

Memorandum to the Board of Royal Dutch Shell plc Group Investment Proposal

Summary Information

Business unit and company	Shell Petroleum Development Company of Nigeria Limited (SPDC)																																																																						
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.																																																																						
Other shareholders / partners	Nigeria National Petroleum Company (NNPC: 55%), Total Exploration and Production Company Nigeria (TEPNL 10%), Nigeria Agip Oil Company (NAOC: 5%)																																																																						
Amount	US\$533.7mln Shell share, MOD, 50/50 is requested for approval in this proposal of the 100% JV estimate of US\$924.8mln. US\$93.1mln 100% JV has been approved in the Pre-FID proposals. This proposal includes Shell equity share (30%) of US\$249.5mln and Shell's MCA commitment on NNPC Share of US\$284.2mln																																																																						
Project	Gbaran Infill.																																																																						
Main commitments	<table><thead><tr><th>Description</th><th>Previously approved (100% JV)</th><th>Requested Budget (100% JV)</th><th>Complete Budget (100% JV)</th><th>Complete Budget (30% Shell Share)</th><th>Total Shell Share (Equity + Carry)</th><th>NNPC MCA Carry (36.67% Shell Share)</th><th>This Proposal (30% Shell Share)</th><th>Total Shell Share (Equity + Carry) This Proposal</th></tr></thead><tbody><tr><td>NAG Wells</td><td>46.3</td><td>213.2</td><td>259.5</td><td>77.8</td><td>156.0</td><td>78.2</td><td>64.0</td><td>142.1</td></tr><tr><td>Facilities & Pipelines</td><td>46.1</td><td>605.6</td><td>651.7</td><td>195.5</td><td>401.5</td><td>206.0</td><td>181.7</td><td>387.7</td></tr><tr><td>Total CAPEX (\$ mln)</td><td>92.4</td><td>818.8</td><td>911.2</td><td>273.4</td><td>557.6</td><td>284.2</td><td>245.6</td><td>529.8</td></tr><tr><td>SCD</td><td>0.7</td><td>13.0</td><td>13.7</td><td>4.1</td><td>4.1</td><td>0.0</td><td>3.9</td><td>3.9</td></tr><tr><td>Total OPEX (\$ mln)</td><td>0.7</td><td>13.0</td><td>13.7</td><td>4.1</td><td>4.1</td><td>0.0</td><td>3.9</td><td>3.9</td></tr><tr><td>Total Project (\$ mln)</td><td>93.1</td><td>831.8</td><td>924.8</td><td>277.5</td><td>561.7</td><td>284.2</td><td>249.5</td><td>533.7</td></tr></tbody></table>								Description	Previously approved (100% JV)	Requested Budget (100% JV)	Complete Budget (100% JV)	Complete Budget (30% Shell Share)	Total Shell Share (Equity + Carry)	NNPC MCA Carry (36.67% Shell Share)	This Proposal (30% Shell Share)	Total Shell Share (Equity + Carry) This Proposal	NAG Wells	46.3	213.2	259.5	77.8	156.0	78.2	64.0	142.1	Facilities & Pipelines	46.1	605.6	651.7	195.5	401.5	206.0	181.7	387.7	Total CAPEX (\$ mln)	92.4	818.8	911.2	273.4	557.6	284.2	245.6	529.8	SCD	0.7	13.0	13.7	4.1	4.1	0.0	3.9	3.9	Total OPEX (\$ mln)	0.7	13.0	13.7	4.1	4.1	0.0	3.9	3.9	Total Project (\$ mln)	93.1	831.8	924.8	277.5	561.7	284.2	249.5	533.7
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Source and form of financing	The source of funding for the project is being discussed with the JV partners; the proposal is for this investment to be financed via Alternative Funding (AF). The premise for this proposal is the Modified Carry Agreement (MCA) funding vehicle and the proposal is a part of the Gbaran-Ubie 2 MCA bundle.																																																																						
Summary cash flow (Shell Share)	<div><p>Gbaran Phase 2A JV+MCA project cashflow plot (Shell Share PSV RV-RT)</p></div>																																																																						
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Section 1: The Proposal (Management Summary)

1.1 Management Summary

This Group Investment Proposal requests approval for funding of US\$533.7mln Shell Share (US\$249.5mln Equity & US\$284.2mln Carry) for the execution of the Gbaran Infill Project, which aims to develop 1.3Tscf of gas to keep the Gbaran Central Processing Facility (CPF) full to meet SPDC JV gas supply commitment to NLNG trains 1-6 and Domestic gas supply. The approval is being sought based on the conclusion of the commercial round of the contracting process with the eventual contractors already identified.

The full project scope includes the drilling of Nine (9) new NAG development wells from three fields (1 in Gbaran, 5 in Koroama; and 3 in Epu), one (1) appraisal well and the re-completion and hook-up of Koroama-002 NAG appraisal well drilled in 2005. All these wells are on the approved Oct 2012 STDWS.

