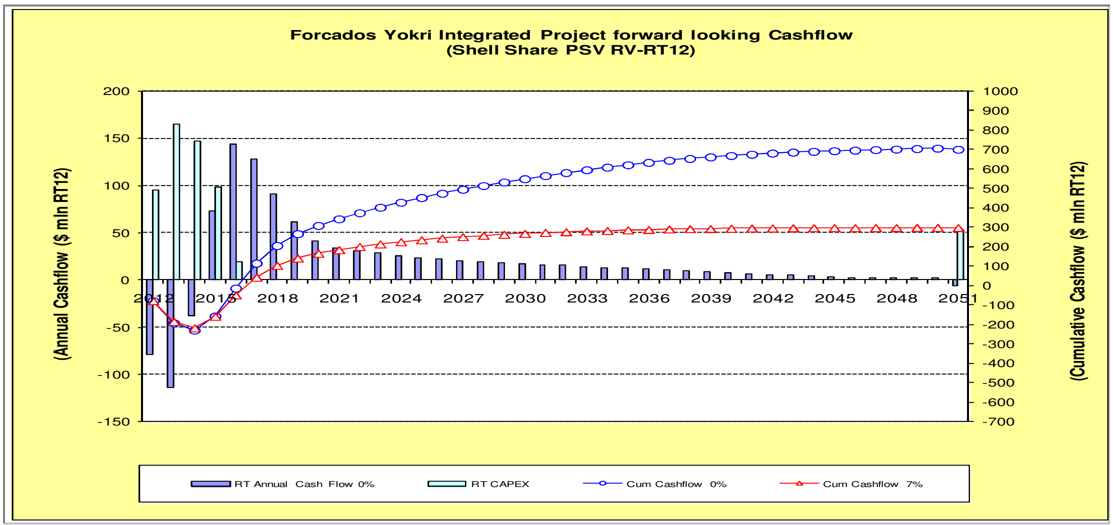
Group Investment Proposal

Summary information

<table>
<tr><td>Business unit and company</td><td>The 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>This IP seeks approval for further Shell Equity Investment of US$ 508million MOD 50/50 (CAPEX- US$ 503million and OPEX- US$ 5million). Previously, US$ 359million (Shell Equity) was approved on GIP 21.11.07 out of which US$ 40million is unspent and will be added to requested amount to make up the US$ 548million required for project completion. With this proposal, total Shell Equity Investment in the project becomes US$ 867million of which US$ 319million is sunk cost.</td></tr>
<tr><td>Project</td><td>Forcados Yokri Integrated Project (FYIP)</td></tr>
<tr><td>Main commitments</td><td>
<table>
<tr><th rowspan="2">Description</th><th colspan="3">100% JV ($'mln, MOD)</th><th colspan="2">Shell Share ($'mln, MOD)</th></tr>
<tr><th>Previous IP</th><th>Incremental IP</th><th>Total JV</th><th>Incremental</th><th>Total Shell Share</th></tr>
<tr><td>Oil Facilities</td><td>435</td><td>601</td><td>1,036</td><td>180</td><td>311</td></tr>
<tr><td>AG Gathering & Gaslift Facilities</td><td>448</td><td>764</td><td>1,212</td><td>229</td><td>363</td></tr>
<tr><td>Drilling/Completion/Recompletion</td><td>150</td><td>141</td><td>291</td><td>42</td><td>87</td></tr>
<tr><td>Owners Costs (excl SCD & Training)</td><td>121</td><td>13</td><td>134</td><td>4</td><td>40</td></tr>
<tr><td>Contingency (50/50)</td><td>37</td><td>158</td><td>196</td><td>47</td><td>59</td></tr>
<tr><td>Project OPEX (SCD & Training)</td><td>7</td><td>15</td><td>22</td><td>5</td><td>6</td></tr>
<tr><td>SUB TOTAL (50/50 MOD)</td><td>1,198</td><td>1,692</td><td>2,890</td><td>508</td><td>867</td></tr>
<tr><td>Overrun Allowance to 90/10 MOD</td><td>13</td><td>260</td><td>273</td><td>78</td><td>82</td></tr>
<tr><td>TOTAL (90/10 MOD)</td><td>1,211</td><td>1,952</td><td>3,163</td><td>586</td><td>949</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 89.91 MMstb of oil and 55.73 Bscf of gas (Shell Share) and 1P reserves of 55.65 MMstb of oil and 11.56 Bscf of gas.</td></tr>
<tr><td>Production</td><td>Oil production from this project peaks at 89.6 Mbopd (NFA safeguarded is 42.6 and New oil is 47.0 Mbopd) of oil and gas production of 60.7 MMscf/d (33.2 MMscf/d of NAG and 27.5 MMscf/d of AG) by 2015; thus contributing to SPDC's gas supply to DomGas and elimination of gas flaring.</td></tr>
<tr><td>Source and form of financing</td><td>The Shell Share of the investment will be financed with SPDC own resources.</td></tr>
<tr><td>Summary cash flow</td><td>
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Summary economics		NPV7% (US$ mln)	VIR7%	RTEP (%)
	Base Case HV-RT12	430.7	0.91	33
	Base Case RV-RT12	298.2	0.63	26

