Reservoir Facies Impact on Drilling, Completion and Production in the Cardium Tight Oil Play*

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Abstract

Development of the Cardium tight oil play through horizontal drilling and multistage hydraulic fracturing since 2008 has established an important unconventional resource. With approximately 3,900 Cardium horizontal wells with multistage hydraulic fracture treatments drilled to date, industry continues to push towards the depositional limits of the Cardium play fairway, where understanding the reservoir is key. The two main Cardium reservoir facies, thickly bedded sandstones and bioturbated sandstones, are described and their reservoir characteristics discussed. This presentation discusses the impact of the reservoir facies on drilling, completion and production from three distinct areas of the play, West Pembina, Garrington and Lochend. Regionally, the study area is spread over 250 kilometers from northwest to southeast within the Cardium play fairway.

Beginning in the northwest at West Pembina, the Cardium reservoir is characterized by thickly bedded sandstones in a halo around the conventional Pembina Cardium oil field. Further south at Garrington, the Cardium reservoir is characterized by bioturbated sandstones with reservoir permeability too low to be economically developed by vertical wells. The most southern area is Lochend and there the Cardium play is characterized by thickly bedded sandstones overlying bioturbated sandstones with reservoir previously too thin for economic development by vertical wells. Drilling considerations such as well bore placement, steering (sliding percentage), number of bit runs, and time drilling the lateral section are compared in the three areas. Completion design can be optimized through understanding the influence of reservoir facies on completion break-down

pressure, scour requirements, pumping rates and proppant size and concentration. Optimal completion design lessens occurrences of missed stages and screen outs. Ultimately, more efficient drilling and completion operations reduce costs and improve well economics.

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http://ags.aer.ca/publications/chapter-pdfs

IMPACT OF DEPOSITIONAL FACIES ON DRILLING, COMPLETIONS AND PRODUCTION IN THE CARDIUM TIGHT OIL PLAY

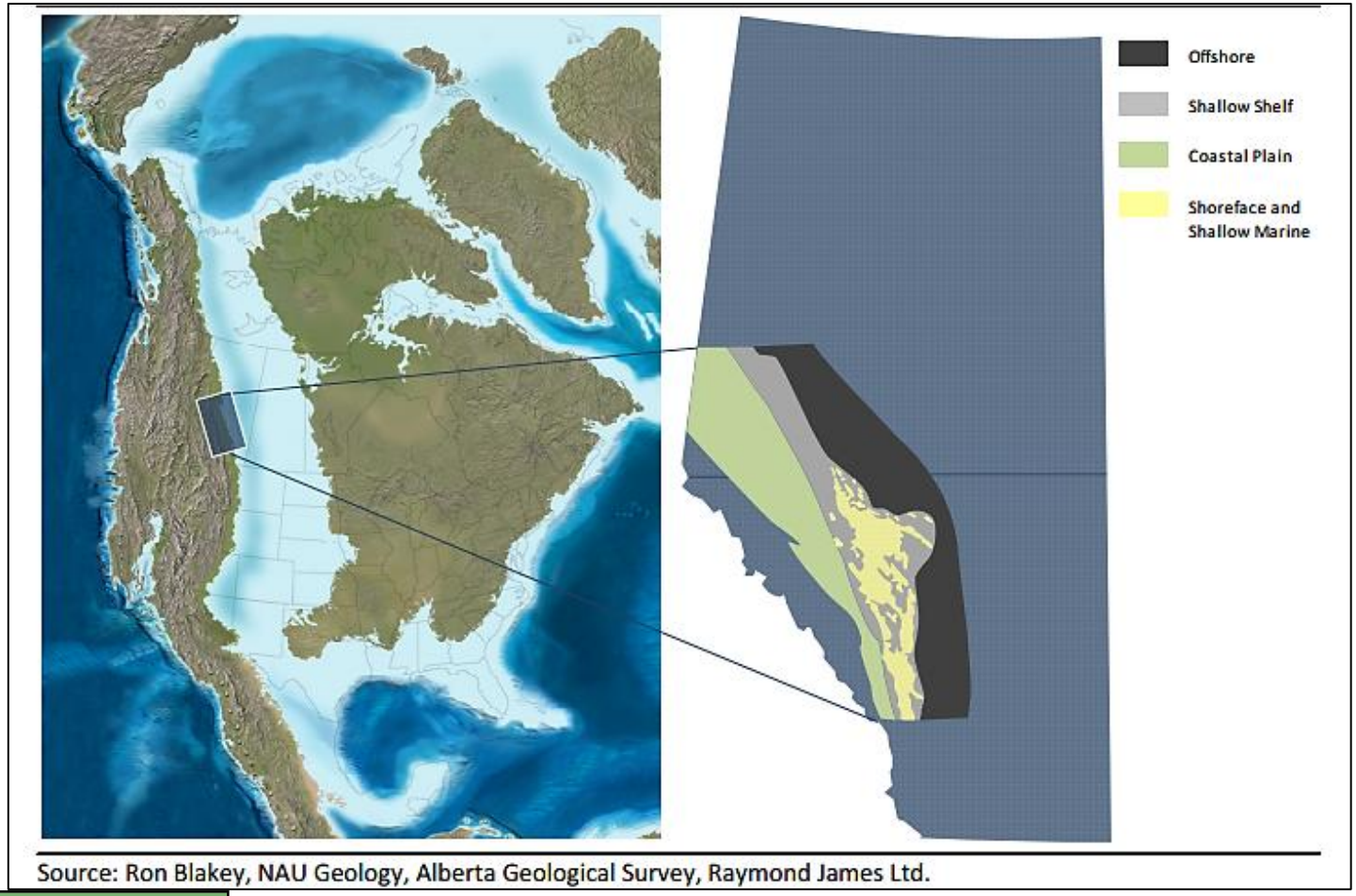
RAINER CZYPIONKA, DALE GULEWICZ, DON KEITH, MARLON REY

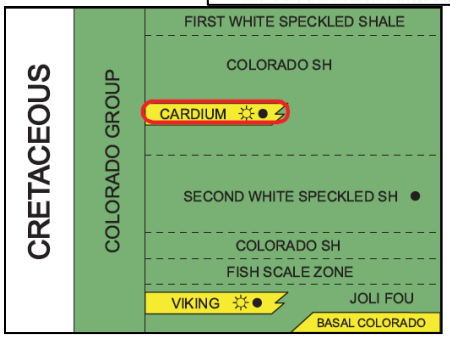
Identify the main reservoir facies and associated challenges to economically develop the Cardium tight oil play.

Identify the main reservoir facies and associated challenges to economically develop the Cardium tight oil play.

- Area Data Set
  - West Pembina, Garrington, Lochend
- Reservoir Facies in each area
  - Net Pay
  - PhiH (average porosity X net pay)
  - Permeability
  - Bulk volume shale
  - Residual water saturations
- Lateral Drilling Challenges
  - Area specific
- Drilling Performance
  - Lateral drilling days
  - % sliding & number of bit runs in lateral
- Completion Performance & Strategies
  - Treating Pressures
  - Fluid Rates
  - Screen Outs
- Production performance by area

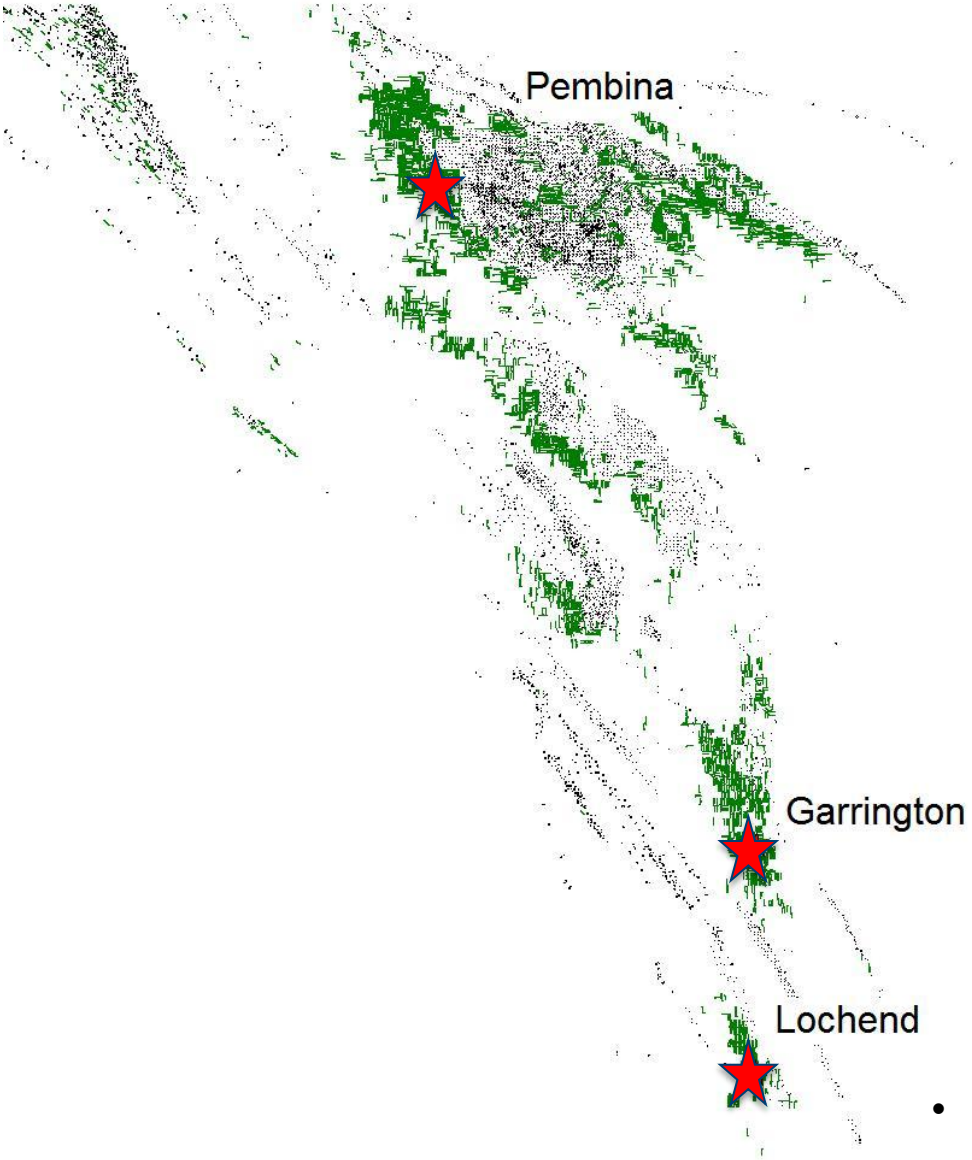
CARDIUM PALEOGEOGRAPHY





- Deposited on the western margin of the Cretaceous interior seaway 89 million years ago

CARDIUM PRODUCING AREAS



- Pembina – Multistage fracing, horizontal well development in the ‘halo’ of the conventional oil field
- Garrington and Lochend - Cardium tight oil play economic through horizontal drilling and multistage fracing

- **Black dots vertical Cardium producers**
- **Green lines horizontal Cardium producers**

AREA DATASET

1350-1500m laterals, monobore design drilled with invert,
N/S and E/W oriented

WEST PEMBINA (48-11W5)

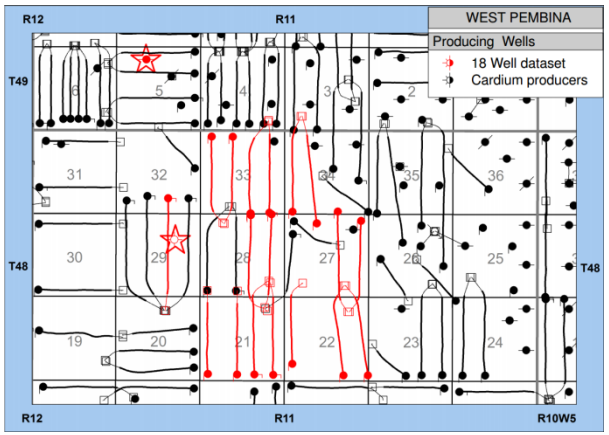
- TVD 1880 meters
- P*= 20 MPa
- 18 well data set

