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Analysis of the Petroleum Fiscal Framework of Venezuela

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Analysis of the Petroleum Fiscal Framework of Venezuela

James L. Smith, Ph.D

This report follows a series of regional analyses carried out by the Inter-American Development Bank on the performance region's fiscal frameworks for mining and hydrocarbons. Particularly, this study compares the performance of Venezuela's present tax regime for hydrocarbon projects to alternative regimes. It is focused on spending across a diverse set of model projects, including greenfield oil and gas projects, a brownfield oil project, and an Orinoco heavy oil belt project. The projects that form the basis of our conclusions are realistic but hypothetical, meaning that we have based the analysis of each project on typical capital and operating expenditures, investment lead times, proved reserves, and recovery factors. The analysis finds that the existing fiscal regime in Venezuela severely discourages investment in exploration, development, and enhanced recovery operations. This results in reduced levels of Government revenue, potential oil and gas reserves being left in the ground, and lost profits for oil companies.

JEL Codes: Q32, Q35, Q38, Q43, E62

Keywords: Venezuela, oil & gas, petroleum, fiscal framework, tax, royalty.

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1. Overview

This report compares the performance of Venezuela's present tax regime for upstream oil and gas projects to alternative regimes that are structured to increase investment in the upstream sector and to increase Government revenue. We focus the analysis on investments across a diverse set of projects, including greenfield oil and gas developments, a brownfield oil development, and investments to increase production from the Orinoco heavy oil belt. The projects that form the basis of our conclusions are realistic but hypothetical, meaning that we have based the analysis of each project on typical capital and operating expenditures, investment lead times, proved reserves, and recovery factors as reported by petroleum engineers who are experienced in Venezuela's upstream petroleum sector.

The main objective of our study is to assess the ability of Venezuela's fiscal regime to capture economic rents for the nation without discouraging resource development. We also examine several fiscal alternatives that could increase that ability and help to reverse the trend of declining oil production. Equally important is the robustness of the chosen regime to perform well under a range of unpredictable economic circumstances, including high versus low prices and high versus low costs. We examine the robustness of Venezuela's fiscal regime with respect to variations in these factors.

Our analysis is conducted using a peer-reviewed, state-of-the-art economic optimization model that takes into account an Investor's incentive to tailor upstream petroleum projects in ways that mitigate the burden of taxes and maximize the after-tax value of the investment.[1] This includes adapting the intensity of exploration (in the case of greenfield projects), determining the scope of primary resource recovery, the rate of extraction, the timing and scope of enhanced recovery operations (if any), as well as the time of abandonment. There are many ways in which upstream projects can be designed or tweaked, and the tax provisions play an important part in the Investor's final choice—just as market price levels and development costs also do.

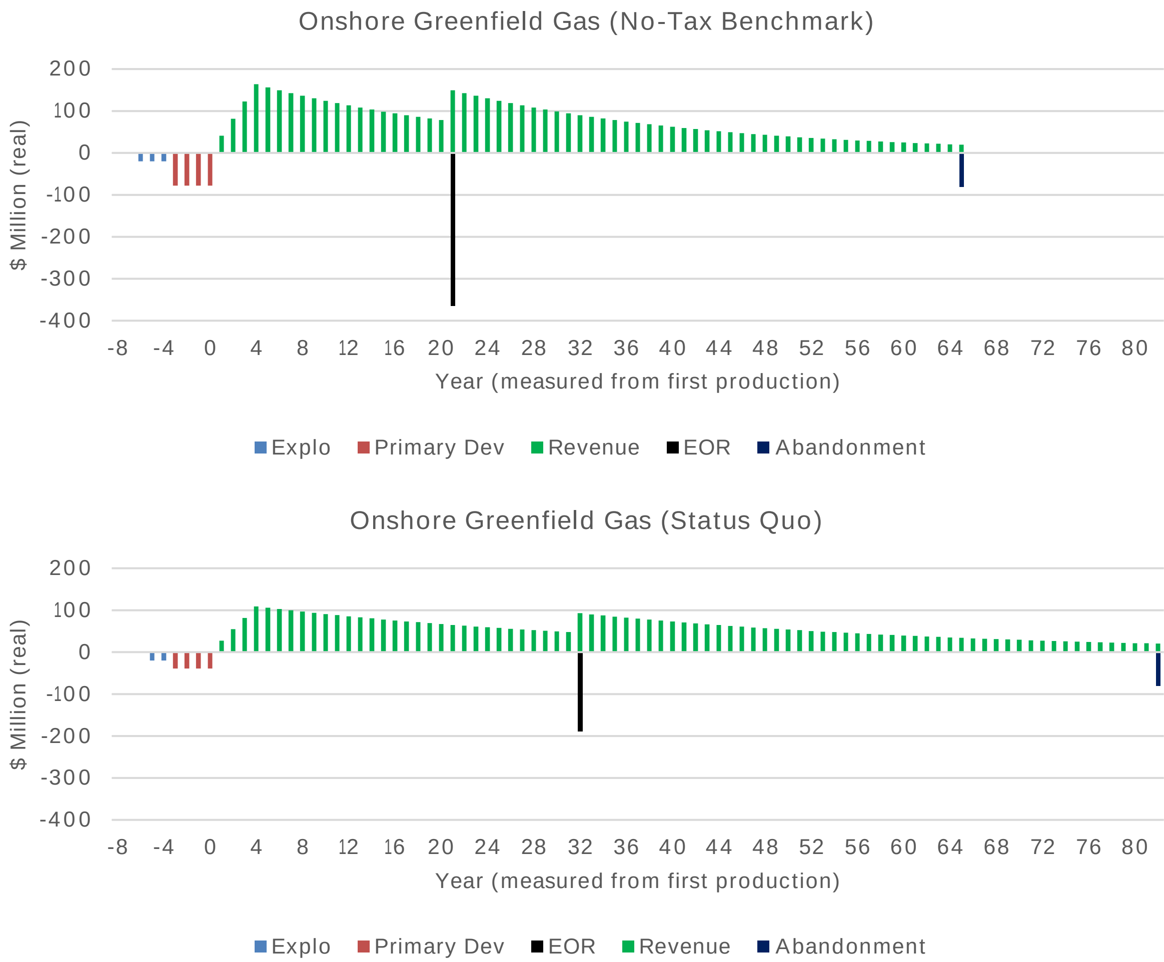
The model is structured to reveal the tendency of a given fiscal regime to influence or distort the Investor's decision relative to a No-Tax benchmark. Based on that investment decision, the model then calculates Investor profits, Government take, total resource recovery factors, etc. in the usual fashion—by projecting the distribution of resulting cash flows between the Investor and the Government according to the tax provisions in force, and discounting to account for the time value of money.

An example of the type of tax distortions that reduce investment and diminish Government revenue is illustrated in Figure 1.1 below. The upper panel shows how an Investor would structure investment in a Venezuelan onshore greenfield gas prospect in the absence of taxes. The bars represent various components of cash

[1] The model is described and fully documented in Smith (2014). Additional detail is provided in Appendix A to this report. The model was previously applied in the analysis of Latin American and Caribbean petroleum fiscal regimes conducted by Davis and Smith (2019).

flow, including exploration capex, development capex, production revenues, etc. This picture reflects the "optimal" plan of exploitation, i.e., the plan that maximizes the expected net economic value of the underground resource. The lower panel shows how the same Investor would alter planned investments and operations to mitigate the burden of taxation under Venezuela's current fiscal regime.

Figure 1.1 Example of Simulated Resource Exploitation with and Without Tax



The Investor's reaction to the tax regime results in fewer exploratory wells, less chance of a commercial discovery, smaller investment to build primary production capacity, slower extraction, delayed implementation of enhanced oil recovery, and lower overall resource recovery. In combination, these distortions reduce the potential value of the resource and shrink the tax base from which Government is able to extract revenues. Alternative fiscal regimes that create fewer distortions to the plan of exploitation would restore some of the diminished tax base and thereby potentially increase Government's profit, relative to the existing regime.

1.1 The Existing Fiscal Regime

Venezuela's existing fiscal regime is built upon the standard concession model that involves both corporate income tax payments and royalty payments, plus an investment tax credit intended to stimulate oil and gas development. In addition to a special corporate income tax rate of 50% (above the standard 34% rate applied to other industries), there are also small income-related levies to fund social, scientific, and technological initiatives within Venezuela. Finally, there is an Alternative Minimum Tax (AMT) provision that ensures total payments to Government each year amount to at least 50% of gross oil revenue. All tangible capital expenditures starting from the exploration phase, are assumed to be depreciated on a ten-year straight-line basis.

Natural gas developments are not taxed as heavily as oil developments. The royalty on gas revenues is fixed at 20%, and income is taxed at the regular corporate rate of 34%. In addition, natural gas projects are exempt from the Alternative Minimum Tax.

Under special circumstances, Venezuela levies a special Windfall Profits Tax on oil revenues. However, we have not incorporated the impact of Venezuela's existing Windfall Profits Tax because the range of market prices we consider falls mostly below the level of "exorbitant" prices that would trigger its application.

The national oil company (Petróleos de Venezuela, SA - PDVSA) is entitled to hold at least 51% of any upstream development in joint venture with the private Investor. The after-tax net value of that fractional share of the enterprise therefore redounds to Government and is in addition to the other revenue streams that constitute the measure of Government NPV that we use in this analysis. The structure and provisions of Venezuela's fiscal regime are summarized in Table 1.1.

Table 1.1 **Summary of Venezuela's Fiscal Regime**

Tax Provision	Applicable Rate
Oil Royalty	33%
Non-associated Gas Royalty	20%
Corporate Income Tax, Oil	50%
Corporate Income Tax, Gas	34%
Social & Endogenous Tax	1% of net income
Social Inv. & Anti-Drug Tax	1% of net income
Science & Tech. Tax	0.5% of gross revenue
AMT	50% of gross oil revenue
Investment Tax Credit	12% of tangible inv.
Depreciation	Ten-year straight line

1.2 The Alternative Fiscal Regimes

We consider alternative fiscal regimes that eliminate the Alternative Minimum Tax and replace the fixed royalty rate (33% for oil, 20% for gas) with a sliding scale royalty rate that increases with either (1) the project's cumulative X-Factor, or (2) the project's realized internal rate of return (IRR).[2] Performance of the alternative regimes depends on how quickly the royalty rate increases during the life of the project, and on how large are the increases. We consider three strategic alternatives in this regard:

Plan A: *Generous Approach*, in which the royalty starts at 16.67% and rises slowly to 30%. This approach is intended to remove distortions and reduce deadweight losses, and to allow the Investor to capture most of the additional profits. The NPV of Government revenues is intended to be roughly the same as in the existing (Status Quo) regime.

Plan B: *Balanced Approach*, in which the royalty again begins at 16.67% and still rises slowly, but to a higher maximum level of 50%. This approach is intended to remove distortions and reduce deadweight losses, but to share the additional profits more equally between Investor and Government.

Plan C: *Aggressive Approach*, in which the royalty begins at 16.67% but rises more rapidly to the maximum level of 50% than under Plan B. This approach is also intended to remove distortions and reduce deadweight losses, while allowing the Government to capture most of the additional profits.

The structure of the six alternative regimes defined in this manner is illustrated in Figure . For example, under Plan A, the royalty rate jumps from 16.67% to 18% once the X-Factor reaches 1.00 (or when the realized IRR reaches 10%). It jumps further to 20% once the X-Factor reaches 1.25 (or when the realized IRR reaches 14%). It jumps again to 25% once the X-Factor reaches 1.50 (or when the realized IRR reaches 18%), and finally the royalty jumps to the maximum rate of 30% when the X-Factor reaches 1.75 (or the realized IRR reaches 22%). Plans B and C can be interpreted similarly.

We also incorporate within each of the alternative fiscal regimes the existing corporate income tax rate (50% for oil and 34% for gas), depreciation schedule, and investment tax credit—all as in the Status Quo. And we incorporate the three smaller levies that were described above (Science and Technology Tax, Social & Endogenous Development Fund, and the Social Investment and Anti-Drug Tax). None of the alternative fiscal regimes incorporates the Alternative Minimum Tax or the Windfall Profits Tax.

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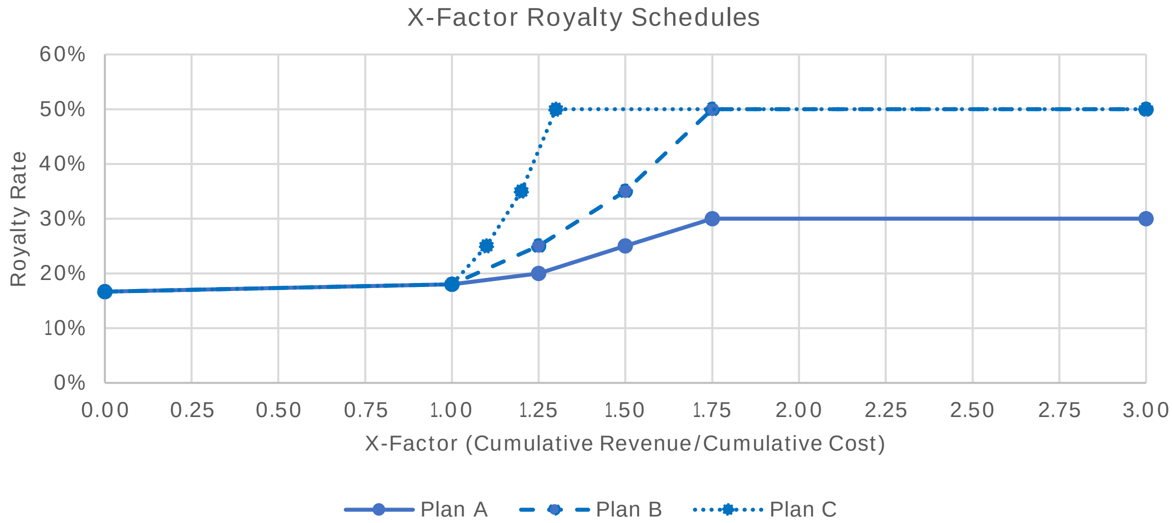
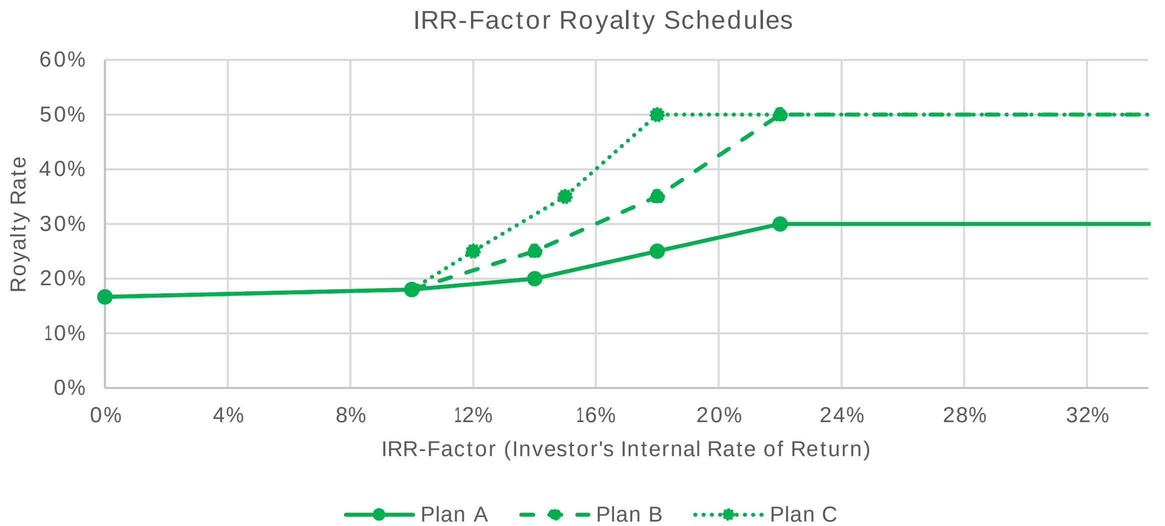
[2] The X-factor computed at any given time is simply the ratio of cumulative (undiscounted) net revenues to cumulative (undiscounted) expenditures. An X-factor of 1.0 indicates that project payback has been achieved without accounting for the time-value of money. The internal rate of return does account for the time value of money and (based on the Investor's cost of capital) determines when economic payback of the initial investment has been achieved.

Figure 1.2. Sliding-Scale Royalty Regimes





1.3 The Upstream Petroleum Projects

The performance of the current and alternative fiscal regimes is judged by simulating their impacts (physical and financial) on four illustrative upstream projects:

- Greenfield Onshore Oil Prospect (Eastern region)
- Brownfield Onshore Oil Prospect (Western region)
- Greenfield Onshore Gas Prospect (Eastern region)
- Heavy Oil Development (Orinoco)

The two greenfield prospects entail exploration risk, both in terms of chance of success and size of the discovered resource (if any). The brownfield project does not require exploration but is subject to some uncertainty regarding size of the existing resource base, and likewise for the heavy oil project. Further description of the respective projects is provided in Table 1.2.

Table 1.2 Project Parameters

	Greenfield Onshore Oil	Brownfield Onshore Oil	Greenfield Onshore Gas	Orinoco Heavy Oil
Exploration Cost (million/well)	$20	NA	$20	NA
Development Cost (thousand/boe peak production capacity)	$30	$55	$30	$61
Fixed Operating Cost/year (% of capex in place)	1%	2%	2%	2%
Variable Production Cost (/boe)	$1	$12	$2	$0.75
Enhanced Recovery Factor	1.5	1.5	2	NA
Abandonment Cost (million)	$80	$80	$80	$80
Original Resource-In-Place (million boe), Probability of Occurrence	0 (51%)	0 (0%)	0 (44%)	0 (0%)
	200 (25%)	150 (50%)	100 (28%)	10,245 (50%)
	600 (17%)	300 (35%)	250 (20%)	14,636 (35%)
	1,000 (7%)	450 (15%)	400 (8%)	15,807 (15%)
Geological Risk Factor (probability that a commercial deposit exists)	70%	100%	75%	100%
Drilling Risk Factor (probability of successful exploration well given that deposit exists)	70%	NA	75%	NA
Lead time from discovery to first production (years)	4	0	4	5
Lead time from discovery to peak production (years)	8	7	8	9
Resource Composition	88% oil	88% oil	7% oil	88% oil
	0% NGL	0% NGL	18% NGL	0% NGL
	12% gas	12% gas	75% gas	12% gas

Each project is analyzed in conjunction with the background economic assumptions shown in Table 1.3, below. As the table indicates, sensitivity analysis has been conducted with respect to oil and gas prices and with respect to capital and operating cost levels.

Table 1.3 Economic Parameters and Background Assumptions

Parameter	Range and Benchmark Value
Oil Price ($/barrel)	$45, $55, $65, $75, $85
Gas Price ($/mcf)	$2.00, $2.50, $3.00, $3.50, $4.00
Development Cost Contingency	+/- 30%
Operating Cost Contingency	+/- 30%
Discount Rate (real)	10%
Inflation Rate	2%

1.4 Method of Analysis

The performance and impact of Venezuela's existing tax regime, and each alternative regime, is inferred by simulating the Investor's investment decision, i.e., by identifying the particular exploration, development, and operating decisions that maximize the Investor's expected after-tax NPV. The impact of these investment decisions, and resulting tax distortions, is described in both physical and financial terms. Where applicable, we report on the maximum number of dry holes the Investor would be willing to drill before giving up the search for a new greenfield reservoir, the planned resource recovery factor for primary production as well as the intended extraction/decline rate, the timing and expansion of primary reserves via investments in enhanced recovery, and finally the date at which a producing field would be abandoned.

These operational decisions are translated into financial results, including the total economic profit and its distribution between Investor and Government, and the Deadweight Loss (relative to the No-Tax case) due to each tax regime. Deadweight Loss measures the foregone total profit (a shrinkage of the tax base) caused by tax-induced distortions of the optimal investment program. We report results separately based on Full-Cycle economics (which includes all expenditures during both exploration and subsequent development) and Half-Cycle economics (which includes only the cost of developing a specific field after exploration costs have been sunk).

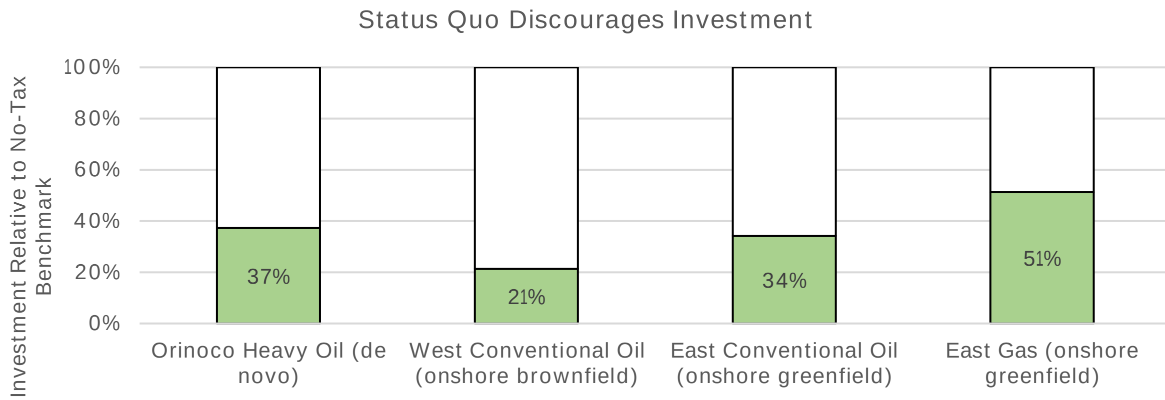
1.5 Failings of the Existing Fiscal Regime

There are many indices by which the negative impact of the existing fiscal regime can be seen. Some of these negatives impact the Government, others impact the Investor. Many of the negative impacts of the existing regime impact both parties, as discussed below.

Resource wealth can only be captured through investment, and investment is strongly discouraged under the existing fiscal regime. The intensity of investment (number of wells, production capacity, etc.) in any project is determined by an Investor who weighs the additional cost of incremental expenditure against the incremental net profits that result from that expenditure. A heavy burden of taxation that cuts the value of net profits that flow to the Investor will therefore curtail

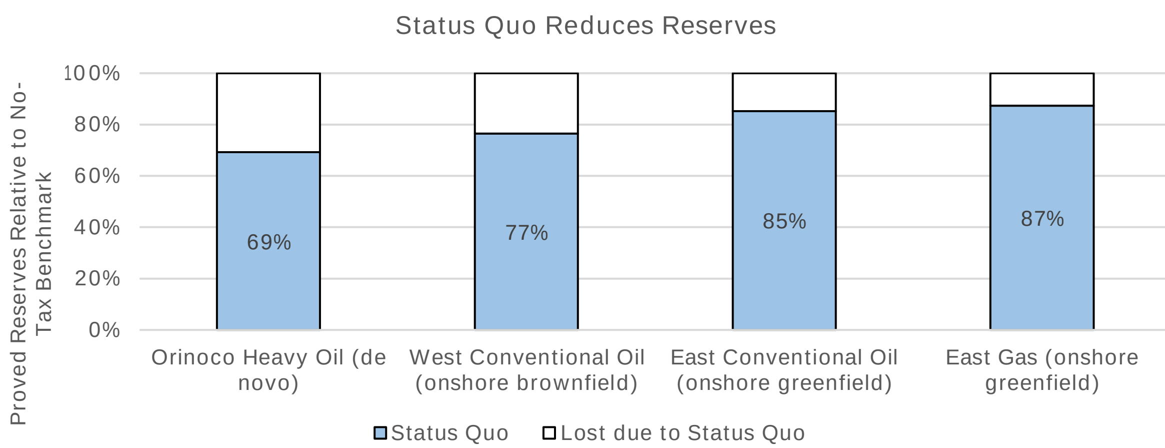
investments that should and would otherwise have been made. This problem is particularly acute under the existing Venezuelan fiscal regime, as shown in Figure 1.3. The size of investment in exploration for new fields and development of successful discoveries is cut in half (or worse) under the current regime. All the representative projects shown in the figure are adversely affected in this manner.

Figure 1.3 Impact of Status Quo on Total Investment, by Project Type



One consequence of reduced investment is a reduction in the volume of resources that will be extracted over the life of the project. Reserves in the Orinoco Heavy Oil projects would be reduced by roughly one-third relative to the No-Tax benchmark, as shown in Figure 1.4.

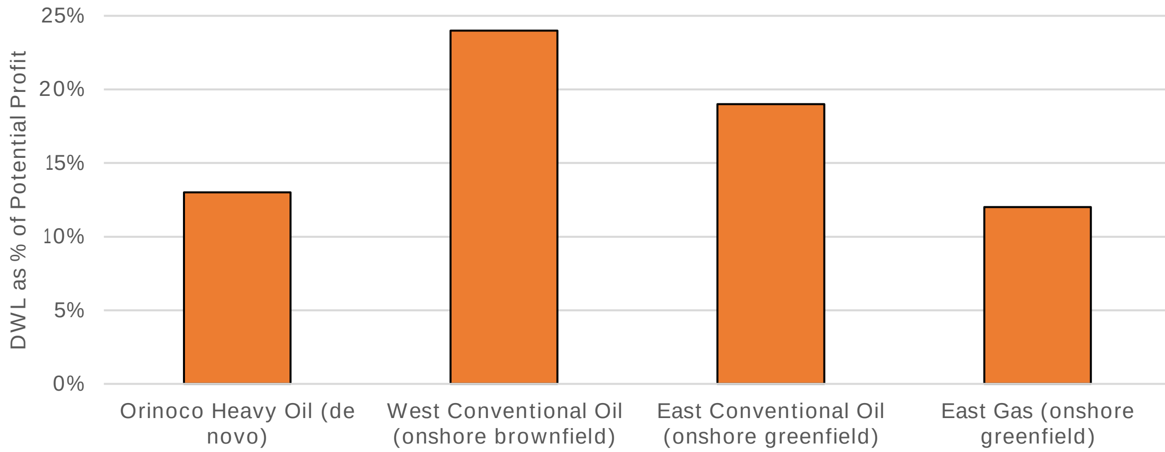
Figure 1.4 Impact of Status Quo on the Volume of Proved Reserves



The resulting loss of production (and the fact that those resources that do actually get produced are extracted too slowly) exacts a punishment in economic terms: potential profits that might be generated are sacrificed simply for lack of effort. Economists call this shortfall the "Deadweight Loss" due to taxation. It measures the shrinkage in the size of the pie (relative to the No-Tax benchmark) that is available for Government and Investor to divide. The estimated Deadweight Loss affecting each of the representative projects is shown below in Figure 1.5. One should not think that a Deadweight Loss of 13% (as in the case of the Orinoco Heavy Oil project) is

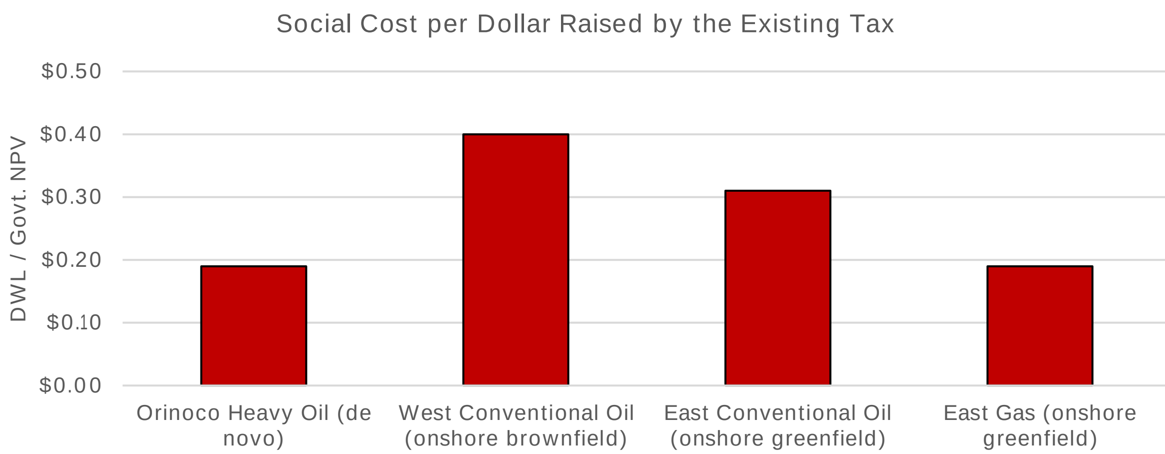
small; such a sacrifice when applied to the enormous value of the Orinoco reserves is itself enormous. Under the existing regime, this shrinkage hurts the Government as well as the Investor, as we will see in the next section of this report.

Figure 1.5 Deadweight Loss Due to the Existing Fiscal Regime



The Deadweight Loss represents a cost of imposing the tax system, whereas Government Revenue represents the benefit of imposing that system. It is reasonable to compare the magnitude of these two. The ratio (Deadweight Loss divided by Government NPV) shows how much potential profit is lost per dollar of revenue raised. In the case of the West Conventional Oil project (shown below in Figure 1.6), 40 cents of potential profit is sacrificed for every dollar of revenue raised by the tax. Throughout this report, we will use this ratio to measure the Fiscal Inefficiency of alternative tax regimes.

Figure 1.6 Fiscal Inefficiency of the Existing Fiscal Regime



2. Full-Cycle Economic Analysis of the Four Projects

Full-cycle analysis of economic performance is predicated on the Investor's intended exploratory (for greenfield prospects) and development efforts (for greenfield and brownfield projects) within the contract area. For greenfield prospects, we assume

that the first exploratory (wildcat) well may result in a discovery of varied size, or a dry hole, with volumes of original oil equivalent in place and probabilities of occurrence that reflect the perceived prospectivity of the contract area. We implement this approach by focusing on the four exploratory outcomes that were documented in Table 1.2: dry hole, small field, medium field, or large field, each reported with the respective probability of occurrence.

If the initial exploration well is a dry-hole or otherwise unsuccessful, the Investor is assumed to update (reduce) the probability of success and drill a second well if the expected after-tax NPV of that incremental investment is positive. This process is assumed to continue until an oil field is discovered or the expected value of an additional exploratory well becomes negative. Each dry hole causes the Investor to further reduce the probability of success according to the Bayesian model described in Smith (2005).[3]

Depending on the cost of exploration, chance of success, tax provisions, etc., the exploration sequence may extend to more than one well. Therefore, one important metric of full-cycle performance under each fiscal regime is the maximum number of dry holes that would be drilled before abandoning the search. By this measure, our analysis will reveal, among other things, how a given fiscal regime impacts the intensity of exploration.

For each possible exploratory outcome, we calculate the NPV of resulting cash flows to the Investor and the Government, as determined by our optimization model and contingent on the selected tax regime and resource scenario, through the development phase and up to the point of abandonment of any field that is discovered. All possible exploratory outcomes are then weighted by the probabilities of occurrence to calculate the expected NPV of each party, the expected volume of production, expected Government revenues, and the expected Deadweight Loss associated with the respective fiscal regimes.

For the brownfield projects (Onshore Oil and Heavy Oil Development), no sequence of exploration wells or exploration expense is required. However, the size of the underlying resource base is assumed to be resolved only after initial development investments have been undertaken. Therefore, the full-cycle analysis of brownfield projects reported here reflects the probability-weighted average of values based on the range of potential resource volumes that are listed in Table 1.2.

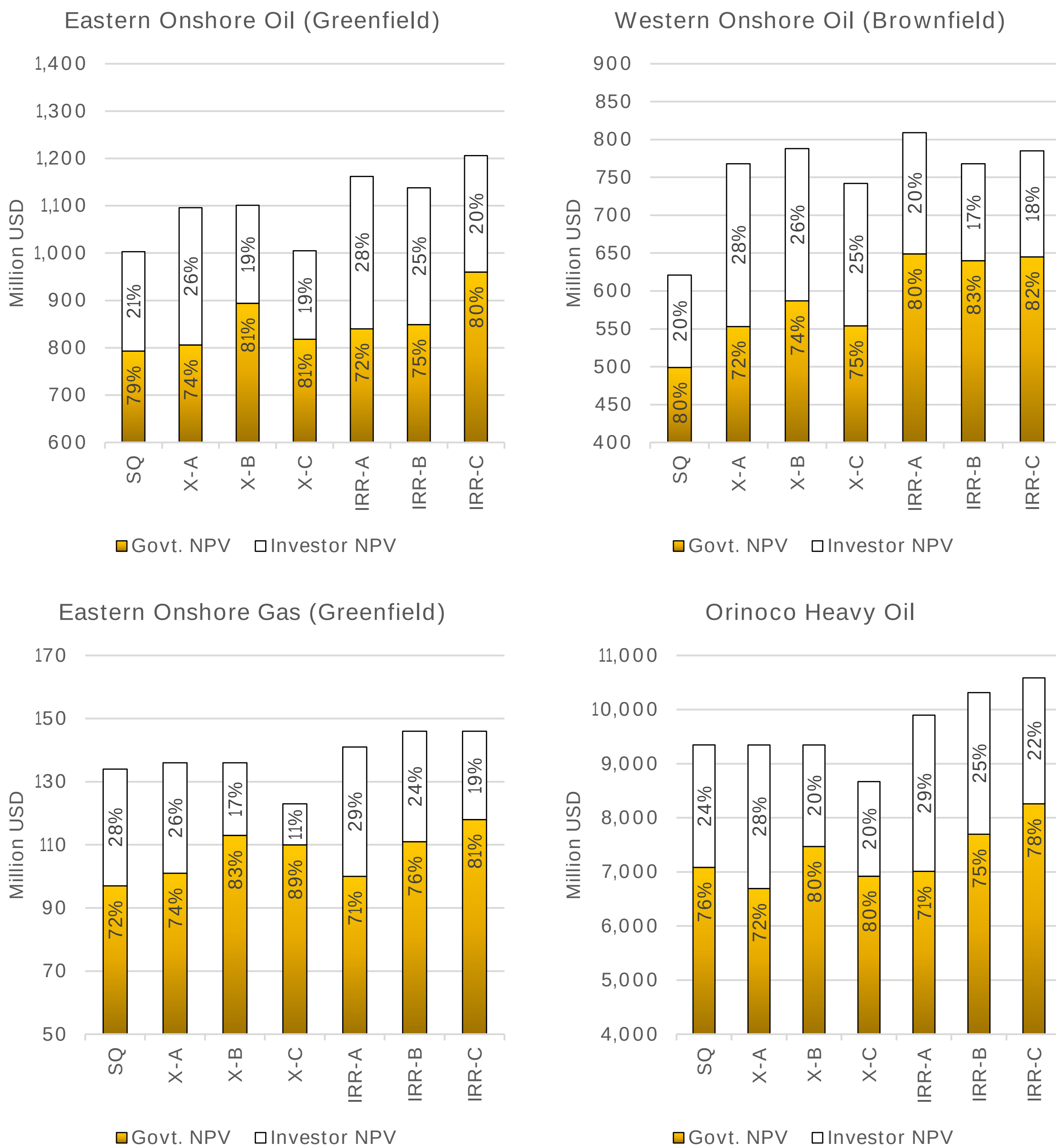
2.1. Fiscal Impact on Division of Profit Between Investor and Government

Venezuela's existing fiscal regime enables the Government to capture the majority of actual profits, between 70% and 80% depending on the field type, as shown in Figure 2.1. The relatively light taxation of gas projects accounts for the low end of this range

[3] The Bayesian model incorporates two sources of uncertainty: the probability that an oil field is actually contained within the contract area (referred to as geological probability), and the probability that a given well will discover the field given that one exists (referred to as technological probability). The probability of a dry hole on the first attempt is therefore given by 100% minus the product of geological and technological probabilities.

(72%). The fraction of total profit captured by Government is called “Government Take,” but of more importance is the absolute magnitude of Government revenues, as shown by the height of the solid bars in Figure 2.1

Figure 2.1 Distribution of Full-Cycle Profits



It is evident, for example, that regarding the Eastern Onshore Oil Field, the IRR-A regime permits the Government to capture *more* revenue than the Status Quo ($840 million versus $793 million) even though it generates a *lower* Government Take (72% versus 79%). Further, the IRR-C regime enables the Government to capture much more revenue than the Status Quo ($979 million versus $793 million) even though the reported Government Take is about the same (80% versus 79%).

This seeming paradox is fundamental to understanding (and curing) the problems with the existing fiscal regime. Because that regime creates many investment distortions that reduce the size of the tax base, Government does not fare so well even while taking a large share of the smaller pie. For most of the projects shown in Figure 2.1, the alternative fiscal regimes allow the Government to capture significantly more revenue regardless of the computed value of Government Take. A large share of a small pie is still small. Better to grow the size of the pie by removing the distortions that have caused it to shrink.

The strategic distinctions between Plans A, B, and C are also illustrated in Figure 2.1 Plan A is designed to award most of the additional profits to the Investor, and by comparing the heights of the white bars in the figure, this is mostly borne out.

Although Plan A ("Generous") regimes do not tend to increase Government NPV much for the individual projects, it may still make each project more beneficial to investors and attract more capital to the sector, and thereby increase the size of the tax base in ways that are not captured in our analysis.

Plan B ("Balanced") regimes tend to provide more of a win-win outcome, where Government and Investor are both rewarded directly with higher profits than under the Status Quo.

Plan C ("Aggressive") regimes involve even higher royalties that are intended to favor the Government, and the IRR-based versions of Plan C mostly achieve that goal (compare the successive heights of the last three solid bars within each chart). However, the X-Factor based versions of Plan C fail to achieve this objective.

For each of the four projects, Plan B raises more revenue for the Government than Plan C if implemented using the X-Factor rather than the IRR. This problem stems from the fact that the X-Factor is a quite imperfect measure of the Investor's profitability (failing to account for the time value of money), so linking higher royalty rates to the X-Factor may impose undue tax burdens and discourage investment, in a manner similar to the existing regime.

This is especially true under the aggressive version of the X-Factor regime, which inflates the bad consequences of this problem and creates a "Laffer Curve" effect: Higher tax and/or royalty rates may, up to a point, allow Government to capture more revenue, but after that point is reached, higher rates will reduce investment, shrink the tax base, and decrease Government revenue. Moreover, this represents a lose-lose situation in which the Investor's profit also shrinks.

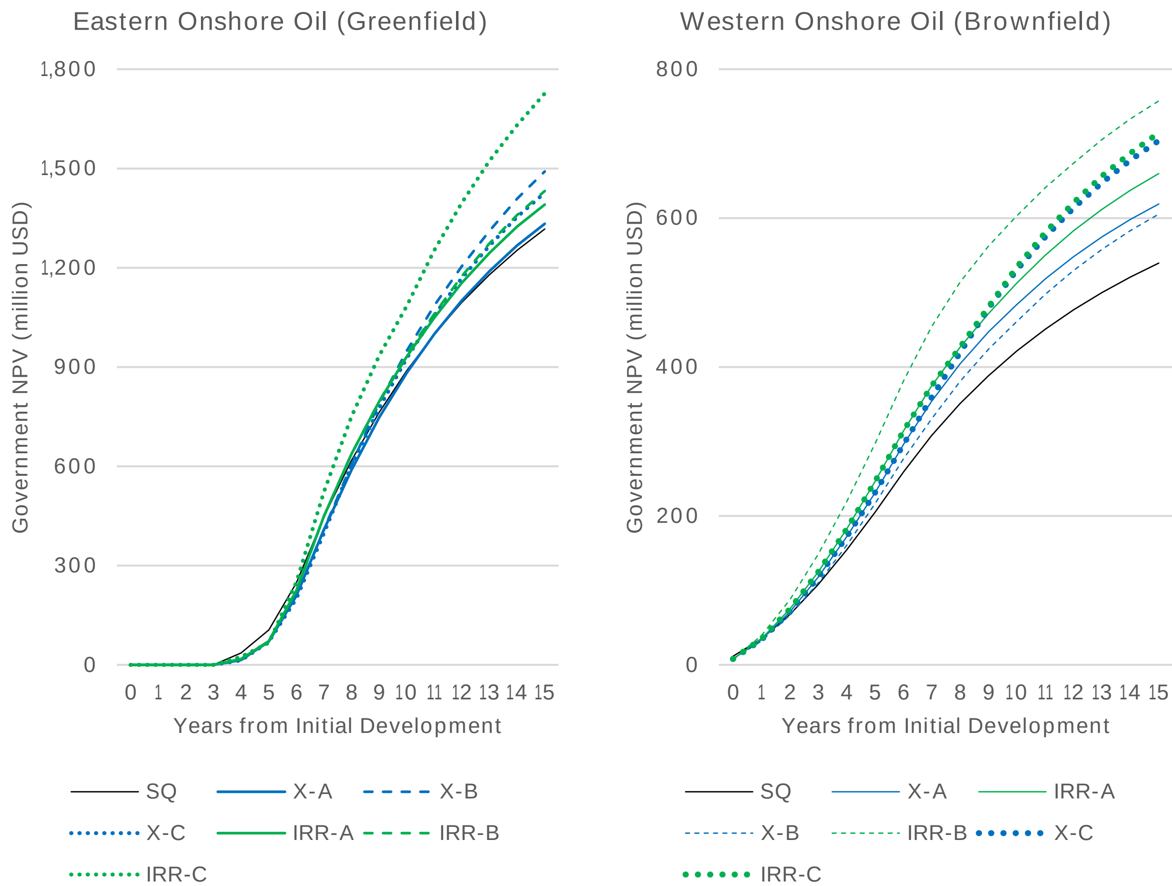
2.2. Impact on the Timing of Government Receipts

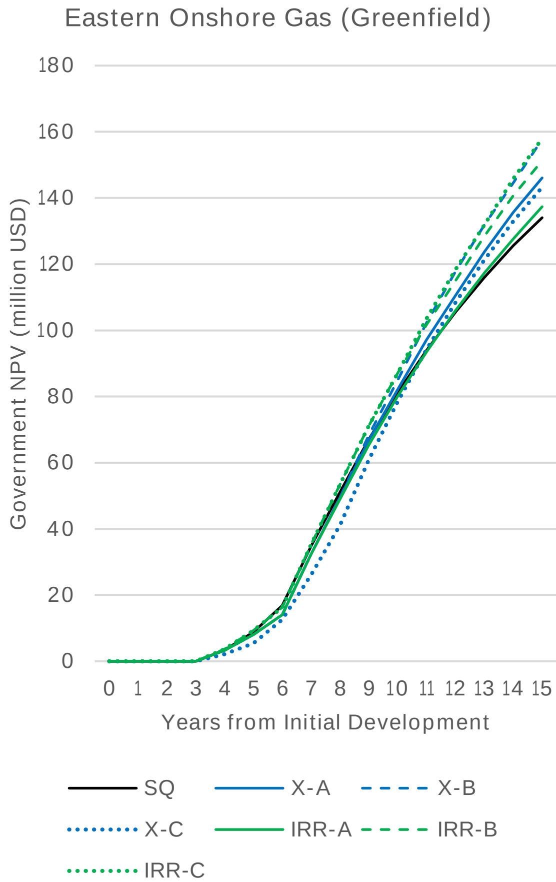
Given current financial exigencies, the timing of Government revenues must also be considered. Replacing the Status Quo with alternative regimes that might cause delays in the flow of Government receipts could raise further financial difficulties, even if those regimes are expected to eventually generate higher overall profits for

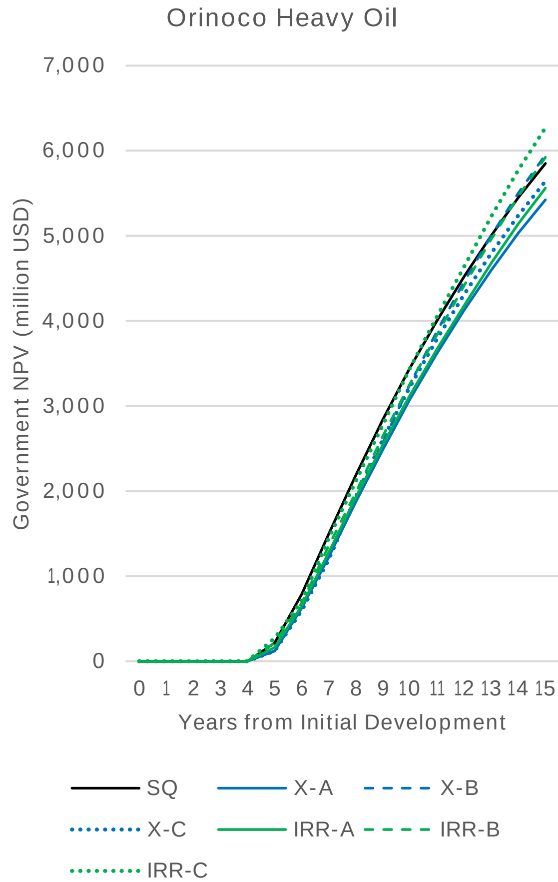
the Government. However, this does not appear to be a concern regarding the alternative regimes examined here.

This is illustrated in Figure 2.2, where the black line represents the rate at which Government NPV accumulates under the existing fiscal regime over the early years of each project, assuming development of the medium field size (see Table 1.2). There is some, but very little difference between the Status Quo and the alternative regimes in this regard. The main difference arises in the redevelopment of Western oil fields, where the alternative regimes tend to generate Government receipts at a faster pace than the Status Quo.

Figure 2.2 Fiscal Impact on the Timing of Government Receipts





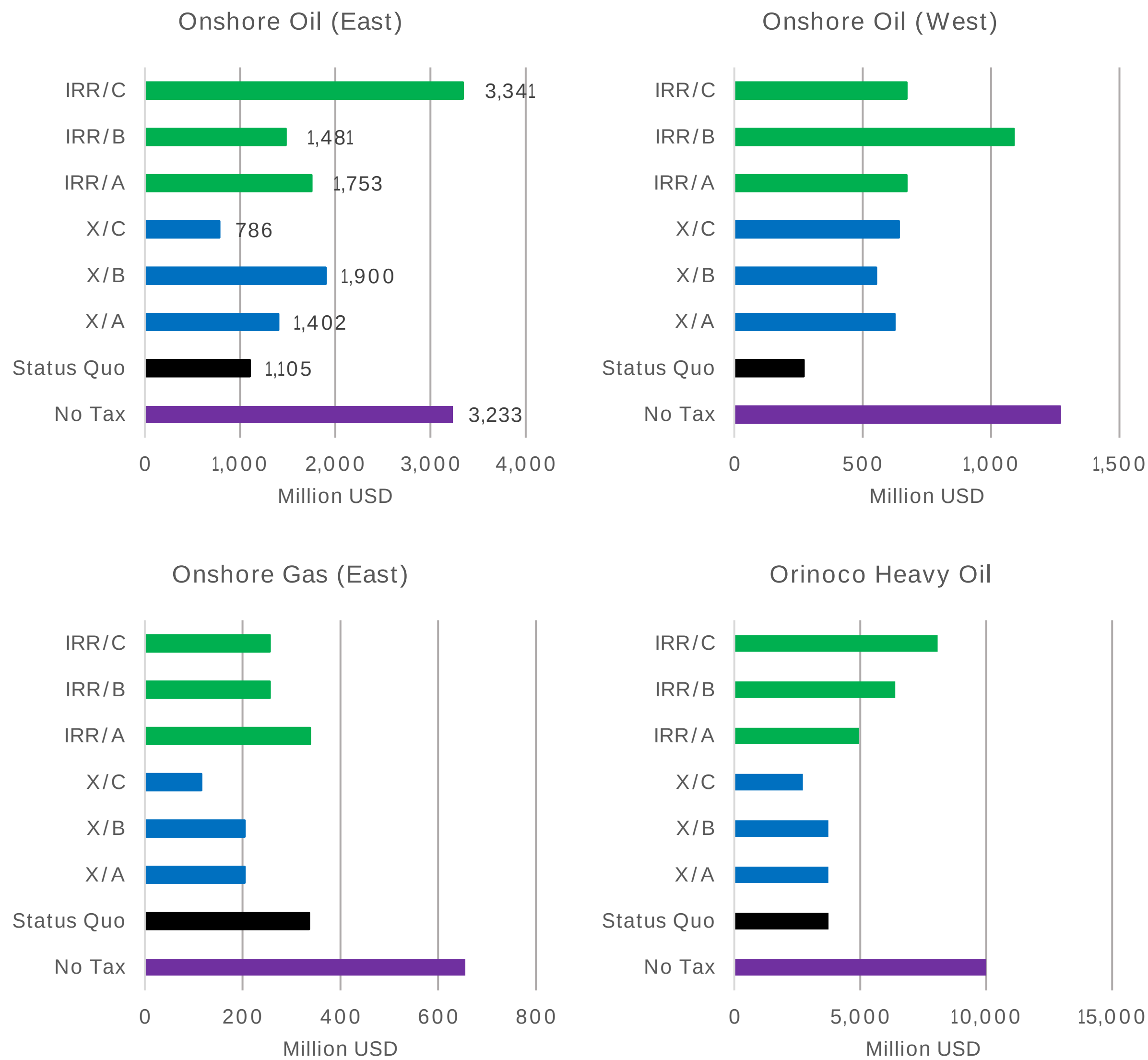


2.3. Impact on Total Investment and Operations

The distortions induced by heavy taxation potentially affect the intensity of exploration and development activities chosen by the Investor. The total capital expended during the course of developing a successful discovery under the alternative fiscal regimes is shown in Figure 2.3. The No-Tax benchmark is provided (purple line) to indicate the extent to which taxes discourage potential investment. In every case, the Status Quo regime reduces potential investment by more than 50%. In almost every case, the alternative regimes encourage greater investment, which leads to more reserves, faster production, and greater Government NPV.

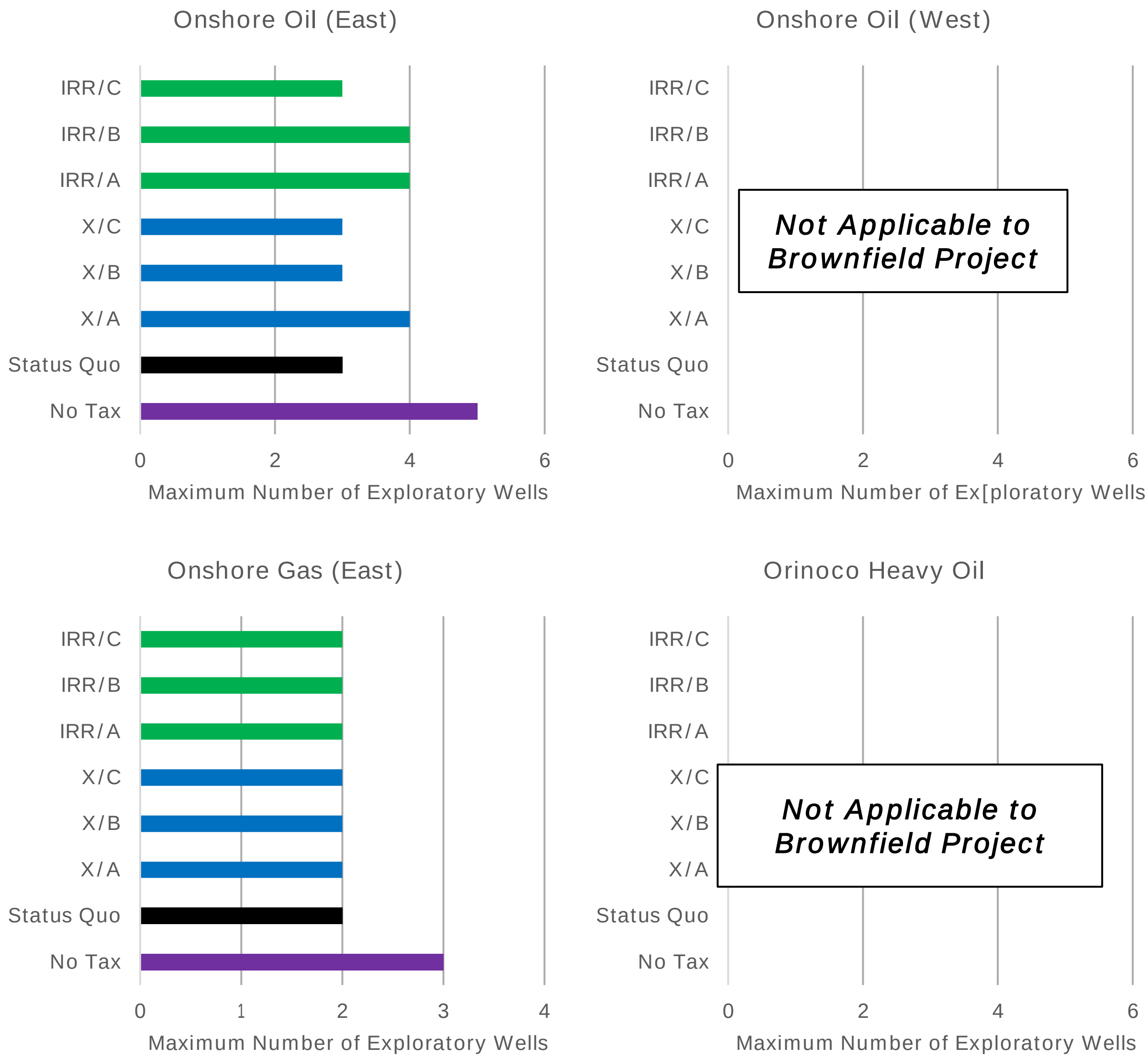
The notable exception is, again, the X-Factor Plan C. In three of the four projects, this approach generates even less investment than the Status Quo. This is the price paid for being overly aggressive with an instrument that is not closely related to the Investor's profitability. But even with the less aggressive "Generous" and "Balanced" fiscal strategies, the X-Factor implementation stimulates less investment than the IRR implementation.

Figure 2.3 Fiscal Impact on Total Investment



The impact of these regimes specifically on the exploration phase of exploitation is shown in Figure 2.4. Here we chart the maximum number of dry holes the Investor would tolerate before abandoning the prospect. Of course, this measure is only relevant to the greenfield projects, which is why two of the four panels are blank. Absent taxes, the Investor would be willing to drill one or two more exploratory wells than under the Status Quo regime. This is because, although the cost of each exploratory well remains the same, the net value of a potential discovery to the Investor is reduced in proportion to the taxes levied on a successful discovery. Only to a limited extent do the alternative regimes create incentives that would increase the intensity of exploration. The generous regimes provide the greatest exploration incentives because they are designed to increase the Investor's NPV in the event of a discovery.

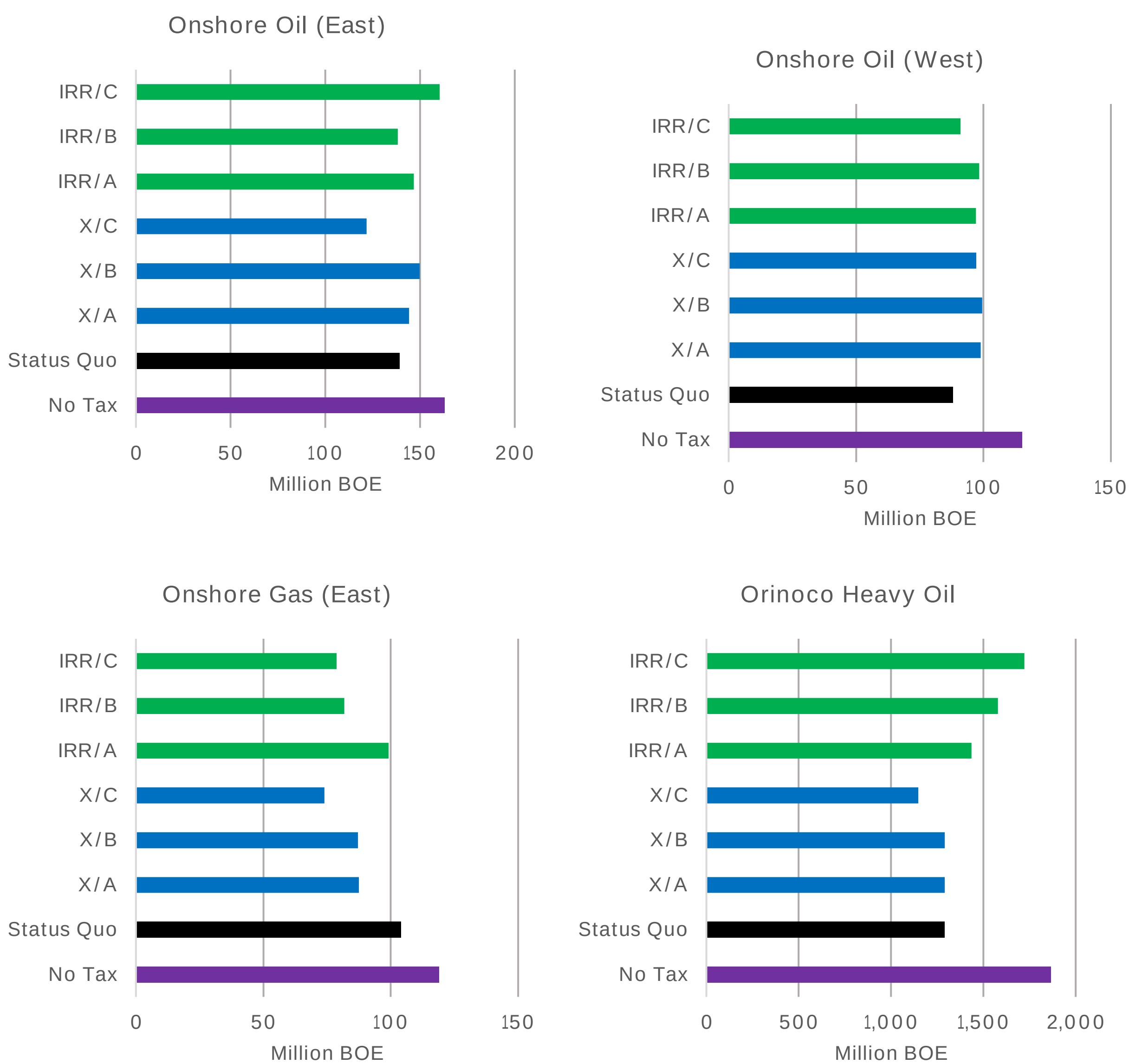
Figure 2.4: Fiscal Impact on Exploration Intensity



Reduced investment in exploration and development leads to a decrease in the expected volume of reserves obtained from each prospect. We show in Figure 2.5 the volume of Risked Reserves. This measure incorporates dry hole risk specific to each project in question, as well as the resource recovery factor from successful development of the potential deposit. It provides, from the full-cycle perspective, the expected volume of production to be derived from the prospect—including the possibility of no production. All regimes reduce the volume of Risked Reserves relative to the No-Tax benchmark. Regarding the Status Quo regime, this reduction is most pronounced for the Orinoco Heavy Oil project, where risked reserves decrease by almost one-third. Relative to the Status Quo, the alternative regimes often increase, but sometimes decrease, the volume of Risked Reserves. However, the financial impact of these differences is ambiguous, as we shall see, due to accompanying differences in the rate of extraction of the reserves over the life of the

field. Faster extraction of a smaller reserve can be more profitable (for Investor as well as Government) than slower extraction of a greater reserve.

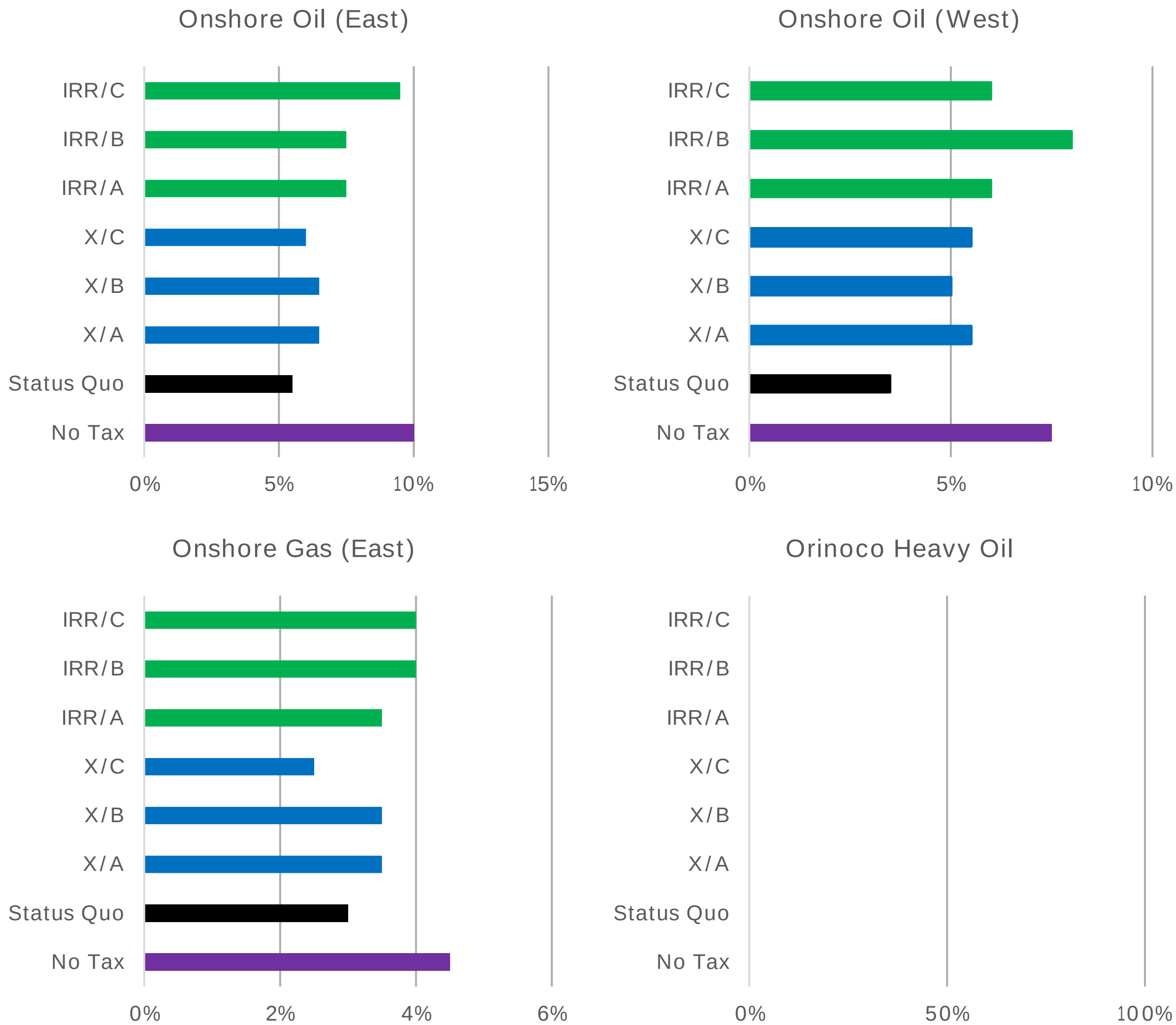
Figure 2.5: Fiscal Impact on Risked Reserves



The actual Extraction Rates are shown in Figure 2.6. As we use the term, the Extraction Rate measures the percentage of remaining reserves in the deposit that are produced each year. The extraction rates shown for each project reflect development of the medium-size field (see Table 2.1). Our simulation model incorporates an exponential decline curve for which the rate of extraction is constant each year. The exception is the Orinoco Heavy Oil project, where development drilling is scheduled throughout the life of the contract to maintain roughly constant production levels (to fill the pipeline and fully utilize the heavy crude converter facility) even as the remaining reserve is depleted. In that case the observed rate of

extraction is not constant, but actually increases each year. For that reason, we are not able to show a single extraction rate as in the other three cases.

Figure 2.6: Fiscal Impact on Rate of Extraction



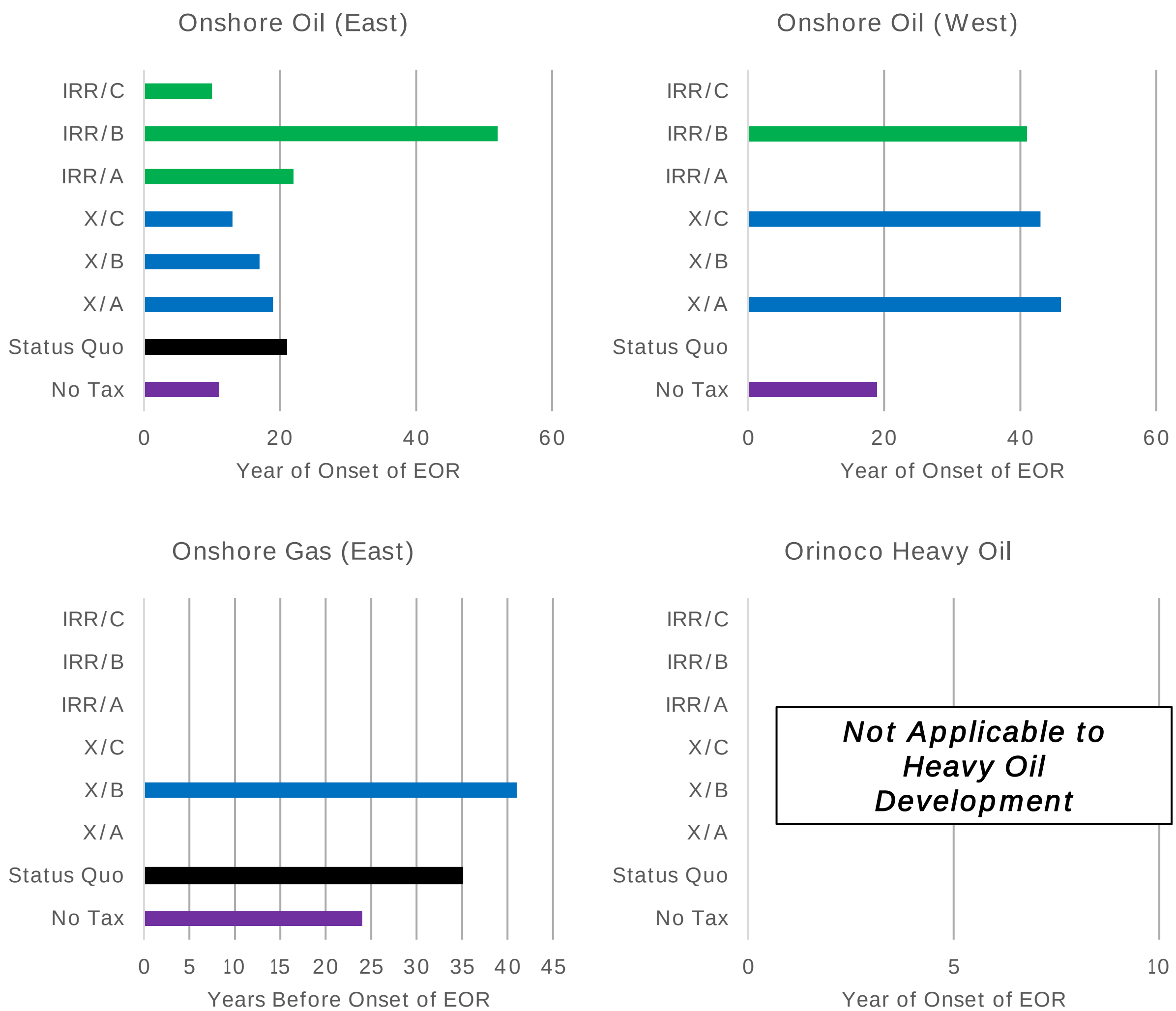
It is apparent from Figure 2.6 that the Status Quo substantially slows the extraction of reserves relative to the No-Tax benchmark. Production rates are reduced by one-third to one-half. This delay in monetizing the resource greatly reduces the present value of the revenue stream for Investor and Government alike—even if an equal volume of resource is ultimately produced over a longer time span. The alternative regimes almost invariably increase rates of extraction relative to the Status Quo, and thereby speed up revenues. The only exception is the X-Factor Plan C regime (when applied to natural gas), which as we have seen discourages investment that would be required to install increased production capacity.

