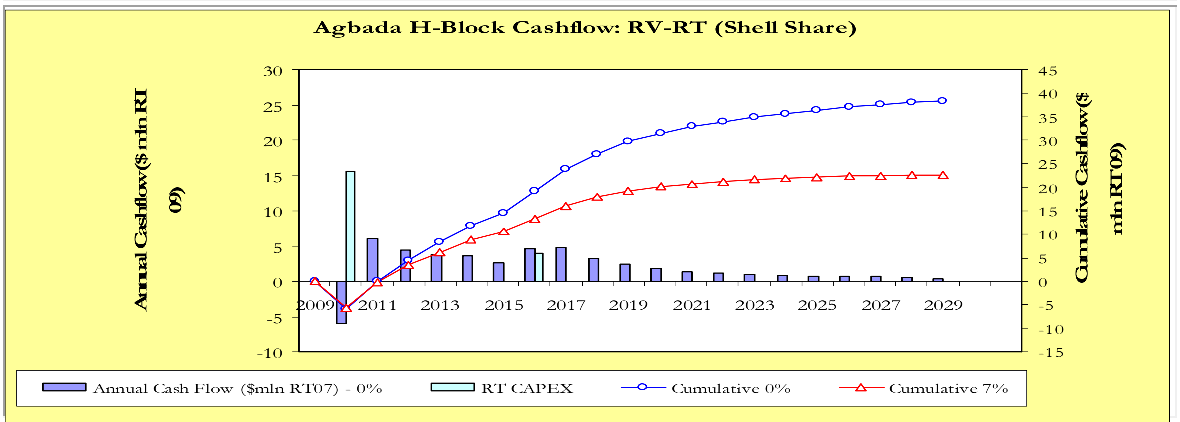
Group Investment Proposal

Summary Information

<table>
<tr><td>Business unit and company</td><td>Shell Petroleum Development Company of Nigeria (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>Nigeria National Petroleum Company (NNPC: 55%), Total E & P Nigeria Limited (10%), Nigeria Agip Oil Company (NAOC: 5%).</td></tr>
<tr><td>Business or Function</td><td>Exploration & Production (EP)</td></tr>
<tr><td>Amount</td><td>US$ 20.45 million MOD 50/50 Shell Share (US$ 68.17 million, 100% JV).
(Phasing: 2010 15.9 US$ mln SS, 2016 4.6 US$ mln SS)</td></tr>
<tr><td>Project</td><td>Drilling, completion and hook-up of Agbada 2X (PISV-3) & Agbada 3X (PISV-4) appraisal wells and a re-completion workover on Agbada 2X (PISV3) in 2016.</td></tr>
<tr><td>Main commitments</td><td>
<table>
<tr><th></th><th colspan="2">50 / 50 Base Case</th><th colspan="2">90 / 10**</th></tr>
<tr><th>Main Scope*</th><th>US$ mln MOD100%JV</th><th>US$ mln MOD SS</th><th>US$ mln MOD100%JV</th><th>US$ mln MOD SS</th></tr>
<tr><td>Drilling and Completion (2 wells)</td><td>44.8</td><td>13.4</td><td>53.7</td><td>16.1</td></tr>
<tr><td>Flowlines and hook-up</td><td>8.2</td><td>2.5</td><td>9.8</td><td>3.0</td></tr>
<tr><td>Re-completion workover (2016)</td><td>15.2</td><td>4.6</td><td>18.2</td><td>5.5</td></tr>
<tr><td>TOTAL</td><td>68.17</td><td>20.45</td><td>81.80</td><td>24.54</td></tr>
</table>
*Drilling and completion in Q3/Q4 2010 and hook-up to Agbada-2 flowstation in Q1 2011. A workover on well 2X to re-complete on shallower reservoirs in 2016.
** Includes TECOP contingency. Presented as “High CAPEX” economic sensitivity in Table 2
</td></tr>
<tr><td>Source and form of financing</td><td>This investment will be financed from SPDC’s own cash flow and/or the existing shareholding facility. Formal JV partners’ approval will therefore be obtained.</td></tr>
<tr><td>Summary cash flow</td><td>