Section 1: The proposal (management summary)

The Forcados Yokri Field, located some 50 km South-West of Warri in the Western Niger Delta (OMLs 43 and 45), next to Forcados Terminal and commenced oil production in 1970. The Forcados Yokri Integrated Project (FYIP) was initiated to redevelop the field and eliminate flaring in late 1990s. With FID in 1999, the scope covered development of 25 new oil wells and gaslift of 62 existing drainage points, installation of replacement flowstations, gas gathering & export plant at North Bank, Forcados Terminal Power upgrade and field wide electrification network. The new FYIP oil and gas facilities have combined installed capacities of 265 Mb/d and 110 MMscf/d respectively.

With the installation of the facilities nearing completion in Feb 2006, the project site was impacted by effects of militant insurrection in the Niger Delta. Project execution was stalled and assets were abandoned in a hurry without preservation. 25 new wells were drilled but 12 wells were not yet hooked up. The new flowstations and gas plants were at various stages but close to completion (80 – 95% completion) when abandoned.

Revised Project Objectives

The scope included in this GIP revision is to: 1) complete the original scope, 2) accommodate the change of gas market from NLNG to domestic, 3) replace the existing platforms and bulklines in the Estuary for integrity reasons and 4) provide security upgrades. The project was initially planned to gather AG in Forcados Yokri and neighboring fields like Odidi and export the gas to Nigerian Liquefied Natural Gas (NLNG) via Offshore Gas Gathering System (OGGS). To enable NNPC funding under the DomGas budget the project was reconfigured to supply gas to the domestic market whilst maintaining flexibility to still supply NLNG. The change requires installation of additional gas treatment facilities in the central gas compression plant and construction of a 18" x 5km pipeline link from Odid to Escravos Lagos Pipeline (ELPS) pipeline link to provide route to the ELPS.

Due to degradation and adverse effect of bunkering, the offshore infrastructures must be renewed 18 existing offshore clusters and 93km out of the 122km of 6inch bulklines.