Interventions to enhance recovery of petroleum (EOR) from aging fields represents another phase of investment that is impacted by the fiscal regime. Figure 2.7 shows the optimal time for initiating EOR in each project, as simulated by our model, based

on the medium field size. By optimal, we mean the time that maximizes the after-tax NPV for the Investor. Depending on the tax treatment of EOR investments and resulting revenues, it may even be optimal not to initiate EOR at all.

The alternative fiscal regimes give mixed results in this regard. For the greenfield oil field, the X-Factor regimes appear to accelerate the introduction of EOR, whereas the IRR regimes have less predictable outcomes. For the greenfield gas field, none of the alternative regimes promotes investments in EOR. But, even under the No-Tax benchmark, EOR on this gas field is postponed so long it has very little impact on the volume of remaining reserves.

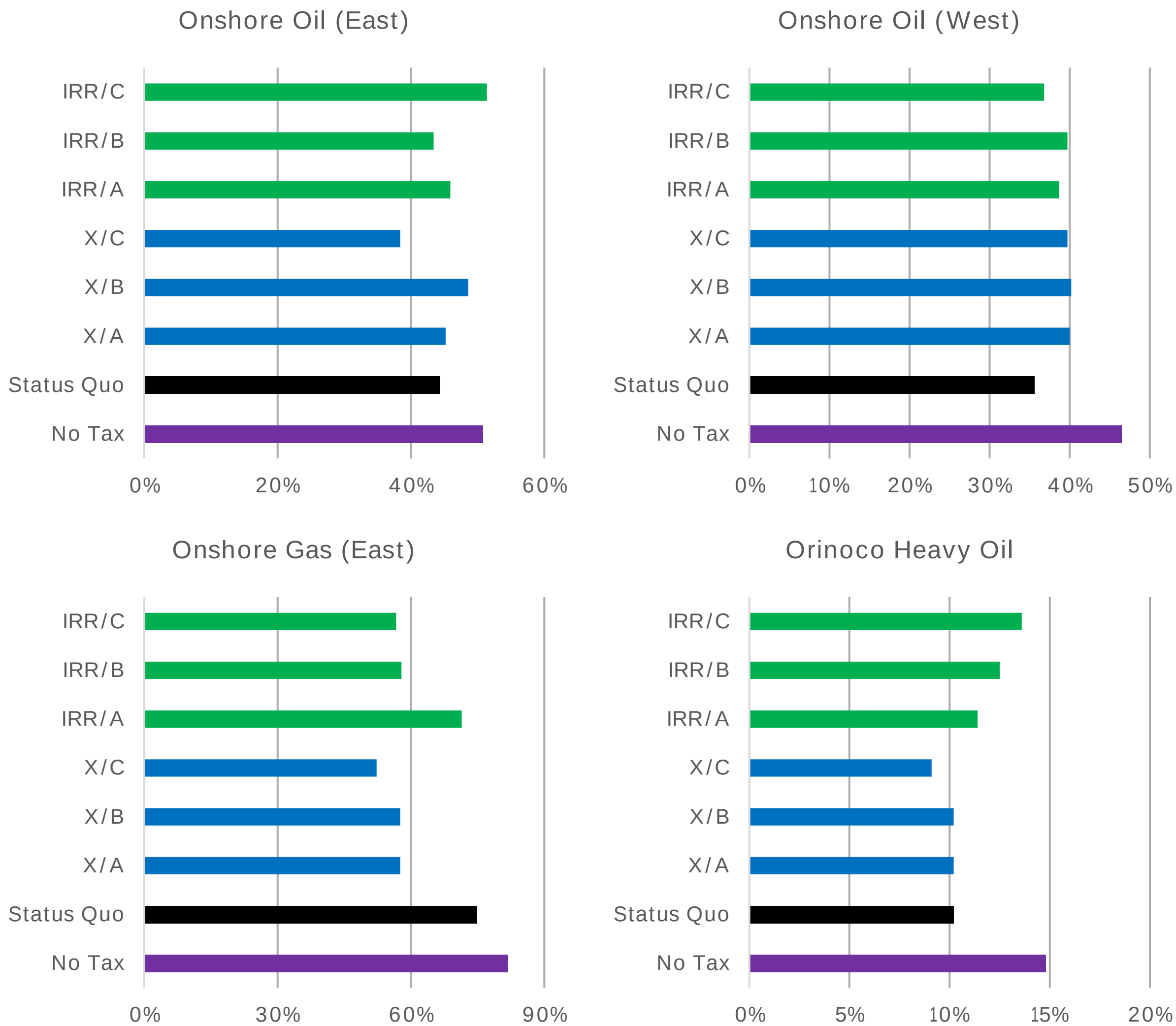
Figure 2.7: Fiscal Impact on Implementation of Enhanced Oil Recovery



The brownfield oil project represents a case where the Investor's initial investments are in fact already for the purpose of enhancing production from an aging oil field. Although our model envisions the possibility of yet another opportunity to exploit EOR even later in the life of that field, this may not be realistic, so we tend to discount those results. EOR is not envisioned as being part of the relevant

development concept for heavy oil—at least not during the initial term of contract—and has been suppressed from the modeling of that project.

Figure 2.8: Fiscal Impact on Resource Recovery Factor



We also note that although the timing of EOR may have significant impacts on the physical volume of reserves, its implementation has very little financial impact on these projects. Neither Investor nor Government NPV would change much if EOR were entirely suppressed. This is simply because EOR represents a low-margin investment that is made far in the future. Although the investment may be quite consequential at the time it is made, the net present value of the net cash flow it generates will be negligible when reckoned from the present time.

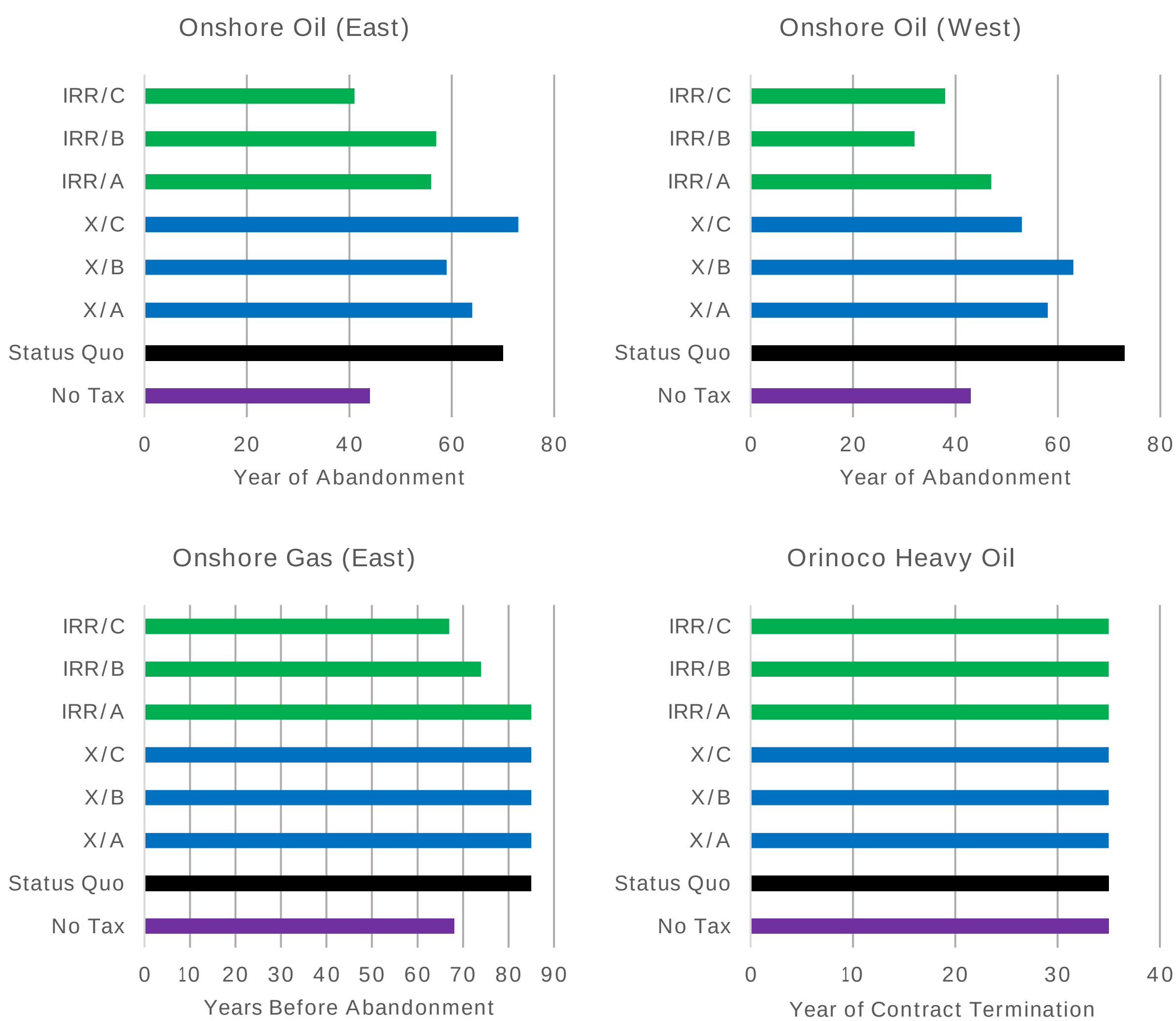
The Resource Recovery Factor measures the fraction of original oil or gas in place that is actually produced before the field is abandoned. It is jointly determined by the levels of investment to develop primary production capacity and subsequent enhanced oil recovery operations. For this reason, the investment disincentives inherent in the Status Quo also decrease the Resource Recovery Factors, relative to

the No-Tax benchmark, as shown in Figure 2.8 which depicts production from the medium size field.

The effect is quite substantial in the Brownfield Onshore Oil project and the Orinoco Heavy Oil project, where 23% and 31% of potential reserves are lost, respectively, relative to the No-Tax benchmark. The IRR-based regimes tend to restore a significant portion of these lost reserves. So, too, do the X-Factor -based regimes in the case of the Brownfield Oil project, but the aggressive X-Factor Plan C regime again has the potential to backfire due to excessive taxation, as in the Greenfield Oil project shown below, where the result is an even lower volume of reserves than produced by the Status Quo.

The Onshore Gas project is also an exception to the general rule. That is because the level of taxation under the Status Quo regime as applied to gas is already light (fixed royalty of 20%). The alternative regimes take the royalty much higher than 20%, which leads to lower investment and smaller reserves than under the Status Quo.

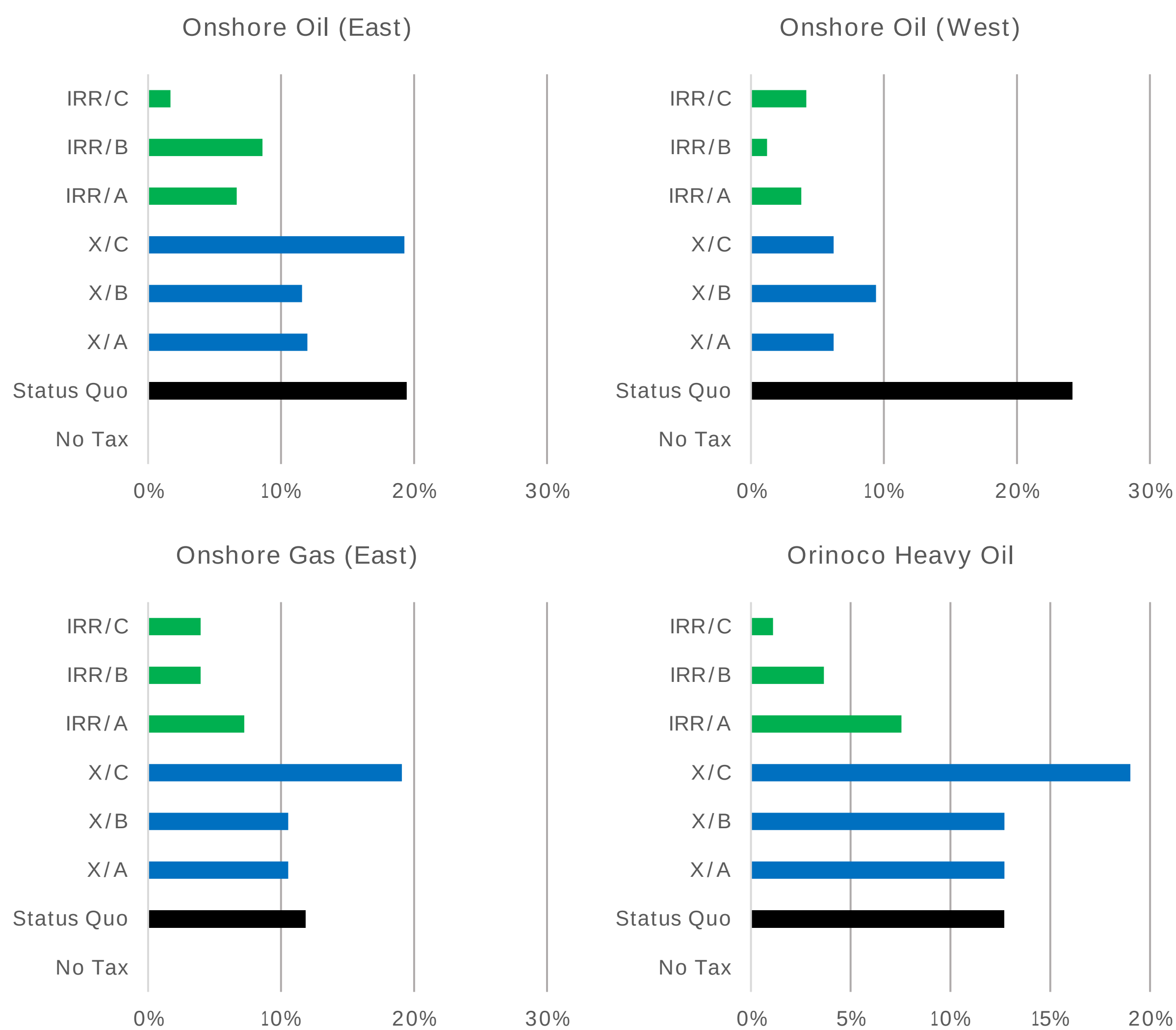
Figure 2.9: Fiscal Impact on Years to Abandonment



Next, we consider the impact of the fiscal regimes on the abandonment decision. The lifetime of a field depends mostly on the rate of extraction. Once production falls to a level where revenue fails to cover variable cost, the field will be shut down and decommissioned. Higher extraction rates deplete the reserves more quickly and bring the field to the economic limit sooner, which shortens its life. This effect is illustrated in Figure 2.9 for the medium size field. Because the Status Quo regime tends to discourage investment, it results in slower extraction and thus longer field life relative to the No-Tax benchmark.

The alternative regimes also discourage investment relative to the No-Tax benchmark, but to a lesser degree. This generally results in more rapid extraction and shorter field life relative to the Status Quo. The X-Factor Plan C regime is again an exception to the rule. We saw earlier that this aggressive implementation imposed a too heavy tax burden that reduced investment even below the Status Quo (see Onshore Oil East in Figure 2.3).

Figure 2.10: Fiscal Impact on Deadweight Loss



The magnitude of distortions induced by any particular fiscal regime is indicated by the total Deadweight Loss it creates. Deadweight Loss is simply the amount by which the tax base shrinks relative to the No-Tax benchmark. It represents the amount of total profit that never gets generated and is simply foregone due to the tax-induced reductions in investment, production, and revenues. These lost profits constitute a reduction in wealth that neither the Investor nor Government will be able to capture.

Under the Status Quo regime, Deadweight Losses amount to roughly 20% of the potential value of conventional oil resources, and 13% of the value of heavy oil resources, as shown in Figure 2.10. The corresponding Deadweight Loss attending gas development is somewhat smaller (12%) mainly due to the lighter taxation of gas under the Status Quo.

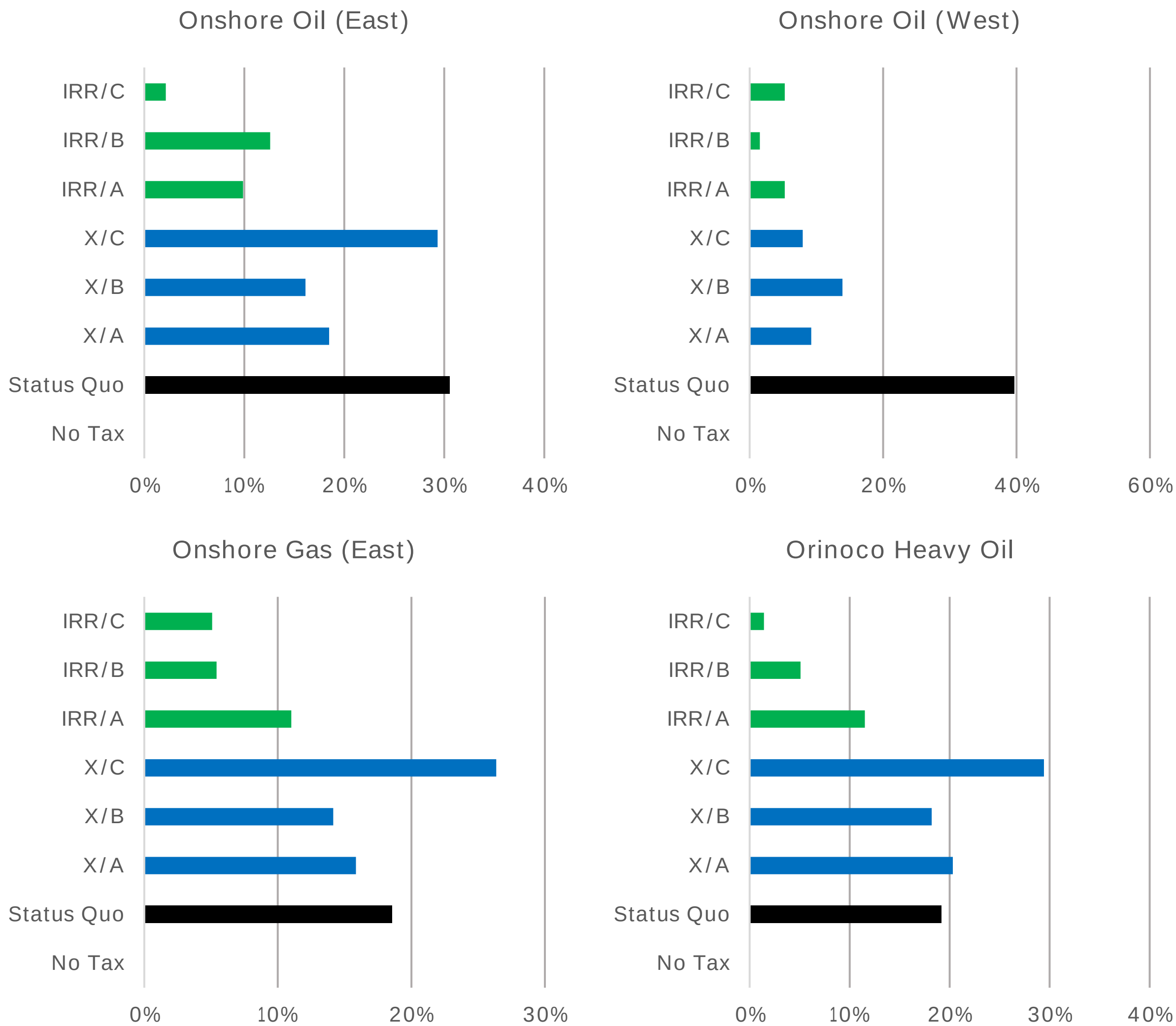
The IRR-based regimes tend to cut these losses by half or more, and this represents a significant increase in the value of the resources—an increase in the size of the pie that allows the Government to capture more revenues relative to the Status Quo.

The X-Factor regimes, except for the aggressive version, also significantly reduce the Deadweight Losses attending conventional oil and gas development, but to a lesser degree than the IRR regimes. The X-Factor regimes do not reduce the size of the Deadweight Losses attending heavy oil development.

We have noted that Deadweight Losses represent the social cost of taxation. They are rents that theoretically could be captured by Government under a less distortionary tax regime. The estimated size of those losses relative to the NPV of Government revenues produced by a given regime provides a simple measure by which the performance of different regimes may be compared. This ratio, called Fiscal Inefficiency, is an important index of fiscal performance and is defined as the size of DWLs divided by the NPV of Government net cash flows. A ratio of 25%, for example, indicates that for every dollar captured by the Government, the size of the pie (total project NPV) shrinks by 25 cents due to tax-induced distortions. Thus, the cost of raising money is 25% of the amount raised.

The Fiscal Inefficiency of the existing Venezuelan tax regime and the alternatives are shown in Figure 2.11. The Fiscal Inefficiency of the Status Quo regime is quite high, ranging between 19% and 40% across the four projects. This means that one-fifth to two-fifths of the taxes collected by Government are offset by losses imposed on the rest of society. The IRR regimes cut these losses by half, or more. The X-Factor regimes (except for the aggressive form) also reduce these losses by a significant amount, but to a lesser degree than the IRR regimes.

Figure 2.11: Fiscal Inefficiency of Alternative Regimes

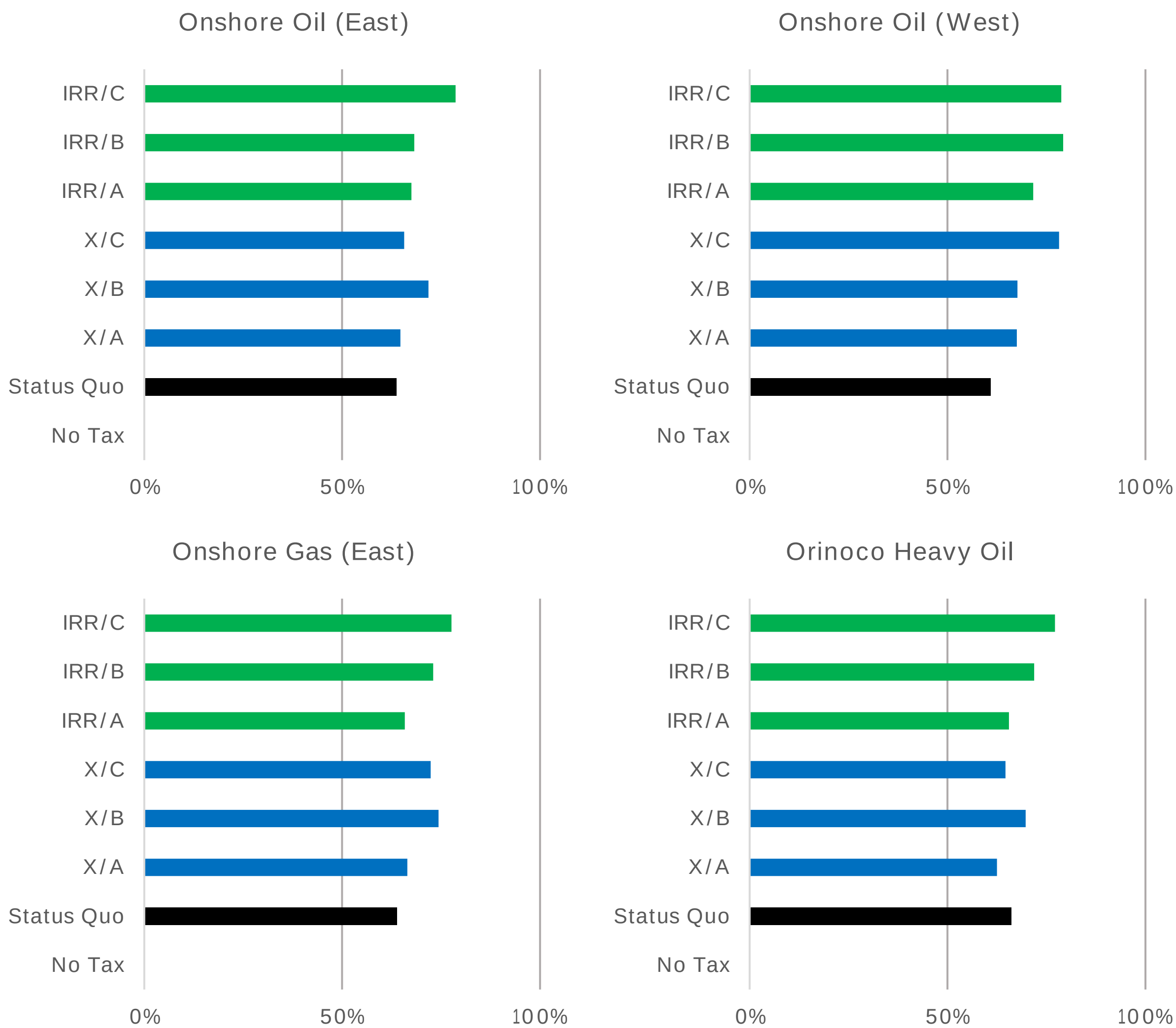


The performance of a given fiscal regime can also be assessed by calculating the fraction of total potential resource value actually captured by the Government. This measure, called True Fiscal Yield, differs from the conventional measure of Government Take, which reflects the portion of actual profits (not potential profits) generated under the tax regime that are captured by Government. Government Take fails to account for the impact of Deadweight Losses on total Government NPV and fails to warn if the fiscal regime is capturing a large share of a small pie. True Fiscal Yield fills this information gap. A fiscal regime ranked higher in terms of True Fiscal Yield will necessarily return a higher absolute profit to the Government. A fiscal regime ranked higher in terms of Government Take may not return a higher absolute profit to the Government if it creates large Deadweight Losses.

As shown in Figure 2.12, Venezuela's existing fiscal regime generally delivers a lower True Fiscal Yield than any of the alternative regimes. The X-Factor regimes applied to the heavy oil project, which sometimes exhibit slightly lower True Fiscal Yield than

the Status Quo, are the only exception. The IRR regimes consistently produce significantly higher True Fiscal Yields than the Status Quo.

Figure 2.12: True Fiscal Yield of Alternative Regimes
(portion of potential mineral rent actually captured by each regime)

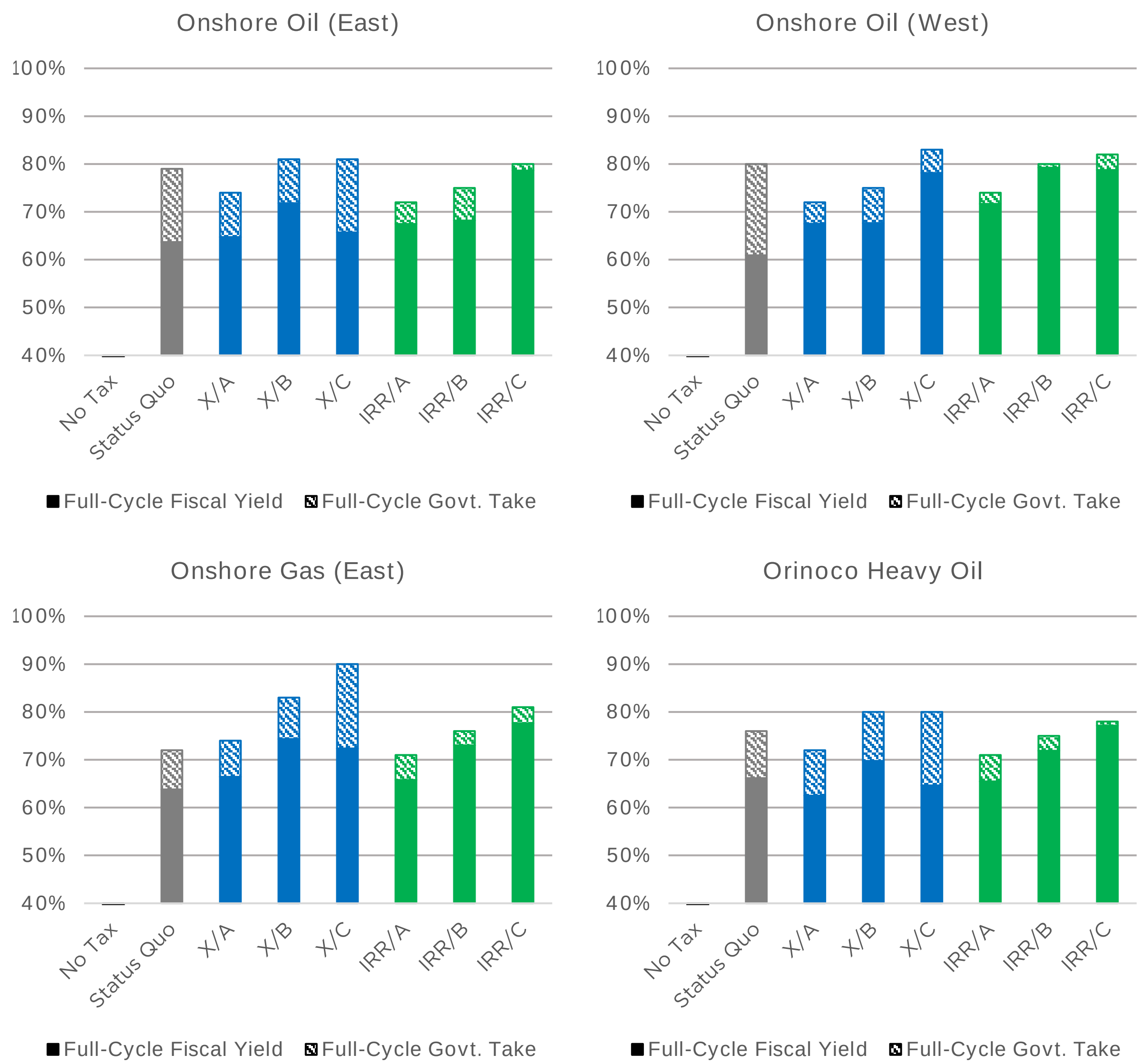


For each regime, the difference between True Fiscal Yield and Government Take is shown in Figure 2.13. The height of the solid bar represents True Fiscal Yield, whereas the extended cross-hatching represents Government Take. (Government Take always exceeds True Fiscal Yield if there are Deadweight Losses—its numerator is identical, but its denominator is smaller)[4]. Considering the brownfield oil prospect, for example, the Status Quo has a higher Government Take than the IRR-A regime (80% versus 74%), but a lower True Fiscal Yield (61% versus 72%). It is apparent that although the Status Quo in many cases seems to dominate the alternative regimes based on Government Take, this is a misleading indicator of fiscal performance. In

[4] For Government Take, denominator is the actual level of project NPV. For True Fiscal Yield, denominator is the potential level of Project NPV if there were no tax-induced distortions.

almost all of the cases, the Status Quo is actually dominated by all of the alternatives when we consider True Fiscal Yield.

Figure 2.13: True Fiscal Yield vs. "Government Take"



3. Half-Cycle Economic Analysis

Once an oil field has been discovered and exploration costs are sunk, we assume the Investor will design a development program to maximize the after-tax value of the resource. Our model searches for advantageous variations in the scope of primary development, the rate of extraction, the timing and scope of subsequent enhanced resource recovery, and final abandonment of the field, and selects the combination that maximizes after-tax NPV. These calculations incorporate all provisions of the given fiscal regime, including the allowed recovery of previously expended exploration costs.

Below, based on development of the medium size field, we show how the Status Quo and alternative fiscal regimes impact:

1) The distribution of half-cycle profits (which exclude sunk exploration costs) between Investor and Government.

2) The size of half-cycle Deadweight Losses (which exclude the impact of any reduction in exploration incentives).

3) The half-cycle Fiscal Inefficiency of each regime as applied to the development of a commercial oil or gas field (excluding Deadweight Losses incurred at the exploration stage).

4) The half-cycle True Fiscal Yield of each regime, where only expenses and revenues incurred during the development stage are considered.

5) The difference between True Fiscal Yield and Government Take, reckoned on the basis of half-cycle cash flows.

Judged on the basis of half-cycle cash flows, the performance of each fiscal regime is generally similar to what was seen in the full-cycle analysis. The main difference pertains to levels of True Fiscal Yield and Government Take observed in the greenfield prospects. Because exploration costs do not enjoy much of a tax shelter and can only be recovered with delay if exploration is successful, the Investor shoulders a higher percentage of exploration costs than development or operating costs. This heavier tax treatment of exploration expenditures causes both Government Take and True Fiscal Yield to be higher when measured on the basis of full-cycle cash flows.

The effect can be seen by comparing the results for the two greenfield prospects (Eastern oil and Eastern gas) in Figures 3.1 and 3.4 with the corresponding results in Figures 2.1 and 2.12. For any given fiscal regime, Deadweight Losses are also somewhat larger when reckoned on the basis of full-cycle cash flows due to the inclusion of tax-induced reductions in the intensity of exploration (cf. Figure 3.2 and 2.10).

Figure 3.1: Fiscal Impact on Distribution of Half-Cycle Profits (Excluding Exploration)

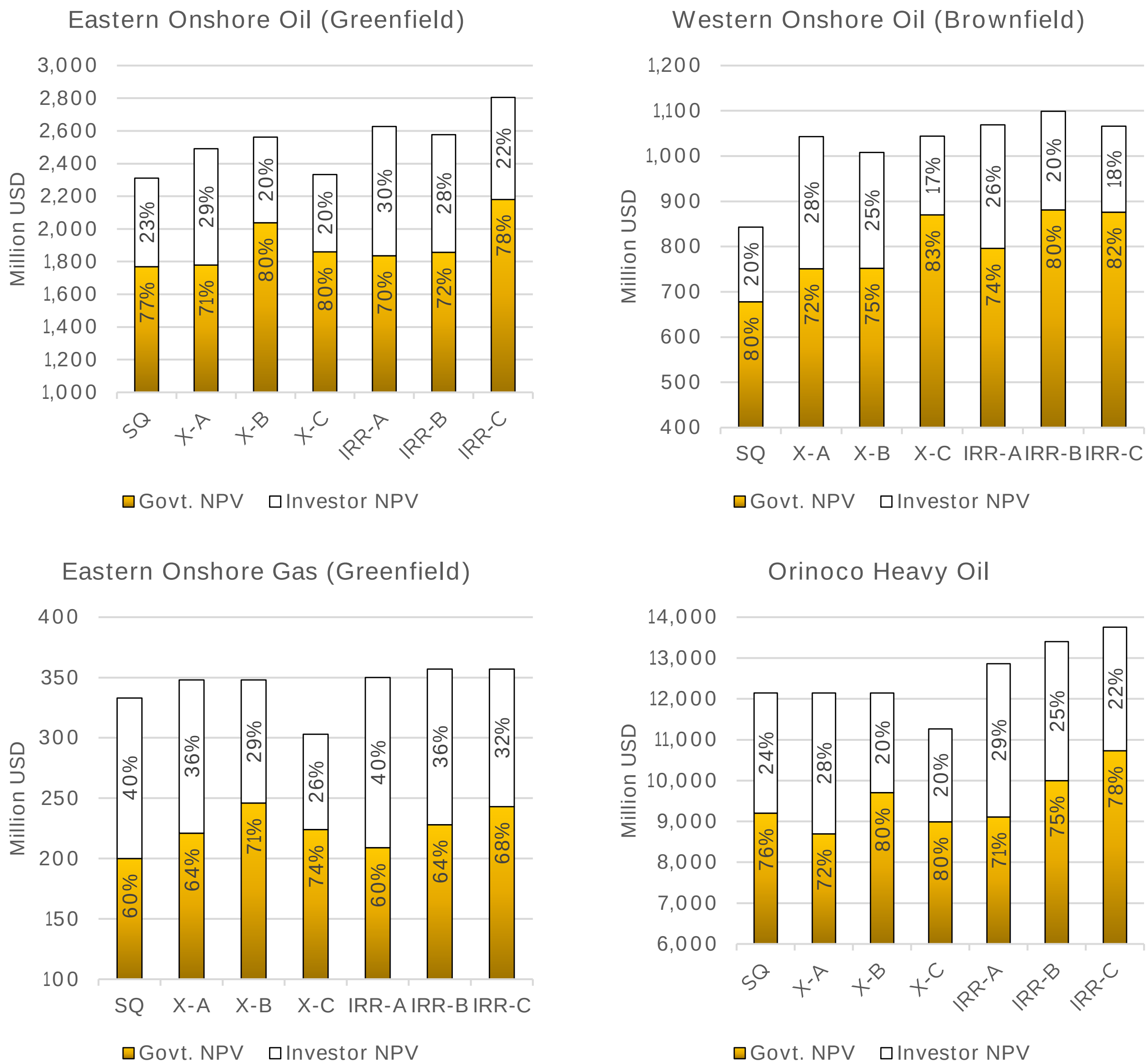


Figure 3.2: Fiscal Impact on Half-Cycle Deadweight Loss

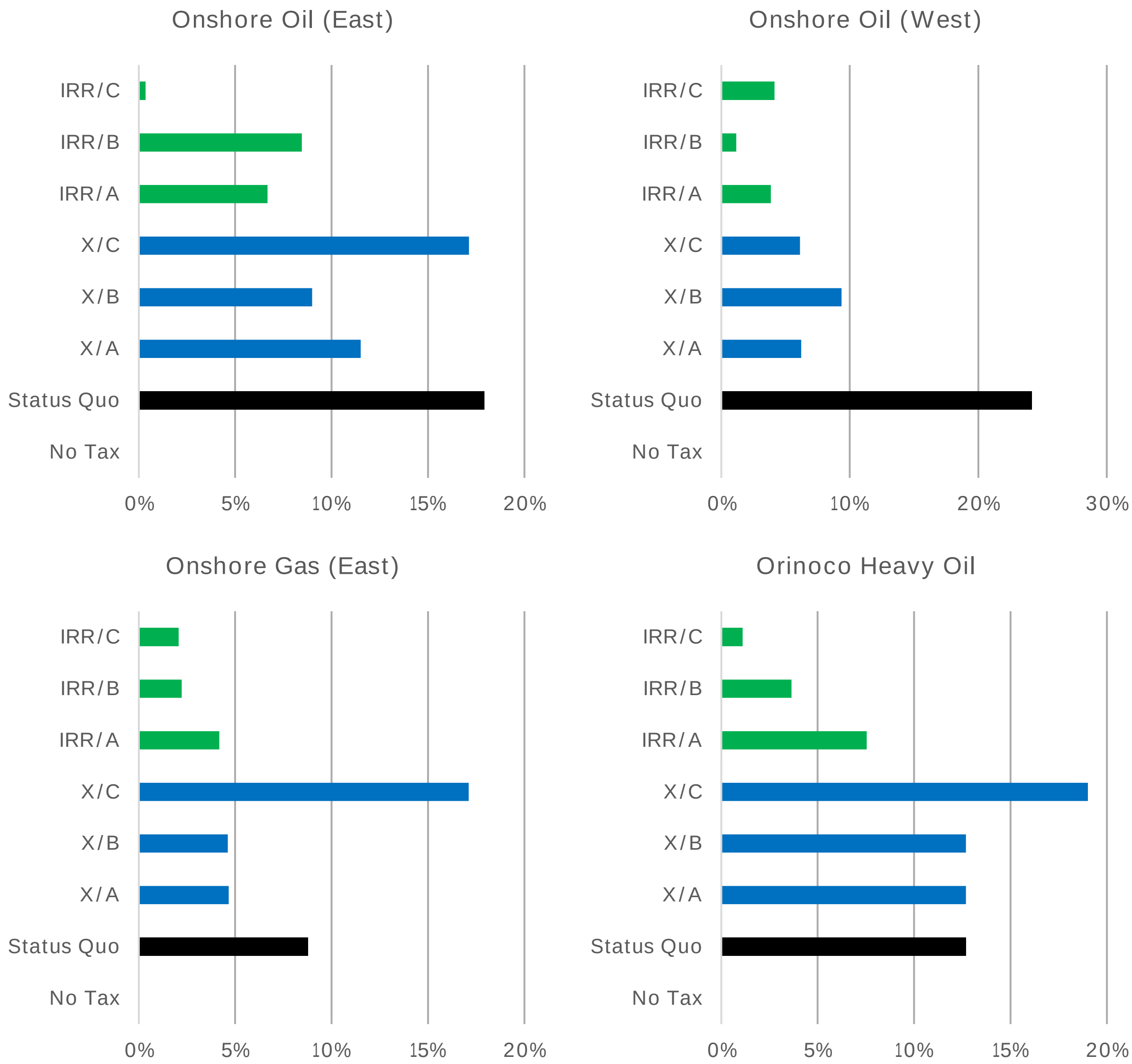


Figure 3.3: Fiscal Impact on Half-Cycle Fiscal Inefficiency

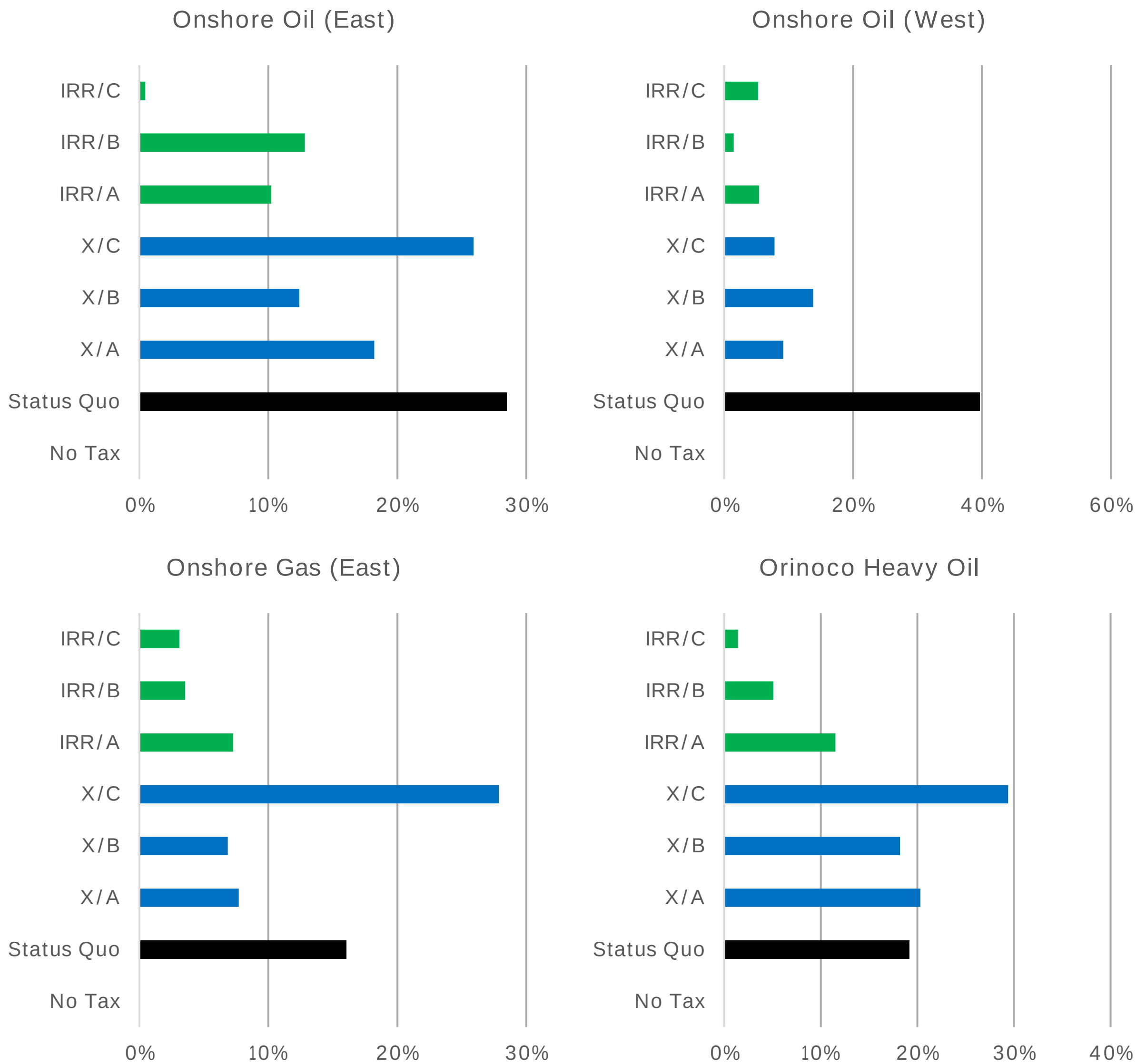


Figure 3.4: Fiscal Impact on Half-Cycle True Fiscal Yield

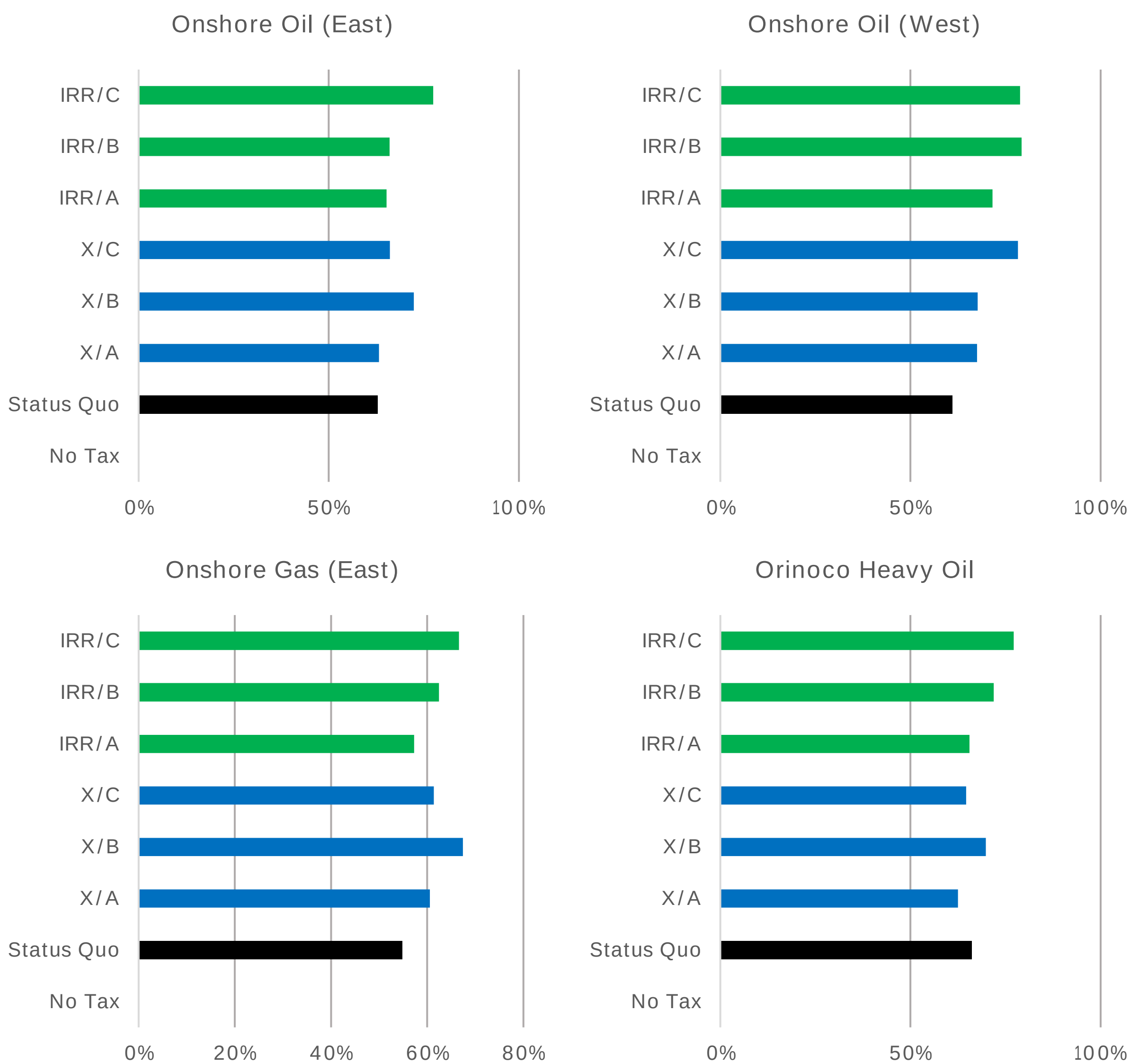
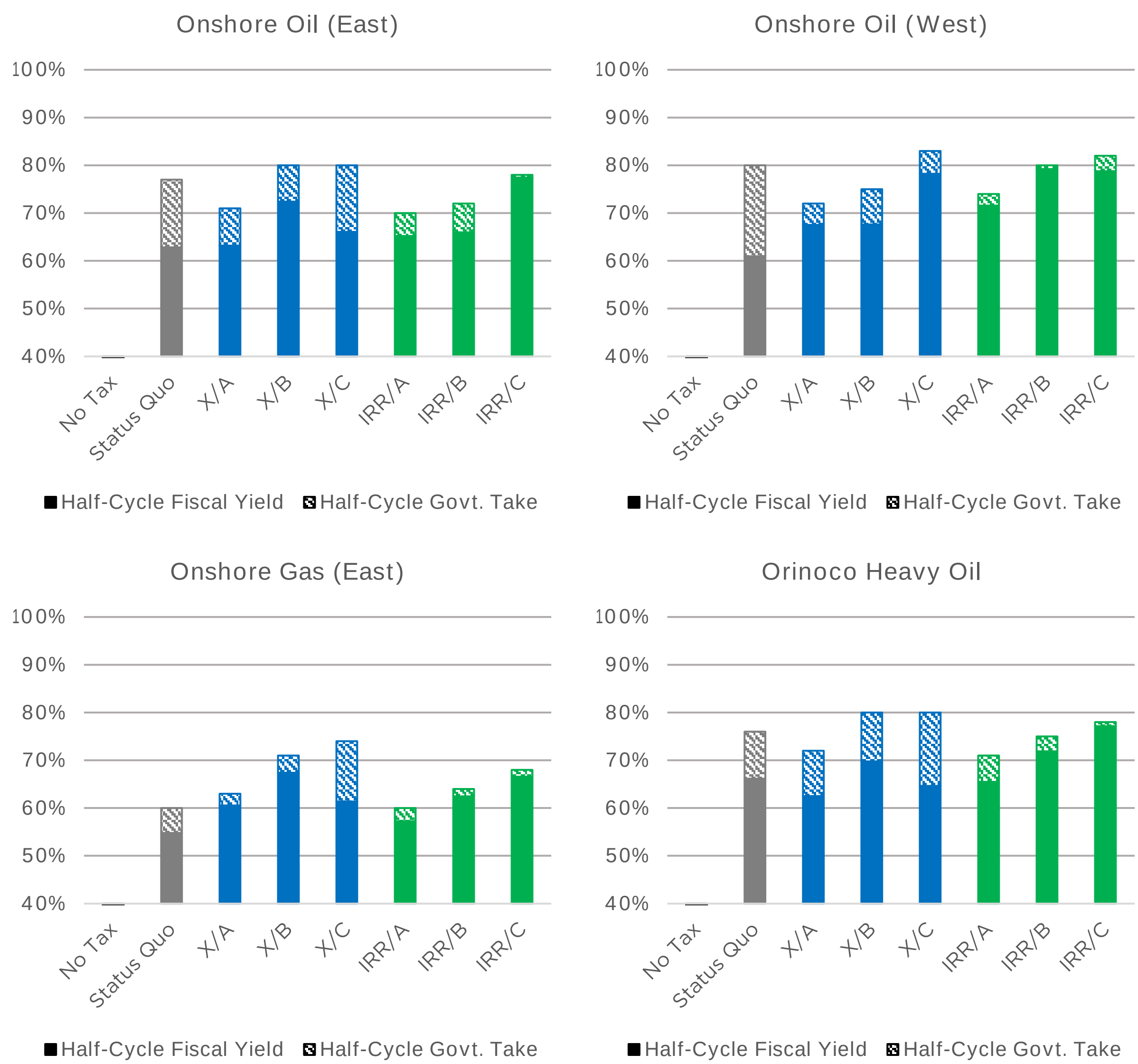


Figure 3.5: Half-Cycle “Government Take” vs. True Fiscal Yield



4. Main Conclusions

The main conclusions that emerge from this study are as follows:

The existing oil and gas fiscal regime in Venezuela severely discourages investment in exploration, development, and enhanced recovery operations.

The result is reduced levels of Government revenue, potential oil and gas reserves being left in the ground, and lost profits for oil companies.

Alternative fiscal regimes based on sliding-scale royalties and elimination of the Alternative Minimum Tax would mitigate these problems and trigger more intensive exploration plus increased investment to raise production levels and expand reserves, and by so doing permit increased profits for Government and Investor alike.

Sliding-scale royalty regimes substantially reduce the tax-related distortions that limit current investment. More reserves would be produced over the life of the field and they would be extracted faster than under the existing fiscal regime. The result would be an increase in the economic value of the underground resources.

Whether the resulting increase in resource value is mainly left to the Investor, or alternatively captured by Government via taxes is determined by the structure of the sliding-scale royalty regime. A “generous” approach would involve slowly increasing the royalty rate in small increments as the field matures. An “aggressive” approach would involve increasing the royalty rate faster and by larger increments. A “balanced” approach would sit somewhere in between.

The criterion by which royalty rates are increased must be related to the profitability of the Investor’s project; if not, new barriers and disincentives to investment will arise and create new distortions that foil the attempted reform.

The two criteria we considered, the X-Factor (cumulative revenue divided by cumulative expense) and IRR (internal rate of return) are both related to project profitability. However, the IRR criterion relates more closely to profitability than does the X-Factor, and consequently produces greater incentives for investment, fewer distortions, and increased Government revenue relative to the X-Factor.

Royalty rates that are too high can backfire, even when applied to highly profitable projects, and raise even less Government revenue than lower royalty rates. This is a general phenomenon that is recognized in the broader public finance literature as the “Laffer Curve,” by which Government revenues first rise as the tax rate is increased, but ultimately fall as the tax rate is raised further due to the increasing disincentives for investment.

Aggressive sliding-scale royalties based on the X-Factor are particularly prone to the Laffer Curve effect and likely to be counterproductive—raising less Government revenue than a more balanced implementation of the same regime. Sliding-scale royalties based on IRR are less prone to the Laffer Curve effect, primarily because

the criterion by which royalty rates are increased is closely related to profitability of the Investor's project.

Assessing any fiscal regime by the criterion of "Government Take" is a mistake. Government Take simply reports the fraction of project profits that are captured by Government. But it fails to account for the negative influence of tax-induced distortions that reduce the size of those profits and shrink the tax base. Even a large share of a small pie is still small.

Instead of looking at Government Take when comparing two fiscal regimes, one should consider the total amount of Government revenue that is captured by each regime, not the shares of actual profits. This is because the size of actual profits will likely vary. A measure we call "True Fiscal Yield" facilitates a proper comparison by measuring the fraction of potential resource value (the value of the deposit if exploited free of tax-induced distortions) each regime is expected to capture.

After comparing the existing fiscal regime to the three sliding-scale royalty regimes based on IRR, and considering a wide range of prices ($45-$85/barrel, $2-$4/mcf) and costs (+/- 30% contingencies), we find that the True Fiscal Yield of the IRR-based regimes exceeds that of the existing regime in every scenario (84 scenarios overall).

After comparing the existing fiscal regime to the three sliding-scale royalty regimes based on the X-Factor, and considering a wide range of prices ($45-$85/barrel, $2/$4/mcf) and costs (+/- 30% contingencies), we find that the True Fiscal Yield of the X-Factor-based regimes exceeds that of the existing regime in the most of the scenarios (72 out of 84 scenarios overall), with the 12 failures divided about equally between royalty schedules were either too aggressive or too generous.

The 12 failures of the X-Factor approach noted in the previous bullet illustrate the difficulty of successfully implementing a royalty-based regime that is not tied closely to profits.

In addition to the overall performance of the alternative fiscal regimes, the timing and size of initial Government revenues is also an important consideration. In this regard, the sliding-scale royalty regimes we examined do not tend to create significant delays in the onset of initial Government revenues or reductions in the rate at which Government revenues accrue. The only exception is the aggressive version of the sliding-scale royalty based on the X-factor when applied to greenfield gas development.

Regarding the existing, legacy Orinoco heavy oil projects in particular, the alternative fiscal regimes should not reduce or delay government revenues. These projects are at an advanced stage where the computed X-factor and/or IRR would be high from the start of the new regime, which means royalties at the maximum rate (of 50%) under Plans B and C. This exceeds the 33% rate that would be due under the status quo. There is also the 50% Alternative Minimum Tax under the status quo, which ensures the government of a total stream of 50% of gross revenue—but that is no higher rate than is delivered by the royalty under Plans B and C.

Annex A: Sensitivity of Results to Higher and Lower Price Levels

Figures A.1 through A.11 indicate how performance of the respective fiscal regimes is affected by variations in the assumed price levels. The results in this section assume capital and operating costs at the benchmark levels indicated in Table 1.3, constant real prices of oil ranging between $45/barrel and $85/barrel, and constant real prices of gas ranging between $2/mcf and $4/mcf.

Figure A.1a | Sensitivity of Government NPV to Price (Eastern Onshore Oil)

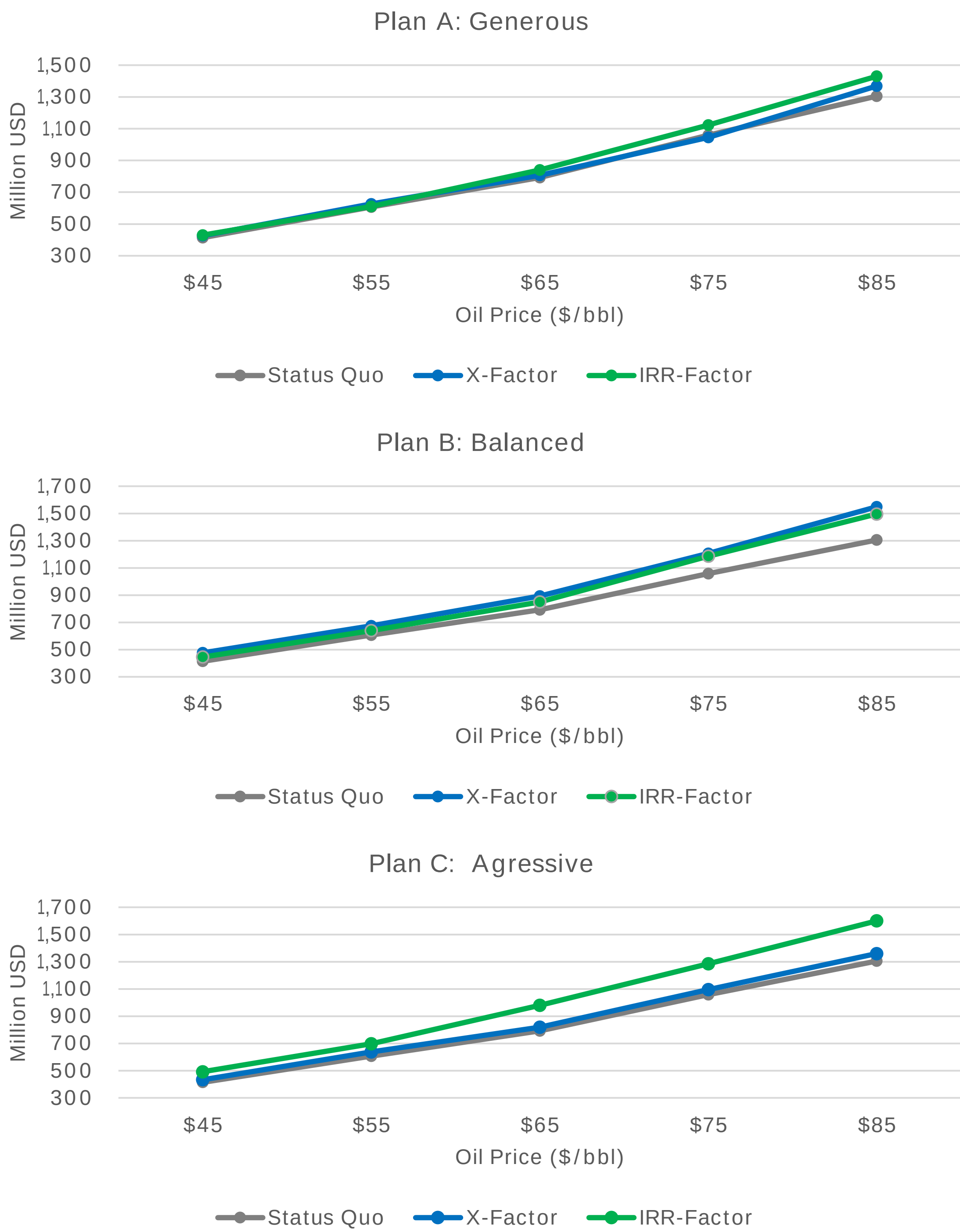
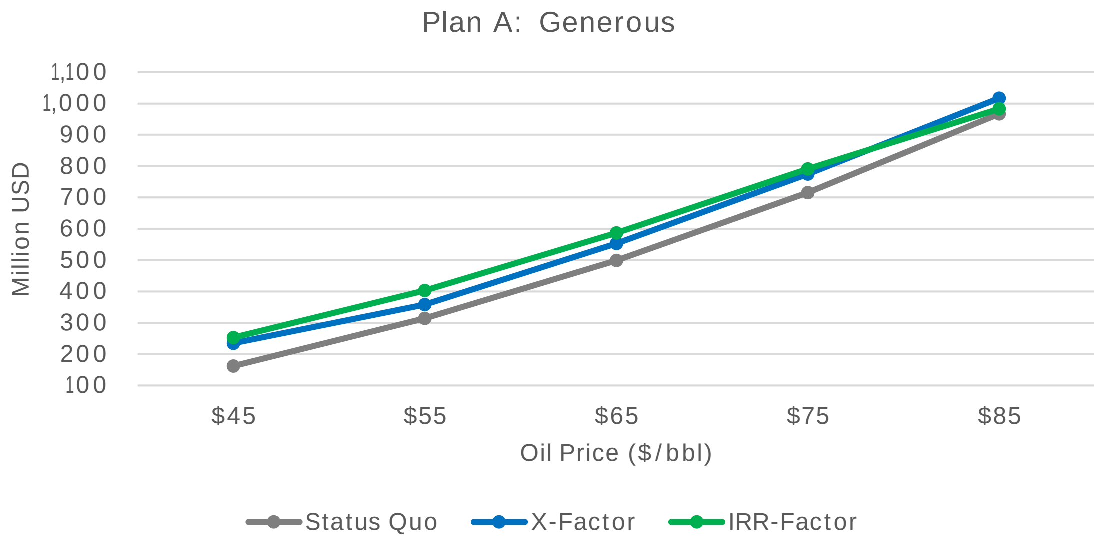
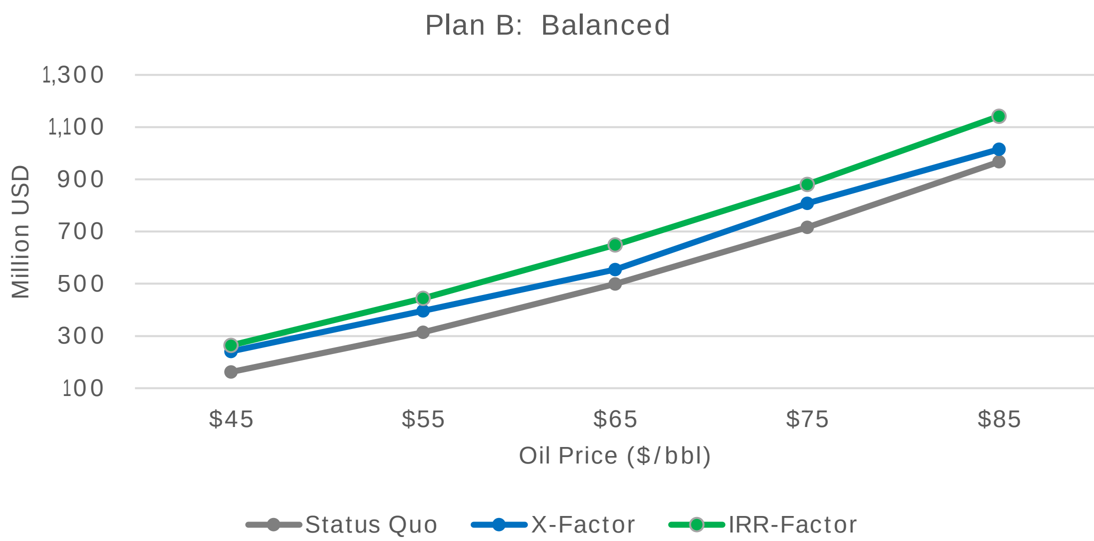


Figure A.1b: Sensitivity of Government NPV to Price (Western Onshore Oil)





