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

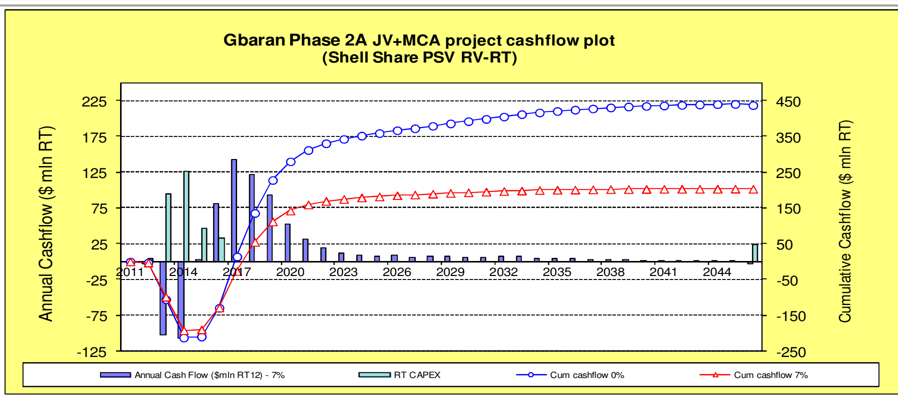
Summary Information

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	(see table below)

Main commitments

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**

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)	(see chart below)



Summary economics (Shell Share)

Summary Economics (RV-RT12)	NPV7 (USD mln)	RTEP (%)	VIR7
Base case	203.3	25	0.46
High Capex	196.4	22	0.40

Section 1: The Proposal (Management Summary)

1.1 Management Summary

This Group Investment Proposal requests approval for funding of US$924.8mln 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 1 below.

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$3.29 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.

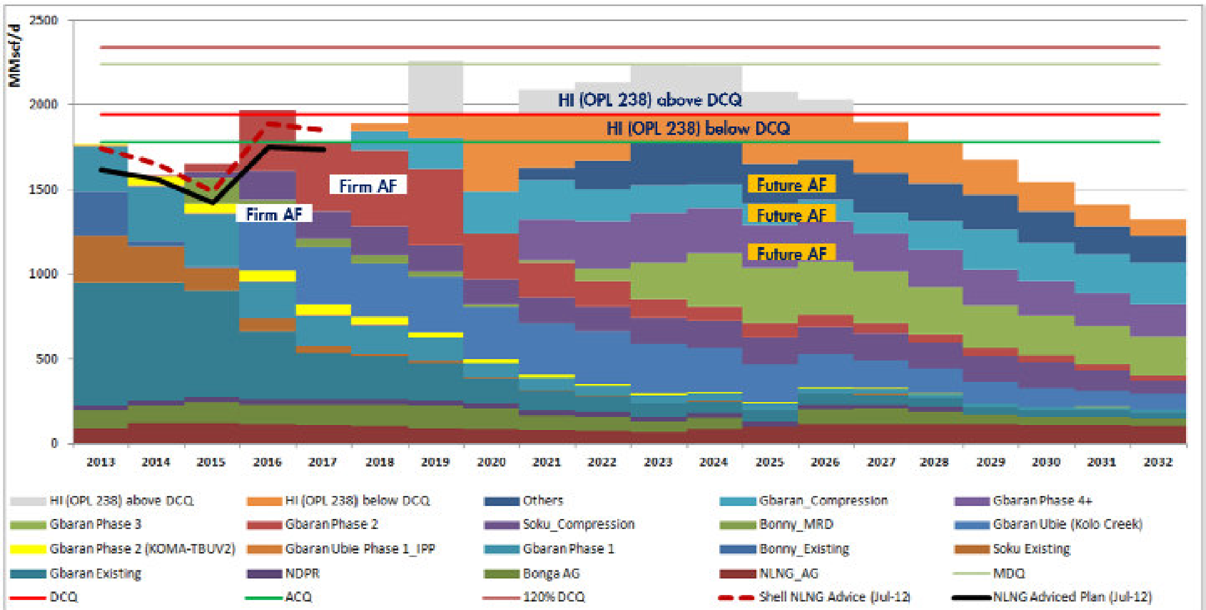


Figure 1: NLNG Trains 1 to 6 supply plot

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 2 and the Tornado Plot and Profitability Plots are shown in Figures 2 & 3.

