Group Investment Proposal

Summary information

<table>
<tr><td>Business unit and company</td><td>Shell Petroleum Development Company of Nigeria Limited (SPDC)</td></tr>
<tr><td>Group equity interest</td><td>100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.</td></tr>
<tr><td>Other shareholders/partners</td><td>Nigerian National Petroleum Corporation (NNPC: 55%), Total E&P Nigeria Ltd (10%), and Nigerian Agip Oil Company (NAOC: 5%)</td></tr>
<tr><td>Business or Function</td><td>Upstream International (UI)</td></tr>
<tr><td>Amount</td><td>The headline size of US$711mln Shell Share MOD 50/50 composed of US$694 mln CAPEX Shell Share MOD and US$17.1 mln OPEX Shell Share is being requested for approval in this revised GIP. This is made up of US$52.3 mln approved in the pre-FID proposal and US$659 mln being requested for in this proposal.</td></tr>
<tr><td>Project</td><td>Southern Swamp AG Solutions Project Plus (SSAGS+), incorporating Kanbo, Opomoyo, Opukushi North, Opukushi, Benisede, Ogbotobo, Tunu, Agbaya, Ajatiton, Akono and Dodo North Fields</td></tr>
<tr><td>Main commitments</td><td>
<table>
<tr><th>Description</th><th>pre-FID proposal (100% JV)</th><th>This proposal (100% JV)</th><th>This proposal (Shell Share_Equity)</th><th>Total IP (100% JV)</th><th>Total IP (Shell Share_Equity)</th></tr>
<tr><td>Production Facilities</td><td>122</td><td>823</td><td>247</td><td>945</td><td>284</td></tr>
<tr><td>Flowlines/Bulklines/Pipeline</td><td>37</td><td>425</td><td>128</td><td>462</td><td>139</td></tr>
<tr><td>Location Preparation (Wells)</td><td>-</td><td>24</td><td>7</td><td>24</td><td>7</td></tr>
<tr><td>Owners Cost (excl. SCD)</td><td>15</td><td>150</td><td>45</td><td>166</td><td>50</td></tr>
<tr><td>Contingency (Surface Facilities)</td><td>-</td><td>210</td><td>63</td><td>210</td><td>63</td></tr>
<tr><td>SCD</td><td>-</td><td>35</td><td>11</td><td>35</td><td>11</td></tr>
<tr><td>20 New Wells, (Drilling, Completion & Testing 2 NAG Wells, 18 Oil Wells) & Recompletion of 1 NAG Well[1]</td><td>-</td><td>527</td><td>158</td><td>527</td><td>158</td></tr>
<tr><td>Total (50/50 MOD)</td><td>174</td><td>2,196</td><td>659</td><td>2,370</td><td>711</td></tr>
<tr><td colspan="6">[1] Well Costs is net of SCD cost and also includes provision to recomplete one NAG Well n 2018</td></tr>
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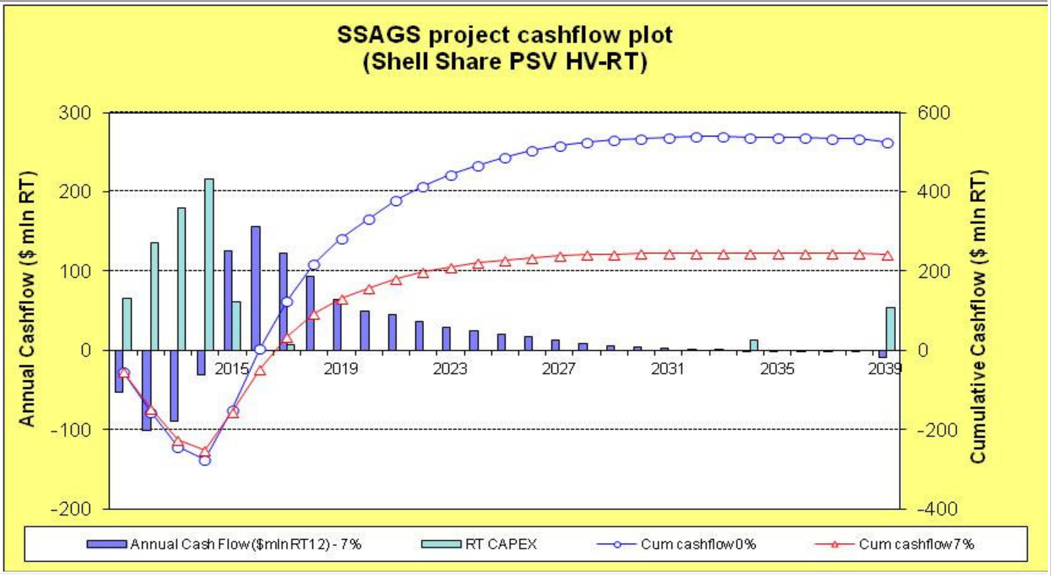
</td></tr>
<tr><td>Reserves/Resources</td><td>All 2C and 2P HC volumes covered by this GIP have been endorsed through a RAR-lead Resource Endorsement Session (RES) with closure of all recommendations for FID.

This project is aligned with SPDC’s strategic goals and priorities, and include:
- Already booked 2P NFA oil reserves of 27.21 MMboe SS from currently producing fields: Benisede, Kanbo, Opukushi, Opukushi North, Opomoyo and Tunu
- Further Oil and Gas development of 46.13 MMboe SS 2C resource volume in 8 fields (29.48 MMboe of Oil/NGL and 16.65 MMboe of Sales Gas)
- Ogbotobo Re-entry with total of 2.76 MMboe SS of 2C resource volume (2.59 MMboe Oil and 0.17 MMboe Sales Gas)

Economics used in this GIP to evaluate bookability of 2P for the SSAGS project (step 1 and step 2) are based on consolidated project costs and incremental resource volume estimates, resulting in the further oil and gas development to be classified as Contingent Resources. Once the FID has been taken on the AG facilities, the 2C volumes associated with further development activities can in principle be re-</td></tr>
</table>

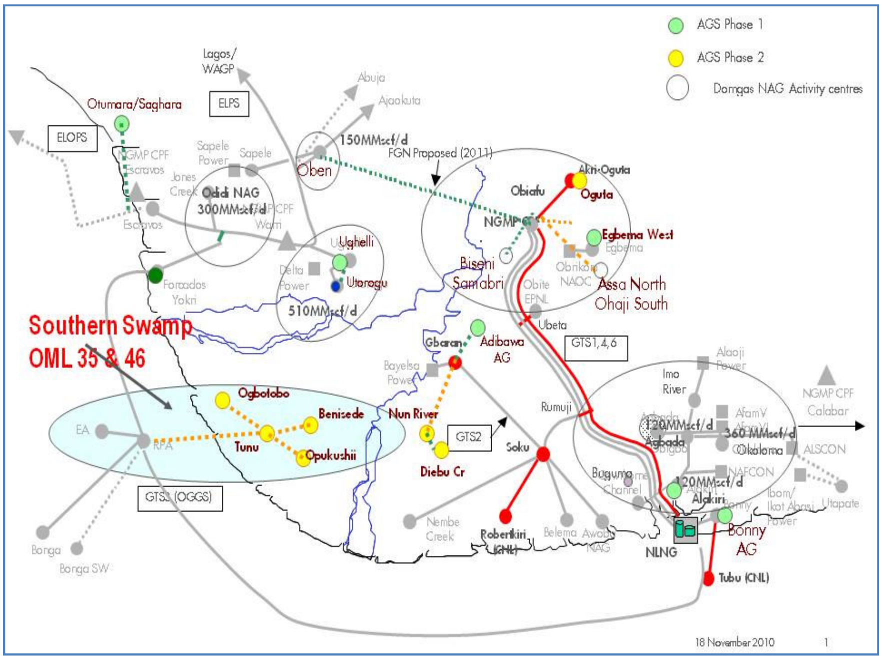
<table>
<tr><td></td><td>classified as Reserves once FID on the incremental project is taken (currently planned together with the FID on the AGS project).</td></tr>
<tr><td>Production</td><td>Incremental oil production from this project peaks at 30.1 Mbopd (100%) in 2016 with an accompanying sales gas production of about 105 MMScf/day (100%) (comprising about 40MMscf/d AG sales and 65 MMScf /d NAG).</td></tr>
<tr><td>Source and form of financing</td><td>This investment will be financed with JV funding. Total Shell commitments will be financed with SPDC Limited own generated funds and existing intra-group facilities. An MCA financing sensitivity is included in the economics section to evaluate the risk of NAPIMS inability to support the funding of the Step 2 activity - Oil development drilling under the JV base financing.</td></tr>
<tr><td>Summary cash flow</td><td>
</td></tr>
<tr><td>Summary economics</td><td>

