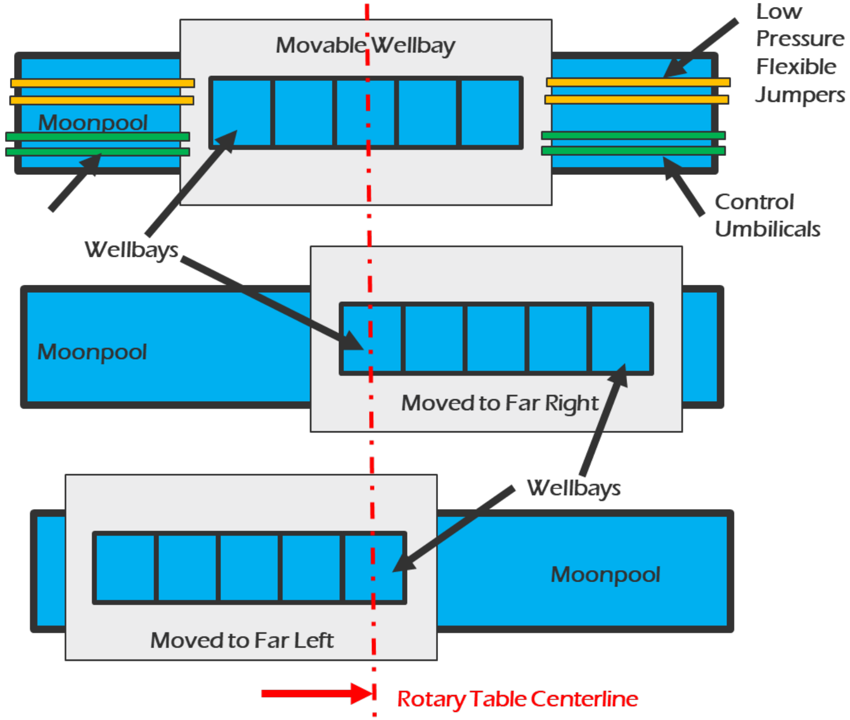
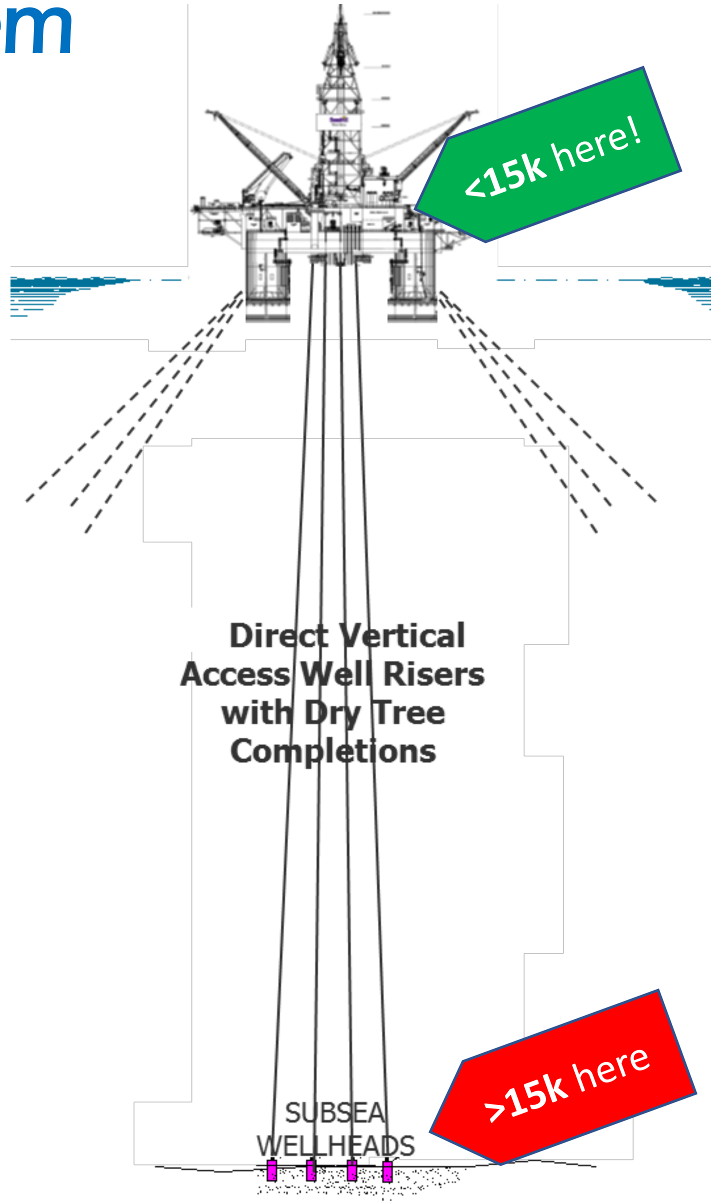
GREEN OPS & Frontier Production System (FrPS) with Movable Wellbay



Movable Wellbay in Moonpool



AGENDA

- Intro's, Safety Moment, and Objectives Review ➔
- Company/Tech Brief Overview (FrPS overview)
- Case study for green field development
  - ALARP & AHARP… really?
- Future deployment opportunities
- NEXT STEPS
  - Next Meeting(s)?
- More Q & A

OBJECTIVES:

- Ensure solid understanding of Movable Wellbay concepts and advantages
- Explore value of ALARP & AHARP principles to Murphy
- Clarify basis for and meaning of Case Study
- Explore future deployment opportunities
- Establish NEXT STEPS

GREEN topics from Frank Garcia's suggested agenda

Frontier brings together an elite team of industry leaders

- **Roy Shilling**, President
  - 40yrs BP Technology and Deepwater Project Delivery leadership
- **Charles N. White**, EVP
  - 40+yrs, Naval Architect/Mech. Eng. Field Dev. Leader with Conoco and Statoil
- **Terri Ivers**, Chair
  - 30+yrs Senior Executive Mgt (KBR, Wood Group, AMEC, Bilfinger USA)
- **Howard Day**, VP Rig Systems and Equipment
  - 35+yrs, Drilling Systems and Equipment Delivery (F&G, Unocal, COP, WEL)
- **Paul Hyatt**, VP Drilling and Completions
  - 30+yrs, Drilling Operations Manager (Amoco, BP, Woodside…)
- **Vamsee Achanta**, VP Engineering
  - ~20+yrs, CEO AceEngineer, 2H Technical Manager
- **Ellen Coopersmith**, Decision Quality Lead
  - 30+yrs, Reservoir Engineer/DQ leadership(Decision Frameworks, Conoco)

Movable Wellbay

US009976364B2

(12) **United States Patent**
Shilling, III et al.

(10) **Patent No.: US 9,976,364 B2**
(45) **Date of Patent: May 22, 2018**

(54) **FLOATING OIL AND GAS FACILITY WITH A MOVABLE WELLBAY ASSEMBLY**

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(72) Inventors: **Roy B. Shilling, III**, Houston, TX (US); **Charles N. White**, Spicewood, TX (US); **Howard W.F. Day**, Houston, TX (US)

(73) Assignee: **FRONTIER DEEPWATER APPRAISAL SOLUTIONS LLC**, Houston, TX (US)

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 0 days. days.

(21) Appl. No.: **15/482,064**

(22) Filed: **Apr. 7, 2017**

(65) **Prior Publication Data**

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Related U.S. Application Data

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(51) **Int. Cl.**

E21B 19/00	(2006.01)
E21B 15/02	(2006.01)
B63B 35/44	(2006.01)
B63B 21/20	(2006.01)

(52) **U.S. Cl.**
CPC ***E21B 19/006*** (2013.01); ***B63B 21/20*** (2013.01); ***B63B 35/4413*** (2013.01); ***E21B 15/02*** (2013.01); *B63B 2021/203* (2013.01)

(58) **Field of Classification Search**
CPC E21B 19/006; E21B 15/02; E21B 15/003; E21B 19/004; B63B 21/20; B63B 35/4413; B63B 2021/203
See application file for complete search history.

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Primary Examiner — James G Sayre
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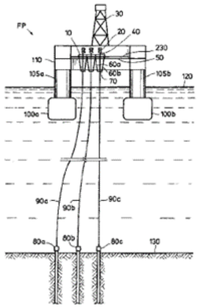
(57) **ABSTRACT**

A mobile offshore drilling unit is converted to provide drilling, completion and workover access to multiple dry tree wells from a drilling derrick to allow production and export of oil and gas from high pressure, high temperature reservoirs in deep offshore waters. Existing practice has been for the drilling derrick on a production platform supporting dry tree wells to be moved over a fixed well slot. The present invention provides a movable wellbay that supports multiple top-tensioned subsea well tieback risers, which may be positioned directly below the derrick's rotary table and/or beneath another operating device. The use of top-tensioned subsea well tieback risers supported by the movable wellbay allows the converted facility to drill, complete, maintain, improve and produce from subsea wells through dry trees.

19 Claims, 5 Drawing Sheets



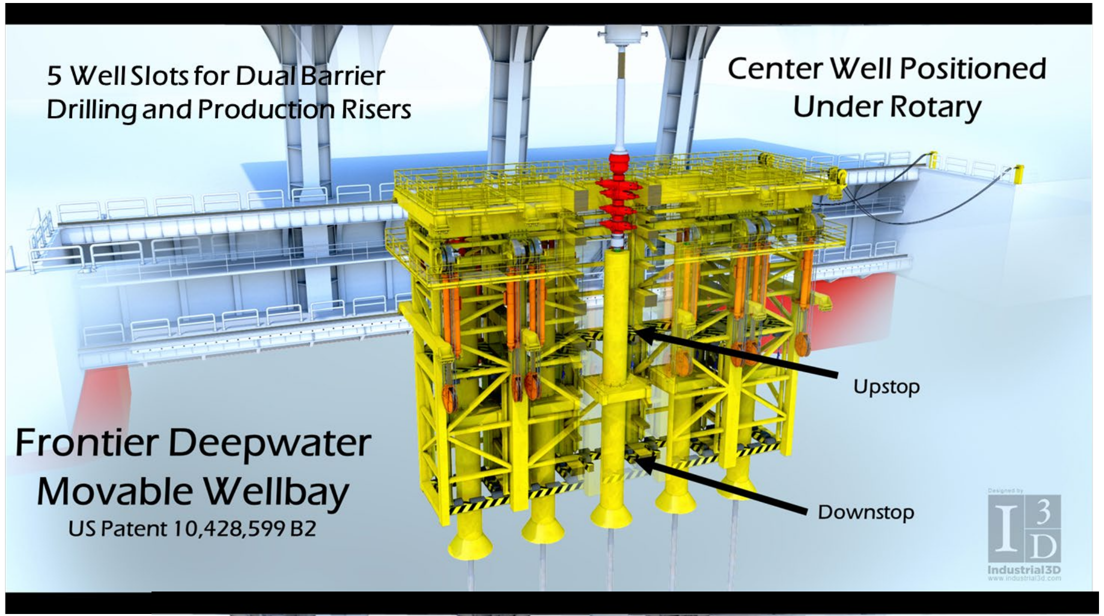
So, what's the BIG DEAL – a wellbay that moves???

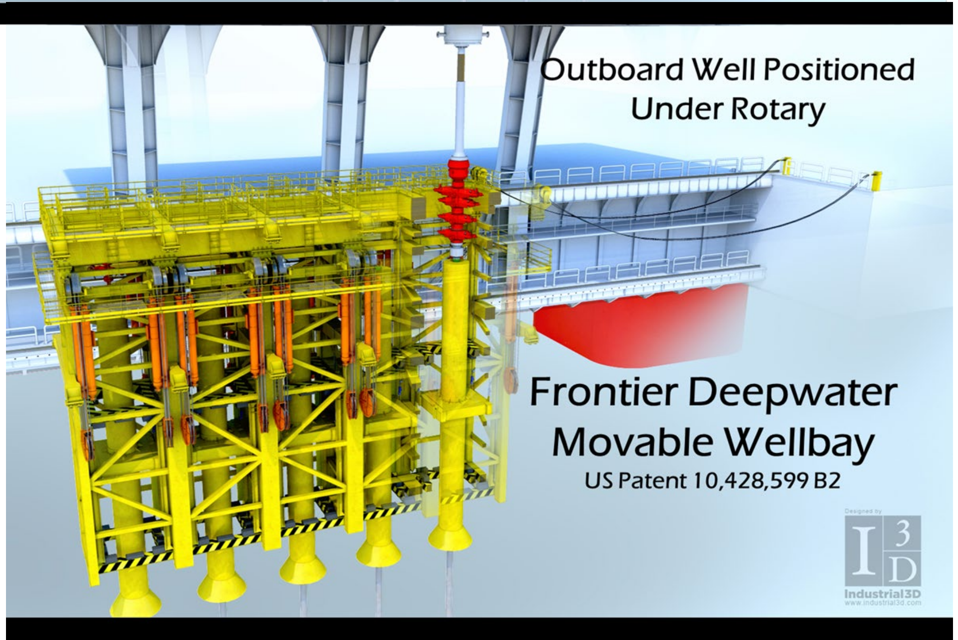
It's true... no one thought of this before!

- Allows reuse of 6th / 7th gen DW MODUs
- Employs proven technology (versus high pressure subsea systems)
  - Fully rated, top tensioned dual barrier risers
  - Reliable direct hydraulic surface BOP
  - Better more reliable instrumentation and automation
- Provides safety of a permanently moored platform for drilling (versus Dynamic Positioning)
- Low Total Cost and rapid deployment enables real risk reduction for big DW fields
- Easier well access and interventions

➔ INCREASED OIL RECOVERY

FrPS increases Safety while decreasing Costs





A Breakthrough for NEWBUILDINGS

Rather than skidding this mountain around - bring "the Wellbay to the Mountain"

- Rig can be fixed into the platform
  - Eliminates HUGE movable sub-base
    - ➔ **MUCH Lower Center of Gravity**
  - Simplifies equipment interfaces
  - Place utilities more flexibly versus vertically on the sub-base (big impact for Spars!)

- **Reduces platform size and cost**
  - A typical Spar <u>rig floor is **225 feet above sea level**</u>

Rig Floor Way up Here!

Breakthroughs for ALL FLOATERS

Let the platform heave
& let the RISERS STRETCH!

