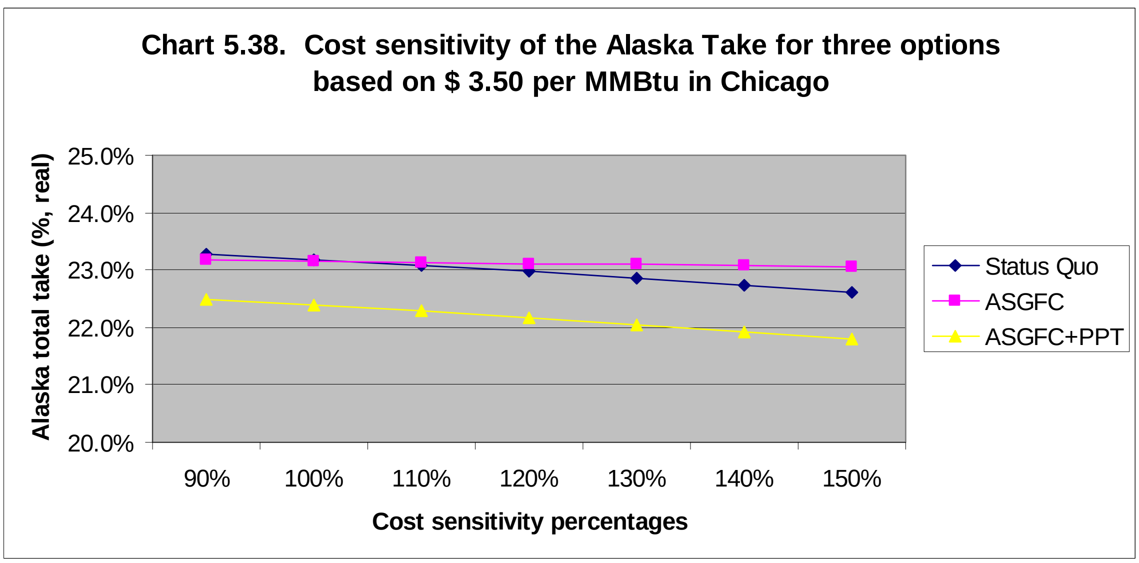


In real terms there is a loss of $ 3.6 billion for the Status Quo from 100% to 150% of costs. For the ASGFC the loss is $ 3.1 billion. As discussed under the nominal section of this Chapter, under the ASGFC the Total Alaska Income is more resistant to cost overruns, because the State benefits from the higher tariff income that would be the result of higher costs, on the assumption that these higher costs are reflected in the tariffs.

Also the Total Alaska Income under the ASGFC+GTP is somewhat more resistant under cost overruns, but the higher credit on the GTP and lateral lines, erodes some of this advantage.

Charts 5.37 and 5.38 show the government take and the Alaska Take under different levels of costs in real terms.





The two graphs show approximately the same pattern as in Charts 5.16 and 5.17.

However, as discussed before the difference in Alaska take is somewhat more between the ASGFC and ASGFC+GTP because the GTP credit in relatively more important on a real basis.

5.2.2. Project ending in Chicago.

Following is a review of the real $ 2006 data for a Project to Chicago.

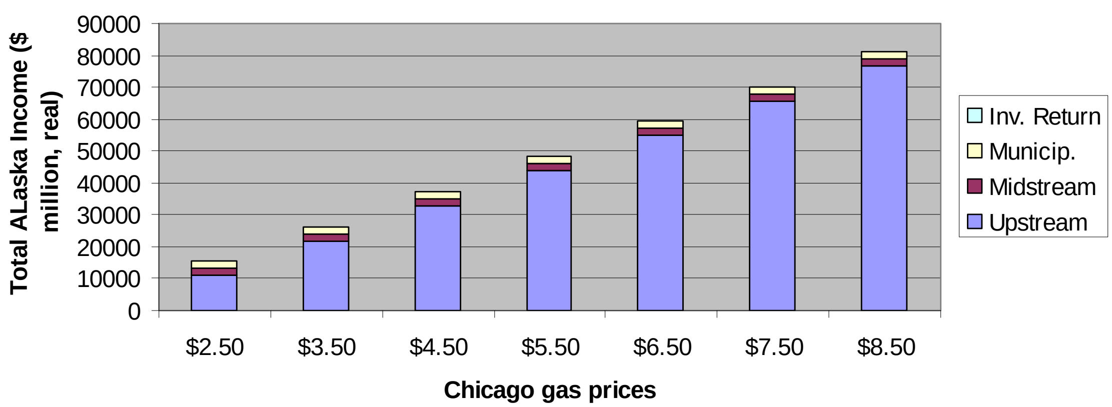
5.2.2.1. Status Quo

Table 5.39 and Chart 5.39 provide an overview of the Status Quo to Chicago under constant $ 2006.

Table 5.39. Alaska real income (Chicago project) ($2006)- Status Quo

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	10951	2256	2265	15472	0	15472
$3.50	21781	2256	2265	26302	0	26302
$4.50	32869	2256	2265	37390	0	37390
$5.50	43779	2256	2265	48300	0	48300
$6.50	54768	2256	2265	59289	0	59289
$7.50	65734	2256	2265	70255	0	70255
$8.50	76645	2256	2265	81166	0	81166

Chart 5.39. Total Alaska Income (Chicago project) ($ 2006) - Status Quo



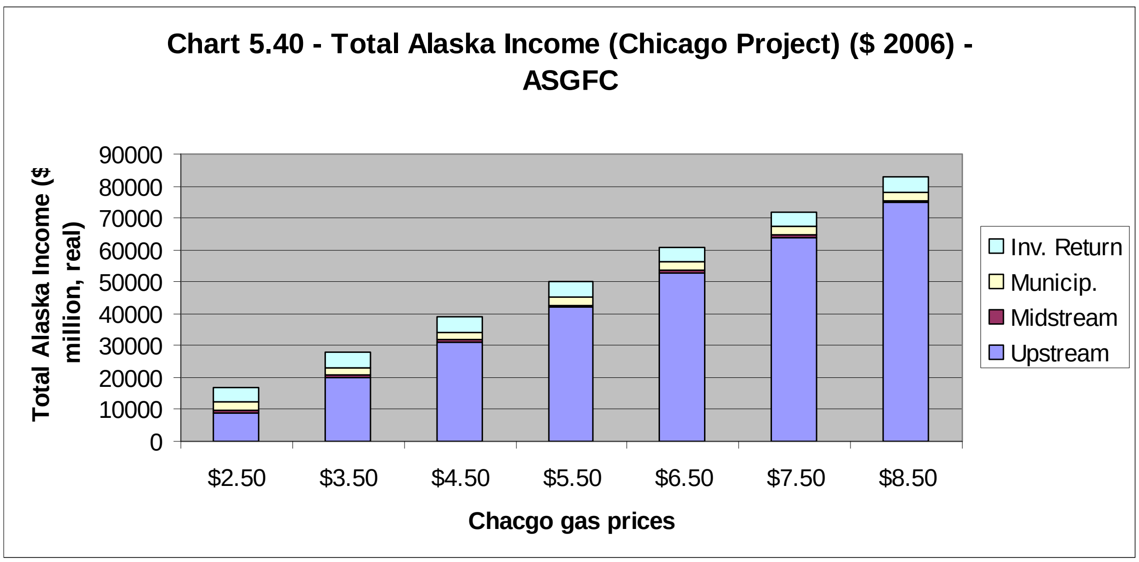
It can be seen how the upstream revenues are now higher than under the Alberta project, because under the methodology for tariffs for real conditions, the tariff to Chicago is attractive compared to the Alberta-Chicago price differential.

5.2.2.2. ASGFC

Table 5.40 and Chart 5.40 provide an overview of the ASGFC in constant $ 2006.

Table 5.40. Alaska real income (Chicago Project) ($ 2006) - ASGFC

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	9056	740	2564	12360	4674	17034
$3.50	19894	740	2564	23198	4674	27872
$4.50	30989	740	2564	34293	4674	38967
$5.50	41907	740	2564	45211	4674	49885
$6.50	52904	740	2564	56208	4674	60881
$7.50	63878	740	2564	67182	4674	71855
$8.50	74796	740	2564	78100	4674	82773



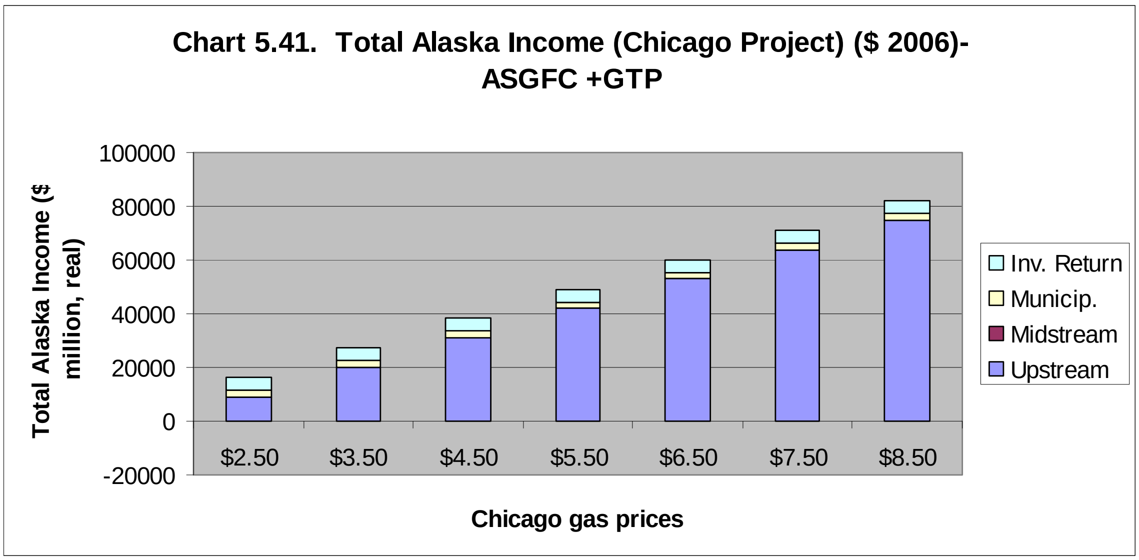
As was also already identified for the nominal Chicago project, the increased tariff income for the State provides additional income which in turn makes the ASGFC more attractive than the Status Quo (before financing)

5.2.2.3. ASGFC+GTP

Table 5.41 and Chart 5.41 illustrate the Chicago project with the GTP and lateral line credits.

Table 5.41. Alaska real income (Chicago project) ($ 2006) - ASGFC with GTP

	Upstream	Midstream	Municip.	Subtotal	Inv. Return	Total
$2.50	9056	-47	2564	11573	4674	16247
$3.50	19894	-47	2564	22411	4674	27085
$4.50	30989	-47	2564	33506	4674	38180
$5.50	41907	-47	2564	44424	4674	49098
$6.50	52904	-47	2564	55420	4674	60094
$7.50	63878	-47	2564	66394	4674	71068
$8.50	74796	-47	2564	77312	4674	81986



As for the Alberta project the GTP and lateral line credits create an income that is $ 787 million less.

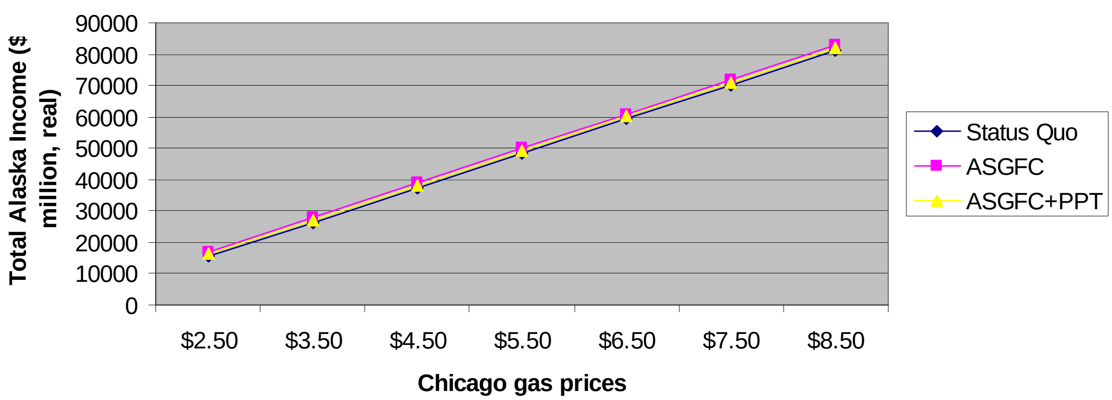
5.2.2.4. Total of three options

Table 5.42 and Chart 5.42 illustrate the three options.

Table 5.42 Comparison of Total Alaska Income ($ million, real)

	Status Quo	ASGFC	ASGFC+GTP
$2.50	15472	17034	16247
$3.50	26302	27872	27085
$4.50	37390	38967	38180
$5.50	48300	49885	49098
$6.50	59289	60881	60094
$7.50	70255	71855	71068
$8.50	81166	82773	81986

Chart 5.42. Total Alaska Income (Chicago Project) - nominal - for the three options.



It can be seen how the Chicago Project under the ASGFC is about $ 1.6 billion more attractive than the Status Quo, because of the higher tariff income. The GTP and lateral line PPT credit reduces this amount with $ 787 million.

5.2.2.5. Distribution of Divisible Income

Tables 5.43 through 5.48 illustrate the distribution of the divisible income.

Table 5.43 Income distribution (Chicago Project)($2006) Status Quo

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	15472	26076	41548	38783	80331
$3.50	26302	39223	65525	62484	128009
$4.50	37390	52280	89669	86018	175688
$5.50	48300	65399	113699	109667	223366
$6.50	59289	78490	137779	133266	271045
$7.50	70255	91589	161845	156878	318723
$8.50	81166	104708	185874	180527	366402

Table 5.44 Take distribution (Chicago Project) ($2006) Status Quo

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	19.3%	32.5%	51.7%	48.3%	100.0%
$3.50	20.5%	30.6%	51.2%	48.8%	100.0%
$4.50	21.3%	29.8%	51.0%	49.0%	100.0%
$5.50	21.6%	29.3%	50.9%	49.1%	100.0%
$6.50	21.9%	29.0%	50.8%	49.2%	100.0%
$7.50	22.0%	28.7%	50.8%	49.2%	100.0%
$8.50	22.2%	28.6%	50.7%	49.3%	100.0%

Table 5.45 Income distribution (Chicago Project)($2006) ASGFC

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	17034	26152	43186	36770	79956
$3.50	27872	39296	67168	60467	127635
$4.50	38967	52351	91318	83996	175313
$5.50	49885	65467	115352	107640	222992
$6.50	60881	78556	139437	131233	270670
$7.50	71855	91652	163508	154841	318349
$8.50	82773	104769	187542	178485	366027

Table 5.46 Take distribution (Chicago Project) ($2006) ASGFC

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	21.3%	32.7%	54.0%	46.0%	100.0%
$3.50	21.8%	30.8%	52.6%	47.4%	100.0%
$4.50	22.2%	29.9%	52.1%	47.9%	100.0%
$5.50	22.4%	29.4%	51.7%	48.3%	100.0%
$6.50	22.5%	29.0%	51.5%	48.5%	100.0%
$7.50	22.6%	28.8%	51.4%	48.6%	100.0%
$8.50	22.6%	28.6%	51.2%	48.8%	100.0%

Table 5.47 Income distribution (Chicago Project)($2006) ASGFC+GTP

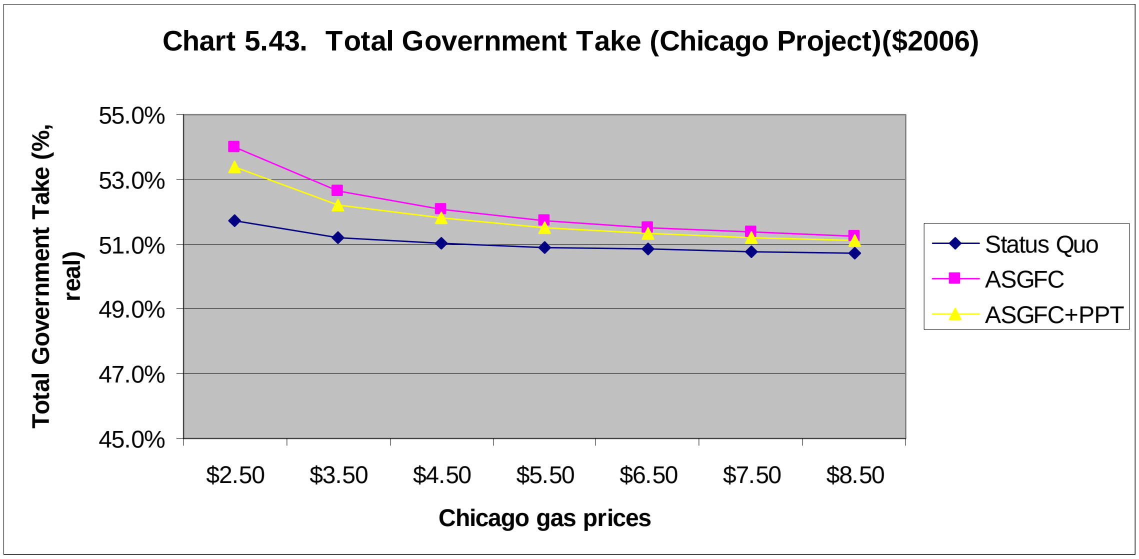
	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	16247	26428	42674	37282	79956
$3.50	27085	39572	66657	60978	127635
$4.50	38180	52626	90806	84508	175313
$5.50	49098	65742	114840	108152	222992
$6.50	60094	78831	138925	131745	270670
$7.50	71068	91928	162996	155353	318349
$8.50	81986	105044	187030	178997	366027

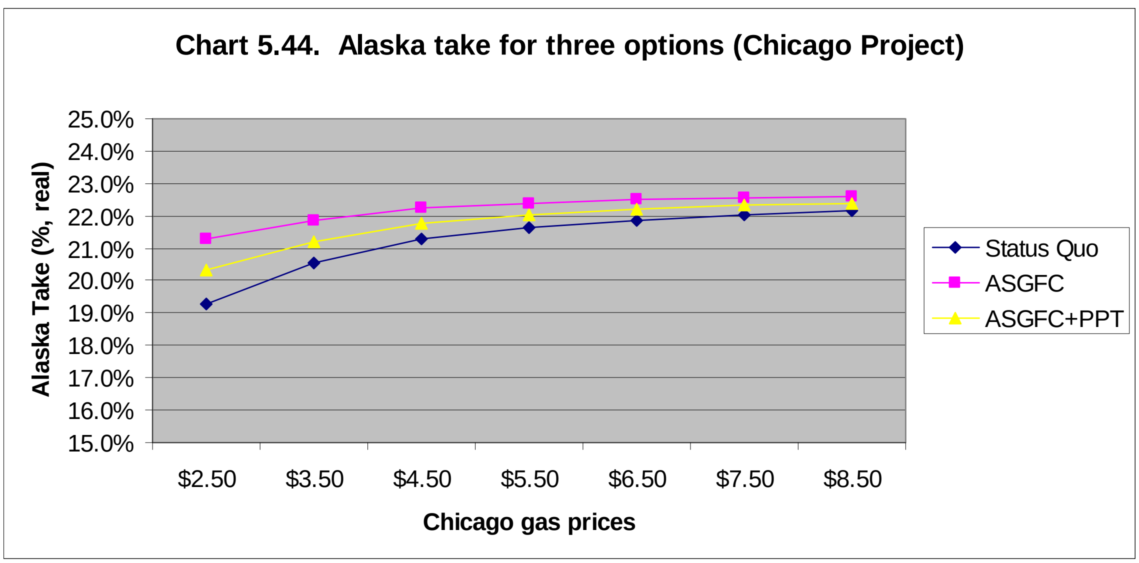
Table 5.48 Take distribution (Chicago Project) ($2006) ASGFC+GTP

	Total Alaska	Federal &Other	Total Governm.	Producers	Divisible Income
$2.50	20.3%	33.1%	53.4%	46.6%	100.0%
$3.50	21.2%	31.0%	52.2%	47.8%	100.0%
$4.50	21.8%	30.0%	51.8%	48.2%	100.0%
$5.50	22.0%	29.5%	51.5%	48.5%	100.0%
$6.50	22.2%	29.1%	51.3%	48.7%	100.0%
$7.50	22.3%	28.9%	51.2%	48.8%	100.0%
$8.50	22.4%	28.7%	51.1%	48.9%	100.0%

As was noted before, the Total Alaska Income now is progressive on the basis of a project for which the divisible income is determined in Chicago. The total government take remains regressive.

Charts 5.43 and 5.44 illustrate this overall concept.





5.2.3. Mixture of Alberta and Chicago economics

The comments that were made for the mixture of Alberta and Chicago under nominal economics apply equally for the constant $ 2006 economics.

6. Economic analysis of the Alaska Stranded Gas Fiscal Contract – Producer perspective

6.1. Introduction - Profitability indicators

All profitability indicators were calculated on the basis of nominal and real cash flows. The methodology for developing nominal and real cash flows was discussed in Section 2.5.

Based on the PFC Energy report (to be discussed in a separate report) it was assumed that currently major oil companies would evaluate investments on the basis of the following constant dollar price forecasts:

- A stress (low) price of about WTI $ 22 per barrel, corresponding with a Chicago gas price of $ 3.50 per MMBtu.
- An average price of about WTI $ 35 per barrel, corresponding with a Chicago gas price of $ 5.50 per MMBtu
- An high price of WTI $ 55, corresponding with a Chicago gas price of $ 8.50 per MMBtu.

The project cash flow is a total project cash flow.

This means the cash flow includes the share of the project owned by the Sponsors as well as other producers that may make long term commitments for the shipment of gas. This means field development costs and shipment commitments by other parties than the Sponsors are included in this cash flow. The State's share is not included in the total project cash flow.

It should be noted that it is likely that the Sponsor economics will be slightly less attractive than the total Producer economics. This is because the Sponsors will be responsible for the initial project evaluation and the associated risk.

It should also be noted that the following economics are "un-risked" economics. In other words, the modest risk associated with the fact that the project may be abandoned, due to deteriorating economic circumstances, after the initial evaluation of potentially as much as a billion dollars or more is not separately evaluated in this report.

The profitability indicators used for evaluation will be reviewed below.

Internal Rate of Return (IRR)

The internal rate of return on a cash flow basis (IRR) illustrates how fast profits are being made and the attractiveness of the cash flow relative to the initial investment.

Net Present Value discounted at 10% (NPV @10% or NPV10)

The net present value discounted at 10% per year (NPV@10% or NPV10) illustrates the present value of a project. It is a good indicator of the total amount of profits that is being made with the venture. If an oil company would want to sell the project to another company, this would be the indicator that would be used. The 10% discount rate is a widely used international discount rate. This rate will be used for nominal as well as real values. This rate reflects the cost of capital plus a "safety" margin for project evaluation. The absolute size of the NPV10 is primarily a function of the size of the project. Large projects have large NPV10 values and small projects have small values.