</td></tr>
<tr><td>Summary economics</td><td>
<table>
<tr><th>Base Case Summary Economics</th><th colspan="3"></th></tr>
<tr><th>Project Title
Agbada 2X and 3X appraisal wells</th><th>NPV
USD mln</th><th>RTEP(%)
-</th><th>VIR</th></tr>
<tr><td>Discount Rate</td><td>7%</td><td>7%</td><td>-</td></tr>
<tr><td>SV-RT ($50/bbl Brent + $0.2/Mmbtu) RT 09</td><td>15.9</td><td>60.6</td><td>0.68</td></tr>
<tr><td>RV-RT ($60/bbl Brent + $0.22/Mmbtu) RT 09</td><td>22.3</td><td>80.6</td><td>1.31</td></tr>
<tr><td>High Price (80/bbl Brent + $0.25/Mmbtu) RT 09</td><td>31.1</td><td>>100</td><td>1.83</td></tr>
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Section 1: The proposal (management summary)

Approval is sought for US$20.45 mln CAPEX Shell share MOD to drill and complete two appraisal wells in Q3/Q4 2010 on Agbada H-block and hook the wells up to the Agbada-2 flow station. A workover operation will be executed in 2016 to re-complete one of the wells on shallower reservoirs. First oil is expected in Q1 2011.

Through the drilling and completion of the wells some 19.5 MMbbls of oil and 9.0 Bscf of Associated Gas (100% JV) would be developed (see Figure 1). The Associated Gas will be gathered at the Agbada-2 flow station, compressed to 60 bar and evacuated through the Agbada Associated Gas Gathering (AGG) system for sale via the Eastern Domestic Gas Network.

In 2006 SPDC drilled an exploration well from the Agbada-66 surface location targeting the Aghata prospect. The Aghata prospect comprised a horst structure between the south heading Agbada main synthetic fault and the north heading Aghata antithetic. The well, which TD-ed in January 2007, discovered 88 MMboe (recoverable volume) in 12 reservoirs. The crude is medium to light gravity (20 - 38 API), medium viscosity (0.5 – 8.0 Cp) and moderate to high GOR (300 - 1200 scf/stb).

The well was completed as a Two-String Dual (TSD) on the E1000 and E3000 reservoir levels and hooked up to Agbada 2 flowstation. Production commenced after 6 weeks and attained a rate of 5,700 bopd by June 2007. The well was subsequently tested and reopened for production with an allowable production flowrate of 4,200 bopd with reported average producing GOR of 400 scf/stb, THP 700 psia and 0% BSW.
Following this discovery, the Aghata prospect was renamed Agbada H-block and two appraisal wells (2X and 3X) are planned to be drilled between Q3/Q4 2010:

Agbada 2X will be drilled on the western side of the structure and the location of the well will be as crestal as possible at/or above the Agbada-66 well. The objective of the well will be to test for the presence of gas caps and reservoir development at the E1-E8 levels on the western side of the structure. Given the relatively low GOR observed during the production of Agbada-66 it is expected that either none or only a limited gascap will be present. The well will be completed using a "bottoms up" philosophy. The plan is to initially complete on the E4000H and E8000H levels, followed later by a workover operation in 2016 to re-complete the well on the E1000 and E2000 levels.

Agbada 3X will be drilled on the eastern side of the structure which is the optimum location to test the presence of a gascap at the E1000/E2000 levels (crest of the structure moves towards west with increasing depth) and reservoir development at these levels. The well will be located a safe distance from the northern and eastern boundary faults and on/above the Agbada-66 penetration.
Given the fact that after two-years of production, Agbada-66 produces dry oil from the E1000 level and 20% water at E2000 level no downdip appraisal is required.

Agbada-2X and 3X appraisal wells are critical to support full Agbada H-block concept selection. Additional development wells will be drilled (not part of this IP) to develop the remaining hydrocarbons recoverable resource volumes (74 MMbbls of oil and 110 Bscf of AG) in Agbada H-block.