Permanently moored FrPS unit rides the biggest waves

Riser stresses managed by -

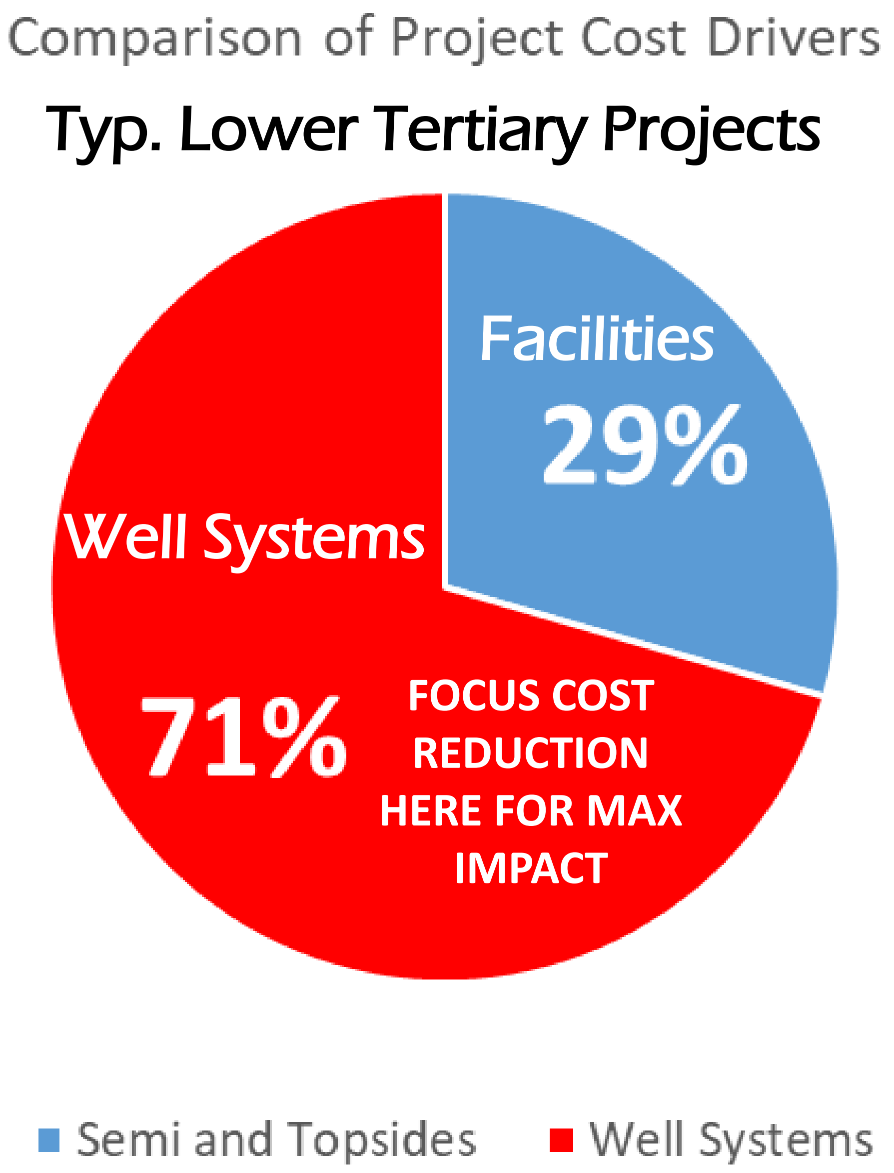
- Distributed buoyancy (& strakes)
- Top Tensions
- Tensioner Stroke, and
- Riser Stretch ➔ <80%YS in 1,000yr event

TLPs, spars, & deep-draft semis need very tall columns to maintain air gap

100 Year Central GoM Hurricane 95' Wave Height– Maximum Wave

Keys to Profitability in the Lower Tertiary

- Success requires strategic focus on reducing costs for:
  - Drilling
  - Completion
  - EOR
  - Intervention, and
  - Maintenance
  - Dry tree equipment much cheaper than 20K subsea system
- Well Completions and Maintenance drive economic performance:
  - Dry trees provide better well access at a much lower cost
  - Dry trees with gas lift or ESP's are much less costly and much more efficient than subsea pumping
  - Intervention and well maintenance can be performed cheaply by the rig on the FrPS
- Avoid need for costly 20K MODU in GoM



Industry announced billions of HP Wilcox barrels, but...

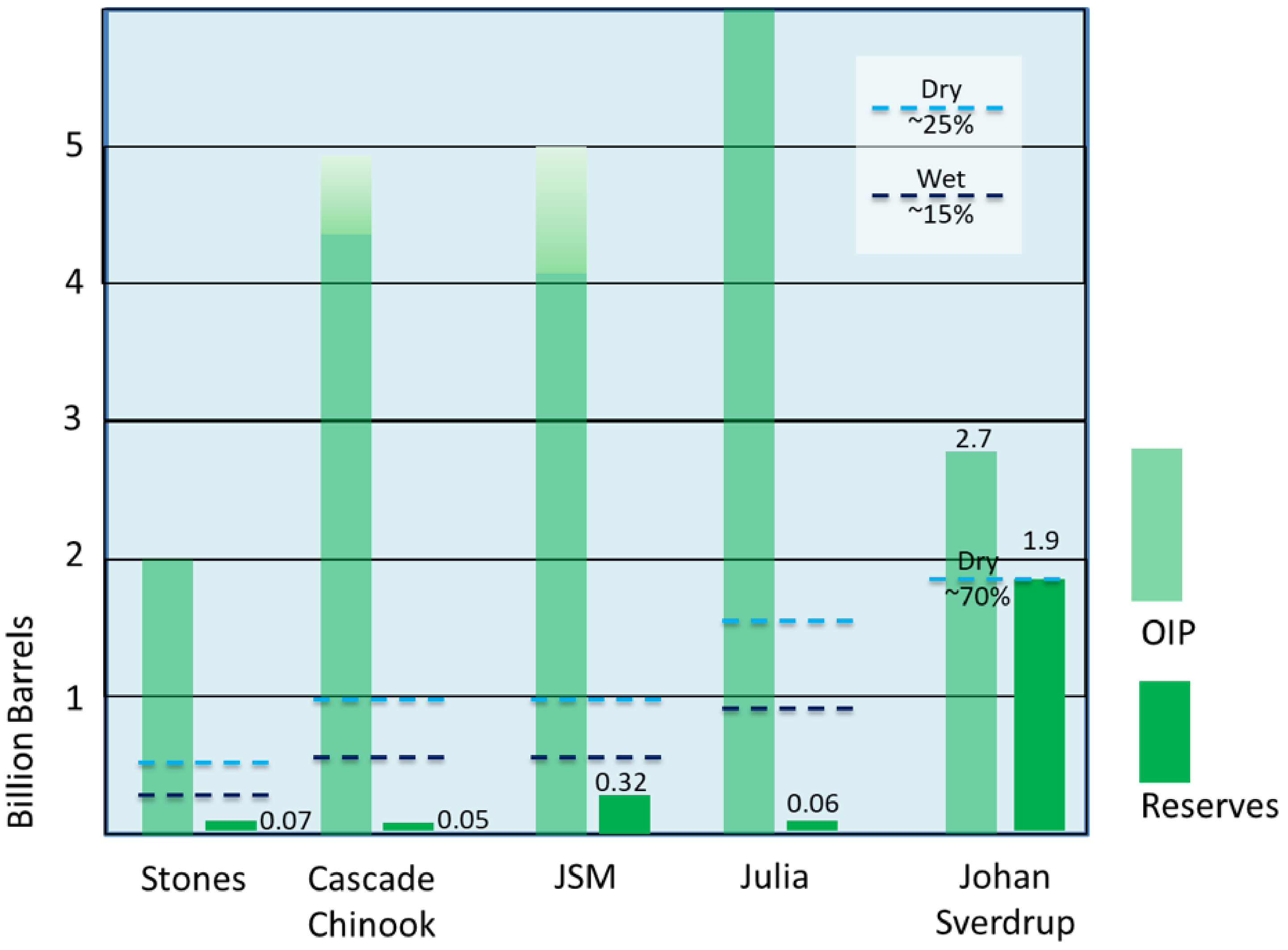
While discoveries excited...

Exploitation has disappointed!

For example, Chevron

- Developed
  - St. Malo, 2003 ➔ >2B bbls
  - Jack, 2004 ➔ >2B bbls
  - ➔ FID 2012
- Sanctioned
  - Anchor, 2015 ➔ >2B bbls; FID 2019
- Postponed
  - Tigris (Kaskida)
- Abandoned / Sold
  - Buckskin/Moccasin
  - Tiber
  - Gibson
  - Guadalupe

Comparing EUR recovery for wet versus dry tree developments



“GREEN OPS” CASE STUDY

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ALARP & AHARP… really?

ALARP

ALARP and AHARP principles are the twin foundations of a more sustainable offshore oil and gas industry.

The US requires that operators document how proposed offshore field development plans reflect the **ALARP** principle with regard to hazards / risk management. BSEE works to ensure safety, while BOEM must ensure that resources are developed in environmentally and economically responsible ways. Thus, BOEM should only approve field development plans that also reflect the **AHARP** principle to maximize the value of the resources being exploited.

AHARP

APPRAISAL DRILLING PROGRAM Comparison

The average HP Willcox appraisal* requires at least 7 more reservoir penetrations

➔ an additional 2,000 days of drilling operations

Appraisal Philosophy	Current Practice*	Frontier's Approach	Comments [*Julia's $6B phased subsea sanctioned after just 1 appraisal is excluded]
Number of Wellbores for Appraisal	**11.4** incl. sidetracks	2 wells + 2 sidetracks	Much lower total costs, quick delivery, & possibility for reuse of converted unit allow early sanction for FrPS phased project.
Drilling Days / Well	~200	200 / 75	Per BOEM/BSEE data and Frontier simulation results
Total Drilling Days	2,567	550	Assuming 200 days/well
Appraisal Program Cost	~$2.3B	$0.55B	Assuming $1M/day "all in" cost of appraisal program (instead of just $800k/day for MODU ops to account for 20Ksi Tech Dev)
Difference	**~2,000 days more**		Extra days of dangerous, potentially highly polluting operations
Difference	**~$1.7B**		Extra cost (which is even worse considering full cycle NPV impact)
	145.7mt CO2 / day		Assuming 14.3kgpd fuel (incl. 10% refueling) at 22.46#CO2/gal
Difference	**~252,000 mt of CO2**		Extra CO2 exhaust from DP MODU (incl. fuel resupply vessels)
Difference	**~$25,000,000**		Assuming **$100/mt CO2 TAX** ($50-150/mt per Net Zero proposals

*Excluding Julia's $6B failed development that was sanctioned after just ONE appraisal well

Operating Fuel Consumption Comparison

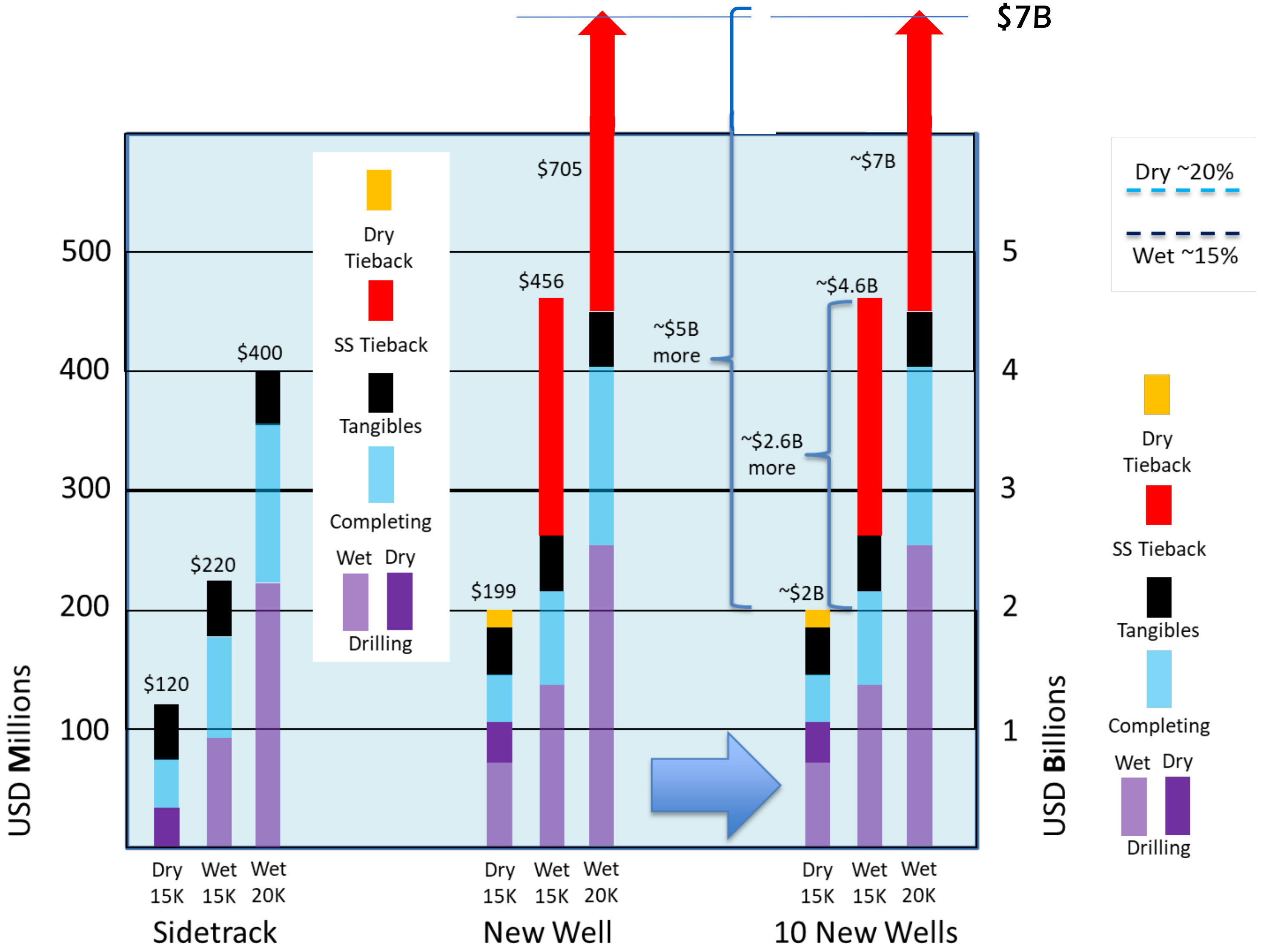
DAILY FUEL CONSUMPTION (incl. 10% fuel delivery burden)

WET (Subsea) CASE		
20Ksi DP MODU	14,300gals/day	13-15kgpd working (metocean sensitive)
Hub FPS	3,300gpd	3-4kgpd (**electrification** is possible)
TOTAL	**~17,600gpd**	
DRY (FrPS) CASE		
FrPS #1 (working)	4,400gpd	3-5kgpd (**electrification** is possible)
FrPS #2 (working)	4,400gpd	3-5kgpd (**electrification** is possible)
	8,800gpd	

Billions of Barrels will be left behind because…

The high cost of HP subsea well interventions & recompletions in ultra-deep waters means…

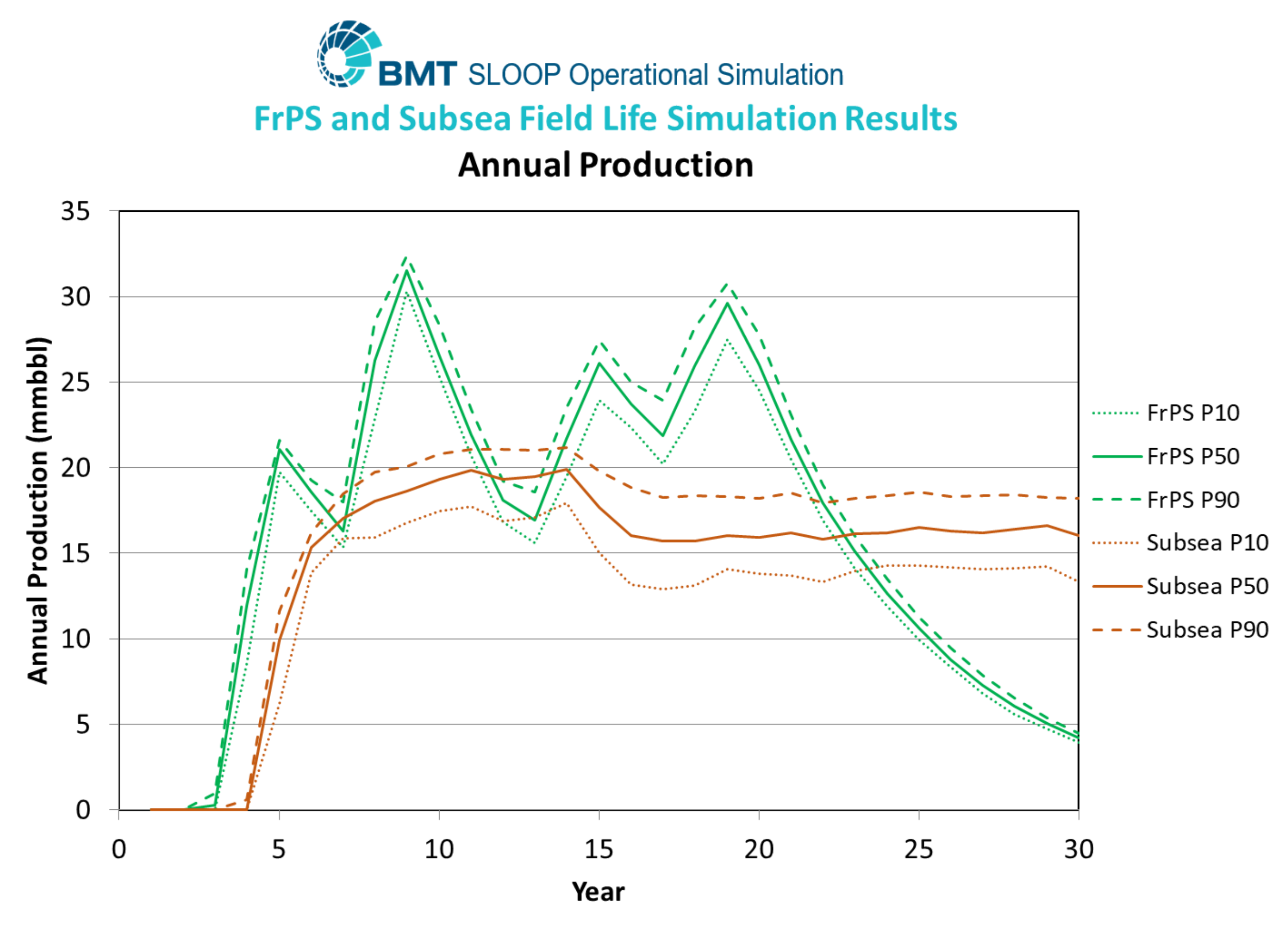
- More high cost appraisal wells needed to justify FID (w/o dynamic production data)
- Complex HP completions will produce less over core years
- Costly recompletions are harder to justify
- Subsea wells will be abandoned before dry tree wells



