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Fiscal Affairs Department

UGANDA

FISCAL REGIMES FOR EXTRACTIVE INDUSTRIES: NEXT PHASE

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ABBREVIATIONS AND ACRONYMS

AETR	Average effective tax rate
CIT	Corporate Income Tax
CNOOC	China National Offshore Oil Corporation
DROP	Daily Rate of Production (in barrels of oil)
DTA	Double taxation agreement
DCF	Discounted cash flow
EA	Exploration Area
EAC	East African Community
EITI	Extractive Industries Transparency Initiative
EL	Exploration License
EMV	Expected Monetary Value (exploration analysis)
EPCC	Engineering, procurement and construction contract
FARI	Fiscal Analysis of Resource Industries (FAD modeling system)
FEED	Front end engineering and design
FID	Final Investment Decision
FOB	Free on Board
HGA	Host Government Agreement
IGA	Inter-Governmental Agreement
IRR	Internal rate of return
ITA	Income Tax Act 1997
JV	Joint Venture
LIBOR	London Inter Bank Offered Rate
MEMD	Ministry of Energy and Mineral Development
MFPED	Ministry of Finance, Planning and Economic Development
m(mm)bpd	Thousands (millions) of barrels of oil per day
NATOIL	National Oil Company of Uganda
NOGP	National Oil and Gas Policy for Uganda
NPV(X)	Net present value (X = discount rate)
PEDPA	Petroleum Exploration, Development and Production Act 2013
PEPD	Petroleum Exploration and Production Department
PFMA	Public Finance Management Act 2015
PL	Production License
PSA	Production sharing agreement
R-Factor	Ratio of cumulative net revenues to cumulative capital costs (payback ratio)
ROR	Rate of return
TPA	Third Party Access
UGX	Uganda Shillings
URA	Uganda Revenue Authority
VAT	Value-added tax
WEO	World Economic Outlook

PREFACE

In response to a request from the Delegation of the Republic of Uganda at the Annual Meetings 2014, a technical assistance mission visited Kampala and Entebbe during the period February 25 to March 10 2015 to provide advice on extractive industry (EI) fiscal regimes. The mission followed from approval by the Steering Committee of the IMF's Topical Trust Fund on Managing Natural Resource Wealth of a full project on EI Fiscal regimes in Uganda (MNRW TTF Module 1 Project). The mission was led by Philip Daniel with Diego Mesa Puyo (both FAD), Emil M. Sunley (FAD External Expert) and Lee Burns (LEG Expert). This aide-mémoire contains the analysis and conclusions of the mission, which are subject to review at IMF headquarters.

The mission acknowledges valuable discussions with many officials including the following: At the Ministry of Finance, Planning and Economic Development (MFPED), Mr. Keith Muhakanizi, Permanent Secretary / Secretary to the Treasury, Mr. Lawrence Kiiza, Director of Economic Affairs, Mr. Moses Kaggwa, Commissioner for Tax Policy, and Mr. Francis Twinamatsiko, Head of Oil and Gas Taxation Division. At the Ministry of Energy and Minerals Development (MEMD): Petroleum Exploration and Production Department, Mr. Ernest Rubondo, Petroleum Commissioner and Acting Director, Mr. Robert Kasande, Assistant Commissioner (and Head of the Refinery Project); Geology and Mines Department, Ms. Agnes Alaba, Ag.Commissioner, and Mr. Joseph Okedi, Principal Inspector of Mines. At the Uganda Revenue Authority: Ms. Doris Akol, Commissioner General, Ms. Patience Tumusiime Rubagumya, Commissioner, Legal Services and Board Affairs, Messrs. Silajji Kanyesige, Mayanja Walakira , and Cyprian Chillanyang, Assistant Commissioners. At the Bank of Uganda: Mr. Louis Kasekende, Deputy Governor, Mr. Martin Brownbridge, Advisor to Governor, and Mr. Turyamwijuka Paddy, Director, Petroleum Investment Fund. The mission met frequently with the Technical Group on Petroleum consisting of officials from MFPED, MEMD, URA, and the Ministry of Justice.

The mission met with civil society representatives from the Africa Initiative for Energy Governance and the Natural Resource Governance Institute. The mission met jointly with representatives of Tullow Uganda, Total E & P Uganda, CNOOC Uganda, and PwC; also with Deloitte, the Uganda Chamber of Mines and Petroleum, and Kampala Associated Advocates. The mission met with Ms. Elin Grae Jensen, First Secretary, Royal Norwegian Embassy. The mission acknowledges the prior cooperation at the World Bank of Messrs. Bryan Land and David Santley.

The mission appreciates the excellent cooperation and warm hospitality of the authorities. Ms. Ana Lucia Coronel, the IMF's Senior Resident Representative in Kampala, provided guidance for the mission. Thanks are also due to Ms. Caroline Ntumwa and Ms. Winifred Bisamaza of the IMF Office, Ms. Vanessa Ihunde and Mr. Edmund Awiyo, MFPED, for administrative and logistical support.

EXECUTIVE SUMMARY

Petroleum and mining in Uganda

Uganda is poised to become a major oil producer if key preconditions are met. A joint venture of three international companies plans a major Uganda Oil Project, in partnership with the government. Up to 1.7 billion barrels (bbl) of recoverable reserves have been discovered with a high exploration success rate. However, challenges for commercialization of petroleum have been significant: infrastructure for commercialization of oil, and a number of outstanding regulatory and fiscal issues addressed in this report. Oil market developments since mid-2014 have created a difficult environment for project decisions. Uganda has made important progress in the legal framework for petroleum development, with two new Acts of 2013. The first competitive licensing round is being held in 2015.

Minerals development offers potential though has not been historically significant. A large number of exploration and mining rights have been issued, though many with little work in progress. Two mineral agreements have recently been signed, though implementation depends upon tax changes since the agreements do not fully conform to tax law provisions.

For both petroleum and mining, VAT, withholding taxes under the Income Tax Act (ITA), and the income tax rules themselves present challenges that are inhibiting development. The report gives particular attention to solutions for these challenges. The report also focuses on the prerequisites in specification of tax and the fiscal aspects of the production sharing scheme that are essential for the 2015 licensing round.

Upstream petroleum

Upstream petroleum fiscal terms combine royalty, production sharing, income tax and state participation. The existing production sharing agreements (PSAs) will govern the Uganda Oil project and represent a balance of the parties' objectives while offering substantial revenues to government when production starts. A new Model PSA for the licensing round will be geared towards attraction of exploration commitments, as well as significant revenue to government in the event of commercial development.

The royalty, the cost oil limit, and the minimum government profit oil share interact to produce the minimum "effective royalty". As the country's portfolio of projects diversifies, the minimum take could be adjusted to allow for possible bonus bids, and for higher shares in the most successful projects. The royalty design also needs to take account of new provisions for distribution of a portion to local governments. The cost recovery limit could be set at 70 percent after deduction of royalty. In addition to work program, either a signature bonus or an upper tier of production sharing should form the bid variable in the licensing round, with all other items fixed and non-negotiable.

The authorities propose to shift from production sharing on a scale of daily rate of production (DROP) to a scale of the R-Factor, or "payback ratio". The report supports this change, which allows cost, prices and volumes to be taken into account automatically, but overall requires no more data than for the DROP system. The report outlines, with simulations, a scheme in which the government's share rises progressively (by formula) after achievement of initial payback (R-Factor of one) from 50 percent to 75 percent when the R-Factor reaches three.

Income tax on petroleum companies remains at 30 percent but implementation through legislation requires reform. Combined cost and profit oil should comprise gross income: it should be possible to reconcile allowable deductions for tax purposes with cost recovery for production sharing, but the two sets of rules may differ for policy reasons.

State participation is envisaged in the Production Exploration and Development Act (PEDPA), of 2013 and will feature in the model PSA. A continuation of the carried interest scheme is appropriate, where the government's participation costs will be advanced by the private contractors and repaid with interest out the government's participation share of oil, without recourse to other government assets. The percentage participation option should be set at a maximum, probably 15 percent.

Fiscal issues for the Uganda Oil Project

The Uganda oil project requires a series of linked activities and decisions. Among these are solutions to the VAT and income tax issues. The pricing of oil at the delivery point from upstream facilities also requires settlement. For oil exported by pipeline, pricing will be determined by a netback from the price at the seaport subtracting the tariff charged for pipeline transportation. The report outlines options for determination of the transportation tariff: both Uganda and the contractors have a strong interest in maximizing value at the upstream delivery point. Once the export price is determined, it provides a benchmark for the price of oil going into the proposed refinery. If the refinery can sell products at import parity prices the report's economic analysis shows this to be a feasible combination. The report also draws attention to cross-border allocation issues and to the need for third party access to infrastructure facilities, provided that initial investors retain sufficient capacity.

Midstream facilities need no special income tax treatment. Neither pipeline nor refinery will operate within the PSA regime, but will be subject to income tax as normal processing or transportation businesses. In particular, tax holidays are not necessary. For the pipeline, the option of a common tax scheme with the transit country exists—on balance, however, the report suggests that the application of national tax systems with apportionment of cost and revenues will be simpler.

Mining and minerals fiscal regime

Uganda's royalty for high-value minerals is assessed on the gross value of the mineral based on the prevailing market price. It is not clear whether the base used for assessing royalty is the value of the mineral contained in the ore at the mine mouth, contained in the first product sold or exported (such as a concentrate), or the value of minerals recoverable. For minerals sent to a smelter or refinery, gross value would be the net smelter return. For other minerals that are subject to ad valorem rates, the value would be gross revenues from the first sale or free on board (FOB) export value, if the mineral product is exported without being sold.

For a company carrying on mining operations, the income tax rate is sliding scale with a minimum rate of 25 percent and a maximum rate of 45 percent. For non-mining companies, the corporate tax rate is 30 percent. The variable rate is designed to impose a lower-than-average rate of tax in years of poor relative profitability offset by a higher-than-average rate of tax in years of high relative profitability**.** The variable rate should be retained. To address the problem of excessive use of debt, the profitability ratio should be defined as the ratio of chargeable income *before any net interest expense* to gross revenue. For mining, the power to make a fiscal stability assurance, if needed, should be made explicit in legislation.

Common Fiscal and Tax Issues

Income Tax

Uniform rules for determining the chargeable income of resource companies should be included in the ITA. This can be achieved by applying a modified Part IXA to all resource companies with specific deduction rules for exploration, development, rehabilitation (decommissioning), and social infrastructure expenditures. For petroleum companies, this will involve reverting to the pre-2010 design of Part IXA whereby tax is based on chargeable income calculated in the usual way, rather than being based on profit oil.

International tax rules need to be modernized and strengthened. In particular, the withholding tax rules for technical fees paid to non-resident subcontractors need to be reviewed. This involves modernizing the source rules for technical fees and the definition of "branch", applying net taxation to technical fees attributable to a Ugandan branch of a non-resident, and reviewing the rate of withholding tax. Furthermore, Uganda's future tax treaties must preserve Uganda's taxing rights in relation to lease payments, technical fees, and gains on indirect transfers.

VAT Treatment of the Petroleum and Mining Chain

The goal of VAT should not be to raise revenue during the exploration and development phases of a resource project. It should not hinder investment. The design of Uganda's VAT includes several deficiencies that burden investments in the resource sector, which should be addressed as an integrated package as part of this year's budget proposals. The critical reforms include (1) allowing companies to register voluntarily for VAT during the exploration and development phases of a resource project, and allow companies constructing refineries and pipelines to register during the construction phase of midstream facilities; (2) exempting imports by a subcontractor from VAT if the imports are for direct and exclusive use in a resource project, but with proper surveillance measures to ensure that the exempted goods are used directly and exclusively for purposes of the resources project; (3) work towards implementing a properly functioning refund system for resources companies, but, in the short term and as an interim measure, adopt a remission scheme for domestic suppliers who are first tier subcontractors to a resource project under which the VAT, charged on supplies to resource companies, is deemed to have been paid by the companies; (4) restoring the input credit for the reverse charge; and (5) repealing the VAT exemption for petroleum products and reduce the excises on these products.

I. INTRODUCTION

A. Petroleum

1. **Uganda has the potential to become a major oil producer**. The existence of significant oil discoveries was confirmed in 2006, but in 2007 the government placed a moratorium on further licensing in order to put in place a modernized regulatory and fiscal framework. The National Oil and Gas policy (NOGP) was published in 2008, and two new pieces of petroleum legislation entered into force in 2013: the Petroleum Exploration, Development and Production Act (PEDPA), replacing the Petroleum Exploration and Production Act of 1985, and the Petroleum Refining, Conversion, Transmission and Midstream Storage Act. In February 2015, the moratorium was lifted with the announcement of Uganda's first competitive licensing round for six blocks. The model Production Sharing Agreement (PSA) is undergoing revision for the purpose of this licensing round.

2. **A joint venture of three international companies now plans a major Uganda Oil Project, in partnership with the government.** The original blocks (with PSAs) were licensed to relatively small companies, though one of them, Tullow Oil, has since grown to be a significant international independent company. As result of transactions between 2008 and 2010 the holders of licenses for blocks on which discoveries have been made are Tullow Oil,[1] Total E&P Uganda B.V, and China National Offshore Oil Corporation (CNOOC) Uganda Ltd. Each company has a one-third interest in each block, and each is an operator (responsible for the conduct of operations on behalf of the joint venture (JV) partners for at least one block).

3. **Current estimates indicate up to 1.7 billion barrels (bbl) of recoverable reserves, from 6.5 billion bbl of indicated resources (oil in place)**. The JV and the government plan combined crude oil production from 15 discoveries[2] in four Exploration Areas (EA), to be sold partly to a domestic refinery and partly for export via a pipeline to the coast of Kenya or Tanzania (Chapter III has more details). The JV partners submitted development plans for the discoveries in 2014, but so far only the plan for the Kingfisher discovery in EA3A has been approved and only one production license (PL) issued. A number of other preconditions for development need to be in place, of which those with a fiscal dimension are discussed in this report. Once PLs are granted, the mission understood that it may take up to two years for commercial and financial arrangements to be secured, for an engineering, procurement and construction contract (EPCC) to be negotiated and settled, then to complete front end engineering and design (FEED), and thus for the JV to take a final investment decision (FID). These processes require coordination among the plans for field development, pipeline, and for the refinery—though in principle the pipeline or refinery could proceed independently. Thereafter it will take three to four years until

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[1] For historical reasons through two companies: Tullow Uganda Ltd. and Tullow Uganda Operations Ltd.

[2] There are six discoveries in EA1, one in EA1A, six in EA2 (north), three in EA2 (south); and one in EA3A.

the full project is commissioned and begins production, though there are plans for earlier production of small scale to fuel local electricity generation.

4. **The discovery success rate in Uganda has been high but challenges for commercialization of petroleum have been significant**. The recorded rate of success in discovery by exploration wells exceeds 85 percent:[3] this is an extraordinarily high success rate that potentially makes the new licensing round attractive. Nevertheless, the development of Ugandan oil has presented some of the same problems that are faced in trying to develop reserves of gas, which are remote from large domestic or international markets. Large-scale development requires coordinated development of major transport or processing facilities, or both (as planned for Uganda). The oil discovered in Uganda so far has a high wax content (it is "paraffinic"); its viscosity will require the export pipeline to be electrically heated throughout, increasing pipeline capital and operating costs

B. Mining and Minerals Development

5. **Uganda has historically had a small copper mining industry and may have significant deposits of other minerals.** Airborne geophysical surveys undertaken in 2010 and 2011 indicated reported resources of at least 50 mineral commodities. Companies hold 498 exploration licenses and 37 mining leases – exclusive rights to carry on exploration and mining operations – of which 30 are in production. Current hard mineral production includes hematite iron ore, cement, kaolin, wolfram, and vermiculite. Uganda, however, has no large-scale mining projects that are at the production stage. The mining legislation dates back to 2003.

6. **Two projects with mining leases are at the development stage**. First, the government and a consortium of Chinese companies signed a concession agreement in 2013 to restart the Kilembe copper-cobalt mine, which dominated the mineral sector until it stopped operating in 1982. This project will include the cobalt processing facilities that were used by Kasese Cobalt Company to extract cobalt from Kilembe's slag heaps. Second, the government and Guangzhou Dongsong Group signed a mineral development agreement in December 2014 for the development of the Sukulu phosphate and steel project. Future large-scale projects could include iron ore, tin, and tungsten. There is potential for geothermal energy.

[3] According to the Ministry of Energy and Minerals Development, 116 deep wells have been drilled in the Albertine Graben and 102 of these wells have encountered hydrocarbons in the subsurface.

7. **Mining in Uganda has a large artisanal sector and faces challenges of land tenure and community opposition**. The largest mineral export by value is gold, all mined in small-scale operations. The Chamber of Mines and Petroleum and others indicated to the mission that problems of access to land for exploration were causing many licenses to remain dormant. These problems are not taken up in this report but provide important background for mineral sector development.

C. The Project and Outline of the Report

8. **Against this background the authorities requested support through a project on extractive industries (EI) fiscal regimes**. The project forms part of the program of the IMF's Topical Trust Fund on Managing Natural Resource Wealth (MNRW TTF, see Box 1) and is delivered by the IMF's Fiscal affairs Department (FAD) in collaboration with the Legal Department (LEG). The project builds on past technical assistance from FAD and LEG (Appendix 3), and operates in close cooperation with inputs from other development partners (notably the NORAD Oil for Development Programme and the EI Technical Advisory facility of the World Bank).

Box 1. Managing Natural Resource Wealth TTF
Uganda Project on Extractive Industry Fiscal Regimes

Uganda has been an eligible country since the inception of the MNRW Topical Trust Fund (MNRW TTF) in 2010. The MNRW TTF is a multi-donor fund to help developing countries in the development and management of their natural resources.[1] The fund is concentrated in five modules: (1) extractive industries (EI) fiscal regimes, licensing and, contracting; (2) EI revenue administration; (3) EI macro-fiscal policies and public financial management; (4) EI asset and liability management; and (5) statistics for EI. This diagnostic mission is the first activity under module 1, EI fiscal regimes, licensing and, contracting.

The purpose of the MNRW project is to support the government in development of EI fiscal regimes that secure a rising share of benefits from profitable projects, while creating a stable and attractive climate for private investment. In addition, the project also aims at building the authorities' capacity to analyze and design fiscal regimes for EI. Specifically, the project aims to support Uganda to: (1) review the existing petroleum and mining fiscal regimes, and design and implement a package of reforms as necessary; (2) address midstream and downstream fiscal issues to enable a major petroleum project for domestic processing and/or export to proceed; and (3) improve the capacity of the different ministries to evaluate and design fiscal regimes for EI.

The project is designed over an 18– month period, comprising multiple visits by FAD staff, FAD experts and an external legal expert to assist on drafting issues. The project may also include a series of workshops to train government officials on how to use FAD's fiscal analysis of resources industries (FARI) model. The model is intended to be transferred to Ugandan authorities upon formal request to FAD.

[1] The partners with the IMF are: Norway (Oil for Development), the European Commission, Australia, Switzerland (SECO), the Netherlands, Kuwait and Oman.

9. **The authorities gave priority to fiscal issues for development of the Uganda oil project, and also the new licensing round, for initial work under the project**. These include: on tax matters (i) the application of value added tax (VAT) to the chain of EI activities,

transportation and processing, and sales; (ii) application of withholding taxes on technical services acquired from nonresidents; and (iii) the provisions of the Income Tax Act (ITA) for petroleum (and also for mining); and on production-sharing (iv) the terms of the new model PSA required for the 2015 licensing round.

10. **The mission constructed preliminary models, using FAD's FARI system, of the upstream fiscal regime with project examples, of the potential linked project including a pipeline and refinery, and of the fiscal regime for mining with a potential iron ore project**. These are put to use for the analysis in Chapters II, III, and IV; as preliminary work, the modeling outputs are more than usually subject to caveats that the models are not audited and are subject to review and revision.

11. **This draft report also covers a full agenda of EI fiscal issues**:

- Chapter II covers the upstream petroleum fiscal regime;
- Chapter III covers fiscal issues for the proposed Uganda Oil Project (except general tax matters);
- Chapter IV addresses the fiscal regime for mining and minerals development;
- Chapter V covers tax issues, from both a fiscal and legal perspective, common to oil, gas and mining, including the application of VAT.

12. **Transparency and disclosure continue to be important priorities for governance of the potential petroleum sector**. The mission noted its support for Uganda's intention stated in the National Oil and Gas Policy to become a candidate in the Extractive Industries Transparency Initiative, and for public disclosure of PSAs as recommended in the IMF Guide on Resource Revenue Transparency and in the consultation draft of the Natural Resource Revenue Management Pillar of the new Fiscal Transparency Code.

II. UPSTREAM PETROLEUM FISCAL REGIME

A. Sector Legislation and the Allocation of Rights

The Petroleum Exploration, Development and Production Act (PEDPA) 2013

13. **Uganda introduced the new PEDPA in 2013, repealing its much less detailed predecessor, the Petroleum Exploration and Production Act of 1985**. The new Act is comprehensive, covering all stages of petroleum development from the award of rights through to abandonment and decommissioning. It vests all rights to petroleum in the ground in the government on behalf of the Republic of Uganda. It also establishes two new institutions: the Petroleum Authority of Uganda as regulator and a National Oil Company (NATOIL) which is to be incorporated under the Companies Act as the commercial arm of government to hold state participation shares. The PEDPA of 2013 covers many regulatory matters that were previously incorporated in agreements or regulations. The Act explicitly continues license rights granted under the previous law, as if granted under the PEDPA, and it also maintains in force any statutory instruments (regulations) that were previously in force, provided that they are not inconsistent with the new Act. The PEDPA is thus a major step in implementing the framework set out in the NOGP of Uganda of 2008.[4]

14. **The PEDPA has an internationally-standard licensing scheme**. It provides for non-exclusive reconnaissance licenses and then for exploration licenses (EL) and production licenses (PL), with rules governing the transition between ELs and PLs after a discovery. ELs carry work program and minimum expenditure obligations, together with environmental and social obligations, divided usually into three exploration periods of two years each, though with the availability of extension for an appraisal period after a discovery. EL holders must relinquish 50 percent of their remaining area (excluding any discovery area) at each renewal of the EL. Except where an EL holder declines to develop a discovery, only an EL holder can apply for a PL. The Act sets out clear criteria for the content and approval of proposals for grant of a PL. The PL includes the obligation to prepare and fund an abandonment and decommissioning plan at the end of field life.

15. **The PEDPA makes provision for agreements in combination with ELs or PLs**. Under s6 the government may enter into an agreement governing the grant of a license, including conditions for grant or renewal, and for the conduct of operations. The Act calls for a model PSA, or other form of agreement, to be submitted to Cabinet for approval and then laid before Parliament. The model agreement appears not to have full legal force but "shall guide negotiations of any future agreements." (s6(4)). The presumption seems to be in favor of a

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[4]At http://www.energyandminerals.go.ug/petroleum-exploration-supply

production sharing regime, but other fiscal schemes remain possible, including one that uses only tax, royalty and state participation.

16. **Detailed provisions now govern opening of new areas and applications for licenses**. In the past, Uganda operated a system of discretionary allocation where companies could apply for areas they wished to explore. The PEDPA replaces this with requirements for the minister to submit a report to Parliament on, and make a public announcement of, new areas to be opened for exploration, with provision for public review and comment. For both areas previously licensed and new areas, the presumption is now that a process of competitive bidding will be followed for allocation of ELs (and for PLs where a discovery has been relinquished). Exceptions are set out where direct application is possible: where invitations to bid have been made three times and resulted in no applications; where a reservoir extends beyond a license area to an unlicensed block;[5] or where the aim is to enhance the participating interest of the State. Direct applications must be published (s54).

17. **ELs require work program and expenditure commitments, fees, bonuses, and perhaps a state participation option**.[6] A signature bonus is required upon granting either an EL or PL; details may be prescribed in regulations—meaning that the bonus could be a fixed sum or an amount reached by bidding. The signature bonus is a "single, non-recoverable lump sum payment." When announcing areas for ELs, and thus for a bidding round, the minister, with approval of Cabinet, is to specify the maximum state participation share. The form of the option, its timing, or financial terms is not established in the PEPDA.

18. **Government has now announced the commencement of Uganda's first licensing round under the new Act**. A moratorium on new licenses was in place from 2007 until this announcement, while the new regulatory framework was being established and while the focus of government was on matters arising from discovery of substantial crude oil reserves by existing licensees. The Ministry of Energy and Mineral Development (MEMD) published a notice of request for qualification on February 26, 2015, with a view to licensing six blocks.[7] The process of application and pre-qualification was set to be complete with the issue of a request for proposals (RFP) and bidding documents to qualified applicants on July 20, 2015. No time period was set for completion of the bidding process and announcement of winning bids or allocations.

[5] "Block" means a graticular surface area (and perhaps limited to a stratigraphic depth or interval) measured as set out in the Act.

[6] The provision (s59 (2)) also provides for "a person identified in the license" to have an option acquired, which might mean a state company or, it seems, anyone else.

[7] Two of the blocks are defined by area but may also be open to stratigraphic licensing, meaning licensing according to depth or stratigraphic interval as well as surface area. (Daily Monitor, Uganda, March 3, 2015, announcement on page 7.

19. **The licensing round has significant fiscal implications**. The bonus and state participation results will eventually be of direct fiscal effect. Meanwhile the preparations of a new model agreement, including fiscal provisions, and solution to numerous anomalies in the tax system have become urgent.

Issues for new licensing round

20. **The new licensing round requires completion of a model PSA and solution to a number of tax issues.** The previous round of PSA negotiations, completed in 2012, concerned revision of terms for further exploration and development of blocks in which discoveries had already been made. The new model (discussed in the next section) will be designed principally for exploration programs that will lead to discoveries and development. The tax matters are: revision of the petroleum provisions of the ITA Part IX9; clarity on the application of withholding tax under the ITA on payments to non-residents for technical services, and associated issues with the definition of "branch" in Uganda; and reform of the rules for application of VAT to the chain of EI activities. These tax matters are addressed later in this report.