As part of the full life development it is proposed to progress the H-block as follows:

- Continued production of Agbada 66 well to Agbada-2 flowstation.
- Drill 2 appraisal/development wells in 2010 and complete/hook-up to Agbada-2 flowstation.
- Carry out a workover operation to re-complete well 2X on the E1 and E2 reservoirs
- Drill additional oil development wells and complete/hook-up to Agbada-2 flowstation.

The number of additional development wells will be dependent on the results of the appraisal drilling/production performance and these will be matured through the Opportunity Realisation Process (ORP) funnel. Future development wells are planned to be drilled with a dedicated land rig in a campaign mode. All wells will be completed as dual string (TSD). The potential for horizontal wells application, smart well and new technology applications will be investigated during the maturation phase in 2011.

The Agbada-2X&3X wells are on the 2009 Short-term Drilling and Workover sequence (new land rig) and in the business plan (BP09).

The Agbada-2 facility, is a 50 Mbpd capacity flowstation while present field production to the flowstation is 40 Mbpd. Combined gross rate from the completed appraisal wells will average 7.2 Mbpd in 2011 with a peak gross production of 9.5 Mbpd in 2016 after the workover hence, there is available ullage to handle the expected rates from these wells.

The present AG rate is 30 MMscf/d with an AG plant capacity of 59 MMscf/d. This is also sufficient for the expected combined AG rate of the wells which has a maximum rate of 2.2 MMscf/d.

Location preparation and drilling operations will also entail shutting in 2100 bopd of production from AGBD-47 and AGBD-66 wells for over three months in 2010. Efforts will be made to minimise this (see section 3.1).

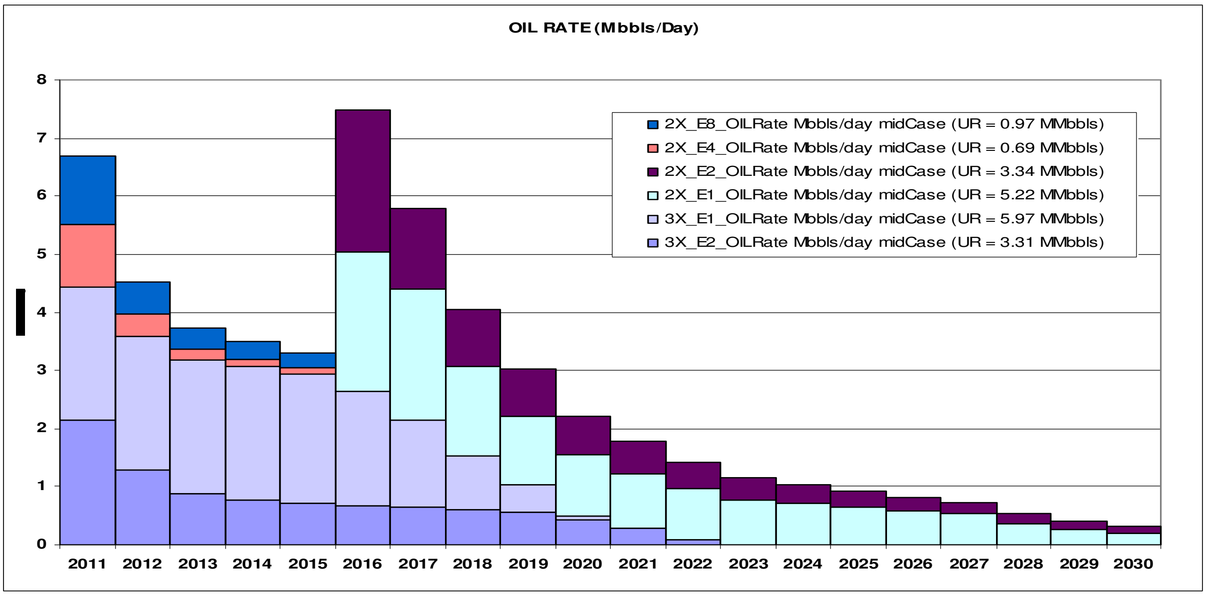

Figure-1: Oil production forecast from Agbada H-block 2X and 3X wells

Section 2: Value proposition and strategic and financial context

2.1 Value Proposition

The two wells (Agbada-2X & 3X) will develop expectation oil and gas reserves of 20.77 MMboe (19.5 MMbbl and 9.0 Bscf), 100% SPDC JV.

