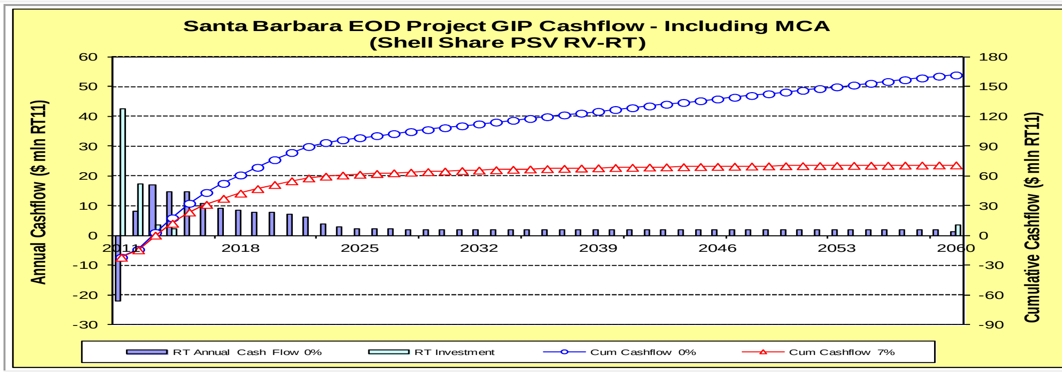
Group Investment Proposal

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 Nigeria Agip Oil Company Limited (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 U$114.10 mln Shell Share MOD 50/50 composed of US$112.81 mln CAPEX Shell Share MOD and US$1.29 mln OPEX Shell Share MOD is being requested for approval in this revised GIP. This is made up of US$41.34 mln Shell share approved in the previous proposal and US$72.76 mln Shell share being requested for in this proposal.

The total commitment for Shell of $114.10 is made up of Shell Equity contribution of US$64.59 mln and MCA contribution of US$49.51 mln.</td></tr>
<tr><td>Project</td><td>Santa Barbara Further Oil Development (FOD) Phase 1 (also known as Early Oil Development, EOD)</td></tr>
<tr><td>Main Commitments</td><td>
<table>
<tr><td>50/50 MOD</td><td colspan="5">100% JV ($'mln) MOD_Revised GIP</td><td colspan="5"><b>Shell Share ($'mln) MOD_Revised GIP</td></tr>
<tr><td>Description</td><td>Previous IP_JV Spent not part of MCA</td><td>Previous IP_JV spent but part of MCA</td><td>Incremental IP Request_ JV Funding</td><td>Incremental IP Request_ MCA Funding</td><td>Total IP</td><td>Shell Share_Previous IP</td><td>Shell Share_Incremental IP</td><td>Shell Share_Equity</td><td>Shell Share_MCA</td><td>Total Shell Share</td></tr>
<tr><td>Flowline & Hookups</td><td>3.92</td><td>2.51</td><td></td><td>11.99</td><td>18.42</td><td>2.85</td><td>7.99</td><td>5.53</td><td>5.32</td><td>10.84</td></tr>
<tr><td>Facilities</td><td>-</td><td>0.99</td><td></td><td>16.99</td><td>17.98</td><td>0.66</td><td>11.33</td><td>5.39</td><td>6.59</td><td>11.99</td></tr>
<tr><td>Facilities (MPF Refurbishment)</td><td></td><td></td><td>28.50</td><td></td><td>28.50</td><td>-</td><td>8.55</td><td>8.55</td><td></td><td>8.55</td></tr>
<tr><td>Wells & Location Prep.</td><td>37.95</td><td>38.68</td><td></td><td>58.37</td><td>135.00</td><td>37.17</td><td>38.91</td><td>40.50</td><td>35.59</td><td>76.09</td></tr>
<tr><td>PMT</td><td>0.58</td><td>-</td><td>5.03</td><td></td><td>5.61</td><td>0.17</td><td>1.51</td><td>1.68</td><td>-</td><td>1.68</td></tr>
<tr><td>Contingency</td><td>-</td><td>-</td><td></td><td>5.50</td><td>5.50</td><td>-</td><td>3.67</td><td>1.65</td><td>2.02</td><td>3.67</td></tr>
<tr><td>Total CAPEX</td><td>42.45</td><td>42.18</td><td>33.53</td><td>92.85</td><td>211.01</td><td>40.86</td><td>71.96</td><td>63.30</td><td>49.51</td><td>112.81</td></tr>
<tr><td>SCD (OPEX)</td><td></td><td>1.62</td><td>2.67</td><td></td><td>4.29</td><td>0.49</td><td>0.80</td><td>1.29</td><td>-</td><td>1.29</td></tr>
<tr><td>Total Cost</td><td>42.45</td><td>43.80</td><td>36.20</td><td>92.85</td><td>215.30</td><td>41.34</td><td>72.76</td><td>64.59</td><td>49.51</td><td>114.10</td></tr>
</table>
</td></tr>
<tr><td>Reserves/ Resources</td><td>This project is aligned with SPDC's strategic goals and priorities by maturing economic truncated 2P reserves of 11.58 MMstb of oil and 0.18 bln sm3 of gas (SS) to production and transferring of equivalent SEC Proved reserves of 9.75 MMstb of oil and 0.14 bln sm3 of gas (SS) from PUD to Proved Developed in 2012 with positive impact on SPDC DD&A (This includes economic truncated 2P and proved oil reserves of 2.18 MMstb and 1.85MMstb (SS) respectively for the SBAR-10T well re-categorized as NFA, Ref Page 3 & HCM table attached). In addition, 0.23 MMstb PUD associated with the MCA had been booked in 2010 (Ref 31.12.2010).</td></tr>
<tr><td>Production</td><td>Incremental oil production from this project peaks at 8.8 Mbopd with associated gas production of 2.8 MMscf/d (2.64 Mbopd and 0.84 MMscf/d SS) by 2013 thus increasing the effective utilization of the new NCTL pipeline and contributing to SPDC's gas supply to NLNG.</td></tr>
<tr><td>Source and Form of Financing</td><td>This investment will be financed through the agreed MCA funding for NCTL Bundle, reference GFP approved by the RDS Board on 22.07.2008. Total Shell commitments including NNPC carry under the MCA will be financed with SPDC limited own generated funds and existing intra-group facilities. The MCA terms do not include PMT CAPEX and all OPEX related expenditures.</td></tr>
</table>

