Senate Resources Committee

Cook Inlet Royalty Analysis

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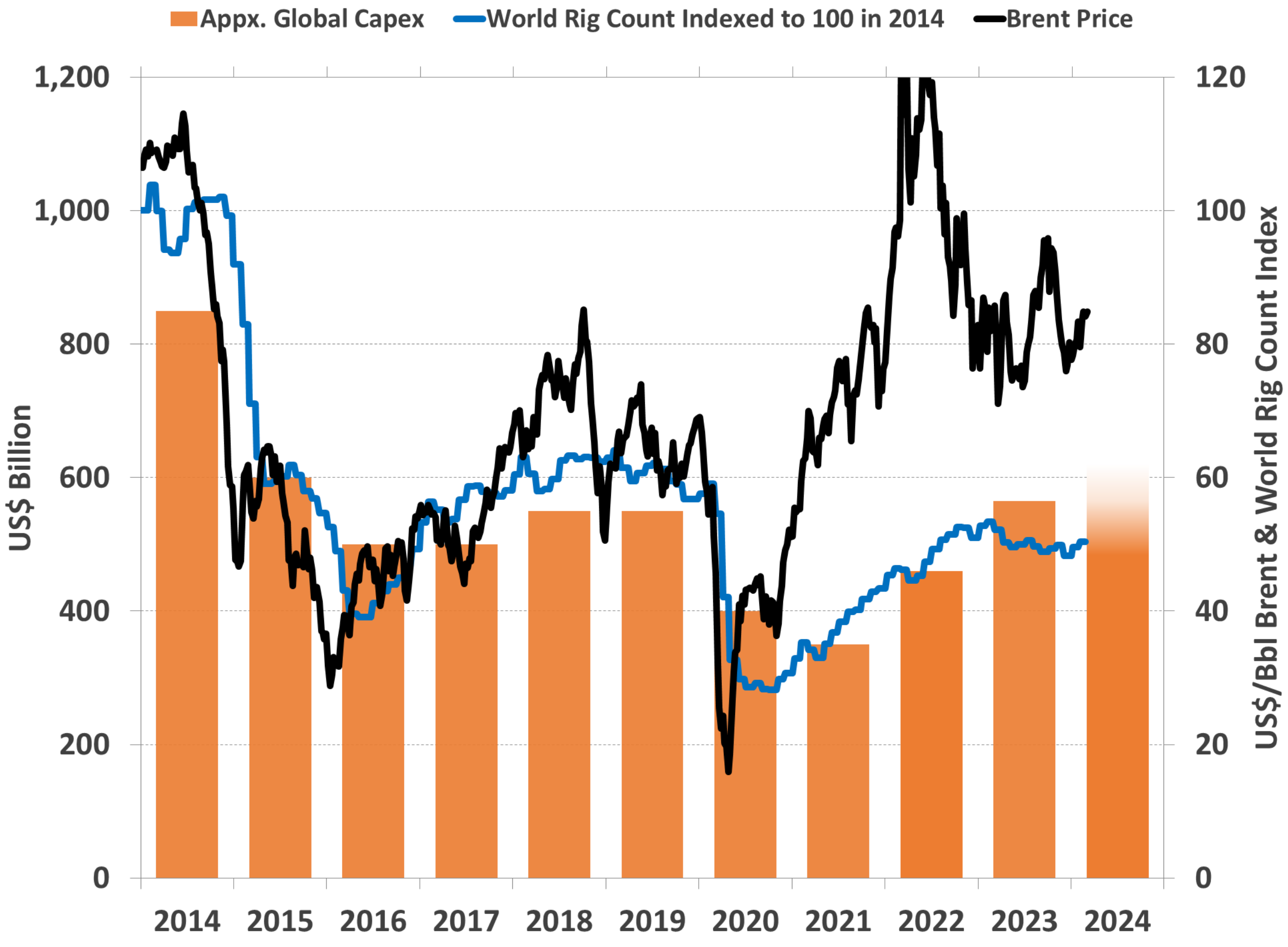
Market Conditions

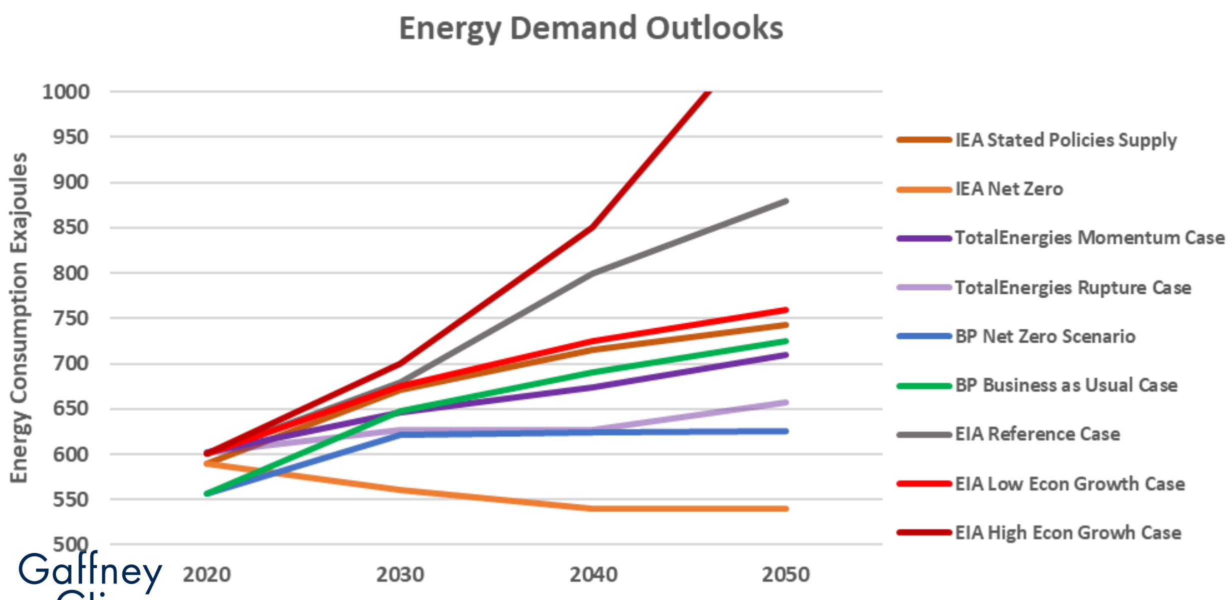
- The oil and gas industry has been battered by deeply disruptive events in recent years
  - Leading to volatility, which is equivalent to financial risk and impacts long term planning
  - Even with recovery and recently realized elevated levels of hydrocarbon prices, companies continue to be cautious with capital
- Investors have demanded better capital discipline, improved financial performance and action on climate change
- Governments that rely upon petroleum revenues face challenges of attracting new investment in industry that continues to be very sensitive to capital efficiency

