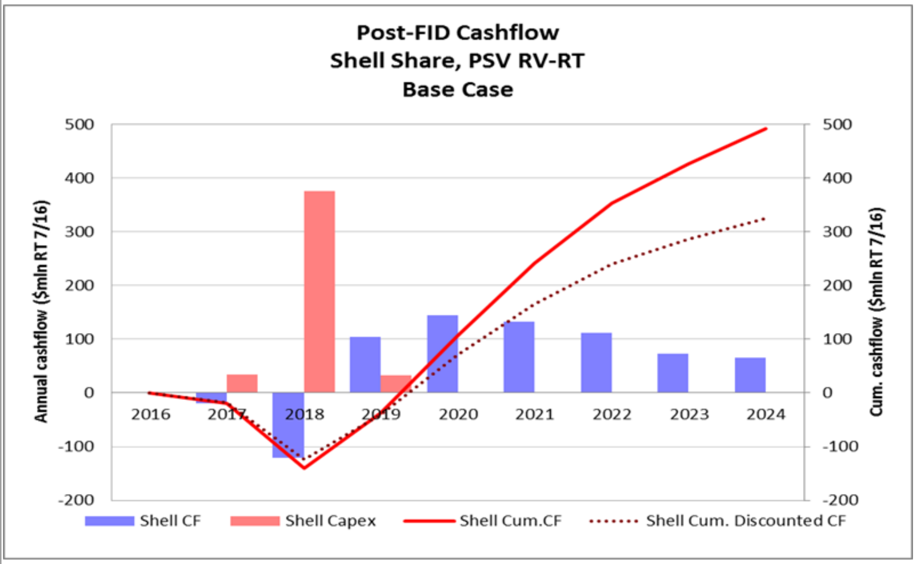
Proposal to Commence Negotiations

Summary information

Business unit and company	Shell Nigeria Exploration and Production Company ("SNEPCo")
Group equity interest	100% in SNEPCo; 55% Shareholder Interest in Oil Mining License OML 118 operated by SNEPCo
Other shareholders/partners	Esso Exploration & Production Nigeria Ltd (20%), Total E&P Nigeria Ltd (12.5%) and Nigerian Agip Exploration Ltd (12.5%)
Business or Function	Upstream Production Deepwater (UPD)
Potential third parties	Drilling/ Rig Contractor emerging from the DW Rig tender exercise, subsea equipment providers such Pressure Controls Nigeria Ltd (GE), FMC Technologies and also OCTG suppliers.
Project	Revise the original BSW/A Deepwater Rig tender tenure from a 4 year fixed term with 2 times 1 year extension options into a 1 year firm commitment with extension options for 1 year and 4 years, covering Bonga Main scope and subsequently locking in an option for the BSW/A project. This PCN covers the mandate to finalise negotiations for a Deepwater drilling rig and long lead items (LLI's) to drill the 3 Bonga Main Ph3 wells (covered under an existing GIP), 5 Bonga Main Phase 2b wells (FID in Q3 2017) and 2 Bonga NW Ph2 wells (FID in Q3 2017). The team will look for ways to limit the 1 year (12 months) firm commitment with some form of condition precedent on the pre-DG03 projects.
Headline Size	The commitment (MOD) for the drilling rig and LLI's is expected to be around US$ 223 mln (US$122 mln SS) of which ~ US$ 153 mln (US$ 85 mln SS) is for wells for which FID is only expected to be taken in 2017. Base case, the rig is expected to drill the 8 wells in 365 days starting January 2018 which would result in an estimated NPV7 of US$324 mln (SS) and a VIR of 0.84 @ PSV-RV of $80/bbl. Assuming continuation of past years drilling performance at Bonga, a 10 wells scenario (full firm scope) is very much possible to be drilled in 12 months, resulting in an NPV7 of US$341 mln (SS) and a VIR of 0.73 @ PSV-RV of $80/bbl. Subject to the outcome of the commercial tender and final negotiations, a 12 months firm rig commitment may have to be made in Sept/ Oct 2016 to enable a spud-date of January 2018: the team will seek to bring some form of condition precedent into the agreement covering the tenure for the pre-FID wells, but in light of the opportunities in the market and the attractive pre-DG4 economics, may seek earlier formal approvals via a separate GIP.
Project objectives and expected deliverables	The objective of this PCN is to obtain a mandate to finalise tendering and negotiate a contract for a DW drilling rig (and some LLI's) which would allow SNEPCo to mature a portfolio of 10 wells to keep the Bonga FPSO full of economically viable oil over the remaining life of the FPSO (incremental production capacity of 34kbopd). The maturation of the 10 wells should enable the ultimate recovery of 62MMstb

