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$463.5mln Shell share, MOD, 50/50 is requested for approval in this proposal of the 100% JV estimate of US$733.4mln. US$9.0mln 100% JV has been approved in the Pre-FID proposal. This proposal includes Shell equity share (30%) of US$220mln and Shell's MCA commitment on NNPC Share of US$243.5mln
Project	Kolo Creek Deep Development and Evacuation to Soku gas plant.

Main commitments

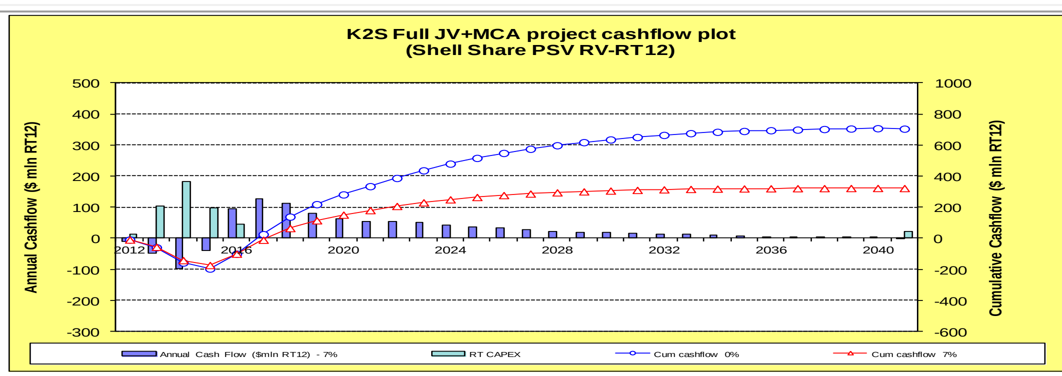
Description	Previously approved Pre-FID (100% JV)	Previously approved Pre-FID (30% Shell Share)	Requested Budget (100% JV)	Complete Budget (100% JV)	Complete Budget (30% Shell Share)	NNPC MCA Carry (36.67% Shell Share)	Total Shell Share (Equity + Carry)	This Proposal (30% Shell Share)	Total Shell Share (Equity + Carry) This Proposal
NAG Wells			244.0	244.0	73.2	89.5	162.7	73.2	162.7
Facilities and Pipelines*	9.0	2.7	477.5	486.5	145.9	154.0	300.0	143.2	297.3
Total CAPEX ($ mln)			**721.5**	**730.5**	**219.1**	**243.5**	**462.6**	**216.4**	**459.9**
SCD			12.0	12.0	3.6		3.6	3.6	3.6
Total OPEX ($ mln)			**12.0**	**12.0**	**3.6**		**3.6**	**3.6**	**3.6**
Total Project ($ mln) excl Capitalized interest	**9.0**	**2.7**	**733.4**	**742.4**	**222.7**	**243.5**	**466.2**	**220.0**	**463.5**

Capitalized interest of US$48.9mln on SS + MCA Carry is excluded from the headline size

*Includes PMT cost of US$60.1mln 100% (US$18mln SS) and Pre-FID cost of US$9mln 100% (US$2.7mln SS) which are not included in the MCA SS calculations - refer to Table 2 in Appendix

Reserves/ Resources	The project will mature economic 2P reserves of 462.9Bscf (13.1bln sm3) of gas and 16.8MMstb of NGL (Shell share) to production and transferring equivalent SEC proved reserves from Proved Undeveloped (PUD) to Proved Developed (PD) with positive impact on SPDC's Reserves addition. The transfer of PUD reserves to PD will commence in 2015 with 94.3Bscf (2.67bln sm3) of gas and 3.3MMstb of NGL (Shell share) respectively.
Production	Production: Incremental gas production from this project peaks at 353MMscf/d with associated condensate production of 18.9kbopd (172.2MMscf/d and 9.2kbopd Shell share) in 2017 to sustain gas supplies to the Soku gas plant and meet SPDC JV gas supply commitments to NLNG Trains 1 to 6.
Source and form of financing	This project is to be financed via the Alternative Funding (AF) mechanism. 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)



Note: SPDC Upstream only (Midstream NLNG not included)

Summary economics	Summary Economics (RV-RT12)	NPV7 (USD mln)	RTEP (%)	VIR7
	Base Case	322.2	31.0	0.84
	High CAPEX	315.6	29.1	0.75

Section 1: The Proposal (Management Summary)

1.1 Management Summary

This Group Investment Proposal requests approval for funding of US463.5mln Shell Share ($220mln Equity & $243.5mln Carry) to progress the execution of the Kolo Creek Deep field development Project.