Profitability Ratio discounted at 10% (PFR @10% or PFR10)

The profitability ratio discounted at 10% reflects how effectively the capital is being used in project. The ratio in this report is being determined as follows:

PFR10 = (NPV10 + Total Capital @10%)/(Total Capital @10%)

In order to determine PFR10 the total capital expenditures are also discounted at 10%. The PFR10 indicates the profitability per dollar invested. The capital that is taken into consideration is the Producer Capital only. It excludes for the ASGFC and ASGFC+GTP options the capital contributed by the State.

Producer Undiscounted Net Cash Flow (NCF)

This is the total amount of cash generated by the project. With respect to the analysis used in this report, the NCF of the "Producers" , including the Sponsors is being used. This means field development costs and shipment commitments by other parties than the Sponsors are included in this cash flow. Major oil companies value high long term undiscounted cash flow. This is the profitability indicator that provides important information about the impact of the project on the long term future of the company.

Net Present Value @ 10% per barrel equivalent (NPV10/BOE)

The NPV10/BOE makes it possible to compare the NPV10 values of projects around the world, irrespective of whether the projects are small or large. It is an important indicator to reveal which project makes the highest amount of profit per barrel equivalent.

In this report is was simply assumed that 6 Mcf would equal one barrel, although based on heating value it would be approximately 5 Mcf per barrel. The Alaska Gas Project was assumed to produce 7358 million barrels equivalent over the 30 year operation of the gas pipeline based on 6Mcf/barrel.

Net Present Value @ 10% per Undiscounted Capex (NPV10/Capex)

The NPV10/Capex makes it also possible to compare NPV10 values around the world. This ratio is similar to the PFR10 except that the capital expenditures are not discounted, and capex is not added back in when determining the ratio. For these reasons this ratio results in lower values than the PFR10. The Undiscounted Capex is a yardstick that correlates to the "effort required" for a project over time. Companies seek high NPV10 values per capex, because this means that such a project is worth the management and human resource effort.

Net Cash Flow per BOE (NCF/BOE)

The NCF/BOE makes it possible to compare cash flows around the world. It permits companies to identify the most attractive cash flow projects on a relative basis. Projects with a relatively high NCF/BOE are projects that will strongly support the long term future of the company.

Profitability Criteria

Projects around the world are typically compared on a real constant $ basis. This provides more comparable data.

Table 6.1 provides a typical list of the minimum values that investors may seek for typical projects around the world on a real and nominal basis.

This list is compiled for the stress price of $ 3.50 per MMBtu in Chicago or a WTI price of $ 22 per barrel. In this list the **bold** values are relatively "hard" numbers. The hard numbers are based on the PFC Energy analysis of 60 competing oil and gas projects in the world with an investment requirement of $ 1 billion or larger. The targets represent values for which 20% of the 60 projects have less attractive indicators and 80% of the projects have more attractive indicators. Projects in the world, may have an NPV10 in the lower 20% bracket and an IRR in the 80% group or vice versa.

Unattractive projects are projects for which many of the indicators are below the targets or for which some of the indicators are substantially below the targets. It should be noted that these targets only apply to the stress price of $ 3.50 per MMBtu in Chicago. At higher prices companies would select higher targets.

The evaluation of the Alaska Gas Project will therefore be done primarily on the basis of these targets based the real values.

The other numbers are relatively "soft" numbers. It is difficult to compare international projects on a nominal basis. The relationship between real and nominal values depends very much on the project time frames and escalation and inflation rates that were used.

It should be noted that the list of minimum values in Table 6.1. would be different from company to company. It depends very much on the projects that companies have under development.

Table 6.1. Minimum Profitability Criteria as applicable to the Alaska Gas Project, for a price of $ 3.50 per MMBtu in Chicag

		Real	Nominal
IRR	**(%)**	**13%**	**15%**
NPV10	**($ million)**	**2500**	5000
PFR10	**($/$)**	**1.15**	1.35
NCF	**($ billion)**	**20**	40
NPV10/BOE	**($/BOE)**	**0.33**	0.66
NPV10/Capex	**($/$)**	**0.12**	0.25
NCF/BOE	**($/BOE)**	**2.50**	5.00

6.2. Producer Economics - Nominal Results

First the nominal results will be evaluated in this section of the report. In the next section the real results will be reviewed.

6.2.1. Project ending in Alberta

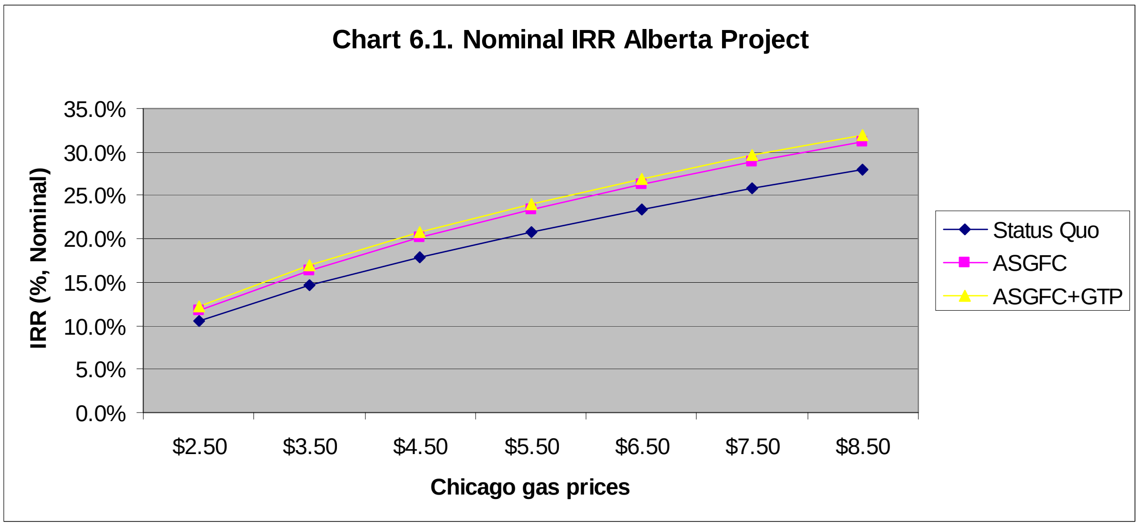
Also for the evaluation of the Producer economics, the project will be evaluated ending in the Alberta and in Chicago. First the project ending in Alberta will be reviewed.

6.2.1.1. 6.2.1.1. IRR

Chart 6.1 and Table 6.2 provide the Nominal IRR for a project ending in Alberta.

Table 6.2. Nominal IRR for Alberta Project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	10.6%	11.8%	12.3%
$3.50	14.6%	16.4%	16.9%
$4.50	17.9%	20.1%	20.7%
$5.50	20.8%	23.4%	24.0%
$6.50	23.4%	26.2%	27.0%
$7.50	25.8%	28.8%	29.6%
$8.50	27.9%	31.2%	32.0%



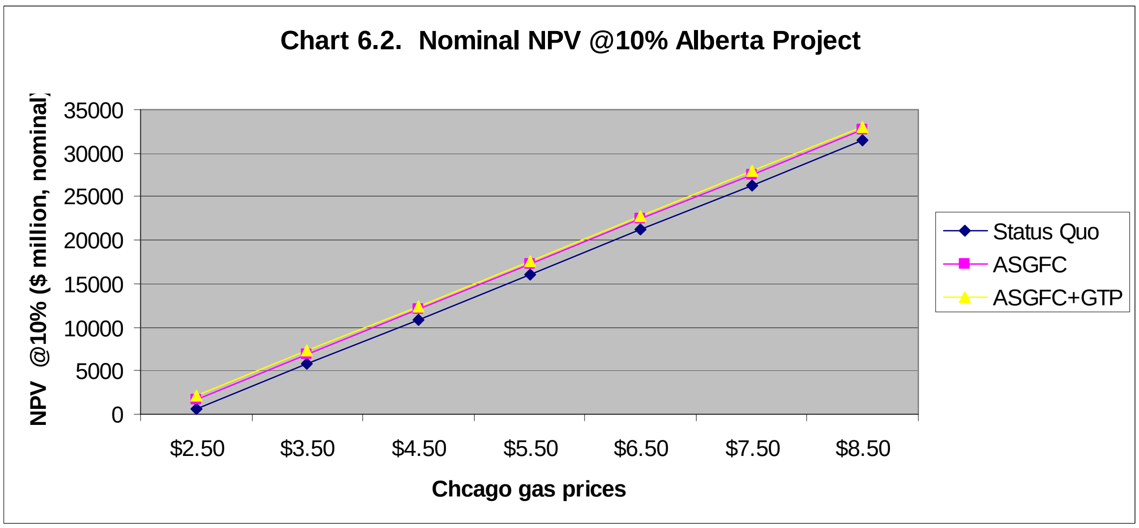
The ASGFC and ASGFC+GTP options improve the nominal IRR relative to the Status Quo. At $ 3.50 per MMBtu the improvement is from 14.6% to 16.4% and 16.9% respectively. **The specific nature of the proposed stranded gas contract therefore results in improving the IRR materially. Therefore, this contract is an important step in making the project more viable. It can be noted how the credit for the GTP and lateral lines is very material for the IRR improvement.**

6.2.1.2. 6.2.1.2.NPV @10%

Table 6.3 and Chart 6.2 provide the nominal NPV10 for the project.

Table 6.3. Nominal NPV10 for the Alberta Project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	607	1719	2065
$3.50	5784	6917	7262
$4.50	10915	12069	12415
$5.50	16071	17247	17592
$6.50	21207	22403	22748
$7.50	26345	27563	27908
$8.50	31499	32738	33083



The improvements in the NPV10 as a result of the ASGFC and ASGFC+GTP options are material at the stress price of $ 3.50 per MMBtu.

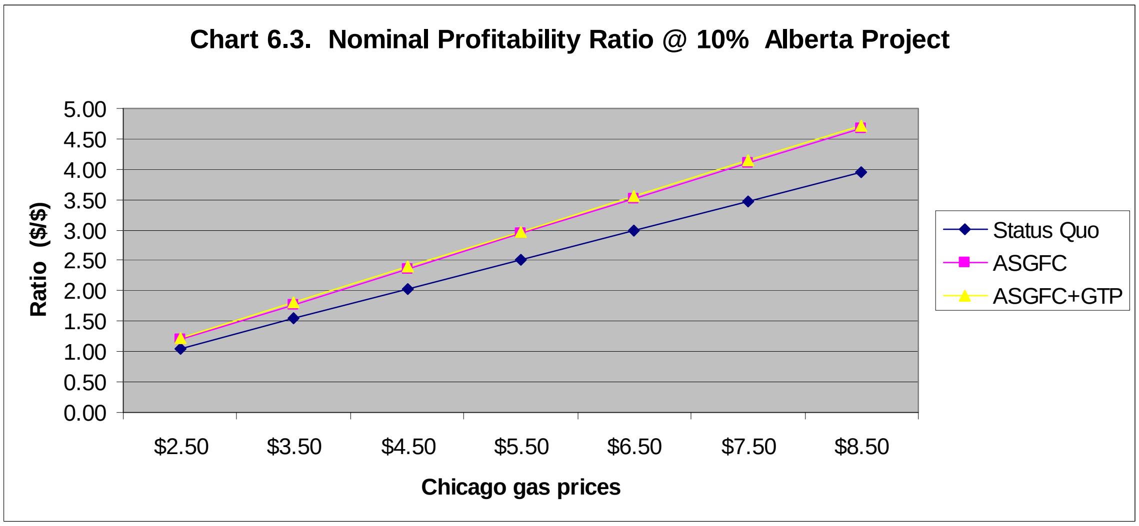
The provisions of the stranded gas contract add over $ 1.2 billion NPV10 in nominal terms. The GTP credits add another $ 350 million. Also in NPV10 terms the stranded gas contract provisions are therefore important to the economic realisation of the project.

6.2.1.3. 6.2.1.3.PFR @10%

The PFR10 is provided in Table 6.4 and Chart 6.3.

Table 6.4. Nominal PFR10 for the Alberta project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	1.06	1.19	1.23
$3.50	1.54	1.78	1.82
$4.50	2.02	2.36	2.40
$5.50	2.50	2.94	2.98
$6.50	2.98	3.52	3.56
$7.50	3.46	4.10	4.14
$8.50	3.94	4.68	4.72



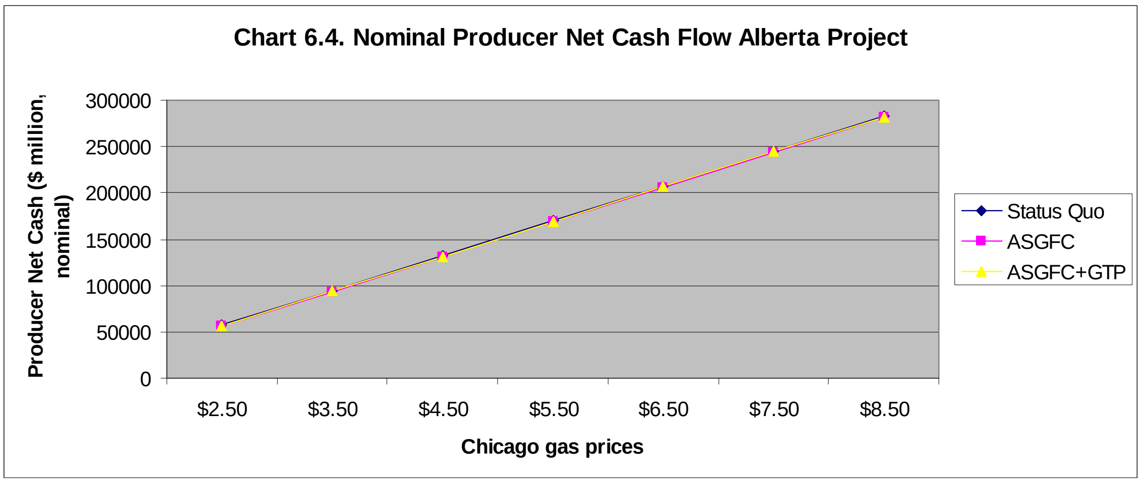
The profitability ratio of the Alaska Gas Project is relatively acceptable under Status Quo conditions. Nevertheless the stranded gas contract improves this ratio to the point where it becomes relatively attractive from a general perspective. This is primarily due to the fact that the Producers now have to contribute only a share of the capital. This provides this ratio with a considerable boost.

6.2.1.4. 6.2.1.4.NCF

Table 6.5 and Chart 6.4 provide the Producer Net Cash Flow.

Table 6.5. Nominal NCF for the Alberta Project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	56998	55863	56431
$3.50	94709	93520	94089
$4.50	132233	130991	131559
$5.50	169928	168633	169201
$6.50	207564	206216	206784
$7.50	245217	243816	244384
$8.50	282911	281456	282025



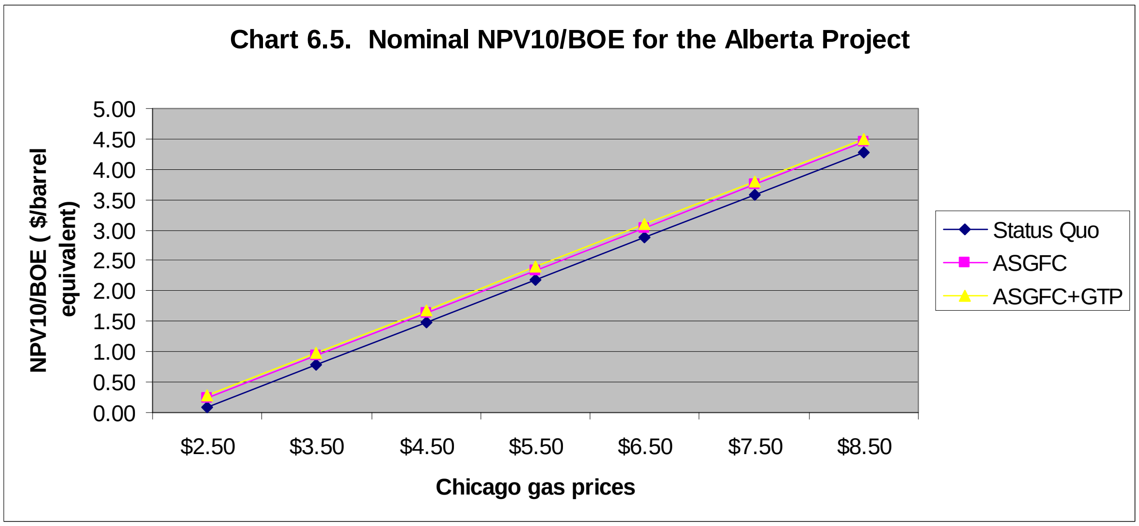
The total amount of Producer NCF of the Alaska Gas Project is huge by any yardstick for any of the three options. It is an extremely attractive aspect of the project for the investors and secures their long term future in a very significant manner. As will be discussed in a separate report, the project generates the largest NCF in the world on a single project basis. The huge Net Cash Flow is directly the result of the very large size of the project and the anticipated long duration of the project compared to many other projects in the world.

6.2.1.5. 6.2.1.5.NPV10/BOE

Table 6.6 and Chart 6.5 provide the NPV10/BOE.

Table 6.6. Nominal NPV10/BOE for the Alberta project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	0.08	0.23	0.28
$3.50	0.79	0.94	0.99
$4.50	1.48	1.64	1.69
$5.50	2.18	2.34	2.39
$6.50	2.88	3.04	3.09
$7.50	3.58	3.75	3.79
$8.50	4.28	4.45	4.50



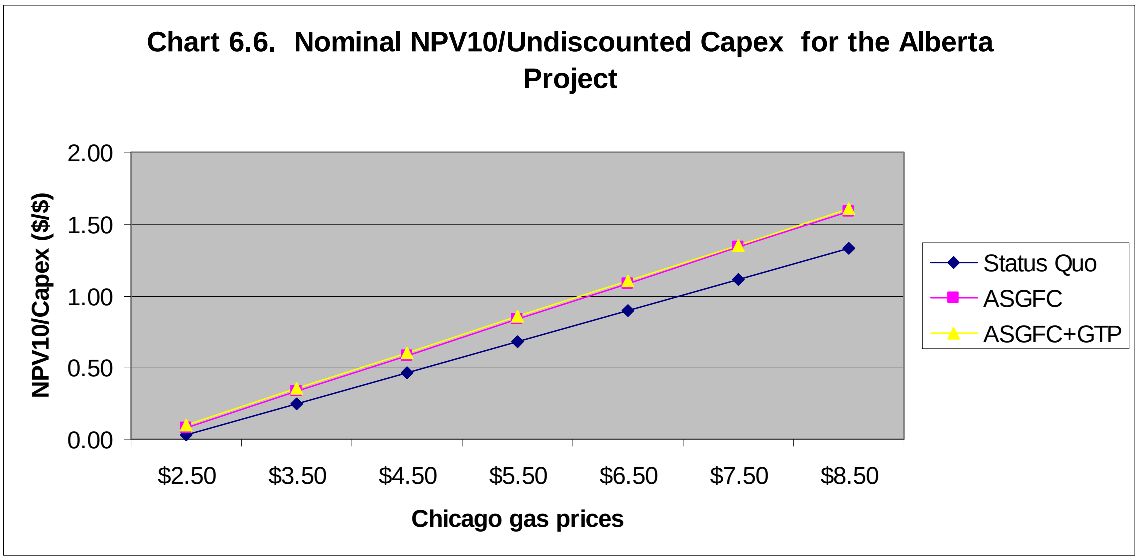
The stranded gas contract improves the NPV10/BOE materially. The GTP credit is a further assistance to adequate levels of NPV10/BOE. Therefore, the provisions of the contract assist considerably in increasing the probability of eventual success of the project.

6.2.1.6. 6.2.1.6.NPV10/Capex

Table 6.7 and Chart 6.8 illustrated the NPV10/capex.

Table 6.7. Nominal NPV10/Capex for the Alberta project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	0.03	0.08	0.10
$3.50	0.24	0.34	0.35
$4.50	0.46	0.59	0.60
$5.50	0.68	0.84	0.85
$6.50	0.90	1.09	1.10
$7.50	1.12	1.34	1.35
$8.50	1.33	1.59	1.60



The huge undiscounted capital requirements for the project and the relatively modest NPV10 at the stress price, creates conditions that are marginal with respect to this profitability indicator based on NPV10 per total project capital expenditures.

The fact that the State participates in the project creates by assuming the long term shipping commitments, create a situation where the "net" capital expenditures that remain for the Producers are reduced in a material way.

The Stranded gas contract therefore contributes in an important way to the economics of this aspect of the project.

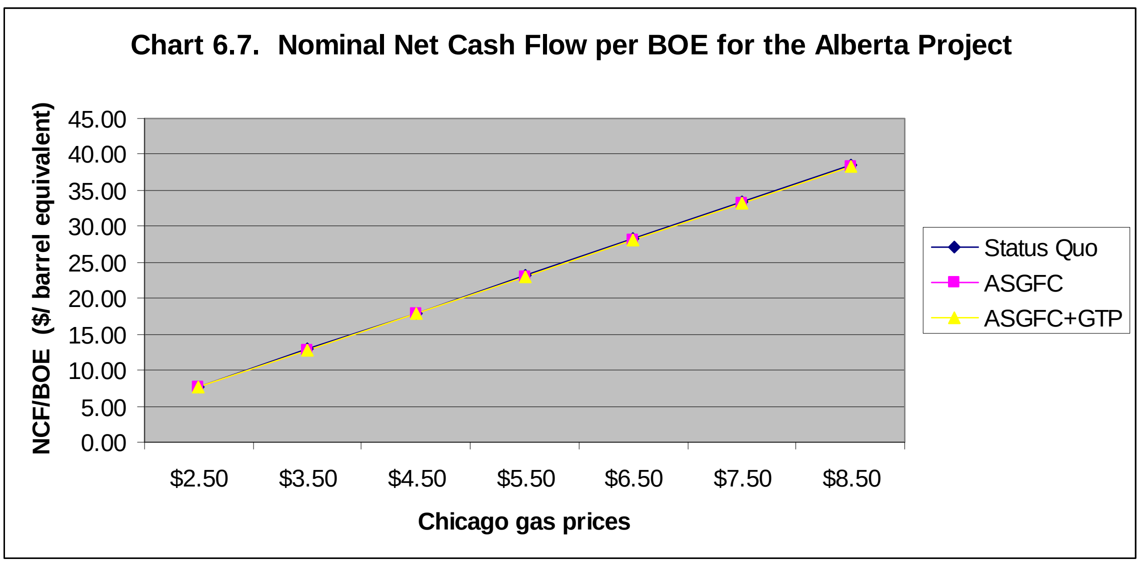
The above graph uses the net capital expenditures for the Producers in order to determine the ratio for the ASGFC and ASGFC+GTP cases.