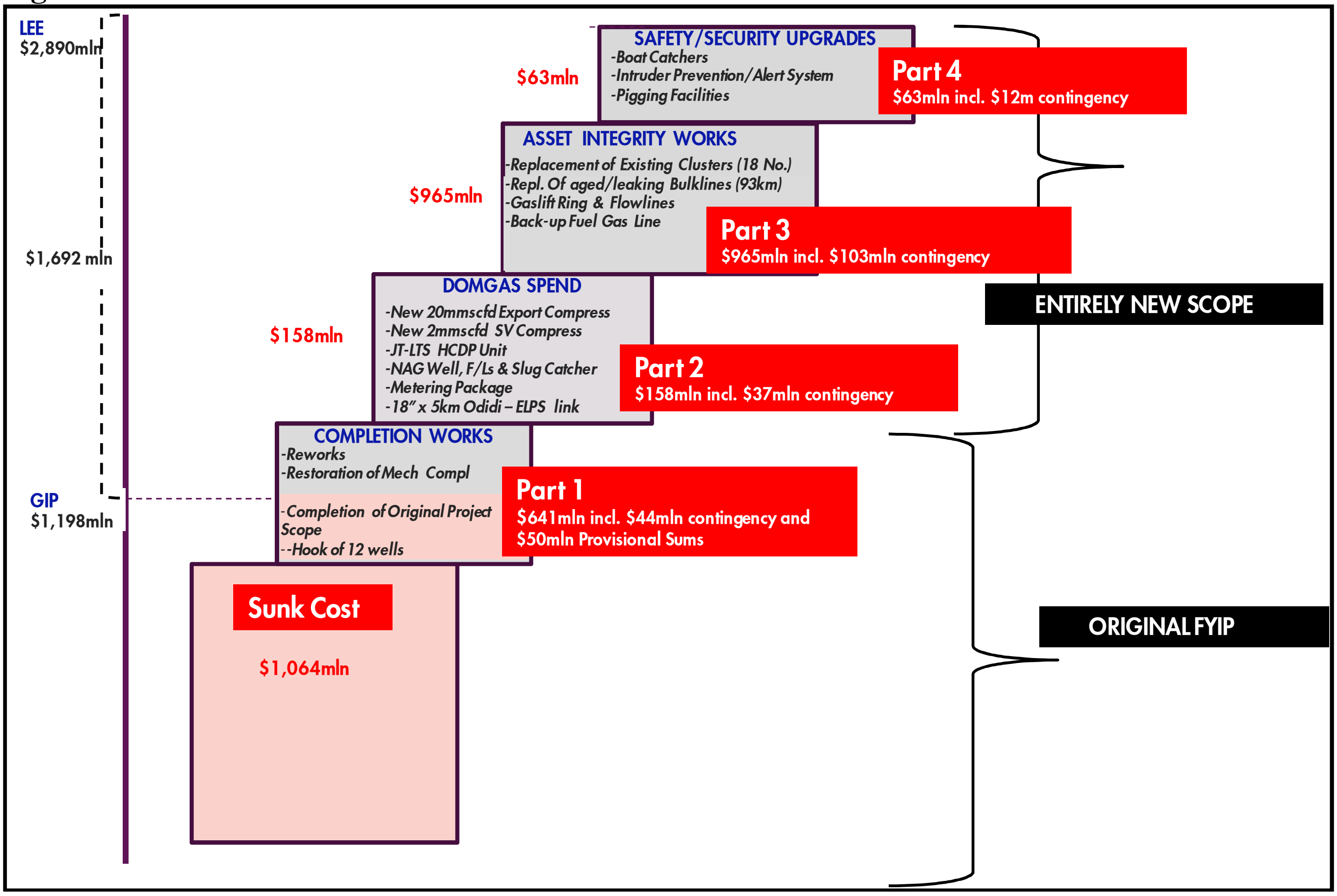
Delivery target: Project OSD aspiration by Project Team, P50 Promise and P90 Promise are Oct 2013, **May 2014** and Feb 2015 respectively. Onstream is First Gas Export to either Domgas or NLNG from the CPF with gas intake from any of the flowstations

Cost Growth

The budget approved under the existing GIP is $1,198million. Figure 1 below provides a breakdown of the costs required to complete the original scope as well as the additional scope to shift to the DomGas market and to execute integrity and security upgrades in the Estuary.

1. Completion of original scope (incl re-work degraded or vandalized items) to eliminate flaring ($641million)
2. New scope to support domestic gas supply objective ($158million)
3. Asset Integrity scope to restore Estuary Assets functionality ($965million)
4. Safety and Security upgrades on Estuary Assets ($63million)

Figure-1: FYIP COST GROWTH



This investment proposal is to cover increase from $1,198million (US$359million Shell Share) to US$2,890 million 50/50 (US$867million Shell share) a net increase of $1,692million (141%), in the capital required to complete the original scope as well as execute new scope of the project.

Section 2: Value Proposition and financial context

Failure to complete the project will mean that the remaining booked reserves(99.7MMboe-Shell Share), other planned 'medium term' development activities with contingent resource development of some 50 MMboe-Shell Share, and longer term development prospects will be regretted and SPDC may also prejudice its ability to obtain renewal of the license, which expires in 2019. The planned 'medium term' activities include Forcados West Development, Workovers and Further Oil Development.

Summary Economics[1]

The economics for the Forcados Yokri Integrated Project (FYIP) IP were carried out on a forward-looking basis using the project 50/50 level III Latest Estimate (LE) cost estimate and the associated production forecast from the project team. Project value is based on PSV-HV indicators. All sensitivities are based on PSV-RV

The project is very robust at all the PSVs. Even with a consideration for an unlikely situation of license not being renewed post 2019 the project base case is still robust. 46% of the value is achieved within current license period due to the initial high production volumes.

[1] Economics based on post ESAR dataset.