	of which about 20MMstb is within the approved BM Phase 3 scope. Prior to final commitments for the DW drilling rig and LLI's, a GIP will be issued (Sept/ Oct 2016) which will also document the details on the conditions precedent for the pre-DG/3 wells. The new scope on the BM Phase 2b and BNW Phase 2 projects will also be subject to a GIP in 2017.
Timescales	A 12-months commitment for the DW drilling rig would need to be made in Sept/ Oct 2016 to enable drilling to commence on the 3 BM Phase 3 wells in January 2018. The remaining 7 wells are expected to reach DG3 in December 2016 (BM Phase 2b) and May 2017 (BNW Phase 2) respectively, with FID scheduled for Q3 2017. As such, between 3-9 months of rig commitments and ordering of LLI's maybe required ahead of an FID on the remaining projects.
Summary cash flow	 *Cost recovery will commence immediately as drilling expenditures are mostly considered intangibles are recovered same year as expensed. First oil expected in 2018.*
Summary economics	The forward looking economics of the 8 wells (RT'16, Shell Share) generate NPV7 of US$ 324 mln, VIR7 of 0.84 which meets the Group Requirements for a VIR7 of 0.6 before DG4. Project is robust with a RTEP of 72.2% at PSV-RV ($80/bbl) based on NNPC's interpretation of the existing 1993PSC fiscal regime. The economics based on IOC view of the PTT/ 1993PSC returns a SS NPV7 of US$ 347 mln and a VIR7 of 0.9 (RT'16), the deviation not being large due to limited Investment Tax Credits being applicable as usually a significant portion of drilling expenditures are intangible in nature and are therefore recoverable in the same year they are incurred as expenses in the income statement. The project value is assessed as incremental over existing Bonga production - in the same tax and cost recovery ring-fence, but taking into account different profit oil tranches. Economics for a "lower for longer" scenario at US$ 40/bbl ("LV" RT) still result in a positive NPV7 of US$ 120 mln (VIR 0.31).

Summary economics (PSV-RV, RT16)	NPV7 (USD mln)	RTEP (%)	VIR
Base case UR	324	72.2	0.84
Low case UR*	108	30.8	0.28
High case UR*	454	96.8	1.17

**Based on average Low / High range of projects in BP15 (-50% to +30%), not based on actual Low / High incremental production forecast.*

Section 1: The proposal

Approval is requested to commence negotiation towards contracting a Deepwater mobile drilling unit for SNEPCo with commencement in January 2018 to support drilling and completion of 10 wells consisting of 3 Bonga Phase 3 wells, 5 Bonga Phase 2b wells and 2 BNW Phase 2 wells in order to realise SNEPCo key priority of utilising the Bonga FPSO spare capacity with drilling infill wells and support Shell's ambition to grow the Deepwater business in Nigeria.

As per OP'15, production forecast for Bonga Main shows a decline in oil production from the developed wells from 2019. The incremental opportunities planned for execution are the undeveloped Bonga Main phase 3 well (for which GIP approvals have been maintained), Bonga NW phase 2 wells and the newly structured Bonga Main Phase 2b (BMPh2b) project (made up of the original Bonga Phase 2b wells, a new opportunity in the 740 reservoir i.e. the 710p5 well and the Inter Channel Thin Bed (ICTB) appraisal well). The BMPh2b project is expected to pass DG3 in December 2016 with FID date in Q3 2017, while the BNW phase 2, which is also an infill wells project, is expected to pass DG3 in May 2017 and take a joint FID with the BM Phase 2b project also in Q3 2017.

The project team's directive has been to focus on wells which are economical in the base case of 1993 PSC (NOC view) with an FPSO end of technical design life[1] of end 2024. To secure a decent rig and competitive pricing, a minimum commitment of 12 months would be required covering at least 8 wells, however with the potential for drilling the firm 10 wells within 365 days. Based on the attractiveness of the existing portfolio, the team is proposing 12 months drilling time and ordering LLI's for the first 10 wells (value in range of $ 24 Mln). The P50 rig sequence is shown in Appendix 3. Whilst there is virtually no demand in the current market for Deepwater rigs, some 24 Deepwater rigs still under construction and more rigs coming off contract, the global rig category manager expects a worsening utilisation over the next 6-12 months, with contract prices approaching OPEX levels. A rig contract award in 2016 will therefore secure very attractive contract prices and access to high quality rigs. It is realised that a 12 months commitment may need to be made before FID on remaining 7 wells, however efforts will be made to bring FID further forward whilst the team will seek to make an award conditional on obtaining DG3 or even FID in relation to these pre-DG3 projects. If there is a 6 months delay in committing the rig this would have an impact on the spud-date, resulting in average production loss of ~3kbopd in 2018, UR loss of ca. 6-8MMbbls and NPV loss of -US$63 mln (SS) by the end of 2024.

The total recovery from the 10 wells is ~62MMstb which is categorized into both 2U and 2C resource volume buckets. Each well needs to be economically viable with the pre-2025 resource numbers and would be ranked on case by case basis. The wells are expected to deliver an incremental peak oil production of ~34kbopd (100%) and an average incremental production over the period 2018-2024 of ~24kbopd (100%), unlocking 62MMstb ultimate recovery (100%). Drilling is planned to commence in January 2018 with FOD for the first well targeted for April 2018. Oil production forecast is shown in Figure 1 below.

The project aims to fill available FPSO ullage and maximize dry oil production, as well as to accelerate hydrocarbon development into the license and design life period to improve OML118 overall block value; these are expected to be attractive wells from economic perspective. Drilling these wells in time before production falls off plateau would deliver stakeholder value for the Bonga Main and ensure that resources which are easily reachable from existing slots are monetised.

