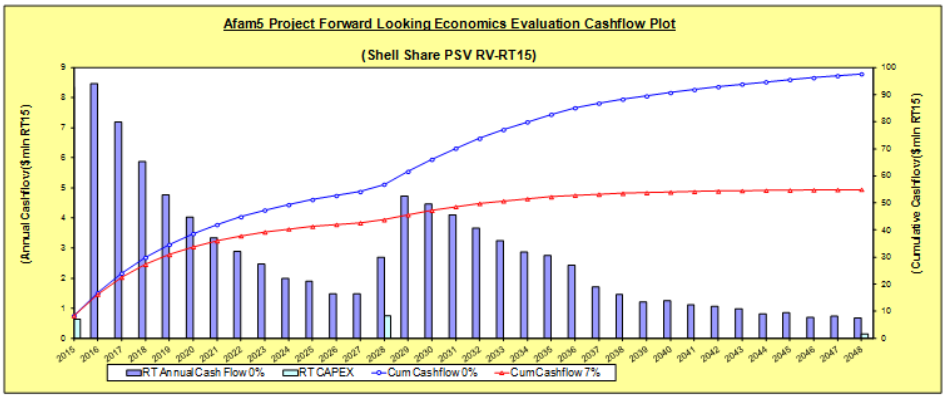
Group Investment Proposal

GIP Lite for proposals **< USD 20 mln** Shell share, aligned with the Business Unit Manual of Authorities

<table>
<tr><td>Business unit</td><td>Shell Petroleum Development Company of Nigeria</td></tr>
<tr><td>Shareholders / partners</td><td>Shell 30%, Nigeria National Petroleum Company (NNPC): 55%, Total Exploration and Production Company Nigeria (TEPNL): 10%, and Nigeria Agip Oil Company (NAOC): 5%</td></tr>
<tr><td>Amount (Shell share) MOD, 50/50</td><td>USD5.31 Mln
Amount Previously supported USD44.82 Mln</td></tr>
<tr><td>Project</td><td>AFAM-F5 Reservoir Development</td></tr>
<tr><td>Summary Economics(Shell Share)</td><td>


<table>
<tr><th>RV-RT15</th><th>NPV 7% (US$ mln)</th><th>RTEP</th><th>VIR</th></tr>
<tr><td>Base Case (Forward Look)</td><td>55</td><td>>50%</td><td>57.63</td></tr>
<tr><td>Full Life Cycle</td><td>42</td><td>25%</td><td>0.66</td></tr>
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Proposal Management Summary

The project seeks to provide additional gas supply from the AFAM F5 reservoir in Afam field to Okoloma Gas Plant (OKGP) in order to bridge a projected shortfall in gas supply to the Okoloma facilities and to meet with growing gas demand from the Eastern Domestic Gas Network.

This Investment proposal seeks additional FID approval for US$5.31mln Shell Share, 50/50, MOD ($17.69mln 100% JV). Previous FID approval for US$44.82mln Shell Share 50/50 MOD (US$149.40 mln 100% JV) was granted in April 2011. This additional FID request amounts to 12% of the previously approved GIP.

The purpose of this additional FID Proposal is to cater for the increase in the project cost and schedule which arose due mainly to the following reasons:

- Changes in Shell group engineering standards which mandatorily had to be incorporated into the project, e.g. updates to Design and Engineering Manuals 1 & 2 (DEM1 & DEM2) which placed greater emphasis on Technical Integrity and Process safety.
- Brown field scope creep (repair/replacement of faulty existing equipment not initially foreseen).
- Use of specialist welding habitats and associated delays.
- Increases in well drilling and completion costs.

The approved Afam F5.0 Reservoir Development Plan (RDP) proposes development of 5 MMstb of oil, 172.2 Bscf of gas and 8 MMstb of condensate, resulting in life cycle recoverable volume of 20.8 MMstb for oil and 8 MMstb for condensate, 226.0 Bscf of gas. The April-15 MTIAP Forecast gives the daily production volumes as 4 kbpd of oil, 29MMscfd of AG, 87 MMscfd of NAG, and 2 kbpd of condensate.
This development plan is a concurrent oil & gas development and consists of: drilling of 3 wells (a NAG well, an oil well and a swing oil/gas well), procurement and installation of flowlines, and associated equipment to evacuate the wells fluids to OKGP for processing. Gas export is via the Eastern Domestic Gas Network whilst oil/condensate export is to Bonny Terminal via the Kom Kom manifold export axis. See project scope below for details.