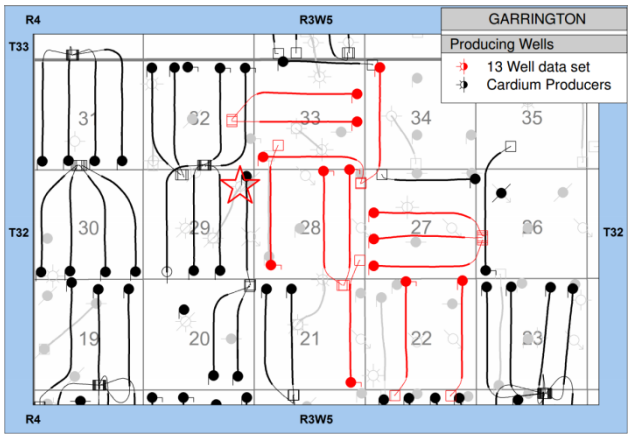
GARRINGTON (32-3W5)

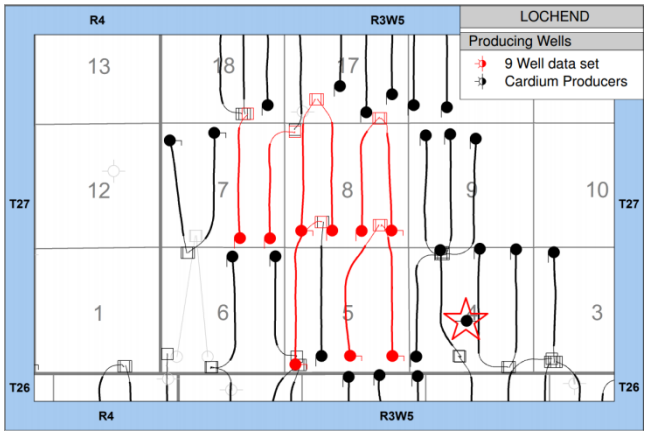
- TVD 1950 meters
- P*= 22-24 MPa
- 13 well data set

LOCHEND (27-3W5)

- TVD 2250 meters
- P*=25-26 MPa
- Close to deformation belt
- 9 well data set

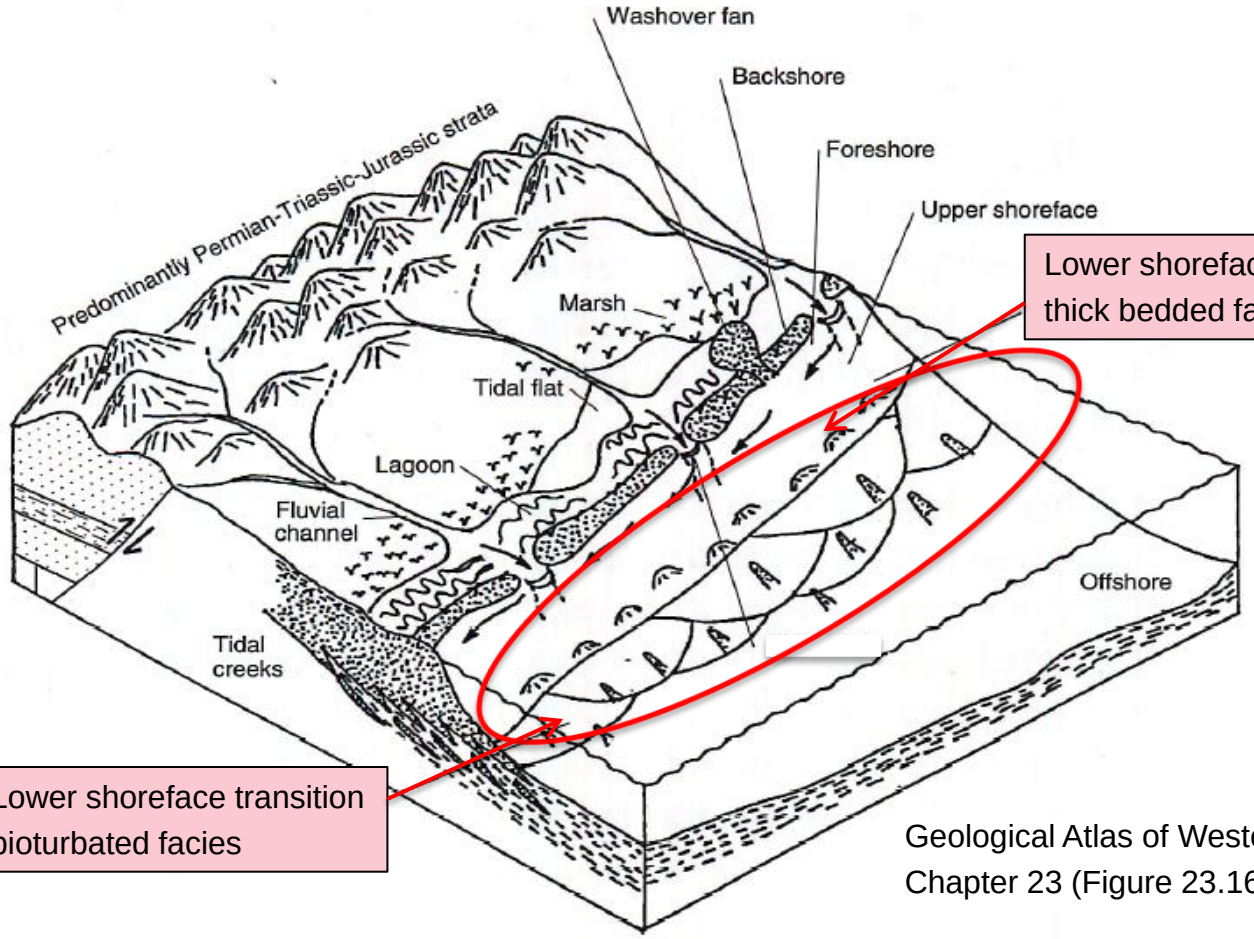






Cored wells

SHOREFACE DEPOSITIONAL MODEL



Geological Atlas of Western Canada
Chapter 23 (Figure 23.16).

- Deposition in lower shoreface and lower shoreface transition setting

WEST PEMBINA CARDIUM CORE

THICK BEDDED FACIES

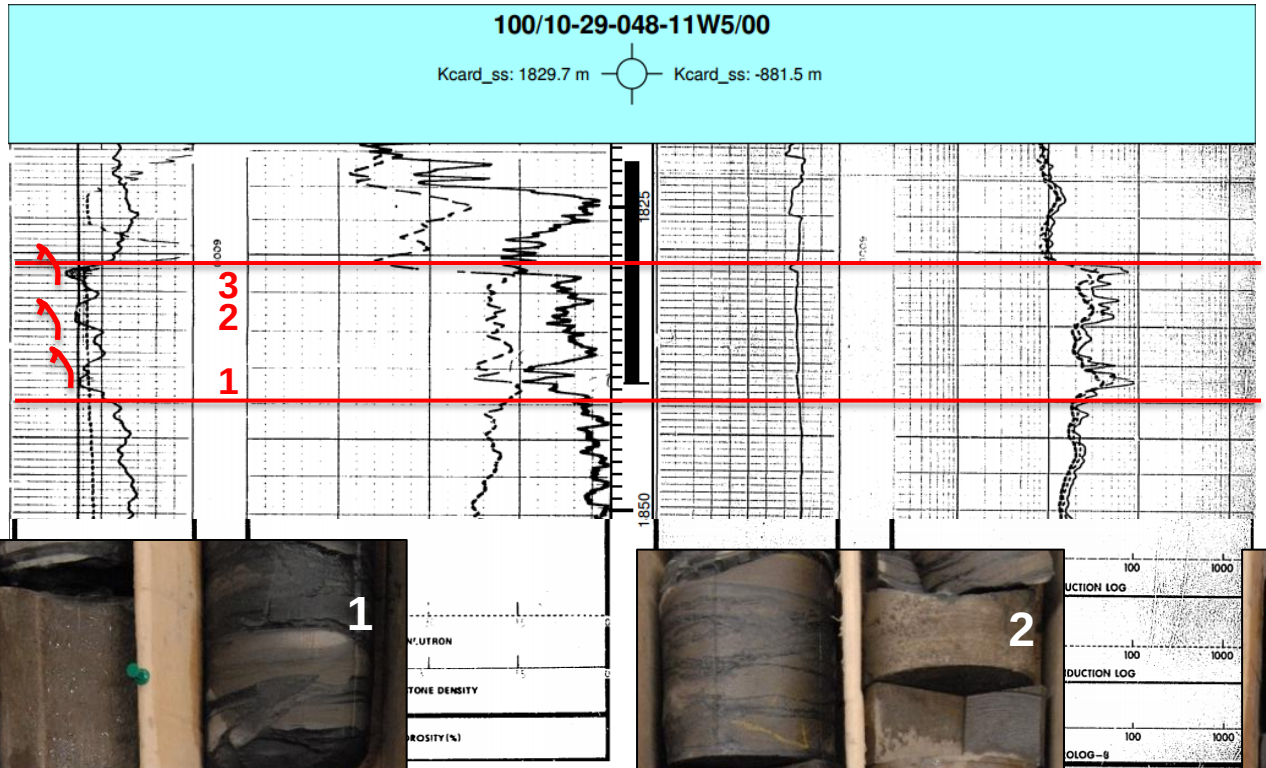
TOP

BTM

0.7m
96mm

- Stacked parasequences (3 cycles) of **clean**, thick bedded lower shoreface reservoir sandstone with interbeds of tight silty mudstones

WEST PEMBINA CARDIUM LOG



Gross 11.0 meters

Net Pay 6.5 meters

Avg. Porosity 9.8%

PhiH 0.64

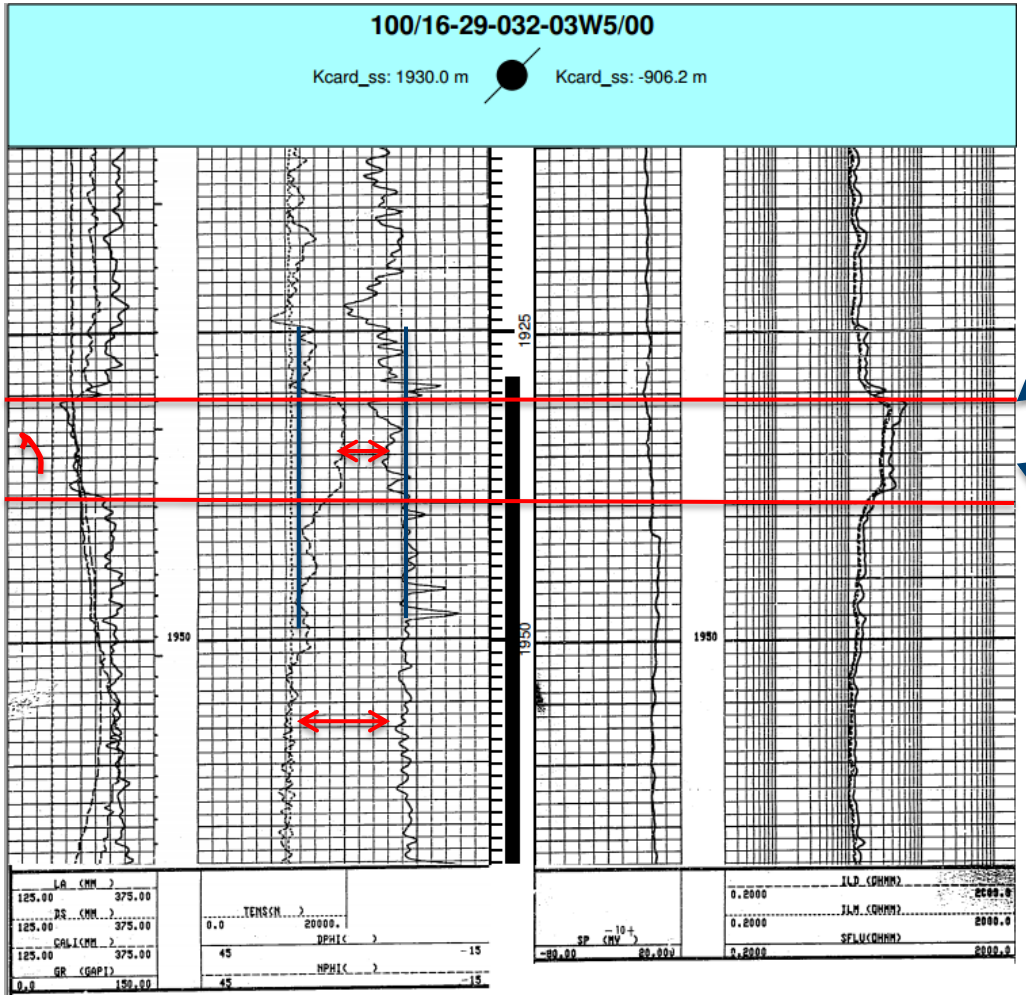
SW 15%

GARRINGTON CARDIUM CORE

BIOTURBATED FACIES

- Lower shoreface transition comprising **muddy**, burrowed, reservoir sandstone
- Sediment reworked or churned up by organisms including worms and crustacean
- Original sedimentary structures commonly obscured through bioturbation
- Burrowing may enhance vertical permeability