Table 2a: 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**							
NPV(P90)		**77.4**							
EMV at RV		**180.6**							
Probability of NPV > 0 at RV		**97%**							
Dispersion = EMV / (NPVP10-NPVP90) at RV		**0.96**							

Key project Parameters (Shell share)

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	247.0	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 year of production

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.

Mitigation: Efforts have been intensified at all levels to ensure that the alternative funding discussions are concluded by December 2012 and funds available in January 2013. In addition, a contingency of 3mths delay to FID and contract award have been included in Schedule Risk analysis (cost within this GIP). 1) .

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 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 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, Supply Chain Management, HSE, Operations, Legal, Security, Treasury 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 MCA's are calculated in line with the base case MCA specific assumptions and are 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. Formal sign-off is being finalized with JV partners. However, it is planned to make commitments upon NAPIMS approval of MCA figures

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

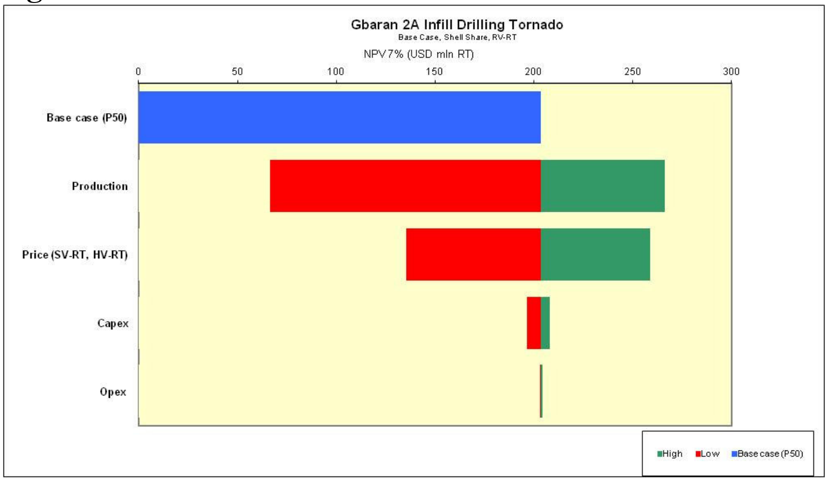
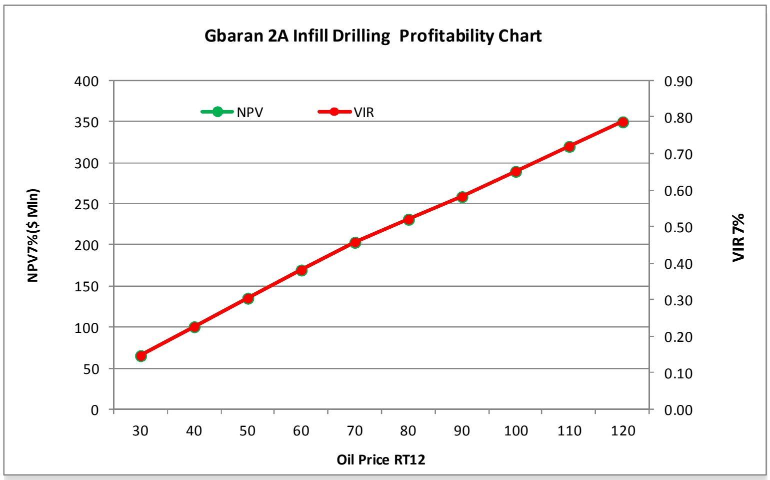