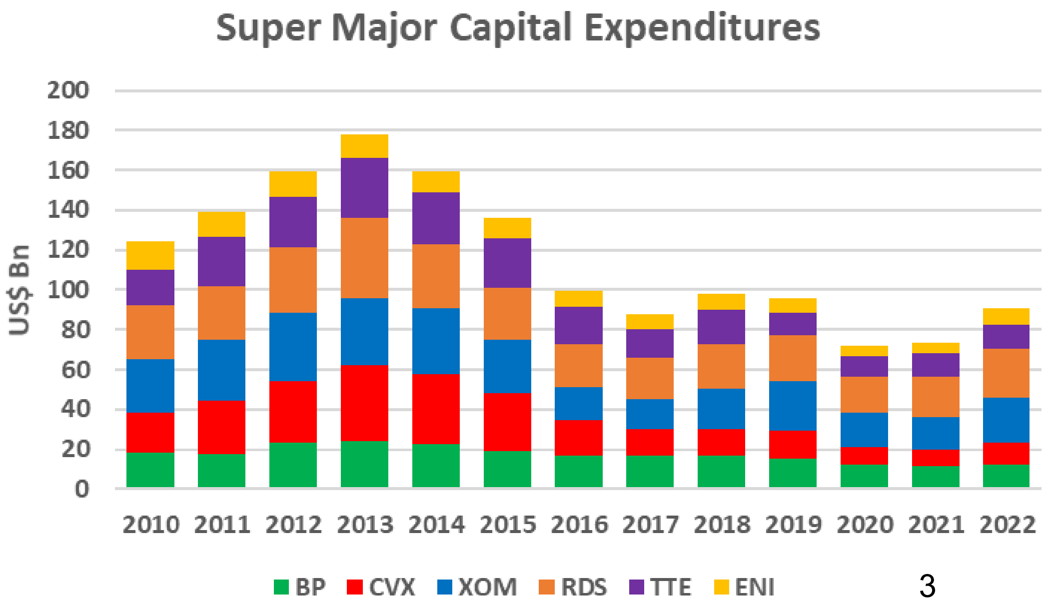


Sources: Baker Hughes Rig Count, public domain statements on Capex and GaffneyCline analysis, EIA Brent

Energy Demand and Competition for Upstream Capital

- Future of the world's energy demand and its composition carries a high degree of uncertainty
  - However, almost all current scenarios require substantial new oil and gas development to meet energy demands
- The Capital spending from the Super Majors is not currently expected to return to pre 2015 levels
- Many governments globally are seeking investment in the hydrocarbon resources from the largest oil and gas companies
  - Competition for capital continues to be fierce
  - IRR requirements and hurdle rates change depending on many factors but Shell, Eni and BP have all made public indication that new oil and gas investments require IRRs of ~15-20%+





Sources: Annual Reports

Responses to changes in Market Conditions

- In response to changes in market conditions, many proactive governments reassessed existing fiscal terms to consider incentives to ensure continued investment

"in an effort to mitigate underinvestment in the Norwegian shelf stemming from market conditions and uncertainty"
the Norwegian parliament enacted temporary changes to the Petroleum Tax Act in June 2020

"In order to protect jobs and investment in the North Sea…"
The UK implemented multiple tax reductions and simplifications in 2015 and 2016

- Petroleum Industry Act passed in 2021
- New Hydrocarbon Law passed
- Legislation to change several PSC terms
- Reduction to shallow water royalties
- Marginal and Gas terms allowed
- Adjusted royalty in Alberta & exploration initiative in N&L
- Allowed for accelerated tax deductions and some reduced royalties
- Reduced offshore royalties
- Improved Contract offering and renegotiations
- All reduced various forms of Export Tax/Duty

- Above are just some examples of primarily **legislative** changes made since 2015
- However, asset level contracts continually evolve under each iteration offered and there have been numerous asset specific contract renegotiations, many details of which do not make the public domain

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Increased Consideration of Asset Specific Characteristics

- The diversity of upstream oil and gas assets are becoming better understood, even within the same jurisdiction
  - Impact of asset maturity, complexity, proximity to infrastructure, hydrocarbon commerciality

- Trend globally to allow for optionality for multiple different Contract Types to accommodate
  - Mexico, Thailand, Angola plus many that already had legal option are reconsidering its application

- Irrespective of headline Contract type, more emphasis is being placed on asset level value drivers and enabling IEC returns
  - Leads to larger variance of fiscal elements
  - Complicates traditional “benchmarking” exercises, as fiscal burden in comparable jurisdiction are less directly informative to appropriateness of fiscal burden for any particular asset

- Significant progress in options for commercializing natural gas has required close and detailed reviews of natural gas terms, particularly for non-associated natural gas discoveries
  - Terms that have historically left gas fiscal burden at parity to oil have had to revisit contract or laws in order to enable new non-associated gas developments

Considerations for Cook Inlet

An array of downside risks will face any oil / gas investor

- ***Supply Risk:***
  - Cost pressures
  - Aged infrastructure
  - Lack of access for services
  - Challenging climate and operational environment
  - Environmental considerations
  - Decommissioning liabilities

- ***Market Risk:***
  - Lack of access to liquid wholesale market
  - Gas buyers are actively seeking diversification
    - Renewable generation
    - LNG
  - Potential for competing gas from North Slope

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Economics of Cook Inlet Developments

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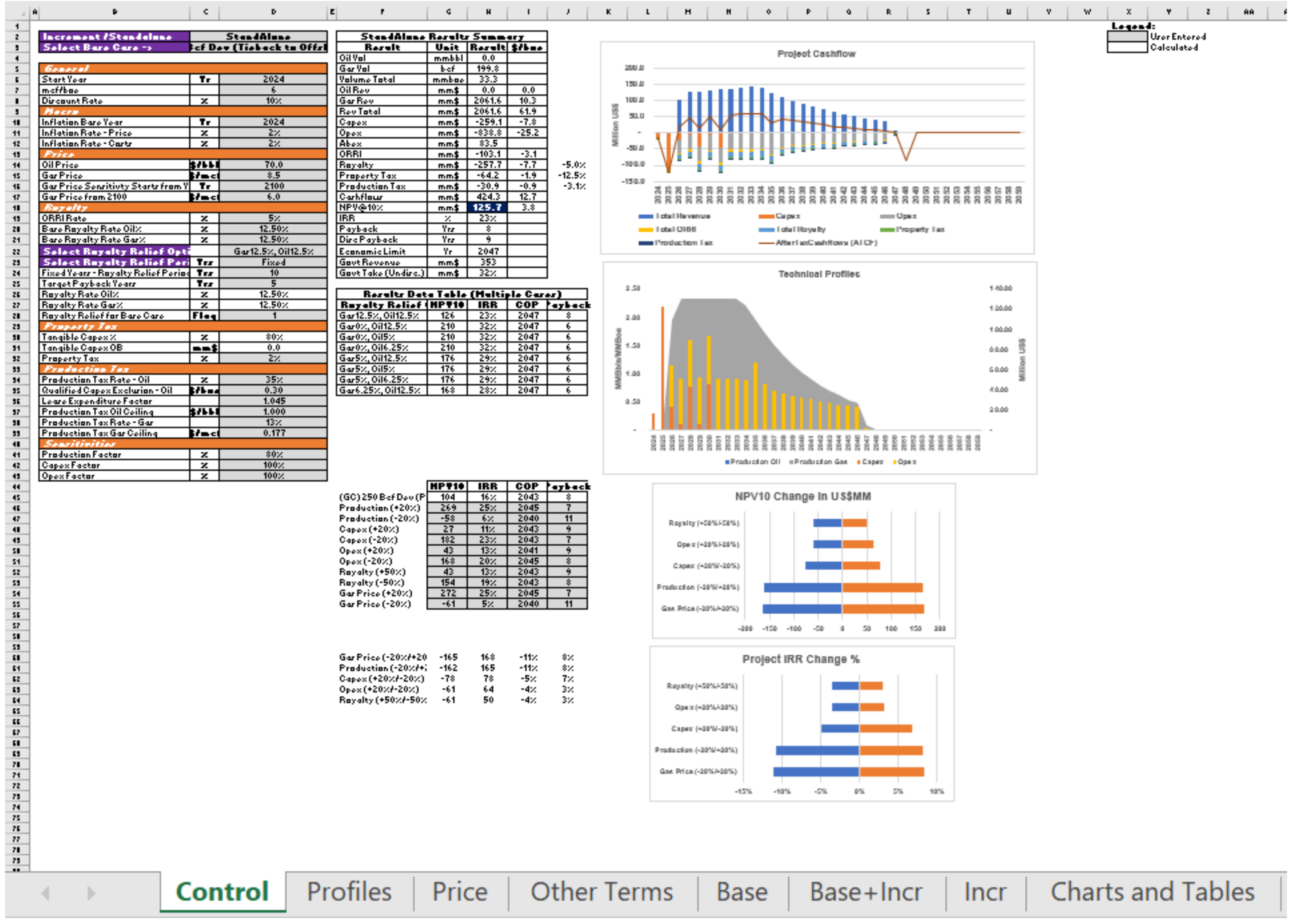
Development Cases Evaluated