21. **Prequalification criteria are available on application (with a fee) and have not been published**. Applicants are asked to submit applications for pre-qualification by May 29, 2015, which will then be evaluated. If international practice is followed, the prequalification criteria will include technical competence and financial capacity, but there may be other criteria. The authorities might consider making these prequalification criteria public. It is also not clear whether prequalification will result in a single class of qualification, or (as in Angola, for example) in two classes: one for participants, and one for those also qualified as operators.

22. **Before issue of the bidding documents, the bidding process, criteria, variables, and weighting must be specified.** It is not yet clear whether eventual proposals by qualified applicants will be measured against specific criteria in an open process (bids opened and scrutinized in public) resulting in an immediate determination of successful bids. The alternative is a less definitive process in which "lead qualifiers" are then invited to negotiate. A clear auction process is preferable but may not be feasible (particularly if the expectation is for a very limited number of applicants). The bid variables should be limited in number: if the work program (seismic area, number of wells, and interpretation expenditure) is one of the variables, the fiscal terms should either be non-biddable (and non-negotiable) or limited to one item such as the signature bonus, or the top tier of production sharing. A weighting of 50/50 between the two variables would work, though alternatives could be justified according to the priorities of the government.

Recommendations

- Combine completion of a new model PSA and necessary tax reforms before issuance of requests for proposals in the licensing round for petroleum.

- Consider publication of prequalification criteria.

- Determine the bidding process, with preference for an open auction with no more than two bid variables.

B. Overall Fiscal Scheme

23. **A model PSA was last issued in 1999 and the government now proposes a full overhaul**.[8] The new scheme under consideration will retain the combination of royalty, production sharing, income tax and state participation. Bidding, perhaps for a signature bonus, may assume greater importance. The production-sharing scheme is likely to adopt the R-Factor (or payback ratio) scale for sharing between the contractor and the government. Meanwhile ITA provisions for petroleum were introduced in 2010 in an apparent attempt to make the contractor's share of profit oil the net chargeable income for application of the corporate tax rate.

24. **Two PSAs were signed in 2012**. These apply to Exploration Area EA1A, an area surrounding the principal discoveries now held by Tullow, Total and CNOOC, with Tullow (EA2 north) and Total (EA1) as operators respectively, and to a block called Kanywataba in EA3A held by CNOOC but since relinquished. The new model PSA is required for the 2015 licensing round, which is designed to attract applications for exploration licenses and commitments to substantial exploration work programs. The EA1 and EA1A PSAs are included in the economic evaluation of petroleum terms but are not assessed in detail here.[9]

25. **Uganda has secured very favorable terms in PSAs, and particularly in the 2012 PSAs**. While those terms form a baseline for comparison, the EA1A PSA was tailored to the circumstances of known discoveries in an oil price environment more favorable than prevailed early in 2015. The aim of attracting exploration calls for a scheme which, overall, is more flexible in response to changes in the combination of costs, prices and production volumes than is production-sharing using the daily rate of production (DROP) alone. For this reason, the

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[8] The 1999 model and other terms agreed using the model were outlined in the 2008 FAD Report: P. Daniel, L. Burns, E. Sunley, D. Mesa Puyo, *Uganda: Fiscal Arrangements for the Petroleum Sector*, May 2008.

[9] The mission understood that the 2012 PSA applies to EA1A, which was originally part of EA1. Both areas are operated by Total. EA1 (also known as Jobi-Rii area), where most discoveries were made, continues to be subject to the 2004 PSA; it is only EA1A that is subject to the 2012 PSA. Furthermore, according to Total E & P Uganda *"The EA-1A license expired in February 2013, following a campaign involving the drilling of five exploration wells that resulted in one discovery (Lyec). With the exception of the scope relating to this discovery, the license has been returned to the authorities."* from Total's Registration Document 2013, including the annual financial report, available at http://publications.total.com/Registration-Document-2013/index.html .

government wishes to explore the R-Factor scheme and the report endorses this decision if a production-sharing framework is retained.

Production sharing basics

26. **Under the Constitution and the PEDPA 2013, the government always retains the rights to resources in the ground**. This remains true whether the production license is subject to a tax and royalty scheme alone, or to a production sharing or other contractual scheme. The difference comes only when petroleum is produced: it is then divided between the government and the investors (the "contractor") according to the agreed scale under production-sharing; under tax and royalty alone the licensee takes ownership of petroleum produced subject to payment of royalty and tax liabilities to the government. In economic and fiscal terms, the two types of scheme can be made equivalent if the parameters are correctly set. Indeed, if the contractor markets the government's share of petroleum produced on its behalf, the arrangement becomes a "proceeds-sharing" scheme, little different in practical effect from a tax and royalty scheme.

27. **Under production-sharing the parties agree that the contractor will meet exploration and development costs in return for a share of any production that may result**. The contractor's production share thus replaces any fee that might be paid under various forms of service contract. The contractor has no right to be paid in the event that discovery and development does not occur. The government retains and disposes of its share of petroleum extracted, though joint-marketing arrangements may be made with the contractor.

28. **The mechanics of production sharing in principle are quite straightforward**: (1) the PSA may provide for an explicit royalty payment to the government (in accordance with s154 of the PEDPA); (2) the agreement specifies that a portion of total production (after the royalty payment) can be retained by the contractor to recover costs ("cost oil"); (3) the remaining oil (including any surplus of cost oil over the amount needed for cost recovery) is termed "profit oil" and is divided between the government and the contractor according to some formula set out in the PSA; and (4) the contractor pays income tax (Figure 1).[10] Any state participation would yield a portion of the contractor's share to the state in addition.

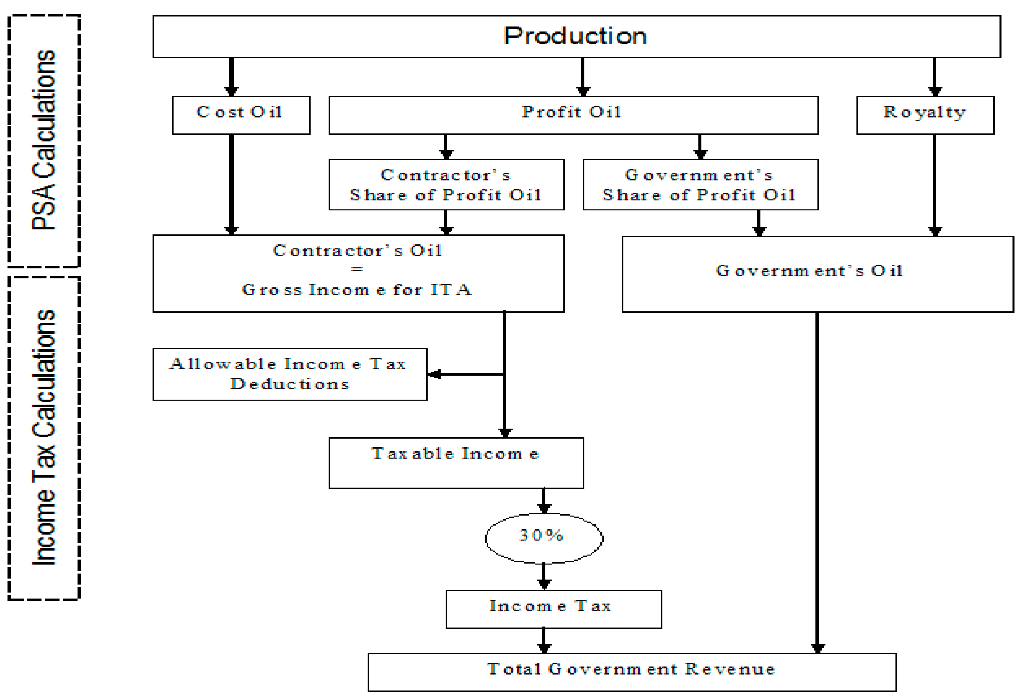
29. **Under a PSA the government's profit oil is typically the largest piece of the government's overall take from a project**. Income tax and royalty then follow, and sometimes a substantial bonus is obtainable. The aim is usually to ensure that the government share of the returns from the project rises with the overall profitability of the project—a feature usually termed "progressivity". In earlier forms of production sharing (adopted by Uganda in its 1999 model), the DROP was taken as a proxy for project profitability. In long periods of stable costs and prices DROP may have been a useful proxy but such periods no longer persist: in any case,

[10] Reproduced from FAD 2008 Report

DROP scales do not combine field size, costs, and prices in a single measure. Accordingly, modern sharing schemes are designed by reference to cumulative profitability—typically measured by the R-Factor or the rate of return (ROR).

30. **Progressivity is a practical alternative to direct targeting of resource rent as the tax base**. Resource rent is the surplus over all necessary costs of production, including the minimum acceptable return to the capital invested. Provided that taxation of resource rent leaves sufficient managerial incentive to companies, and in some way incorporates compensation for failed exploration, progressivity in rent taxation is not an aim in itself. Countries with targeted systems of rent taxation that are not progressive, however, find ways to share in losses—systems in Canada (Alberta), the UK, Norway and Australia have this characteristic in different ways. In the case of Norway, for example, there is direct refund by the government of the tax value of failed exploration expenditure if it is not otherwise recovered, and also of the tax value of unrecovered losses at the end of field life. Such refunding or sharing of losses is less practicable in Uganda and in most other developing countries. Thus a progressive scheme has some advantages.

Figure 1. Production Sharing and Income Taxation 1/



1/ Excluding withholding taxes and state participation

31. **In designing the PSA regime, there is a clear trade-off between preference for maximizing early government revenue and achieving the largest feasible share for the government over the whole of project life**. Put another way, the government's choices reflect the anticipated discount rate on government funds. In earlier PSAs, the government has appropriately chosen to prefer early revenue over late: with just one major project in prospect, the alternative choice would be highly risky. The new licensing round, however, aims to secure

exploration resulting in new production at a later date when Uganda's fiscal position may have been transformed by production from the first project. Uganda is thus aiming to diversify its portfolio of petroleum projects, and thus to diversify the risk that uncertainty over any one project can jeopardize the expected fiscal position. Both from the point of view of attracting exploration investment and from the preferences of government with respect to the time profile of revenue, therefore, it is appropriate for fiscal regime design to change in future. Within reasonable limits, the new model PSA can trade early revenue for late and have a more progressive structure.

Royalty

32. **The PEDPA calls for royalty and so the issue is the form it should take**. The conventional practice is a flat rate of royalty as a percentage of production, measured most easily at the delivery point from field facilities. The 1999 model however, provided for very small fields by using a scale of royalty that rose to 12.5 percent as shown in Table 2.1.

Table 1. Petroleum Royalty Scale from Model PSA of 1999

III. Daily Production IV. (bpd)	V. Royalty VI. (In percent)
Up to 2,500	5.0
2,500 up to 5,000	7.5
5,000 up to 7,500	10.0
Greater than 7,500	12.5

There was uncertainty about whether these rates were to be applied separately (incrementally) to production in each tier, or whether the higher rate once triggered applied to all production. That question is settled in favor of the incremental scheme in the PSA for EA1A, where the tiers and rates replicate the 1999 model. The royalty applies by contract area, not by production field, and therefore the daily production rates are aggregates if there is more than one field in the contract area.

33. **While a flat rate of royalty would be simpler, there is a case for maintaining the incremental scheme**. The report favors a general royalty rate of 8 to 12.5 percent for crude oil, which fits well with international standards where royalties are applied (see Appendix II). This rate, however, is quickly reached during the first year of production in the incremental scale of 1999 under any field currently contemplated in Uganda. The royalty loss over project life is therefore negligible, especially when measured in present value. The incremental scheme could be useful, however, late in field life if a single field remains from an original contract area. If production tails off at a relatively slow rate, the reducing royalty could prolong field life without

the need for discretionary remission of royalty. Where there is more than one field, the scheme does not help the smaller field since the DROP is an aggregate across the contract area.

34. **An alternative incremental DROP scheme has 12 to 14 percent as its midpoint, starting at 8 and rising to 18.** This scheme (Table 2) keeps the royalty below the suggested 12.5 percent at DROP rates up to 75,000 barrels of oil per day (bpd) achievable at sustained plateau production on a field of 300 million barrels (mm bbl) recoverable reserves. In the example in Figure 2, an average royalty of 10 percent is triggered in the first four years of production. This is a workable scheme when taken in conjunction with the slightly higher cost oil limit suggested in the next section.

Table 2. Petroleum Royalty Scale from Draft Model PSA of 2015

VII. Daily Production VIII. (bpd)	IX. Royalty X. (In percent)
Up to 25,000	8
25,000 up to 50,000	10
50,000 up to 75,000	12
75,000 up to 100,000	14
100,000 up to 130,000	16
Greater than 130,000	18

35. **Additional royalty by reference to a scale of cumulative production was added to the PSA for EA1A and for the Kanywataba area**. The mission understood that this additional and higher rate was unique to the circumstances of revision of this PSA in 2012. The intention is not to incorporate it in the new model PSA. Since the additional royalty is regressive, and additional revenue can be obtained more efficiently from sharing under the R-Factor scheme, this report concurs with the proposal not to include additional royalty in the future.

36. **The Public Finance Management Act 2015** (**PFMA) makes provision for distribution of six percentage points of royalty revenues to local governments.** This may influence the structure of royalty chosen. A flat rate royalty may now be simpler, because localities will find it hard to manage the variations implied by the sliding scale. The PFMA (s 75, with allocation formula in Schedule 6) allocates half of the local government amount to local governments where "production or impact" is located, and half to all governments, including those where production is located. One percentage point of the remaining central government receipts of royalties will be granted to a "gazetted cultural or traditional institution."

Cost recovery rules

37. **A limitation on cost oil serves as an additional tier of royalty on gross production while the limit applies**. Thus the 60 percent limit in EA1 implies that 40 percent of gross production is treated as profit oil, of which 45 percent goes to the government: 18 percent of gross production if there is no formal royalty. If the formal royalty is 12.5 percent and cost oil is calculated only from the balance after royalty, then cost oil is 60 percent of 87.5 percent, or 52.5 percent, and the minimum share of profit oil to government is 15.75. The total minimum share, or effective royalty to government, is then 12.5 plus 15.75 equals 28.25 percent. Coincidentally, this is also the percentage implied by the minimum royalty and the cost-recovery scheme in the 1999 model PSA.

38. **For a rebalanced model PSA with the R-Factor scheme, a higher cost oil limit is appropriate.** A shift in the limit to 70 percent creates room both for bonus bidding and for higher sharing rates in profitable projects, since initial risk of loss to the contractor is reduced. Figure 2 shows the new minimum effective royalty under the PSAs for EA1 and EA1A and the fiscal terms proposed here. The combination of a relatively modest flat-rate royalty (in the first option) or a royalty structured not to reach its maximum level in the early years of production (second option), a higher cost recovery limit, and the R-Factor production sharing scheme reduce the minimum effective royalty rate (see Figure 2), lessening the fiscal burden on less profitable projects.[11]

39. **Financing costs should not be recoverable, but a one-time uplift could be substituted.** A PSA is analogous to an unincorporated joint venture among private parties, where each party is obliged to provide financing, irrespective of source (equity or debt), and does not charge interest costs to the venture as a whole. Thus the calculations of the PSA are made on cash flows of total funds, not on returns to equity (as for book accounting and for regular CIT). Thus recovery of interest as a cost item is not warranted, whatever the permitted treatment for CIT. An uplift on all initial exploration and development capital costs, however, is consistent with the cash flow treatment and does not discriminate between equity and debt.

40. **The uplift is a modest level of recompense for the time value of money**. It is probably less expensive, in terms of government revenue, than permitting the recovery of financing costs. As with any measure that accelerates or increases cost recovery, it reduces risk to the contractor and has positive effect on the expected monetary value (EMV) in an exploration

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[11] For the 2012 and 2004 PSAs, the starting royalty (and base royalty) are lower than the numbers used here. However, since the DROP are very low, higher royalty rates will be triggered since first day of production. Here we used the royalty rates that would be triggered in the first years of production in a medium to large field. In option 2, a similar situation occurs resulting in an average royalty of 10 percent in the first years of production.

risk calculation. It thus also raises the possibility of positive bonus bids, and also brings forward the triggering of higher tiers under the R-Factor scheme.

Sharing of profit oil

41. **The authorities already favor a switch to the R-Factor system as the scale for sharing of production**. The report concurs with this approach and so does not rehearse again the arguments for or against this scheme, when compared with sharing by DROP. The R-Factor scheme is a simple cumulative ratio of revenue net of operating costs to exploration and development costs outlaid. When combined with uplift, the time value of money is also substantially taken into account. The formula is along the following lines:

$$\boldsymbol{R = \frac{Cumulative\ revenues\ net\ of\ operating\ costs}{Cumulative\ exploration\ and\ development\ expenditures}}$$

Where cumulative revenues include contractor's receipts of both profit and cost oil, including any recovery of uplift and adjustments for net credits to the cost recovery account.

42. **The data required for calculation of the R-Factor are the same as those used in DROP**. A quantity of production multiplied by a price gives total revenues, while costs must be assessed for recovery under both schemes. The assessed costs enter into the calculation of remaining profit oil, and the tier of the scale that is reached, under both schemes.

43. **When the R-Factor is less than one, the minimum share of government profit oil applie**s. Thereafter there are two options: (i) a scale of tiers in which each is a discrete step to a new rate of sharing; or (ii) a band in which progressive increasing rates of sharing to government are interpolated between the government's minimum and maximum shares. Since the first option requires somewhat arbitrary decisions on the steps, and may give rise to distortions at the point of crossing from one tier to another, the report favors the sliding scale with interpolation. The formula is as follows:

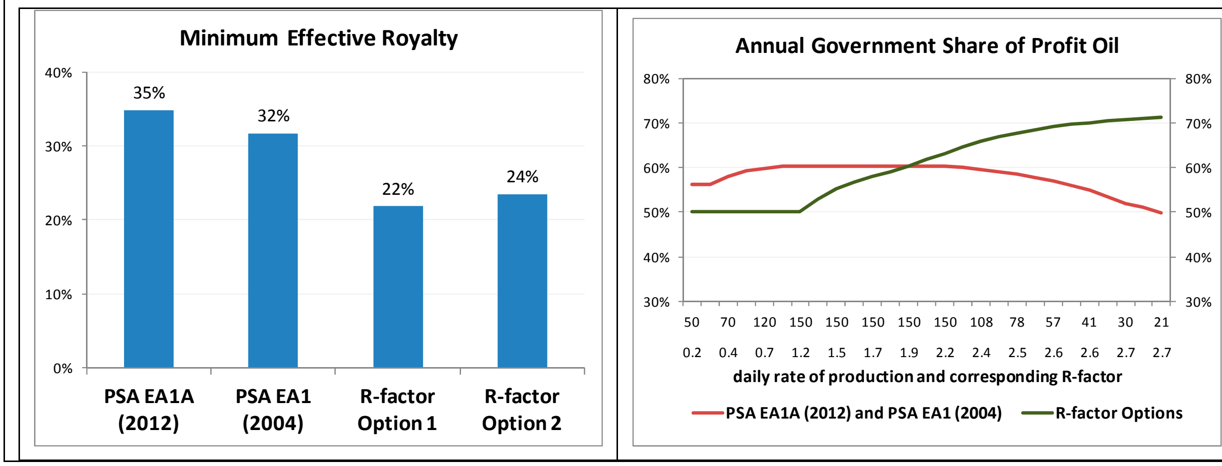
$$\boldsymbol{\begin{aligned} Gov.Share\ &= Min\ Gov.Share \\ &\quad + Max\left(0, \left[(Max\ Gov.Share - Min\ Gov.Share)x\ \frac{RFactor - 1}{RFactor\ max.band - 1}\right]\right) \end{aligned}}$$

44. **The minimum and maximum shares should be simple and transparent**. The report suggests 50 and 75 percent, applying across a band interpolated between an R-Factor of one and then of three.

45. **The advantages of the R-Factor over DROP sharing are evident when the mechanisms are compared over the production cycle of an oil project.** Figure 2 plots the annual government share of profit petroleum under DROP and the R-Factor over the production cycle of a stylized field example. The horizontal axis includes the annual DROP along with the corresponding R-Factor achieved under the project. Since DROP depends on production rates,

the government share of profit petroleum follows closely the production profile. As a result, the government share starts to increase during the first years of production, reaching its maximum at peak production, to then decline steadily. Under the R-Factor, on the other hand, the government share remains constant until the "payback" point is achieved, roughly around peak production, and then increases gradually towards its maximum rate, as the profitability of the project increases.

Figure 2. Minimum Effective Royalty and Profit Oil Sharing



46. **It is important to note that the maximum level of government share under DROP is never achieved in absolute terms.** Since DROP operates on an incremental basis, this means that there are always certain amounts of profit petroleum that will be shared at lower rates. In other words, the effective government share is a weighted average of the different government shares applying in the incremental scale at a given production rate. In the previous example, the highest DROP achieved is 150,000 bbl, and the corresponding government share is 60.4 percent, which is well below the maximum level of 67.5 percent.[12]

Income tax on petroleum licensees

47. **The standard CIT rate for companies at 30 per cent remains appropriate within the PSA framework proposed**. Without the production sharing and royalty framework, there would be a case for an additional tax or surcharge that would approach the collection of resource rent, but that is currently the function of the production sharing system. Conversely, the governments should consider whether the rate of tax on petroleum companies should rise and fall with the general rate or remain at 30 percent unless deliberately changed.

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[12] The calculation for a DROP of 150,000 bbl is as follows: of the first 5,000 bbl the government will receive 45 percent; of the next 5,000 bbl 47.5 percent; of the next 10,000 bbl 52.5 percent; of the next 10,000 bbl 57.5 percent; of the next 10,000 bbl 62.5 percent; and of anything in excess of 40,000 bbl 67.5 percent. In sum the government receives 90,150 bbl or 60.4 percent of the DROP of 150,000.

48. **The law on income tax for petroleum companies currently does not work as drafted.** This problem is discussed in detail in Chapter V. A decision is necessary on whether to make adjusted profit oil the base for application of the tax rate, or whether to return to the more common method of aggregating the licensee's cost and profit oil as gross income and then applying allowable tax deductions to arrive at chargeable income.

49. **The two-stage calculation with cost and profit oil making up gross income is preferable.** While either method is workable, the second has the advantage of uniformity and transparency. The tax rules for petroleum companies will be clearly set out in law as for other companies, and the calculation will not depend on how cost oil is calculated in individual PSAs which may differ. The allowable deduction rules, including capital allowances, in the ITA need to be uniform, and thus will not always replicate the cost recovery rules in a PSA.

50. **For administrative reasons, easy reconciliation between allowable deduction rules for tax and cost recovery rules under PSAs is desirable**. That will first require standardization of cost recovery rules across PSAs. Even then, there will be legitimate policy reasons for cost recovery and allowable deduction rules to differ. PSA cost recovery follows cash flow principles, whereas ITA rules follow adjusted corporate accounting to tax returns to equity. Thus interest should be allowable (subject to limits) under the ITA but not recoverable under the PSA. Similarly, economic depreciation may be approximated under the ITA but is not necessary under the PSA. Finally, the cost oil limit under the PSA is a limit on the rate at which expenditures ("losses") carried forward are recovered; such a limitation could be imposed under the ITA but not necessarily at the same rate, if any, as for cost oil. For clarity, the terms "recoverable costs" under the PSA and "allowable deductions" under the ITA should be kept distinct.

Recommendations

- Set crude oil royalty either at a fixed rate of 8 to 12 percent or by sliding scale of DROP.
- Ensure the provisions of the PFMA on royalty sharing can be implemented simply under the chosen royalty scheme.
- Continue with a cost recovery limit, probably at 70 percent (depending on the royalty scheme chosen).
- Remove financing charges as a cost recoverable item.
- Introduce a 15 percent one-time uplift for development costs during the first five years of development expenditure.
- Adopt the R-Factor scheme for profit petroleum sharing.
- Calculate income tax on petroleum companies from gross income consisting of both cost and profit oil, applying allowable deductions.

C. Fiscal Modeling of Existing Terms and Alternative Terms for New Model PSA

51. **Using FAD's Fiscal Analysis of Resources Industries (FARI) modeling framework, the report evaluates two existing and two alternative PSA fiscal terms for Uganda.** The four sets of terms evaluated are set out in Table 3, including the terms in the PSA for exploration area 1A (EA-1A), which was signed in 2012; the terms for the EA1 PSA, which was signed in 2004; and two alternative set of fiscal terms proposed in this report.

Table 3. Fiscal Terms Evaluated

	PSA EA1A (2012)	PSA EA1 (2004)	R-Factor Option 1	R-Factor Option 2
Royalty	DROP (mbbl) — % DROP < 2.5 — 5 2.5 > DROP > 5.0 — 7.5 5.0 > DROP > 7.5 — 10 DROP > 7.5 — 12.5 (no terms for gas; oil equivalency assumed)	DROP (mbbl) — % DROP < 2.5 — 5 2.5 > DROP > 5.0 — 7.5 5.0 > DROP > 7.5 — 10 DROP > 7.5 — 12.5 (no terms for gas; oil equivalency assumed)	Flat-rate 8% oi; 6% gas	DROP (mbbl) — % DROP < 25 — 8 25 > DROP > 50 — 10 50 > DROP > 75 — 12 75 > DROP > 10(— 14 100 > DROP > 13 — 16 DROP > 130 — 18 Gas royalty on oil equivalency
Additional royalty	Cummulative (mmbbl) — % Production < 50 — 2.5 50 > Production > 100 — 5 100 > Production > 150 — 7.5 150 > Production > 250 — 10 250 > Production > 350 — 12.5 Production > 350 — 15	NA	NA	NA
Cost recovery limit	60% oil; 70% gas	60% oil and gas	70% oil and gas	70% oil and gas
Profit petroleum sharing	DROP (mmbbl) — Gov Share (% — Contractor (%) DROP < 5 — 45 — 55 5 > DROP > 10 — 47.5 — 52.5 10 > DROP > 20 — 52.5 — 47.5 20 > DROP > 30 — 57.5 — 42.5 30 > DROP > 40 — 62.5 — 37.5 DROP > 40 — 67.5 — 32.5	DROP (mmbbl) — Gov Share (% — Contractor (%) DROP < 5 — 45 — 55 5 > DROP > 10 — 47.5 — 52.5 10 > DROP > 20 — 52.5 — 47.5 20 > DROP > 30 — 57.5 — 42.5 30 > DROP > 40 — 62.5 — 37.5 DROP > 40 — 67.5 — 32.5	R-Factor — Gov Share (% — Contractor (%) R-Factor < 1 — 50 — 50 1 < R-Factor < 3 — Interpolation between 50-75 R-Factor > 3 — 75 — 25	R-Factor — Gov Share (% — Contractor (%) R-Factor < 1 — 50 — 50 1 < R-Factor < 3 — Interpolation between 50-75 R-Factor > 3 — 75 — 25
CIT rate (%)	30	30	30	30
State participation (%)	15 Carried through development	15 Carried through development	15 Carried through development	15 Carried through development

52. **The two alternative sets of fiscal terms maintain the same overall structure of existing PSAs, but introduce important variations.** The first option introduces a flat-rate royalty, instead of the incremental royalty based on the daily rate of production present in existing contracts. The second option maintains the incremental royalty at rates slightly higher than those used in previous PSAs, but does not include the additional royalty introduced in 2012. Both options replace the DROP mechanism for production-sharing with an R-Factor scheme discussed above. Finally, both options increase the cost recovery limit from 60 to 70 percent and eliminate the recoverability of interest expense for cost recovery purposes, but offer instead a one-time limited uplift for development costs.