In a bid to accelerate the project and optimize cluster drilling at Koroama, the Koroama TBUV-2 well was drilled in Oct 2012 as an early opportunity and Koroama 002 recompletion is ongoing, while the remaining five Koroama wells will be drilled from Jul 2013 to April 2014. The Gbaran VZTX-2 well will be spudded in February 2013, while the Epu wells will be drilled in 2014 and 2015.

The project will also install 2 x 10MMscf/d booster compressors, two slug catchers and associated process and utility tie-in facilities at the Gbaran CPF; six (6) remote site process and utility facilities; 30 km of inter-sites HV/FO composite cables; and a 40 km network of pipelines linking the remote well locations to the Gbaran CPF. Production will start in December 2014 for Gbaran, December 2015 for Koroama, and August 2016 for Epu, while peak daily project production is planned at 600 MMscf/d and 37,000 bbl/day of condensate. The detailed project scope and life cycle costs can be found in Appendix 1.

The project is in the Alternative Funding (AF) tranche in BP12. The JV Partners (NAPIMS & IOCs) have been engaged regarding the cost estimates (facilities, wells and owners cost) and alignment reached. Proposed funding vehicle is the Modified Carry Agreement (MCA). The agreed costs are as outlined in Table 2 in the appendix.

1.2 Project Background

The Gbaran Infill Project is part of the initial Gbaran-Ubie Phase 2 project, which passed VAR3 in November 2006, DG3 in July 2007, and completed in-house FEED in December 2008 but was put on hold due to funding constraints until a reframing workshop with Joint Venture Partners in March 2009. The reframing workshop resulted in the splitting of the initial Gbaran-Ubie Phase 2 opportunity into three separate scopes (a) Gbaran, Koroama, and Epu fields (Gbaran infill), (b) Kolo Creek Deep Fields, (c) Ubie/Oshi filed) to minimize overall capital investment, optimize SPDC's infrastructure usage, and provide a better focus for the individual sub-opportunities.

Detail design for the Gbaran Infill project was completed in 2011, in line with the contracting strategy agreed with NAPIMS that required the completion of detail design prior to receipt of the commercial bids in support of the FID decision. Tendering of the procurement and construction scope has been concluded and the selected contractors known. Project VAR4 was completed in September 2011 and all high urgency actions have been successfully completed.

1.3 Previous proposals

In April 2010, a pre-FID investment proposal of \$ 16.6mln (Shell Share) was approved for Detail design, Survey, Location preparation for Koroama field, Land acquisition, Environmental Impact Assessment studies and line pipe pre-payment. The proposal also covers the Gbaran Infill Project's share of the initial Gbaran-Ubie Phase 2 project sunk costs related to Front-End Engineering Design. All these have been completed except for the ongoing location preparation works.

In addition to the pre-FID approvals, US\$11.3mln Shell share investment has been approved, US\$8.01mln in August 2012 to accelerate the drilling, completion and hook-up of Koroama TBUV-2 NAG well as an early opportunity and US\$3.29mln in November 2012 for the re-completion of the KOMA 002T well which was accelerated as a result of location imposed constraints (inaccessibility of planned well locations as a result of flooding and unusually high water levels)

Section 2: Value proposition and strategic and financial context

The proposal aligns with SPDC JV contractual commitment to supply gas to NLNG.

2.1 Justification for Expenditure

Having taken the opportunity to accelerate Koroama TBUV2 & Koroama 002T recompletion, this proposal only seeks approval for the drilling of eight (8) NAG development wells (including one appraisal well) in Gbaran (1 NAG development well), Koroama (4 NAG development wells and 1 appraisal well) and Epu (1 NAG development well and 2 NAG development/appraisal wells), as well as the installation of the infrastructure required to evacuate the production to the Gbaran CPF. These activities must be pursued to keep the Gbaran CPF full and avoid penalties for not meeting SPDC JV gas contractual commitments to NLNG Trains 1-6 (See Fig 1) and domestic gas supply.

2.2 Production and Reserves

The Gbaran Infill Project will develop 1.3Tscf of gas and 13 Mmbbls of condensate from the Gbaran, Koroama, and Epu fields to sustain gas supplies to the Gbaran CPF and meet SPDC JV gas supply commitments to NLNG Trains 1-6 and domestic gas supply.