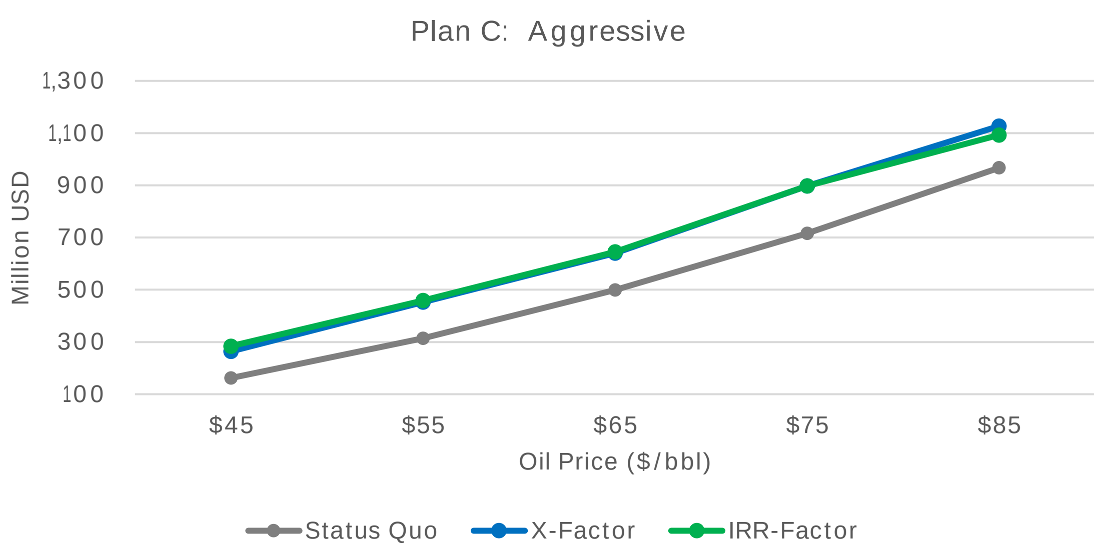
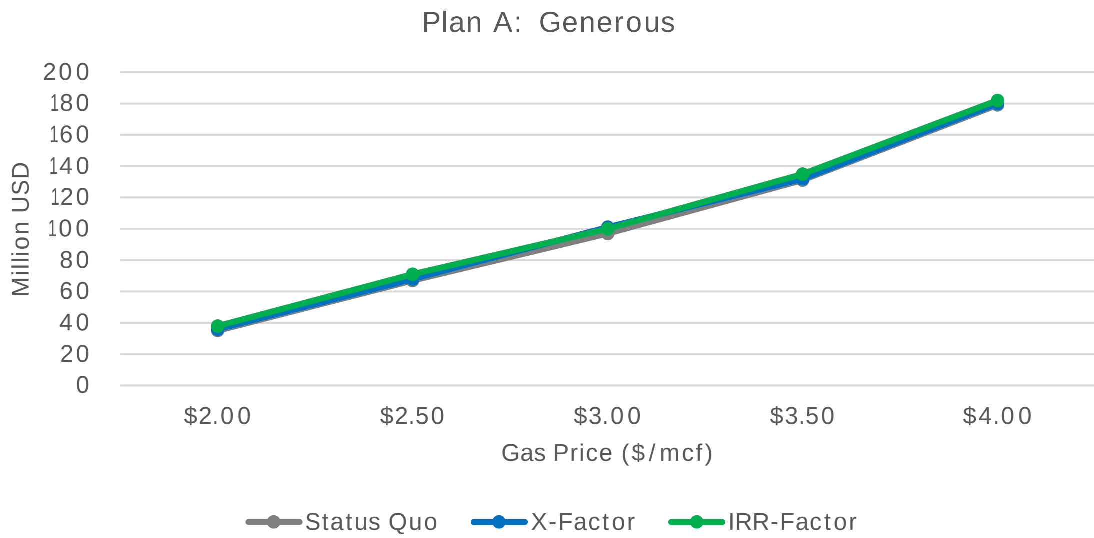
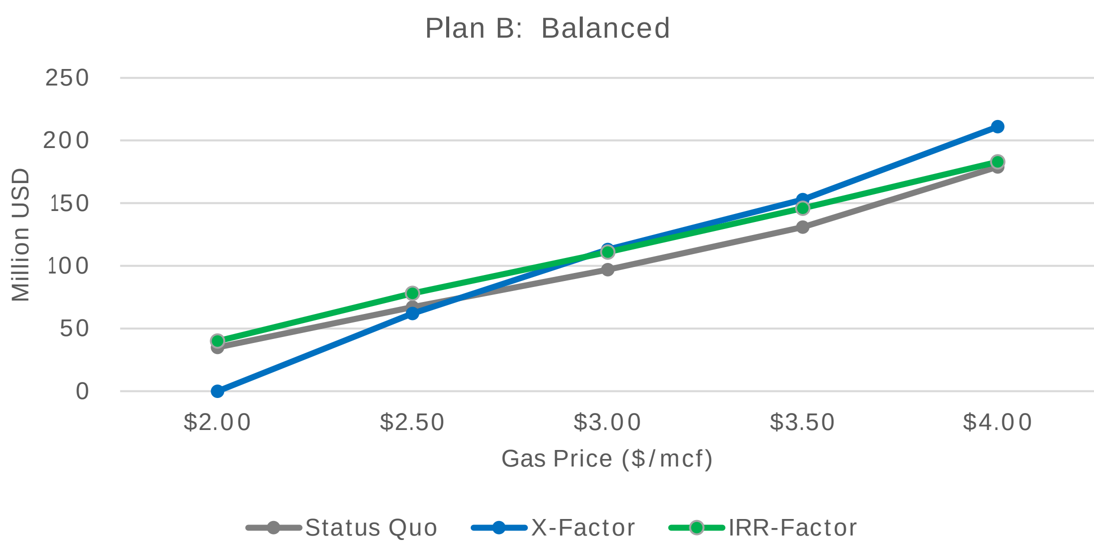


Figure A.1c: Sensitivity of Government NPV to Price (Eastern Onshore Gas)





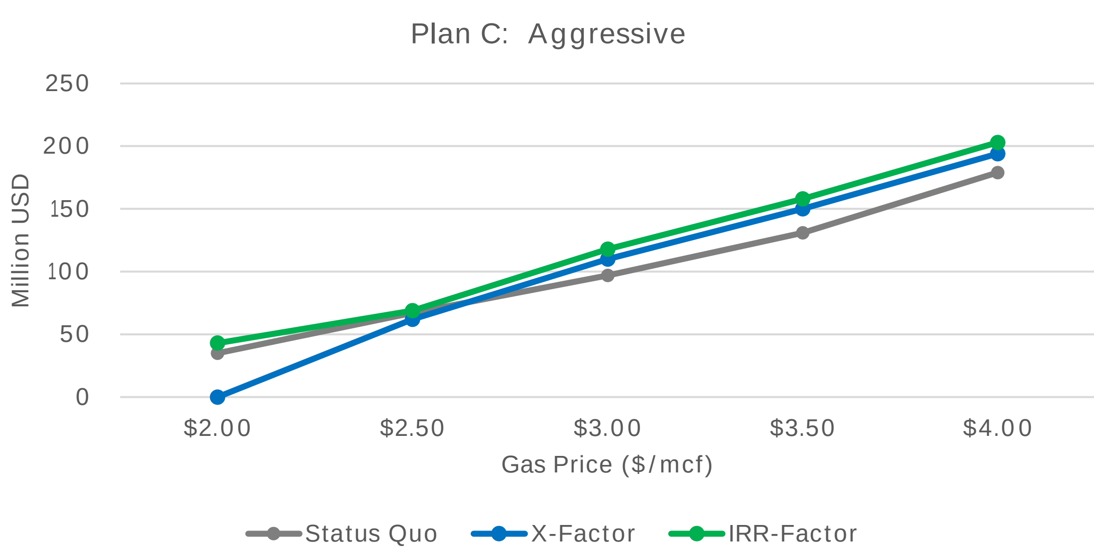


Figure A.1d: Sensitivity of Government NPV to Price (Orinoco Heavy Oil)

Figure A.2a: Sensitivity of Deadweight Loss to Price (Eastern Onshore Oil)

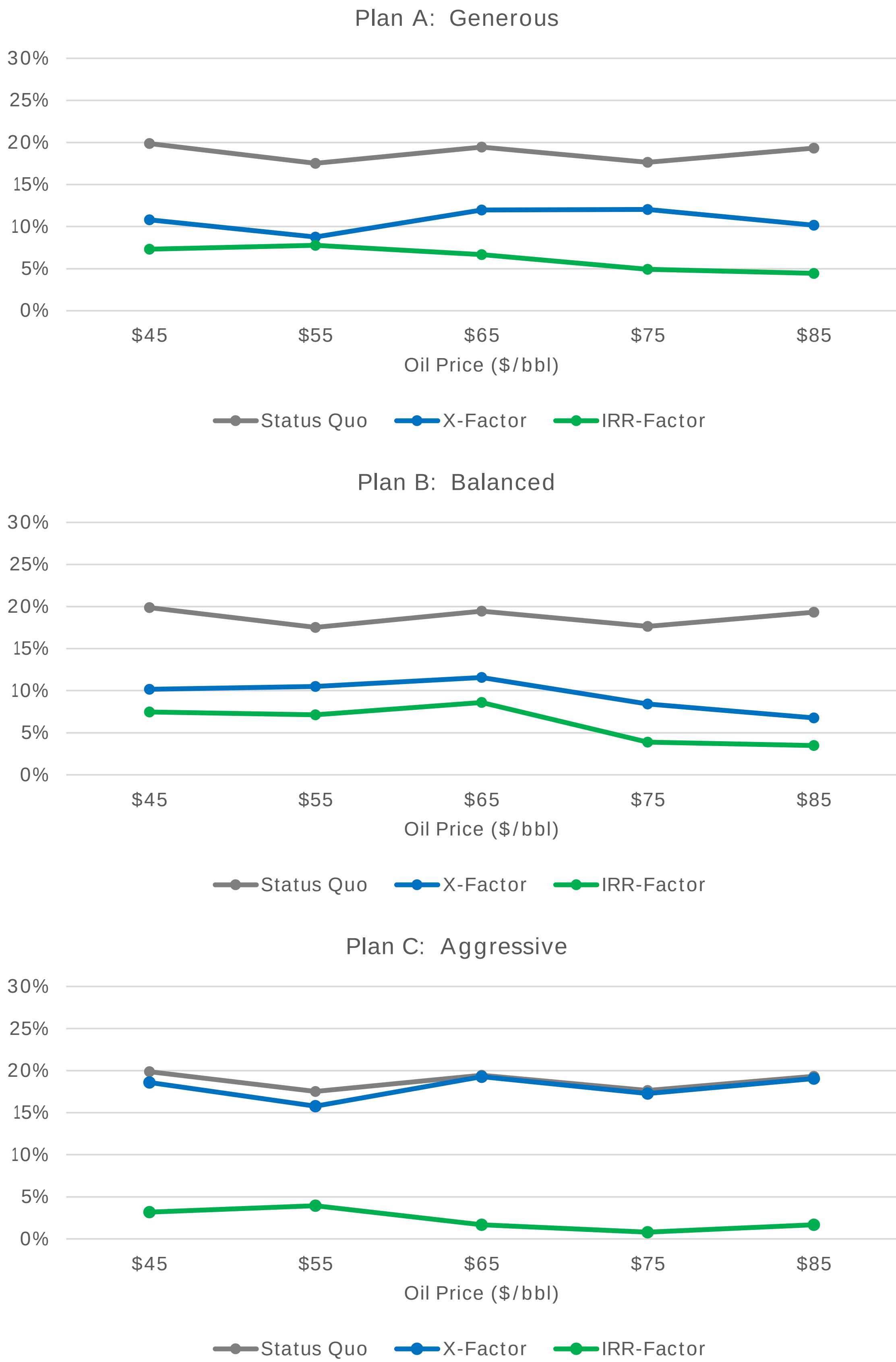
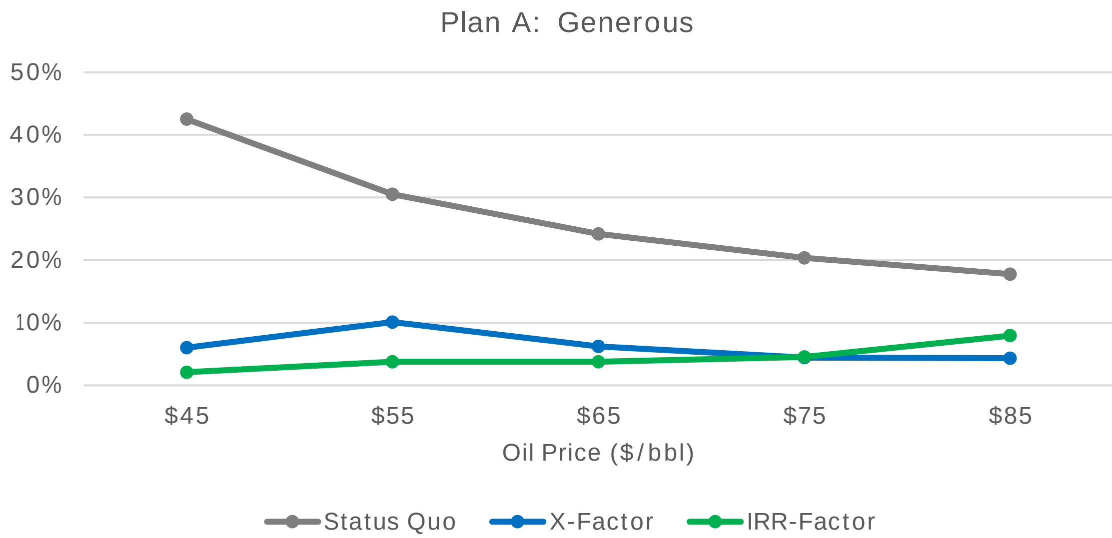
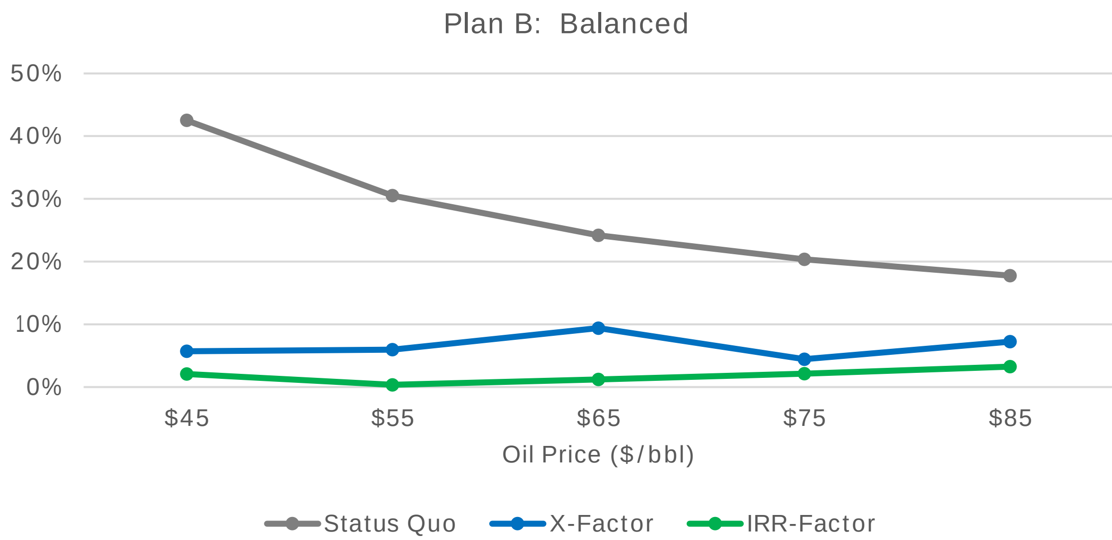


Figure A.2b: Sensitivity of Deadweight Loss to Price (Western Onshore Oil)





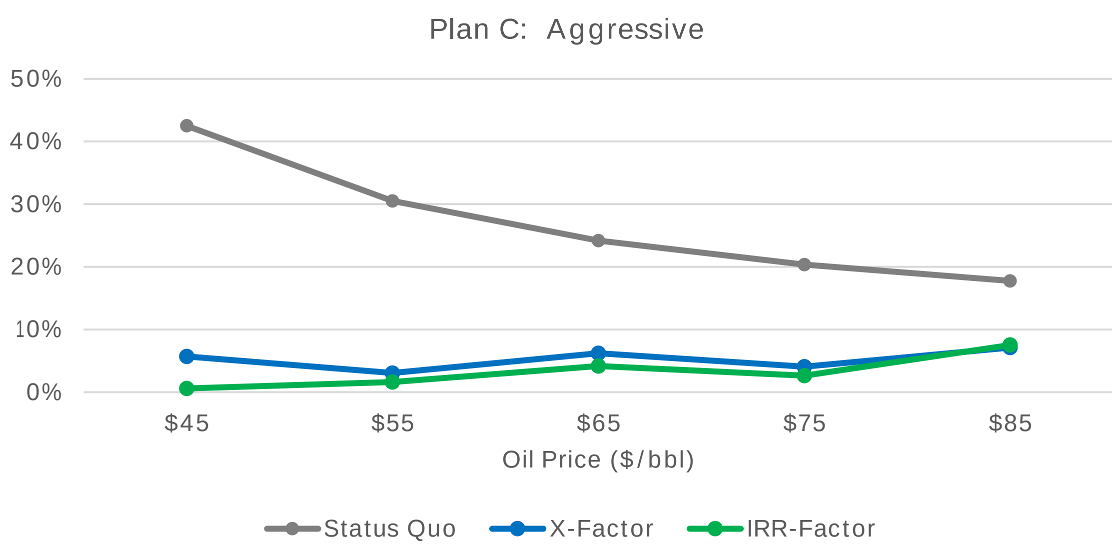


Figure A.2c: Sensitivity of Deadweight Loss to Price (Eastern Onshore Gas)

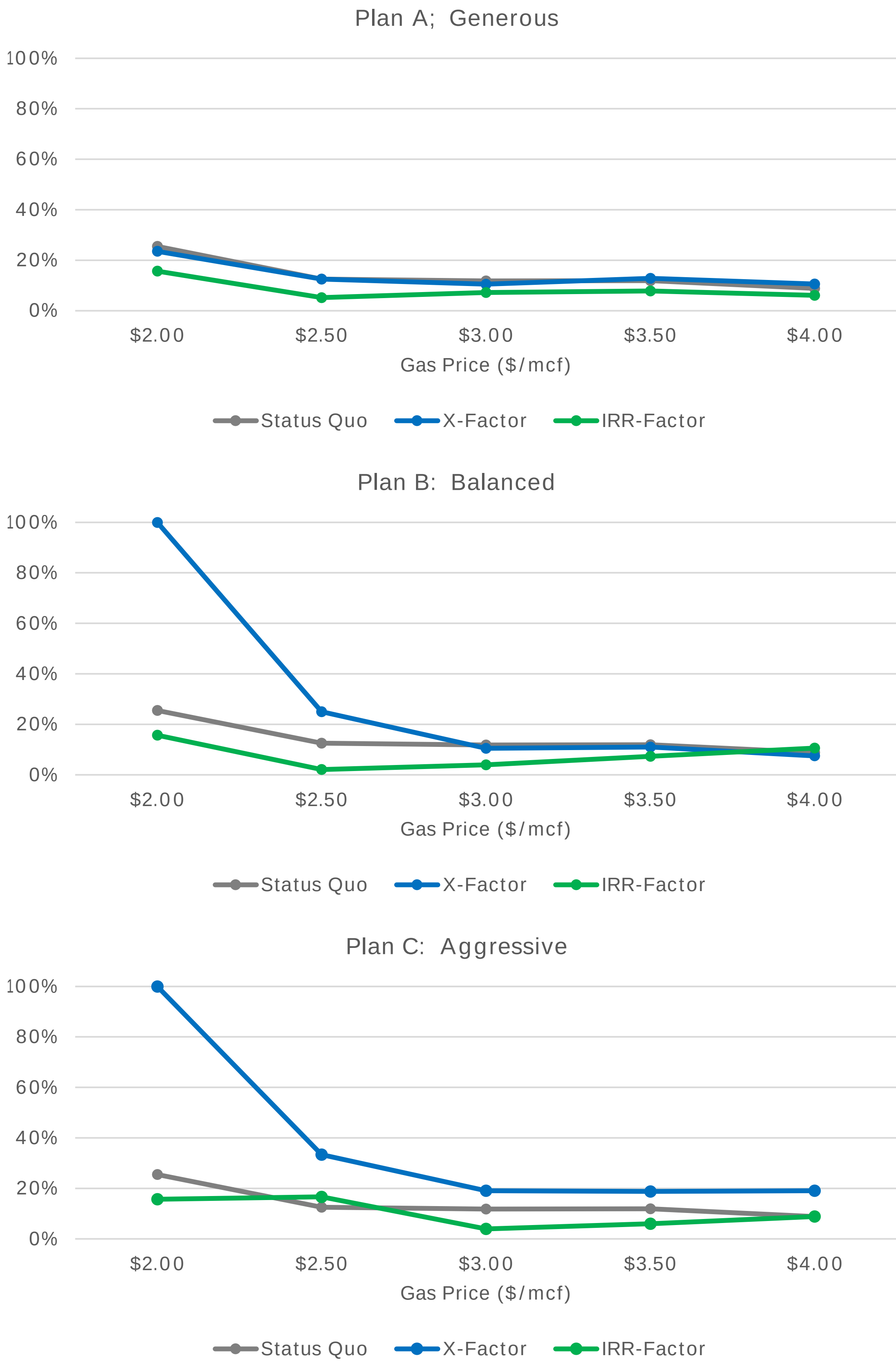


Figure A.2d: Sensitivity of Deadweight Loss to Price (Orinoco Heavy Oil)

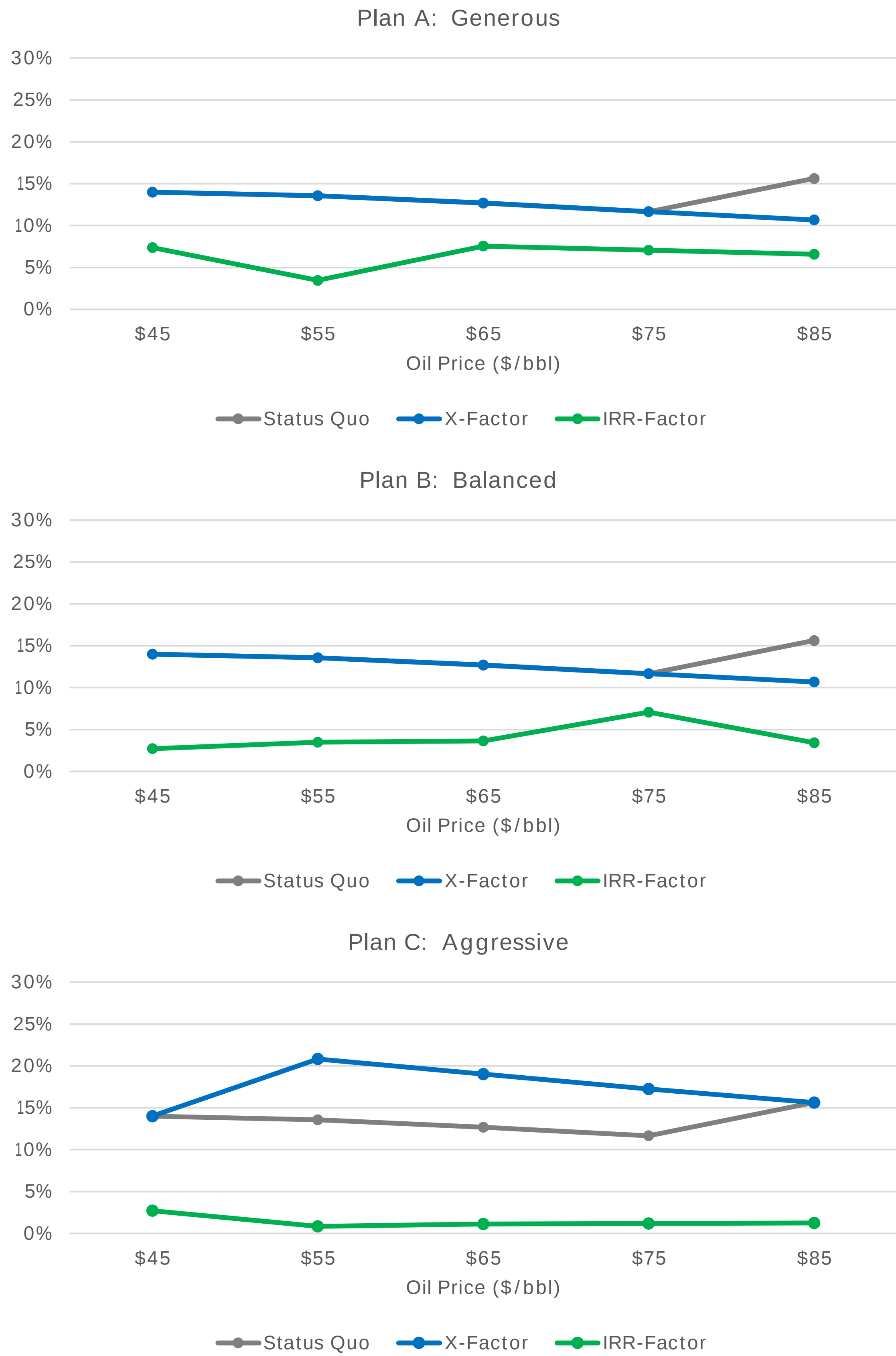
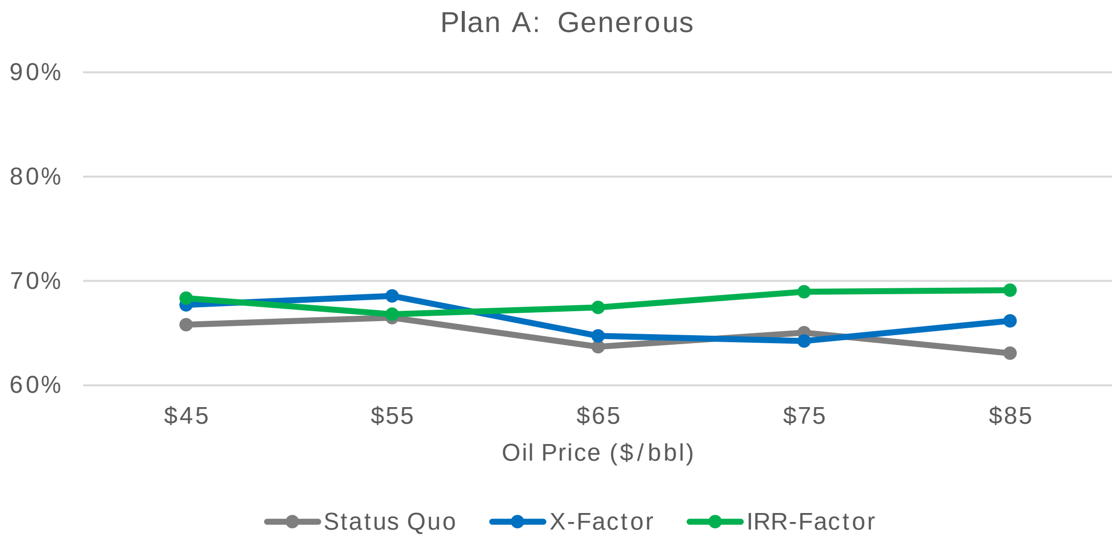
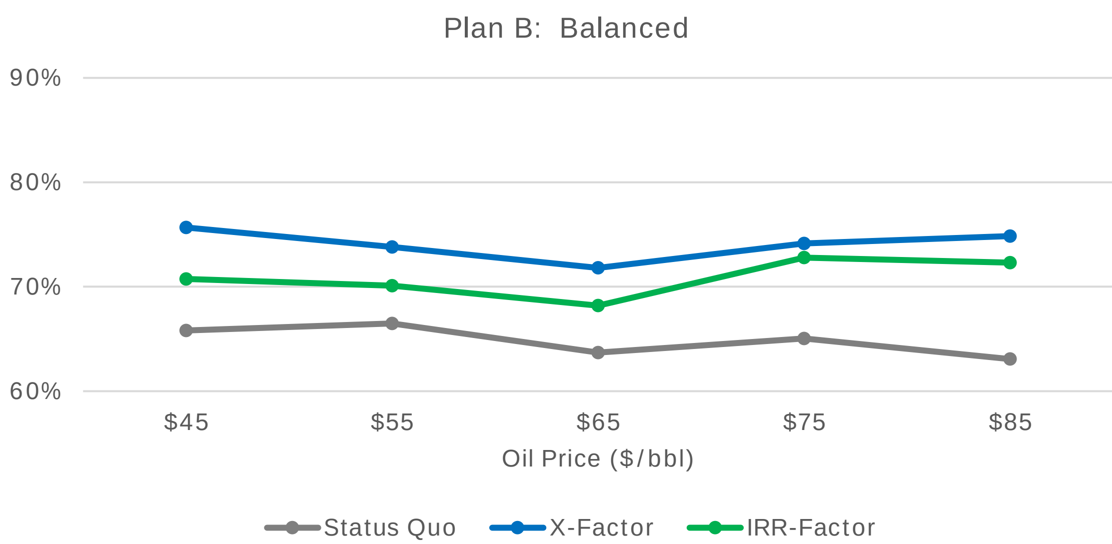


Figure A.3a Sensitivity of True Fiscal Yield to Price (Eastern Onshore Oil)





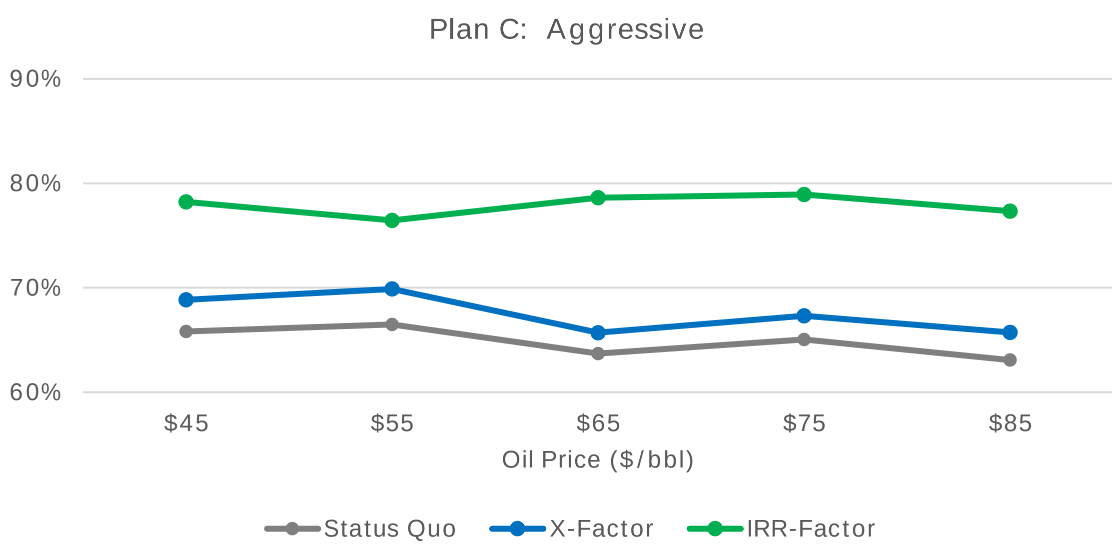
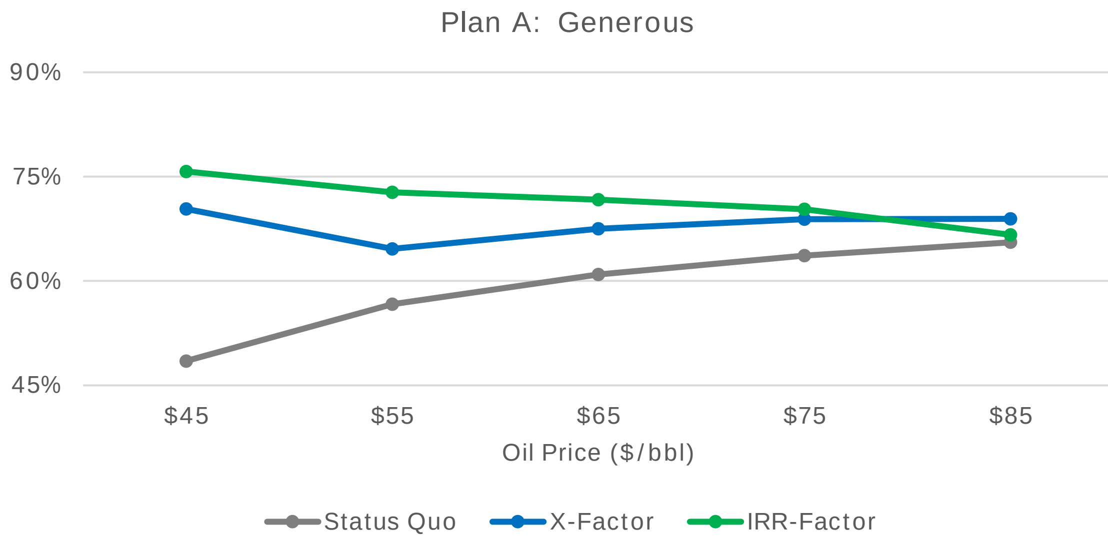
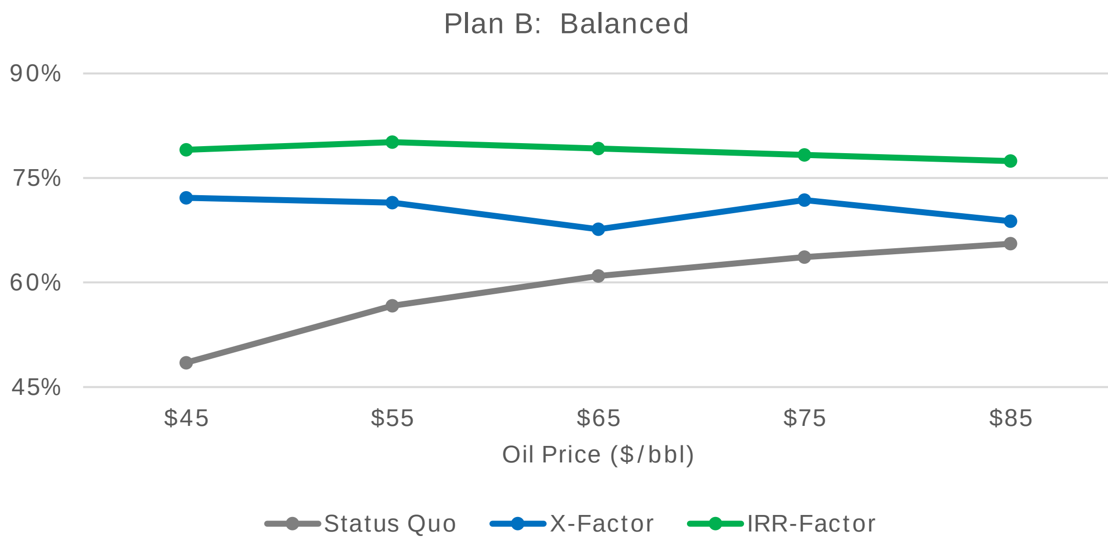


Figure A.3b Sensitivity of True Fiscal Yield to Price (Western Onshore Oil)





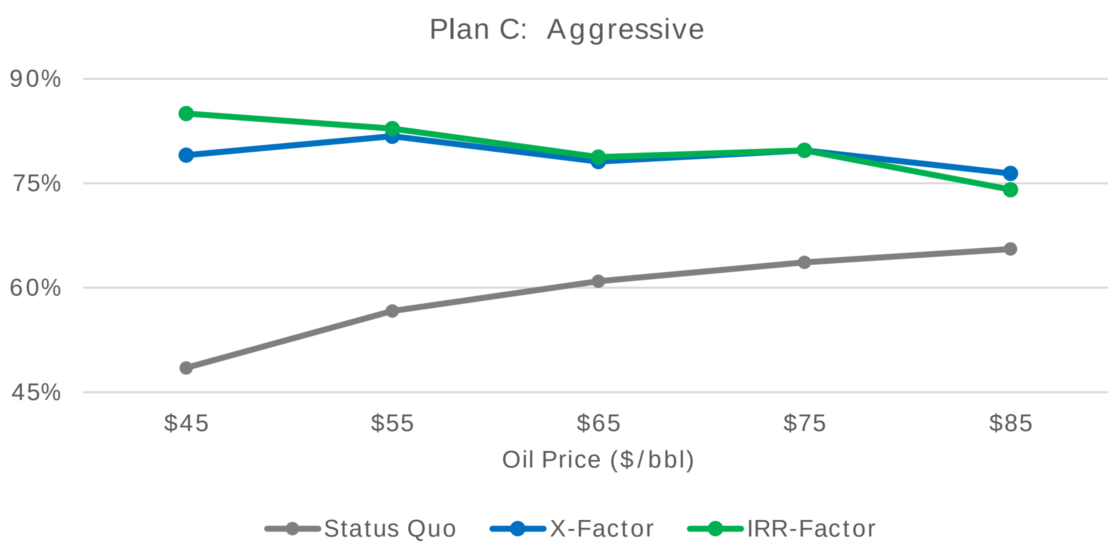
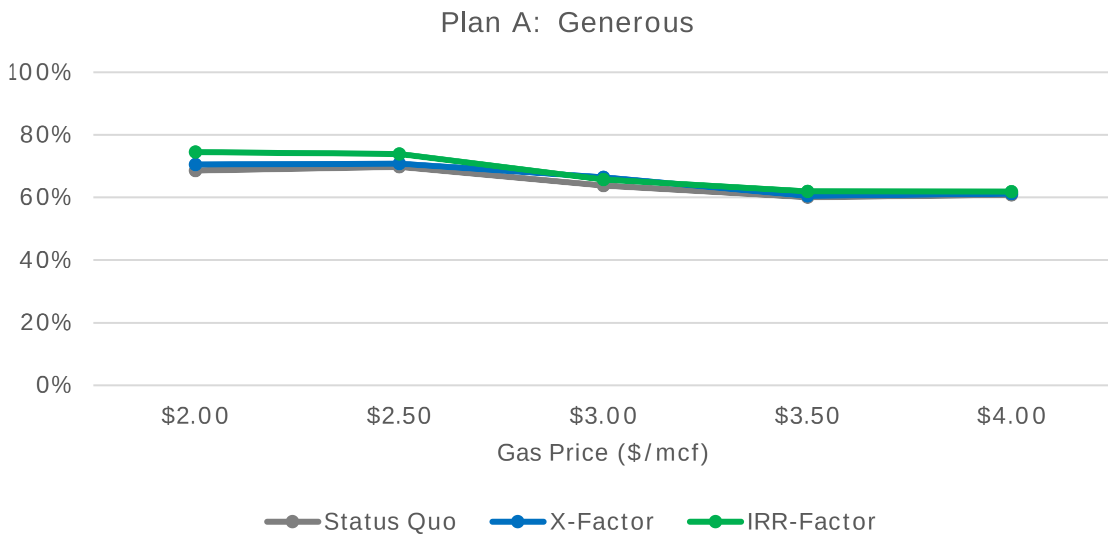
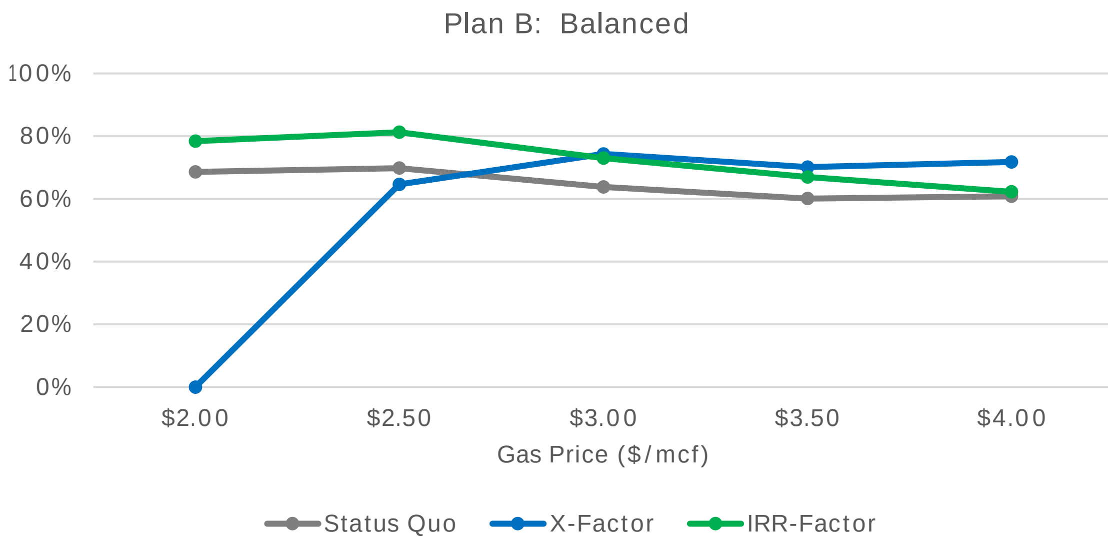


Figure A.3c Sensitivity of True Fiscal Yield to Price (Eastern Onshore Gas)





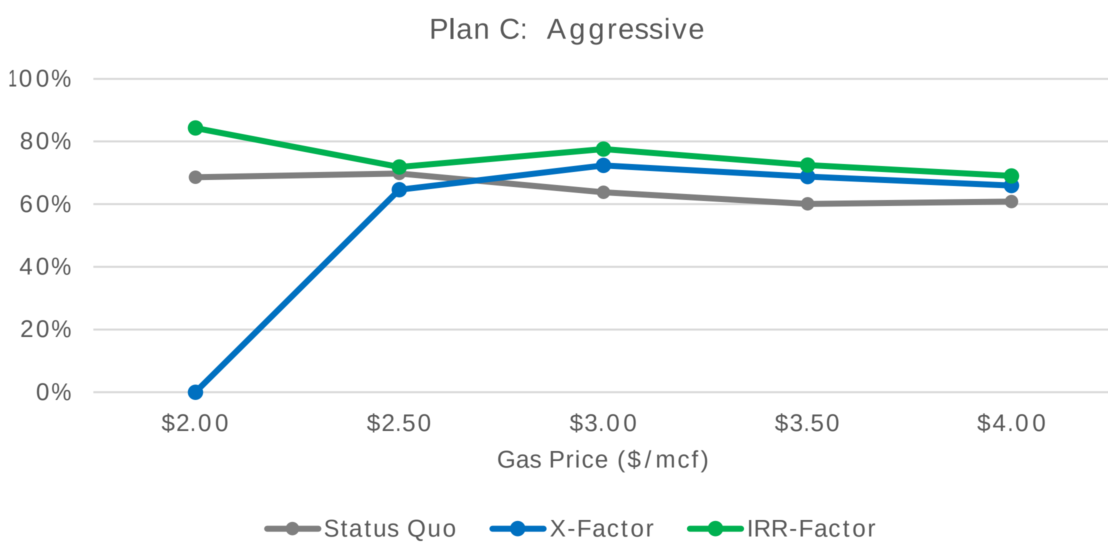


Figure A.3d Sensitivity of True Fiscal Yield to Price (Orinoco Heavy Oil)

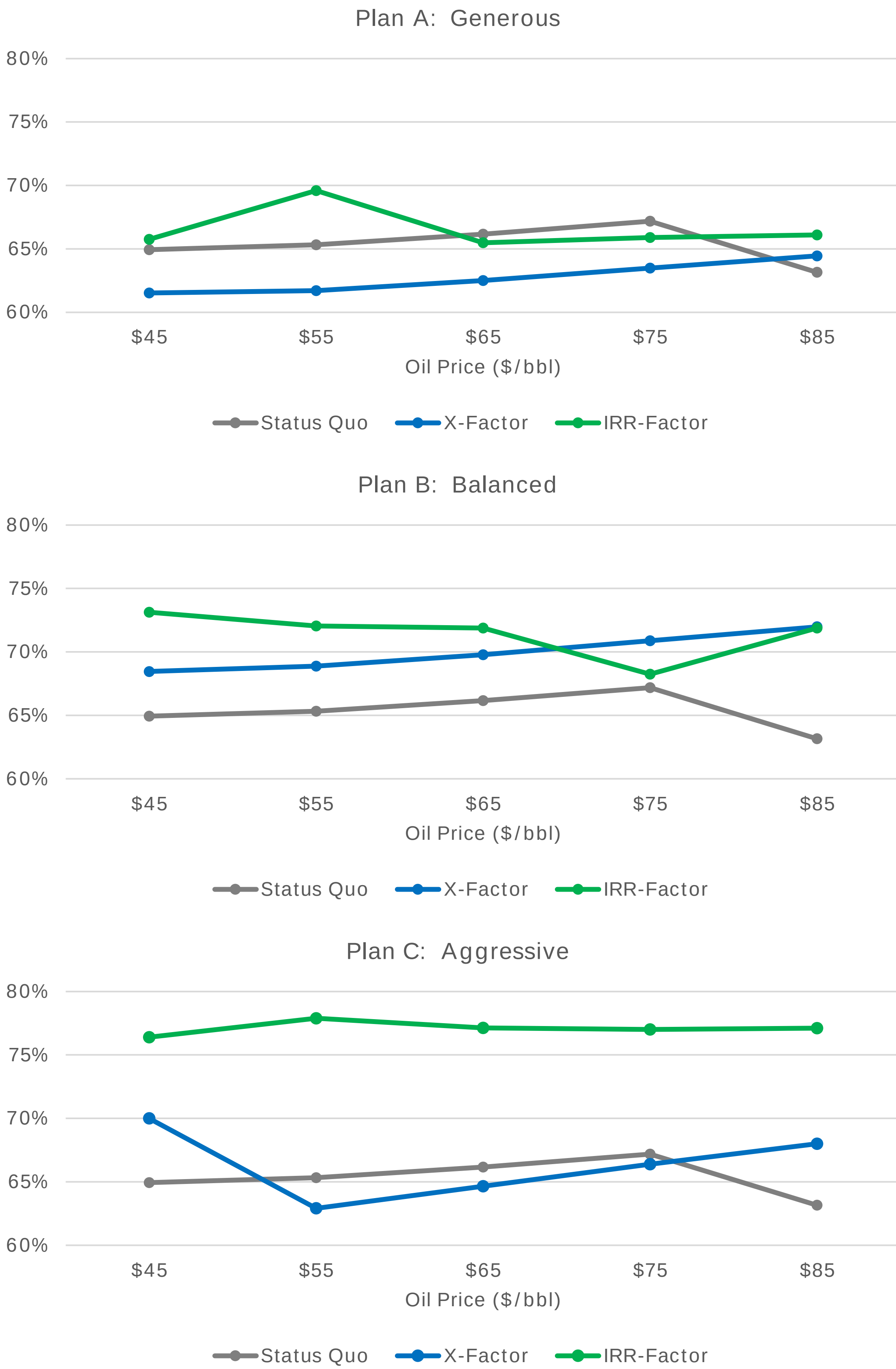
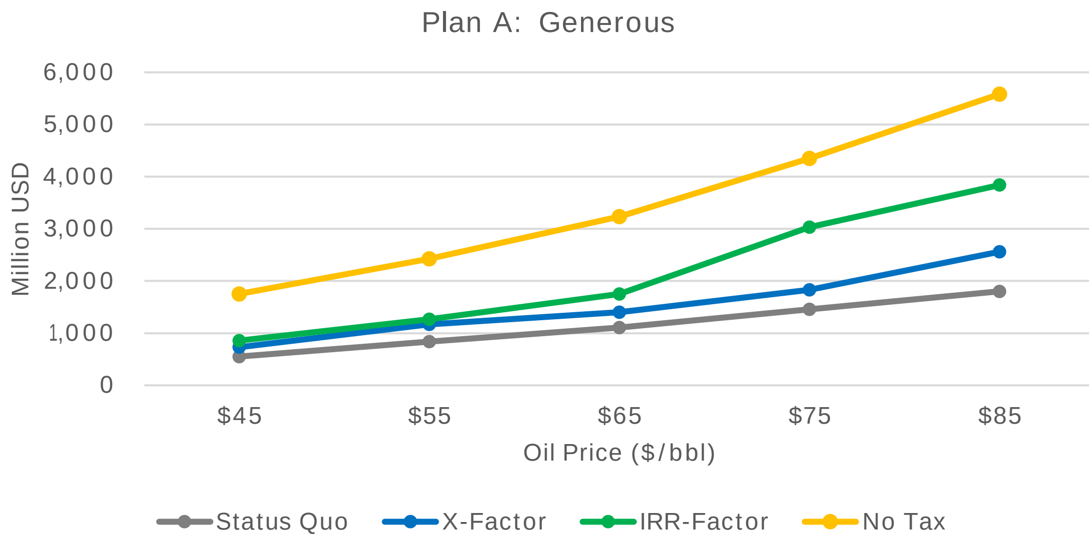
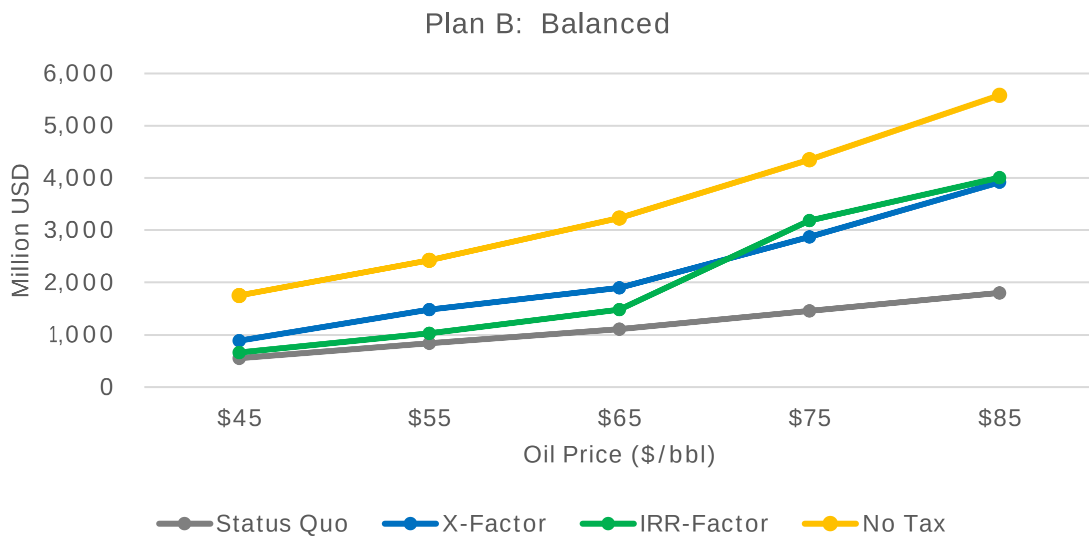


Figure A.4a Sensitivity of Total Investment to Price (Eastern Onshore Oil)





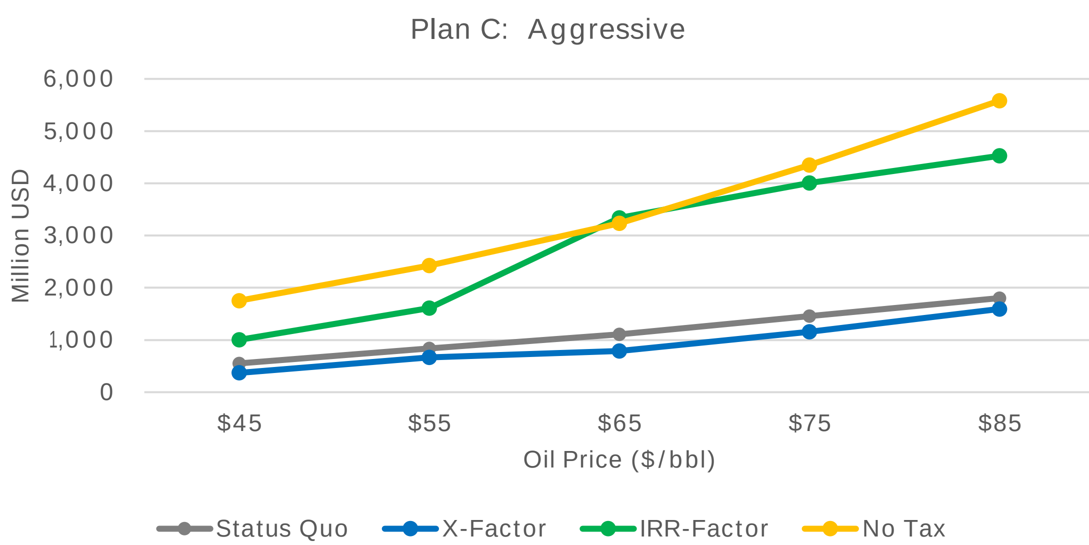
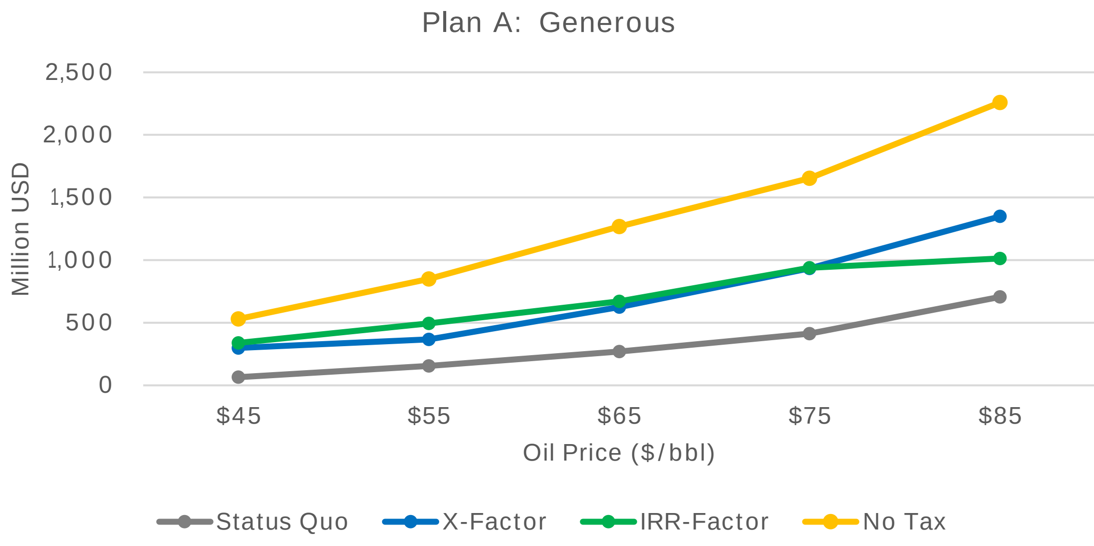
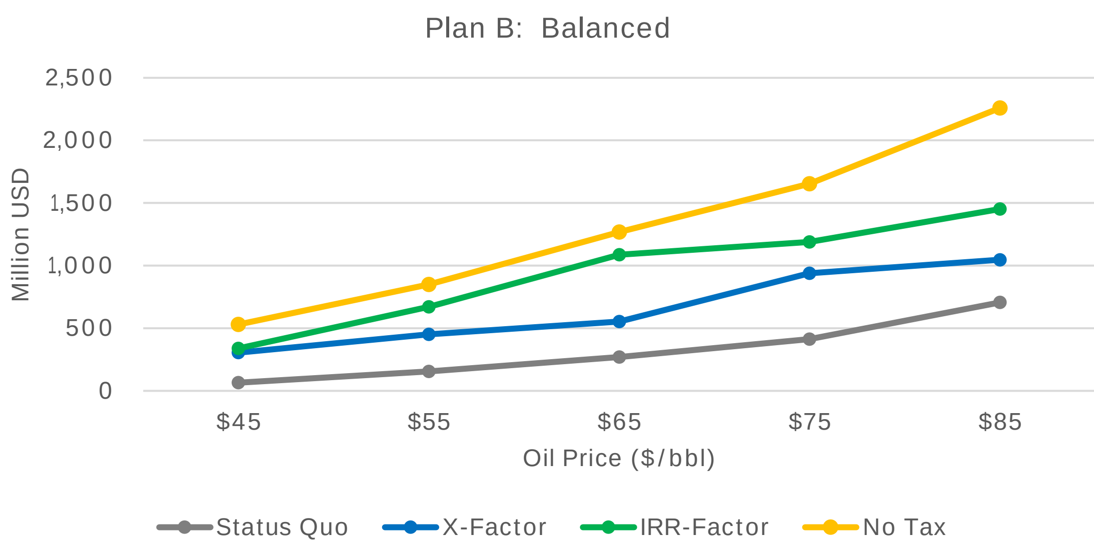


Figure A.4b Sensitivity of Total Investment to Price (Western Onshore Oil)





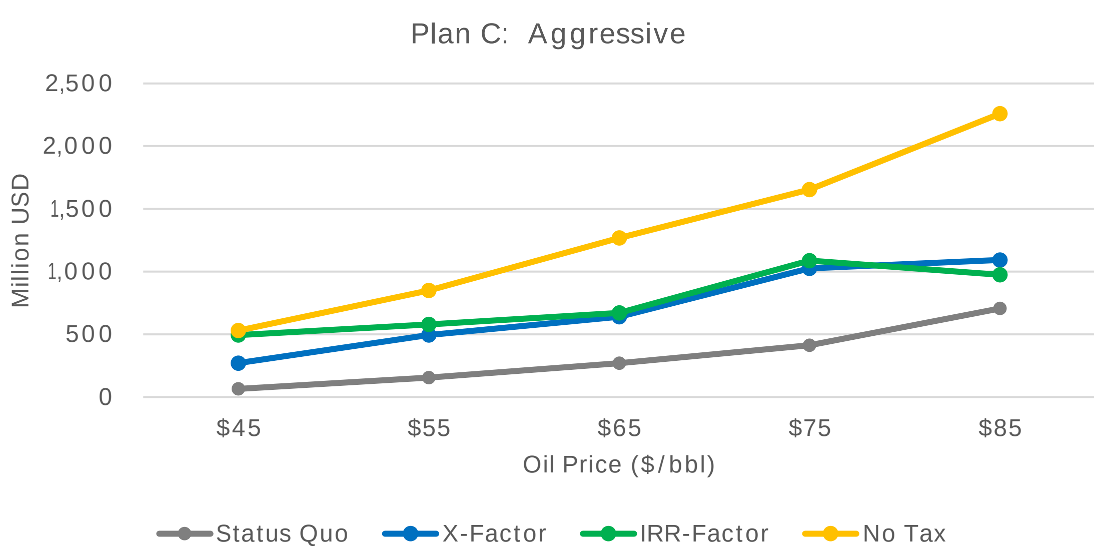


Figure A.4c Sensitivity of Total Investment to Price (Eastern Onshore Gas)

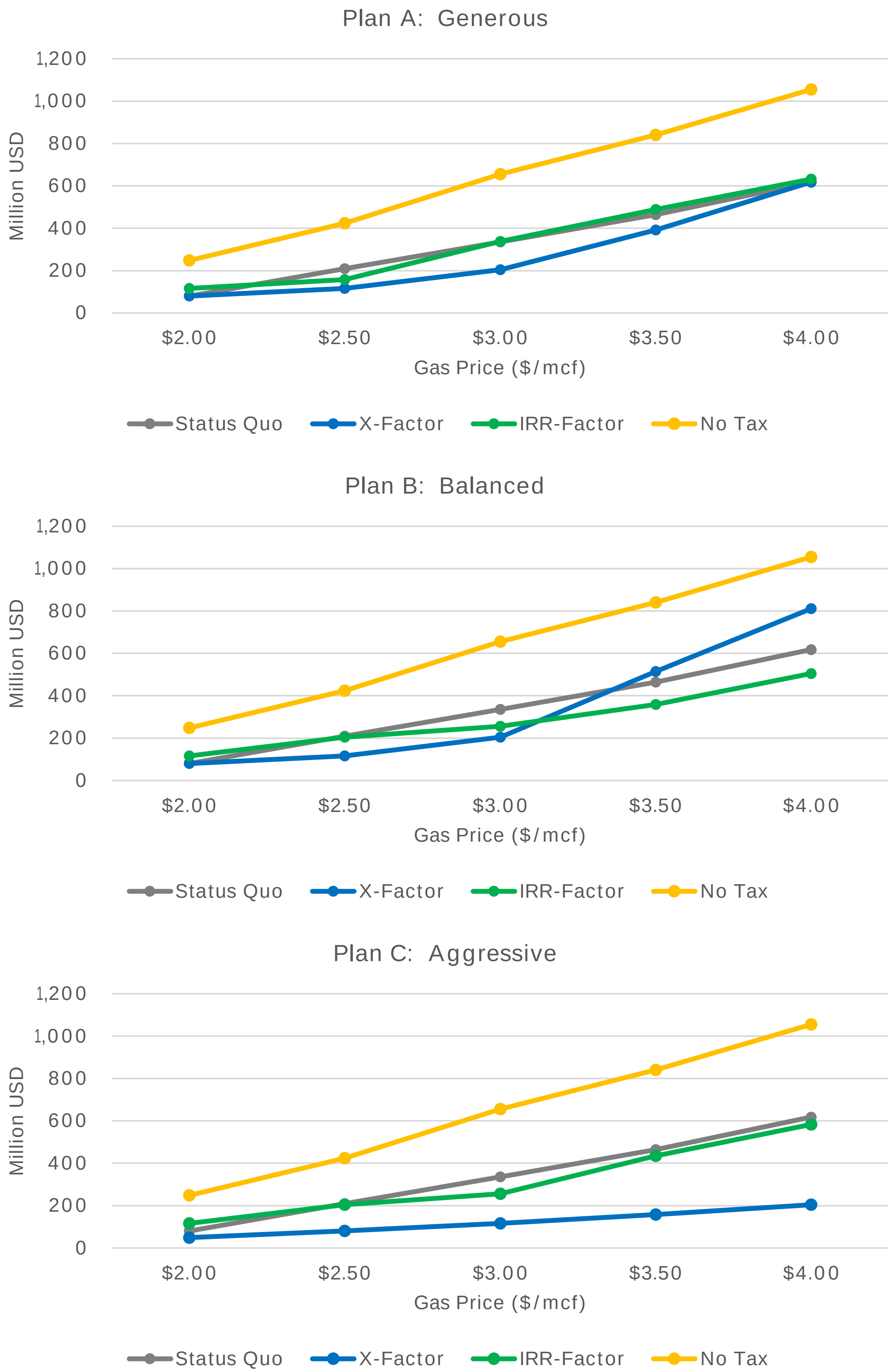
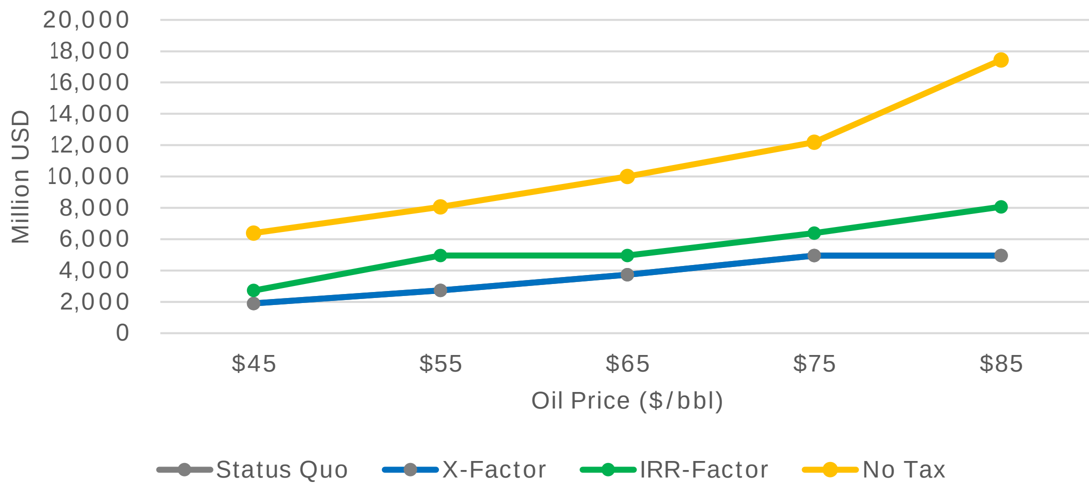
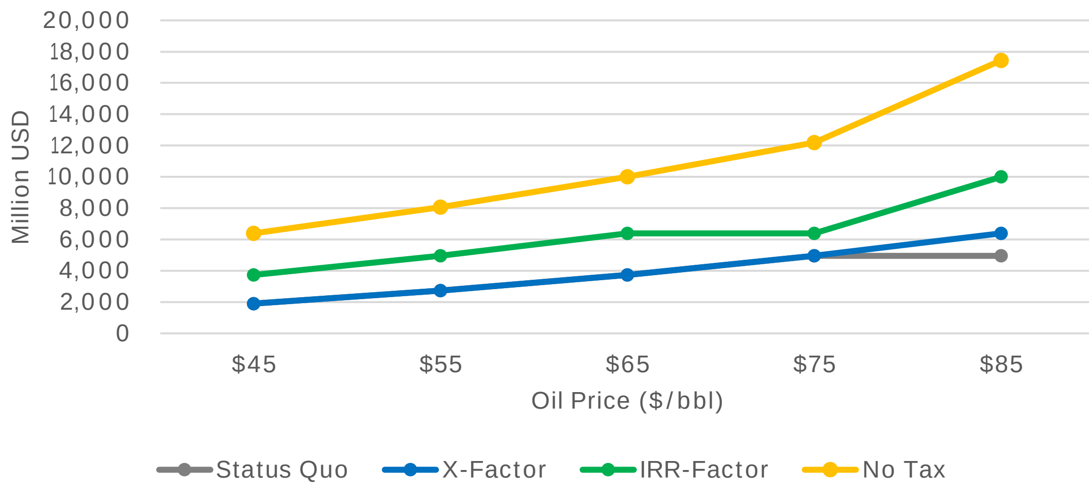


Figure A.4d Sensitivity of Total Investment to Price (Orinoco Heavy Oil)

Plan A: Generous



Plan B: Balanced



Plan C: Aggressive

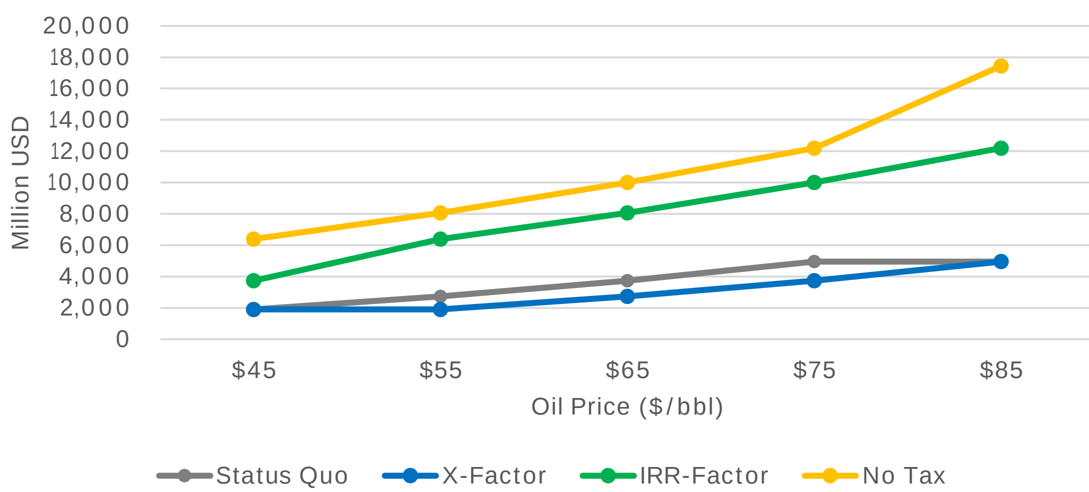
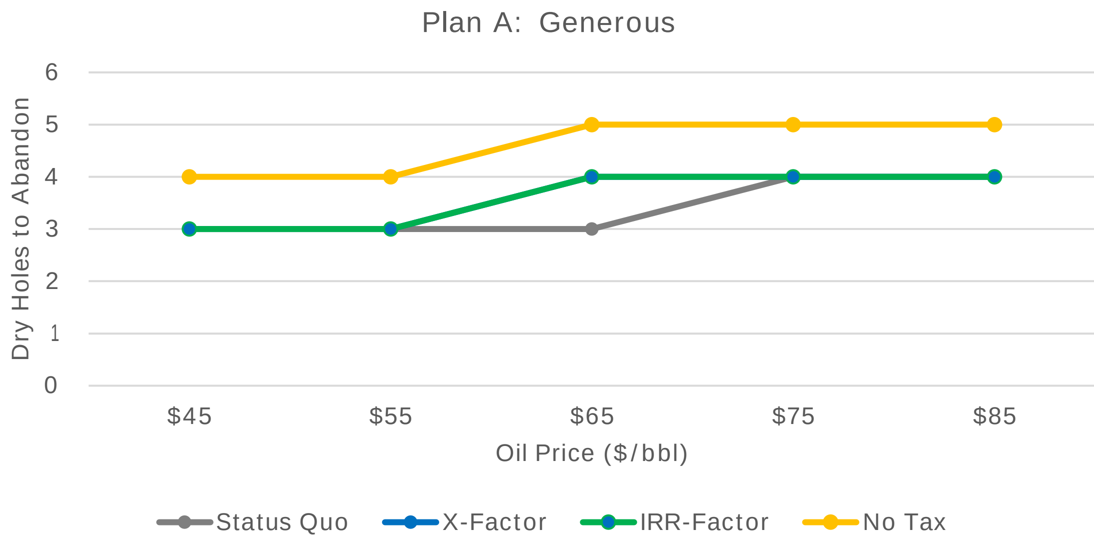
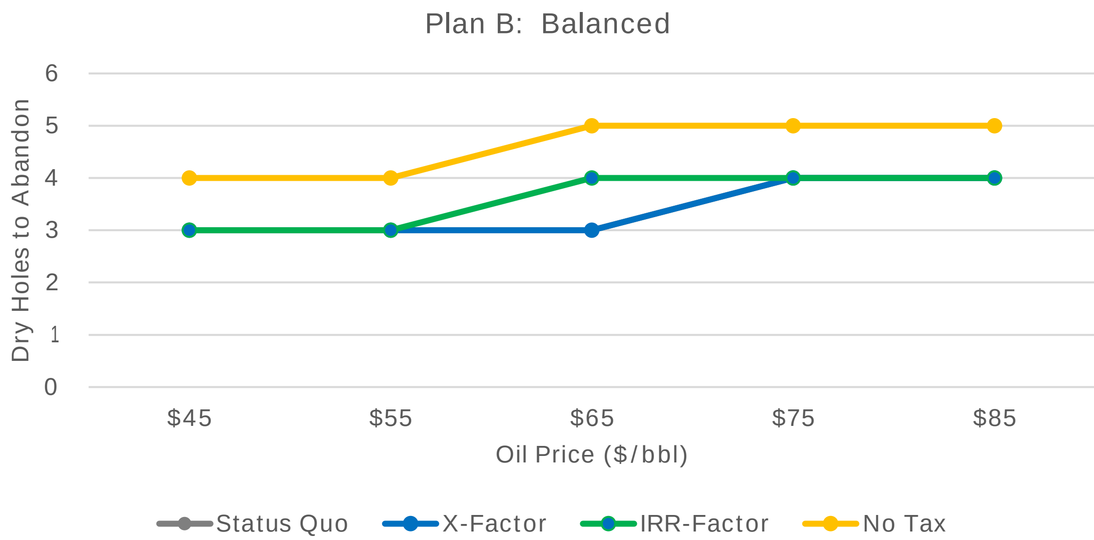