53. **The alternative terms aim to reduce the fiscal burden on marginal projects, make the system more responsive to projects' profitability, and maintain the government take close to current PSAs' levels.** The combination of a relatively modest royalty, a higher cost recovery limit, and a profit-base production sharing scheme reduce the fiscal burden on less profitable projects. The R-Factor scheme, on the other hand, ensures that the government share of profit petroleum increases as the project's profitability increases, regardless of the production rate. If the parameters are properly calibrated, it would also be possible to achieve similar levels of government take to those found in current PSAs.

54. **This report evaluates the four sets of terms on a large and a medium size stylized oil fields examples.** The first project is a large field with total production of approximately 956 MM bbl, and could be seen as representative of discoveries in EA1, which appears to be the more prolific discovery thus far. The second project is smaller in size, with total production of 264 MMbbl, and may be seen as representative of discoveries in EA2. With a price assumption of US$51/bbl FOB Mombasa, in constant dollars of 2015, the large field yields a pre-tax internal rate of return (IRR) of 19 percent, while the medium field has a pre-tax IRR of 10 percent. The project economics of the two fields are presented in Table 4. All the results are measured in real terms unless otherwise noted.

Table 4. Economics of Stylized Oil Projects[1]

	Large Oil Field		Medium Oil Field	
		Years		**years**
Total production	956 MM bbl	27	264 MM bbl	26
Project costs	**$MM**	**$/bbl**	**$MM**	**$/bbl**
Exploration costs	1,250	1.3	900	3.4
Development costs	5,400	5.6	2,500	9.5
Operating costs	7,648	8.0	1,846	7.0
Pipeline tariff (deduction from FOB price)[2]	11,092	11.6	2,678	11.6
Decomreporting	550	0.6	250	0.9
Total costs	25,940	27.1	8,174	32.4
Crude price FOB Mombasa ($/bbl)	51		51	
Pre-tax IRR	18.9%		9.7%	

Note: All figures are in 2015 constant dollars

[1] Created as IMF staff estimates from information published by the oil companies, supplemented with information kindly shared by World Bank staff. These estimates have been reviewed again using, in particular, commentary on them supplied by the oil companies after the conclusion of the mission.
[2] The assumptions for the pipeline tariff calculations are explained in detail in Chapter III of the report. These are not costs under the PSA regime but are deducted from revenue under a netback pricing scheme.

Profile of government revenues and total revenue

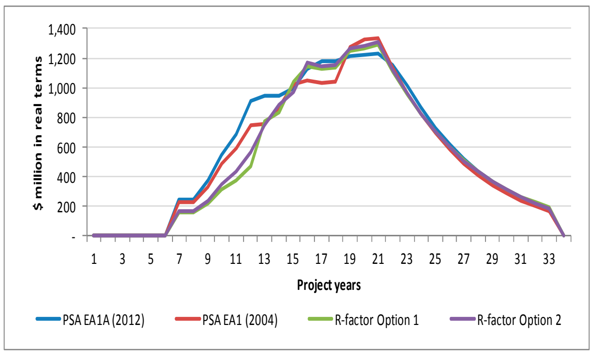
55. **The report first evaluates the path of government revenue under the four PSA options discussed above.** Figure 3 displays the revenues collected by the government from royalty, profit petroleum sharing, CIT, and state participation. The results show that the four sets of fiscal terms modeled yield relatively similar revenue profiles for the government under the large oil field project. In the medium field, the R-Factor options raise less revenue in the early years of the project, but towards the middle they more than offset the differences of the first years. Under both projects, in all four PSAs the government starts receiving revenue from day one of production, mainly due to royalties, and the combination of a cost recovery limit with a

minimum share of profit petroleum. However, the magnitude of these early revenues is larger under the 2012 PSA, mainly as a result of the additional royalty.

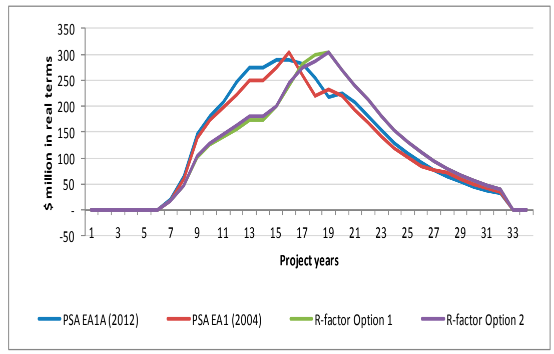
56. **The report also evaluates total government revenue over the life of the project at different prices.** Figure 3 shows that while the 2012 PSAs generate more revenue for the government under current price conditions, as prices increase the revenue generated by the R-Factor alternatives increases faster than the existing PSAs. Eventually, in a scenario of high prices ($100/bbl and above), the R-Factor options generate higher revenue for the government.

Figure 3. Government Revenues under the Four PSA Terms Evaluated

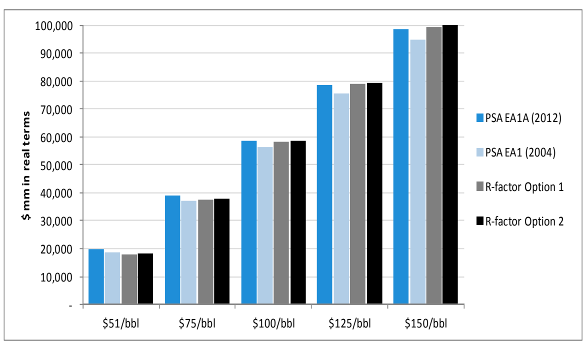
XI. Large oil field – Revenue profile at $51/bbl



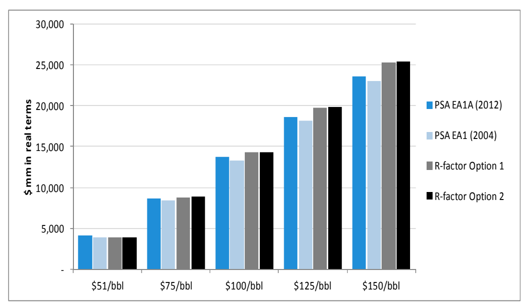
Medium oil field - Revenue profile at $51/bbl



Large oil field – Total revenue at different prices



Medium oil field – Total revenue at different prices



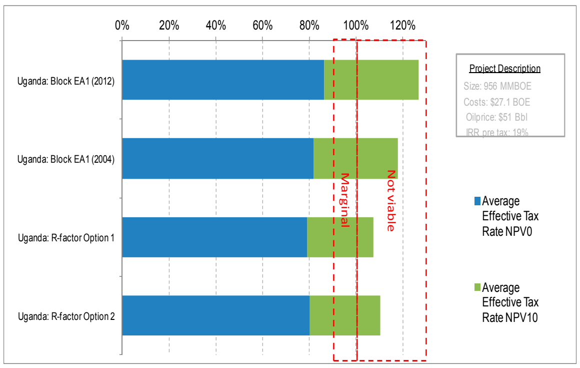
Revenue generating capacity, progressivity, and tax burden on marginal projects

57. **The report evaluates the revenue generating capacity of the four fiscal regime options by estimating the Average Effective Tax Rate (AETR) or "government take".** The AETR is calculated as the ratio of government revenue from a profitable project to the project's pre-tax net cash flows. Figure 4 shows the AETR of the four fiscal regimes evaluated both under the large and medium oil fields. In undiscounted terms, the four regimes yield relatively similar AETRs of between 79 and 86 percent, and between 79 and 83 percent for the large project and medium project respectively. Using a discount rate of 10 percent, under the large field, the 2004 and 2012 PSAs have AETRs of 118 and 125 respectively, while R-Factor option 1 and option 2 yield AETRs of 107 and 110 percent, respectively (the discounted AETRs under the medium field

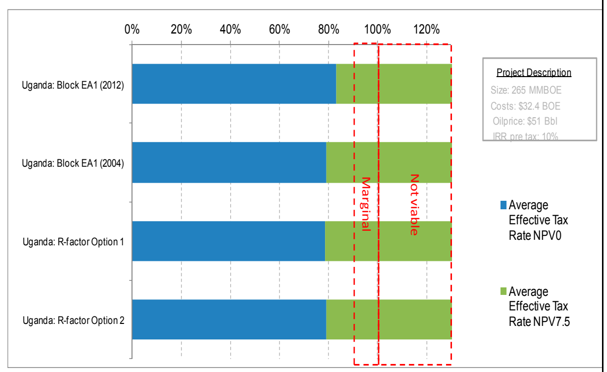
are well in excess of 100 percent even when using a discount factor of 7.5 percent). The reason for these extremely high AETRs is that the discount rate used is higher than project post-tax IRR under all four regimes. Under current price conditions, the projects' post-tax IRR (9.2 and 2.5 percent on the large medium field respectively) are below the government and companies' discount rates of 10 and 12.5 percent respectively.

Figure 4. AETR under Fiscal Regime Options

XII. Large oil field



Medium oil field



58. **The degree of progressivity of the tax regime is important for governments and investors if a properly targeted rent tax is not available.** A more progressive regime allows the government to increase its share of revenue when the investment is highly profitable, while giving some relief to investors for projects with low rates of return. It serves as a proxy for more accurate taxation of economic rent. In addition, a progressive regime could attract investment for marginal projects (increasing government revenue in the long run), just as a heavy fiscal burden on a project could deter investment altogether.

59. **The report evaluates the progressivity of the four PSAs by estimating the government share of total benefits[13] over a range of different prices and corresponding pre-tax IRR for the projects**. A progressive fiscal regime would yield a higher share of total benefits for the government as the profitability of the project increases; progressivity is only relevant above the minimum acceptable rate of return required by the investor. Figure 5 below illustrates the government share of total benefits over a range of different oil prices and the corresponding projects' pre-tax IRRs. A range of pre-tax IRRs is used to indicate how the project profitability increases with prices, and by no means implies a ranking of projects by IRR.

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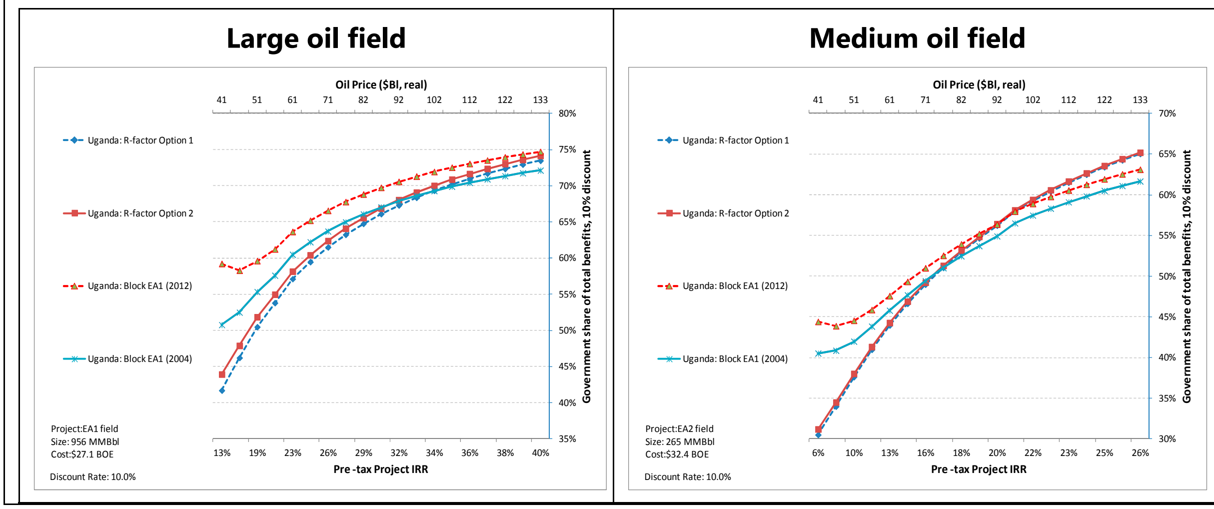
[13] Total benefits are defined as revenues minus operating costs and capital replacement computed from the date of commencement of production (ignoring upfront capital expenditures). In the other words, total benefits represent the available net proceeds from which taxes are paid, debt is serviced, and equity providers are rewarded, measured here at a 10 percent discount rate.

60. **The two alternative sets of fiscal terms are more progressive than the existing PSAs, with both options exhibiting identical degrees of progressivity.** The main reason for this is the switch from the DROP mechanism to the R-Factor one. The difference in progressivity between option 1 and 2 is almost imperceptible, since the only difference between the regimes is the royalty (flat relatively low rate vs. incremental rate). It is important to note, however, that while progressivity allows countries to capture a higher share on the upside, it may also mean that countries share some risk by reducing their global take on the downside (unless there is sufficient minimum government revenue whenever production is occurring).

Figure 5. Government Share of Total Benefits under Fiscal Regime Options

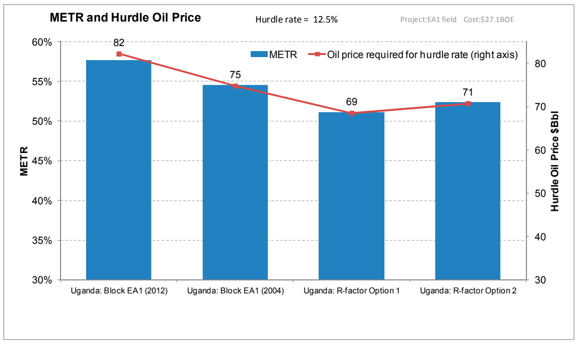
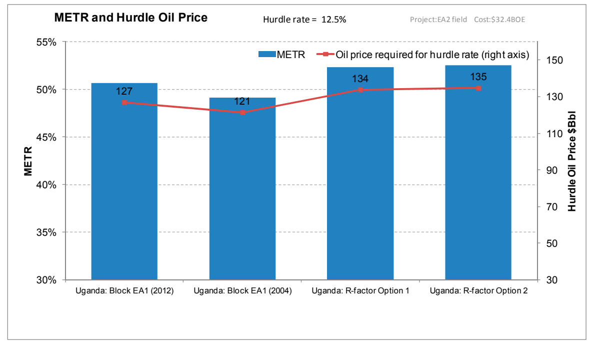


61. **The report also compares the relative burden that the four PSAs would put on a marginal project.** A key indicator is the "breakeven price" or the minimum price required to meet the minimum rate of return required by the investor (assumed in the model to be 12.5 percent in real terms). Under the large field, the 2012 and 2004 PSAs place a higher burden on marginal projects than the R-Factor options. This is a combination of the higher royalty rates being triggered early on in the project and the DROP mechanism. The introduction of the R-Factor mechanism reduces the breakeven price, with the option with the flat royalty reducing it even further (Figure 6).

62. **Interestingly, the results are reversed in the medium field.** There are two reasons that explain this result. First, since the field is smaller and has lower production rates in its early years, the government share of profit petroleum during these years is on average lower under the DROP mechanism than under the R-Factor system (the first two tiers of government share in DROP are 45 and 47.5 percent vs. a minimum government of 50 percent in the R-Factor). And secondly, when the project reaches a post-tax IRR of 12.5 percent (the minimum required by the investor), the R-factor is likely to be already higher than 1, triggering higher shares of profit petroleum for the government. The combination of these two effects results in a higher breakeven price for the R-Factor than the DROP mechanism in fields with lower rates of production. It is important to note, however, under both projects all the PSAs evaluated here

require a higher breakeven price than the one assumed for the rest of the analysis presented in this report.

Figure 6. Breakeven Price and METR under Fiscal Regime Options

XIII. Large oil field	**Medium oil field**
	

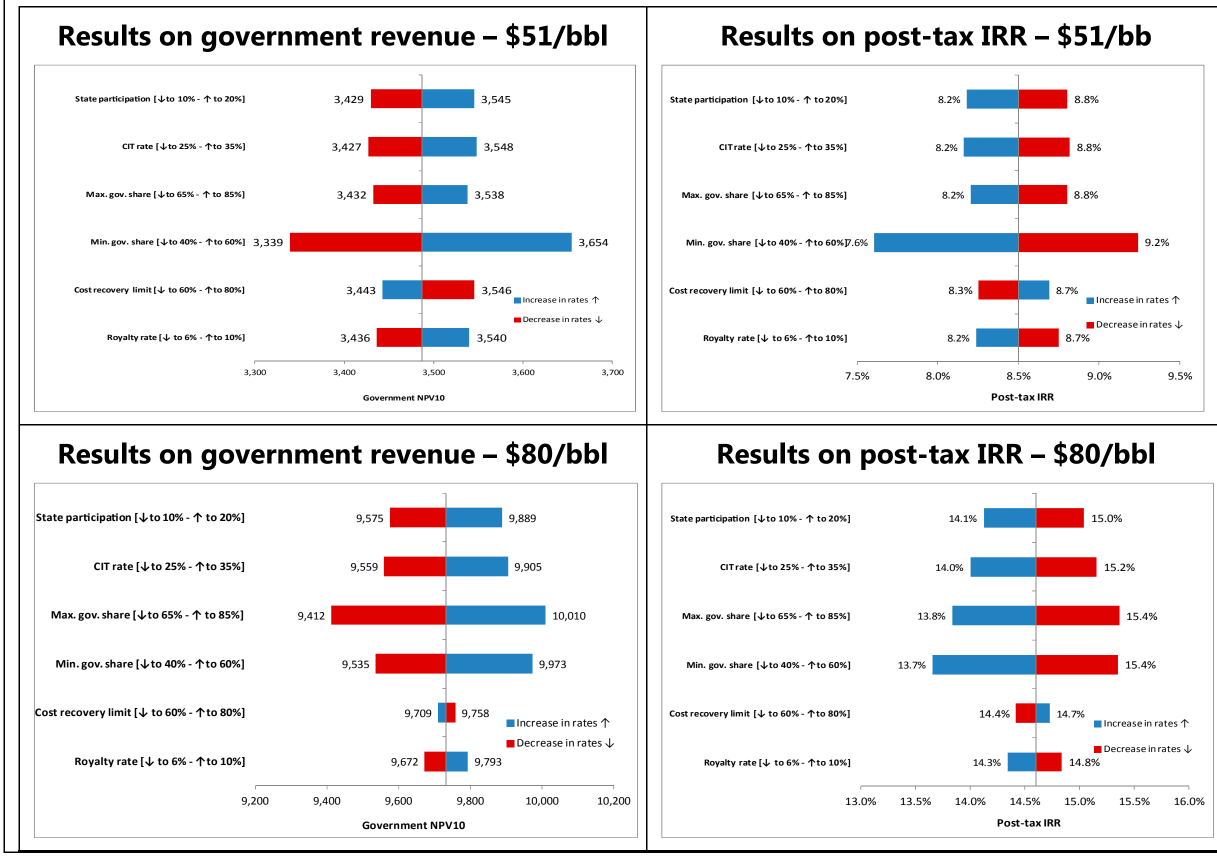
Sensitivity analysis on fiscal terms and effect on government NPV and post-tax IRR

63. **The report illustrates sensitivity analysis on the fiscal parameters contained in the R-Factor option 1, and evaluates the results on government revenue and investor return.** The analysis was done under two price scenarios. The first scenario used a price of $51/bbl, which is the price used throughout most of the analysis in this section. The second scenario used a relatively higher price of $80/bbl, as possible future developments are likely to start production several years after 2015 when prices may rebound from their current low levels.

64. **Under the lower price scenario, changes to the minimum government share of profit petroleum have the greatest effect on both government revenue and post-tax IRR.** Decreasing the minimum government share from 50 to 40 percent would result in a 4 percent reduction in government NVP10, or $147 million. Conversely, increasing the minimum government share from 50 to 60 percent would result in an additional $163 million in government revenue, or an increase of 5 percent. On the investor return, the 10 point decrease in the minimum government share would increase the post-tax IRR from 8.2 to 8.9 percent, while a 10 percent increase would lower the post-tax IRR to 7.3 percent.

65. **Under the high price scenario, on the other hand, changes to the maximum government share of profit petroleum have the greatest effect on both government revenue and post-tax IRR.** For example a 10 point increase in the maximum government share would increase government revenue by $268 million, while a 10 percent decrease will reduce revenue by $230 million. Conversely, the 10 percent increase would reduce the post-tax IRR of the project from 14.6 to 13.8 percent, while a 10 percent decrease would increase it to 15.4 percent. Other results are displayed in Figure 7 below.

Figure 7. Sensitivity Analysis on Fiscal Parameters



Expected monetary value analysis and "implied" bid bonus

66. **The report uses EMV analysis to calculate an "implied" bid bonus under the two project examples for the two R-Factor options.** The analysis incorporates exploration uncertainty to estimate the investor's perceived risk-adjusted return after-tax. In other words, the report calculates the expected NPV per dollar of exploration expenditure by adding: (i) the probability of unsuccessful exploration multiplied by the expected NPV loss from failed exploration costs; and (ii) the probability of a successful discovery multiplied by the expected after-tax positive NPV from the project.

67. **If the expected NPV is positive, in principle this would be a proxy for the maximum bid bonus investors would be willing to pay.** However, there are other considerations that companies take into account when deciding on a bid bonus, such as budgeting capital issues and market interest in the blocks being auctioned. Based on the positive rate of successful

exploration in Uganda so far,[14] the report assumes an 85 percent chance of discovery—though the probability of large commercial discoveries will in practice be lower. In addition, since production from blocks auctioned in either 2015 or 2016 is likely to start production several years after the auction, a higher price of $80/bbl was used to reflect a possible price scenario in the medium term. Table 5 shows that under the large field, companies may be willing to offer a bid bonus of $236 and $166 million under option 1 and 2 respectively. Under the medium field the EMV is negative, since the assumed price of $80/bbl is lower than the minimum price required by investors.

Table 5. EMV and "Implied" Bid Bonus

Large oil field

Probability of discovery :	85%	
Company discount rate:	12.5%	
Oil price ($/bbl):	80	
	R-factor Option 1	**R-factor Option 2**
NPV of exploration failure	-1,209	-1,209
NPV of successful discovery	492	409
EMV (implied bid bonus)	236	166

Medium oil field

Probability of discovery :	85%	
Company discount rate:	12.5%	
Oil price ($/bbl):	80	
	R-factor Option 1	**R-factor Option 2**
NPV of exploration failure	-880	-880
NPV of successful discovery	-387	-394
EMV (implied bid bonus)	-461	-467

D. International Comparison

68. **The report compares the four PSAs with fiscal regimes applicable in other oil producing countries in the region and elsewhere**. The comparator countries in the sample include some established onshore producers (like Chad and Sudan,), current and potential producers from the region (DRC, Mozambique, Tanzania and Kenya), and countries with onshore production from outside the region (Australia and Colombia). Fiscal terms for the comparator countries are included in Appendix I.

69. **The international comparisons confirm the results of the AETR, progressivity and breakeven price analysis conducted for the four sets of fiscal terms for Uganda.** For example, the 2012 and 2004 PSA fall in the higher end of the sample under the AETR, in line with countries such as Tanzania (Model PSA 2013) and Sudan (Model EPSA 2011). While the R-Factor options come in the mid part of the range, with a slightly higher government take to the newly introduced model PSC of Kenya. (Figure 8).

70. **In terms of progressivity, the R-Factor options appear to be relatively more progressive than many countries in the sample.** The 2012 and 2004 PSA, on the other hand, fare relatively similar to other countries in the region and elsewhere. Countries like Australia and Colombia appear to exhibit relative progressive regimes. This is perhaps due to the use of rent

[14] According to the MEMD "to date 116 deep wells have been drilled in the Albertine Graben and 102 of these wells have encountered hydrocarbons in the subsurface" for a success rate of 87 percent: http://www.petroleum.go.ug/10/Exploration-Drilling

capturing mechanisms (similar to the R-Factor) and the absence of very high minimum effective royalties.