The 50/50-project cost for this proposal (drilling and completion in Q3/Q4 2010 and hook-up of Agbada 2X & 3X in Q1 2011 and workover of Agbada 2X in 2016), is US$20.45 mln Shell share Capex. A breakdown of these costs (Shell Share) are shown in table 1 below.

Main Scope	Well 2X:US$ mln (MOD (SS))	Well 3X:US$ mln (MOD (SS))	Total
Drilling and Completion	7.16	6.27	13.43
Flowlines and hook-up	1.23	1.23	2.46
Re-completion workover	4.56	-	4.56
Total	12.95	7.5	20.45

Table 1: Agbada 2x and 3X Shell Share 50/50 Well cost Summary

Both wells are planned to be drilled and completed in Q3/Q4, 2010 and hooked up in Q1 2011. First oil from both wells is expected in 2011 and the production will increase the utilisation of Agbada-2 flowstation and support gas supply to the Domgas network.

2.2 Economics

The Agbada H-block 2X & 3X appraisal drilling, completion and hook-up is an infill development, evaluated on a forward-looking basis using the 50/50 CAPEX estimates and volumes.

The base case economics assumes appraisal and workover re-completion success of the two wells.

Sensitivities were carried out to cover the Reserves, CAPEX, slippage in first oil dates, the "tops down" completion option (see section 3.7) and impact of the Petroleum Industry Bill (PIB) using version 4.2. Sensitivity on PIB version 3.2 is also included for tax purposes based on the last fiscal assumption advised by tax. The PIB start date is assumed to be 2010. The results for these sensitivities and a tornado chart are below. The economic assumptions applied have also been listed.

PV Reference Date: 1/7/2009	NPV (S/S $mln)		VIR	RTEP	UTC (RT $/boe)		Payout Time (RT)	AT Maximum Exposure
Cash flow forward from: 1/1/2009	0%	7%	7%	%	0%	7%	yyyy	US$mln (yyyy)
Base Case								
SV-RT ($50/bbl Brent + $0.2/Mmbtu) RT09	27.6	15.9	0.68	60.57				
RV-RT ($60/bbl Brent + $0.22Mmbtu) RT09	37.9	22.3	1.31	80.58	4.00	5.35	2012	7.6 (2010)
HV-RT ($80/bbl Brent + $0.25Mmbtu) RT09	52.1	31.1	1.83	107.72				
BEP ($/bbl, RT)	5.35	8.36						
Sensitivities (using RV-RT)								
High CAPEX(+20%)		21.7	1.06				2012	9.2 (2010)
Low CAPEX (-10%)		22.6	1.48				2011	6.9 (2010)
Low Reserves (-20%)		17.2	1.01				2012	7.6 (2010)
High Reserves (+10%)		24.9	1.46				2011	7.6 (2010)
1-Year Delay -2012 First Oil		20.7	1.23				2012	7.6 (2010)
Appraisal well 2X only		11.1	1.09				2012	4.0 (2010)
Appraisal well 3X only		11.7	1.70				2011	3.6 (2010)
Base Case PIB sensitivity Version 3.2		29.6	1.69				2011	8.8 (2010)
Base Case PIB sensitivity Version 4.2		29.0	1.66				2011	7.6 (2010)
Project Ringfenced sensitivity		21.7	1.28				2012	16.4 (2010) - BT
"Tops Down" completion strategy		24.2	1.51				2011	7.6 (2010)

Key Project Parameter Data (Shell share)

Parameter	Unit	Bus Plan 2009 Case	Low	Mid	High			Comments
CAPEX (MOD)	US$mln	17.37	18.41	20.45	24.54			
Production volume	MMboe	4.69	4.98	6.23	6.85			
Start Up Date	mm/yyyy	Jan-11	-	Jan-11	Jan-12			
Production in first 12 months	MMboe	0.58	0.62	0.77	0.85			