Figure 3: Project Profitability Plot



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: Yearly estimated expenditure (FUS$ mln)

	COST PHASING						
Description	**Previously approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**
Facilities Capex 100% JV (FUS$mln) - less PMT& SCD	44.0	0.0	161.1	191.5	120.7	88.5	605.8
Wells Capex 100% JV (FUS$mln)	46.3	2.0	76.3	134.8	0.0	0.0	259.5
Total Capex 100% JV (FUS$mln) - less PMT&SCD	90.3	2.0	237.5	326.3	120.7	88.5	865.3
PMT 100% JV (FUS$mln)	2.1	9.9	12.3	12.7	6.8	2.1	45.9
Opex 100% JV (FUS$mln)	0.7	0.0	3.8	4.5	2.7	2.1	13.7
Total 100% JV (FUS$ mln)	**93.1**	**11.9**	**253.5**	**343.5**	**130.2**	**92.6**	**924.8**
Total 100% JV (FUS$ mln) excluding Pre-FID							**831.8**
Shell Share Equity (30%)	27.9	3.6	76.1	103.1	39.1	27.8	277.5
MCA Carry Shell Share (36.67%)	0.0	0.7	87.1	119.7	44.3	32.4	284.2
Total Shell Share (FUS$ mln)	**27.9**	**4.3**	**163.1**	**222.7**	**83.3**	**60.2**	**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

Lifecycle HCM Forecast Sheet

Version 2.0 | Confidential

Project Title

Project Location & Country

Project No.:

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

OIL/NGL [mln bbl] DG/Key event	Date (mm)-yy	2U Prospective Resources Additions: Play and/or Lead	2U Prospective Resources Additions: Prospect	2C Contingent Resources Additions: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: Dev. Unclarified or On Hold: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves Additions: Undeveloped: Post DG3	PRMS 2P Reserves Additions: Undeveloped: Post-DG4	PRMS 2P Reserves Additions: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed		Annual Production	CHECK developed reserves additions minus cum produciton: 2P Reserves Developed	CHECK developed reserves additions minus cum produciton: SEC Proved Developed
IPa_event	IPa_date	IPa_Playlead_Add	IPa_Prospect_Add	IPa_NV_Add	IPa_Unclarified_Ad	IPa_Hold_Add	IPa_PreDG1_Add	IPa_PostDG1_Add	IPa_PostDG2_Add	IPa_PostDG3_Add	IPa_PostDG3_Und	IPa_PostDG4_Und	IPa_Dev_Add	IPa_SEC_Undev	IPa_SEC_Dev_Add		IPa_Ann_Prdn	IPa_Cum_Exp_Dev	IPa_Cum_Prv_Dev
DG1	Jun-05																	0.0	0.0
DG2	Jun-06																	0.0	0.0
DG3	Aug-09									0.3	3.3	0.0	0.0	0.2				0.0	0.0
FID	Jan-13									0.0	0.0	0.0	0.0	0.0				0.0	0.0
OSD	Dec-14									0.0	0.0	0.0	0.0	0.0				0.0	0.0
										0.0	0.0	0.0	0.0	0.0				0.0	0.0
										0.0	0.0	0.0	0.0	0.0				0.0	0.0
										0.4	0.0	0.0	0.0	0.0				0.0	0.0
																		0.0	0.0
																		0.0	0.0
																		0.0	0.0
																		0.0	0.0
																		0.0	0.0
																		0.0	0.0
																		0.0	0.0
	2013									-0.7	0.7	0.0	0.0	0.1	0.0	0	0.0	0.0	0.0
	2014									0.0	-3.3	0.0	3.3	0.0	1.0	0	0.0	3.3	1.0
	2015									0.0	-0.4	0.0	0.4	-0.2	0.4	0	0.2	3.6	1.3
	2016									0.0		0.0	0.0	0.0	0.1	0	0.7	2.8	0.6
	2017									0.0	-0.3	0.0	0.3	-0.1	0.1	0	0.7	2.4	0.0
	2018									0.0	0.0	0.0	0.0	0.0	0.7	0	0.6	1.8	0.1
	2019									0.0	0.0	0.0	0.0	0.0	1.0	0	0.6	1.2	0.5
	2020									0.0	0.0	0.0	0.0	0.0	0.5	0	0.4	0.8	0.6
	2021									0.0	0.0	0.0	0.0	0.0	0.2	0	0.3	0.5	0.5
	2022									0.0	0.0	0.0	0.0	0.0	0.0	0	0.2	0.4	0.4
	2023									0.0	0.0	0.0	0.0	0.0	0.0	0	0.1	0.3	0.3
	2024									0.0	0.0	0.0	0.0	0.0	0.0	0	0.1	0.2	0.2
	2025									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.2	0.2
	2026									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.2	0.2
	2027									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.1	0.1
	2028									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.1	0.1
	2029									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.1	0.1
	2030									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.1	0.1
	2031									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.1	0.1
	2032									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.1	0.1
	2033									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2034									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2035									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2036									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2037									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2038									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2039									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2040									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2041									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2042									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2043									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2044									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2045									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
	2046									0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
later years										0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0
Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	4.0		4.0	negative numbers are incorrect	