GARRINGTON CARDIUM LOG



Bioturbated
1.5m Net Pay
Avg. Por 10%
Sw 16%

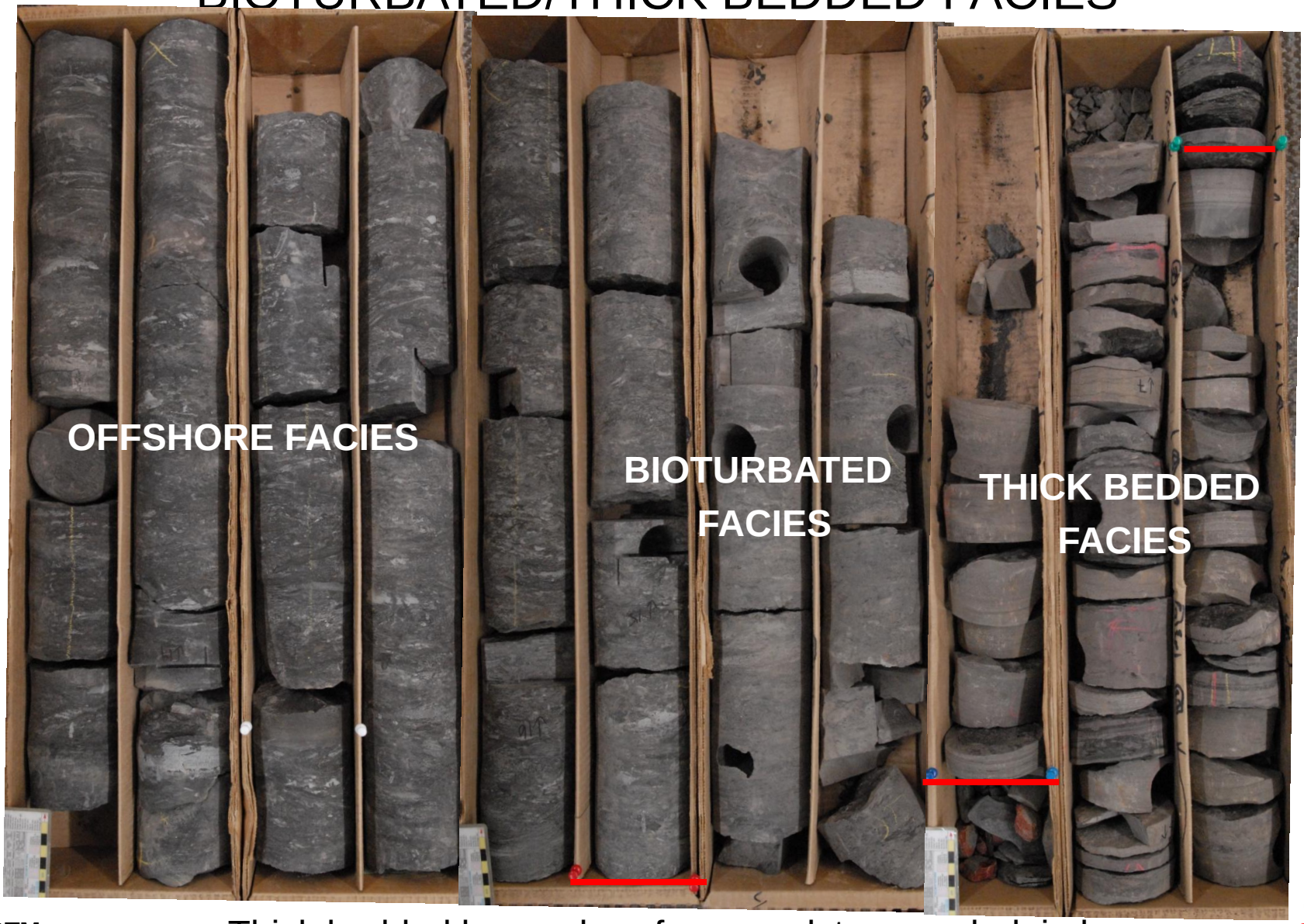
Bioturbated
6.0m Gross
Avg. Por 6%
No CA

- Bioturbated facies characterized by high shale volume in reservoir
- V_{sh}=deltaphi bioturbated/deltaphi shale - V_{sh}=9/21=43% (**V_{ss}=57%**)
- **Net Pay 3.4m**
- BVW = V_{sh}XSw_{sh}Xphi_{sh} +V_{ss}XSw_{ss}Xphi_{ss}
- **Sw** = BVW/Avg por = **36.8%**

LOCHEND CARDIUM CORE

BIOTURBATED/THICK BEDDED FACIES

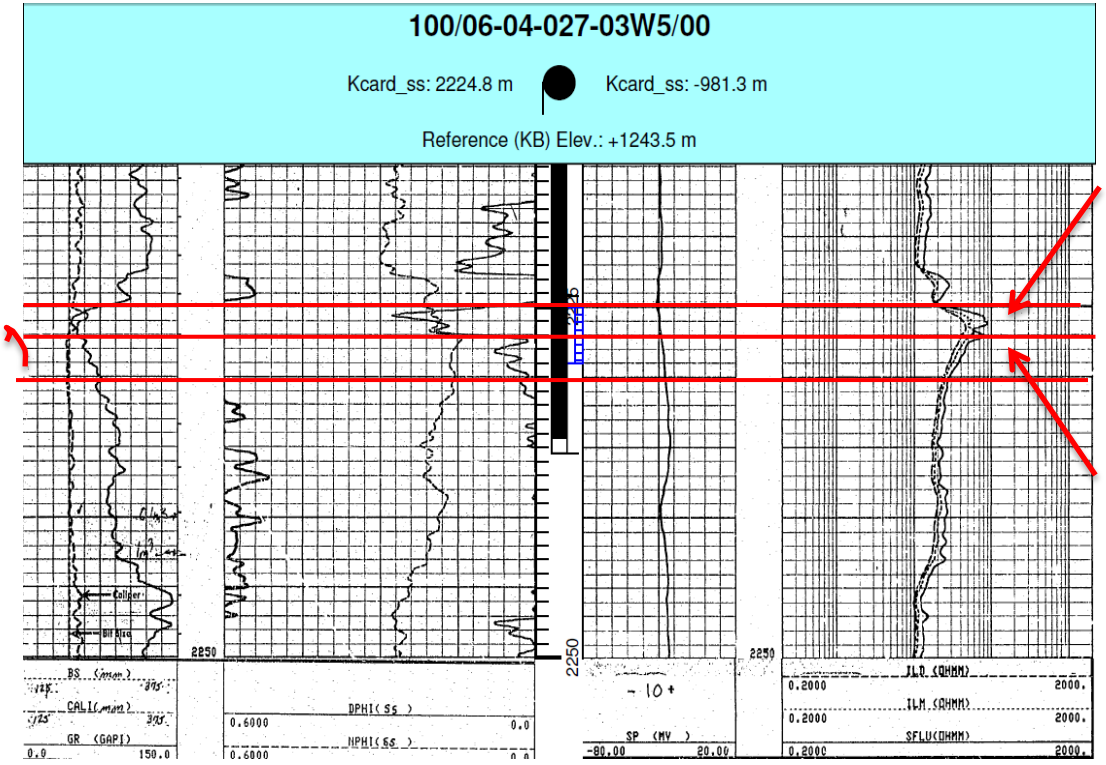
TOP



BTM

- Thick bedded lower shoreface sandstone underlain by bioturbated lower shoreface transition **muddy** sandstone

LOCHEND CARDIUM LOG



Thick bedded
2.0m Net Pay
Avg. Por 13%
Sw 7.5%

Bioturbated
3.0m Net Pay
Avg. Por. 6%
Sw 36.5%

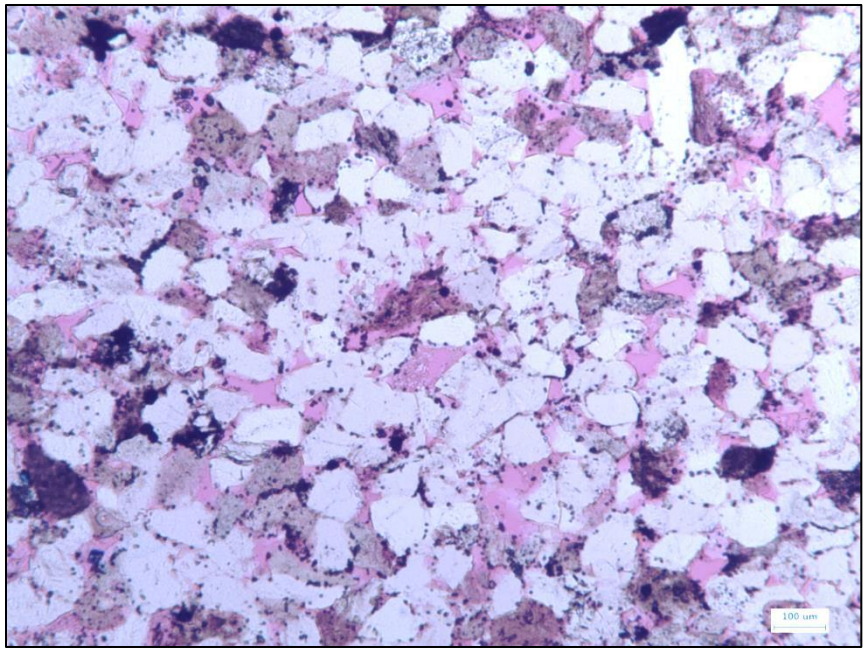
Net Pay 5.0m (Thick bedded + bioturbated)

