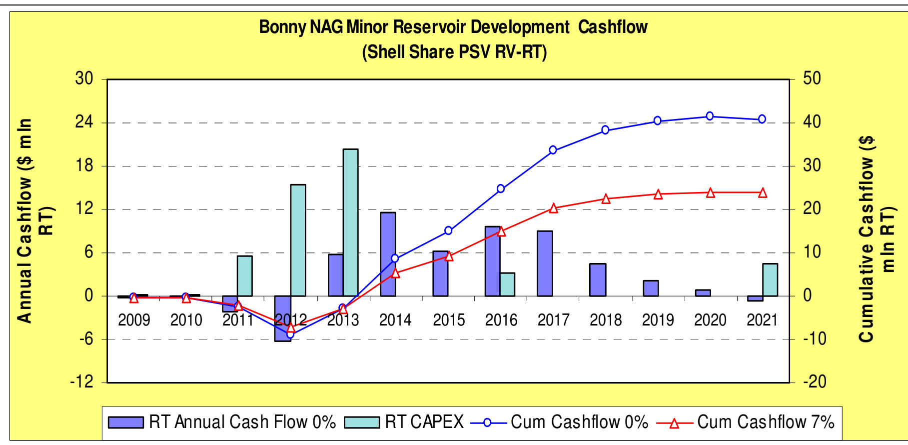
The Shell Petroleum Company Limited

Group Investment Proposal

Summary Information

Business unit and company	Shell Petroleum Development Company of Nigeria
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other shareholders / partners	Nigeria National Petroleum Company (NNPC: 55%), Total: 10%, Nigeria Agip Oil Company (NAOC: 5%) in SPDC-JV
Business or Function	EP
Project	Bonny Minor NAG Reservoirs Development Project
Amount	US$ 49.5mln Shell share (i.e. US$ 165.0mln 100% JV), 50/50, MOD.

Description	JVUS $mln (100%)	US $mln (Shell Share)
4nos conventional NAG wells drilling and completion	112.3	33.7
Re-completion of 2nos gas wells	9.4	2.8
Location Preparation	10.6	3.2
FEED / Detailed Design (including front-end loading like ESHIA, ROW surveys)	1.6	0.5
4 Gas flowlines (2nos 8" x 7km plus 2nos 6" x 2km carbon steel)	20.4	6.1
Manifold extension	6.6	2.0
SCD	4.0	1.2
Total	**165.0**	**49.5**

Source and form of financing	This investment will be financed from JV funding. Shell share capital expenditure will be met by SPDC's own cash flow and/or the existing shareholder facility.
Summary cash flow	

Summary economics (Shell Share, RT-09)	NPV (USD mln)	VIR	RTEP (%)
Base case	24.6	0.70	66
Low Realization Forecast	17.9	0.50	57
High Realization Forecast	39.6	1.12	82

Section 1: The proposal (management summary)

This Investment Proposal (approval for a funding of US$ 49.50 Shell share (i.e. US$ 165.00 – 100% JV)) is required for the execution of the Bonny Minor NAG Reservoirs Development Project.

The objective of the project is to develop about 162Bscf non-associated gas from six gas reservoirs in the Bonny and Bonny North fields.

The project was initiated post DG 1 on the 15th of May 2007 and taken through the Assess and Select phases between May and October 2007.

In combined Project Assurance Reviews (PARs 2 and 3) held 24th of October 2007, the supported development concept was drilling of three gas wells (two smart and one conventional well) and the extension of the BNAG manifold at Oloma. However, because emphasis was on early gas, the Decision Review Board (DRB) at the Decision Gate 3 (DG3) which held in January 2008, supported the alternative concept of drilling 4 conventional gas wells. The DRB at the DG3, which held in April 2009, approved the FDP concept, with the following scope:

1 Drilling 4 conventional wells and installing downhole gauges and V-monitors for all wells.
2 Installing 2nos 6" x 2km and 2nos 8" x 7km flowlines from the wellheads to Oloma NAG manifold.
3 Extending the Oloma manifold by the installation additional manifold skids (4nos x 6" lig x 14" hdrs x 1500# CS skids).