RDS Board support for this project was secured in December 2012 as part of the GU2 bundle. Tables 3 & 4 in Appendix 2, show that this GIP is aligned with the board approved GFP, in which it was stated that individual investment proposals for the projects part of the Bundle would be approved at the right authority level, for a Final Investment Decision (FID). With the Modified Carry Agreement now signed 16 May 2013 between NNPC, NAOC, TOTAL and SPDC agreeing the financing mechanism, this FID support is now requested.

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

1.2 Project Background

In 2009 the Gbaran-Ubie Phase 2 project was re-framed and a number of alternative concepts evaluated for the evacuation of the Kolo Creek Deep gas. Taking into consideration the declining Soku production, the resource base in the Soku and Gbaran Nodes, the need to minimize capital investment and optimize SPDC's infrastructure usage, it was proposed that Kolo Creek Deep gas be processed at the existing Soku gas plant instead of building a new, third gas treatment train at the Gbaran CPF. The KoloCreek to Soku project passed VAR4 in July 2011 and all high urgency actions have been successfully closed out. Also, tendering for the EPC contract was concluded in 2012 and award recommendation approved by NNPC in February 2013

The Project will develop 1.5Tscf of gas from Kolo Creek Deep to the Soku Gas Plant for processing and sales to NLNG Trains 1 to 6. The project scope includes the drilling/completion of four (4) NAG wells into the F2 reservoir, three (3) NAG wells into the F1 reservoir as well as one (1) appraisal well in the F1 reservoir. A 20-inch x 40 km pipeline would be installed for evacuation of the production to the Soku gas plant. The project would also engineer, procure and install API 10000 DSS manifold/flowliines and tie-in to exiting utilities at KoloCreek

1.3 Targets

Economics evaluation was based on BP12 production forecast and maturation schedule which had FID in January 2013 and P50 RFSU in January 2016. However, due to the delay in concluding MCA discussions, FID has been revised to June 2013 with attendant impact on the project P50 RFSU date. The project is now scheduled to come on-stream in June 2016. The project cost and schedule targets are outlined in Table 1 below while the detailed project scope and life cycle costs are shown in Appendix 2.

	P50	P90
Total Project Cost F$mln *CAPEX + OPEX*	742	843
RFSU: *Facilities completed, wells drilled and hooked up*	June 2016	September 2016

Table 1: Project Target

1.4 Previous proposals

In April 2010, a pre-FID investment proposal of $ 2.7mln (Shell Share) was approved for the FEED, Survey, Land acquisition, and for conducting EIA studies for the Kolo Creek Deep to Soku Project. All of these have been completed except land acquisition which is ongoing and not on the critical path.

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

The proposed expenditure is required for the drilling/completion of eight (8) NAG wells (including one appraisal well) and infrastructure for evacuation of the production to the Soku gas plant (See Figure 1: location map). These activities must be pursued to prevent the risk of shortfall of gas supplies to the Soku gas plant and the risk of not being able to maintain SPDC JV gas contractual commitments to NLNG Trains 1 to 6.

