Group Investment Proposal (GIP)

Summary information

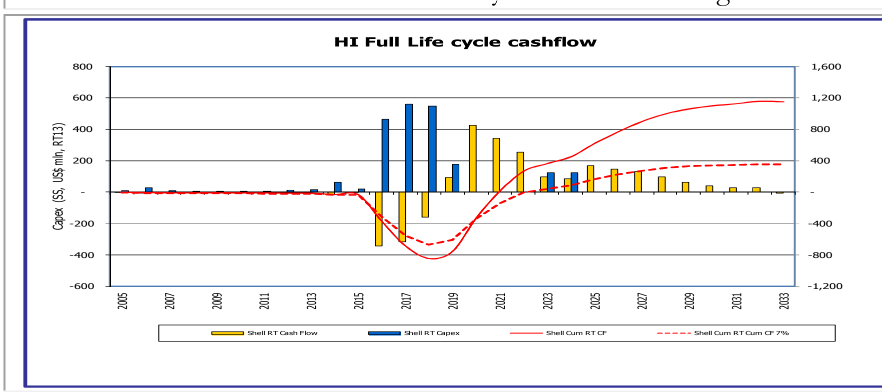
Business unit and company	The Shell Petroleum Development Company of Nigeria Limited (SPDC)
Group equity interest	100% in SPDC Ltd whereas SPDC Ltd holds 40% in OPL 238 (now OML144)
Other partners	Sunlink Petroleum (60%) in OML144
Business or Function	Upstream International Operated (UIO)
Amount	**US$34.8mln** (100% JV, MOD) in addition to previously approved pre-FID funds of **US$70.9mln**, bringing the total amount to **US$105.7mln.** This Amount constitutes 100% of the JV expenditure incurred to date (SPDC Ltd has a carry arrangement to cover Sunlink's share of the development and production costs).
Project	HI Gas Development

Main commitments

Activity (100%, $m)	Previously Approved GIP Spend	This Proposal		Revised IP budget
		GIP Overrun	pre-FiD	
	ITD 2009	2010-2013	2014	
Signature bonus, Lease Conversion	10.0	0.84	-	10.8
Farm-In Fee	10.0	-	-	10.0
Appraisal Well	30.3	(0.02)	-	30.3
Studies & PMT Costs (Shell staff)	8.0	19.5	2.8	30.3
Sunlink overheads	7.5	8.5	3.2	19.2
Bonus (FID Advance)	5.0	-	-	5.0
	70.9	**28.8**	**6.0**	**105.7**

Reserves/ Resources	This project is aligned with Shell's strategic goal to grow the gas business in Nigeria. Estimated recoverable volumes from discovered reservoirs are 1.72Tcf of gas and 14.2MMbbls of condensate. There is an additional opportunity of deep exploration prospects estimated at 1.2Tcf of gas. Though the gas destination is uncertain, the project has been evaluated with gas supply to the NLNG T1-6 as the reference concept. The FDP has been provisionally approved by the Department of Petroleum Resources (DPR). As a potential supplier to NLNG, HI has less technical and security risks than onshore projects but is significantly more commercially complex.
Source and form of financing	Shell share and the Carry portion of this investment will be financed with SPDC Ltd own resources. OML144 does not rely on NNPC funding.

Summary cash flow



Total project costs for the concept (P50) is estimated at US$2.3bln MOD, including US$0.2mln pre-FID costs, as at VAR3 (April 2013). Future cashflows in above chart are expected to slip by 12months as DG3 was previoulsy planned for Dec-2013 in BP13.

Summary economics

PV Reference Date : 1/7/2013	NPV $US mln Shell Share		VIR	RTEP	UTC $/bbl - RT		Payout Time(RT)	Maximum Exposure. (Shell Share)
Cash flow forward from : 2013	0%	7%	7%	%	0%	7%	Year	$mln, RT**
Base Case								
RV (90/bbl RT13)	-15.5	-14.4	-0.17	NA	NA	NA	NA	-15
Sensitivities (Using PSV-RV)								
High Pre-FID cost (+20%)		-17.3	-0.17					
Low Pre-FID cost (-15%)		-12.2	-0.17					
PIB Jan 2013-Base		-18.8	-0.22	NA				
PIB July 2012-Base		-21.1	-0.23					
** Immediate tax write off from SPDC								

Table 3: Pre-FID cost economics Grid (all based on RV, no revenues included)

Section 1: The Proposal (Management Summary)

Given commercial challenges in getting HI gas monetized via the NLNG, further technical work has been suspended till a viable commercial solution is worked out.

Thus, this Investment Proposal caters for sunk costs up to end 2013 and anticipated 2014 expenditures to resolve commercial issues. These total **US$34.8mln** (100% JV, MOD) for:

- **US$28.8mln** spent from 2010 – 2013 covered Sunlink annual overheads & manpower costs per JoA plus Shell PMT & Studies costs to mature project to VAR3.
- **US$6mln** to cover 2014 costs for JV Partner Overheads as per JoA and Shell staff costs required to seek gas monetization options for the Project.