OIL/NGL [mln bbl]		2U Prospective Resources: Play and/or Lead	2U Prospective Resources: Prospect	2C Contingent Resources: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: Dev. Unclarified or On Hold: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves: Undeveloped: Post DG3	PRMS 2P Reserves: Undeveloped: Post-DG4	PRMS 2P Reserves: Developed	SEC Proved Reserves: Undev	SEC Proved Reserves: Developed
ARPR 1.1.2011	before last	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.7	0.0
ARPR 1.1.2012	last	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.7	0.0

GAS [bln sm3] DG/Key event	Date (mm)-yy	2U Prospective Resources Additions: Play and/or Lead	2U Prospective Resources Additions: Prospect	2C Contingent Resources Additions: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: Dev. Unclarified or On Hold: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves Additions: Undeveloped: Post DG3	PRMS 2P Reserves Additions: Undeveloped: Post-DG4	PRMS 2P Reserves Additions: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed	Annual Production	CHECK developed reserves additions minus cum produciton: 2P Reserves Developed	CHECK developed reserves additions minus cum produciton: SEC Proved Developed
DG1	Jun-05																0.00	0.00
DG2	Jun-06																0.00	0.00
DG3	Aug-09									2.51	8.29	0.00	0.00	0.12	0.00		0.00	0.00
FID	Jan-13									0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
OSD	Dec-14									0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										-0.60	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
										0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
	2013									-1.91	1.91	0.00	0.00	0.72	0.00	0.00	0.00	0.00
	2014									0.00	-7.22	0.00	7.22	0.00	2.31	0.01	7.21	2.30
	2015									0.00	-0.57	0.00	0.57	-0.12	0.12	0.18	7.60	2.24
	2016									0.00	0.00	0.00	0.00	0.00	0.15	1.05	6.55	1.34
	2017									0.00	-2.41	0.00	2.41	-0.72	0.92	1.29	7.66	0.96
	2018									0.00	0.00	0.00	0.00	0.00	1.06	1.36	6.30	0.66
	2019									0.00	0.00	0.00	0.00	0.00	2.58	1.29	5.02	1.96
	2020									0.00	0.00	0.00	0.00	0.00	2.38	0.92	4.09	3.41
	2021									0.00	0.00	0.00	0.00	0.00	0.54	0.70	3.40	3.26
	2022									0.00	0.00	0.00	0.00	0.00	0.10	0.43	2.96	2.92
	2023									0.00	0.00	0.00	0.00	0.00	0.03	0.29	2.67	2.66
	2024									0.00	0.00	0.00	0.00	0.00	0.00	0.24	2.43	2.42
	2025									0.00	0.00	0.00	0.00	0.00	0.00	0.20	2.23	2.22
	2026									0.00	0.00	0.00	0.00	0.00	0.00	0.21	2.02	2.01
	2027									0.00	0.00	0.00	0.00	0.00	0.00	0.16	1.86	1.85
	2028									0.00	0.00	0.00	0.00	0.00	0.00	0.18	1.68	1.67
	2029									0.00	0.00	0.00	0.00	0.00	0.00	0.18	1.51	1.50
	2030															0.16	1.34	1.33
	2031															0.16	1.18	1.17
	2032															0.16	1.02	1.01
	2033															0.17	0.85	0.84
	2034															0.12	0.73	0.72
	2035															0.11	0.62	0.61
	2036															0.10	0.53	0.52
	2037															0.09	0.44	0.43
	2038															0.08	0.36	0.35
	2039															0.07	0.29	0.28
	2040															0.05	0.24	0.23
	2041															0.04	0.20	0.19
	2042															0.04	0.17	0.16
	2043															0.03	0.13	0.12
	2044															0.03	0.10	0.09
	2045															0.03	0.08	0.07
	2046															0.03	0.05	0.04
later years		0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.04	0.01	0.00
Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.2	0.0	10.2	10.19	negative numbers are incorrect	