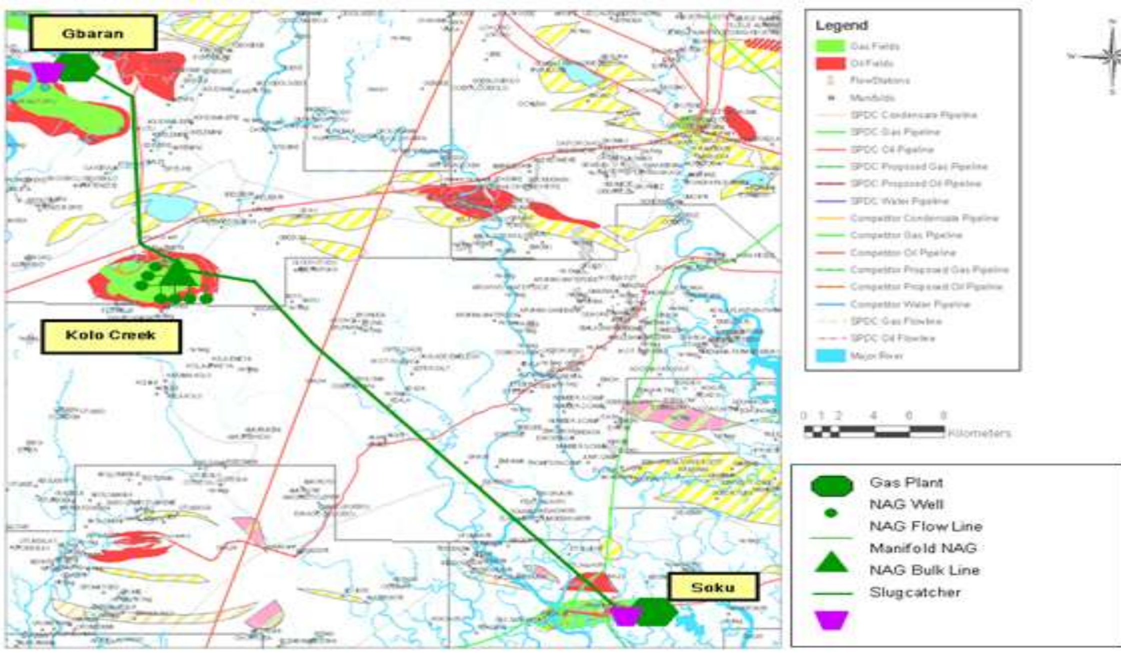


Figure 1: Location Map

The Kolo Creek Deep development to Soku will develop 1.5 Tscf of gas and 52 MMSTB of condensate from the Kolo Creek F1 and the F2 reservoirs to sustain gas supplies to the Soku gas plant and meet SPDC JV gas supply commitments to NLNG Trains 1 to 6 (See Figure 2).

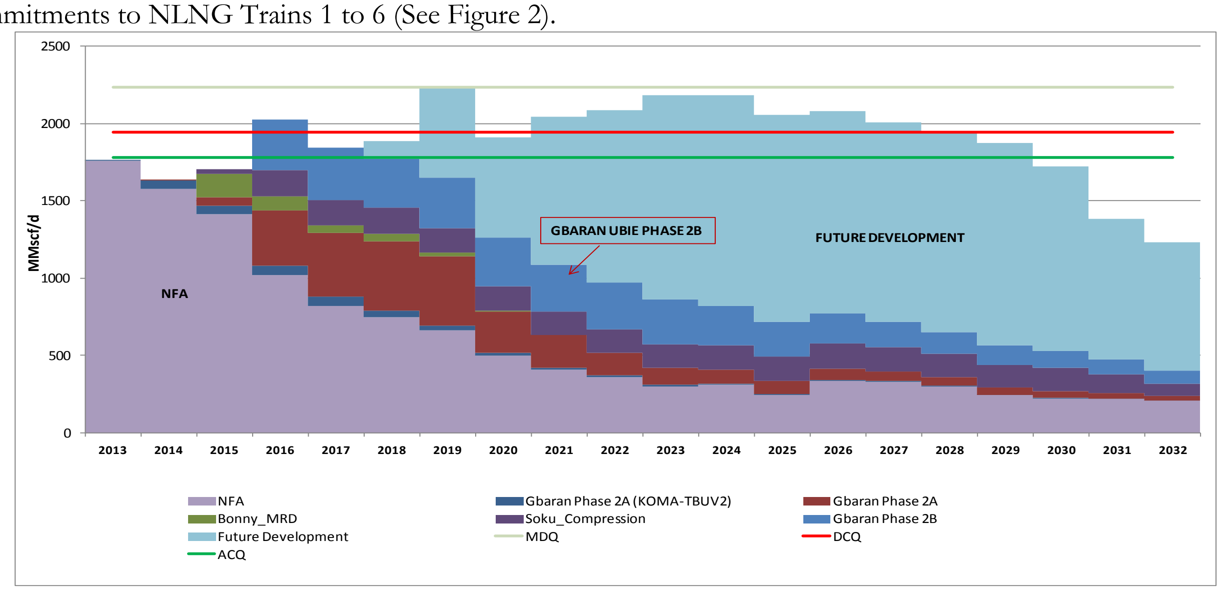


Figure 2: NLNG Trains 1 to 6 supply profile

2.2 Summary Economics

The economic evaluation was carried out on a forward-looking basis using production forecast and contractors cost. Sensitivity analysis was carried out to test the robustness of the project at different production volumes and CAPEX. Additional risk and uncertainty analysis was also carried out and shows a 100% chance of the project returning a positive NPV. The evaluation assumed funding under the agreed Modified Carry Arrangement (MCA) terms with full Shell share costs reflected (Shell equity + Shell share of the Carry). Economics is Upstream only (does not capture midstream value) and is based on 2012 PSVs.

A sensitivity analysis of the current view of the PIB is also included. The details of the results are in Table 1 while the Tornado Plot and Profitability Plot are shown in the appendix 1 (Figures 1 & 2)

