INTERNATIONAL MONETARY FUND

IMF Country Report No. 16/259

SOUTH AFRICA

July 2016

TECHNICAL ASSISTANCE REPORT—PETROLEUM SECTOR FISCAL REGIME REFORM—ADDITIONAL ANALYSIS FOR THE DAVIS TAX COMMITTEE

This Technical Assistance Report on South Africa was prepared by a staff team of the International Monetary Fund. It is based on the information available at the time it was completed on June 2016.

Copies of this report are available to the public from

International Monetary Fund • Publication Services
PO Box 92780 • Washington, D.C. 20090
Telephone: (202) 623-7430 • Fax: (202) 623-7201
E-mail: publications@imf.org Web: http://www.imf.org
Price: $18.00 per printed copy

International Monetary Fund
Washington, D.C.

INTERNATIONAL MONETARY FUND

Fiscal Affairs Department

SOUTH AFRICA

PETROLEUM SECTOR FISCAL REGIME REFORM

ADDITIONAL ANALYSIS FOR THE DAVIS TAX COMMITTEE

Philip Daniel and Alpa Shah

June 2016

Contents **Page**

Tables

Figures

1. **This memorandum follows the meetings between the FAD mission and the Davis Tax Committee (DTC) – Sub-Committee on Oil and Gas - in March 2016.** The first part of the note lists the main issues discussed with the DTC oil and gas sub-committee regarding their planned recommendation for tax reform in the oil and gas sector. The second part of the note provides additional fiscal analysis prepared at the request of the subcommittee. The basis of the discussion was both the FAD 2015 report[1] and the DTC draft oil and gas report which outlined the preliminary recommendations of the sub-committee.

A. Key Issues

2. **The mission first sought to understand the committee's further objectives in reforming the fiscal regime**. The DTC's focus was on defining a robust and stable fiscal regime appropriate to the South African context, with a focus on maintaining a palatable regime for investors. However, the potential instability of the current regime in the event of a large discovery was also recognized by the committee, particularly in the country's current fiscal context. The importance of revenue generation was also highlighted, given the current urgent revenue needs of the fiscus.

3. **Following discussion of individual fiscal regime elements and evaluation of different fiscal regime packages, the subcommittee appears to be moving towards a regime consisting of:** (i) a 5 percent royalty, (ii) corporate income tax at the statutory rate with some reform to the current capital depreciation treatment; and (iii) an additional rent capture element in the form of either state participation or a cash flow surcharge.

4. **The key issues discussed are outlined in the table below.**

[1] *South Africa – Fiscal Regimes for Mining and Petroleum: Opportunities and Challenges,* Philip Daniel, Martin Grote, Peter Harris, and Alpa Shah, IMF Fiscal Affairs Department, April 2015

Issue	Commentary
Royalty Rate	The royalty should have a single flat rate, rather than the current variable rate formula which has its origins in the mining sector. It is common practice for countries to have different royalty rates for the mining and petroleum sector, and the 5 percent flat rate proposed in the FAD report is modest by international standards, allowing some early revenues from petroleum developments without acting as a deterrent to investment. At such levels, there is no need to distinguish between the offshore and onshore sectors in terms of the royalty rate.
Royalty Base	It is important for the base of the royalty to be clearly defined. At present the basis for petroleum royalties is gross sales, and for existing operations the first saleable point is determined to be the inlet flange to the gas to liquids refinery. More commonly the first saleable point is the inlet flange of the pipeline which brings the oil onshore. Nevertheless, the proposed royalty rate is low and ease of valuation may favor continuation of the present valuation point, or an analogous one for other developments. Legislation, regulations and/or contracts must also be developed for the cases in which petroleum is exported, and to define gas pricing methodologies, as well as arm's length principles for related party sales.
Corporate Income Tax Depreciation	For corporate tax purposes, the current immediate expensing of capital expenditure and the 100 percent and 50 percent uplifts for exploration and development expenditure are overly generous and will lead to a both revenue loss and a long delay before revenue is collected. A slower 5-year straight line treatment was recommended by the IMF mission, together with an allowance for corporate capital (ACC) on any undepreciated balance of capital. Such a system removes the debt bias inherent in systems which allow the deductibility of interest, but not returns to equity, and should make the investor indifferent to the rate of tax depreciation since faster depreciation reduces the amount of ACC deductible. While it was agreed that such treatment may be appropriate in the offshore sector, there was some discussion of whether this should apply to shale gas projects, for which there is typically continuous expenditure on well development over a large portion of the project life.

	The mission emphasized that alternative specifications for the uplift could be considered, as well as an alternative depreciation schedule. The DTC requested additional modeling analysis to assess the alternative reforms to capital depreciation treatment, including a move to the accelerated depreciation treatment currently applicable to the manufacturing sector (a straight line scheme over four years at percentages of 40:20:20:20).
State Participation/ Cash Flow Surcharge	The FAD analysis emphasized the need to be able to tax resource rents in the event of a windfall, and the potential instability of the current regime in the event of a large discovery. An additional rent tax mechanism allows the state to receive a portion of the resource rents as they arise. The mission also explained that it was possible to design additional rent capture instruments of different structures to be fiscally equivalent: specifically, state participation can produce results fiscally equivalent to those for a cash flow surcharge, the two options currently under consideration by the subcommittee. On a practical level, while the subcommittee is open to the cash flow surcharge, since the MPRDA Bill already contains a provision for 20 percent state participation (an increase from the10 percent interest currently contained in petroleum production rights), a political preference for the state participation option may prevail. The subcommittee is aware of the complexities introduced by state participation in the petroleum sector. The liabilities that the state will assume by being a joint venture partner to the project in terms of rehabilitation, financing obligations and guarantees were highlighted during the discussions. The subcommittee is also aware of the public financial management issues associated with state participation, in particular the collection of revenue from state participation interest and whether it would flow to the National Treasury or be retained by the Department of Mineral Resources. The DTC requested further analysis on scenarios including a 10 and 20 percent cashflow surcharge instruments and state participation interests.