Summary Cash Flow



Summary Economics

Summary economics*	NPV (USD mln)	RTEP (%)	VIR
Project title: Santa Barbara EOD Project GIP			
RV ($70/bbl & $1.73/mmbtu RT11)	70.9	54	1.10
SV ($50/bbl & $1.30/mmbtu RT11)	47.0	40	0.73
HV ($80/bbl & $2.27/mmbtu RT11)	95.1	68	1.48

Section 1: The proposal (Management Summary)

This revised Group Investment Proposal (GIP) seeks support/approval for funding of US$64.59 mln Shell Equity Share MOD and already approved additional investment of US$49.51 million as NNPC carry under MCA to fully execute Santa Barbara Further Oil Development (FOD) phase 1 (SBAR phase 1) project.

The GIP update is necessitated by: the change in funding mechanism from Shell Equity Share only to Shell equity plus NNPC carry under MCA arrangement, project cost increase resulting from higher than anticipated Rig and materials cost, refurbishment of the Santa Barbara Mobile Production facility (MPF), re-categorization based on MCA guidelines and also the need to re-run the economics.

Santa Barbara and Santa Barbara South fields are located in OML 25 and 29, about 60 km South-West of Port Harcourt. The fields have expectation STOIIP of 1084.1 MMstb, Expectation Ultimate Recovery (100%) of 445.2 MMstb (reference NNS ARPR 31/12/2010). The fields came on stream in February 2001. Cumulative production as at 31/12/2010 was 32.3 MMstb of oil and 23.3 Bscf of gas from 8 wells.

Santa Barbara phase 1 project aims to drill and complete 5 wells (4 horizontal, 1 conventional well), install flowlines, hookup wells to flowstations, facility refurbishment and upgrade. Of these, three wells (Sbar-10T, 11T and 12T) were drilled and completed in 2008. The original objective of the EOD project (ref 2007 GIP) was to develop 52 MMstb (100%) expectation oil reserves. However, based on the BP10 HCM forecast, the project will develop economic truncated 2P reserves of 38.6 MMstb of oil (100%) having drilled, hooked-up and produced SBAR-10T before now.

Santa Barbara field has an AG infrastructure in-place which delivers produced gas to Soku Gas Plant via an existing gas export pipeline. The total liquid processing capacity of Santa Barbara Mobile Production Facility (MPF) is 30 Mbpd. Crude will be evacuated from the field via the new Nembe Creek Trunkline (NCTL). However, the Santa Barbara MPF will not be available until end Q1 2012 as it is currently undergoing refurbishment.

Santa Barbara MPF facility refurbishment comprises re-entry activities to restore the integrity of the facility in order to produce current locked-in oil potential of 20.7 Mbopd at the shortest possible time. Re-entry activities involve refurbishment of all major equipments like generators, pumps, compressors, replacement of control system, electrical/instrument cables, UPS systems and transformers and procurement/replacement of 25 km of flowlines. The re-entry activities commenced in September 2010.

The previously approved JV 100% funding of US$86.25 mln (shown in Table under main commitments, page 1) was to drill, complete and hookup 5 oil producers (4 horizontal and 1 Conventional wells) and carry out minor facility upgrade in Santa Barbara field in 2007. The 2007 GIP economics returned a life cycle project NPV (7%) of US$32.2 mln at a Project Ranking Value (PRV) of $40/bbl compared to the full life cycle evaluation of this updated GIP at US$37.6mln NPV (7%) at a higher PRV of $70/bbl based on higher cost premise (ref. Summary Economics section, Table 2).

As at June 2008, 3 horizontal wells had been drilled, completed and hooked up with spend already above 2007 approved expenditure for the project. The project cost overrun is attributed to:

- Increased maintenance cost of SPDC's Rig-2 while drilling the 3 wells.
- Higher than anticipated rig and materials cost, Drilling Contractor (Lonestar) internal management problems leading to high NPT, as well as escalating security challenges in the Niger Delta.

Drilling of the outstanding two wells is planned to start in December 2011 with Passion rig pickup based on the signed August 2011 Short-Term Drilling and Workover Sequence. The first oil is expected in April 2012 when SBAR MPF will come on stream.