Comparing Production for Ultra-DW HP Wilcox Field

Key modeling aspects

- HPHT reservoir ("20Ksi subsea wells")
- Two drill centers each with five wells
- 15,000 bopd initial flow for all wells
  - Decays exponentially -4.86% every quarter
- Identical well performance and intervention requirements
- Identical reliability for completions
- BOPs mean failure at 180days (wet) / 270days (dry)
- Pre-drilling programs differ
  - WET case has 3 wells drilled to target depth
  - DRY case has just 2 wells to full depth, but 3 wells are drilled thru 14" casing string



Modeling Interventions

Three Interventions are modeled:

- Tubing clean-out
  - Required for each well at intervals between 2 and 5 years (rectangular distribution).
  - Well **production stops** as soon as this intervention is deemed as necessary, and not resume until the intervention has been completed.
- Acid stimulation
  - Required for each well at intervals between 2 and 5 years (rectangular distribution) once the total production from the reservoir exceeds 100 mmbbl.
  - Well **production stops** as soon as this intervention is deemed necessary, and not resume until the intervention has been completed.
- Production log.
  - Annual for the first seven years of the life of the well **and** for seven years after completing a side-track, postponed for a year after any other intervention.
  - **Production continues unabated** while this intervention is due but is suspended for most of the duration of the actual intervention.

NOTE – The start of any new well or sidetrack is delayed until an intervention is completed

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Well Operations – Detailed Intervention Model

Modeling – TUBING CLEAN OUT

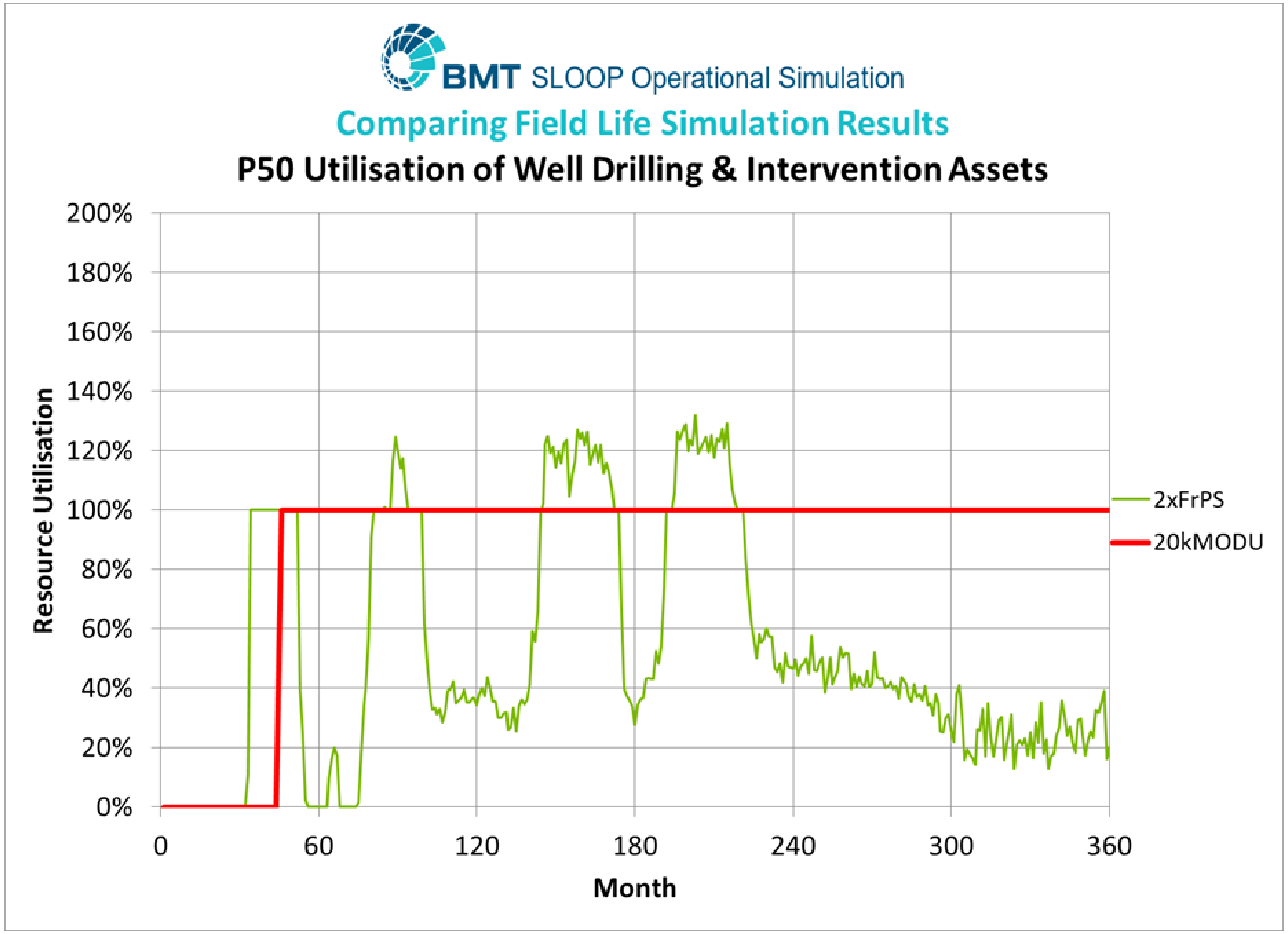
Wet	**Frontier Deepwater - Wet Tree Model**																	
Task	Operations				Hole	Running	**Suspend**				**Abandon**							
		Mininum	Median	Maximum	Section	Cost	Current	Wave	Wind	Time Penalty	Hurricane Forecast	Task Class	Next Task	Abandon Task	Task Priority	Fail Action	Fail Name	Fail Task
	20K MODU Clean Out	days	days	days			kts	ft	kts	h	h							
0																		
F	20K_MODU																	
1	Mobilize to location	1.45	1.82	7.27	Clean	$ 2,727,273	2.5	10	30	8	168	N	2	131	5	RF	M20K_BOP	
2	Rig-up & Stump Testing of Intervention System	2.91	3.64	14.55	Clean	$ 8,181,818	2.5	10	30	8	168	N	3	131		AF	Test_BOP	801
3	Run Intervention System & Subsea Test	2.55	3.18	12.73	Clean	$ 12,954,545	1.5	8	30	8	168	N	4	131		AF	Test_BOP	801
4	Move over & latch up.	0.36	0.45	1.82	Clean	$ 13,636,364	1.5	8	30	8	168	N	5	131		AF	Test_BOP	801
5	Subsea test	0.73	0.91	3.64	Clean	$ 15,000,000	1.5	8	30	8	168	N	6	131		AF	Test_BOP	801
6	RU 20K Slickline, Test & gauge runs	1.45	1.82	7.27	Clean	$ 17,727,273	2.5	10	30	8	168	N	7	131		AF	Test_BOP	801
7	RU & Test CT BOP's	1.45	1.82	7.27	Clean	$ 20,454,545	2.5	10	30	8	168	N	8	131		FF	M20K_BOP	231
8	RIH & Cleanout with xylene sweeps	3.64	4.55	18.18	Clean	$ 27,272,727	2.5	10	30	8	168	N	9	131		AF	Test_BOP	801
9	Load hole & POOH.	0.73	0.91	3.64	Clean	$ 28,636,364	2.5	10	30	8	168	N	10	131		AF	Test_BOP	801
10	Rig Down CT	0.73	0.91	3.64	Clean	$ 30,000,000	2.5	10	30	8	168	N	11	131		AF	Test_BOP	801
11	Rig up E-line equipment & Test.	1.45	1.82	7.27	Clean	$ 32,727,273	2.5	10	30	8	168	N	12	131		AF	Test_BOP	801
12	Dummy/Gauge Run	0.73	0.91	3.64	Clean	$ 34,090,909	2.5	10	30	8	168	N	13	131		AF	Test_BOP	801
13	PL Run while flowing to production facility	2.18	2.73	10.91	Clean	$ 38,181,818	2.5	10	30	8	168	N	14	131		AF	Test_BOP	801
14	Rig Down	0.73	0.91	3.64	Clean	$ 39,545,455	2.5	10	30	8	168	N	15	131				
15	Unlatch Riser System & Move to Safe Zone	0.36	0.45	1.82	Clean	$ 40,227,273	1.5	8	30	8	168	N	16	131				
16	Pull Riser System	2.18	2.73	10.91	Clean	$ 44,318,182	1.5	8	30	8	168	N	17	131				
17	Demob	0.73	0.91	3.64	Clean	$ 45,681,818	2.5	10	30	8	168	N		131				

Working to keep up with the field's demands

Comments on P50 Rig Utilization

- Once FrPS #1 comes on duty, it is fully occupied with D&C for the wells at Drill Center #1 (mos. ~34 thru 52)
- Once FrPS #2 comes on duty, it is fully occupied with D&C for the wells at Drill Center #2 (mos. ~80 thru 98)
- Their combined utilization exceeds 100% during the 2 sidetracking programs… otherwise, demand is low
- The 20Ksi MODU is fully occupied at the field once it arrives ~46th month

NOTE – This graph excludes work by the 15Ksi DP MODUs

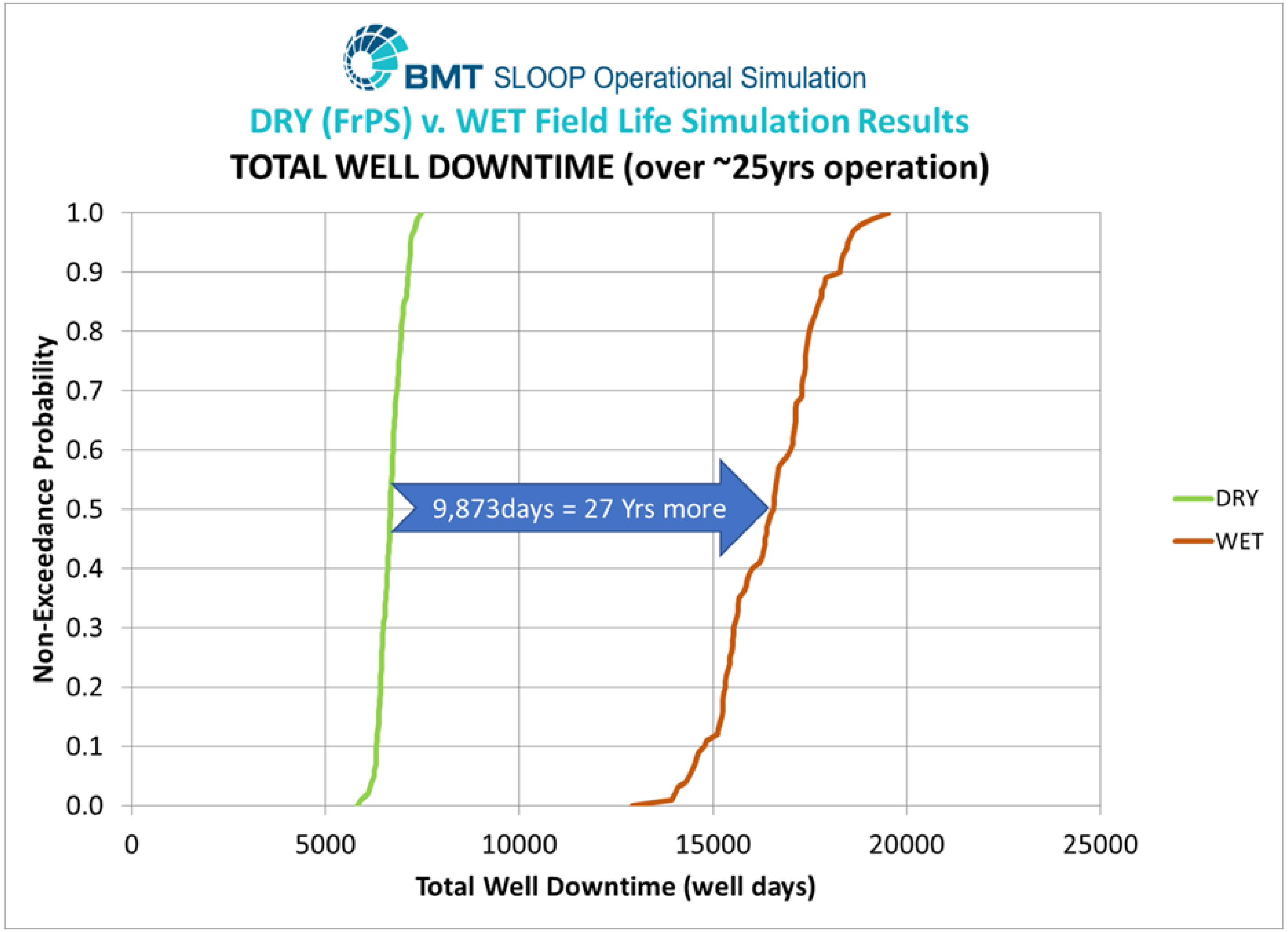


Having 2 rigs is better than 1 (of course)

P50 expectation is that the WET/subsea development will experience 27 years more well downtime (i.e., not producing)

- The DRY case also suffers well downtime due to many causes that will be explored further on…
- Operating 2 rigs can be expensive, but the OPEX is still much lower than keeping a 20Ksi DP MODU fully employed

[**Total "well downtime"** includes periods when producing wells are being serviced or sidetracked / recompleted… and, times when a well needs a critical service but the rig is otherwise occupied.]



So, what does this add up to?