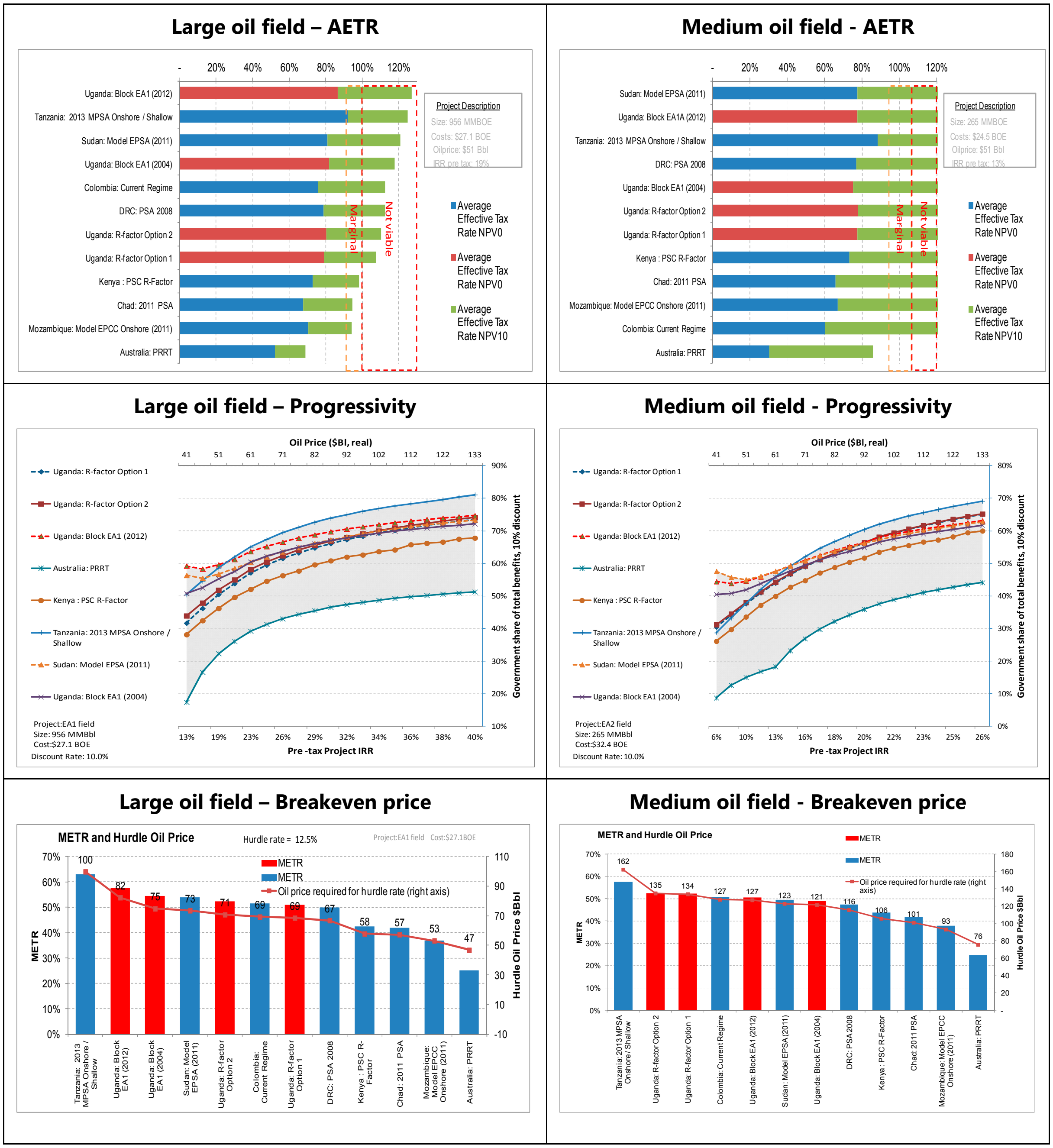
71. **Finally, the 2012 and 2014 PSAs appear to be the upper part of range in terms of breakeven prices under the large field, with the R-Factor options coming closer to the middle**. In the medium field, the R-Factor options and the 2012 and 2004 PSAs positions are pretty much reversed. The range of breakeven prices is quite broad, with Tanzanian investors requiring a price of $100/bbl and $162/bbl to breakeven in the large and medium field respectively, while an Australia investor only requires a price of $47/bbl and $76/bbl to breakeven respectively in the same fields.

Implied risk premium across fiscal regimes

72. **Evaluating the tax burden using a single projected price path may not fully take into account the effects of the tax system on returns under a wide range of expected price developments.** An investor may prefer a faster payback from the project, or may perceive wide dispersion of expected outcomes as a strong risk factor, or may be reluctant to accept possible returns below the required rate. In order to analyze the effect of the tax system on returns, under a range of prices, the report shows a probability distribution of returns for a range of simulated oil prices.[15]

[15] Prices are generated randomly from using a simple autoregressive model that replicates the behavior of past oil prices. Lower (US$20/bbl) and upper (US$200/bbl) bounds on oil prices are imposed to avoid extreme values. This exercise is repeated hundreds of times to construct a range of possible outcomes for future oil prices.

Figure 8. International Comparisons[1]



[1] On the progressivity chart, only Australia (petroleum resource rent tax), Kenya (newly introduced R-Factor), Tanzania (DROP), and Sudan (DROP) were included as comparators to allow for a better visualization of the results.

73. **The report evaluates the expected average post-tax IRR, together with a measure of variation in the post-tax returns, and the probability of tax-induced negative returns for the investor over a range of simulated oil prices for the large field.** The PSAs are tabulated in descending order of the mean IRR (Table 6). The low mean expected post-tax for current fiscal terms in Uganda indicates that a typical investor may on average expect lower returns from

investing in Uganda under these regimes than in other countries. This low return is also associated with higher volatility than in other countries. Under the current fiscal terms in Uganda, the probability of generating returns below the target range is among the highest in the sample, only after Tanzania and Sudan. The R-Factor options fare better than the current PSAs in Uganda. For example, these options increase the mean expected after-tax IRR from 8.1 to 11.2 percent in large field, while reducing the tax induced probability of below target returns from 72 to 54 percent.

Table 6. Post-Tax IRR and Tax Induced Probability of Below Target Returns

Large oil fie

Medium field	Mean Investor post tax IRR	Coefficient of variation of IRR	Tax Induced Probability of below target return of 12.5%
	%	%	%
Project before tax	22.5	41	0
After tax:	-	-	-
Tanzania: 2013 MPSA Onshore / Shallow	6.4	77	82
Uganda: Block EA1 (2012)	8.1	76	72
Sudan: Model EPSA (2011)	9.6	65	64
Colombia: Current Regime	9.7	51	68
Uganda: Block EA1 (2004)	9.7	64	64
Uganda: R-factor Option 2	10.6	56	56
Uganda: R-factor Option 1	11.2	53	54
DRC: PSA 2008	11.3	60	50
Kenya : PSC R-Factor	13.6	49	36
Mozambique: Model EPCC Onshore (201	15.2	47	26
Chad: 2011 PSA	14.0	51	36
Australia: PRRT	17.8	38	12

State Participation and Public Finance Management Act

74. **Following the NOGP, a state carried interest is modeled under each scenario**. This is set at 15 percent in each case (as an assumption, recognizing that actual terms may differ), with election made after commercial discovery and prior to issue of a PL. The state (or NATOIL) does not reimburse proportionate exploration expenditure and has the right to be “carried” through initial development by the private contractors. The government reimburses its share of development costs from its share of oil produced, with interest at LIBOR, and without recourse to any other state assets in the event of problems in the project.

75. **Alternatives to this assumption include different participation percentages and different terms of repayment**. Carried participation of this type protects interest of the state, notably against initial contingent liabilities. It also functions as an additional layer of tax or production sharing, payable to the government when the carry is repaid with interest. If the carry is repaid only out the government share of cost oil, the repayment is naturally slower and the cost in present value to the private contractors is greater.

76. **Clarity will be needed on the treatment of state participation after recovery of initial development expenditure**. The points to be settled include whether the carry continues, or whether the government must meet subsequent cash calls for both operating and

development expenditure. If the government has cash call obligations, then the joint operating agreement should also treat the question of what happens if a cash call is delayed or missed, and whether government participation can be diluted.

77. **The new PFMA provides rules for flows of petroleum revenues**. The Act received Presidential assent on February 23, 2015. "Petroleum revenue" under the PFMA means "*tax paid under the Income Tax Act on income derived from petroleum operations, government share of production, signature bonus, surface rentals, royalties, proceeds from the sale of government share of production, any dividends due to government, proceeds from the sale of Government's commercial interests, and any other duties or fees payable to the Government from contract revenues under a petroleum agreement*." (PFMA s3). Petroleum revenue is collected by the Uganda Revenue Authority (URA) and then transferred to the Petroleum Fund, from where it goes either to the Consolidated Fund or to the Petroleum Investment Reserve.

78. **The definition of petroleum revenues seems to imply that the "government share of production" does not include cost oil due to government**. Unless that is the case, the carried interest arrangements cannot work as intended and all government contributions to costs (cash calls) will have to be voted through the budget.

79. **Bonuses other than signature bonuses are also excluded from the definition**. Bonuses other than signature bonuses are also excluded from the sources of funds under the PEDPA 2013 (s33) for the proposed Petroleum Authority of Uganda. Surface rentals are due to the Petroleum Fund under the PFMA 2015, but are due to the Petroleum Authority under the PEDPA 2013. These matters require clarification even though, as the more recent statute, the PFMA presumably prevails.

80. **The reference to dividends in the definition of petroleum revenues affects the operations of NATOIL**. The definition now provides that NATOIL returns dividends and its own tax payments to the government, rather than gross proceeds from participation. This is appropriate but then requires that in due course, rules concerning NATOIL's dividend policies, retention of profits and investment programs be set out.

Recommendations

- Continue with carried interest for state participation at a maximum rate fixed in the Model PSA.
- Clarify the obligations of the government (or its nominee) after recovery of initial capital investment.
- Align the definitions of petroleum revenues in the PFMA, PEDPA, and model PSA for consistency.
- Develop rules for NATOIL's policies on investments, profit retention, and dividends.

III. FISCAL ISSUES FOR THE UGANDA OIL PROJECT

A. Background and Configuration

81. **The project will consist of upstream production from four contract areas, early petroleum production for power generation, a refinery in Uganda, and a crude oil export pipeline.** The Memorandum of Understanding for the project as a whole is not published. Nevertheless, public reports indicate that upstream production will utilize anticipated recoverable reserves of about 1.2 to 1.7 billion bbl, early petroleum production for power production will probably come from the Kingfisher discovery area, for which a PL has already been issued; the refinery will be separate from the upstream joint venture and will have priority initially for 30,000 bpd of crude oil production rising to 60,000 bpd as refinery capacity expands; the crude oil export pipeline is to be sponsored by the upstream JV partners (with likely government participation). A preferred bidder was announced by MEMD in February 2015 for construction of the refinery, with which negotiations on a contract now proceed. A pipeline route is not yet selected, but is expected to pass through Kenya and to have a spur or link for transporting Kenyan oil from fields in the Turkana region also operated by Tullow.

82. **The project requires a series of linked activities, decisions, or preconditions in order to proceed.** The PSA contractors forming the JV have not yet commenced FEED, essential before a FID, because other preconditions are not in place. The upstream discovery areas each require approval of development plans and grant of PLs; only the PL for Kingfisher was issued at the time of the mission, while consideration of the other development plans has been in process for more than one year. The extent to which the contractors have explored financing options is not known. The grant of PLs, giving the right to develop and produce, is essential, but would probably have to be simultaneous with, or effectiveness contingent upon at least the following; (i) settlement of an intergovernmental agreement (IGA) on terms and conditions for the export pipeline between Uganda and Kenya; (ii) settlement of counterpart host government agreements (HGA) on the pipeline between the JV partners, and the two governments and/or the grant of licenses (with suitable terms and conditions) for pipeline construction and operation under the relevant legislation;[16] and (iii) a commitment by the relevant investors and the government to refinery construction and offtake arrangements, if the project is to commence with the obligation to supply 30,000 bpd for domestic refining increasing to 60,000 bpd as capacity refinery expands. It was understood by the mission, however, that in principle either the pipeline or the refinery could proceed independently.

83. **Tax issues on VAT and the ITA may also influence the timing of project decisions.** The application of VAT currently operates potentially to increase exploration costs. The issue needs a solution for purposes of the project as well as for the new licensing round. ITA issues concern withholding tax on technical services provided by non-residents, and the working of the

[16] For Uganda this is the Petroleum (Refining, Conversion, Transmission and Midstream Storage) Act, 2013.

schedules of the ITA applicable to petroleum companies. These issues are addressed elsewhere in this report.

B. Upstream Oil Pricing

84. **Crude oil is valued for production sharing at the "delivery point" from the field facilities.** Beyond that point, the upstream fiscal regime no longer applies, and normal business taxation takes over. In the PEDPA 2013 (s2) the delivery point means "the point at which petroleum passes through the intake valve of the pipeline, vessel, vehicle or craft at a terminal or refinery in Uganda." The PSAs provide for "such other point, which may be agreed in writing by the Parties." The PEDPA post-dates the PSA and is presumed to prevail. Thus for present purposes, the report assumes that crude oil supplied to a refinery will be valued at the inlet of that refinery, while crude oil exported by pipeline will be valued at the main inlet flange of that facility. Costs incurred in moving petroleum from field wellheads to these delivery points will form part of the upstream accounts.

85. **A netback from the FOB price at the port of export will determine the value of crude oil exported by pipeline**. By "netback," here is meant the value of the oil after deduction of the transportation tariff levied by the pipeline company. The transportation tariff could be calculated in a number of ways, of which two are illustrated in Box 2: the essential difference being that one calculates the tariff by reference to the equity contributions of the pipeline owners, while the other calculates by reference to the total cost of the pipeline and its expected throughput life.

Economics and Operation of Petroleum Pipelines

86. **Cross-border pipelines pose more complex legal, regulatory and fiscal issues than purely domestic lines.** Different national laws apply, complemented by any applicable international law. International law remains however limited in this domain.

87. **A cross-border pipeline is generally governed by an IGA among the countries concerned, ratified as a treaty**. This treaty is supplemented by a series of agreements: such as an agreement between each country and the pipeline company (or companies), the HGA, governed by the IGA and the national laws of the country. It defines among other things the tax regime applicable to the pipeline company. A "transportation agreement" between the pipeline company and the users of the infrastructure will include the tariff clause. Depending on the pipeline project structure,[17] the number of agreements to be entered into could be many, requiring long negotiations before a final investment decision to construct could be taken by the pipeline company. In most cases, the period for negotiating the agreements and arranging the

[17] Several alternatives exist: for example, a single entity owns and operates the entire transnational pipeline or a separate entity is constituted in each country for that purpose.

structure of the cross-border pipeline project and its financing is considerably longer than the construction itself.

Box 2. Pipeline Transportation Tariffs

All mechanisms require definition of an allowed rate-of-return. That return is often assessed on a formula, including an element on equity invested by the pipeline company, either directly or through a weighted-average cost of capital if applied to the total asset base. The central question is how to discover a market rate-of-return that a utility should be allowed to earn. In principle, it should be a rate of return, which would prevail in a competitive market where no monopoly rents exist, market prices are charged, and output distortions are avoided.

Traditionally a utility rate of return reflects a cost of capital of the regulated company. It is simply the return on invested capital that a company has to receive to service its debt (repayment of loan and interest), pay return to equity (dividends to shareholders) and ensure sufficient capital to meet future needs (sustaining capital). Whereas discovering the cost of debt and sustaining capital is not difficult, estimating the cost of equity, most importantly the cost of common stock, is not that straightforward. Certain techniques exist: a discounted cash flow analysis approach, a risk premium approach, the capital asset pricing model, a comparable earnings approach or market price-to-book value ratio. However, none is perfect—most of the techniques require assumptions or forecasts of future financial indicators which inevitably involve judgments that cannot be verified. Other techniques rely on past indicators which may not be relevant in the future.[1]

An alternative to regulation by a measure of return to the asset base is to calculate the annuity needed to return capital and provide a rate of return over a defined period. This approach uses a discounted cash flow calculation, rather than an annual return on equity or assets-employed approach. It is independent of the financing structure of the pipeline. The setting of the discount rate in this case will inevitably be somewhat arbitrary, but the government of Uganda and the petroleum companies share an interest in maximizing the revenues from upstream production of oil. After the initial period, when the tariff is the capital annuity plus the operating cost, the capital is fully recovered and the subsequent tariff can be negotiated at marginal cost—potential providing a large cost advantage to future oil production projects.

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[1] T. Gunton (1995) Regulating Utility Rates of Return: the Case of the Ontario Natural Gas Sector, Energy Studies Review: Vol. 7, Iss. 3, Article 1.

88. **Pipelines have high capital costs but low operating costs.** Economies of scale can minimize the unit tariffs (in US$/bbl) to be paid for transporting petroleum in a pipeline. Countries generally prefer to minimize the number of pipeline projects, authorizing the building of larger capacity pipelines that can be used not only by the shareholders of the pipeline company but also by other oil producers under a "third party access" (TPA) provision. The objective is to maximize the petroleum upstream revenues by minimizing the transportation tariffs for pipeline transportation of crude oil.

89. **A TPA clause is often imposed on the pipeline company under the national pipeline law to facilitate the negotiation by the third party of the terms of its transportation agreement.** A pipeline creates a natural monopoly and may render negotiation of TPA quite

tough. Two main alternatives exist for determining the tariffs applicable to TPA: the solution of regulated tariffs mainly used in OECD countries where many infrastructure projects are in operation; or the solution of commercial tariffs, negotiated on the principle of using "fair and reasonable tariffs" (Box 2) and often assessed on a formula including an element on equity invested by the pipeline company either directly or through a weighted-average cost of capital if applied to the total asset base. Under tariff regulation, the profitability of a pipeline project is usually limited and considerably lower than for upstream projects, but sufficient to recover costs, taxes and a profit component. To minimize the tariff, pipeline projects have often a high debt/equity ratio. In many countries, the pipeline law or regulation provides that tariffs have to be submitted to government for approval. Such tariffs may be different for the shareholders of the pipeline and the TPA users, depending on the terms stipulated in the transportation agreements.

Implications

90. **The pipeline tariff, once determined, sets a yardstick for the pricing of oil produced in Uganda.** This "export parity price" forms the benchmark for pricing of crude oil entering the proposed refinery. As shown in the economic evaluation, the refinery appears capable of profitably sustaining this input price provided that its petroleum products are price at or near import parity levels.

91. **The combination of agreements and price determinations should provide clarity for both governments and suppliers of capital**. The governments involved may have both a supply role and a transit role, since both Uganda and Kenya may supply oil through the pipeline (and perhaps other infrastructure). Capital participants will include equity holders: the upstream JV partners for the pipeline company, and an independent venture for the refinery. Capital participants will also include third party lenders, since both upstream and midstream facilities are likely to be substantially debt financed. The Ugandan government expects to participate as a joint venture participant or equity partner throughout the chain; the Kenyan government may intend the same for facilities within its territory. The project structure will need to specify a fair and practical allocation of transportation revenues and costs across countries, mirrored in taxing rights.

92. **Exclusive rights to transport infrastructure should be limited—third-party access is vital in the long term**. The long term value of the infrastructure is not only for export or domestic use of oil from known discoveries, but also to improve the economics of exploration and future discoveries. Nevertheless, there may be a need for a period of exclusivity to attract the required initial investment. The EAC countries do not at present intend to impose transit fees (as distinct from any transportation tariff charge by owners of facilities) for intra-Community pipelines and similar infrastructure. Third party access rights are in any case usually more important than transit fees.

Recommendations

- Confirm the definition of delivery point for valuation of crude oil.
- Determine the pipeline tariff formula to govern netback pricing of crude oil at the delivery point.
- Confirm the pricing schemes for input of crude oil to the refinery and the output of petroleum products.
- Limit exclusive rights to capacity in transportation infrastructure to the minimum necessary to induce initial investment.

C. Income Taxation of Midstream Facilities

93. **The pipeline company is usually subject to the tax regime applied to pipeline activities in each country.** Applying a common fiscal regime across countries, desirable for simplification purposes, is not the option usually selected—though a common regime was adopted for the West Africa Gas pipeline. Within the EAC partner states, domestic tax rules are clear and preferable to a separately negotiated common scheme for cross border facilities.

94. **With separate regimes, the pipeline company must prepare and submit its accounts and tax returns separately for each country's tax authorities.** Rules have to be therefore jointly defined and agreed among the transit countries in order to allocate the revenues and costs of the transit pipeline project in a fair manner between the two countries. Each country then applies its tax system to determine the relevant tax deductions, chargeable income, and the CIT to be paid. This requires that the pipeline satisfy the permanent establishment rules in each country.

95. **Under current law, the income tax treatment of refineries and pipelines is straightforward, as these businesses would be taxed under the general income tax rules**. In the case of an international pipeline, the pipeline owner would be subject to the regular profit tax on the share of the pipeline's income attributable to each country. In order to allocate costs and revenues between the two countries for tax purposes, rules should be jointly defined under IGA procedures. The allocation can follow the relative length of each segment of the pipeline or any other more relevant criterion, such as location of capital cost incurred. The allocation rules would also be set out in the pipeline agreement between the countries the pipeline crosses and the producers of petroleum. The income attributable to domestic shipments to the sea would be allocated solely to the domestic country (e.g., Kenya or Tanzania).

96. **The depreciation rates for capital expenditure for a refinery or pipeline are set out in the Sixth Schedule of the Income Tax Act**. In the case of a refinery, the depreciation rate for plant and equipment would be 30 percent declining balance, as a refinery operation is

manufacturing. The rate for a pipeline is 20 percent declining balance as a pipeline is "a depreciable asset not included in another class." These rates are accelerated but reasonable.[18]

97. **A pipeline or a refinery investment should not be granted a tax holiday.** The pipeline or refinery will only be constructed if petroleum producers agree to ship sufficient oil though the pipeline and to the refinery to ensure that the owner of the pipeline or refinery can recover costs and earn a rate of return on the investment. While it is true that a dollar of tax relief for the pipeline increases profit oil by a dollar, the government loses net revenue when tax relief is given to midstream facilities.

Recommendations

- Confirm that a cross border pipeline and associated facilities in the territory of Uganda are subject to the domestic tax regime of Uganda.
- Determine, with Partner States, the inter-state allocation principles for costs and revenues of a cross-border pipeline and associated infrastructure.
- Ensure that, within Uganda, the pipeline and refinery are subject to standard ITA rules, without special tax reliefs or exemptions.

D. Fiscal Modeling of the Uganda Upstream, Midstream and Downstream Projects

98. **The report models the upstream segment, the pipeline, and the refinery projects over their proposed life.**[19] The project comprises (i) an upstream segment, which will be developed as one integrated project by Tullow, Total and CNOOC, (ii) a pipeline to export crude oil via Mombasa, and (iii) a refinery to supply finished products to the local market and other countries in the region. The upstream segment is subject to the respective PSAs, while the pipeline and the refinery are assumed to be subject to normal business taxation. The pipeline and the refinery projects are assumed developed as separate entities, independent of each other.

99. **The upstream segment is assumed to produce mainly crude oil from the three exploration areas where most of the discoveries have been made.** These include areas EA1 (6 discoveries), EA2 north and south (four discoveries each), and EA3A (one discovery). The total estimated production is in excess of 1.3 billion bbl (Figure 9), with most of the production coming from EA1. Total is the operator for EA1, while Tullow and CNOOC operate EA2 and EA3A respectively. The partners plan to set up three plants to process the crude before it is sent to the pipeline and the refinery. The largest plant will serve EA1 and EA2 north, with a capacity to

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[18] Kenya's depreciation rate for a pipeline is 12.5 percent declining balance.

[19] All figures are in 2015 real terms, unless noted otherwise.

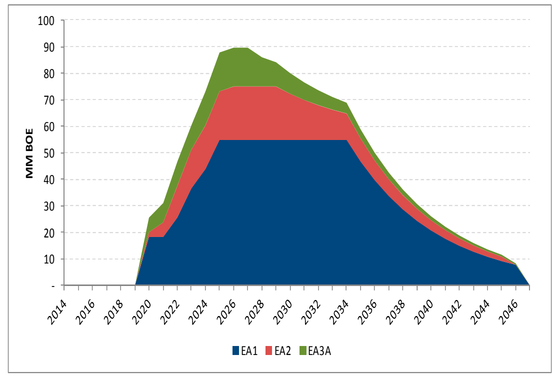
handle 190,000 bpd. Processing plants with capacities of approximately 15,000 and 40,000 bpd will be installed in EA2 south and EA3A respectively. These three areas are ring-fenced for fiscal purposes. The terms of the three PSAs applying to these three areas are assumed to be the same as the terms for EA1 modeled in s II of the report. Figure 9 shows the economics of the integrated upstream segment and the production profile from the three areas.

Figure 9. Integrated Upstream Segment Economics and Production Profile

IV. Upstream Segment Economics

Upstream Project		
Production oil	1,343	MMbbl
Production gas	33	MMBOE
Production BOE	1,376	MMBOE
Production years	27	
Constant 2015 US$	$ million	$/Bbl
Exploration costs	2,850	2.1
Development/capital costs	9,800	7.1
Operating costs	9,994	7.3
Tariff pipeline costs (outside PSA)	15,601	11.6
Decommissioning	1,000	0.7
Total	39,245	28.5

Upstream Petroleum Production



100. **The report assumes that a crude export pipeline, with capacity to transport 210,000 bpd, would be built from Uganda to the Kenyan coast.** The approximate length of the pipeline is 1,400 km, of which approximately 40 percent would lie in Ugandan soil.[20] Given the physical characteristics of the Ugandan crude, the pipeline would be required to be heated to be able to transport the crude. The report assumes that the government would take up a 15 percent fully paid equity interest in the pipeline company. The pipeline company is assumed to charge a tariff sufficient to recover capital and operating costs, and yield real post-tax rate of return of 7.5 percent (for simulations only, this rate could differ). The initial economics of pipeline project are presented in Figure 10 below.

101. **The key assumption made for the refinery project is that it would operate on an export parity basis to purchase crude from the upstream segment, and on an import parity basis to sell refined products into the market**. This assumption should be the subject of further review later in this project, since alternative pricing schemes exist and this assumption generates substantial profits in the refinery. Another possibility is to consider a special excise tax on refined products from the refinery in conjunction with the other VAT and excise reforms proposed in this report. The refinery is modeled with an initial capacity to process 30,000 bpd, increasing to 60,000 bpd after seven years, and to produce slightly under 3,000 kt/year of

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[20] As a result, the analysis presented here only reflects the pro-rata share of the project domiciled in Uganda.

finished products, including gasoline, diesel, fuel oil, jet kerosene, and liquefied petroleum gas. In addition, it is assumed that the government would take a 40 percent fully paid equity interest in the refinery. Figure 10 presents the economics of the refinery, as well as its production profile.