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)	456.9	171.3	0.36	19	0.55	9.1	11.6		
RV ($70/bbl & NGMP based gas price)	700.6	298.2	0.63	26	0.97	9.1	11.6	2017	*300.2 (2014)*
HV ($90/bbl & NGMP based gas price)	953.7	430.7	0.91	33	1.43	9.1	11.6	2016	*295.6 (2014)*
BEP* (RT $/bbl)						12.9	23.6		
Sensitivities (using RV-RT12)									
High CAPEX (P90)		280.3	0.52					2017	*352.4 (2014)*
Low CAPEX (P10)		313.6	0.76					2016	*252.5 (2014)*
High OPEX (+15%)		294.7	0.62					2017	*301.9 (2014)*
Low OPEX (-10%)		300.6	0.64					2017	*299.7 (2014)*
High Reserves (P10)		337.5	0.71					2016	*299.7 (2014)*
Low Reserves (P90)		243.2	0.51					2017	*315.3 (2014)*
Production not shut in from 2012		340.4	0.72					2016	*219.1 (2014)*
Life Cycle Economics		297.2	0.26	19	1.00			2017	*289.2 (2014)*
Project with ring fencing		282.4	0.60					2017	*358.5 (2014)*
1-Yr Production delay		271.5	0.57					2017	*313.1 (2014)*
License expires in 2019		136.5	0.29					2017	*300.2 (2014)*
1-Yr Production delay together with 2019 license expiry		93.8	0.20					2017	*313.1 (2014)*
1.5% cost markup due to BVA issues		267.0	0.54						
Project under MCA		263.9	0.25						
All Capex from 2014 onwards funded under MCA		293.6	0.40						
PIB IAT_v9		291.4	0.62						
PIB House_v12		350.2	0.74						
Additional Uncertainty and Risk Analysis - using RV *(only required for proposals > $ 300 mln S/S)*									
NPV(P10)		340.1	0.77						
NPV(P90)		241.1	0.47						
EMV at RV & eVIR at RV		292.4	0.62						
Probability of NPV > 0 at RV		100%							
Dispersion = EMV / (NPVP10-NPVP90) at RV		3.0							

*Corresponding gas price is 14% reduction of the domestic gas profile

Key Project Parameter (Shell Share)

Parameter	Unit	BP11 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	727.4	470.3	542.3	621.4	Change in project objectives and scope
Opex (MOD)_Project	US$ mln	NA	5.7	5.7	5.7	SCD OPEX and training costs A significant OPEX amount was spent in previous IP / Community project and related activities already met
Production Volume	mln boe	101.0	96.1	107.2	121.4	Change in project objectives and scope 9% of the volume produced is gas
Start Up Date	mm/yy	Sep-13	Feb-14	May-14	Feb-15	The BP11 first Gas date of September 2013 was based on a schedule risk analysis performed before award of the Offshore Flares Down contract DG3, without the benefit of input from the offshore installation contractor
Production in first 12 months	mln boe		3.4	4.3	6.6	4% of the total volume produced

Economics Assumptions

Base Case, PIB and MCA economics assumptions are shown in Appendix-1

Section 3: Risks, opportunities and alternatives

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

1. **Scope Reduction/Increase Potential:**

The FYIP completion scope and associated schedule estimate defined in this GIP has been developed on a 'worst case' scenario philosophy with robust provisions for scope creep from asset integrity inspections, but in view of the heavy brown field complexity there may also be some scope not yet fully identified. Major overhaul of equipment packages, factory refurbishment of control systems, workshop repairs/re-calibration for instrument and valves, and replacement of all electronics etc, have been assumed. All 18 offshore Cluster Jackets and 93km of Bulklines (streamlined to 122km to align with current production forecast) have been considered for replacement. **Opportunity:** The final scope may prove to be less extensive. To realise this opportunity $190million shall be held in Management Reserve and disbursed under control of EVP- Sub Saharan Africa (SEPA-UIG).

2. **Non-availability of Domgas Funding:**

NNPC's share of Project funding is ring fenced in the Domgas/IPP budget of the Federal Government of Nigeria for domestic gas supply projects. There is a risk that NAPIMS may demand that Asset Integrity works (Steps 3 and 4 in fig 1) be funded under the MCA arrangement. **Mitigation:** A sensitivity of this MCA scenario shows that FYIP project remains viable, but that the VIR@7% drops from 0.63 to 0.25 at PSV-RV. Integrity expenditure will be phased forwards as much as possible to retain it in the DomGas budget where it currently is.

3. **Impact of year by year Budget Approval by NNPC:**

The lack of formal project funding approval and the yearly budget approval cycles by NNPC portends a risk of inadequate funding 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 for NNPC failing to fund contracts after they have been approved by their Board.

4. **Subsurface Uncertainties:**

These are considered minimal based on well data. All 25 wells in the revised scope have already been drilled. Only one was found wet, while others were on prognosis. However, pressure depletion in the major reservoirs (D5.000 and D6.000) is a concern. **Mitigation:** Production forecast and reserves estimates have considered the pressure depletion issues and studies have already been initiated for introduction of Water Injection for the purpose of pressure maintenance in the Forcados Yokri Field in the future.