Figure A:5a Sensitivity of Exploration Intensity to Price (Eastern Onshore Oil)





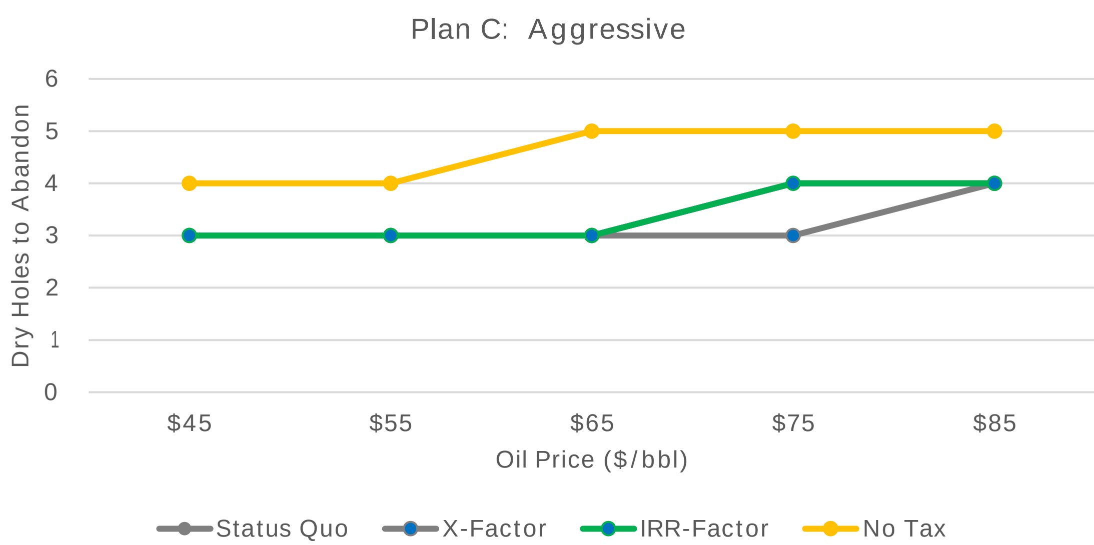
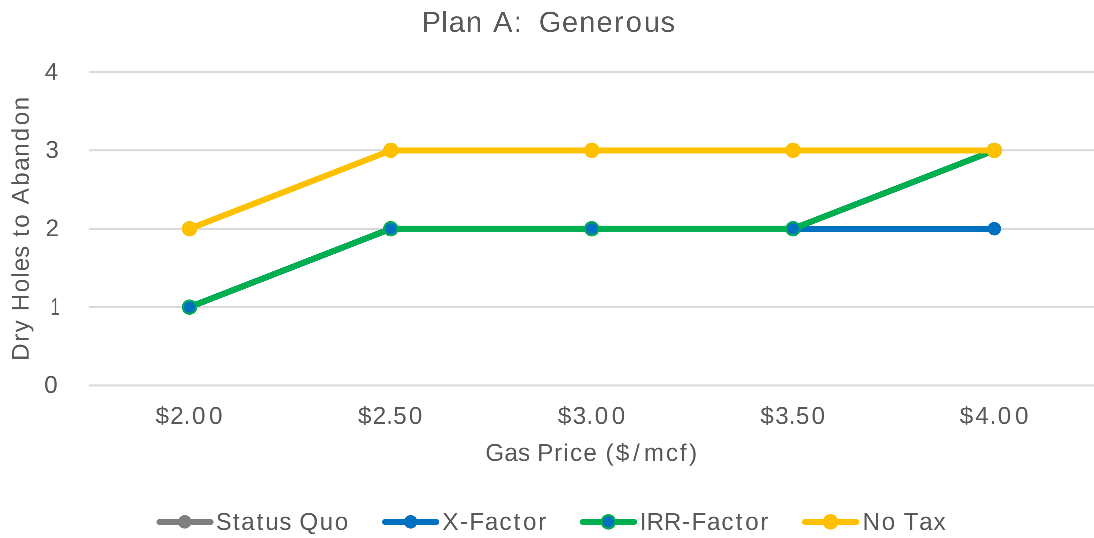
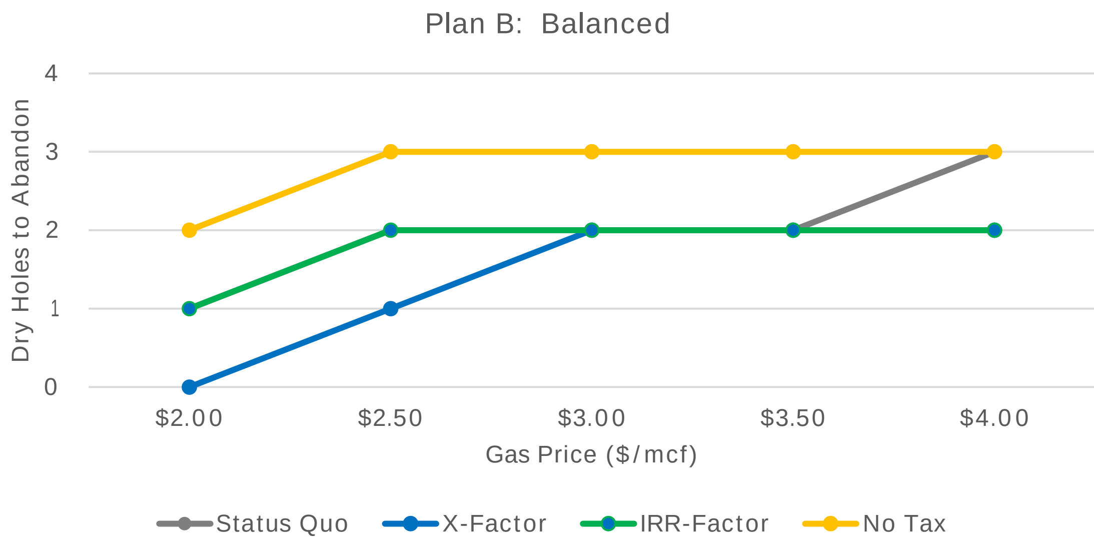


Figure A.5b Sensitivity of Exploration Intensity to Price (Eastern Onshore Gas)





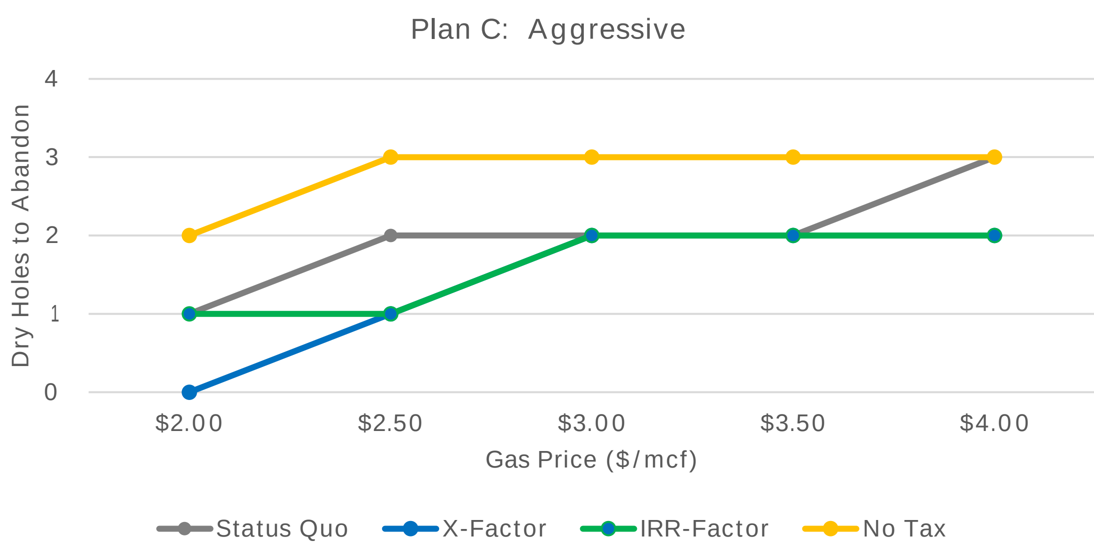
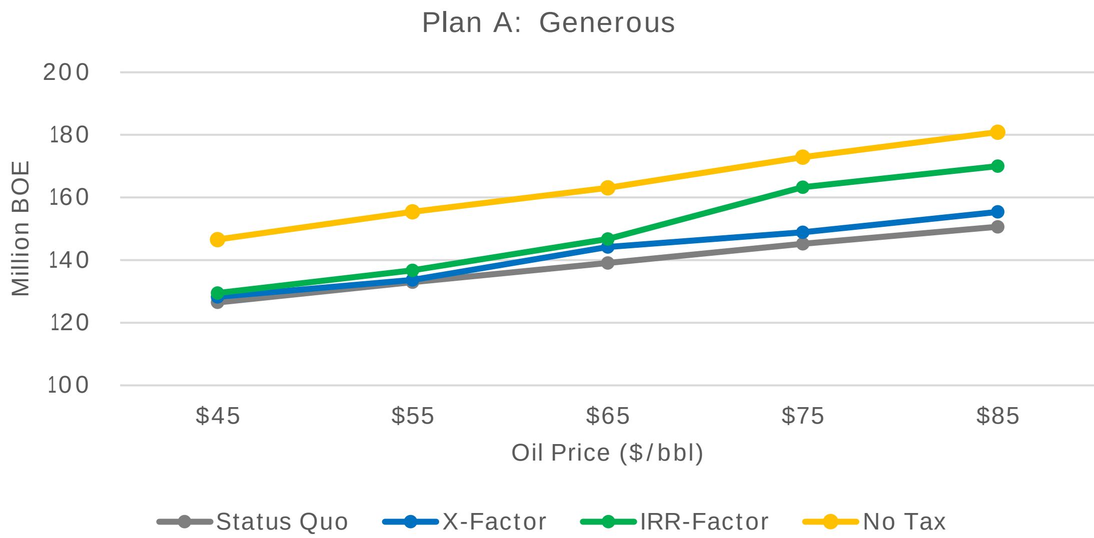
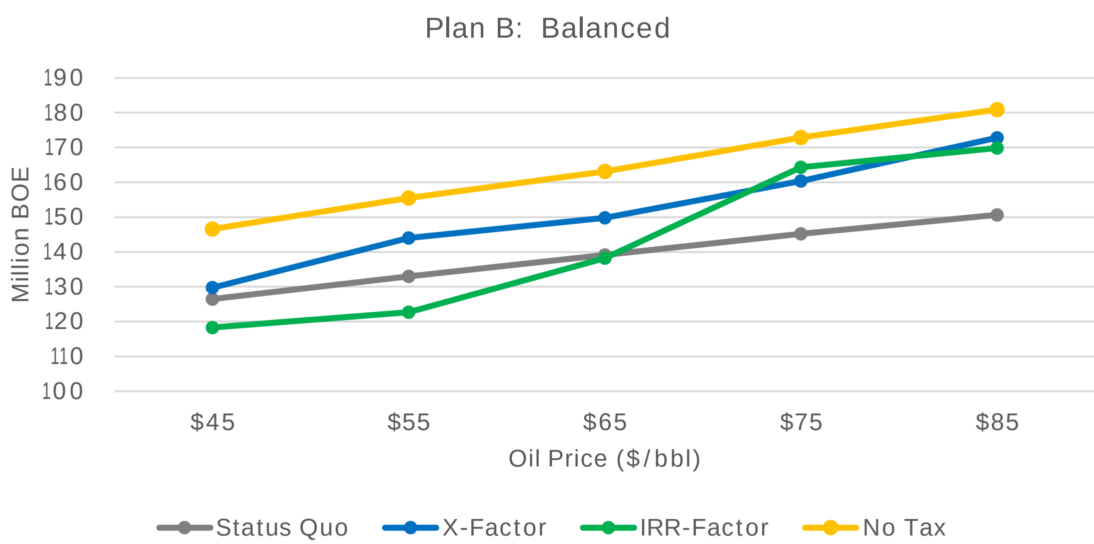


Figure A.6a Sensitivity of Risked Reserves to Price (Eastern Onshore Oil)





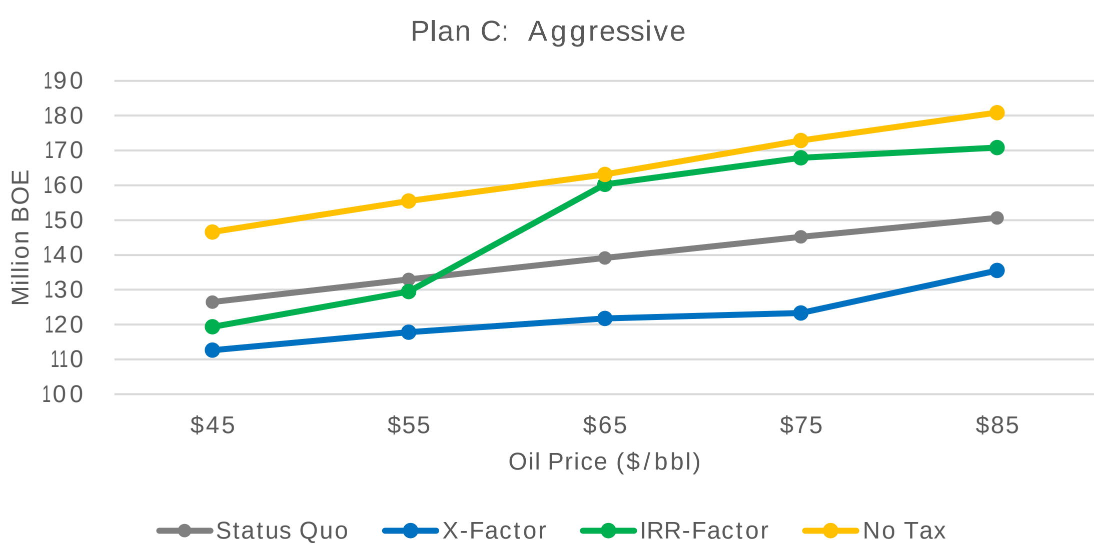


Figure A.6b Sensitivity of Risked Reserves to Price (Western Onshore Oil)

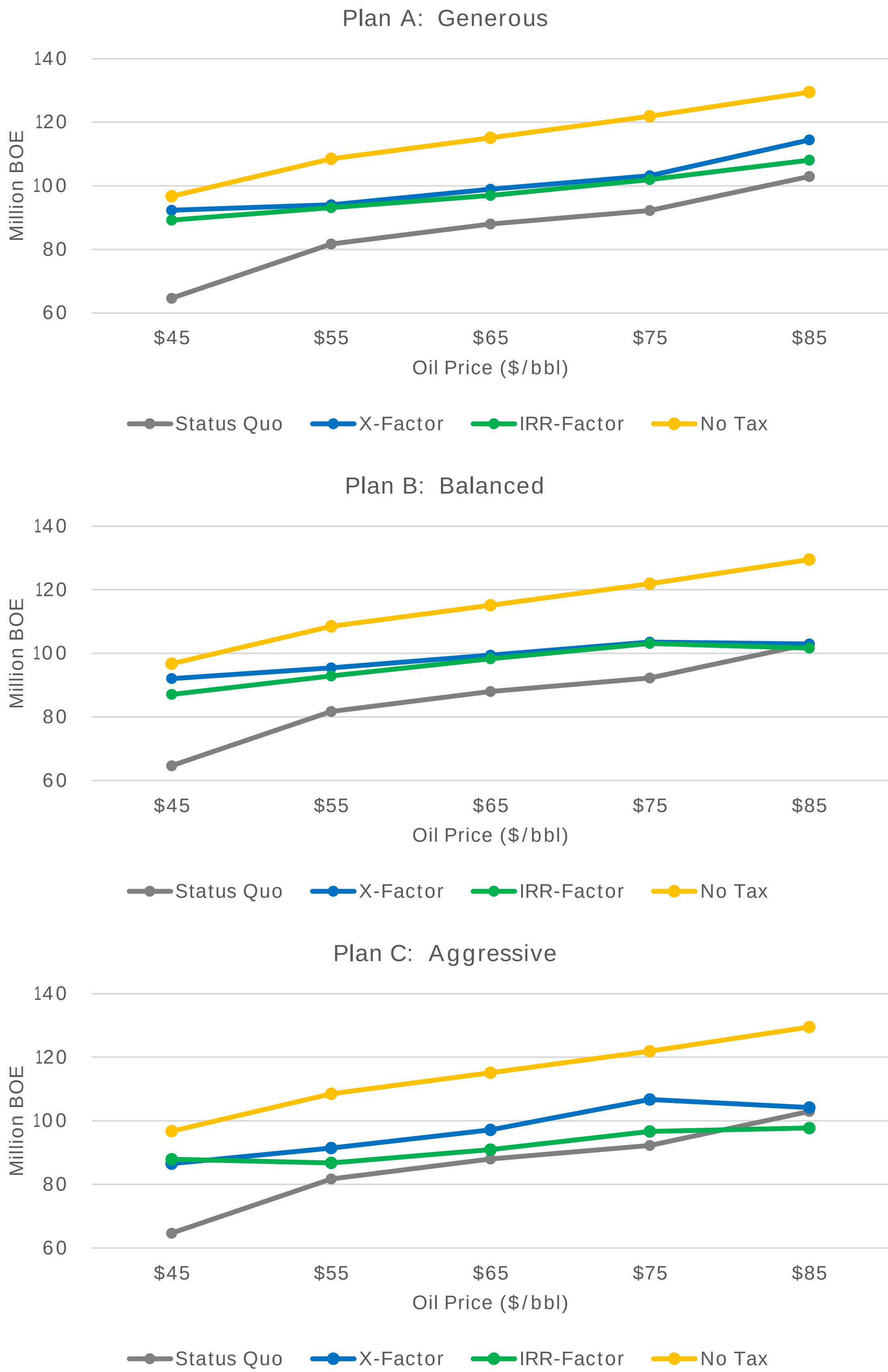


Figure A.6c Sensitivity of Risked Reserves to Price (Eastern Onshore Gas)

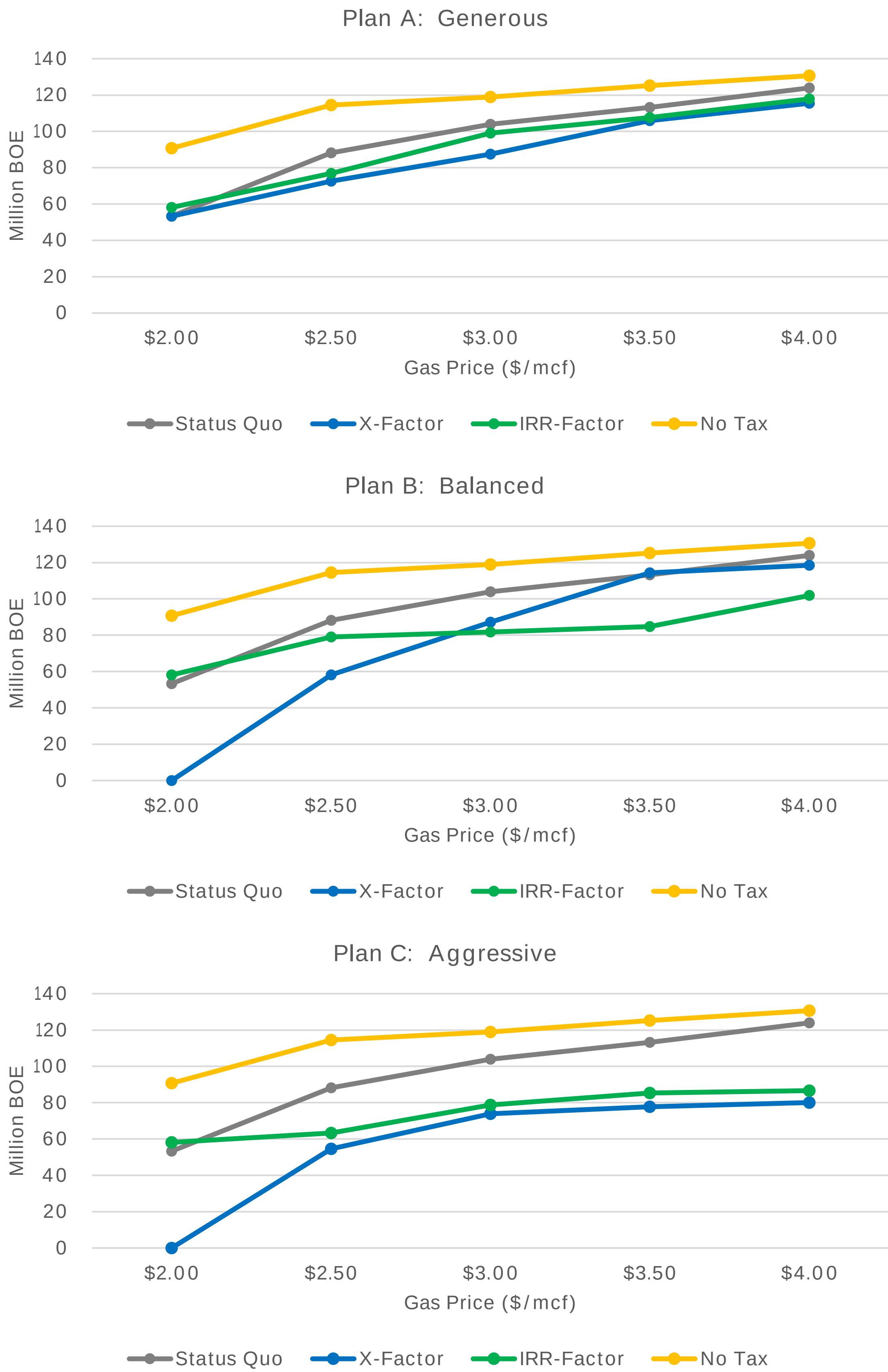


Figure A.6d Sensitivity of Risked Reserves to Price (Orinoco Heavy Oil)

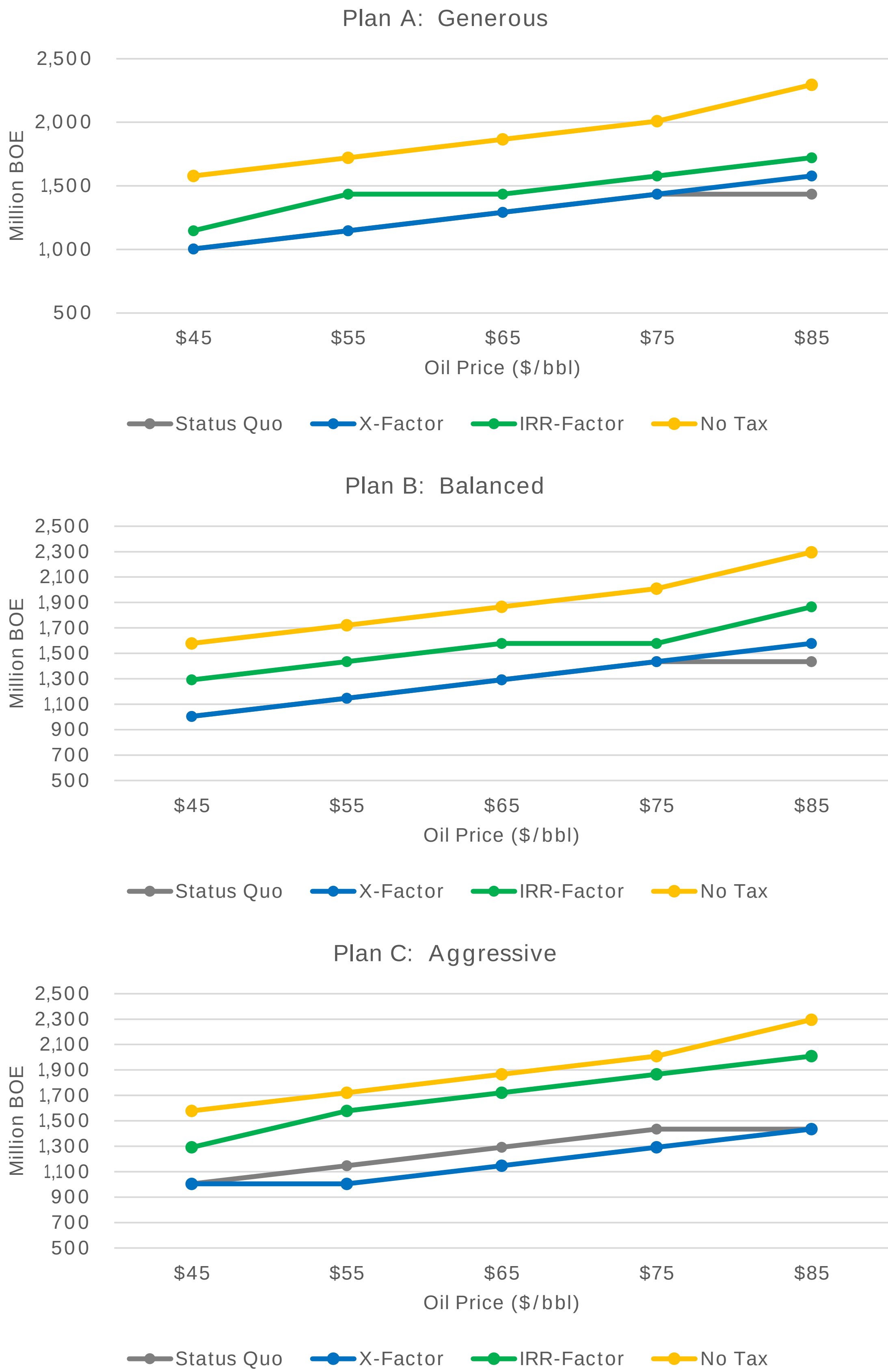


Figure A.7a Sensitivity of Rate of Extraction to Price (Eastern Onshore Oil)

Figure A.7b Sensitivity of Rate of Extraction to Price (Western Onshore Oil)

Figure A.7c Sensitivity of Rate of Extraction to Price (Eastern Onshore Gas)

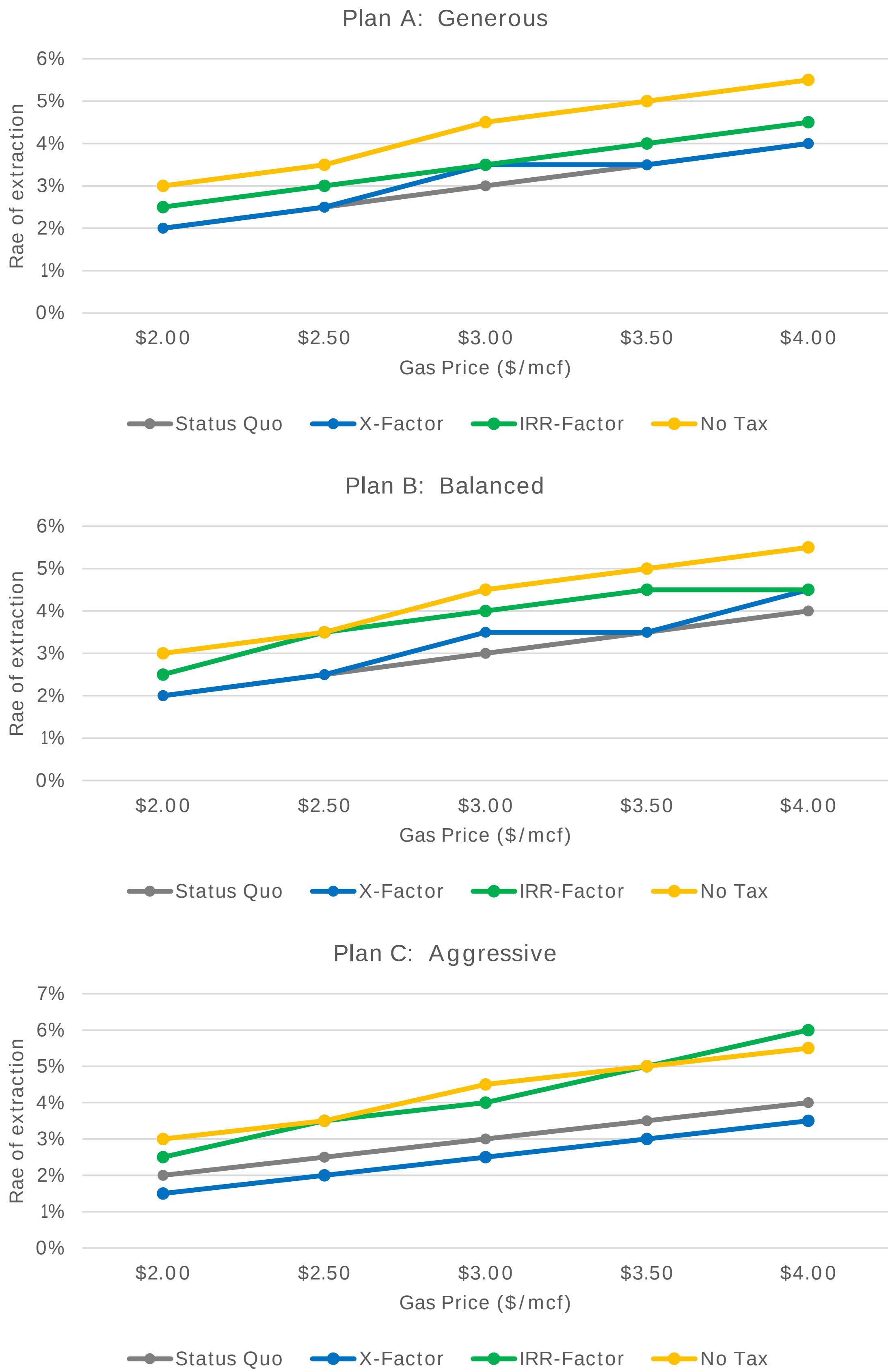
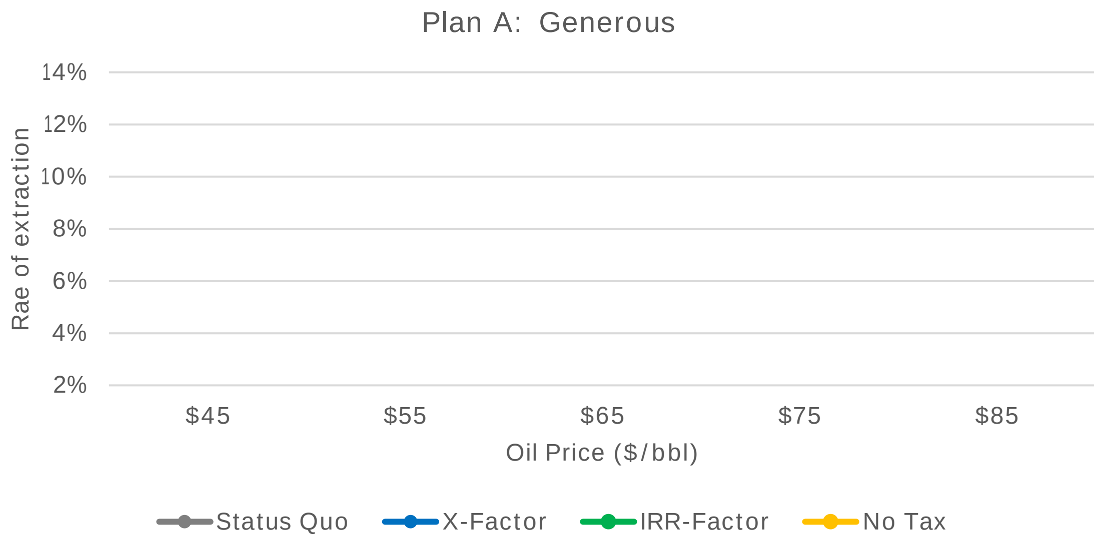
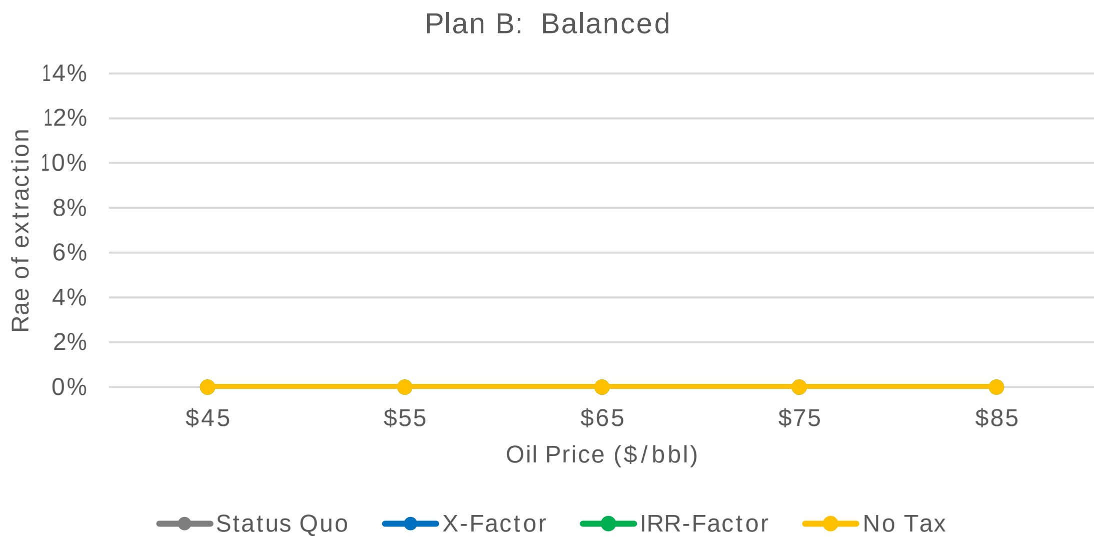


Figure A.7d Sensitivity of Rate of Extraction to Price (Orinoco Heavy Oil)





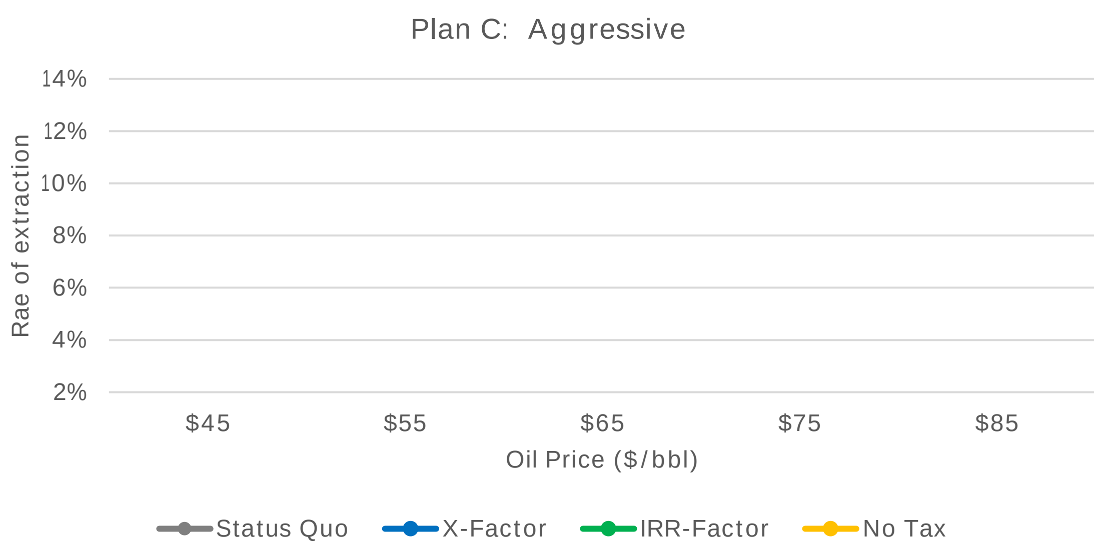
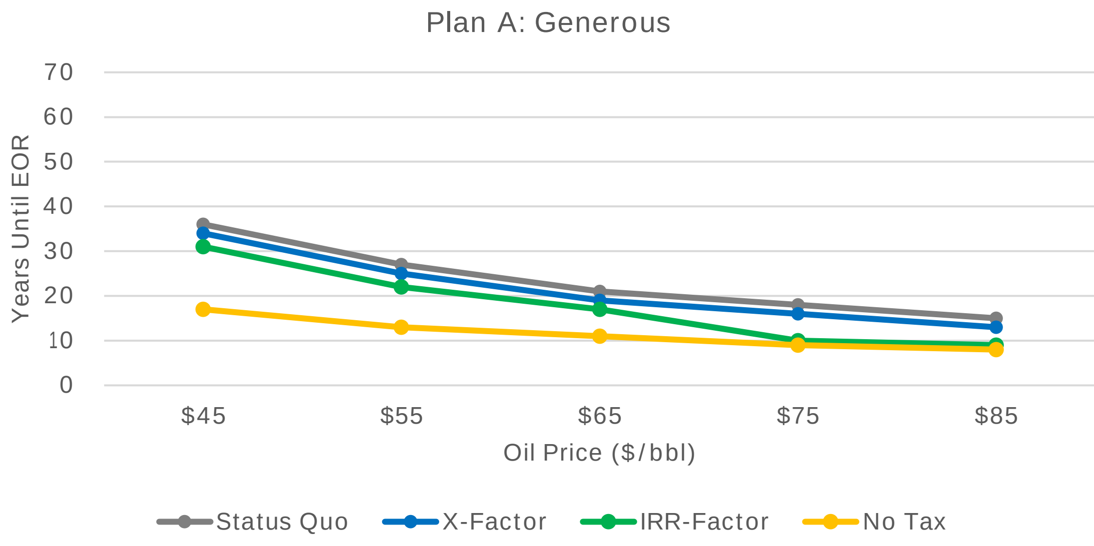
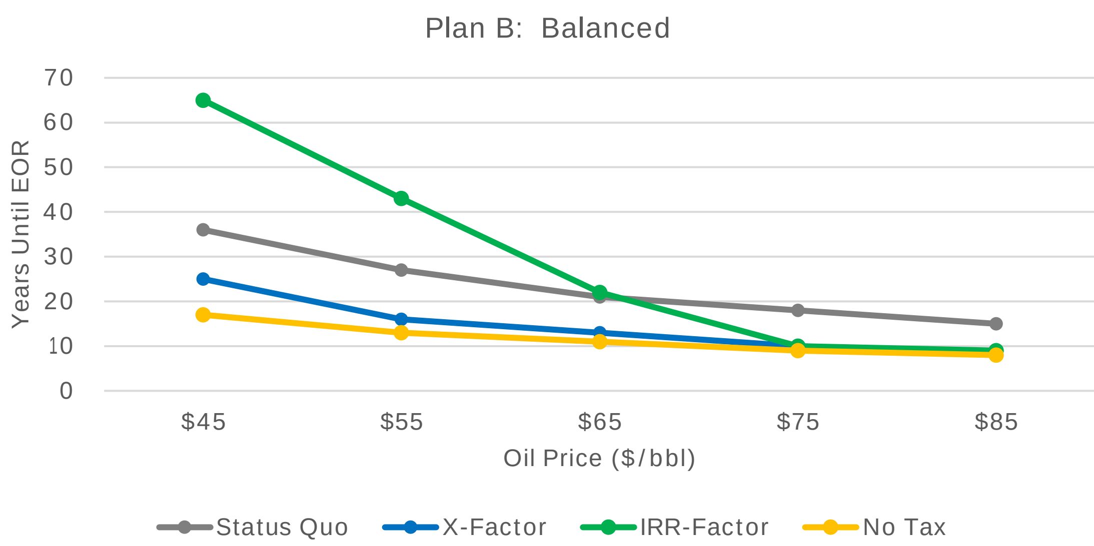


Figure A.8a Sensitivity of Implementation of EOR to Price (Eastern Onshore Oil)





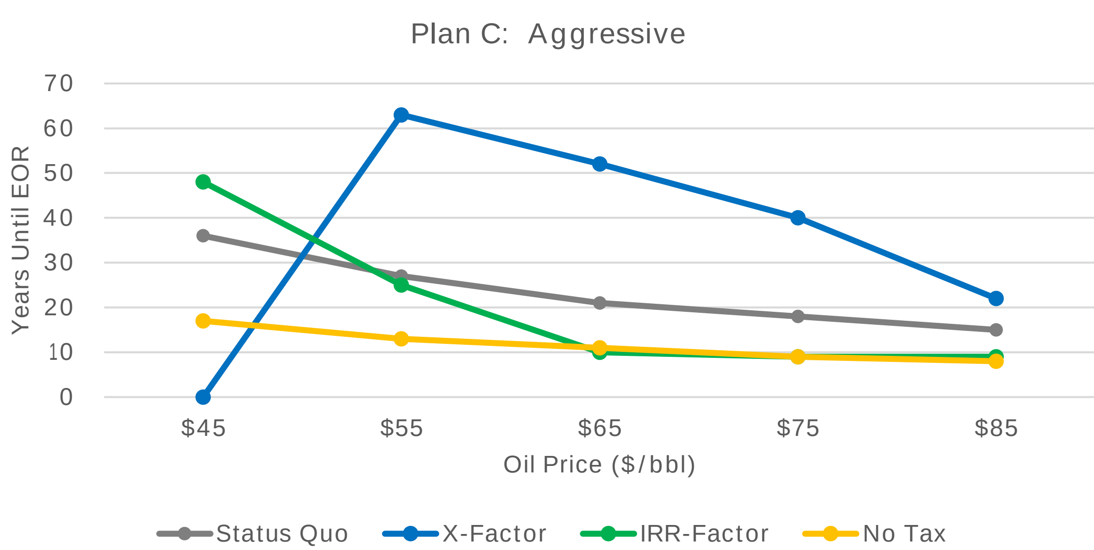
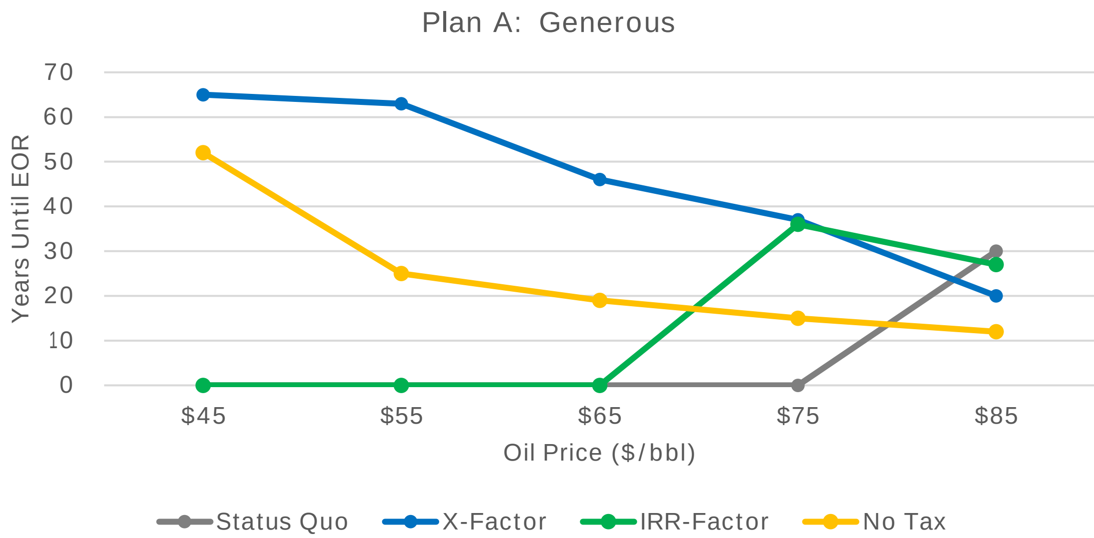
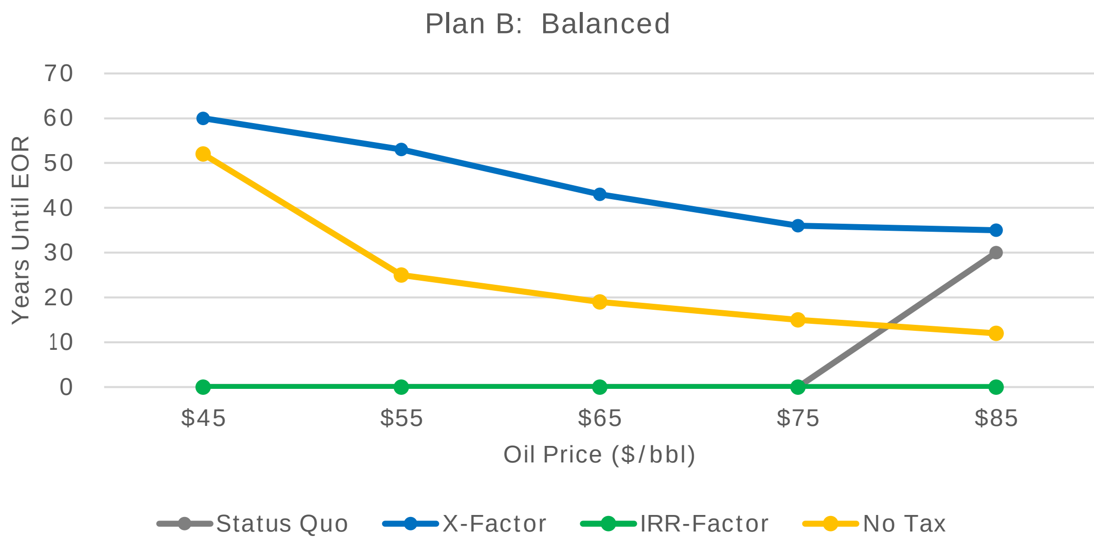


Figure A.8b Sensitivity of Implementation of EOR to Price (Western Onshore Oil)





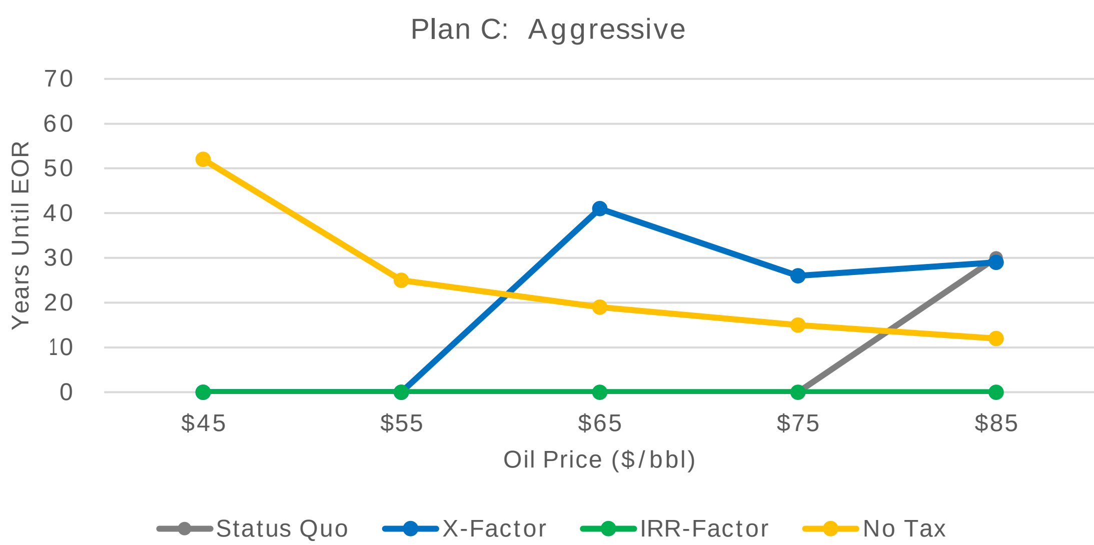
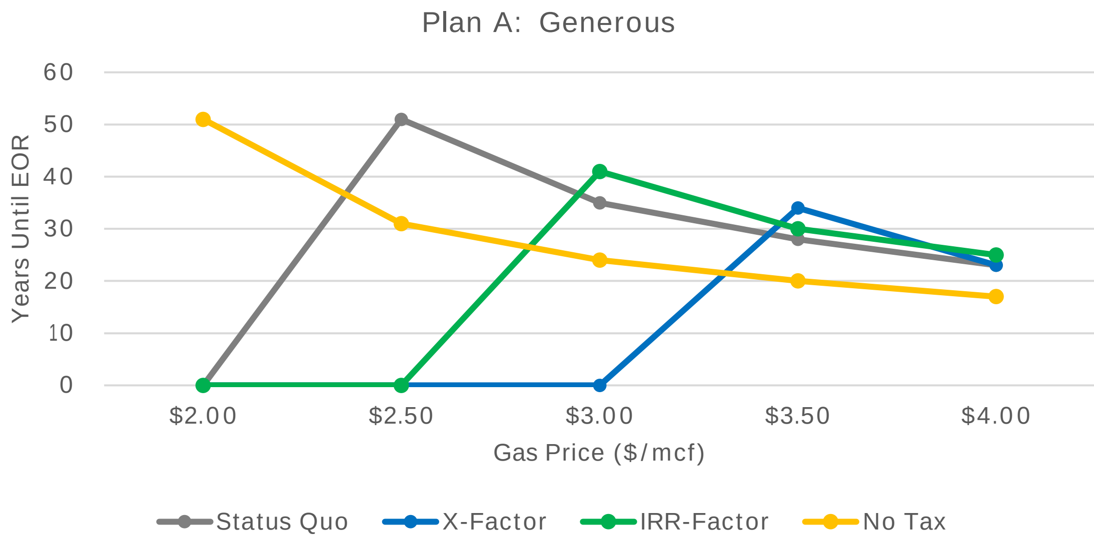
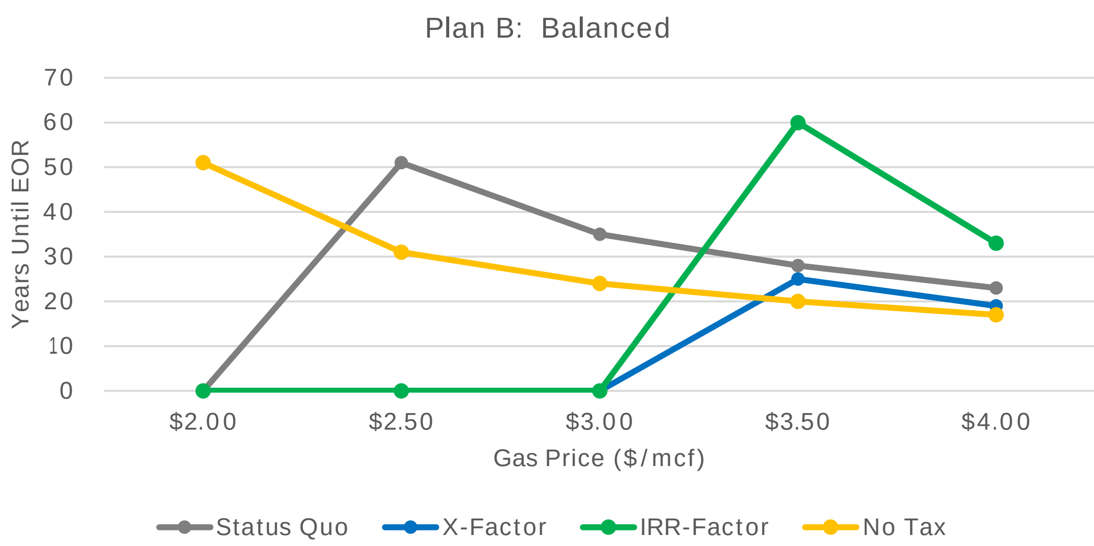


Figure A.8c Sensitivity of Implementation of EOR to Price (Eastern Onshore Gas)





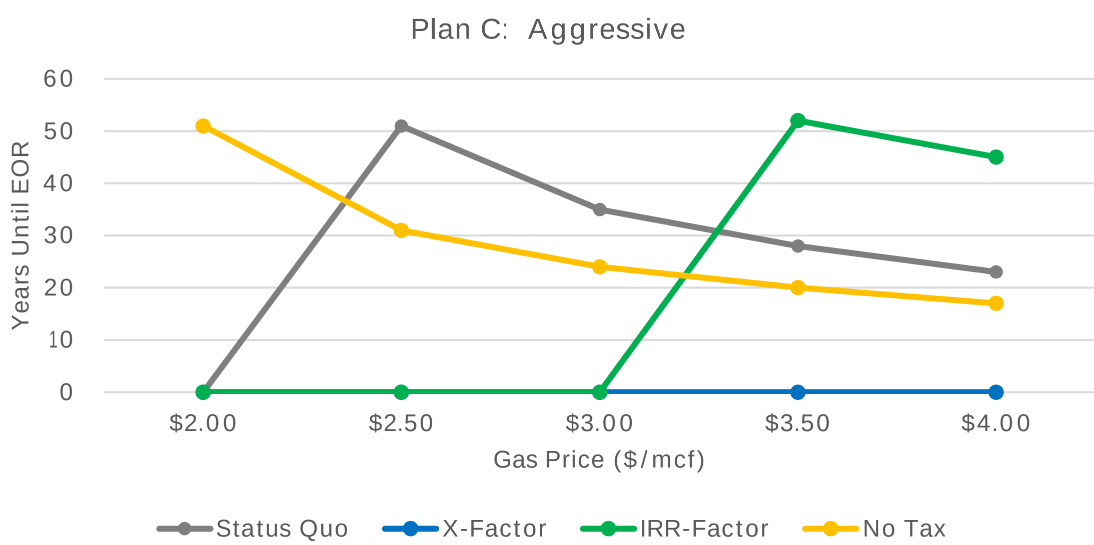
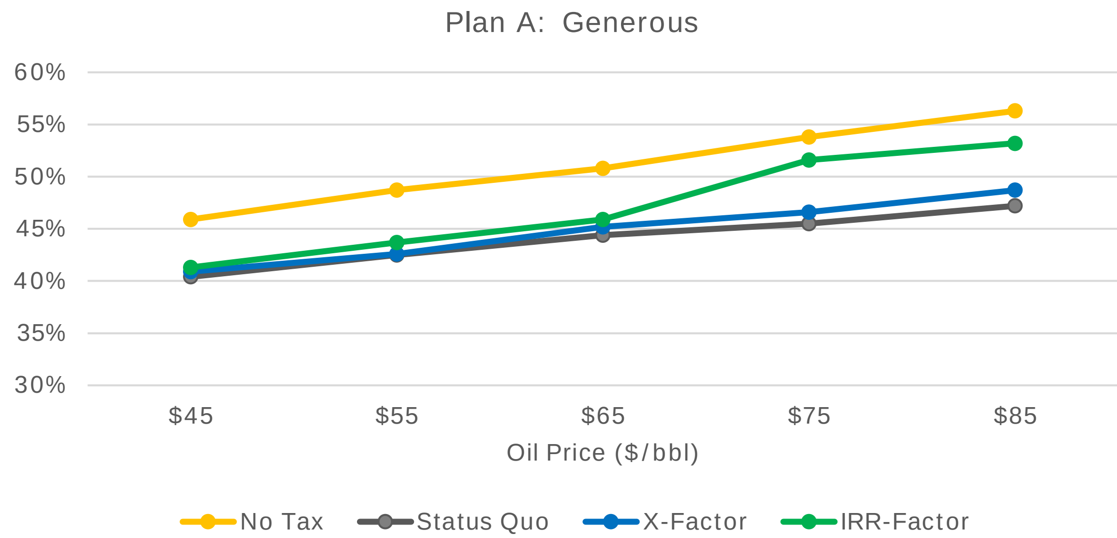
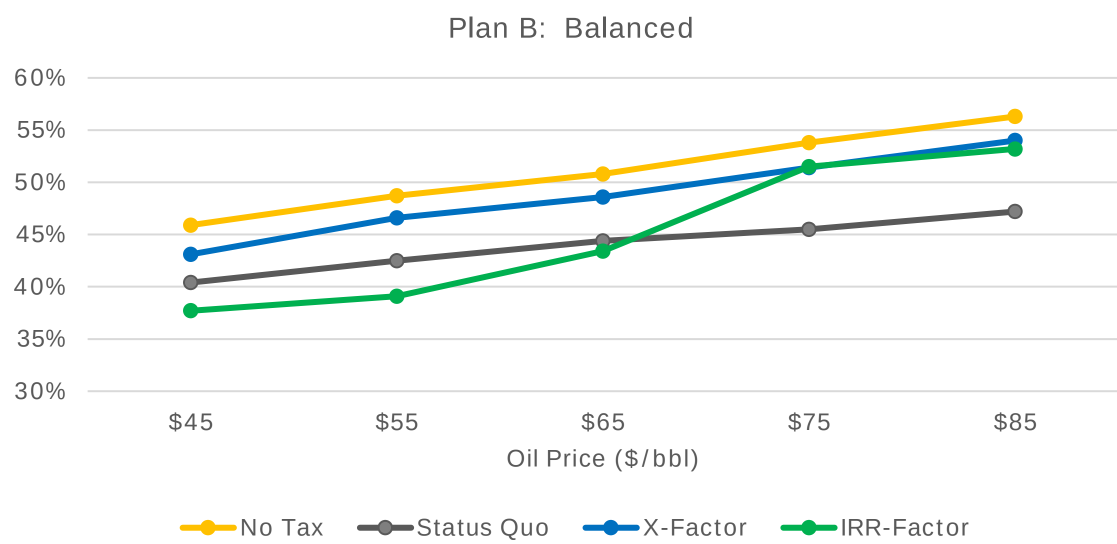


Figure A.9a Sensitivity of Resource Recovery Factor to Price (Eastern Onshore Oil)





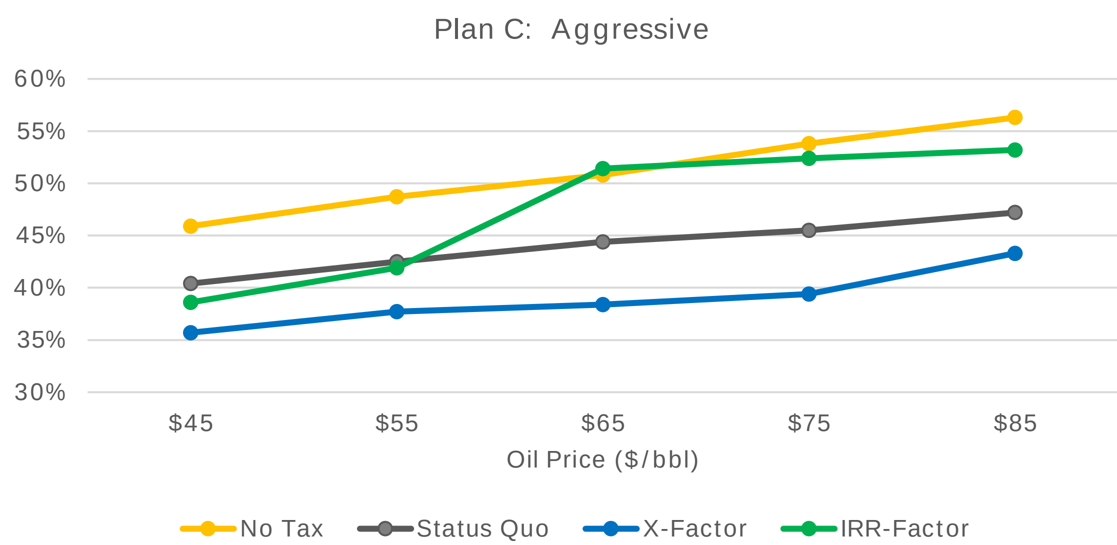


Figure A.9b Sensitivity of Resource Recovery Factor to Price (Western Onshore Oil)

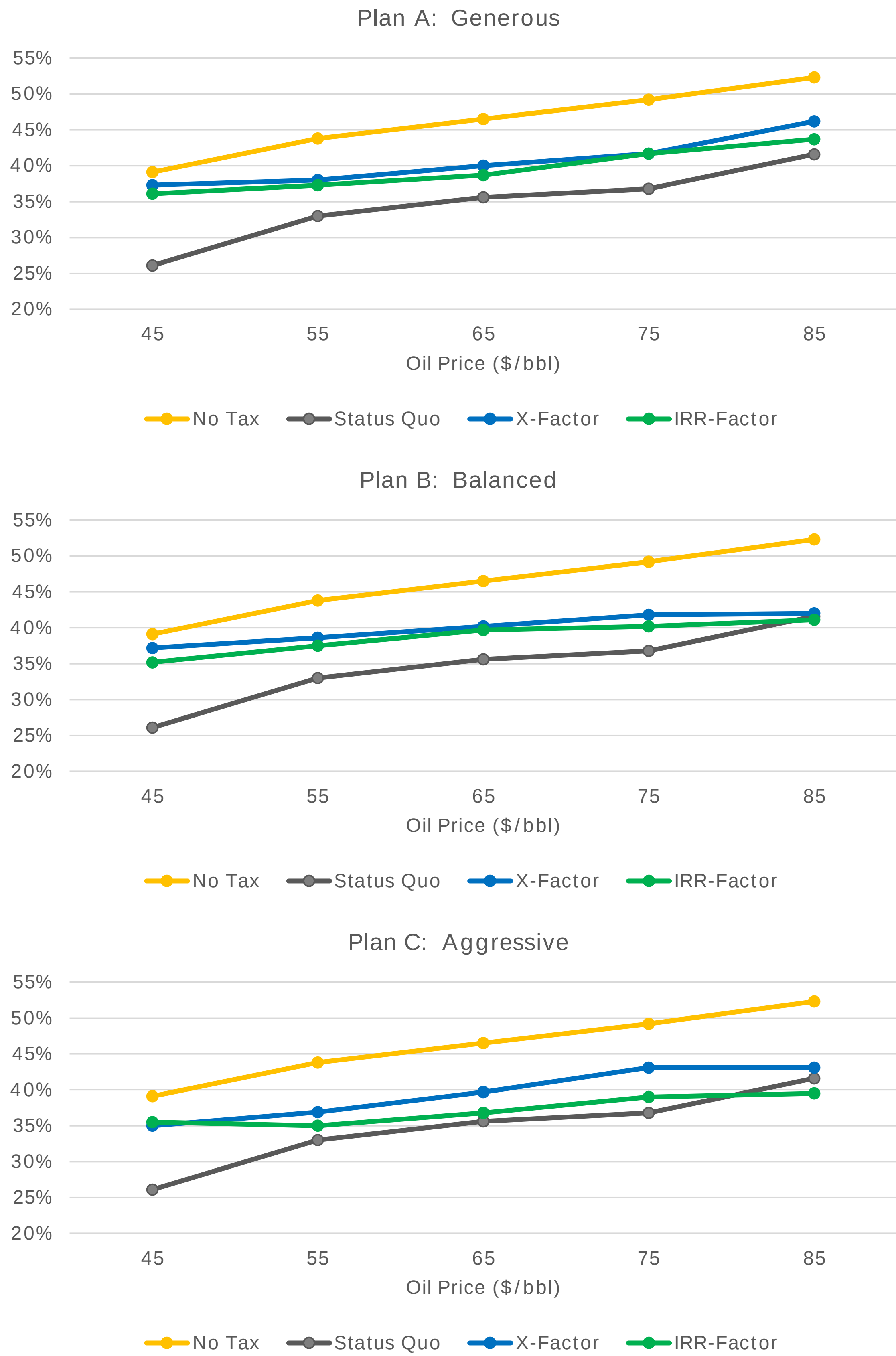
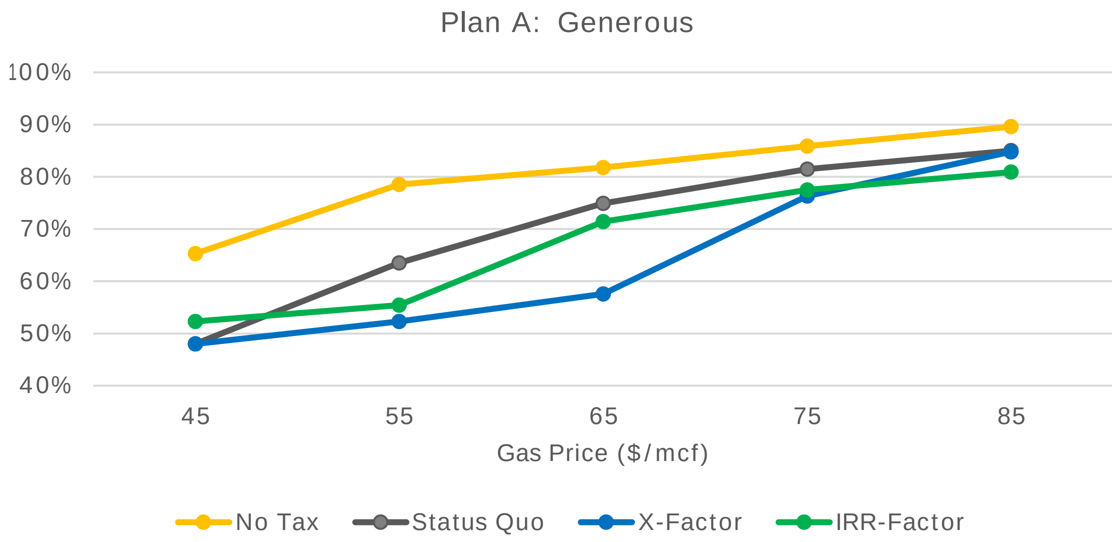
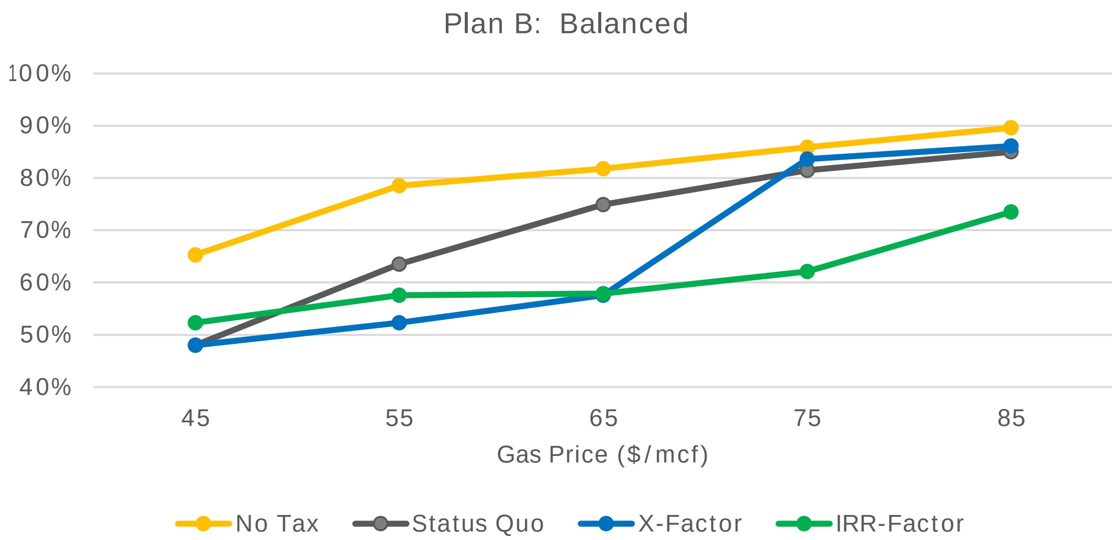