6.2.1.7. 6.2.1.7.NCF/BOE

Table 6.8 and Chart 6.7 provide the NCF/BOE.

Table 6.8. NCF/BOE for the Alberta Project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	7.75	7.59	7.67
$3.50	12.87	12.71	12.79
$4.50	17.97	17.80	17.88
$5.50	23.09	22.92	23.00
$6.50	28.21	28.03	28.10
$7.50	33.33	33.14	33.21
$8.50	38.45	38.25	38.33



The NCF/BOE is well over international requirements for a project. Even on a BOE basis, the project shows highly attractive net cash flow characteristics.

In other words, it is not just the total size and duration of the project that creates an attractive NCF.

The NCF/BOE is also highly attractive for any of the three options, which indicates that relative to the size of the possible cumulative production, the project retains highly attractive characteristics.

One reason that the NCF/BOE is so attractive is that the operating costs of the Alaska Gas Project are low. In constant dollar terms the costs are only $ 2.25 per BOE. Compared to many international competing projects these are low operating costs.

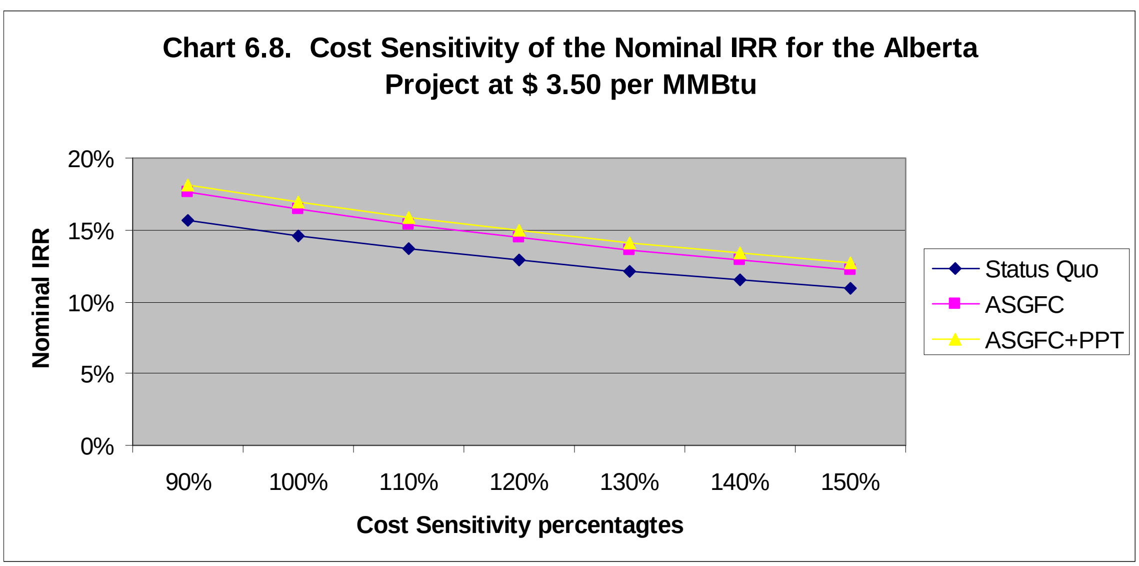
The relatively low operating costs are in part a direct result of the fact that the Prudhoe Bay gas does not need new production and operating facilities in order to be produced. It is gas that needs to be re-injected otherwise.

6.2.1.8. 6.2.1.8.Cost Sensitivity analysis

One of the most important risks for the Alaska Gas Project is the risk of cost overruns.

Therefore, from an investor's point of view this requires detailed attention.

Charts 6.8 through 6.14 illustrate the cost overrun risk. These graphs are based on the $ 3.50 per MMBtu price in Chicago. Subsequently, sensitivity analysis was done on the the total capital and operating costs (except for the future production capital costs in the late 2020's in order to bring on new production).



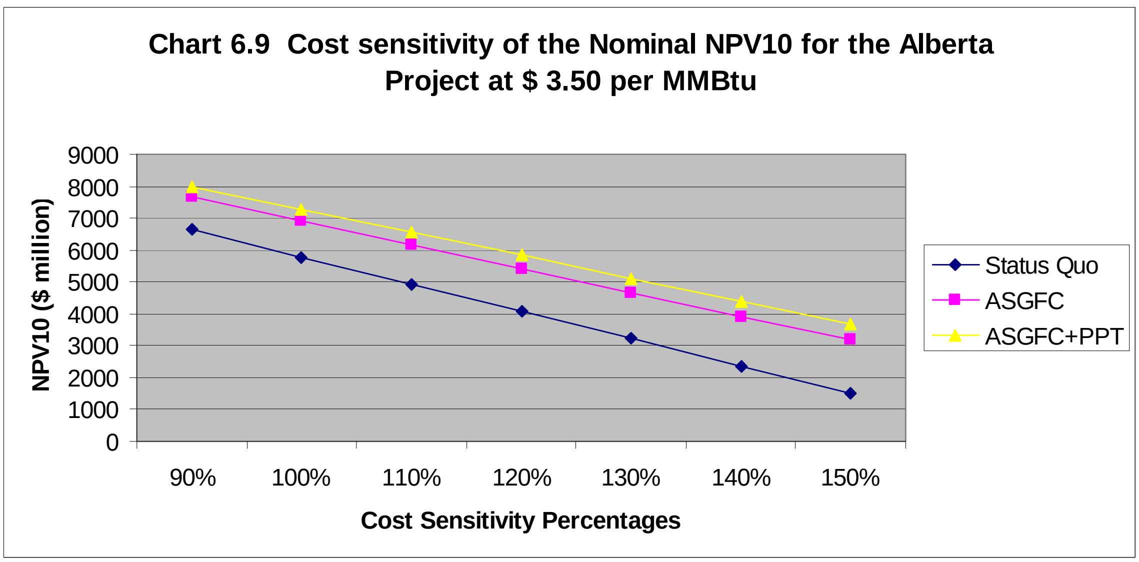
Cost overruns have a dramatic effect on the IRR.

As can be seen, even with the significant improvements in economics contained in the stranded gas contract, the ASGFC+GTP terms do not permit a cost overrun of more than 20% at the stress price of $ 3.50 per MMBtu, if we assume a IRR target of 15% nominal.

Under Status Quo terms, it would not be possible to have any cost overruns with respect to this target IRR.

Cost overruns runs higher than 20% make a project ending in Alberta clearly unattractive at the stress price.

In other words, even with the ASGFC+GTP terms, the Alaska Gas Project cannot withstand both a modestly low price of $ 3.50 per MMBtu and a cost overrun of more than 20% if the objective is to have a target IRR of at least 15% nominal.

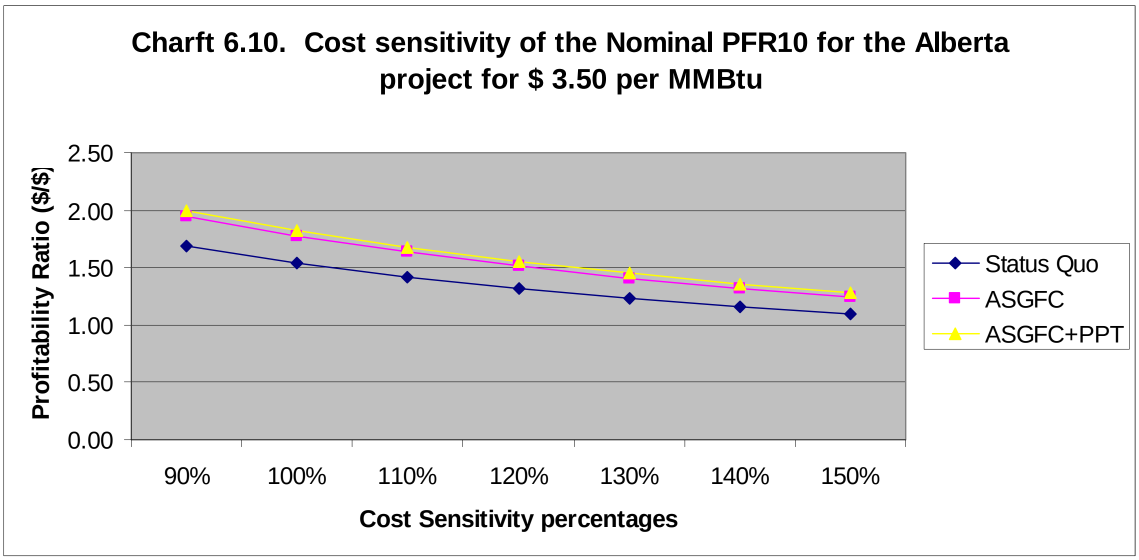


The cost sensitivity analysis has also a very dramatic impact on the NPV10. A "soft" target number of $ 5000 million NPV10 can be assumed.

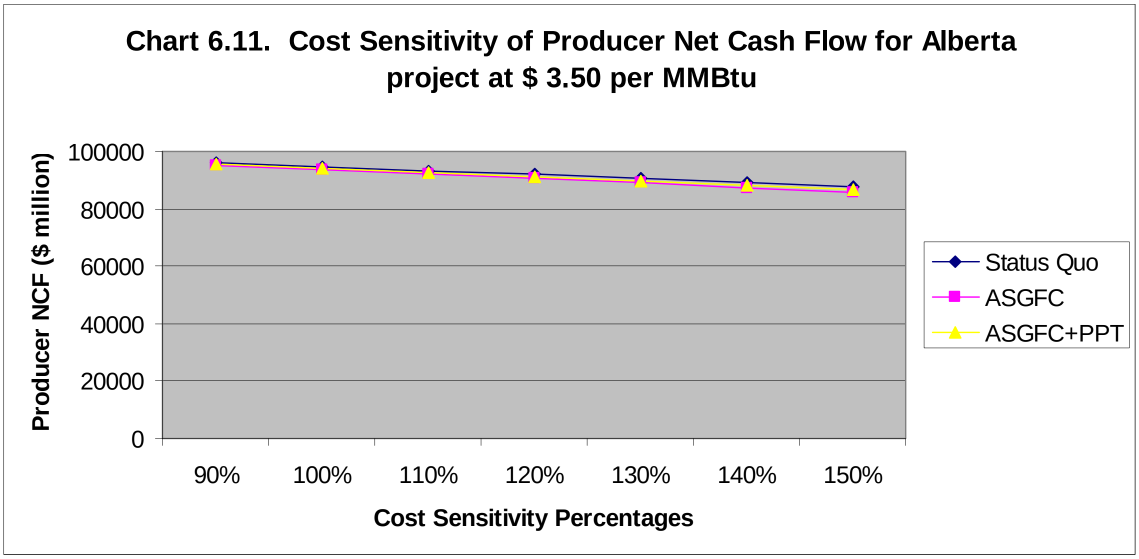
Based on this target, as long as the Alaska Gas Project does not have cost overruns, the NPV10 seems to be marginally acceptable for the Status Quo and reasonably acceptable under the ASGFC+GTP or ASGFC terms.

Cost overruns have a very strong negative impact on the NPV10. It can be seen how the ASGFC+GTP terms would only be able to handle a 30% cost overrun and still reach a target of $ 5000 million.

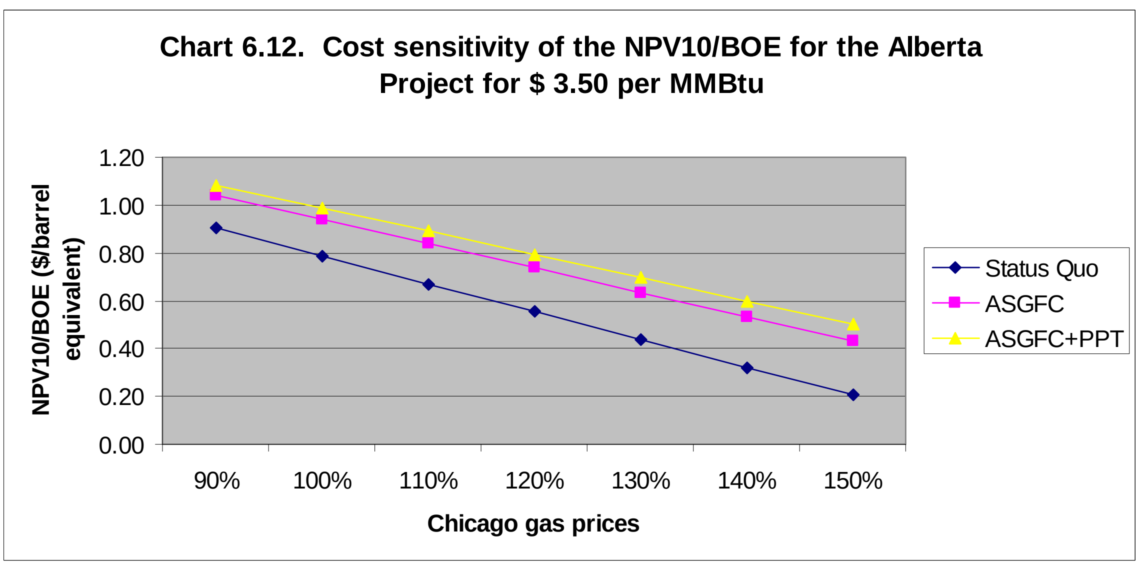
The Status Quo terms become rapidly unattractive under a combination of the stress price of $ 3.50 per MMBtu and cost overruns. Even a 10% cost overrun would create marginal conditions.



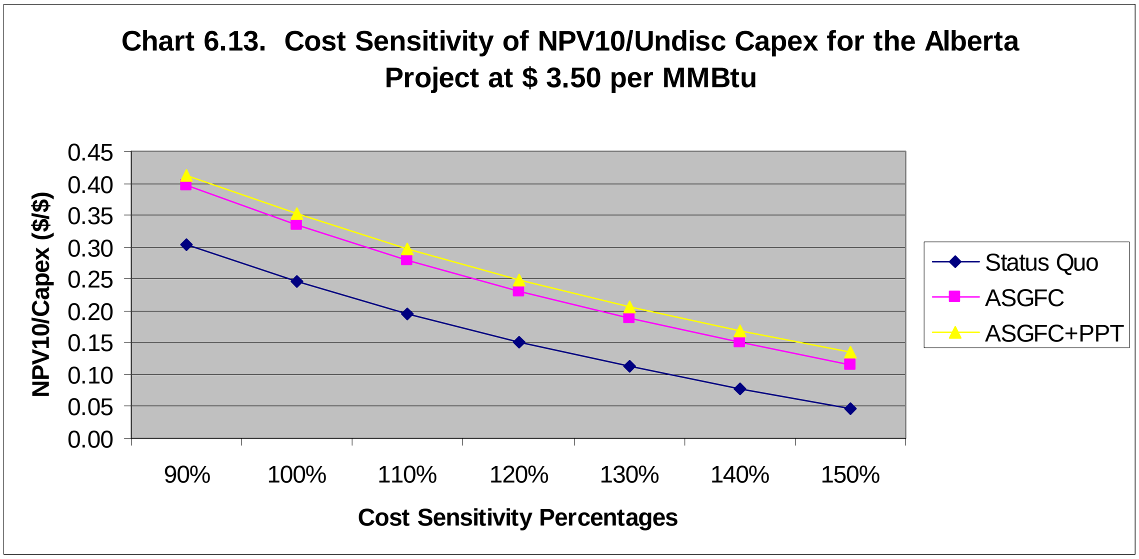
The profitability ratio seems to be able to "weather" a cost overrun reasonably well. Assuming a target nominal PFR10, the Status Quo would handle a 20% cost overrun and the ASGFC+GTP a 40% cost overrun.



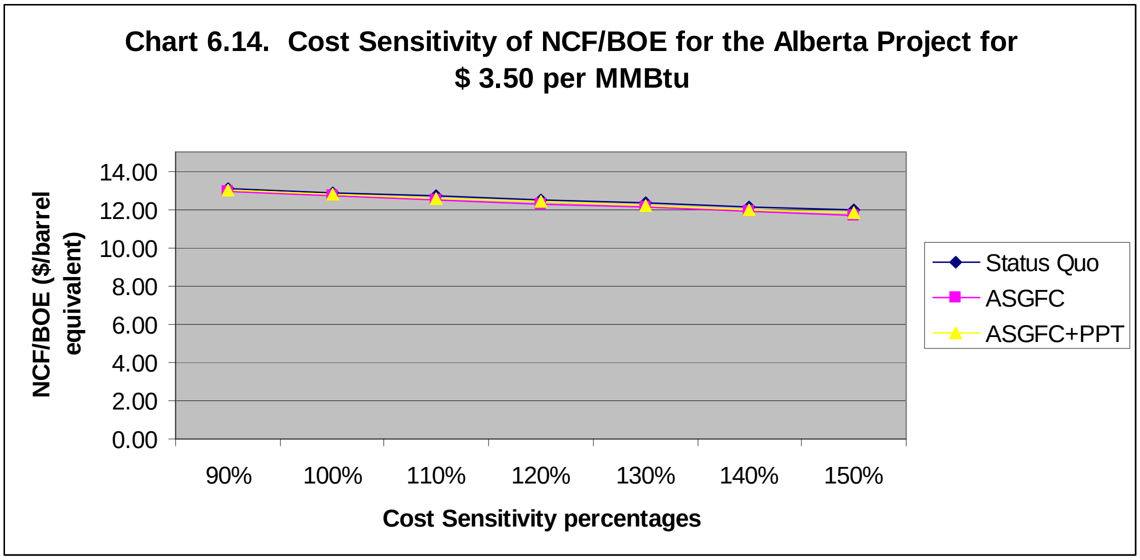
The NCF is huge despite any cost overruns. Even a target NCF of $ 40 billion could easily be maintained with considerable cost overruns.



Just as the NPV10 itself, the NPV10/BOE is significantly affected by cost overruns. Assuming a nominal target of $ 0.66/BOE, the Status Quo can handle a 10% cost overrun and the ASGFC+GTP can handle a 30% cost overrun.



The weakest potential variable is the NPV10/Capex. Assuming a target of $ 0.25 NPV10 per dollar capex on a nominal basis, the Status Quo cannot handle any cost overruns. Even the ASGFC+GTP could only deal with a 15% cost overrun before the profitability indicators drop below the target. However, as can be seen, the ASGFC+GTP considerably improves the values.



The NCF per BOE is barely affected by cost overruns.

6.2.2. Project ending in Chicago

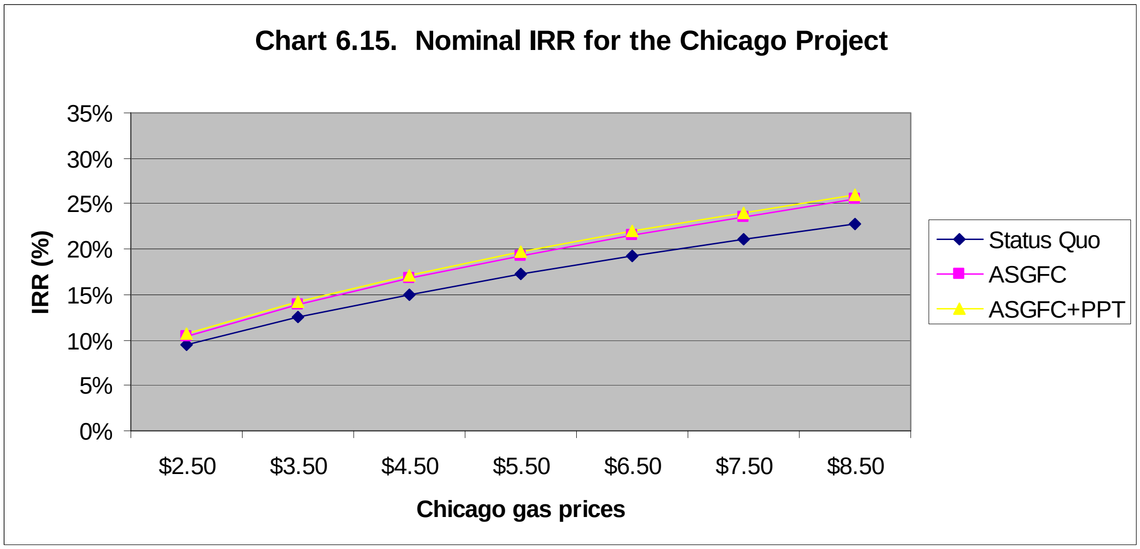
Following is the analysis of the nominal results of a project ending in Chicago.

6.2.2.1. 6.2.2.1.IRR

Table 6.9 and Chart 6.15 illustrate the nominal IRR for the Chicago Project.

Table 6.9. Nominal IRR for Chicago Project

	Status Quo	ASGFC	ASGFC+PPT
$2.50	9.4%	10.4%	10.7%
$3.50	12.5%	13.9%	14.2%
$4.50	15.0%	16.8%	17.1%
$5.50	17.2%	19.3%	19.7%
$6.50	19.2%	21.6%	22.0%
$7.50	21.1%	23.6%	24.0%
$8.50	22.8%	25.5%	26.0%



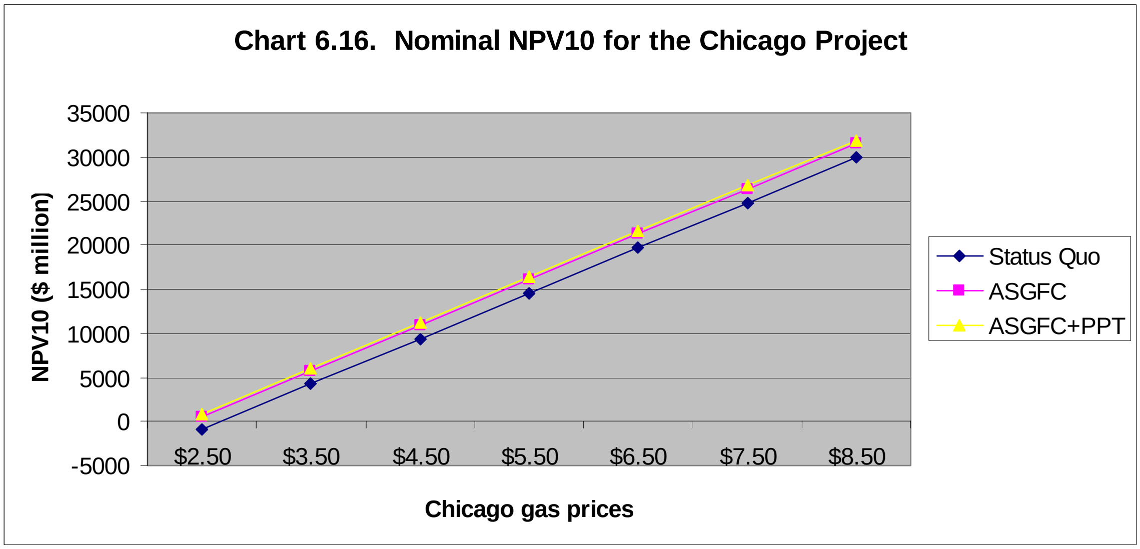
It can be seen how even with the ASGFC+GTP terms a notional target of a nominal 15% IRR is not being reached at the stress price. **Therefore, the viability of the Alaska Gas Project with respect to the IRR depends in part on how significant the long term transport commitments will be related to shipping gas to Chicago.**

6.2.2.2. 6.2.2.2. NPV @10%

Table 6.10 and Chart 6.16 illustrate the NPV10.