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[1] Proof of technical feasibility of a 10 years Life Extension of Bonga Main FPSO is still ongoing and as such would not be considered in this PCN

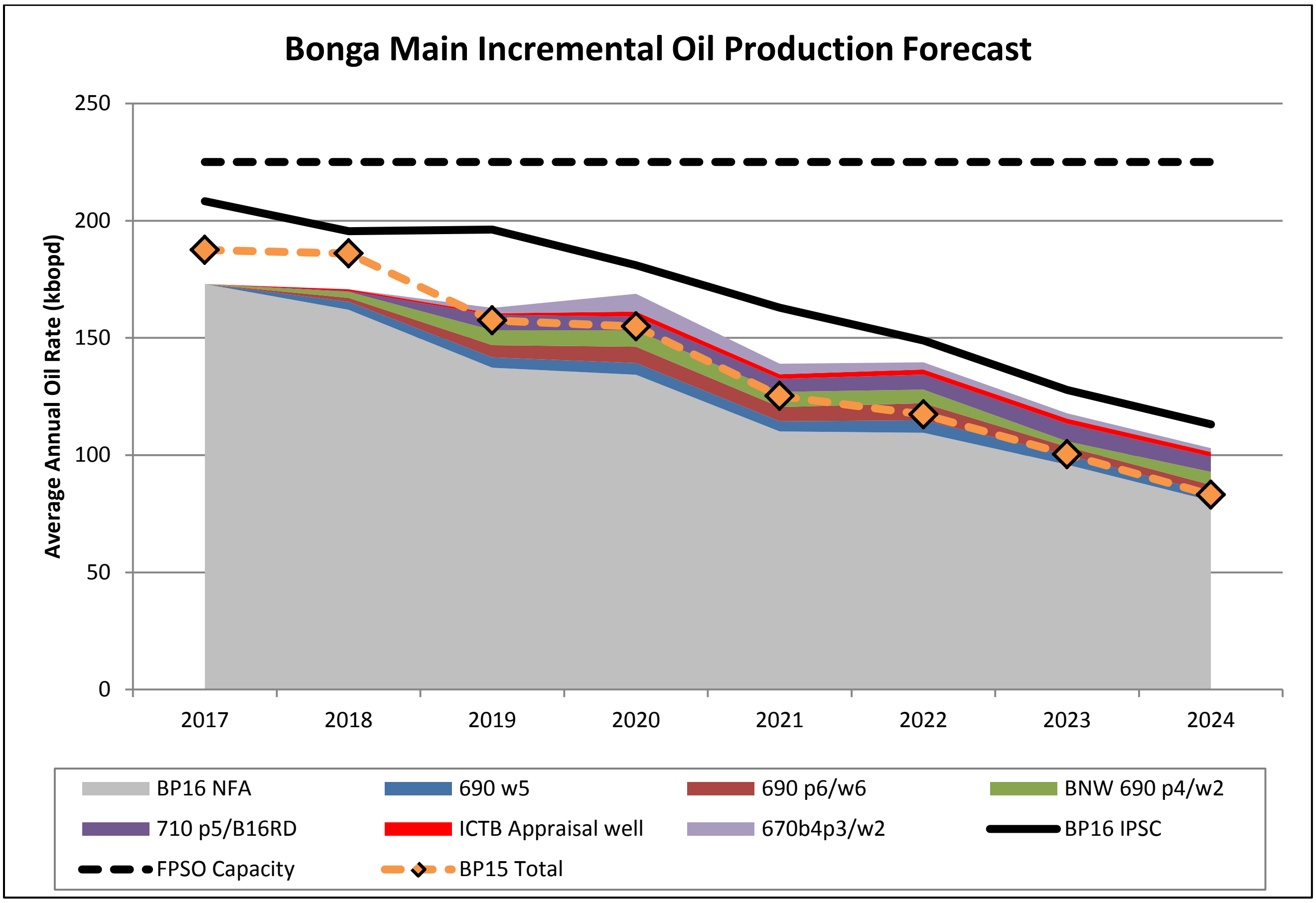


Figure 1: Incremental Production Forecast showing the individual well streams.

Section 2: Value proposition and strategic and financial context

The maturing Bonga Main portfolio, which is being firmed in OP'16, is made up of un-risked 14 wells which equals 14-20 months of rig work (14 months assuming continuing performance). The firm portfolio of 8-10 wells is used to underpin this PCN as not all 14 wells have been sufficiently matured or have equal economic attractiveness. This proposal is in line with the RDS strategy of growing the Upstream Engine which includes investments and production in Nigeria Deepwater and Gas. Additionally, this incremental production will maximize the utilization of the existing Bonga Main FPSO - keeping the FPSO full of economically viable dry oil.