	NPV7%	VIR7%	RTEP
HV-RT	242.9	0.42	22%
RV-RT	139.8	0.24	16%

</td></tr>
</table>

Section 1: The proposal (management summary)

This Group Investment Proposal seeks approval for funding of $659mln Shell Share ($2,196 mln, MOD, 50/50 100% JV) bringing total IP value to $711mln Shell Share (2,370 mln 100%JV) for the execution of Associated Gas Gathering Solutions to protect No Further Activity (NFA) production in Kanbo, Opomoyo, Opukushi North, and further oil development drilling in the Opukushi, Benisede, Ogbotobo, Agbaya, Ajatiton, Akono and Tunu fields as well as NAG development drilling in Dodo North field.



The Southern Swamp area comprises 16 fields (12 producing and 4 Partially Appraised) in OMLs 35, 36 &

46 with significant oil and gas resources; EUR of 1,636 MMstb (100%) and 2,138 Bscf (100%) of associated gas. Of this, 811 MMbbl with 456 Bscf associated gas has been produced from the fields in the period January 1976 to December 2011. The fields lay in the coastal swamp area, 65km South of Warri, currently with 100 oil wells and flow lines producing through 4 flow stations (Benisede, Opukushi, Ogbotobo and Tunu) and a new Field Logistics Base (FLB) at Tunu at advanced stage of completion. Oil evacuation is via the Trans Ramos pipeline to Forcados Terminal whilst associated gas is flared. NAG resources in the node have not been developed and the SSAGS+ project represents the first of such developments.

The effort to provide AG solution in the Southern swamp began in October 1999 with the SSAGG project. This was later expanded to include a nodal wide development called Southern Swamp Integrated Oil & Gas Project (SSIOGP) aimed at developing 407 MMstb (100%) oil expectation reserves and 505 Bscf (100%) associated gas (87 MMboe) through drilling and completion of 51 oil and 2 Cutting Re-injection (CRI) wells. The project passed VAR4, but became stalled in 2006 at DG4 due to higher than expected bid prices for the main EPC contracts and constrained funding. Renewed effort was launched in 2008 to provide AGS for NFA production only but given the resource potential in the node and the opportunity of funding that came with domestic gas supply, the project was re-conceptualised as a Domgas supplier (previous concept was to supply AG to NLNG). However, this revised concept meant that a reasonable volume and long term gas supply has to be guaranteed to meet the Government aspiration. This could not be met with AG alone and therefore a portfolio review was performed to identify a more secure source of gas supply. In 2010, a due diligence study of the previous SSIOGP Nodal Development work confirmed the selection of 21 oil wells out of the original 51 wells to be developed in a phased manner once the AG infrastructure has been provided.

Detailed performance reviews, including 3D reservoir simulation modelling of key reservoirs and 2P resource volume evaluation have been carried out for 11 fields (3 NFA, 1 NAG and 7 Further oil development, FOD, fields). This resulted in revalidation of 18 out of the 21 oil wells and identification of 3 high risk wells that have been excluded from the full scope. The 2P reserves Endorsement Session (RES) further supported the 18 oil wells. Also as part of the Nodal Development Plan (NDP), a feasibility study of Dodo North field was carried out to develop NAG to supplement the AG in order to sustain supply of 100MMscf/d (100%) minimum to the domestic market for at least 10 years.

The new project called Southern Swamp Associated Gas Solutions plus (SSAGS+) is primarily aimed at providing AG solutions to secure NFA production (100.1 MMbbl + 69.3 Bcf associated gas, 100%) while also drilling 18 oil wells to utilise capacity in the flow stations, thereby developing 90.4 MMbbl (100%) new oil (with 54.3 Bcf AG). It also includes the drilling of 2 gas wells from Dodo North to guarantee the sustenance of the 100 MMScf/d supply (268Bcf of NAG). In support of an accelerated project delivery, a pre-FID IP of F$174.3m 100% JV (US$52.3mln SS) was approved in April 2011 to facilitate completion of FEED and placement of orders for Long Lead Materials. The project successfully passed DG4 in March 2012, following the close out of high urgency recommendations from VAR4 and ESAR4 held in January and March respectively.

The Gas Flaring (Prohibition and Punishment) Bill 2009, currently before the national assembly, specifies payment of fines by non-compliant companies, of not less than the cost of gas at the international market plus another 50% of the penalty sum to the Local Government Area for community development activities. The impact of the law could include shut-in of the assets post-flares out date (2012 proposed at the National assembly), the likelihood of non-renewal of expiring Acreage Licenses due in 2019, loss of surface assets to vandalisation (when left idle) and loss of opportunity to develop and book significant reserves (both NFA and FOD).

This FID Investment Proposal:
The scope of the FID expenditure will cover for the following:
1. Facilities:

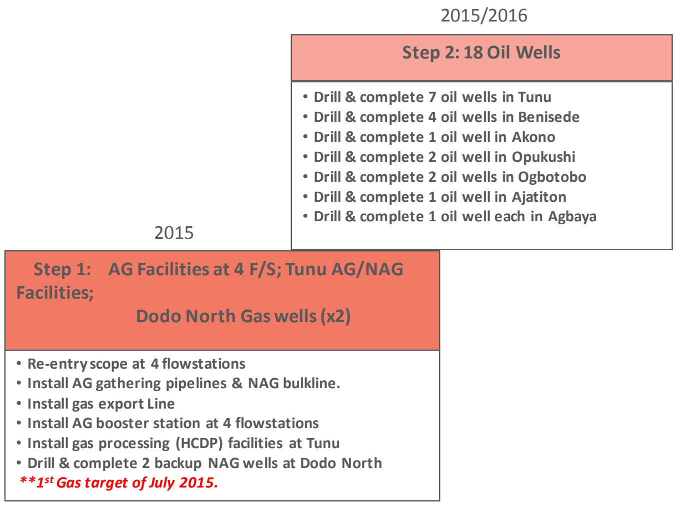
   a. Provision of AG booster compression facilities as well as brown-field facilities upgrade for the Tunu, Benisede, Opukushi and Ogbotobo flowstations.
   b. Laying of pipelines for associated gas from Benisede (12" x 16 km), Opukushi (12" x 24 km) and Ogbotobo (8" x 16 km) to Tunu, where the CPF is located.
   c. A new 70 MMscf/d AG compression facility (with slug catcher) at Tunu.
   d. A new 120 MMscf/d slug catcher at Tunu for non-associated gas.
   e. A 160 MMscf/d hydrocarbon dew-pointing facility at Tunu for AG & NAG.
   f. A 160 MMScf/d Gas Compression and Metering system at Tunu to deliver gas to the domestic supply grid.
   g. Laying of 16"x 32km high-pressure gas pipeline for export from Tunu to EA-RPA.
   h. Condensate handling system, associated metering, instrumentation and electrical systems.
   i. Island power generation at all the Facility Locations to include community power supply in support of inter-dependencies with host communities.
2. Wells scope:
   a. Drilling, completion and hook-up of 2 NAG wells from Dodo North field to supplement and back-up AG production into the Nigerian Domestic Gas network. Recompletion of one of the NAG well in 2018.
   b. Drilling, completion and hook-up of 18 oil wells – to utilize the existing ullage in the facilities