Table 6.10. Nominal NPV for Chicago Project

	Status Quo	ASGFC	ASGFC+PPT
$2.50	-913	556	901
$3.50	4264	5755	6100
$4.50	9394	10906	11251
$5.50	14550	16083	16428
$6.50	19685	21238	21584
$7.50	24823	26397	26743
$8.50	29977	31573	31918



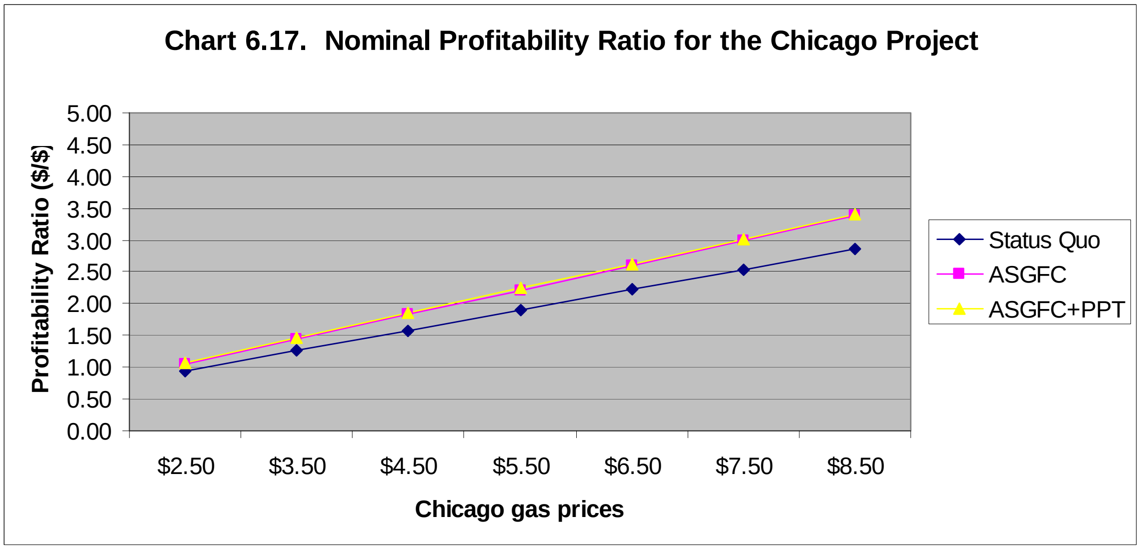
As can be seen, the ASGFC improves the nominal NPV10 by about $ 1.5 billion, while the GTP credits add again another $ 350 million. In the context of the stress price this is a very material improvement of the NPV10 and would bring the NPV10 about a notional nominal $ 5 billion NPV10 target. The NPV10 would be unattractive under Status Quo conditions.

6.2.2.3. 6.2.2.3. PFR @10%

Table 6.11 and Chart 6.17 illustrate the nominal PFR10 for the Chicago Project.

Table 6.11. Nominal PFR10 for a Chicago Project

	Status Quo	ASGFC	ASGFC+PPT
$2.50	0.94	1.04	1.07
$3.50	1.26	1.43	1.46
$4.50	1.58	1.82	1.85
$5.50	1.90	2.21	2.24
$6.50	2.22	2.60	2.63
$7.50	2.54	2.99	3.02
$8.50	2.86	3.38	3.41



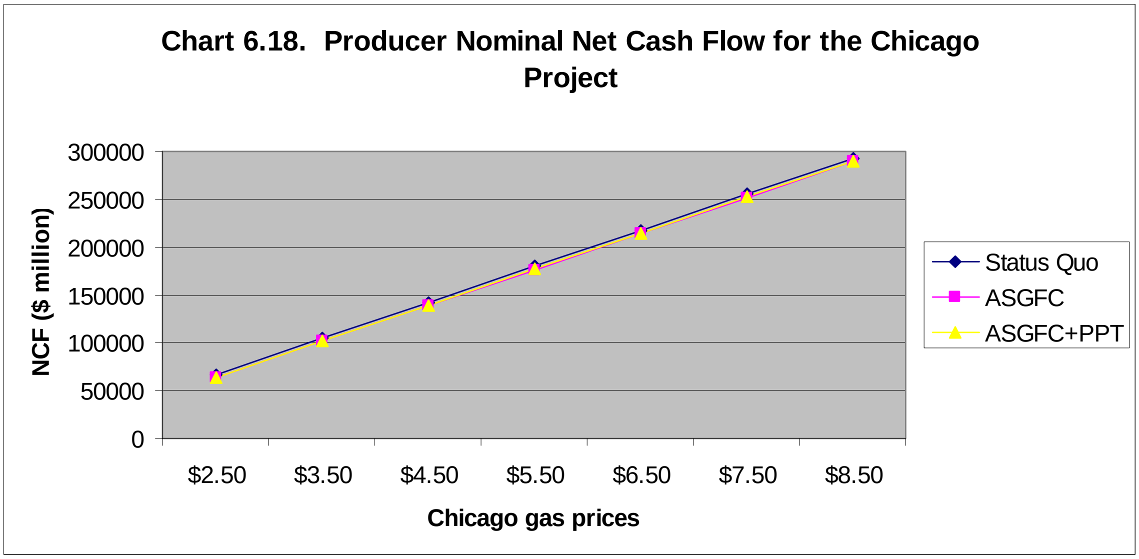
The PFR10 is boosted significantly with the ASGFC and ASGFC+GTP terms because the State's share of the midstream capital investments is now not included in the denominator of this ratio. This is crucial for the Chicago Project, since on a Status Quo basis the PFR10 would be rather weak.

6.2.2.4. 6.2.2.4. NCF

Table 6.12 and Chart 6.18 illustrate the total NCF.

Table 6.12. Nominal NCF for the Chicago Project

	Status Quo	ASGFC	ASGFC+PPT
$2.50	67113	63671	64240
$3.50	104835	101340	101908
$4.50	142357	138808	139377
$5.50	180051	176449	177018
$6.50	217684	214029	214598
$7.50	255336	251628	252197
$8.50	293029	289268	289837



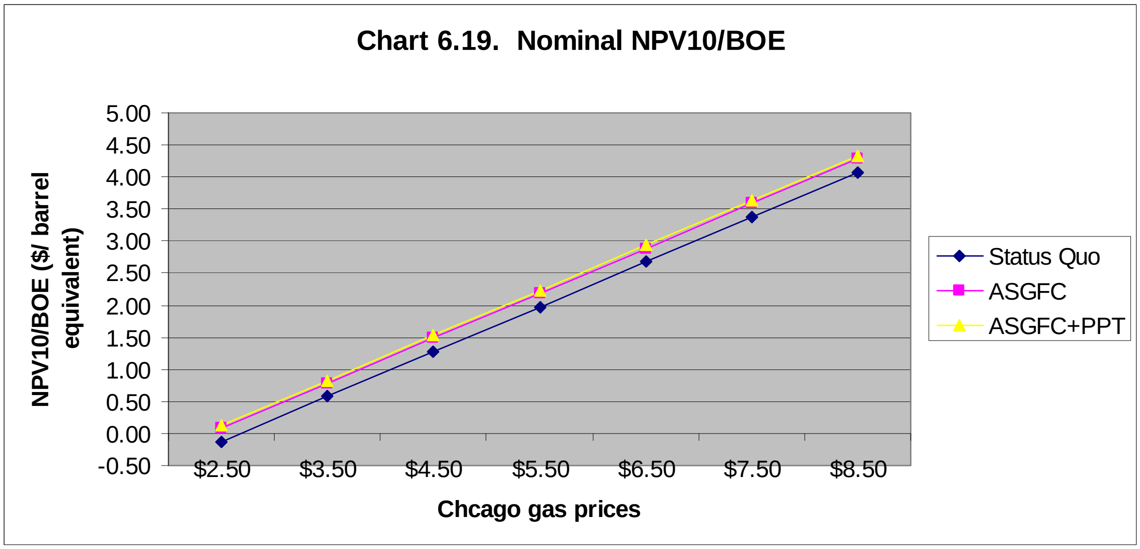
In comparing Table 6.12 with Table 6.5 it can be noted that the NCF actually increases substantially for the Chicago project, because in this case the additional pipeline tariff revenues between Alberta and Chicago are and additional net income source. The NCF well exceeds levels that are required for a viable project.

6.2.2.5. 6.2.2.5. NPV10/BOE

The NPV10/BOE information is provided in Table 6.13 and Chart 6.19.

Table 6.13. Nominal NPV10/BOE for the Chicago Project

	Status Quo	ASGFC	ASGFC+PPT
$2.50	-0.12	0.08	0.12
$3.50	0.58	0.78	0.83
$4.50	1.28	1.48	1.53
$5.50	1.98	2.19	2.23
$6.50	2.68	2.89	2.93
$7.50	3.37	3.59	3.63
$8.50	4.07	4.29	4.34



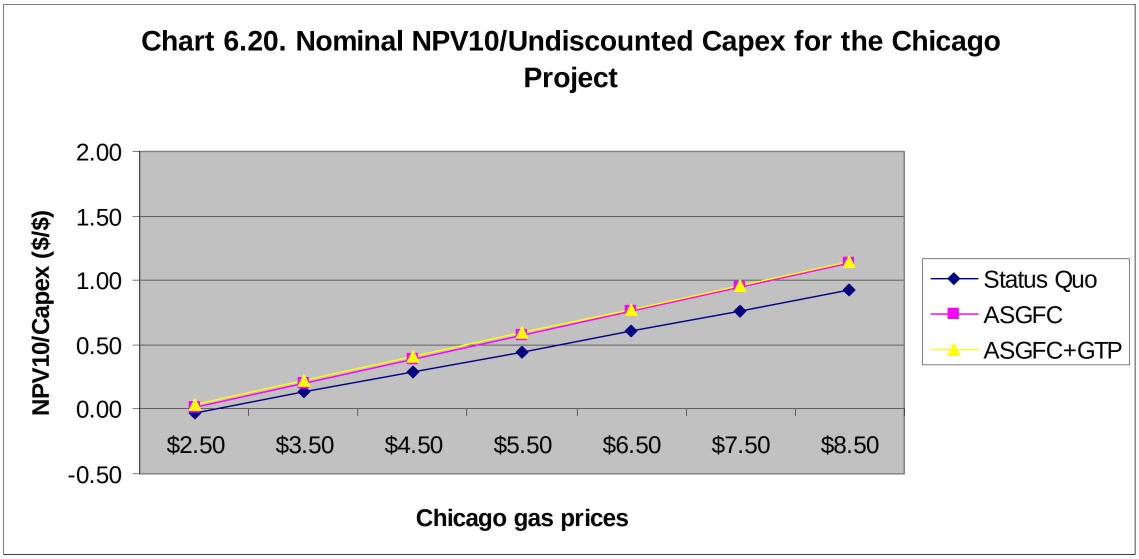
The ASGFC and ASGFC+GTP terms boost the NPV10/BOE values considerably relative to the Status Quo, to levels that would be well above a notional $ 0.66 NPV10/BOE target.

6.2.2.6. 6.2.2.6. NPV10/Capex

Table 6.14 and Chart 6.20 provide the NPV10/Capex.

Table 6.14. NPV10/Capex for Chicago Project

	Status Quo	ASGFC	ASGFC+GTP
$2.50	-0.03	0.02	0.03
$3.50	0.13	0.21	0.22
$4.50	0.29	0.39	0.40
$5.50	0.45	0.58	0.59
$6.50	0.60	0.76	0.78
$7.50	0.76	0.95	0.96
$8.50	0.92	1.14	1.15



As can be expected, the Chicago Project involves more Capex than the Alberta Project and therefore the NPV10/Capex ratios are even less attractive than for the Alberta Project.

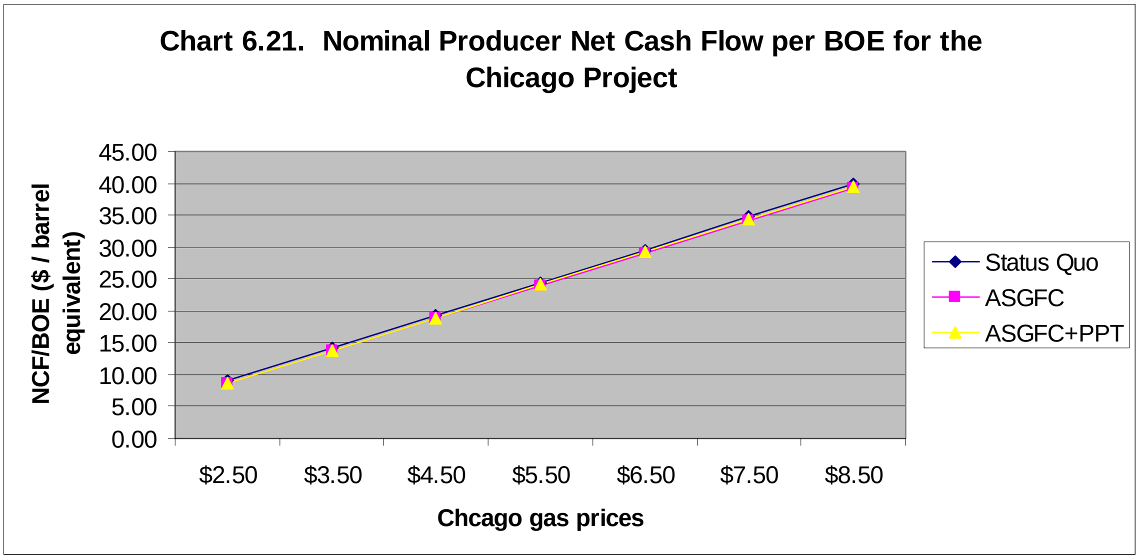
The ASGFC and ASGFC+GTP terms boost the NPV10/Capex ratio considerably relative to the Status Quo. This ratio is highly unattractive under the Status Quo and is marginal under the stranded gas contract.

6.2.2.7. 6.2.2.7. NCF/BOE

Table 6.15 and Chart 6.21 provide the NCF/BOE.

Table 6.15. NPC/BOE for the Chicago Project

	Status Quo	ASGFC	ASGFC+PPT
$2.50	9.12	8.65	8.73
$3.50	14.25	13.77	13.85
$4.50	19.35	18.86	18.94
$5.50	24.47	23.98	24.06
$6.50	29.58	29.09	29.17
$7.50	34.70	34.20	34.28
$8.50	39.82	39.31	39.39

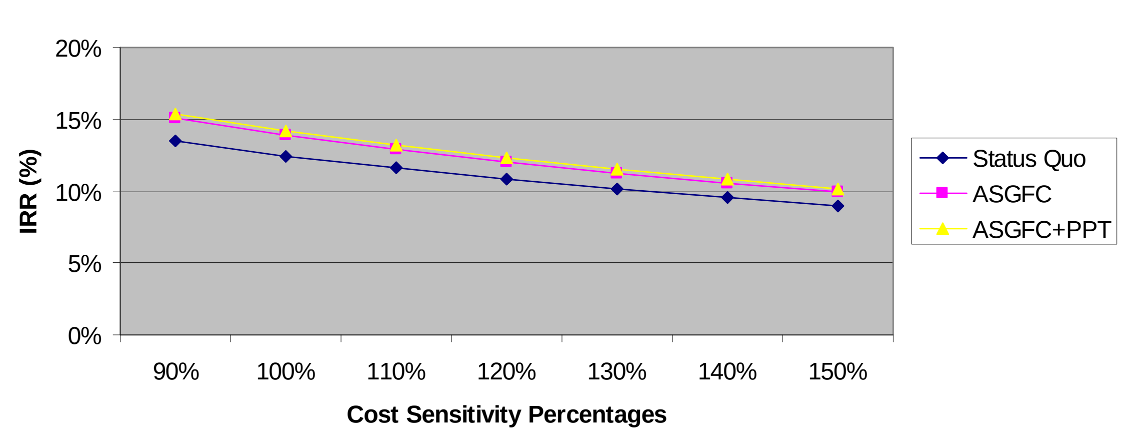


With the higher total amount of NCF for the Chicago Project, the NCF/BOE is also very attractive.

6.2.2.8. 6.2.2.8. Cost Sensitivity Analysis

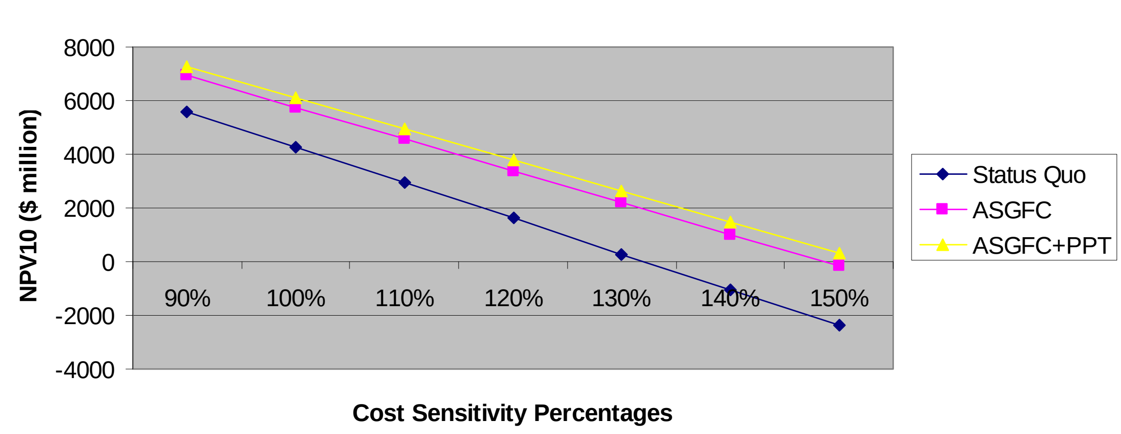
As can be expected, significant cost overruns on a project to Chicago would be a dramatic event. The high capital requirements would push the effect of cost overruns into very negative territory for most of the profitability indicators.

Chart 6.22. Cost Sensitivity of the IRR for the Chicago Project at $ 3.50 per MMBtu



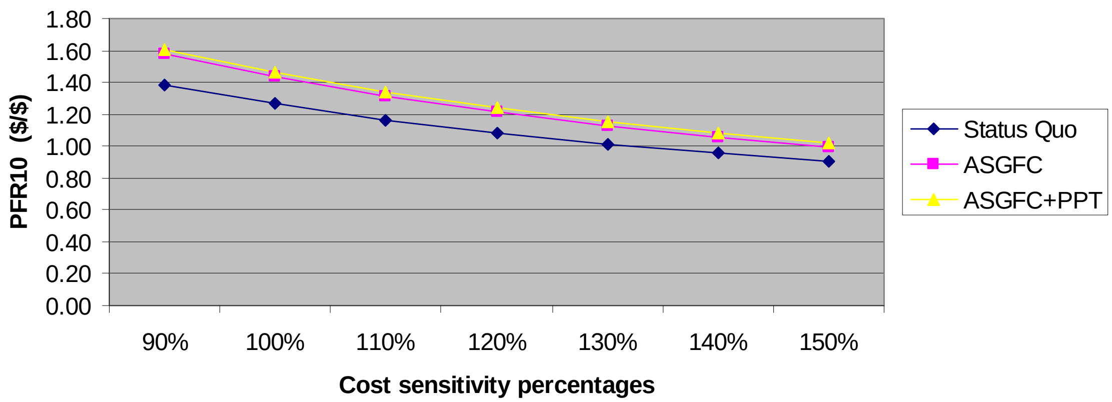
The already very meagre nominal IRR on the Chicago project would become very unattractive with cost overruns in the range of 20% or more. The IRR would end up well below minimum targets that investors may have even for the ASGFC+GTP stranded gas contract option.

Chart 6.23. Cost Sensitivity of the NPV10 of the Chicago Project at $ 3.50 per MMBtu



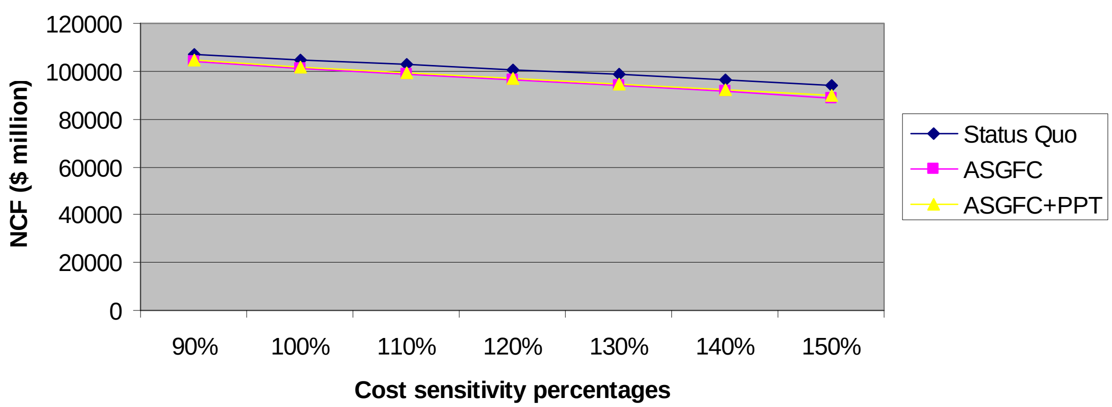
Also the NPV10 would be very negatively affected by the significant cost overrun. The ASGFC+GTP terms would be able to accommodate a 10% cost overrun. With a 20% cost overrun the project would be highly unattractive under Status Quo conditions and would be sub-marginal under ASGFC+GTP conditions.