Section 2: Value proposition and strategic and financial context:

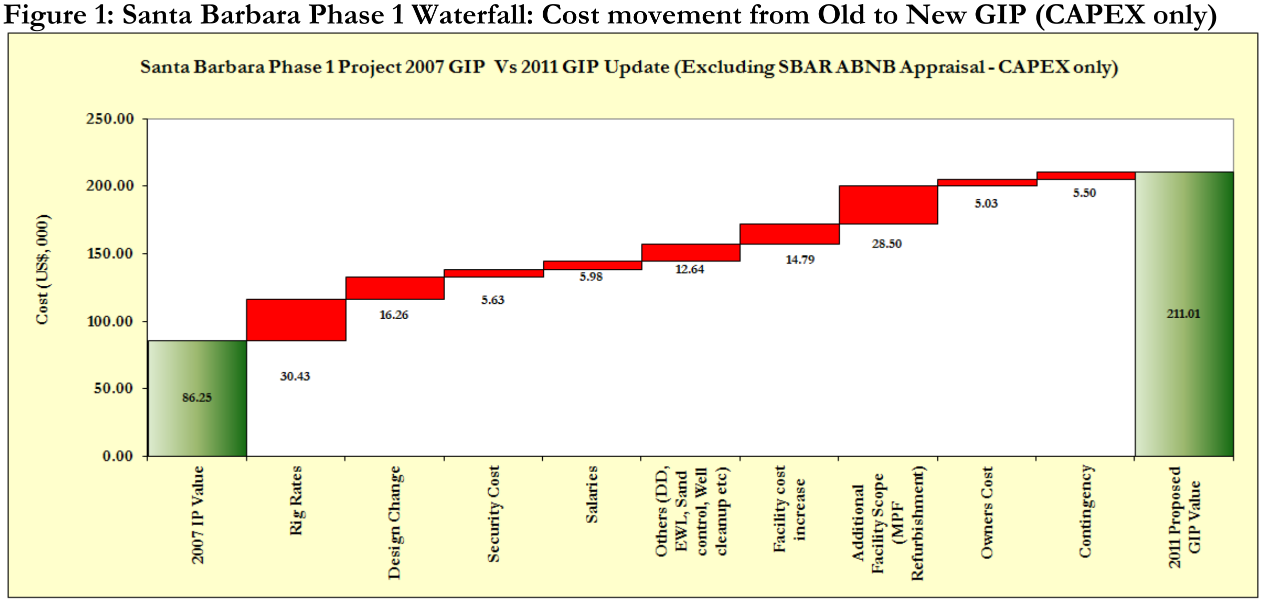
- This project is aligned with SPDC's strategic goals and priorities by maturing economic truncated 2P reserves of 11.58 MMstb of oil and 0.18 bln sm3 of gas (SS) to production and transferring equivalent SEC Proved reserves of 9.75 MMstb of oil and 0.14 bln sm3 of gas (SS) from PUD to Proved Developed in 2012 with positive impact on SPDC DD&A (Ref HCM table attached). The reserves of SBAR-10T (2.18 MMstb SS) were excluded in the HCM forecast attached since the well is categorised as NFA having been drilled, completed, hooked-up and produced shortly before the flowstation outage. Though the HCM forecast includes the Santa Barbara Appraisal well (SBAR-ABNB-1) 2C Oil resources of 3.4 MMstb (SS), the current GIP update does not include the appraisal well as there is already a separate approved IP for the well.

- Incremental oil production, peaking at 8.8 Mbopd by 2013 thus increasing the effective utilization of the new NCTL pipeline and contributing 2.8 MMscf/d to SPDC's gas supply to NLNG. This optimizes further the use of existing Right of Way (RoW) and facilities thereby lowering Unit Technical Cost (UTC) of development and minimizing the footprint.

Cost Increase/Market Situation

Costs have escalated from the last IP approval from US$86.25 mln to US$215.3 mln due mainly to increase in rig rates, design changes and additional facilities scope/cost. The chart below reflects details of the key changes.

Figure 1: Santa Barbara Phase 1 Waterfall: Cost movement from Old to New GIP (CAPEX only)



Summary Economics

The base case economics was evaluated on a forward-look basis and assumes that Shell will fund its NNPC share of the Carry (MCA) component of the costs and its Equity share of the project costs. The Project Management (PMT) CAPEX and Social Performance OPEX are excluded from MCA funding (treated as JV cost) as they were not originally part of the carry cost under the agreement. The 100% Capex phasing (including Social Performance Opex of US$4.29 mln) at 50/50 MOD estimate is shown in Table 1:

Table 1: SBAR FOD Phase 1 project Cost Phasing MOD 100% JV and Shell Share

P50 Estimate & Expenditure Phasing															
	JV Funded								*MCA Funded*						PROJECT TOTAL
	2007	2008	2009	2010	2011	2012	2013	2014	2008	2010	2011	2012	2013	2014	
Facilities	3.92	-	-	3.55	20.15	4.80	-	-	2.50	-	15.50	6.00	5.00	3.00	64.42
PMT	0.58		-		0.11	1.20	2.40	1.32	-	-					5.61
Wells	37.95		-	-	-	-	-	-	47.33	-	33.47	16.73			135.48
Contingency			-				-	-	-	-	5.50	-	-	-	5.50
OPEX (SCD)	0	1.62	-	-	2.19	0.28	0.1	0.1		-					4.29
100% CAPEX Phasing	**42.45**	**0.00**	**0.00**	**3.55**	**20.26**	**6.00**	**2.40**	**1.32**	**49.83**	**0.00**	**54.47**	**22.73**	**5.00**	**3.00**	**211.01**
100% Cost Phasing	**42.45**	**1.62**	**0.00**	**3.55**	**22.45**	**6.28**	**2.5**	**1.42**	**49.83**	**0.00**	**54.47**	**22.73**	**5.00**	**3.00**	**215.30**
Years / Phasing (Shell Share)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2008**	**2010**	**2011**	**2012**	**2013**	**2014**	**PROJECT TOTAL**
JV_Cost Phasing (Shell Share)_CAPEX	12.74	0.00	-	1.07	6.08	1.80	0.72	0.40	14.95	-	16.34	6.82	1.50	0.90	63.30
JV_Cost Phasing (Shell Share)_OPEX	0	0.49			0.66	0.08	0.03	0.03							1.29
Total JV_Cost Phasing	**12.735**	**0.49**	**-**	**1.07**	**6.735**	**1.884**	**0.75**	**0.43**	**14.95**	**-**	**16.34**	**6.82**	**1.50**	**0.90**	**64.59**
MCA_Cost Phasing (Shell Share)_CAPEX			**-**						**18.27**	**-**	**19.97**	**8.33**	**1.83**	**1.10**	**49.51**
Total Shell Share_JV & MCA	**12.74**	**0.49**	**0.00**	**1.07**	**6.74**	**1.88**	**0.75**	**0.43**	**33.22**	**0.00**	**36.31**	**15.15**	**3.33**	**2.00**	**114.10**

The headline number covers the CAPEX and OPEX Shell Share, under JV funding required for the project execution and the Shell share of the NNPC portion of the project cost, bringing total Shell Share of the project cost to approximately 53% of the SPDC JV 100% cost of US$215.3mln.

Sensitivities evaluated include:

- High CAPEX
- 1yr schedule delay
- Full Life Cycle
- PIB House Version
- High & Low reserves
- Concession expiration in 2019
- 1.5% cost mark up as provision for costs dispute by NNPC.

Table 2: Economic indicators for the full scope of Santa Barbara EOD Phase 1

PV Reference Date: 1/7/2011	**NPV (S/S $ mln)**		**VIR**	**RTEP**	**UTC (RT $/boe**		**Payout-Time (RT)**	**Maximum Exposure (RT)**
Cash flow forward from: 1/1/2011	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	**0%**	**0%**
Base Case + MCA								
SV ($50/bbl & $1.30/mmbtu RT11)	110.3	**47.0**	**0.73**	40	6	9		
RV ($70/bbl & $1.73/mmbtu RT11)	161.6	**70.9**	**1.10**	54	6	9	2013	*$22.1mln in 2011*
HV ($90/bbl & $2.27/mmbtu RT11)	210.8	**95.1**	**1.48**	68	6	9		
Oil BEP (RT $/bbl)						6.2		
Sensitivities (using RV)								
High CAPEX (P90)		**70.1**	**0.98**				2013	*$24.5mln in 2011*
High Reserves		**73.6**	**1.15**				2013	*$17.3mln in 2011*
Low Reserves		**57.5**	**0.89**				2014	*$26.9mln in 2012*
1-Yr Production Schedule Delay		**65.7**	**1.02**				2014	*$26.9mln in 2012*
Concession Expiration (2019)		**46.8**	**0.73**				2013	*$22.1mln in 2011*
Full Life Cycle		**37.6**	**0.30**				2015	*$51.3mln in 2011*
1.5% cost markup due to BVA issues		**68.2**	**1.03**					
PIB House_v12		**82.7**	**1.29**					

Key Project Parameter Data Ranges (Shell Share)

Parameter	**Unit**	**BP10 Provision**	**Low**	**Mid**	**High**	**Comments**
Capex (MOD)	US$ mln	72.76	68.34	72.76	80.99	Incremental CAPEX under MCA Funding of $34.04mln and JV Funding of $38.72mln. FLC CAPEX under MCA Funding is $50.25mln and FLC JV Funding is $64.59mln
Opex (MOD)_Project	US$ mln	0.80	0.72	0.80	0.96	Incremental project OPEX under JV Funding. FLC OPEX is $1.29mln
Production Volume	mln boe	21.61	16.13	21.61	21.82	Production volume forecast till end of fields' lives
Start Up Date	mm/yy	Apr-12	Apr-13	Apr-12	Jul-11	Base re-start Up production
Production in first 12 months	mln boe			1.67		Production vloume from April, 2012 - March, 2013

The impact of earlier approved expenditure (US$86.25mln 100% JV MOD) and additional expenditures of $10.68mln (Wells - $5.94mln, MPF - $3.55mln, and OPEX – $1.19mln), i.e. $96.93mln 100% JV MOD on the base case economics is shown under the Full Life Cycle sensitivities. The tornado plot is shown in Figure 2 while details of the evaluation results are shown in the economics grid in Table 2.