An earlier pre-FID cost of US$174.3 mln (100% JV) was approved to cover the following scope
   a. Studies including FEED (Complete NDP, FDPs and carry out FEED)
   b. Project Management (Staff salaries, travels and incidental costs for project team and support team members)
   c. Surveys and Permits acquisition (revalidate/acquire new PTS, OPL, ESHIA, NCD waivers, NDP, FDPs)
   d. Procurement of Long Lead items (LLI, including Line pipes, Twister Package, Centrifugal Compressors)

Schedule for some of the key project activities are shown below:

Activity	Schedule		
	Target Date	P50 Date	P90 Date
FID	31-Mar-12	3-Apr-12	16-Apr-12
EPC Contract Award (1)	1-May-12	18-May-12	29-May-12
First Gas (2)	31-Dec-14	26-Jul-15	25-Dec-15
NAG Well Drilling complete	11-Jun-14	8-Sep-14	9-Nov-14
Project Complete	09-Dec-15	11-Jun-16	19-Nov-16

(1) Schedule assumes Shell LDL approval to award the full EPC contracts once NAPIMS Contract Review Committee (CRC) endorses the award recommendations
(2) First Gas is defined as first gas export from Tunu CPF.



Funding

The estimated total Capex for the SSAGS+ project is $2.370 bln (MOD, 100%) plus SCD (Opex) cost of $35 mln (100%). The project is phased into 2 discrete steps for funding in installments under the Domgas tranche (Step 1: Gas Infrastructure plus NAG wells) and JV Base tranche (Step 2: Oil Development drilling – 18 Wells) as a base case. A funding sensitivity for MCA funding is included in the economics to evaluate the impact of NAPIMS in-ability to fund the oil related development activity. It is noteworthy that circa 80% of the funding comes under the Domgas funding tranche (for Step 1), which has been fully supported by the Government and continues to enjoy priority during the annual budgeting cycle

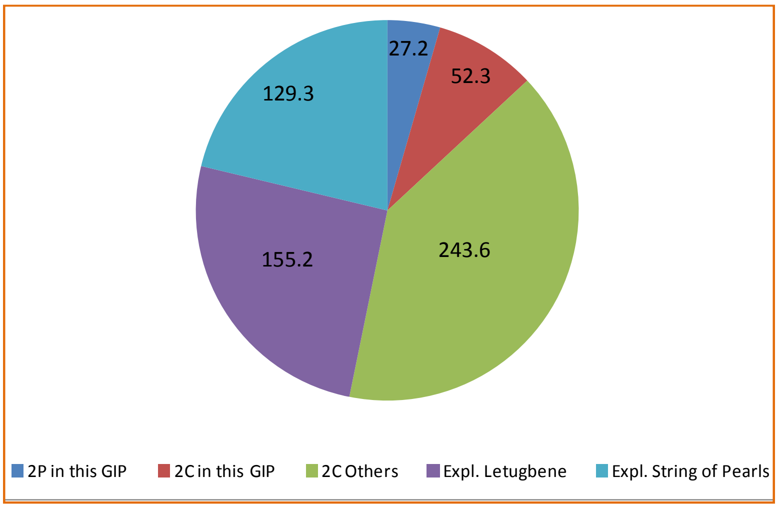
The total project expenditure and phasing is shown below. These figures are updates to BP11 reflecting the final outcome of VAR4 and ESAR4 concluded in January and March 2012 respectively.

Table 1: Full Project COST phasing

SSAGS P50 Estimate and Expenditure Phasing												
		Cost $million										
	Funding Tranche	Pre-FID Opex			Post FID Capex - JV Funded							
Scope		2010	2011	2012	2012	2013	2014	2015	2016	2017	2018	Total
Step_1 Gas Facility / Infrastructure Incl. 2 NAG Wells + 1 Recompletion	Domgas/IPP	2	19	2	218	463	489	477	188	-	25	1,881
Step_2 Oil Development (18 wells)	Base JV						131	265	58	-	-	454
SCD (Opex)	Domgas/IPP	-	-		4	9	13	7	3			35
Total		**2**	**19**	**2**	**222**	**472**	**628**	**737**	**247**	**-**	**25**	**2,370**

Section 2: Value Proposition and financial context

The primary objective of the AG Solutions project is to ensure continued economic production from the affected fields, in compliance with Group Policy and statutory requirements for non-routine flaring of associated gas. Protection of Shell's reputation and possible loss of Freedom-To-Operate (FTO) makes flaring of associated gas an unattractive proposition, with attendant negative repercussions. In addition, the execution of the project opens up opportunity for further oil and gas development in the fields as well as enables SPDC JV to meet the Nigerian government aspiration for Domestic Gas supply for power generation.



The implementation of this project will enable continued production of 100.1 MMstb (100%) of NFA oil (+ 69.3 Bcf associated gas) by securing the surface assets and also enabling further growth in the affected fields once AG gathering facilities are in place. Immediate development scope to be executed as part of the project will produce 90.4 MMstb (100%) of Oil (with 54.3 Bcf AG) and 268 Bcf of NAG (100%).

The total resource volume covered in this phase of development is only a small fraction of the total resource base in the area and hence significant opportunity still exists for future development as shown below.

The 243.6 MMboe SS (58% Oil) of '2C Others' are discovered Contingent Resources not part of this SSGAS+ GIP. In addition there are some 284.5 MMboe SS (100% Gas) of undiscovered Exploration hydrocarbons volumes sitting within the same development area as the SSAGS+.

Summary Economics

The economic evaluation for the Southern swamp project was on a forward-look basis using NFA plus further development production forecast from July 2015 (Oil and NAG) for the affected fields and 50/50 level 3 CAPEX LE. Base case assumes Joint Venture funding for both Steps 1 and 2 and HV price scenario. The project value was also determined at RV-RT price scenarios.

The value of the project is greatly enhanced by executing both Steps 1 and 2; Step 2 brings about 2/3 of the overall value and the VIR above the hurdle. It is imperative to achieve license renewal since only 36% of the value is realized within the current license period. Oil contributes 97% of the total revenue; therefore no sensitivity on domestic gas price has been considered. Having to fund Step 2 with an MCA, would preserve 96% of the value, but brings the VIR below the hurdle.

Risk and uncertainty analysis was also carried out for the project base case. The NPV probability density function (PDF) curve is shown in Appendix 3

Table 2: Economics Grid

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 & NGMP based gas price)	195.4	47.3	0.08	11%	0.17	13.4	16.2		
RV ($70/bbl & NGMP based gas price)	351.0	139.8	0.24	16%	0.49	13.4	16.2		
HV ($90/bbl & NGMP based has price)	524.6	242.9	0.42	22%	0.86	13.4	16.2	2016	*252.0(2015)*
BEP (RT $/bbl)						26.3	40.3		
Sensitivities (using HV-RT12)									
Step 1 under JV and step 2 under MCA funding		232.4	0.33						
Above sensitivity with 2019 licence expiry		76.5	0.10						
Low Reserves (Prob < 0.90)		145.1	0.25					2016	*276.4 (2015)*
High Reserves (Prob < 0.10)		268.4	0.47					2016	*252.0 (2015)*
Low CAPEX		257.6	0.49					2016	*247.9 (2015)*
High CAPEX		222.0	0.33					2018	*323.6(2015)*
6-months delay		227.8	0.40					2018	*325.0 (2015)*
Impact of December 2012 shut in		220.7	0.38					2017	*252.0 (2015)*
Impact of 2015 shut in		174.9	0.30					2018	*282.3 (2015)*
Base Case w'out already booked NFA production		81.0	0.14					2018	*281.7 (2015)*
Full Life Cycle		228.2	0.41	22%	0.80			2016	*257.3 (2015)*
2019 License expiry		87.3	0.15					2016	*252.0 (2015)*
Step -1 Standalone		89.8	0.19					2018	*231.2 (2015)*
Step-2 Standalone		153.0	1.37					2016	*20.5 (2015)*
Step-1Standalone with licence expiry		4.9	0.01					2018	*231.2 (2015)*
Step 2- stand alone with licence expiry		82.4	0.74					2016	*20.5 (2015)*
NFA standalone (No AG facility)	224.7	132.6	NA					NA	*NA*
PIB IAT Version		134.0	0.20						
PIB House_v12		250.8	0.44						
Additional Uncertainty and Risk Analysis - using HV									
NPV(P10)		269.0	0.48						
NPV(P90)		154.0	0.24						
EMV at HV / eVIR at HV		218.8							
Probability of NPV > 0 at HV		100%							
Dispersion = EMV / (NPVP10-NPVP90) at HV		1.9							