Figure A.9c Sensitivity of Resource Recovery Factor to Price (Eastern Onshore Gas)





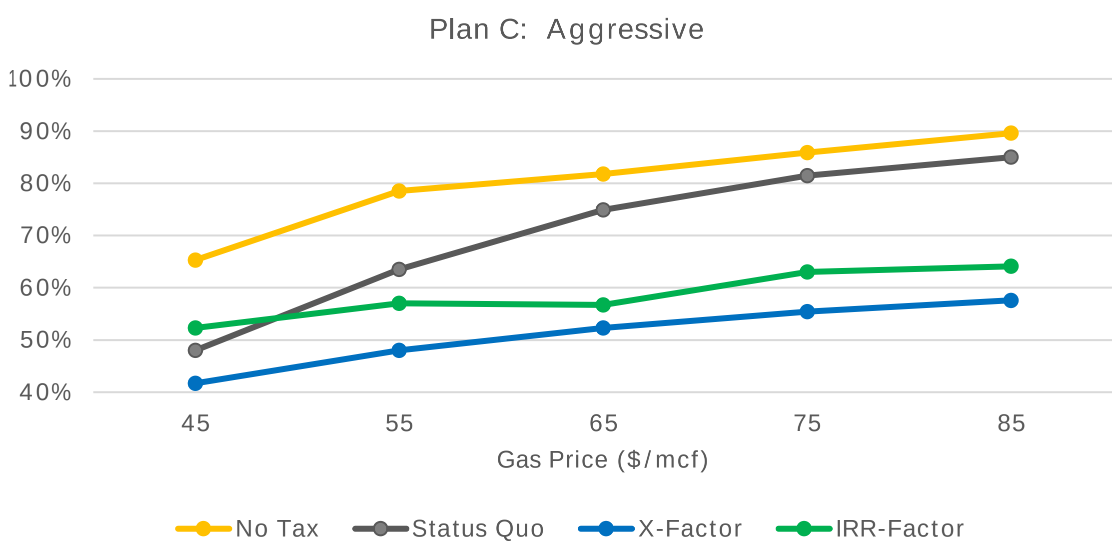


Figure A.9d Sensitivity of Resource Recovery Factor to Price (Orinoco Heavy Oil)

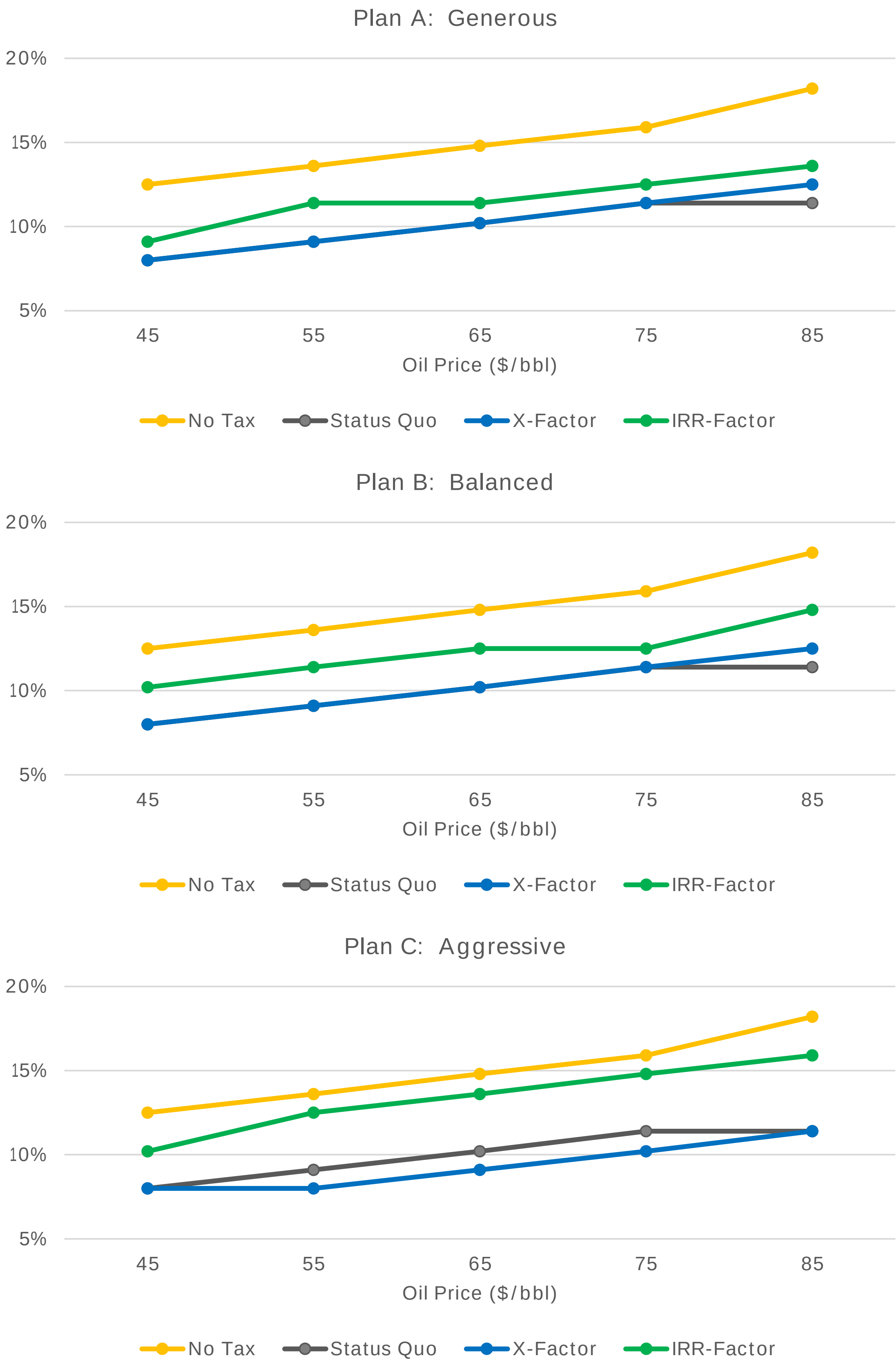


Figure A.10a Sensitivity of Project Lifetime to Price (Eastern Onshore Oil)

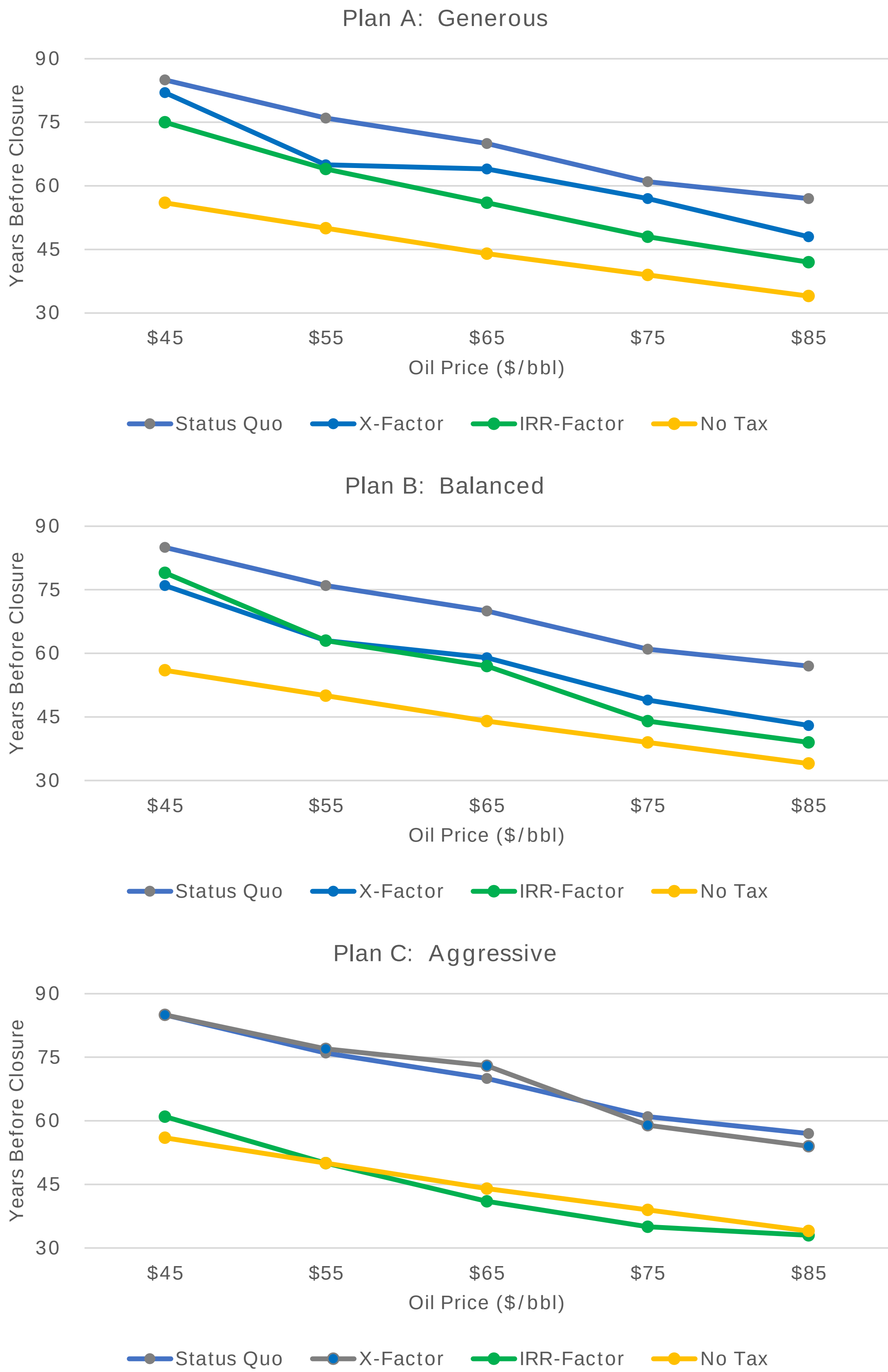
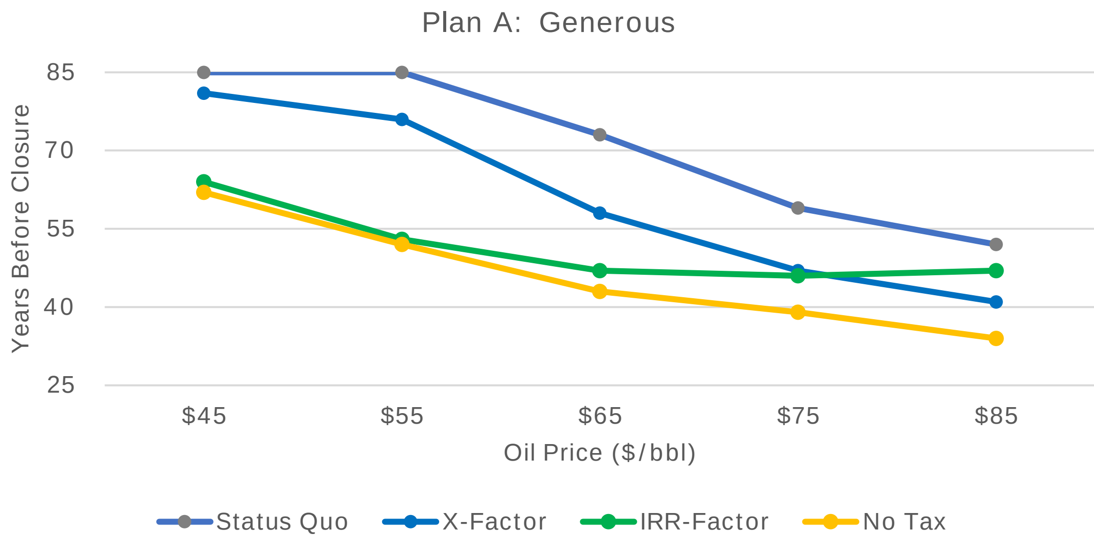
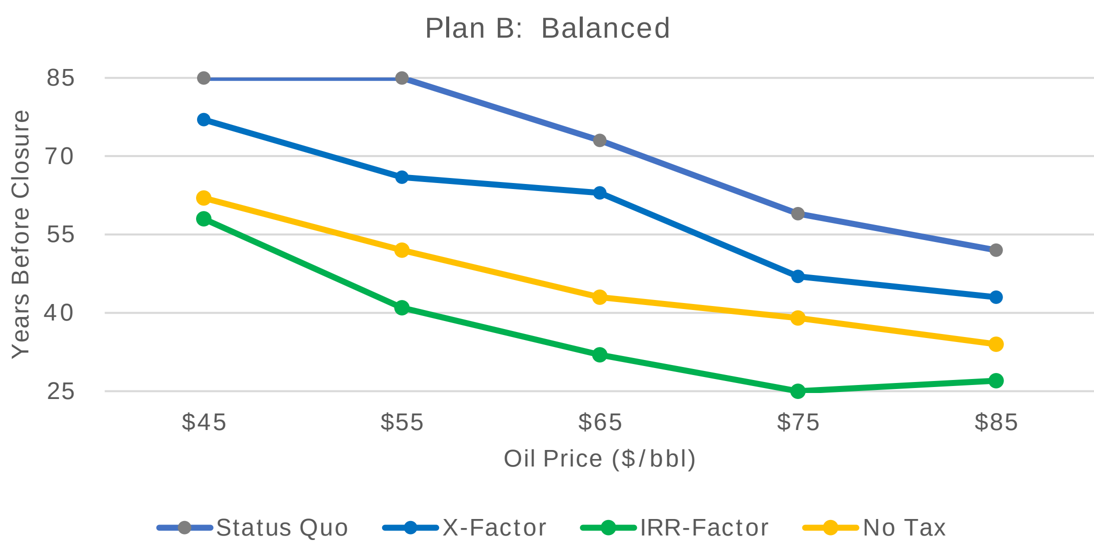


Figure A.10b Sensitivity of Project Lifetime to Price (Western Onshore Oil)





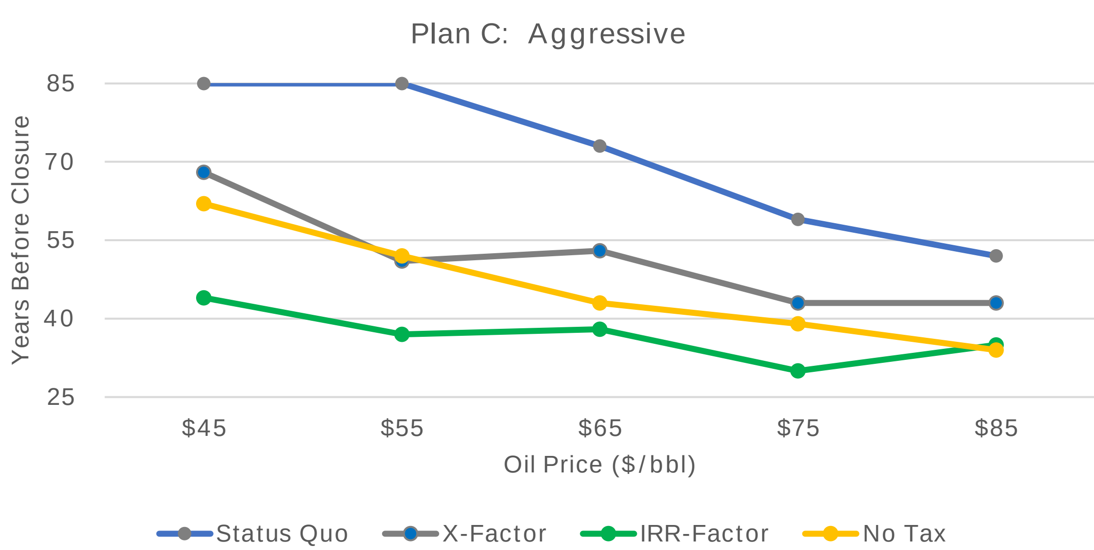
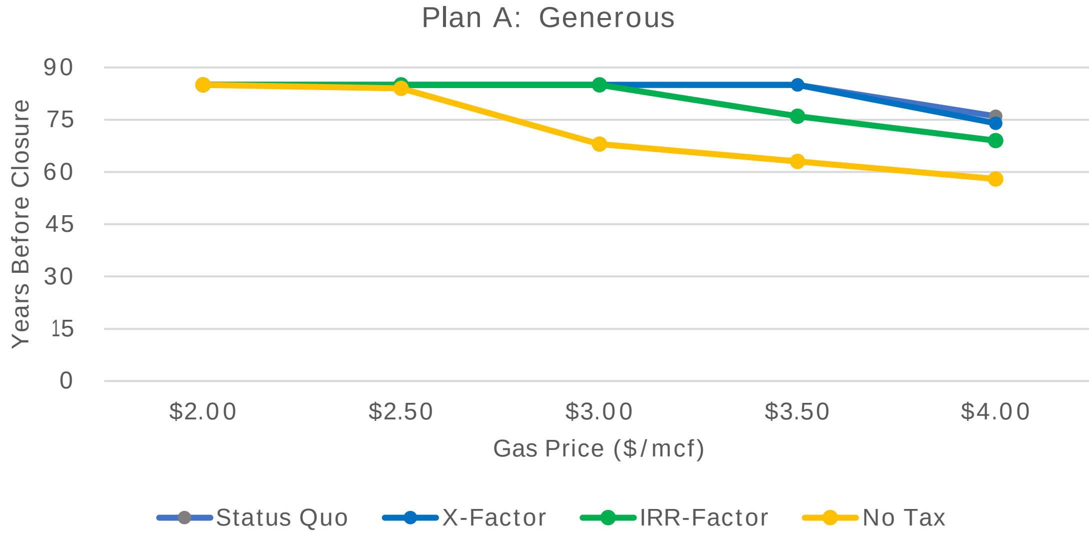
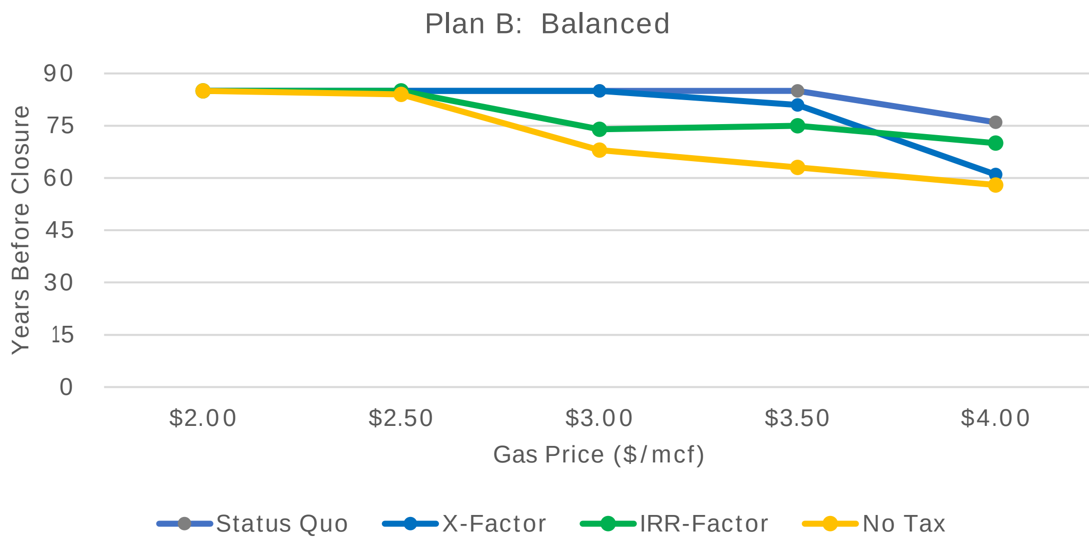


Figure A.10c Sensitivity of Project Lifetime to Price (Eastern Onshore Gas)





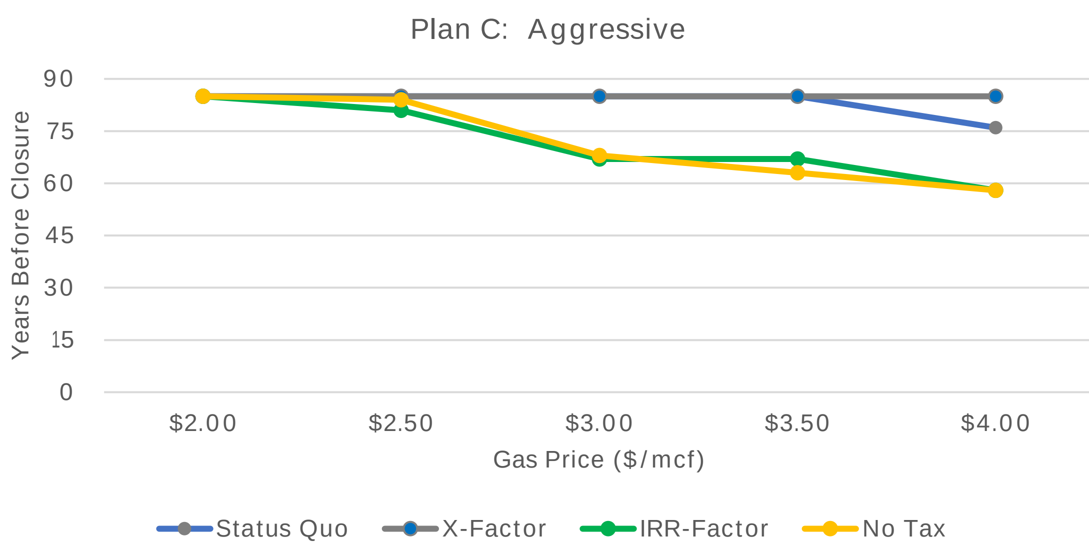


Figure A.10d Sensitivity of Project Lifetime to Price (Orinoco Heavy Oil)

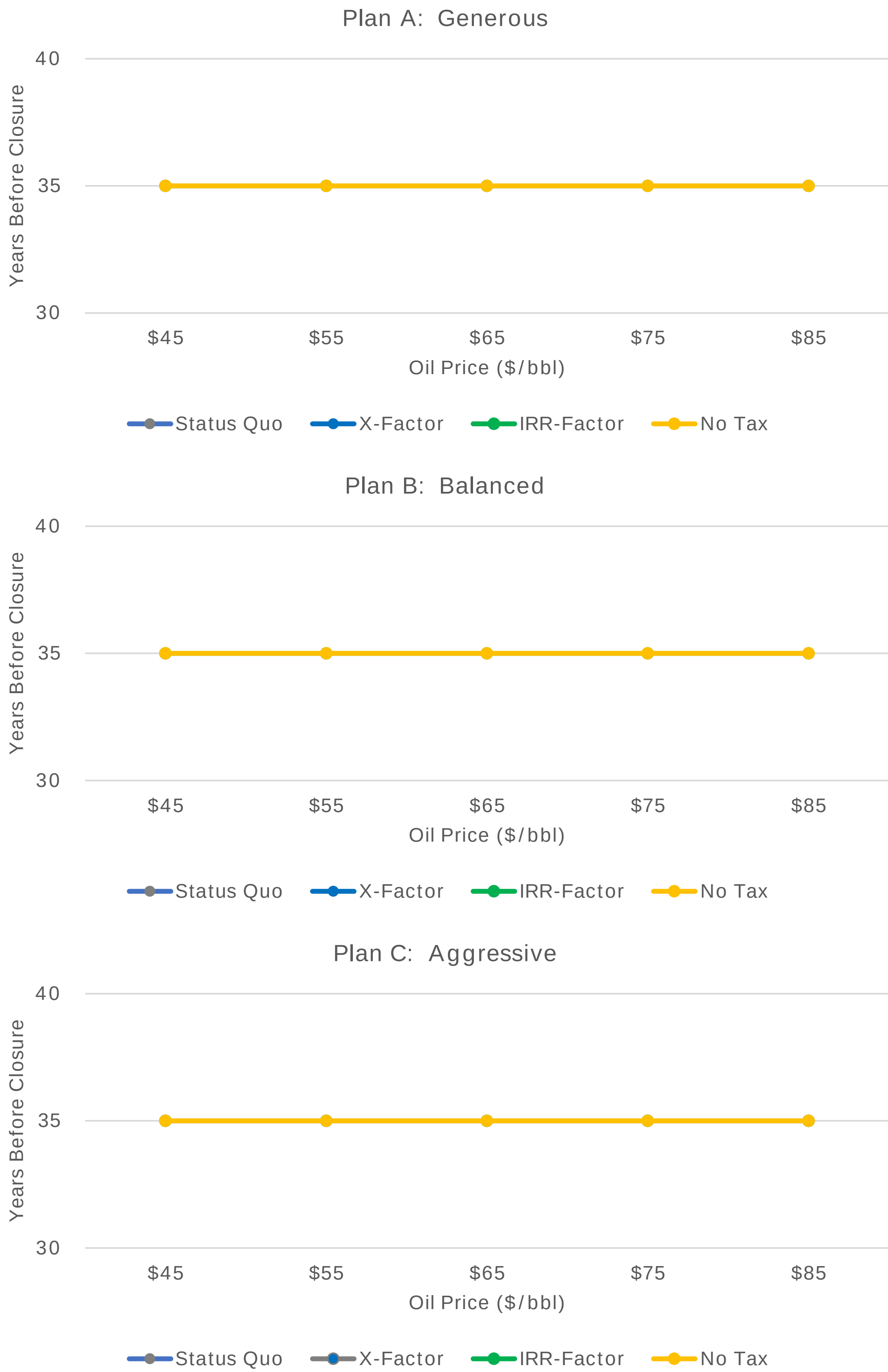
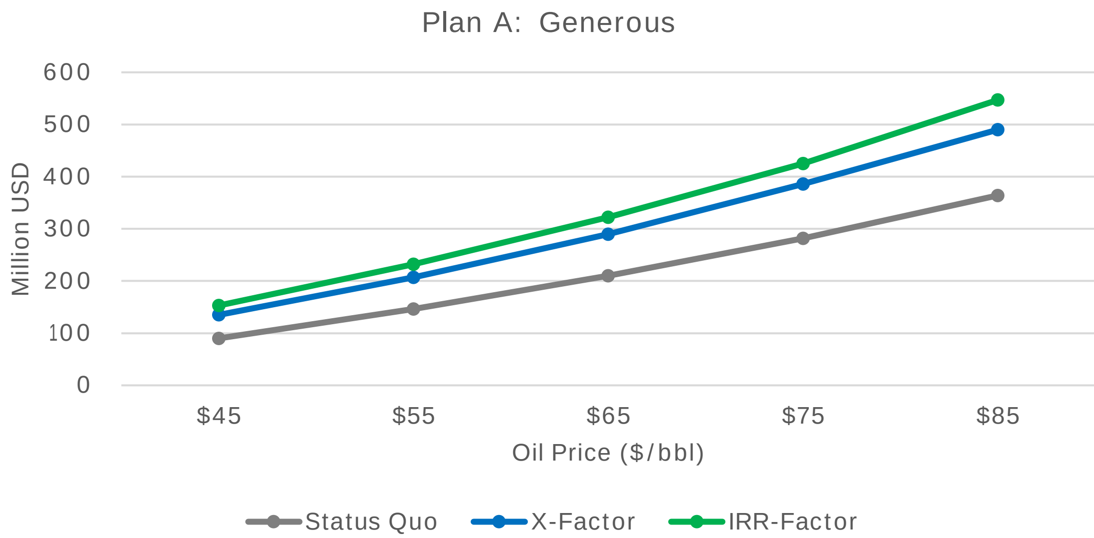
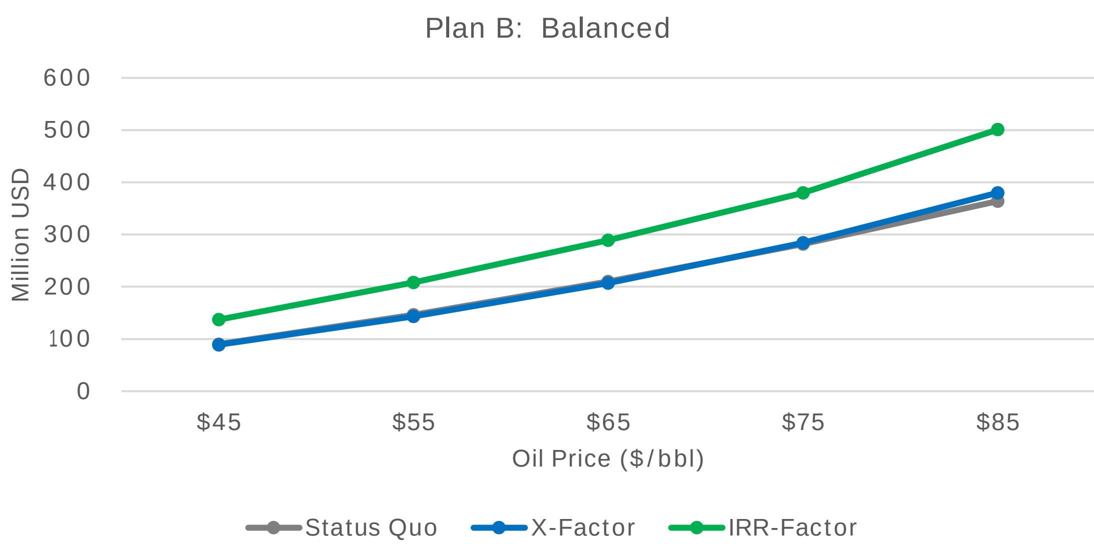


Figure A.11a Sensitivity of Investor NPV to Price (Eastern Onshore Oil)





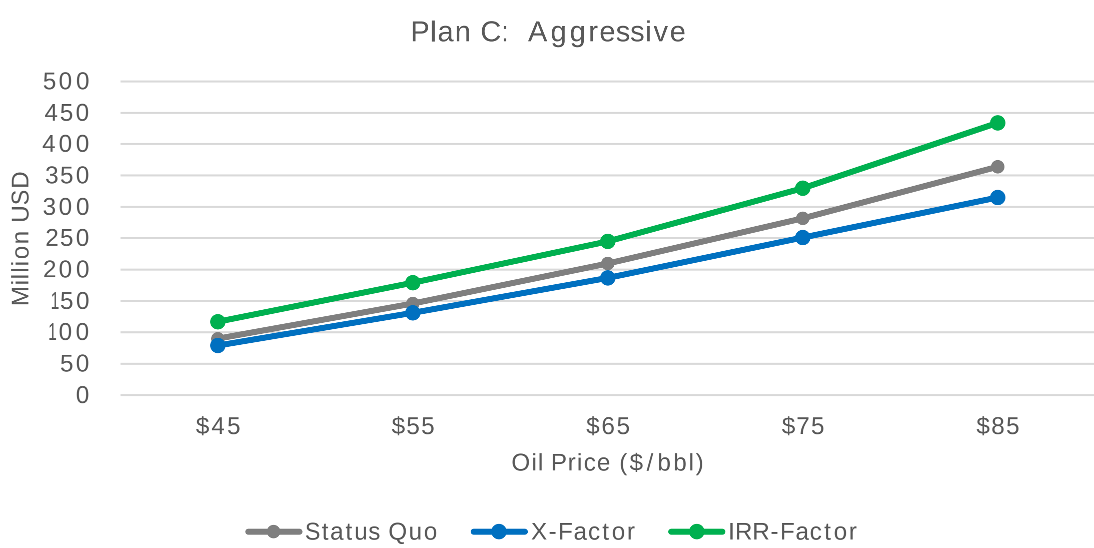
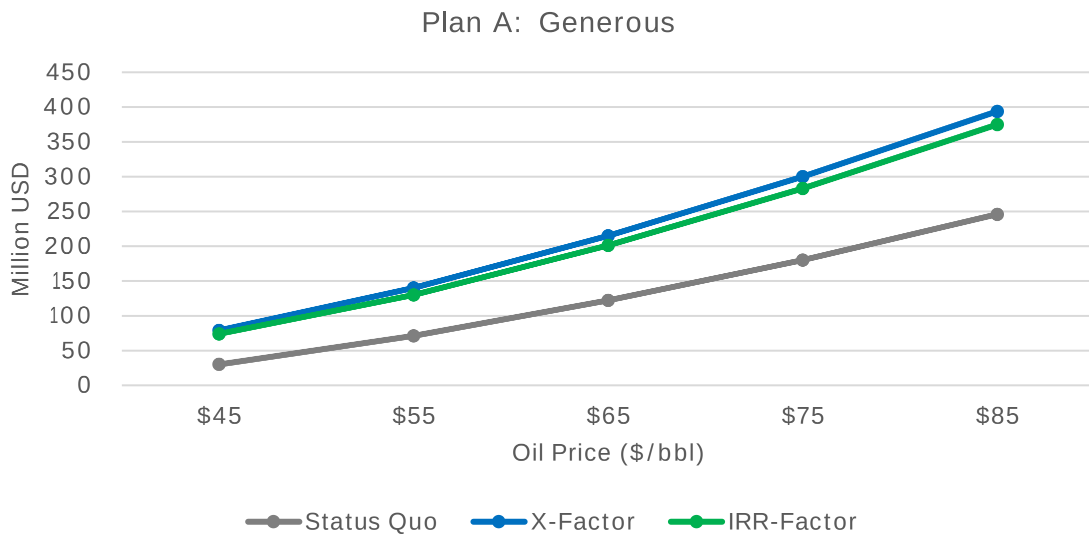
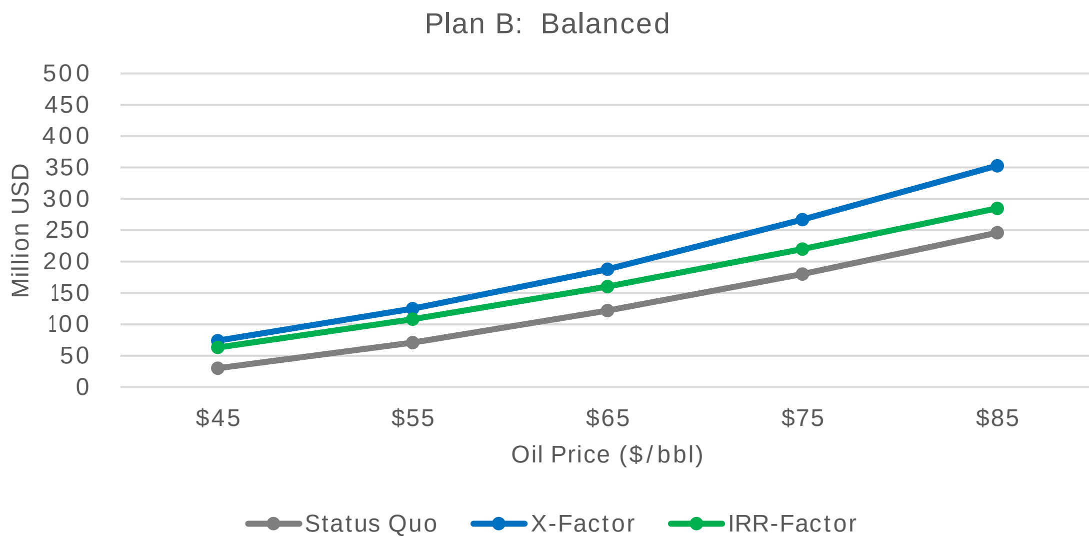


Figure A.11b Sensitivity of Investor NPV to Price (Western Onshore Oil)





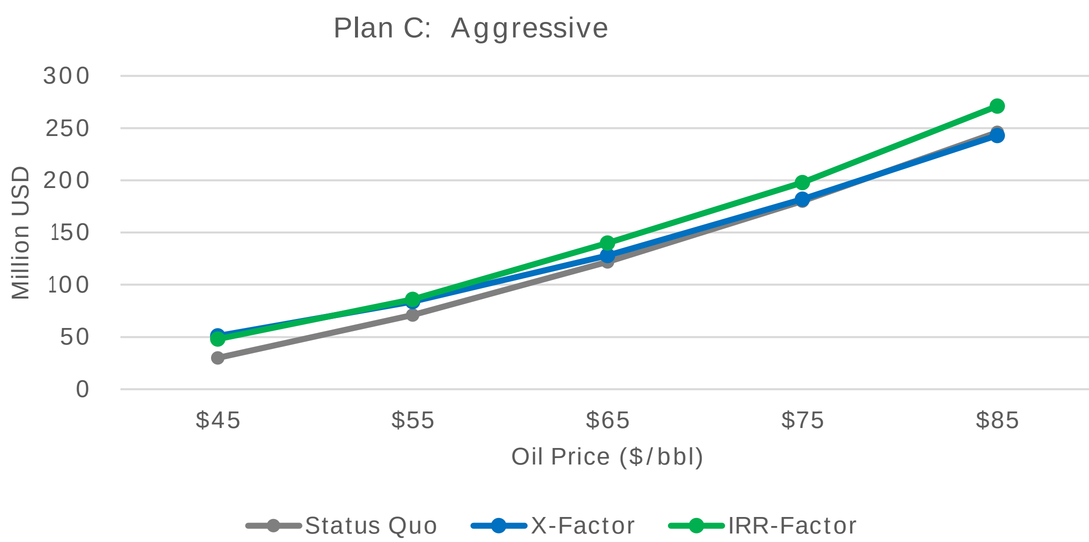


Figure A.11c Sensitivity of Investor NPV to Price (Eastern Onshore Gas)

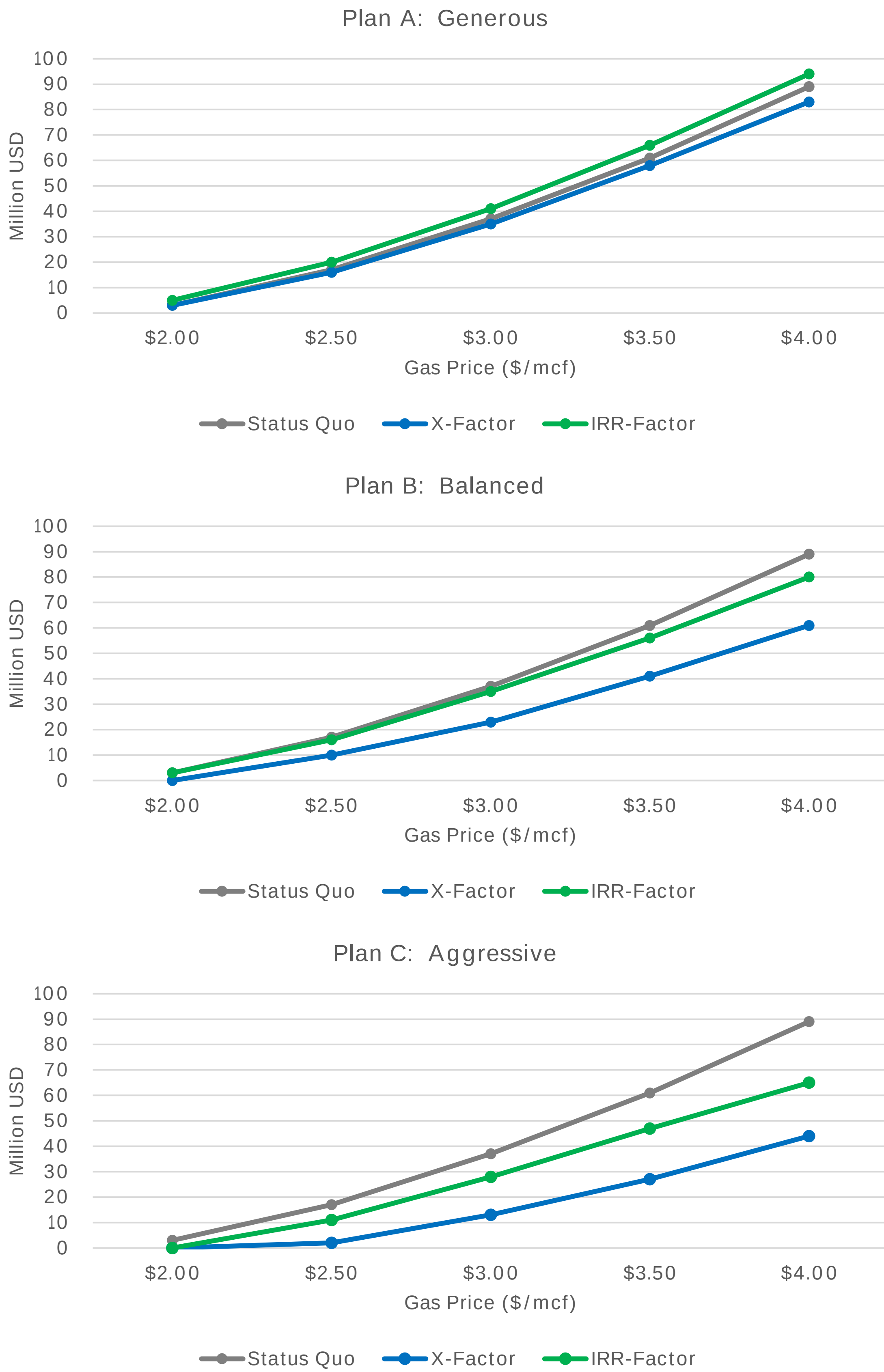
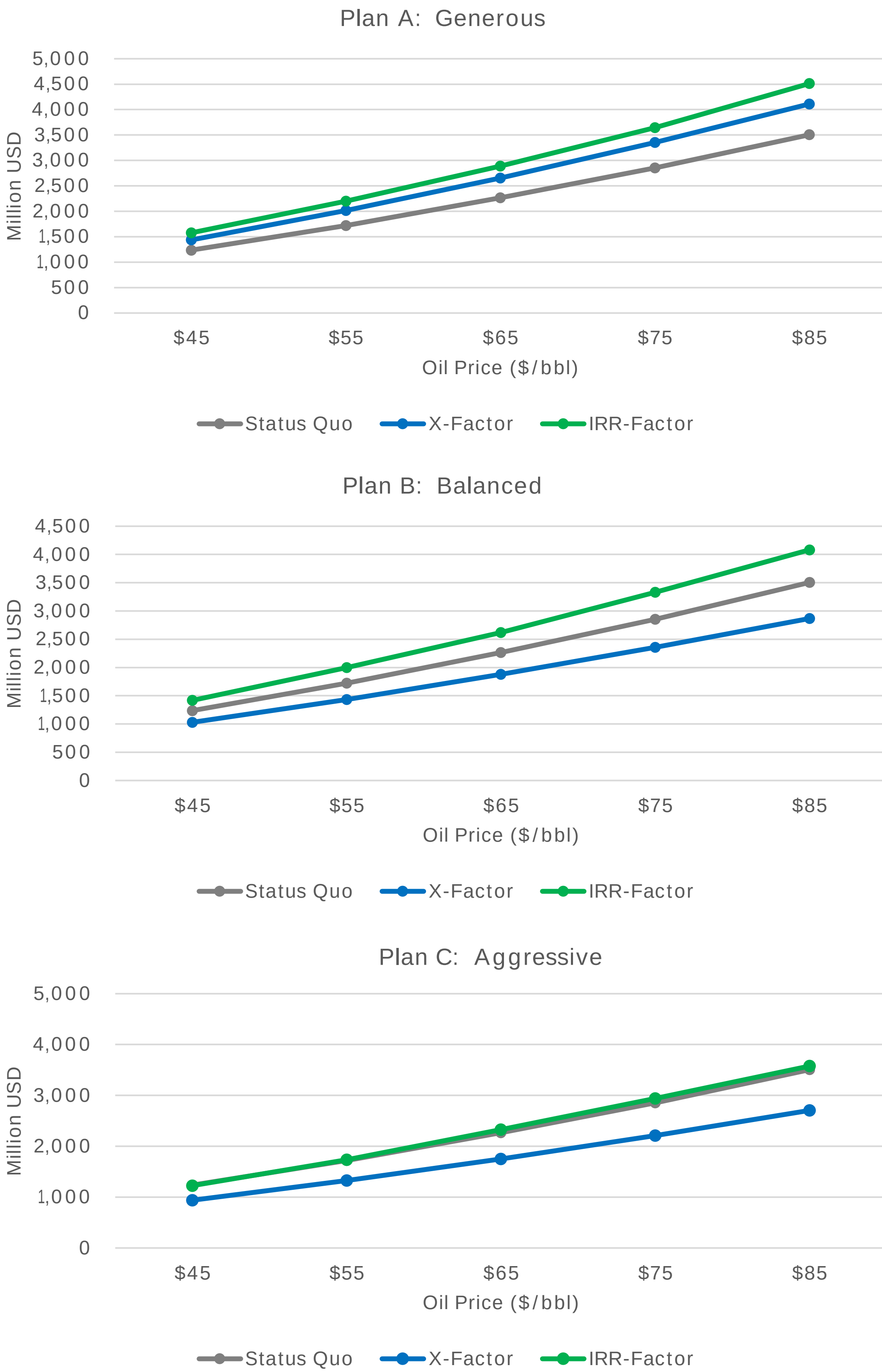


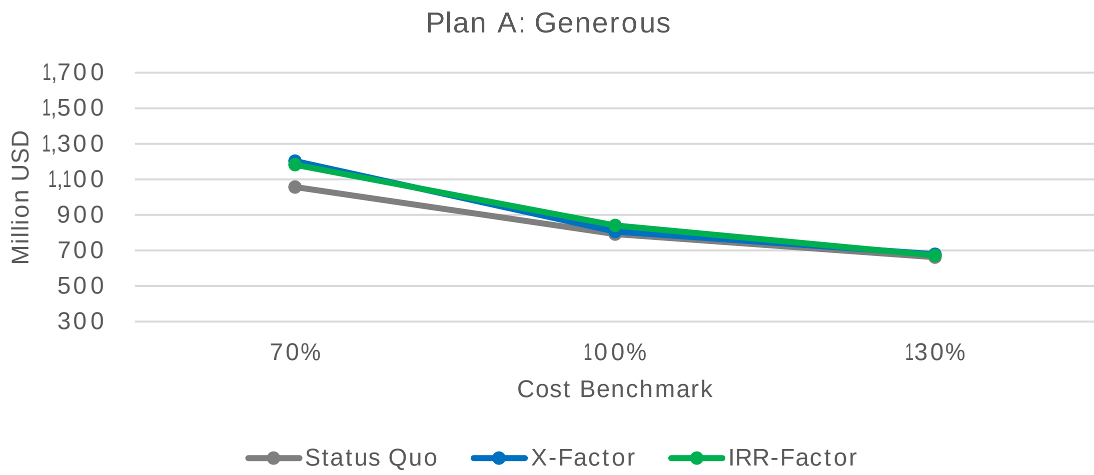
Figure A.11d Sensitivity of Investor NPV to Price (Orinoco Heavy Oil)

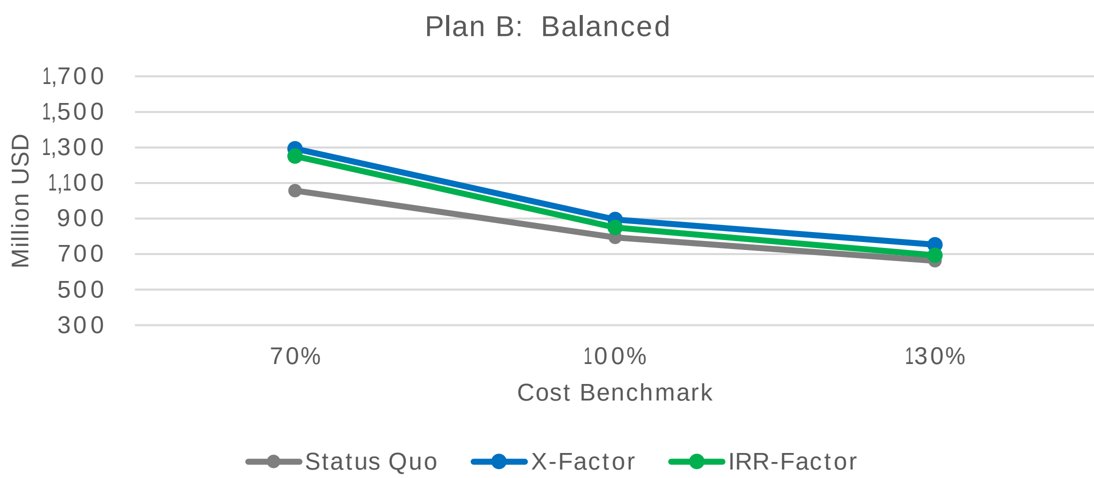


Annex B: Sensitivity of Results to Higher and Lower Cost Levels

All results in this section assume constant real prices of $65/barrel and $3/mcf, with variations in capital and operating costs amounting to +/- 30% relative to the benchmark cost levels indicated in Table 1.3.

Figure B.1a: Sensitivity of Government NPV to Cost (Eastern Onshore Oil)





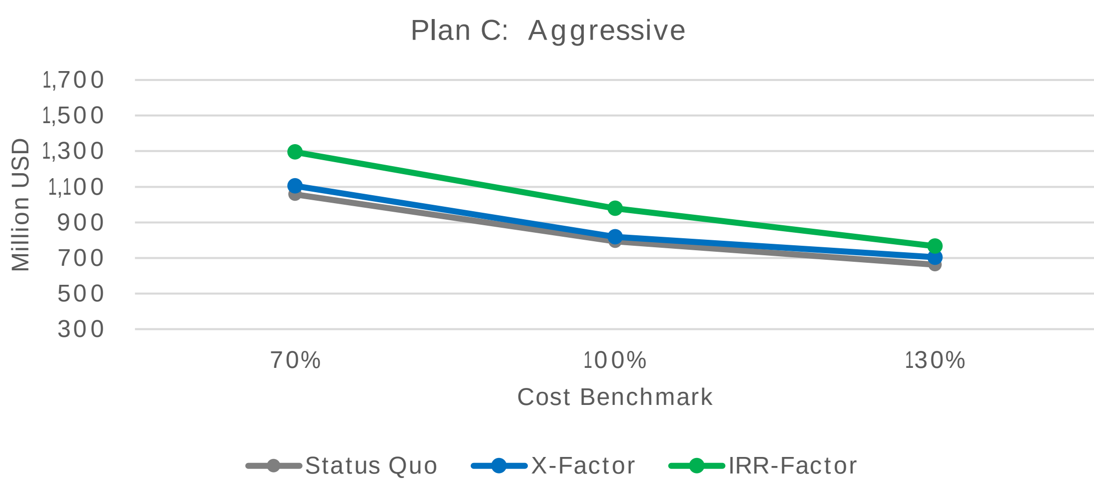


Figure B.1b: Sensitivity of Government NPV to Cost (Western Onshore Oil)

Figure B.1c: Sensitivity of Government NPV to Cost (Eastern Onshore Gas)

Figure B.1d: Sensitivity of Government NPV to Cost (Orinoco Heavy Oil)

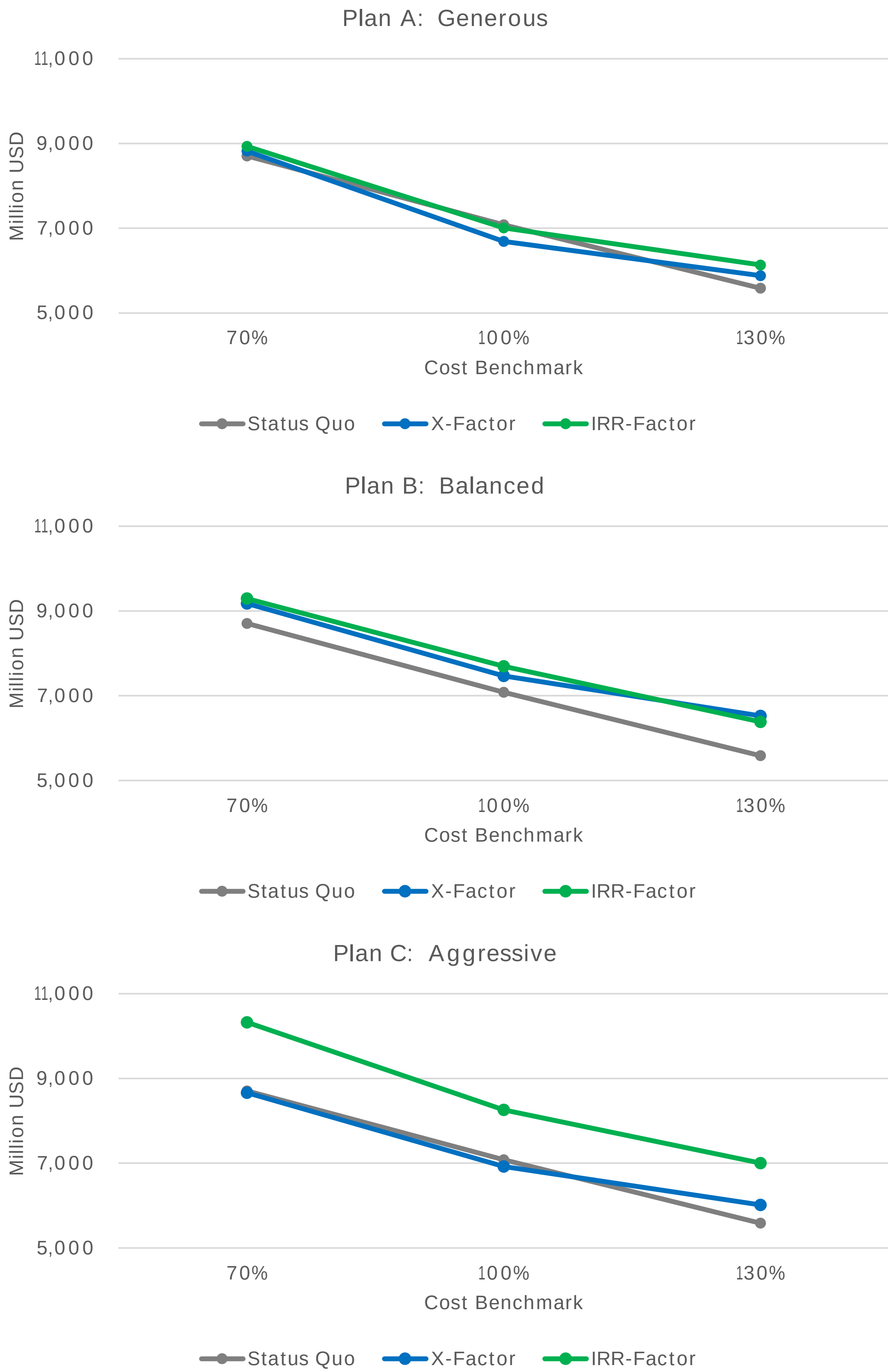
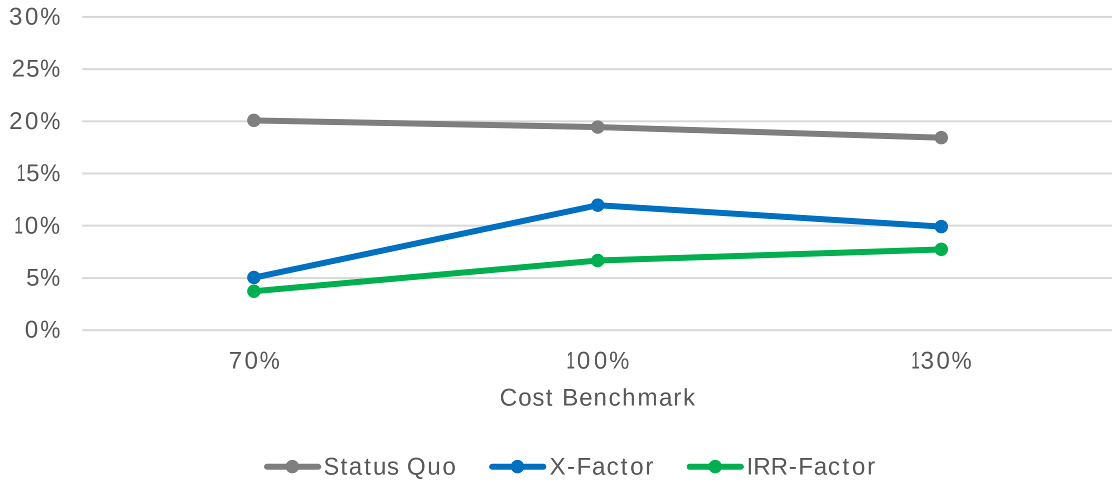
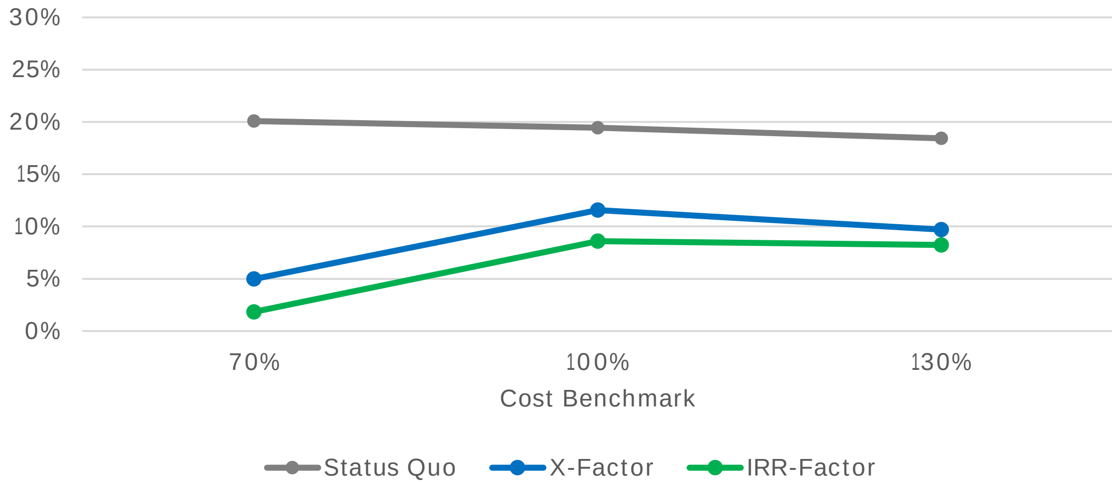


Figure B.2a: Sensitivity of Deadweight Loss to Cost (Eastern Onshore Oil)

Plan A: Generous



Plan B: Balanced



Plan : Aggressive

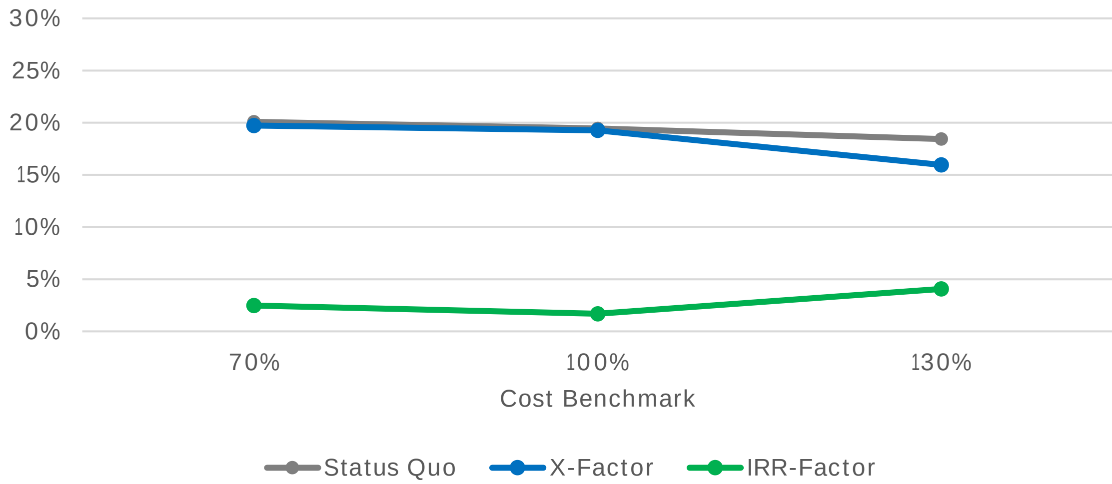


Figure B.2b: Sensitivity of Deadweight Loss to Cost (Western Onshore Oil)

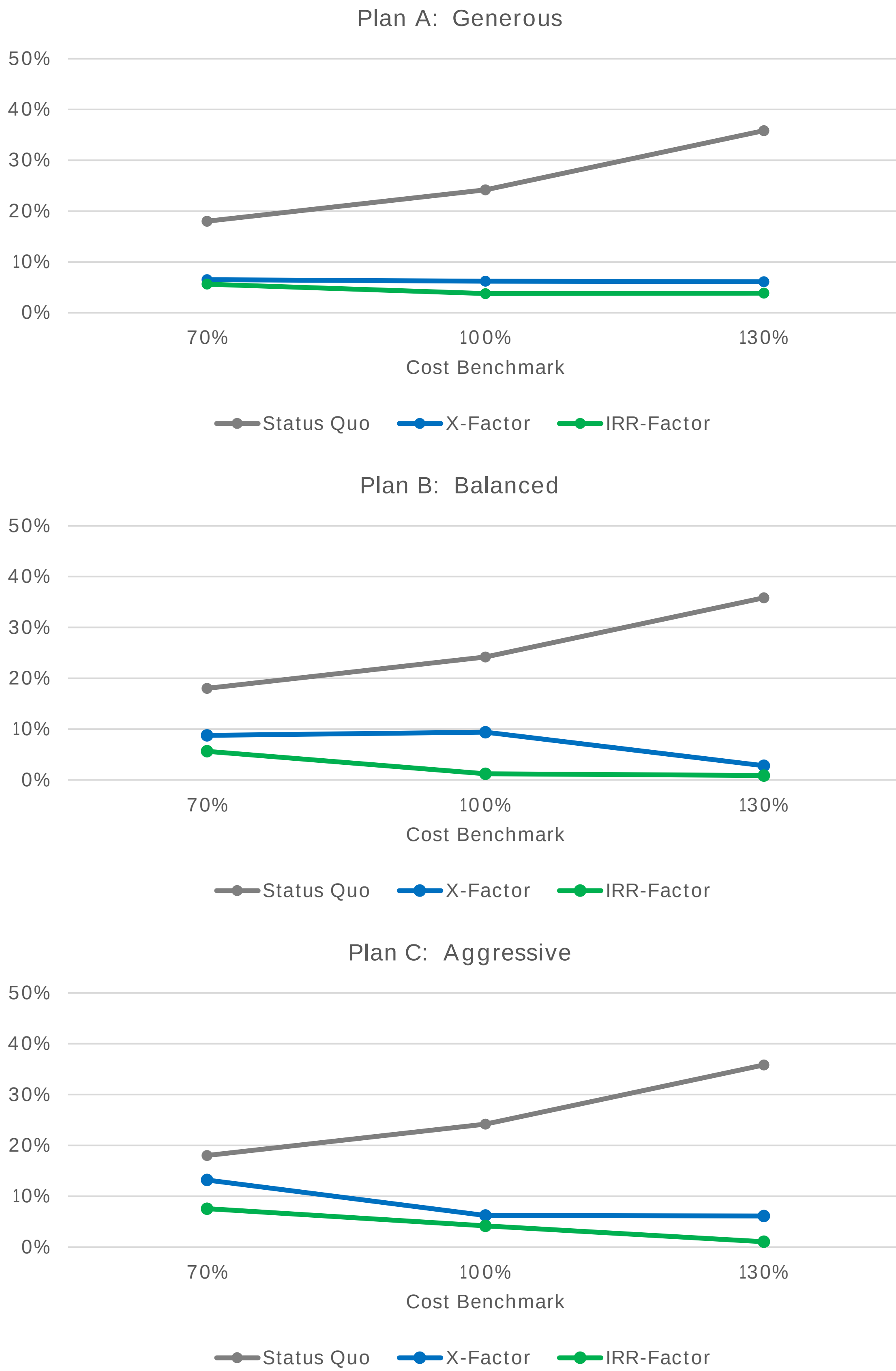


Figure B.2c: Sensitivity of Deadweight Loss to Cost (Eastern Onshore Gas)

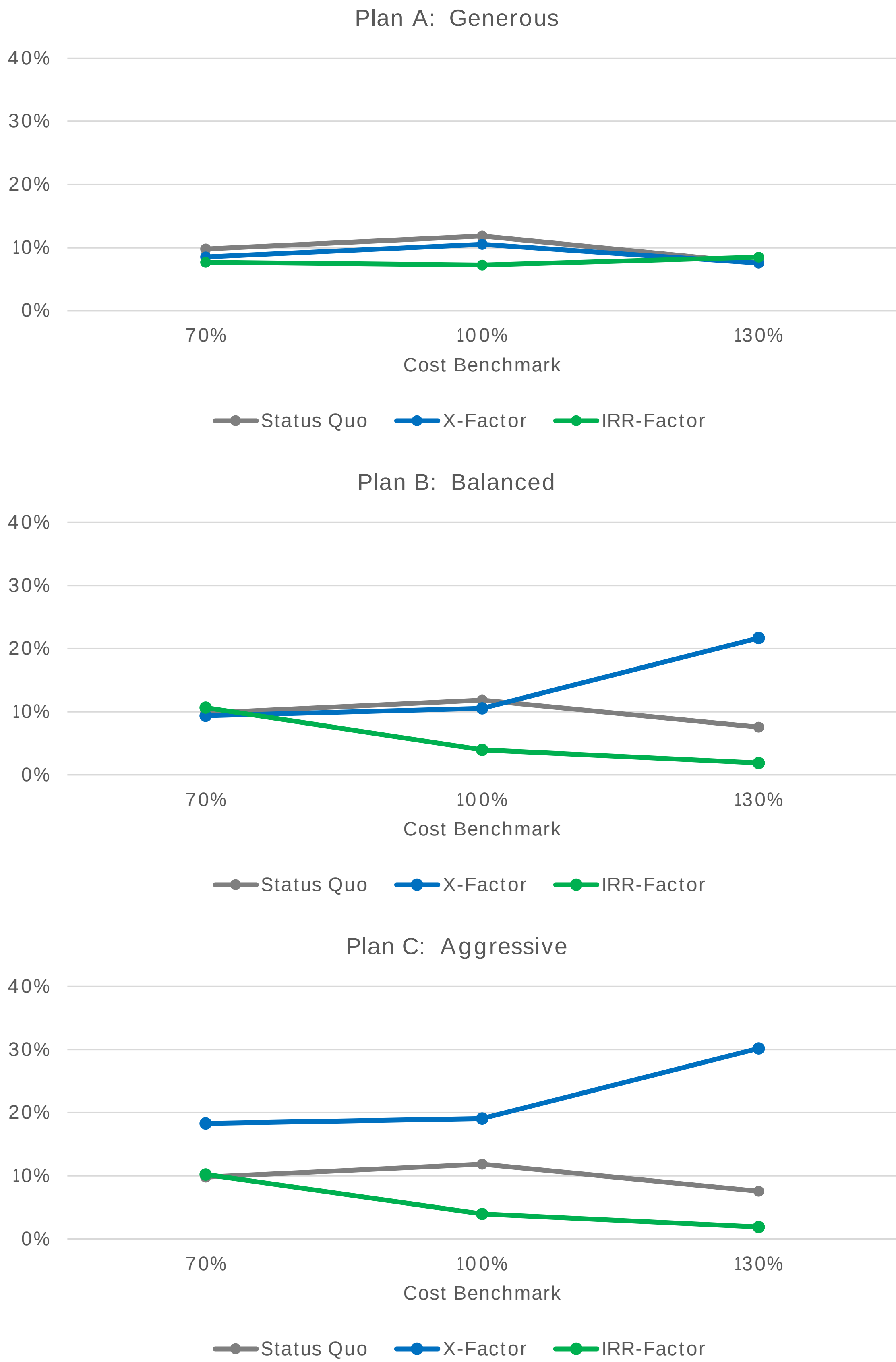


Figure B.2d: Sensitivity of Deadweight Loss to Cost (Orinoco Heavy Oil)