Project Scope
Details of the project scope are as follows:

Sub-surface scope
- Drilling and completion of 1 dedicated oil, 1 dedicated NAG well and 1 swing oil/gas well initially to be completed as an oil well.
- Re- completion of the swing well as a gas well at the end of the oil production life in 2019.

Surface scope
- Location preparation for two well sites (existing Afam-16 & -17 well locations).
- Construction of a 6 inch x 0.6 km gas flowline to Afam gas manifold, and 2 nos. 8 inch x 12.5 km each of oil flowlines to Okoloma gas plant.
- Installation of a corrosion inhibitor injection system at Afam gas manifold.
- Extension of the bulk header, and all tie-ins, at Afam gas manifold.
- Installation and tie-in of an XXHP separator and other surface facilities at Okoloma gas plant.

The project scope has essentially been completed and production started from the facilities in November 2014 utilising the existing Test Separator in place of the XXHP separator, delivery of which was delayed. Installation of the XXHP separator package has now been completed while pre-commissioning/commissioning activities are ongoing and will be completed by Q-1 2016. Production has however continued from the Afam F5 wells through the Test Separator.

Main Commitments (F$mln)

Description	2015 & Prior	2016 - 2018	2019	2019
FEED/Detailed Design	2.65	0	0	2.65
Well Location Preparation	7.34	0	0	7.34
LLI's (Flowlines, XXHP Separator)	10	0	0	10
Facilities (incl Flowlines constr)	48	0	0	48
Wells Drilling & Completions	80.49	0	3	83.49
Project Management Cost	6.21	0	0	6.21
Contingency	7.7	0	0	7.7
Total Capex	**162.39**	**0**	**3**	**165.39**
SCD (Opex)	1.5	0	0.2	1.7
Total (50/50, MOD)	**163.89**	**0**	**3.2**	**167.09**

The 2019 costs are for the recompletion of the swing oil/gas well from an oil well to a gas well.

Value Proposition and Economics Summary

Include sensitivities only on exception basis (using RV-RT). Project Economics; include Value of Information for Appraisal activity. Include Key Economic assumptions

Round off the entries to one decimal point, two for VIRs.

PV Ref. Date: 01/07/2015; Cash flow from: 01/01/2015	NPV7 SS (USD Mln)	VIR 7%
SV-RT ($70/bbl RT15 & 2015 Gas to Power Price)	47.1	49.36
RV-RT ($90/bbl RT15 & 2015 Gas to Power Price)	55.0	57.63
HV-RT ($110/bbl RT15 & 2015 Gas to Power Price)	63.1	66.07
UTC (RT USD/bbl, USD/MMBtu)	0.4	

KEY PROJECT PARAMETER DATA (SHELL SHARE)

Parameter (Shell Share)	Unit	Bus Plan (RV)	Low	Mid	High	Comments
Capex (MOD)	US$ mln	1.6	1.5	1.6	1.8	
Opex (MOD)	US$ mln	5.9	5.8	5.9	6.7	ABCM
Production Volume	mln boe	12.20	10.20	12.20	14.10	
Start Up Date		Nov-14	Nov-14	Nov-14	Nov-14	Production started November 2014

Summary Economics

This economics evaluation was carried out on a forward-looking basis using Latest Estimate (LE) CAPEX, Production forecasts and ABCM OPEX provided by the project team.

Sensitivities were carried out to access the impact of the following on the project value:

a. High (P10) and low Realization (P90)

b. High (+10%) and low (-5%) capex on the project value,

c. 1 year production delay.

d. PSV SV RT15 and PSV HV RT15

e. 2039 License expiry

A project Full life cycle evaluation was also carried out with its value evaluated at different PSVs.

The result also showed that the project value is most sensitive to production thus efforts should be directed at ensuring that the uncertainties around the realization of the volumes promised are reduced to as low as reasonably practicable.