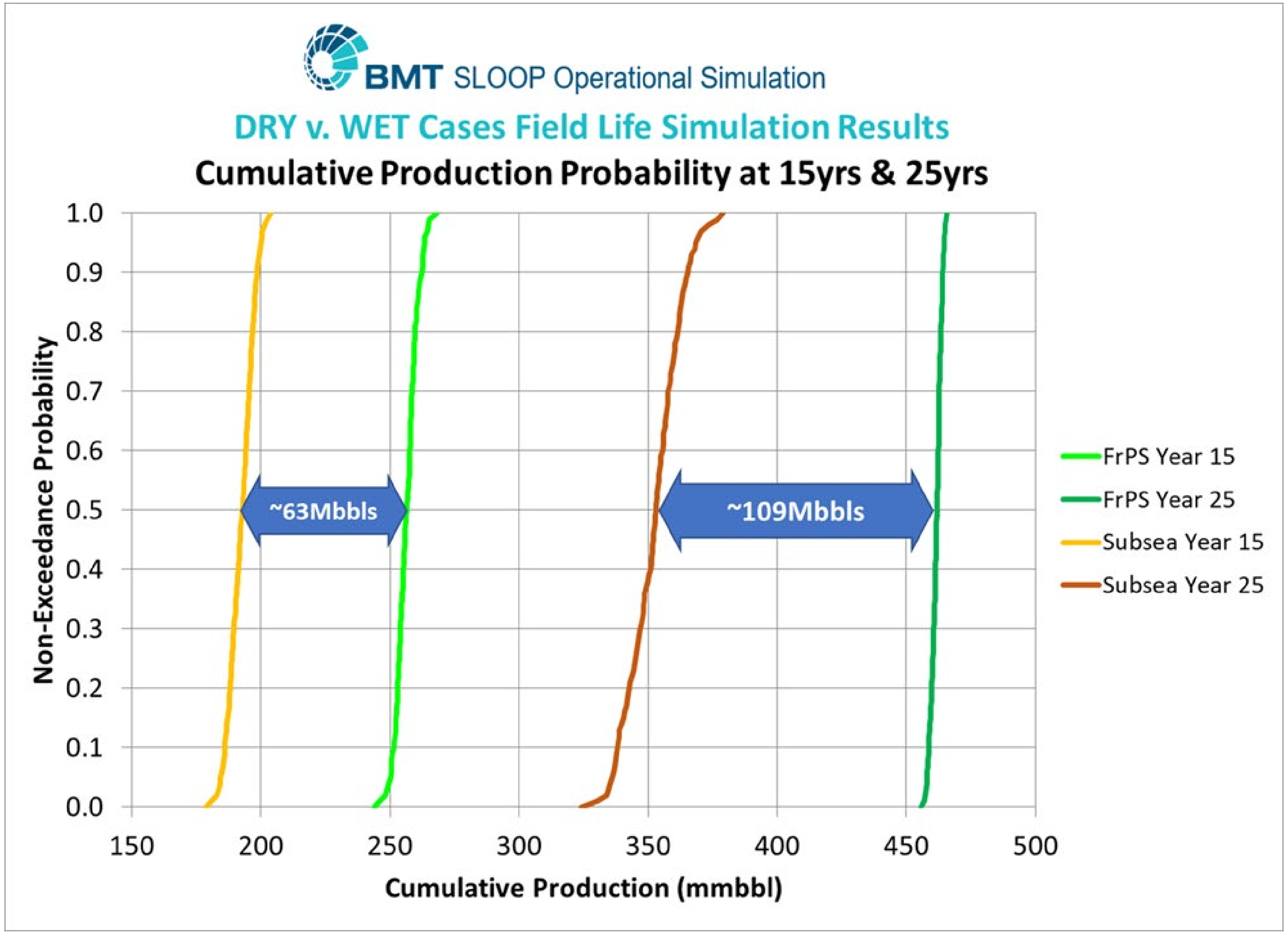
In the first 10 to 20 years of operations, the WET case falls far behind

At P50, assuming $100/bbl…

- The DRY case will generate >$6B more revenue by Yr15
- By Yr25, the DRY case will have **>$10B** higher revenue
- After Yr25, the WET case cumulative production begins to catch up…

That is, IF the FrPS units do no more sidetracks by!

Our model only allowed ONE sidetrack per well.

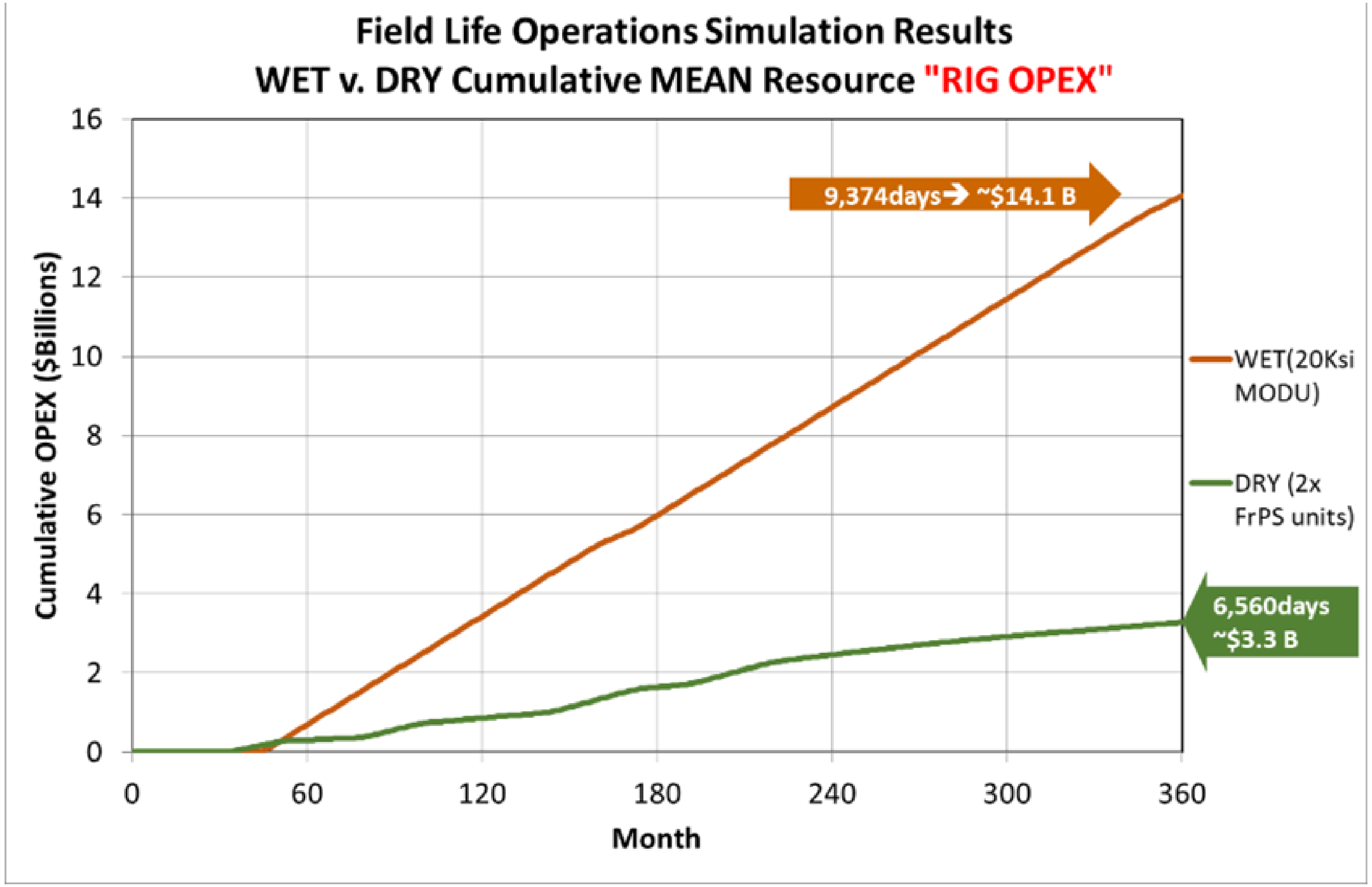


But, can we really afford to have 2 rigs working?

The answer appears to be a big YES…

- By the end of the 30yr simulated lifecycle, <u>mean</u> total days worked was
  - **9,374days** (~25.7yr) for the 20Ksi MODU
  - **6,560days** (~18yrs) for the two FrPS units combined
- At full "all up" dayrate when working
  - The 20Ksi MODU has cost the Operator **~$14.1B** (at $1.5M/day)
  - The two FrPS rigs have cost **~$3.3B** (at 2x $250K/day = $0.5M/day)

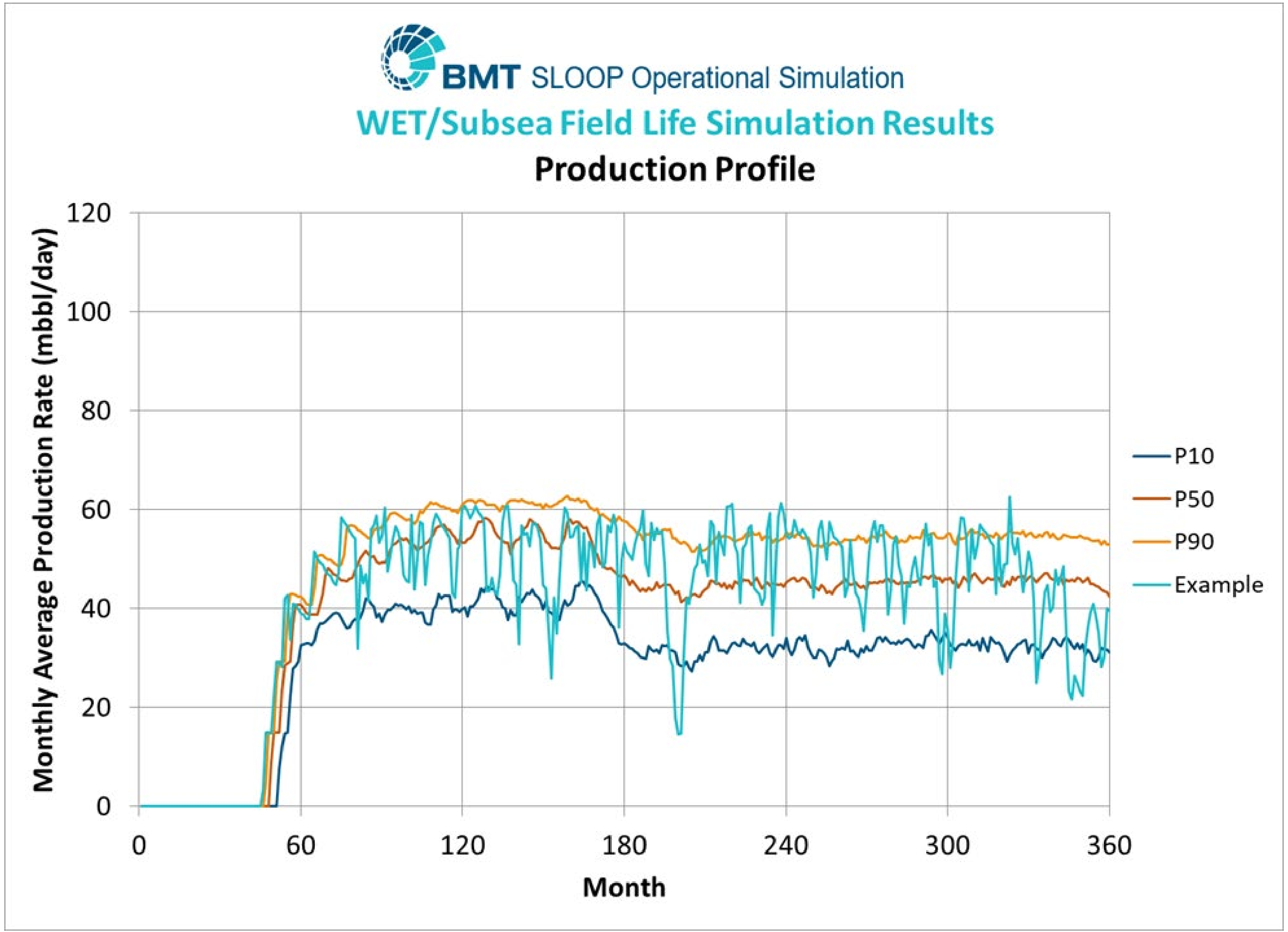
<u>**NOTE**</u>: Costs **exclude** the hub FPS in the WET case and for the FrPS units as "producers" in the DRY case



Generating the Production Profile Statistics

Revealing "hidden complexity"

- 240 randomized realizations of 30yr lifetimes provide meaningful statistics
- However, aggregated data yields smoothing that belies the complexity
- Overlaying one "Example" realization on the aggregated statistical curves in this graph gives a sense of the variability in monthly production that the simulations generate
    - Big dips in production may be due to hurricanes or, for deeper/longer dips, by an extended absence of the 20K MODU



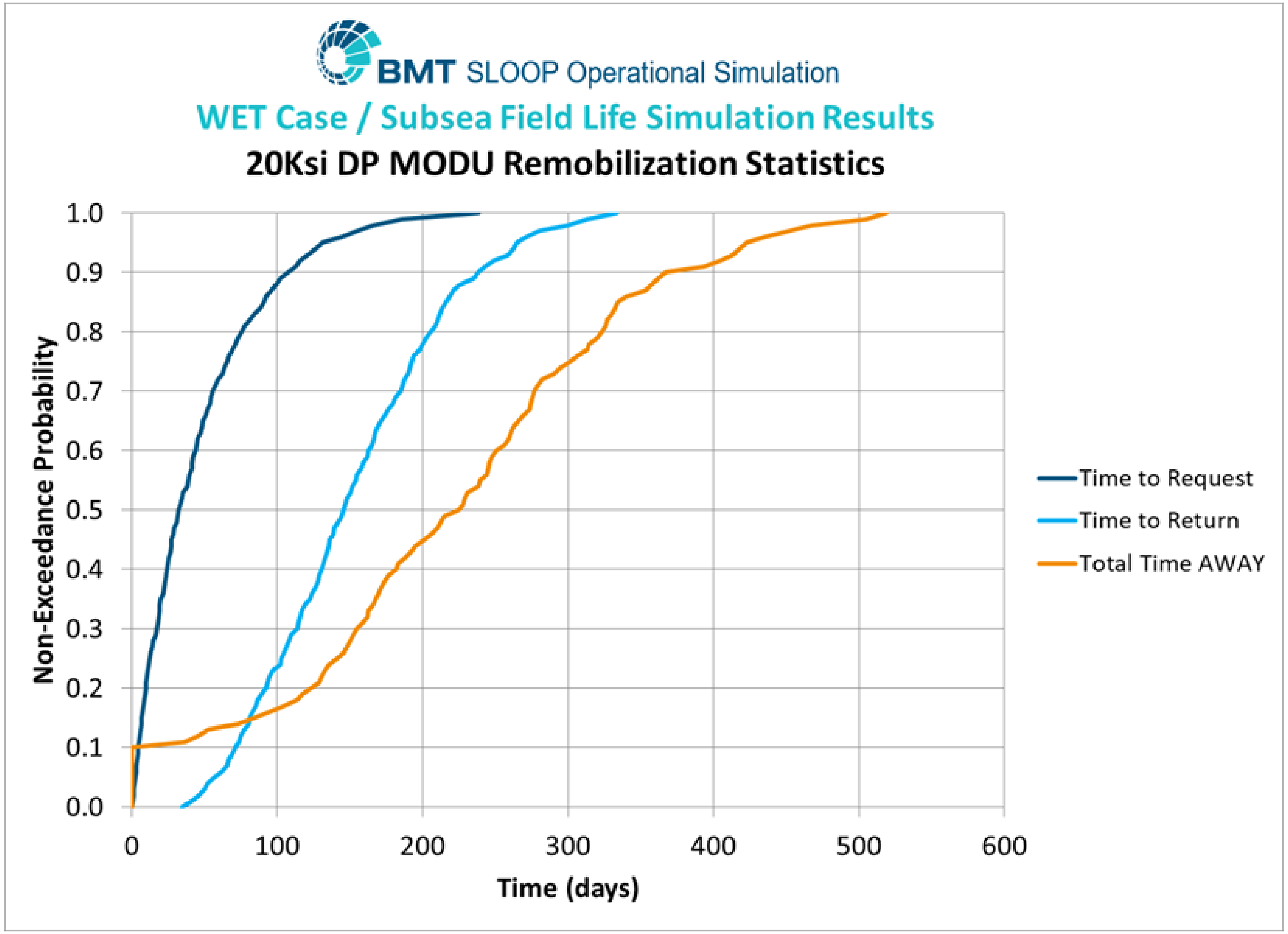
Allowing the 20Ksi MODU to leave (temporarily!)