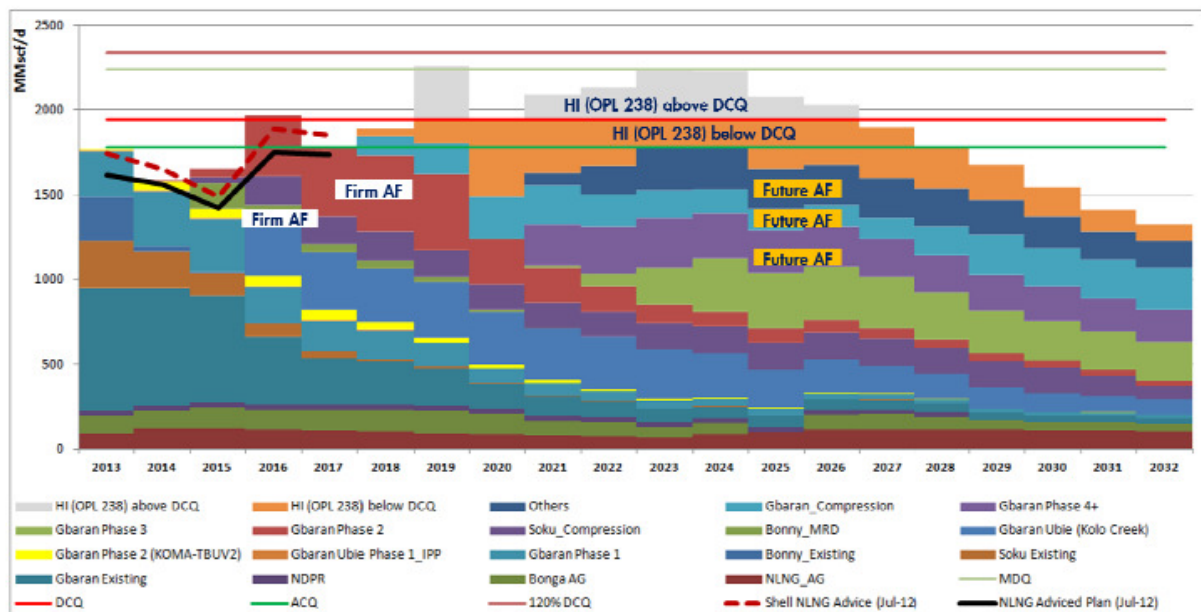


Figure 1: NLNG Trains 1 to 6 supply plot

2.3 Summary Economics

The FID economics evaluation was carried out on a forward-looking basis using production forecast and contractors cost provided by the project team. Sensitivity analysis was carried out to determine the values of the project at different production volumes and high CAPEX. Additional risk and uncertainty analysis was

also carried out which shows a 100% chance of the project returning a positive NPV. The evaluation assumed funding under the 2008 Modified Carry Arrangement (MCA) terms.

The details of the results are in Table 1 and the Tornado Plot and Profitability Plots are shown in Figures 2 & 3 in the appendix.

Table 1a: Summary economics grid for Gbaran Infill Project

PV Reference Date: 1/7/2012	NPV (S/S \$ mln)		VIR	RTEP	VTE	UTC (RT \$/boe)		Payout-Time (RT)	Maximum Exposure (RT- AT)
Cash flow forward from: 1/1/2012	0%	7%	7%	%		0%	7%	(yyyy)	\$mln (yyyy)
Base Case									
SV (\$50/bbl RT12)	318.3	135.2	0.30			4.6	6.3		
RV (\$70/bbl RT12)	437.3	203.3	0.46	25		4.6	6.3	2018	192.4(2014)
HV (\$90/bbl RT12)	534.0	258.7	0.58			4.6	6.3		
Sensitivities (using RV-RT12)									
Low Volumes (P90)		66.5	0.15						
High Volumes (P10)		266.0	0.60						
High CAPEX (P90)		196.4	0.40						
Project funded under JV		207.4	1.01						
1.5% cost markup due to BVA		192.6	0.40						
PIB		16.5	0.04						
Additional Uncertainty and Risk Analysis - using RV (only required for proposals > \$ 300 mln S/S)									
NPV(P10)		265.7	0.61						
NPV(P90)		77.4	0.17						
EMV at RV		180.6							
Probability of NPV > 0 at RV		97%							
Dispersion = EMV / (NPVP10- NPVP90) at RV		0.96							

Table 1b: Key project Parameters (Shell share)

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US\$ mln	531.6	487.5	529.8	591.4	JV +MCA
Opex (MOD)_Project	US\$ mln	NA	38.0	72.1	115.9	ABC + SCD
Production Volume	mln boe	68.7	23.9	62.4	118.6	latest Data set as per ARPR
Start Up Date	mm/yy	Dec-14	NA	Dec-14	NA	
Production in first 12 months	mln boe		5.2	5.1	4.8	The optimizer pulls more volumes from the Low and Base cases to ensure that the CPF is kept full, hence the higher volumes in the 1st

Section 3: Risks, Opportunities and alternatives

3.1 Risks and Mitigation Plans

The project employs a comprehensive Risk and Opportunity Management system, with Risks affecting the Cost and schedule analyzed and worked into the project cost estimate and schedule accordingly. The top project risks and mitigation plans are described below;

Funding constraints risks (C, E)

The proposal is for this project to be financed via Alternative Funding (AF) as agreed with Joint Venture Partners. However, the MCA agreement is yet to be signed off by the JV Partners

Mitigation: Approval for this Investment proposal is premised on the MCA agreement being in place. Based on level of progress achieved on the funding discussions with the JV Partners, there is a high probability of the MCA/Funding being in place by Jan 2013. The final requirement for the MCA sign-off (which is the NAPIMS CRC support for the execution contract award) is being worked.