The Project is sufficiently robust. The FLC also returns a VIR7 >0.4. For the FLC, gas ONLY returns a VIR of 0.38. The project FLC returns a VIR7 of 0.41 even at an oil price of $10/bbl (while maintaining current gas price). 25.84% of the forecast volumes are required for the project to breakeven at FLC, while 71% of the forecast volumes are required for the FLC to achieve a VIR7 of 0.4

The very high VIR7 of the forward look evaluation is essentially due to the low additional capex been requested for the project completion as over 97% of the project scope had already been completed and production had commenced. Only 2.6% of the forecast volume is required for project to breakeven going forward.

The details of the economics evaluation results are presented in tables below

Economics Assumptions:

- Oil PSV of $90/bbl @RV-RT15 (Base) with applicable offset.
- 2015 Gas to Power price of $2.12/Mscf @ RV RT15.
- Condensate treated as Oil and taxed under Petroleum Profit Tax (PPT tax rate of 85%).
- Gas taxed under Companies Income Tax Act (CITA) with Associated Gas Framework Agreement (AGFA) incentive.
- Education Tax of 2% of assessable profit.
- NDDC levy of 3% total expenditure.
- Gas Heating Value (GHV) of 1000 btu/scf).
- Flare Fee of NGN10/Mscf was applied and is not tax deductible.
- Abandonment cost is estimated at 10% of total project RT CAPEX.
- License will be renewed in 2019

Risks and Alternatives

Funding/ Discontinuation of Project after Partial IP commitments:
NAPIMS Gas division have consented that SPDC proceed with this project during various engagements. JV Partners have approved the expenditure for years 2010 – 2014, and the budget for 2015. All variation orders on the facilities contract have been discussed with NAPIMS and their endorsement obtained at Project Manager level. Official request for approval has been sent to NAPIMS and NNPC board approval is being awaited. The project is 99% complete, production has started, albeit through a temporary mode, and the JV is reaping the benefits of the project.

HSE Risk
The project HSE risks include but not limited to working in/around live facilities (the Okoloma gas plant and Afam remote field manifold), overpressure/loss of containment, poor weather condition, equipment failure/transportation hazards and contractor's HSE/technical incompetence during construction phase which could lead to incidents.

Mitigation
Construction has been essentially completed and the project is in the final phase of pre-commissioning/commissioning. All HSE risks have been effectively mitigated and the project / OKGP HSE systems are in place to manage the remnants of the work.

Execution of Petroleum Industry Bill (PIB):
Project is already in operate phase while the remaining scope of commissioning the XXHP separator is being completed.

Security Risks:
The unstable security situation in the Niger Delta area is a key risk, however these have been effectively managed and the remaining work will continue to be managed in line with the Project and Asset team Security plans.

Community Interface:
Community Relations has been managed in line with the project and Asset team community relations plans leveraging on the provisions of the GMOU with the Oyigbo cluster.

Scope Creep/ Escalation in Project Cost
The project is essentially completed, save for the XXHP separator, and the final scope and cost have been determined.

Delays in Approvals
Through continuous stakeholder engagement, requisite partner and regulator approvals to commission and start-up the plant were obtained. Final LTO is being awaited from DPR.

Subsurface Uncertainties:
Project is in operate phase and actual production mirrors the forecast production.

Technical/NCD:
The applicable NCD schedule targets were all met on the project.

Procurement Delays & Alignment with Well Engineering:
Project is essentially completed and production has started.

Carbon Management

The only source of HC emission into the air on this project is via leak of HC from normal operation, e.g. leaks from relief valves which are routed to the flare and is infrequent, and leaks from flanges.

However the right level of tightening has been applied to flanges to ensure that this does not occur. Also, flaring shall no longer be routine, as surge vessel gas will be collected and pilot gas will be of such little quantity as to be insignificant.

All liquid emissions are routed to the closed drain header and from thence pumped back into the export system, to avoid contact with the environment.

The proposal will not add appreciable amounts of flare gas hence Carbon Management effects have not been considered.

Corporate Structure and Governance

This project fits within the existing SPDC corporate structure and governance.

Group and Business Standards

This proposal complies with Group Business Principles, policies and standards. Full functional support covering SCD is provided for in the full project scope. Additionally, there will be a focus on Nigerian Content Development (NCD) as already indicated above. Functional support for this proposal is provided by the Finance, Supply Chain Management, Legal, Treasury and Tax functions.