Royalty relief proposals were evaluated for two hypothetical Cook Inlet developments.

- Project 1: Standalone shallow water gas field
- Project 2: Gas well (incremental development) in an existing onshore gas-condensate field. (work in progress)



Detailed excel model has been developed, capable of modelling multiple scenarios

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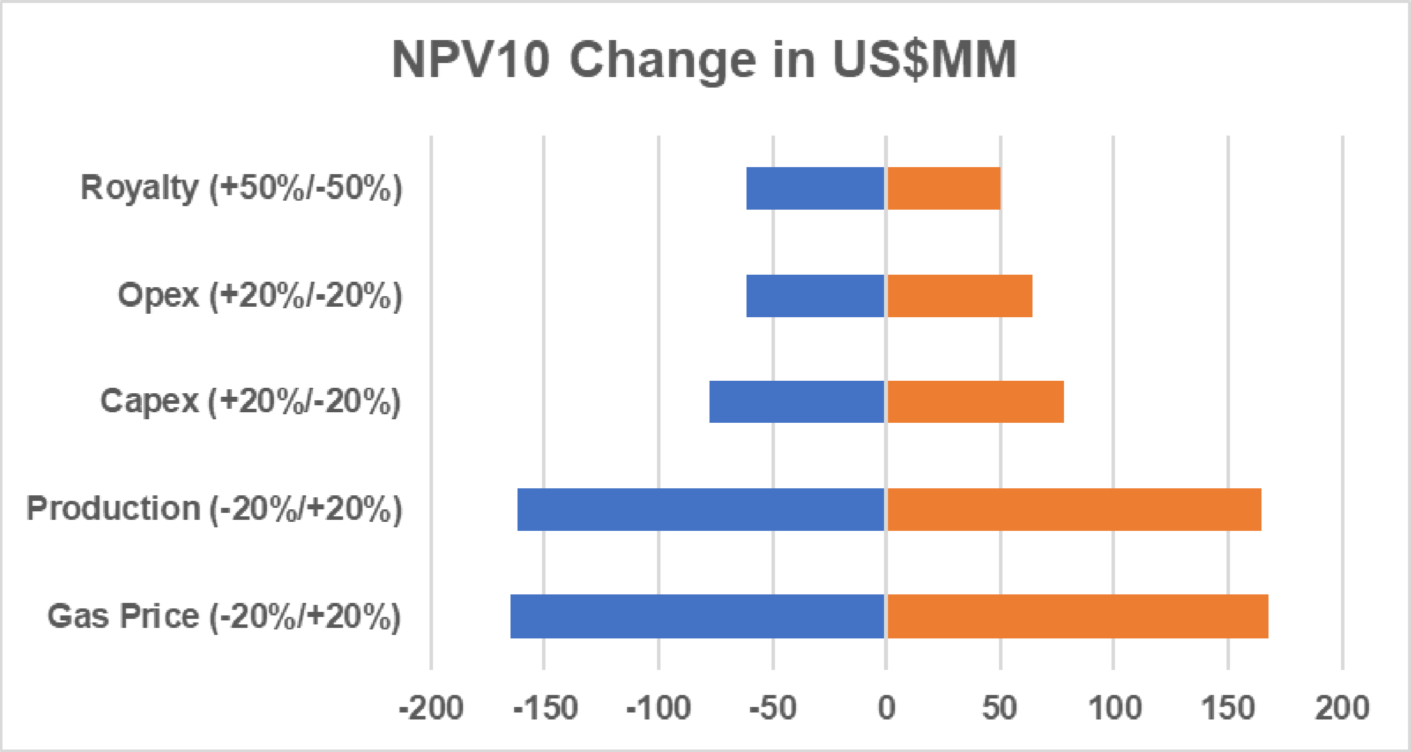
Sensitivity to Royalty Changes

- Royalty changes will help to create an investment case
- Other features are more influential, especially gas purchase price and production levels
- Higher production levels can be facilitated by additional gas storage



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250 bcf New Development

Permanent

10 year

250 bcf stand alone platform

10 year

Royalty Relief Case	NPV10	IRR	COP	Payback
Gas12.5%, Oil12.5%	-135	-4%	2040	15
Gas0%, Oil12.5%	-66	4%	2040	11
Gas0%, Oil5%	-66	4%	2040	11
Gas0%, Oil6.25%	-66	4%	2040	11
Gas5%, Oil12.5%	-94	2%	2040	11
Gas5%, Oil5%	-94	2%	2040	11
Gas5%, Oil6.25%	-94	2%	2040	11
Gas6.25%, Oil12.5%	-101	1%	2040	12

Results Data Table (Multiple Cases)

Permanent

Royalty Relief Case	NPV10	IRR	COP	Payback
Gas12.5%, Oil12.5%	-135	-4%	2040	15
Gas0%, Oil12.5%	-53	6%	2040	11
Gas0%, Oil5%	-53	6%	2040	11
Gas0%, Oil6.25%	-53	6%	2040	11
Gas5%, Oil12.5%	-86	3%	2040	11
Gas5%, Oil5%	-86	3%	2040	11
Gas5%, Oil6.25%	-86	3%	2040	11
Gas6.25%, Oil12.5%	-94	2%	2040	12

Results Data Table (Multiple Cases)

250 bcf tie back to offshore

10 year

Royalty Relief Case	NPV10	IRR	COP	Payback
Gas12.5%, Oil12.5%	40	15%	2047	9
Gas0%, Oil12.5%	113	23%	2047	7
Gas0%, Oil5%	113	23%	2047	7
Gas0%, Oil6.25%	113	23%	2047	7
Gas5%, Oil12.5%	84	20%	2047	8
Gas5%, Oil5%	84	20%	2047	8
Gas5%, Oil6.25%	84	20%	2047	8
Gas6.25%, Oil12.5%	77	19%	2047	8

Results Data Table (Multiple Cases)

Permanent

Royalty Relief Case	NPV10	IRR	COP	Payback
Gas12.5%, Oil12.5%	40	15%	2047	9
Gas0%, Oil12.5%	131	24%	2047	7
Gas0%, Oil5%	131	24%	2047	7
Gas0%, Oil6.25%	131	24%	2047	7
Gas5%, Oil12.5%	95	20%	2047	8
Gas5%, Oil5%	95	20%	2047	8
Gas5%, Oil6.25%	95	20%	2047	8
Gas6.25%, Oil12.5%	85	19%	2047	8