Modeling policy allowed the MODU to leave and work elsewhere if "idle time" occurs because…

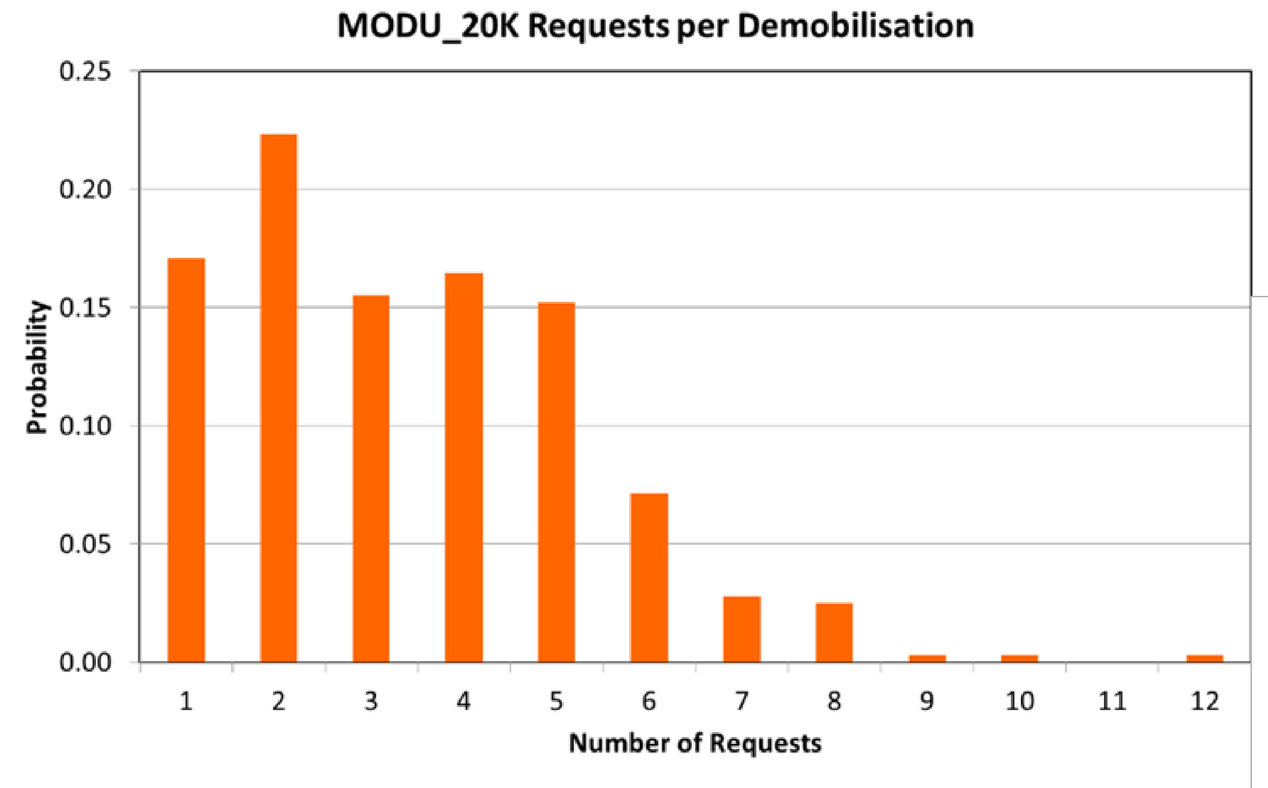
- The field owners may want the rig to service another field they own – possibly to drill a well
- Still, for ~11% of the realizations, it never gets a chance to leave the field
- But, there's a 50% probability that if it does leave, it will be ~224days before it returns to work
- Even though there's a 50% likelihood that a service request popped within ~32days after departure

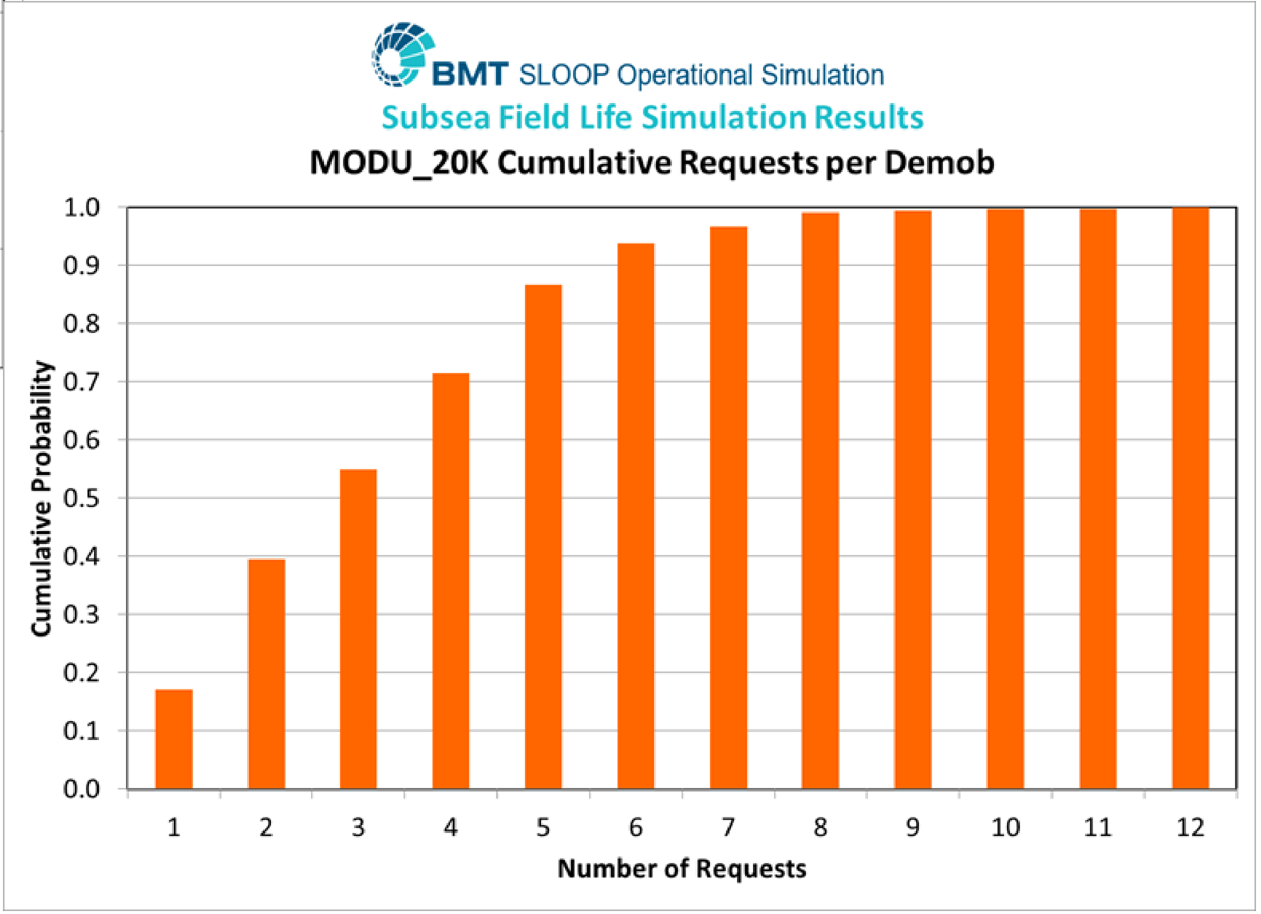
So, the Operator will be wondering…

- **How big a backlog are we going to face?**



20Ksi DP MODU Service Request Backlog Statistics





If a Demob does occur there will be...

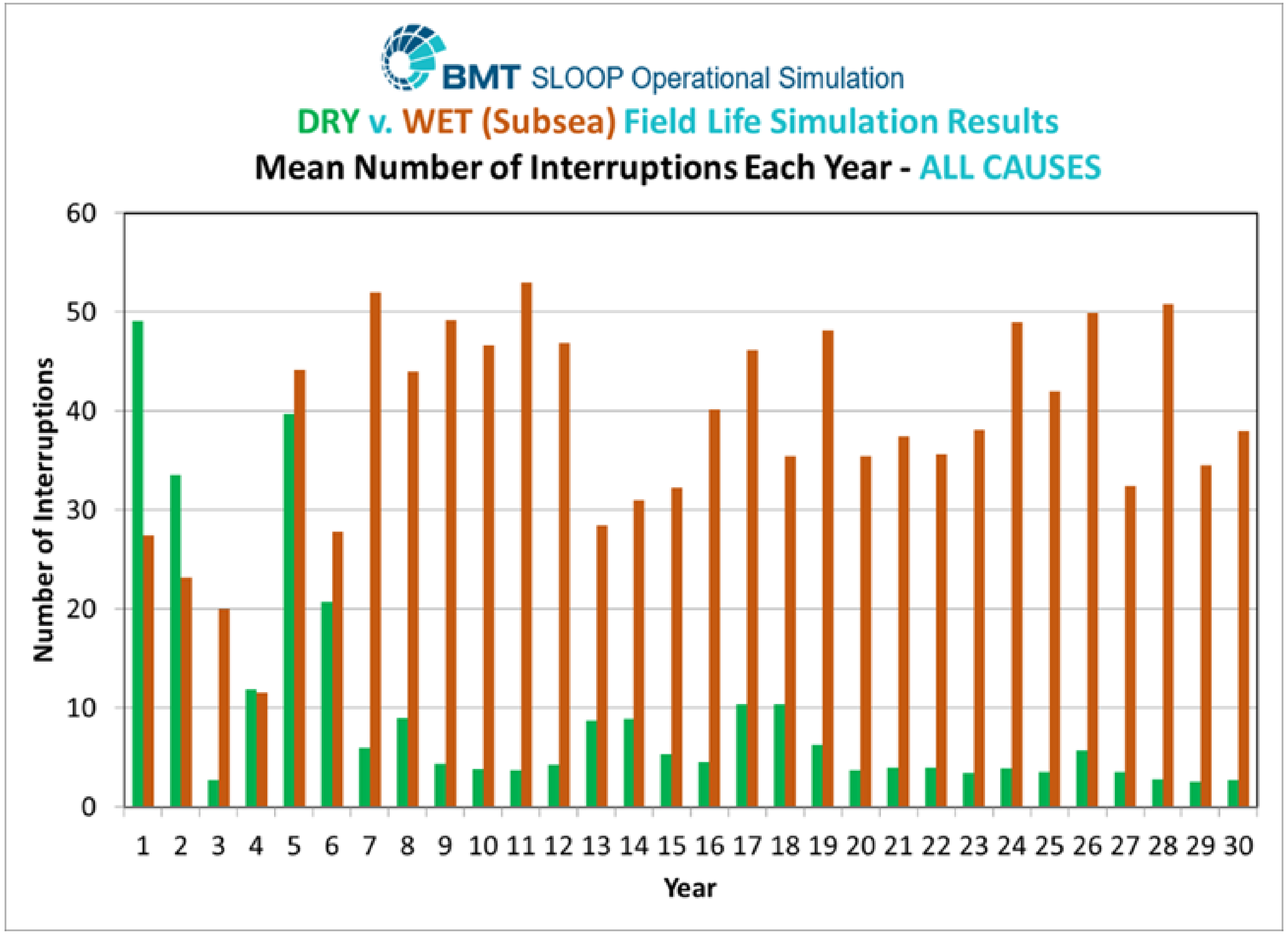
- >60% likelihood of 3 or more service requests piling up with
- ~30% chance that >4 jobs will be waiting when the MODU returns to the field, and
- ~5% chance of 7 or more jobs waiting

Well Operations face weather & equipment interruptions

Interruptions are caused by

- Severe metocean conditions
  - Winds, waves, and/or currents
  - Hurricanes... predicted and actual arrival completely shut down production and well ops for both cases
- **BOP failures** (as the only equipment failure modeled) using industry-wide study results:
  - Subsea MUX BOPs have **180days** mean time to failure (MTBF)
  - Surface / direct hydraulic BOPs have **270days** MTBF

The DRY case suffers more interruptions during pre-drilling with the15Ksi MODU



The DRY case sees small increase when sidetrack/recompleting

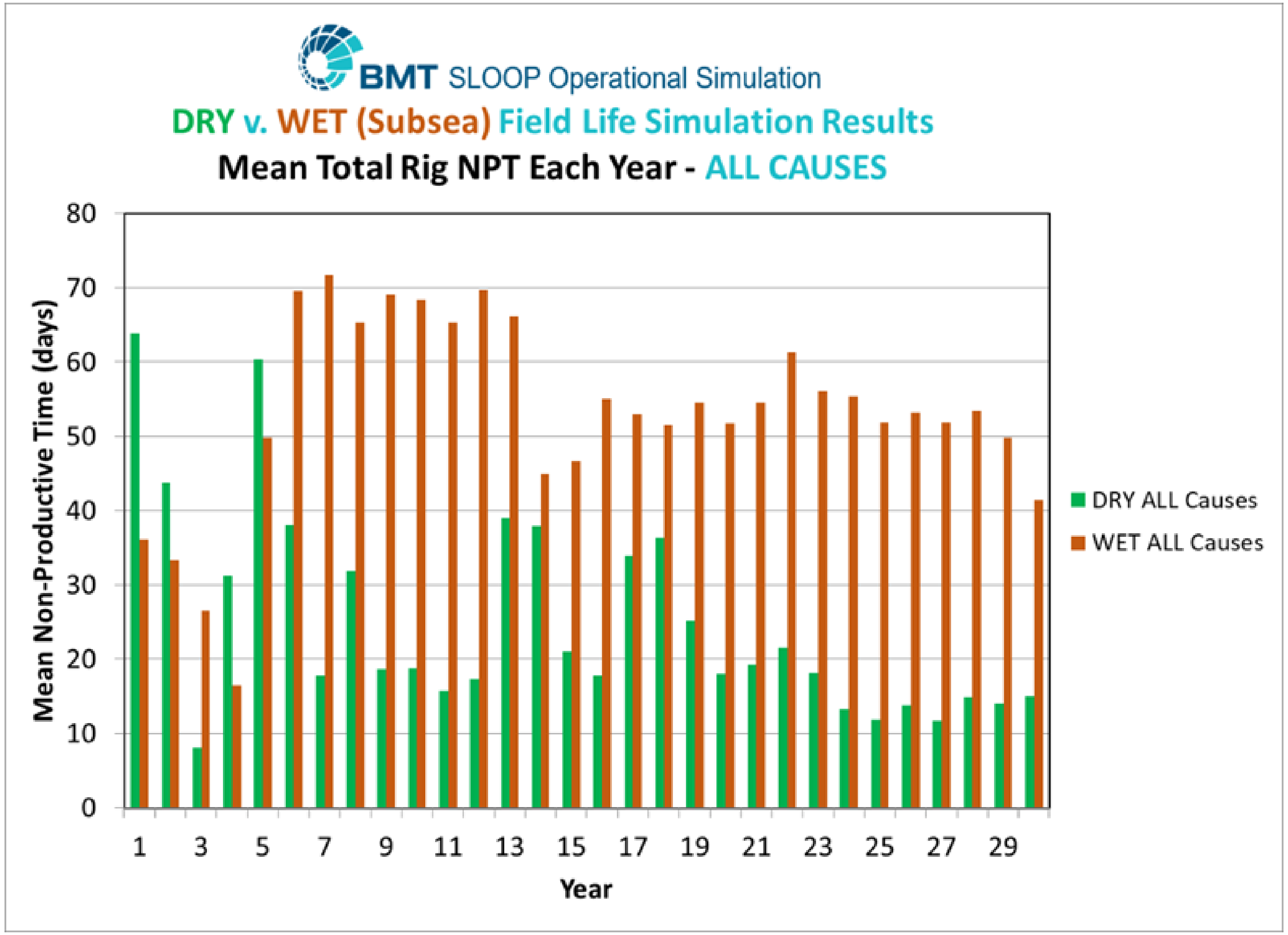
Mean Total Annual Rig Non-Productive Time [ALL CAUSES]