HSSE & SP Risks (P, T):

HSE risks of executing relatively complex project (project transverses land, seasonally swamp and swamp terrains across several communities) have been identified and assessed using the HEMP processes /tools. Upon analysis, the threats, controls measures, top events, recovery measures were identified, with responsible action parties assigned. In addition, HSSE requirements were included and evaluated during the tendering process. The project will develop strong HSSE Leadership by SPDC and Contractor Management Team as well as leverage on National and SPDC corporate security plans, lessons learnt from Gbaran Ubie Phase 1 project, and successful HSE initiatives such as the Injury Free Club. A few Examples of the top risks includes: Risk of Hydrocarbon under pressure (Gas); Transportation (Land & Marine); Lifting and Hoisting; Security etc:

Risk of Hydrocarbon under pressure (Gas): Project involves work at the Gbaran CPF. Approved Concurrent operations plan and Matrix of Permitted Operations (MOPO) will be enforced, including robust procedure for managing Hydrocarbon under pressure (Gas) alongside Permit to work system, Positive isolation requirements, Gas testing, equipment selection/certification with 100% site supervision, etc.

Risk of Transportation (Land and Marine): A journey management procedure and plan will be instituted with Journey Managers appointed to implement the procedures. Monitoring systems and feedback processes will be in place for continuous improvement. In addition, every journey request will be challenged, and optimized where possible, to reduce exposure. Prior to embarking on any journey, the Security Operating Level (SOL) shall be confirmed.

Security Risk: The project is located in the Niger Delta, where security issues are particularly significant. This is highlighted by cases of hostage taking, armed attacks and sabotage of, especially, pipeline systems. Additionally, deteriorating Security situation in the Northern part of the Country, in the form of targeted bombing, could migrate down south and requires that this risk be carefully monitored

The amnesty programme of the federal government has helped to calm the security situation although uncertainty still pervades. Based on outcome of security risk assessment, a detailed project security plan for the project has been developed which dovetails into relevant operations security plan. The security operating level of risk will be assessed from time to time to determine necessary line of action when there is a change in risk level.

In the event of unforeseen incidents, all of the identified mitigation measures are backed up by emergency response preparedness, both on the part of the contractors and in collaboration with SPDC depending on severity.

Community related Risks (P)

The project straddles 11 main communities; hence the community stakeholder base is large and diverse. Also there are delays in completing some Gbaran Phase 1 GMoU Projects, deploying GMOUs (Steady State) in the Operating areas, and the fact that project will impact new activity area (Epu) may lead to community agitations, work stoppages and reputational damage.

- Mitigation: Community interfaces will be managed through the Global Memorandum of Understanding (GMoU) mechanism (as detailed in the project SP Plan); this will be deployed in alignment with the project schedule. Also an allowance has been made in the project budget for funding of social investment programmes

Contractor Capacity (T, O)

The high activity level and limited EPC contractor base puts pressure on contractors' capacity as they are involved in executing multiple contracts at the same time, and lead to Government pressuring IOCs to contract out with untested local emerging contractors in the effort to build local contractor base capability.

Mitigation: The project work scope has been divided in two separate work packages. Package 1 covers the facilities scope, which drives the project schedule, and Package 2 covers the flowlines and pipelines scope. The facilities scope has been recommended for award to a contractor with experience of working with SPDC whilst the flowline and pipeline scope has been recommended for award to a contractor that will be working for SPDC for the first time. The Contractors' capacities will be reviewed prior to mobilization to site and additional SPDC project management resources mobilized to support the package 2 contractor. In addition, contractor's performance will be monitored closely to enable early intervention on appearance of any red flag.

NNPC Award Approvals for EPC Contracts (C, E)

To safeguard the project schedule it is necessary to award the contract packages by Q1 2013. The commercial bids have been evaluated and award recommendation made to NAPIMS. However, approval protocols within NAPIMS/NNPC can take upwards of 6-12 months to process and contract award ahead of the formal NNPC approval could expose Shell to cost recovery issues (if NAPIMS declines to honour cash calls or approve end of year performances at OPCOM).

Mitigation: SPDC has and will continue to maintain close and rigorous engagement with NAPIMS to ensure common understanding of project priorities and urgencies. There is also a high chance of NNPC GEC /Board approvals for proposals that have passed and obtain the endorsement of the NAPIMS Contract Review Committee (CRC), which in most cases are given in a timely manner. Against this background the proposal is to secure Shell LDL approval to award the contracts packages once NAPIMS CRC endorses and forwards the award approvals to NNPC GEC / Board. It is also noteworthy that a couple of recent awards were similarly made under LDL e.g. FYIP Ph1 Offshore and Otumara pipeline and these were later approved by NNPC board some 9 – 12 months after submission as well as the Southern Swamp which is still awaiting approval. It is estimated that the risk of exposure becomes minimal once the support of the NAPIMS CRC is received.

Opportunities

The project scope includes the drilling of the Koroama SPUU-1 appraisal well, which will be completed and hooked up if successful. The potential production volume of 100MMScf/d for this well has not been accounted for in the project base case economics and therefore represents an upside.