Figure 10. Pipeline and Refinery Economics and Refinery Annual Output

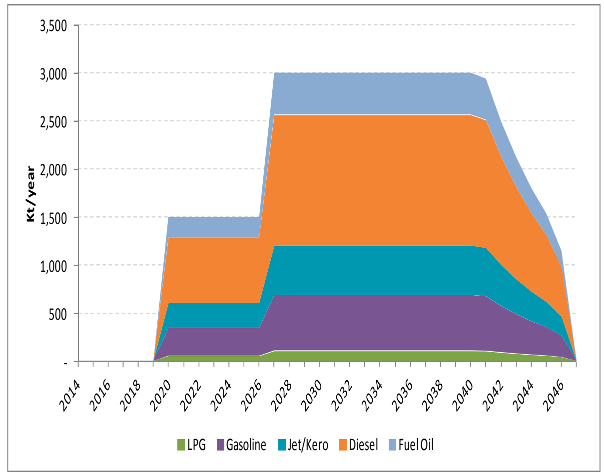
V. Pipeline and Refinery Economics

Pipeline		
Capacity daily	210	Mbopd
Maximum crude oil throughput (daily)	210	Mbopd
Total crude oil throughput	872	MMBOE
Operation years	21	
Constant 2015 dollars	$ million	$/Bbl
Capital costs	3,621	4.2
Operating costs	1,728	2.0
Total	5,349	6.1

Refinery		
Capacity daily - initial rising to 60	30	Mbopd
Maximum crude oil processed (daily)	60	Mbopd
Total crude oil processed	471	MMBOE
Operation years	27	
Constant dollars	$ million	$/Bbl
Capital costs	2,268	4.8
Operating costs	1,212	2.6
Cost of crude oil processed	32,218	68.4
Total	35,698	75.8

* All figures are in 2015 terms

Refinery Outputs



102. **Since the project is expected to commence production and operations in 2019,**[21] **the mission considered that it was appropriate to use a price of $80/bbl FOB Mombasa to conduct the analysis.** The price assumption will not only have a direct impact on the upstream results, but also on the refinery output prices given that import parity is also assumed. The pipeline results are independent of the prices, as the tariff depends on the cost of the project and assumed throughput.

103. **The project as whole generates pre-tax net cash flow of almost $98 billion over its entire life, yielding a pre-tax IRR of 23.4 percent.** The large majority of revenue comes from the upstream segment, followed by the refinery and the pipeline. However, taken as a single project, the refinery is the more profitable component of the integrated project, with a pre-tax IRR of 30 percent. The main reason for this is the assumption that refinery would sell product at import parity prices, which will allow it to make very good margins on most of its products.[22] This assumption requires careful future review.

[21] From announcements by companies as recently as December 2014, delays are possible.

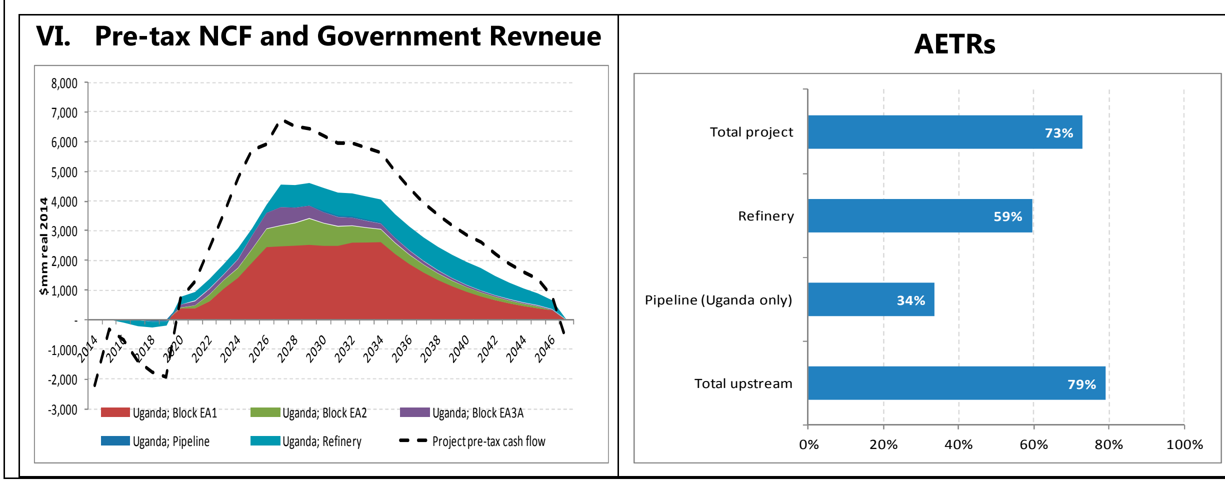
[22] Calculation of product prices in this analysis starts with the FOB Arab Gulf price for each product, then adds transportation costs to Mombasa, and then inland transportation costs to arrive at a price in Uganda.

104. **Government revenue is estimated to be in excess of $60-70 billion over 27 years.** Again most of the revenues would come from the upstream sector subject to PSAs, followed by the refinery, where the government is assumed to take a 40 percent stake. The modeling analysis, including government revenue and AETR for each project at different discount rates is presented in Table 7 and Figure 11.

Table 7. Summary of Fiscal and Financial Results

NPV Analysis at different discount rates	0%	10%	12.5%
Total upstream			
Project pre-tax NCF	70,419	12,726	8,204
Government revenue	55,720	12,290	8,909
AETR	79%	97%	109%
Pre-tax IRR		23.3%	
Post-tax IRR		11.4%	
Pipeline (Uganda portion only)			
Project pre-tax NCF	1,907	-1	-138
Government revenue	642	71	30
AETR	34%	-6292%	-22%
Pre-tax IRR		10.0%	
Post-tax IRR		7.5%	
Refinery			
Project pre-tax NCF	25,728	4,401	3,570
Government revenue	15,301	2,421	1,611
AETR	59%	55%	45%
Pre-tax IRR		29.9%	
Post-tax IRR		26.0%	
Total project			
Project pre-tax NCF	98,053	16,725	10,689
Government revenue	71,663	14,781	10,550
AETR	73%	88%	99%
Pre-tax IRR		23.4%	
Post-tax IRR		13.7%	

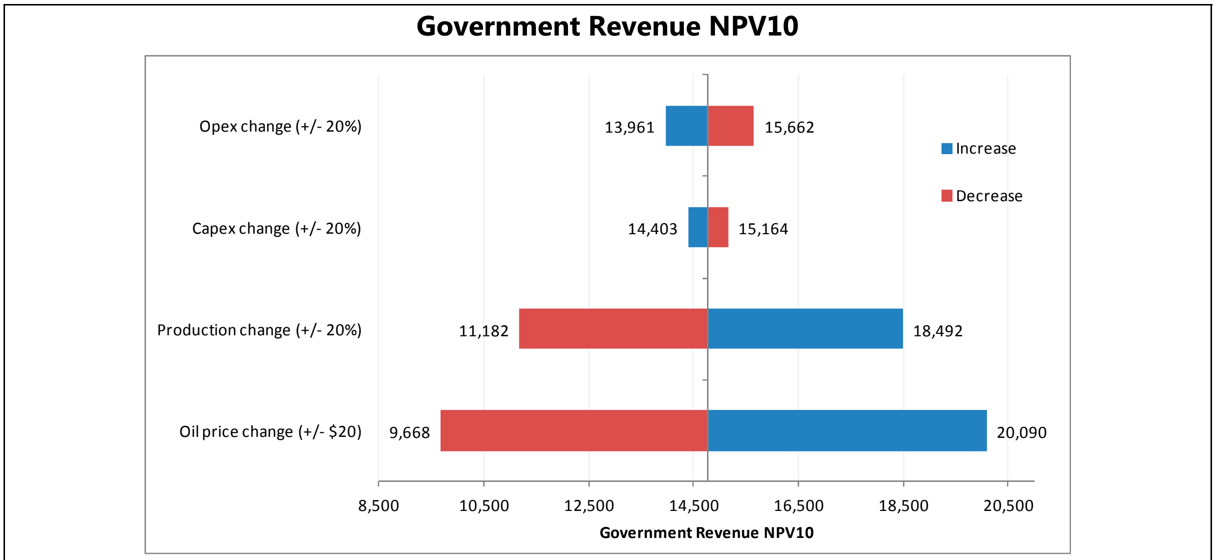
Figure 11. Pre-Tax NCF, Government Revenue and Project's AETR

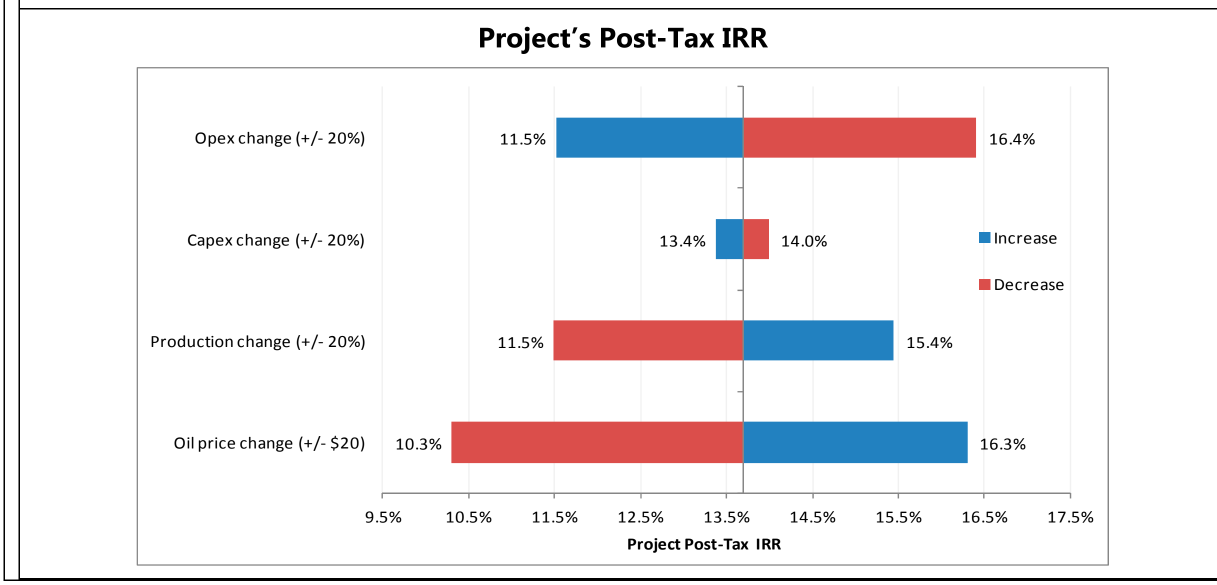


105. **The report provides sensitivity analysis to evaluate the effect of changes in prices, production, and costs on the overall government revenue and the project pre-tax IRR.** Figure 12 shows that changes in price are likely to have the bigger effect on government revenues, followed by changes in production. For example, a reduction in the price used for the analysis of $20/bbl will reduce government revenue by more than 35 percent in NPV terms, using a discount of 10 percent. Similarly, a 20 percent reduction in total production would almost have a one for one effect on government revenue, which is estimated to decrease by about 25 percent. As for the for the project return (Figure 12), changes in price and production are likely to

also have the largest impact on the project's post-tax IRR. However, changes in capital costs can also have an important effect on the project post-tax results.

Figure 12. Sensitivity Analysis on Total Project Results





IV. MINING AND MINERALS FISCAL REGIME

A. Sector Legislation

106. **Mining in Uganda is regulated by the Mining Act of 2003.** The Act includes provisions for a prospecting license (a non-exclusive right), an exploration license, retention license, a mining lease, and a location license (small scale exploration and mining). Under the Mining Act Regulations, priority for a mineral right other than a prospecting license is on a first-come, first-served basis if more than one person applies for a mining right over the same area of land (section 6 of the regulations). A holder of an exploration license has priority for the grant of a mining lease on land subject to the exploration license (section 42 of the Mining Act). Exploration licenses and mining leases are exclusive licenses. Explorations licenses are for up to 3 years with two 2-year extensions for a maximum period of 7 years. Mining leases for mine development and mineral production are for an initial period of 21 years, or the estimated life of the ore body, whichever is shorter. There is one renewal for a period up to 15 years or the estimated life of the ore body.

107. **The Act imposes a royalty and creates a power for the Minister to make mineral agreements with the mineral rights holder.** These agreements may cover any matter relating to or connected with operations and activities under an exploration license or a mining lease (s 18). The agreement can set the basis on which the market value of any mineral or group of minerals may be determined. However, the agreements cannot override any requirement prescribed by law. At present, there is a mining concession agreement to restart the Kilembe copper-cobalt mine and mineral development agreement for the development of the Sukulu phosphate and steel project. The phosphate agreement contains provisions that modify the tax obligations of the mining companies. The government has given assurances that applicable legislation will be amended to regularize the mineral agreement. The Act contains no provision for bidding of licenses, state participation, or fiscal stability. Prospecting licenses cannot be transferred. Other types of mineral rights can be transferred with the approval of the Commissioner for the Geological Survey and Mines Department (Commissioner). The provision in the Act relating to the transfer of a mineral right does not cover indirect transfer such as a transfer of control of the license or lease holder.

B. The Overall Fiscal Regime[23]

108. **The fiscal regime for mining includes royalties, the income tax, rents, and fees.** The royalty for high-value minerals is assessed on gross value of the minerals. The rates, which were increased in 2011, are 5 percent for precious metals and base metals, and 10 percent for precious

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[23] The World Bank is currently advising MEMD on other matters concerning the legal and regulatory regime and cadastre management.

stones (Third Schedule of the Regulations). The royalty rates for other minerals, including coal, are specific rates based on the weight of the mineral produced. The corporate income tax for a company carrying on mining operations is sliding scale with a minimum rate of 25 percent and a maximum rate of 45 percent (Part II of the Third Schedule of the ITA). Mining companies paid UGX 59 billion (about $21 million) in income and withholding taxes (other than on employees), of which withholding payments were 63 percent of the total, and UGX 4.9 billion (about $1.7 million) in non-tax revenue in 2013, of which royalty payments were 68 percent of the total.

Royalty

109. **Royalties secure revenue for the government as soon as production commences, are considerably easier to administer than most other fiscal instruments, and ensure that companies make a minimum payment for the minerals they extract.** Royalties, however, raise the marginal cost of extracting minerals, as they are based on the volume or value of production. A royalty set too high may discourage development of marginal deposits and lead to high grading and early closure of productive mines, thus discouraging maximization of the value of the deposit. Nevertheless, a regular minimum payment is usually necessary to justify extraction of the resource in the public mind, to assure stability of the fiscal regime, and to broaden the tax base. The royalty also functions as an implicit depletion policy, since mines will raise their cut-off grade to ensure that ore mined is of sufficient value to cover the royalty charge: the lower grade material left behind, however, may not easily be recoverable at a later time.

110. **Uganda's royalty for high-value minerals is assessed on the gross value of the mineral based on the prevailing market price (s 98).** Under the Mining Regulations, the market price for determining gross value is deemed to be the price on the London Metal Exchange or any other Metal Exchange or market as known to the Commissioner. What is not clear is whether this market or reference price is used to assess the value of the mineral contained in the ore at the mine mouth, contained in the first product sold or exported (such as a concentrate), or the value of minerals recoverable. The Regulations, however, specify that where a precious mineral or non-precious metal is exported to a refinery approved by the Commissioner, the value shall be the gross sum realized, defined as the sum realized without any reduction or abatement for transport, marketing, insurance, or other charges; that is, the gross value is value of the refined ore adjusted for smelter and refining (the net smelter return). Furthermore, the Regulations specify an assumed fineness for gold (95 percent) and tin (75 percent), which seems to represent a discount. The valuable contents of other minerals shall be such as the Commissioner may determine, which gives the Commissioner considerable discretion.

111. **A way forward would be to amend the Regulations to specify clearly what is meant by gross value.** For minerals sent to a smelter or refinery, the value could be the net smelter return. For other minerals that are subject to ad valorem rates the value would be gross revenues from the first sale or FOB export value if the mineral product is exported without being sold. Reference prices could also be used to determine gross value.

112. **The royalty rates are 5 percent for precious and base metals and 10 percent for precious stones.** The rates for other minerals are specific rates per ton; e.g. UGX 10,000 per ton for phosphate. Among African countries that impose flat-rate royalties, Uganda's rates are on the high side (Table 8), but reasonable if capital expenditure has accelerated cost recovery, as recommended in Chapter V. Any reduction in the royalty rates would increase the public perception that the mining companies are paying little for the resource in the ground, particularly as the royalty payments are shared by the central government (80 percent), local governments (20 percent) and owners or lawful occupiers of the land subject to mineral rights (3 percent).

Table 8. Fixed Rate Mineral Royalties in Selected African Countries

Country	Copper/Base Metals	Gold
Burkina Faso	4	3
Botswana (N)	3	5
Central African Republic	2.5	2.5
Cameroon	3	3
Congo	4	5
Congo DR (N)	2	2.5
Gabon	5	5
Ghana (N)	5	5
Guinea	3	5
Liberia (N)	3	3
Malawi	5	5
Mauritania	4	4
Mozambique	5.5	5
Namibia	5	3
Niger	5.5	5.5
Senegal	3	3
Sierra Leone (N)	4	5
Tanzania	4	4
Uganda	5	5
Zambia	8/20	8/20
Zimbabwe (N)	2	7

Source: African Development Bank, IMF Reports, and PricewaterhouseCoopers
Note: The royalty base is gross sales with the exception of countries with (N) after their name where the base is net sales and Zambia were the base in the norm value. Zambia's rates are 8 percent for underground mining and 20 percent for open pit.

113. **The royalty regime has some strong features.** An export permit for minerals can be issued only if the royalty due on the minerals has been paid or secured. There is ministerial

discretion, with approval of Cabinet, to waive royalty if the minister considers it expedient to do so in the interest of the production of such minerals.[24] Royalty is assessed on stockpiled minerals.

114. **There are two deficiencies in the royalty regime that should be addressed.** First, there may be sales to a related party where no reference price is available. In this situation, the government needs the power to adjust prices where related parties have understated the value of the mineral. Second, under the regulations, mineral royalty is not payable to the URA until 30 days after when the Commissioner has assessed the value of the mineral. The better international practice is for mining companies to self-assess the royalty and make monthly payments. The Commissioner can audit the royalty returns.

Recommendations:

- Define gross value for royalty purposes to be gross revenues from the first sale or FOB export value if the mineral product is exported without being sold or the net smelter return if the minerals are sent to a smelter or refinery.

- Require mineral companies to self-assess the royalty and make monthly payments.

Income tax

115. **In contrast to the petroleum sector, which has specific income tax provision in Part IXA and Schedule 8 of the ITA, the few mining specific income tax provision are scattered through the Act.** The two key mining-specific issues addressed in the Act are the tax rate on mining operations and the cost recovery rules. There are no provisions in the Act for mine reclamation and closure expenditure, ring fencing, or for fiscal stability. These issues and other issues common to both petroleum and mining are discussed in Chapter IV.

116. **For a company carrying on mining operations, the income tax rate is the sliding scale with a minimum rate of 25 percent and a maximum rate of 45 percent.** For non-mining companies, the corporate tax rate is 30 percent. The sliding scale formula is: 70 – 1500/X, where X is the ratio of chargeable income to gross revenue (includes net gain from the disposal of business assets used in mining operations but not any net loss) expressed as a percentage point (Part II of the Third Schedule).[25] The variable rate is designed to impose a lower-than-average rate of tax in years of poor relative profitability offset by a higher-than-average rate of tax in years of high relative profitability. The variable income tax retains all the other features of

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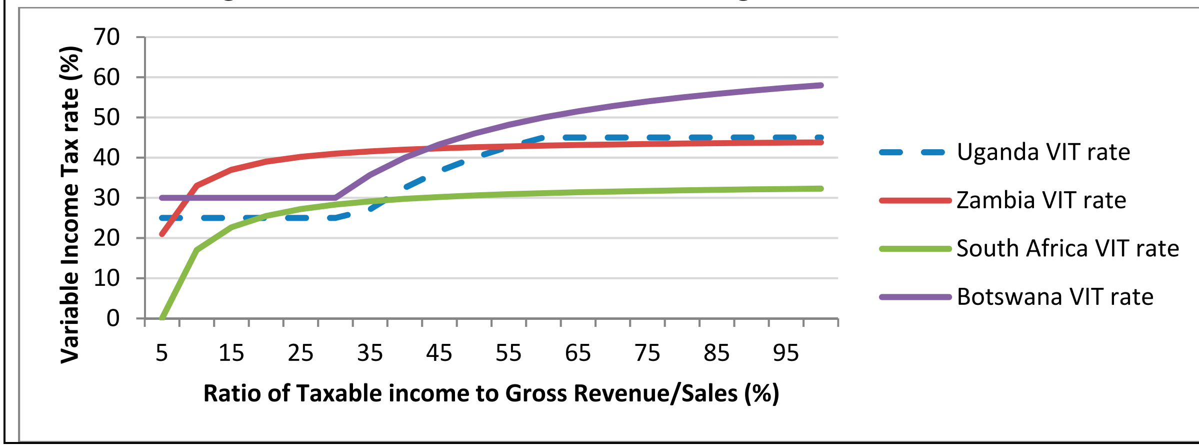
[24] An alternative to discretion would be a rule for deferral of royalty payments in periods when cash operating expenses rise above revenues. This would ensure that the royalty payment would never cause marginal cost to exceed marginal revenue, which could result in early mine closure.

[25] Under this formula, the variable rate would be 25 percent if the profitability ratio is 33.3 percent or lower. The variable rate would be 45 percent if the profitability ratio is 50 percent or higher.

the regular income tax, including the special capital recovery rules for investments in the mining sector; it only adjusts the tax rate. The South Africa variable rate for gold mines was adapted for use in the mining tax legislation of Namibia for non-diamond mines. A variable income tax was introduced in Botswana in 1998 and Zambia in 2008 (Figure 12). Compared to Uganda, Zambia's variable rate is more progressive when the profitability ratio is low. Botswana's variable rate formula is similar to Uganda's but has no maximum rate. The minimum rate is 30 percent.

Figure 13. Variable Income Tax for Mining in Selected Countries



117. **An advantage of a variable rate tax is that it is simple in practice[26] and can produce revenue in the early years if the profitability ratio is high.** It may encourage the mining of low-grade ores, which would otherwise be uneconomic. It also has the property that a mine, which proves to have a relatively low profitability ratio will bear a lower tax burden. For some investors, this possibility could reduce perceived risk and, thus, encourage investment. Other rent tax devices could be considered. Box 3 sets out a range of alternatives.

[26] It does require ring fencing the income from mining operations from other income the mining company may have.

Box 3. Two Leading Forms of Rent Tax

1. **The 'Brown Tax,' or 'R-based cash flow tax,'** has as its base all current receipts less all current expenses (both non-financial), with immediate refund (or carryforward at interest) when this is negative. Accounting and tax depreciation do not feature—all capital is immediately expensed—and there are no deductions for interest or other financial costs. There are two main variants:

- ***Resource rent tax***. This replicates many features of the Brown Tax, with the investor receiving an annual *uplift* on accumulated losses until these are recovered. (As originally designed by Garnaut and Clunies Ross (1975), the uplift rate is set at the minimum required rate of return for the investor; this choice is now widely questioned. Australia uses this scheme for both mining and petroleum, while Angola's production-sharing scheme uses the mechanism. It is usually applied with *ring-fencing* by license.
- ***Tax surcharge on cash flow***. Adjusting accounting profit by adding back depreciation and interest, and deducting any capital expenditure in full yields a base of net cash flow. This, too could form the base for a surcharge. Instead of permitting an annual uplift for losses carried forward, a simple uplift (investment allowance) could be added to capital costs at the start—this is done in the United Kingdom by a time-limited uplift on losses. In the UK, this surcharge is combined with conventional CIT, within the same sector-wide ring fence. The "R-factor" or payback ratio scale used in some PSCs is a further variant, as is the "investment credit" of Indonesian PSCs.

2. **Allowance for Corporate Equity (ACE) or Capital (ACC) schemes**. The former amends the standard CIT by providing a deduction for an imputed return on book equity; tax depreciation remains, but becomes irrelevant in that faster depreciation reduces equity and hence future deductions by an offsetting amount. The latter also gives the interest deduction at a notional rate, so eliminating any distinction between debt and equity finance. Norway's special petroleum tax approximates the ACC, though its combination of uplift on total investment and limitation on interest deduction differs from a "pure" ACC. It also offers refund of the tax value of exploration losses and of ultimate losses on licenses. In 2010, the Henry Report proposed for Australia "a uniform resource rent tax…[using] an allowance for corporate capital system" (*Henry Proposal*). Several countries (Belgium, Brazil, Italy, and others) apply ACE-type schemes as their main corporate tax.

A central difference between these two types of rent tax is the timing of tax payments—which is generally earlier under the ACE/ACC. Under the Brown Tax, tax is payable only at the perhaps distant date in which costs have been fully recovered; under the ACE/ACC by contrast, it is payable as soon, roughly speaking, as annual income covers the annual cost of financial capital.

118. **If the variable rate tax is retained, as this report recommends, one technical correction should be made.** To address the problem of excessive use of debt, the profitability ratio should be defined as the ratio of chargeable income *before any net interest expense* to gross revenue. The variable rate would continue to apply to chargeable income from mining operations.

Fiscal Stability

119. **There is no provision in the Mining Act or other legislation for the government to give assurances of fiscal stability.** Stability assurances have been given in a recent mineral

agreement. The parties agreed that if there is a change in the law relating to income tax that adversely alters the economic benefits of the project for the mining company, they will agree on the necessary adjustments and modifications to the agreement in order to maintain the net present value of the project for the mining company.[27] The modifications would not necessarily override current law, as it could take the form of a cash payment from the government, or the government deeming to pay the additional tax on behalf of the mining company. Assurances of fiscal stability could be reviewed in the future.

Recommendation:

- Retain the variable income tax rate and define the profitability ratio as the ratio of chargeable income *before any net interest expense* to gross revenue.