Results Data Table (Multiple Cases)

250 bcf tie back to onshore

10 year

Royalty Relief Case	NPV10	IRR	COP	Payback
Gas12.5%, Oil12.5%	-8	9%	2046	10
Gas0%, Oil12.5%	66	17%	2046	8
Gas0%, Oil5%	66	17%	2046	8
Gas0%, Oil6.25%	66	17%	2046	8
Gas5%, Oil12.5%	37	14%	2046	9
Gas5%, Oil5%	37	14%	2046	9
Gas5%, Oil6.25%	37	14%	2046	9
Gas6.25%, Oil12.5%	29	13%	2046	9

Results Data Table (Multiple Cases)

Permanent

Royalty Relief Case	NPV10	IRR	COP	Payback
Gas12.5%, Oil12.5%	-8	9%	2046	10
Gas0%, Oil12.5%	84	18%	2046	8
Gas0%, Oil5%	84	18%	2046	8
Gas0%, Oil6.25%	84	18%	2046	8
Gas5%, Oil12.5%	47	14%	2046	9
Gas5%, Oil5%	47	14%	2046	9
Gas5%, Oil6.25%	47	14%	2046	9
Gas6.25%, Oil12.5%	38	14%	2046	9

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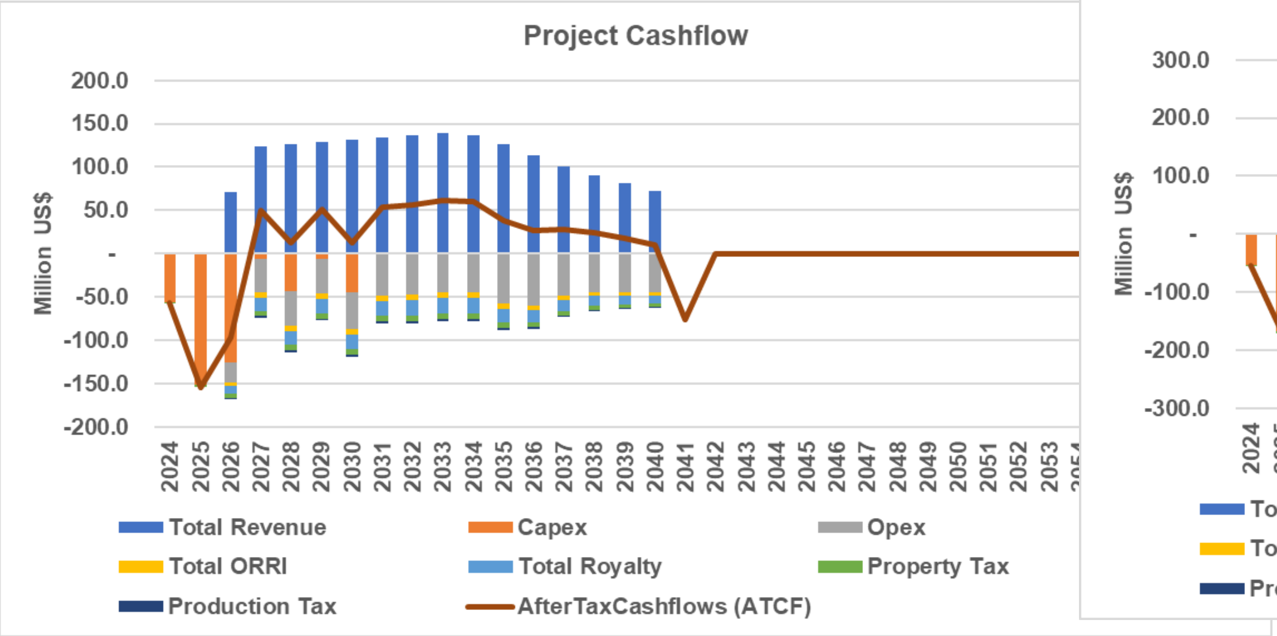
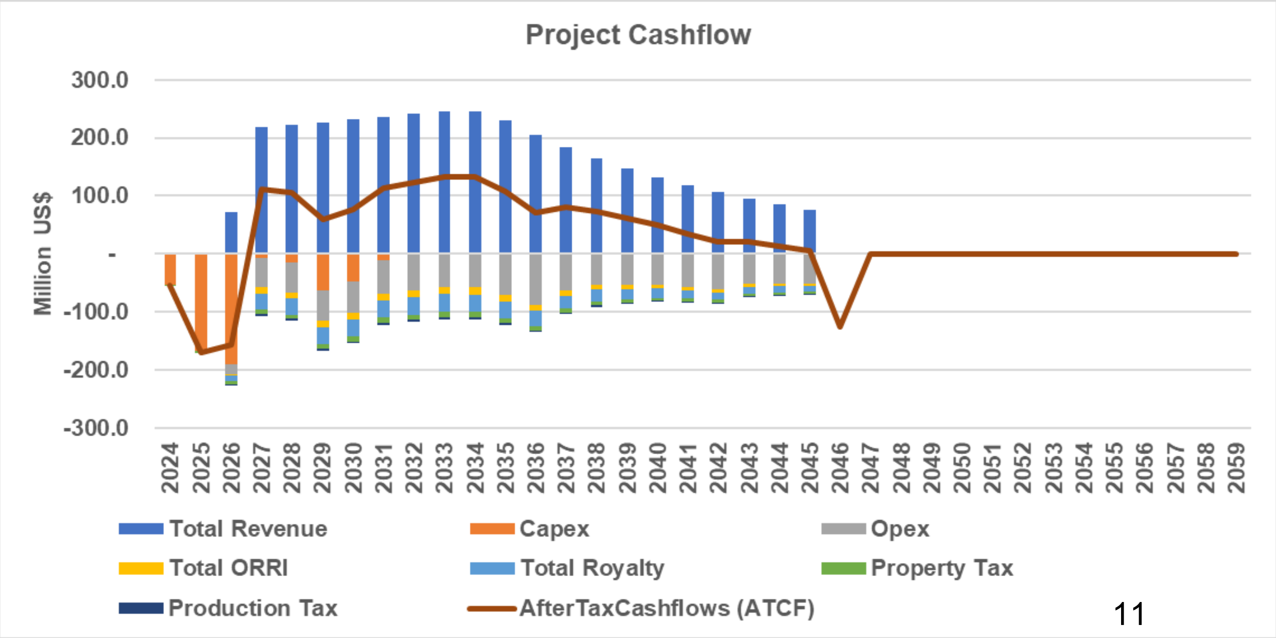
Example Economics – 250bcf vs 500bcf standalone platform

Results Data Table (Multiple Cases)				
Royalty Relief Case	**NPV10**	**IRR**	**COP**	**Payback**
Gas12.5%, Oil12.5%	-135	-4%	2040	15
Gas0%, Oil12.5%	-53	6%	2040	11
Gas0%, Oil5%	-53	6%	2040	11
Gas0%, Oil6.25%	-53	6%	2040	11
Gas5%, Oil12.5%	-86	3%	2040	11
Gas5%, Oil5%	-86	3%	2040	11
Gas5%, Oil6.25%	-86	3%	2040	11
Gas6.25%, Oil12.5%	-94	2%	2040	12