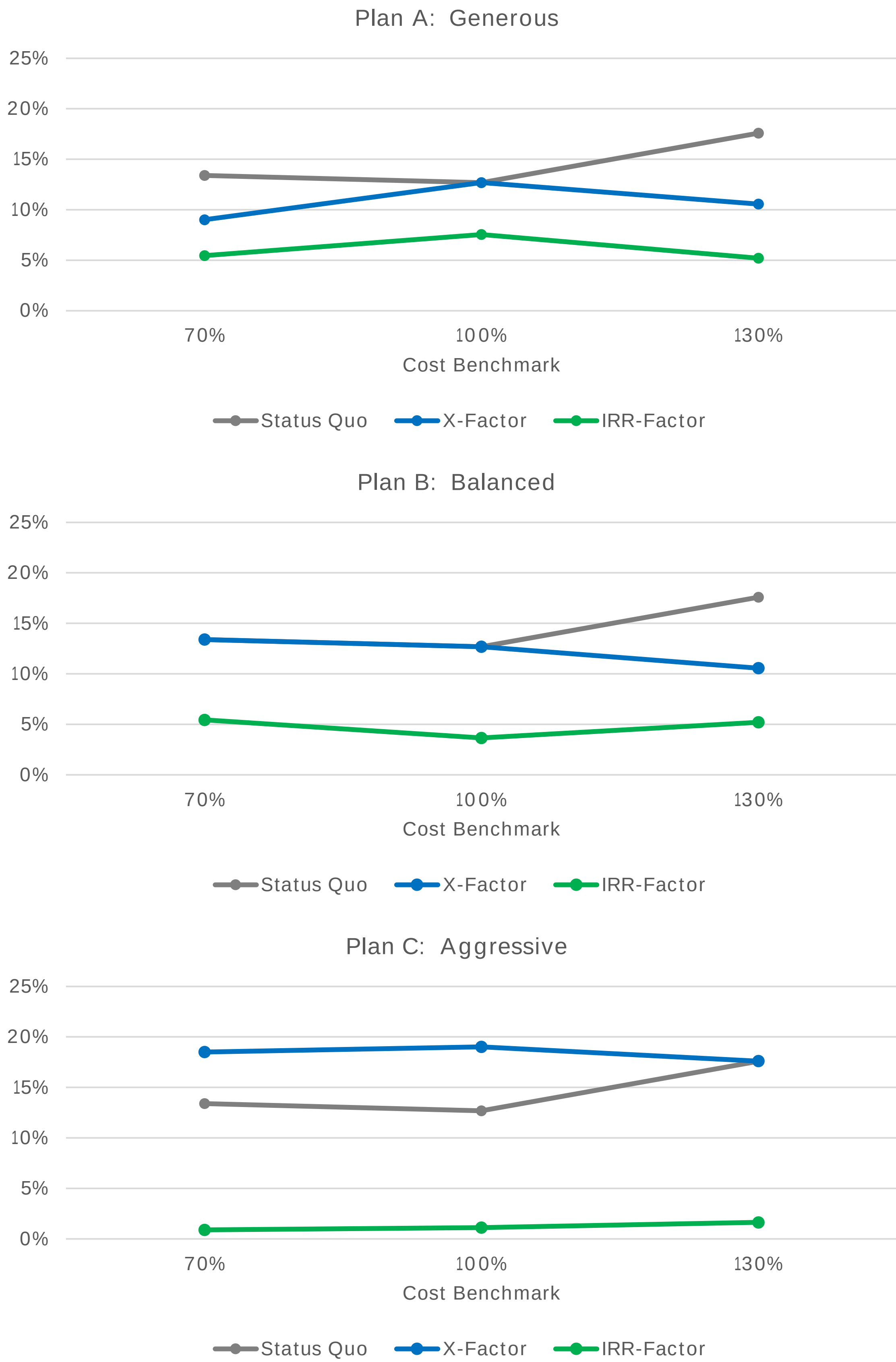
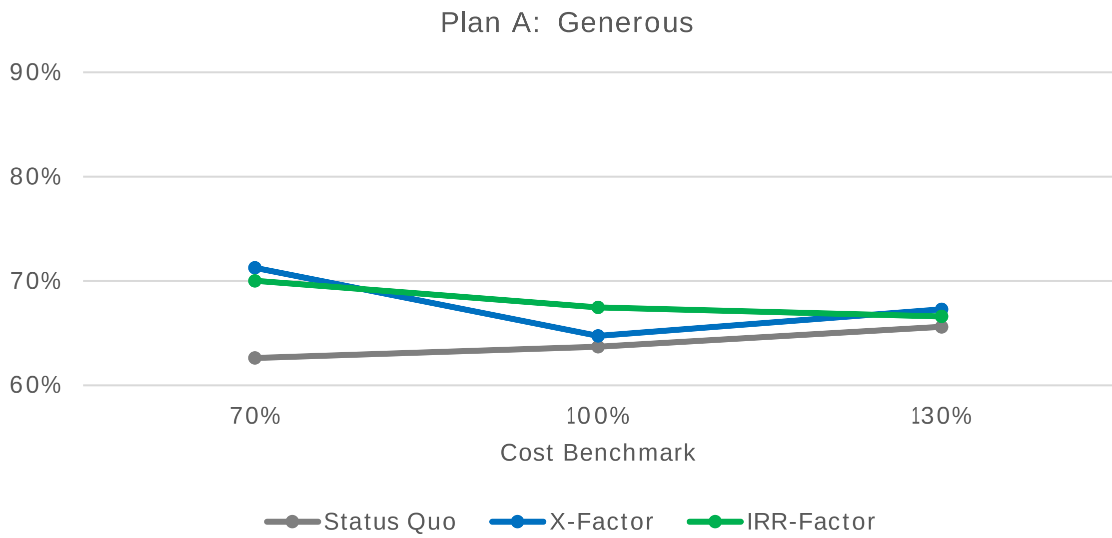
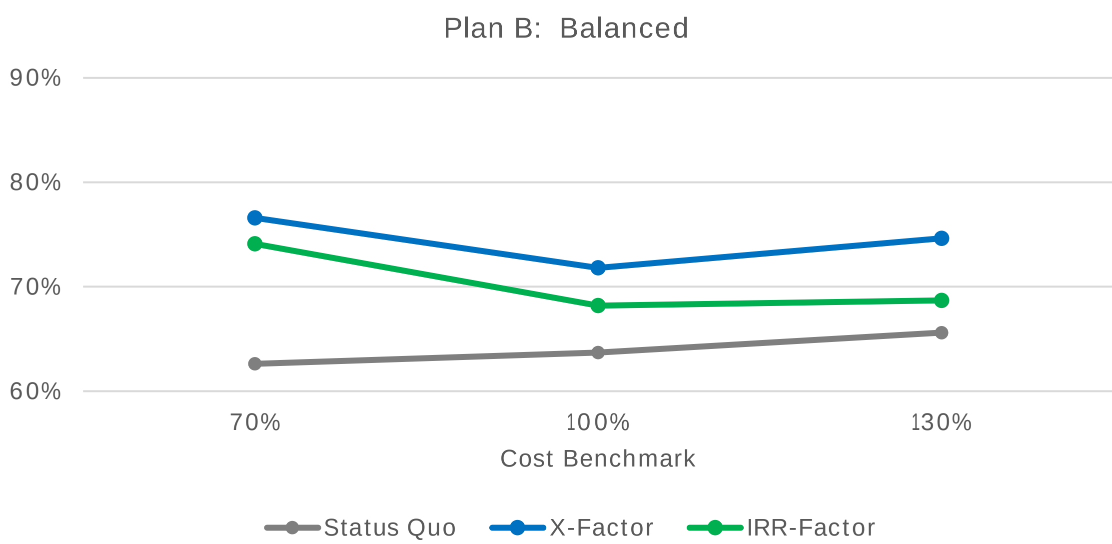


Figure B.3a Sensitivity of True Fiscal Yield to Cost (Eastern Onshore Oil)





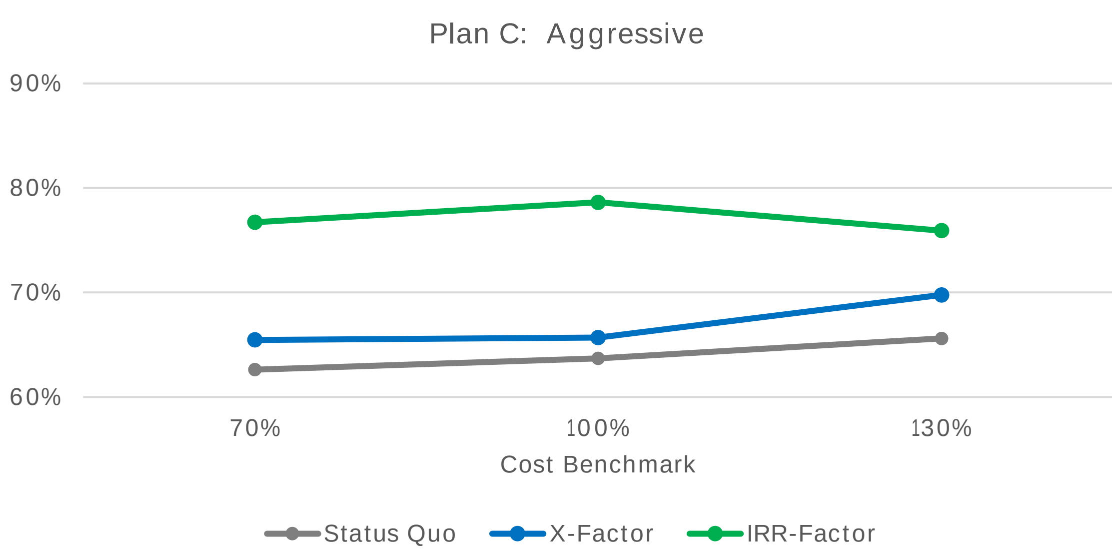
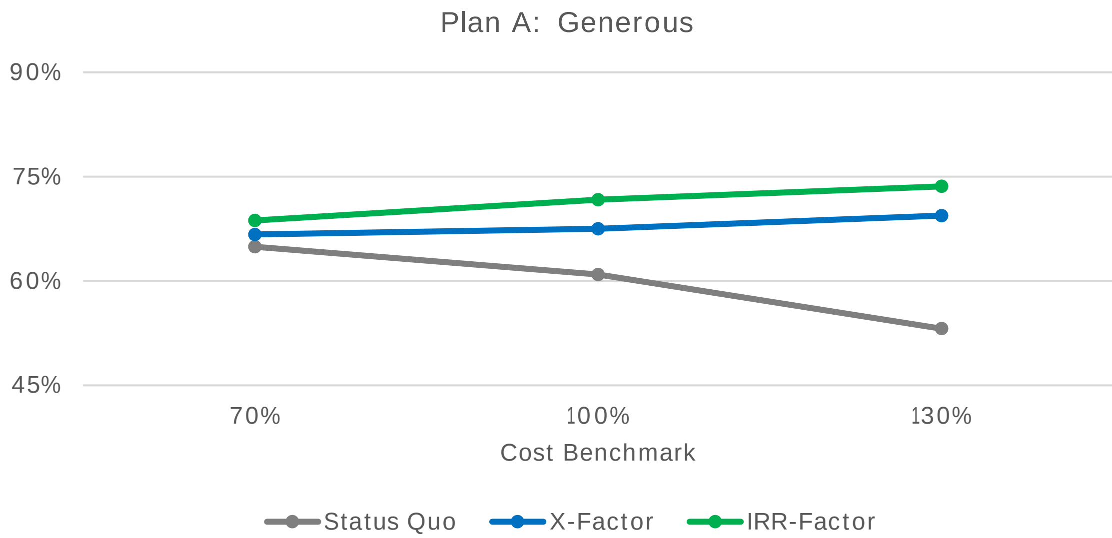
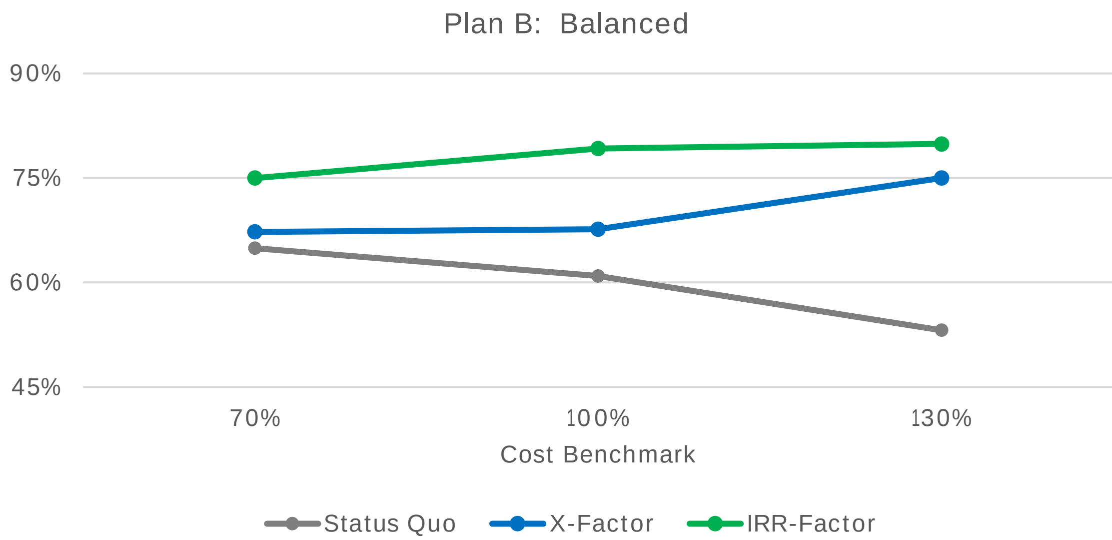


Figure B.3b Sensitivity of True Fiscal Yield to Cost (Western Onshore Oil)





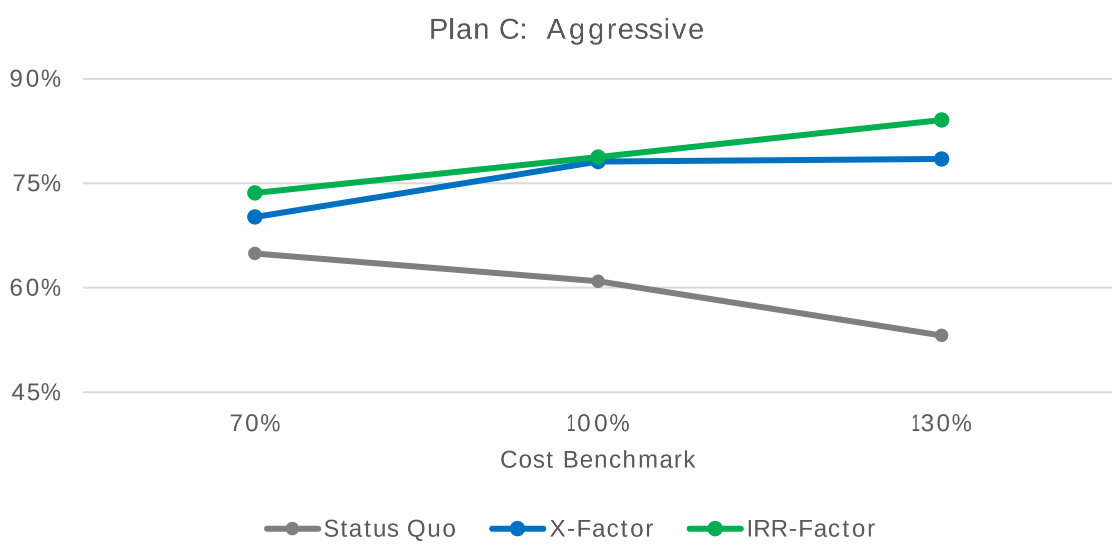
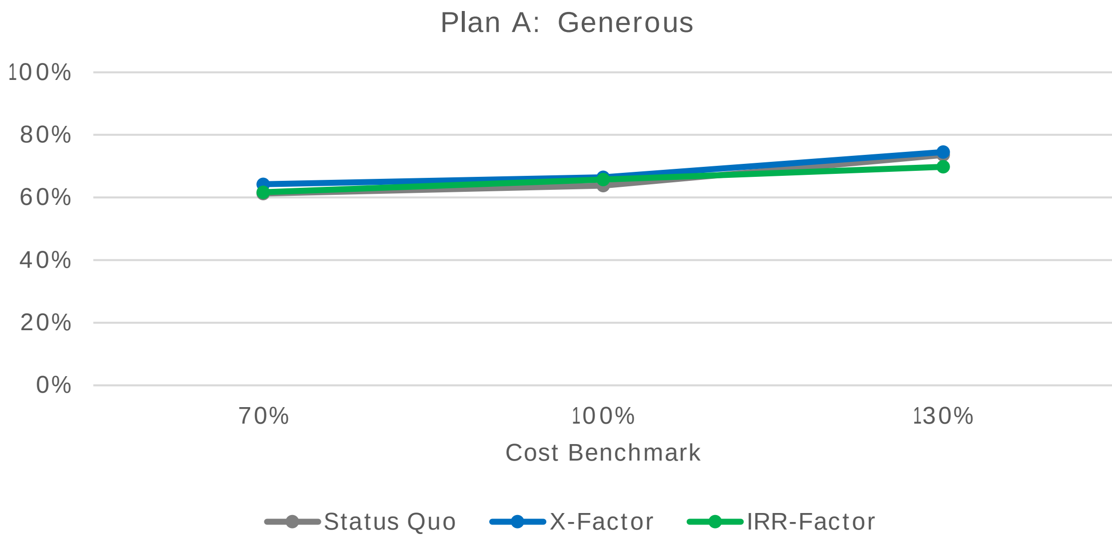
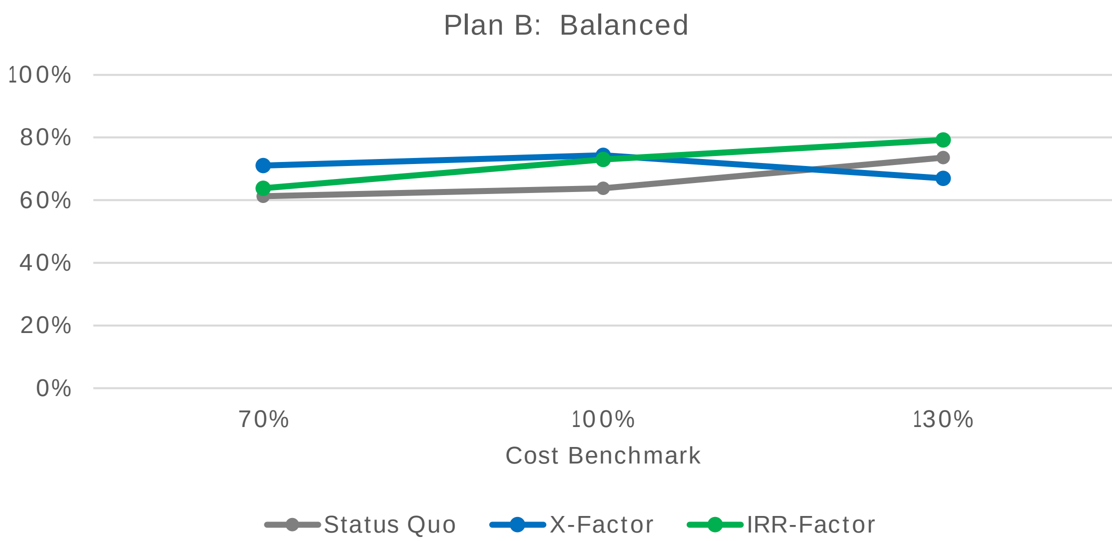


Figure B.3c Sensitivity of True Fiscal Yield to Cost (Eastern Onshore Gas)





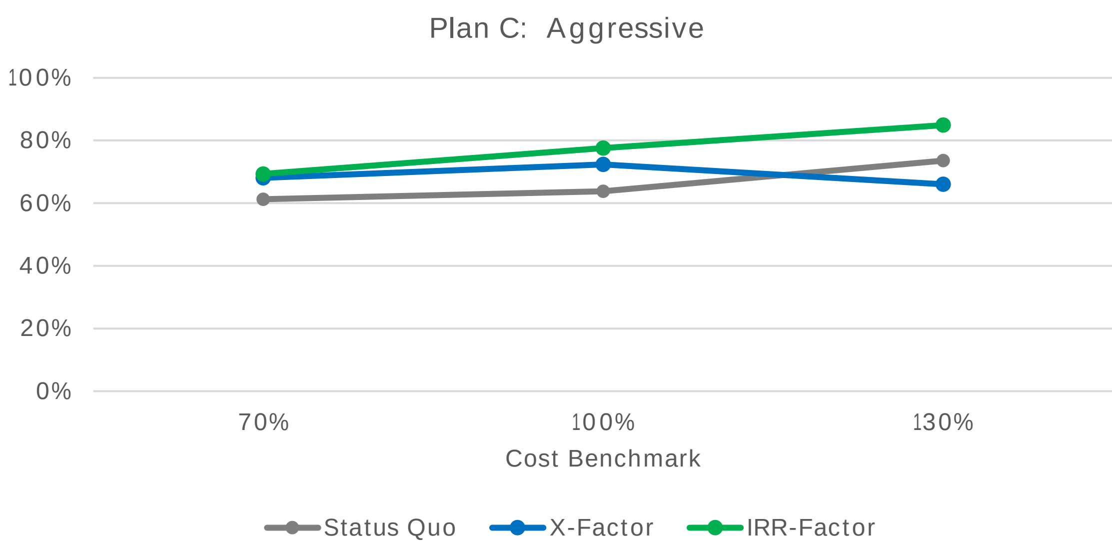


Figure B.3d Sensitivity of True Fiscal Yield to Cost (Orinoco Heavy Oil)

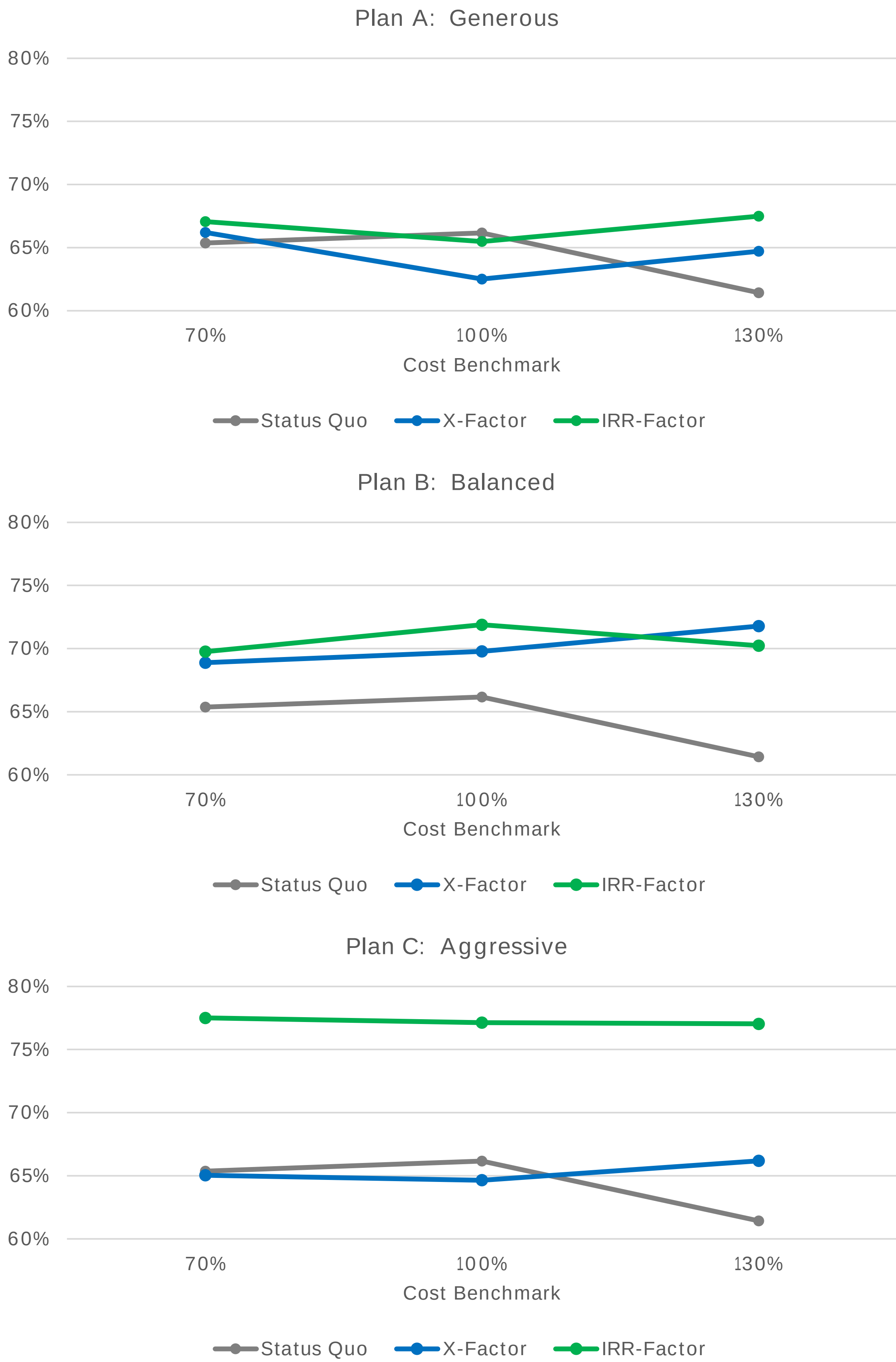
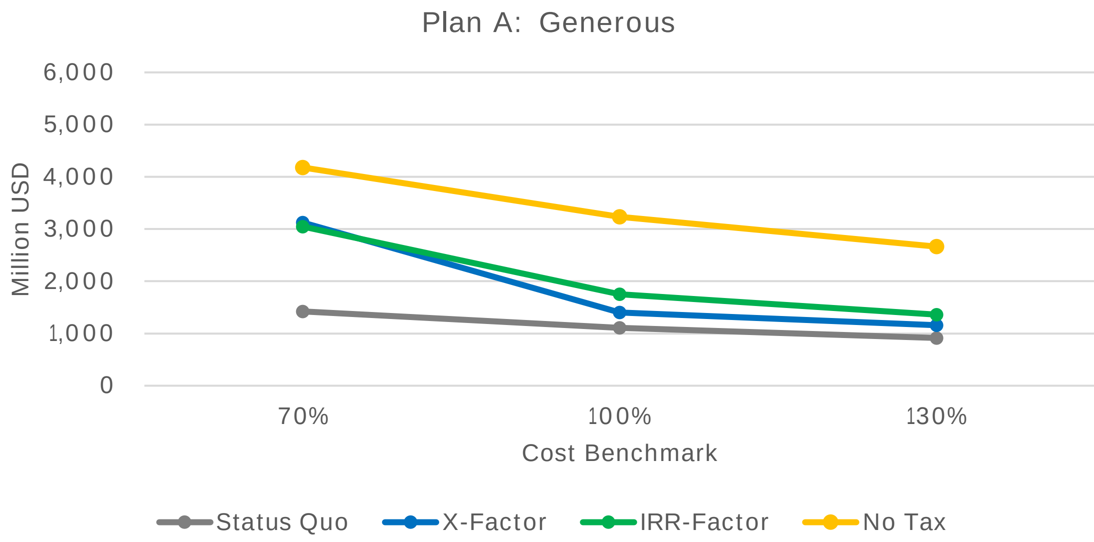
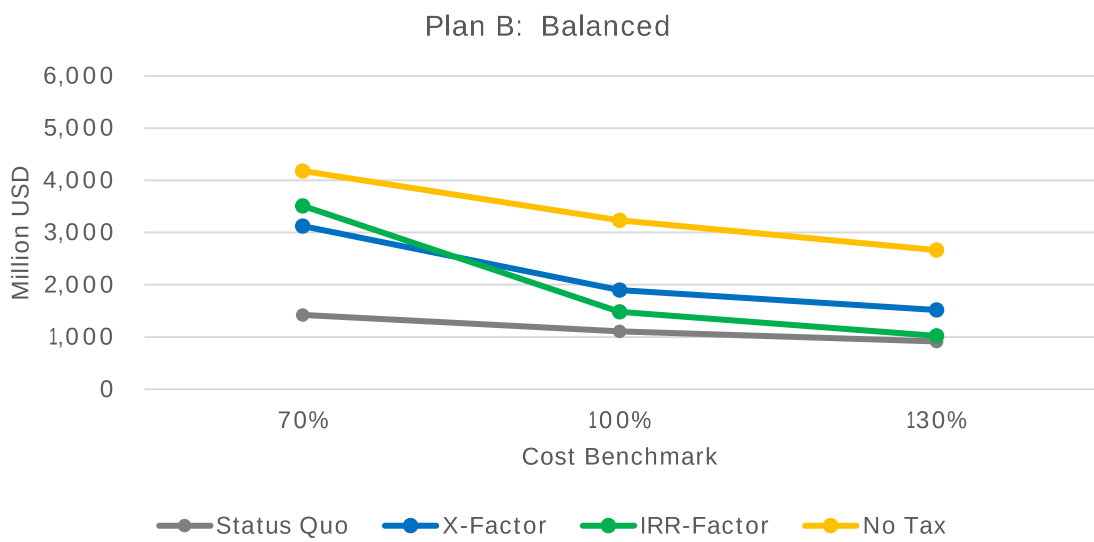


Figure B:4a Sensitivity of Total Investment to Cost (Eastern Onshore Oil)





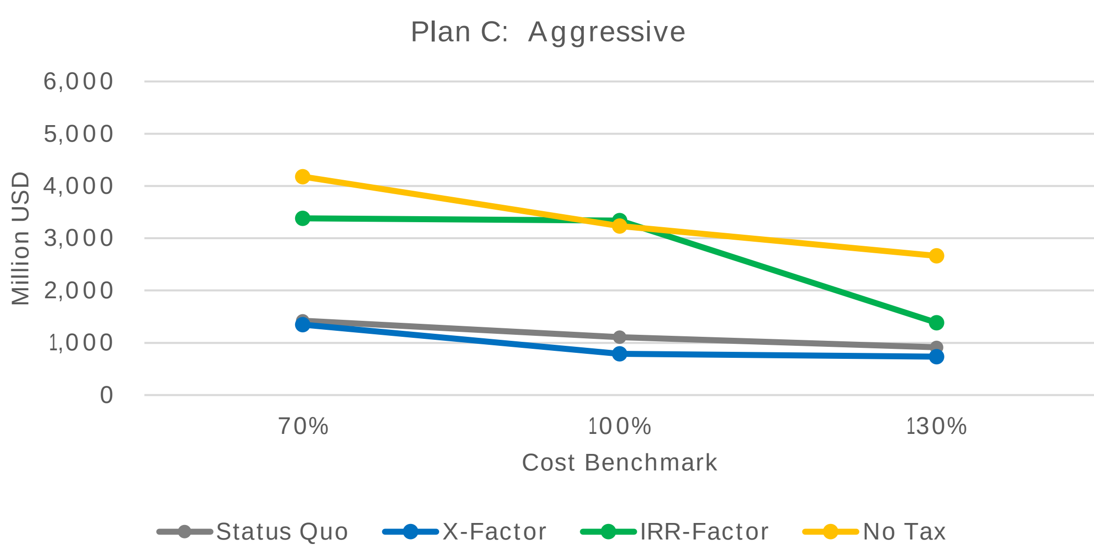
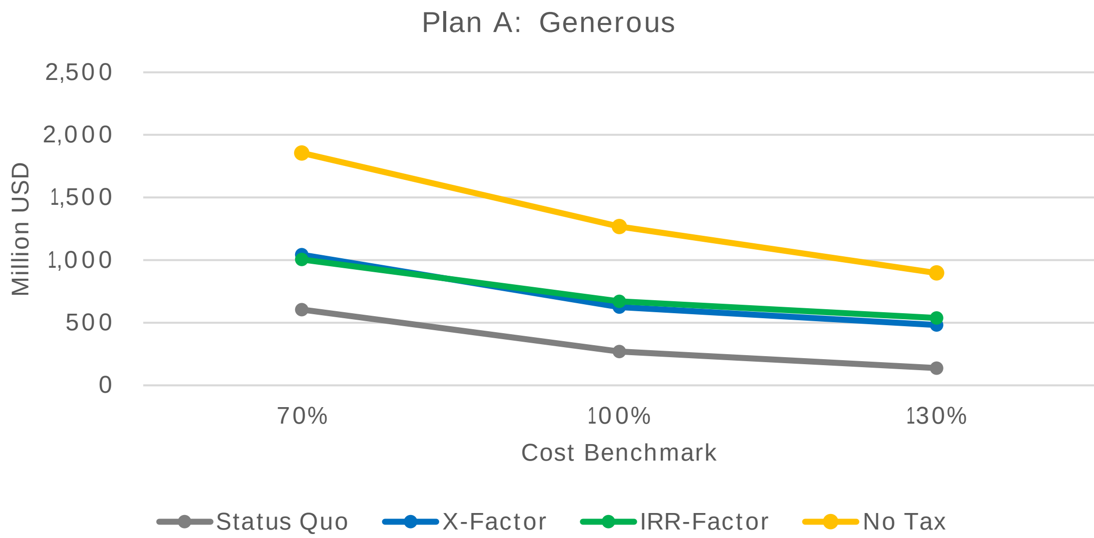
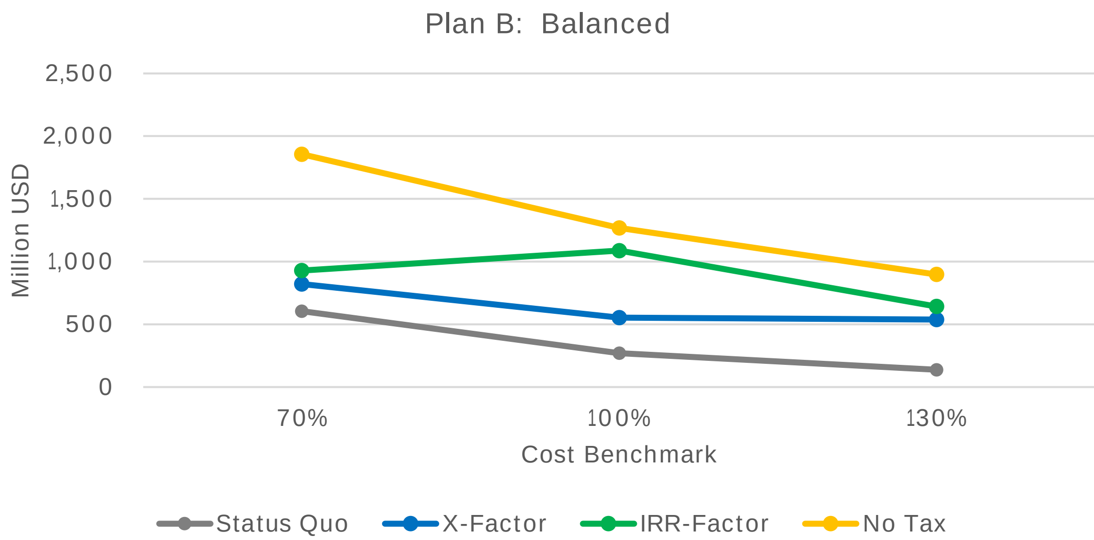


Figure B.4b Sensitivity of Total Investment to Cost (Western Onshore Oil)





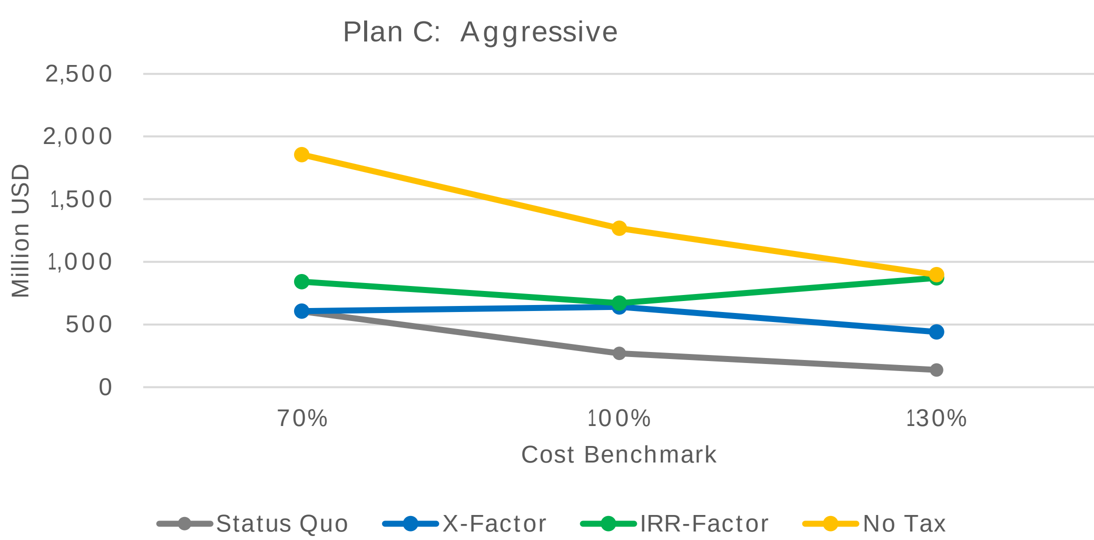
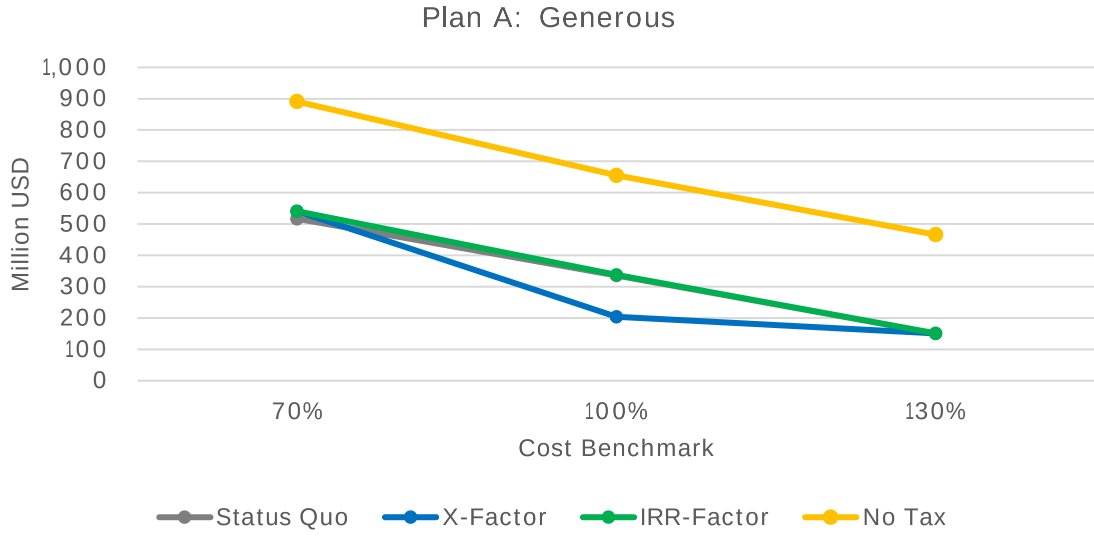
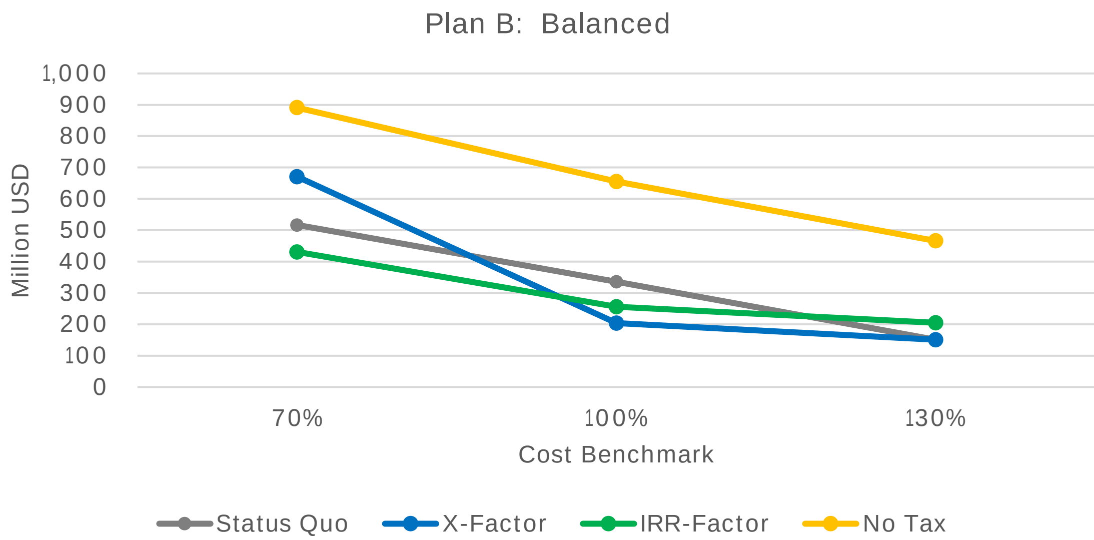


Figure B.4c Sensitivity of Total Investment to Cost (Eastern Onshore Gas)





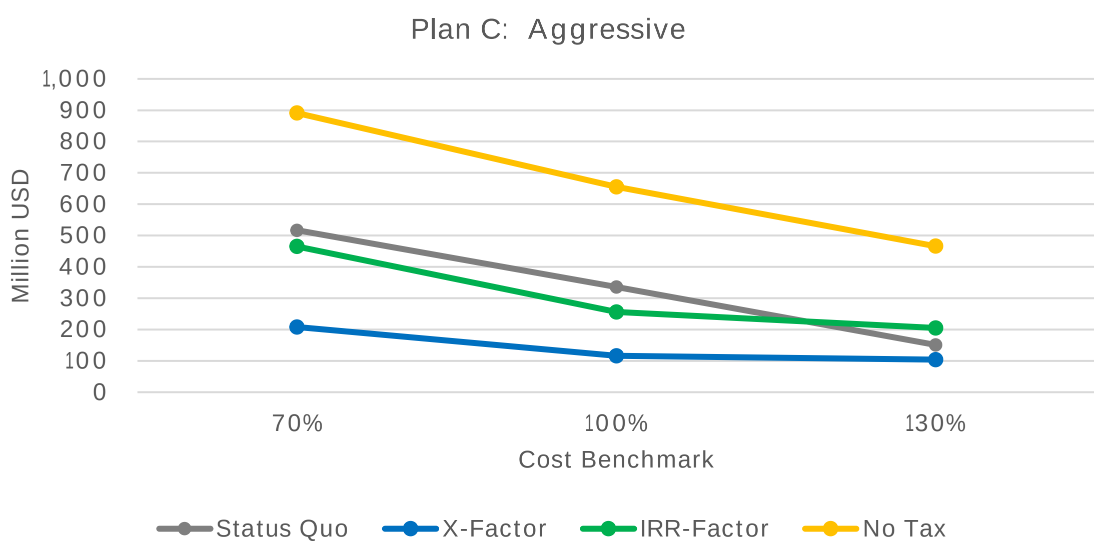
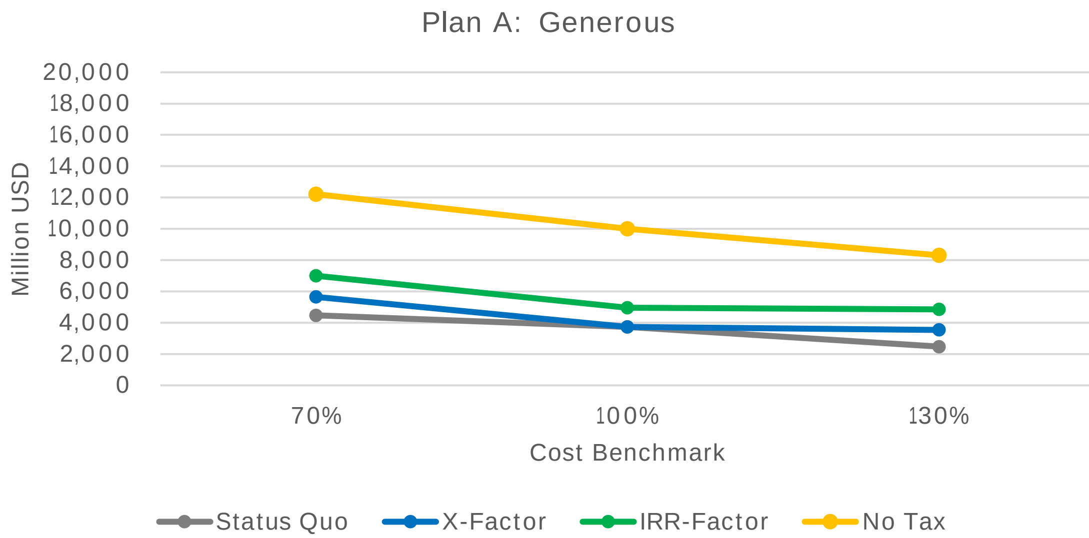
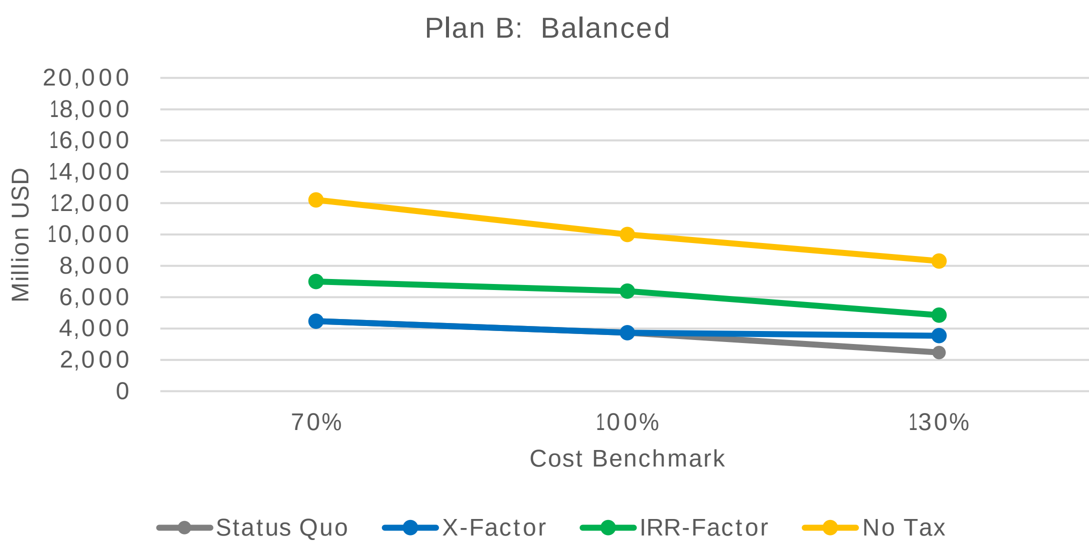


Figure B.4d Sensitivity of Total Investment to Cost (Orinoco Heavy Oil)





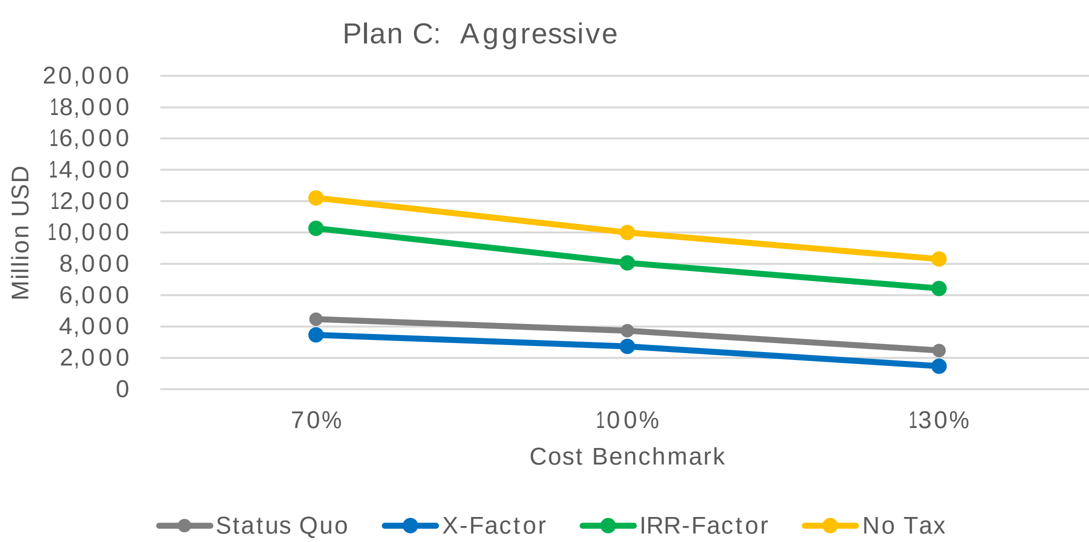


Figure B.5a Sensitivity of Exploration Intensity to Cost (Eastern Onshore Oil)

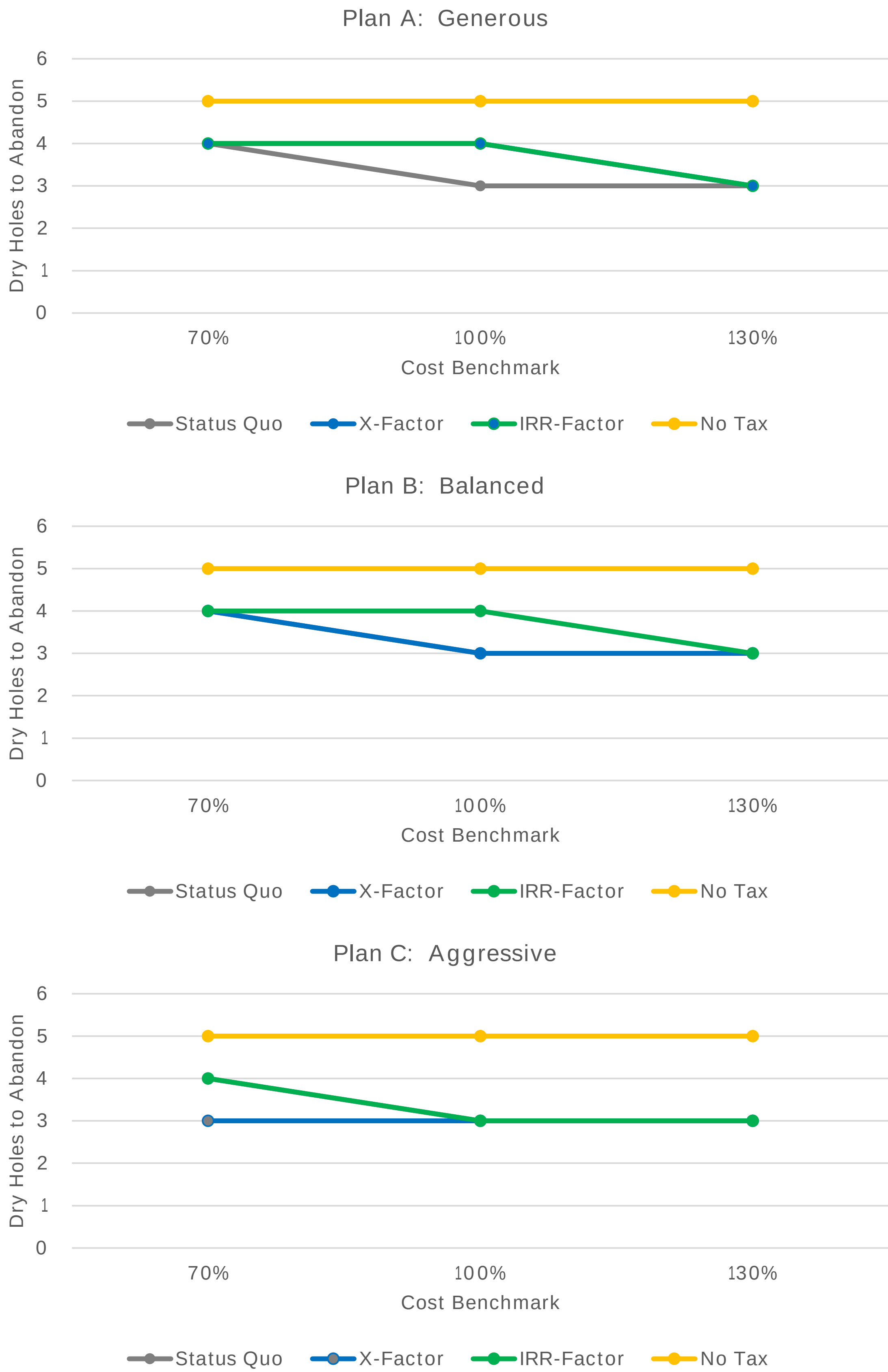


Figure B.5b Sensitivity of Exploration Intensity to Cost (Eastern Onshore Gas)

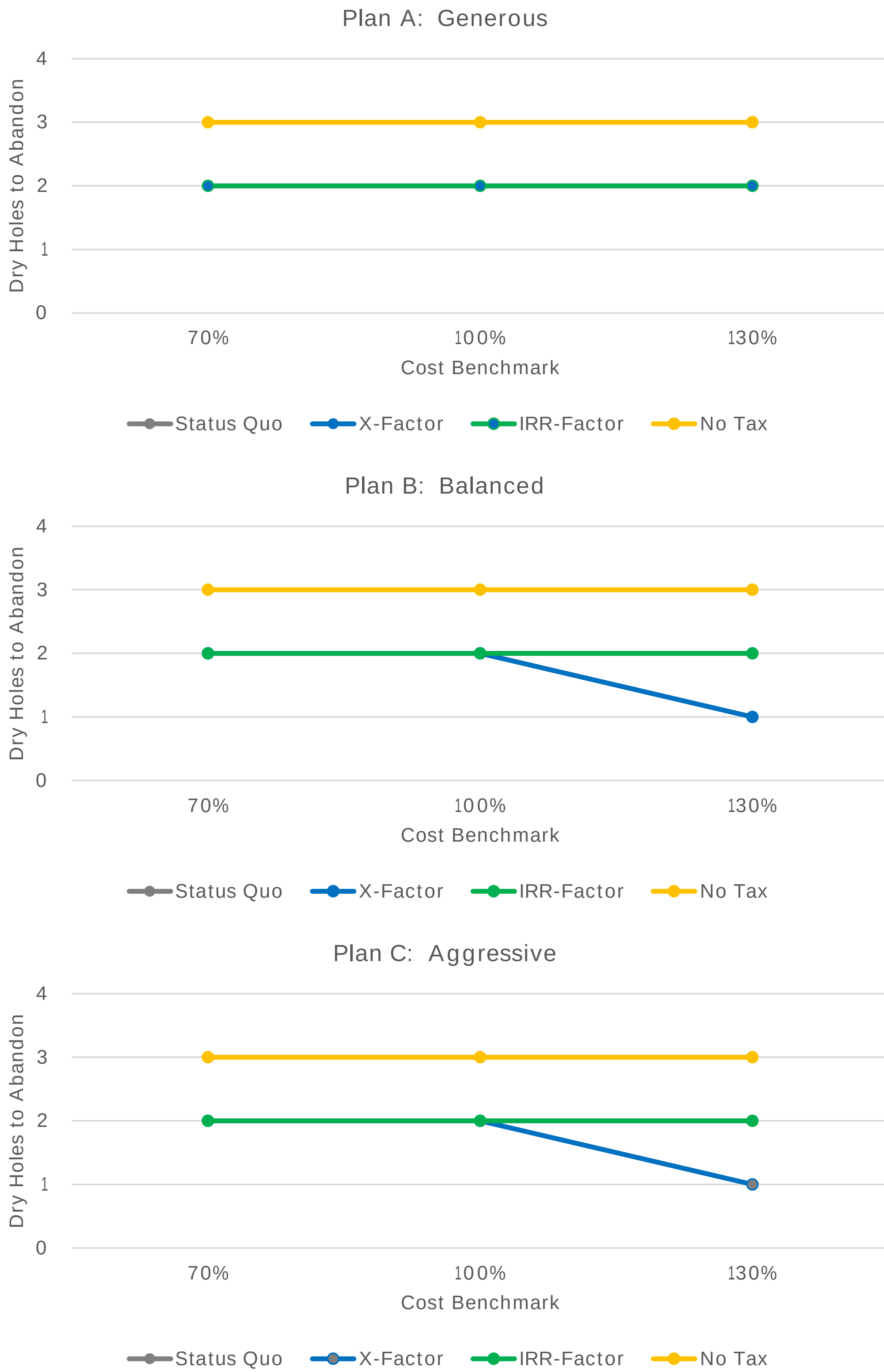


Figure B.6a Sensitivity of Risked Reserves to Cost (Eastern Onshore Oil)

Figure B.6b Sensitivity of Risked Reserves to Cost (Western Onshore Oil)

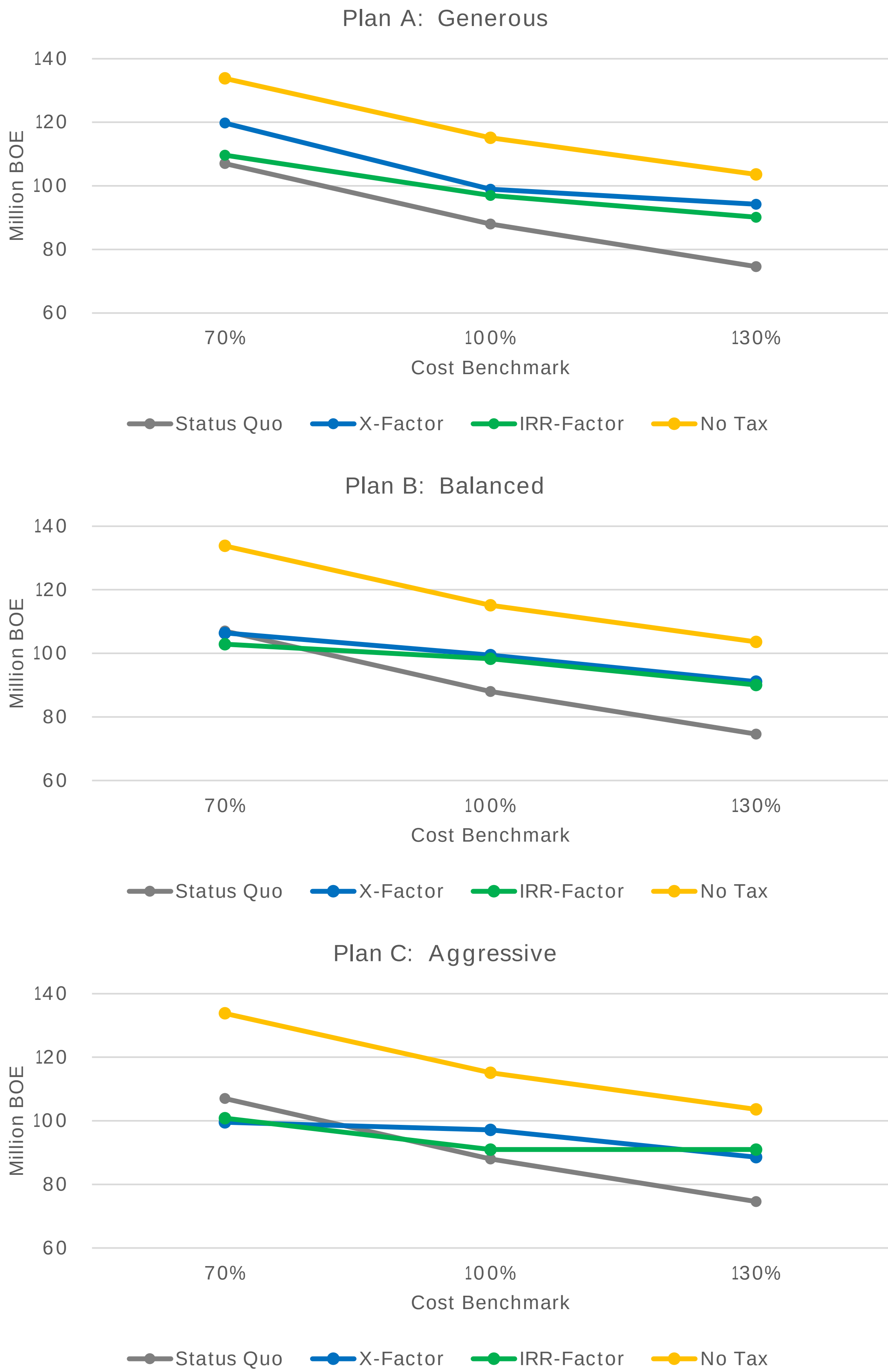
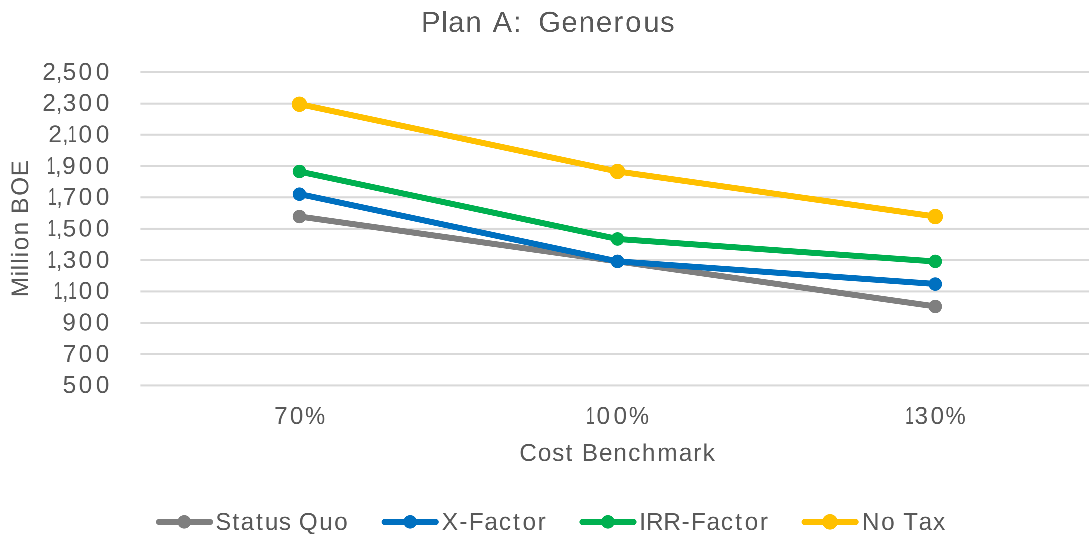
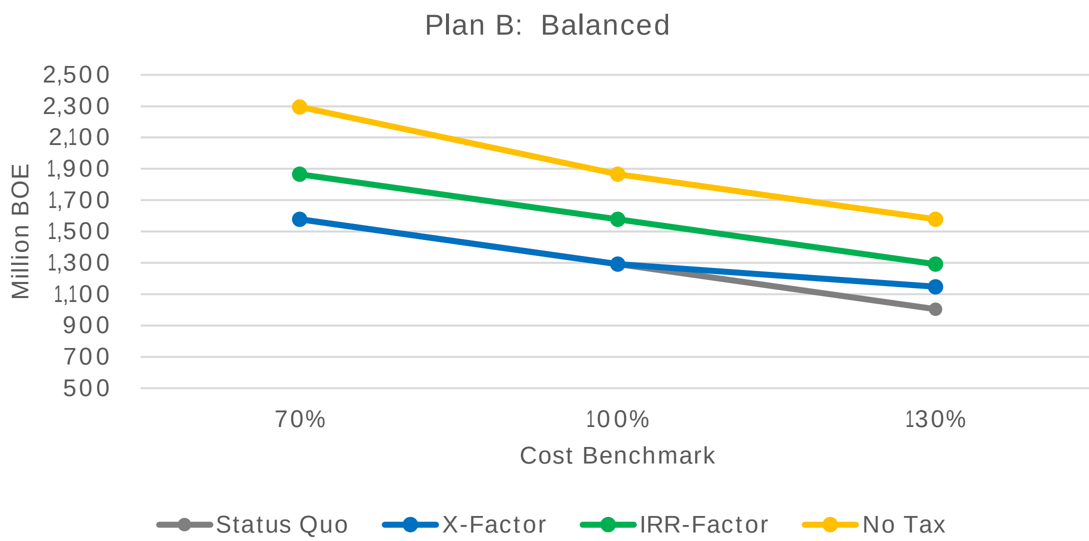


Figure B.6c Sensitivity of Risked Reserves to Cost (Eastern Onshore Gas)

Figure B.6d Sensitivity of Risked Reserves to Cost (Orinoco Heavy Oil)





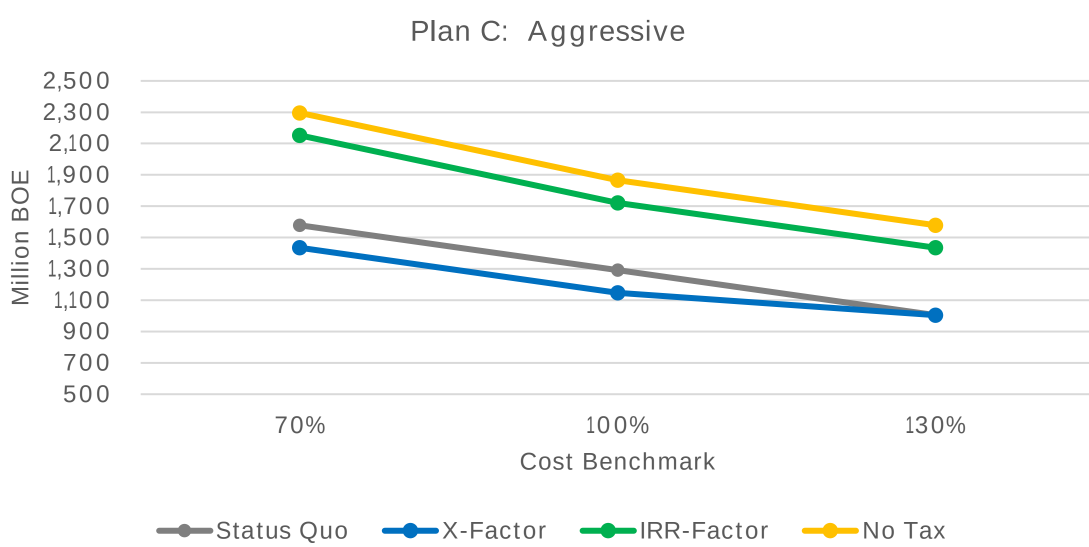


Figure B.7a Sensitivity of Rate of Extraction to Cost (Eastern Onshore Oil)