Capital Gains Tax	The FAD mission identified that the current Tenth Schedule options to elect either a rollover or participation treatment in the case of disposal of rights means that such transactions are taxed only in certain cases, rather than consistently across the board. There is scope to simplify the current system. The IMF mission recommended that cash gains from disposal are taxed as revenue in the hands of the seller and the purchase price amortized in the hands of the buyer. Such treatment would be uniform across types of transactions. Work undertaken as a result of farm-in transactions would simply create depreciable assets in the normal way and would not create an imputed gain for the farm-out party.
Carbon tax	The DTC expressed concerns that the proposed carbon tax would add a further tax burden on oil and gas companies. The mission noted that as currently drafted carbon tax would have the effect of a royalty instrument on petroleum rights holders. The DTC requested analysis on the impact of the carbon tax on a petroleum project.
Fiscal Stability	The fragmentation of stability assurances was highlighted by the 2015 mission. For the future, a stability assurance under a revised Schedule 10, and also under royalty legislation, should suffice. If state participation is the choice for an additional rent taxation device, any assurance about stability of participation terms would probably have to be contractual, though enabled in the law establishing the participation right.
Ring-fencing	For ring-fencing purposes, the current system allows for a 10 percent offset of losses against non-petroleum income. This should be removed to maintain a clear ring-fence at the level of the petroleum taxpayer.

B. Petroleum Fiscal Regime Analysis

5. **This analysis builds upon the results of the 2015 Analysis Supplement.** First, the modeling of the current fiscal regime is amended, adding the 10 percent state participation interest understood to apply to existing production rights holders. The analysis then goes on to consider variations in fiscal variables as requested by the oil and gas sub-committee,

including (i) alternative royalty rates (2 and 5 percent); (ii) alternative capital depreciation treatments, including the accelerated depreciation treatment currently applicable to the manufacturing sector; and (iii) alternative rates for the state participation interest and cashflow surcharge.

Methodology

6. **The analysis is based on the medium deepwater offshore oil field example of the 2015 report.** To facilitate comparisons with the Analysis Supplement results, the same economic and modeling assumptions are used. Section G later considers the onshore shale gas field example.

7. **A key variable underpinning the project economics is the oil price**. As a base case assumption, the 2015 analysis assumed the oil price projections of the IMF World Economic Outlook at the time of writing (Figure A45 in the Analysis Supplement) until 2020 beyond which the price projection was kept constant in real terms and inflated at a rate of 2 percent per annum. The petroleum sector has seen a dramatic change in price levels over the past year. To understand the implications of these new market dynamics, the analysis later includes a sensitivity analysis involving lower price assumptions, as well as a consideration of breakeven oil and gas prices under alternative fiscal regimes.

8. **The project's underlying profitability was tested under a range of cost and price assumptions (Figure 1).** Under the current cost assumptions, the project would require an oil price of at least $40/Bbl to breakeven on a pre-tax basis, i.e. before any fiscal imposition. This may be moderated by the recent decline in upstream capital and operating costs, although this decrease has not been as significant as the downward price trends.

Figure 1. Sensitivity Analysis (Pre-Tax Project IRR)

Project: Offshore_South Africa_500MMBbl Indicator: Pre tax IRR

Price per barrel	Cost per Barrel 40.8	32.1	24.4	17.7	12.1	7.6
30	0.0%	0.0%	6.6%	15.0%	24.3%	35.4%
35	0.0%	3.0%	10.8%	18.8%	28.0%	39.1%
40	0.0%	6.9%	14.2%	22.1%	31.1%	42.2%
45	3.3%	10.1%	17.1%	24.9%	33.9%	45.0%
50	6.4%	12.9%	19.7%	27.4%	36.4%	47.5%
55	9.0%	15.3%	22.1%	29.7%	38.7%	49.7%
60	11.3%	17.5%	24.2%	31.8%	40.7%	51.8%
65	13.4%	19.4%	26.1%	33.7%	42.6%	53.7%
70	15.3%	21.2%	27.9%	35.4%	44.4%	55.5%
75	17.0%	22.9%	29.5%	37.0%	46.0%	57.1%
80	18.6%	24.5%	31.0%	38.6%	47.5%	58.6%
85	20.1%	25.9%	32.5%	40.0%	49.0%	60.1%

C. Current Regime

9. **The inclusion of the 10 percent carried state participation interest increases the government take by 7-8 percent in discounted terms.** It is understood that in addition to the terms modeled for the current regime in the 2015 report, companies are also subject to a 10 percent state participation requirement, provided for in their petroleum production rights. Under this arrangement, the development costs are assumed to be carried by the IOC and repaid out of the cash flows attributable to the state under this participating interest. The analysis assumes that the carried costs are repaid with an interest rate of 7 percent (nominal), reflecting a reasonable premium over the LIBOR benchmark interest rate. Figure 2 and Table 2 shows the simulation results and the government revenue profile under this updated regime. If the BEE participation is considered as part of the government take, the AETR is now between 45 and 55 percent, depending on the price assumption used.