In August 2009, the Project Team presented a schedule with execution in 2012/2013 mainly driven by rig availability in line with the BP09 approved LTDS. Coinciding with this is the production forecast showing that some of the existing NAG wells will be quitting around 2012/2013. Consequently, management requested for a review of the sidetrack concept. Whereas sidetracking of some of the wells are technically impossible, re-completion of the identified wells is not possible because the target reservoirs are deeper than the existing well depths. Though three wells passed the sidetrack evaluation criteria for technical feasibility, their combination in the sidetrack concepts required the drilling of more wells and thus their economic evaluation showed no advantage over the FDP concept. Hence, on 10th November 2009, the DRB approved to carry on with the FDP concept as originally proposed, dropping the concept with sidetracks.

The project is targeting drilling the first well by June 2012 and first gas is expected October 2012. Table 1 contains the project expenditure phasing (with units in million US Dollars).

Table 1: Total Project Expenditure Phasing

Activity	100% Total	2009	2010	2011	2012	2013	2016
	***US $mln MOD* JV 100%**						
4 Conventional NAG wells drilling and completion plus 2 re-completion in 2016.	121.71	-	-	15.73	33.69	62.89	9.41
Location Preparation	10.58	-	-	-	5.29	2.12	3.17
FEED / Detailed Design (including front-end loading like ESHIA, ROW surveys)	1.63	0.71	0.85	0.10	-	-	-
4 Gas flowlines (2nos 8" x 7km plus 2nos 6" x 2km carbon steel)	20.43	-	-	2.04	10.21	8.18	-
Manifold Extension	6.60	-	-	1.32	5.28	-	-
SCD	4.02	0.02	0.02	0.48	1.36	1.83	0.31
Totals	**164.97**	**0.73**	**0.87**	**19.66**	**55.84**	**75.01**	**12.90**

Section 2: Value proposition and strategic and financial context

The project will add additional 50 to 100MMscfd NAG for 2 to 4 years via the Bonny NAG Plant to NLNG T1 – 6 from Q3 2012, making use of available free capacity resulting from the decline of production from the existing gas wells. The project will also maintain supply of fuel gas to the Bonny Oil and Gas Terminal (BOGT) from the BNAG wells for about 4 years.

Summary Economics

The project economic evaluation was done on a forward-looking basis using the 50/50 CAPEX and expectation production forecasts. Sensitivity analysis was carried out for the project using 90/10 CAPEX estimate, the low realisation and high realisation forecasts. The base-case investment returns NPV7% of $24.6mln RT09 with a VIR7% of 0.70. See Tables 2 below.

Table 2: Economic Grid (Shell Share)

PV Reference Date: 1/7/2009	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/boe)		Payout-Time (RT)	Maximum Exposure (RT)
Cash flow forward from: 1/1/2009	0%	7%	7%	%	0%	7%		AT (S/S $ mln)
Base Case								
SV ($50/bbl & $1.37/Mscf))	31.8	18.8	0.53	53.5	7.5	8.4		
RV ($60/bbl & $1.63/Mscf))	40.7	24.6	0.70	66.1	7.5	8.4	2014	11.6 (2012)
HV ($80/bbl & $2.15/Mscf)	58.5	36.3	1.03	89.6	7.5	8.4		
BEP (RT $/Mscf)					0.47	0.58		
Sensitivities (using RV)								
High Capex (Prob < 0.10)		22.7	0.51	52.3			2014	15.5 (2013)
Low Reserves (Prob < 0.85)		17.9	0.51	57.1			2014	11.6 (2012)
High Reserves (Prob < 0.15)		39.6	1.12	82.0			2014	11.6 (2012)
CITA only		4.9	0.14	15.4			2016	22.5 (2010)
PIB version 3.2 Terms		-5.9	-0.17	NA				
PIB version 4.2 Terms		-3.6	-0.09	NA				

Key Project Parameter Data Ranges *(Shell Share)*

`	Unit	Bus Plan (BP09)	Low	Mid	High
Capex (MOD)	US$ mln	34.5		48.3	60.4
Production Volume	mln boe	8.2	6.4	8.3	12.3
Start Up Date	mm/yyyy	Jan-12	Oct-12	Oct-12	Oct-12
Production in first 12 months	mln boe	2.0	0.2	0.2	0.2

Economic assumptions (Base case):