Avg. Por 9.0%

PhiH 0.45

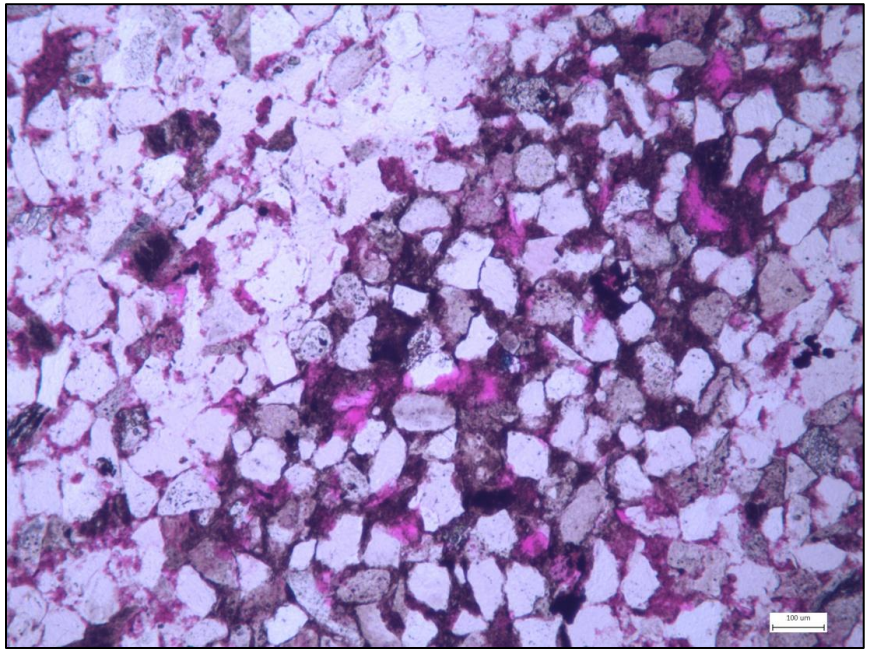
Avg. Sw 24.6%

THIN SECTION COMPARISON OF RESERVOIR FACIES



Thick bedded facies

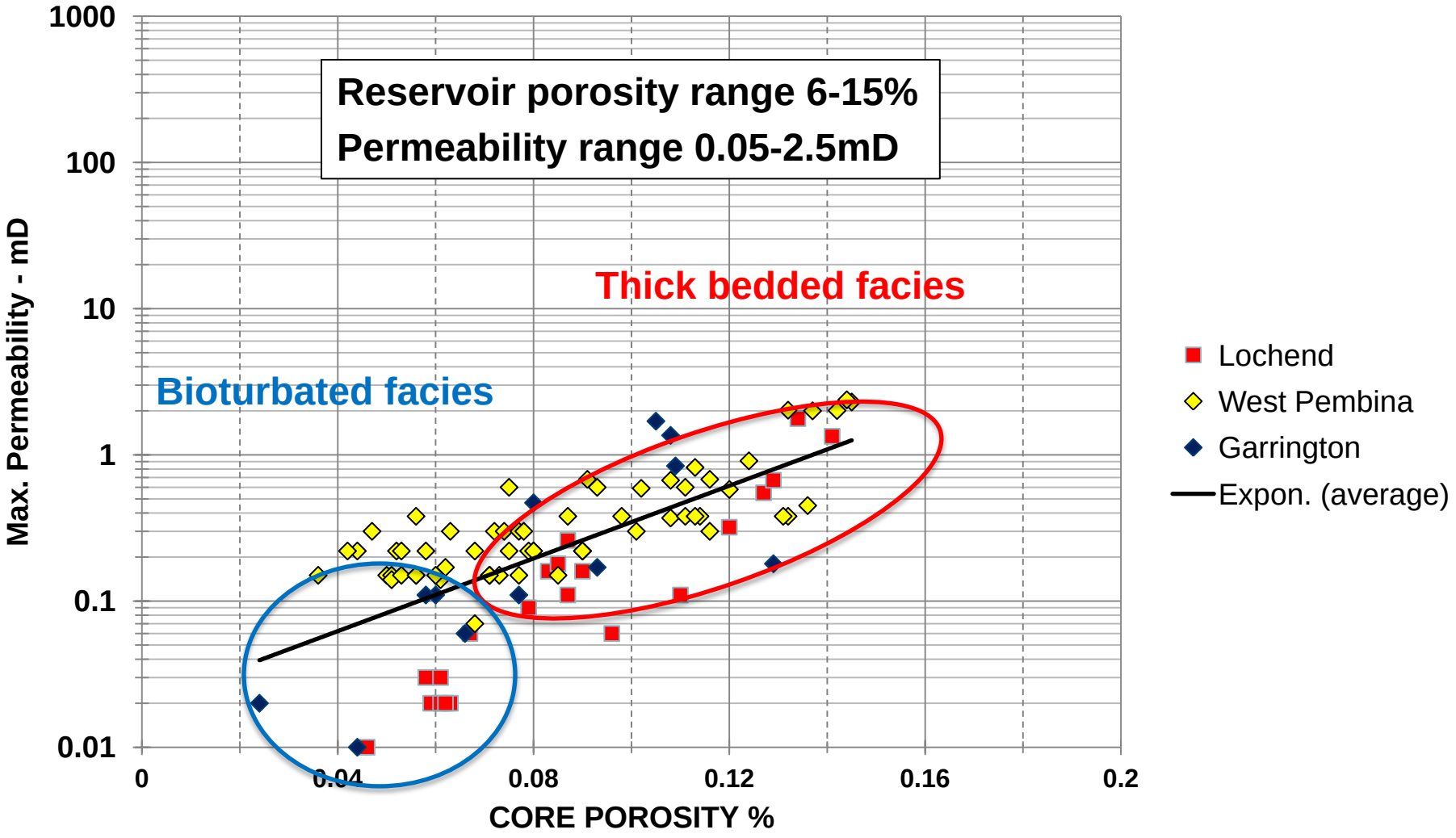
- 14% porosity; 2.0md permeability
- Low clay content
- common quartz overgrowths/cement
- Abrasive when drilling



Bioturbated facies

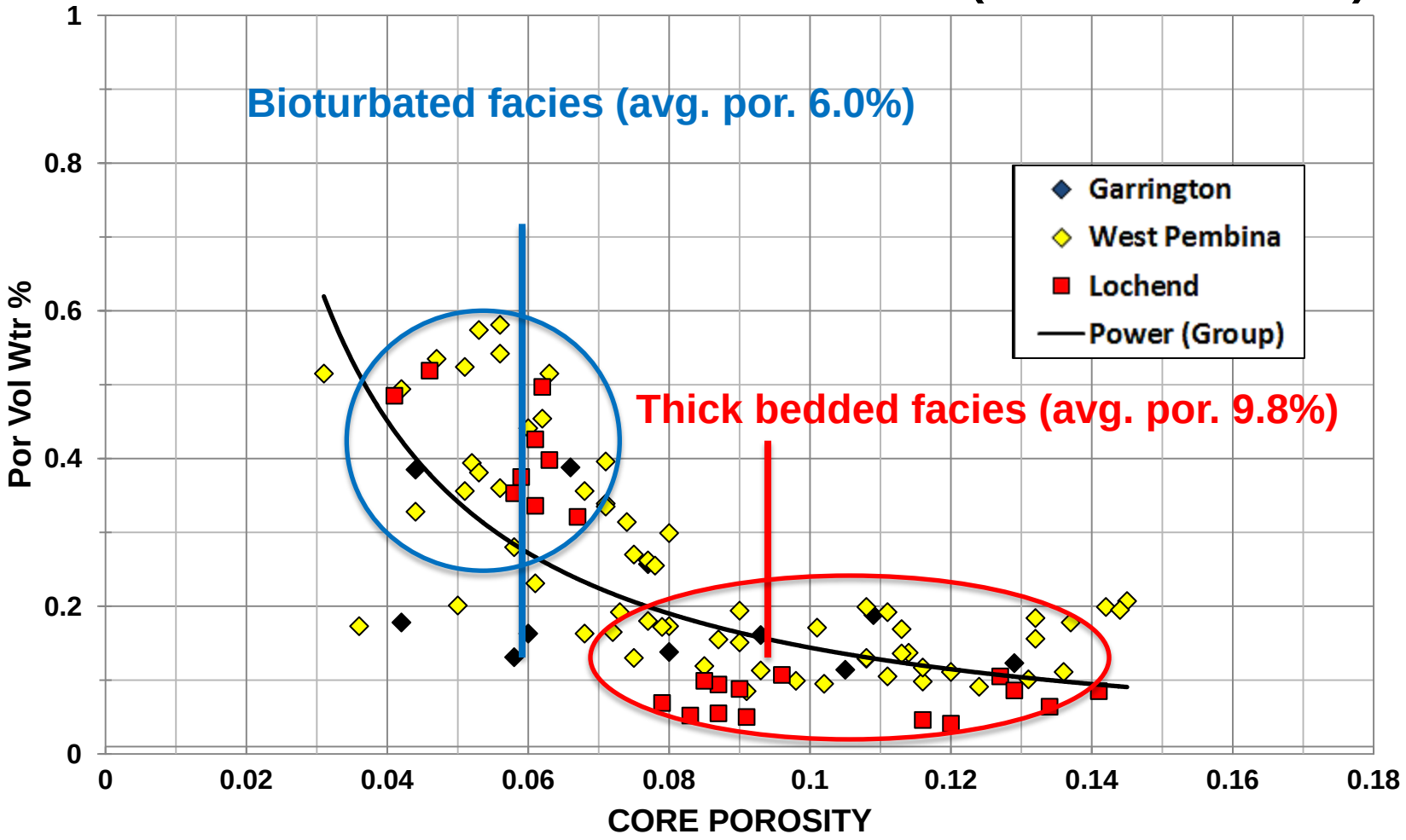
- 6-7% porosity; 0.1-0.2md permeability
- High detrital clay/shale volume
- Less abrasive & easier to drill

CORE PERMEABILITY/POROSITY CROSS PLOT



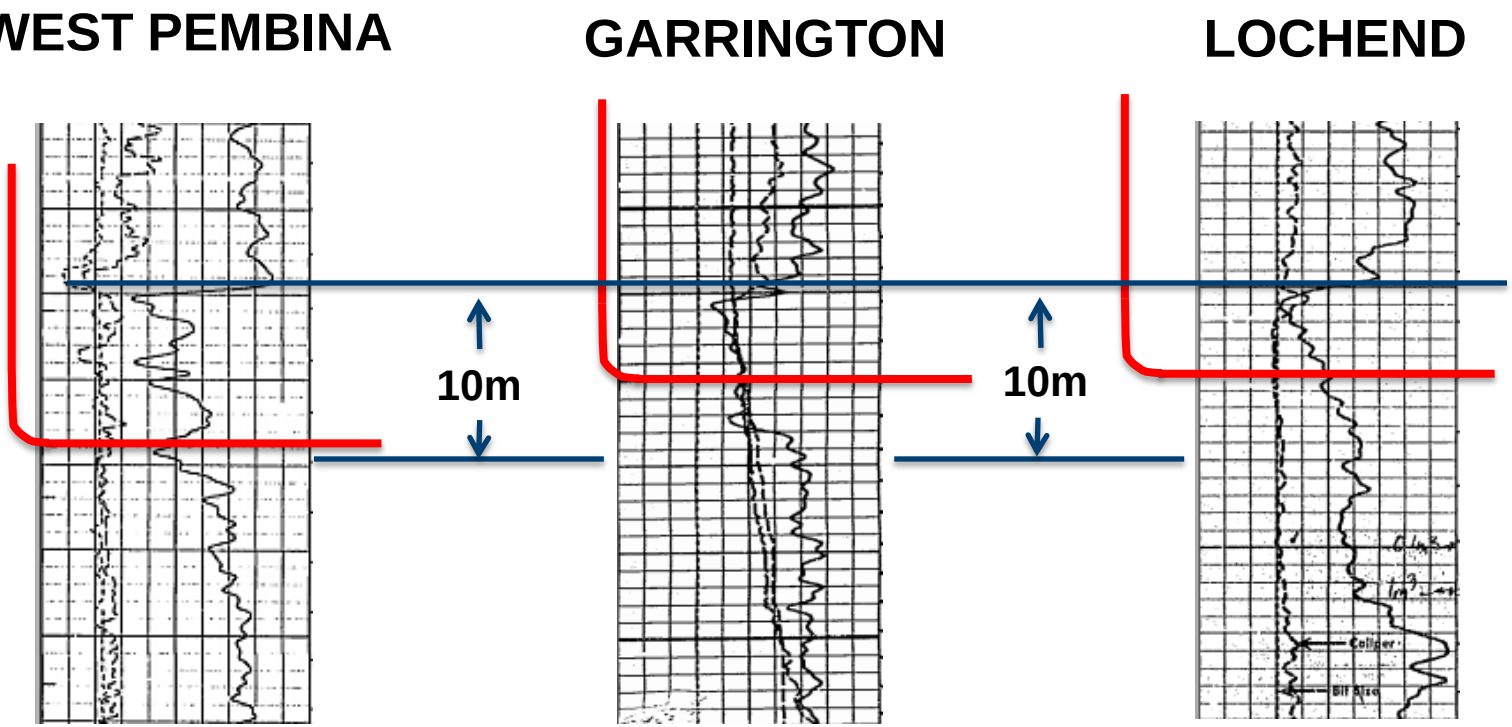
- West Pembina thick bedded facies exhibits higher average permeability
- Lochend thick bedded facies porosity & permeability > bioturbated facies
- Garrington bioturbated facies – core analysis over top one meter

