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Optimality test of marginal field development financing arrangements in Nigeria.

EKEH, C. and ASEKOMEH, A.

2015

Optimality Test of Marginal Oil Field Development Financing Arrangements In Nigeria

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Background (1)

Marginal Fields – What are they?

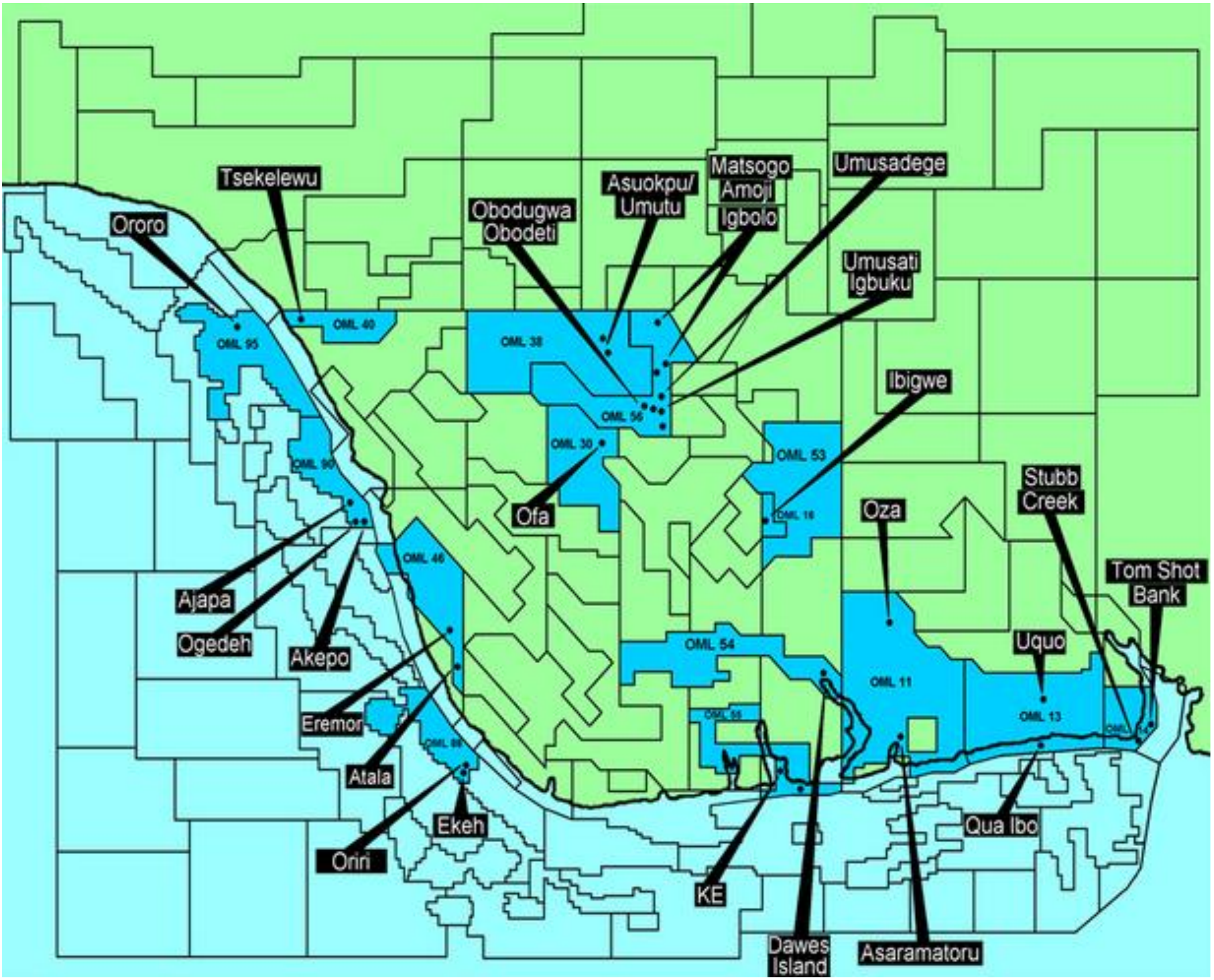
- Generally, defined as oil fields that may not produce enough hydrocarbon cash flows to justify development at a given time.

- Defined or characterised by:
  - ✓ Depleted pressure
  - ✓ Stranded (location)
  - ✓ Reserve size (usually small)
  - ✓ Risk profile - Inability to attract finance

Background (2)

- Changes in technical, political and/or economic conditions (especially price and price stability) may change viability of such fields.
- Marginal fields abandoned by international oil companies (IOCs) are now being awarded to indigenous oil companies or marginal field operators (MFOs) in Nigeria.
- Financing the development of such fields remains a major challenge for MFOs.

Background (3)



Locations of some marginal fields in the Niger Delta Region of Nigeria

Background (4)

Marginal Field Financing Arrangements

1. MFO finances operations using its equity or debt
   - ✓Use is constrained by high interest rates and limited access to the Nigerian Stock Exchange (NSE).

2. MFO brings in a foreign-listed partner who ‘carries’ some or all of the development costs and partakes in profit sharing after full recovery of investments.

Background (5)

- Given that marginal field licensing rounds have continued and marginal fields remain a vital part of the energy agenda, we seek to test the optimality of financing arrangements for MFOs.
- Application employs available field data, economic assumptions and field production simulation.

Literature & context (1)

- Project feasibility assessment involves examining a project's prospects using economic, financial, technical and fiscal variables (Gatti, 2013).
- Kasriel & Wood (2013) advocate the use of Net Present Value (NPV) technique (with a discount rate of 10% in the industry); Discounted Profit per Barrel (DPB) and Profitability Index (PI) are also useful valuation criteria.
- Internal rate of return (IRR) and modified IRR (MIRR) are also used.

Literature & context (2)

- Seba (1987) prefers PI in the absence of the real option of delaying a project.
- Randall (1989) and Schaaf (2003) argue that quality reserves, rather than capital, is the main constraint for oil companies so metrics measured per unit of reserves are better measures of viability.
- Variants of these techniques and other relevant considerations e.g., strategic issues, risk appetite and adjustment and tail end producing fields, are also common (Pedersen et al. 2006; Pablo, 2011).

Literature & context (3)

- Ayodele & Frimpong (2003); Kue & Orodu (2006); Akinpelu & Omole (2009) and Adamu et al. (2013) have tested the viability of marginal fields in Nigeria, but not the implications of different financing arrangements.
- Adetoba (2012) reckons that proposed new petroleum fiscal regime in Nigeria favours marginal field economics.
- We test different financing scenarios for optimal financing arrangement.