5. **Licence Expiry in 2019:**

The OMLs (43 & 45) expires in 2019. **Mitigation:** Although risk is carried at Company rather than project level, a sensitivity has been included in the Economics to show that payout period occurs before the licence expiry date of 2019.

Licence renewal negotiations will leverage Governments desire for acceleration of Domestic Gas Supply projects including FYIP, as expressed in a recent letter from NNPC's Group Executive Director (GMD) to the ECMB. Although, SPDC secured an injunction to maintain the status quo pending confirmation of licence renewals in her acreages, recent renewal of Exxon's SWL licence and Government's indications that Chevron and SPDC are next in line for licence renewal gives additional comfort.

6. **Crude Theft**

There is a risk that 7 to 10% of forecast production volumes will be lost due to theft. **Mitigation:** A thorough review of additional security measures to combat oil theft will be conducted. Project is also located very close to the terminal, which reduces exposure.

7. Constrained Domestic Gas Pipeline Capacity

ELPS ullage constraints could impact export to the Domestic gas market. **Mitigation:** The FYIP project is designed with flexibility to export gas to NLNG via OGGS when Domgas export route is not available.

8. Security and Social Performance

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. 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).

Key Opportunities

- **Opportunity for Further Oil Development**

The proposal provides the leverage for development of further oil in the medium term of some 178.3MMstb (100%) from Forcados Workover, Forcados west and Forcados FOD projects.

In the long term, over 200 MMboe (100%) near-field exploration prospects exist (Forcados North, OML43_WFN01, Forcados Deep, Forcados Northwest and Ogulagha) and are currently being matured.

Section 4: Carbon management

The purpose of this project is to limit green house gas emissions to the environment. Being already in late execution, the opportunity to register the Project under the Clean Development Mechanism (CDM) in order to access an income stream from tradable Certified Emissions Reduction Certificates (CERTS) cannot be initiated. However, the project will help in promoting associated gas utilisation in Nigeria.

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 for this proposal is provided by Finance, Sustainable Development, Supply chain management, HSE, Operations, Legal, Treasury and Tax functions.

Section 7: Project management, monitoring and review

Project execution has progressed in accordance with the Opportunity Realization Process and Shell Global Processes. This is a "P&T executed" project delivered by the UIG/T/P team. The ORP compliant governance structure is in place, including a project specific DRB, DE and BOM. Critical positions for project delivery have now been fully resourced after an initial challenge with attracting talent when future status of project was still uncertain. The 'Fact Sheet' supporting the projects latest cost and schedule view, has been reviewed and endorsed by PTE/S.

Section 8: Budget provision

The estimated total funding for FYIP project is $2.890billion (MOD), of which $1.064billion is already sunk. The project is funded under the IPP/DomGas Portfolio of projects which enjoys priority, ring fenced budgetary allocation from NAPIMS. The project is in the JV Base Plan for BP11 and will remain a feature in BP 12, BP13 and BP 14 submittals. The expenditure figures are updates to BP11 reflecting the final outcome of ESAR4 concluded in March 2012.

Provision made for budget in BP11 covers the requirement for the year 2012. The additional budget to cover the requirements for 2013, 2014 and 2015 has been re-phased in line with re-scheduled activities and 2013 will be requested as part of the BP12 and future year's budget allocation discussions with Partners.

FYIP CAPEX PHASING (US$, 'mln)

ACTIVITIES	Prior 2010	2010	2011	2012	2013	2014	2015	2016	Total
WELLS	142		-	-	33	80	36		291
OIL FACILITIES & INFRASTRUCTURE	369	5	47	173	226	256	174	70	1,320
GAS INFRASTRUCTURE	454	7	36	146	303	174	138	-	1,258
PROJECT OPEX (SCD &TRAINING)	3	-	0	7	6	6	1	1	22
TOTAL	**968**	**12**	**83**	**325**	**568**	**515**	**348**	**70**	**2,890**

Section 9: Group financial reporting impact

The impact of this Investment Proposal on Shell Group Financials is shown in the table below (commitment phasing and expenditure are Shell Share (50/50) MOD on the project's base case at $70/bbl RV-RT 1/7/2012):

US$ Mln	2012	2013	2014	2015	2016	Post 2016
Total Commitment	98	170	155	104	21	0
Cash Flow						
SCD Expenditure	1	1	2	0	0	
Other Opex Expenditure (Train.)	1	1				
Capital Expenditure	96	169	153	104	21	
Operating Expenditure	15	18	19	17	15	471
Cash flow From Operations	-4	36	98	162	189	982
Cash Surplus/(Deficit)	-99	-133	-55	58	168	982
Profit and Loss						
NIBIAT +/-	1	4	37	95	93	808
Balance Sheet						
Avg Capital Employed	50	169	284	349	330	123

Section 10: Disclosure

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

Section 11: Financing

Shell's share of the capital expenditure will be funded by SPDC's own resources. If this does not prove sufficient in the future, any further financing requirements will be included in the annual SPDC GFP. If, as identified under the Risks section, the partners need to carry NNPC's share of the project financing via an MCA, a separate GFP will be submitted for approval.