Project Management, Monitoring and Review

The Major Projects Team under PTP/O/ND is managing the project. The Project assurance plan is compliant with the ORP stipulations with project specific DRB, DE and BOM in place. The project has progressed through the VAR process with PAR4 done 2nd – 4th November 2010. VAR 5 is planned to be held in Q1-2016.

Budget Provision

The Afam F5.0A Reservoir Development Project has been in SPDC's Business Plans from 2010 to date and budget has been continuously provided, including the 2015 budget which has been approved by the partners.

Group Financial Reporting Impact

No material finance reporting impact.

Disclosure

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

Financing

This investment is being 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.

Taxation

No extraordinary tax issues arise from this proposal.

Key Parameters

This IP seeks approval for further Shell Equity Investment of US$5.30mln MOD 50/50. Previously, US$44.82mln (Shell Equity) was approved which is now fully spent. With this proposal, total Shell Equity Investment in the project becomes US$50.12mln of which US$48.51mln is sunk cost. The additional amount requested is 12% of the previously approved GIP

This investment proposal seeks FID Investment approval of additional US$5.30mln Shell Share, 50/50, MOD ($17.68mln 100% JV) in support of the implementation of the AFAM-F5 Reservoir Development Project bringing the overall project expenditure to US$50.12mln Shell share.

Functional Support

Initiator			
Name:	Ranti Oluranti-Ahmed	Water Egemba	Mojeed Okunade
Date:		*Date:*	*Date:*
Prepared		*Endorsed*	*Endorsed*

Signatures

Supported by:
Toyin Olagunju
....
Date ...../...../.....

For SEPCIN:

Name: Jan van Bunnik SPDC-FUI/OG
Date:
Approved

for SEPCIN:

Name: Bayo Ojulari MD - SNEPCO
Date:
Approved

Appendix A - Detailed Project Parameter Data

appropriately rounded figures

Project Focal Point / Indicator	Ranti Oluranti-Ahmed (PM)
DRB: Decision Executive if applicable	Philip Mshelbila
DRB: Members if applicable	Grzeg Kulawski Toyin Olagunju Victor Okoronkwo Jan van Bunnik Emmanuel Ogagarue Halim Bello (BOM)

Performance Parameters	Unit	BP'11	GIP	Variance details
Total GIP Capex (Shell share)	USD Mln	44.82	50.13	1. Changes in Shell group engineering standards which mandatorily had to be incorporated into the project, e.g. updates to Design and Engineering Manuals 1 & 2 (DEM1 & DEM2) which placed greater emphasis on Technical Integrity and Process safety. 2. Brown field scope creep (repair/replacement of faulty existing equipment not initially foreseen). 3. Use of specialist welding habitats and associated delays. 4. Increases in well drilling and completion costs.
FID Date	MMM/YY	Apr-11	Apr-11	
First Oil/Gas Date	MMM/YY	Mar-12	Nov-14	Delay due to changes mentioned above.

Performance Parameters	Unit	BP'11	GIP	Variance details
Proved Developed Reserves (GES(1) @ RV-RT)	MMboe	42.7	42.7	
Expectation Developed Reserves (GES or SWIS(2))	MMboe			
UDC (3) (MOD)	USD/boe			
Oil - Initial Rate (100%)(4) Gas - Capacity (100%)(4)	b/d – Oil MMscf/d- Gas	4,000 40	4,000 40	

NOTES: Conversion of gas volumes to boe: use SIEP standard conversion of 1 Bcf = 0.1724 MMboe

(1) GES: Group Entitlement Share

(2) In PSC environment quote SWIS.

[3] UDC: SS Project Capex/GES Developed Expectation Reserves (or SWIS in PSC environment)

[4] Initial stable oil flow or first 3 months average production rate.

Major Milestones

at least five (5) for most projects … specific dates (month/year) included for securing key materials, meeting key dates prior to FID, between FID and 1st Oil, etc.

Date	Description
Dec-10	Complete FEED
Apr-11	FID
Oct-12	Ready for Gas Out
Nov-14	First Oil
Mar-16	VAR 5