Methodology (1)

- Using DCF method:
  - ✓We model two oil fields (one onshore and one offshore [circa 20 mmbbls and 100 mmbbls recoverable reserves respectively) under the Nigerian Marginal Fields Fiscal Regime.
  - ✓We test four (4) different development scenarios for each, depending on the level of participation and financial/cost contribution by a MFO and a foreign-listed financial partner (FP)

Methodology (2)

	Sole Risk (MFO)	Sole Risk (FP)	JV (no carry)	JV (full carry)
Participation	MFO (100%)	MFO (0%)	MFO (51%)	MFO (51%)
	FP (0%)	FP (100%)	FP (49%)	FP (49%)
Cost Contribution	MFO (100%)	MFO (0%)	MFO (51%)	MFO (0%)
	FP (0%)	FP (100%)	FP (49%)	FP (100%)

JV – Joint Venture
MFO – Marginal Field Operator
FP – Financial Partner

Hypothesis:

For a MFO utilising a domestic equity and debt funding structure, the JV (full carry) arrangement is NOT less economically beneficial than the Sole Risk and JV (no carry) arrangements for onshore and offshore marginal field developments.

Methodology (3)

- Model specification

Net cash flows

$$Gross\ Revenue_{(t)} = Annual\ Production_{(t)} \times Average\ Real\ Oil\ Price\ (i = 2\%) \cdots\cdots [1]$$

$$Royalty_{(t)} = Royalty\ Rate\ \times Gross\ Revenue_{(t)} \cdots\cdots [2]$$

$$Overriding\ Royalty_{(t)} = Overriding\ Royalty\ Rate\ \times Gross\ Revenue_{(t)} \cdots\cdots [3]$$

$$Net\ Revenue_{(t)} = Gross\ Revenue_{(t)} - [2] - [3] \cdots\cdots [4]$$

$$OPEX_{(t)} = Annul\ Production_{(t)} \times OPEX\ per\ barrel (i = 2\%) \cdots\cdots [5]$$

$$Profit\ Before\ Tax_{(t)} = [4] - [5] \cdots\cdots [6]$$

$$Investment\ Capital\ Allowance_{(t)} = \sum_{1}^{N} Capital\ Allowance_{(n)(t)} \cdots\cdots [7]$$

$$Taxable\ Income_{(t)} = [6] - [7] \cdots\cdots [8]$$

$$Petroleum\ Profit\ Tax_{(t)} = Tax\ Rate\ \times [8] \cdots\cdots [9]$$

$$Net\ Cash\ Flow_{(t)} = [6] - [9] - CAPEX_{(t)} \cdots\cdots [10]$$

Methodology (4)

- Model specification (cont'd)

Sole risk (MFO) and sole risk (FP) cash flows

$$Discount\ Factor_{(t)} = \frac{1}{(1+WACC)^t} \cdots\cdots\cdots \quad [11]$$

$$Present\ Value_{(t)} = Net\ Cash\ Flow_{(t)}[\text{for MFO or FP}] \times [11] \cdots\cdots\cdots \quad [12]$$

$$Cumulative\ Discounted\ Cash\ Flow_{(t)} = [12] + CDCF_{(t-1)} \cdots\cdots\cdots \quad [13]$$

Joint Venture (No Carry) cash flows

$$Party\ Net\ Cash\ Flow_{(t)} = Party\ Participating\ Interest \times [10] \cdots\cdots\cdots \quad [14]$$

$$Party\ Discount\ Factor_{(t)} = \frac{1}{(1+Party\ WACC)^t} \cdots\cdots\cdots \quad [15]$$

$$Party\ Present\ Value_{(t)} = [14] \times [15] \cdots\cdots\cdots \quad [16]$$

$$CDCF_{(t)} = Party\ Present\ Value_{(t)} + CDCF_{(t-1)} \cdots\cdots\cdots \quad [17]$$

Methodology (5)

- Model specification (cont'd)

Joint Venture (Full Carry) cash flows

Let Cost Recovery Economic Benefit be CREB; this is the opportunity cost of capital for the MFO for forgoing opportunity to source capital domestically

Let Incremental Economic Benefit be IEB

$$MFO\ CREB_{(t)} = MFO\ Participating\ Interest \times Cost\ Recovery_{(t)} \cdots\cdots\cdots \quad [18]$$

$$MFO\ IEB_{(t)} = MFO\ Net\ Cash\ Flow_{(t)} - MFO\ CREB_{(t)} \cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots \quad [19]$$

$$FP\ IEB_{(t)} = FP\ Net\ Cash\ Flow_{(t)} + MFO\ CREB_{(t)} \cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots \quad [20]$$

Each party's discount factor, present value and cumulative discounted cash flows are computed as in equations [15] to [17]

Methodology (6)

- Model specification (cont'd)

Economic evaluation criteria

$$NPV = \sum_{1}^{T} Present\ Value_{(t)}$$

$$NPV\ per\ barrel = \frac{NPV}{Recoverable\ Reserve\ Size}$$

$$MIRR = \left(\sqrt[T]{\frac{FV(Positive\ Cash\ Flows, Reinvestment\ Rate)}{-PV(Negative\ Cash\ Flows, Finance\ Rate)}} \right) - 1$$

$$Payback\ Period = COUNT(CDCF < 0) + \frac{-CDCF_{(t-1)}}{Present\ Value_{(t)}}$$

Data & assumptions (1)

- Oil price (average real oil price from 1994 to 2013)

Mean	57.77
Standard Error	7.53
Median	42.87
Mode	#N/A
Standard Deviation	33.68
Sample Variance	1134.67
Kurtosis	-1.21
Skewness	0.58
Range	97.05
Minimum	18.17
Maximum	115.22
Sum	1155.32
Count	20