- NAG will be sold to NLNG T1-6 at $1.63/Mmbtu RT09
- Condensate treated and sold as oil at $60/bbl RT09
- Project was evaluated under CITA fiscal regime with AGFA incentives
- ARPR (01-JAN-2009) OPEX estimate used for evaluation.
- 10% of total project CAPEX RT cost assumed as abandonment cost
- GHV of 1150 btu/scf
- NDDC levy of 3% of total expenditure
- Education tax of 2% assessable profit
- 2.5% of total MOD CAPEX assumed as SCD cost

PIB version 4.2 assumptions:

- PIB start year is 2010
- Revenue levy is charged at $0.50/bbl RT2009 for oil/condensate and $0.01/Mcf RT2009 for gas. This levy is credited against royalty payments
- Royalty rates based on product (value) prices and production rates per PML
- NHT rate is 50% and CIT is 30% of taxable income and is not deductible from NHT
- 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 corporate budget (Expex+Capex + Opex)
- Withholding tax is applicable at a rate of 7.5%
- 20% of overseas cost is non-deductible for determination of NHT taxable income

Section 3: Risks, opportunities and alternatives

<u>RISKS</u>	<u>MITIGATION MEASURES</u>
Volume Uncertainty	The volume uncertainty associated with this development results from structural and petrophysical uncertainties identified and analysed in the course of this project. This uncertainty is taken into account in the range of scenarios evaluated and the low case is also economic. (see table 2).
Insecurity of the waterways	The general insecurity and current tension (hostage-taking, vandalism, disruptions, etc) in the Niger Delta may persist or repeat in the future. This may affect the project, especially during execution and operation, with consequent project delays and cost overrun. Continuous stakeholder engagement and flexible project management (e.g. acceleration of critical activities) are proposed as preventive and recovery mechanisms against this threat.
Procurement delays and cost escalation	Robust economic models have been built and sensitivity studies performed on the integrated project and these results are favourable. However, unanticipated cost escalation and delays could erode project value. Securing the approval for this investment proposal in 2009 will enhance placing order for the procurement of long lead materials and

	equipment (in time for the main construction works planned from Q3 2011) and will mitigate these potential threats and ensure project value is realised. These early procurements will be carried out through SPDC's Supply Chain Management (SCM).
Legacy SCD Issues in the Bonny Node	Some legacy SCD projects from the previous developments in the area have been identified. If unresolved, these could result in community disturbances during the execution phase of the project, with consequent project delays and cost overrun. This threat will be mitigated by continuous stakeholder engagement and ensuring that other benefits to the communities e.g. employment opportunities and provision of contract services are agreed upon before commencement of project execution. Also key legacy projects i.e. Bonny Integrated Business Complex (BIBC), completion of Oloma, Ayaminima, Epelema, Minima & Sangamabie electricity project as well as the repair of Oloma water projects were already in the plan for 2009.
Inability to secure ESHIA approval within scheduled timeframe	Project categorization received from the FMEV in November 2007 rated it a category 1 project, which requires 2 seasons sampling. Strict adherence to the schedule should be maintained. Stakeholder identification/engagement, and samples collection would be carried out as planned to eliminate schedule slippage.

Opportunities

- Unique attraction offered by the Bonny Minor NAG Reservoirs Development Project stems from its proximity to existing gas infrastructure (Bonny NAG plant and Oloma NAG manifold).
- Reduction of footprint and environmental impact through the use of Selective completion wells.
- Provision of some 162 Bcf of short-term gas supply to mitigate against supply shortfall at NLNG.
- Maintaining synergies with other on-going projects in the Bonny node i.e. the Bonny Flowstation AG Solution Project.

Alternatives

1. The alternative concept will involve the drilling of three gas wells in the six target reservoirs (two smart wells and one conventional) and the extension of the Oloma NAG manifold by the installation of an additional manifold skid. This concept was not selected because the project schedule and the smart well contractual process were misaligned, with the latter potentially delaying the former.
2. The other alternative will involve sidetracking Bonny well 27T in addition to drilling of three conventional wells (two in Bonny North and one in Bonny). The economics evaluation shows that the FDP concept returns marginally higher NPV / VIR than this concept because of consequent drop in UR in spite of the seeming drop in well and flowline costs.