Table 2:Economics summary

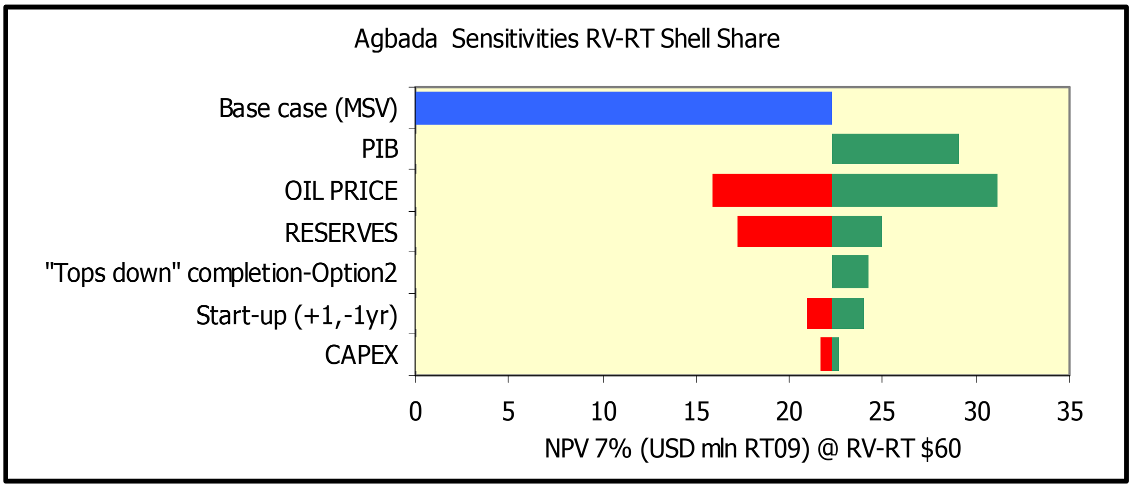

Figure 2: Agbada Tornado chart. (Increased NPV under PIB is due to a reduction in effective Tax rate for oil projects from 85% down to 80% although this is partly offset by reduction in some tax allowances.)

The following assumptions were applied for the economic evaluation:

- Oil sales price of RV-$60/bbl (RT-09) and gas sales price of $0.22/MMbtu (RT-09) @ RV-RT. Associated gas will be sold to the Eastern Domestic gas network.
- SPDC generic Opex assumption: Oil and gas Opex of $0.5/bbl and $0.3/boe respectively.
- Oil corporate overhead of $2.0/bbl and oil oncost of $2.0/bbl was added @ SV-RT.
- Agbada activity base cost model (ABCM) applied as oil independent OPEX.
- 10% of the project RT CAPEX assumed as abandonment cost.
- Sales of 81% of AG produced assumed.
- Flare penalty of USD$4/Mscf.
- AGFA fiscal regime assumed for gas sales to Domgas.
- GHV of 1000 btu/scf.
- Education Tax of 2% assessable profit.
- NDDC Levy of 3% of total expenditure.
- 2% of project MOD CAPEX assumed as SCD cost.

PIB (Ver 4.2 Nov 30th 2009) Assumptions for Upstream (Tax /Royalty – SPDC)

- PIB start year is 2010 .
- Royalty rates based and production rates and netback prices. Production rates are per PML (assumed equal to a field) and range from 5% to 25% for production over 5kb/d (onshore) . Royalty on product netback prices start at netback prices of $70/bbl.
- Similar royalty provisions for gas – production rates > 200 MMscf/d attract 25%; Netback values > $ 1/ Mmbtu
- PPT replaced by Nigerian Hydrocarbon Tax (NHT) and CIT levied on a company wide basis on all hydrocarbons ie same rate for oil and gas
- NHT tax deductions reduced in many areas eg 20% of overseas cost (assumed to be 30% for SPDC) , any costs that are not benchmarked, verified and approved (assumed to be 5% of expenditure for SPDC)
- NHT depreciation schedule is 4x20%, 19% for qualifying expenditure.
- No capital investment allowance (ITA)
- Significant production allowances (as deductibles for taxable income determination) are granted for oil, gas and condensate to encourage field development and production – note only applies to PMLs with no past production.
- NHT rate is **50**% for onshore and shallow water
- Minimum NHT amount of 2% of total revenue.
- CIT depreciation schedule is 3x25%, 24%, for qualifying expenditure.
- CIT is **30**% of taxable income and is not deductible from NHT.
- Flaring penalty is calculated at $4mln/Btu MOD flat and it is not tax deductible for both CIT and NHT
- Withholding tax is applicable at a rate of 7.5%