A further US$92.3mln estimate will be required in 2015 and 2016 to take the project to FID if the current concept is retained. This amount covers FEED, project management, data acquisition, CPF site acquisition and sand-filling, and Sunlink bonuses and admin costs. This will be subject to a revised GIP post-DG3.

The conditions precedent for progression through DG3 as recommended at VAR3 in April 2013 are:

1. The signing of the HOA by SPDC JV Partners in pursuance of the Gas Sales Agreement to NLNG.
2. The conversion of OPL 238 to an OML. This was acheived in May 2013. (See Appendix 3).
3. The approval of the FDP. Provisional approval in place. (See Appendix 4). Full approval to come on confirmation that the first development well has appraisal objectives. This is because the hydrocarbon resources are currently defined by just two wells, short of the statutory three wells required by DPR.

Whereas the last 2 conditions precedent have been met (awaiting the first development well), the first has been overtaken by events as SPDC JV has recently indicated it should have sufficient gas in its forecast to meet its NLNG T1-T6 supply obilgations. Thus, the requested 2014 funding is to seek further commerical options.

The initial GIP provided for US$71mln and covered activities upto DG2 that was taken in July 2010. Following DG2, in July 2010, technical work was hibernated while commercial maturity was pursued. From project hibernation to end of 2011 the main activities were largely commercial and the "Carry" of Sunlink based on JOA commitments approved as part of of Business Plan and spending endorsed by DRB.

After dehibernation in 2012 and based on the full reconciliation of the project past costs including Sunlink costs undertaken in Q4 2012, the likelihood of exceeding the 20% headroom from the existing GIP was identified which triggered requirement for additional funds and a draft GIP was prepared and shared with the DRB. The issue will however be logged as a control incident as learnings can be extracted from the late reconcilliation of partners carry-costs to avoid such late requests for additional funding.

Project Background: OML 144 is located in the predominantly gas-rich central axis of shallow offshore Niger Delta, some 50km from shore. The block covers a total area of 96 km^2 in average water depths of 100m.

The Shell Nigeria Exploration & Production Company ("SNEPCO") acquired a 40% participating interest in OML144 from Sunlink in November 2005. Under the JOA, whilst Sunlink is the Operator, SNEPCo was vested with the role of the Technical Partner, to exercise all the responsibilities, rights, functions and duties ordinarily ascribed to an Operator in joint petroleum exploration and production. All rights and obligations under the original agreement were subsequently assigned from SNEPCO to the Shell Petroleum Development Company Nigeria Limited (SPDC). A key provision in the JOA is for SNEPCO (now SPDC) to carry Sunlink's 60% equity share of all approved costs of joint operations. Following full recovery of all costs and interest (at LIBOR% + 5%), Sunlink will resume full operatorship (subject to both parties agreeing Sunlink has developed the capability and obtained the experience to assume the Operator functions) and SPDC's economic interest in the block will increase to 60%.

The strategic advantages of this project are that it is less prone to onshore security issues, and does not require NNPC funding. The project was de-hibernated fully in January 2012 with the belief that NLNG needed the gas volumes, a reasonable PIB outcome was possible and that these strategic advantages of the project warranted continued maturation through VAR4 in readiness for FID.

There is a notional approval for the HI FDP (Appendix 4) obtained in 2010. Full approval is dependent on conversion of OPL 238 to an OML (achieved in May 2013) and the drilling of the first appraisal cum development well (part of the initial development drilling campaign) and hence fullfill the DPR appraisal requirement for the field.

There is also an additional exploration scope for 1.2Tcf of gas in HI that could be further matured. The proposed new 3D seismic will be included in the final GIP. These deep exploration prospects will be the basis for further development that can easily be tied in to that being proposed in the project. Commercial and funding requirements will be the subject of a separate GIP.

Project Scope:

The current front-runner concept (highly dependent on NLNG demand for HI gas) is to develop the field with six to nine phased development wells to be drilled from a four-legged 12 slot Normally Unattended Installation (NUI) Well Head Platform (WHP) in 100m of water within the central HI field. The wells will be produced at 450 MMscf/d via a DSS manifold and evacuated through a 24" x 120 km multiphase pipeline to an onshore Central Processing Facility (CPF) at Bonny Island where it will be pre-processed to LNG plant intake specification. Stabilized condensate will be transferred to the nearby SPDC Bonny terminal for export. The wells will flow naturally to a landing pressure of 65-75 Barg during the first three to five years after which compression facilities will be installed to boost pressure from 30 Barg to the LNG plant intake pressure. The total project costs for this concept using the P50 cost breakdown is estimated at US$2.3bln.

The expected base case resource volume forecast is as shown below.

Condensate:

Total	Low	Mid	High
CIIP (mmbbls)	10.65	31.88	60.50
UR (mmbbls)	7.20	14.25	24.23
RF	68%	44%	40%

Gas: *(incl. Fuel gas)*

Total	Low	Mid	High
GIIP (Bscf)	1650	2350	3280
UR (Bscf)	1199	1721	2424
RF	73	73	74

Project Status:

On the 31st of January 2014, the DRB decided to suspend further technical work on the project because, based on the latest NLNG supply forecasts (see figure 1), HI gas will not be required for NLNG T1-6.