***Probabilistic analyses have been based on uncertainty in reserves, Capex and Opex**

Key Project Parameter Data (Shell Share)

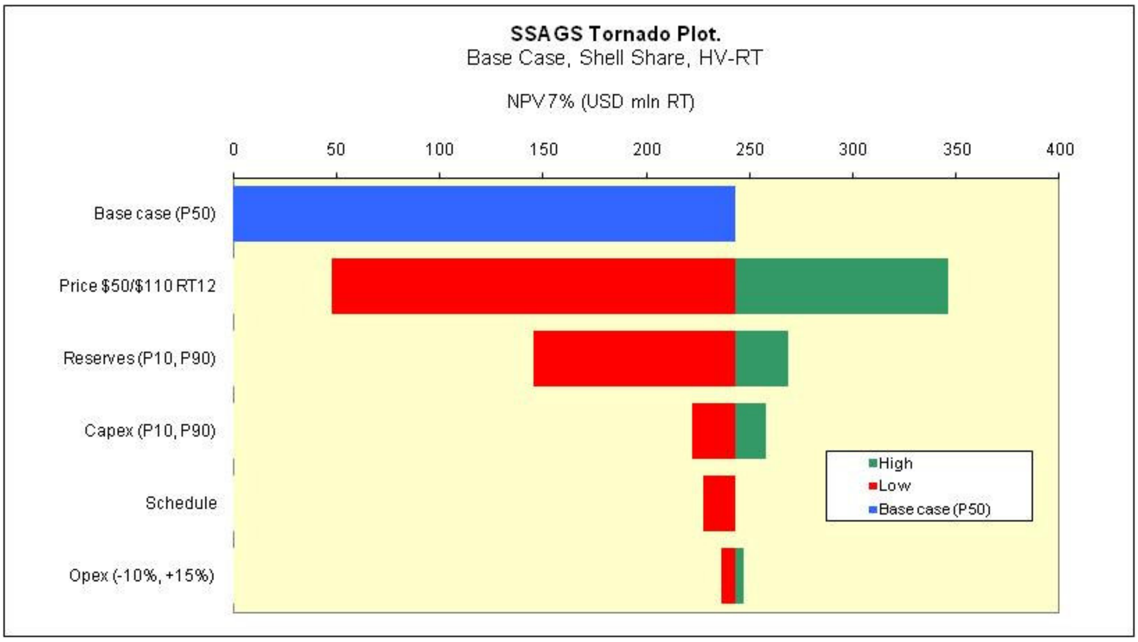
`	Unit	Bus Plan (BP11)	Low	Mid	High	Comments
Capex (MOD)	US$ mln	671;9	628.6	693.4	810.5	
Production Volume	mln boe	96.4	55.9	79.5	85.7	
Start Up Date	mm/yyyy	Dec-14	Dec-14	Jul-15	Dec-15	
Production in first 12 months	mln boe			12.6		Forward Looking

Economics Assumptions

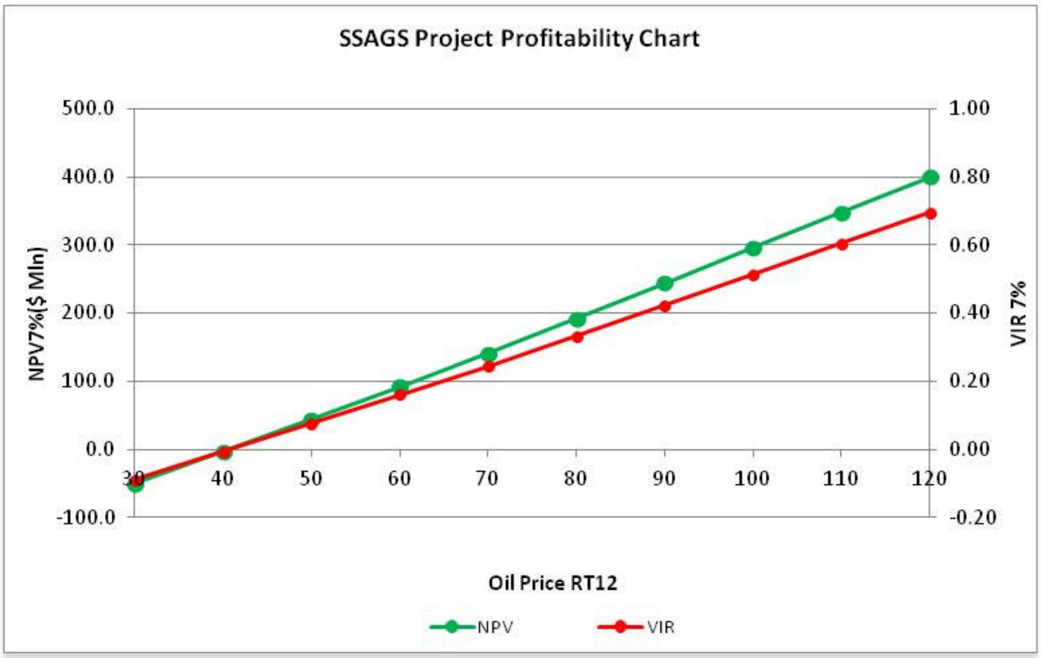
- Oil taxed under PPT (PPT tax rate of 85%)
- Oil price at the three PSVs: SV, RV and HV ($50/bbl, $70/bbl and $90/bbl respectively) with applicable offsets.
- Gas price at SV, RV and HV forecasts from the Nigeria Gas Master Plan (NGMP) profile with 15%, 40% and 65% implementation assumed for SV, RV and HV respectively.
- Gas taxed under CITA with Associated Gas Framework Agreement (AGFA) incentive.
- Education Tax of 2% assessable profit
- NDDC levy of 3% total expenditure
- GHV of 1000btu/scf for Domgas
- 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.
- SCD Cost was provided by project team
- ABC OPEX.

PIB and MCA Assumptions are contained in Appendix-4.

SSAGS Tornado Plot.



SSAGS Profitability Plot



Section 3: Risks, opportunities and alternatives

The key risks and opportunities identified in the project are as follows:

Under-delivery of gas in the medium to long term (T)

The under-performance of identified gas wells or demand for higher-than-planned gas supply plan of 100MMscfd will reduce the plateau of Dodo North NAG source and result in low capacity utilization in the longer term – this will impact on SPDC's corporate reputation.

Mitigation: Pre-DG1 work has been initiated to identify additional gas resources to be matured for possible acceleration to back-up Dodo North (for example the Opukushi gas cap blow down (F3 & F5), Opukushi Deep development requiring appraisal), and NAG development drilling in Orobou and Egunabo fields.

Continued production without AG solutions in place post Mar 2012 (T, P)

As a result of the uncertainties around the flares down date, continued production of Southern Swamp fields without AG utilization post March 2012 (GIP date) will result in the reduction of AG volumes to be produced & monetized by the SSAGS+ project, potentially impacting the gas supply promise.