The project economics are evaluated on a forward looking basis (from 1.1.2016) using the P50 Capex estimates and volumes for a base case of 8 wells and additionally for the total firm basket of 10 wells under a conservative view based on the NNPC interpretation of the 1993 PSC cut-off 2024. The NNPC interpretation is carried as a "base case", whilst the IOC interpretation (Shell's position) is shown as a sensitivity. The NNPC interpretation of the 1993 PSC base case is for info only and does not reflect a change in SNEPCo position or strategy vis-a-vis the arbitration/litigations; rather it reflects the current practice of NNPC "overlifting". The project base case scenario using 8 wells is attractive with an estimated NPV7 of US$324 mln (SS) and a VIR of 0.84 @ PSV-RV of $80/bbl. The PSC for OML118 allows this project to benefit from immediate recovery of expenditure (as cost oil barrels) from existing Bonga production. Project value is assessed as incremental over existing Bonga Main production. See Appendix 1 for economics results details and sensitivities.

<u>Underpinning activity</u>: One year contract is underpinned by 365 rig days of activities delivering 8-10 wells (this PCN assumes 8 wells for economics), with Best-in-Class (BiC) performance enabling 12 wells in one year); note that various BiC wells were already drilled with a 3rd-generation rig during 2015-2016. The remaining 4 wells are currently sub-economic; however, the team is working to optimise the costs (incl. drilling performance) for these wells further (they are however not subject of a firm scope for this PCN).

Firm Wells		**Project**	**Level of Maturity**	**POS**	**Remarks**
1	690w5	BMPh3	Post FID	100%	Already Funded
2	690p6	BMPh2b	Pre-DG3 (DG3; Dec-16)	>90%	Joint FID planned in Q3 2017
3	690w6	BMPh2b	Pre-DG3 (DG3; Dec-16)	>90%	
4	BNW-690p4	BNWPh2	Pre-DG3 (DG3; May-17)	>90%	
5	BNW-690w2	BNWPh2	Pre-DG3 (DG3; May-17)	>90%	
6	710-p5	BMPh2b	Pre-DG3 (DG3; Dec-16)	>90%	
7	Injector RD (B16 or 39)	Re-drill	N/A	>50%	Injector re-drill depends on current injector performance
8	ICTB appraisal well	BMPh2b	Pre-DG3 (DG3; Dec-16)	80%	To test producibility of ICTB reservoirs.
9	670b4p3	BMPh3	Post FID	>80%	Already funded. *Poorest well pair. Stand-alone economics: $40mln NPV7 (RT 16), RTEP 79% and VIR of 0.49.*
10	670b4w2	BMPh3	Post FID	>80%	
Contingent wells		**Project**	**Level of Maturity**	**POS**	**UR/Max*CAPEX/ Current CAPEX**
1	740SEp3	BMPh2b	Pre-DG3 (DG3; Dec-16)	<<50%	5MMstb/$75m /$150m** (for well pair) Uneconomic
2	740SEw3	BMPh2b	Pre-DG3 (DG3; Dec-16)	<<50%	
3	Injector RD (B16 or 39)	Re-drill	N/A	50%	0[1]
4	BNW702p5	BNWPh2	Pre-DG3 (DG3; May-17)	<<50%	2MMstb/Non-viable

Table 1: List of Undeveloped wells in Bonga Main

***Maximum CAPEX required to make well pair economic at $90/bbl**

****Well cost estimate**

1 currently just a placeholder to safeguard NFA

Section 3: Risks, Opportunities and Alternatives

Risks

Risk	Mitigation	
• **Immaturity of projects:** Most of the projects that underpin the rig are at pre DG3 stage of the ORS Process. BNW phase 2 oil volumes are dependent on the performance of phase 1. Volumes from these wells may not rank due to low volume *(UR less than 10MMstb)* and lower oil price premise (PSV-RV). Some of the Water Injector RD may drop off if the existing injector performance increases.	If the volumes from the wells are unable to meet the rig sequence schedule, we will attempt to fill the slots with other OML 118 wells/opportunities (includes acceleration of infill opportunities in BMIRP which will then be matured to DG-3 by 2018). NAPIMS and CoVs are regularly engaged and will be informed on time. However, the likelihood of the number of mature wells falling below 10 is low, most had earlier progressed to DG3 and FDP written and approved. Current update is with respect to new seismic, and performance data. Team will seek to negotiate a condition precedent into the contract covering part of the tenure of the pre-DG/3 wells.	
• **Early termination of the contract:** The contract is planned for one year to drill 8-10 wells, however only 3 of these wells are firm. The total rig contract cost is \$70 mln (SS) excluding LLI's. The economics of drilling only the 3 wells GIP is shown in the Appendix (Table 5).	The phase 3 wells are already funded and ready to be drilled. The other wells are currently being matured and have a high probability of being drilled as these wells show very good economics indices with the current data. The award will be made conditional upon obtaining FID.	
• **OML 118 CoVs approvals may not be achieved on time due to ongoing business challenges:** OML 118 Co-Ventures may opt to delay the contract due to the current cash crunch and the PSC renewal and may delay or vote against the rig contract due to NAPIMS/NNPC challenges with cost recovery and lifting issues.	Continuous engagement with the CoVs on the project status and seeking their support and approvals along the line and final GIP approval. COV's are supportive of the initial Bonga Main Phase 3 wells, but careful engagement on the other 7 wells is required before committing to 12 months rig tenure.	