Section 3: Risks, opportunities and alternatives

The principal risks associated with this proposal and key mitigation measures are as follows:

3.1 Concurrent Operations

At key stages of the planned operation it will be necessary to close in the AGBD-47 and AGBD-66 well streams (total 2,100 Mbopd). The maximum case is a 12-month period to cover the entire location preparation and drilling operation. At DG4 the project team committed to the decision executive (DE), to undertake a comprehensive evaluation of the possibility of doing some of the location preparation and drilling operations concurrent with production of the above wells where assessed safe to do so and subject to appropriate work permits. The DE has so far given approval for up to 3 months of shut in. The team will meet with the DE again before end of January 2010 to demonstrate concurrent operation plan and opportunities evaluated to safely minimise shut in.

3.2 Timely Completion of well hook-up

There is some downside risk to the project economics due to a delay in the hookup and early production of the wells once drilled and completed in Q4 2010. The plan allows some 6 months for the laying of the flowlines and hookup of the wells. To mitigate against this risk the Minor Projects department have been engaged since early 2009 in the planning of the project and the project now features in the IAP. It has been confirmed that flowline materials have been ordered (as part of wider SCM corporate order) and are expected in Q1-2 of 2010. Hookup will take place along the free-and-clear existing right of way from Agbada PISV location to the Agbada II flowstation. EIA approval to hookup the wells has already been sought from Federal Ministry of Environment, Housing and Urban Development.

3.3 Project Cost

Cost estimates have been benchmarked against relevant projects and escalation factors included to address risk.

3.4 Well deliverability

A dynamic reservoir model was built which was calibrated using the actual Agbada-66 production data. This well produces inline with expectations and only limited water is being produced after over 2 years of production. Agbada 2X & 3X well are planned higher/at the same level on the structure as Agbada-66 hence they are expected to yield similar or higher production performance.

3.5 Community Disturbance/Security issues

The project is located in OML 17 of the Nigerian Niger Delta just north of Port Harcourt. SPDC has full Licence to Operate in this area and a GMOU has been implemented with the host communities. The area has had no location specific serious security issues. There is however the security threat of random kidnappings known to occur in the Greater Port Harcourt area in recent years. This threat will be militated against by fully implementing all journey management procedures, and religiously adhering to the asset security plans. An integrated Community Relations, Sustainable Community Development & Security Plan is in place to address stakeholder engagement, legacy issues, skills development and sustainable development. The recent amnesty offered by the Federal Government to the Niger Delta militants will provide leverage in the safe and secure execution of this project.

3.6 Opportunities

The opportunity will be utilised to drill the current wells from existing surface facilities (Agbada-47 cellar). This will save cost by re-using the existing well equipments/accessories. Appraisal and production data from the 2 wells is critical to support full Agbada H-block concept selection.

3.7 "Tops Down Completion" Alternative

With the E1.0 and E2.0 levels having a higher initial rate than the E4 and E8 levels, a "tops down" re-completion philosophy for Agbada 2X has been considered. This completion strategy would require that the well be initially completed on the E1.0 and E2.0 levels and re-completed via a workover on the E4 and E8 levels. As a result of this, initial production profile would be higher and the workover will be delayed to 2022, however the overall ultimate recoverable reserves from the well remains approximately the same.

This option improves the overall project NPV7% by approx. $2 mln (SS), with an associated additional cost of US$60,000.00 for running and setting a bridge plug to isolate the deeper E4 and E8 levels for initial completion. The economics sensitivities for this option are reported in Table 2.