Rig NPT statistics

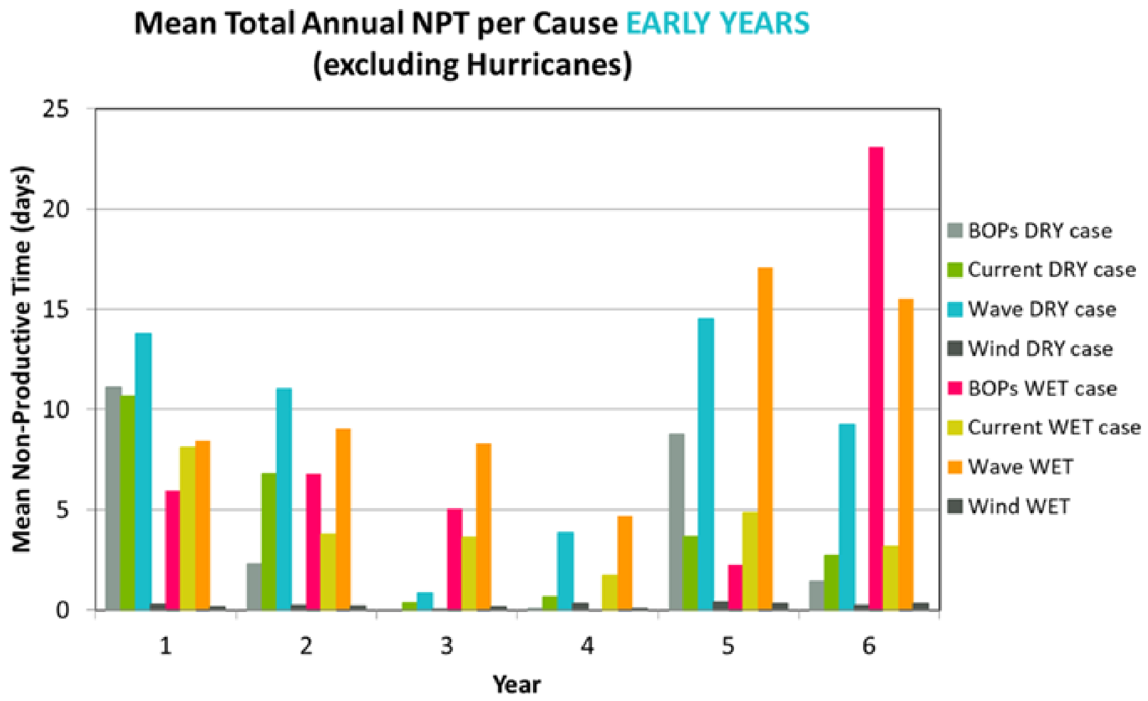
- The WET case 20Ksi DP MODU will experience a lot more NPT

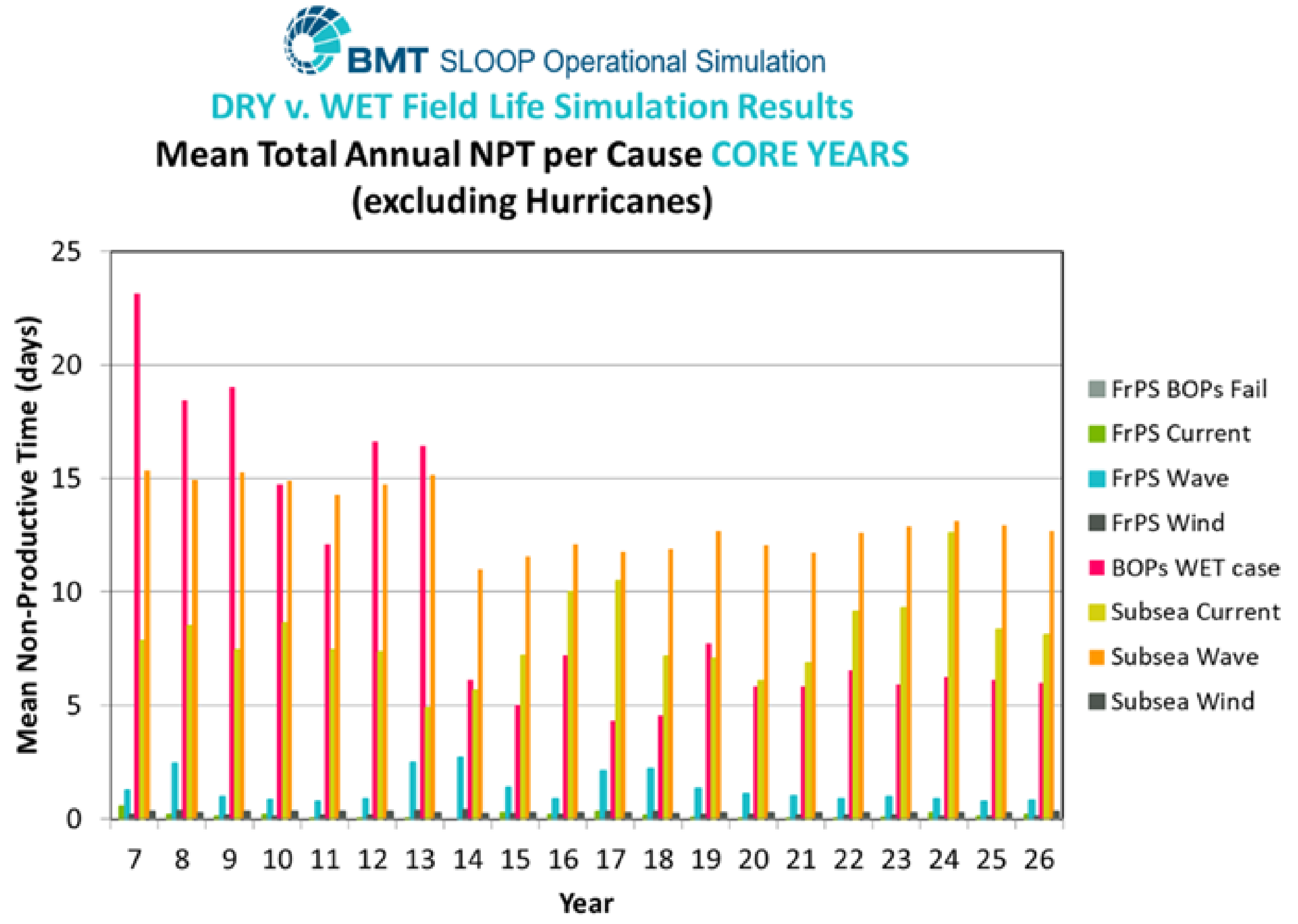
However,

- We do see some big hits on the DRY case in the early years and when in the sidetrack / recompletion programs



Mean Total Annual NPT per Cause





NPT *excluding hurricanes*

- BOP failures dominate NPT for the WET case in Yr 6 as the 20Ksi DP MODU arrives and the 15Ksi MODU moves to Well Center #2
- WET case's 15Ksi MODU finishes up in Yr 7
- Deepsea currents and waves are always big part of NPT for the WET case

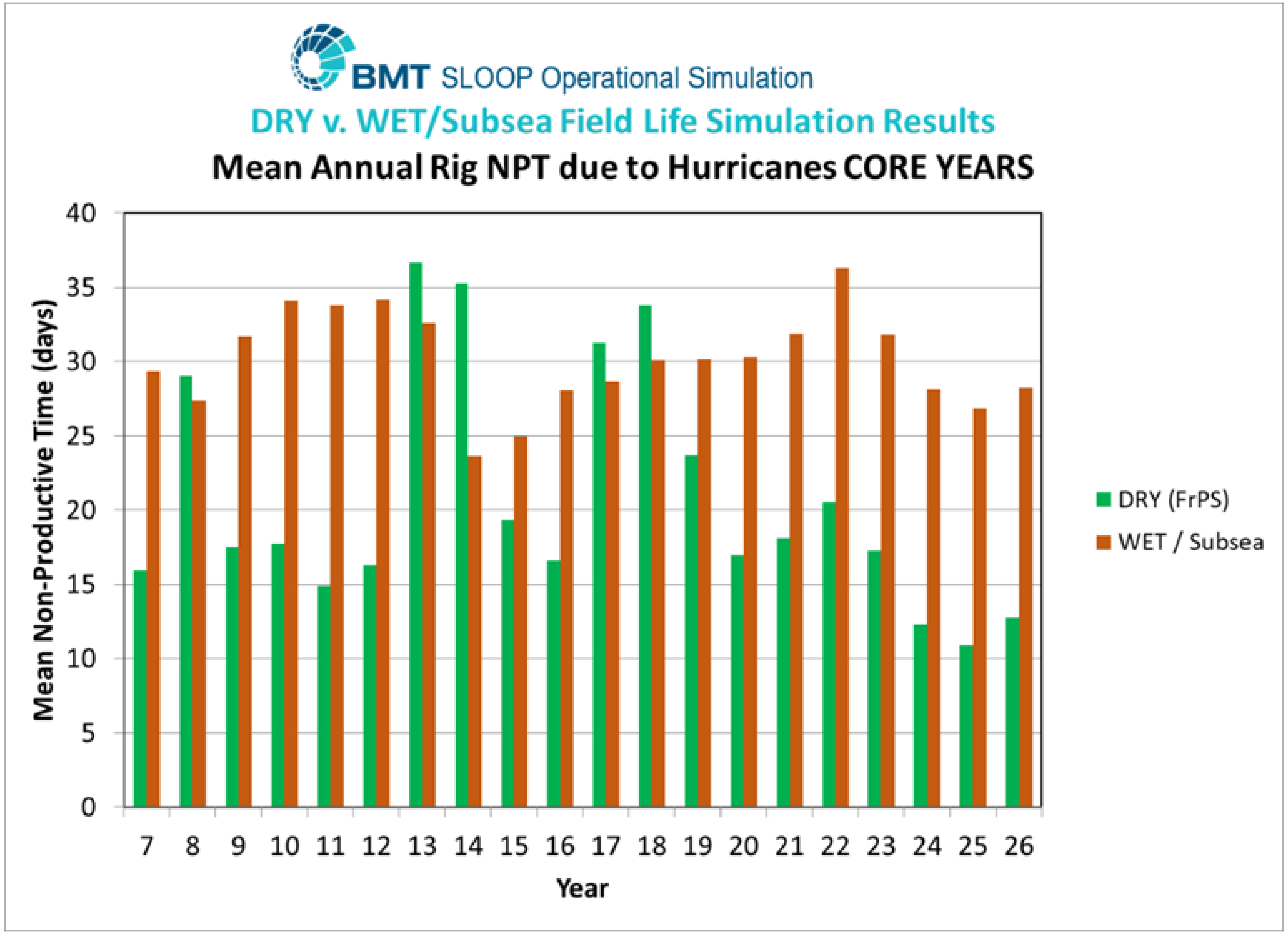
Hurricane-induced Mean Total Annual NPT - CORE YEARS

Key observations

- When the FrPS units of the DRY case are sidetracking / recompleting wells, hurricane-induced NPT rises dramatically

Still,

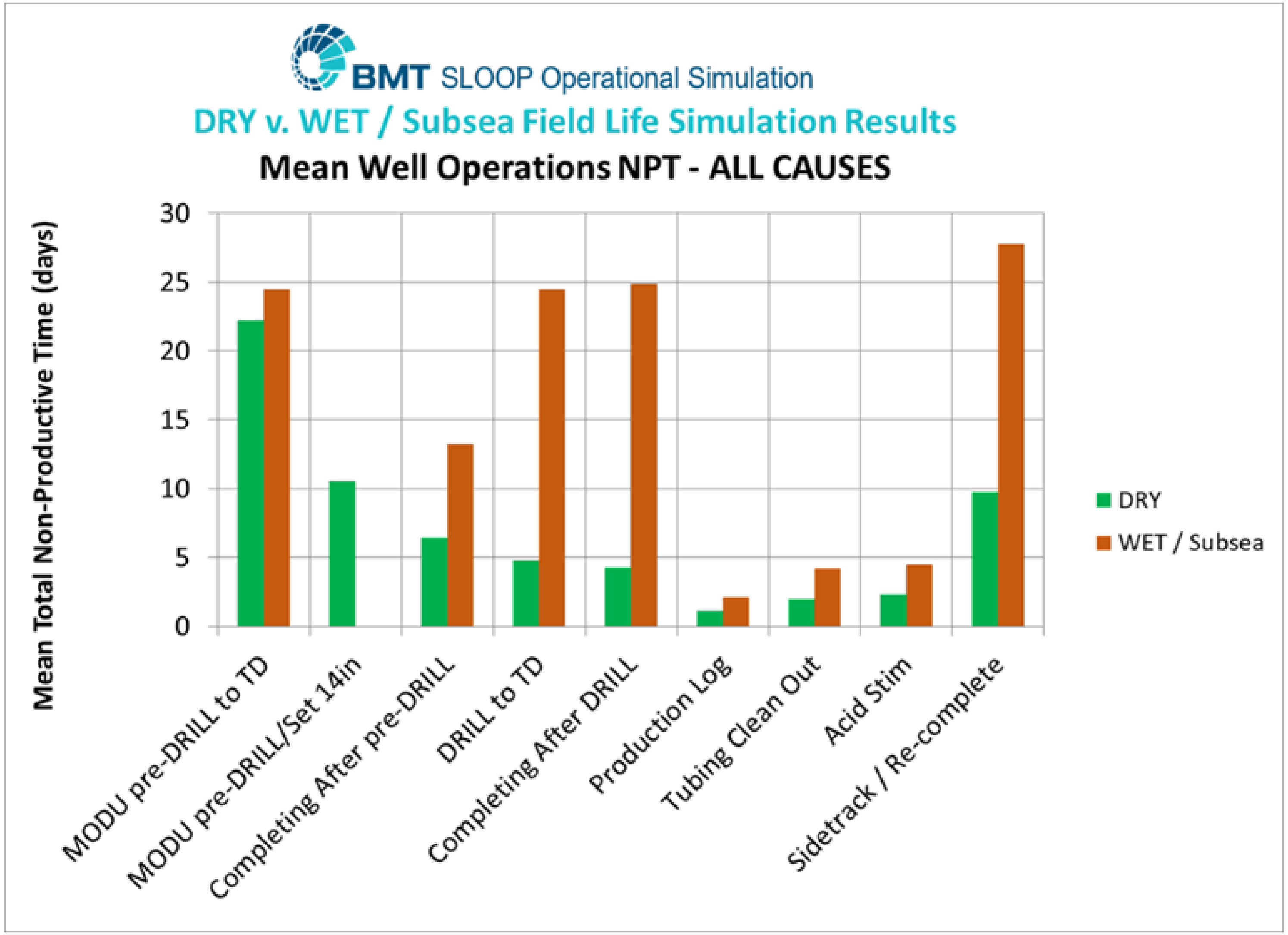
- On average, the WET case experiences about 50% more hurricane-induced NPT… primarily, because restart of operations takes longer