C. Economic Evaluation of Mining Fiscal Regimes

120. **Using FAD's FARI modeling framework, the report evaluates the existing fiscal regime applying in Uganda and compare it against other jurisdictions in the region and elsewhere**.[28] In addition to the existing regime, the report also evaluates a modified version of the variable income tax formula in which the profitability ratio is defined as the ratio of chargeable income before any net interest expense to gross revenue. The variable rate continues to be applied to chargeable income from mining operations. The international comparators include established producers in the region and elsewhere, such as Australia, Brazil, South Africa, India, and Russia; and other medium size and potential producers like Guinea, Liberia, Mauritania, and Ukraine.

121. **For the analysis, the report uses a stylized medium size iron ore project, with approximate production of 720 million tons of iron ore over 21 years.** While Uganda mineral potential is broad and diverse, the mission decided to model an iron ore project, given that officials of the MEMD announced, in December 2014, that a recent airborne geophysical survey revealed the presence of more than 260 million tons of iron ore,[29] with a significant upside potential if exploration takes place. With an assumed price of $63/ton of ore, the project is profitable with a pre-tax IRR of approximately 35 percent. Total capital expenditures are in the order of $3.8 billion, or $5/ton and operating cost are approximately $28/ton. Figure 13 shows the government revenue over the life of the project, by revenue category, along with the project

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[27] The stabilization provision in the agreement follows closely the stabilization provision in the PSA dated 3rd February 2012.

[28] All figures are in 2015 terms, unless otherwise noted.

[29] See http://www.newvision.co.ug/news/662611-over-260-million-tonnes-of-iron-ore-discovered-in-uganda.html

pre-tax cash flow. The variable income tax is by far the largest contributor to government revenue.

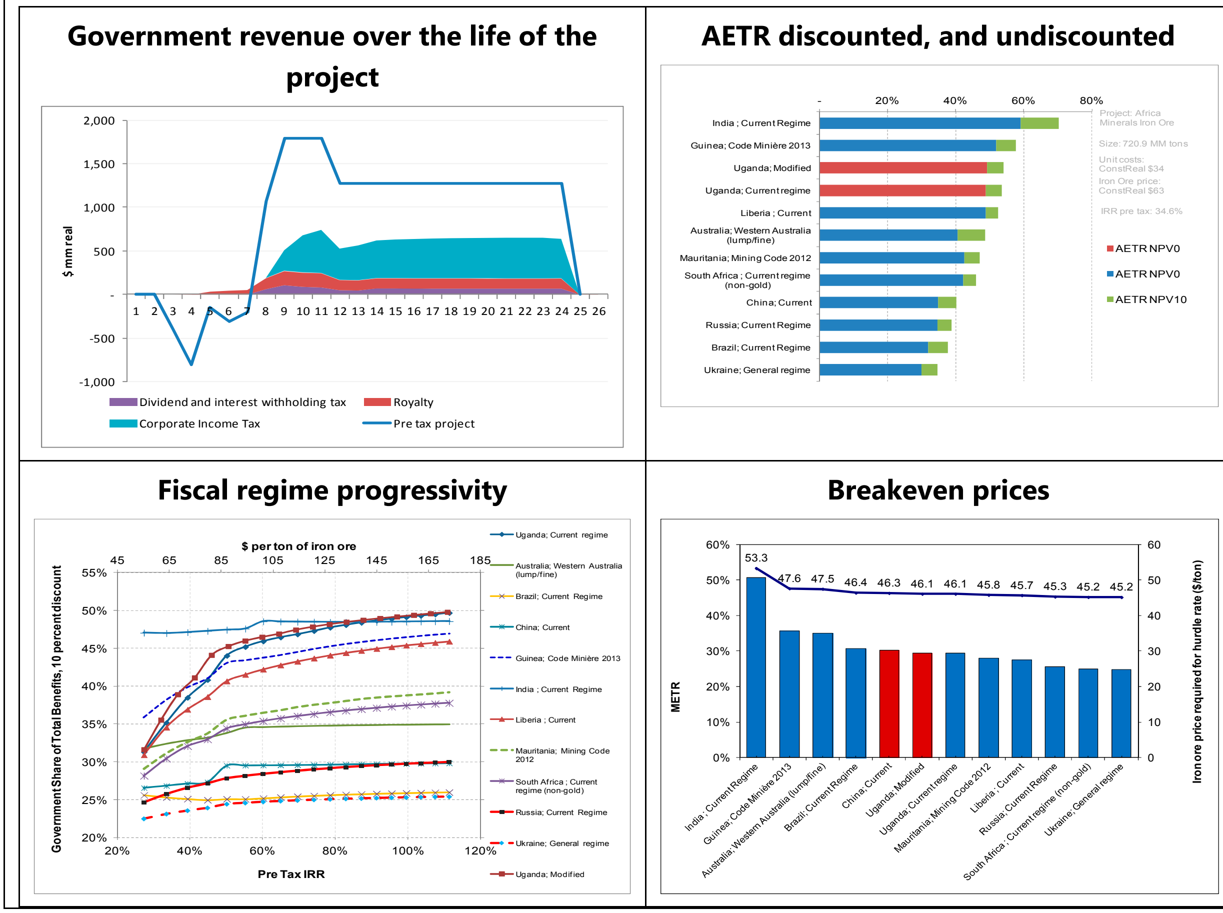
122. **The report evaluates the revenue generating capacity of the Ugandan fiscal regimes and the international comparators by estimating AETR or "government take".** The existing and modified Ugandan regimes yield pretty much identical AETRs of 50 and 54 percent in undiscounted, and using a 10 percent discount rate respectively. The Ugandan regime fares very well when compared to international comparators, sitting in the mid to upper part of the range. India, which comes at the top of the AETR ranking, levies an export duty of 10 percent on iron ore (Figure 14).

123. **The report also evaluates the progressivity of the fiscal regimes by estimating the government share of total benefits over a range of different prices and corresponding pre-tax IRR for the project.** A more progressive regime allows the government to increase its share of revenue when the investment is highly profitable, while giving some relief to investors for projects with low rates of return; progressivity is only relevant above the minimum acceptable rate of return required by the investor. Figure 14 below illustrates the government share of total benefits over a range of different iron ore prices and the corresponding projects' pre-tax IRRs. The range of pre-tax IRR's are used to indicate how the project profitability increases with prices, and by no means implies a ranking of projects by IRR.

124. **The Ugandan regimes appear to be quite progressive when compared to other jurisdictions.** This is largely the result of the variable income tax rate, which increases as the margin of chargeable income to gross income increases. Moreover, since the rate starts a rate lower than the standard CIT rate, projects with low profitability margins will be subject to a lower fiscal burden than would otherwise be the case.

125. **Finally, the report compares the relative burden that the fiscal regime would put on a marginal project.** A key indicator is the "breakeven price" or the minimum price required to meet the minimum rate of return required by the investor (assumed in the model to be 12.5 percent in real terms). Under the project evaluated, the Ugandan regimes come in the middle of the sample, with relatively low breakeven prices. Again, the variable income tax, with a lower rate applying to less profitable projects, appears to provide a relief for marginal projects.

Figure 14. Government Revenue, AETRs, Progressivity, and Breakeven Price



V. Common Fiscal/Tax Issues

A. Introduction

126. **This chapter outlines reforms to the tax laws so as to provide for effective taxation of resource companies throughout the life cycle of a resources project**. The discussion covers both income tax (including international tax) and VAT. Recent legislative amendments have created a number of uncertainties in the application of the tax laws to resource operations.

127. **There are very few specific provisions in the ITA dealing with mining.** This means that the income taxation of mining operations is largely based on the ordinary operation of the ITA. In contrast, a specific tax regime was introduced in 2008 for petroleum operations. This regime was substantially amended in 2010 with the purpose of more closely aligning tax deductibility with PSA cost recovery. However, it is unclear that the 2010 amendments were effective in achieving their purpose. Both URA and the contractors agree that there is uncertainty in the application of the revised tax regime for petroleum operations.

128. **While not perfect, the investment trader scheme and the 2011 amendment to provide for reverse charging for imported services provided for an effective VAT regime during exploration and development of resource operations.** However, amendments to the VAT Act in 2012 to repeal the investment trader scheme and deny input tax credits for imported services has resulted in VAT becoming a tax on mining and petroleum investment because of the inability of resource companies to claim a refund of input tax credits during exploration. This is a serious issue that has become an impediment for existing projects to move forward.

B. Location of Tax Provisions

129. **The tax provisions applicable to resource companies should be provided for in the relevant tax legislation rather than in mining and petroleum agreements.** While the latest model PSA cross-refers to the tax provisions in the ITA, recently negotiated mining agreements include tax provisions. There is a risk to the government if tax provisions are negotiated on a case-by-case basis as the licensee or contractor is likely to have better information about the value of a resource and also may be more skilled at negotiation. A further issue for the government with case-by-case negotiation is that the tax provisions will differ from agreement to agreement depending on the negotiations. This increases the administrative burden on URA as there will be multiple tax regimes that it will have to enforce.

130. **Tax provisions in a mining or petroleum agreement cannot override the tax law.** If there is a conflict between the agreement and the tax law, the tax law will prevail. This outcome can be avoided only when the tax provisions in the agreement are given legislative force. Consequently, and despite the potential sovereign risk, it is always open to the government to subsequently apply the tax law in priority to the agreement, particularly if the government is later

of the view that favorable tax arrangements were not negotiated. It is better to avoid this by having the tax provisions in the tax law.

131. **Part IXA was inserted into the ITA so as to include the income tax provisions that were, at that time, located in the model PSA.** It is for this reason that the current model PSA simply cross-refers to the tax law. The same approach should apply for mining. As discussed below, this can be achieved by extending the scope of Part IXA to mining operations.

132. **The income tax provisions for resource companies should be included either as a separate Part or as a Schedule at the end of the legislation, rather than being spread throughout the legislation by topic.** This is currently the case under the ITA for petroleum operations with the sector specific provisions included in Part IXA. It is considered that this approach is more transparent and better facilitates compliance with, and administration of, the income tax as it applies to resource companies.

133. **The principle of uniformity should apply to the tax rules for mining and petroleum operations.** Currently, this is not the case under the ITA. While Part IXA specifies rules for petroleum operations, there is no equivalent part applicable to mining. For mining, s 36 provides for the deduction of mineral exploration expenditure and class 3 of the table in Part I of the Sixth Schedule specifies the depreciation rate for plant and machinery used in mining, but, in other respects, the general rules in the ITA apply to mining. This is relevant, for example, to the deductibility of development and rehabilitation expenditure. Part IXA (revised as discussed below) should be extended to apply also mining operations and, as far as possible, there should be uniform rules for mining and petroleum operations.

Consistency with Sector Legislation

134. **As far as possible, the ITA should be aligned with the relevant sector legislation so that there is consistency in characterization.** This is particularly relevant in defining exploration and development expenditure, and in applying the transfer of interest rules to mining or petroleum rights. For example, in relation to petroleum operations, "exploration" could be defined to have the same meaning as under the PEDPA. The risk in having a separate definition in the ITA is that it may not exactly align with the definition in the PEDPA and this may result in disputes at the margin as to whether a particular expenditure is exploration or development expenditure. Such disputes would be expected, given the different tax treatment of exploration and development expenditure. Even if the tax law definition starts out the same as that in the sector legislation, the definitions may fall out of alignment over time due to legislative change to the sector legislation that is not replicated in the ITA. Aligning the definitions through a cross-reference ensures that any legislative change for the purposes of the sector legislation applies automatically for the purposes of the ITA. It is acknowledged, though, that this may increase compliance and administrative burdens, as reference will need to be had to both the ITA and the sector legislation, but this is justified to ensure consistency in characterization.

135. **It should also be provided that any term that is not defined in the ITA has the meaning in the sector legislation.** This may be relevant for terms like "petroleum" and "mineral". This is currently done for petroleum under s 89A(2) and a similar provision should be included for mining. It is also important that any reference to the sector legislation refers to any successor legislation. For example, s 89A(2) refers to the "Petroleum (Exploration and Production) Act", but this Act has now been replaced by the "Petroleum (Exploration, Development and Production) Act 2013. It means that the cross-reference in s 89A(2) no longer works.

C. Income Tax

Relationship between Production Sharing and Income Tax

136. **Under Uganda's PSAs (including the latest model PSA), production sharing is done before corporate tax.** This means that there is a separate calculation of the contractor's corporate tax liability. There are two possible bases for the corporate tax under pre-tax production sharing: (i) the corporate tax base is chargeable income computed in the normal way subject to any special rules for petroleum operations; or (ii) the corporate tax base is profit oil subject to some adjustments to reflect the differences between production sharing and corporate tax. The first approach was implemented when Part IXA was introduced into the ITA in 2008. However, Part IXA was substantially amended in 2010 to implement the second approach. There are some uncertainties in the application of the 2010 amendments.

137. **The intention of the 2010 amendments is to make the contractor's profit oil the corporate tax base for petroleum operations.** This is expressed in s 89B(4), which provides that the tax payable by a contractor is calculated by applying the corporate tax rate in the Third Schedule (30 percent) to the "contractor's production share". The term "contractor's production share" is not defined. "Production share" ordinarily means the total share of production, which, for a contractor, would include both cost and profit oil. Despite this, the reference to "contractor's production share" must be intended as a reference to the contractor's profit oil; otherwise the corporate tax rate would be applied to gross income. This conclusion is also supported by s 89C, which provides that expenditures can be deducted only against cost oil. If it is decided to continue with the approach under 2010 amendments, then s 89B(4) should be revised to refer to the "contractor's profit oil", with a definition of "profit oil" included in s 89A(1).

138. **The 2010 amendments inserted a new s 89F and the Eighth Schedule into the ITA, which provide for the allowable deductions in relation to petroleum operations.** S 89F provides that the expenditures allowed as a deduction in ascertaining the chargeable income of a contractor for petroleum operations are those expenditures prescribed in the Eighth Schedule. The Eighth Schedule contains a detailed list of deductible expenditures that is understood to be a slightly modified version of the cost recovery schedule in the model PSA at the time of the amendments. The main modifications are: (i) the cost limit does not apply under the Eighth Schedule; and (ii) development expenditure is depreciated for tax purposes (rather than expensed as happens for cost recovery purposes). Generally, development expenditure is

depreciated straight-line over the lesser of: (i) the life of the project; or (ii) six years. The cost of transportation facilities is depreciated under the units of production method. In addition to the deductions specified in the Eighth Schedule, s 89E provides for the deductibility of amounts carried to the decommissioning costs reserve of the contractor, although how s 89E links with s 89F is unclear.

139. **While the 2010 amendments included the detailed rules on deductible expenditures referred to above, these rules would appear to have no actual operation.** S 89F refers to the expenditures deductible in ascertaining the chargeable income of a contractor in relation to petroleum operations. Similarly, s 89E refers to an amount "allowed as a deduction", which would be relevant in ascertaining chargeable income. However, under s 89B(4), a contractor is not taxed on chargeable income but, rather, is taxed on their share of profit oil. Under the relevant PSA, profit oil is computed as the total value of production reduced by cost oil. Profit oil is split as between the government and the contractor based on the formula in the PSA. In effect, therefore, the "allowable deductions" of the contractor for a year of income are not those specified in Part IXA and the Eighth Schedule, but the recoverable costs allowed for the year under the relevant PSA. While there will be a significant degree of commonality between recoverable costs and the deductible expenditures specified in the Eighth Schedule, there will be some important differences. In particular, the cost limit and expensing of capital expenditure for cost recovery purposes will apply also for the purposes of the corporate tax.

140. **Similarly, the ring-fencing rule in s 89C appears to have no operation; rather ring fencing under the relevant PSA will apply.** Again, this is because s 89C refers to an amount that a contractor may "deduct" under the Act. Deductions are relevant in computing chargeable income but, as explained above, chargeable income is not the corporate tax base for contractors in relation to petroleum operations.

141. **The 2010 amendments aimed to align tax deductibility with cost recoverability.** This approach assumes that the cost recovery rules will be the same under all PSAs, which is unlikely to be the case.

142. **If the "profit oil as tax base" approach is retained, then the corporate tax base should be reframed.** To this end, it could be provided that the chargeable income of a contractor, in relation to petroleum operations for a year of income, is the contractor's profit oil under the PSA, subject to certain adjustments to reflect the differences between production sharing and corporate tax. These adjustments would include the adding back of new development expenditure, and the making of a corresponding deduction for the depreciation of such expenditure. The corporate tax base is likely to vary from contractor to contractor depending on the terms of the cost recoverability rules in the relevant PSA

143. **The preferable alternative is to revert to the pre-2010 approach.** This involves calculating the chargeable income of a contractor under the normal rules in the ITA subject to any special rules for petroleum operations, such as rules for the deductibility of exploration,

development and decommissioning expenditure as discussed below. The advantage of this approach is that the corporate tax base is the same for all contractors.

Exploration and development expenditure

144. **A distinction is usually made in the tax treatment of exploration and development expenditure.** Exploration expenditure is incurred at a time when there is uncertainty as to whether a commercial discovery will be made, in which case the expenditure is regarded as high risk. Consequently, such expenditure will often be expensed as an incentive to undertake exploration activities. A similar incentive is not necessary in the case of development expenditure as it is incurred after a discovery has been made. Consequently, development expenditure should be amortized over the life of the project, although the legislation may provide for some acceleration in the deduction. As discussed above, the ITA should cross-refer to the sector legislation in distinguishing between the exploration and development phases of operation.

145. **For both mining and petroleum operations, the ITA provides for the expensing of exploration expenditure.** For mining, this is provided for in s 36 and, for petroleum, this is provided for in s 89F and the Eighth Schedule. For both mining and petroleum, the expensing of exploration expenditure has the effect of creating losses carried forward until revenues are derived from production.

146. **The definition of exploration expenditure should include the cost incurred in acquiring the relevant exploration right.** It is not clear for both mining and petroleum under current law whether this is the case. In the absence of such rule, the cost of the exploration right will be an intangible asset deducted on an amortization basis under s 31.

147. **The same tax treatment can apply to depreciable assets used in exploration activities.** This ensures consistency as between the tax treatment of tangible and intangible expenditure relating to exploration activities. However, the deduction should be limited only to those depreciable assets for which the first use of the asset is in exploration activities.

148. **The same rules for exploration expenditure should apply to both mining and petroleum operations.** A simplified version of the exploration expenditure rules in the Eighth Schedule should be included in the body of Part IXA and apply to both mining and petroleum.

149. **The ITA treatment of development expenditure currently differs between mining and petroleum operations.** There are no specific provisions dealing with development expenditure for mining operations. The deduction of such expenditure thus uses the general rules of the ITA. To the extent that development expenditure gives rise to an intangible asset, the cost of the asset is amortized over its useful life (s 39 of the ITA). The useful life will depend on the nature of the asset, but, for some intangible assets, it may be the life of the project. This would be the case, for example, for a development right. It would appear that there is no deduction for mining development expenditure of a capital nature that does not give rise to an

intangible asset (i.e., intangible expenditure). For petroleum, s 89F and paragraph 7(2) of the Eighth Schedule provide for the amortization of development expenditure over the lesser of: (i) the life of the petroleum operations as specified in the petroleum agreement; or (ii) six years.

150. **There are also differences in the treatment of depreciable assets used in development as between mining and petroleum operations.** For mining, the normal rules under the ITA apply. Industrial buildings are depreciated 5 percent a year using the straight-line method of depreciation. Plant and equipment used in mining operations are depreciated 30 percent a year using declining balance method of depreciation and pooled accounts (Sixth Schedule). Prior to the 2014 amendments to the ITA, industrial buildings were allowed a 20 percent initial allowance, and plant and equipment (other than transport vehicles) were allowed a 75 percent initial allowance. Current law (after the 2014 amendments) provides reasonable depreciation deductions for mining. While not entirely clear from the legislation, it would appear that depreciable assets used in petroleum operations are depreciated over the lesser of: (i) the life of the petroleum operations as specified in the petroleum agreement; or (ii) six years. The depreciation of depreciable assets for mining and petroleum development operations should be aligned and the depreciation rule for mining would be an appropriate rule for this purpose.

151. **The deductions for petroleum development expenditure (including for depreciable assets) do not commence until the year of income in which commercial production commences (paragraph 7(3) of the Eighth Schedule).** There is no similar limitation in relation mining development expenditure. The deferral of deductions for development expenditure to the time of commencement of commercial production provides for the accumulation of lower carryforward losses in the early years of development operations, thereby resulting in earlier recognition of chargeable income by the holder of a development right for those years. The same rule should apply for mining development expenditure.

152. **Common rules for mining and petroleum development expenditure (including depreciable assets) should be adopted as suggested above.** These rules should be included in the body of Part IXA.

Decommissioning, mine closure and rehabilitation costs

153. **Mine rehabilitation and mine closure costs should be prefunded or at least guaranteed.** One alternative is to allow companies to deduct payments to an interest-bearing escrow account, under joint control of the government and the company, and obtain a current tax deduction. If, when the project is closed and there are surplus funds in the account, the funds would be returned to the company and taxed. If the escrow approach is adopted, the Mining Act should be amended to require prefunding of mine closure and reclamation costs through an escrow account under joint control of the government and the company. There is an alternative approach to ensure that mine closure and rehabilitation obligations are met. This approach would allow tax-deductible provisioning for these future costs. The company would be allowed to make a provision in its tax accounts for future mine closing and rehabilitation expenses and

receive a tax deduction for increases in the provision. If this is done, the company should be obliged to put in place acceptable security for carrying out its environmental obligations, as required under the Mining Act. The guarantee would, however, disappear upon a transfer of interest. On balance, the first approach, which the report recommends, is less risky—money is set aside.

154. **The PEDPA requires establishment of a decommissioning fund for each development area (s 113).** However, the ITA envisages that petroleum projects will establish a decommissioning cost reserve, and only allows a deduction for the amount that the contractor carries to the decommissioning cost reserve (s 89E). S 89E needs to be amended to align with the PEDPA.

155. **Under the Mining Act, the Commissioner may require the holder of an exploration license or a mining lease to execute an environmental performance bond (s 112).** However, the ITA contains no provision relating to the tax treatment of mine closure and rehabilitation costs. Therefore, these costs are recognized for tax purposes as they are incurred when there may be no income against which to offset the costs.

Social infrastructure expenditure

156. **The holder of a mining or petroleum right may incur expenditure (referred to as "social infrastructure expenditure") on the construction of a school, hospital, community facilities, or other similar social infrastructure.** The expenditure may be required to be incurred under the terms of the mining or petroleum right, or the holder of the right may incur the expenditure voluntarily, including as part of its corporate social responsibility program. An issue arises as to the deductibility of this expenditure.

157. **There are no specific rules in the ITA dealing with the social infrastructure expenditure and, therefore, deductibility of the expenditure depends on general principles.** In broad terms, for an amount of expenditure to be deductible, there must be a sufficient connection between the incurring of the expenditure and the derivation of business income. Essentially, the issue is whether a particular amount of social infrastructure expenditure is incurred in deriving business income (in which case it is deductible) or is an application of business income after it has been derived (in which case it is non-deductible). A charitable donation may be an example of the latter. This issue will be determined on a case-by-case basis having regard to all the facts and circumstances.

158. **The ITA could make a distinction between social infrastructure expenditure incurred as a requirement under a mining or petroleum right and such expenditure incurred voluntarily.** The ITA could expressly provide for the deductibility of compulsory social infrastructure expenditure and align the deductibility with exploration and development expenditure. If compulsory social infrastructure expenditure is incurred during the exploration phase of the project, then the expenditure is deducted on the same basis as exploration

expenditure. Similarly, compulsory social infrastructure incurred during the development phase is deducted on the same basis as development expenditure. Voluntarily incurred social infrastructure expenditure would continue to be dealt with under general principles on a case-by-case basis.

Thin capitalization

159. **To protect Uganda's income tax base from the deduction of excessive interest payments, the ITA includes a thin capitalization rule (s 89).** Specifically where a foreign-controlled resident company, which is not a financial institution, has a foreign debt-to-foreign equity ratio in excess of 1 to 1, a deduction is disallowed for interest paid on that part of the debt which exceeds the 1 to 1 ratio. Prior to 2014, the allowable ratio was 2 to 1. Some countries apply a limit on excessive use of debt, only in the case of debt supplied by a related party broadly defined. It would be better for the limit on excessive debt to apply to all loans, as it is sometimes difficult to know whether the debt is from a related party, particularly when back-to-back loans are used or the parent company guarantees a loan by a third party to the subsidiary. If the thin capitalization rule is extended to all debt, the allowable debt-to-equity ratio should be increased to 1.5 to 1.

Ring fencing

160. **Ring fencing means a limitation on consolidation of income and deductions for tax purposes across different activities, or different projects, undertaken by the same taxpayer.** Some countries ring fence petroleum and mining activities; others ring fence individual license areas or projects. Uganda ring fences income from petroleum operations from other income that the company may have contract by contract. For purposes of the variable income tax, Uganda ring fences income from mining operations (which could be from two or more projects operated by the same company). It does not ring fence different mining projects carried out by a single company. Consideration could be given to ring fencing future mining projects, but this is not a high priority issue at this time. The approach taken should be consistent with the classification of activities under the MA: thus any ring-fence should be by reference to license areas granted, with exceptions for failed exploration on relinquished areas and for technically warranted joint development or adjacent mines.

Transfer of Interest

161. **There are two ways that an interest in a mining or petroleum right may be transferred, each with differing tax consequences**. First, the holder of the right may transfer the whole or part of the right itself (direct transfer) or, secondly, the owner of the entity holding the right may transfer their interest in the entity (indirect transfer).

Direct Transfers

162. **There are rules in s 89G of the ITA applicable to the transfer by a contractor of an interest in a petroleum agreement.** The rules are confusing in their operation and, therefore, the discussion below looks at the issue afresh. Two scenarios are considered: (i) a simple transfer of interest; and (ii) a transfer of interest under a farm-out agreement.