PORE VOLUME WATER VS. POROSITY (CORE ANALYSIS)



- Increase in Pore Volume Water with lower porosity
- Bioturbated reservoir average Sw 25-36%
- Thick bedded sandstone reservoir average Sw 10-17%

TARGETING AND WELL PATH CONTROL

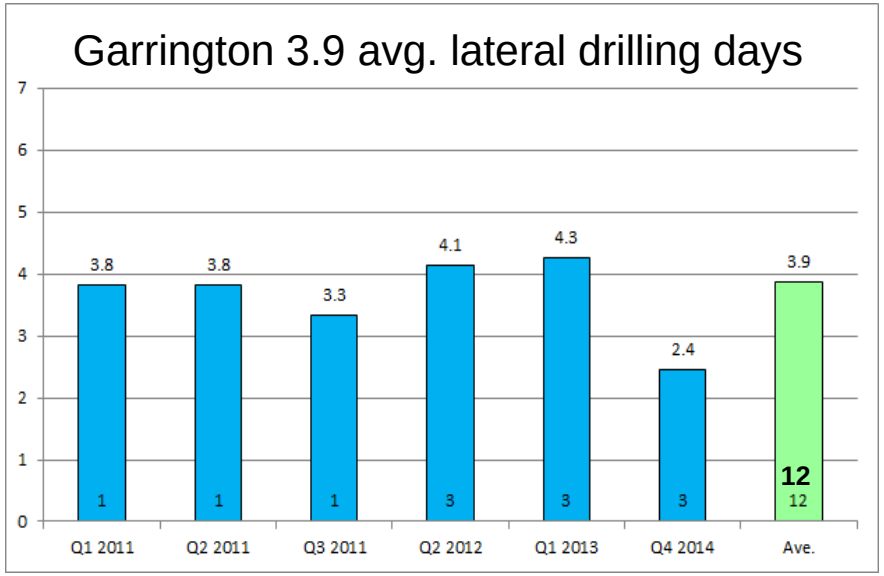


- Interbedded lithology
- Complex gamma interpretation
- Difficult well path steering due to variability in formation hardness

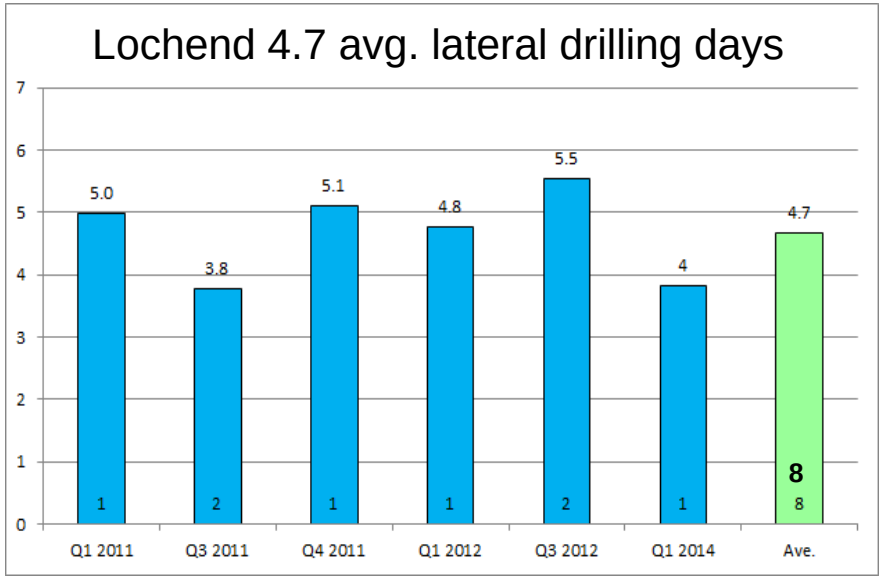
- Cleaning-upward gamma profile
- Basic gamma interpretation
- Easy well path steering in bioturbated facies

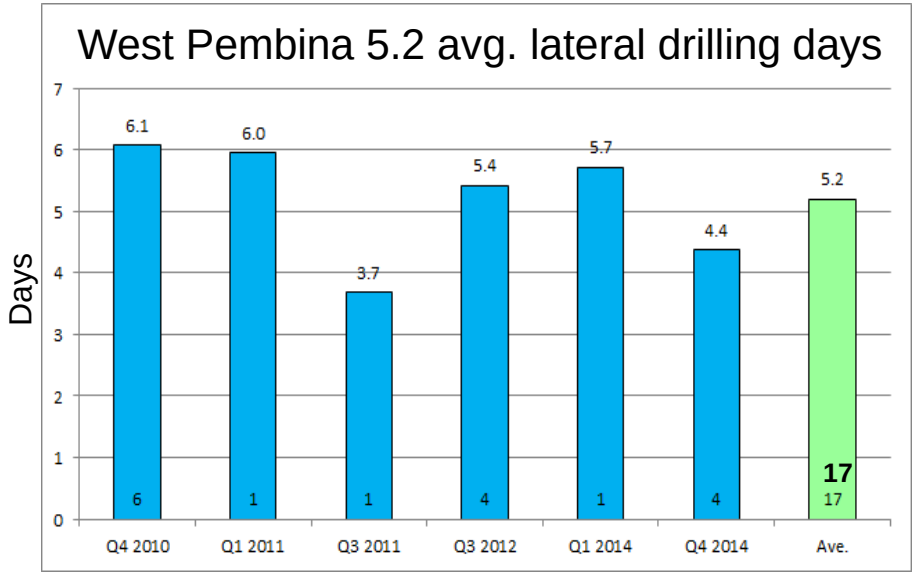
- Thick muddy sandstone reservoir
- Moderate gamma interpretation
- Easy well path steering due to high clay content

DRILLING PERFORMANCE
Average Lateral Drilling Days

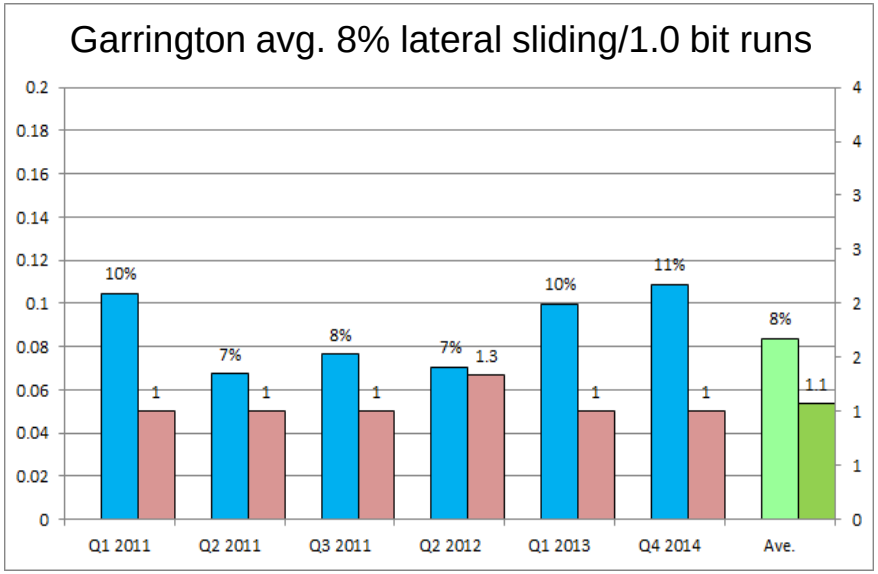


- Among the 3 areas, Garrington drills the fastest followed by Lochend and then West Pembina

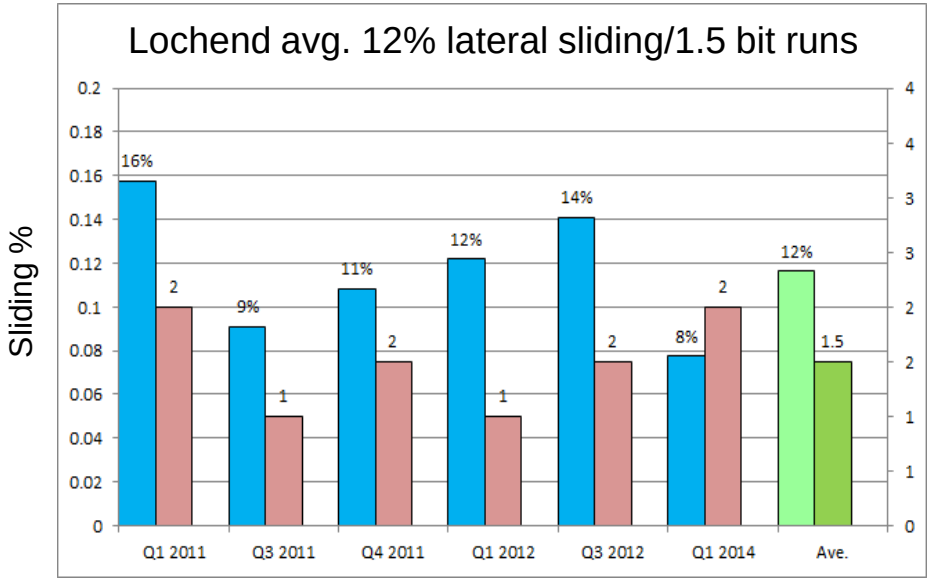


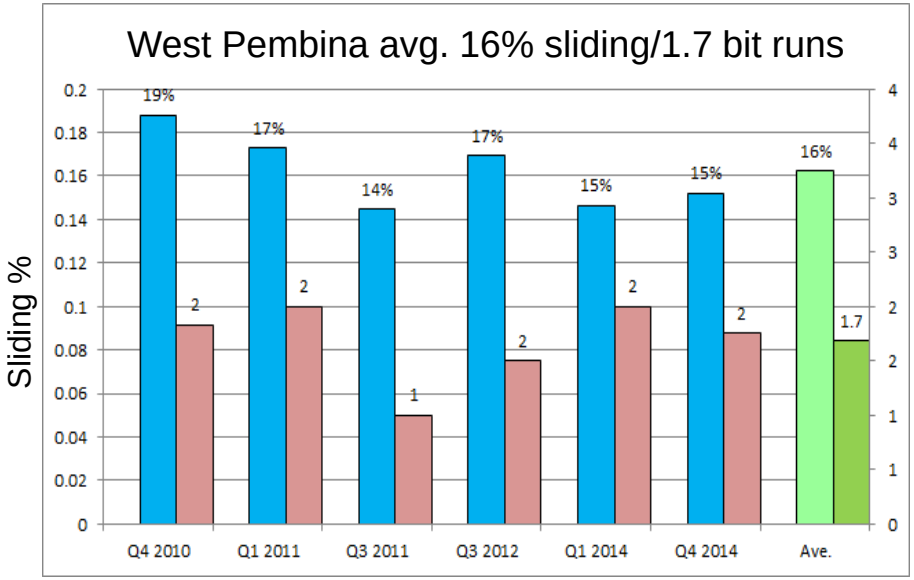


DRILLING PERFORMANCE
% Sliding / Bit Runs in the Lateral



- Garrington wells have less average % total slides and average number of bit runs in the lateral followed by Lochend and West Pembina
- Attributed to depositional facies