Alternatives

SPDC has committed to supply NLNG (trains 1 to 6) for a 20-year period and gas supply to the CPF, which is expected to deliver about half of the required volumes, will decline from 2013. The alternative to developing the Gbaran Node Further Development is to develop the Gbaran Deep reservoirs. However these projects are still in the exploration stage. Efforts are being made to align these Gbaran Deep exploration wells with the Gbaran Ubie projects to save costs and to be able to hook-up these exploration wells up if prospects are promising.

Section 4: Carbon Management

Green House Gas (GHG) Emissions for the Gbaran Infill Project over the 25 year forecasted project life are estimated at 227,168 tonnes of CO₂eq; for an expected average production of about 24,000 bpd (net condensate) and 600 MMSCFD NAG. Fugitive emissions are the main source of emission amounting to about 82% of the total emissions. Venting due to routine maintenance and depressurization accounts for

14%, and the fuel gas combustion by the gas engines, for electricity generation, accounts for the remaining 4%.

Over a forecast period of ten years, projected energy intensity is 4.245E-07 GJ per tonnes of hydrocarbon produced. Regarding GHG emissions and energy consumption, this project is considered ALARP.

In addition, the following proposals have been made which will have a direct impact on emissions reduction as well as enabling accurate measurement and analysis of energy use. These include;

1. Use of fully pressure rated facilities which will eliminate the need for relief valve as ultimate safeguard for overpressure protection of facilities downstream of the wellhead. Depressurization philosophy is to depressurize the flowlines at the Gbaran CPF, where it will be flared.
2. Installation of pressure protection on the slug catcher at the Gbaran CPF to reduce demand on installed relief valve. This reduces relief events and consequently flaring emissions.
3. Provide Vent and Flare Gas Meters respectively to measure and Monitor venting/flaring incidents, frequency and flow rates

Section 5: Corporate structure, and governance

The existing corporate structure and governance arrangements of SPDC-JV with SPDC as operator still subsist for this investment.

Section 6: Functional Support and consistency with Group and Business Standards

This proposal complies with Shell Group Business Principles, policies and standards. Functional support for this proposal is provided by Projects & Technology (P&T), Finance, Social Performance, Contracting & Procurement, HSE, Operations, Legal, Security, Treasury, Controllers and Tax functions.

Section 7: Project management, monitoring and review

This is a “P&T executed” project delivered by the UIG/T/PD Major Projects team. The ORP compliant governance structure is in place, including a project specific DRB, DE and BOM. A Project Control and Assurance Plan (PCAP) has been approved that defines the applicable controls for the EXECUTE phase.

Section 8: Budget Provision

It is proposed that at FID, the project budget requirement will be from the alternative funding tranche. In line with current AF agreements, it is expected that project FID OPEX and project management costs will continue to be funded via the regular JV budgetary process.

Section 9: Group Financial Reporting Impact

MCAs are accounted for in the same way as ordinary course investments in JV projects i.e. recording resulting CAPEX, depreciation, gross revenues, royalties and taxes and associated production and reserves in line with Group Policy. The financial impact of the project is calculated in line with the base case MCA specific assumptions and is indicated in the table below.

US\$ mln	2012	2013	2014	2015	2016	Post 2016
Total Commitment	4	76	190	159	72	32
SCD OPEX	0	1	1	1	1	0
Pre-FID	0	0	0	0	0	0
Cash Flow						
Capital expenditure	4	75	189	158	71	32
Cash Flow from Operations	1	23	64	89	142	745
Cash Surplus/(Deficit)*	-3	-52	-125	-69	71	713
Profit and Loss						
NIBIAT +/-	0	3	10	31	79	431
Balance Sheet						
Average Capital Employed	2	31	126	244	298	69

Section 10: Disclosure

Material disclosure, if any, will be done in line with the Group Disclosure Guidelines.

Section 11: Financing

The pre-FID portion of this investment has been financed with JV funding. It is expected that financing for the main project scopes shall be through the MCA funding mechanism. NNPC approval has been obtained for project scope and amount; however formal sign-off is being finalized with JV partners. Commitments will be made upon NNPC sign off of MCA

Section 12: Taxation

There are no unusual taxation features.

Section 13: Key Parameters

Approval is sought for additional US\$533.7mln (Shell Share), for the drilling/completion of 9 NAG wells and the construction of infrastructure for evacuation of production to the Gbaran CPF.

Section 14: Signatures

This Proposal is submitted for approval.

Supported by:

.....
Bichsel, Matthias
ECMBi
Date.... /... /....

For Business Support:

.....
Andrew, Brown
ECAB
Date.... /... /....

Supported by:

.....
Henry, Simon
Chief Financial Officer
Date.... /... /...

For Business Approval:

.....
Voser, Peter
Chief Executive Officer
Date.... /... /....