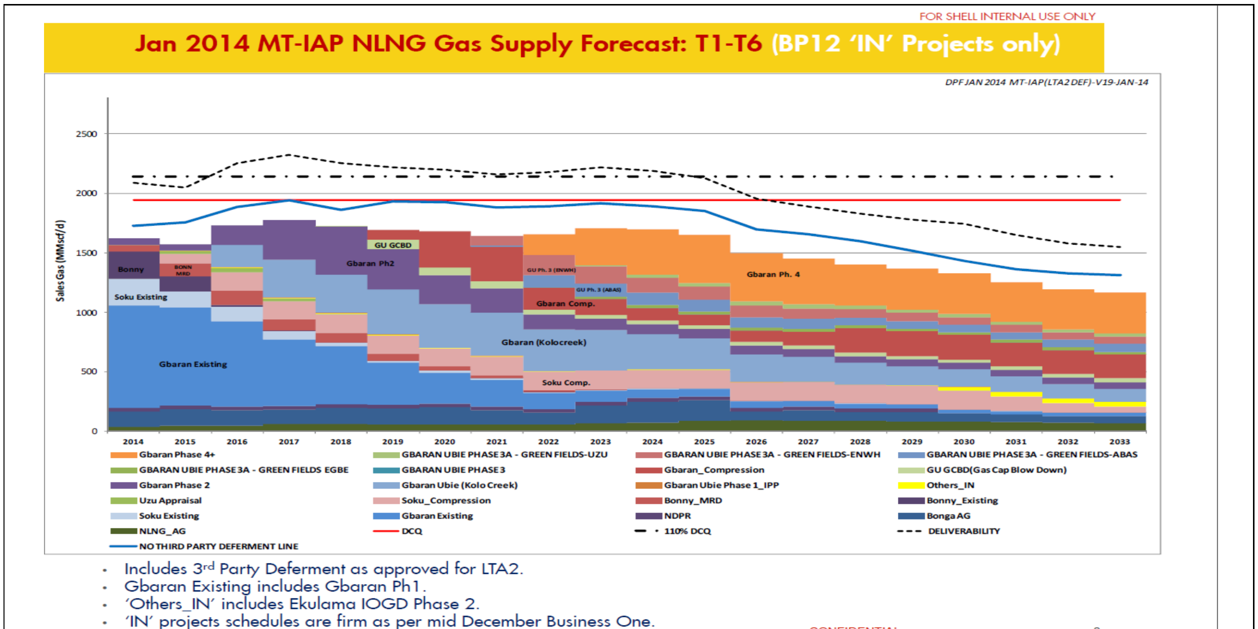


Figure 1: NLNG Gas Supply: T1-T6

This situation has arisen because current efforts to reduce 3rd Party deferments from Gbaran and Soku will increase SPDC JV Gas availability. In that scenario HI gas will not be required to meet T1-6 DCQ. Thus, immediate focus is on seeking commercial options for monetization.

The current front-runner concept to site the CPF at Bonny is expected to meet the investment hurdle. See Chart below for VIR/Capex sensitivity (and Appendix 6 for Capex Evolution).