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 of US$ 508million MOD 50/50 composed of CAPEX-US$ 503million and OPEX-US$ 5million to be added to US$40million unspent sum from GIP 21.11.07 to fund completion of the revised scope of the Forcados Yokri Integrated Project (FYIP). This additional cost brings the overall FYIP cost to US$ 867million, Shell share.

GIP Request is premised on a 08-May-2014 (P50- OSD) First Gas Export to either Domgas or NLNG from the CPF with gas intake from any of the flowstations.

Section 14: Signatures
This Proposal is submitted to UI for approval.

Supported by:	**For Business Support:**
....	....
Bichsel, Matthias F RDS-ECMBI	Brown, Andrew RDS-ECAB,
Date.... /.... /...	Date.... /.... /....
Supported by:	**For Business Approval:**
....	....
Henry, Simon P RDS-ECSH	Voser, Peter R RDS-CEPV,
Date.... /.... /...	Date.... /.... /....

Appendices:
1) Base Case, PIB and MCA economic assumptions
2) Tornado and Profitability plots
3) Production Forecast and Resource Base
4) Estimate Fact Sheet
5) Lifecycle HCM forecast Sheet

Appendix-1: Base Case, PIB and MCA Economics Assumptions.

Base case

- Oil PSVs of $70/bbl @RV-RT12 with appropriate offset applied.
- Gas sales to domestic market Aggregate Domgas PSV (based on NGMP framework as at 21/03/2012).
- Oil taxed under PPT (PPT tax rate of 85%).
- Gas taxed under CITA with Associated Gas Framework Agreement (AGFA) incentive.
- ABCM OPEX provided by the project team.
- SCD provided by the project team.
- Education Tax of 2% assessable profit.
- NDDC levy of 3% total expenditure.
- GHV of 1000 btu/scf.
- Flare Penalty of $3.5/Mscf was applied and is not tax deductible.
- Abandonment cost is estimated at 10% of total project RT CAPEX.

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)

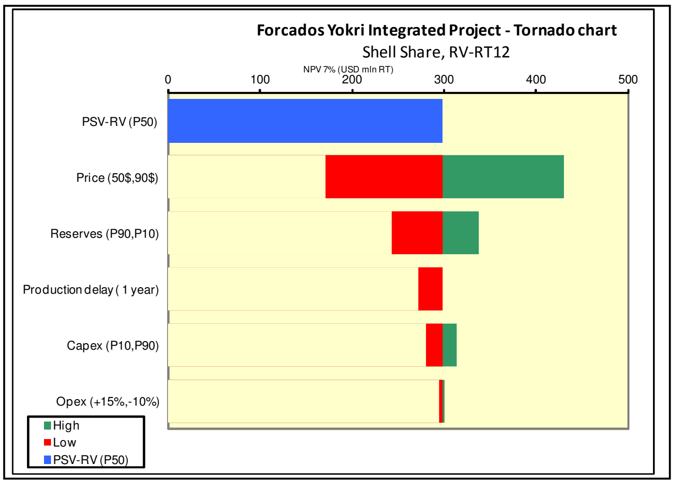
- No production allowance used in analysis
- NHT depreciation schedule is 4x20%, 19% for qualifying expenditure.
- No capital investment credit/allowance (ITC or ITA) or uplift is granted under the PIB
- CIT depreciation schedule is 3x25%, 24%, for qualifying expenditure.
- CIT is 30% of taxable income 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