Mitigation: There are other in-field oil development opportunities within the node (e.g. remaining 33 wells in the original SSIOGP) that will be investigated as acceleration candidates in order to increase AG production and add value. Additional NAG resources have also been identified and assessed as backfill to dwindling NAG/AG production, including Egunabo, Orobou, Opukushi and the huge potential in Tolugbene exploration.

Security & Social Risks (P, E)

The project is located in the swamp of the Nigeria Delta; community interfaces, HSE and security issues are particularly significant in these areas, highlighted by cases of hostage taking, and armed attacks and sabotage of, especially, pipeline systems. There is also a risk of community agitations outside agreed GMOU terms that could lead to SCD related cost growth.

Mitigation:

The amnesty programme of the federal government has helped to calm the security situation although uncertainty still pervades. The Security Information Network Centre (SINC) will monitor Delta threat traffic and provide timely early warning to the project team on a `need to know and act` basis. All work will be done according to the approved security plan under the oversight of the Head of Security Operations – West. Community interfaces will be managed through the Global Memorandum of Understanding (GMoU) mechanism to be deployed in alignment with the project schedule. An allowance has been made in the project budget for funding of social investment programmes (including a community interdependency power supply project). Offsite fabrication work will be maximized and done at a safe and secure location thereby limiting site activities to a minimum.

NCD Act Implementation (E, C, P)

The requirement to comply with the Nigerian Content Directive (NCD) Act could result in project cost and schedule overrun due to limited in-country material manufacturing capacity and capability.

Mitigation: A detailed NCD compliance Plan has been worked out together with the EPC contractors and approved by the Nigerian Content Development and Monitoring Board (herein after referred to as Board). This plan highlights areas of gaps in compliance with the NCD Act, with the intent to seek waivers from the Board for out-of-country procurement. An early engagement with the Board in 2011 indicates that it is amenable to granting waivers for the project where there is a compelling business case. In this respect the board has already granted waivers to carry out elements of the FEED work outside Nigeria and for procurement of Line pipes outside Nigeria. The NCD plan already approved by the Board has recognised the need for waivers for out-of-country procurement of certain items e.g. Valves, HV Cables, Major Rotating equipment and Twister Components.

NNPC Award Approvals for EPC Contracts (C, E)

To safeguard the project schedule it is necessary to award the two major EPC contracts within Q2 2012 (1st May 2012). With the conclusion of commercial negotiation with bidders, award approval by SPDC MTB is possible within the required time period but approval protocols within NAPIMS/NNPC easily take 6 to 12 months period to process. Contract award ahead of the formal NNPC approval could expose Shell to cost recovery issues, if NAPIMS decline to honour cash calls or approve end of year performances at OPCOM.

Mitigation: SPDC has maintained close and rigorous engagement with NAPIMS to ensure common understanding of project priorities and urgencies. Thus far NAPIMS has demonstrated good faith in approving Budget requests, cash calls and financial performances even where formal contractual approvals have not been given by NNPC GEC / Board (e.g. POs for FEED to UMP and LLI). NNPC has also recognised SSAGS+ project amongst the priority Domgas projects to be given accelerated approvals in order to meet with the medium term Domgas supply of government. There is also a high chance of NNPC GEC / Board approvals for proposal 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 EPC contracts once NAPIMS CRC endorses the award approvals to NNPC GEC / Board. It is also noteworthy that a couple of recent awards were similarly made under LDL, although at smaller value (e.g. FYIP Ph1 Offshore, Otumara pipeline) and was later approved by NNPC board some 9 – 12 months after submission. We estimate risk of exposure to become minimal once supported by NAPIMS Board. Furthermore, the EPC contracts can be cancelled without significant cancellation fee and therefore the exposure is much lower than the commitment. The estimated exposure 9-months after award is circa 20% of the contract ceiling (or F$240Mln for the 2 EPC contracts).

Funding for Oil Wells (C, E,)

The base proposal is to fund the 18 oil wells in step 2 under the JV base, as compared to the BP11 assumption of 12 Oil Wells in JV base and the remaining 6 funded by Alternative Funding (MCA). However, there is a concern that NNPC may be unable to provide JV funding for some or all of the oil wells due to funding constraints and competition for JV funds from other projects. Furthermore it is recognised that constraints also exists within the MCA basket given other competing projects.

Mitigation An economic sensitivity has been included in the economic section, which shows the impact on the project economics where these oils wells are funded under MCA (2008) terms, giving a VIR of 0.26.

SPDC will continue to engage NAPIMS and highlight the need to preserve project value by executing the complete scope of work under the JV budget, especially as the AG attached to the oil wells is included in the Domgas supply volumes premised in the project. As an upside, other Alternative Funding mechanisms may be available from 2014, which could offer better economic terms compared with MCA. If Alternative Funding is required, a Group Financing Proposal will be raised for the Shell Share and requisite approvals obtained after conclusion of negotiations. Three of the wells have been pulled forward in the drilling sequence to early 2013 with preparatory expenditure in 2012 already thereby setting a precedent for JV funding as the first 12 wells are based on JV funding in BP11.

Licence Expiry in 2019 (C, E, P)

The OMLs (35, 36 & 46) expires in 2019. There is a risk that some of the investment value will be lost if the licences are not renewed.

Mitigation: A sensitivity has been included in the Economics to show that payout period occurs before the licence expiry date of 2019 under JV and MCA funding scenarios as well as for the NFA only case. In a recent letter from the Group Executive Director (GMD) to the ECMB, NNPC has expressed desire to have the SSAGS+ project accelerated in support of the Government's Domestic Gas supply programme. SPDC will attempt to leverage the Government's enthusiasm for the SSAGS+ project in negotiations for licence renewal.

Impact of year by year Budget Approval by NNPC (C, E, P)

The absence of a formal project funding approval at FID from NNPC means that funding requirement are subject to the annual budget approval cycle with a risk that full funding is not guaranteed over the project period.

Mitigation: It is important to leverage the priority NNPC has placed on the project as a Domestic gas supplier to demand for the appropriate funding levels during the annual budget approval cycles. Furthermore past experience has shown that approval of the EPC contracts by the NNPC Board represents a form of commitment to meet annual funding requirements, and there is no precedent of NNPC failing to fund contracts after they have been approved by their Board.

Non-availability of Domgas Funding (C, E, P)

The project economics rely on the availability of ring-fenced Domgas funding from NNPC for Step 1 (Gas infrastructure plus NAG wells). There is a risk that NNPC may consider that this is an expensive project for only relatively little gas and hence they may prefer to invest Domgas funding elsewhere.

Mitigation: There is a large demand to supply gap for domestic gas in the West of Nigeria. Other potential supply sources in the West include CNL Okan (2015+), Exxon Bosi/Erha (2017+), NPDC Odidi (2018+) and SPDC Okpokuno (2018+) but these do not fully meet the projected demand growth and they are all high cost projects. The Government also recognises that there is further gas growth potential in the Southern Swamp area. In summary, the SSAGS+ gas volume is badly needed by the Government, and it is possible that they will ask for more. Therefore, the SPDC Development team continues to mature the gas opportunities in the Southern Swamp area to identify commercially attractive expansion options.

Impact of Divestment from Western Division (C, T)

Due to on-going divestments in the Western division and possible relocation of SPDC offices out of Warri during the project execution period, there is the risk of schedule and / or cost overruns arising from project disruption in the event of change in base location or changes to logistics services e.g. marine and air transport required for effective project supervision.

Mitigation: Arrangements are in place to set-up a base for the project team in Port Harcourt early in the project. The EPC contractors' base for Engineering and Fabrication are also located within the Port Harcourt Area. In addition the EPC contractors will be required to make independent logistics arrangements to support their site operations. The project team will maintain close communication with corporate Logistics functions to ensure that the project requirements are factored into decisions relating to future logistics support in Western Division.

Constrained Domestic Gas Pipeline Capacity (T)

There is a risk that the gas export route to the Domestic gas market may be constrained by lack of ullage in ELPS (Escravos-Lagos Pipeline System).