Table 1. Fiscal Terms – Current Regime

Royalties	Current regime
Variable Royalty	0.5 + [earnings before interest and taxes/(gross sales in respect of refined mineral resources x 12.5)]. Max rate 5%.
Income Tax	
Rate	28%
Depreciation:	
Investment Allowance/Accelerated Depreciation	100% immediate expensing
Uplift on Exploration Costs	100%
Uplift on Post-Exploration Costs	50%
Loss Carry Forward	Unlimited
Withholding Taxes	
Dividends	0%
Interest	0%
Participation Requirements	
State Participation	10% State Participation: Carry through to production with repayment of development costs from participation cashflows with interest
Local Participation	10% HDSA Ownership

Figure 2. Government Revenue Profile – Current Regime

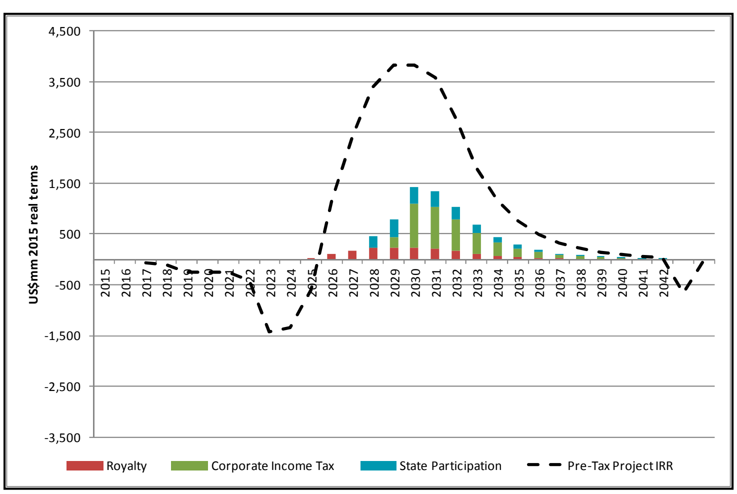


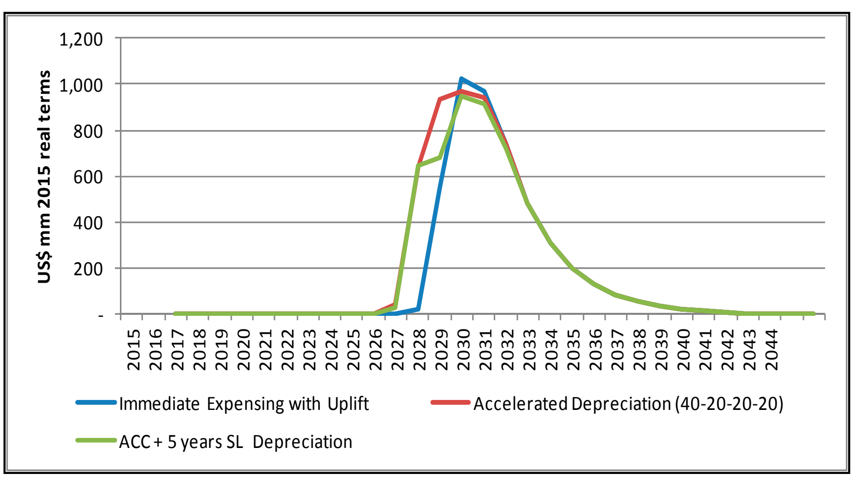
Table 2. Simulation Results – Current Regime

	Oil Price Assumption		
Project Fiscal Results (in US$ million real or %)	**$50/bbl (2015 Real Terms)**	**WEO Price Projections**	**$80/Bbl (2015 Real Terms)**
Pre-tax project IRR	19.7%	26.4%	31.0%
Post-tax IRR on total funds	15.7%	21.5%	25.7%
Post-tax IRR on equity	18.6%	25.6%	30.2%
IOC IRR	18.2%	25.0%	29.6%
BEE Entity IRR	23.7%	32.7%	39.5%
Pre-tax NCF undiscounted	12,824	20,721	27,824
Post-tax investor NCF undiscounted	7,753	12,640	17,029
o/w IOC	6,793	11,138	15,040
o/w BEE Entity	960	1,502	1,990
Investor Payback Period (years from production)	5.26	4.46	4
Government revenue undiscounted	4,190	7,200	9,914
AETR undiscounted	32.7%	34.7%	35.6%
AETR (including BEE)	*40.2%*	*42.0%*	*42.8%*
Pre-tax NCF 10% discount	2,367	4,707	6,811
Post-tax investor NCF 10% discount	1,347	2,862	4,201
o/w IOC	1,154	2,504	3,696
o/w BEE Entity	194	358	504
Investor Payback Period (years from production) NPV 12.5%	7.76	5.79	5
Government revenue 10% discount	1,064	1,889	2,654
AETR 10% discount	45.0%	40.1%	39.0%
AETR 10% discount (including BEE)	*53.1%*	*47.7%*	*46.4%*