Results Data Table (Multiple Cases)				
Royalty Relief Case	**NPV10**	**IRR**	**COP**	**Payback**
Gas12.5%, Oil12.5%	239	21%	2045	8
Gas0%, Oil12.5%	414	27%	2047	7
Gas0%, Oil5%	414	27%	2047	7
Gas0%, Oil6.25%	414	27%	2047	7
Gas5%, Oil12.5%	343	25%	2046	7
Gas5%, Oil5%	343	25%	2046	7
Gas5%, Oil6.25%	343	25%	2046	7
Gas6.25%, Oil12.5%	326	24%	2046	7

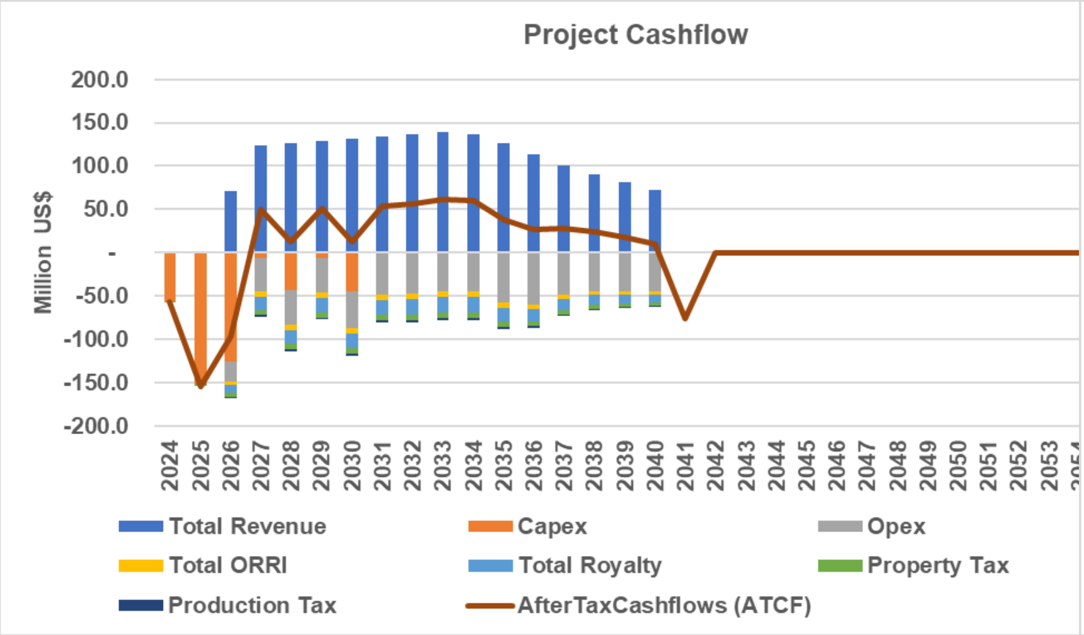


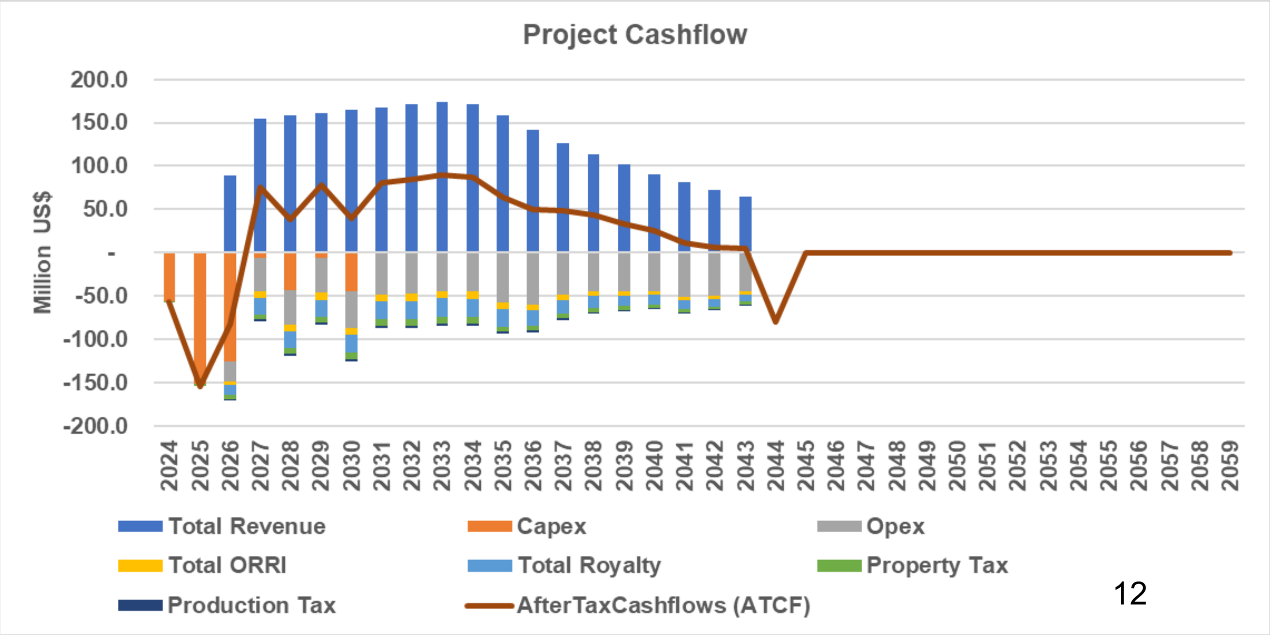


Example Economics – Impact of 100% Take or Pay and flat daily nominations

Results Data Table (Multiple Cases)				
Royalty Relief Case	**NPV10**	**IRR**	**COP**	**Payback**
Gas12.5%, Oil12.5%	-135	-4%	2040	15
Gas0%, Oil12.5%	-53	6%	2040	11
Gas0%, Oil5%	-53	6%	2040	11
Gas0%, Oil6.25%	-53	6%	2040	11
Gas5%, Oil12.5%	-86	3%	2040	11
Gas5%, Oil5%	-86	3%	2040	11
Gas5%, Oil6.25%	-86	3%	2040	11
Gas6.25%, Oil12.5%	-94	2%	2040	12

Results Data Table (Multiple Cases)				
Royalty Relief Case	**NPV10**	**IRR**	**COP**	**Payback**
Gas12.5%, Oil12.5%	104	16%	2043	8
Gas0%, Oil12.5%	229	23%	2044	7
Gas0%, Oil5%	229	23%	2044	7
Gas0%, Oil6.25%	229	23%	2044	7
Gas5%, Oil12.5%	179	20%	2044	8
Gas5%, Oil5%	179	20%	2044	8
Gas5%, Oil6.25%	179	20%	2044	8
Gas6.25%, Oil12.5%	167	20%	2044	8