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)	513.8	224.3	0.59						
RV ($70/bbl)	704.6	322.2	0.84	31.0	1.6	2.6	4.0	2017	196.5 (2015)
HV ($90/bbl)	864.2	404.5	1.06						
BEP* (RT $/bbl)									
Sensitivities (using RV-RT12)									
High CAPEX (P90)		315.6	0.75						
Low CAPEX (P10)		326.3	0.94						
High Reserves (P10)		398.9	1.04						
Low Reserves (P90)		203.2	0.53						
Full Life Cycle		321.4	0.83						
Project with ring fencing		305.7	0.80						
JV Funding		325.3	1.81						
PIB(May 2012 version Technical Committee draft)		119.3	0.29						
1-Yr Scehdule Acceleration		347.8	0.91						
1-Yr Production delay		299.5	0.82						
1.5% cost markup due to BVA issues		312.9	0.77						
Additional Uncertainty and Risk Analysis - using RV									
NPV(P10)		445.6	1.23						
NPV(P90)		172.8	0.40						
EMV at RV & eVIR at RV		312.6	0.82						
Probability of NPV > 0 at RV		100%							
Dispersion = EMV / (NPVP10-NPVP90) at RV		1.1							

Table 1: Summary economics grid for Kolo Creek Deep to Soku (Shell Share)

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	459.9	413.9	459.9	505.9	JV+MCA
Opex (MOD)_Project	US$ mln	NA	34.3	41.8	52.0	ABC+SCD
Production Volume	mln boe	96.9	57.2	97.2	122.6	Reduced Deferments
Start Up Date	mm/yy	Jan-16	Dec-15	Jan-16	May-16	
Production in first 12 months	mln boe			8.2		

Table 2: Key project Parameters (Shell share) used for the economics analysis

The economics for the entire GU2 MCA Project Bundle, as was approved by the RDS Board in December 2012 for the upstream and midstream (NLNG) elements is summarized below, and are still the same for the overall project MCA bundle:

	Upstream Only		Integrated Up/Midstream	
Summary Economics (RT12)	NPV7 ($mln)	VIR7	NPV7 ($mln)	VIR7
Base case (RV-RT $70/bbl)	706	0.54	1656	1.26
Base case (HV-RT $90/bbl)	903	0.69	2038	1.55
PIB case (RV-RT $70/bbl)	91	0.07	1041	0.81
PIB case (HV-RT $90/bbl)	168	0.13	1303	1.01

Section 3: Risks, Opportunities and alternatives

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 and schedule accordingly. The top project risks and mitigation plans are described below

NNPC Cost Overrun Risk

Project is to be financed via Alternative Funding (AF) as it is not carried on the JV base budget. The NAPIMS approved budget of US$684.4mln excludes prior year costs and part of the P50 contingency in the cost estimate. Furthermore, MCA funding is available for the P50 cost as agreed in 2012. With the project having other material risks to be mitigated, any overrun on the P50 estimate will trigger funding challenges.

Mitigation: Enforce rigorous cost control & Management of Change process to achieve project execution within the NAPIMS mandate. However, in a situation where overrun of the cost in the AF (MCA) agreement is envisaged, NAPIMS and IOC Partners will be engaged and upon agreement, additional budget will be sought from equity contribution of the JV Partners via the base JV budget or Carrying Parties (IOCs) in line with the AF (MCA) agreement. All efforts will be made to ensure that any cost overrun can be justified for base JV funding.

Petroleum Industry Bill (PIB)

For over 10 years now Nigeria is considering to change their Petroleum Laws (PIB) including fiscal terms. A sensitivity based on the July 2012 PIB draft version, which was submitted to the National Assembly for consideration, was carried out as part of the economic evaluation. It showed the project will not meet the screening hurdle rates (upstream only) if this version of the PIB is passed into law. It should be noted that on an integrated bases (including the Shell share midstream NLNG value) the projects are still attractive and will meet the screening hurdle rates even under the PIB July 2012 version (as indicated in the economic table above under 'PIB case').

Mitigation: The Shell PIB team in collaboration with Industry Group (OPTS/CIG) have combined to continue dialogue and engagement, based on a structured and detailed plan across all stakeholders group locally and internationally. The government has openly acknowledged the need for an investment friendly Act and changes are being collated for submission to the National Assembly (parliament). If indeed a PIB passes during the present administration (election planned in 2015) which is still highly uncertain, it is reasonable to assume a more investor friendly PIB will emerge in the end.

HSE and Security Risks

HSE risks of executing a complex project with novel technologies (e.g. use of API 10,000 piping class and the drilling of HP wells) in complex environment i.e. geographic complexities (project transverses land, seasonally swamp and swamp terrains across 2 states) 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. A few Examples of the top risks includes: Risk of Hydrocarbon under pressure (Gas); Transportation (Land & Marine); Lifting and Hoisting; Security etc.

Land Acquisition

Acquisition of land required for right-of-way is yet to be completed. The Lands Compensation Board has approved rates for compensation of the land owners and discussions with the Land owners have been completed. Payment has been initiated. Ideally land acquisition should be completed prior to FID as land owners' leverage increases considerably afterwards.

Mitigation: Expedite compensation payment to land owners

Risk of Hydrocarbon under pressure (Gas): Project involves work at Soku gas plant and Kolocreek Oil/ NAG manifold. 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.