D. Alternative Capital Depreciation Methods

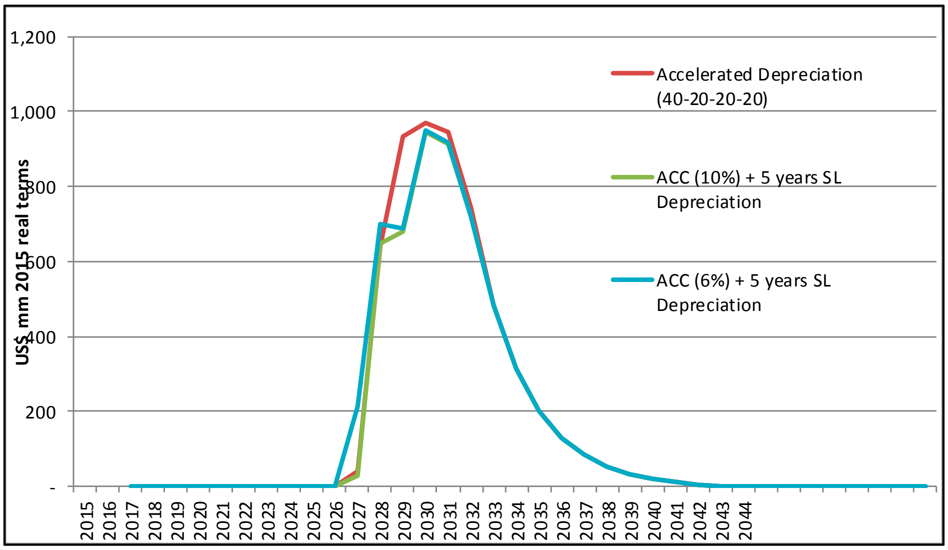
10. **The impact of varying the capital depreciation treatment applicable to the current regime was analyzed.** In particular, the option of an accelerated depreciation over 4 years according to a 40-20-20-20 schedule, as currently applicable to the South African manufacturing sector, was analyzed. Figure 3 ilustrates the impact of varying depreciation treatments under the hypothetical scenario where corporate income tax is the only charge on the project. It shows that the accelerated depreciation treatment yields a similar revenue result and time profile when compared to the option of 5-year straight line depreciation and 10 percent allowance for corporate capital (ACC) combination proposed in the 2015 report.

Figure 3. CIT Profiles under Alternative Depreciation Regimes



11. **The impact of varying the rate of ACC uplift was tested.** The exact results of the modeling depend on the assumptions assumed for the interest rate and debt-equity ratio in the accelerated depreciation case, and the ACC rate under the IMF proposed scenario. The analysis assumes that 70 percent of development expenditure is debt-financed, and the real interest rate assumed is LIBOR (1 percent) + 3.5 percent, which amounts to a nominal rate of approximately 6.6 percent, assuming an inflation rate of 2 percent. Under these assumptions, the total ACC uplift deductible is larger than the interest payments deductible under the accelerated depreciation regime and outweighs the effect of the acceleration in depreciation, explaining the difference in CIT receipts in the two scenarios. However, assuming a higher rate for the interest payments, or using a lower ACC rate would eliminate this discrepancy. Figure 4 illustrates this using a scenario assuming a 6 percent ACC uplift.

Figure 4. CIT Profiles – Varying the ACC rate



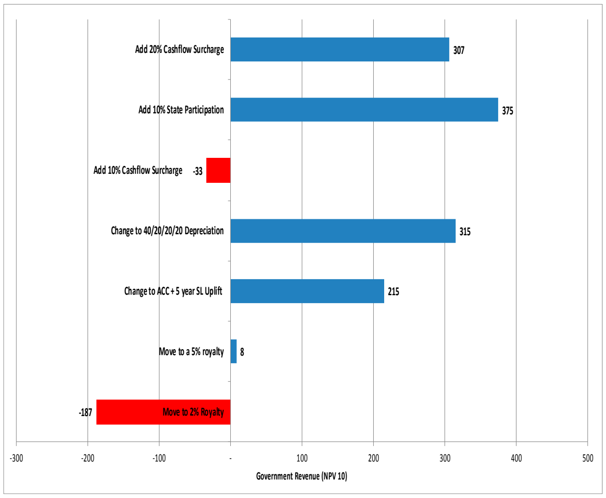
E. Variation of Royalty and Additional Rent Capture Parameters

12. **As per the recent request of the DTC, the impact of varying a range of fiscal parameters is analyzed.** Figure 4 demonstrates the impact on government revenue, government take and the investor's return when various fiscal parameters are adjusted relative to the current regime modeled in Section B. Many of the options analyzed are revenue enhancing. However, it is clear that a move to a 2 percent royalty would leave the government with less revenue. In addition, as currently calibrated, the cashflow surcharge yields slightly less revenue than the state participation due to differences between the uplift mechanism and the interest on carried costs, as well as the fact that exploration costs are not repaid under the state participation arrangement.