• **The rig award is not achieved due to not being able to achieve Shell internal approvals or condition precedent becoming effective:** Shell unable to afford pre-DG3 or pre-FID rig award in the context of rig idle or condition precedent becoming effective. In this scenario, due to the tendering process with NAPIMS and NCDBM, it is unlikely that a rig would be secured before 2019.	NAPIMs and NCDMB approval letter to continue with the tender on the 1+1+4 basis have been received. Subject to NAPIMS approval, contractor will be requested to accept a conditional award (including some form of a condition precedent for the pre-DG/3 wells) as part of the commercial ITT. It is critical that the current rig tender is kept alive. If not, SNEPCo would need to restart the entire tendering process, making it unlikely that a rig would be contracted earlier than 2019 hence missing the rig market opportunity and sub-optimising the ullage in Bonga FPSO. If spud in 2018 is delayed passed January 2018 (say to mid-2018), the impact of such is an average production loss of ~3kbopd in 2018 and NPV loss of -US$63 mln (SS) by the end of 2024. The impact of a one-year delay is shown as a sensitivity in the tornado chart in figure 2 of the appendix Contractor will be requested to accept a conditional award (including some form of a condition precedent for the pre-DG/3 wells) as part of the commercial ITT. This may still require NAPIMS approval. NAPIMs approval letter to continue with the tender on the 1+1+4 basis has been received.	
• **Nigerian Content Requirements:** The strict and increasing requirements for Nigerian Content may lead to uncompetitive rig rate from the Tenderers due to limited competition and/or bidders pricing in the stricter requirements.	There are 4 drilling contractors that have passed the technical stage and shortlisted by NCDMB to submit commercial bids. Due to the current market downturn and the optional 1+4 years bid request embedded in the commercial tender, expectation is that the Bidders will have a long term view of the opportunity and price in their bids in a rational manner. IDD issues on one of tenderers may need to have to be addressed.	

Opportunities

- By end 2013 Shell Group had 16 DW rigs in operation. End 2016, there will be only 8 DW units working plus one stacked. Current RDS DW rig idle time exposure is 816 mln USD in 2016, 649 mln in 2017 and 634 mln for 2018. In SNEPCo, the tender process has progressed for the last 3+ years, with 4 bidders still competing for the best commercial pricing. NAPIMS and NCDMB approval to progress the rig tender in support of the Bonga Main infield drilling opportunities was received in May 2016. Whilst there may be an opportunity to seek to award a contract to a bidder who already has Shell contract thereby potentially offsetting the RDS rig idle exposure, this cannot be enforced and the outcome of the rig tendering will need to be awaited (in-line with PSC processes and Partners/ COV's requirements). The tender instructions have been amended such to allow non-evaluated rigs (i.e. Shell incumbent rigs) to be offered for exchange. The commercial framework under which such exchange could /would occur is not yet defined as it may also depend on the outcome of the global RIMO negotiations and could only be applicable for one of the four drilling contractors that have passed the technical evaluation. Exchange for a Shell incumbent rig after award, will also require COV's, NAPIMs and NCDMB support.

- Contracting a rig now makes best use of the current low price environment giving low day rates to drill these economically viable wells and add to the pre-2025 production. Priced options will be requested for the optional years in order try to lock in the low day rates for the future and also provide a more accurate day rate cost estimating norm as input to the BSWA project well cost estimate.
- Opportunity will be pursued to drill some of the less viable wells by negotiating for low rates/ cost with the contractors in view of the harsh business climate.
- One of the benefits (upside) that can be explored is that the incremental production resulting from this incremental investment can be allocated towards repayment of PSC dispute amounts dating from 2008 (SS $2bln Shell Share). This package is currently being negotiated.

Alternatives

The other option would be to rely on farm-in which was also not considered on the basis of likely higher prices, loss of synergy with BSW/A and doubt on availability of an acceptable rig at the time SNEPCo needs it. The exposure that comes from 365 days rig contract need to be assessed against this alternative and the opportunity (option) the rig tender/ commitment offers for maturing BSW/A project in 2018.

Section 4: Negotiation strategy

The intent is to make use of the current rig tender of BSW/A which was discontinued when the decision was made to delay FID on BSW/A in Q1-2016. The BSW/A contracting process of the rig was at the stage where the commercial bids (4 drilling contractors passed technical) were ready to be opened. The strategy is that the contractors will be requested to reconfirm their bids but for a contract term of 1 year firm (plus 1 year option and 4 years option) compared to 4+1+1 in the current rig tender for BSW/A. The 1+4 option will enable continuing with the same drilling rig and build on the rig performance in the event that more infill wells are required in the second year and also ensure that we are properly set up for success if FID is achieved on BSW/A project. Where possible, certain terms and conditions will be amended in the commercial ITT as to take full advantage of the market. The plan is to award contract to the lowest bidder for 12 months although only 3 of wells have approved GIP, with the other projects being pre-DG/3, hence the need for this PCN to support the tender for 12 months drilling contract.

The contracting process for the various Long Lead Materials is on-going however there is no commitment until we place orders for these materials by Sept/Oct 2016. The other rig support services are also call-off contracts, hence no exposure currently.

Section 5 Corporate structure, and governance

SNEPCo is a 100% Group Company with ownership vested in SPNV (NL). Governance will be provided in line with the UPD Operating Model.