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

Mitigation: 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 risk level will be assessed from time to time to determine necessary line of action when there is a change in risk level.

- All of the identified mitigation measures are backed up by emergency response preparedness, in the event of unforeseen incidents.
- In addition, HSE requirements were included and evaluated during the tendering process. The project will also develop strong joint HSE Leadership by SPDC Management Team and Contractors Management Team as well as leverage on successful HSE initiatives such as the Injury Free Club.

The flowlines and pipelines are inter-field lines transporting unprocessed fluid from the wellheads to the Gas Supply Plant at Soku. As there is no record of attack on inter-field gas lines (probably because they do not transport processed Condensate), the lines will be laid 1.5m below grade as per standard construction specification. However, surveillance contracts which have so far proven to be effective for inter-field gas lines will be put in place for the new lines.

Delay in obtaining NCDMB waiver for Line pipe procurement

The Nigerian Content Directive (NCD) Act requires that a waiver be obtained for out of country procurement of line pipes less than 24". SPDC has an existing Corporate Line pipe procurement waiver based on the Corporate Line pipe procurement call off contract. However based on NAPIMS directive, line pipe procurement strategy for the project is for EPC contractor to procure. There is therefore the need for the project to obtain the required waiver from NCDMB

Mitigation: Time lost to Contractor (up to a maximum of 2 months) ordering of line pipes has been included in the project schedule, to further mitigate the risk; the plan is for Contractor to place the order for the line pipes as soon as EPC contract is awarded. Project has investigated the possibility of extending SPDC's waiver to cover 3rd party procurement and recently received confirmation that the SPDC waiver will cover this procurement. Risk diminished towards nil.

Community related Risks

The project straddles 2 states and over 14 main communities, hence the community stakeholder base is large and diverse. Legacy issues from the EGGS2 project have also been identified as the project pipeline largely follows the same RoW. This may lead to community agitations, work stoppages and reputational damage. There is also a risk of community agitations outside agreed GMOU terms that could lead to delay and cost growth.

- 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. GMOU is in place for all communities. Also an allowance has been made in the project budget for funding of social investment programmes. Contractors were also directed to engage labour unions for applicable wages in all work areas and use in estimating project management costs in contract bids while reference to wages have been expunged from the GMoUs.

Pressure on Contractor Capacity due to Workload

EPC Contractor has multiple contracts and contractor's capacity might be stretched

Mitigation: Contractor's capacity to be reviewed prior to mobilization to site and additional project management resources will be mobilized to support contractor. In addition, Contractor performance will be monitored closely to enable early intervention on appearance of any red flags

Changes to drilling sequence for F1 wells

Based on the directive from DPR, an appraisal well is to be drilled into the F1 reservoir in order to update the FDP prior to drilling the development wells. However, in a bid to fill gaps in the drilling sequence, the F1 development wells are being accelerated. This acceleration reduces the amount of time required to obtain DPR approval of the revised FDP (post appraisal drilling) from the required 12 months to just 7 months

Mitigation: Front end studies team would ensure that all front end work required to update the FDP is carried out to reduce the turnaround time for the FDP update. In addition DPR representatives would be engaged Q2 2013 to obtain buy-in for fast track approval. It should be noted that the project RFSU date is dependent on the F2 reservoir (not F1) hence this risk does not impact the project RFSU date

API 10,000 piping class Design, Manufacturing and installation risk (T)

The reservoirs within the KoloCreek Deep fields are expected to have significantly high pressures; hence the project would require the use of a new class of piping (API 10,000). Both SPDC and the EPC contractor do not have prior experience (design, manufacturing and installation) with this class of piping and there is the potential that this would impact quality and lead to schedule delays

Mitigation: The piping class was developed by SGSi during the project's Front End Engineering Design, SGSi's support would be retained for the design, manufacturing and installation of the piping. Additionally, the project would put in place a strong QA/QC team to provide control and assurance.

Need for sufficient tax base of SPDC Ltd (C, E)

The MCA recovery mechanism is largely dependent on having a sufficient tax base within SPDC Ltd to absorb the capital allowances associated with the carry amounts. Analysis shows that SPDC Ltd has sufficient tax base to recover the MCAs and achieve the desired IRR of 8% at/or above US$1.56m/scf RT12 based on the BP12 production forecast, which is well below RV price assumptions.

Opportunities

Specification for a new piping class (API 10000Ibs) was developed in partnership with SGSI. This will be useful going forward as Shell explores deeper reservoirs.