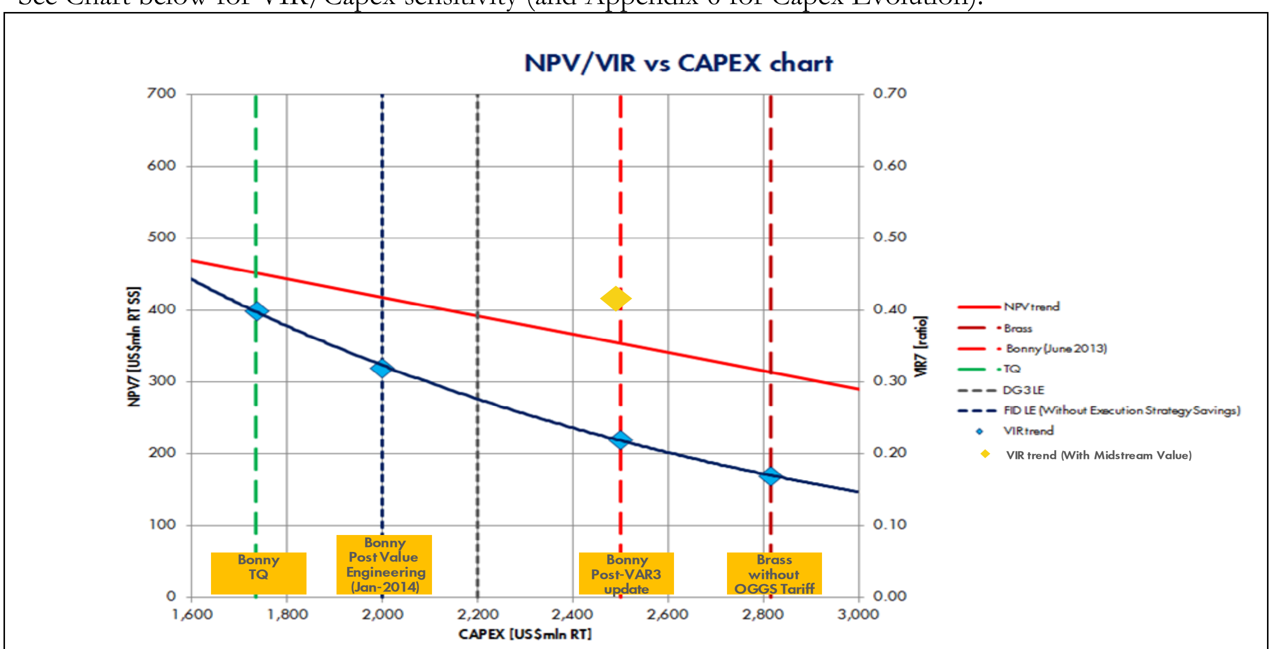


Figure 2: VIR/Capex sensitivity for HI

Section 2: Value Proposition and financial context

This pre-FID Investment Proposal is required to progress the commercial options for HI project in 2014. Thereafter, a revised GIP will be submitted for funds required up to FID, covering seismic acquisition, geotechnical survey, FEED and project management plus ongoing Sunlink related costs.

The HI Gas Development is driven by business objectives that are fully aligned with the SPDC Business Priorities and Nigerian Government aspirations:

- Opportunity to monetize discovered gas estimated recoverable volumes at 1.72Tcf of gas and condensate resources estimated at 14.2MMbbls in the HI fields Additional Opportunity to mature the deep exploration prospects estimated at 1.2 Tcf of gas in HI
- Diversification of SCiN's gas supply portfolio from predominant SPDC JV onshore gas supply assets
- Develop the capacity of Indigenous Players in the Nigerian Oil & Gas Industry

Summary Economics

Based on the economic evaluation, the standalone upstream project VIR of 0.25 (RV) does not yet meet the hurdle at (0.4 VIR) PSV-RV;

PV Reference Date : 1/7/2013	NPV $US mln Shell Share		VIR	RTEP	UTC $/bbl - RT		Payout Time(RT)	Maximum Exposure. (Shell Share)
Cash flow forward from : 2013	0%	7%	7%		0%	7%	Year	$mln, RT
Base Case								
SV (70/bbl RT13)	758.8	188.6	0.12	11.2%				
RV (90/bbl RT13)	1163.9	375.3	0.25	14.9%	8.8	12.5	2021	835.7
HV (110/bbl RT13)	1558.7	557.4	0.36	17.8%				
Sensitivities (Using PSV-RV)								
RV (90/bbl RT13)-Pre-FID cost	-15.5	-14.4	-0.17	NA	NA	NA	NA	-15.5
High UR (P10)		567.7	0.37					
Low UR (P90)		198.3	0.13					
High Capex (P90)		288.9	0.15					
Low Capex (P10)		433.0	0.35					
1-year project delay (OSD only)		310.2	0.20					
300Mmscf		163.3	0.11	9.9%				
Lifecycle		357.5	0.22					
PIB Jan 2013 - Base		-195.2	-0.13	-0.2%				
PIB July 2012 - Base		-207.3	-0.14	0.0%				
Integrated Value (Upstream, Margin & Midstream)		682.0	0.45					

Table 2: Base Case Economics Grid (Shell Share)

Analysis was carried out to ascertain the value of the project's full scope when the project takes FID using the 50/50 full project cost estimates and the production forecast. Sensitivities were also carried out on the base case to show the impact of various scenarios on the value of the project. Refer to the tornado chart (chart 1) for the results of these sensitivities. Results of the project economics analysis are given in table 2 above.

The project benefits from the "AGFA incentive" which allows Capex for gas developments to be treated as a deductible from the condensate tax base (85%). See Appendix 2.

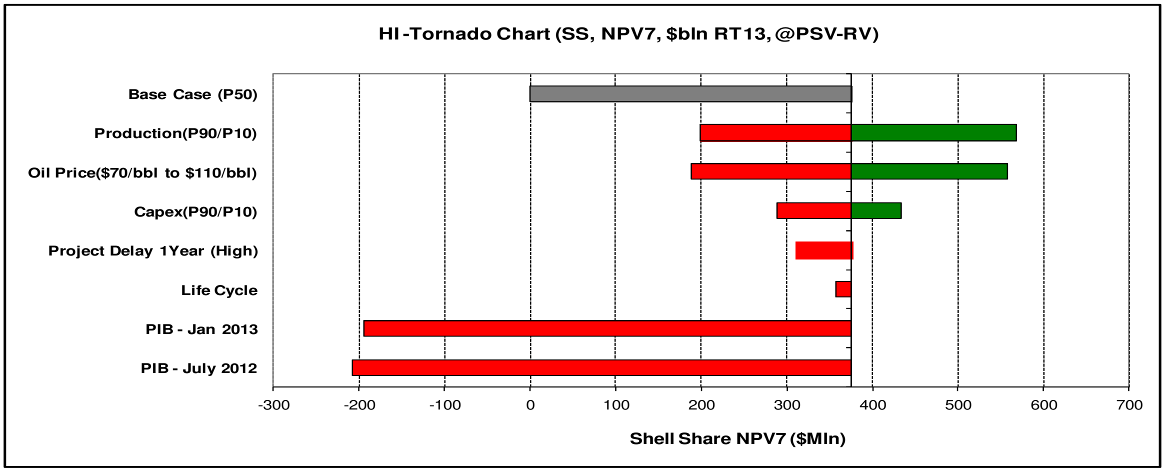


Chart 1: Full scope Tornado Plot

Section 3: Risks and alternatives

Risks:

Risk of Licence Expiration:

With the project effectively back in the feasibility phase post the DRB of 31st January 2014, there is a risk that viable commercial options may not be sufficiently matured within the licence period considering the entire TECOP spectrum for a project of this nature. The current licence expires by May 2033.

Planned Mitigation Actions:
The mitigation is to find a commercially attractive outlet for the gas ahead of NLNG's forecasted requirement for circa 2024. In addition, the project team will need to resolve the commercial issues and mature the project technically (e.g. lower costs). It will be critical to optimize our internal processes and align during the development with Sunlink and ensure early engagement of key external stakeholders.

Potential for non acceptance of current reference concept by key stakeholders:

Despite NNPC's non-participating interest in OML 144, NNPC has assumed a 'de-facto' role of master planner for the country's oil and gas infrastructure. As a result, a key enabler is OML 144's ability to address NNPC's key concerns around;

1. underutilization of existing gas infrastructure;
2. monetization of stranded assets in shallow offshore.

Planned Mitigation Actions:
The team will explore the potential to align with NNPC's interest to monetize stranded shallow offshore molecules by designing access and capacity in OML 144 facilities for future Shell and 3rd party (e.g. Agbara in OML 116) volumes.

Precedent of gas projects developed solely for supply to NLNG by a party other than existing JV Gas suppliers:

There is a risk that the proposed deal sets precedent for gas projects being developed solely for supply to NLNG by a party other than existing JV Gas suppliers, which will compete against or displace upstream gas developments from the existing JV Gas suppliers thereby jeopardizing the high-value export monetization route for SPDC-JV's gas. Particularly where there is a vested interest for any of the individual JV partners in developing a non- SPDC JV gas project with potential of delivery into NLNG.

Planned Mitigation Actions:

NLNG T7 has more flexibility on 3rd party JV suppliers and the HOA could be initiated on that premise. The proposed commercial structure which provided for intermediate ownership of molecules by SPDC-JV, sets the foundation for guiding principles which will govern supply to NLNG by parties other than existing JV Gas suppliers. For example, an NLNG supply order of preference could be proposed as follows: (i) SPDC JV, NAOC JV, Total JV; (ii) projects with one or more SPDC JV partners as shareholders; (iii) others

<u>Fiscal Risk under PIB:</u>

There is a potential risk of an adverse Petroleum Industry Bill (PIB) impact on the project when enacted into law. The risk has both fiscal (Tax and Royalties) and regulatory effect on project viability.

Planned Mitigation Actions:
Dedicated teams within Shell continue to monitor and lead advocacy efforts to manage this risk. A PIB sensitivity has been included in the project economics based on the July 2012 and January 2013 versions of the Bill This risk is not unique to HI and it will make the project uneconomic.

<u>Risk of NNPC claw back into OML 144:</u>

There is risk that NNPC might try to claw back into OML 144 as a participating stakeholder.

Planned Mitigation Actions:
In the event of NNPC claw back, the claw back will be into Sunlink's participating interest in line with the Farm-In Agreement with Sunlink.

<u>Risk of FGN opposition due to a drop in FGN take on the project:</u>

There is the risk that FGN will oppose the project because of the negative FGN take of $338mln (NPV7) on the upstream part. (See Appendix 2).

Planned Mitigation Actions:
The mitigation is to get the FGN to focus on the integrated midstream value of the project. The FGN take from the midstream is $575mln (NPV7) making net FGN take from this project still positive. It should also be noted that the undiscounted cashflow for FGN is positive even for the upstream.

<u>Tax Deductibility Risk:</u>

In the event SPDC exits this opportunity, there is a risk that the Federal Inland Revenue Service (FIRS) may successfully challenge the costs (60%) being carried by SPDC due to the fact that they represent disproportionate costs SPDC incurred on behalf of another counter-party. These costs would otherwise have been offset against future production once H1 starts producing. The 40% Shell share equity will not be affected by this challenge as it would continue to enjoy tax relief via capital allowances under AGFA provisions in SPDC's books.

Planned Mitigation Actions:
The mitigation is to provide support to the Commercial team and help design viable alternatives to monetizing the gas via supplies into NLNG. In addition, an evaluation of SPDC's tax base threshold to be conducted by the Economics team taking into cognizance all planned major projects to identify how much head room is available within SPDC.