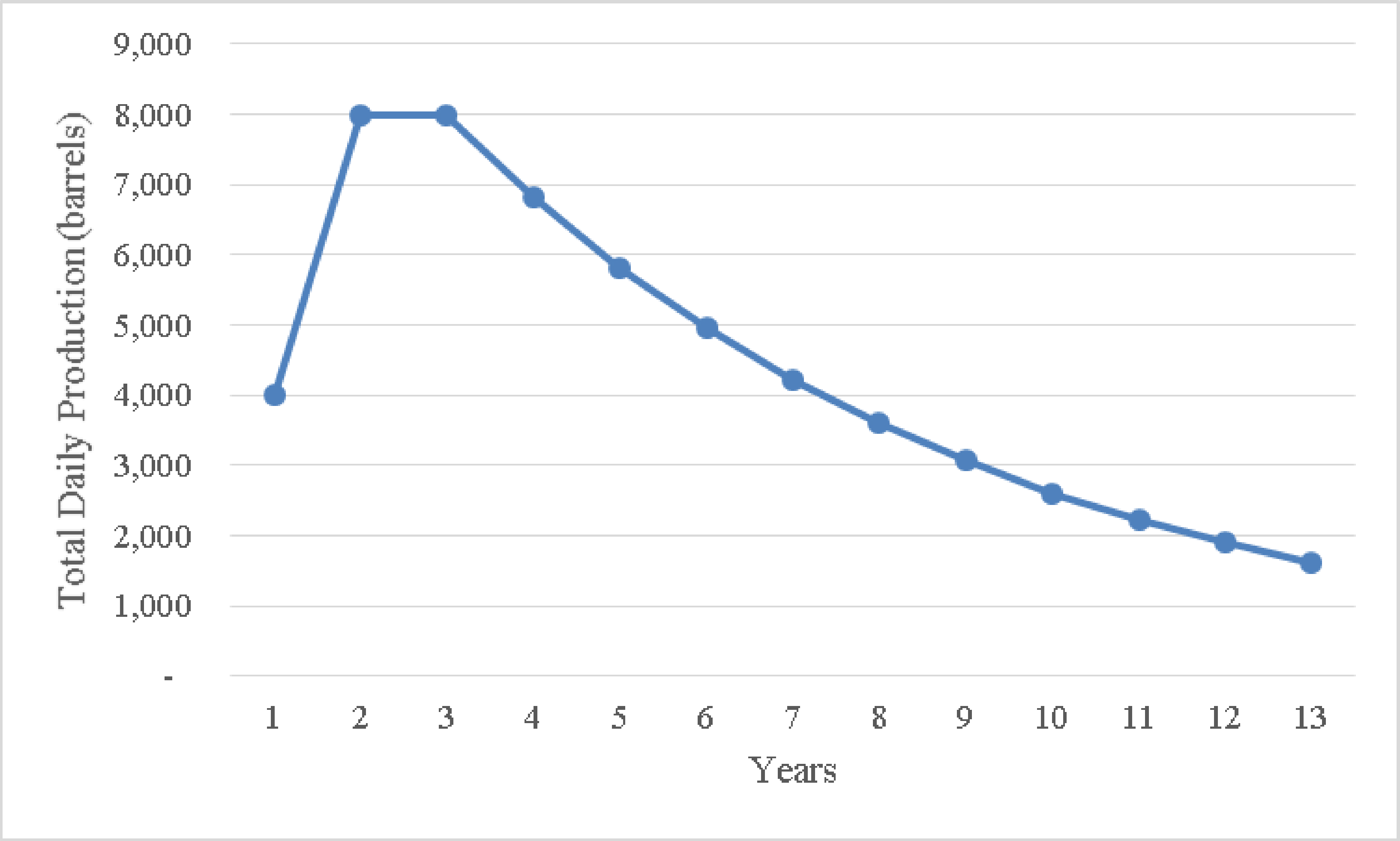
Data & assumptions (2)

- Reserve/production characteristic

	Onshore field	Offshore field
Reserve size (mmbbls)	20,000,000	100,000,000
Production Rate at Plateau (bpd)	2,000	4,000
Production Decline Rate (%)	16%	16%
Years to plateau	1	1
Years at plateau	2	4
No. of wells	4	10
Operating days	365	
Production Uptime	95%	

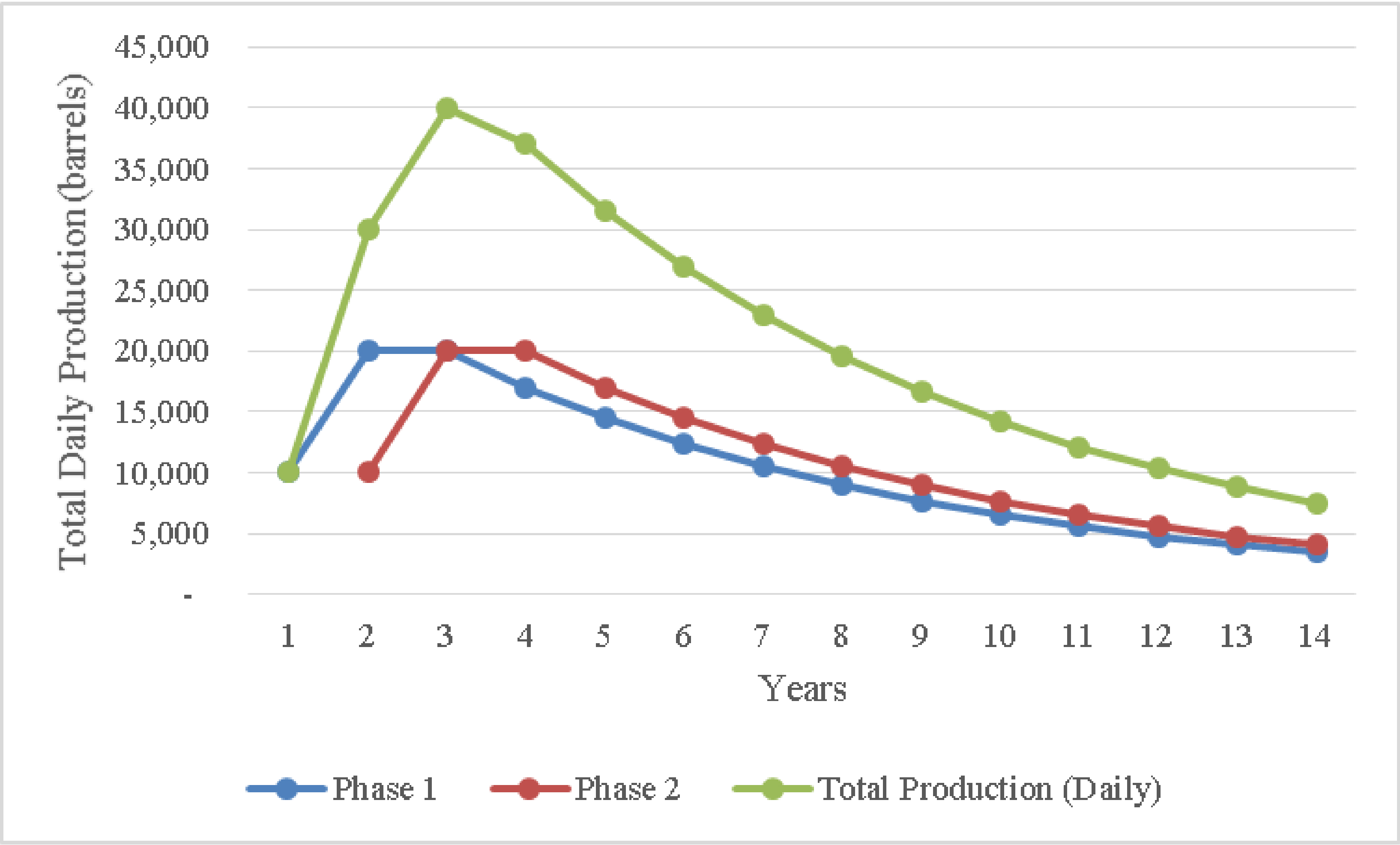
Data & assumptions (3)

- Production profile (onshore model)



Data & assumptions (4)

- Production profile (offshore model)



Data & assumptions (5)

- Royalty rates

Oil production		Royalty rate
Lower bound	Upper bound	
0	5,000	2.50%
5,001	10,000	7.50%
10,001	15,000	12.50%
15,001	25,000	18.50%

- Overriding royalty rates

Oil Production		Overriding Royalty Rate
Lower bound	Upper bound	
0	2,000	2.50%
2,001	5,000	3.00%
5,001	10,000	5.50%
10,001	15,000	7.50%
> 15,000		7.50%

- PPT = 55% for marginal fields

Data & assumptions (6)

CAPEX (Typical of marginal fields in the Niger Delta)

Onshore (4 wells)

(all in US$ million)	
Cost per well	15
Flow station facilities	20
Pipeline	10
Sub-total Capex	90
Miscellaneous	9
Total Capex	99

Offshore (10 wells)

(all in US$ million)	
Cost per well	40
Jackets & flowlines	10
Offshore Infrastructure	15
Pipelines	10
Sub-total Capex	435
Miscellaneous	43.5
Total Capex	478.5

- CAPEX is recoverable as 78% of net cash flows annually, abandonment cost is 30% of CAPEX in last year of production
- ICA is 20% of CAPEX in first 4 years and 19% on 5th anniversary of investment.