Alternatives

A. Processing Facility

Following the reframing workshop of Mar 2009, a decision was taken to process the Kolo Creek Deep gas at the existing Soku gas plant rather than at a new, third gas treatment train at the Gbaran CPF as originally conceptualized, for the following reasons

1. The KoloCreek to Soku option offeres a F$120mln Capex savings over the Gbaran 3rd train option
2. Declining Soku production and the need to optimize SPDC's infrastructure usage

B. Production Rate

Production rates of 500, 400 and 300 MMscf/d from Kolo Creek to Soku were considered.

The 500 MMscf/d Kolo Creek to Soku option would require a finger type slug catcher and additional condensate stabilization capacity at the Soku CPF since it would be competing with the Awoba NAG project for liquid handling space. The 300 MMscf/d Kolo Creek Deep to Soku option results in minimum CAPEX, but will not fulfill SPDC supply obligations to the NLNG Trains 1 to 6 in the short term.
Short/Medium term supply obligations can be met with the 400 MMscf/d Kolo Creek to Soku as an optimum production rate.

Section 4: Carbon Management

Green House Gas (GHG) Emissions for the Kolo Creek Deep Well Development Project over a 10 year forecast period are estimated at 35,510 tonnes of CO2eq, when average production is about 24,000 stbpd (net condensate) and 400 MMscf/d. Fuel gas combustion by the gas engines for electricity generation accounts for 90.8 % of the total emissions, and is the major source of emission in the project. Fugitive emissions from valves and flanges account for 8.95 % of the total GHG emissions. Venting at Kolo Creek Remote Field Manifold (RFM) due to routine maintenance depressurizing accounts for less than 0.3 % of the total GHG emissions, while Flaring emissions at Soku LGSP due to pig trap depressuring is insignificant.

Over the forecast period, the total emissions and energy intensities are 0.8 kg CO2 equiv. and 0.013 GJ per Tonne of hydrocarbon produced respectively. Also the SCEI? and UEEI? are 43 and 0.52 respectively. These are generally low compared to peer facilities in the group. Regarding GHG emissions and energy consumption therefore, this project is considered ALARP.

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. Reserves/Production/HCM confirmation and the Cost / Schedule Fact sheets have been duly signed off and available in the file.

Section 7: Project management, monitoring and review
Project Assurance is in place for all work scope and management of change. The Opportunity Assurance Plan (OAP) has been established and signed off by the Decision Executive, with active roles for Partners, UI Nigeria and P&T. This is a "P&T executed" project with P&T being accountable for the delivery of technical project integration and execution. A DRB with UI Nigeria and P&T participation is in place. A TQ plan is in place and approved by the DE. Key gaps have been identified and a gap closure plan put in place and been worked.

Section 8: Budget Provision
It is proposed that at FID, the project budget requirement will be from the Alternative Funding (AF) tranche. In line with current AF (MCA) agreements, it is expected that project FID OPEX and project management costs will continue to be funded via the regular JV budgetary process. These costs are fully captured in BP12 under AF.

Section 9: Group Financial Reporting Impact
There are no unusual accounting issues related to this GIP. Expenditure related to the project will be accounted for in line with Group Policy. The estimated yearly expenditure phasing for the full project work scopes is indicated in Table below

US$ mln	2012	2013	2014	2015	2016	Post 2016
Total Commitment	12.0	104.6	192.0	105.2	49.6	
SCD OPEX		0.7	1.3	1.0	0.6	
Pre-FID						
Cash Flow						
Capital expenditure	12.0	104.0	190.7	104.2	49.1	
Cash Flow from Operations	2.1	44.4	83.1	69.4	138.2	1007.4
Cash Surplus/(Deficit)*	-9.9	-59.6	-107.6	-34.8	89.1	1007.4
Profit and Loss						
NIBIAT +/-	0.6	4.1	8.2	6.0	97.7	795.3
Balance Sheet						
Average Capital Employed	5.2	42.3	132.0	210.3	235.0	57.4

Table 3: Financial implications of the Project

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. Financing for the main project scope shall be through the MCA funding mechanism. NAPIMS & JV Partners approval of MCA figures has been received and MCA signed-off by all JV partners.

Section 12: Taxation
For all the tax consequences associated with the MCA, reference is made to the tax section of the PCN covering MCA. A possible entry into force of PIB has a significant impact on the value of this project. Other than the foregoing, there are no unusual tax features to this proposal.

Section 13: Key Parameters

Approval is sought for additional US$463.5mln Shell Share ($220mln Equity & $243.5mln Carry), to progress Engineering, Procurement and Construction works, drilling/completion of 7 NAG and 1 appraisal wells and the infrastructure for evacuation of production to the Soku Gas Plant from the Kolo Creek Deep field.

Section 14: Signatures

This Proposal is submitted for approval.