163. **The holder of a mining or petroleum right may dispose of its rights (including its interest in co-owned assets) and obligations under a mining license or petroleum agreement.** In effect, the licensee or contractor is disposing of its business assets comprising its interest in tangible property (such as machinery) and intangibles (such as its interest in the mining right or petroleum agreement). Tangible assets may be leased rather than owned. If assets are co-owned, the licensee or contractor is disposing of its interest in the co-owned asset. The gain (including a gain resulting from depreciation or amortization recapture) or loss arising from the disposal of each asset must be determined. There may also be intangible expenditure (included in development expenditure) incurred by the licensee or contractor that has not been deducted or fully deducted at the time of the transfer. The transfer agreement will allocate a part of the overall consideration to each asset transferred, including the mining or petroleum right. A significant part of the consideration will probably be allocated to the mining or petroleum right.

164. **A mining or petroleum right is a business asset as defined in s 2 of the ITA.** The tax treatment of any gain arising on disposal of a mining or petroleum right depends on the interplay between: (i) the rules for taxing business income (particularly taxation of gains on disposal of business assets); (ii) the depreciation recapture rules; and (iii) the application of any applicable tax treaty. Tangible assets will be depreciated within a pool under s 27 of the ITA. The consideration for the disposal of a pooled asset reduces the balance of the pool. If the consideration exceeds the written down value of the pool, the excess is included in business income. The gain on disposal of an intangible asset (such as a mining or petroleum right) is included in business income under s 18(1)(a) of the ITA. In calculating the amount of the gain, the cost of the asset is reduced by the deductions allowed in respect of the asset, particularly amortization deductions allowed under s 31. The chargeable income of the transferor for the year of income in which the transfer occurs is computed as the total amount of business income reduced by total allowable deductions for the year, including the deduction allowed under s 38 of the ITA for losses carryforward. Thus, for example, deducted exploration and development expenditure carried forward as a loss will reduce the amount of any gain arising on disposal of the tangible and intangible assets (including the mining and petroleum right) of the transferor.

165. **An issue arises as to the treatment of intangible capital expenditure of the transferor that has not given rise to an asset for income tax purposes.** This is relevant, for example, to drilling expenditure. To the extent that the expenditure has been deducted as exploration or development expenditure, the deducted amount will be included in the loss carried forward, taken into account in the calculation of chargeable income. The issue is the treatment of such expenditure that has not been deducted or fully deducted by the transferor at

the time of the transfer, such as drilling expenditure treated as development expenditure and deductible on an amortization basis. At the time of transfer of the right, it is possible that no deductions may have been allowed for the expenditure as deductibility does not start until the commencement of commercial production.

166. **The intangible expenditure could be treated as giving rise to a notional intangible (and business) asset that is disposed of at the time of transfer of the mining or petroleum right.** The cost of the notional asset is the amount of the expenditure. The normal rules applicable to the disposal of business assets would then apply. This will result in a loss equal to the undeducted cost of the notional asset being treated as a deduction under s 22(1)(b) of the ITA.

Farm-outs

167. **An interest in a mining or petroleum right may be transferred under a "farm-out" agreement.** A farm-out agreement may be entered into when a holder of a mining or petroleum right wants to bring in a "partner" to secure additional capital and mitigate risks of exploring or developing the project on its own. Further, the new partner may also bring special expertise to the project. Under a farm-out agreement, a holder of a mining or petroleum right ("farmor") may transfer a percentage interest in the right to another person ("farmee") in exchange for value that may comprise a cash amount and the farmee agreeing to meet some or all of the farmor's future work commitments under the right. The transfer of the interest in the right may be immediate on signing of the agreement (an "immediate transfer farm-out agreement") or deferred to a later point in time, usually when the farmee has fulfilled its work commitments under the agreement ("deferred transfer farm-out agreement").

168. **A farm-out agreement may be characterized as a transfer of interest in return for the farmee meeting the costs of the farmor's future work commitments.** A farm-out agreement may also oblige the farmee to pay a cash amount usually on signing the agreement. In this case, an important issue is the tax treatment of the cash amount. The amount may be characterised as a pro-rata reimbursement by the farmee of the past costs incurred by the farmor that relate to the interest in the mining or petroleum right transferred to the farmee. To the extent that these costs have been deducted by the farmor (such as exploration expenditure), the cash reimbursement may be properly characterised as reimbursed tax deductions and included in business income under s 62 of the ITA. This will reduce the loss carryforward comprising the deducted expenditure. To the extent that the past costs have not been deducted (for example, they relate to development expenditure incurred before the commencement of commercial production), the reimbursement will reduce the deductible amount of the expenditure for the farmor. In turn, the farmee should be allowed a deduction under the normal rules for deduction of mining or petroleum expenditure to the extent that the cash amount paid by the farmee is a reimbursement of the farmor's past costs. If the cash amount paid by the farmee exceeds the amount reasonably characterised as a reimbursement of the farmor's past costs, the excess

should be included in income as a gain on the transfer of the interest in the mining or petroleum right to the farmee under the rules discussed above.

169. **The issue then is the treatment of the future work commitments.** While the future work commitments undertaken by the farmee - which relate to the interest in the mining or petroleum right retained by the farmor- may be characterized as either in-kind income of the farmor, or, in-kind consideration for the transfer of the interest to the farmee as an incentive to encourage exploration or development; the value of work commitments may be excluded from income and also not treated as consideration for the transfer of the interest in a mining or petroleum right. This is the approach taken in Kenya for example. This means that only the cash amount is taxed under the principles outlined above. The deduction for costs of the farmor carried by the farmee under a farm-out agreement should be deductible only to the farmee.

Indirect Transfers

170. **The shares or other equity interests in an entity derive their value from the assets held by the entity.** Thus, if the principal asset of a company is a mining or petroleum right, the value of the shares in the company will equate to the value of the right. Consequently, in broad terms, the gain arising on the disposal of the shares in a company holding a mining or petroleum right should equate to the gain that the company would derive on disposal of the right. Indeed, it is a common form of tax planning for non-residents to invest through a multi-tier non-resident corporate structure so as to facilitate possible tax-free exit from the investment.

171. **While the taxation of indirect transfers of interest may be complex and difficult administratively, it is important that indirect transfers are taxed so as to protect the integrity of Uganda's taxation of direct transfers.** If there is no indirect transfer taxing rule, it would be expected that non-residents will use indirect transfers to avoid Ugandan taxation of gains on direct transfers. It is also the case that taxation of indirect transfers is consistent with international norms as articulated in Article 13(4) of the OECD Model.

172. **Gains on indirect transfers are taxable under the ITA.** The shares are business assets as defined in s 2. Gains on disposal of business assets are included in business income under s 18(1)(a) of the ITA. However, as a non-resident has made the gain, it is included in business income only if it has a Ugandan source. S 79(g) of the ITA provides that the gain arising on the disposal of a share in a company the property of which consists, directly or indirectly, principally of immovable property in Uganda is Ugandan-source income. It is noted that this source rule could be avoided through the interposition of a unit trust or limited partnership in the offshore chain of entities and then disposing of the units in the trust or interest in the partnership. To protect against this planning, s 79(g) should be revised to apply also to the disposal of a unit in a unit trust and an interest in a partnership. It is also important that the meaning of "immovable property" includes mining and petroleum rights.

173. **Uganda's taxing rights in relation to gains on indirect transfers must be preserved under tax treaties.** Presently, only the treaties with China and India preserve Uganda's taxation of gains on indirect transfers, although only in relation to gains on the disposal of shares in companies. This gives rise to the possibility of treaty shopping with the non-resident company making the gain, being resident in a treaty country that does not provide for taxation of gains on indirect transfers. While s 88(5) of the ITA provides some protection against treaty shopping, it is important that all future treaties preserve Uganda's taxing rights over gains on indirect transfers.

174. **Given Uganda's jurisdiction to tax indirect transfers of interest, administrative mechanisms needs to be in place to ensure enforcement of the tax.** This really has two aspects: (i) URA discovering that the transaction has occurred; and (ii) collection of the tax due. In relation to the first, s 87 of the Petroleum (EDP) Act requires the Minister to approve a change in control of the holder of a license. There is no equivalent provision in the Mining Act as s 7 applies only to the transfer of mineral rights. S 7 of the Act could be extended to apply also to a change in control of the holder of the mineral right;, similar to that, it should be made applicable under s 87 of the PEDPA. It should then be provided either in the sector legislation, or the ITA, that the relevant Ministry has an obligation to advise URA of a change in control of the holder of the mining or petroleum right so that the URA can pursue collection of the tax liability resulting from the change in ownership. Alternatively, the reporting obligation could be imposed on the holder of the right under the ITA. This addresses the information problem.

175. **The collection problem can be dealt with by treating the holder of the mining or petroleum right as agent of the non-resident person liable for the tax.** If the non-resident person does not pay the tax, the contractor is treated as personally liable for the tax. This would allow the URA to collect any unpaid tax from the holder of the mining or petroleum right using the normal debt recovery rules under the Tax Procedures Code applicable to unpaid tax.

Recommendations

- Adopt common rules for mining and petroleum development expenditure (including depreciable assets).
- Allow a tax deduction for deposits into an approved escrow account for future decommissioning, mine closure and rehabilitation expenses.
- Provide for the deductibility of compulsory social infrastructure expenditure, and align the deductibility with exploration and development expenditure.
- Extend the thin capitalization rule to cover all debt and increase the allowable debt-to-equity ratio to 1.5 to 1.
- Consider ring fencing future mining project license area by license area with exceptions only for failed exploration on relinquished areas elsewhere, and for technically warranted joint development or adjacent mines.

- Ensure that undeducted capital expenditure is recognized on a transfer of interest.
- Include rules dealing with farm-outs.
- Provide administrative rules to facilitate the collection of tax in relation to indirect transfers.

D. International Income Tax

Taxation of Subcontractors

176. **The resources sector usually involves a high level of subcontractors, particularly non-resident subcontractors, and Uganda is no different to elsewhere in this regard.** In relation to petroleum operations, it is noted that the local content rules in s 125 of the Petroleum (EDP) Act may have the effect of significantly limiting the use of non-resident subcontractors in the petroleum sector. The local content rules in s 113 of the Mining Act are not as strict as those in the PEDPA. The discussion below proceeds on the basis that services may be provided by non-resident subcontractors.

177. **The benchmark for taxation of non-resident subcontractors requires that: (i) taxation should be limited to Ugandan-source technical fees; and (ii) the basis of taxation should depend on whether or not the subcontractor has a branch in Uganda.** Technical fees derived by a non-resident subcontractor through a branch in Uganda should be taxed on a net basis (i.e. based on chargeable income) at the normal corporate rate on an ordinary assessment basis. If a non-resident subcontractor does not have a branch in Uganda, then Ugandan-source technical fees derived by the non-resident should be subject to final withholding tax on the gross amount of the fee. Uganda’s taxation of technical fees derived by a non-resident subcontractor may be limited or excluded by a tax treaty.

178. **Ss 85, 119, and 121 of the ITA apply to technical fees derived by non-resident subcontractors, but these ss do not exactly follow the benchmark set out above.** In particular, there is no clear delineation under these ss as to when technical fees are taxed on a gross or net basis. Further, the rules for determining when a technical fee is Ugandan-source income need to be modernized. The application of these ss, and their lack of proper co-ordination, was discussed in detail in the 2008 FAD Report. The discussion below only briefly sets out the operation of these ss.

179. **The following issues arise in relation to the current law: (i) the determination of the source of services income; (ii) the taxation of branches of non-resident subcontractors; and (iii) the rate of final withholding.** Ss 85 and 121 of the ITA apply only to services income that is Ugandan-source income. S 79 of the ITA provides rules for determining the source of income. There are four possible bases under s 79 upon which services income may be Ugandan-source income. First, services income is Ugandan-source income if: (i) the income is derived from services rendered in Uganda (s 79(c)). S 79 provides for apportionment when the services are

performed partly in Uganda and partly outside Uganda. Second, services income is Ugandan-source income when the services are rendered under a contract with the Government of Uganda (s 79(d)). Third, services income is Ugandan-source income when Uganda is permitted to tax the income under a tax treaty (s 79(r)). For example, under the technical fees article of Uganda's treaties with India, Italy, RSA, and the UK, Uganda is permitted to tax the fee if a Ugandan resident or a Ugandan permanent establishment of a non-resident pays the fee and the effect of s 79(r), therefore, is that such a fee is Ugandan-source income. Finally, services income is Ugandan-source income if it is attributable occurring in Uganda, including an activity conducted through a Ugandan branch (s 79(s)).

180. **The source rules in s 79 were drafted nearly 20 years ago and since then there have been significant change in the way that cross-border services are provided.** Twenty years ago, it was usual for services to be physically provided in the same country in which the services were being utilized and, therefore, place of performance was the standard source rule. However, today it is common for there to be a separation of the place of performance and place of utilization. This has led to concerns about base erosion arising through the deductibility of the service fee by the payer but with little or no taxation of the payee of the corresponding income generated by the fee. To counter base erosion, countries are aligning the source rule for services income with that commonly applicable to royalties so as to focus on the place of utilization rather than the place of performance (see s 79(j)(i) and (ii)). Thus, services income should have a source in Uganda when it is paid by: (i) a Ugandan resident (other than as an expenditure of a business carried on by the resident outside Uganda through a branch); or (ii) a non-resident as an expenditure of a Ugandan branch. This also aligns the source rule under the ITA with the taxing right under the technical fees article in Uganda's tax treaties. The source rule should apply regardless of whether the service fee is paid directly to the non-resident service provider, or through a recharge arrangement with a related non-resident company.

181. **Services attributable to a Ugandan branch of a non-resident contractor should be taxed on an ordinary assessment basis rather than through final withholding.** Under current law, such services are taxable through final withholding under s 85 of the ITA and may also be subject to non-final withholding under s 119 of the ITA. It is understood that the present practice of URA is to apply non-final withholding under s 119 to technical fees derived by Ugandan branches of non-residents. This practice should be formalized in the legislation by excluding the operation of s 85 when the fee is attributable to activities conducted by a non-resident through a Ugandan branch. This will align s 85 with s 83 (see s 83(6)).

182. **The definition of "branch" in s 78 of the ITA should be reviewed and modernized.** In particular, a services branch rule should be included based on Article 5(3)(b) of the UN Model Taxation Convention Between Developed and Developing Countries. Under such rule, the furnishing of services in Uganda, including consultancy services, by a person through employees or other personnel should be treated as a branch, but only if the rendering of the services continues for the same or a connected project within Uganda for a period or periods

aggregating more than 183 days in any 12-month period commencing or ending in the year of income. This also aligns the definition of "branch" with the definition of "permanent establishment" under Uganda's tax treaties with China, Mauritius and Norway.

183. **The rate of tax under s 85 of the ITA is 15 percent of the gross amount of the fee paid.** This rate seems to assume that the fee is essentially for the labor of the subcontractor - assuming a 50 percent profit margin, the 15 percent tax on gross income roughly equates to 30 percent on net income. However, if the subcontractor has significant expenses, such as for employee labor, the 15 percent rate may equate to a rate that is much higher than 30 percent on net income. It is noted that the rate limit under the technical fees article of Uganda's tax treaties is 10 percent.[30]

184. **Withholding on technical fees can increase the cost of resource projects as some subcontractors insist on negotiating contracts on a net-of-tax basis**. This may be because they do not want to have to deal with the local tax authority, because the withholding tax may not be creditable or fully creditable in the residence country, or because they are not taxed in the residence country on their foreign income. When contracts are priced net of tax, the contract price is grossed up by the amount of the withholding tax. The 15 percent rate should be reviewed to ensure that it is not significantly increasing the cost of resource projects in Uganda. The rate could be reduced to 10 percent to align with the tax treaty rate.

Tax Treaties

185. **Tax treaties can have a significant negative impact on the level of government take from the resources sector.** The mission was supplied with a Ugandan model tax treaty that will be used in future negotiations. It is important that all aspects of the model are carefully reviewed before being used in future treaty negotiations. Of particular relevance to resource operations, it is important that Uganda's future tax treaties include a services permanent establishment rule, and preserve Uganda's taxing rights in relation to lease payments, technical fees, and gains on indirect transfers.

Recommendations:

- Modernize the source rules for technical fees paid to non-residents.
- Tax subcontractors on a net basis when the fee is attributable to a branch in Uganda.
- Reduce the withholding tax rate on technical fees to 10%.

[30] Other than the UK treaty where the rate limit is 15 percent.

- Ensure that Uganda's tax treaties include a services permanent establishment rule, and preserve Uganda's taxing rights in relation to lease payments, technical fees, and gains on indirect transfers.

E. VAT Treatment of the Petroleum and Mining Chain

186. **The value-added tax is the most common form of a broad-based consumption tax imposed by central governments.** Properly designed, it is collected on imports and at each stage of production and distribution. All persons or businesses that are engaged in the supply of taxable goods and services are required to register for the VAT and charge VAT on all taxable supplies.[31] Their actual liability, however, is only in respect to their value added; that is, they remit only the net proceeds of the VAT charged on their sales (output tax), less the VAT paid or payable by them (input tax) in respect of goods and services purchased for use in making their taxable supplies. The VAT on imported goods is collected at the time of importation along with any applicable import duties and excise taxes. Uganda exempts imports from its VAT, which has an 18 percent standard rate, if the goods are exempt under the Fifth Schedule of the EAC Customs Management Act. The design of Uganda's VAT includes several deficiencies that burden investments in the resource sector. These deficiencies that burden investment in exploration and development of resource projects and in downstream pipelines, refineries and mineral processing facilities should be addressed as an integrated package.

VAT refunds

187. **A common complaint of companies is the delay in refund payments.** This is partly due to the burdensome administrative requirements and procedures. It is also due to URA's lack of financial resources to make a payment, as the payment of refunds continues to be restricted by a budgeted amount for refunds. As recommended by the 2011 FAD tax policy mission, Uganda should end the budgeting for VAT refunds as a spending item and move to VAT accounting on a net basis.

VAT registration

188. **Resource companies cannot register for VAT and claim input tax credits during the exploration and development phases, since they are not as yet supplying goods or services.** Under Uganda law, a company *supplying goods or services* that is not required to register for VAT can voluntarily register and claim input tax credits (s 7(4)), but resource companies are not supplying goods and services during the exploration and development phases. Prior to 2012, the VAT regulations (s 6) allowed a company that plans to make taxable

[31] Persons or businesses with turnover of taxable supplies below a specified threshold are exempted from the requirement to register for the VAT.

supplies in due course to voluntarily register as an investment trader. The investment trader regime was repealed because of an apparent concern that, if the taxpayer never makes taxable supplies, the government will have erroneously refunded the VAT. However, as VAT is in fact a tax on final consumption, no net VAT at all should be realized by the government if the investor simply fails to successfully launch its business and never makes supplies—failed investment is not final consumption. There was also a concern that the regime was subject to abuse and required the URA to allocate scarce administrative resources to audit VAT refund claims.

189. **In 2011, the FAD tax policy mission recommended that the government should repeal the refund scheme for registered investment traders and provide refunds of input tax credits prior to the commencement of taxable supplies.** The second part of the recommendation was based on the assumption that persons that may previously have qualified as investment traders would be permitted to register voluntarily for VAT.[32] The first part of the recommendation was adopted but not the second part. Under current law, therefore, a resource company cannot register during the exploration and development phases of operations and, therefore, cannot claim an input tax credit for taxable supplies made to the company prior to registration. The non-creditable VAT payments add to project costs, which in the case of a petroleum project can be recovered through cost oil, once production commences. However, the company is not fully refunded for the cost of VAT through cost oil because, if the amount of cost oil is increased, profit oil is reduced and the company's profit oil is reduced.

190. **The best way forward would be to allow resource companies to register voluntarily for VAT during the exploration and development phases and during the construction phase of downstream facilities (refineries and pipelines).** The VAT refund system should be strengthened to pay refund claims that have been duly vetted. The refund claims should be controllable as: (1) most imports of goods for resource projects are exempt from VAT; (2) the VAT charged by local suppliers can be handled through a remission scheme (discussed below); and (3) the credit for the reverse charge is taken in the same period as the reverse charge is reported—a wash transaction for companies expecting to make taxable supplies. A second alternative would be to allow resource companies to carryforward the input tax credit (with interest) to be offset against output tax once production commences. This alternative eliminates the immediate budget effect of allowing a credit for VAT paid on inputs during exploration and development. For petroleum companies, a third alternative would be to carryforward the input tax credit (with interest) and have the accumulated amount be the first claim on the government's share of profit oil when production is split. This would likely require an amendment to the PSAs. It would ensure that the "refund" would be paid once production commences.

[32] Madagascar allows mining companies to register for VAT during the construction period and claim credit for VAT paid on purchases.

VAT on imports

191. **Under the VAT law, goods exempt from customs duty under the Fifth Schedule of the EAC Customs Management Act are exempt from VAT (s 20).** The Customs Management Act exempts certain imports from customs duty if imported by a licensed petroleum company or a licensed mining company. In the case of petroleum, the exemption is fairly broad as it covers machinery and inputs for direct and exclusive use in petroleum exploration and development. The exemption for mining only covers machinery and spare parts. Other inputs generally would be subject to an import duty of 10 percent (intermediate goods) or 25 percent (finished goods).

192. **Subcontractors import a large share of inputs required for a resource project and these inputs are not exempt from import duty under the Customs Management Act.** The imported goods are, therefore, subject to VAT in Uganda. The government should seek two amendments to the Customs Management Act. First, the import exemption for imports by resource companies would apply to subcontractors if the goods are for the direct and exclusive use in a resource project. Second, the exemption for mining should be broadened to parallel the petroleum exemption; that is, the exemption would cover machinery and inputs.

193. **The VAT Act should be amended to provide an exemption from VAT for imports by a subcontractor for a resource project, which for this purpose might include a pipeline or refinery.** The report suggests this route as it may take time to amend the EAC Customs Management Act. This exemption should only apply if the importation would be exempt under the Fifth Schedule of the Customs Management Act and if the subcontractor were a licensed petroleum company or a licensed mining company. VAT relief for subcontractors can be problematical.[33] In order to limit abuse of the proposed relief, Uganda should put in place procedures to ensure that the goods are imported for a resource project. This could include the petroleum or mining company holding the license to certify that the goods will be used for the project and that the goods have arrived on the site of the project. It could also involve use of an independent surveillance and tracking company to verify the "chain of custody" of such goods; the costs of this service would be borne by license holders but would be cost recoverable.

Treatment of domestic suppliers

194. **Under current law, local companies must charge VAT on supplies of goods to resource companies.** However, as explained above, resource companies cannot register for VAT and, therefore, cannot recover the input VAT paid on these supplies. This puts local suppliers at a disadvantage as most imported goods are exempt from VAT. The correct way to deal with this issue is to allow resource companies to register and for timely refunds of excess VAT to be paid.

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[33] Kenya's new VAT does not provide special relief for subcontractors.

In addition, as stated above, to facilitate the making of refunds, Uganda should end the budgeting for VAT refunds as a spending item and move to VAT accounting on a net basis.

195. **The mission was advised that, at this time, it is not practical for refunds to be paid to resource companies and that a second best solution needs to be found as an interim measure.** One possibility would be to zero-rate local supplies to resource companies. This would treat local supplies and imported supplies the same, but it could push the refund problems back one stage and create significant administrative problems for the URA. The report does not recommend this option.

196. **An accounts-based remission system for local suppliers is an alternative that could limit the need to pay refunds and serve as an effective interim measure.** To understand this alternative, assume that \$10 of output tax is payable on a taxable supply by a local supplier to a resource company and that the supplier has \$4 input tax in relation to making that supply. At the moment, the VAT works in the normal way for the supplier—it collects \$10 output tax, claims a credit of \$4 input tax and pays the \$6 difference to URA. But the resource company bears the VAT as the equivalent of an end user, as refunds are not paid. Assume the same numbers except that the resource company is deemed to have paid the VAT (the government pays the VAT on its behalf through the deeming rule). The supplier's net VAT situation is exactly the same—it has \$10 of deemed output tax, claims a credit of \$4 input tax, and is liable to pay the \$6 difference to URA. The Government then remits the liability to actually pay the \$6 net VAT. The remission scheme differs from zero-rating because the supply to the resource company is a taxable supply at the standard rate of VAT, but with the VAT paid by the Government through the deeming rule. The remission scheme should be limited to the first tier of suppliers to resources companies.

197. **While the supplier's net VAT position is the same under the remission system, the deeming of the VAT payment by the resource company means that the supplier does not actually receive an amount to cover its input tax.** Provided the supplier is also making taxable supplies to non-resource companies, the output tax received on those supplies should cover the input tax in relation to taxable supplies to resource companies. There may be cases, though, when a supplier to a resource company is in an excess input tax credit situation, and there must be procedures in place for the payment of refunds in that case. However, the refunds that may have to be paid to suppliers should be relatively small as compared to the refunds that would be payable to the resource companies. It is highly important that these refunds be paid to signal support for local suppliers to resource companies. Note that the use of output tax receipts from non-resource companies, by these suppliers, to cover input tax credits on supplies ultimately made to resource companies will cause some reduction in remittances of net VAT to the URA. This should be seen as necessary and equivalent to a small increase in the overall budget for VAT refunds.

198. **A properly functioning refund system should apply to resource companies.** However, given the government's advice that this is not practical in the short term, the remission

scheme offers a reasonably effective second best solution that could be applied as an interim measure until the refund system is implemented.

Reverse charge rule

199. **Normally, it is the supplier of a service who must account to the tax authorities for any VAT due on its supplies.** However, for services supplied by non-residents, the position is reversed and it is the purchaser who must account for any VAT due. This procedure is referred to as a "reverse charge". A VAT taxpayer importing services, subject to a reverse charge, charges itself output tax and accounts to the tax authority for the amount of tax charged on the imported service. The purchaser of the imported service is also able to claim an input tax credit for the self-assessed reverse charge, assuming that the purchaser makes taxable supplies. The practical effect of this is that there will be no net VAT payable on the transaction except by companies that are not entitled to full crediting of input tax, such as those companies wholly or partly making exempt supplies. The reverse charge rules ensure that the VAT does not favor imported services (not subject to VAT) over domestic services (subject to VAT).