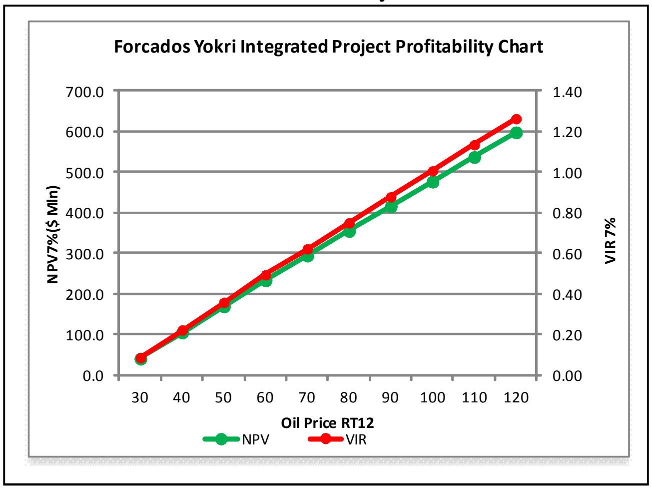
- All FYIP costs on the MCA would be recovered through cost oil.
- Profit oil ceiling of 8% IRR on carried costs
- Current agreement for recovery of carry costs is maintained
- $70/bbl – oil at PSV RV-RT in 2012 for RV MCA Economics
- OPEX not carried under current MCA arrangement.

Appendix 2: Tornado and Profitability plots

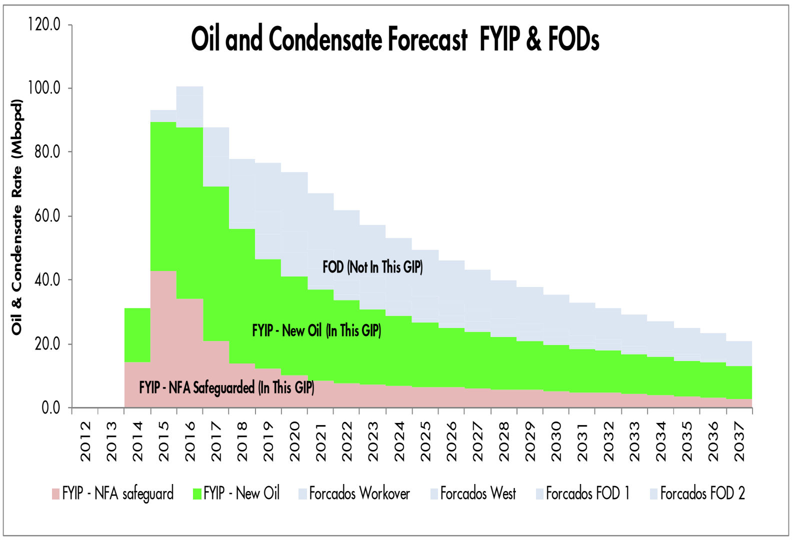
FYIP Tornado Plot.

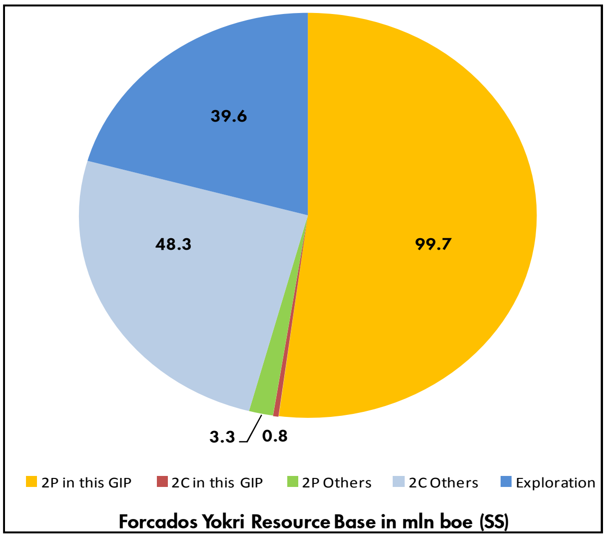


FYIP Profitability Plot



Appendix 3: FYIP forecast and Resource Base





Appendix-4: Estimate Fact Sheet.