Supported by:

Chris Streng
EVP Finance Upstream International
Date 10/06/2013

For Shareholder Approval:

Andrew Brown
Upstream International Director
Date 07/06/2013

Initiator: Toyin Olagunju, SPDC GM Major Projects

Appendix 1: Assumptions

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.
- No facility upgrade/replacement required for the project until economic limit.
- 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

- May 2012 version (Technical Committee draft)
- Production Royalty based on Company production rates
- SPDC – Oil & Condensate 22% - Gas 12.5%
- Price Royalty – 4% for Oil/Condensate RV, 0% for Gas RV
- Nigerian Hydrocarbon Tax 50%; Corporate Income Tax 30%
- Community Fund (PHCF) treated as Tax Credit
- No Production Allowances granted for this development
- Capital allowance for all CAPEX (except drilling intangibles) at On-stream date

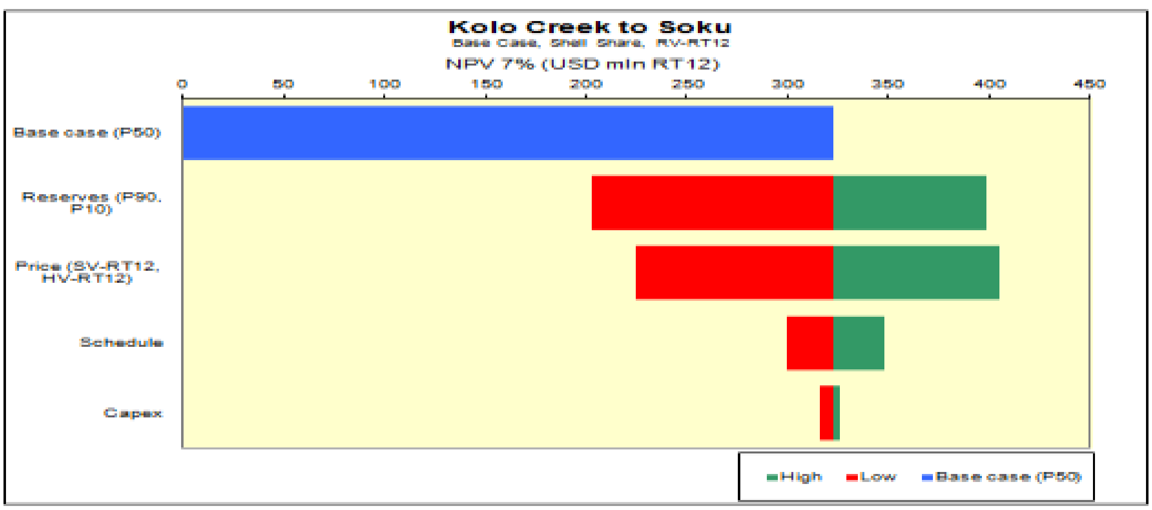


Figure 1: Tornado Chart

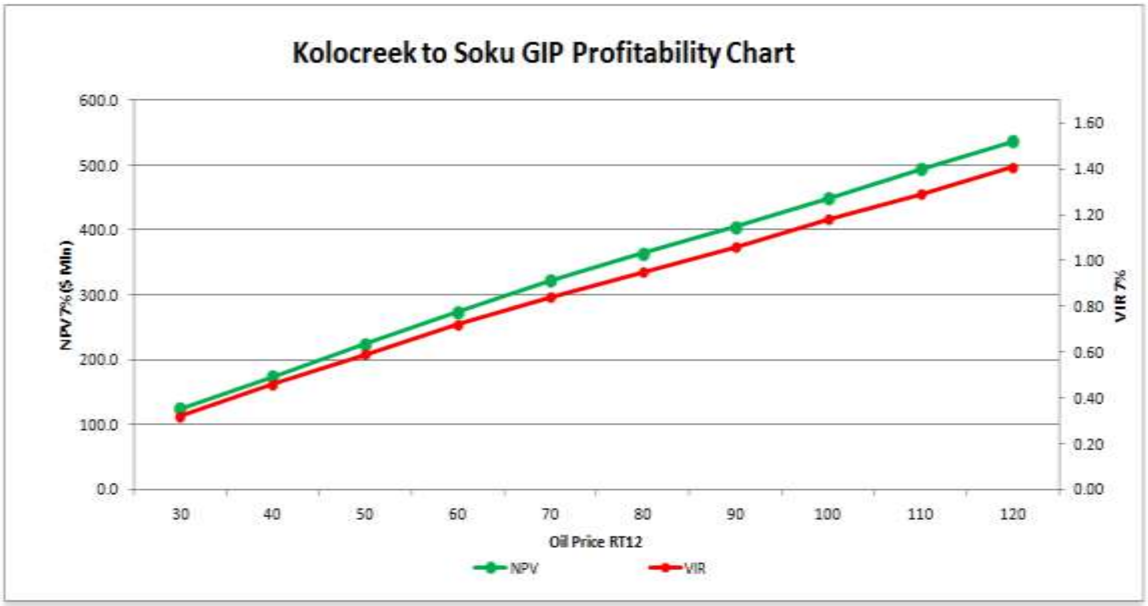


Figure 2: Project Profitability Plot

Appendix 2: Scope and Cost Estimate for the KoloCreek Deep Field Development to Soku Project