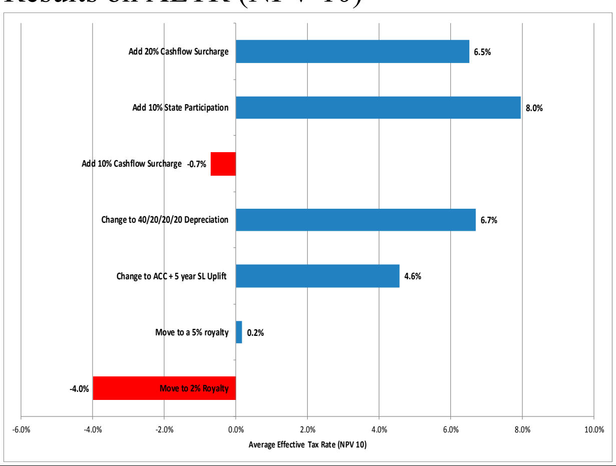
Figure 5. Impact of Fiscal Parameter Adjustments

WEO 2015 Prices

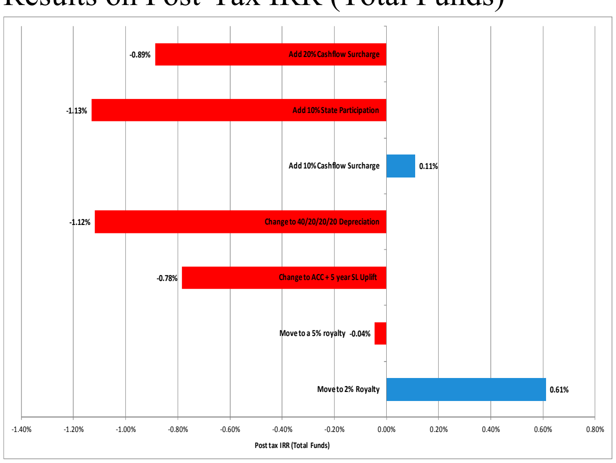
Results on Government Revenue (NPV 10)



Results on AETR (NPV 10)

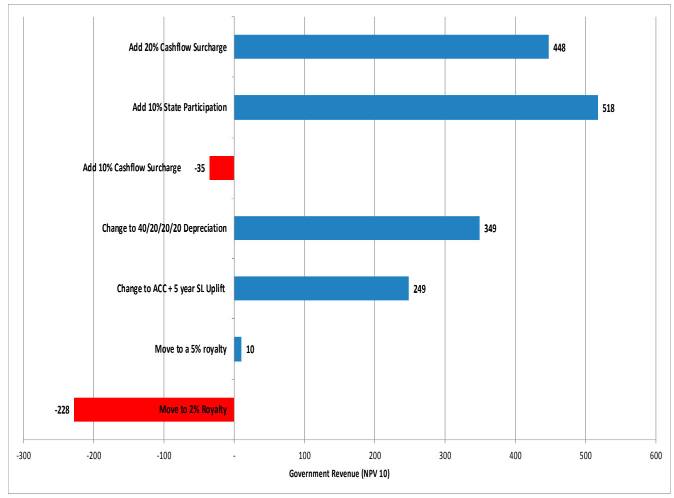


Results on Post-Tax IRR (Total Funds)

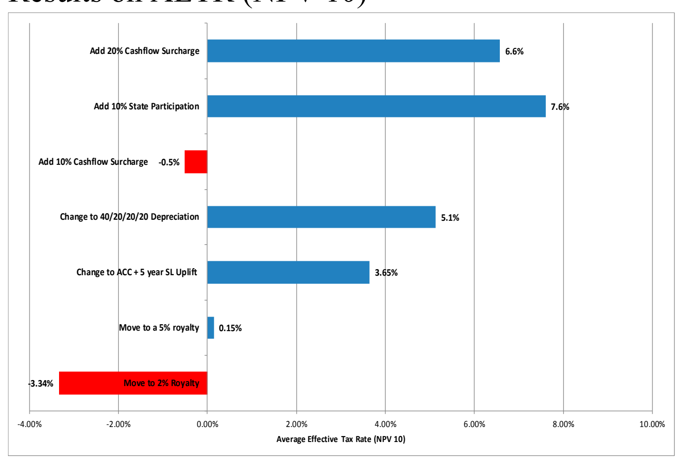


$80/Bbl

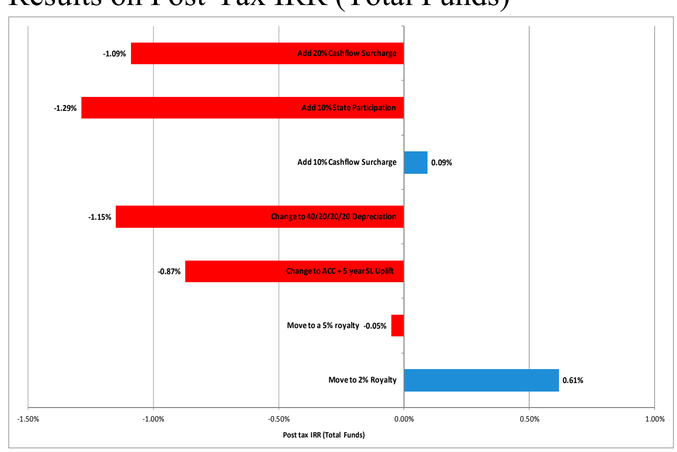
Results on Government Revenue (NPV 10)



Results on AETR (NPV 10)



Results on Post-Tax IRR (Total Funds)



F. Analyzing the Fiscal Package

13. **At the request of the DTC, a series of new scenarios was analyzed.** The scenarios of the 2015 report contain a 5 royalty and the cashflow surcharge and state participation mechanisms set at 20 percent levels. The scenarios in this analysis assess the implications of setting or maintaining the cashflow surcharge or state participation at 10 percent, and of lowering the royalty to 2 percent. The accelerated depreciation is assumed under these scenarios as per the DTC request, and not the 5-year straight line and ACC treatment assumed in the 2015 report. However, for the overall fiscal package the differences between the two depreciation options do not result in significant differences in the headline fiscal regime indicators.