Data & assumptions (7)

Production costs (Typical of marginal fields in the Niger Delta)

- Onshore: US$12.80 per barrel
- Offshore: US$4.45

Discount Rate

Average Nigeria cost of debt = 18%

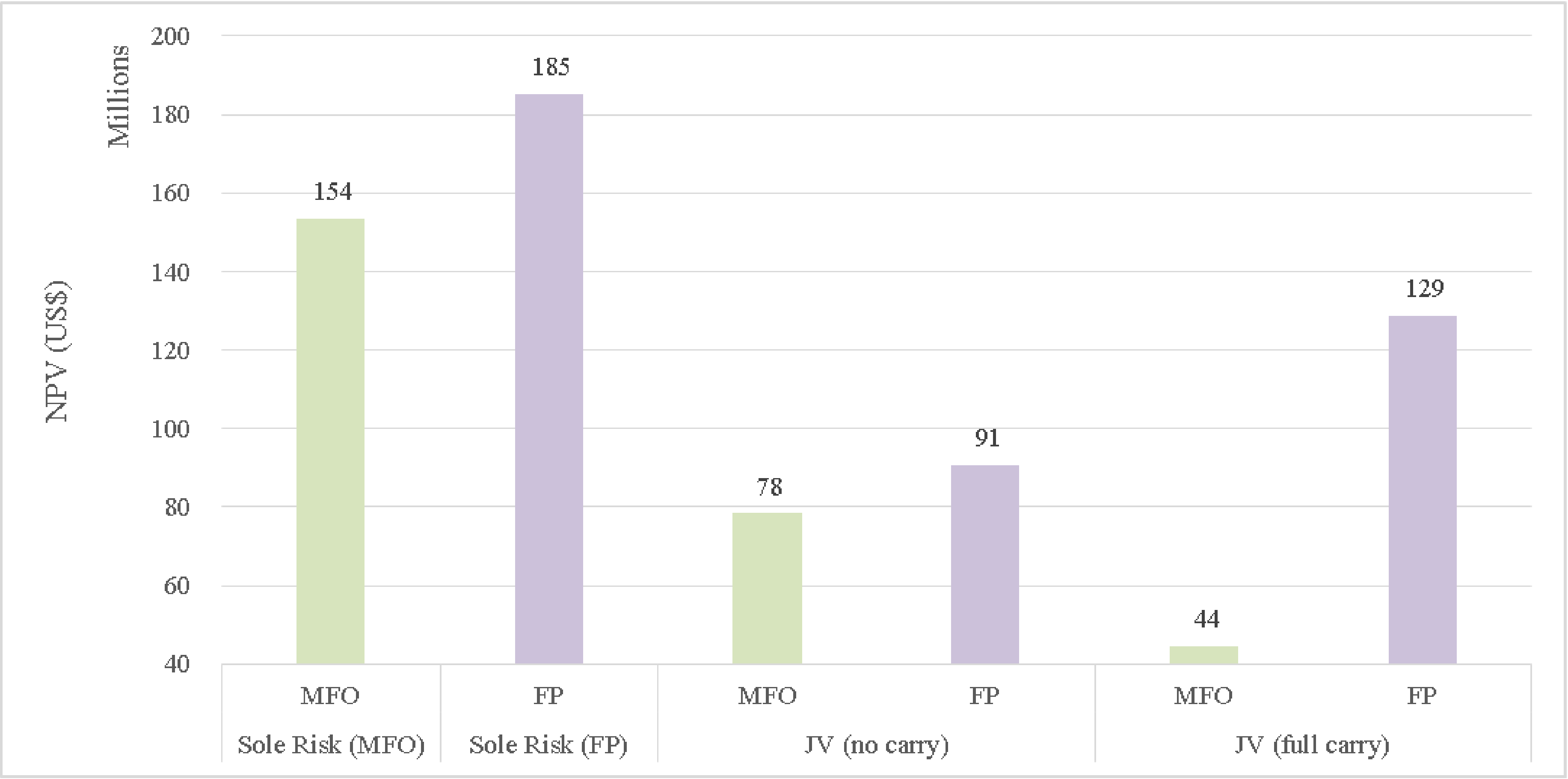
Average return on equity on NSE = 8%