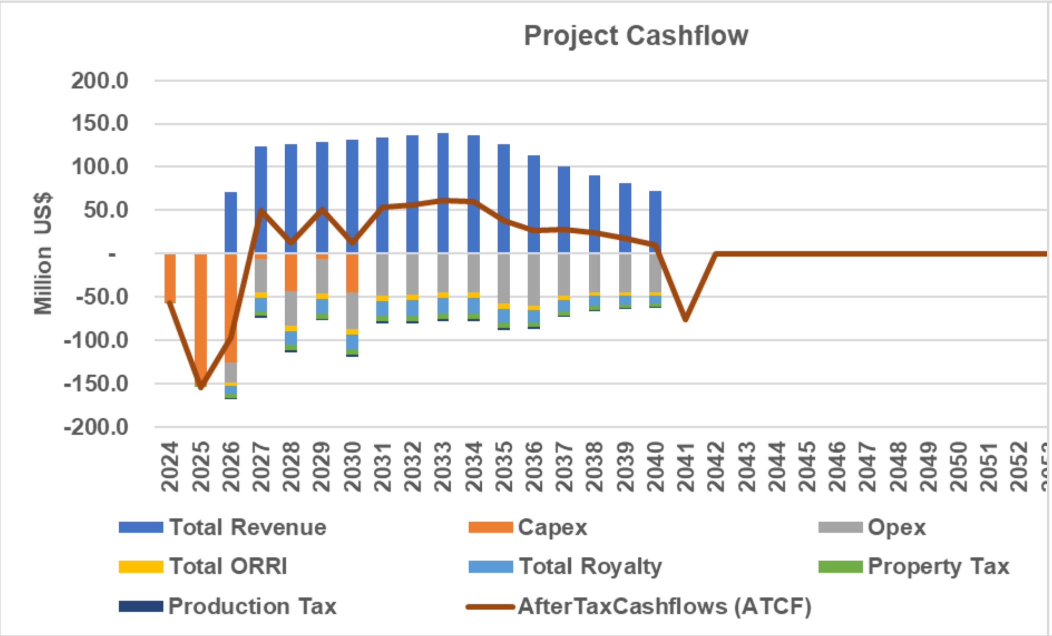


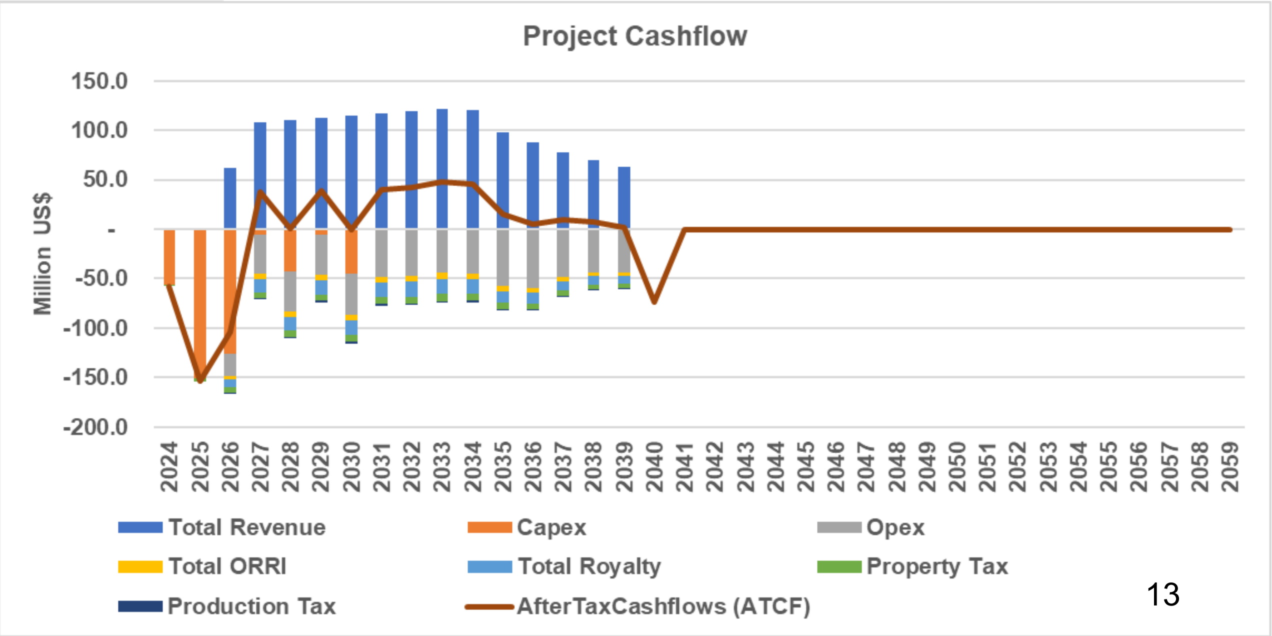


Example Economics – Impact of potential Gas Line / Price Adjustment ($1/MMBtu discount in 2035)

Results Data Table (Multiple Cases)				
Royalty Relief Case	**NPV10**	**IRR**	**COP**	**Payback**
Gas12.5%, Oil12.5%	-135	-4%	2040	15
Gas0%, Oil12.5%	-53	6%	2040	11
Gas0%, Oil5%	-53	6%	2040	11
Gas0%, Oil6.25%	-53	6%	2040	11
Gas5%, Oil12.5%	-86	3%	2040	11
Gas5%, Oil5%	-86	3%	2040	11
Gas5%, Oil6.25%	-86	3%	2040	11
Gas6.25%, Oil12.5%	-94	2%	2040	12

Results Data Table (Multiple Cases)				
Royalty Relief Case	**NPV10**	**IRR**	**COP**	**Payback**
Gas12.5%, Oil12.5%	-150	NA	2039	#N/A
Gas0%, Oil12.5%	-69	4%	2040	11
Gas0%, Oil5%	-69	4%	2040	11
Gas0%, Oil6.25%	-69	4%	2040	11
Gas5%, Oil12.5%	-101	0%	2040	11
Gas5%, Oil5%	-101	0%	2040	11
Gas5%, Oil6.25%	-101	0%	2040	11
Gas6.25%, Oil12.5%	-109	-1%	2040	12





Key Conclusions

- A 250bcf offshore development typical of the Cook Inlet currently has marginal economics if developed as a stand alone platform
- A tie-back to offshore or onshore infrastructure is needed
- In this case, changes to royalty may be help in establishing an investment case for development
- A larger resource base considerably improves economics
  - Royalty reductions may still be required to meet investor requirements
- Higher average production significantly helps investment case
- The potential for “disruption” owing to a gas line from the North Slope is material within the lifetime of these projects
  - There are many examples internationally of material changes in the market creating “stranded assets”
- In fill wells appear to have strong economics, without royalty changes

What facets may be helpful to spur continual exploration and development?

- The key economic impact of tie-ins and tariffs for access to infrastructure may support regulatory action to improve utilization of existing pipelines and processing facilities
- High take or pay gas offtake contracts would assist in improving economics, but may lead to higher consumer prices for gas and electricity
  - Potential for a socialized “reliability charge” on utility bills
  - Cooperation between buyer groups, with sub-allocation
- Additional storage may also release greater value by reducing volumetric flexibility needs of the field production
- Very strong contractual mechanisms to maintain commerciality of Cook Inlet environment, should a gas line be constructed.

Other commentary

- HB 393 requires further study, with benefit of oil examples
- If differential royalty changes are applied, they may be better assigned to utility contracts, owing to the more variably demand pattern
  - Could be administratively complex to administer
  - Unlikely to make a difference to investment levels
  - Export market for Cook Inlet gas not considered viable
- HB280 appears to have been appropriate for the environment that existed in 2010. Other jurisdictions have experienced similar investment challenges owing to a changed market conditions.
- Recent history suggests that a relaxation on oil royalties may be necessary to maintain or slow decline in the basin, but this has not been studied yet.

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Development Scenarios and Key Assumptions

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Economic Modelling of Cook Inlet Gas Project

- GaffneyCline has built an economic model to evaluate the economics of an oil and gas investment in Cook Inlet and to understand the impact of the various royalty relief proposals.
- A summary of the Cook Inlet fiscal regime terms used in the model are as shown in the Table.
- Some fiscal terms such as ORRI vary widely for different leases.
- The terms in the economic model are an average approximation for evaluating a hypothetical oil and gas development in Cook Inlet.