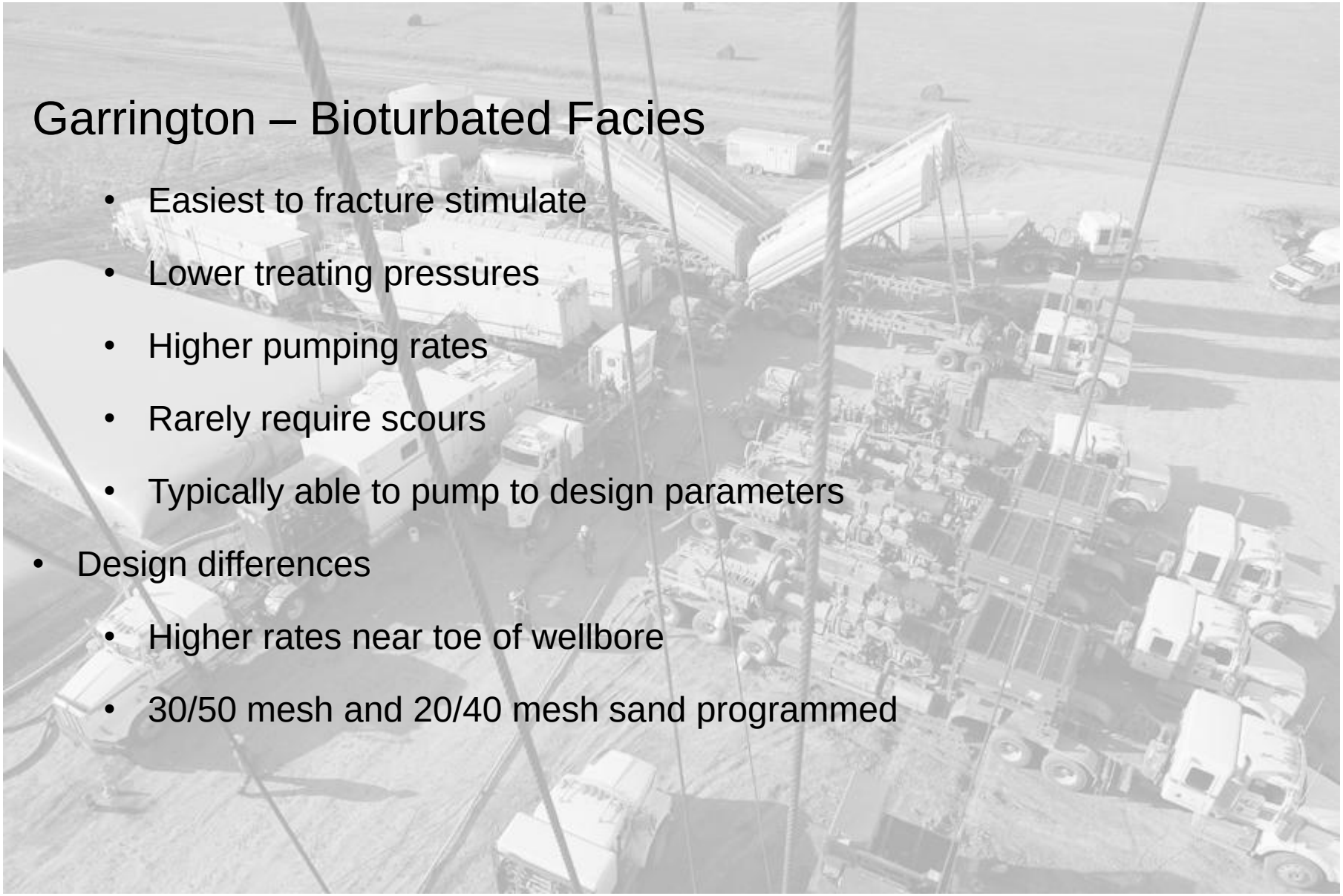
COMPLETIONS

COMPLETIONS DESIGN ALL AREAS

- Slickwater fluid
- Pumped at 6 – 9 m^3/min
- 20 tonne / stage
- ±80 m average stage lengths
- 20 stages
- Open hole ball drop systems

- Our ultimate goal is to successfully fracture stimulate well, eliminating expensive screen outs, lost production and lower reserves recovery due to incomplete or skipped stages

GARRINGTON COMPLETIONS



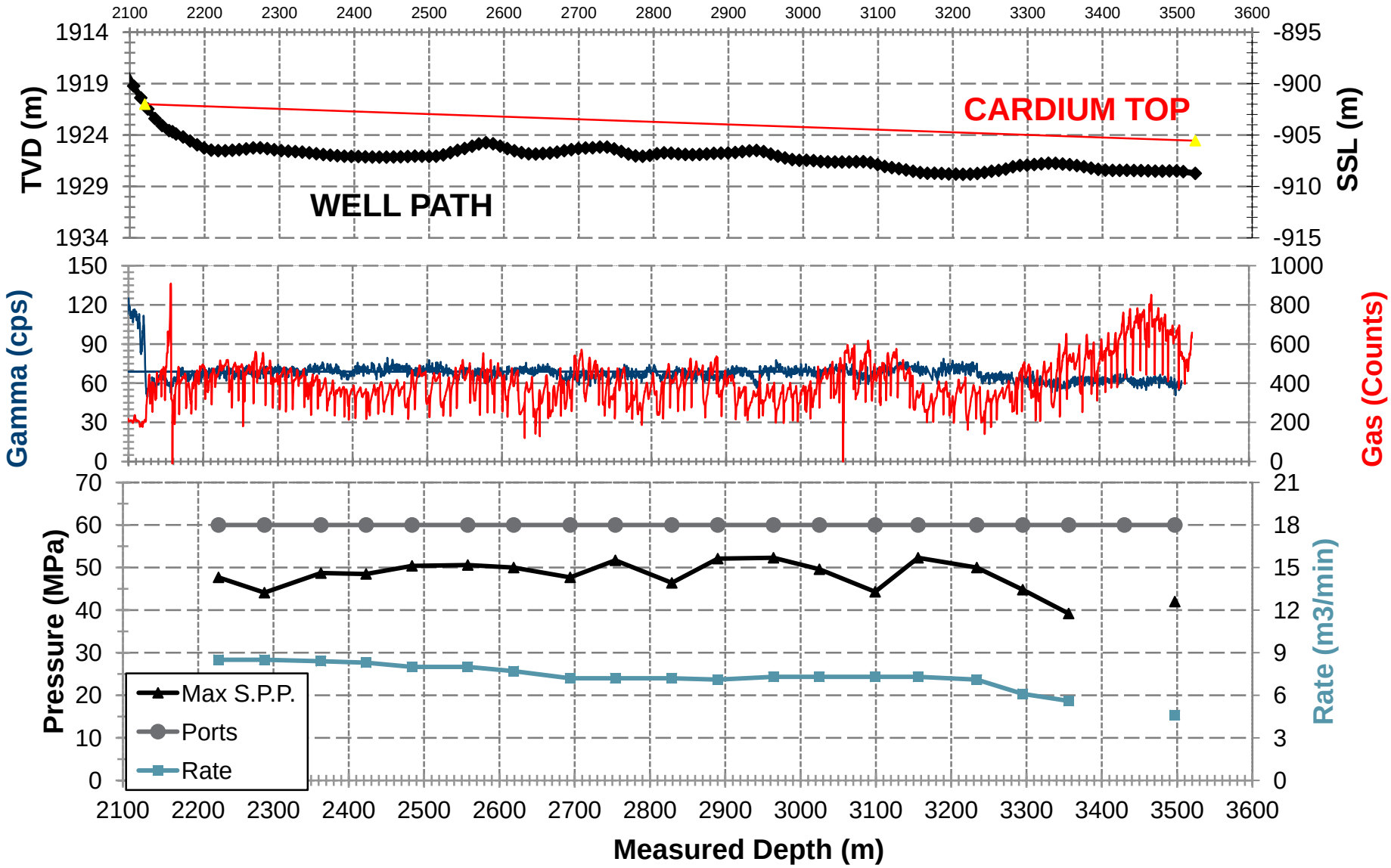
Garrington – Bioturbated Facies

- Easiest to fracture stimulate
- Lower treating pressures
- Higher pumping rates
- Rarely require scours
- Typically able to pump to design parameters

- Design differences
  - Higher rates near toe of wellbore
  - 30/50 mesh and 20/40 mesh sand programmed