Details and Cost Estimate (MOD 100% JV) for the Kolo Creek Deep Field Development to Soku
The scope of the Kolo Creek Deep field development consists of the following:

1. Drilling and completing of four NAG wells to develop 0.92Tscf from the Kolo Creek Deep F2 reservoir.
2. Drilling of one appraisal well into the F1 reservoir
3. Drilling and completing of three NAG wells to develop 0.54Tscf from the Kolo Creek Deep F1 reservoir.
4. Construct a remote field manifold at the Kolo Creek Oil and NAG Manifold Location
5. Install (on-plot) flowlines from the wells to the Kolo Creek NAG manifold
6. Install a 20-inch diameter, 40 km long carbon steel pipeline from the Kolo Creek Manifold to the Soku gas plant designed to evacuate 400 MMscf/d of gas and 40,000 bbl/d of condensate from Kolo Creek NAG Manifold.
7. Installation of a slug catcher at the Soku gas plant and connection to existing production, control and safeguarding systems.

Description	
Location Preparation	35.7
Drilling and Completion	208.3
Pipeline and Hook-up	49.2
NAG Facilities* (inclusive of PMT, VAT & Owners Cost)	428.26
Total CAPEX (100% JV)	**721.5**
SCD	11.95
Total OPEX (100% JV)	**11.95**
Total (100% JV)	**733.4**
Total (Shell Share)	**463.5**

Table 1: Details of the cost estimate (MOD 100% JV) for the full scope of the Project

Description	COST PHASING Previously approved Pre-FID	2012	2013	2014	2015	2016	Total
Facilities Capex 100% JV (FUS$mln) - less PMT& SCD	6.4	15.00	55.92	155.53	121.08	72.50	426.4
Wells Capex 100% JV (FUS$mln)			94.94	121.51	27.56		244.0
Total Capex 100% JV (FUS$mln) - less PMT&SCD	6.4	15.0	150.9	277.0	148.6	72.5	670.4
PMT 100% JV (FUS$mln)	2.6	6.7	11.4	19.9	17.1	2.4	60.1
Opex 100% JV (FUS$mln)			2.2	4.4	3.4	1.9	12.0
Total 100% JV (FUS$ mln)	9.0	21.7	164.5	301.4	169.1	76.8	742.4
Total 100% JV (FUS$ mln) excluding Pre-FID							733.4
Shell Share Equity (30%)	2.7	6.5	49.3	90.4	50.7	23.0	222.7
(36.67%)		5.5	55.3	101.6	54.5	26.6	243.5
Total Shell Share (FUS$ mln)	2.7	12.0	104.7	192.0	105.2	49.6	466.2
This proposal Total Shell Share excluding Pre-FID (FUS$ mln)							463.5

Table 2: Yearly estimated expenditure (FUS$ mln)

Gbaran Ubie Phase 2 MCA 2 Projects	100% SPDC JV	Shell Equity Share	SPDC LTD MCA Share	Total Headline Size
Bonny NAG Minor Reservoirs Devt.	116	35	42	77
Gbaran Ubie 2A (C4+Epu+ Koroama+NB)	1018	305	352	657
Gbaran Ubie 2 B (Kolo Creek)	721	216	245	461
Soku NAG Compression	92	28	33	60
Soku Pipeline (All 4 loops)	460	138	159	297
Total – Gbaran Ubie 2 MCA 2 Bundle	2407	722	831	1553

All Values in $Million

Table 3: Excerpt from Group Finance Proposal showing projects with the MCA2 Bundle

	BASIS FOR THE GFP				BASIS FOR THE INFILL GIP			
	100% JV cost	Shell Equity Share	SPDC Ltd Share	Total Headline Size	100% JV cost (GIP)	Shell Equity Share	SPDC Ltd Share	Current IP Request -
Total project cost	742	223	272	495	742	223	272	495
Pre-FID (JV Funded)	(9)	(3)	(3)	(6)	(9)	(3)	(3)	(6)
SCD	(12)	(4)	(4)	(8)	(12)		(4)	(4)
	721	216	265	481	721	220	264	485
PMT Element	(58)		(20)	(20)			(20)	(20)
			245	461	721	220	244	464

Table 4: Reconciliation between the GFP and the GIP

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

HIPPS – High Integrity Pipeline Protection System

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 & Work over Sequence

SV – Screening Value

VIR – Value Investment Ratio