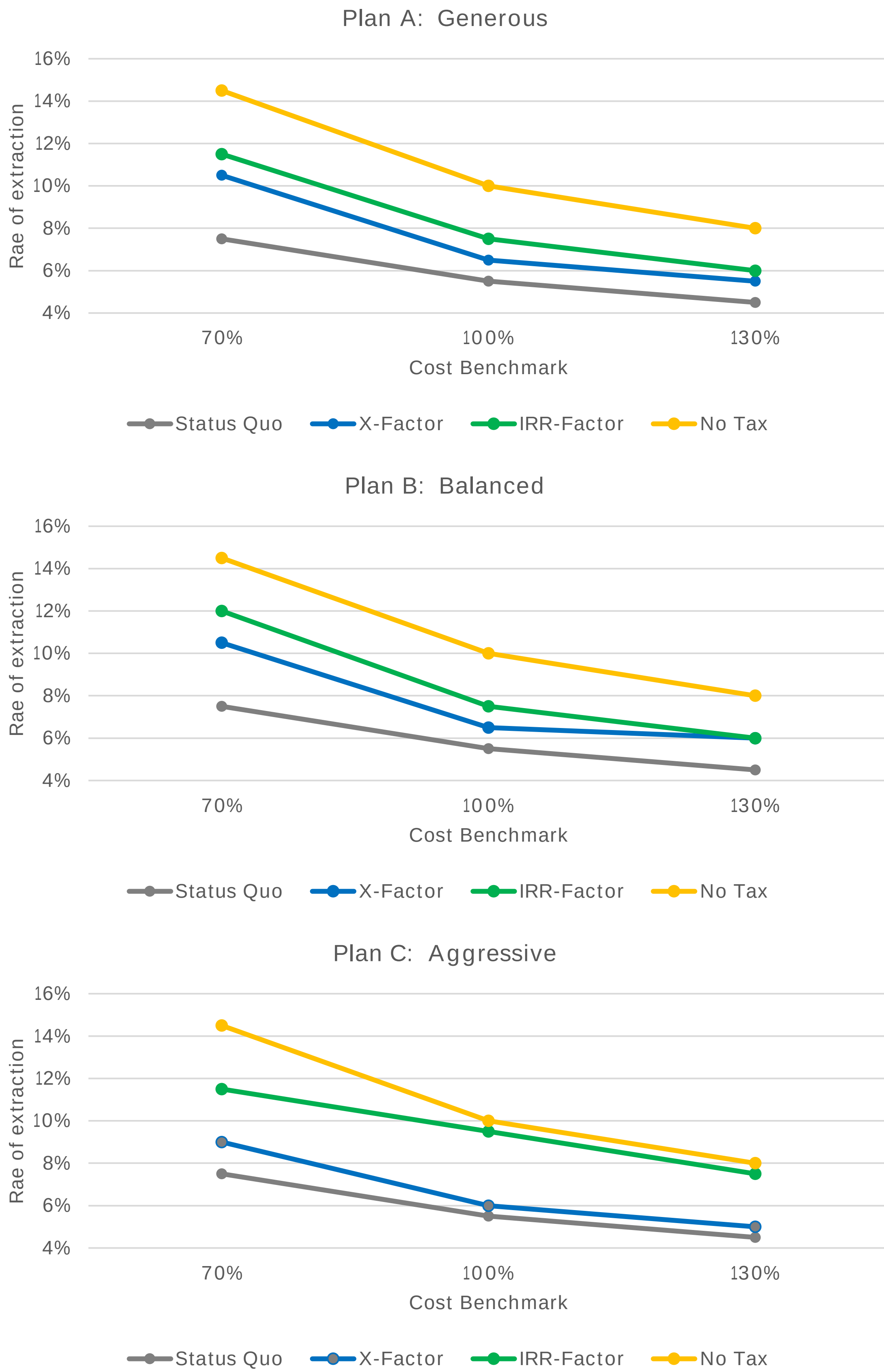


Figure B.7b Sensitivity of Rate of Extraction to Cost (Western Onshore Oil)

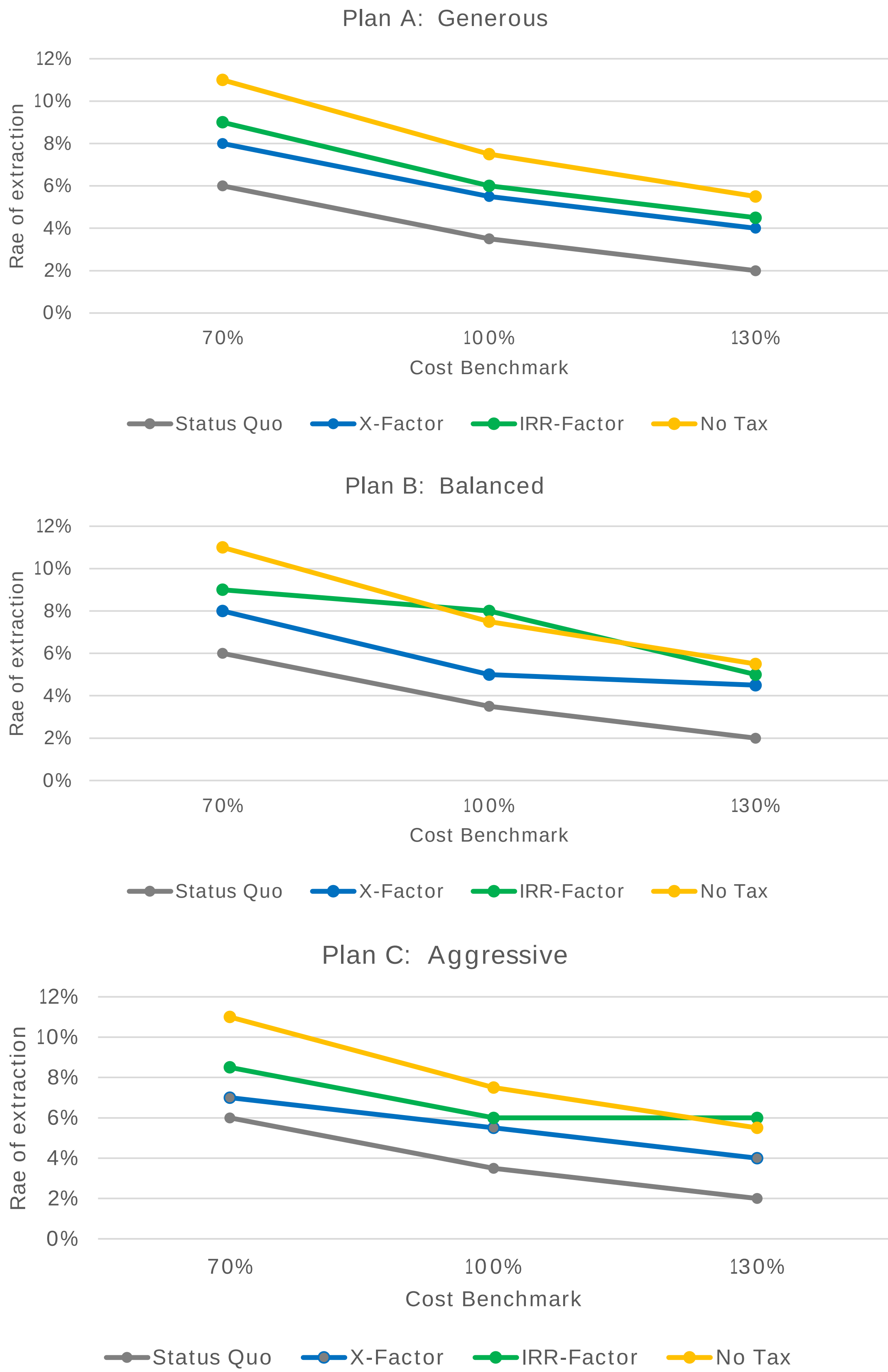


Figure B.7c Sensitivity of Rate of Extraction to Cost (Eastern Onshore Gas)

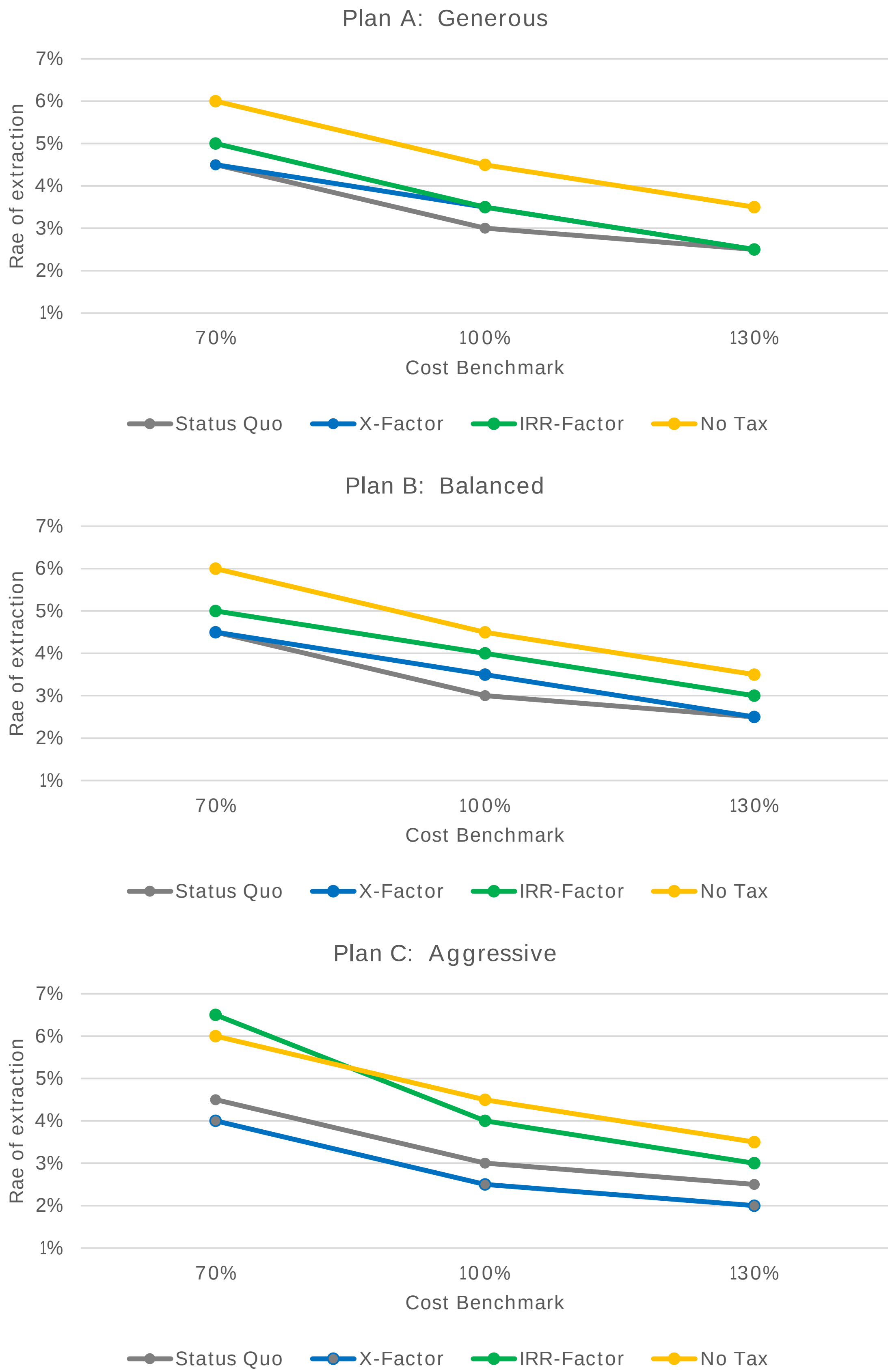
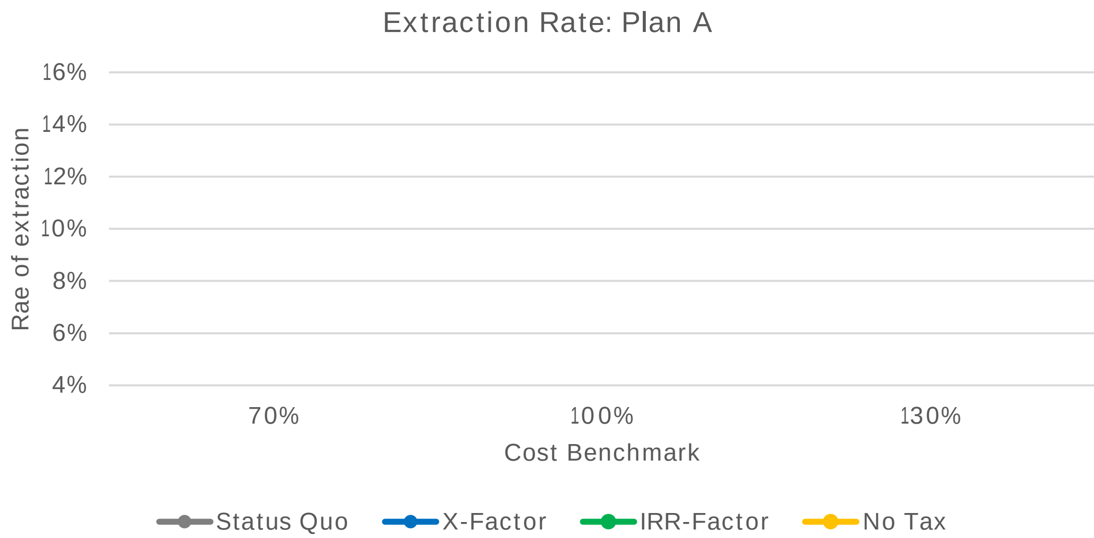
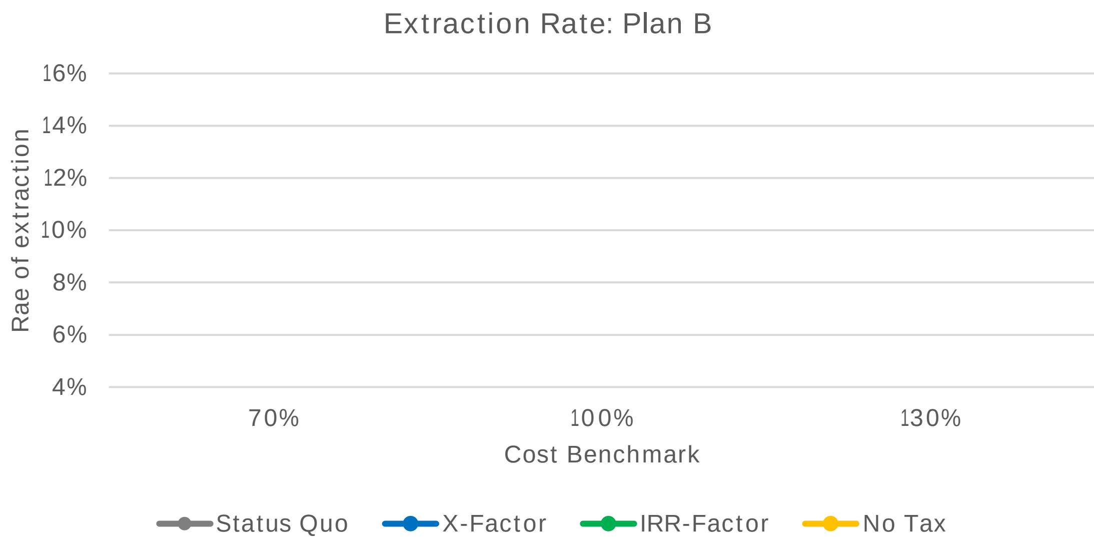


Figure B.7d Sensitivity of Rate of Extraction to Price (Orinoco Heavy Oil)





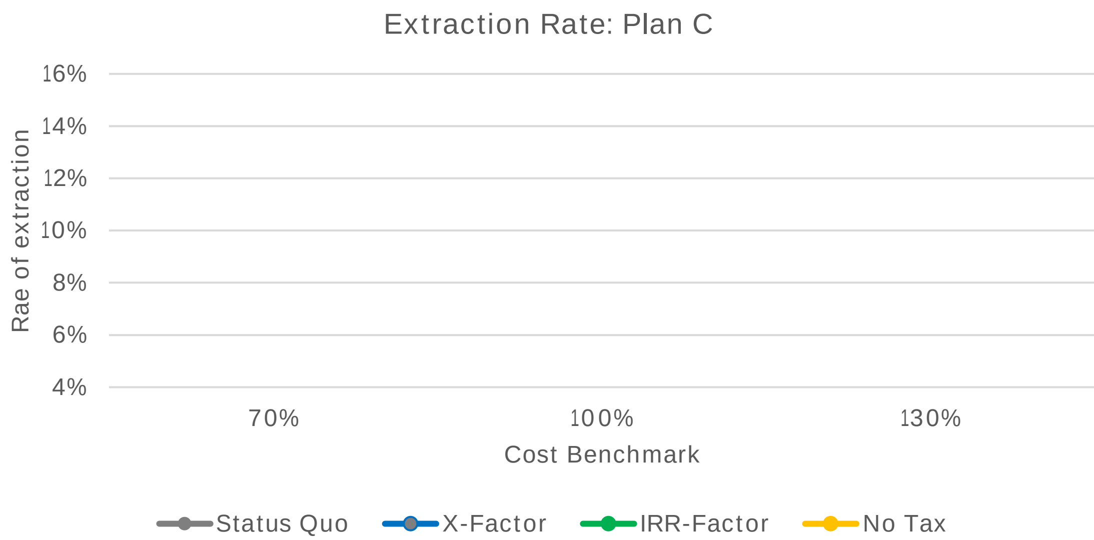
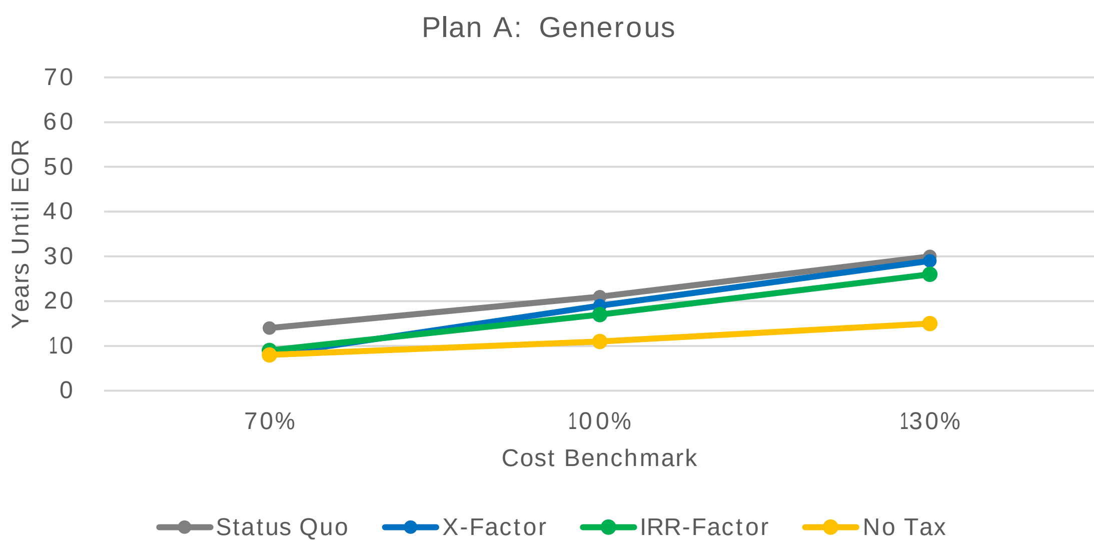
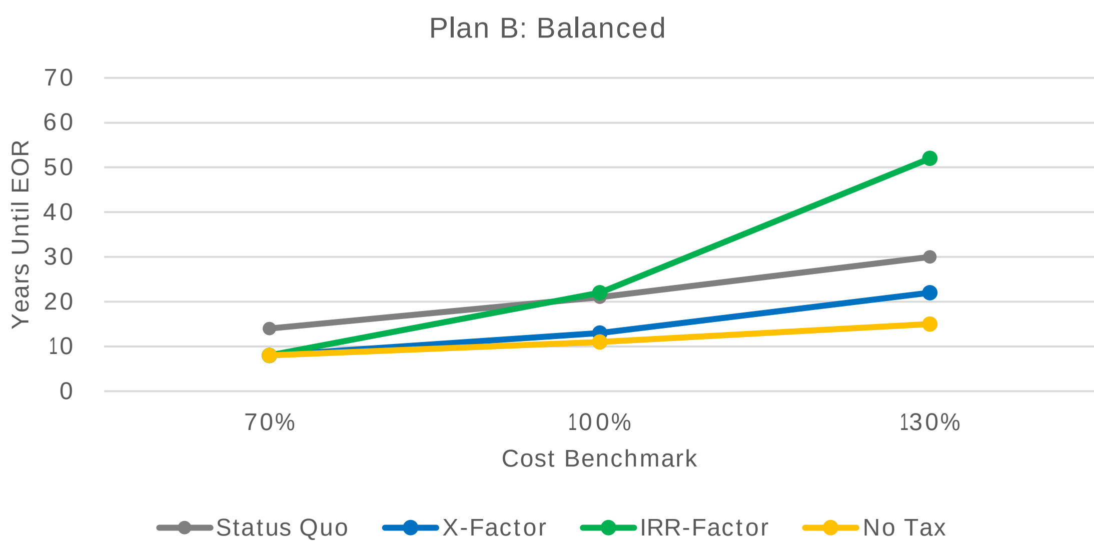


Figure B.8a Sensitivity of Implementation of EOR to Cost (Eastern Onshore Oil)





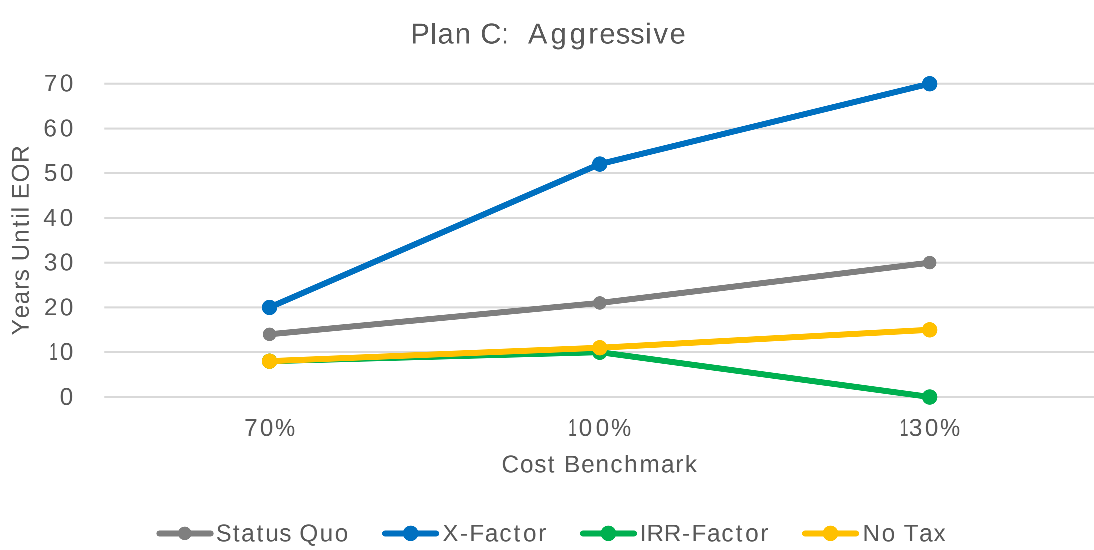
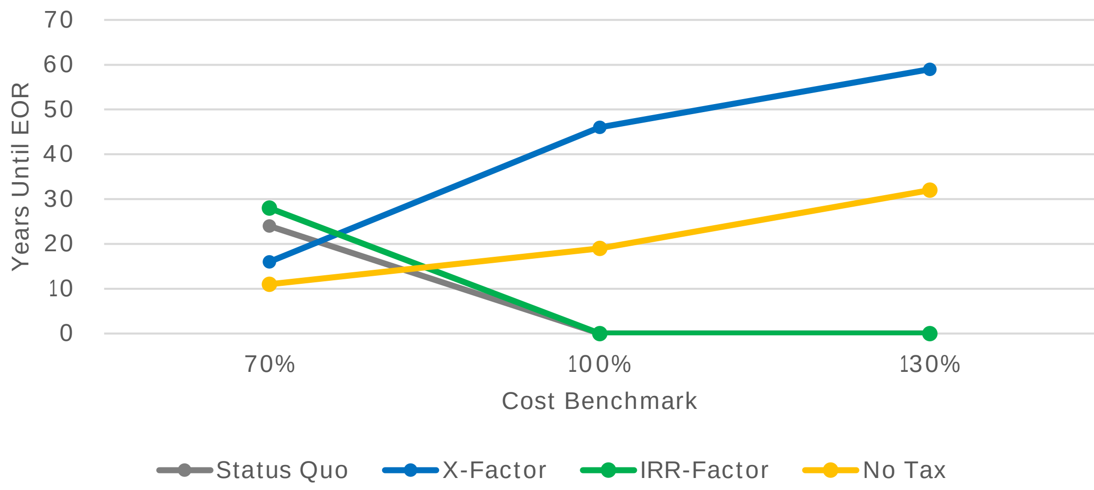
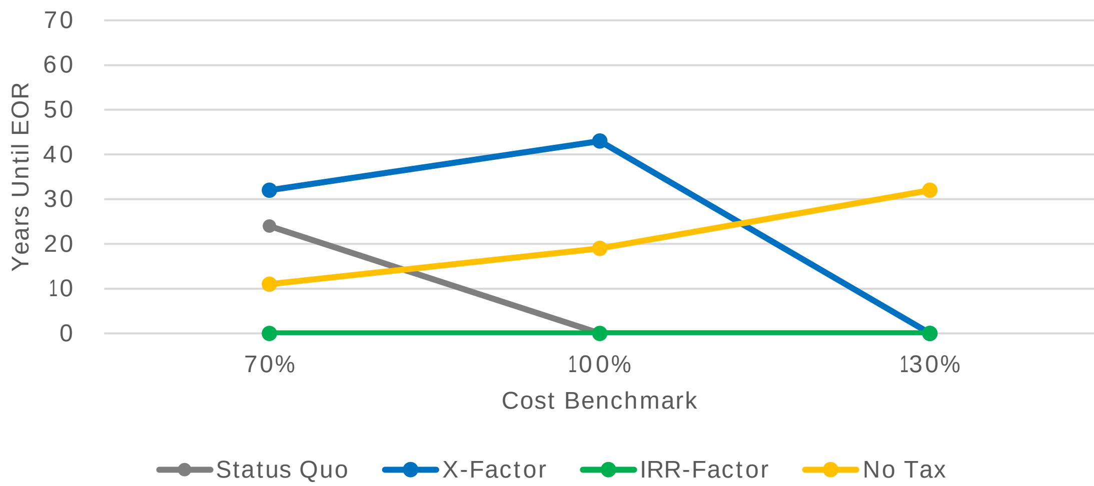


Figure B.8b Sensitivity of Implementation of EOR to Cost (Western Onshore Oil)

Plan A: Generous



Plan B: Balanced



Plan C: Aggressive

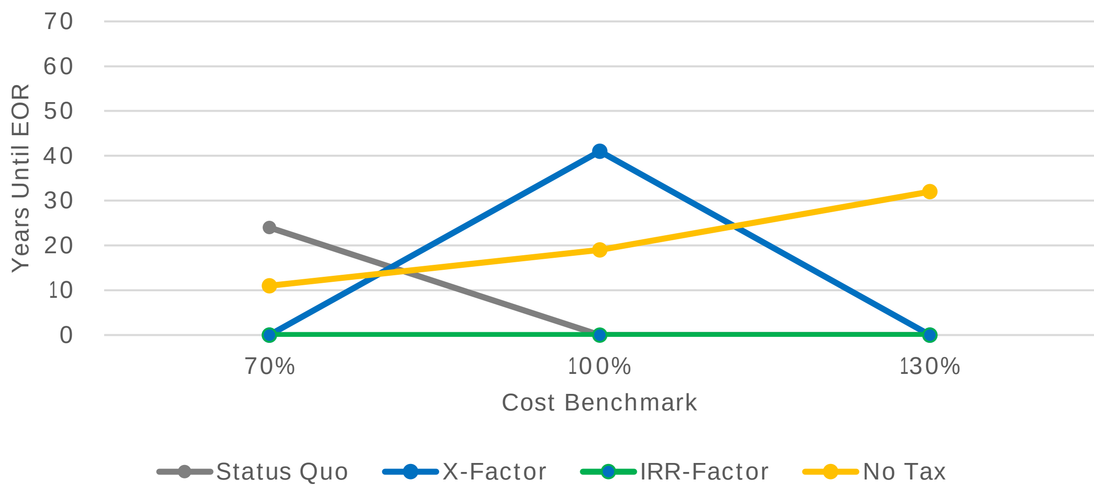
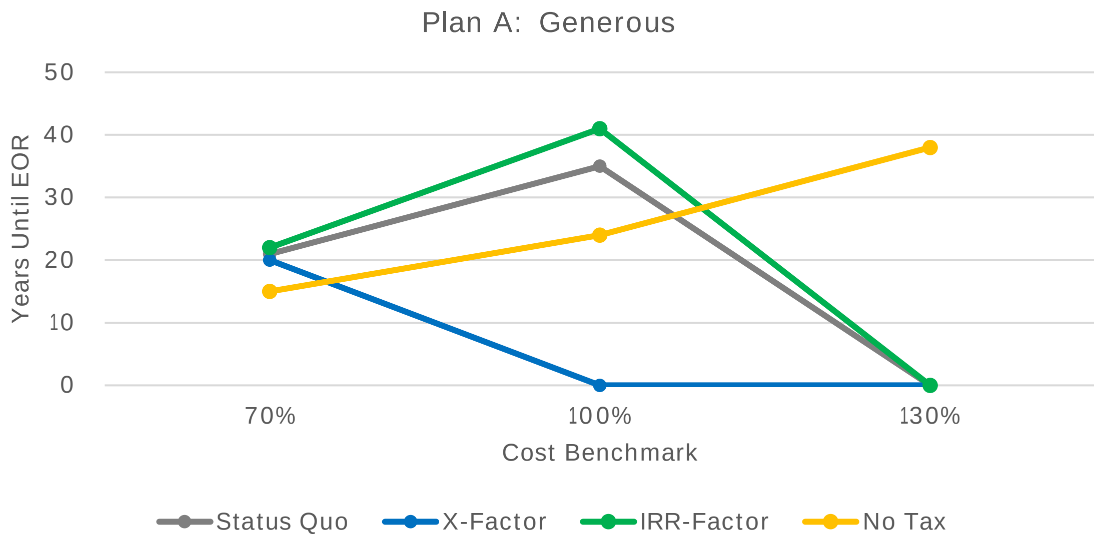
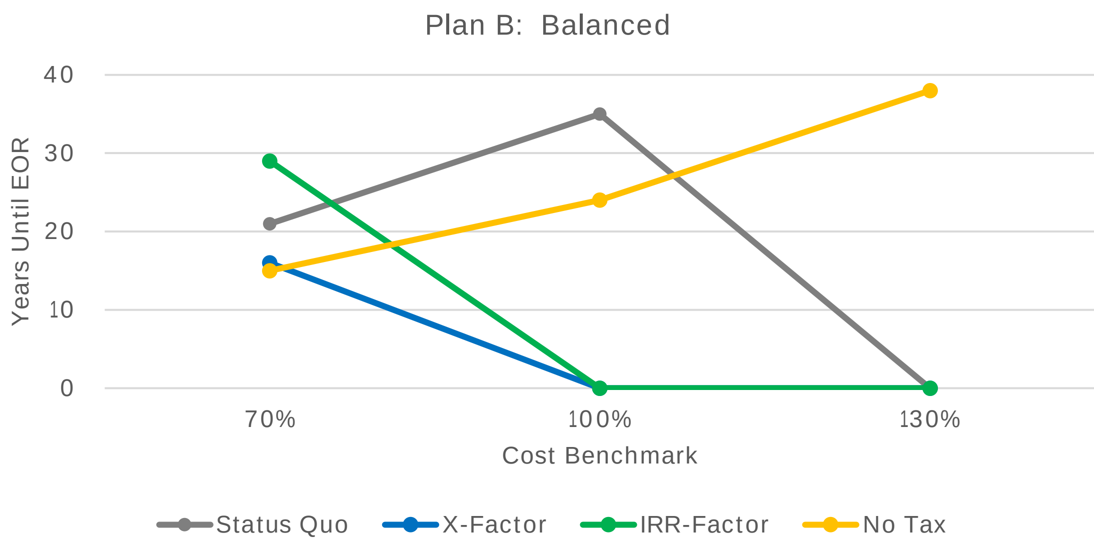


Figure B.8c Sensitivity of Implementation of EOR to Cost (Eastern Onshore Gas)





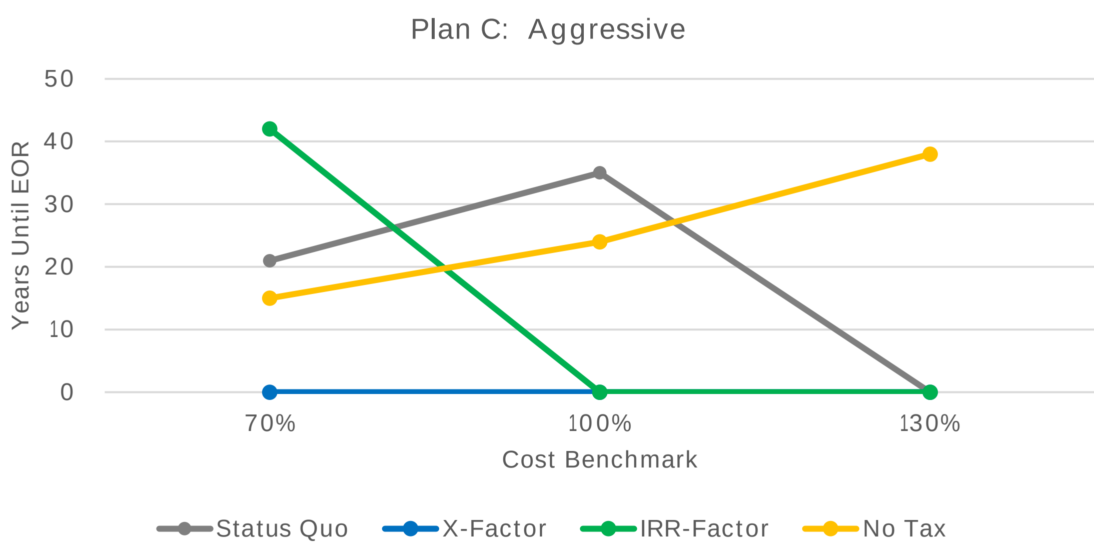


Figure B.9a Sensitivity of Resource Recovery Factor to Cost (Eastern Onshore Oil)

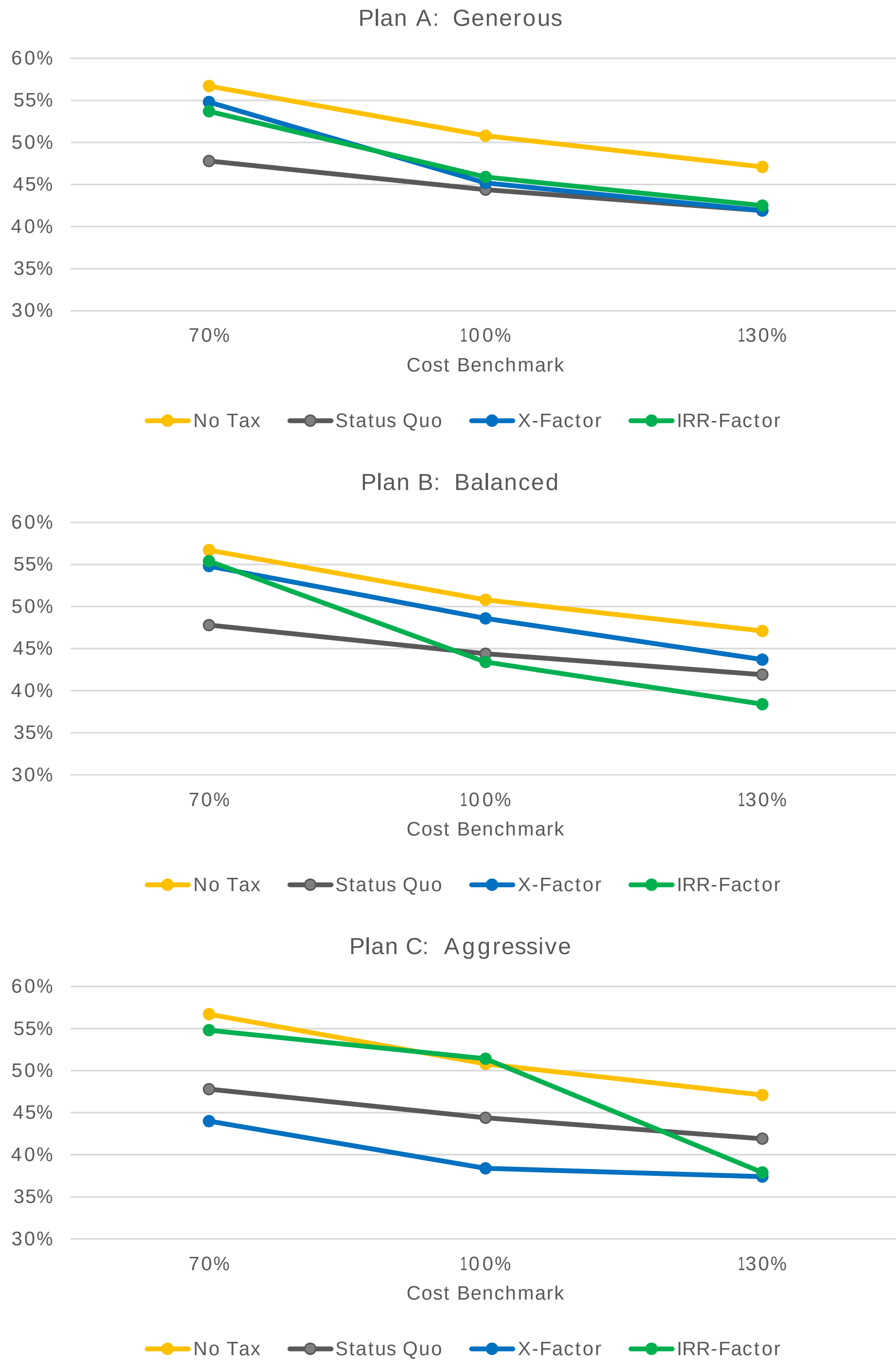


Figure B.9b Sensitivity of Resource Recovery Factor to Cost (Western Onshore Oil)

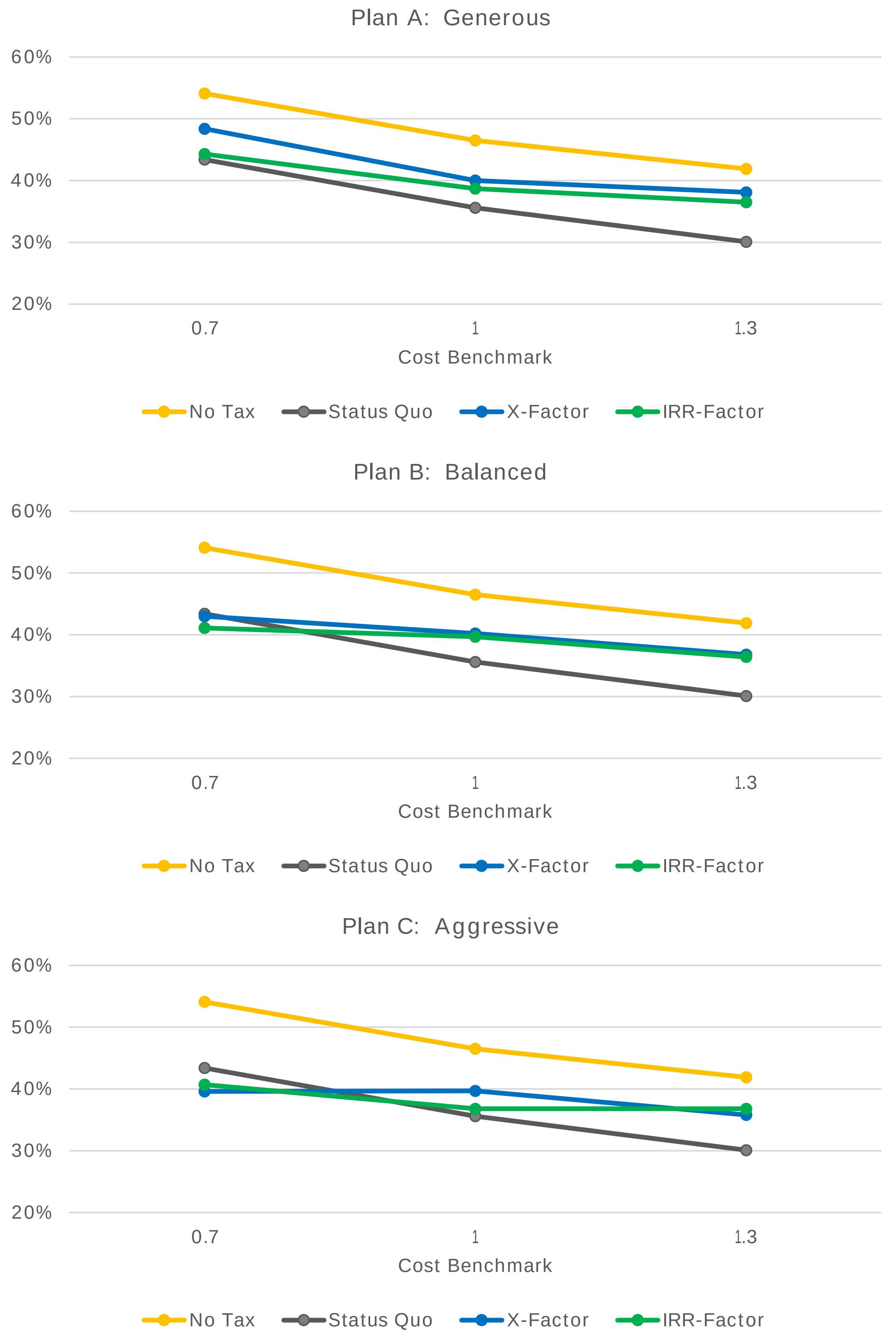


Figure B.9c Sensitivity of Resource Recovery Factor to Cost (Eastern Onshore Gas)

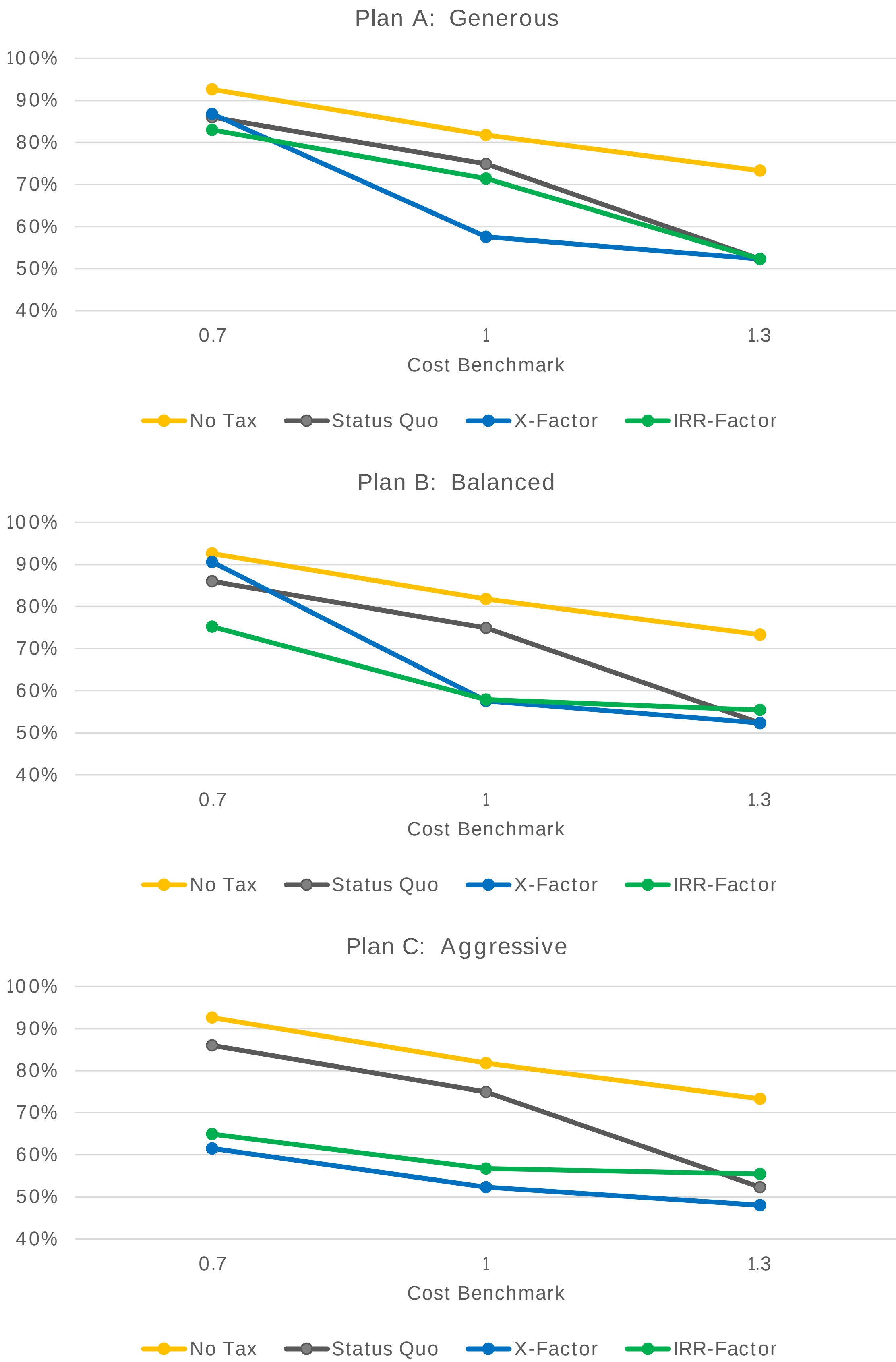


Figure B.9d Sensitivity of Resource Recovery Factor to Cost (Orinoco Heavy Oil)

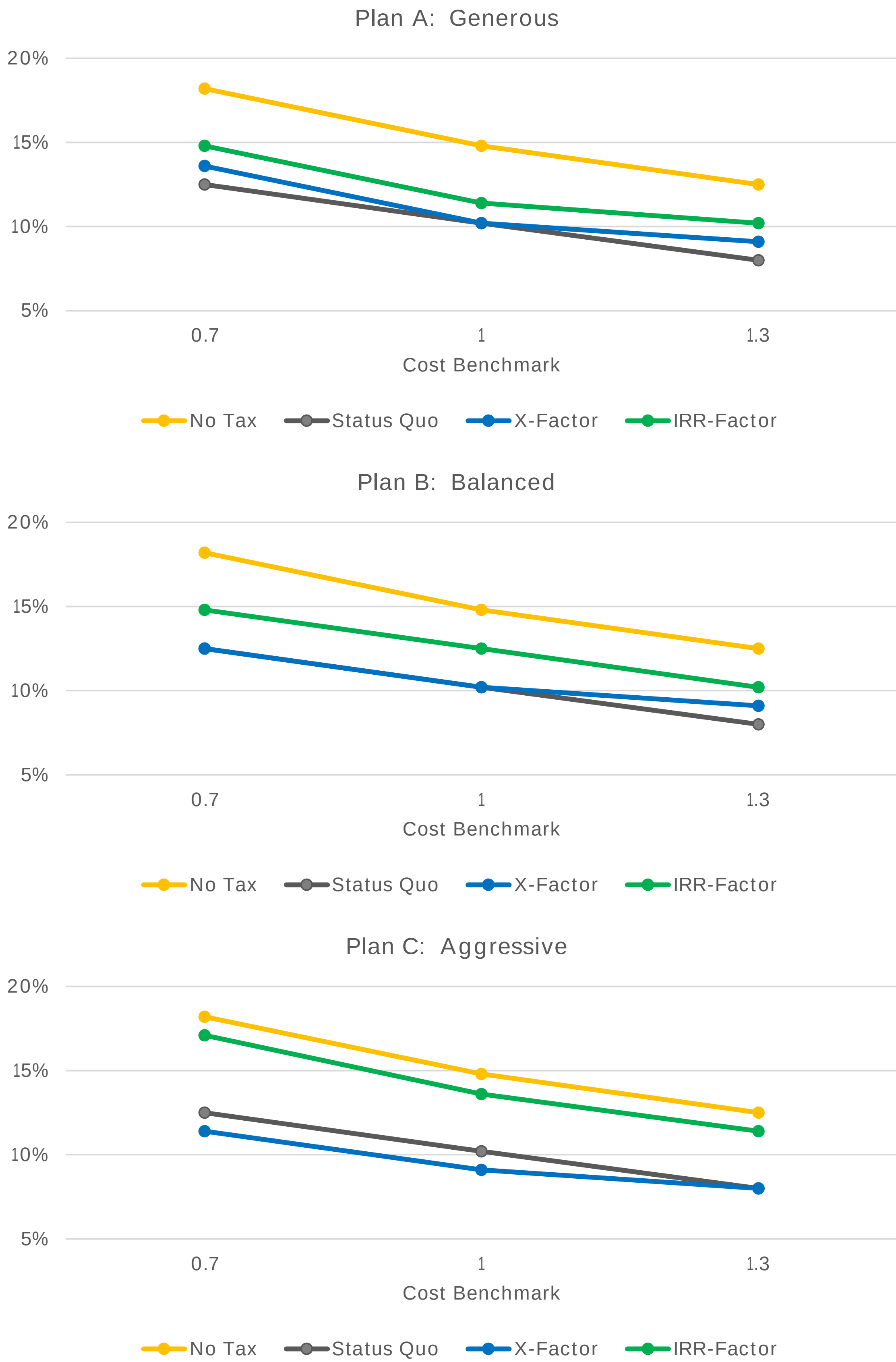
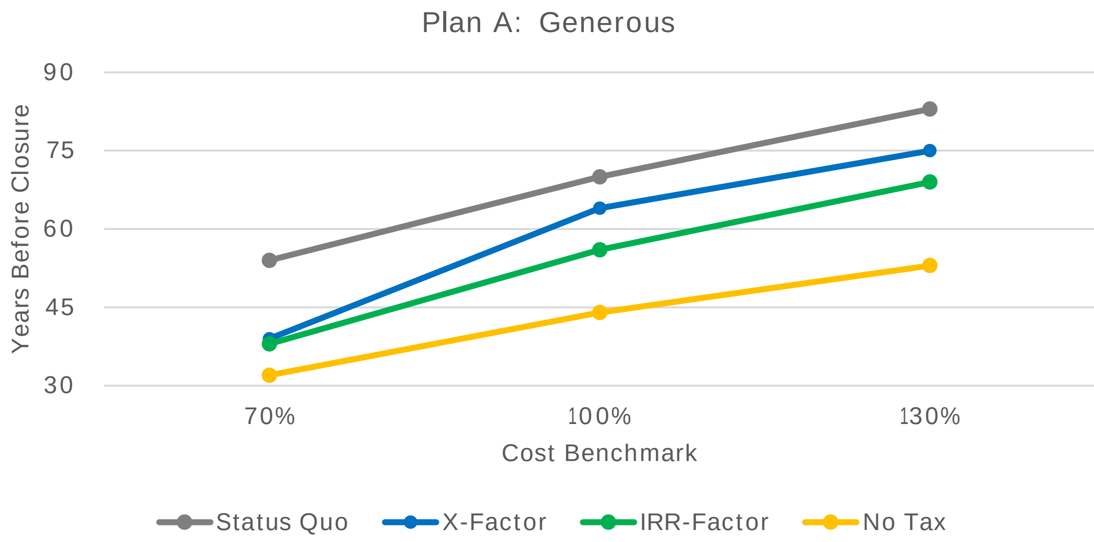
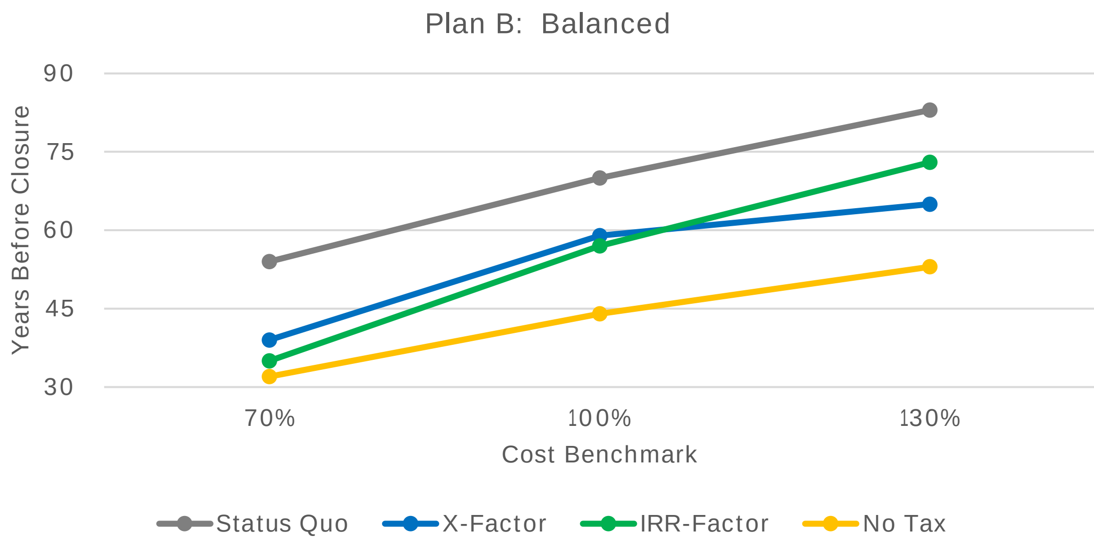


Figure B.10a Sensitivity of Project Lifetime to Cost (Eastern Onshore Oil)





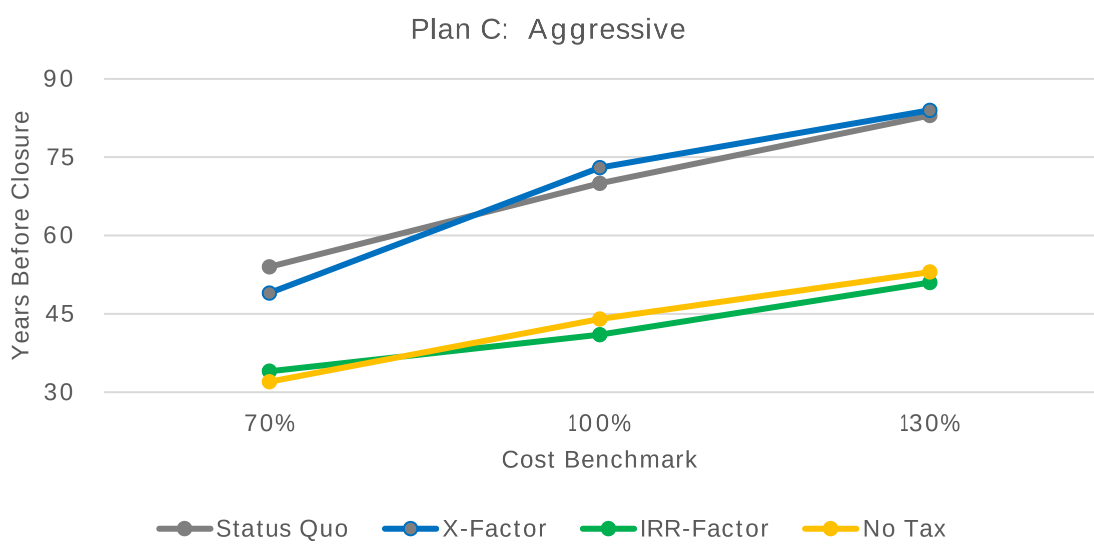


Figure B.10b Sensitivity of Project Lifetime to Cost (Western Onshore Oil)

Figure B.10c Sensitivity of Project Lifetime to Cost (Eastern Onshore Gas)

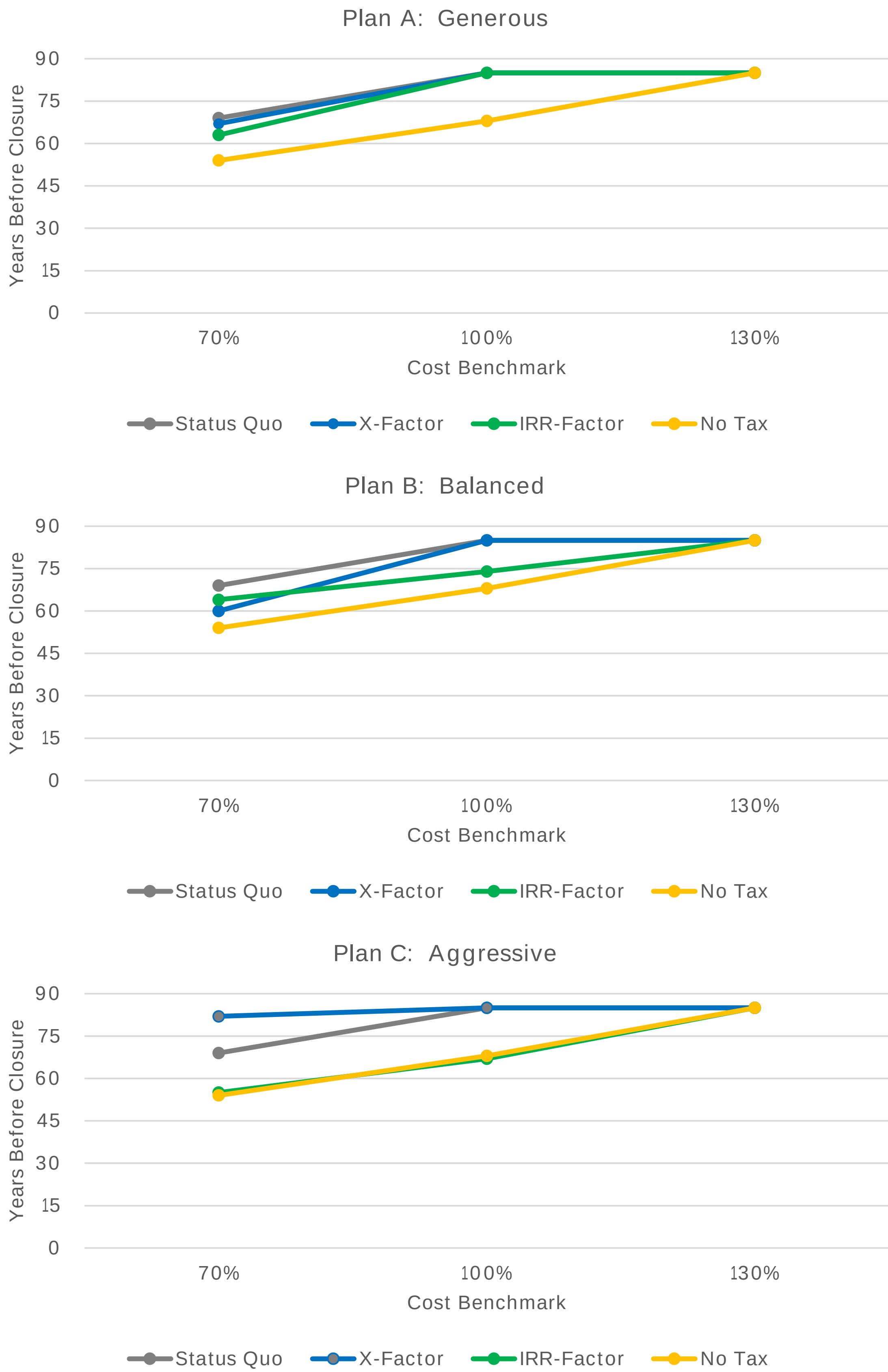
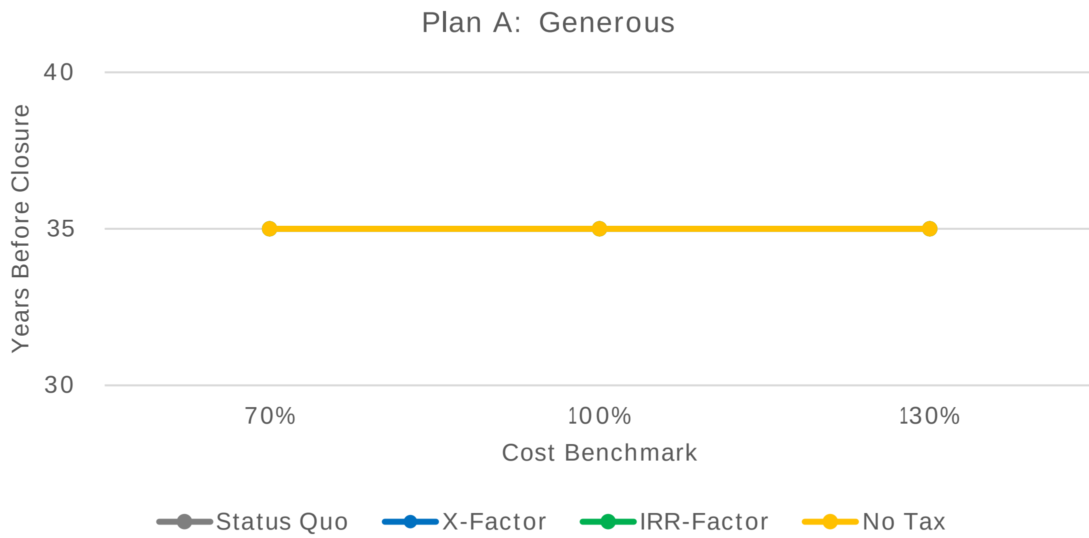
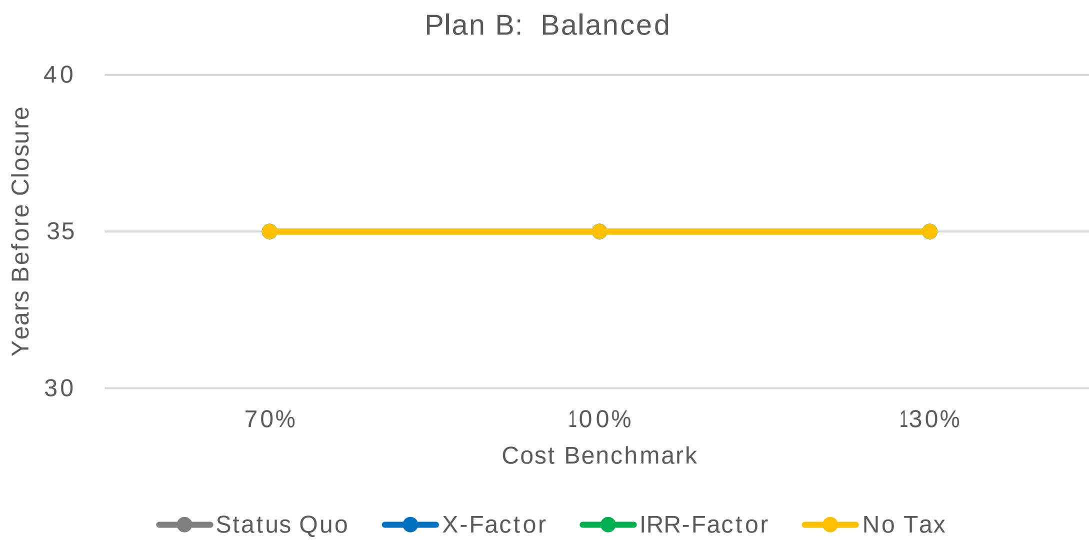


Figure B.10d Sensitivity of Project Lifetime to Cost (Orinoco Heavy Oil)





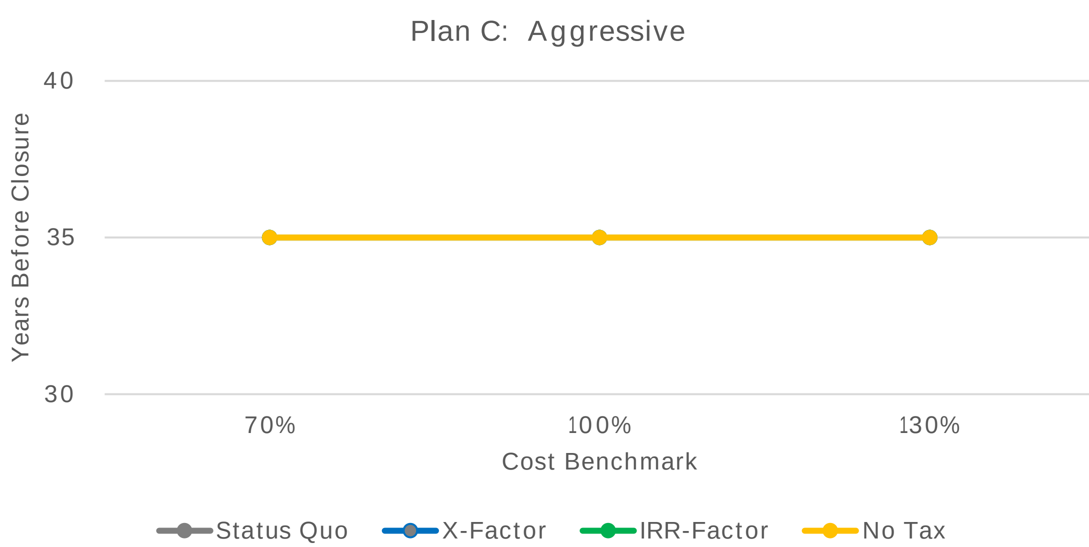


Figure B.11a Sensitivity of Investor NPV to Cost (Eastern Onshore Oil)

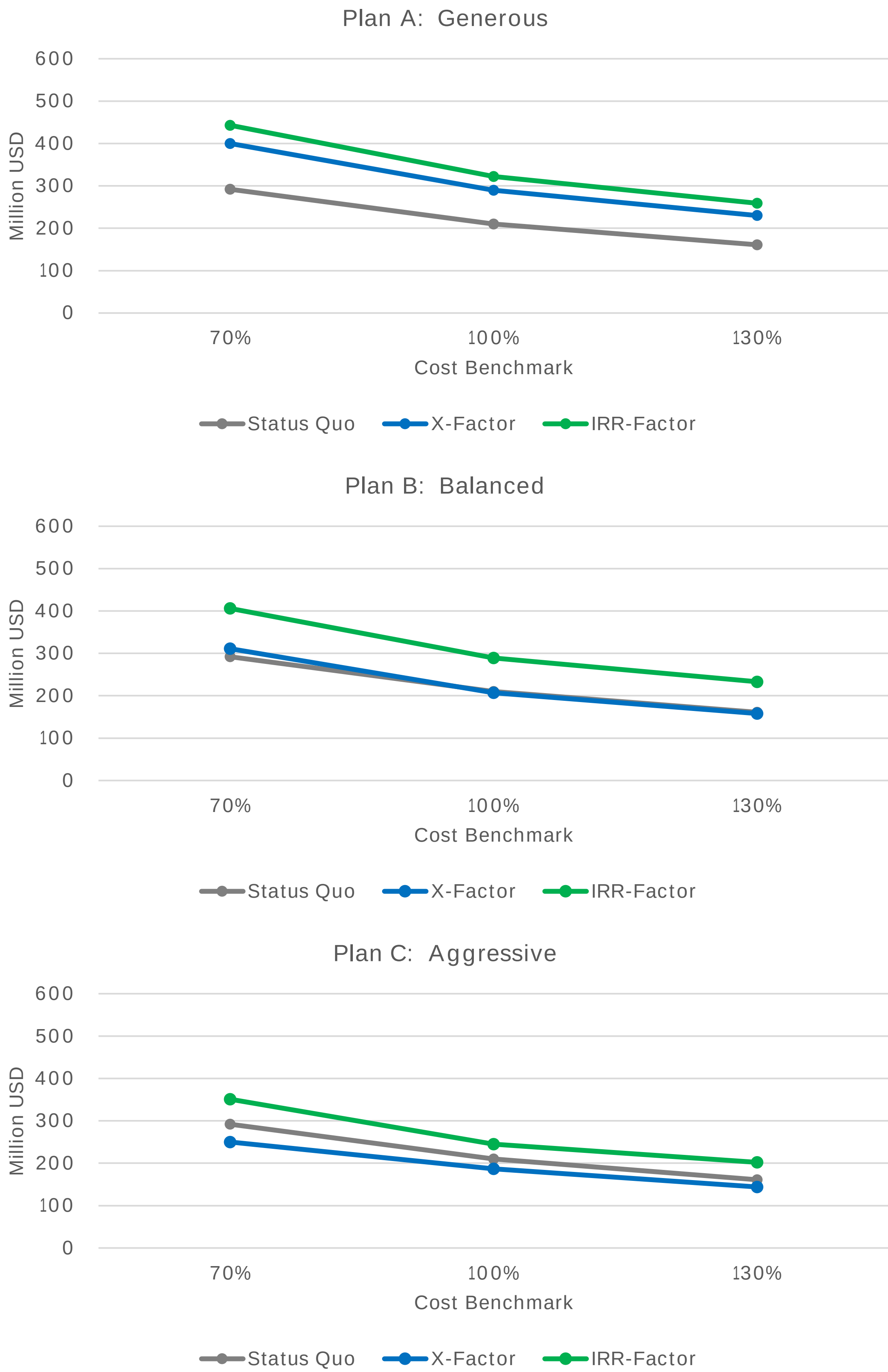


Figure B.11b Sensitivity of Investor NPV to Cost (Western Onshore Oil)