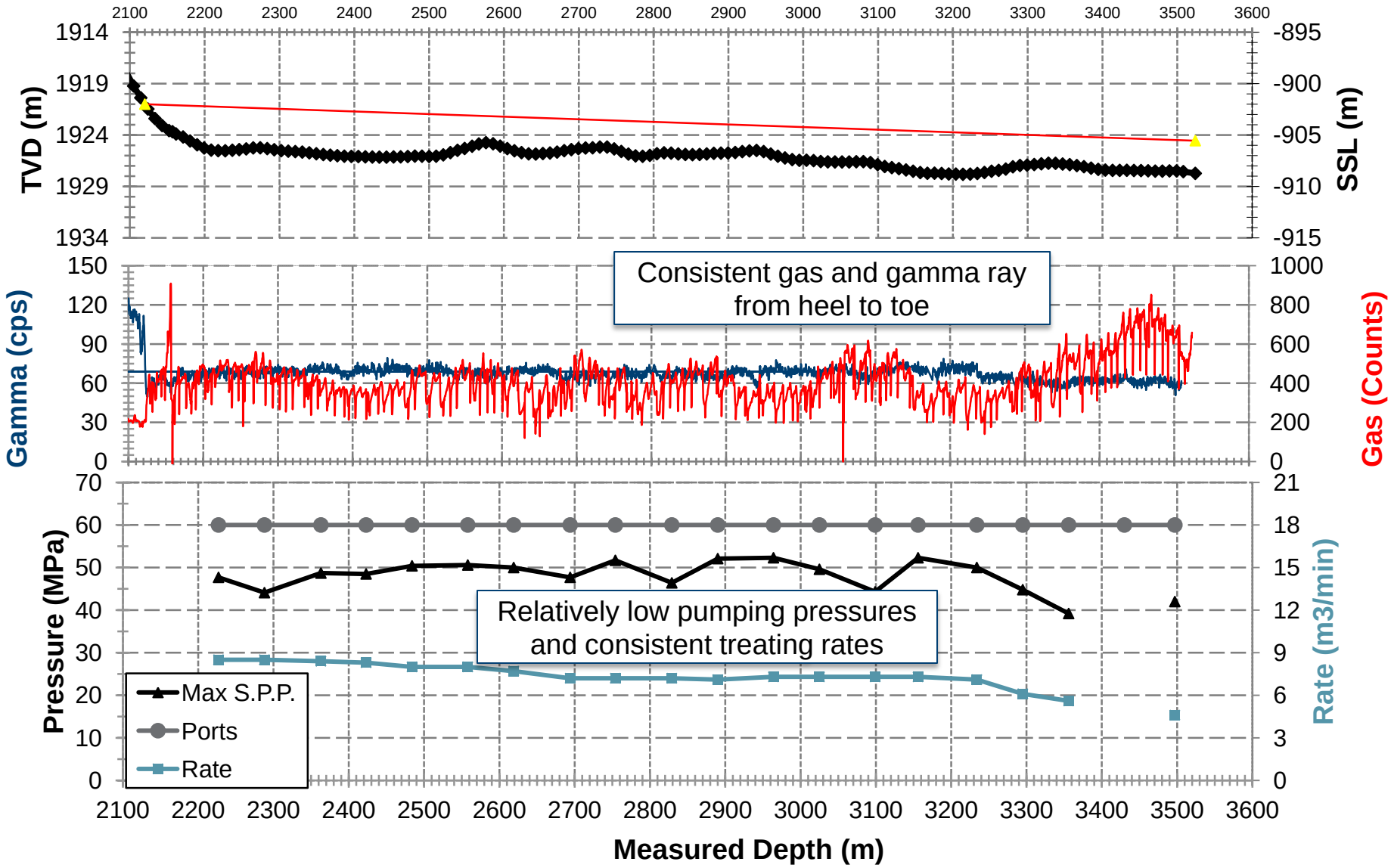
GARRINGTON COMPLETIONS

BIOTURBATED FACIES

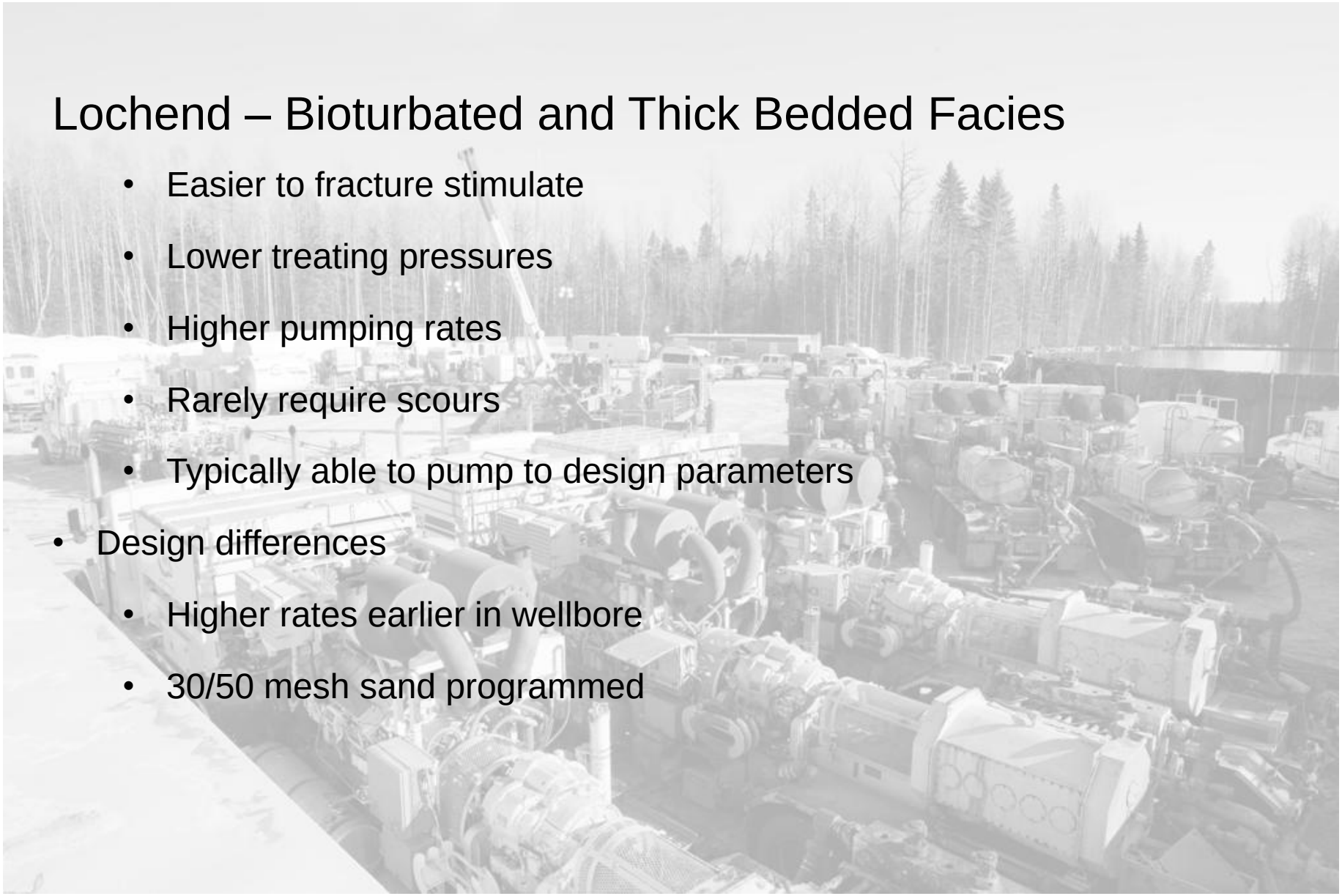


GARRINGTON COMPLETIONS

BIOTURBATED FACIES



LOCHEND COMPLETIONS



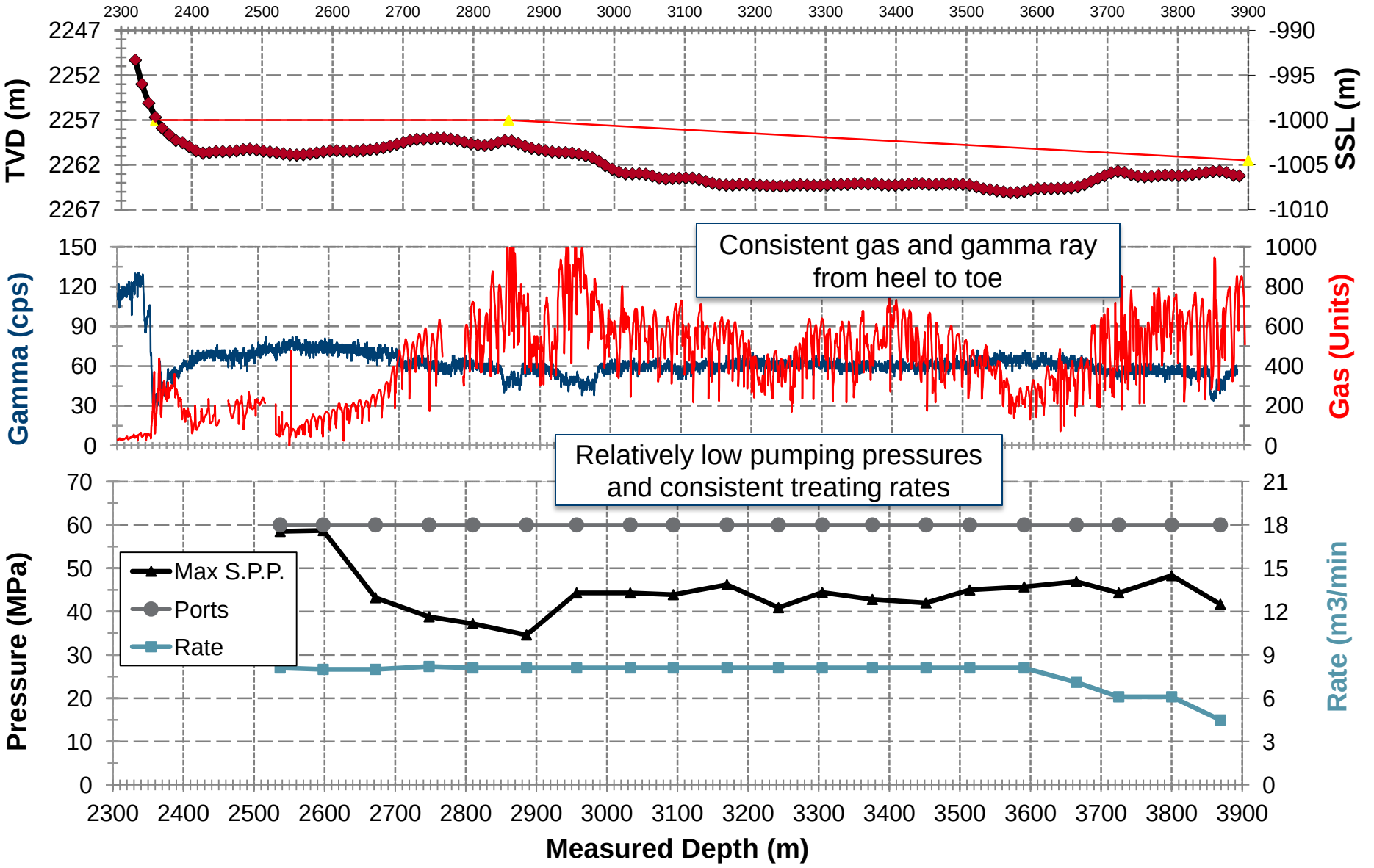
Lochend – Bioturbated and Thick Bedded Facies

- Easier to fracture stimulate
- Lower treating pressures
- Higher pumping rates
- Rarely require scours
- Typically able to pump to design parameters

- Design differences
  - Higher rates earlier in wellbore
  - 30/50 mesh sand programmed

LOCHEND COMPLETIONS

BIOTURBATED AND THICK BEDDED FACIES



WEST PEMBINA COMPLETIONS

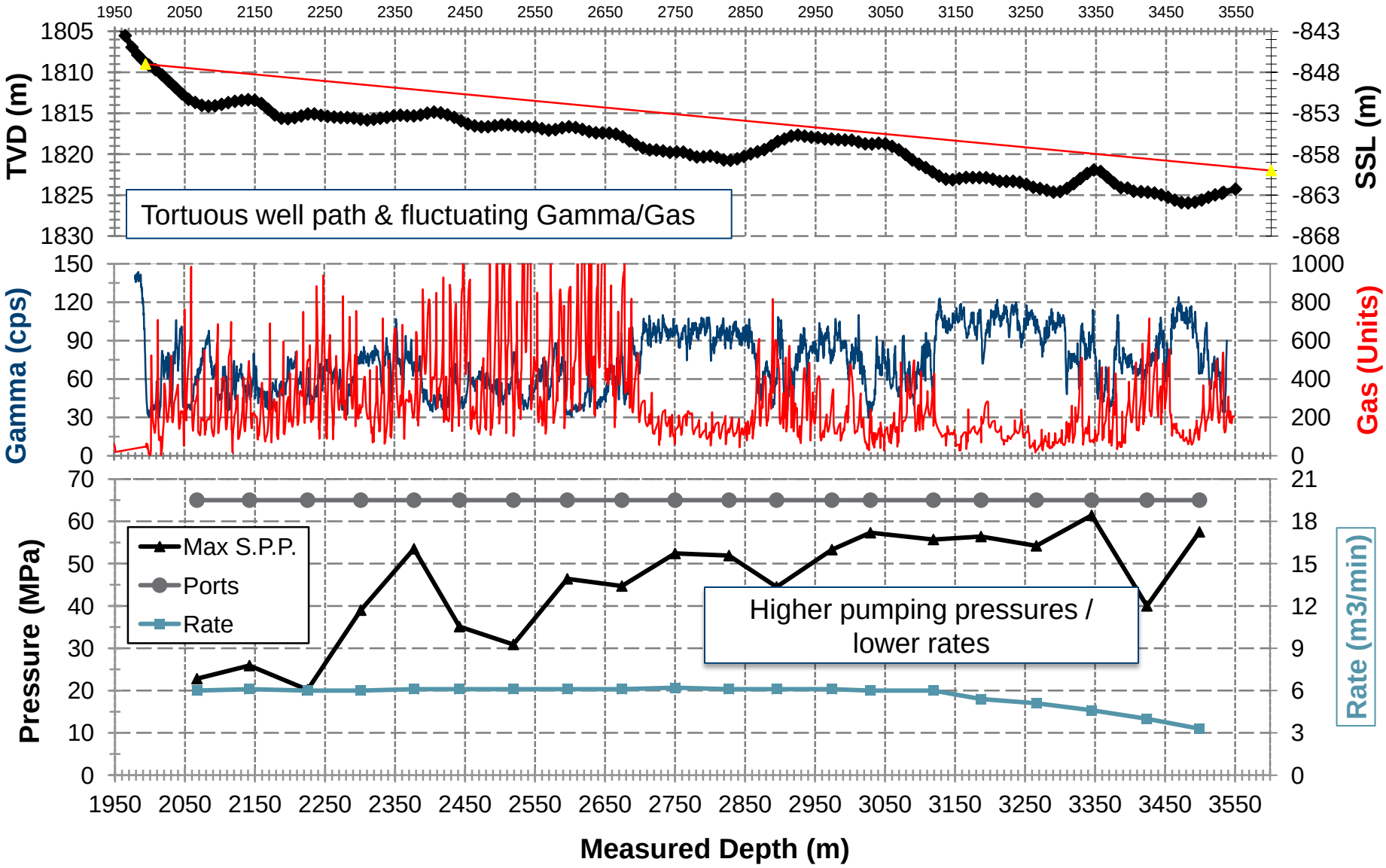
West Pembina – Thick Bedded Facies

- Toughest to fracture stimulate
- Highest breakdown pressures
- Highest maximum treating pressures
- Lowest average pumping rate
- Slickwater minimum rate of 5 – 6 m^3/min can be difficult to achieve and may require scours
- Increased chance of incomplete and skipped stages and higher risk of screen outs