While providing c.a. 10% improvement in the NPV the tops down completion carries a significant technical risk of incomplete zonal isolation of the shallower levels during re-completion. The zonal isolation requires a cement squeeze job to close in the shallower perforations which has the potential to compromise pressure integrity of the casing. Further, this is non-standard practice in SPDC requiring DPR approval and judged to be a complex/high risk operation, which outweighed the economic benefits. If the deeper levels should prove, after drilling/logging the well, to be less attractive than expected/non-commercial, then the opportunity to advance production by completing on shallower levels will be revisited.

Section 4: Corporate structure, and governance

This proposal is within the SPDC corporate structure and governance framework.

Section 5: Functional Support and consistency with Group and Business Standards

This proposal complies with Group Business Principles, policies and standards. Regional functional support was obtained (Finance, Technical and Legal). The proposal also has the strong support of NAPIMS and the other JV Partners.

Section 6: Project management, monitoring and review

This project is being managed by Exploration, Asset Development team (ADM), Minor Projects Team and Asset Engineering Team in line with SPDC's organisational model. Project activities will be reported weekly and monthly to SPDC Management.

The general project management is spelt out in the Opportunity Realisation Process (ORP). SPDC Decision Review Board (DRB) will approve all major decision gates. All significant reviews and status of follow up actions have been done in the various teams with the respective team leaders and discipline Chiefs.

Section 7: Budget provision

IP has adequate 2010 JV budget cover but was rephased to 2011 as part of efforts to stay within the Upstream Capex Ceiling for 2010. If approved, offsets will be identified from the Egbema-West NOV projects which are progressing slower than planned to ensure UIG remains within the approved Capex Ceiling.

Section 8: Group financial reporting impact

The incremental impact of the project on Group Financials is reflected in the table below:

	2010	2011	2012	2013	Post 2013
Total Commitment	15.89				4.56
Cash Flow					
SCD Expenditure					
Pre-FID Expenditure					
Capital Expenditure	15.89				4.56
Operating Expenditure	0.8	0.55	0.38	0.31	4.25
Cash flow From Operations	7.97	5.47	5.4	4.35	42.06
Cash Surplus/(Deficit)	-7.92	5.47	5.4	4.35	37.5
Profit and Loss					
NIBIAT +/-	0.49	5.34	3.71	3.13	36.41
Balance Sheet					
Avg Capital Employed	4.21	8.34	7.43	5.97	4.47

Table 3: Project impact on Shell Group financials- Base case.

Section 9: Disclosure

Disclosures, if required, will be done in line with existing Group and SPDC policies and guidelines.

Section 10: Financing

This investment will be financed with JV funding and Shell share capital expenditure will be met by SPDC's own cash flow and/or the existing shareholder loan facility.

Section 11: Taxation

Base case and sensitivity for standalone economics:

In the economics base case, the current regime (AGFA) is applied to the project and it is assumed that tax base will be available for offset of costs and allowances. However, due to concerns around sufficient taxable capacity to absorb all relief, the sensitivity is run that tax capacity is only available insofar generated by the project itself.

Tax proposals in the Petroleum Industry Bill:

The PIB is being read in the National Assembly. If enacted as drafted, it would have an impact on the upstream project's economics as indicated in the economics grid. There are still sizeable gaps in the Bill's definition of the proposed regime, for which assumptions have had to be made. Economics sensitivities were based on PIB V3.2 and 4.2 and were also run on a stand-alone basis.

Section 12: Key Parameters

The following is the main aspect of this proposal:

Approval for the amount of US$20.45 mln (50/50 MOD, Shell share), to execute the drilling and completion in Q3/Q4 2010 and hook-up of the Agbada 2X & 3X appraisal wells to Agbada-2 flow station in Q1 2011 plus re-completion workover on Agbada 2X in 2016. Thus the costs are phased as follows: 15.9 US$ mln SS in 2010 and a further 4.6 US$ mln SS in 2016.

Section 13: Signatures

This Proposal is submitted to REVP, EPG for approval.

For Business Approval	Supported by:
....	....
Ann Pickard	***Bernard Bos***
Regional EVP, EPG	VP Finance, EPG
Date ..../..../....	Date ..../..../....

Initiator:

Edward Curl (SPDC-EPX-G-NO)/***Esta Eleluwor*** (SPDC-EPG-TDLE)

Date: 07/01/2010