Cook Inlet Fiscal Regime	
Fiscal Regime	Royalty-Tax
Royalty	Base Case rates: 12.5% Oil; 12.5% Gas
Overriding Royalty Interest (ORRI)	5%
Property Tax	2% of taxable property value
Production Tax	35% of Taxable Oil ($1/Bbl tax ceiling); 13% of Taxable Gas ($0.177/mcf tax ceiling)

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Prices and Other Macro Assumptions

- Oil price of $70/Bbl and Gas price of $8.5/mcf escalated at 2% has been used as the base case price assumption.
- Costs are estimated to be escalated at 2% annually from 2025.

Project 1 Development Assumptions

- Resource base assumptions from previous presentations and public domain technical papers
  - 250 Bcf or 500 Bcf EUR
  - 42 Bcf/well EUR
  - Dry gas (low CGR)
  - Reservoir depth 2500 to 7500 feet TVDSS
  - CO_2 below 0.5%
  - No H_2S
- GaffneyCline assumptions
  - Water depth of 100 to 200 feet (based on Cook Inlet bathymetry)
  - 5 to 10 mile tieback to existing infrastructure (inlet is <20 miles wide)
  - Spare capacity is available in existing gas production/transport infrastrucute
  - 50 mmscfd plateau (250 Bcf) or 100 mmscfd plateau (500 Bcf)
  - Developer can access existing capacity under a tariff structure
  - Case results compared on "Unit Technical Cost" (UTC)= Total development cost/EUR ($/mcf)

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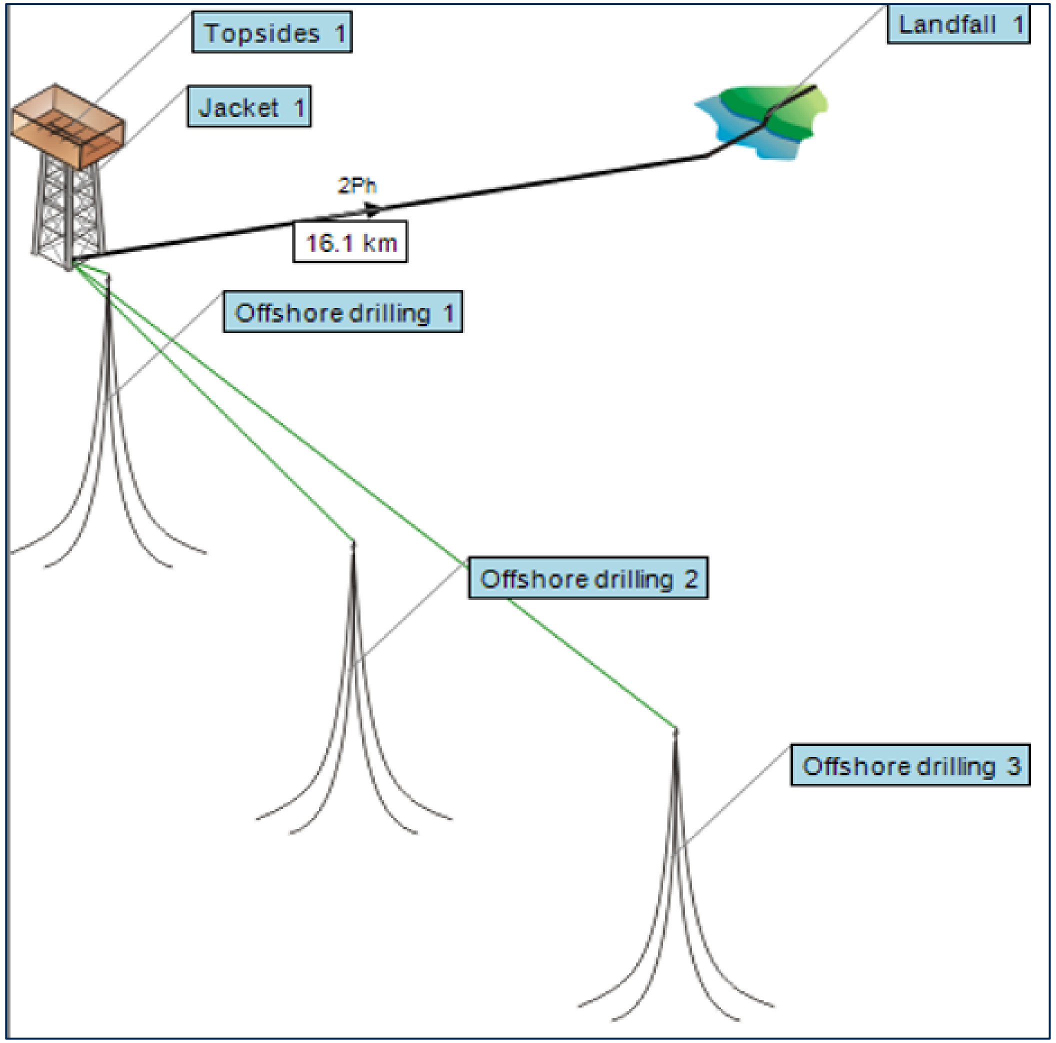
Project 1 Development Concept 1: Tie-back to Onshore



- Offshore field (5 or 10 miles offshore)
- Water depth of 100 ft or 200 ft
- Reservoir depths of 2500’, 5000’, or 7500’
- Wellhead platform tied back to existing onshore plant to existing sales gas line
- Assume \$0.50/mcf gas transport tariff and \$1.50/mcf gas processing tariff
- Development drilling in three phases to maintain plateau
- UTC range \$3.95 to \$4.37/mcf for 250 Bcf and \$3.23 to \$3.56/mcf for 500 Bcf