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. CO2, Commercial, Finance and Controllers, Contracting & Procurement, Communication, Environment, Government Relations, Health, HR, HSSE, Social Performance & Sustainable Development, IT, Legal, Risk & Insurance, Safety, Security, Tax, Upstream Economics, Venture Support Integration as well as P&T functional support has been obtained.

Section 7: Project management, monitoring and review

The opportunities (Bonga Phase2b, Bonga NW Phase2 projects) are managed by a Business Opportunity Manager and steered by the Decision Review Board (DRB) comprising all relevant functions with the GM Development Deepwater as Decision Executive. The team responsible for the project management and facilities development scope is under direct line of sight of the P&T organization, with the design and execution of well activities is governed by the Global Well Delivery Process (GWDP). The technical oversight of the project is further hard wired by use of P & T technical authorities (discipline TA1's and TA2's) in the approved Project Control and Assurance Plan (PCAP). The Project Controls and Assurance Plan (PCAP) for this project follows the SNEPCo Discipline Control and Assurance Framework (DCAF), with specific focus on key well deliverables reflecting the maturity of the project where all significant project documentation.

Section 8: Budget provision

Budget for 2017 and 2018 will be requested as part of OP16 and subsequent project FIDs. The activities will also be included in the annual Work plan & Budget as submitted to the Partners and NNPC/ NAPIMS. For 2016, any commitments would need to be covered as part of the existing approved funding requirements.

Section 9: Group financial reporting impact

There are no unusual accounting issues related to this PCN. Expenditure related to the project will be accounted for in line with Group Policy.

The following table summarises the financial impact of the 8 wells:

US $mln, Shell Share MOD	2017	2018	2019	2020	2021	2022	2023	2024	Total
GES mbbl	0.04	1.05	2.96	3.15	2.71	2.26	1.85	2.09	**16.11**
Price/bbl	62.32	72.82	83.34	90	91.8	93.64	95.51	97.42	
Revenue	3	76	247	283	249	212	176	203	**1,450**
Commitment Phasing:									
Shell Share:	31	208	220	6	5	5	4	4	**483**
Cash-flow:									
Capital Expenditure	31	208	216	0	0	0	0	0	**455**
Operating Expenditure		0	4	6	5	5	4	4	**29**
Cash-flow from Operation	13	130	222	151	135	114	90	54	**911**
Cash Surplus/Deficit	-18	-78	6	151	135	114	90	54	**456**
Profit & Loss:									
NIBIAT Gain/Loss	1	26	73	90	80	68	57	68	**463**
Balance Sheet:									
Average Capital Employed	31	231	396	307	221	148	88	31	

Small rounding effect on NIBIAT and CSD due to treatment of Abex

Section 10: Disclosure

Disclosures, if required, will be done in line with existing Group and SNEPCo policies and guidelines.

Section 11: Financing

The Shell share of the full costs of this investment will be financed by SNEPCo's own cash flow. No specific funding arrangements with Group Treasury likely to be required.

Section 12: Taxation

No unusual tax features.

Section 13: Key Parameters

Market forces should drive the lowest rig rate. Final award will be subject to GIP approval unless it covers the 3 already approved remaining BM Phase 3 wells and CoV approvals.

Commitment Drilling Rig:	US$ 128 Mln (US$ 70 Mln SS)
Long Lead Items:	US$ 95 Mln (US$ 52 Mln SS)
Economics:	US$ 324 (NPV7) VIR: 0.84

Section 14: Signatures

This Proposal is submitted for approval and approval shall be conditional to formal support from the OML118 Co-Venturers.

Supported by:

Azza Fawzi

VP Finance Deep Water

Date ……. /2016

For Shareholder approval:

Wael Sawan

EVP Deep Water

Date ………/2016

Sponsor:

Markus Droll

VP Nigeria & Gabon

Date ………/2016

Thierry De Meyer - GM Wells SNEPCo

Segun Owolabi – BOM Bonga Main, North and OML 135

Ralph Wetzels – Finance Manager, SNEPCo

Bayo Ojulari – GM Deepwater/MD SNEPCo

Appendix

Appendix 1: Economic Assumptions and Results Sensitivities

The Shell share economic evaluation is premised on the following assumptions:

Fiscal Parameters

- Applicable fiscal regime is PPTA/PSC1993 (as interpreted by NNPC, with IOC interpretation as a sensitivity)
- Petroleum Profit tax of 50%, Education Tax of 2% assessable profit and Niger Delta Development commission (NDDC) levy of 3% of total expenditure
- Investment Tax Credit rate 50%, ITC portion of Capex excl. from depreciation (NNPC view)
- Royalty rate of 1.75% is applied (as NNPC's interpreted Bonga Main field average)
- Profit oil rate declines (according to schedule in PSC) with increasing production from the block
- Depreciation for cost recovery is 5 x 20% - i.e. over five years
- Tax depreciation is 4 x 20%, 19% of (QCE less ITC), also over 5 years, 1% book value retention
- 90% of Well Capex is expensed and 10% is depreciated for tax calculation
- The July version of the Petroleum Industry Bill (PIB) that was submitted to the National Assembly in July 2012 has been tested as a sensitivity