Mitigation: NNPC is already looping ELPS; the first section (Escravos to Warri) is 95% completed and should be on stream by about May 2012. The second section (Warri to Lagos) is less than 50% completed and is planned for commissioning in the first half of 2013. The SSAGS+ production facilities and export pipeline system have been designed to allow the associated gas to be routed to NLNG via OGGS, in the event that the Domgas export route is not available. (Note that this scenario would have to be carefully managed with NNPC, who may be reluctant to allow gas from SSAGS+ to be routed to NLNG).

Integrity of Trans Ramos Pipeline for Oil Evacuation (T)

Although the Trans Ramos pipeline is only 17 years old, the integrity of the pipeline is impaired due to sabotage and possible corrosion.. An Intelligent Pig (IP) run was carried out in 2000 and a defect assessment was performed with Pipe Risk Base Assessment. Following the replacement of damaged (sabotaged) sections in 2008 as part of the re-entry campaign, the line failed pressure test at 60 bar but passed at 40 bar. On this basis, a safety factor of 0.8 was applied and the line was de-rated to 32 bar.

Mitigation: The current pressure rating of 32 bar can support a flow rate from Southern Swamp up to 200kb/d, which is higher than the maximum gross liquid production expected from the Southern Swamp node. A sectional replacement of the dented section of the pipeline is in BP11 (to be executed in 2012) to enable an IP run which will form the basis for further assessment and required upgrade programme. The Pipeline Operations team is planning to inject biocides on a continuous basis after the IP run to extend the life of the pipeline. Future development in Southern Swamp (beyond the SSAGS+ project) will likely be linked to restoring the Trans Ramos Pipeline to full rating by full or partial replacement. The ballpark cost for full replacement of the line is $600 mln.

Crude Theft (P)

An estimated 7 to 10% of crude production in the SPDC Western Division is currently lost due to bunkering, and therefore the oil volumes from the project could be reduced due to theft.

Mitigation: Mitigation options to tackle crude theft on major pipelines fall within the SPDC Company Plan. Potential options include improved pipeline surveillance contracts and cooperation with the Government to tackle the issue.

Key Opportunities

The following key opportunities have been classified using the TECOP criteria.

Exploration Scope and Future Development (T/C)

Opportunities exist in Orobou, Egunabo and Opukushi (deep) fields to develop 620 Bcf of NAG in the short to medium term, as already included in BP11.

In the long term, additional gas could be matured from currently un-appraised prospects within the node. There is also an exploration potential of some 3 Tcf (100%) in Letugbene.

Other exploration synergies with SSAGS development project that are being evaluated include the reduction in unit finding cost through deepening of development wells to exploration targets (Opuk-6 & 6ST).

Opportunity to provide Electricity to Communities (P)

There exists an opportunity to provide free electrification for the communities within the Southern Swamp Node as part of a strategic sustainable development drive that would create a positive social impact. This would have to be considered on a nodal level to assess local or partial electrification.

Opportunity to use existing Well Locations (T)

A rigorous risk assessment of clustering philosophy was conducted during the well concept selection process and well locations were placed to optimize the use of existing surface facilities, whilst being mindful of other project objectives.

Alternatives Considered

1. Continue to produce the fields and pay flaring penalty till end of field life: *Rejected:* This is not recommended viewed against the environmental concerns, imminent stiffer flaring penalties, the impact on company reputation and the Group commitment towards Flares Out.
2. Shut-in and abandon the fields: *Rejected:* Significant proven recoverable volumes and production will be lost, and high cost will be used on abandonment.
3. 3rd Party Alternative Solutions: Given the strategic nature of the southern swamp fields, the search for the third party AG solution has been discontinued as any third party solution could constrain future Oil development. The fields have therefore been withdrawn from the market accordingly.

Section 4: Carbon management

On commissioning of the AG solution system, the project will recover some 124 Bscf of associated gas that would otherwise have to be flared to produce 190.5 MMbbl oil (from NFA and new Oil). This will translate in removal of circa 8Million tonnes CO_2 that would have otherwise been released to the atmosphere during routine flaring. Furthermore the capture and utilization of this gas brings about economic benefits in terms of income (gas monetization) and improve Energy supply in Nigerian economy by supporting Electrical Power Generation.

Post project implementation the bulk of CO_2 emissions (96%) will come from gas-fired drivers and Mechanical drivers (exhausts) used in the plant and also from flaring during emergencies accounts for the remaining 4% of CO_2 emission. This will be managed through proper equipment selection at the design stage and implementing appropriate operating practices to comply with extant regulations and company policies on emission limits including the SPDC's flaring policy.

Section 5: Corporate structure, and governance

This project fits within the existing SPDC corporate structure and governance. Consequently, it will comply and respect all relevant and existing governance.

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

This proposal complies with Group Business Principles, policies and standards. Functional support from HSSE, Finance, Legal, IT, CP and SPCA has been obtained for the full project scope. Additionally, there will be a focus on Nigerian Content Development (NCD) as already indicated above.

Section 7: Project management, monitoring and review

The Major Projects Team under UIG/T/PD is managing the project. 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 to define the applicable controls for EXECUTE phase.

Section 8: Budget provision

The project is fully funded in BP11 base plan although under-funded in the 2012 JV programme, principally because NAPIMS concern that EPC contract has not been awarded yet. The additional requirements will be addressed in the course of the year during budget re-alignment. The understanding kept with NAPIMS, during DEVCOM, was that they are willing to support the additional funds once contracts have been awarded in good time.

Section 9: Group financial reporting impact

The Financial impact of this activity on Shell Group Financials is as indicated in the Table below:

US$ mln	Prior years	2012	2013	2014	2015	2016	Post 2016	Cumulative
Total Commitment	6	68	141	190	232	67	7	**711**
Cash Flow								
SCD Expenditure	0	1	3	4	2	1	0	**11**
Pre-FID Expenditure	6	1	0	0	0	0	0	7
Capital Expenditure		65	139	186	230	66	7	693
Operating Expenditure		2	4	16	22	18	325	387
Cash flow From Operations		0	21	73	151	193	695	1,133
Cash Surplus/(Deficit)		(65)	(118)	(113)	(79)	126	688	**439**
Profit and Loss								
NIBIAT +/-		1	3	1	44	78	461	
Balance Sheet								
Avg Capital Employed		33	127	244	363	400	157	

Section 10: Disclosure

Material disclosures, if any, will be done in line with the Group and SPDC Disclosure policies and guidelines.

Section 11: Financing

This investment is expected to be financed with JV partners funding (within the IPP/Domgas and JV base budget), and Shell Share of capital expenditure will be met by SPDC's own cash flow.

Section 12: Taxation

There are no unusual taxation features at this stage

Section 13: Key Parameters

The following is the main aspect of this proposal:

Approval for the total revised headline size of $711mln Shell Share (2,370 mln 100%JV) 50/50 MOD for the execution of AG Solutions to protect NFA production in Kanbo, Opomoyo, Opukushi North, and further oil development drilling in the Opukushi, Benisede, Ogbotobo, Agbaya, Ajatiton, Akono and Tunu fields as well as NAG development drilling in Dodo North field.

Section 14: Signatures

This Proposal is submitted for approval.

Supported by:

....

Bichsel, Matthias F RDS-ECMBI

Date.... /.... /...

For Business Support:

....

Brinded, Malcolm A RDS-ECMB,

Date.... /.... /....

Supported by:

....

Henry, Simon P RDS-ECSH

Date.... /.... /...

For Business Approval:

....

Voser, Peter R RDS-CEPV,

Date.... /.... /....