MFO's WACC (with 50% debt) = 13%

Equivalent figures for typical UK FP = 9.4%; 9.1% & 9.25%

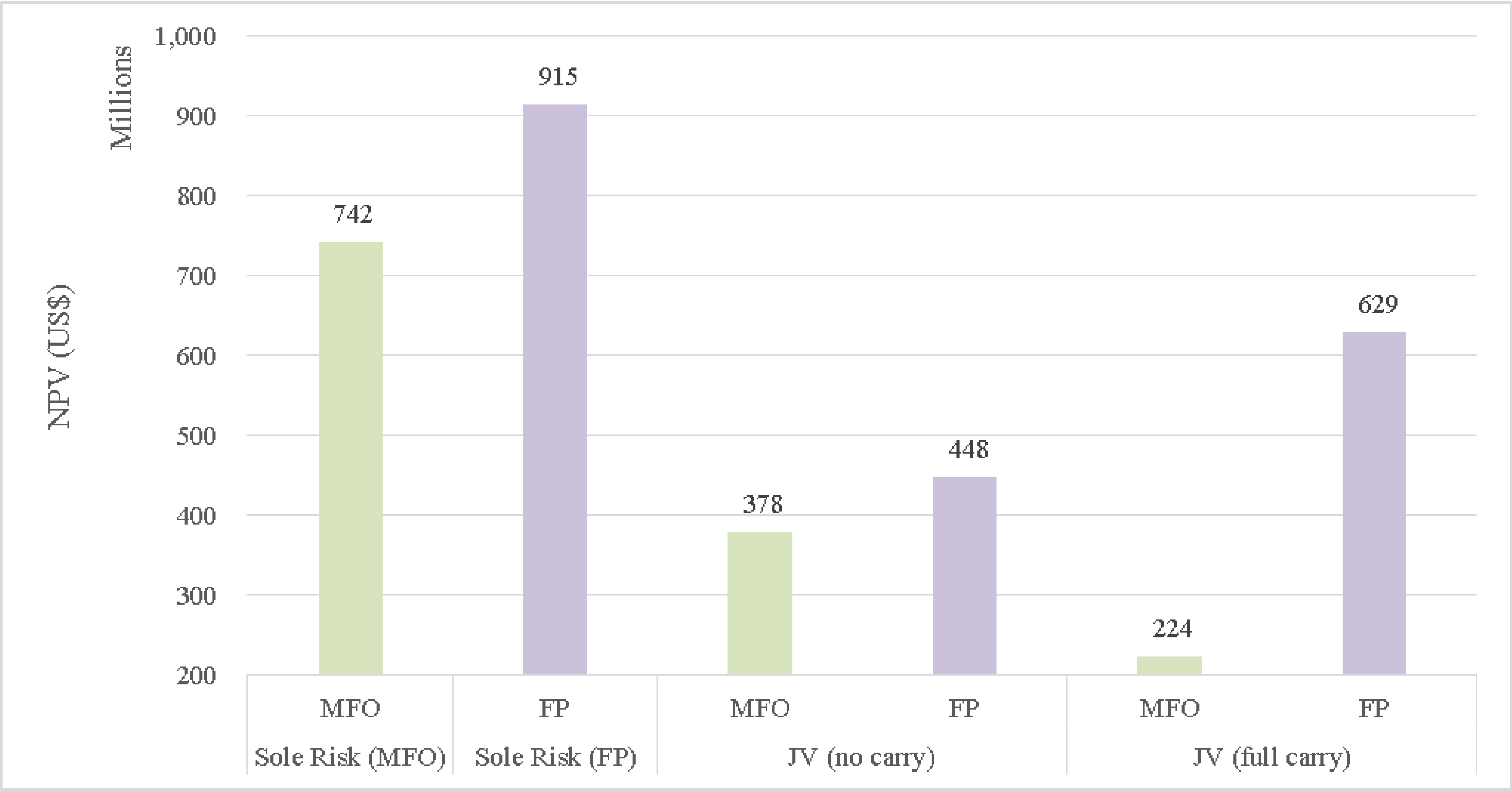
Results (1)

- NPV (Onshore)



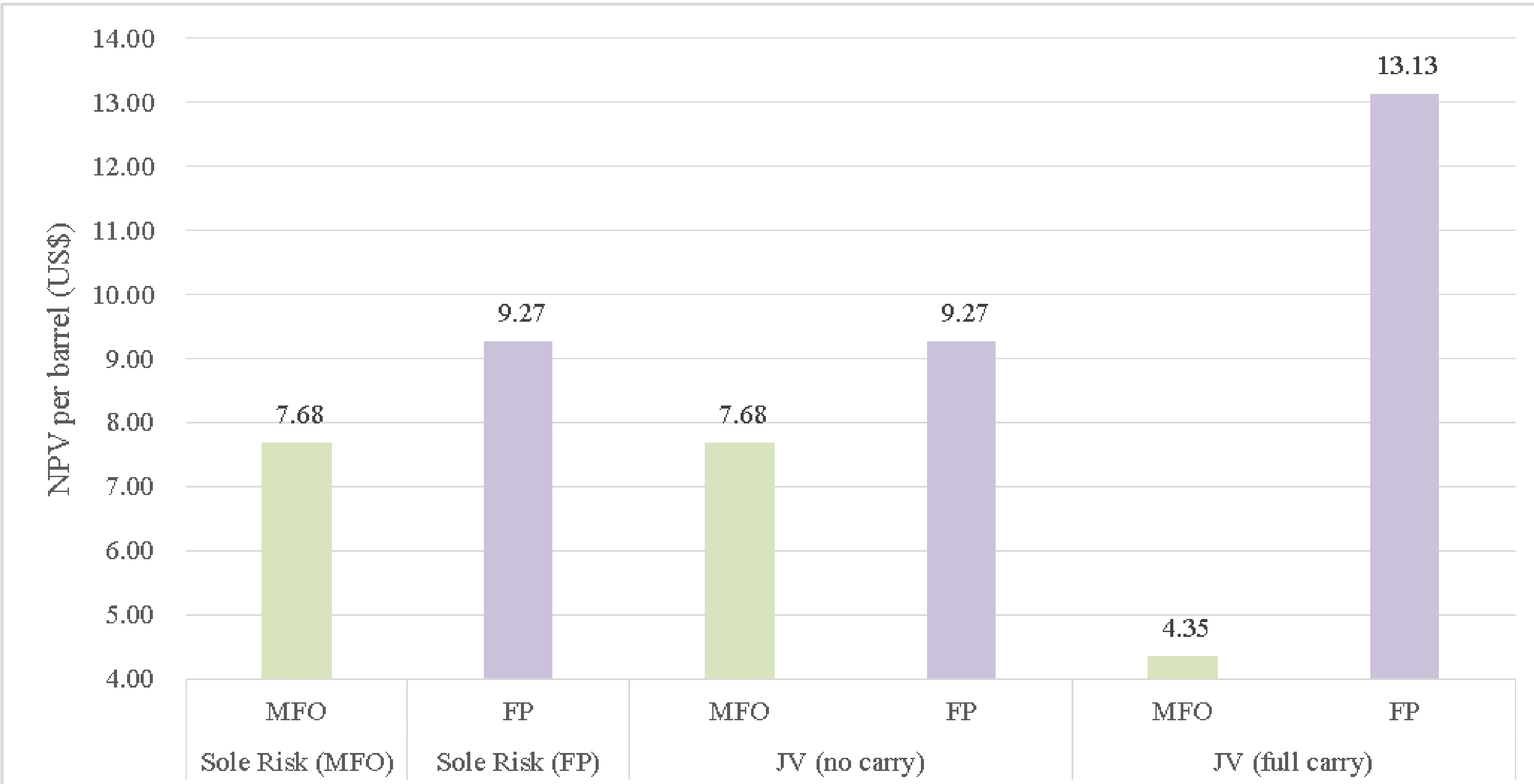
Results (2)

- NPV (Offshore)