200. **Although actual practices in handling the reverse charge varies across countries, the preferred international practice is for the reverse charge and the input tax credit to be accounted for in the same tax period.** Companies registered for VAT would account for the reverse charge in a separate schedule on the monthly VAT return.[34] The output tax would comprise the VAT charged on sales and the VAT charged on imported services. The input tax credit for the reverse charge would be allowed in the same month, ensuring that no net VAT is payable.

201. **In 2012, Uganda repealed the credit for VAT paid on imported services (s 5(c)).** Under this new regime, the importer of a service is treated as an end-user. The VAT chain is broken and the VAT is no longer a tax on final consumption; investment is taxed. The only possible justification for this change is that the government wants to tilt the playing field to favor domestic suppliers by imposing what is, in effect, an 18 percent import duty on the imported services. Although this "import duty" will be recoverable as part of cost oil and deductible under the income tax, it increases the cost of investments in the resource sector. Restoring the input tax credit for the reverse charge is an urgent matter and should be done before the request for proposals for the first petroleum licensing round are issued on July 20, 2015.

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[34] Companies not registered for VAT, which are required to account for the reverse charge on imported services, would file a simple declaration that would not be part of the monthly VAT declaration used by registered VAT taxpayers.

VAT on petroleum products

202. **Uganda levies excises on gasoline, diesel, and illuminating kerosene while exempting these products from VAT (second schedule 1(o)).** Other petroleum products such as lubricants are subject to VAT. The excise on VAT-exempt products can be viewed as comprising two components: (i) the VAT at the 18 percent rate and (ii) a true excise, equal to the amount of the tax in excess of the VAT that would otherwise be applied (Table 3.1).

203. **Exempting petroleum products from VAT is workable under current circumstances.** All petroleum products are imported and the excise is collected by customs – the strongest link in the production and distribution chain. The excise rate can be set taking into account that the petroleum products are not subject to VAT. The current approach, however, will not be workable when Uganda begins to produce crude oil and refine products locally. The crude oil producers will charge VAT on production sold to the refinery. If refined products remain exempt from VAT, the refinery will not be able to claim the credit for the VAT paid on inputs.

Table 9. Excise and Embedded VAT on Petroleum Products

Petroleum Product	Retail Price (UGX per liter)	Excise (UGX per liter)	Embedded VAT (18 percent)1/	True Excise (UGX per liter)
Gasoline	3,600	950	549	401
Diesel	2,800	630	427	203
Illuminating kerosene		200		

1/ 15.25 percent on a tax inclusive basis

204. **The preferred reform would be to repeal the VAT exemption for petroleum products and adjust the excise rates.** In 2013, Kenya extended its VAT to petroleum products with a three-year transitional arrangement that can be revoked earlier. Petroleum products will be subject to VAT from September 1, 2016. Extending VAT to petroleum products ensures that the VAT chain is not broken. Petroleum products are treated like other excisable goods. For example, manufacturers of beer and soft drinks are able to claim a credit for VAT paid on inputs.

205. **With the downward adjustment of the excise rates on petroleum products, the reform could be price neutral but would lead to a small decrease in government revenue**. Today, the explicit VAT embodied in the excise is not allowed as an input tax credit. If the VAT becomes an explicit charge, businesses that use petroleum products to produce taxable supplies will be able to claim the input tax credit. The potential revenue loss is due to the elimination of

the tax cascading inherent in having the VAT embodied in the excise.[35] The reform could be revenue enhancing if the reduction in excises is smaller than required for a revenue neutral proposal.[36] Given that oil prices are more likely to rise than to fall in the near term, shifting the tax burden on petroleum products from a specific levy only (the excise) to a combination of a specific levy and an ad valorem levy (the VAT) would increase revenue in the near term, particularly as specific-rate excises often are not adjusted to keep up with inflation.

206. **An alternative approach would be to impose VAT on refined petroleum products at a single stage when the products are either imported or sold by the refinery.** The base for the VAT would be the monthly average retail price of the products as determined by the Uganda Bureau of Statistics, possibly made publicly available on the URA web site, and the rate would be the tax-inclusive rate of 15.25 percent.[37] Like the preferred approach, the refinery would be able to claim input tax credit for VAT paid on purchases. Petroleum products would be VAT exempt at the distribution and retail stages, as under current law. The case for this approach, which is more often used for cigarettes and alcoholic beverages, is avoidance of any VAT revenue leakage at the retail stage, where there are many sellers who are not required to register for VAT. Adoption of this proposal would add a special VAT regime and could lead to initial confusion.

Recommendations

- Prior to release of the request for proposals for the first petroleum licensing round, adopt an integrated package of VAT reforms as follows:
    - Allow companies to register voluntarily for VAT during the exploration and development phases of a resource project and allow refineries and pipelines to register during the construction phase of midstream facilities;
    - Exempt imports by a subcontractor from VAT if the imports are for direct and exclusive use in a resource project;
    - Adopt a limited remission scheme for first tier domestic suppliers to a resource project, with assured refunds of excess credits;
    - Allow an input credit for the reverse charge;

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[35] The potential revenue loss of a retail price neutral proposal should be further investigated.

[36] In 1997, when the Philippines repealed its VAT exemption for petroleum products, the reform was revenue enhancing.

[37] The collection point for imported petroleum products is Mombasa. It would be possible to collect both excise and VAT at Mombasa so these products would not transit to Uganda free of tax.

- Repeal the VAT exemption for petroleum products and reduce the excises on these products.

F. Fiscal Stability

207. **Fiscal stability clauses are widespread in petroleum and mining contracts**. These clauses are generally justified by: (1) the large size and the sunken nature of the initial investment, (2) a long period required to recover investment and earn a reasonable return, and (3) a lack of credibility on behalf of the host country to abstain from changing the fiscal rules—possibly singling out high rent petroleum or mining operations—once the investment is sunk.

208. **It can be argued that the need for a fiscal stability clause is less compelling under certain conditions**: a history of sound fiscal management, statutory and effective corporate tax rates in line with international rates, low tariff rates and non-imposition of taxes that distort investment and production decisions (e.g., asset taxes, excises on machinery), non-discrimination between domestic and foreign investors, a low level of corruption, a transparent tax policy process, and a reasonably efficient tax administration.

209. **There is no provision in the PEDPA or the Mining Act or other legislation for the government to give assurances of fiscal stability.** Stability assurances have been given in PSA agreements and in a recent mineral agreement. In the mineral agreement, the parties agreed that if there is a change in the law relating to income tax that adversely alters the economic benefits of the project for the mining company, they will agree on the necessary adjustments and modifications to the agreement in order to maintain the net present value of the project for the mining company.[38] The modifications would not necessarily override current law, as it could take the form of a cash payment from the government or the government deeming to pay the additional tax on behalf of the mining company.

210. **The Mining Act could be amended to make fiscal stability assurances permissible under an agreement, but on fixed terms.** The amendment would further provide that these assurances should be time limited – five years from the start of commercial production – and cover only the income and withholding tax rates, the royalty rates, and the cost recovery rules for capital expenditure. However, any tax law change that affects businesses generally (e.g., a change in the thin capitalization rules) and that does not discriminate against the resource sectors would apply. While production sharing prevails, and thus a contractual assurance of stability can be given through the PSA, there is no need for such a provision in petroleum law.

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[38] The stabilization provision in the agreement follows closely the stabilization provision in the PSA dated February 3rd 2012.

Recommendations:

- Amend the Mining Act to make a fiscal stability assurance available if conditions specified in the Act are met.

- Assurances of fiscal stability should be time limited and cover only the income and withholding tax rates, the royalty rates, and the cost recovery rules for capital expenditure.

G. Stamp Duty

211. **Stamp duty is charged on a wide variety of financial, trading, and other transactions.** Most of Uganda's stamp duties are specific levies (e.g., UGX 5,000 per document). The principal duties affecting resource companies are the ad valorem duties: the 0.5 percent duty on new share capital, the 0.5 percent duty on debentures, the 1 percent duty on the total value of a lease or a hire/purchase agreement, and the 1 percent of the total value of a transfer of shares (0.5 percent if the company is listed on a stock exchange).

212. **Stamp duties have significant attractions: attaching to documents (which have no legal force unless properly stamped); and to the gross revenue of transactions (not requiring any sophisticated calculations to determine net "income").** They can therefore be seen as relatively secure sources of revenue, with relatively low costs of collection for the revenue authorities. However, they have drawbacks, in the mirror image of these advantages. They have to be paid each time a dutiable document is handled or (as appropriate) payment received (with a cascade effect; if a single transaction requires different documents to be prepared at successive stages; or if an asset is transferred at short intervals, or if the transaction requires offsetting payments to be made).

Recommendation

- Consider eliminating ad valorem stamp duties that apply to financing transactions and increased equity.

Appendix 1. International Comparators for Upstream Petroleum and Mining

Table A.1. Fiscal Regimes of International Comparators for Upstream Petroleum

Country	Regime	Bonuses	Royalty rate	Cost recovery limit	State share	Corporate income tax	Depreciation rule	Loss carry forward	Supplementary profit tax	VAT (if not refunded)	Duties	Dividend withholding tax	Interest withholding tax	State participation
Australia	PRRT	NA	NA	NA	NA	30%	100% exploration, SL effective life for development (15 years) and replacement capital (5 years); government determines the effective life of assets	Indefinite	40% PRRT after uplift of LTBR + 15% for exploration and LTBR + 5% for general expenditure		5%	0% for franked dividends; 30%; if reduced by treaty	30% for nonresidents only; 10% if reduced by treaty	NA
Chad	2011 PSC	SB	Oil: 14.25% Gas: 5%	70%	40-60%; R-factor	Exempt	100% exploration and drilling costs; 20% other capex; SL	Indefinite	NA		Exempt	0%	0%	10%-25% carried
Colombia	Tax / Royalty	NA	Oil: 8%-25%; DROP Gas: 80% of oil rate (1000ft <); 60% of oil rate (>1000ft)	NA	NA	25%	20% all capex	Indefinite	30%-50% when prices exceed base level		Exempt during exploration; 0%-20% thereafter	0%	33%; 10% if reduced by treaty	Yes, unknown rate
Democratic Republic of the Congo	PSC	SB & PB	9-12.5%; cumulative production	75%	40-45%	0%; other contracts have paid CIT	100% exploration; 17% capital costs (assumed)	6 years	NA	0-5% in past contracts; not eligible until production	Exempt	20%; 5% if reduced by treaty; 0% in past contracts	14%; 10% if reduced by treaty; 0% in past contracts	7-12% carried (assumed)
Kenya - R-factor	PSC	SB	NA	60%	50%-75%; R-factor	Discharged by the state	20% straight-line	Indefinite	NA		Exempt	0%	0%	5%-20% carried to discovery
Mozambique - Onshore PSA	PSC	PB	Oil: 8%Gas: 5%	75%	10%-50%; R-Factor	32%	100% exploration cost; 20% development	8 years	NA		Exempt	20%; reduced to 10% in contracts	20%; reduced to 0% in contracts	15% carried to discovery
Sudan - Onshore PSA	PSC	PB	Discharged by the state	45%	60%-80%; DROP	Discharged by the state	20% SL	5 years	NA		Exempt	0%	0%	5% carried through to production
Tanzania -MPSA 2013	PSC	SB/PB	12.5% onshore; discharged by the state oil company	50%	Oil: 70%-90% Gas: 60%-80%	30%	25% SL on capital cost	Indefinite	25% FANCP+35% SANCP; Real ROR		Exempt	10%	10%	25% min. carried to development

Table A.2. Fiscal Regimes of International Comparators for Mining

Country	Mineral	Royalty rate	Royalty base	Corporate Income Tax	Loss carry forward	Depreciation rule	VAT	Import duties	Export Tax	Additional Profit Tax	DWT	IWT	Equity
Australia - Western Australia	Iron ore	5% [beneficiated iron ore] 7.5% [lump or fine iron ore]	Gross invoice value of the mineral less any allowable deductions for the mineral such as transport and packaging	30%		100% exploration; effective life development and replacement capital, 15 and 7 years respectively; effective lives are determined by govt	10% [none for exported minerals or first supply]	Concessions apply if values > $10 million	None [assumed]	None	30% [unfranked dividends]; 0% [assuming all franked credits are used]	10%	None
Brazil	Iron ore	2% [iron ore]	Net revenue, i.e., the mineral sales revenue less taxes levied on revenue, insurance and freight costs.	34%	Indefinite w/ 30% limit on taxable income	100% for exploration and development costs; SL 10% for equipment and machinery and buildings	17% (refundable)	5%-12%; 7% modeled	Exempt	3.65% social contribution (cumulative regime)	0%	15%; reduced to 10% by treaty	None
China	Iron ore	CNY 2% + 0.4-30/ton [copper] CNY 2% + 2-30/ton [iron ore]	Volume and net revenue	25%	5 years	100% on exploration; 10% SL on deveopment; 25% SL on replacement [assumed]	Zero-rated on exports	Exempt	None [assumed]	None	10%; 5% reduced by treaty	10%	None
Guinea	Iron ore	3% [iron ore]	Net value	30%	3 years	33.3% on startup cost; 20% on machiery and equipment; SL	18%; exempt until after first 3 years of production	Exempt	2% [iron ore]	None	10%	10%	Max. 15% initial free equity; supplemental equity of up to 35%
India	Iron ore	15% [iron ore]	LME/sale prices * volume	30%+ 3%-13% surcharge if above thresholds	8 years	20% SL exploration; 15% DB all exploration and capital expenditure	2%-10%; exports are zero-rated	Exempt	10% [iron ore]	None	16.22%; reduced to 10% by treaty	21.01%; 10% reduced by treaty	None
Liberia	Iron ore	4.5% [iron ore]	FOB Liberia; London pm gold fixing	30%	7 years	100% pre-production cost; 20% production capital cost	Zero-rated on exports	Exempt until production starts; max around 4% thereafter	None	20% Surtax when pre tax IRR > 22.5%; deductible for income tax	5%	5%	None
Mauritania	Iron ore	2.5%-4% based on price [iron ore]	Gross revenue (assumed)	0% for first 3 years after exploration permit; then 25%; ring-fenced around each mine	5 years; effectively indefinite due to deferred depreciation	50% exploration; 33% other capex	14% eligible for refund	5% after first 5 years of a project	None	None	10%	16%	10% free with an option of 10% carried
Russia	Iron ore	4.8% [iron ore]	Volume x sales price less freight and refining cost	20%; reduction possible	10 years	50%-100% years SL for extraction equipment; 10% for intangible assets	18%; 0% exports and sales of precious metals	Exempt	None	None	15%; reduced to 10% with treaty	20%; reduced to 0% with treaty	None
South Africa	Iron ore	Formula-based max 5% [refined minerals] max 7% [unrefined minerals]	Gross sales	28%	Indefinite	100% exploration and capital expenditures	14%; exports are refundable	None	None	None	15%; reduced to 10% with treaty	15%; reduced to 0% with treaty	None
Ukraine	Iron ore	5% [iron ore]	Net value	18%	Indefinite	100% exploration, 8 years SL development and replacement capital	20%; modeled as exempt on 2014 mission			None	15%; reduced to 5% by treaty	15%; reduced to 10% by treaty	None

Appendix 2. Summary of Royalties and Minimum Effective Royalties for Crude Oil in Selected Countries

Table A.3. Royalties and Minimum Effective Royalties for Selected Countries (continued)

Country	Oil royalty rate ; PSC type	Cost recovery limit	State share	PSC-imposed implicit royalty rate	Minimum effective royalty	Maximum effective royalty rate	Region	Comment
Afghanistan	12.6%-15%	100%	0-70%	0%	12.6%	15.0%	ME	
Algeria	5.5%-23%; DROP and zones	NA	NA		5.5%	23.0%	AFR	DROP and zones
Angola	0%	50%	30%-90%	15%	15.0%		AFR	
Argentina	12%	NA	NA		12.0%		SA	
Azerbaijan	0%	100% opex; 50% capex	20%-90%; IRR or R-Factor	10% for all capex costs, 0% for opex	0.0%	10.0%	ME	50% cost recovery for capex; 100% for opex
Bahrain	0%	70%	70%	21%	21.0%		ME	
Bangladesh	0%	55%	60%-80%; DROP	27%	27.0%		ASIA	
Bolivia	18%	100%	Varies by contract; R-Factor, producation rate and price		18.0%		SA	
Brazil	10% for CC; negotiable for PSC	100%			0.0%	10.0%	SA	Concession vs. PSC
Brunei	12.5% onshore, 8% offshore	Onshore: 60% Offshore: 80%	Onshore: 50%-70% Offshore: 25%-40%; DROP	17.5% (onshore), 4.6% (offshore)	12.6%	30.0%	ASIA	Onshore vs. offshore
Bulgaria	2.5%-30%; R-factor	NA	NA		2.5%	30.0%	EUR	R-factor
Burundi	12.5%	NA	NA		12.5%		AFR	
Cambodia	12.5%	90%	45%-55%; DROP	3.9375%	16.4%		ASIA	
Cameroon	0%	60%	40-70%; R-factor	16%	16.0%		AFR	
Canada	10%-45%; location, production and price	NA	NA		10.0%	45.0%	NA	Location, production and price
Chad	14.25%-16.5%	70%	Min 40%; R-factor [assumed]	10.29% (min), 10.02% (max)	24.5%	26.5%	AFR	
China	6%	62.5% offshore, 60% onshore	5%-55%; DROP	1.88% (onshore), 1.7625% (offshore)	7.8%	7.9%	ASIA	Onshore vs. offshore
Colombia	Oil: 8%-25%; DROP Gas: 80% of oil (shallow); 60% of oil (>1000ft)	NA	NA		6.4%	25.0%	SA	Onshore vs. offshore
Congo, Dem. Republic of	9%-12.5%	60%-85%	40-60%	5.46% (min), 14% (max)	14.5%	26.5%	AFR	Varies by contract
Congo, Republic	15%	60%-85% Based on price	35%-65%	11.9%	26.9%		AFR	
Cote d'Ivoire	NA	80%	45-60%	9%	9.0%		AFR	

Table A.3. Royalties and Minimum Effective Royalties for Selected Countries (continued)

Country	Oil royalty rate ; PSC type	Cost recovery limit	State share	PSC-imposed implicit royalty rate	Minimum effective royalty	Maximum effective royalty rate	Region	Comment
Ecuador	12.5%-18.5%; DROP	100%	19%-40%; DROP		12.5%	18.5%	SA	DROP
Egypt	10% (discharged by state in previous PSCs)	25%	85%; DROP	64%	64.0%		ME	
Equatorial Guinea	13%-16%; DROP	70%	10%-60%; DROP	2.61% (min), 2.52% (max)	15.6%	18.5%	AFR	DROP
Ethiopia	5%-15%; DROP	65%	18%-80%; DROP	5.985% (min), 5.355% (max)	11.0%	20.4%	AFR	DROP
Gabon	3%-11%	80%	50%-63%; DROP	9.7% (min), 8.9% (max)	12.7%	19.9%	AFR	DROP
Ghana (general)	10%	NA	NA		10.0%		AFR	
Guinea Bissau	5%-10%; DROP or water depth	50%	10%-60%; DROP	9.75% (min), 9.1% (max)	14.8%	19.1%	AFR	DROP
Hungary	12%	NA	NA		12.0%		EUR	
Iceland	5%	NA	NA		5.0%		EUR	
India	5%-12% based on onshore/offshore and water depths	100%	Biddable; R-Factor		5.0%	12.0%	ASIA	Depth
Indonesia	20% FTP	100% after FTP	Oil: 37.5%-55.36% Gas: 28.57%		20.0%		ASIA	
Iraq	NA	40%	90.4% (total gvn't take?)	54%	54.0%		ME	
Israel	12.50%	NA	NA		12.5%		ME	
Italy	7%	NA	NA		7.0%		EUR	
Japan	1%	NA	NA		1.0%		ASIA	
Kazakhstan	5%-18%; DROP	NA	NA		5.0%	18.0%	ME	
Kenya	NA	50%	50%-78%; DROP	25%	25.0%		AFR	
Korea, South	Min. 12.5%; negotiable	NA	NA		12.5%		ASIA	
Liberia	5%-10%; depth	70%	40%-60%; DROP	11.4% (min), 14.58% (max)	16.4%	24.6%	AFR	Depth
Libya	16.67%	100%	10%-70%		16.7%		AFR	
Malawi	10.00%	NA	NA		10.0%		AFR	
Malaysia	10%	20%-70%; Revenue/cost (R/C) ratio	R/C based; 20%-70% if cum. production <= cumulative Total Hydrocarbon Volume (THV), 60%-90% otherwise	5%	15.0%		ASIA	

Table A.3. Royalties and Minimum Effective Royalties for Selected Countries (continued)

Country	Oil royalty rate ; PSC type	Cost recovery limit	State share	PSC-imposed implicit royalty rate	Minimum effective royalty	Maximum effective royalty rate	Region	Comment
Mozambique	3%-10%	65%-85%; depth	10%-60%; R-Factor	1.455% (min), 3.15% (max)	4.5%	13.2%	AFR	Depth
Myanmar	10%	40% onshore; 50% offshore	60%-90% depending on daily production and location	27% (min), 32.4% (max)	37.0%	42.4%	ASIA	Onshore vs. offshore
Namibia	5%	NA	NA		5.0%		AFR	
Netherlands	0%-7% depending on production and progressive with price	NA	NA		0.0%	7.0%	EUR	DROP and price
New Zealand	greater of 5% ad valorem or 20% accounting profits	NA	NA		5.0%		ASIA	
Niger [concessionary]	12.5-15%; cumulative production (concession)	70% (PSC)	40-55%; R-factor (PSC)	12%	12.0%	15.0%	AFR	Concession vs. PSC
Nigeria	0%-16.67% depending on onshore/offshore and water depth	80%	30%-75%; R-Factor	4.9998% (onshore), 6% (offshore)	6.0%	21.7%	AFR	Onshore vs. offshore
Oman	NA	30%-50%; depending on price	80%	40% (min), 56% (max)	40.0%	56.0%	ME	
Pakistan	0-12.5% offshore, time since production began; 12.5% onshore	85%	20%-80% if water depth<=200 m & depth to reservoir<=4000 m; 5%-70% if 200m<=water depth<1000m & depth to reservoir >4000 m; 5%-60% if water depth>=1000 m	2.625% (onshore), 0.65625% (offshore)	13.2%	15.1%	ME	Onshore vs. offshore
Papua New Guinea	2%	NA	NA		2.0%		ASIA	
Peru	0%-40%; R-Factor, DROP and Price	NA	NA		0.0%	40.0%	SA	R-factor, DROP and price
Philippines	NA	70%	60%	18%	18.0%		ASIA	
Poland	US$11 per tonne of oil	NA	NA				EUR	US$11 per tonne of oil
Qatar	NA	40%	55%-88%; BOPD and R-factor based	33%	33.0%		ME	

Table A.3. Royalties and Minimum Effective Royalties for Selected Countries (concluded)

Country	Oil royalty rate ; PSC type	Cost recovery limit	State share	PSC-imposed implicit royalty rate	Minimum effective royalty	Maximum effective royalty rate	Region	Comment
Romania	3.5%-26.5%; cumulative production	NA	NA		3.5%	26.5%	EUR	10% additional fee for transportation using public systems
Russia	US$8.81/tonne; adjusted by coefficients	NA	NA				EUR	US$8.81/tonne; adjusted by coefficients
Sao Tome and Prin	2%	80%	0%-50%;ROR		2.0%		AFR	
Senegal	2%-8%	Negotiable; 2011:75% (no royalty)	2011: 35%-58% (no royalty)	9%	2.0%	9.0%	AFR	
Sierra Leone	10% < 200m; 8% > 200m	NA	NA		8.0%	10.0%	AFR	Onshore vs. offshore
South Africa	Max 7% based on ratio of EBIT to gross sales	NA	NA		0.5%	7.0%	AFR	Ratio of EBIT to gross sales
South Sudan	Discharged by the state	50%	60%-80%; DROP	30%	30.0%		AFR	
Sudan	Discharged by the state	45%	60%-80%; DROP	33%	33.0%		AFR	
Syria	7%	48%	70%	34%	41.0%		ME	
Tanzania (MPSA 2	12.5% onshore, 7.5% offshore; discharged by the state oil company	50%	65%-90%	33%	33.0%		AFR	
Thailand	5%-15% progressive with sales volume	NA	NA		5.0%	15.0%	ASIA	Sales volume
Timor-Leste	5%	100%	40%		5.0%		ASIA	
Trinidad and Toba	10%-15%; based on location	80% (no royalty)	65%-85% (no royalty)	13%	10.0%	15.0%	SA	Location
Tunisia	2%-15%; R-factor	100%	50%		2.0%	15.0%	AFR	R-factor
Turkmenistan	3%-15%; DROP	60%	40%-80%; R-Factor	15.52% (min), 13.6% (max)	18.5%	28.6%	ME	DROP
Uganda	5%-12.5%; DROP 2.5-15% Cumulative production	60%-75%	43.5%-68.5%; DROP	10.603125% (min), 12.94125% (max)	13.1%	27.9%	AFR	Cumulative production
Ukraine	18%-39%; location/depth	70% for PSC	30% before payout, 50% after payout for PSC	7.38% (min), 5.49% (max)	25.4%	44.5%	EUR	Concession vs. PSC
United States	12.5% onshore; 18.75% offshore	NA	NA		12.5%	18.8%	NA	Offshore (18.75%), federal lands (12.5%)
Uzbekistan	20%	60%	70%-80%; DROP	22%	42.0%		ME	
Venezuela	30%	NA	NA		30.0%		SA	
Vietnam	7%-29%; DROP	70%	50%-70% (late 1990s); DROP	13.95% (min), 10.65% (max)	21.0%	39.7%	ASIA	DROP
Yemen	5%-20%; DROP	20%-30%	80%-90%; DROP	53.2% (min), 51.2% (max)	58.2%	71.2%	AFR	DROP
Zambia	12.5%	100%	After tax ROR		12.5%		AFR	

Appendix 3. FAD Tax Policy and Revenue Administration Reports

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