Well Operations NPT - ALL CAUSES

Key observations on NPT during specific well operations

- In the first 6 years of the project, DRY case NPT is a combination "MODU pre-DRILL to TD" plus "MODU pre-DRILL/Set 14in"
  - 22.2 days + 10.5 days ~ **33days**
- NPT for WET case pre-drilling is just **24.5 days**
- NPT for WET case exceeds the DRY case for all other operations



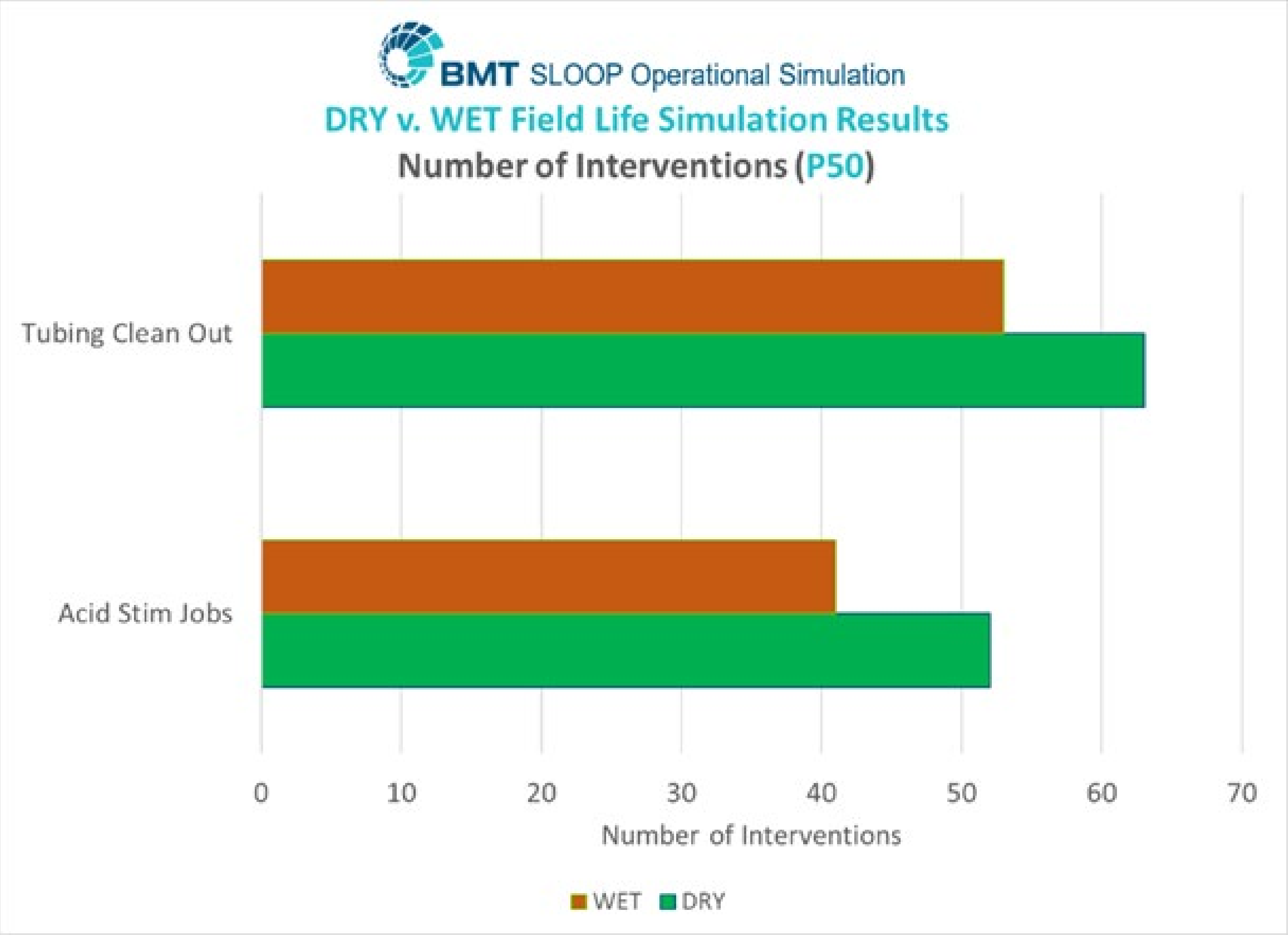
Results from the full life simulations - **not just core producing years**

Well Interventions Performed

- Rig Utilization statistics show that the FrPS units have no trouble keeping up with service requests
- As a result, more of the most critical well service requests can be handled over the lifecycle
- Production is interrupted, every time a stim job or tubing clean out is "flagged" as required… and, while the service is being performed

So,

- If more interventions are being performed, it is important that they are done timely and efficiently as well as safely
- If needed interventions are not being performed, field production dips



Future Deployment Opportunities

Many ways & places to use the Movable Wellbay

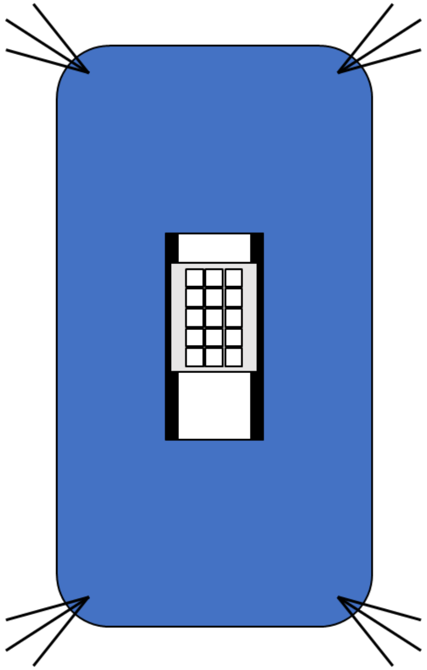
Drill Rig Conversions

- 5th or 6th+ gen semi's
- Dry Trees (>5 wells in mild waters)
- Dry Tree + Remote Subsea wells
- Direct Access Subsea Wells with "lift" + Remote Subsea wells

NEWBUILDING FDPUs & FDPSO's

- Semi's, barges, buoys, spars… and TLPs!
- Many Dry Tree wells (>10 wells)
- Dry Tree + Remote Subsea wells
- Direct Access Subsea Wells with "lift" + Remote Subsea wells

Movable Wellbay for FDPSO in mild deep waters



ABS Approval in Principle	*2017*
BSEE Concept Review	*2018*
US & Foreign Patents	*2018-2019*

A World of Opportunities!

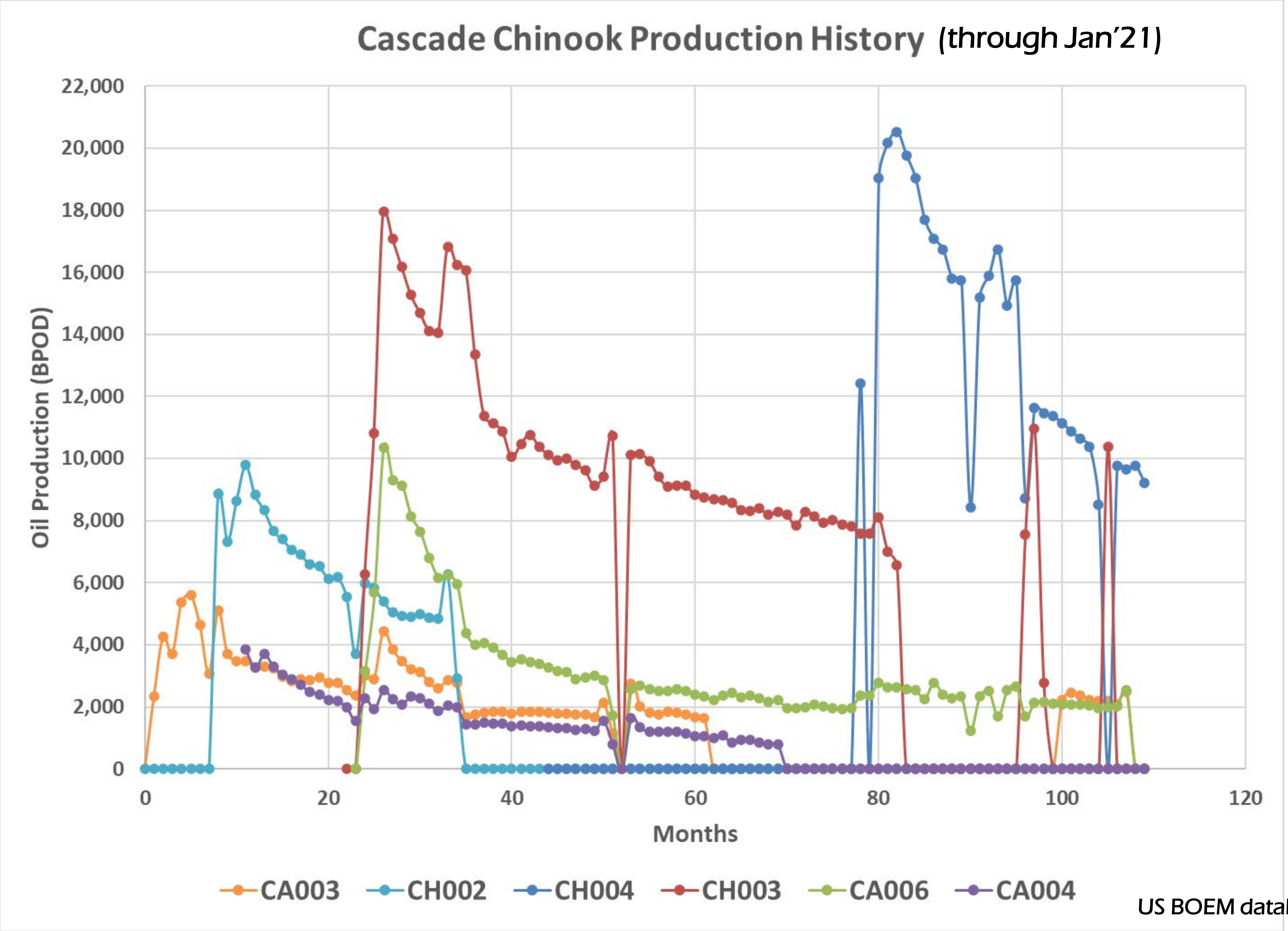
Oil Production TOTALS (Mbbls thru Jan'21)

- Cascade ~15.7
- Chinook ~35.4
- TOTAL ~51.1Mbbls

WELLS

- CA003 ~5.1
- CA004 ~2.9
- CA006 ~7.7
- CH002 ~5
- CH003~18.4
- CH004 ~12.1

The only well onstream by Feb'21 was CH004, producing almost 9,000bopd



US BOEM database

… NEXT STEPS

Proposed Pre-FEED Study Objectives

Perform SELECT engineering on 6th Gen Semi with movable wellbay design for Gulf of Mexico environment:

- Acquisition* and conversion of existing MODU
- 5 slot movable wellbay with dual barrier drilling and production risers
- Permanent synthetic mooring system (HMPE or polyester)

Confirm FrPS design and cost:

- Vessel air gap in extreme wave events
- Mooring system sizing and cost
- Production module sizing and rig integration
- Production riser sizing and stroke requirements
- Movable wellbay configuration and loads

** - Locking in "study basis MODU" is additional cost*

Pre-FEED Work Breakdwn Scope

1. Design Basis
2. 65K BPD Production Module and 6th Gen Semi Rig Interfaces
3. Mooring System Design & Air Gap Analysis
4. Design of Movable Wellbay
5. Dual Barrier Production Riser Design
6. Select Cost and Schedule Estimate
7. FEED engineering plan

6 - 9 months, $1-1.5 M

Appraise	Select	Define	Execute	Operate

Discuss NEXT STEPS?

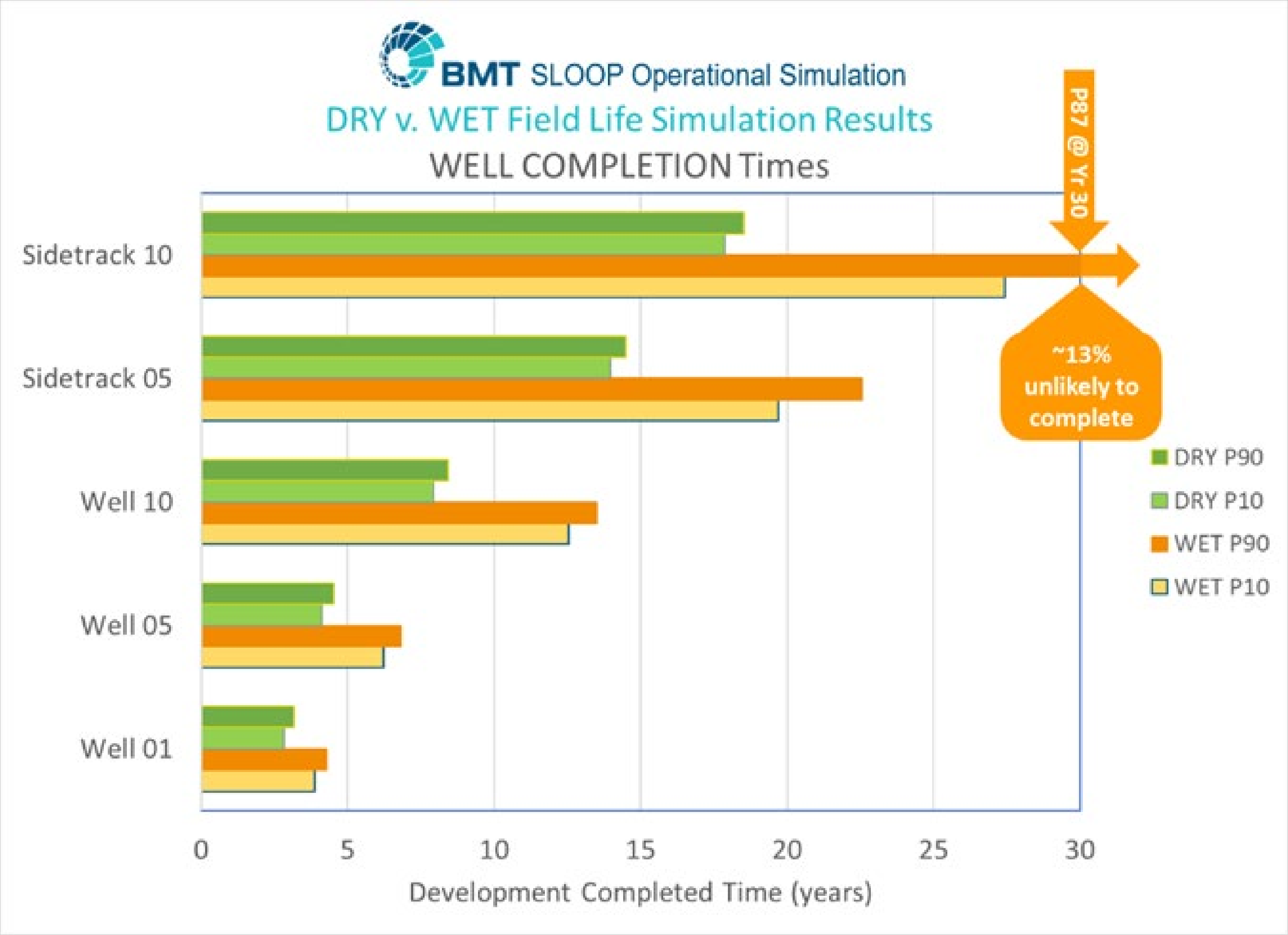
Thank you!