Gas [bln sm3]		2U Prospective Resources: Play and/or Lead	2U Prospective Resources: Prospect	2C Contingent Resources: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: Dev. Unclarified or On Hold: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves: Undeveloped: Post DG3	PRMS 2P Reserves: Undeveloped: Post-DG4	PRMS 2P Reserves: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed
ARPR 1.1.2011	before last	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.17	0.00	0.00	0.00	0.00
ARPR 1.1.2012	last	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.94	0.00	0.00	0.56	0.00

	VP Techncical (or VP-X)	RDL-RE (RXC or RXHM)
Date :		
Name :		
Signature :		

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

ESTIMATE & SCHEDULE FACT SHEET
to be included in GIP and PCN submissions

Version 2.6 Confidential

Gbaran Ubie Infill Project

Approved Cost & Schedule Estimate

LAND, East.

Project No.: C-12060

Estimator: Emaviwe, Anthony

Planner: Harry, Bateyim

Case: Base

Rates of Exchange are as per SI-SX Data Set

Market Scenario: LE Estimate Type: 3

Costs are in: USD Millions

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

EDM Date: 1-Jul-11

Category			Total Costs
Facilities			408
Wells			217
Owners Cost (i)	(incl. Insurance, pre-FID & Taxes)		103
EPC Premium (ii)			78
Contingency	(i) 16.44%, (ii) 0% Facilities 16%	Wells: 0%	84
Inflation			35

	P10	P50	P90
	867	925	1,002
	-8%		11%

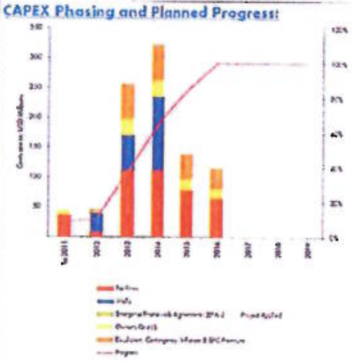
Enterprise Framework Agreement Effects	Project Applied	Verified, Not Applied
EFA Effects incorporated in the P50 above:	12	

OK

Assumptions

Estimate & Schedule Premise	Flowlines & manifold of duplex steel material, slug catcher, pig trap systems and tie-in estimates have been built using CAPCO$T 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		Project Manager	
Date:	29-NOV-2012	Date:	29. 11. 12
Name:	Nwakaeze, Emeka	Name:	Ojo, Afolabi
Signature:		Signature:	

VP Project Services		EVP Projects	
Date:	29/11/2012	Date:	
Name:	Mes, Hans	Name:	Kretzers, Rob
Signature:		Signature:	