<u>Risk of unattractive Commercial Project:</u>

The project currently has economics which do not yet meet the Shell screening criteria. It will be critical to find alternative and attractive gas outlets and ensure that the technical teams bring down the capital investment required.

Planned Mitigation Actions:
DE role has been moved to the Commercial function to expedite the search for outlets. Lessons from the various Value Engineering work items done to date will be incorporated into future project work/activity. By these, the Capex will be brought down to $1.8billion at FID with a VIR of 0.38 with upside opportunities for further improvements.

Alternatives considered:

Options being considered are as follows:

1. Exploration of gas destinations other than NLNG.

2. Pursuance of the HoA in support of monetisation via NLNG Train-7 with potential gas processing at Brass or Bonny

3. Exit the opportunity

To facilitate these, the DE role has been transferred from Development to the Commercial function.

Section 4: Carbon management
The project portends negligible CO2 emissions, flaring will not be routine, as all gas will be produced and sent into the pipeline en-route to the central processing facility in Bonny. Carbon tax has not been included in project economic yet as forecast is not available, but will be included in the final FID GIP.

Section 5: Corporate structure, and governance
Governance of this opportunity will be carried out in line with the Joint Operating Agreement. Shell is the Technical Partner until hand-over to Sunlink as the Operator.

Section 6: Functional Support and consistency with Group and Business Standards
The scope of work covered by this proposal is consistent with Group HSE, External Relations and Sustainable Development policies. Functional support for this proposal is provided by the Finance & Controllers, Supply Chain Management, Legal, Treasury and Tax functions.

Section 7: Project management, monitoring and review
This opportunity is managed by a Business Opportunity Manager and steered by the DRB with the GM Commercial now as Decision Executive.

Section 8: Budget provision
HI Gas Development was included in SPDC's BP13 (BP'12 LTA/2) at $66m. The Project DRB has however subsequently endorsed $6m only to seek alternative commercial monetization options in 2014. Thus, 2014 budget is adequate and this adjustment has been communicated back to Upstream International Planning.

Section 9: Group financial reporting impact
There are no unusual accounting issues related to this GIP. Expenditure related to the project will be accounted for in line with Group Policy.

Section 10: Disclosure
Material disclosures, if any, will be done in line with the Group and SPDC Disclosure policies and guidelines.

Section 11: Financing
The full costs of this investment (Shell and Sunlink) will be financed by SPDC Ltd's own cash flow, in line with existing Carry arrangement with Sunlink. As specified in the Joint Venture Agreement, Sunlink share of past costs plus interest at LIBOR plus 5% will be recovered from production. After total recovery is achieved, the equity split will change from the current 60:40 equity ratio (Sunlink: Shell) to 40:60 (Sunlink: Shell).

Section 12: Taxation
Taxation assumptions have been reviewed and all material tax risks have been identified under the Risk section above.

Section 13: Key Parameters
This Investment proposal seeks a further pre-FID approval for **US$34.8mln** (100% JV, MOD) to cover:

- **US$28.8mln** spent from 2010 – 2013 covered Sunlink annual overheads & manpower costs per JoA plus Shell PMT & Studies costs to mature project to VAR3.
- **US$6mln** to cover 2014 costs for JV Partner Overheads as per JoA and Shell staff costs required to seek gas monetization options for the Project.

Section 14: Signatures

This Proposal is submitted for approval.

Supported by:

....
Erwin Nijsse (SIEP-FUI/O)

Date: .../..... /...

For shareholder approval:

....
Harry Brekelmans (SIEP-UIO)

Date: .../.... /....

Sponsor:

....
Markus Droll (UIO/G)

Date: .../..... /.....

Initiator: Chux Uguru (UIO/G/DF)

Appendix 1: Full scope Key Project Parameter Data ranges (100%)

Key Project Parameter Data Ranges (100% project)					
Parameter	Unit	Low	Mid	High	Comments
Capex (MOD)	US$mln	1863	2305	2968	Includes the recoverable pre-FID cost of $103.9mln
Opex (MOD)	US$mln	1020	1031	1047	Includes SCD cost of $55.3Mln (Mid)
Production Volume	Mmbbls	7	14	24	
Production Volume	Bcf	1177	1638.5	2299	
Start-up Date		Jan-21	Jan-20	Jan-20	
Prouction in first 12 months	Mmboe	32	34	37	