Economics Parameters and Assumptions

- Inflation rate of 2% applied in RT vs MOD money type conversions
- Discount rate of 7% Real
- Evaluation reference data is July 1st, 2016
- Cost input as MOD profiles
- 2016 PSV applied (Brent maker prices of LV40, SV60, RV890, HV100) – all $/bbl, RT16, including Short Term Oil Prices between 2016 and 2019 of $42.5, $60, $70 and $80
- Economics are premised on the 2016 Project Evaluation and Screening Criteria, as per Group guidelines.
- Rig-rates of US$ 461k/day used for the existing rigs (S-702 and DWD) with US$ 600k used as estimated rates for the replacement rigs (based on advice from Group Wells). Well cost estimates also include VAT (5% over gross) and Nigerian Content Levy and Duty. The rig replacement contract is currently undergoing tendering processes with NAPIMS
- Estimates for subsea costs are based upon similar recent contracts from GE, existing norms, and other in-country project information. The GE contract has been fully supported by NAPIMS and final approval is being flowed up with the NNPC Board. This does not pose cost recovery risk.
- The costs for materials (trees/ wellheads) are based on latest pricing obtained from OEM's, with the estimate including the full costs for hook-up and direct staff supporting the activities
- Production, and includes SNEPCo overhead costs. Project economics do not include loan interest.
- No value is currently assigned to associated gas pending finalisation of gas terms with NNPC. Gas is evacuated to Nigerian Liquefied Natural Gas (NLNG);
- Project evaluated incremental to existing Bonga Production (no further activity cases).

Summary economic results

PV Reference Date: 1/7/2016	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/bbl or $/mln btu)		Payout-Time (RT)	Maximum Exposure (RT)
Cash flow forward from: 1/1/2016	0%	7%	7%	%	0%	7%		
Base Case								
LV ($40/bbl, RT16)	204	120	0.31	34.1%	18.1	21.1		
SV ($60/bbl, RT16)	353	226	0.58	55.3%	18.1	21.1		
RV ($80/bbl, RT16)	492	324	0.84	72.2%	18.1	21.1	2020	-141
HV ($100/bbl, RT16)	608	404	1.04	81.1%	18.1	21.1		
BEP (RT $/bbl or $/mln btu)					17.5	19.6		
Sensitivities (using RV)								
High Capex* (+30%)		296	0.58					
Low Reserves* (-50%)		108	0.28					
High Reserves* (+30%)		454	1.17					
Life-Cycle Economics		324	0.84	72.2%				
VTE			2.22					

Table 2: Bonga Main Rig Tender Economics summary and Sensitivities (Disputed case) – 8 wells

PV Reference Date: 1/7/2016	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/bbl or $/mln btu)		Payout-Time (RT)	Maximum Exposure (RT)
Cash flow forward from: 1/1/2016	0%	7%	7%	%	0%	7%		
Base Case								
LV ($40/bbl, RT16)	196	111	0.24	29.4%	22.4	25.4		
SV ($60/bbl, RT16)	363	230	0.49	50.9%	22.4	25.4		
RV ($80/bbl, RT16)	520	341	0.73	68.7%	22.4	25.4	2020	-145
HV ($100/bbl, RT16)	654	478	1.02	78.6%	22.4	25.4		
BEP (RT $/bbl or $/mln btu)					19.2	22.8		
Sensitivities (using RV)								
High Capex* (+30%)		307	0.50					
Low Reserves* (-50%)		96	0.20					
High Reserves* (+30%)		488	1.04					
Life-Cycle Economics		341	0.73	68.7%				
VTE			2.27					

Table 3: Bonga Main Rig Tender Economics summary and Sensitivities (Disputed case) – 10 wells

The project delivers good economic value with a Shell Share NPV7 of 324$mln, RT16 and VIR7 of 0.84 RT16 at PSV-RV ($80/bbl, RT16) for the Base Case scenario under NNPC's view of the PPT/93PSC fiscal regime. Project is also robust with a RTEP of 72.2%, Shell share maximum exposure of -141$mln, RT16 and a pay-out time of 2020 based on Real-Term cash flow.