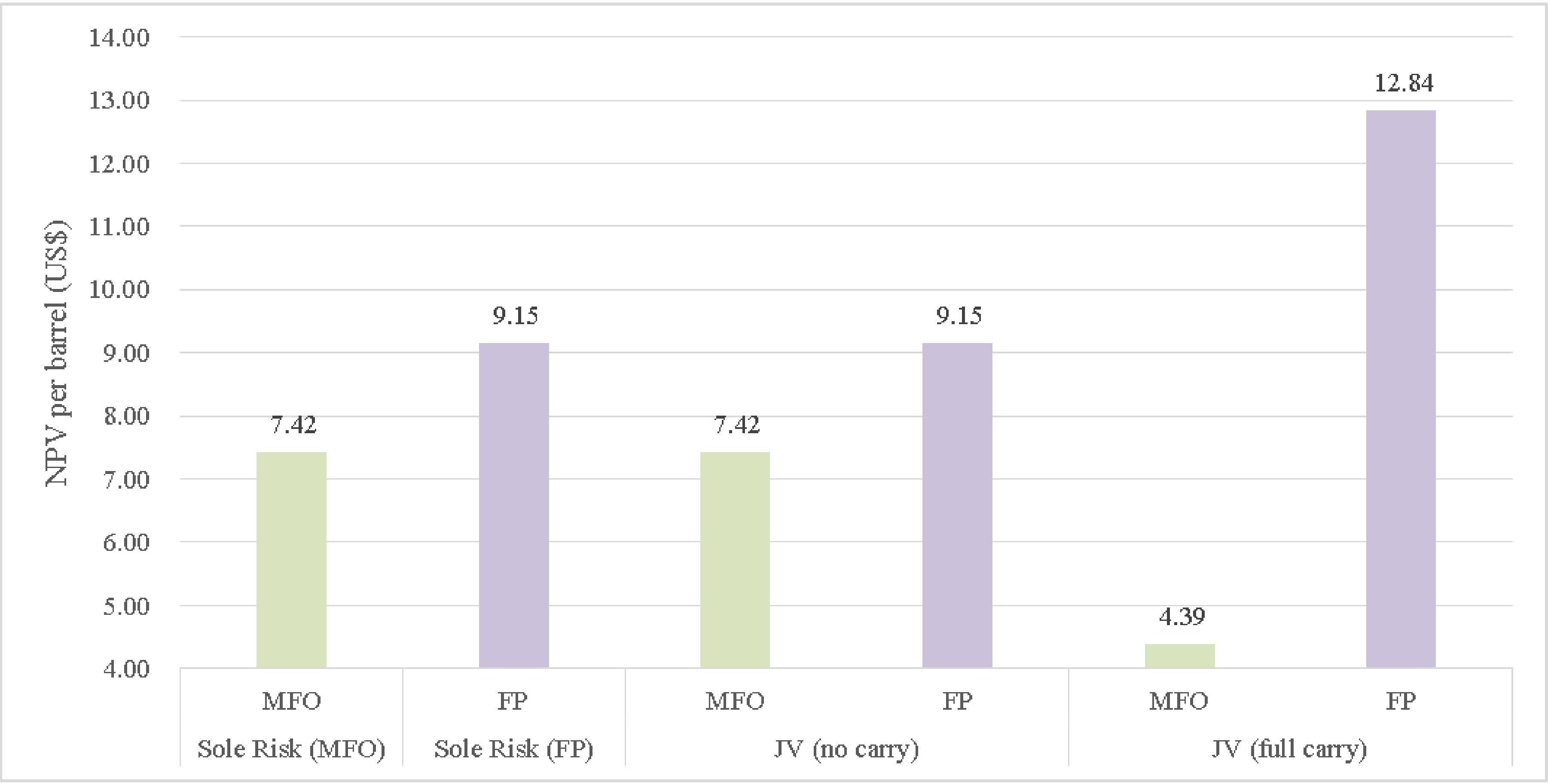
Results (3)

- NPV per barrel (Onshore)



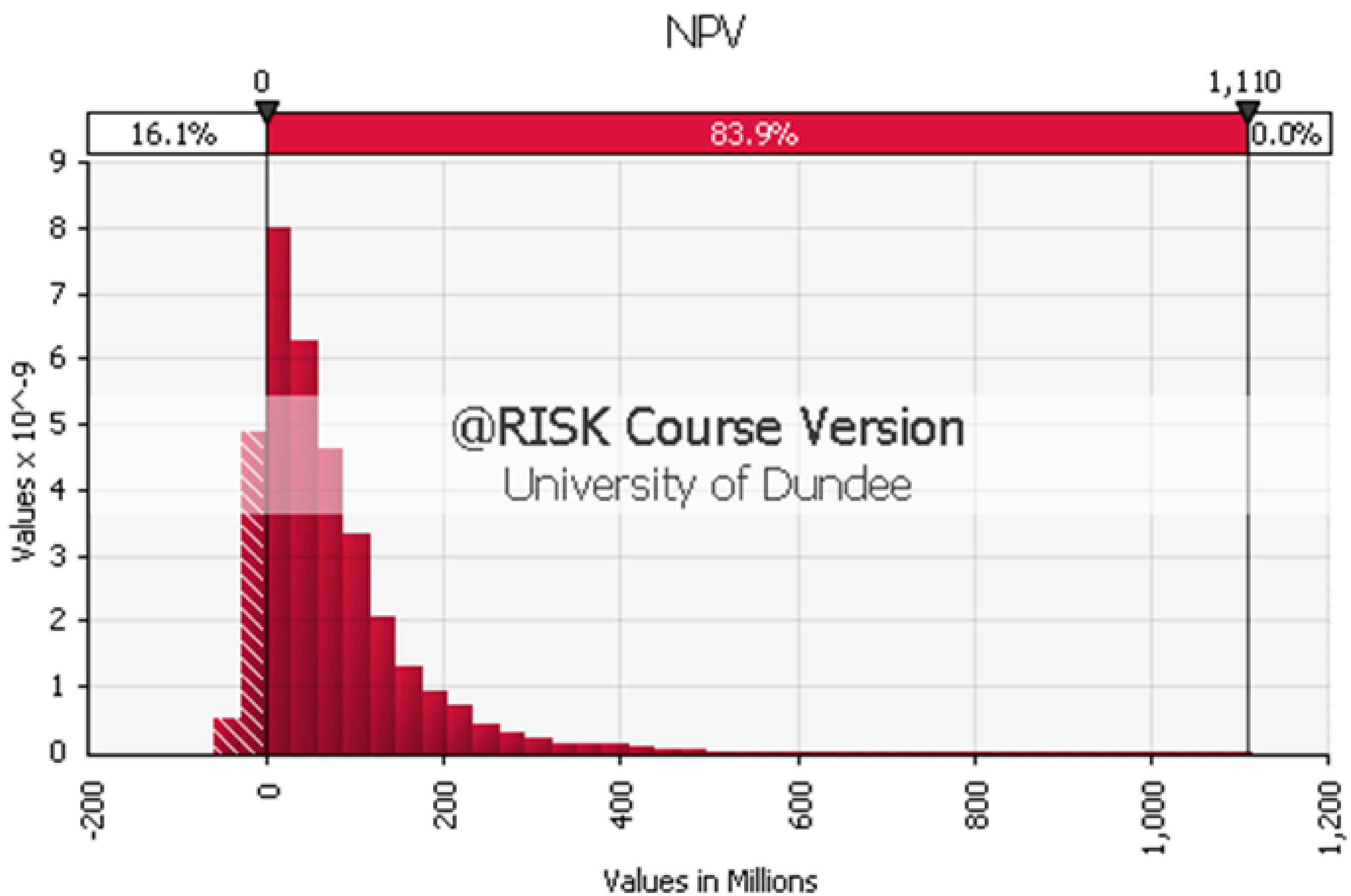
Results (4)