BACK-UP SLIDES

Timing for WELL COMPLETION Milestones

P10-P90 results

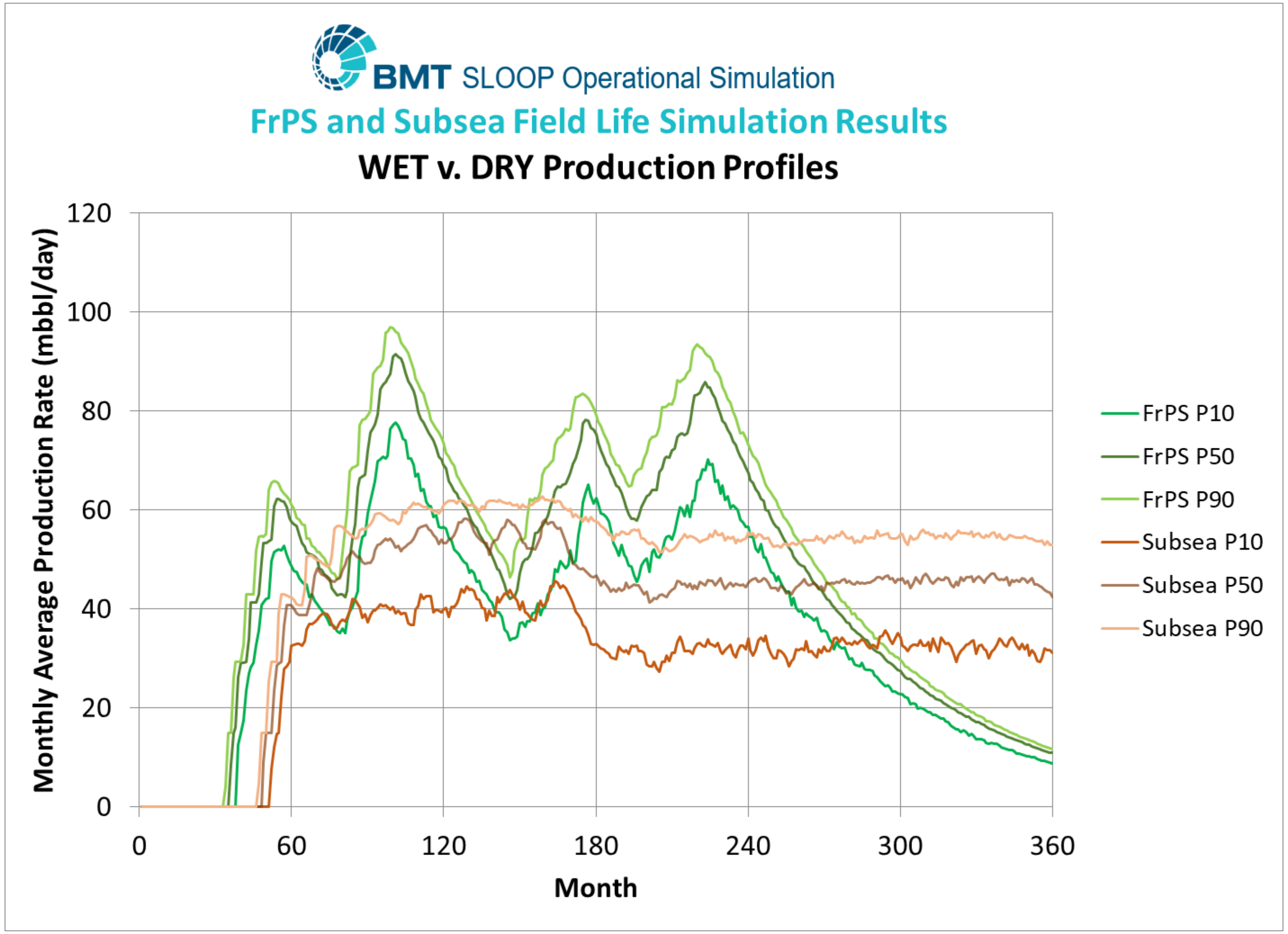
- DRY case has all 10 of its wells completed within years ~8.5 years,
- WET case does not finish until 5 years later
- Sidetracking results are even more disappointing for the WET case as the 10th sidetrack has ~13% chance of being delayed to beyond Yr 30



Comparing Production for Ultra-DW HP Wilcox Field

Key modeling aspects

- HPHT reservoir (“20Ksi subsea wells”)
- Two drill centers each with five wells
- 15,000 bopd initial flow
  - Decays exponentially -4.86% every quarter
- Identical well performance and intervention requirements
- Identical reliability for completions
- BOPs mean failure at 180days (wet) / 270days (dry)
- Pre-drilling programs differ
  - WET case has 3 wells drilled to target depth
  - DRY case has just 2 wells to full depth, but 3 wells are drilled thru 14” casing string



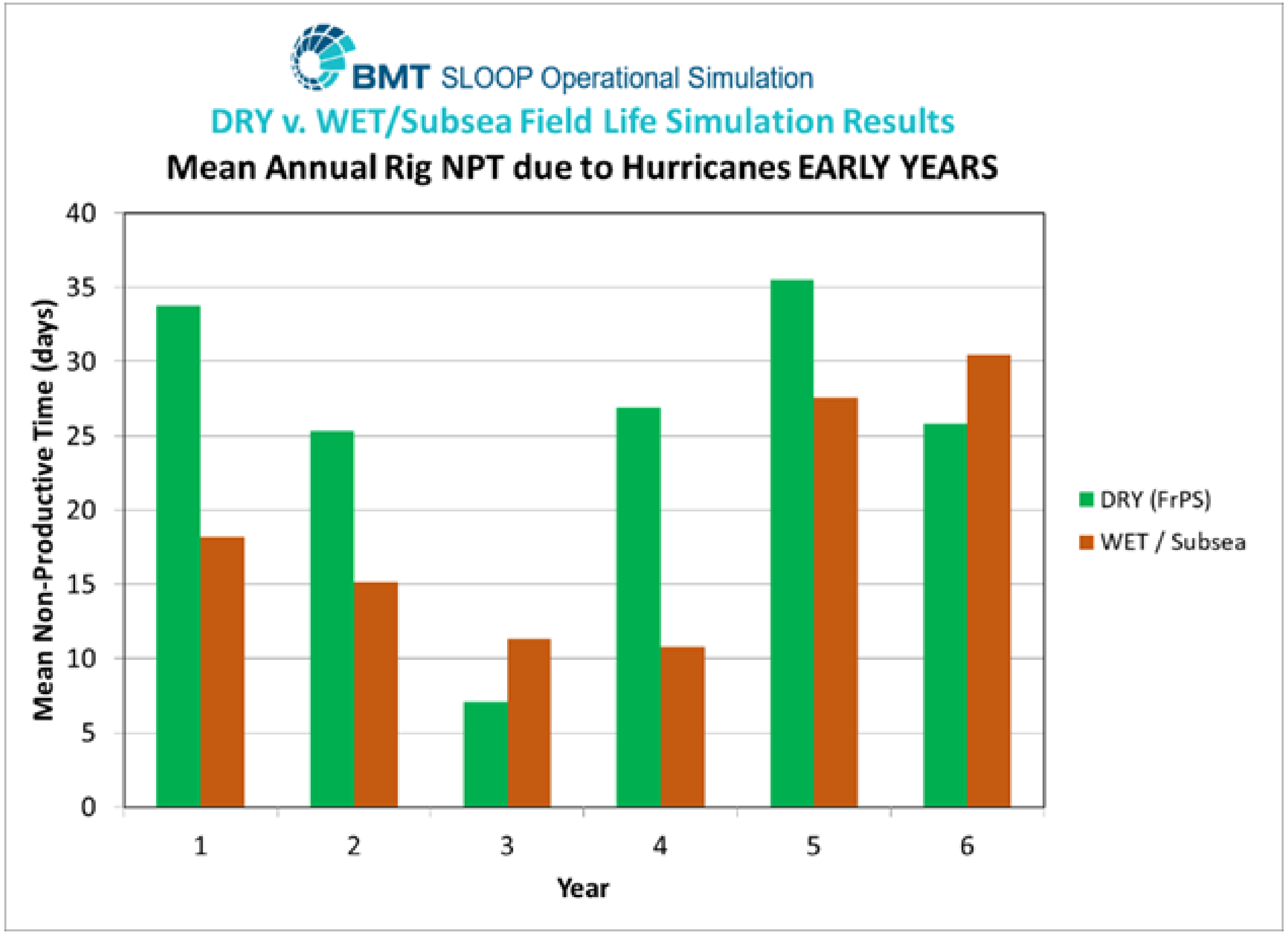
At $100/bbl, WET case “simple” $NPV_{8\%}$ at Yr15 lags by $3.5B; at Yr25 by $4.7B; $4.1B at Yr30

Hurricane-induced Mean Total Annual NPT - EARLY YEARS

Key observations

- DRY case suffers more hurricane-induced NPT during pre-drilling
- When the 20Ksi DP MODU arrives, the WET case NPT catches up

- *Hurricane NPT dominates for the FrPS units overall (on average ~90% of NPT)*
- *Since many other issues impact the WET case, NPT due to hurricanes is just over 50%*



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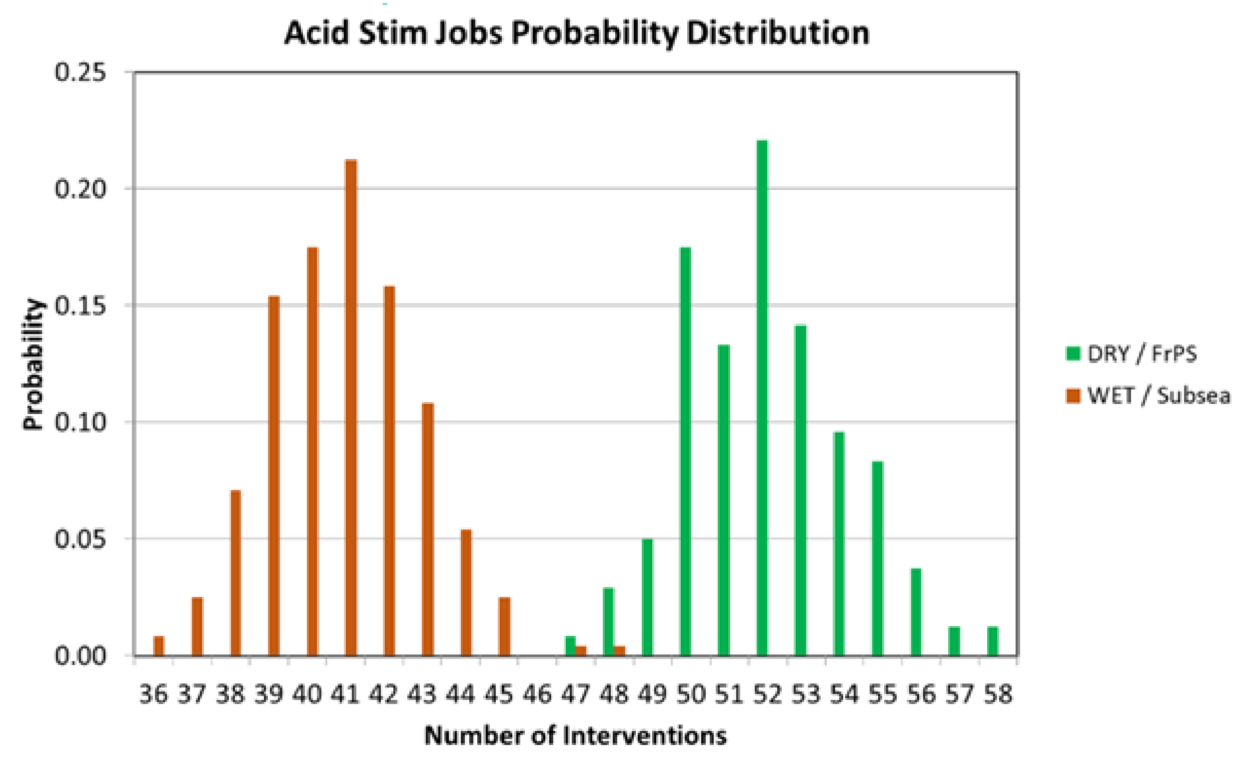
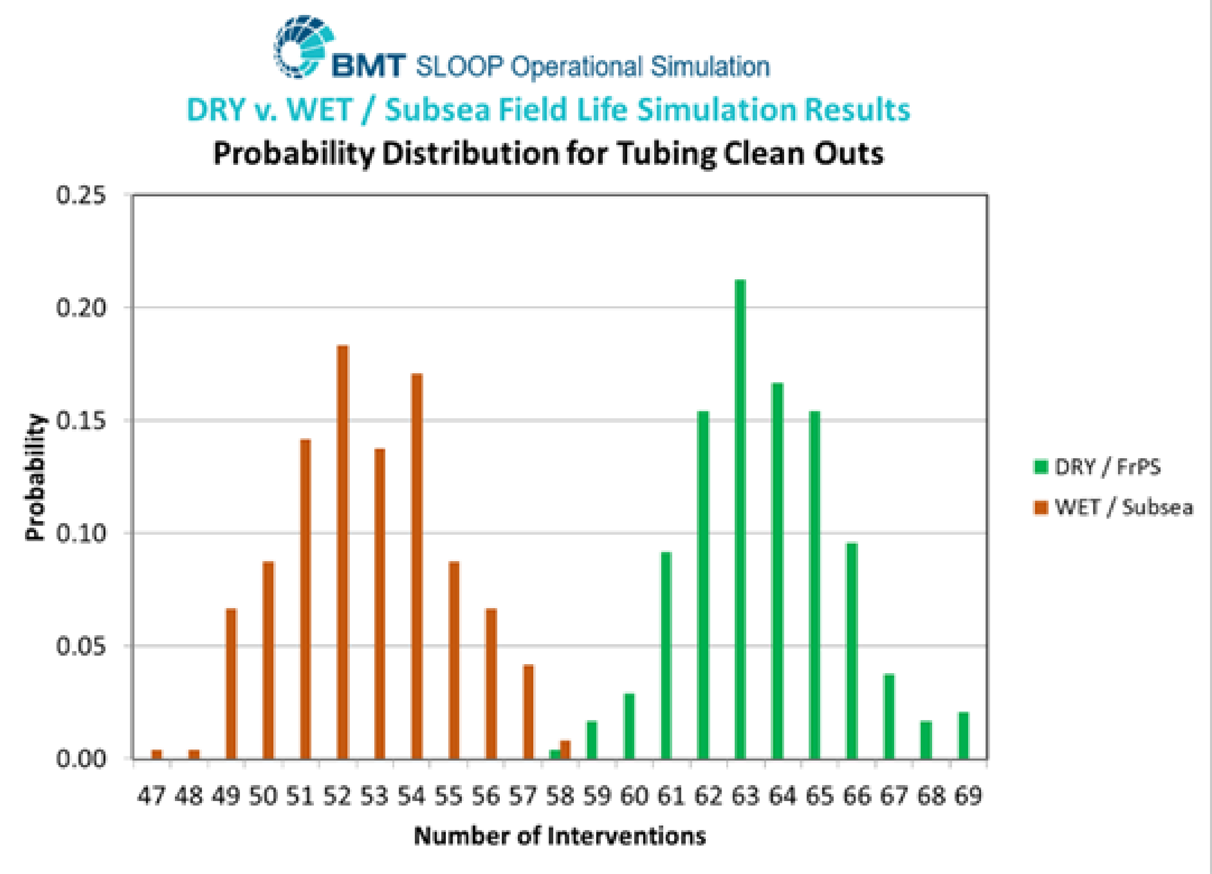
The Next Step in Deepwater – Proven Solutions with Innovation

Well Interventions Performed





- Rig Utilization statistics show that, unlike the WET case, the FrPS units have no trouble keeping up with service requests
- As a result, more of the most critical well service requests can be handled over the lifecycle