Figure 2: Tornado Plot for Santa Barbara EOD Project GIP

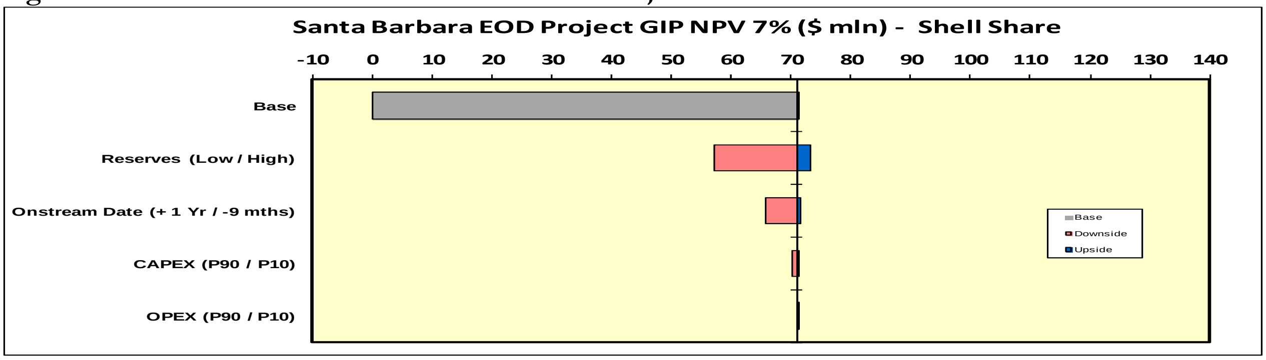
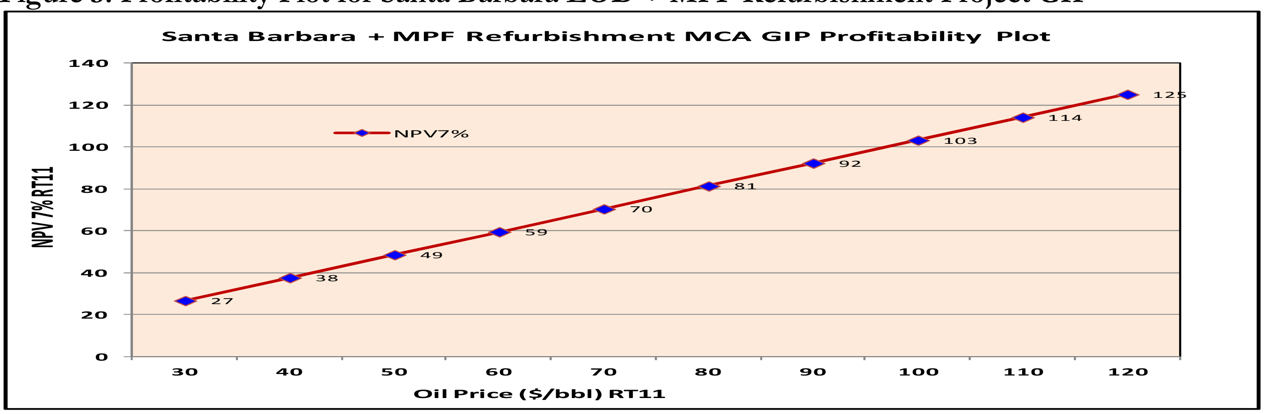


Figure 3: Profitability Plot for Santa Barbara EOD + MPF Refurbishment Project GIP



Key Economic Assumptions:

- Gas taxed under CITA with AGFA fiscal incentive applied.
- Gas Supply to NLNG T1-6 assumed Gas Sales Price $1.73/mmbtu at PSV RV-RT in 2011.
- Gross Heating Value (GHV) of 1150btu/scf applied.
- ARPR OPEX of 31/12/2010 was applied in addition to project Social Performance OPEX.
- NDDC Levy of 3% of total expenditure excluding flare penalty
- Education Tax of 2% assessable profit
- Flare penalty of $3.5/Mscf applied.
- Water treatment cost at $0.50/bbl applied.
- 10% of total project RT CAPEX assumed as abandonment cost

MCA assumptions:

- All costs over the MCA ceiling would be recovered through cost oil.
- Project management costs were not included among the carried cost.
- Profit oil ceiling of 8% IRR on carried costs
- Current agreement for recovery of carry costs is maintained

PIB assumptions:

- Overseas_Capex_Fraction_Assumed at 30%
- 70$/bbl – oil at PSV RV-RT in 2011
- 1.73$/mmbtu – gas (export) at PSV RV-RT in 2011
- NHT depreciation schedule is 4x20%, 19% for qualifying expenditure.

- CIT depreciation schedule is 3x25%, 24%, for qualifying expenditure.
- Royalty rates based on product (value) prices and production rates per PML (assumed equal to a field).
- 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
- Withholding tax is applicable at a rate of 7.5% for IAT version but not for the alternate version
- Flaring penalty is calculated at $3.5mln/Btu MOD flat and it is not tax deductible for both CIT and NHT
- 20% of overseas cost is non-deductible for determination of NHT taxable income
- NHT rate is 50% for onshore and shallow water, and 30% for frontier acreages and Deep Water.
- CIT is 30% of taxable income and is not deductible from NHT
- Santa Barbara is an existing field hence no production allowance is applicable.