Chart 6.24. Cost Sensitivity of the PFR10 for the Chicago Project at $ 3.50 per MMBtu

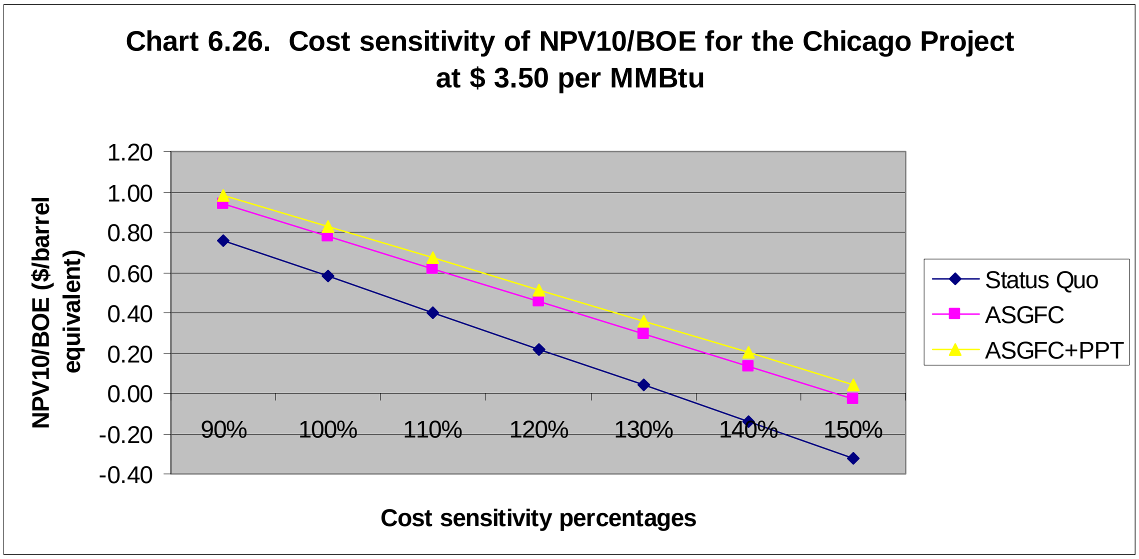


The PFR10 would permit a cost overrun of 10% for the ASGFC+GTP option, but at any level of cost overrun the PFR10 would be unattractive with respect to the Status Quo.

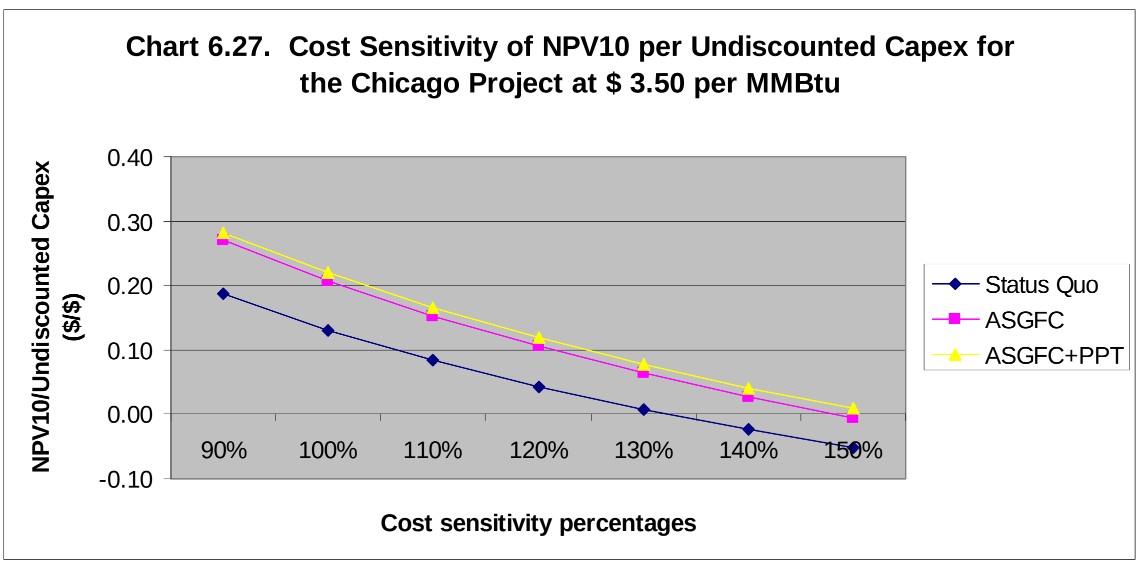
Chart 6.25. Cost sensitivity of the Producer NCF of the Chicago Project for $ 3.50 per MMBtu



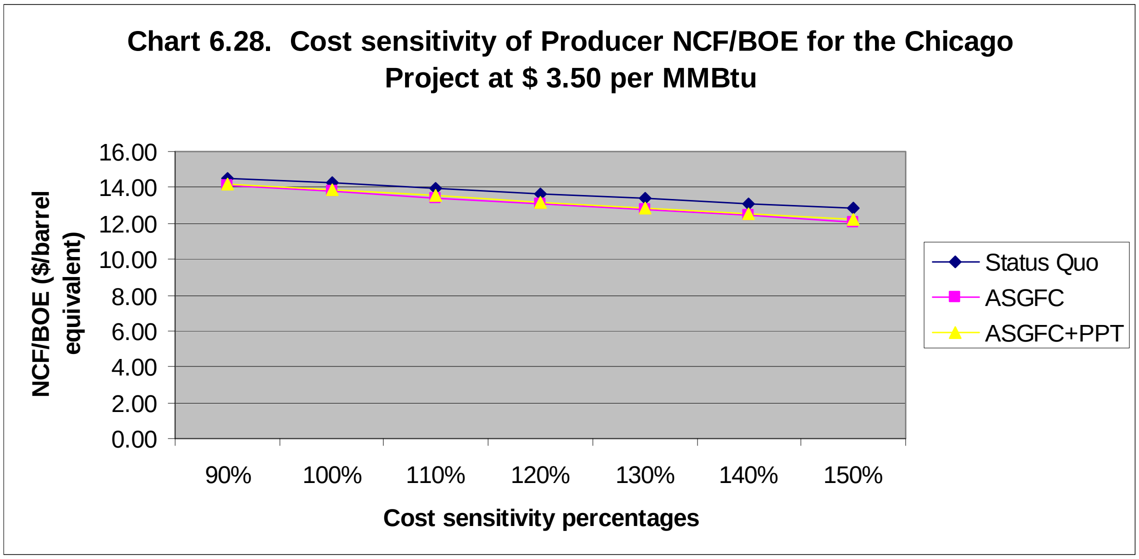
As can be expected, the only variable that is only modestly effected by a cost overrun is the Producer NCF. The NCF remains high and attractive regardless of the level of cost overrun.



Just as the NPV10 itself, the NPV10/BOE is significantly affected by cost overruns. Assuming a nominal target of $ 0.66/BOE, the ASGFC+GTP terms can handle a 10% cost overrun.



The NPV10/Capex, which is already poor without cost overrun, would become very low with a cost overrun as illustrated in Chart 6.27.



As indicated for the Alberta Project, the NCF/BOE would be attractive regardless of the level of cost overrun.

6.3. Producer Economics – Real Results

In this section the real economics will be evaluated. This can be done on the "hard" benchmarks that were developed in Section 6.1. These were targets for the stress price of $ 3.50 per MMBtu in Chicago. These targets will be added to the tables and the graphs for easy reference. Only targets for the $ 3.50 per MMBtu case are added. Therefore in the graphs these targets are "flat". In reality the targets would be higher with higher prices.

Due to the importance of the evaluation of the stranded gas contract structure and Producer Economics a special report will be prepared on this topic. However, in this report some of the main economic comments that can be made will be reviewed.

6.3.1. Project ending in Alberta

As above, first a project ending in Alberta will be evaluated.

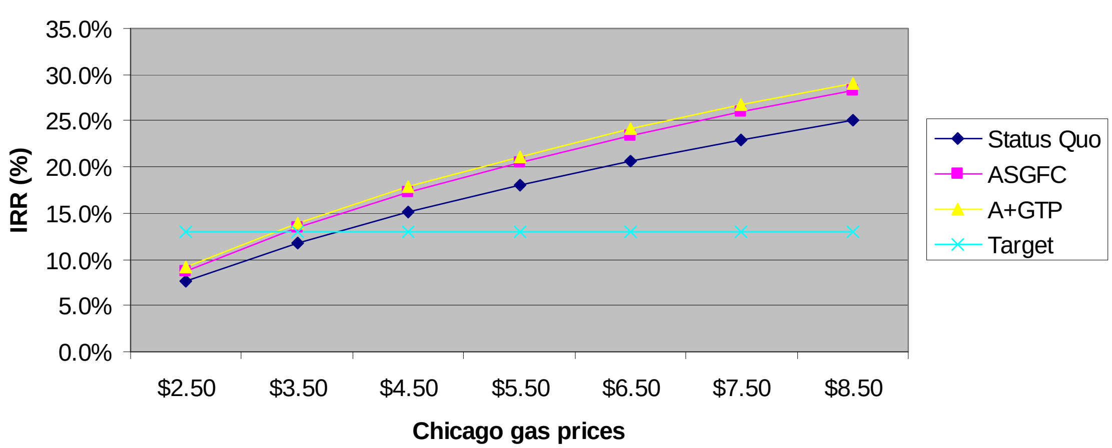
6.3.1.1. IRR

The real IRR is provided in Table 6.16 and Chart 6.29.

Table 6.16. Real IRR for Alberta Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	7.6%	8.7%	9.1%	13.0%
$3.50	11.8%	13.5%	14.0%	13.0%
$4.50	15.2%	17.3%	17.8%	13.0%
$5.50	18.1%	20.5%	21.2%	13.0%
$6.50	20.6%	23.4%	24.1%	13.0%
$7.50	23.0%	26.0%	26.7%	13.0%
$8.50	25.1%	28.3%	29.1%	13.0%

Chart 6.29. Real IRR for Alberta Project



Stress Price of $ 3.50 per MMBtu

It can be seen how the ASGFC and ASGFC+GTP options improve the real IRR to the point that it would be slightly over the minimum target of 13% at a price level of $ 3.50 per MMBtu. The Status Quo would create economics that would be below the real IRR target.

It should be noted though that this level of real IRR for the ASGFC+GTP is very close to the minimum target and is therefore by no means a reason for comfort.

Many large projects would have a 20% real IRR at the stress price of $ 22 per barrel for WTI.

The stranded gas contract conditions therefore improve the real IRR in a material way, but not by so much that the Alaska Gas Project becomes a good attractive project. The project remains marginal from an IRR point of view under downside conditions.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

Although economically attractive in an absolute sense, the real IRR remains relatively low compared to other projects in the world for average and high prices.

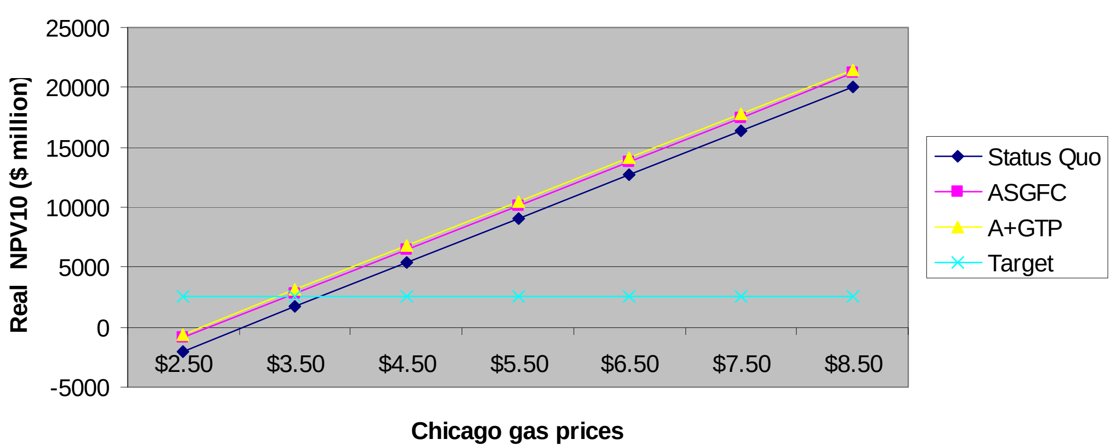
6.3.1.2. NPV @10%

The NPV10 is provided in Tables 6.17 and Chart 6.30.

Table 6.17. Real NPV10 for the Alberta Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	-2005	-921	-609	2500
$3.50	1685	2786	3098	2500
$4.50	5342	6461	6773	2500
$5.50	9014	10150	10462	2500
$6.50	12668	13823	14135	2500
$7.50	16324	17497	17809	2500
$8.50	19993	21184	21496	2500

Chart 6.30. Real NPV10 for Alberta Project



Stress Price of $ 3.50 per MMBtu

In an absolute sense the NPV10 of the project, even at the stress price is already very high. **However, in relation to the possible cumulative production or the anticipated capital expenditures, the NPV10 is relatively modest based on the ASGFC or ASGFC+GTP.** A target of $ 2.5 billion for the stress price would be a modest target.

Against the modest target, under Status Quo terms the level of NPV10 is clearly unattractive.

Average price of $ 5.50 and high price of $ 8.50 per MMBtu per MMBtu

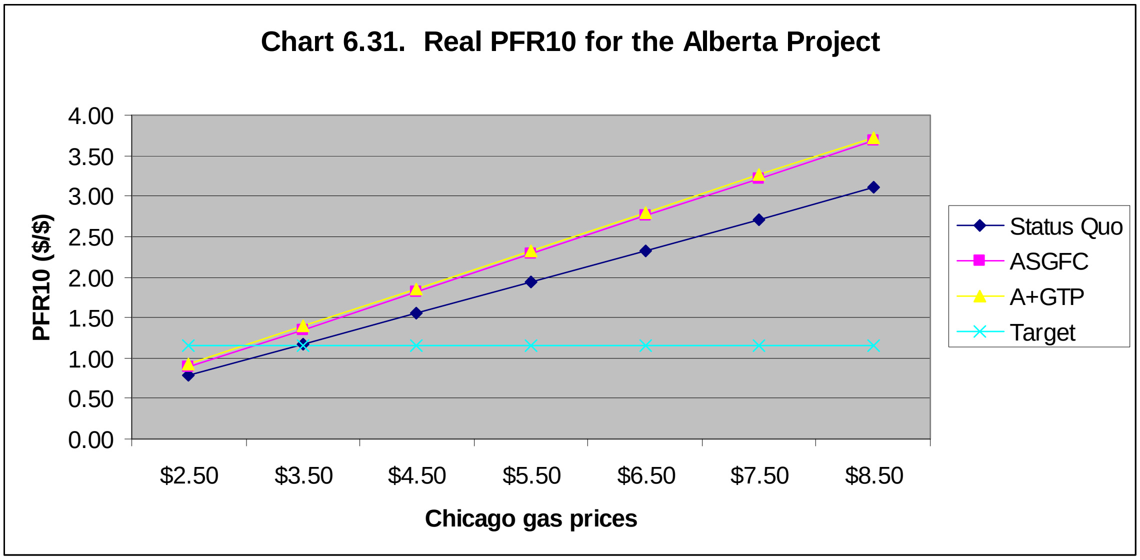
The real NPV10 increases rapidly and disproportionately with the level of price. As a result at average and high gas prices the real NPV10 becomes enormous. The project has among the highest NPV10 values in the world for these levels of price. This is an enormously attractive aspect of the project. The "upside" is phenomenal.

6.3.1.3. PFR @10%

Table 6.18 and Chart 6.31 provide the real PFR10 for the Alberta project.

Table 6.18 Real PFR10 for the Alberta project

	Status Quo	ASGFC	A+GTP	Target
$2.50	0.79	0.88	0.92	1.15
$3.50	1.18	1.35	1.39	1.15
$4.50	1.56	1.82	1.86	1.15
$5.50	1.95	2.29	2.33	1.15
$6.50	2.33	2.75	2.79	1.15
$7.50	2.72	3.22	3.26	1.15
$8.50	3.10	3.69	3.73	1.15



Stress Price of $ 3.50 per MMBtu

The ASGFC and ASGFC+GTP options provide a considerable boost to the PFR10. This is directly due to the participation by the State which reduces the net capital required by the Producers. This improvement in economics is important the PFR10 is an important variable in project evaluation.

Under the Status Quo option the PFR10 would be marginal.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

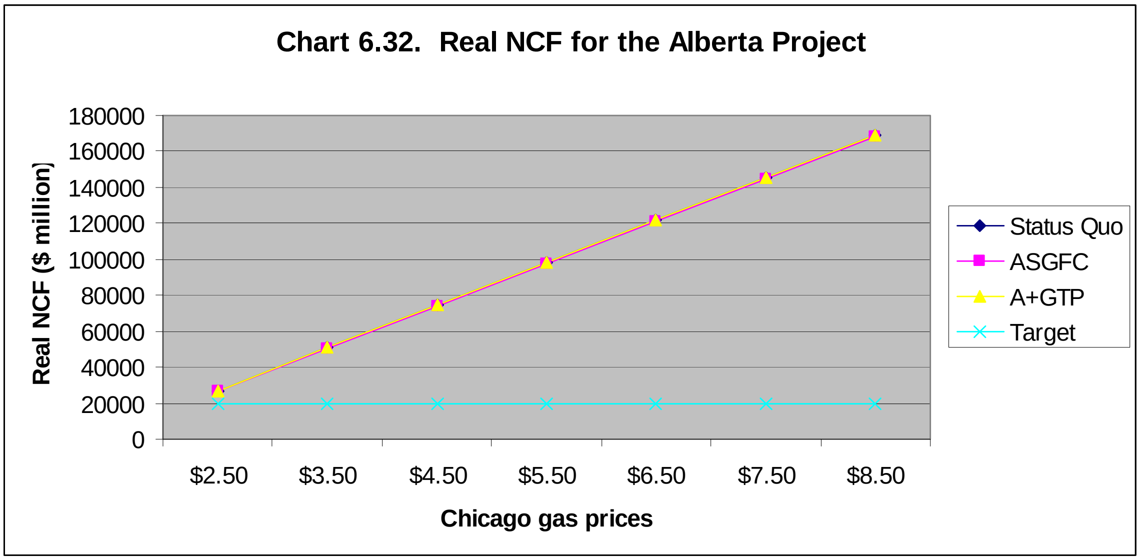
Under average and high prices, the project has typical average solid PFR10 ratios.

6.3.1.4. NCF

The real NCF is provided in Table 6.19 and Chart 6.32.

Table 6.19. Real NCF for the Alberta Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	27082	26528	27039	20000
$3.50	50792	50225	50737	20000
$4.50	74346	73774	74285	20000
$5.50	97998	97421	97933	20000
$6.50	121602	121021	121532	20000
$7.50	145218	144632	145143	20000
$8.50	168867	168276	168788	20000



Stress Price of $ 3.50 per MMBtu

The real NCF of the project is clearly over any reasonable target level. In real terms the project net cash flow is huge even under the stress price. It is a highly attractive aspect of the project.

Average price of $ 5.50 and high price of $ 8.50 per MMBtu per MMBtu

Under average and high prices the real NCF become enormous. This “upside” is a highly attractive feature of the project.

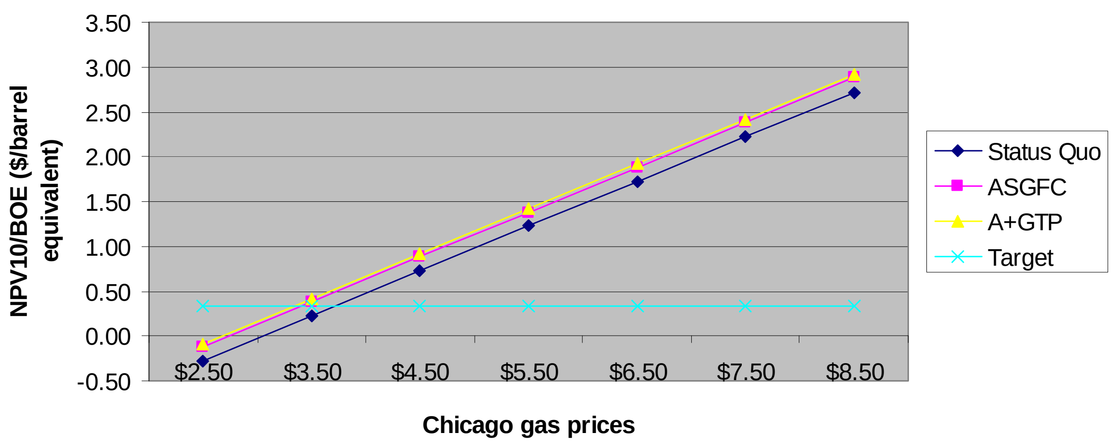
6.3.1.5. NPV10/BOE

The NPV10/BOE data are provided in Table 6.20 and Chart 6.33.

Table 6.20 Real NPV10/BOE for the Alberta project

	Status Quo	ASGFC	A+GTP	Target
$2.50	-0.27	-0.13	-0.08	0.33
$3.50	0.23	0.38	0.42	0.33
$4.50	0.73	0.88	0.92	0.33
$5.50	1.23	1.38	1.42	0.33
$6.50	1.72	1.88	1.92	0.33
$7.50	2.22	2.38	2.42	0.33
$8.50	2.72	2.88	2.92	0.33

Chart 6.33. Real NPV10/BOE for the Alberta Project



Stress Price of $ 3.50 per MMBtu

The ASGFC or ASGFC+GTP terms clearly have a considerable positive impact on this profitability indicator. Nevertheless, as with the IRR and NPV10 this indicator remains relatively low compared to many other projects in the world under stress price conditions.

The Status Quo economics is clearly below the required level for this variable at the stress price.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

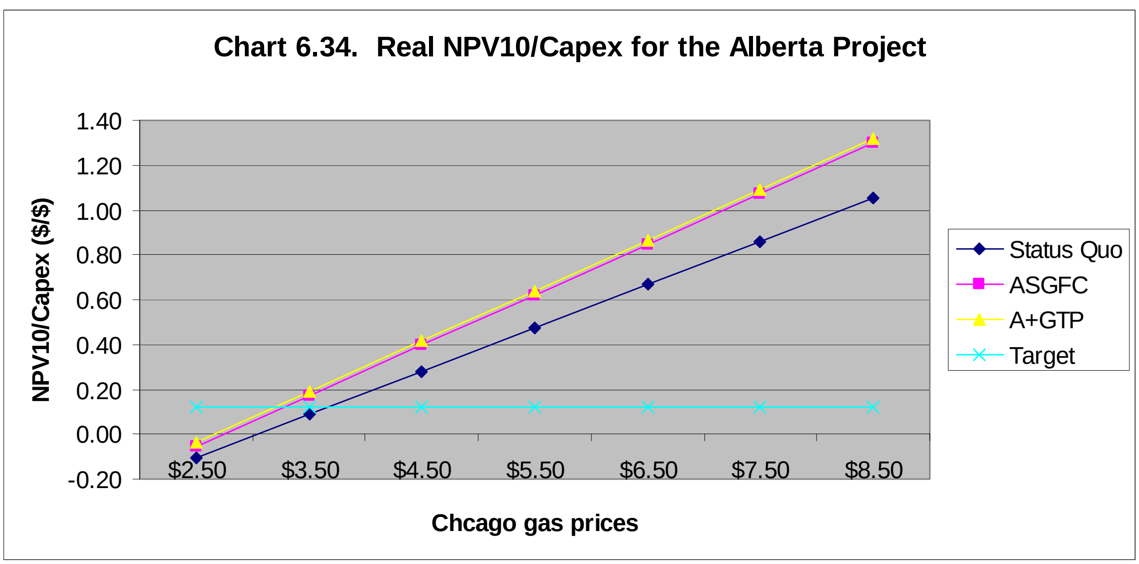
Under average and high prices the NPV10 per BOE becomes relatively more attractive and becomes average.