Appendices

Economics Assumptions

- Oil PSVs of \$50/bbl @SV-RT12, \$70/bbl @RV-RT12 (Base) and \$90/bbl @HV-RT12 with Bonny offset applied.
- 2012 NLNG T1-6 price was used for gas sales to NLNG.
- Education Tax of 2% assessable profit.
- NDDC levy of 3% total expenditure.
- Gas Heating Value (GHV) of 1150btu/scf for Export gas.
- Flare Penalty of \$3.5/Mscf was applied and is not tax deductible.
- Abandonment estimated as 10% of total RT CAPEX.
- Condensate was treated as oil and taxed under Petroleum Profit Tax - PPT (PPT tax rate of 85%).

MCA Assumptions

- Profit gas ceiling of 8% IRR on carried costs.
- All costs on the MCA would be recovered through cost gas and condensate.
- Current agreement for recovery of carry costs is maintained.
- \$70.22/bbl – Condensate at PSV RV-RT in 2012.
- OPEX and PMT not carried under current MCA arrangement.
- P50 Schedule is premised on funding available by end 2012.

PIB assumptions

- PIB as per July 2012 draft version
- Gas royalty rate increased from 7% to 12.5%
- Gas tax rate increased from 30% to 80% (NHT 50% and CIT 30%)
- No ITA

Figure 2: Tornado Chart

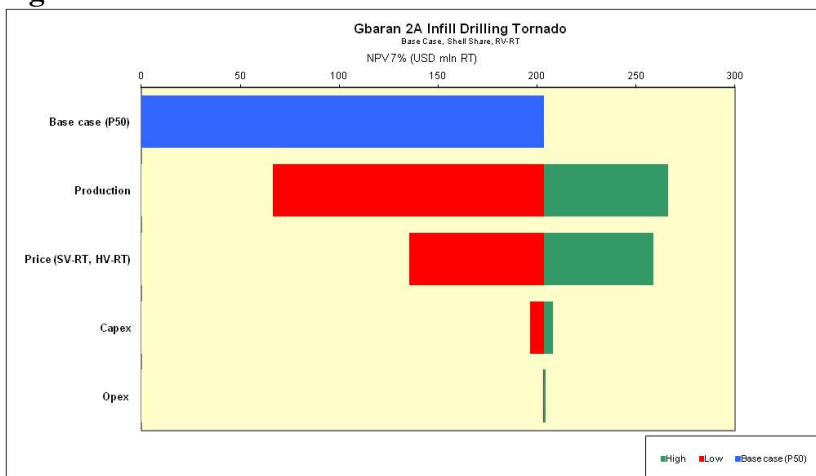
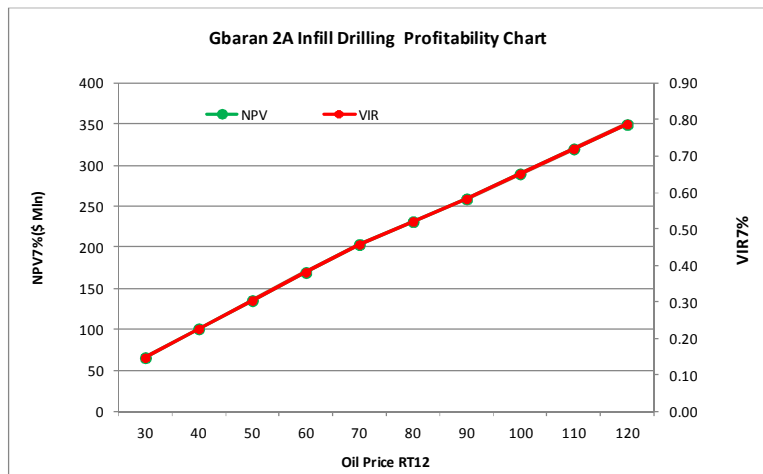


Figure 3: Project Profitability Plot



Appendix 1: Details and Cost Estimate (MOD 100% JV) for the Gbaran Infill Project

The scope of the Gbaran Infill Project consists of the following:

A. Wells

1. Drilling of Nine (9) NAG wells from three fields (1 in the Gbaran, 5 in the Koroama; including the Kororama SPUU-1 appraisal well, and 3 in Epu),

B. Gbaran CPF & Remote Sites Facilities – Package 1 Contract

1. Installation of 2 x 10MMscf/d booster compressors, and two slug catchers at the Gbaran CPF and tie-in to the existing process, electrical, control and safeguarding systems.
2. Construction of (on-plot) DSS piping, and utilities facilities at 6 remote well locations, including Field Auxiliary Rooms, Electrical substations, drain & vent vessels, corrosion inhibition packages, utility water tower and distribution systems, etc.
3. Installation of two (2) 55m microwave tower and telecommunication infrastructure at Epu-1 and Koroama manifold areas, including telecom cabinets PAGA and CCTV and radio field equipments.
4. Installation of CCTV, LAN/WAN, microwave and phone systems for all the remote locations..