Table 3. Fiscal Regime Terms – Alternative Scenarios[1/]

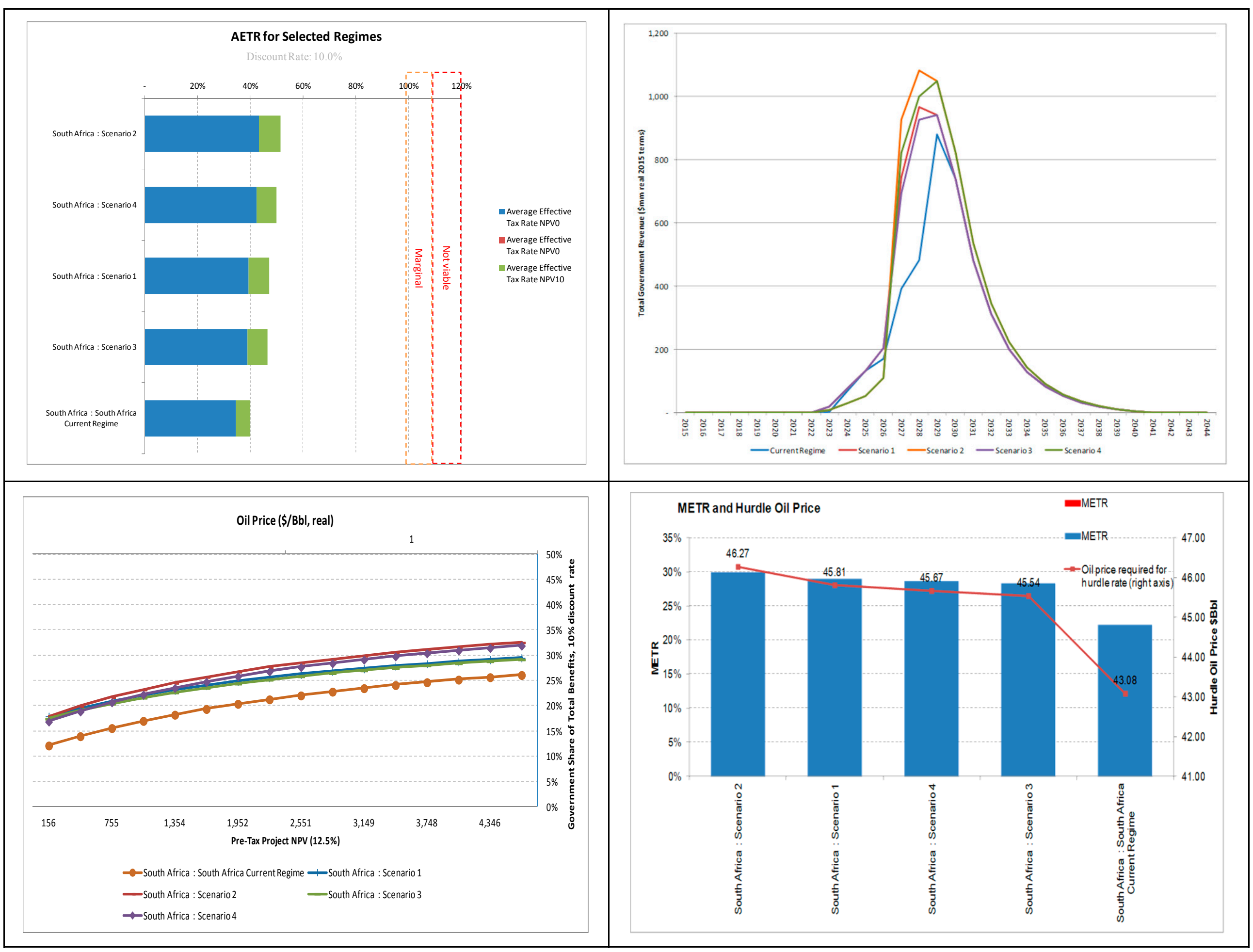
Fiscal provision	Current Regime	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Royalty	0.5 + [earnings before interest and taxes/(gross sales in respect of refined mineral resources x 12.5)] x 100. Max 5%	5% Flat Rate	2% Flat Rate	5% Flat Rate	2% Flat Rate
Income tax	28%	28%	28%	28%	28%
Depreciation	Immediate Expensing of all Capital Expenditure	Accelerated Depreciation (40-20-20-20)	Accelerated Depreciation (40-20-20-20)	Accelerated Depreciation (40-20-20-20)	Accelerated Depreciation (40-20-20-20)
Uplift/Allowance for Corporate Capital	100% uplift on exploration expenditure; 50% uplift on development expenditure				
Loss carry-forward	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited
Additional Tax				Cashflow Surcharge of 10% wth uplift on capital expenditure at 10%	Cashflow Surcharge of 20% wth uplift on capital expenditure at 10%
State Participation	10% State Participation. Carry through to production with repayment of development costs from participation cashflows at interest rate of 7%	10% State Participation. Carry through to production with repayment of development costs from participation cashflows at interest rate of 7%	20% State Participation. Carry through to production with repayment of development costs from participation cashflows at interest rate of 7%		
HDSA Requirements	10% Local Ownership	10% Local Ownership	10% Local Ownership	10% Local Ownership	10% Local Ownership

1/ The ACC is applied as an annual uplift on the balance of undepreciated capital assets. The cashflow surcharge applies a one-time uplift to capital as it is incurred. The interest charges on any carried costs under the state participation arrangement are applied annually to the balance of costs not yet repaid.