Appendix 1: Estimate & schedule Fact Sheet

ESTIMATE & SCHEDULE FACT SHEET

to be included in GIP and PCN submissions

<Southern Swamp AGS+ Project >

<SPDC Western Swamp Location>

Version 2.5 Confidential

Approved Cost & Schedule Estimate

Project No.: <C12001>

Estimator: Augustine Oleru

Planner: James Magluyan

Case: Base

Market Scenario: LE

Estimate Type: 3

Rates of Exchange are as per SI-SK Data Set

Costs are in: USD Millions

Estimate Start / End: FID Apr-2012 / RFSU Jul-2015

EDM Date: 1-Jul-11

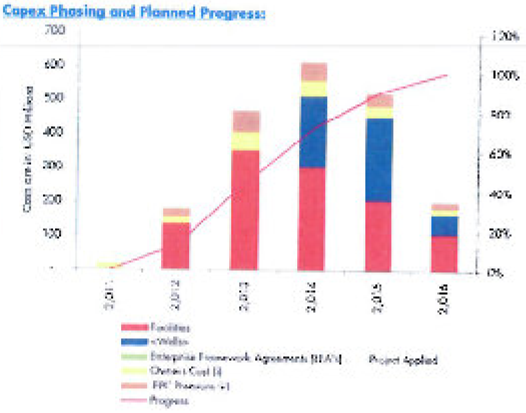
Category		Total Costs
Facilities		981
<Wells>		516
Enterprise Framework Agreements (EFA's) :	Project Applied / Verified, Not Applied	129 /
Owners Cost (i)	(incl. Insurance, pre-FID, Taxes & Capitalized Interest)	188
EPC Premium (ii)		205
Contingency	(i) 14%, (ii) 55% Facilities 14% <Wells> 0%	210
Inflation		116

	P10	P50	P90
Approved Total Project Estimate, MOD	2,156	2,346	2,626
	-10%	OK	15%

Assumptions:

Estimate & Schedule Premise	Processing plant major equipment part of the facilities cost estimates have been built using CAPCOST based on MTO list from the FEED deliverables. Pipeline estimates were based on ongoing as well as recently completed swamp pipeline installation contracts. Civil infrastructure estimates were built using corporate civil call-out contracts. The Q1 2012 latest Estimate (SE) escalation factors have been applied in line with provisions of the Jan 2012 Capital Cost Outlook. Probabilistic cost risk analysis using @Risk has been used to calculate project contingencies and overrun allowance. Owners costs were derived bottom-up using approved project manning profile. Well costs have been calculated using SPDC well cost estimating template by well engineering function and has been adjusted in line with agreed in-house SPDC methodology. Schedule durations were based on recently completed and ongoing projects with similar activities. Risk analysis was carried out on the schedule.
Execution Strategy Premise	The execution is premised on award of two EPC packages (Facilities and Pipelines) while the Gas delivery line will be executed in conjunction with the FYP Offshore Pipelines - cost included in this estimate. Location preparation for well drilling will be undertaken using SPDC corporate dredging callout contract.
Contract Strategy	Two EPC contract packages have been negotiated on lumpsum prices for the processing plant and pipelines. Enterprise Frame Agreements (EFA) have been deployed for procurement of long lead items (LLI) including main compressors, line pipes and Twister modules. A Project Management Services Contract will be used to provide quality assurance & control as well as certification services in the design, procurement/expediting, fabrication, construction, precommissioning/commissioning of the Project.
Key Project Risks	Security/communities issues, Funding issues (could impact contractors' cash flow resulting in delays), HSE risks, Internal and external interface management.
Exclusions	Customs and excise duties. SPDC financing of interest during construction.
	3 months management adjustment have been applied to the P90 for "1st Gas" and "Project Complete" dates to accommodate any force majeure, though no adjustment has been made to the P90 costs.
Benchmarking & Metrics	Pipeline & facilities benchmarked with completed projects. IPA benchmarking undertaken.

Capex Phasing and Planned Progress:



Key Schedule Dates:		
Phase	Finish (P50)	Finish (P90)
FID	Apr-2012	Apr-2012
<Detailed Eng.>	Nov-2013	Mar-2014
<Procurement LLI>	Nov-2013	Dec-2013
<Installation -Twister>	Dec-2014	Feb-2015
<Construction>	May-2015	Jul-2015
<Commissioning -CPF & Booster Stns>	Jul-2015	Sep-2015
<1st Gas>	Jul-2015	Dec-2015
Project Complete	Jun-2016	Nov-2016
RFSU	Jul-2015	Dec-2015

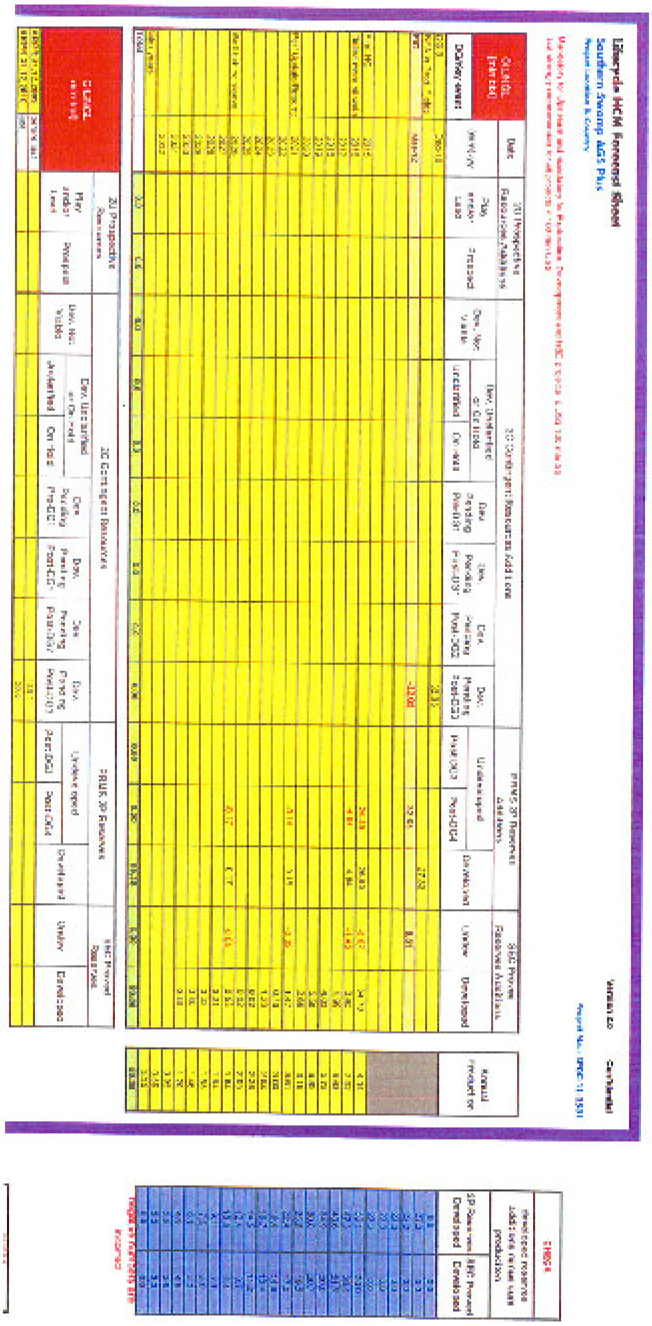
DCAF TA 1
Date : 23-03-12
Name : Nwalogoze, Emeka
Signature :

Development lead
Date : 23-03-2012
Name : Ezugwerele, Chibogwe
Signature :

VP Project Services
Date : 23/3/2012
Name : Harris, Mica
Signature :

Project Manager
Date : 23-03-12
Name : Caroline Rockall
Signature : Caroline Rockall