Section 3: Risks, opportunities and alternatives

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

3.1 Risks

- **Funding:**
  There is the risk that project value to Shell will be eroded if the MCA-approved cost estimate is exceeded. There is also the risk that costs above the approved cost estimate may not be approved by NNPC and therefore become a Shell exclusive charge.
  Mitigation: Project will be executed based on approved budget. Partners would be engaged early where there is variation.
- **Community and Enabling Environment (Security, Sabotage, Political and Environment):** Hostage taking, existence of militant groups and threat of insurgence are realities in the Niger Delta especially in the swamp which could threaten project execution.

  Mitigation: General Memorandum of Understanding (GMoU) has been signed with the community and 2 % of the total project cost will be used for Community project. With improvements in the Niger Delta security following Amnesty programme, it is envisaged that there will be a reduction in Community related NPT. Specific threats will be managed through the Security & Surveillance Centre (SIS) and communicated in good time to those that need to "Know" and "act".
- **HSE:**
  The project will be executed under challenging circumstances in the Niger Delta area.

  Mitigation: There will be site specific HSE adviser and existing HSE-MS culture will be sustained during the project.
- **Cost Overrun:**
  Increase in the rig cost as a result of shortage of suitable swamp rigs, Non-productive time while drilling, escalation of facility upgrade and material costs.

  Mitigation: The well and facility costs have been updated to reflect current reality.
- **Delayed Completion of Flow-station refurbishment Project:**
  The vandalization of the Santa Barbara Flowstation and flowlines resulted in the inability to open up the station post NCTL repairs.

  Mitigation: Currently, Flow-station refurbishment is ongoing and Latest Estimated Completion (LEC) date is Q1 2012. A dedicated project team and DRB are in place to ensure on-time delivery.
- **Facility Uptime Improvement:**
  Facility uptime improvement from 55% to 85%
  Mitigation: As at June 2011, facility uptime is 0% (No recent data as station has been down since July 2008). Activities are currently ongoing to improve the uptime to expected minimum of 85%. These activities include Station power generator and control system change out and are expected to be delivered by end 2014.

- **Risk around unapproved incremental MCA Costs:**
  There is a risk that un-approved MCA costs would be disallowed for tax deductions by the FIRS.
  Mitigation: Upstream Commercial Finance would re-negotiate and ensure that incremental costs are approved by NNPC.

3.2 Opportunities

- **Resources:**
  Critical positions required to deliver the project have been resourced. Swamp East Asset Development (DSSE) Field Development and Execution Team will support the execution. Engineering support will be provided by both Major project Corporate Matrix and Asset Engineering Teams.
- **Project support:**
  This project will provide data for the optimization of Santa Barbara Phase 2 FDP wells.
- **Knowledge Sharing:**
  This project will provide a very good opportunity for the new well-site PEs to have requisite operations experience under the close supervision of their senior PEs and SDEs.

3.3 Alternatives

There are no alternatives to drilling these wells to develop the reserves and implement current re-entry refurbishment activities for early production given in this proposal.

Section 4: Carbon Management

The main impact on Green House Gas (GHG) emission resulting from the hookup of additional production into the existing surface facilities have been addressed by the GHG and Energy Management Plan (EMP) for the facilities. The GHG/EMP also contains the 10 years GHG emission and Energy use forecast for the facilities together with a number of recommended abatement proposals. Some of these proposals are now being implemented in the Santa Barbara refurbishment work. With the flowstation up and running in Q1 2012, emission from flaring will be largely eliminated.

Section 5: Corporate Structure, and Governance

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

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

This proposal and the execution of the project are consistent with the Group Business standards. Functional support for this proposal has been provided by Technical, Finance, Legal, Treasury, Contracting/Procurement, Social Performance and Tax functions etc.

Section 7: Project Management, Monitoring and Review

The execution of the project is managed through the DSSE Field Development & Execution Team, Wells and Engineering Hub Teams in line with the SPDC organizational model. Following successful completion, the wells will be handed back to the Swamp East Production Operations Team. There will be regular progress report of the well delivery activities to Asset Development Manager, the Development General Manager and to the JV Partners. All significant reviews and follow up actions had been done in the Development and Engineering Teams. Details of the ORP review gates are shown below:

- VAR2 (Nov. 2004) and DG2 (May. 2005)
- VAR3/DG3 completed in Oct. 2005/ Dec. 2005, respectively
- VAR4 /DG4 in Aug. 2006/ Nov 2006 respectively and comments have been closed out.
- On-Stream Date: April 2012.

Section 8: Budget provision

This project has budget cover and is included in BP10 and BP11 as well as the 2011/12 JV Programme. Though the revised GIP is in line with capital expenditure allocated to the Santa Barbara phase-1 project in the business plan, there is an increase of US$21.42 mln (100%) when compared to the costs in the 2008 MCA agreement. In line with MCA agreement, NAPIMS will be engaged in order to reach an agreement on how to fund the additional costs if they materialize.