Table 4. Simulation Results

Project Fiscal Results (in US$ million real or %)	**South Africa Current Regime**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Pre-tax project IRR	26.4%	26.4%	26.4%	26.4%	26.4%
Post-tax IRR on total funds	21.5%	20.3%	19.7%	20.4%	20.0%
Post-tax IRR on equity	25.6%	24.1%	23.6%	24.3%	23.9%
IOC IRR	25.0%	23.6%	22.9%	23.9%	23.5%
BEE Entity IRR	32.7%	30.9%	31.9%	29.6%	29.1%
Pre-tax NCF undiscounted	20,721	20,721	20,721	20,721	20,721
Post-tax investor NCF undiscounted	12,640	11,661	10,844	11,765	11,055
o/w IOC	11,138	10,235	9,347	10,468	9,829
o/w BEE Entity	1,502	1,426	1,497	1,298	1,226
Investor Post Tax Payback Period (years from production)	4.46	4.56	4.52	4.56	4.51
Government revenue undiscounted	7,200	8,179	8,996	8,074	8,785
AETR undiscounted	34.7%	39.5%	43.4%	39.0%	42.4%
AETR (including BEE)	*42.0%*	*46.4%*	*50.6%*	*45.2%*	*48.3%*
Pre-tax NCF 10% discount	4,707	4,707	4,707	4,707	4,707
Post-tax investor NCF 10% discount	2,862	2,528	2,330	2,560	2,396
o/w IOC	2,504	2,199	1,980	2,265	2,117
o/w BEE Entity	358	329	350	295	279
Investor Payback Period NPV 12.5% (years from productio	5.79	6.26	6.33	6.22	6.25
Government revenue 10% discount	1,889	2,223	2,421	2,190	2,355
AETR 10% discount	40.1%	47.2%	51.4%	46.5%	50.0%
AETR 10% discount (including BEE)	*47.7%*	*54.2%*	*58.9%*	*52.8%*	*55.9%*

Figure 6. Simulation Results



14. **The scenarios were evaluated for revenue raising capacity, neutrality and progressivity.** In terms of revenue raising capacity, the scenarios yield broadly similar AETRs, between 46 and 51 percent in discounted terms. Scenarios 1 and 3 yield almost identical results, as do Scenarios 2 and 4, reflecting the revenue equivalence of the cashflow surcharge and state participation when set at the same levels. However, all of these scenarios clearly yield a lower government take than the recommended scenarios in the 2015 report due to the presence of either a lower royalty rate or lower rate for the additional rent capture mechanism. The scenarios also yield very similar breakeven prices, and post-tax investor payback periods which range from 6.2 to 6.35 years from production. In terms of progressivity, Scenarios 2 and 4 with their combination of 2 percent royalties and 20 percent additional rent capture mechanisms are marginally more progressive, although again the difference appears to be minimal.

G. Shale Gas

Capital depreciation treatments in shale gas

15. **Analysis of varying capital depreciation treatments was carried out on the shale gas example analyzed in the 2015 report.** The same project production and cost parameters were used as in the 2015 example, and a gas price of $8.8/MMbtu was assumed which allows the project to generate a pre-tax project return of 18.5 percent in real terms. Figure 6 analyzes the impact of varying depreciation treatments under the hypothetical scenario where corporate income tax is the only charge on the project.

16. **The current uplift treatment is very costly in the case of shale gas because of the repeated capital drilling expenditure incurred in shale gas production.** The current regime of immediate expensing of capital combined with generous uplifts results in a 5 year delay in CIT payments relative to the alternative treatments. Even without the uplifts, immediate expensing compared with the alternatives delays CIT payments by 2 years.

17. **As in the offshore example, the accelerated depreciation treatment yields a similar revenue result and time profile to the 5-year straight line depreciation and 10 percent allowance for corporate capital (ACC) combination.** Again, the small difference in the CIT receipts and profiles is explained by the modeling assumptions used. The magnitude of the ACC at 10 percent is significantly larger than the interest payments deductible under the accelerated depreciation regime and outweighs the effect of the acceleration in depreciation. However, a lower ACC rate, as explained in Section F, would eliminate this discrepancy (Figure 8).