<u>Appendix 2: Lifecycle HCM forecast Sheet</u>



Gas [bn scf]	Date	2U Prospective Resources Additions		2C Contingent Resources Additions							PRMS 2P Reserves Additions			SEC Proved Reserves Additions		Annual Production
					Dev. Unclarified or On Hold						Undeveloped					
DG/Key event	mmm-yy	Play and/or Lead	Prospect	Dev. not Viable	Unclarified	On Hold	Dev. Pending Pre-DG1	Dev. Pending Post-DG1	Dev. Pending Post-DG2	Dev. Pending Post-DG3	Post DG3	Post DG4	Developed	Undev.	Developed	
DG3	Dec-12									155.35						
FID	Mar-12									-118.26		119.08		22.81		
First HC	2015											-115.37	115.37	-22.11	47.24	7.83
Drilled wells	2016											-3.42	3.42	-1.69	8.29	14.21
	2017														2.70	5.37
	2018														6.80	14.45
	2019														18.23	5.89
	2020														28.71	8.84
Plat...	2021											[illegible]	[illegible]	[illegible]	3.14	7.90
	2022														1.04	8.60
	2023														7.04	5.38
	2024														3.60	5.78
	2025														3.29	4.94
Well ...	2026											-0.21	0.21	-0.05	3.20	4.08
	2027														0.28	4.27
	2028														0.28	3.72
	2029														0.57	3.16
	2030														0.89	2.87
	2031															2.22
	2032															1.37
other years																1.25
Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	119.08	0.0	119.08	119.08

developed reserves additions minus cum production	
2P Reserves Developed	SEC Proved Developed
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
108.65	19.52
92.06	21.36
83.93	23.96
69.04	17.12
63.04	25.79
51.36	36.43
46.07	41.59
40.23	36.63
35.83	32.15
30.13	26.81
26.25	22.33
20.87	18.39
16.25	15.26
12.33	11.55
8.50	9.28
7.00	7.00
4.27	4.27
3.25	3.25
0.00	0.00

[illegible] numbers are correct

Gas [bn scf]		2U Prospective Resources		2C Contingent Resources							PRMS 2P Reserves			SEC Proved Reserves Additions	
					Dev. Unclarified or On Hold						Undeveloped				
		Play and/or Lead	Prospect	Dev. Not Viable	Unclarified	On Hold	Dev. Pending Pre-DG1	Dev. Pending Post-DG1	Dev. Pending Post-DG2	Dev. Pending Post-DG3	Post DG3	Post DG4	Developed	Undev.	Developed
ARPR 31.12.2009	[illegible]									439.18					
ARPR 31.12.2010	[illegible]									131.48					

VP Technical [illegible]

Date: 26.3.12

Name: [illegible]

Signature: [illegible]

[illegible] (SEC [illegible])

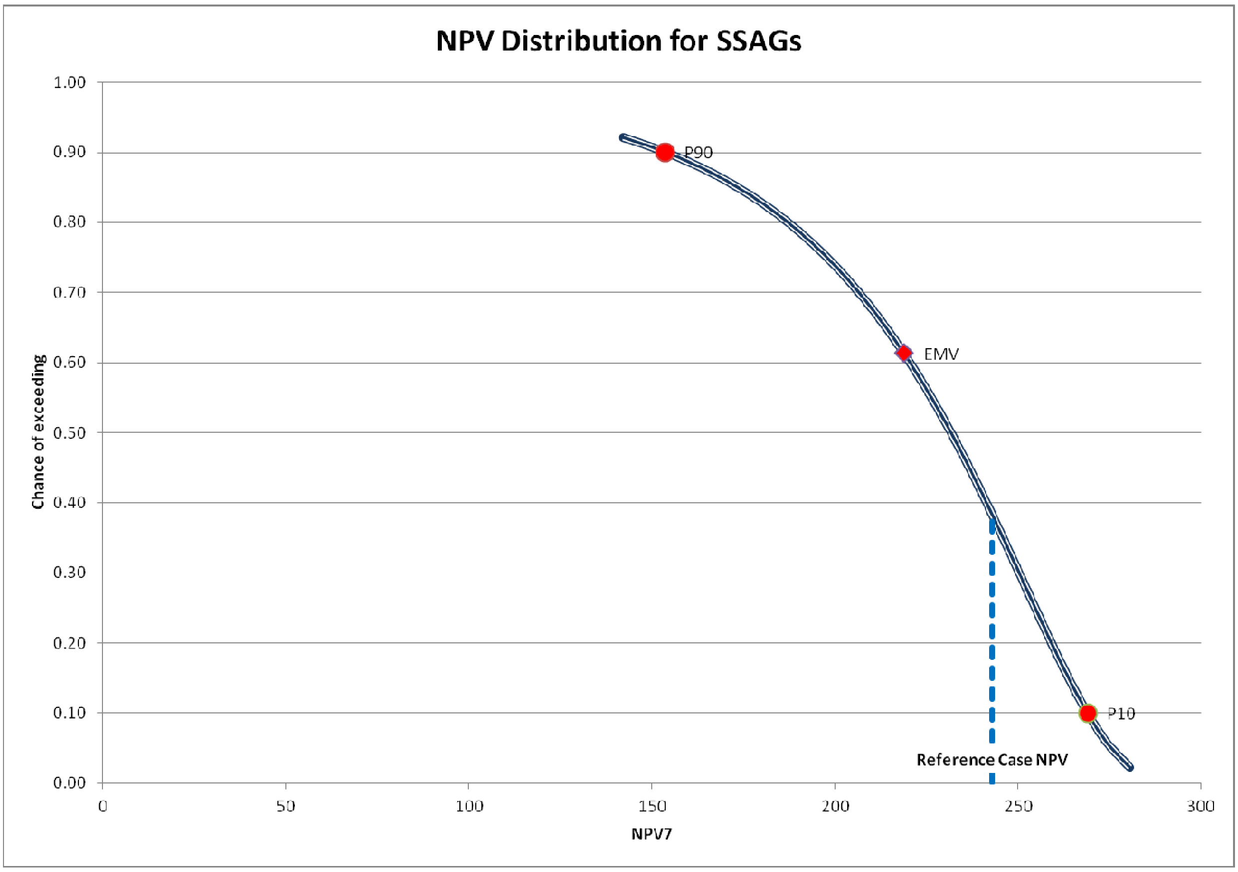
Date: 21-Mar-2012

Name: Matyunkov. A.A

Signature: [illegible]

Note: Production forecast and PRMS forecast need to be fully consistent with economic and financial evaluations [illegible]

<u>Appendix 3: NPV probability density function (PDF) curve</u>



The reference case has no probability of achieving NPV7<0. The EMV being higher than the reference case is attributable mostly to the skewness of the P10 and P90 reserves.

Appendix-4: PIB and MCA Assumptions.

PIB Assumptions (House Version)

- No production allowance used in analysis.
- CIT is 30% of taxable income with a depreciation schedule of 3x25%, 24% for qualifying expenditure and it is not deductible for NHT calculation
- NHT is 50% with a depreciation schedule of 4x20%, 19% for qualifying expenditure.
- Education tax calculated as 2% of its assessable profit and it is not deductible for CIT, but deductible for NHT.
- NDDC levy calculated as 3% of expenditure
- 15% cost overseas applied.

PIB Assumptions (IAT version)

- No production allowance used in analysis
- NHT depreciation schedule is 4x20%, 19% for qualifying expenditure.
- No capital investment credit/allowance (ITC or ITA) or uplift is granted under the PIB
- CIT depreciation schedule is 3x25%, 24%, for qualifying expenditure.
- CIT is 30% of taxable income and is not deductible from NHT
- Education tax calculated as 2% of its assessable profit & is not deductible for CIT, but deductible for NHT.
- NDDC levy calculated as 3% of expenditure
- Withholding tax is applicable at a rate of 7.5%
- 20% of overseas cost is non-deductible for determination of NHT taxable income.

MCA Assumptions

- All step 2 costs on the MCA would be recovered through cost oil.
- Profit oil ceiling of 8% IRR on carried costs
- Current agreement for recovery of carry costs is maintained
- $91.69/bbl – oil at PSV HV-RT in 2012 for HV MCA Economics
- OPEX and PMT not carried under current MCA arrangement.