Section 9: Group financial reporting impact

The financial impact of this proposal on Shell Group financial is as outlined in the table below:

US$ mln	Prior Years	2011	2012	2013	2014	2015	Post 2015
Total Commitment	47.46	42.69	18.18	4.08	2.43	0.00	0.00
Cash Flow							
SCD Expenditure	0.84	0.30	0.08	0.03	0.03	0.00	0.00
Capital Expenditure	46.62	42.39	18.09	4.05	2.40	0.00	0.00
Operating Expenditure	0.00	1.72	2.83	4.28	2.76	2.26	62.79
Cash Flow from Operations	11.55	15.89	27.63	32.20	30.07	21.56	187.46
Cash Surplus/(Deficit)	(35.07)	(26.51)	9.54	28.15	27.67	21.56	187.46
Profit and Loss							
NIBIAT +/-	2.13	2.74	12.59	14.74	10.84	7.24	178.73
Balance Sheet							
Average Capital Employed	56.03	81.43	118.62	133.16	136.61	122.36	422.93

Section 10: Disclosure

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

Section 11: Financing

Both SPDC's direct share of expenditure and its contribution to NNPC's share will be funded from SPDC's own cash flow and existing intra-group facilities.

Section 12: Taxation

MCA fiscal arrangements are acceptable to the Tax authorities, provided their sign off is obtained before implementation.

Section 13: Key Parameters

The following are the main aspects of this proposal:

Approval for the total revised headline size of US$114.10 mln Shell Share 50/50 MOD. This is made up of Shell Equity contribution of US$64.59 mln and MCA contribution of US$49.51 mln.

Section 14: Signatures

This Proposal is submitted to ECMB for approval.

Supported by:	For Business approval:
....	....
Maarten Wetselaar (FUI)	Malcolm Brinded (ECMB)
Date ..../..../....	Date ..../..../....

Initiator: ____________________

Bayo Ojulari (UIG/T/D)
Date: 14/11/2011

Lifecycle HCM Forecast Sheet — Version 2.0 — Confidential

Santa Barbara FOD Phase 1

Project Location & Country — Project No.: SPDC-11-2581

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

OIL/NGL [mln bbl] DG/Key event	Date (mm)-yy	2U Prospective Resources Additions: Prospect	2C Contingent Resources Additions: Dev. Pending Post-DG1	2C Contingent Resources Additions: Dev. Pending Post-DG2	PRMS 2P Reserves Additions: Undeveloped Post DG3	PRMS 2P Reserves Additions: Undeveloped Post-DG4	PRMS 2P Reserves Additions: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed	Annual Production	CHECK (developed reserves additions minus cum produciton): 2P Reserves Developed	CHECK: SEC Proved Developed
DG 2	Sep-05			12.8							0.0	0.0
DG 3	Sep-05			-9.4	9.4						0.0	0.0
FID	Apr-07				-9.4	9.4		7.9			0.0	0.0
											0.0	0.0
											0.0	0.0
											0.0	0.0
	2010										0.0	0.0
Appraisal Well Drillin	2011			-3.4		3.4					0.0	0.0
First HC	2012					-12.8	12.8	-7.9	7.9	0.8	12.0	7.1
	2013								0.0	1.1	10.9	6.0
	2014								0.0	0.8	10.2	5.3
	2015								0.0	0.7	9.5	4.6
	2016								0.0	0.7	8.8	3.9
	2017								0.0	0.7	8.1	3.2
Perf Update	2018								2.0	0.7	7.3	4.4
	2019								0.0	0.7	6.7	3.7
	2020								0.0	0.7	6.0	3.0
Perf Update	2021								1.8	0.7	5.3	4.1
	2022								0.0	0.5	4.8	3.6
	2023								0.0	0.4	4.4	3.2
Perf Update	2024								0.7	0.2	4.1	3.6
	2025								0.0	0.2	4.0	3.5
	2026								0.0	0.2	3.8	3.3
Perf Update	2027								0.5	0.2	3.6	3.6
later years									0.0	3.6	0.0	0.0
Total		0.0	0.0	0.0	0.0	0.0	12.8	0.0	12.8	12.8		

negative numbers are incorrect

OIL/NGL [mln bbl]		2U Prospective: Prospect	2C Contingent Resources: Dev. Pending Post-DG1	2C Contingent Resources: Dev. Pending Post-DG2	PRMS 2P Reserves: Undeveloped Post DG3	PRMS 2P Reserves: Undeveloped Post-DG4	PRMS 2P Reserves: Developed	SEC Proved Reserves: Undev	SEC Proved Reserves: Developed
ARPR 31.12.2009	before last					16.5		9.8	
ARPR 31.12.2010	last					12.4		7.7	

GAS [bln sm3] DG/Key event	Date (mm)-yy	2U Prospective: Prospect	2C Contingent Resources Additions: Dev. Pending Post-DG1	2C Contingent Resources Additions: Dev. Pending Post-DG2	PRMS 2P Reserves Additions: Undeveloped Post DG3	PRMS 2P Reserves Additions: Undeveloped Post-DG4	PRMS 2P Reserves Additions: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed	Annual Production	CHECK (developed reserves additions minus cum produciton): 2P Reserves Developed	CHECK: SEC Proved Developed
DG 2	Sep-05			0.19							0.00	0.00
DG 3	Sep-05			-0.16	0.16						0.00	0.00
FID	Apr-07				-0.16	0.16		0.12			0.00	0.00
											0.00	0.00
											0.00	0.00
											0.00	0.00
	2010									0.00	0.00	0.00
Appraisal Well Drillin	2011			-0.04		0.04				0.00	0.00	0.00
First HC	2012					-0.20	0.20	-0.12	0.12	0.01	0.19	0.11
	2013								0.00	0.01	0.17	0.10
	2014								0.00	0.01	0.16	0.09
	2015								0.00	0.01	0.15	0.08
	2016								0.00	0.01	0.14	0.07
	2017								0.00	0.01	0.13	0.06
	2018								0.00	0.01	0.13	0.05
	2019								0.00	0.01	0.12	0.04
Perf Update	2020								0.03	0.01	0.11	0.06
	2021								0.00	0.01	0.10	0.05
Perf Update	2022								0.03	0.01	0.09	0.07
	2023								0.00	0.01	0.08	0.06
	2024								0.00	0.00	0.08	0.06
	2025								0.00	0.00	0.07	0.05
	2026								0.00	0.00	0.07	0.05
	2027								0.00	0.00	0.07	0.05
later years									0.02	0.07	0.00	-0.00
Total		0.0	0.0	-0.0	0.0	0.0	0.195	0.0	0.195	0.195		