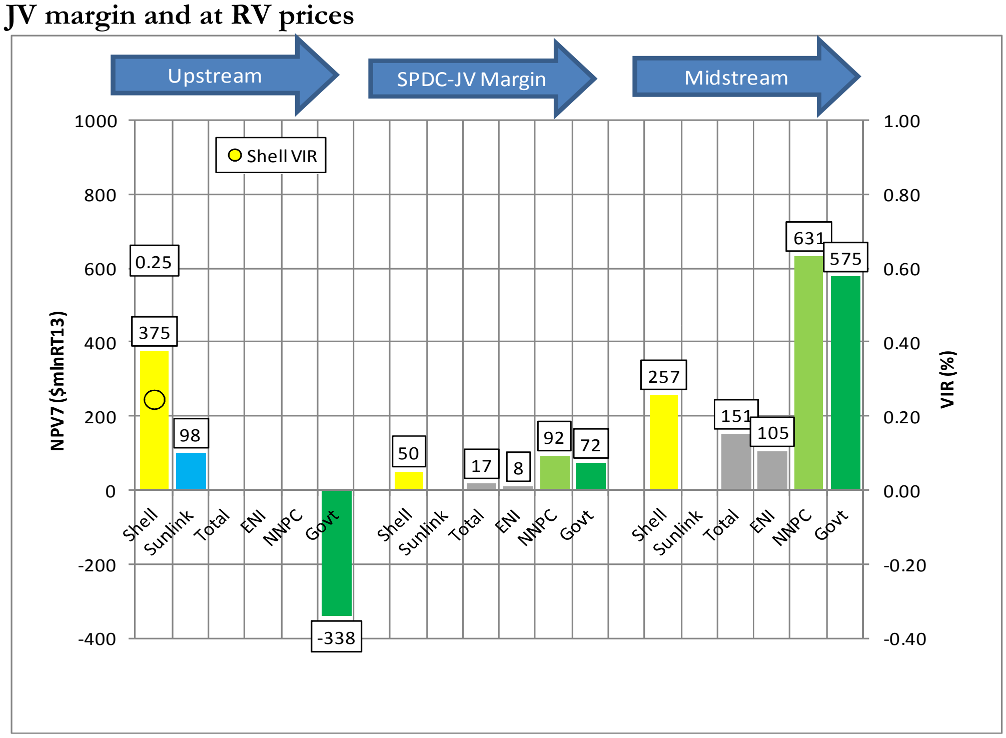
Economics Assumptions

- 450mmscfd for 5 years plateau and 15 years field life.
- Recoverable: 1.72 TCF (sales gas:1.64 TCF, 0.08TCF (consumed in operations) + 14.2 Mln bbl Condensate.
- Capex: 2.3bln $MOD (includes new dedicated facilities, and recoverable forward looking pre-FID cost of $98.3mln)(Note: Pre-FID costs are really Feasex but were included in the project costs for the economics evaluation)
- Opex: (0.98bln $MOD), this excludes the SCD costs of $ 55.3mln.
- SCD: 0.055bln $MOD (2.5% of MOD Capex)
- Condensate handling tariff: $2.5/bbl.
- SPDC-JV margin of $0.29/Mmbtu assumed at PSV-RV

PIB Assumptions

- Capex CIT & NHT deductibility rate: 100%.
- Opex CIT & NHT deductibility rate: 96%.
- Condensate and gas production allowances allocated to Sunlink only (60% equity)
- Production allowance deductibility on NHT only.

Appendix 2: Value Chain Economics under the current fiscals (PPT/CITA/AGFA) with SPDC-JV margin and at RV prices



Appendix 3: OML conversion notification

MINISTRY OF PETROLEUM RESOURCES

DEPARTMENT OF PETROLEUM RESOURCES

7, KOFO ABAYOMI STREET, VICTORIA ISLAND, LAGOS

P.M.B. No: **12650**

Telephone: **3200440-9**

Website: www.dprnigeria.com

Ref. No: **P1.LM/3900/S.13^{A}/Vol.3/418**

Date: **May 17, 2013**

The Managing Director,
Sunlink Petroleum Limited,
7A, Taslim Elias Close,
Off Ahmadu Bello Way,
Victoria Island, Lagos.

RE: APPLICATION FOR CONVERSION OF OPL 238 TO AN OML

We refer to your letter dated November 21, 2011 on the above subject matter.

2. I am directed to convey the approval of the Honourable Minister of Petroleum Resources (HMPR) to your request for the conversion of OPL 238 to an OML.

3. You are hereby advised to forward to this office the following:

(i) Six (6) copies of the map of the area converted to an Oil Mining Lease (OML) delineated with red outline but designated as **OML 144** which has been assigned to your Company. Furthermore, it must be duly signed by a licensed Surveyor agreed to by both your Company and DPR. The scale of the map will be 1:100,000 and area of the derived OML must not exceed the statutory regulated size of 1295 square kilometers.

(ii) The vertices and the boundary description of the concession map should be clearly annotated and in conformity with the ongoing nomenclature harmonisation in DPR.

4. Please note that the submission of 3 (i) and (ii) is the pre-requisite for the preparation of the Title Deeds for the Oil Mining Lease (OML) that has been approved by the Honourable Minister of Petroleum Resources (HMPR).

Yours faithfully,

A. O. Olorunsola
Director of Petroleum Resources

DPR letter converting OPL 238 to OML 144

Appendix 4: OPL 238 FDP Approval

MINISTRY OF PETROLEUM RESOURCES

DEPARTMENT OF PETROLEUM RESOURCES

7, KOFO ABAYOMI STREET, VICTORIA ISLAND, LAGOS.

P.M.B. No: 12650
Telephone: 01-2790000
Website: www.dprnigeria.com

Ref. No. PL.UMR/MFIO/SPL/V.1/241
Date: July 28, 2010.