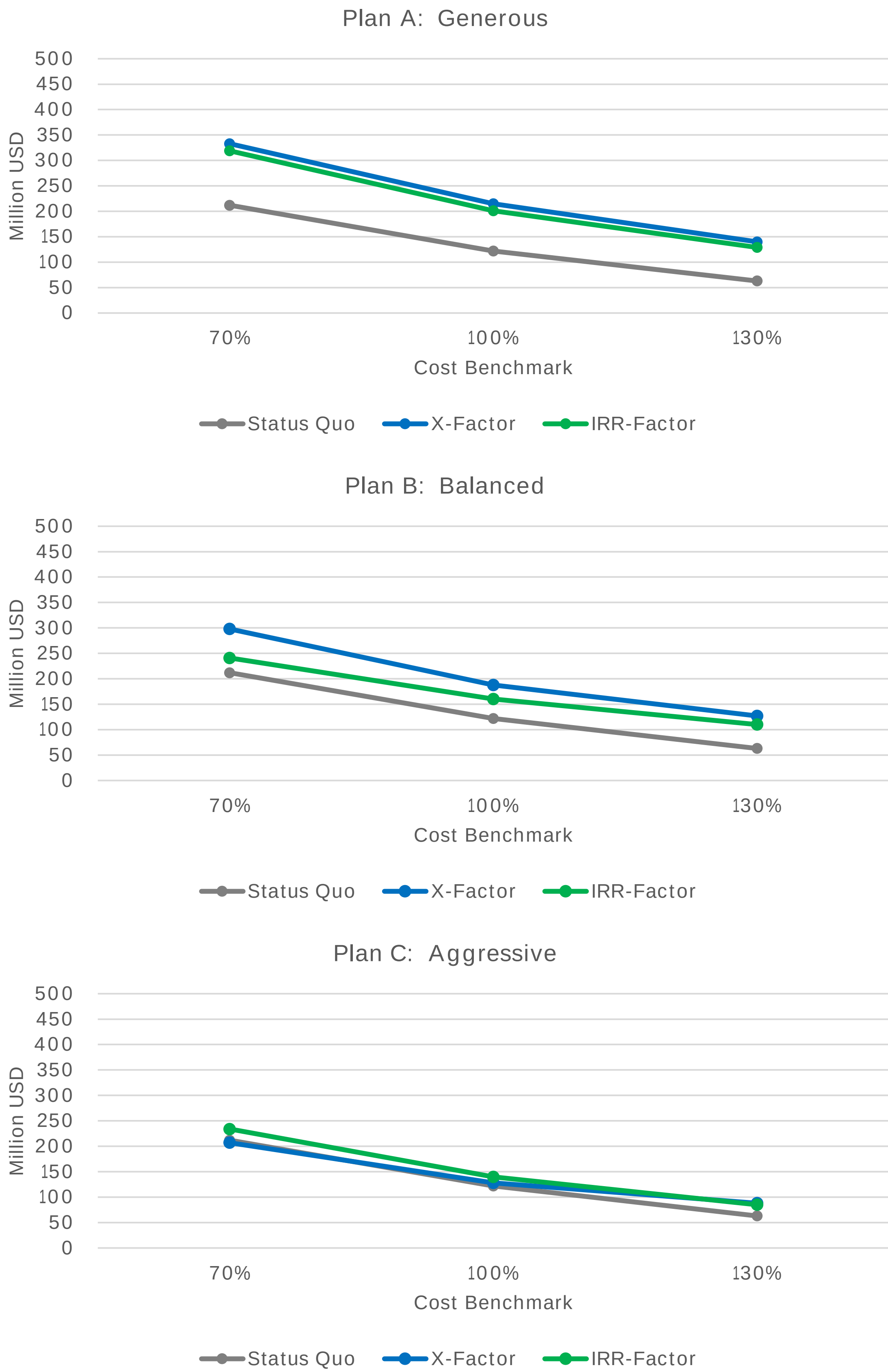
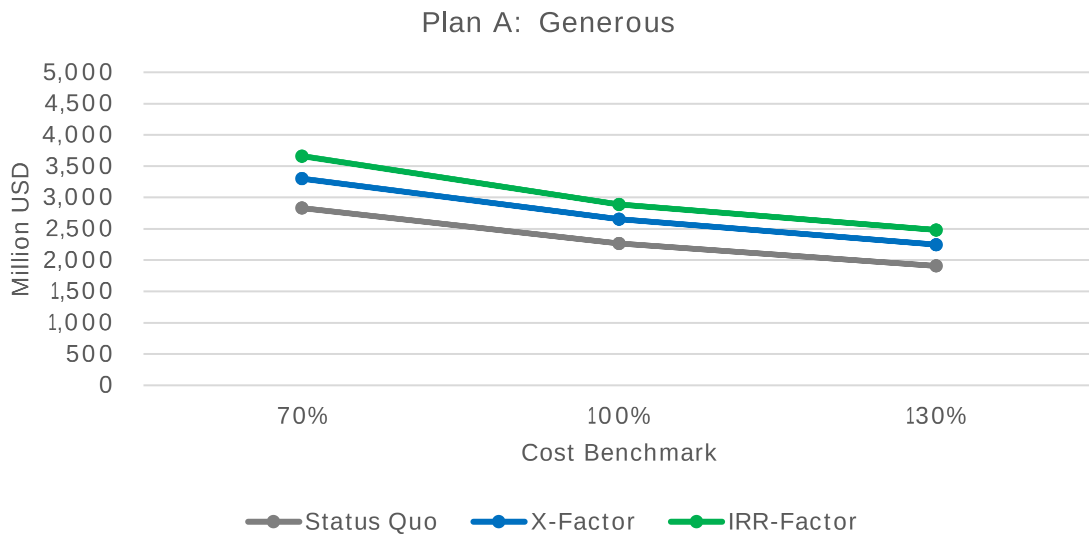
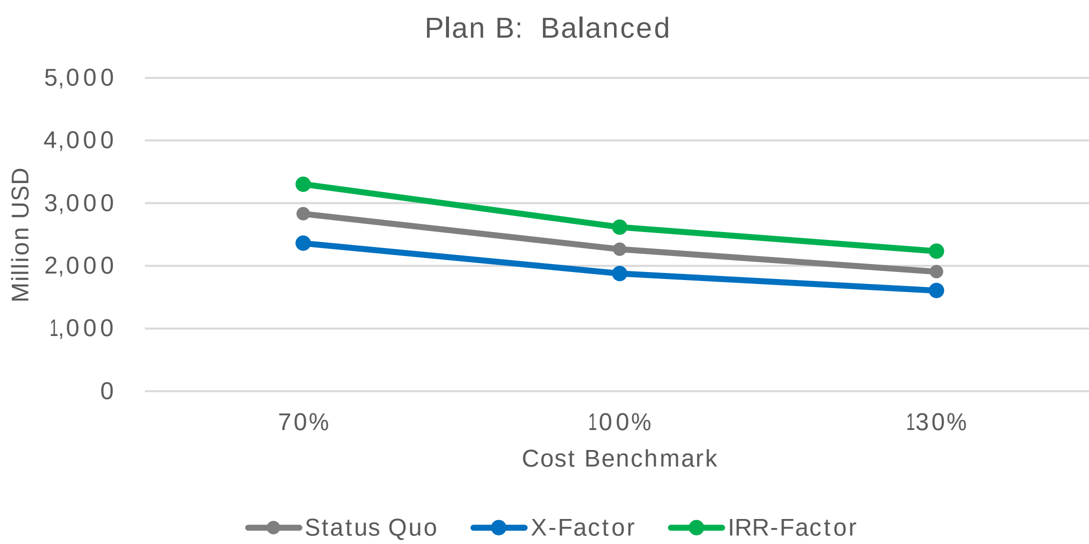
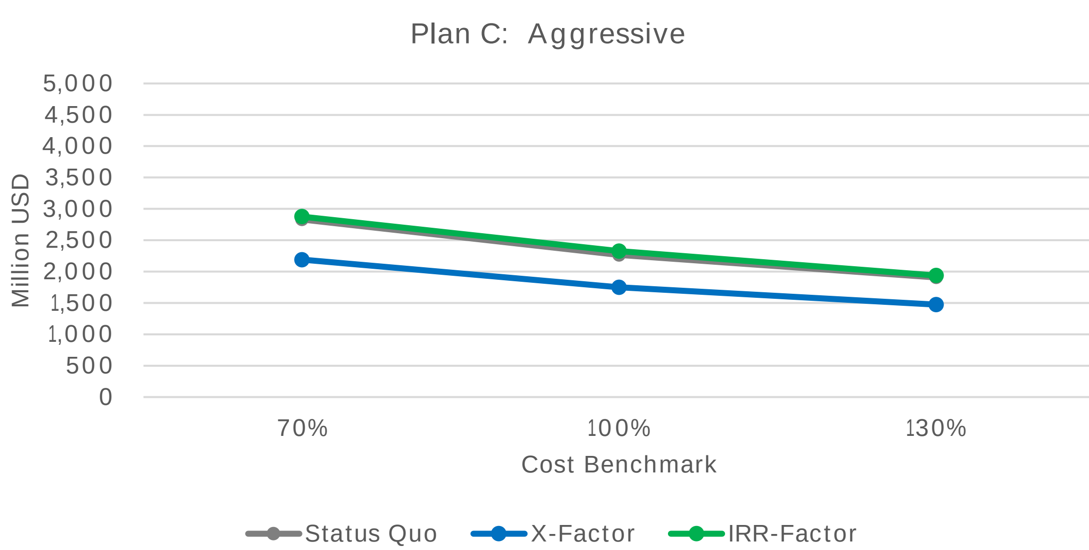


Figure B.11c Sensitivity of Investor NPV to Cost (Eastern Onshore Gas)

Figure B.11d Sensitivity of Investor NPV to Cost (Orinoco Heavy Oil)







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Appendix A: Methodology

The analysis of oil and gas fiscal regimes is adapted from Smith's (2014) model of petroleum exploration, development, and production. The model integrates exploration and development decisions to produce a "full-cycle" analysis of investments and returns. We begin by focusing on a reservoir where the volume of original oil-in-place is fixed and denoted *OIP*. Where oil and gas are both present, we state resource volumes in terms of barrels of oil equivalent with gas converted at the rate of 6 mcf per barrel (boe).

<u>Primary Production Phase</u>

Recovery of reserves during the initial (primary) phase of production is governed by the initial capital investment (number of wells) and geological properties of the reservoir:

$$R_0 = s \times OIP, \tag{1}$$

… where R_0 represents the volume of primary recovery and *s* represents the primary recovery factor. According to Total Exploration and Production (2009), the primary recovery factor is typically around 33% and we adopt that value.

During the primary phase of production, output declines exponentially from the initial level at a fixed rate, *a*, over time:

$$Q_t = Q_0 \times e^{-at} \text{ for t} \geq 0, \tag{2}$$

… where Q_t represents the instantaneous flow of production at time *t*. The volume of primary reserves is by definition the integral of (3):

$$R_0 = s \times OIP = \int_0^\infty Q_t dt = \frac{Q_0}{a}. \tag{3}$$

It follows that $Q_0 = a \times R_0$, which means the rate of decline and the rate of extraction are the same. Likewise, the volume of primary reserves remaining in the reservoir at time *t* is given by:

$$R_t = \frac{Q_t}{a} = R_0 \times e^{-at}. \tag{4}$$

The required investment to realize this production profile depends on the rate of extraction (*a*), which is chosen by the Investor, and the size of the field (*OIP*) and local conditions as reflected in a regional calibration factor (*A*), which are fixed exogenously:

$$I(a) = A \times s \times OIP \times a^{1.68}, \tag{5}$$

…where the elasticity with respect to rate of extraction exceeds one, indicating diminishing returns.[5] Investment requirements may be expressed alternatively in terms of the "capital

[5] Development of the Orinoco heavy oil project differs from conventional deposits because the project is integrated with construction and operation of a pipeline and upgrader facility. For that reason, a drilling program of multiple wells is scheduled over the life of the project to keep the flow of production to the upgrader facility fairly constant. We therefore set the field decline rate, a, equal to 0.25%. The overall capital cost of development then depends on the scale of the project, which is determined by the primary recovery factor, s, and the volume of original oil-in-place, OIP. Equation 5 then takes the following form: $I(s) = A \times$

coefficient," which measures the amount of investment in primary development required per initial daily barrel of production:

$$CC(a,A) \equiv \frac{I(a)}{Q_0/365} = 365 \times A \times a^{0.68}. \tag{6}$$

We assume the capital investment is spread equally across three years.[6] Operating costs are of two types. We assume the Investor incurs a variable cost (*VC*) per barrel as production occurs, plus an additional annual fixed operating cost (*FOC*) that is proportional to the installed capital investment.

Enhanced Production Phase

At a time, *T*, of his choosing the Investor can make an additional investment in enhanced recovery techniques, which are assumed to augment the volume of remaining reserves by the factor λ:

$$Q_t^e = \lambda \times Q_t \text{ for t} \geq T. \tag{7}$$

The extent to which reserves are augmented through EOR depends on the timing of EOR and the state of previous reservoir depletion, as well as on λ. The extent of reservoir depletion is measured by the ratio of remaining primary reserves to the initial volume:

$$d_t = 1 - \frac{R_t}{R_0} = 1 - e^{-at}. \tag{8}$$

The additional investment required for enhanced oil recovery is assumed to depend on the volume of remaining reserves to which EOR is applied ($\lambda \times R_T$) and the state of depletion at the time the EOR investment is made:

$$J(\lambda, T, a) = \frac{Aa^{1.68}\lambda R_T}{d_T}. \tag{9}$$

This is the same functional form that applied to investment in the primary phase of recovery, but scaled inversely by the state of depletion.

Optimal Development

At the time of initial development, and based on the Investor's choice of rate of extraction (*a*), the onset of EOR *(T)*, and the time at which the field is decommissioned ($\bar{T}$), the present value of the oil field net of taxes is given by:

$$\pi^e(a,T,\bar{T}) = \int_0^T (P_t - VC) \times Q_t \times e^{-rt}dt + \int_T^{\bar{T}} (P_t - VC) \times Q_t^e \times e^{-rt}dt - \int_0^{\bar{T}} [I_t(a) + FOC_t(a)]e^{-rt}dt - \int_0^{\bar{T}} \tau_t(a,T,\bar{T}) \times e^{-rt}dt - \frac{e^{-(a+r)T}}{1-e^{-aT}} \times \lambda \times I(a) - D \times e^{-r\bar{T}}, \tag{10}$$

$(s/.15)^{1.68} \times OIP$, where 0.15 is a numeraire from which increasing marginal costs are calculated, and the optimization of profit is with respect to s (recovery factor) rather than a (extraction rate).

[6] In the case of the Orinoco heavy oil project, capital expenditures are spread over the life of the project as needed to maintain sufficient wells to produce constant production from the field. See the footnote immediately above.

...where $\tau_t(a,T,\bar{T})$ reflects the net payment of taxes under a given fiscal regime, D represents decommissioning costs incurred at the end of field life, $\bar{T}$ represents the time at which the field is decommissioned, and $I_t(a)$ represents the portion of total primary capex, $I(a)$, expended at time t. Optimal development of the field is identified by maximizing Equation 10 with respect to the three choice parameters (a, T, $\bar{T}$) using the method of grid search.

<u>Exploration Phase</u>

The Investor is assumed to hold the right to drill a sequence of exploratory wells that target a given prospect. Each well is assumed to cost X, of which a fixed percentage (δ) represents intangible costs. We let RF be a 0/1 indicator that determines whether, according to the given fiscal regime, intangible costs may be expensed against the corporate income tax. After-tax cash flow for the period in which the exploratory well is drilled is then given by: $-X \times [1-\delta \times CIT \times (1-RF)]$, where CIT represents the marginal corporate income tax rate.

Tangible exploration costs are carried forward to offset future income. Thus, total exploration costs (tangible and intangible) carried forward after a series of n wells has been drilled is given by :

$$CF(n) = n \times X \times [1-\delta \times (1-RF)]. \tag{11}$$

Success of each exploratory well is predicted by a physical discovery process in which there are assumed to be four possible outcomes in terms of the size of deposit:

Small Field: $OIP = OIP_1$
Medium Field: $OIP = OIP_2$
Large Field: $OIP = OIP_3$
Dry Hole: $OIP = 0$

Drilling of the prospect is assumed to continue until a discovery is made or the Investor gives up, whichever comes first. The probability of outcome i from well j is denoted p_j^i, and is determined according to the discovery model of Smith (2005) which entails increasing dry hole risk after each successive failure. Let α represent the conditional probability that any given exploratory well will find a commercial field given that the prospect is charged with hydrocarbons and let β represent the unconditional probability that the prospect has been charged with hydrocarbons. Dry hole risk then must increase with each additional failure according to:

$$p_n^4 = \frac{\alpha(1-\alpha)^{n-1}\beta}{(1-\alpha)^{n-1}\beta+(1-\beta)}, \text{ for } n = 1,2,\ldots \tag{12}$$

We assume the relative likelihoods of the three commercial field types are given by q_1, q_2, q_3, the complete set of discovery probabilities at each stage of exploration is then established:

$$p_n^i = (1-p_n^4) \times q_i, \text{ for } i = 1,2,3. \tag{13}$$

The expected net present value of any individual exploratory well in the sequence is given by:

$$V^n = \sum_{j=1}^{3} \frac{p_n^j \times \Pi^e(a^*,T^*,\bar{T}^*|OIP_j)}{e^{-r\Delta t}} - X \times [1-\delta \times CIT \times (1-RF)], \tag{14}$$

… where the present value is computed relative to the date of drilling, $\Pi^{e}\left(a^{*}, T^{*}, \bar{T}^{*} | OIP_{j}\right)$ represents the optimized present value of the field as determined from the development phase, r represents the Investor's annual discount rate, and Δt represents the elapsed time between exploration and field development.

Integration of Exploration and Development

The full-cycle, after-tax net present value of the complete exploratory sequence is given by the value of each of the N wells that constitute the exploration "campaign" (V^{n} for $n = 1,2,\ldots,N$) multiplied by the probability that each of those wells gets drilled, denoted ϕ^{n}. Each of the N wells is drilled if and only if all preceding wells in the sequence were dry. Thus:

$$\phi^{n} = \prod_{j=0}^{n-1} p_{j}^{4}, \tag{15}$$

…where for convenience we define $p_{0}^{4} = 1$. The expected full-cycle, after-tax net present value of an exploration campaign that would be abandoned after N dry holes is then given by:

$$NPV^{FC}(N) = \sum_{j=1}^{N} \frac{V^{j}\phi^{j}}{(1+r)^{j+\Delta w}}, \tag{16}$$

…where Δw represents the time elapsed between each exploration well. Thus, the value of the Investor's right to exploit the prospect in question is given by:

$$max_{N}\ NPV^{FC}(N). \tag{17}$$

Appendix B: Comprehensive Tabulation of Simulation Results

Appendix Table 1a: Greenfield Eastern Oil Project (all price scenarios)
Summary of Results from the East Onshore Oil case study (cost = 100% of benchmark)

Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	82%	76%	74%	85%	76%	85%	81%
$ 55	0.0%	81%	75%	72%	82%	76%	83%	80%
$ 65	0.0%	79%	74%	72%	81%	75%	81%	80%
$ 75	0.0%	79%	73%	73%	81%	76%	81%	80%
$ 85	0.0%	78%	74%	72%	80%	75%	81%	79%

Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0	414	426	430	476	445	433	492
$ 55	0	607	626	610	674	640	638	698
$ 65	0	793	806	840	894	849	818	979
$ 75	0	1,059	1,046	1,123	1,207	1,185	1,096	1,285
$ 85	0	1,305	1,369	1,430	1,549	1,496	1,360	1,600

DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	20%	11%	7%	10%	7%	19%	3%
$ 55	0%	18%	9%	8%	11%	7%	16%	4%
$ 65	0%	19%	12%	7%	12%	9%	19%	2%
$ 75	0%	18%	12%	5%	8%	4%	17%	1%
$ 85	0%	19%	10%	4%	7%	3%	19%	2%

Investment, Medium Field Size ($ million, real)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	1,753	552	731	858	887	661	370	1,003
$ 55	2,425	841	1,171	1,268	1,484	1,027	665	1,608
$ 65	3,233	1,105	1,402	1,753	1,900	1,481	786	3,341
$ 75	4,352	1,459	1,832	3,029	2,874	3,184	1,155	4,008
$ 85	5,583	1,802	2,561	3,839	3,918	4,008	1,594	4,527

Unrisked Recovery Factor, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	46%	40%	41%	41%	43%	38%	36%	39%
$ 55	49%	43%	43%	44%	47%	39%	38%	42%
$ 65	51%	44%	45%	46%	49%	43%	38%	51%
$ 75	54%	46%	47%	52%	51%	52%	39%	52%
$ 85	56%	47%	49%	53%	54%	53%	43%	53%

Risked Reserves (million boe)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	147	126	128	129	130	118	113	119
$ 55	155	133	134	137	144	123	118	129
$ 65	163	139	144	147	150	138	122	160
$ 75	173	145	149	163	160	164	123	168
$ 85	181	151	155	170	173	170	136	171

Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	30%	16%	11%	13%	11%	27%	4%
$ 55	0%	26%	13%	12%	14%	10%	23%	5%
$ 65	0%	31%	18%	10%	16%	13%	29%	2%
$ 75	0%	27%	19%	7%	11%	5%	26%	1%
$ 85	0%	31%	15%	6%	9%	5%	29%	2%

Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	66%	68%	68%	76%	71%	69%	78%
$ 55	0%	66%	69%	67%	74%	70%	70%	76%
$ 65	0%	64%	65%	67%	72%	68%	66%	79%
$ 75	0%	65%	64%	69%	74%	73%	67%	79%
$ 85	0%	63%	66%	69%	75%	72%	66%	77%

Investor NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	629	90	135	153	89	137	79	117
$ 55	913	146	207	232	143	208	131	179
$ 65	1,245	210	290	322	207	289	187	245
$ 75	1,628	282	386	425	284	380	251	330
$ 85	2,069	364	490	547	380	501	315	434

Combined IOC + Govt NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	629	504	561	583	565	582	512	609
$ 55	913	753	833	842	817	848	769	877
$ 65	1,245	1,003	1,096	1,162	1,101	1,138	1,005	1,224
$ 75	1,628	1,341	1,432	1,548	1,491	1,565	1,347	1,615
$ 85	2,069	1,669	1,859	1,977	1,929	1,997	1,675	2,034

Max Exploration Wells

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	4	3	3	3	3	3	3	3
$ 55	4	3	3	3	3	3	3	3
$ 65	5	3	4	4	3	4	3	3
$ 75	5	4	4	4	4	4	3	4
$ 85	5	4	4	4	4	4	4	4

Extraction Rate, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	7.5%	4.0%	5.0%	5.5%	5.0%	5.5%	4.0%	7.0%
$ 55	8.5%	5.0%	6.5%	6.5%	6.0%	7.0%	5.5%	8.5%
$ 65	10.0%	5.5%	6.5%	7.5%	6.5%	7.5%	6.0%	9.5%
$ 75	11.5%	6.5%	7.5%	8.5%	8.0%	9.0%	7.5%	10.5%
$ 85	13.5%	7.0%	9.0%	10.0%	9.0%	10.5%	8.0%	12.0%

Onset of EOR, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	17	36	34	31	25	65	-	48
$ 55	13	27	25	22	16	43	63	25
$ 65	11	21	19	17	13	22	52	10
$ 75	9	18	16	10	10	10	40	9
$ 85	8	15	13	9	8	9	22	9

Abandonment, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	56	85	82	75	76	79	85	61
$ 55	50	76	65	64	63	63	77	50
$ 65	44	70	64	56	59	57	73	41
$ 75	39	61	57	48	49	44	59	35
$ 85	34	57	48	42	43	39	54	33

Following Results Pertain to the Medium Field Size

Half-Cycle Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	77%	72%	70%	80%	72%	80%	77%
$ 55	0.0%	77%	73%	70%	80%	73%	81%	77%
$ 65	0.0%	77%	71%	70%	80%	72%	80%	78%
$ 75	0.0%	77%	71%	71%	80%	74%	80%	78%
$ 85	0.0%	76%	72%	71%	79%	74%	80%	77%

Half-Cycle Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0	925	957	959	1072	985	952	1104
$ 55	0	1,355	1,413	1,363	1557	1421	1453	1558
$ 65	0	1,769	1,779	1,836	2038	1857	1860	2180
$ 75	0	2,327	2,308	2,466	2728	2611	2467	2816
$ 85	0	2,867	3,000	3,142	3391	3286	3039	3510

Half-Cycle DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	18%	10%	6%	9%	7%	19%	2%
$ 55	0%	16%	7%	7%	7%	6%	14%	3%
$ 65	0%	18%	12%	7%	9%	8%	17%	0%
$ 75	0%	17%	12%	5%	6%	3%	16%	1%
$ 85	0%	19%	10%	4%	7%	3%	18%	2%

Half-Cycle Investor NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	1,467	274	369	415	266	381	241	335
$ 55	2,090	398	529	591	384	537	352	474
$ 65	2,815	542	712	791	524	720	473	625
$ 75	3,654	702	921	1,016	692	921	608	811
$ 85	4,619	881	1,148	1,283	904	1,183	740	1,038

Half-Cycle Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	29%	15%	10%	12%	10%	29%	3%
$ 55	0%	25%	10%	10%	10%	9%	20%	4%
$ 65	0%	28%	18%	10%	12%	13%	26%	0%
$ 75	0%	27%	18%	7%	9%	5%	23%	1%
$ 85	0%	30%	16%	6%	10%	5%	28%	2%

Half-Cycle Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	63%	65%	65%	73%	67%	65%	75%
$ 55	0%	65%	68%	65%	74%	68%	70%	75%
$ 65	0%	63%	63%	65%	72%	66%	66%	77%
$ 75	0%	64%	63%	67%	75%	71%	68%	77%
$ 85	0%	62%	65%	68%	73%	71%	66%	76%

Appendix Table 1b: Greenfield Eastern Oil Project (all cost scenarios)
Summary of Results from the East Onshore Oil case study (oil price = $65; gas price = $3)

Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	78%	75%	73%	81%	75%	82%	79%
100%	0%	79%	74%	72%	81%	75%	81%	80%
130%	0%	80%	75%	72%	83%	75%	83%	79%

Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0	1,057	1,203	1,182	1,293	1,251	1,105	1,295
100%	0	793	806	840	894	849	818	979
130%	0	662	679	672	753	693	704	766

DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	20%	5%	4%	5%	2%	20%	2%
100%	0%	19%	12%	7%	12%	9%	19%	2%
130%	0%	18%	10%	8%	10%	8%	16%	4%

Investment, Medium Field Size ($ million, real)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	4,179	1,422	3,124	3,047	3,124	3,511	1,347	3,381
100%	3,233	1,105	1,402	1,753	1,900	1,481	786	3,341
130%	2,663	914	1,158	1,361	1,516	1,021	735	1,384

Unrisked Recovery Factor, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	56.7%	47.8%	54.8%	53.7%	54.8%	55.4%	44.0%	54.8%
100%	50.8%	44.4%	45.2%	45.9%	48.6%	43.4%	38.4%	51.4%
130%	47.1%	41.9%	41.9%	42.5%	43.7%	38.4%	37.4%	37.9%

Risked Reserves (million boe)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	182	153	175	171	175	177	138	175
100%	163	139	144	147	150	138	122	160
130%	151	131	131	133	137	120	116	119

Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	32%	7%	5%	6%	2%	30%	3%
100%	0%	31%	18%	10%	16%	13%	29%	2%
130%	0%	28%	15%	12%	13%	12%	23%	5%

Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	63%	71%	70%	77%	74%	65%	77%
100%	0%	64%	65%	67%	72%	68%	66%	79%
130%	0%	66%	67%	67%	75%	69%	70%	76%

IOC NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	1,688	292	400	443	311	406	250	351
100%	1,245	210	290	322	207	289	187	245
130%	1,009	161	230	259	158	233	144	202

Combined IOC + Govt NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	1,688	1,349	1,603	1,625	1,604	1,657	1,355	1,646
100%	1,245	1,003	1,096	1,162	1,101	1,138	1,005	1,224
130%	1,009	823	909	931	911	926	848	968

Max Exploration Wells

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	5	4	4	4	4	4	3	4
100%	5	3	4	4	3	4	3	3
130%	5	3	3	3	3	3	3	3

Extraction Rate, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	14.5%	7.5%	10.5%	11.5%	10.5%	12.0%	9.0%	11.5%
100%	10.0%	5.5%	6.5%	7.5%	6.5%	7.5%	6.0%	9.5%
130%	8.0%	4.5%	5.5%	6.0%	6.0%	6.0%	5.0%	7.5%

Onset of EOR, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	8	14	8	9	8	8	20	8
100%	11	21	19	17	13	22	52	10
130%	15	30	29	26	22	52	70	-

Abandonment, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	32	54	39	38	39	35	49	34
100%	44	70	64	56	59	57	73	41
130%	53	83	75	69	65	73	84	51

Following Results Pertain to the Median Field Size

Half-Cycle Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0.0%	76%	74%	71%	79%	74%	81%	77%
100%	0.0%	77%	71%	70%	80%	72%	80%	78%
130%	0.0%	77%	72%	70%	81%	72%	81%	76%

Half-Cycle Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0	2,323	2,666	2,596	2,864	2,747	2,500	2,836
100%	0	1,769	1,779	1,836	2,038	1,857	1,860	2,180
130%	0	1,476	1,500	1,498	1,751	1,533	1,605	1,705

Half-Cycle DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	19%	4%	4%	4%	2%	18%	2%
100%	0%	18%	12%	7%	9%	8%	17%	0%
130%	0%	17%	10%	7%	6%	8%	14%	3%

Half-Cycle Investor NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	3,785	724	950	1,056	752	976	603	855
100%	2,815	542	712	791	524	720	473	625
130%	2,301	433	581	652	414	594	380	528

Half-Cycle Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	32%	6%	5%	6%	2%	27%	3%
100%	0%	28%	18%	10%	12%	13%	26%	0%
130%	0%	27%	15%	10%	8%	11%	20%	4%

Half-Cycle Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	61%	70%	69%	76%	73%	66%	75%
100%	0%	63%	63%	65%	72%	66%	66%	77%
130%	0%	64%	65%	65%	76%	67%	70%	74%

Appendix Table 2a: Brownfield Western Oil Project (all price scenarios)
Summary of Results from the West Onshore Oil case study (cost = 100% of benchmark)

Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	84%	75%	77%	77%	81%	84%	86%
$ 55	0.0%	82%	72%	76%	76%	81%	84%	84%
$ 65	0.0%	80%	72%	74%	75%	80%	83%	82%
$ 75	0.0%	80%	72%	74%	75%	80%	83%	82%
$ 85	0.0%	80%	72%	72%	74%	80%	82%	80%

Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0	162	235	253	241	264	264	284
$ 55	0	314	358	403	396	444	453	459
$ 65	0	499	553	587	554	649	640	645
$ 75	0	716	775	791	808	881	897	897
$ 85	0	967	1,017	983	1,015	1,142	1,127	1,093

DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	43%	6%	2%	6%	2%	6%	1%
$ 55	0%	31%	10%	4%	6%	0%	3%	2%
$ 65	0%	24%	6%	4%	9%	1%	6%	4%
$ 75	0%	20%	4%	5%	4%	2%	4%	3%
$ 85	0%	18%	4%	8%	7%	3%	7%	8%

Investment, Medium Field Size ($ million, real)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	530	65	299	339	305	339	271	494
$ 55	849	154	366	494	451	671	494	580
$ 65	1,269	271	625	671	553	1,088	641	671
$ 75	1,655	414	934	939	939	1,189	1,026	1,088
$ 85	2,259	706	1,349	1,013	1,047	1,452	1,093	976

Unrisked Recovery Factor, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	39.1%	26.1%	37.3%	36.1%	37.2%	35.2%	35%	36%
$ 55	43.8%	33.0%	38.0%	37.3%	38.6%	37.5%	37%	35%
$ 65	46.5%	35.6%	40.0%	38.7%	40.2%	39.7%	40%	37%
$ 75	49.2%	36.8%	41.7%	41.7%	41.8%	40.2%	43%	39%
$ 85	52.3%	41.6%	46.2%	43.7%	42.0%	41.1%	43%	40%

Risked Reserves (million boe)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	97	65	92	89	92	87	87	88
$ 55	108	82	94	93	95	93	91	87
$ 65	115	88	99	97	99	98	97	91
$ 75	122	92	103	102	104	103	107	97
$ 85	130	103	114	108	103	102	104	98

Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	88%	9%	3%	8%	3%	7%	1%
$ 55	0%	54%	16%	5%	8%	0%	4%	2%
$ 65	0%	40%	9%	5%	14%	2%	8%	5%
$ 75	0%	32%	6%	6%	6%	3%	5%	3%
$ 85	0%	27%	6%	12%	11%	4%	9%	10%

Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	49%	70%	76%	72%	79%	79%	85%
$ 55	0%	57%	65%	73%	71%	80%	82%	83%
$ 65	0%	61%	68%	72%	68%	79%	78%	79%
$ 75	0%	64%	69%	70%	72%	78%	80%	80%
$ 85	0%	66%	69%	67%	69%	77%	76%	74%

IOC NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	334	30	79	74	74	63	51	48
$ 55	554	71	140	130	125	108	84	86
$ 65	819	122	215	201	188	160	128	140
$ 75	1,125	180	300	283	267	220	182	198
$ 85	1,475	246	394	375	353	285	243	271

Combined IOC + Govt NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	334	192	314	327	315	327	315	332
$ 55	554	385	498	533	521	552	537	545
$ 65	819	621	768	788	742	809	768	785
$ 75	1,125	896	1,075	1,074	1,075	1,101	1,079	1,095
$ 85	1,475	1,213	1,411	1,358	1,368	1,427	1,370	1,364

Max Exploration Wells

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	NA	NA	NA	NA	NA	NA	NA	NA
$ 55	NA	NA	NA	NA	NA	NA	NA	NA
$ 65	NA	NA	NA	NA	NA	NA	NA	NA
$ 75	NA	NA	NA	NA	NA	NA	NA	NA
$ 85	NA	NA	NA	NA	NA	NA	NA	NA

Extraction Rate, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	5.0%	1.5%	3.5%	4.0%	3.5%	4.0%	3.5%	5.0%
$ 55	6.0%	2.5%	4.0%	5.0%	4.5%	6.0%	5.0%	5.5%
$ 65	7.5%	3.5%	5.5%	6.0%	5.0%	8.0%	5.5%	6.0%
$ 75	8.5%	4.5%	7.0%	7.0%	7.0%	9.5%	7.0%	8.0%
$ 85	10.0%	5.5%	8.0%	7.0%	7.5%	9.5%	7.5%	7.5%

Onset of EOR, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	52	-	65	-	60	-	-	-
$ 55	25	-	63	-	53	-	-	-
$ 65	19	-	46	-	43	-	41	-
$ 75	15	-	37	36	36	-	26	-
$ 85	12	30	20	27	35	-	29	-

Abandonment, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	62	85	81	64	77	58	68	44
$ 55	52	85	76	53	66	41	51	37
$ 65	43	73	58	47	63	32	53	38
$ 75	39	59	47	46	47	25	43	30
$ 85	34	52	41	47	43	27	43	35

Following Results Pertain to the Medium Field Size

Half-Cycle Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	84%	75%	77%	77%	81%	84%	85%
$ 55	0.0%	82%	72%	76%	76%	80%	84%	84%
$ 65	0.0%	80%	72%	74%	75%	80%	83%	82%
$ 75	0.0%	80%	72%	74%	75%	80%	83%	82%
$ 85	0.0%	80%	72%	72%	74%	80%	82%	80%

Half-Cycle Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0	220	319	343	327	358	358	386
$ 55	0	426	487	553	538	603	615	623
$ 65	0	678	751	796	752	881	870	876
$ 75	0	972	1,052	1,074	1097	1189	1218	1218
$ 85	0	1,313	1,380	1,316	1379	1550	1533	1484

Half-Cycle DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	42%	6%	2%	6%	2%	6%	0%
$ 55	0%	31%	10%	3%	6%	1%	3%	2%
$ 65	0%	24%	6%	4%	9%	1%	6%	4%
$ 75	0%	20%	5%	5%	4%	3%	4%	3%
$ 85	0%	18%	4%	9%	7%	3%	7%	8%

Half-Cycle Investor NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	453	41	108	101	100	85	69	66
$ 55	753	96	189	177	170	146	114	117
$ 65	1,112	165	292	273	256	218	174	190
$ 75	1,528	245	407	385	363	299	247	270
$ 85	2,003	334	536	510	479	388	329	368

Half-Cycle Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	87%	8%	3%	8%	3%	7%	0%
$ 55	0%	54%	16%	4%	8%	1%	4%	2%
$ 65	0%	40%	9%	5%	14%	1%	8%	5%
$ 75	0%	32%	7%	6%	6%	3%	5%	3%
$ 85	0%	27%	6%	13%	11%	4%	9%	10%

Half-Cycle Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	49%	70%	76%	72%	79%	79%	85%
$ 55	0%	57%	65%	73%	71%	80%	82%	83%
$ 65	0%	61%	68%	72%	68%	79%	78%	79%
$ 75	0%	64%	69%	70%	72%	78%	80%	80%
$ 85	0%	66%	69%	66%	69%	77%	77%	74%

Appendix Table 2b: Brownfield Western Oil Project (all cost scenarios)

Summary of Results from the West Onshore Oil case study (oil price = $65; gas price = $3)

Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	79%	71%	73%	74%	79%	81%	80%
100%	0%	80%	72%	74%	75%	80%	83%	82%
130%	0%	83%	74%	77%	77%	81%	84%	85%

Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0	807	829	854	836	932	872	915
100%	0	499	553	587	554	649	640	645
130%	0	304	397	421	429	457	449	481

DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	18%	7%	6%	9%	6%	13%	8%
100%	0%	24%	6%	4%	9%	1%	6%	4%
130%	0%	36%	6%	4%	3%	1%	6%	1%

Investment, Medium Field Size ($ million, real)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	1,856	605	1,043	1,005	821	928	608	843
100%	1,269	271	625	671	553	1,088	641	671
130%	897	138	482	538	538	642	441	872

Unrisked Recovery Factor, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	54.1%	43.4%	48.4%	44.3%	43.0%	41.1%	39.6%	40.7%
100%	46.5%	35.6%	40.0%	38.7%	40.2%	39.7%	39.7%	36.8%
130%	41.9%	30.1%	38.1%	36.5%	36.8%	36.4%	35.8%	36.8%

Risked Reserves (million boe)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	134	107	120	110	106	103	100	101
100%	115	88	99	97	99	98	97	91
130%	104	75	94	90	91	90	89	91

Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	28%	10%	8%	13%	8%	19%	10%
100%	0%	40%	9%	5%	14%	2%	8%	5%
130%	0%	67%	9%	5%	4%	1%	8%	1%

Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	65%	67%	69%	67%	75%	70%	74%
100%	0%	61%	68%	72%	68%	79%	78%	79%
130%	0%	53%	69%	74%	75%	80%	78%	84%

IOC NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	1,243	212	333	319	298	241	207	234
100%	819	122	215	201	188	160	128	140
130%	572	63	140	129	127	110	88	85

Combined IOC + Govt NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	1,243	1,019	1,162	1,173	1,134	1,173	1,079	1,149
100%	819	621	768	788	742	809	768	785
130%	572	367	537	550	556	567	537	566

Max Exploration Wells

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	NA	NA	NA	NA	NA	NA	NA	NA
100%	NA	NA	NA	NA	NA	NA	NA	NA
130%	NA	NA	NA	NA	NA	NA	NA	NA

Extraction Rate, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	11.0%	6.0%	8.0%	9.0%	8.0%	9.0%	7.0%	8.5%
100%	7.5%	3.5%	5.5%	6.0%	5.0%	8.0%	5.5%	6.0%
130%	5.5%	2.0%	4.0%	4.5%	4.5%	5.0%	4.0%	6.0%

Onset of EOR, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	11	24	16	28	32	-	-	-
100%	19	-	46	-	43	-	41	-
130%	32	-	59	-	-	-	-	-

Abandonment, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	32	48	41	38	42	30	40	32
100%	43	73	58	47	63	32	53	38
130%	56	85	74	57	59	48	62	38

Following Results Pertain to the Medium Field Size

Half-Cycle Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	79%	71%	73%	74%	79%	81%	80%
100%	0%	80%	72%	74%	75%	80%	83%	82%
130%	0%	83%	74%	77%	77%	81%	84%	85%

Half-Cycle Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0.000	1,096.000	1,126.000	1,159.000	1,135.000	1,254.000	1,182.000	1,242.000
100%	-	678.000	751.000	796.000	752.000	881.000	870.000	876.000
130%	0.000	413.000	539.000	580.000	583.000	620.000	610.000	653.000

Half-Cycle DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	18%	6%	6%	9%	6%	13%	8%
100%	0%	24%	6%	4%	9%	1%	6%	4%
130%	0%	36%	6%	3%	3%	1%	6%	1%

Half-Cycle Investor NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	1,688.000	288.000	453.000	434.000	405.000	328.000	281.000	319.000
100%	1,112.000	165.000	292.000	273.000	256.000	218.000	174.000	190.000
130%	776.000	86.000	191.000	176.000	173.000	149.000	119.000	116.000

Half-Cycle Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	28%	10%	8%	13%	8%	19%	10%
100%	0%	40%	9%	5%	14%	1%	8%	5%
130%	0%	67%	9%	3%	3%	1%	8%	1%

Half-Cycle Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	65%	67%	69%	67%	74%	70%	74%
100%	0%	61%	68%	72%	68%	79%	78%	79%
130%	0%	53%	69%	75%	75%	80%	79%	84%

Appendix Table 3a: Greenfield Eastern Gas Project (all price scenarios)
Summary of Results from the East Onshore Gas case study (cost = 100% of benchmark)

Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	93%	93%	89%		93%		100%
$ 55	0.0%	80%	81%	78%	87%	83%	96%	86%
$ 65	0.0%	72%	74%	71%	83%	76%	90%	81%
$ 75	0.0%	68%	70%	67%	79%	72%	85%	77%
$ 85	0.0%	67%	69%	66%	78%	70%	82%	76%

Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0	35	36	38	0	40	0	43
$ 55	0	67	68	71	62	78	62	69
$ 65	0	97	101	100	113	111	110	118
$ 75	0	131	132	135	153	146	150	158
$ 85	0	179	180	182	211	183	194	203

DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	25%	24%	16%	100%	16%	100%	16%
$ 55	0%	13%	13%	5%	25%	2%	33%	17%
$ 65	0%	12%	11%	7%	11%	4%	19%	4%
$ 75	0%	12%	13%	8%	11%	7%	19%	6%
$ 85	0%	9%	11%	6%	7%	11%	19%	9%

Investment, Medium Field Size ($ million, real)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	248	80	80	116	80	116	49	116
$ 55	424	209	116	158	116	204	80	204
$ 65	655	336	204	338	204	256	116	256
$ 75	841	464	392	489	515	359	158	435
$ 85	1,055	618	618	632	811	505	204	583

Unrisked Recovery Factor, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	65.3%	48.0%	48.0%	52.3%	48.0%	52.3%	41.7%	52.3%
$ 55	78.5%	63.5%	52.3%	55.4%	52.3%	57.6%	48.0%	57.0%
$ 65	81.8%	74.9%	57.6%	71.4%	57.6%	57.9%	52.3%	56.7%
$ 75	85.9%	81.5%	76.3%	77.5%	83.6%	62.1%	55.4%	63.0%
$ 85	89.6%	85.0%	84.8%	80.9%	86.1%	73.5%	57.6%	64.1%

Risked Reserves (million boe)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	91	53	53	58	-	58	-	58
$ 55	114	88	73	77	58	79	55	63
$ 65	119	104	87	99	87	82	74	79
$ 75	125	113	106	108	114	85	78	85
$ 85	131	124	115	118	119	102	80	87

Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	37%	33%	21%		20%		19%
$ 55	0%	18%	18%	7%	39%	3%	52%	23%
$ 65	0%	19%	16%	11%	14%	5%	26%	5%
$ 75	0%	20%	21%	13%	16%	11%	27%	8%
$ 85	0%	15%	17%	10%	10%	17%	29%	13%

Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	69%	71%	75%	0%	78%	0%	84%
$ 55	0%	70%	71%	74%	65%	81%	65%	72%
$ 65	0%	64%	66%	66%	74%	73%	72%	78%
$ 75	0%	60%	61%	62%	70%	67%	69%	72%
$ 85	0%	61%	61%	62%	72%	62%	66%	69%

IOC NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	51	3	3	5	0	3	0	0
$ 55	96	17	16	20	10	16	2	11
$ 65	152	37	35	41	23	35	13	28
$ 75	218	61	58	66	41	56	27	47
$ 85	294	89	83	94	61	80	44	65

Combined IOC + Govt NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	51	38	39	43	-	43	-	43
$ 55	96	84	84	91	72	94	64	80
$ 65	152	134	136	141	136	146	123	146
$ 75	218	192	190	201	194	202	177	205
$ 85	294	268	263	276	272	263	238	268

Max Exploration Wells

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	2	1	1	1	-	1	-	1
$ 55	3	2	2	2	1	2	1	1
$ 65	3	2	2	2	2	2	2	2
$ 75	3	2	2	2	2	2	2	2
$ 85	3	3	2	3	2	2	2	2

Extraction Rate, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	3.0%	2.0%	2.0%	2.5%	2.0%	2.5%	1.5%	2.5%
$ 55	3.5%	2.5%	2.5%	3.0%	2.5%	3.5%	2.0%	3.5%
$ 65	4.5%	3.0%	3.5%	3.5%	3.5%	4.0%	2.5%	4.0%
$ 75	5.0%	3.5%	3.5%	4.0%	3.5%	4.5%	3.0%	5.0%
$ 85	5.5%	4.0%	4.0%	4.5%	4.5%	4.5%	3.5%	6.0%

Onset of EOR, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	51	-	-	-	-	-	-	-
$ 55	31	51	-	-	-	-	-	-
$ 65	24	35	-	41	-	-	-	-
$ 75	20	28	34	30	25	60	-	52
$ 85	17	23	23	25	19	33	-	45

Abandonment, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	85	85	85	85	85	85	85	85
$ 55	84	85	85	85	85	85	85	81
$ 65	68	85	85	85	85	74	85	67
$ 75	63	85	85	76	81	75	85	67
$ 85	58	76	74	69	61	70	85	58

Following Results Pertain to the Medium Field Size

Half-Cycle Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	61%	62%	61%	67%	63%	74%	68%
$ 55	0.0%	60%	62%	60%	69%	65%	74%	69%
$ 65	0.0%	60%	63%	60%	71%	64%	74%	68%
$ 75	0.0%	60%	62%	59%	70%	64%	74%	68%
$ 85	0.0%	60%	62%	59%	72%	63%	74%	69%

Half-Cycle Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0	90	91	97	99	100	93	108
$ 55	0	140	142	148	158	163	153	174
$ 65	0	200	221	209	246	228	224	243
$ 75	0	272	276	280	320	303	307	327
$ 85	0	357	371	362	447	378	397	419

Half-Cycle DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	9%	9%	2%	9%	2%	22%	2%
$ 55	0%	9%	9%	3%	9%	1%	19%	1%
$ 65	0%	9%	5%	4%	5%	2%	17%	2%
$ 75	0%	9%	10%	5%	8%	4%	17%	3%
$ 85	0%	8%	8%	6%	3%	7%	17%	6%

Half-Cycle Investor NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	162	57	56	61	48	58	33	50
$ 55	254	91	88	97	73	89	53	79
$ 65	365	133	127	141	102	129	79	114
$ 75	496	182	172	191	137	172	106	153
$ 85	646	238	224	248	178	220	141	190

Half-Cycle Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	17%	17%	4%	15%	4%	38%	4%
$ 55	0%	16%	17%	6%	15%	1%	31%	1%
$ 65	0%	16%	8%	7%	7%	4%	28%	3%
$ 75	0%	16%	17%	9%	12%	7%	27%	5%
$ 85	0%	14%	14%	10%	5%	13%	27%	9%

Half-Cycle Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	56%	56%	60%	61%	62%	57%	67%
$ 55	0%	55%	56%	58%	62%	64%	60%	69%
$ 65	0%	55%	61%	57%	67%	62%	61%	67%
$ 75	0%	55%	56%	56%	65%	61%	62%	66%
$ 85	0%	55%	57%	56%	69%	59%	61%	65%

Appendix Table 3b: Greenfield Eastern Gas Project (all cost scenarios)
Summary of Results from the East Onshore Gas case study (oil price = $65; gas price = $3)

Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	68%	70%	67%	78%	71%	83%	77%
100%	0%	72%	74%	71%	83%	76%	90%	81%
130%	0%	80%	81%	76%	86%	81%	95%	86%

Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0	144	151	145	167	150	160	163
100%	0	97	101	100	113	111	110	118
130%	0	78	79	74	71	84	70	90

DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	10%	9%	8%	9%	11%	18%	10%
100%	0%	12%	11%	7%	11%	4%	19%	4%
130%	0%	8%	8%	8%	22%	2%	30%	2%

Investment, Medium Field Size ($ million, real)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	891	517	541	541	671	431	208	465
100%	655	336	204	338	204	256	116	256
130%	466	151	151	151	151	205	104	205

Unrisked Recovery Factor, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	92.6%	86.0%	86.8%	83.0%	90.6%	75.2%	61.5%	64.9%
100%	81.8%	74.9%	57.6%	71.4%	57.6%	57.9%	52.3%	56.7%
130%	73.3%	52.3%	52.3%	52.3%	52.3%	55.4%	48.0%	55.4%

Risked Reserves (million boe)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	135	119	119	115	123	104	86	90
100%	119	104	87	99	87	82	74	79
130%	107	73	73	73	58	77	53	77

Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	16%	13%	12%	13%	17%	27%	15%
100%	0%	19%	16%	11%	14%	5%	26%	5%
130%	0%	10%	10%	12%	32%	2%	46%	2%

Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	61%	64%	62%	71%	64%	68%	69%
100%	0%	64%	66%	66%	74%	73%	72%	78%
130%	0%	74%	75%	70%	67%	79%	66%	85%

IOC NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	235	68	64	72	46	60	32	48
100%	152	37	35	41	23	35	13	28
130%	106	20	19	23	12	20	4	14

Combined IOC + Govt NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	235	212	215	217	213	210	192	211
100%	152	134	136	141	136	146	123	146
130%	106	98	98	97	83	104	74	104

Max Exploration Wells

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	3	2	2	2	2	2	2	2
100%	3	2	2	2	2	2	2	2
130%	3	2	2	2	1	2	1	2

Extraction Rate, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	6.0%	4.5%	4.5%	5.0%	4.5%	5.0%	4.0%	6.5%
100%	4.5%	3.0%	3.5%	3.5%	3.5%	4.0%	2.5%	4.0%
130%	3.5%	2.5%	2.5%	2.5%	2.5%	3.0%	2.0%	3.0%

Onset of EOR, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	15	21	20	22	16	29	-	42
100%	24	35	-	41	-	-	-	-
130%	38	-	-	-	-	-	-	-

Abandonment, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	54	69	67	63	60	64	82	55
100%	68	85	85	85	85	74	85	67
130%	85	85	85	85	85	85	85	85

Following Results Pertain to the Medium Field Size

Half-Cycle Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0.0%	60%	63%	60%	70%	63%	74%	69%
100%	0.0%	60%	63%	60%	71%	64%	74%	68%
130%	0.0%	63%	64%	60%	70%	64%	76%	69%

Half-Cycle Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0	298	312	301	355	311	330	338
100%	0	200	221	209	246	228	224	243
130%	0	163	165	155	181	174	177	187

Half-Cycle DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	7%	6%	5%	5%	7%	16%	7%
100%	0%	9%	5%	4%	5%	2%	17%	2%
130%	0%	6%	6%	6%	6%	1%	15%	1%

Half-Cycle Investor NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	530	196	185	203	150	180	117	154
100%	365	133	127	141	102	129	79	114
130%	275	96	94	104	78	98	57	85

Half-Cycle Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	12%	11%	9%	7%	13%	25%	11%
100%	0%	16%	8%	7%	7%	4%	28%	3%
130%	0%	10%	10%	10%	9%	2%	23%	2%

Half-Cycle Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	56%	59%	57%	67%	59%	62%	64%
100%	0%	55%	61%	57%	67%	62%	61%	67%
130%	0%	59%	60%	56%	66%	63%	64%	68%

Appendix Table 4a: Orinoco Heavy Oil Project (all price scenarios)
Summary of Results from the Orinoco Heavy Oil case study (cost = 100% of benchmark)

Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	75%	72%	71%	80%	75%	81%	79%
$ 55	0.0%	76%	71%	72%	80%	75%	79%	79%
$ 65	0.0%	76%	72%	71%	80%	75%	80%	78%
$ 75	0.0%	76%	72%	71%	80%	73%	80%	78%
$ 85	0.0%	75%	72%	71%	81%	74%	81%	78%

Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.000	3,811	3,611	3,859	4,018	4,292	4,108	4,484
$ 55	0.000	5,331	5,037	5,680	5,621	5,879	5,134	6,357
$ 65	0.000	7,083	6,692	7,010	7,469	7,696	6,920	8,258
$ 75	0.000	9,063	8,564	8,889	9,561	9,206	8,957	10,389
$ 85	0.000	10,434	10,649	10,923	11,892	11,875	11,234	12,741

DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	14%	14%	7%	14%	3%	14%	3%
$ 55	0%	14%	14%	3%	14%	3%	21%	1%
$ 65	0%	13%	13%	8%	13%	4%	19%	1%
$ 75	0%	12%	12%	7%	12%	7%	17%	1%
$ 85	0%	16%	11%	7%	11%	3%	16%	1%

Investment, Medium Field Size ($ million, real)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	6,392	1,903	1,903	2,722	1,903	3,733	1,903	3,733
$ 55	8,070	2,722	2,722	4,951	2,722	4,951	1,903	6,392
$ 65	10,001	3,733	3,733	4,951	3,733	6,392	2,722	8,070
$ 75	12,198	4,951	4,951	6,392	4,951	6,392	3,733	10,001
$ 85	17,447	4,951	4,951	8,070	6,392	10,001	4,951	12,198

Unrisked Recovery Factor, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	12.5%	8.0%	8.0%	9.1%	8.0%	10.2%	8.0%	10.2%
$ 55	13.6%	9.1%	9.1%	11.4%	9.1%	11.4%	8.0%	12.5%
$ 65	14.8%	10.2%	10.2%	11.4%	10.2%	12.5%	9.1%	13.6%
$ 75	15.9%	11.4%	11.4%	12.5%	11.4%	12.5%	10.2%	14.8%
$ 85	18.2%	11.4%	12.5%	13.6%	12.5%	14.8%	11.4%	15.9%

Risked Reserves (million boe)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	1,578	1,004	1,004	1,148	1,004	1,291	1,004	1,291
$ 55	1,722	1,148	1,148	1,435	1,148	1,435	1,004	1,578
$ 65	1,865	1,291	1,291	1,435	1,291	1,578	1,148	1,722
$ 75	2,009	1,435	1,435	1,578	1,435	1,578	1,291	1,865
$ 85	2,296	1,435	1,578	1,722	1,578	1,865	1,435	2,009

Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	22%	23%	11%	20%	4%	20%	4%
$ 55	0%	21%	22%	5%	20%	5%	33%	1%
$ 65	0%	19%	20%	12%	18%	5%	29%	1%
$ 75	0%	17%	18%	11%	16%	10%	26%	2%
$ 85	0%	25%	17%	10%	15%	5%	23%	2%

Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	65%	62%	66%	68%	73%	70%	76%
$ 55	0%	65%	62%	70%	69%	72%	63%	78%
$ 65	0%	66%	63%	65%	70%	72%	65%	77%
$ 75	0%	67%	63%	66%	71%	68%	66%	77%
$ 85	0%	63%	64%	66%	72%	72%	68%	77%

IOC NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	5,869	1,237	1,437	1,577	1,030	1,418	939	1,226
$ 55	8,161	1,722	2,017	2,198	1,432	1,998	1,328	1,735
$ 65	10,705	2,264	2,654	2,887	1,877	2,618	1,749	2,328
$ 75	13,490	2,855	3,354	3,647	2,357	3,330	2,208	2,942
$ 85	16,522	3,505	4,110	4,512	2,867	4,082	2,705	3,577

Combined IOC + Govt NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	5,869	5,048	5,048	5,436	5,048	5,710	5,047	5,710
$ 55	8,161	7,053	7,054	7,878	7,053	7,877	6,462	8,092
$ 65	10,705	9,347	9,346	9,897	9,346	10,314	8,669	10,586
$ 75	13,490	11,918	11,918	12,536	11,918	12,536	11,165	13,331
$ 85	16,522	13,939	14,759	15,435	14,759	15,957	13,939	16,318

Max Exploration Wells

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	NA	NA	NA	NA	NA	NA	NA	NA
$ 55	NA	NA	NA	NA	NA	NA	NA	NA
$ 65	NA	NA	NA	NA	NA	NA	NA	NA
$ 75	NA	NA	NA	NA	NA	NA	NA	NA
$ 85	NA	NA	NA	NA	NA	NA	NA	NA

Extraction Rate, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	NA	NA	NA	NA	NA	NA	NA	NA
$ 55	NA	NA	NA	NA	NA	NA	NA	NA
$ 65	NA	NA	NA	NA	NA	NA	NA	NA
$ 75	NA	NA	NA	NA	NA	NA	NA	NA
$ 85	NA	NA	NA	NA	NA	NA	NA	NA

Onset of EOR, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	NA	NA	NA	NA	NA	NA	NA	NA
$ 55	NA	NA	NA	NA	NA	NA	NA	NA
$ 65	NA	NA	NA	NA	NA	NA	NA	NA
$ 75	NA	NA	NA	NA	NA	NA	NA	NA
$ 85	NA	NA	NA	NA	NA	NA	NA	NA

Abandonment, Medium Field Size

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	35	35	35	35	35	35	35	35
$ 55	35	35	35	35	35	35	35	35
$ 65	35	35	35	35	35	35	35	35
$ 75	35	35	35	35	35	35	35	35
$ 85	35	35	35	35	35	35	35	35

Following Results Pertain to the Medium Field Size

Half-Cycle Govt. Take

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0.0%	75%	72%	71%	80%	75%	81%	79%
$ 55	0.0%	76%	71%	72%	80%	75%	79%	79%
$ 65	0.0%	76%	72%	71%	80%	75%	80%	78%
$ 75	0.0%	76%	72%	71%	80%	73%	80%	78%
$ 85	0.0%	75%	72%	71%	81%	74%	81%	78%

Half-Cycle Govt. NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0	4,951	4,691	5,015	5,220	5,576	5,338	5,827
$ 55	0	6,926	6,544	7,380	7,303	7,639	6,671	8,259
$ 65	0	9,203	8,695	9,109	9,705	9,999	8,991	10,730
$ 75	0	11,775	11,128	11,550	12,423	11,962	11,638	13,499
$ 85	0	13,556	13,837	14,192	15,452	15,430	14,596	16,555

Half-Cycle DWL

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	14%	14%	7%	14%	3%	14%	3%
$ 55	0%	14%	14%	3%	14%	3%	21%	1%
$ 65	0%	13%	13%	8%	13%	4%	19%	1%
$ 75	0%	12%	12%	7%	12%	7%	17%	1%
$ 85	0%	16%	11%	7%	11%	3%	16%	1%

Half-Cycle Investor NPV ($ million)

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	7,627	1,607	1,867	2,050	1,338	1,843	1,220	1,593
$ 55	10,605	2,238	2,621	2,856	1,862	2,597	1,726	2,255
$ 65	13,909	2,942	3,449	3,752	2,439	3,403	2,274	3,025
$ 75	17,528	3,710	4,358	4,739	3,063	4,327	2,869	3,823
$ 85	21,468	4,555	5,340	5,863	3,725	5,304	3,515	4,649

Half-Cycle Fiscal Inefficiency

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	22%	23%	11%	20%	4%	20%	4%
$ 55	0%	21%	22%	5%	20%	5%	33%	1%
$ 65	0%	19%	20%	12%	18%	5%	29%	1%
$ 75	0%	17%	18%	11%	16%	10%	26%	2%
$ 85	0%	25%	17%	10%	15%	5%	23%	2%

Half-Cycle Fiscal Yield

Price	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
$ 45	0%	65%	62%	66%	68%	73%	70%	76%
$ 55	0%	65%	62%	70%	69%	72%	63%	78%
$ 65	0%	66%	63%	65%	70%	72%	65%	77%
$ 75	0%	67%	63%	66%	71%	68%	66%	77%
$ 85	0%	63%	64%	66%	72%	72%	68%	77%

Appendix Table 4b: Orinoco Heavy Oil Project (all cost scenarios)
Summary of Results from the Orinoco Heavy Oil case study (oil price = $65; gas price = $3)

Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	75%	73%	71%	80%	74%	80%	78%
100%	0%	76%	72%	71%	80%	75%	80%	78%
130%	0%	75%	72%	71%	80%	74%	80%	78%

Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0	8,707	8,820	8,934	9,177	9,293	8,664	10,326
100%	0	7,083	6,692	7,010	7,469	7,696	6,920	8,258
130%	0	5,584	5,882	6,135	6,525	6,384	6,016	7,003

DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	13%	9%	5%	13%	5%	19%	1%
100%	0%	13%	13%	8%	13%	4%	19%	1%
130%	0%	18%	11%	5%	11%	5%	18%	2%

Investment, Medium Field Size ($ million, real)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	12,213	4,474	5,649	7,001	4,474	7,001	3,466	10,273
100%	10,001	3,733	3,733	4,951	3,733	6,392	2,722	8,070
130%	8,309	2,474	3,539	4,853	3,539	4,853	1,474	6,436

Unrisked Recovery Factor, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	18.2%	12.5%	13.6%	14.8%	12.5%	14.8%	11.4%	17.1%
100%	14.8%	10.2%	10.2%	11.4%	10.2%	12.5%	9.1%	13.6%
130%	12.5%	8.0%	9.1%	10.2%	9.1%	10.2%	8.0%	11.4%

Risked Reserves (million boe)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	2,296	1,578	1,722	1,865	1,578	1,865	1,435	2,152
100%	1,865	1,291	1,291	1,435	1,291	1,578	1,148	1,722
130%	1,578	1,004	1,148	1,291	1,148	1,291	1,004	1,435

Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	20%	14%	8%	19%	8%	28%	1%
100%	0%	19%	20%	12%	18%	5%	29%	1%
130%	0%	29%	16%	8%	15%	7%	27%	2%

Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	65%	66%	67%	69%	70%	65%	78%
100%	0%	66%	63%	65%	70%	72%	65%	77%
130%	0%	61%	65%	67%	72%	70%	66%	77%

IOC NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	13,322	2,831	3,301	3,662	2,361	3,304	2,191	2,877
100%	10,705	2,264	2,654	2,887	1,877	2,618	1,749	2,328
130%	9,090	1,907	2,248	2,482	1,605	2,234	1,474	1,938

Combined IOC + Govt NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	13,322	11,538	12,121	12,596	11,538	12,597	10,855	13,203
100%	10,705	9,347	9,346	9,897	9,346	10,314	8,669	10,586
130%	9,090	7,491	8,130	8,617	8,130	8,618	7,490	8,941

Max Exploration Wells

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	NA	NA	NA	NA	NA	NA	NA	NA
100%	NA	NA	NA	NA	NA	NA	NA	NA
130%	NA	NA	NA	NA	NA	NA	NA	NA

Extraction Rate, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	NA	NA	NA	NA	NA	NA	NA	NA
100%	NA	NA	NA	NA	NA	NA	NA	NA
130%	NA	NA	NA	NA	NA	NA	NA	NA

Onset of EOR, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	NA	NA	NA	NA	NA	NA	NA	NA
100%	NA	NA	NA	NA	NA	NA	NA	NA
130%	NA	NA	NA	NA	NA	NA	NA	NA

Abandonment, Medium Field Size

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	35	35	35	35	35	35	35	35
100%	35	35	35	35	35	35	35	35
130%	35	35	35	35	35	35	35	35

Following Results Pertain to the Medium Field Size

Half-Cycle Govt. Take

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	75%	73%	71%	80%	74%	80%	78%
100%	0%	76%	72%	71%	80%	75%	80%	78%
130%	0%	75%	72%	71%	80%	74%	80%	78%

Half-Cycle Govt. NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0	11,313	11,459	11,609	11,924	12,075	11,257	13,417
100%	0	9,203	8,695	9,109	9,705	9,999	8,991	10,730
130%	0	7,255	7,642	7,972	8,478	8,294	7,817	9,100

Half-Cycle DWL

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	13%	9%	5%	13%	5%	19%	1%
100%	0%	13%	13%	8%	13%	4%	19%	1%
130%	0%	18%	11%	5%	11%	5%	18%	2%

Half-Cycle Investor NPV ($ million)

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	17,309	3,679	4,290	4,759	3,068	4,293	2,847	3,738
100%	13,909	2,942	3,449	3,752	2,439	3,403	2,274	3,025
130%	11,811	2,478	2,921	3,226	2,086	2,903	1,916	2,519

Half-Cycle Fiscal Inefficiency

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	20%	14%	8%	19%	8%	28%	1%
100%	0%	19%	20%	12%	18%	5%	29%	1%
130%	0%	29%	16%	8%	15%	7%	27%	2%

Half-Cycle Fiscal Yield

Cost	No Tax	Status Quo	X Factor A	IRR Factor A	X Factor B	IRR Factor B	X Factor C	IRR Factor C
70%	0%	65%	66%	67%	69%	70%	65%	78%
100%	0%	66%	63%	65%	70%	72%	65%	77%
130%	0%	61%	65%	67%	72%	70%	66%	77%