- NPV per barrel (Offshore)



Results (5)

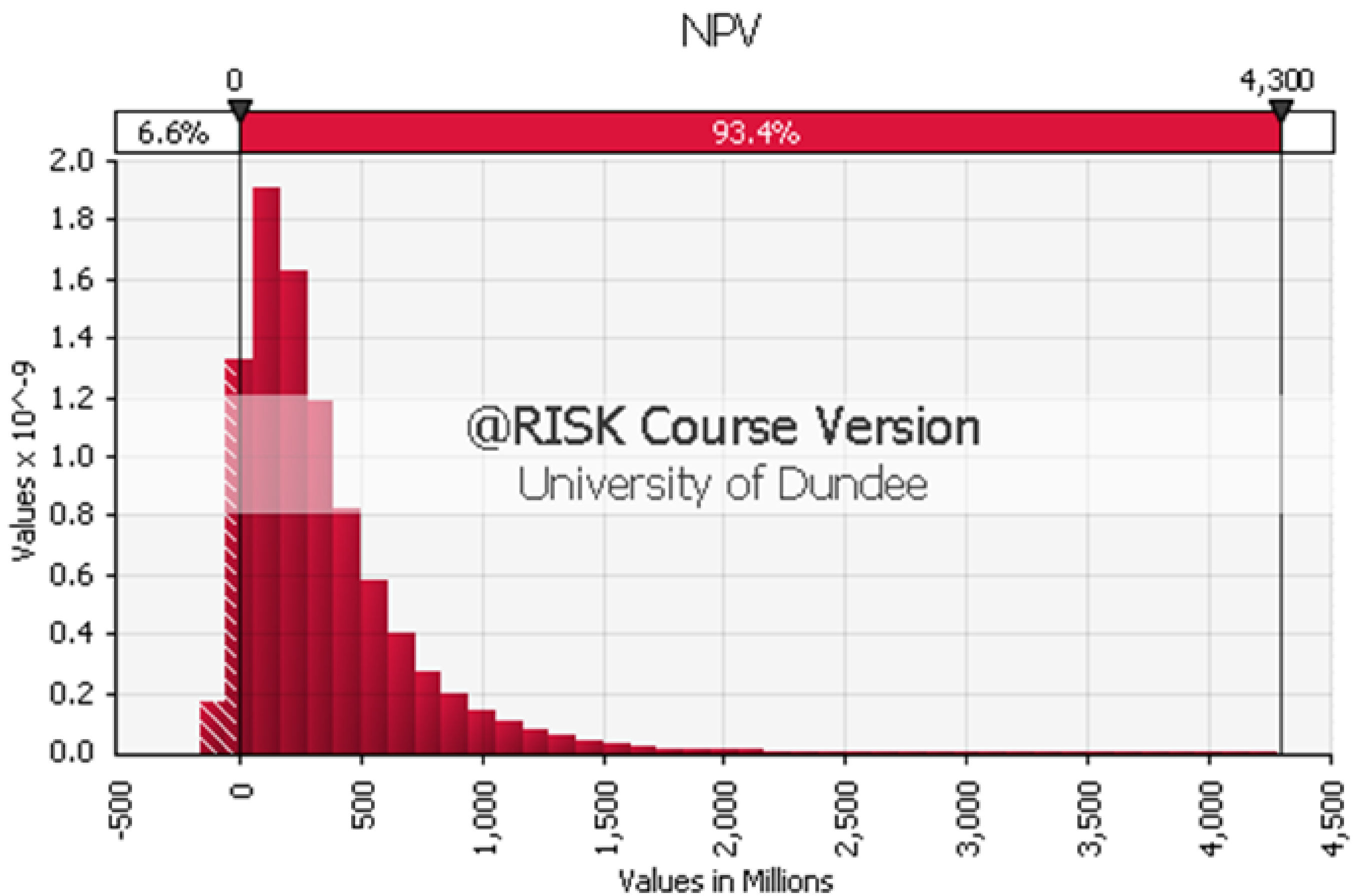
- Sensitivity Analysis (Risk profile – Onshore)



Statistics	NPV
Cell	@Risk!B13
Minimum	-59,184,984.87
Maximum	1.115E+009
Mean	67,091,949.03
Mode	16,941,131.89
Median	44,707,477.84
Std Dev	84,507,561.86
Skewness	2.4006
Kurtosis	13.9691
Values	10000
Errors	0
Filtered	0
Left X	0.00
Left P	16.1%
Right X	1.110E+009
Right P	100.0%
Dif. X	1.110E+009
Dif. P	83.9%

Results (6)

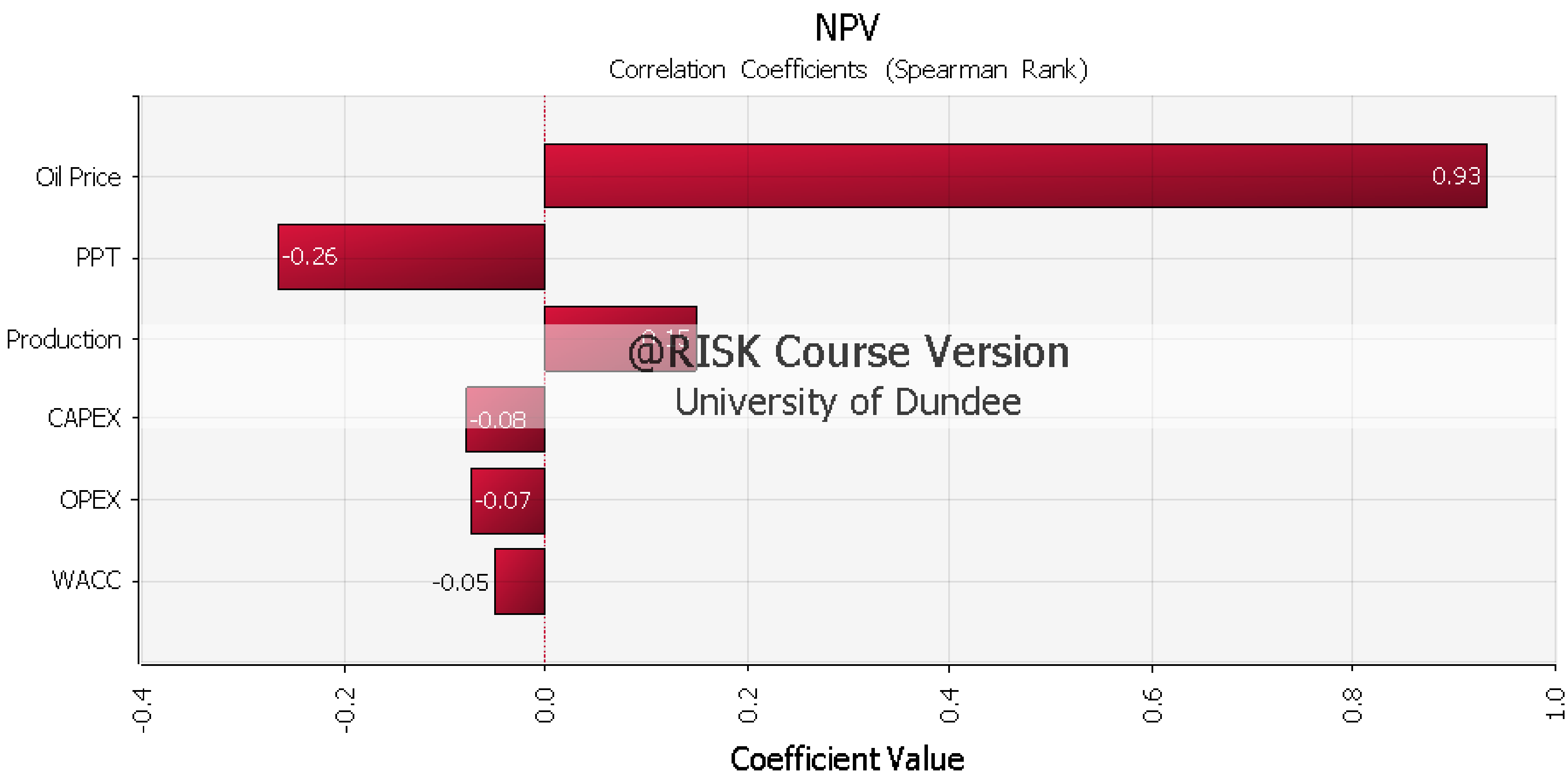
- Sensitivity Analysis (Risk profile – Offshore)