ESTIMATE & SCHEDULE FACT SHEET

to be included in GIP and PCN submissions

FORCADOS YOKRI INTEGRATED PROJECT

SPDC Western Division - Swamp/Shallow Offshore

Version 2.5 Confidential

Approved Cost & Schedule Estimate

Project No.: C-12011

Estimator: Ufondu, Emmanuel

Planner: Dadi, Musa

Case: Base

Rates of Exchange are as per SI-SX Data Set

Market Scenario: LE

Estimate Type: 3

Costs are in: USD Millions

Estimate Start / End: FID Jan-1999 / Project Completion Mar-2016

EDM Date: 1-Jul-11

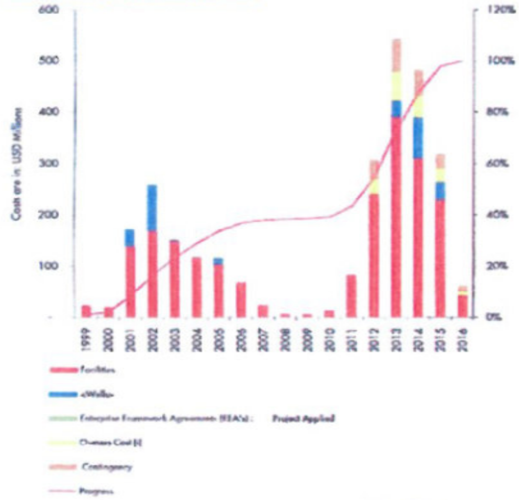
Category		Total Costs
Facilities		2,131
<Wells>		291
Enterprise Framework Agreements (EFA's) :	Project Applied / Verified, Not Applied	- /
Owners Cost (i)	(incl. Insurance, pre-FID, Taxes & Capitalized interest)	160
EPC Premium (ii)		16
Contingency	(i) 14%, (ii) 33% Facilities: 14% <Wells> 0%	196
Inflation		96

	P10	P50	P90
Approved Total Project Estimate, MOD	2,648	2,890	3,163
	-11%	OK	16%

Assumptions:

Estimate & Schedule Premise	FYIP started in 1999 and $1.06bln of this estimate is sunk costs. The rest of the estimates are based on recently completed and ongoing contracts. Probabilistics cost risk analysis using @Risk has been done to calculate the project contingencies P10, P50 & P90 in line with PG 90. Owners costs have been calculated using the manning profile approved for the execution of the remaining scope. Q1 Latest Estimate (LE) escalation factors have been applied in line with provisions of Jan 2012 Capital cost outlook for projects. Well costs have been derived using SPDC well cost estimating template by well engineering; incorporated in line with agreed in-house SPDC methodology. Schedule durations were based on recently completed and ongoing projects with similar activities aligned with project execution strategy. Schedule risk analysis was carried out in line with PG 90. Since the project scope is not fully mature for this stage of the project, an additional management adjustment of 6 months to the P90 project schedule with associated $42mln have been applied to cater for risks not considered, typically force majeure.
Execution Strategy Premise	To guarantee flawless delivery, FYIP is subdivided into three main execution packages. Onshore completion package attending to the outstanding activities of the original project scope involving use of multiple POs and exisiting contracts. New Onshore package comprising new work items required to satisfy flares out and DOMGAS demands utilising EPC strategy. The Shallow offshore package comprising cluster jackets and bulklines replacement using both existing EPC contract and proposed EPC strategy for outstanding work items.
Contract Strategy	Use of existing construction & installation contracts, award of procurement contracts using EFA for rotating equipment replacement parts and EPC for new onshore scope as well as all offshore scope.
Key Project Risks	Security/community issues, Scope creep, Funding issues (which could lead to project delay), Internal and external interface management.
Exclusions	SPDC financing of interest during construction.
Benchmarking & Metrics	Estimate is largely based on awarded contracts; pipeline and cluster activities estimates benchmarked with recently completed projects and ongoing offshore Phase-1 contract. Schedule durations have been benchmarked with completed projects. IPA benchmarking was undertaken.

Capex Phasing and Planned Progress:



Key Schedule Dates:

Phase	Finish (P50)	Finish (P90)
FID	Jan-1999	Jan-1999
South Bank F/S Commissioning	Feb-2013	Mar-2013
Yokri F/S Commissioning	Sep-2013	Nov-2013
CCP/CPF -Mechanical Completion	Jan-2014	Apr-2014
CCP/CPF Commissioning	Feb-2014	May-2014
Commissioning of Odidi-ELPS Line	Apr-2013	Jun-2013
Commissioning & Handover of FLB/Plant Building	Apr-2013	Jul-2013
1st Gas	May-2014	Feb-2015
Handover SSAGS+ Line	Aug-2014	Dec-2014
Onshore complete	Aug-2014	Dec-2014
Phase 1 Offshore complete	Nov-2014	Feb-2015
Phase 2 Offshore complete	May-2015	Feb-2016
Project Completion	Mar-2016	Jul-2016

DCAF TA 1

Date : 03-04-2012
Name : Nwakaeze, Emeka
Signature :

Project Manager

Date : 3/Apr/2012
Name : Egemba, Walter
Signature :

VP Project Services

Date : 4/4/2012
Name : Mes, Hans
Signature :

EVP Projects

Date : 4/4/2012
Name : Kretzers, Rob
Signature :

Appendix-5: Lifecycle HCM forecast Sheet