Section 4: Corporate structure, and governance

The existing corporate structure and arrangements of SPDC-JV (with SPDC as operator) will be used as the vehicle for the investment and operations.

An SPDC Decision Review Board (DRB) will continue to advise.

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

This proposal complies with the Group Business Principles, policies and standards. This project has benefited from full functional support covering ESHIA, Field Development Planning, OR&A and SCD. Besides contributing to SPDC's supply commitment to NLNG and extending fuel gas supply to the

Bonny Terminal, the project will contribute to sustainable development of Nigerian people within the node. Additionally, there will be a focus on Nigerian Content Development (NCD). The Finance, Supply Chain Management, Legal, and Treasury/Tax functions will provide functional support for this proposal.

Section 6: Project management, monitoring and review

The Medium Projects and Discipline Engineering team under EPG-TPPD is managing the project post DG-3. The project team is adequately resourced. The Major Project Services Team EPG-TPS and the Pipeline and Eastern Matrix Technical Support Team EPG-TPPS support the Project Quality Management Systems. This project has been matured in line with the Opportunity Realisation Process (ORP) and has undergone the necessary Project Assurance Reviews - PARs 2 & 3 held 24th October 2007. Key decisions have been reviewed and are supported by the Decision Review Board (DRB) at the Decision Gate 3 (DG3) which held in April 2009, a further engagement meeting with the Decision Executive which held in August 2009 and final approval in November 2009 by the DRB. Value delivery will be ensured through regular reviews (PERT) and GWDP.

Section 7: Budget provision

The project WBS number is C.NG.PTE.DG.08.001 in the 2008 Business Plan (BP08) and is in the base programme in BP09. A provision was made for US$1.0mln in the 2009 budget (i.e. the BP08) to cover front-end activities including kick-off of FEED/Detailed Design. At the BCC dated October 2009, it was recommended to reduce the 2009 budget to F$0.728mln (to cover full preparation survey including requirement for acquisition of Right of Way extension, part of FEED and ESHIA dry season sampling). In BP09, an allocation of $0.872mln was required in the 2010 JV Budget for the project (to cover completion of FEED and Detail Design, ESHIA wet season sampling and delivery of ESHIA report in 2010). The long lead materials for the wells and surface facilities will be ordered in December 2009 or early Q1 2010 and will require a budget of US$19.662 in the 2010 Business Plan to pay for the goods when they arrive in 2011. See table 1 for the expenditure plan.

Section 8: Group financial reporting impact

The impact of this Investment Proposal on Shell Group Financials (**in US $ mln**) is shown in the table below:

	2009	2010	2011	2012	2013	Post 2013
Total Commitment	0.22	0.26	5.89	16.75	22.50	3.87
Cash Flow						
SCD Expenditure	0.01	0.01	0.14	0.41	0.55	0.09
Pre-FID Expenditure						
Capital Expenditure	0.21	0.25	5.75	16.34	21.95	3.78
Operating Expenditure	0.09	0.01	0.32	1.77	2.72	9.73
Cash flow From Operations	-0.02	0.08	3.85	10.47	25.94	54.56
Cash Surplus/(Deficit)	-0.24	-0.18	-1.90	-5.87	3.98	50.79
Profit and Loss						
NIBIAT +/-	-0.05		0.12	0.92	13.44	42.04
Balance Sheet						
Avg Capital Employed	0.10	0.28	1.38	5.79	13.91	10.36

Section 9: Disclosure

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

Section 10: Financing

The project will be funded with JV funding and Shell share capital expenditure will be met by SPDC's own cash call.

Section 11: Taxation

The income tax from the project will be in accordance with Petroleum Profit Tax Rate and relevant income tax applicable.

Section 12: Key Parameters

This investment proposal seeks approval for US$ 49.50mln Shell share (i.e. US$ 165.00mln 100% JV), 50/50, MOD for the implementation of the Bonny Minor NAG Reservoirs Development Project.

Section 13: Signatures

This Proposal is submitted to EPG CEO for approval.

Supported by:	For Business approval:
....	....
Ann Pickard	Bos, Bernard
(Regional VP, EPG)	(FUI/F)
Date …../..../....	Date …../..../....

Initiator: ____________________

Oputa, Nkenamchi Benedict (EPG-TPPD)

Project Manager

…../..../2009