The Managing Director,
Sunlink Petroleum Limited
7A Teslim Elias Close,
Off Ahmadu Bello Way,
P.O. Box 72049, Victoria Island
Lagos.

Dear Sir,

RE: FIELD DEVELOPMENT PLAN FOR HI FIELD (OPL 238)

We refer to your letter dated December 16, 2009 on the above subject matter.

In accordance with Section 37 of the Petroleum (Drilling and Production) Regulation 1969 and its Amendments, provisional approval is hereby granted for you to develop the HI field.

Please note that final FDP approval will be granted upon conversion of the block from OPL to OML and an adequate appraisal of the field using one of the planned development wells.

You should also note that individual well in the field will be approved on its merit upon submission of formal application in accordance with Section 32 of the Petroleum (Drilling and Production) Regulation 1969 and its Amendments.

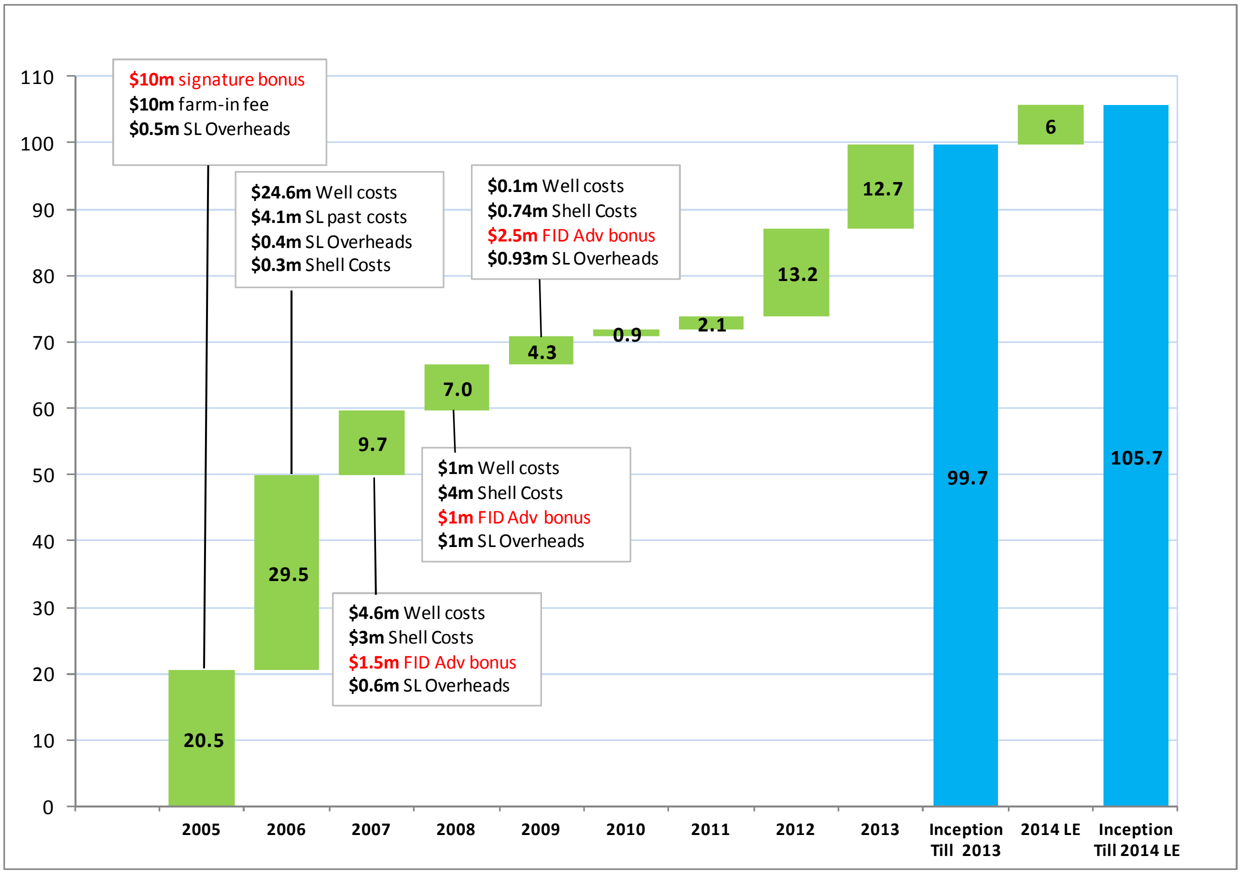
We acknowledge receipt of your Standard Chartered Bank cheque number 6599132018 of July 21, 2010 for Fifty Thousand Naira (₦50, 000.00), being the statutory fee for the Field Development Plan.

Yours faithfully,

M.O. Balogun
For: Director, Petroleum Resources.

FDP Provisional Approval for OPL 238 (Now OML 144)

Appendix 5: HI Gas Development Project: Inception-Till-Date (ITD) Spend for SPDC Ltd (in US$m)



Appendix 6: HI Value Engineering and TQ look Ahead ($'m)