Statistics	NPV
Cell	@Risk!B13
Minimum	-162,754,015.54
Maximum	4.279E+009
Mean	333,785,806.49
Mode	132,761,276.84
Median	243,344,694.68
Std Dev	344,739,867.46
Skewness	2.3678
Kurtosis	13.7794
Values	10000
Errors	0
Filtered	0
Left X	0.00
Left P	6.6%
Right X	4.300E+009
Right P	100.0%
Dif. X	4.300E+009
Dif. P	93.4%

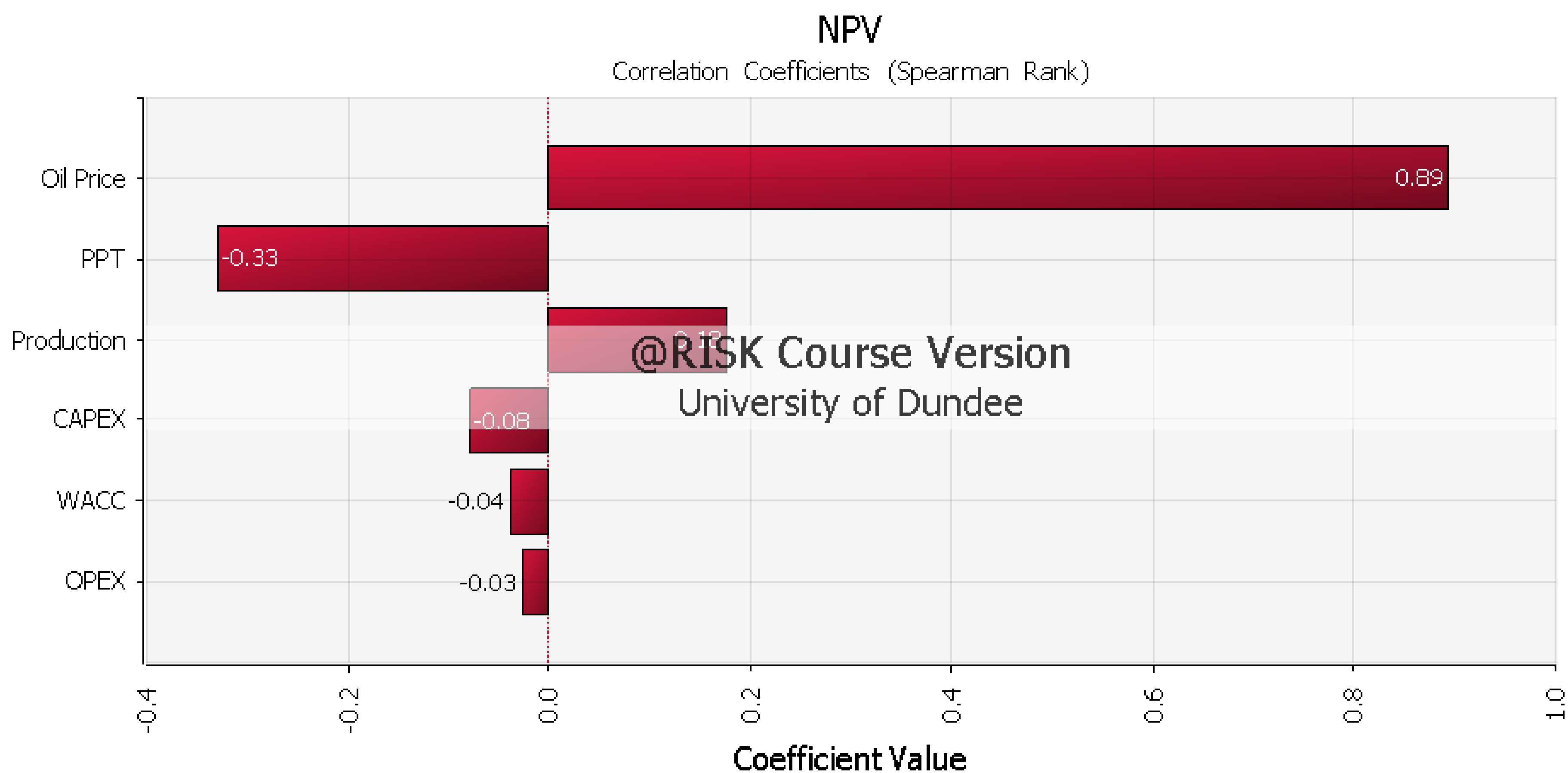
Results (7)

- Sensitivity Analysis (Correlation Coefficients – Onshore)



Results (8)

- Sensitivity Analysis (Correlation Coefficients – Offshore)



Discussion & Conclusions

- MFO is better off bearing sole risk (i.e., sourcing all required funds) or at least bearing its own cost in a JV with a foreign FP
- When MFO is fully carried, it does not enjoy the benefit of any reductions in the cost of finance
- Oil Price and Petroleum Profit Tax (PPT) have the greatest impact on project viability
- Results have implications for MFOs, foreign investors and industry regulators

Q&A/Notes

1. .
2. .
3. .
4. .
5. .

Thank you!