negative numbers are incorrect

Gas [bln sm3]		2U Prospective: Prospect	2C Contingent Resources: Dev. Pending Post-DG1	2C Contingent Resources: Dev. Pending Post-DG2	PRMS 2P Reserves: Undeveloped Post DG3	PRMS 2P Reserves: Undeveloped Post-DG4	PRMS 2P Reserves: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed
ARPR 31.12.2009	before last					0.24		0.14	
ARPR 31.12.2010	last					0.16		0.09	

VP Technical (or VP-X)

Name : Lismont, Bart

Signature : Bar Lm

For RDL-RE (RXC or RXHM)

Name : Emelle, Chima

Signature : NGCEM3 Digitally signed by NGCEM3 DN: cn=NGCEM3 Date: 2011.06.09 17:28:06 +01'00'

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

ESTIMATE FACT SHEET to be included in GIP and PCN submissions — **Version 2.4** — **Confidential**

Santa Barbara FOD Phase 1 (Early Oil Development)

Approved Cost & Schedule Estimate

<Please enter Project Location> — **Project No.:** C11043

Estimator:	Olaribigbe, Elias	**Planner:**	Dadi, Musa
Case:	Base	Rates of Exchange are as per SI-SX Data Set	

Market Scenario: RV — **Estimate Type: 3** — **Cost are in: USD Millions**

Estimate Start / End: FID Apr-2007 / RFSU Oct-2014 — **EDM Date:** 1-Jul-10

Category		Total Costs
Facilities		48
<Wells>		135
Owners cost (incl. insurance, pre-FID, Capitalized interest)		14
Market Escalation, EPC Premium & Taxes		7
Contingency	Facilities: 18% <Wells>: 0%	8
Inflation		3

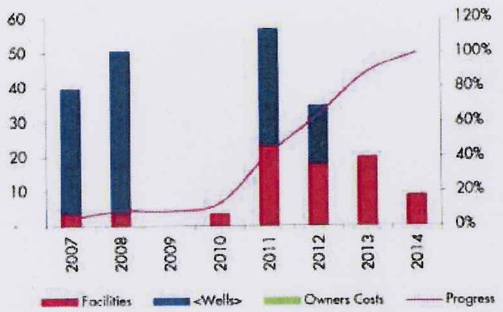
	P10	P50	P90
Approved Total Project Estimate, MOD	189	215	258
	-12%		20%

OK

Assumptions:

Est. and Schedule Premise	About 25% of total Surface Facilities cost estimate is based on actual costs. The outstanding estimates are based on awarded contracts/POs and other recent/ongoing contracts. Wells cost estimate includes wells contingency included by Well Engineering in line with agreed methodology in-house SPDC. Surface Facilities P50 and P90 contingencies are deterministically determined using the TECOP Tool - they have not been applied on the actuals parts of the overall estimate. The shedule is based on early drill to fill using three wells that will back out other high GOR and water cut wells. When the facility is upgraded in 2014, the back-out wells will be re-produced.
Execution Strategy Premise	The Concrete Barge refurbishment and flowlines construction part of the project are in execution based on a DIY strategy involving award of multiple POs and installation contracts, mostly using existing call-out contracts. EPC strategy is proposed for the Off-barge facilities part of the project for which detailed design is being carried out.
Contract Strategy	Use of existing call-out contracts, award of Pos for procurement and proposed EPC for Off-Barge facilities
Key Project Risks	Security/community issues, Poor contractor quality, HSE Risks, Internal and external interface management
Exclusions	SPDC financing of interest during construction
Benchmarking & Metrics	Estimate is largely based on awarded contracts/Pos and existing call-out contracts for similar activities

Capex Phasing and Planned Progress:



Key Schedule Dates:		
Phase	Finish (P50)	Finish (P90)
FID	Apr-2007	
Detailed Eng.	Dec-2011	Jan-2012
Procurement	Sep-2011	Sep-2011
Proc. of Bulk Mat.	Sep-2013	Dec-2013
Construction	Aug-2014	Nov-2014
Commissioning	Oct-2014	Jan-2015
RFSU	Oct-2014	Jan-2015

DCAF TA 1

Date : 5/7/2011
Name : Bensley Andrew PP George Wilke
Signature :

Project Manager

Date : 22-06-2011
Name : Uyouko Ime
Signature :

VP Project Services

Date : 5/7/2011
Name : Hans Mes
Signature :

Business Opportunity Manager

Date : 22-06-2011
Name : Nwabueze Vincent
Signature : PP