6.3.1.6. NPV10/Capex

Table 6.21 and Chart 6.34 provide the overview.

Table 6.21. Real NPV10/Capex for the Alberta project

	Status Quo	ASGFC	A+GTP	Target
$2.50	-0.11	-0.06	-0.04	0.12
$3.50	0.09	0.17	0.19	0.12
$4.50	0.28	0.40	0.41	0.12
$5.50	0.47	0.62	0.64	0.12
$6.50	0.67	0.85	0.87	0.12
$7.50	0.86	1.07	1.09	0.12
$8.50	1.05	1.30	1.32	0.12



Stress Price of $ 3.50 per MMBtu

Due to the enormous capital requirements for the project, the NPV10/Capex ratio is low. This indicator is acceptable under the stress price for the ASGFC and ASGFC+GTP. It is unattractive under Status Quo conditions.

Average price of $ 5.50 and high price of $ 8.50 per MMBtu per MMBtu

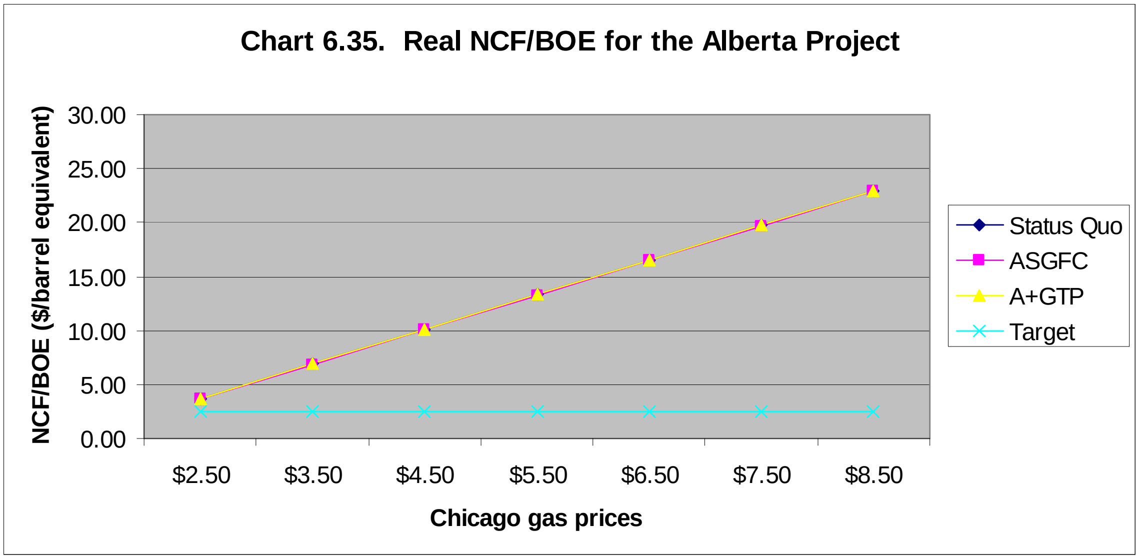
However, due to the rapid growth of the NPV10 with higher prices, the ratio becomes more average at higher prices.

6.3.1.7. NCF/BOE

Table 6.22 and Chart 6.35 provide the overview of the NCF/BOE.

Table 6.22. Real NCF/BOE for the Alberta Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	3.68	3.61	3.67	2.50
$3.50	6.90	6.83	6.90	2.50
$4.50	10.10	10.03	10.10	2.50
$5.50	13.32	13.24	13.31	2.50
$6.50	16.53	16.45	16.52	2.50
$7.50	19.74	19.66	19.73	2.50
$8.50	22.95	22.87	22.94	2.50



Stress Price of $ 3.50 per MMBtu

Even at the stress price the NCF/BOE is attractive due to the large size of the project, its long duration and the relatively low operating costs associated with it.

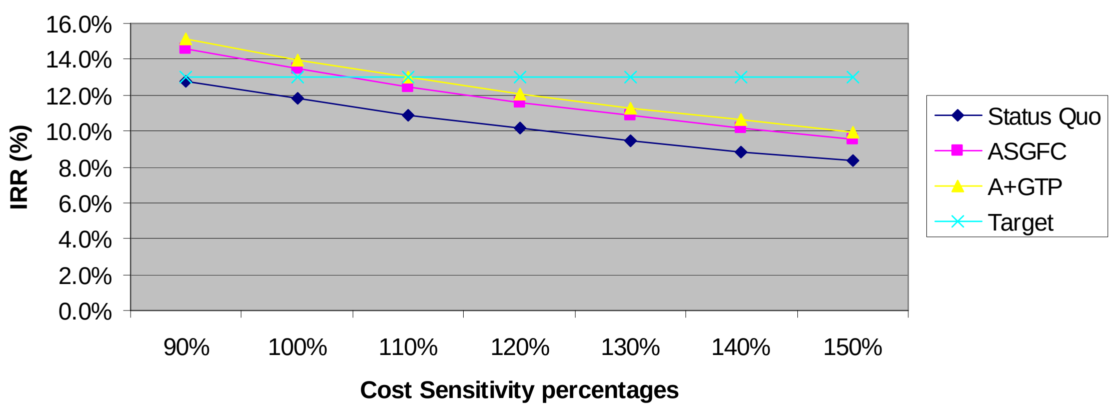
Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

At average and high prices the NCF/BOE becomes rapidly even more attractive.

6.3.1.8. Cost sensitivity

One of the most important risks of the project is cost overrun risk and therefore, this matter requires a special evaluation of the down side conditions. Following is an evaluation of these conditions against the stress price criteria set in Section 6.1.

Chart 6.36. Cost Sensitivity of Real IRR for Alberta Project at $ 3.50 per MMBtu



The ASGFC+GTP concept would handle a cost overrun of 10%, while maintaining a real IRR of 13%. The ASGFC would be slightly under this target.

Even without cost overruns the Status Quo already does not meet the 13% IRR target.

Chart 6.36 illustrates that the cost overrun risk in terms of the real IRR is very high. The project clearly does not produce an acceptable IRR when combining stress price conditions and significant cost overruns. This is a major drawback.

Chart 6.37. Cost Sensitivity of Real NPV10 for the Alberta Project at $ 3.50 per MMBtu

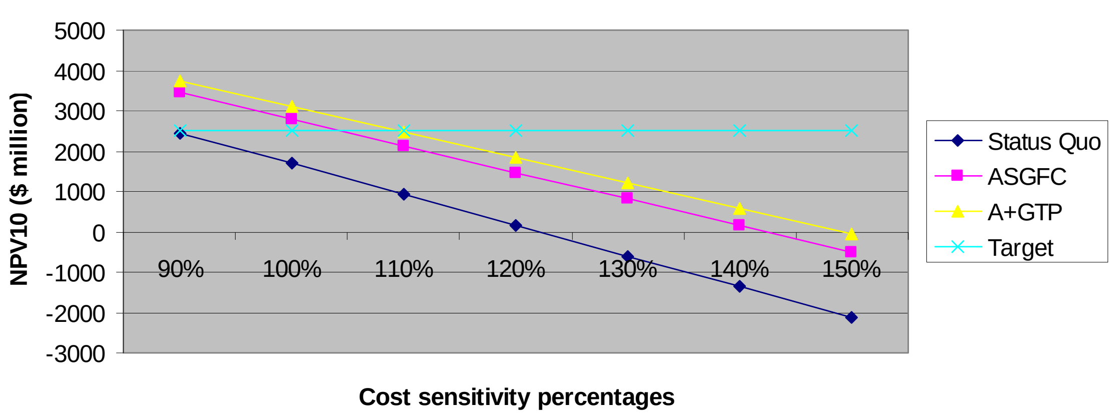
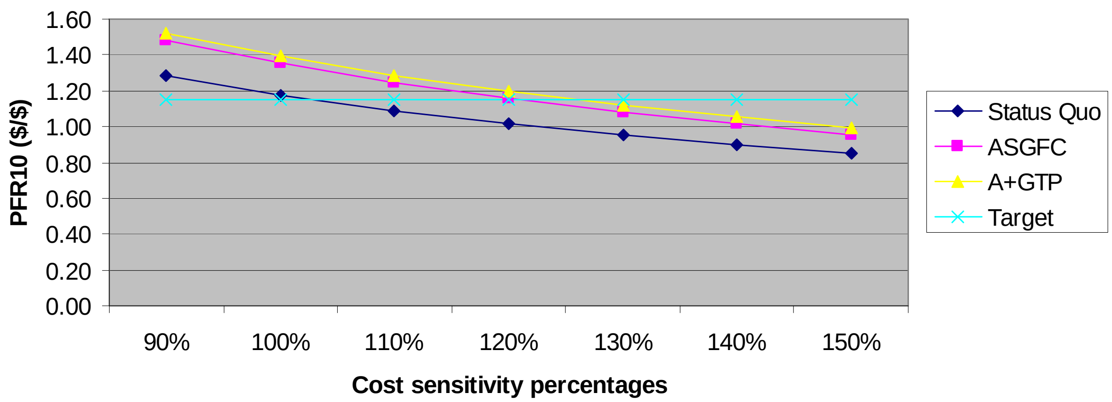


Chart 6.37 illustrates that with respect to the NPV10, the ASGFC and ASGFC+GTP options can absorb approximately a 10% cost overrun. If cost overruns are higher the NPV10 rapidly deteriorates.

The Status Quo is unattractive for the entire cost overrun range.

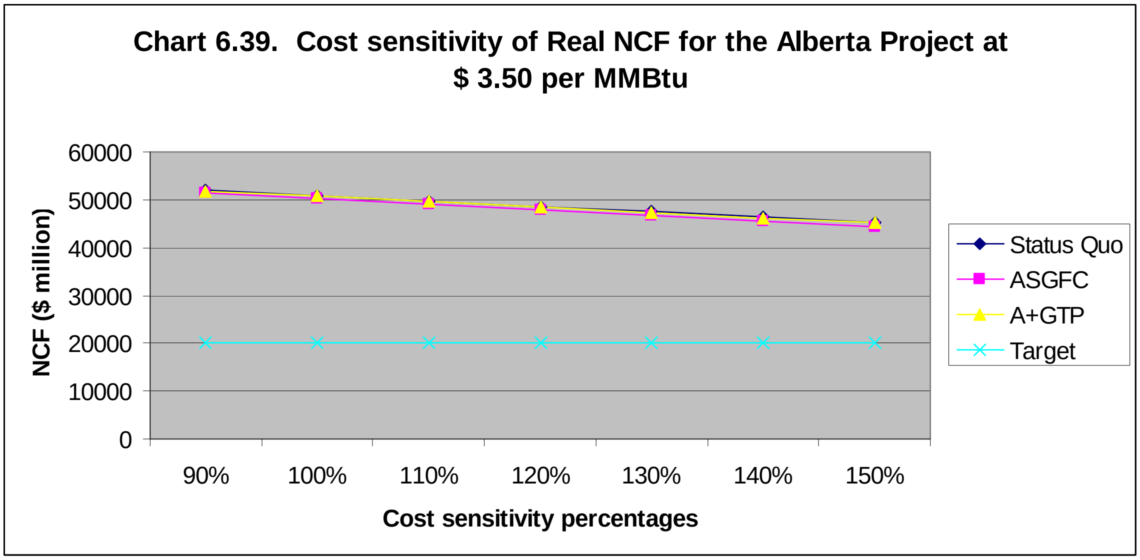
Chart 6.37 illustrates that also in NPV10 terms, the cost overrun risk is very high. The project clearly does not produce an acceptable NPV10 when combining stress price conditions and significant cost overruns. This is also a major problem area for the project.

Chart 6.38. Cost sensitivity of Real PFR10 for the Alberta Project at $ 3.50 per MMBtu

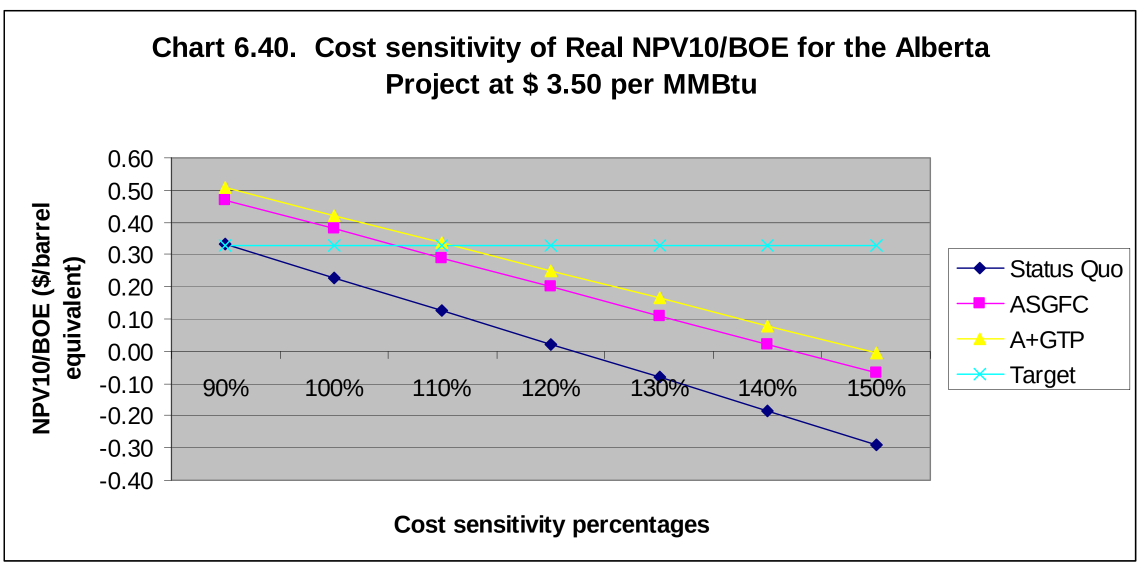


The PFR10 is somewhat more resistant to cost overruns as can be seen in Chart 6.38.

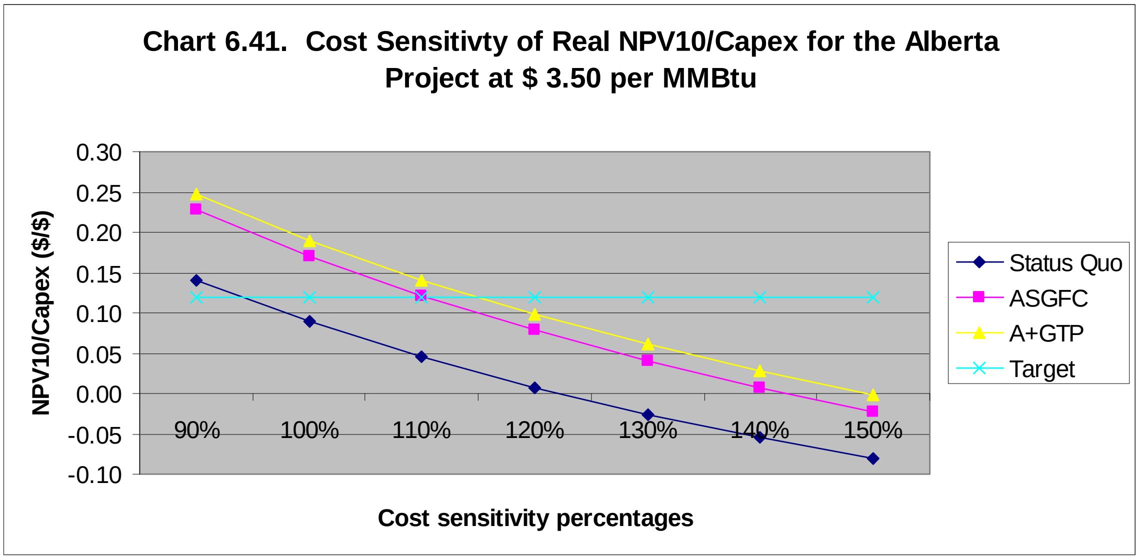
With the ASGFC and ASGFC+GTP the PFR10 is reasonable up to a cost overrun of 20%.



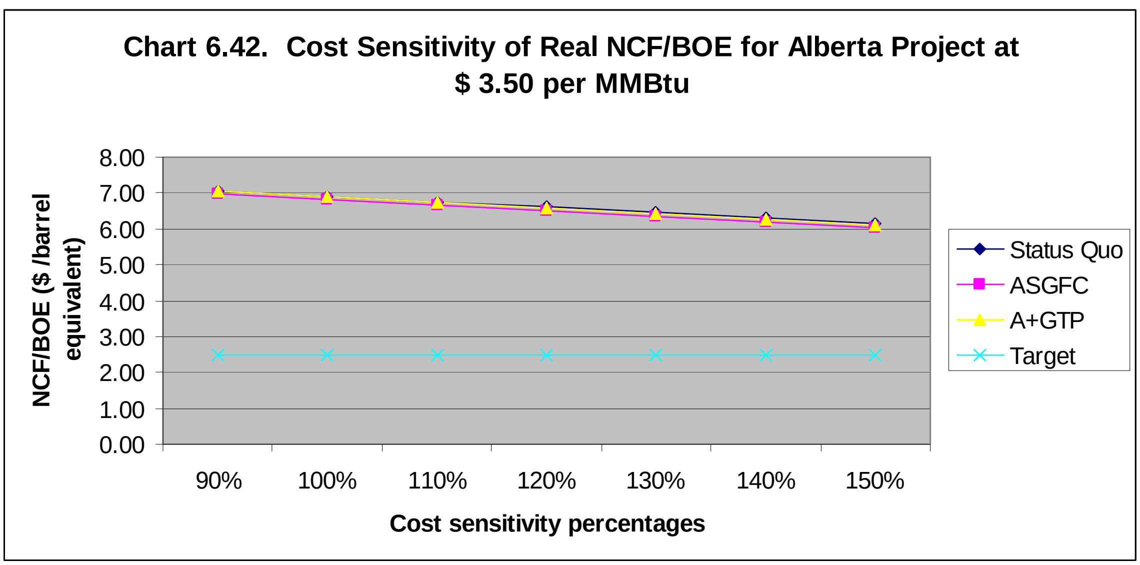
The real NCF of the project well exceeds what is desirable under stress price conditions and therefore, the NCF remains robust under a combination of a stress price and cost overruns.



The ASGFC and ASGFC+GTP improve considerably the NPV10 per BOE. Therefore, under the stranded gas contract this profitability indicator remains acceptable under a cost overrun of 10%.



The NPV10/Capex results in very weak values for the ASGFC and ASGFC+GTP at a 10% cost overrun. This is a concern. For the Status Quo it results in unattractive values.



The NCF/BOE values are highly attractive, even at stress prices and cost overruns.

6.3.1.9. Conclusion on Alberta Project

Stress Price of $ 3.50 per MMBtu and cost overruns

Tables 6.23 through 6.25 illustrate how the Alberta Project would meet the target indicators under stress prices and also combined with cost overruns.

Table 6.23. Minimum Criteria and the Alberta Project
At $ 3.50 stress price - no cost overruns

	Target	**Status Quo**	**ASGFC**	**A+GTP**
IRR	13%	**11.8%**	13.5%	14.0%
NPV10	2500	**1685**	2786	3098
PFR10	1.15	1.18	1.35	1.39
NCF	20	50.8	50.2	50.7
NPV10/BOE	0.33	**0.23**	0.38	0.42
NPV10/Capex	0.12	**0.09**	0.17	0.19
NCF/BOE	2.50	6.90	6.83	6.90

At the stress price, but with no cost overruns, the ASGFC terms as well as the ASGFC+GTP terms provide acceptable values for all profitability criteria.

The Status Quo fails to meet four of the criteria. Also the IRR and NPV10 are well below the target values.

This means that under the Status Quo the Alberta project has unacceptable downside conditions and that it is highly unlikely that investors would go forward with this project under these conditions.

Table 6.24. Minimum Criteria and the Alberta Project
At $ 3.50 stress price - 10% cost overruns

	Target	**Status Quo**	**ASGFC**	**A+GTP**
IRR	13%	**10.9%**	**12.5%**	13.0%
NPV10	2500	**924**	**2128**	**2471**
PFR10	1.15	**1.09**	1.25	1.29
NCF	20	49.7	49.0	49.6
NPV10/BOE	0.33	**0.13**	**0.29**	0.34
NPV10/Capex	0.12	**0.05**	0.12	0.14
NCF/BOE	2.50	6.76	6.67	6.74

Under conditions of 10% cost overruns, the Alaska Stranded Gas Fiscal Contract terms including the GTP and lateral line credits, provide for minimum acceptable conditions at the stress price for all indicators (the NPV10 is close enough).

Under the ASGFC terms, without the PPT GTP and lateral line credits, the project would show unacceptable results for IRR, NPV10 and NPV10/BOE. However, the NPV10/BOE is close and the attractive PFR10 and very attractive NCF and NCF/BOE may pull the project through under these conditions.

This illustrates that the GTP and lateral line PPT credits are very important in ensuring that the project is judged acceptable under down side conditions.

Table 6.25. Minimum Criteria and the Alberta Project
At $ 3.50 stress price - 20% cost overruns

	Target	**Status Quo**	**ASGFC**	**A+GTP**
IRR	13%	**10.2%**	**11.6%**	**12.1%**
NPV10	2500	**163**	**1470**	**1844**
PFR10	1.15	**1.01**	1.16	1.2
NCF	20	48.6	47.8	48.5
NPV10/BOE	0.33	**0.02**	**0.2**	**0.25**
NPV10/Capex	0.12	**0.01**	**0.08**	**0.10**
NCF/BOE	2.50	6.61	6.5	6.59

Under conditions of 20% cost overruns, the project is unattractive under four of the profitability indicators even with the GTP and lateral line credits. This shows that despite a stranded gas contract, the project still cannot absorb a 20% cost overrun under the stress price.

This shows that in general, the project is relatively weak under down side conditions compared to other projects in the world.

However, even under down side conditions the NCF and NCF/BOE are very attractive. Therefore, it is ultimately the huge net cash flow that is the profitability anchor for the project and is vitally important to ensure that the project goes forward.

This illustrates that the fiscal stability provided under the Alaska Stranded Gas Fiscal Contract is essential in ensuring the realization of the project if price and cost conditions would deteriorate. The attractive NCF and NCF/BOE values are

primarily important because of the fiscal stability that is provided. Without such stability these indicators would be much less attractive.

In general the Alaska Gas Project, even with the conditions of the proposed stranded gas contract remains a questionable project under down side conditions of price and cost.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

The down side concerns are considerably offset by the huge NPV10 and NCF values and attractive NCF/BOE values under average and high prices.