Field Size	250 Bcf	500 Bcf
Well Count	6	12
Plateau rate (mmscfd)	50	100

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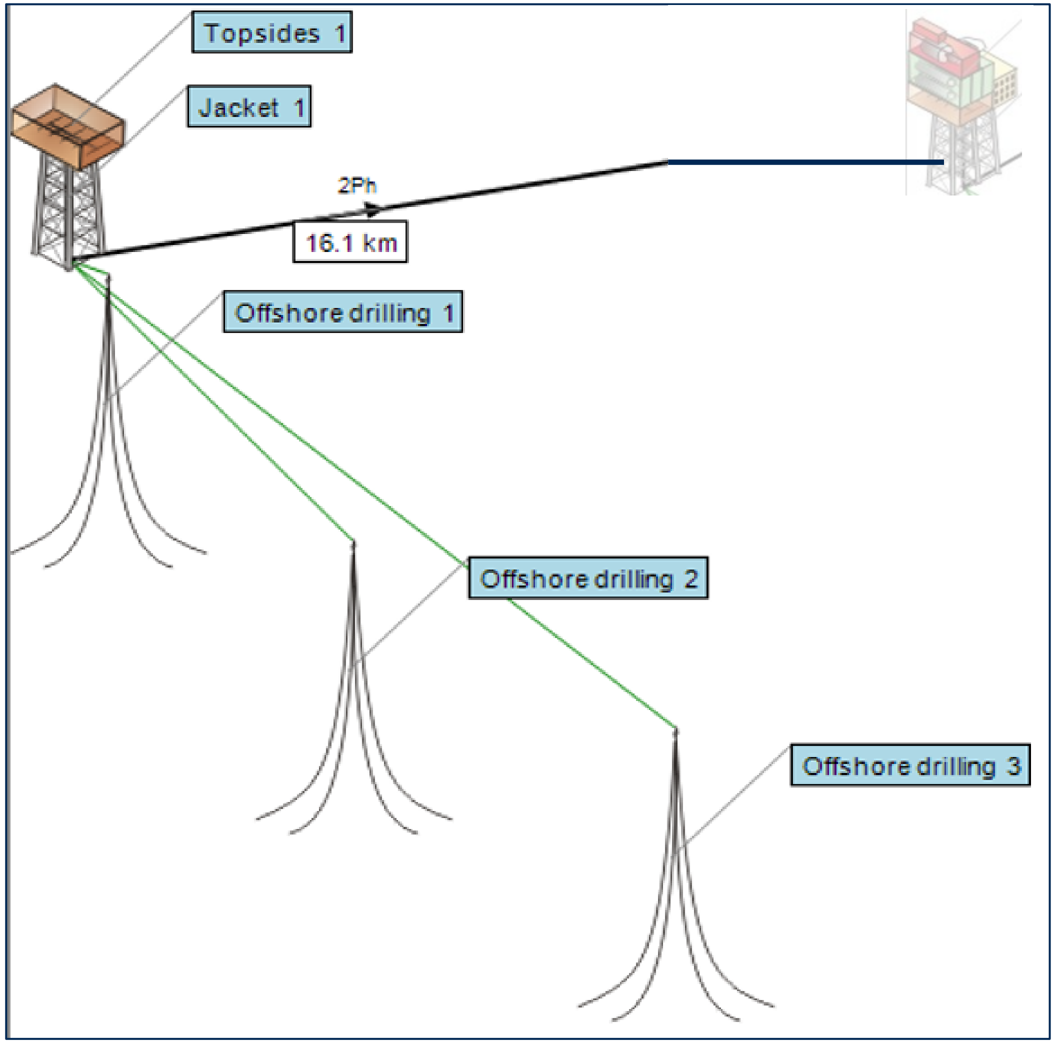
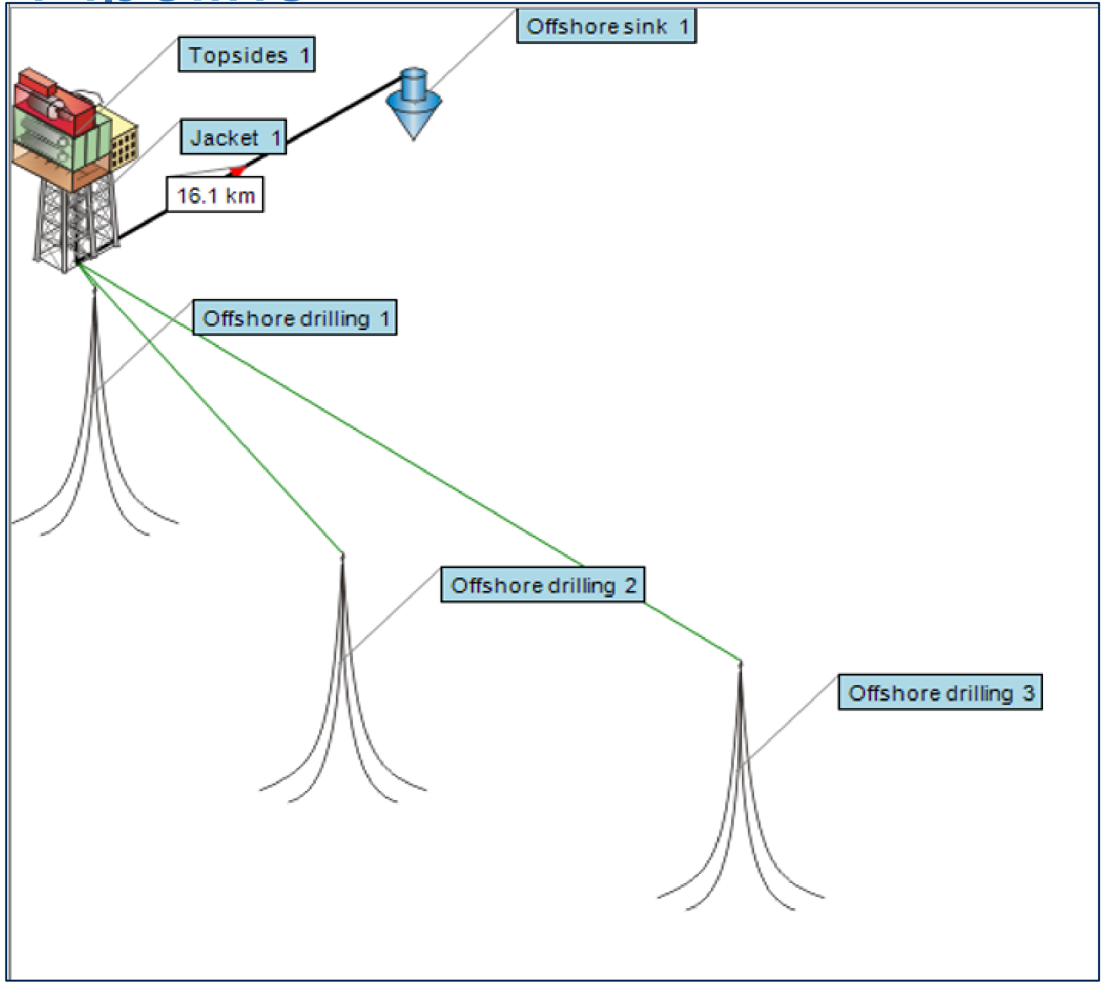
Project 1Development Concept 2: Tie-back to Offshore Production Platform



- Offshore field (5 or 10 miles to tie in)
- Water depth of 100 ft or 200 ft
- Reservoir depths of 2500’, 5000’, or 7500’
- Wellhead platform tied back to existing production platform to existing sales gas line
- Assume $0.50/mcf gas transport tariff and $1.50/mcf gas processing tariff
- Development drilling in three phases to maintain plateau
- UTC range $3.93/mcf (250 Bcf) to $3.22/mcf (500 Bcf)

Field Size	250 Bcf	500 Bcf
Well Count	6	12
Plateau rate (mmscfd)	50	100

Project 1 Development Concept 2: Production Platform to existing Pipeline



- Offshore field (5 or 10 miles to tie in)
- Water depth of 100 ft or 200 ft
- Reservoir depths of 2500’, 5000’, or 7500’
- Production platform tied back to existing sales gas line
- Assume $0.50/mcf gas transport tariff
- Development drilling in three phases to maintain plateau
- UTC range $5.03/mcf (250 Bcf) to $3.16/mcf (500 Bcf)

Field Size	250 Bcf	500 Bcf
Well Count	6	12
Plateau rate (mmscfd)	50	100

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Development Conclusions

- Within the geographic constraints of CI, and the field size range there is little variation in UTC between development options
- Resource size is the main UTC driver
- Key cost drivers are:
  - tariff assumptions: the negotiated price per mcf paid to infrastructure owners for gas process, compression, and/or transport services
  - offshore resource mobilization costs: rig, barges, heavy lift, pipelay, etc. are all specialized resources not normally available in the North Pacific. Assumed mobilization 7500 miles (from Korea or China)
  - offshore manning requirements: Both WHP and gas production platforms can be operated unmanned and fully remote. Permanent offshore manning increases OPEX materially

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