Figure 7. CIT Profiles under Alternative Depreciation Regimes

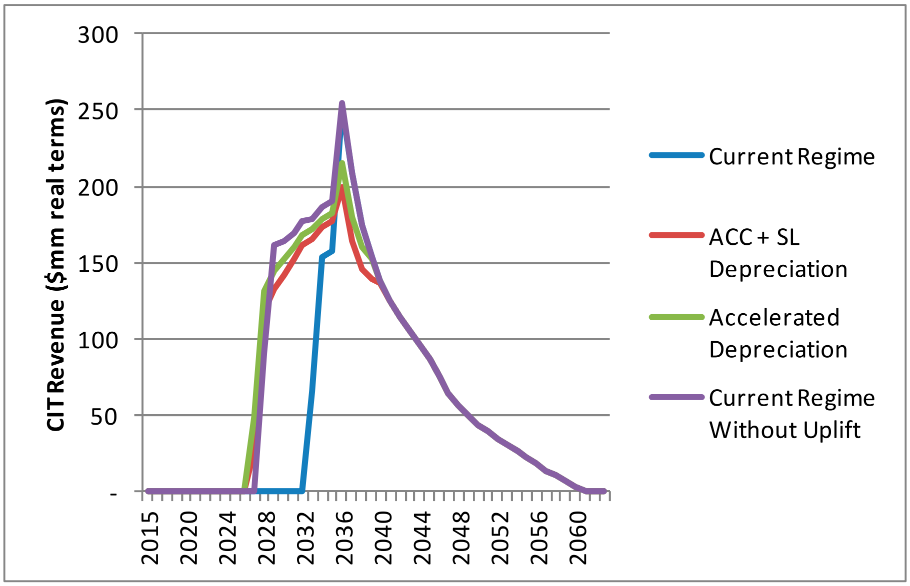
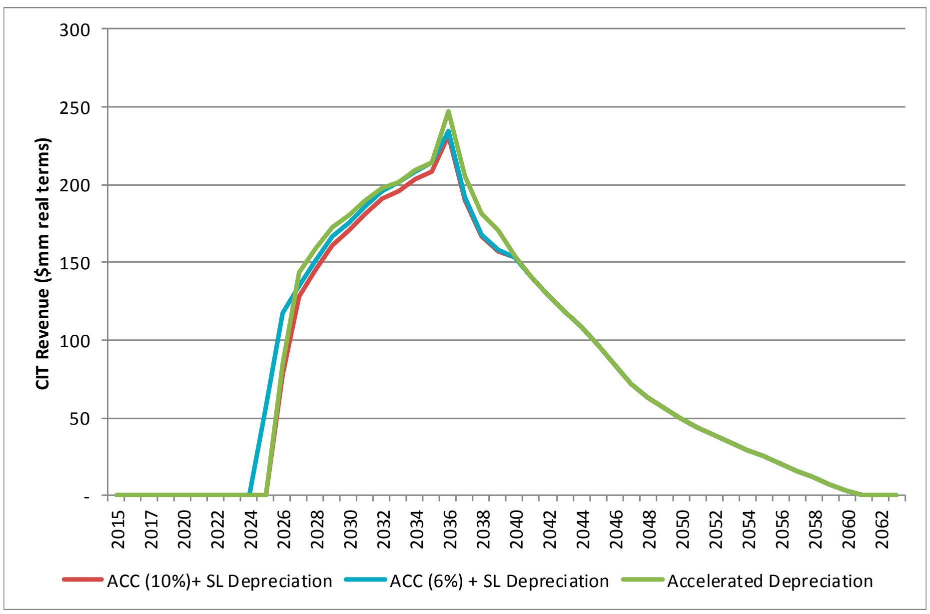


Figure 8. CIT Profiles – Varying the ACC rate



H. Carbon Taxes

18. **The impact of the South African Draft Carbon Tax Bill was analyzed.** The bill proposes a tax of R120/ton[2] of emissions or CO_2 equivalent. However, a large number of allowances may be applicable, which could relieve to up to 95 percent of emissions in oil and gas production from the tax payable, particularly if as under the current royalty legislation both oil and gas are treated as refined products. The global average for CO_2 emissions from petroleum extraction is approximately 130 kg of CO_2 per ton of oil equivalent[3], although the figure is usually lower for offshore operations. Assuming an emissions rate of 100kg per ton of oil equivalent, Table 5 shows the estimated carbon tax applicable to the 500MMBbl project both with and without the allowances contained in the draft bill.

19. **When expressed as an effective royalty, the carbon tax implemented without any allowances would amount to 2.1 percent of the petroleum value under the 2015 WEO price projections.** This figure decreases to 0.11 percent when the effect of the allowances is included. Since the carbon tax is defined as a monetary amount per ton of emissions, Table 5 shows that the effective royalty burden will decrease as prices increase. The calculations in Table 5 use only the global average described above; that average, and also the application of tax allowances, may not accurately represent the eventual position for production in South Africa. Thus Table 5 is shown only for illustration purposes.

---

[2] It is assumed in the analysis that this amount would increase annually in line with inflation, remaining constant in real terms.

[3] https://www.ssb.no/en/forskning/discussion-papers/_attachment/225118?_ts=14de17b6918

Table 5. Fiscal Impact of the Carbon Tax

			Total
Oil Production	MMBoE		500
Oil Production	million tons		68
CO2 emissions	million tons		6.8
Carbon Tax (without allowances)	$mm real		811
Carbon Tax (with allowances)	$mm real		41
Fiscal Impact:			
Oil Price = $50/bbl			
Value of Petroleum	$mm real		29,291
Carbon Tax	$mm real		811
Effective Royalty	%		2.77%
Carbon Tax (with allowances)	$mm real		41
Effective Royalty	%		0.14%
Oil Price at 2015 WEO prices			
Value of Petroleum	$mm real		38,544
Carbon Tax	$mm real		811
Effective Royalty	%		2.10%
Carbon Tax (with allowances)	$mm real		41
Effective Royalty	%		0.11%
Oil Price = $80/bbl			
Value of Petroleum	$mm real		46,866
Carbon Tax	$mm real		811
Effective Royalty	%		1.73%
Carbon Tax (with allowances)	$mm real		41
Effective Royalty	%		0.09%
Assumptions			
Tons per barrel of oil equivalent		7.4	
CO2 emissions rate (kg per ton of oil equivalent)		100	
Carbon Tax (Rand/kg of CO2)		120	
Allowances (% of total carbon tax payable)		95%	