The upside of the project is phenomenal. The massive NPV10 and the huge net cash flow at high prices under conditions of fiscal stability, make this project truly unique in these respects in the world.

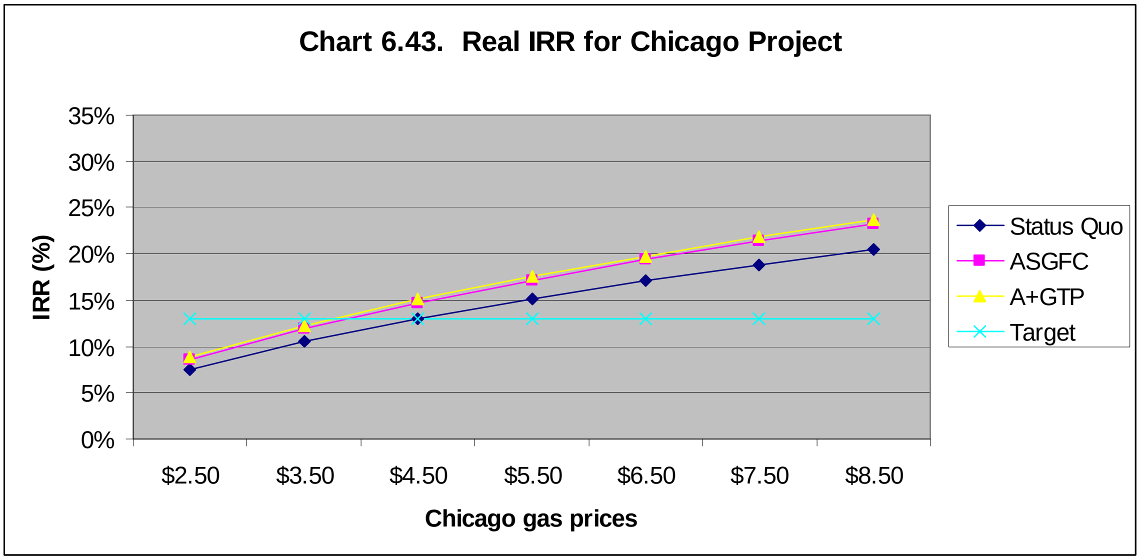
6.3.2. Project ending in Chicago

6.3.2.1. IRR

Table 6.26 and Chart 6.43 provide the data for the real IRR for the Chicago Project.

Table 6.26. Real IRR for Chicago Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	7.5%	8.5%	8.8%	13.0%
$3.50	10.5%	11.9%	12.2%	13.0%
$4.50	12.9%	14.7%	15.1%	13.0%
$5.50	15.1%	17.2%	17.6%	13.0%
$6.50	17.0%	19.4%	19.8%	13.0%
$7.50	18.8%	21.4%	21.8%	13.0%
$8.50	20.5%	23.2%	23.7%	13.0%



Stress Price of $ 3.50 per MMBtu

In general the Alaska Gas Project, remains unattractive with the conditions of the proposed stranded gas contract under the stress price of $ 3.50 per Mcf. The Status Quo to Chicago would be very unattractive.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

Under average Chicago gas prices, a project to Chicago would have a very modest rate of return under the ASGFC or the ASGFC+GTP conditions.

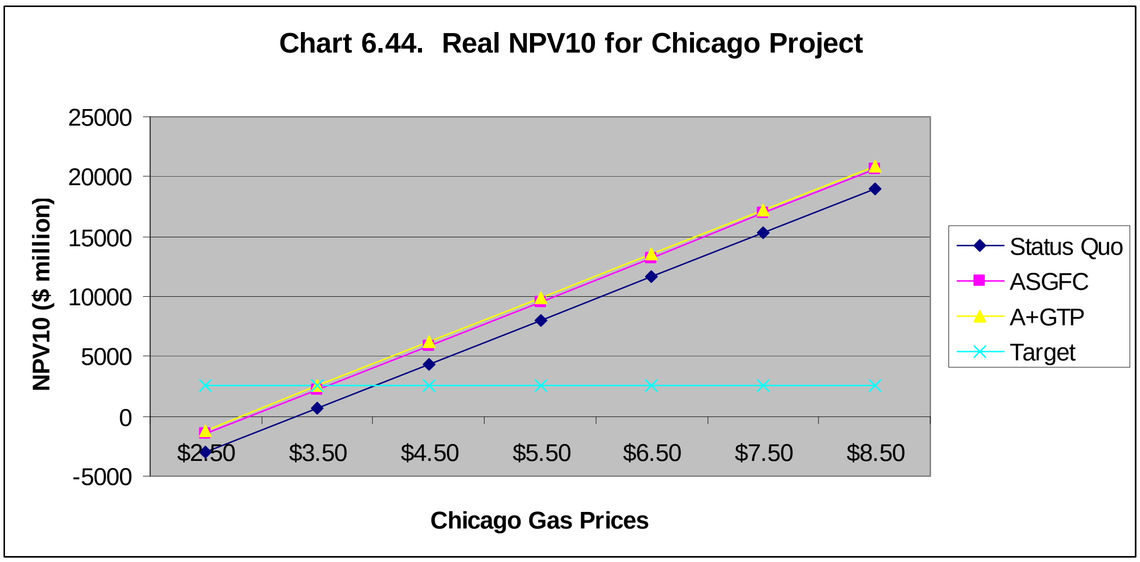
Even under high prices the IRR would not be very attractive compared to most international projects at high price forecasts.

6.3.2.2. NPV @10%

The real NPV10 for the Alaska Gas Project to Chicago can be evaluated with Table 6.27 and Chart 6.44.

Table 6.27. Real NPV for Chicago Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	-3024	-1498	-1186	2500
$3.50	664	2209	2520	2500
$4.50	4317	5880	6192	2500
$5.50	7988	9568	9880	2500
$6.50	11640	13239	13550	2500
$7.50	15295	16912	17224	2500
$8.50	18964	20599	20911	2500



Stress Price of $ 3.50 per MMBtu

Under stress price conditions the Status Quo would have a very unacceptable NPV10. Also the ASGFC and ASGFC+GTP would be very marginal under stress price conditions.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

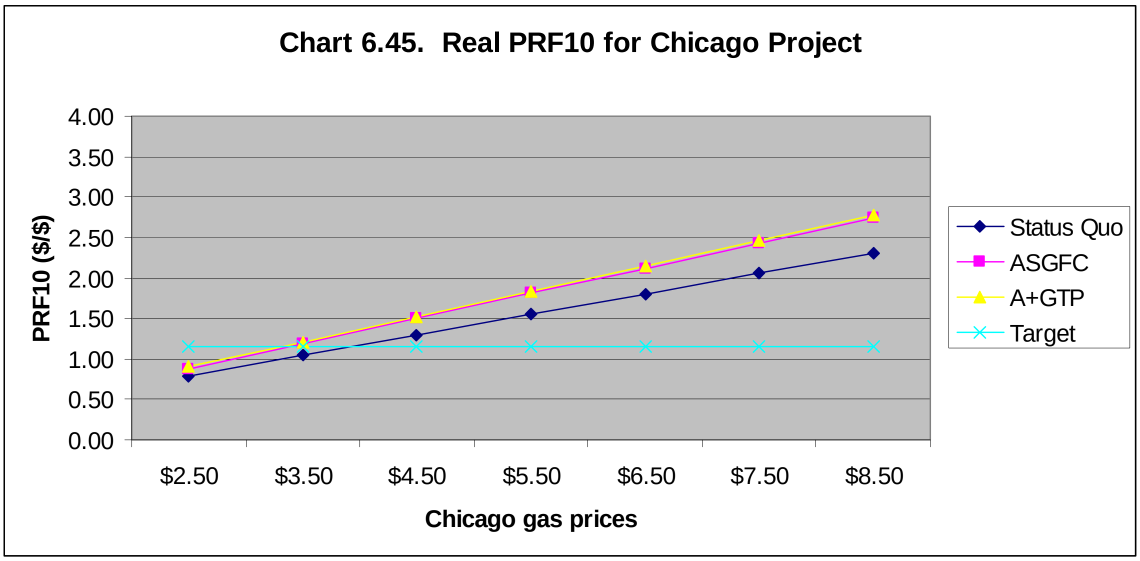
As was concluded for the Alberta project, the NPV10 rapidly increases with higher gas prices because the relative importance of the transport costs declines rapidly. The huge size of the project creates under average prices already a huge NPV10 and under high prices a very high NPV10, which will rate among the best in the world for average and high price conditions.

6.3.2.3. PFR @10%

Table 6.28 and Chart 6.45 display the PFR10 for the Chicago Project.

Table 6.28. Real PFR10 for a Chicago Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	0.79	0.87	0.90	1.15
$3.50	1.05	1.19	1.21	1.15
$4.50	1.30	1.50	1.52	1.15
$5.50	1.55	1.81	1.84	1.15
$6.50	1.81	2.12	2.15	1.15
$7.50	2.06	2.43	2.46	1.15
$8.50	2.31	2.74	2.77	1.15



Stress Price of $ 3.50 per MMBtu

Due to the much higher capital costs related to the Chicago project, the Status Quo is unattractive from a PFR10 standpoint. The PFR10 for the ASGFC and ASGFC+GTP are marginal.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

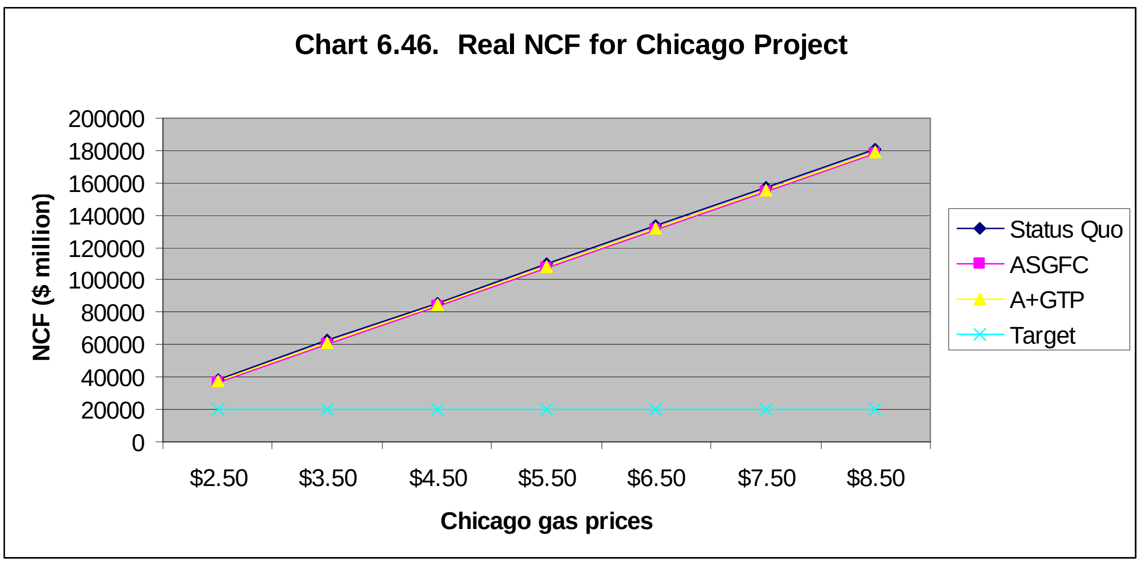
Under average and high price conditions the PFR10 ratios improve rapidly due to the rapid improvement of the NPV10.

6.3.2.4. NCF

Table 6.29 and Chart 6.46 illustrate the Net Cash Flow for the Chicago Project.

Table 6.29. Real NCF for the Chicago Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	38783	36770	37282	20000
$3.50	62484	60467	60978	20000
$4.50	86018	83996	84508	20000
$5.50	109667	107640	108152	20000
$6.50	133266	131233	131745	20000
$7.50	156878	154841	155353	20000
$8.50	180527	178485	178997	20000



Stress Price of $ 3.50 per MMBtu

As was concluded for the nominal results, the Chicago project has actually a higher cash flow than the Alberta Project because of the higher value of the project in Chicago.

Even at the stress price the NCF is well over the minimum levels that would be attractive under stress price conditions.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

Under average and high prices the NCF is phenomenal and probably the highest of any project in the world.

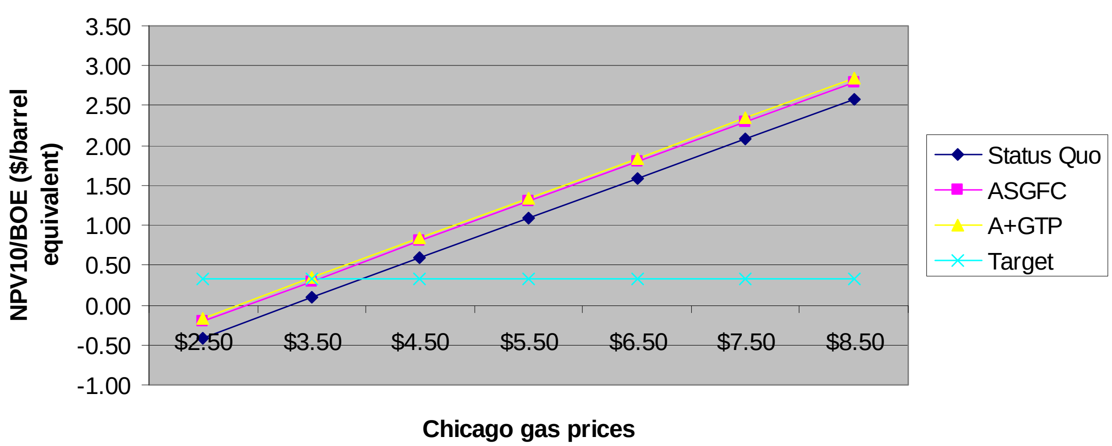
6.3.2.5. NPV10/BOE

Table 6.30 and Chart 6.47 provide the information on the NPV10/BOE.

Table 6.30. Real NPV10/BOE for the Chicago Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	-0.41	-0.20	-0.16	0.33
$3.50	0.09	0.30	0.34	0.33
$4.50	0.59	0.80	0.84	0.33
$5.50	1.09	1.30	1.34	0.33
$6.50	1.58	1.80	1.84	0.33
$7.50	2.08	2.30	2.34	0.33
$8.50	2.58	2.80	2.84	0.33

Chart 6.47. Real NPV10/BOE for the Chicago Project



Stress Price of $ 3.50 per MMBtu

Under stress price conditions only the ASGFC+GTP meets the minimum standards. The ASGFC is below and the Status Quo far below the levels that are needed.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

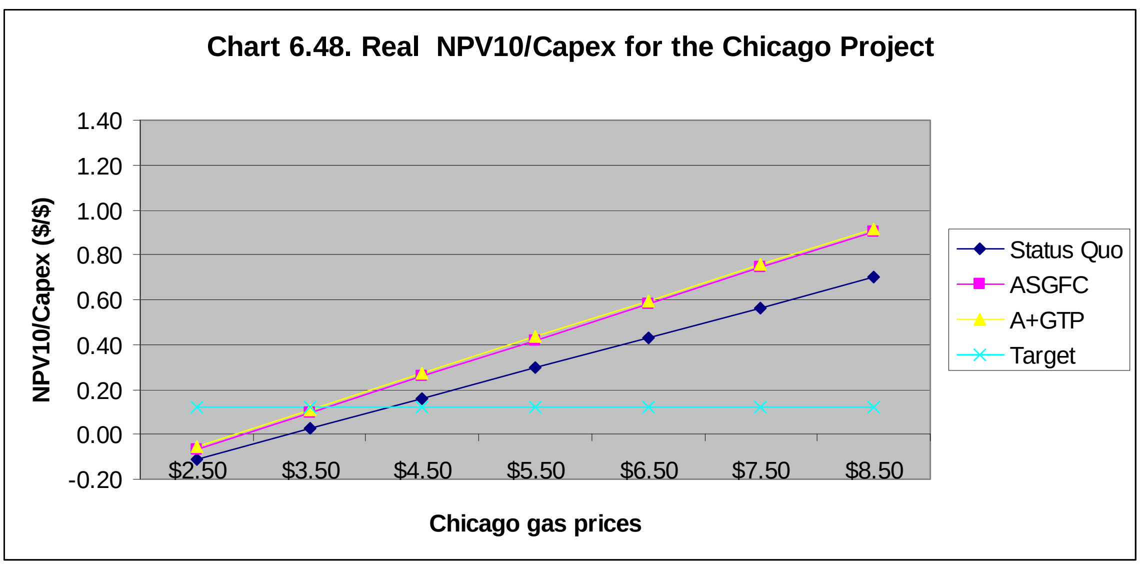
Because the NPV10 improves rapidly with price, the NPV10/BOE also improves and therefore under average and high prices the NPV10/BOE values reach attractive levels.

6.3.2.6. NPV10/Capex

The NPV10 per Undiscounted Capex data are provided in Table 6.31 and Chart 6.48.

Table 6.31. NPV10/Undisc Capex for Chicago Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	-0.11	-0.07	-0.05	0.12
$3.50	0.02	0.10	0.11	0.12
$4.50	0.16	0.26	0.27	0.12
$5.50	0.29	0.42	0.43	0.12
$6.50	0.43	0.58	0.59	0.12
$7.50	0.56	0.74	0.76	0.12
$8.50	0.70	0.90	0.92	0.12



Stress Price of $ 3.50 per MMBtu

The high capital costs associated the Chicago project make the project very unattractive under Status Quo conditions and also under the stranded gas contract terms.

Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

Under average and high price conditions the NPV/Undiscounted Capex remains modest in comparison with many international projects.

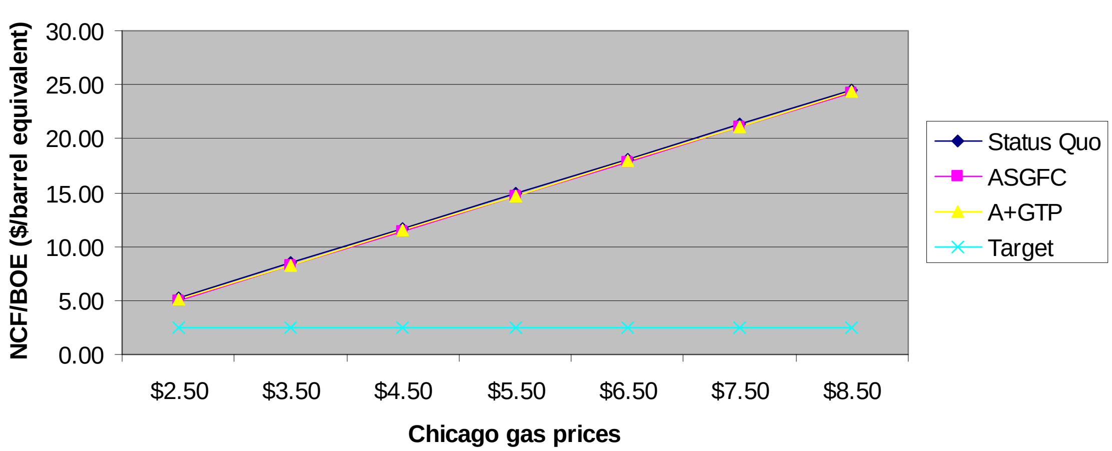
6.3.2.7. NCF/BOE

Table 6.32 and Chart 6.49 provide the NCF/BOE.

Table 6.32. Real NCF/BOE for the Chicago Project

	Status Quo	ASGFC	A+GTP	Target
$2.50	5.27	5.00	5.07	2.50
$3.50	8.49	8.22	8.29	2.50
$4.50	11.69	11.42	11.49	2.50
$5.50	14.90	14.63	14.70	2.50
$6.50	18.11	17.84	17.91	2.50
$7.50	21.32	21.04	21.11	2.50
$8.50	24.53	24.26	24.33	2.50

Chart 6.49. Real NCF/BOE for the Chicago Project



Stress Price of $ 3.50 per MMBtu

The huge NCF provides an attractive NCF/BOE, even under stress price conditions. As can be seen the ratio is more attractive than for the Alberta Project because of the higher value of the project in Chicago.

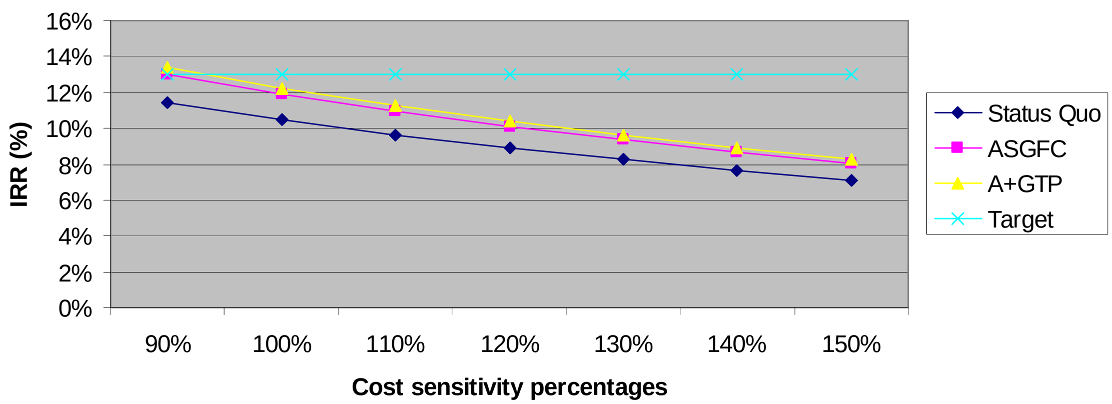
Average price of $ 5.50 per MMBtu and high price of $ 8.50 per MMBtu

Under average and high prices the NCF/BOE values are extremely attractive.

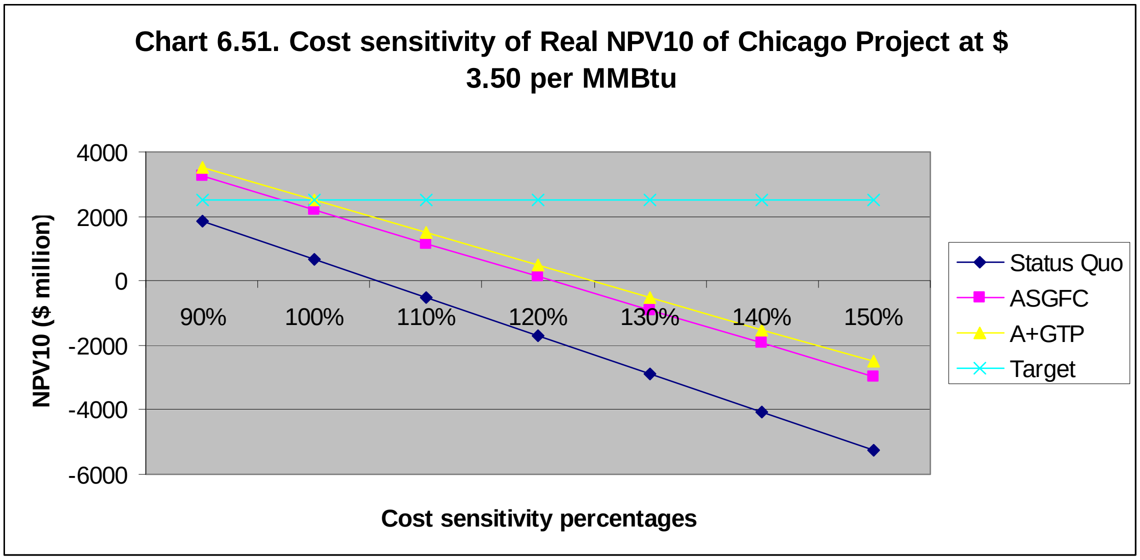
6.3.2.8. Cost Sensitivity

Following graphs illustrate the cost sensitivity for the Chicago Project.