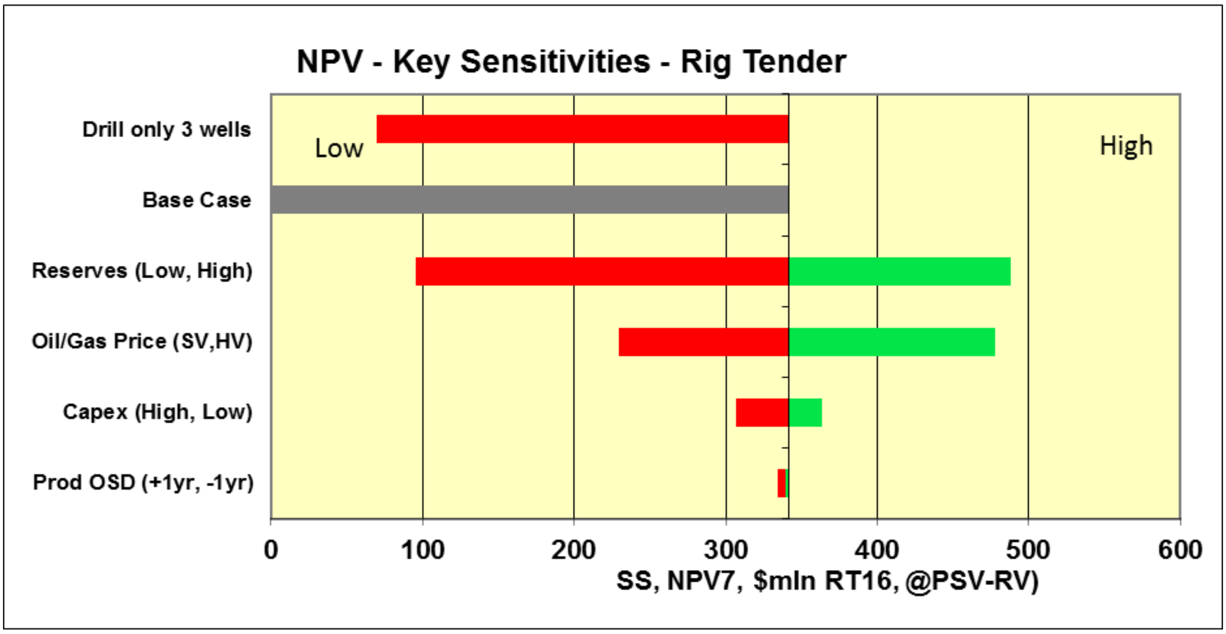
Sensitivity analysis shows Oil Price as the key Non-Technical Risk. At a low Value Oil price of $40/bbl, the project NPV7 drops to 120$mln while the VIR7 also reduces to 0.31. A chart of NPV7 against oil price shows the range of potential values across a wide range of prices.

Parameter	Unit	Low	Mid	High	Comments
Oil Price	$/bbl	PSV-SV 60	PSV-SV 80	PSV-SV 100	
Capex (MOD)	US$mln	671	839	1090	Based on a range of -20/+30%
Opex (MOD)	US$mln		221		
Production Volume (oil)	MMbbl	28	55	72	Based on a range of -50/+30%
Start-up Date					
Prouction in first 12 months (oil	MMbbl		0.5		

Table 4: Key project parameters (100% project)

PV Reference Date: 1/7/2016	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/bbl or $/mln btu)		Payout-Time (RT)	Maximum Exposure (RT)
Cash flow forward from: 1/1/2016	0%	7%	7%	%	0%	7%		
Base Case								
LV ($40/bbl, RT16)	19	0.5	0.002	7.2%	36.5	42.0		
SV ($60/bbl, RT16)	69	36	0.14	23.7%	36.5	42.0		
RV ($80/bbl, RT16)	116	70	0.27	37.2%	36.5	42.0	2020	-64
HV ($100/bbl, RT16)	156	112	0.43	46.2%	36.5	42.0		
BEP (RT $/bbl or $/mln btu)					19.2	22.8		
Sensitivities (using RV)								
High Capex* (+30%)		49	0.14					
Low Reserves* (-50%)		-5	-0.02					
High Reserves* (+30%)		115	0.44					
Life-Cycle Economics		70	0.27	37.2%				
VTE			1.06					

Table 5: Bonga Main Rig Tender Economics summary and Sensitivities – Risk of 3 wells case



Project sensitivities show that the key variables that affect profitability are Reserves and Oil Price. The project does not suffer an NPV7 negative position even at a lower oil price of $40/BBL (PSV-LV). Probabilistic analysis has not been carried out as the input parameters ranges are not based on P90 and P10.

Appendix 2: Approved cost

2.1. Total Well Cost

Order of Completion	Well name	Total Well Cost ($'m)*
1	BMPh3-690 w5	47.14
2	BMPh2b-690 p6	67.42
3	BNW-690 p4	52.40
4	BMPh2b-690 w6	53.62
5	BNW-690 w2	53.62
6	BMPh2b-710p5	56.50
7	BMph2 - 710 w1 (B-39RD)	45.92
8	ICTB-1	84.29
9	BMPh3-670b4 p3	38.51
10	BMPh3-670b4 w2	65.32
Total		**564.74**

*Excludes SURF cost

2.2: Headline Size Computation

HEADLINE SIZE COMPUTATION			
Activity	**Rate ($)**	**Units**	**Amount (SS of 55%)**
Rig	$350,000	365 days	$70,262,500
Wells Long Lead Materials	$9,000,000	5 wells	$24,750,000
Subsea Acessories: TH, THS, EH reels etc			$18,850,000
Jumper Spool	$2,600,000	6 units	$8,580,000
Total			**122,442,500.00**

2.3: OP15 vs LE Overview

DETAILS	LATEST ESTIMATES ($'mln)	OP15 ESTIMATES ($'mln)	DELTA ($'mln)	VARIANCE ANALYSIS
Rig Costs	160	228	68	Rig rate of $500k/d in OP15 as against $350k/d based on current Shell outlook
LLM	90	80	-10	Additional spend due to the Post-Macondo requirement on LLM
MOB/DEMOB	35	35	0	No Change
TOTAL	**285**	**343**	**58**	

- Analysis based on 456 string days

Appendix 3: Rig Sequence (based on Jan 2018 rig-pickup)