C. Pipelines and Inter-Site Composite Cables – Package 2 Contract

1. Construct a 40 km network of seven carbon steel pipelines linking the remote well locations to the existing Gbaran CPF. (pipelines dimensions are 1 off 8km x 10-inch, 2 off 5.5km x 8-inch, 2 off 6km x 12-inch, 1 off 5.0km x 6-inch, and 1 off 4.2km x 10-inch)
2. Install a 30 km network of five HV/Fiber Optic inter-site composite cables linking the remote well locations to the existing Gbaran CPF (1 x 8km, 2 x 5.5km, 1 x 6km, and 1x 4.2km)

D. Accelerated scope

1. Drilling, completion and hookup of 1 NAG well (TBUV2)
2. Recompletion of 1 NAG well (Koroama 002T)

Details of the cost estimate (MOD 100% JV) for the full scope (including TBUV2 and Koroama 002T) of the Gbaran Infill Project can be found below.

50/50 MOD Cost Estimate (US\$ mln)	
Description	
Location Preparation, Drilling and Completion	259.5
Pipeline and Hook-up	66.4
NAG Facilities* (inclusive of PMT, VAT & Owners Cost)	585.3
Total CAPEX (100% JV)	911.2
SCD	13.7
Total OPEX (100% JV)	13.7
Total (100% JV)	924.8
Total (Shell Share)	533.7

Table 1: Prior Approvals (FUS\$ mln)

PRIOR APPROVALS				
F\$mln	Pre-FID	TBUV2	Koma 002T	Total
Facilities	39.5	4.5		44.0
Wells	15.9	19.4	11.0	46.3
PMT		2.1		2.1
SCD		0.7		0.7
Total	55.4	26.7	11.0	93.1
Shell Share Equity (30%)	16.6	8.0	3.3	27.9
MCA Carry Shell Share (36.67%)		8.8	4.0	12.8
Total Shell Share	16.6	16.8	7.3	40.7

Table 2: Yearly estimated expenditure (FUS\$ mln)

Description	COST PHASING						Total (Incl Prior approvals)
	2012 (Incl TBUV2 & Koma 002T)	2013 (Incl TBUV2)	2014	2015	2016	Total	
Facilities Capex 100% JV (FUS\$mln) - less PMT& SCD	2.0	74.6	213.5	193.0	83.2	566.3	605.8
Wells Capex 100% JV (FUS\$mln)	30.4	90.1	123.0	0.0	0.0	243.6	259.5
Total Capex 100% JV (FUS\$mln) - less PMT&SCD	32.4	164.8	336.5	193.0	83.2	809.9	865.3
PMT 100% JV (FUS\$mln)	11.4	12.9	12.7	6.8	2.1	45.9	45.9
Opex 100% JV (FUS\$mln)	0.6	3.8	4.5	2.7	2.1	13.7	13.7
Total 100% JV (FUS\$ mln)	44.4	181.5	353.7	202.5	87.4	869.4	924.8
Total 100% JV (FUS\$ mln) excluding Pre-FID & Prior Approvals							831.8
Shell Share Equity (30%)	13.3	54.4	106.1	60.7	26.2	260.8	277.5
MCA Carry Shell Share (36.67%)	11.9	60.4	123.4	70.8	30.5	297.0	284.2
Total Shell Share (FUS\$ mln)	25.2	114.9	229.5	131.5	56.7	557.8	561.7
This proposal Total Shell Share excluding Pre-FID (FUS\$ mln)							533.7

GLOSSARY

AF – Alternative Funding
CPF – Central Processing Facility
DPR – Department of Petroleum Resources
DRB – Decision Review Board
ESFS – Estimate & Schedule Fact Sheet
FEED – Front End Engineering Design
GHG – Green House Gas
GMOU – Global Memorandum of Understanding
HEMP – Hazard & Effects Management Process
HSE – Health, Safety & Environment
HV – High Value
IOC – International Oil Companies
MCA – Modified Carry Agreement
MOD – Money of the Day
MOPO – Matrix of Permitted Operations
NAG – Non Associated Gas
NAPIMS – National Petroleum Investment Management Services
NCDMB – Nigerian Content Development Management Board
NLNG – Nigeria Liquefied Natural Gas Limited
NPV – Net Present Value
PIB – Petroleum Industry Bill
PMT – Project Management Cost
PPT – Petroleum Profit Tax
PSV – Project Screening Value
RFSU – Ready For Start Up
RT – Real Term
RTEP – Real Term Earning Power
RV – Ranking Value
SCD – Sustainable Community Development
STDWS – Short Term Drilling & Workover Sequence
SV – Screening Value
VIR – Value Investment Ratio

Project Title: Gbaran-Ubie Phase 2A (Infill)
Project Location & Country: SPDC, Nigeria

Resident Name

Mandatory for Upstream and mandatory for Exploration, Development and NBD projects ≥ US\$ 100 mln IS\$ but strongly recommended for all projects < 100 mln US\$

CHECK	
developed reserves additions minus cum production	
2P Reserves Developed	SEC Proved Developed

[illegible]

negative numbers are
incorrect

CHECK	
developed reserves additions minus cum production	
2P Reserves Developed	SEC Proved Developed
0.00	0.00
0.00	0.00
0.00	0.00

[illegible]

negative numbers are incorrect

Signature :

Signature :

Note: Production forecast and PDRA forecast need to be fully consistent with economic and financial evaluations and results presented in the GIP. HCM forecast need to be captured in NRV-MS, which is the single data source for HCM.