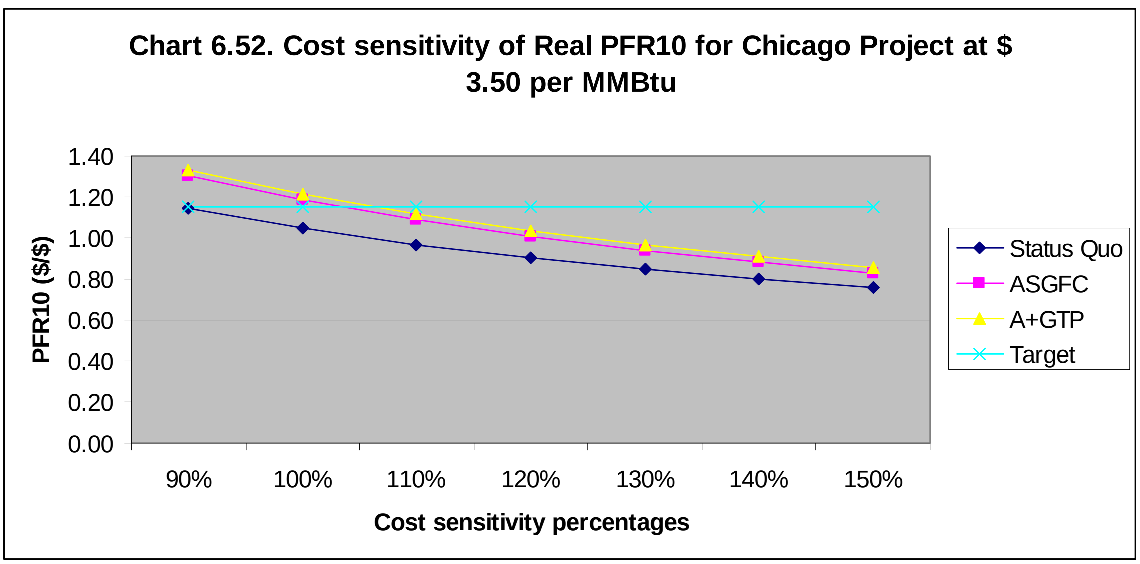
Chart 6.50. Cost Sensitivity of Real IRR for Chicago Project at $ 3.50 per MMBtu



For the Chicago Project, the IRR is already unacceptable without cost overruns at the stress price. With significant cost overruns the project rapidly deteriorates to a completely unacceptable project. This is true even under ASGFC+GTP conditions. Under Status Quo conditions the project would be highly unattractive.

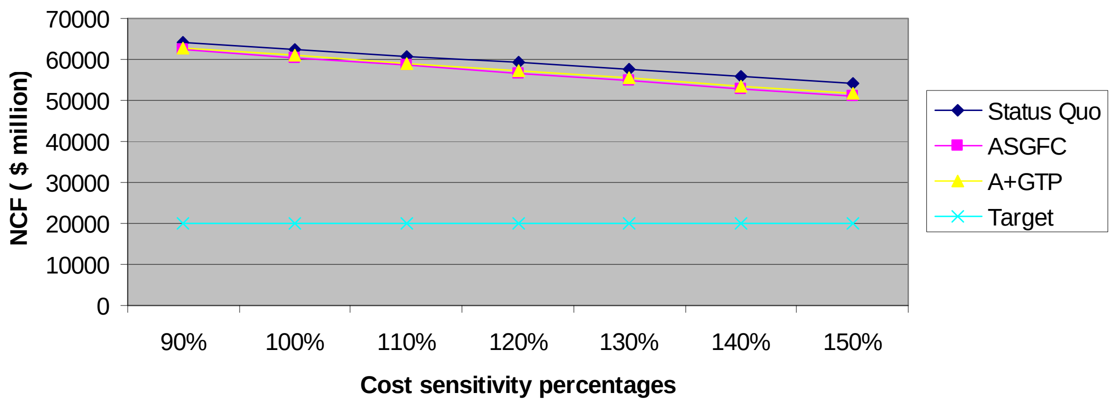


The NPV10 is marginal without cost overruns under the stranded gas contract and unattractive under Status Quo conditions. With modest cost overruns the NPV10 becomes rapidly unacceptable and under high cost overruns over 25% the NPV10 is even negative. This would be a disastrous scenario for such a large project.



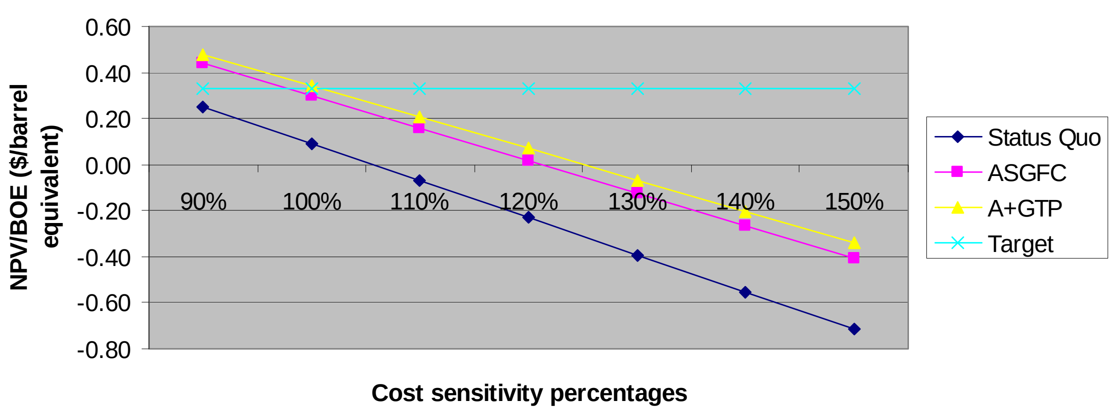
Without cost overruns the PFR10 is marginal for the ASGFC+GTP and unattractive for the Status Quo. With a 10% cost overrun the PFR10 becomes marginal and at higher cost overruns unattractive.

Chart 6.53. Cost sensitivity of Real NCF for Chicago Project at $ 3.50 per MMBtu



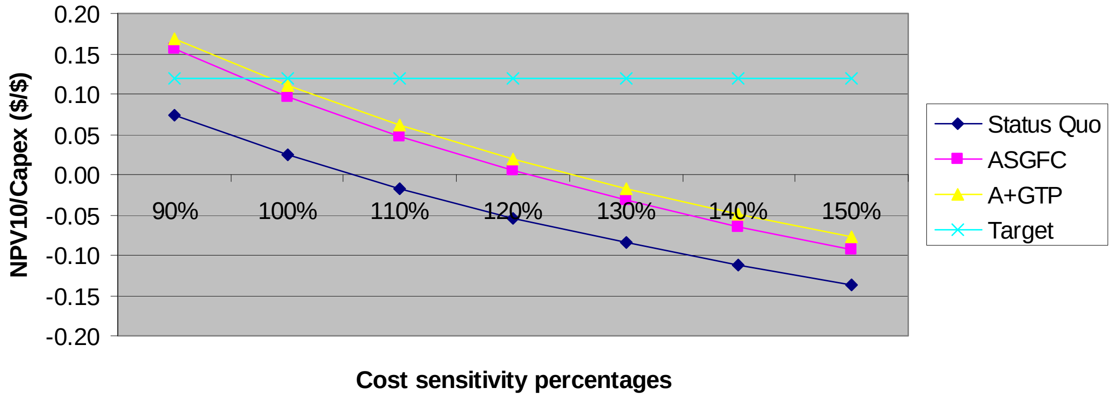
The real NCF remains attractive regardless of the level of costs.

Chart 6.54. Cost sensitivity of Real NPV/BOE for Chicago Project at $ 3.50 per MMBtu



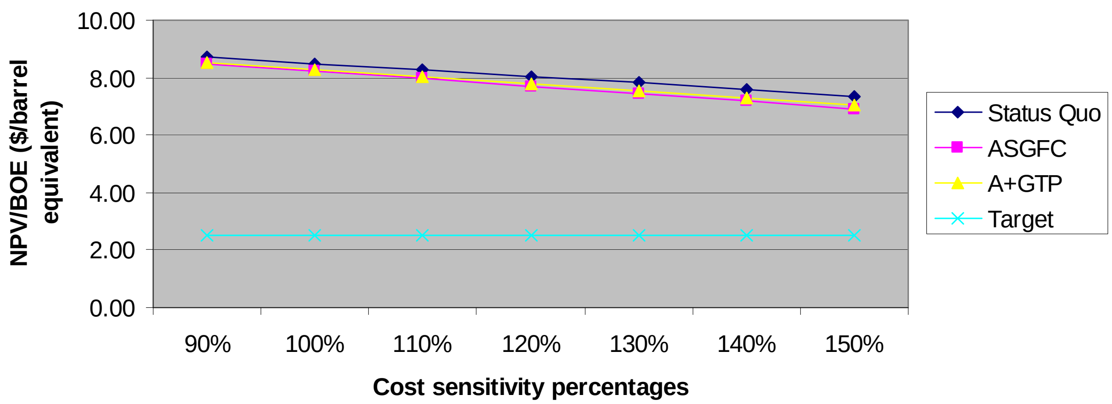
Because the NPV10 rapidly deteriorates with cost overruns, the NPV/BOE does so as well.

Chart 6.55. Cost sensitivity of Real NPV10/Capex for Chicago project at $ 3.50 per MMBtu



The NPV10/Capex is already unattractive without cost overruns for the ASGFC+GTP case. The Status Quo is highly unattractive. With modest cost overruns the Chicago Project rapidly deteriorates.

Chart 6.56. Cost sensitivity of Real NCF/BOE for Chicago Project at # 3.50 per MMBtu



Due to the excellent real NCF, the NCF/BOE is very attractive under any level of cost overrun.

6.3.2.9. Conclusion on Chicago Project

Stress Price of $ 3.50 per MMBtu and cost overruns

Tables 6.33 through 6.35 provide an overview of the Chicago Project under stress price conditions and cost overruns.

Table 6.33. Minimum Criteria and the Chicago Project
At $ 3.50 stress price - no cost overruns

	Target	**Status Quo**	**ASGFC**	**A+GTP**
IRR	13%	**10.5%**	**11.9%**	**12.2%**
NPV10	2500	**664**	**2209**	2520
PFR10	1.15	**1.05**	1.19	1.21
NCF	20	62.5	60.5	61.0
NPV10/BOE	0.33	**0.09**	**0.30**	0.34
NPV10/Capex	0.12	**0.02**	**0.10**	**0.11**
NCF/BOE	2.50	8.49	8.22	8.29

Table 6.33 illustrate how under stress price conditions the Status Quo terms would provide for an unattractive Chicago Project.

Even under the ASGFC the project is unattractive with an unacceptable IRR and weak values for the NPV10, NPV10/BOE and NPV/Capex.

Under ASGFC+GTP conditions the downside provides for a weak IRR and NPV10/Capex, but an acceptable NPV10 and attractive PFR10.

In general it is very clear that a Chicago Project with no cost overruns would be acceptable under the ASGFC terms including the PPT credits on the GTP and lateral lines. Nevertheless even then it would be a marginal project.

Table 6.34. Minimum Criteria and the Chicago Project
At $ 3.50 stress price - 10% cost overruns

	Target	**Status Quo**	**ASGFC**	**A+GTP**
IRR	13%	**9.6%**	**11.0%**	**11.3%**
NPV10	2500	**-519**	**1171**	**1514**
PFR10	1.15	**0.97**	**1.09**	**1.12**
NCF	20	60.8	58.6	59.1
NPV10/BOE	0.33	**-0.07**	**0.16**	**0.21**
NPV10/Capex	0.12	**-0.02**	**0.05**	**0.06**
NCF/BOE	2.50	8.27	7.96	8.03

Tables 6.34 illustrates how a Chicago Project cannot withstand a 10% cost overrun under stress price conditions even under the ASGFC terms with PPT credits on the GTP and lateral lines.

This makes further feasibility work to lower costs a very important issue.

Table 6.35. Minimum Criteria and the Chicago Project
At $ 3.50 stress price - 20% cost overruns

	Target	**Status Quo**	**ASGFC**	**A+GTP**
IRR	13%	**8.9%**	**10.1%**	**10.4%**
NPV10	2500	**-1702**	**133**	**507**
PFR10	1.15	**0.90**	**1.01**	**1.04**
NCF	20	59.2	56.6	57.3
NPV10/BOE	0.33	**-0.23**	**0.02**	**0.07**
NPV10/Capex	0.12	**-0.05**	**0.01**	**0.02**
NCF/BOE	2.50	8.04	7.7	7.78

Table 6.35 indicate that a Chicago Project under stress price conditions and a 20% cost overrun and under the stress price would be a dismal project.

Average Price of $ 5.50 per MMBtu and High Price of $ 8.50 per MMBtu

Under average and high price forecast the Chicago Project is an extremely attractive project, with probably among the highest net cash flow and NPV10 values in the world. The project represents an excellent opportunity under these conditions.

6.3.3. Real Producer Economics - Summary

The Alaska Gas Project is a project with a spectacular real net cash flow under the entire Chicago gas price range considered in this economic analysis, irrespective of whether the project terminates in Alberta or Chicago and for all fiscal options.

In part the strong net cash flow is simply the result of the enormous size of the project.

However, the real net cash flow per barrel equivalent (NCF/BOE) is also attractive for the entire price range compared to international conditions. This means the net cash flow of the project compares favourably with other projects even if we correct for the size of the project by comparing on a barrel equivalent basis. This favourable indicator is caused by the fact that the project consists in large part of the production of the Prudhoe Bay gas resources. This production is incremental to the current operations and therefore the incremental operating costs of the Prudhoe Bay gas are essentially nil. Also the operating costs of the midstream system are low.

Therefore, the operating costs per barrel equivalent of this project are low compared to most projects in the world. This creates a net cash flow per barrel equivalent, which is several dollars higher than most other projects. This is true for a project terminating in Alberta or Chicago and for all three fiscal options.

An important economic characteristic of the project is that the price differential between market and the well head is high. This is due to the high transport costs from the North Slope to either Chicago or Alberta. In case of a project terminating in Alberta the project prices are based on the Alberta Hub which are well below Chicago prices.

This creates an unusual behaviour for the real Net Present Value discounted at 10% (NPV10).

The average Chicago gas price of \$ 5.50 per MMBtu and the high Chicago gas price of \$ 8.50 exceed the wellhead-market price differential by a wide margin. Under these conditions the NPV10 of the project becomes huge. In fact, the total size of the NPV10 is among the most attractive projects in the world. This is the case whether the project ends in Alberta or Chicago and for all fiscal options.

Under a low (stress) price in Chicago of \$ 3.50 per MMBtu, the NPV 10 becomes marginal or unattractive. In this case, there is a considerable differentiation between a project ending in Alberta and Chicago. The Alberta project is relatively more attractive and more resilient against price drops (assuming that the Alberta – Chicago differential indeed evolves as predicted).

Under low prices there is a considerable difference between the results for the various fiscal terms. The Status Quo is unattractive under these conditions. The Alaska Stranded Gas Fiscal Contract creates a marginal NPV10. Adding the PPT tax credits on the GTP and lateral lines improves the NPV10 somewhat further.

In other words the NPV10 “flip flops” from among the best in the world to among the worst in the world, depending on the Chicago gas price. This illustrates that the large size of the Alaska Gas Project creates a very high gas price risk in absolute terms. The proposed stranded gas terms have a very material positive impact on mitigating this downside risk.

The other profitability indicators that were evaluated were: the internal rate of return (IRR), the profitability ratio discounted at 10% (PFR10), the NPV10 per barrel equivalent (NPV10/BOE) and the NPV10 per dollar undiscounted capital expenditures (NPV10/Capex).

Under average and high Chicago gas prices, these indicators show very modest to average results. The Alaska Gas Project is not unusually profitable under these price conditions. In particular the IRR is very modest compared to other international projects.

Under a low Chicago gas price these indicators show a poor project if the project ends in Alberta and a very poor project if the project ends in Chicago.

These poor results are the direct consequence on the very high capital expenditures that are required.

In particular the IRR is very low compared to international conditions because of the huge up front capital expenditures and the long lead time of the project.

At this time it seems that the take-away capacity from Alberta in 2015 will be about 2 Bcf/day. This means that it would be necessary for the remaining volumes to enter into firm transportation commitments in order to expand existing lines or built new pipelines. It is very difficult to predict what the take-away capacity in Alberta will be 10 years from now. Therefore, it seems safe to assume that the actual project economics will be somewhere between the economics of the Alberta and Chicago Project.

The following Table 6.36 provides a summary for the project ending in Alberta and in Chicago for all the profitability indicators for three fiscal options and for a price of $ 3.50 per MMBtu. A **"bold"** indicates that the project does not meet minimum profitability standards.

Table 6.36. Minimum Criteria and the Alaska Gas Project
At $ 3.50 stress price - no cost overruns

	Target	**Status Quo Alberta**	**Status Quo Chicago**	**ASGFC Alberta**	**ASGFC Chicago**	**A+GTP Alberta**	**A+GTP Chicago**
IRR	13%	**11.8%**	**10.5%**	13.5%	**11.9%**	14.0%	**12.2%**
NPV10	2500	**1685**	**664**	2786	**2209**	3098	2520
PFR10	1.15	1.18	**1.05**	1.35	1.19	1.39	1.21
NCF	20	50.8	62.5	50.2	60.5	50.7	61.0
NPV10/BOE	0.33	**0.23**	**0.09**	0.38	**0.30**	0.42	0.34
NPV10/Capex	0.12	**0.09**	**0.02**	0.17	**0.10**	0.19	**0.11**
NCF/BOE	2.50	6.90	8.49	6.83	8.22	6.90	8.29

The table illustrates how under the Status Quo option and the low price of $ 3.50 per MMBtu the Alaska Gas Project would not be viable.

Four profitability indicators are below the target values in the case of an Alberta Project and five in the case of a Chicago Project. The IRR and NPV are will below minimum requirements under the Alberta Project and all five profitability indicators are well below minimum requirements for the Chicago Project. Economics somewhere between Alberta and Chicago economics are therefore dismal.

Therefore the Status Quo is unacceptable under stress price conditions.

Table 6.36 illustrates how the ASGFC option would result in profitability indicators which create stranded gas contract makes the downside viable for a project ending in Alberta. All the profitability indicators achieve minimum acceptable conditions.

The Chicago Project would be a very weak project with a very low IRR and modest NPV10.

Economics somewhere between the Alberta and Chicago Projects create a viable project.

Therefore, the ASGFC option results in acceptable conditions at the stress price.

By providing the PPT credits on the GTP and lateral lines the profitability indicators improve enough to make the Chicago Project marginal. A low IRR is offset by an acceptable NPV10 and NPV10/BOE. In addition there is the highly attractive net cash flow. The economics somewhere between the Alberta and Chicago Project would be well above minimum conditions.

Therefore, the ASGFC+GTP option would create economics under the stress price that are well in excess of minimum requirements.

Due to the high capital expenditures, cost overruns have a very important impact on project profitability indicators.

Table 6.37 shows the summary of profitability indicators in case of a 10% cost overrun.

Table 6.37. Minimum Criteria and the Alaska Gas Project
At $ 3.50 stress price - 10% cost overruns

	Target	Status Quo Alberta	Status Quo Chicago	ASGFC Alberta	ASGFC Chicago	A+GTP Alberta	A+GTP Chicago
IRR	13%	**10.9%**	**9.6%**	**12.5%**	**11.0%**	13.0%	**11.3%**
NPV10	2500	**924**	**-519**	**2128**	**1171**	**2471**	**1514**
PFR10	1.15	**1.09**	**0.97**	1.25	**1.09**	1.29	**1.12**
NCF	20	49.7	60.8	49.0	58.6	49.6	59.1
NPV10/BOE	0.33	**0.13**	**-0.07**	**0.29**	**0.16**	0.34	**0.21**
NPV10/Capex	0.12	**0.05**	**-0.02**	0.12	**0.05**	0.14	**0.06**
NCF/BOE	2.50	6.76	8.27	6.67	7.96	6.74	8.03

It can be seen how even a cost overrun of only 10% has devastating effects on project economics, in particular for the Chicago Project.

The Alberta Project remains viable under ASGFC+GTP terms, but the Chicago project is clearly no longer attractive.

The average between the Alberta and Chicago Project with a 10% cost overrun under ASGFC+GTP terms would be very marginal.

Cost overrun risk is clearly a very high risk for the Alaska Gas Project.

Therefore, it is of vital importance that are being found to reduce project costs and create the level of effective preparation for the project that ensures that cost overruns are kept to a minimum.

Table 6.38 shows the profitability indicators under a 20% cost overrun.

Table 6.38. Minimum Criteria and the Alaska Gas Project
At $ 3.50 stress price - 20% cost overruns

	Target	Status Quo Alberta	Status Quo Chicago	ASGFC Alberta	ASGFC Chicago	A+GTP Alberta	A+GTP Chicago
IRR	13%	**10.9%**	**9.6%**	**12.5%**	**11.0%**	13.0%	**11.3%**
NPV10	2500	**924**	**-519**	**2128**	**1171**	**2471**	**1514**
PFR10	1.15	**1.09**	**0.97**	1.25	**1.09**	1.29	**1.12**
NCF	20	49.7	60.8	49.0	58.6	49.6	59.1
NPV10/BOE	0.33	**0.13**	**-0.07**	**0.29**	**0.16**	0.34	**0.21**
NPV10/Capex	0.12	**0.05**	**-0.02**	0.12	**0.05**	0.14	**0.06**
NCF/BOE	2.50	6.76	8.27	6.67	7.96	6.74	8.03

Under cost overruns of 20% and the stress price, the Alaska Gas Project is not viable, irrespective of the fiscal option, unless gas supply and demand conditions evolve in the Alberta Hub that makes a project exclusively ending in Alberta a reality.