ESTIMATE & SCHEDULE FACT SHEET
to be included in GIP and PCN submissions
Gbaran Ubie Infill Project
LAND, East.

Version 2.6

Confidential

Approved Cost & Schedule Estimate
C-12060

Project No.:

Planner:

Estimator: Emaviwe, Anthony

Case: Base

Harry, Bateyim

Rates of Exchange are as per SI-SX Data Set

Costs are in: USD Millions

EDM Date:

1-Jul-11

Market Scenario: LE
Estimate Start / End: FID Apr-2013 / Project Completion Dec-2016

Category

Facilities

Wells

Owners Cost (i)

(incl. Insurance, pre-FID & Taxes)

EPC Premium (ii)

Contingency

(i) 16.44%, (ii) 0% Facilities 16%

Inflation

Wells 0%

Total Costs			
			408
			217
			103
			78
			84
			35
P10	P50	P90	
	867	925	1,002
-8%			11%
Project Applied		Verified, Not Applied	
		12	

Enterprise Framework Agreement Effects

EFA Effects incorporated in the P50 above:

Assumptions

Estimate &
Schedule
Premise

Flowlines & manifold of duplex steel material, slug catcher, pig trap systems and tie-in estimates have been built using CAPCOST based on MTO list from FEED deliverables. Pipeline estimates were prepared based on ongoing as well as recently completed pipeline installation contracts. Civil infrastructure estimates were built using corporate civil call-out contracts. Latest Estimate (LE) escalation factors data set have been applied in line with provisions of the Jan 2012 Capital Cost Outlook. Probabilistics cost risk analysis using @Risk has been used to calculate project contingencies. Owners costs were derived bottoms up using approved project manning profile. Well costs have been calculated using SPDC well cost estimating template by well engineering and has been adopted in line with agreed in-house SPDC methodology. Zero contingency has been applied to well estimate based on advice from Well Engineering and their assured input. Schedule durations were based on recently completed and ongoing projects with similar activities. Probabilistics risk analysis using Primavera risk analysis tool has been carried out on the schedule to derive the contingencies.

Execution
Strategy Premise

Two EPC packages will be used for the execution of this project, one for pipelines and the other for facilities and tie-in works. Site preparation required for well drilling operations will be undertaken using SPDC Corporate Civil works call-out contracts.

Contract Strategy

EPC contract packages on lumpsum basis will be instituted for facilities and pipeline works. A project management services contract will be used to provide quality assurance & control as well as certification services in the design, procurement, fabrication, construction, pre-commissioning/commissioning of this project.

Key Project Risks

Security/communities issues, Funding issues (could impair contractors' cash flow resulting in delays), HSE risks, Internal and external interface.

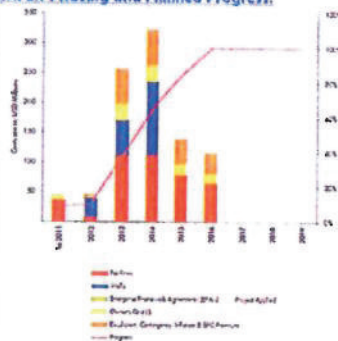
Exclusions

SPDC financing of interest during construction. Management adjustment of 2 - 4 months have been applied on P90 dates, also calculated milestones were moved to the nearest next quarter. The applied management adjustments are to accommodate for any force majeure, no adjustment has been made to the P90 costs.

Benchmarking &
Metrics

Pipeline & facilities costs have been benchmarked with recently completed projects. Schedule durations have been benchmarked with completed projects. IPA external benchmarking was undertaken for this project.

CAPEX Phasing and Planned Progress:



Key Schedule Dates:		
Phase	Finish (P50)	Finish (P90)
FID	Apr-2013	Jun-2013
Detailed Design	Jul-2013	Sep-2013
Contract Award	Jul-2013	Sep-2013
Procurement	Oct-2014	Feb-2015
Mechanical Completion (VZTX-2)	Dec-2014	May-2015
Mechanical Completion (Koroama)	Oct-2015	Feb-2016
Mechanical Completion (Epu)	Jul-2016	Nov-2016
RFSU (VZTX-2)	Jan-2015	Aug-2015
RFSU (Koroama)	Dec-2015	May-2016
RFSU (Epu)	Oct-2016	Feb-2017
Project Completion	Dec-2016	May-2017

Project Services Manager
Date: 29-Nov-2012
Name: Nyakaze, Eneka
Signature: [Signature]
VP Project Services
Date: 29/11/2012
Name: Mes, Hans
Signature: [Signature]

Project Manager
Date: 29.11.12
Name: Ojo, Afolabi
Signature: [Signature]
EVP Projects
Date: [Blank]
Name: Kretzers, Rob
Signature: [Blank]