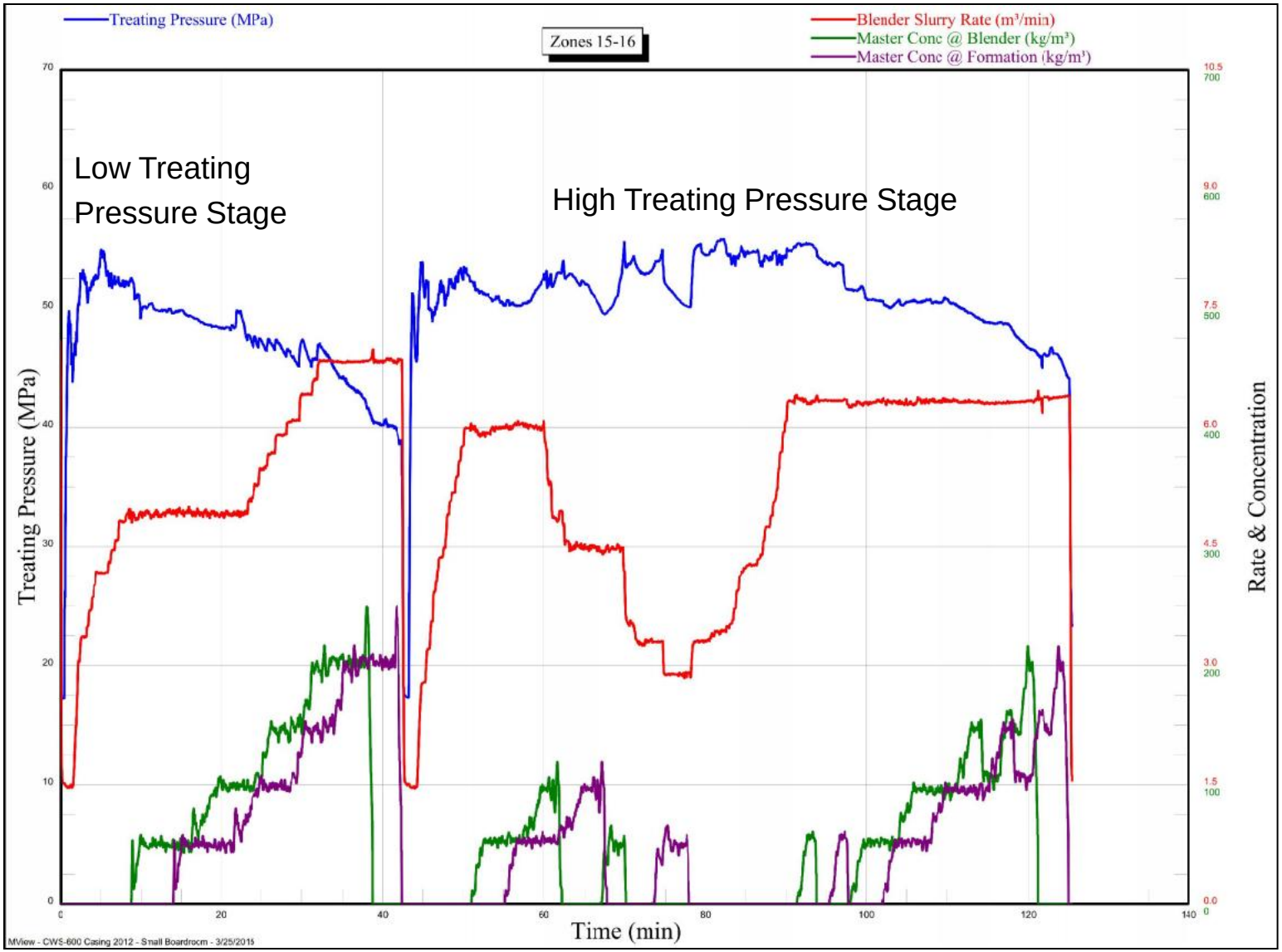
- Design differences
  - Typically lower treating rates
  - Only 40/70 mesh and 30/50 mesh sand programmed

WEST PEMBINA COMPLETIONS

THICK BEDDED FACIES



WEST PEMBINA STIMULATION CHART

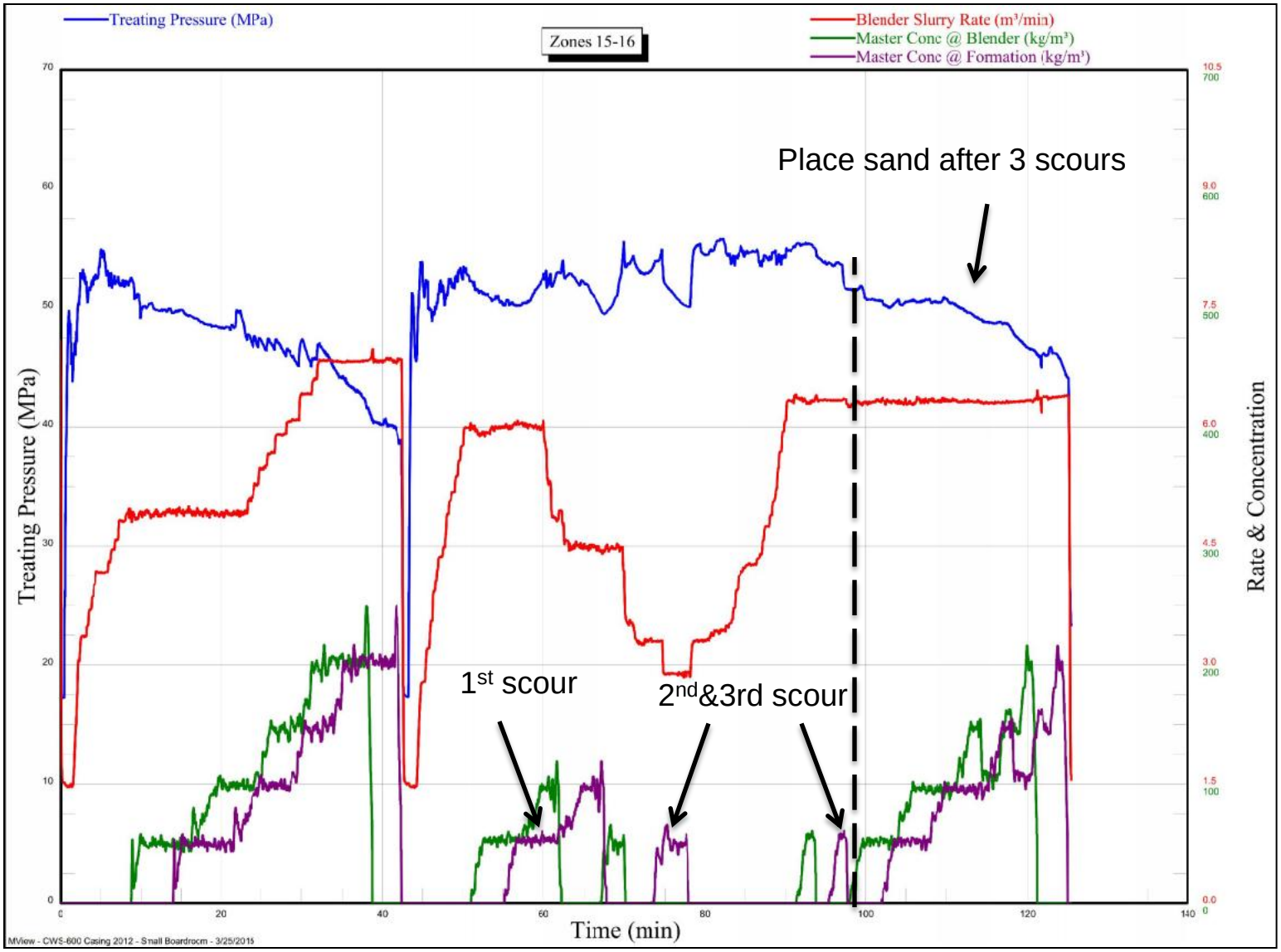


Treating Pressure (Mpa)

Rate & Concentration

Time (min)

WEST PEMBINA STIMULATION CHART

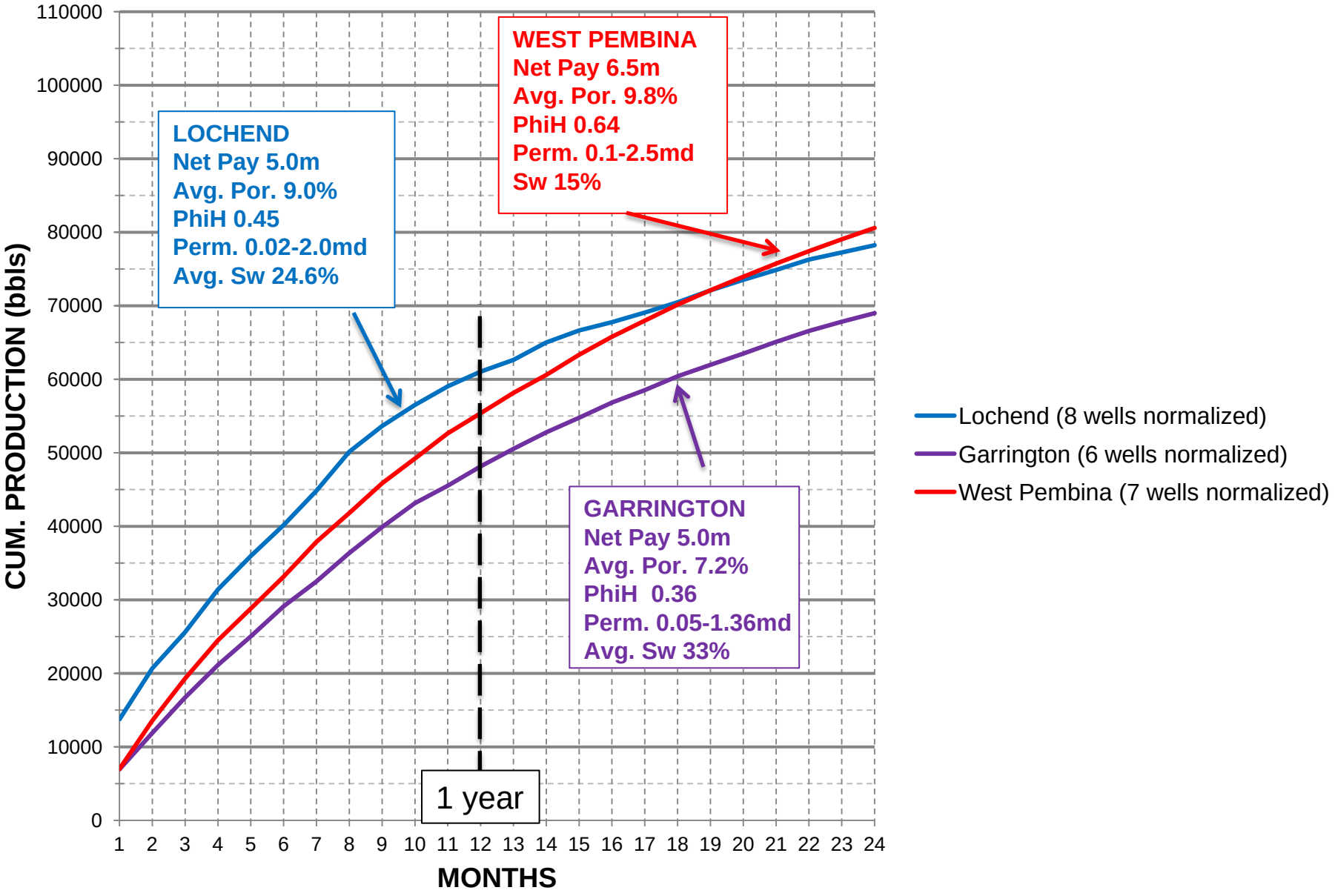


Treating Pressure (Mpa)

Rate & Concentration

Time (min)

CUMULATIVE OIL PRODUCTION (2 YEARS)



SUMMARY

	WEST PEMBINA	GARRINGTON	LOCHEND
RESERVOIR FACIES	Stacked thick bedded sandstone	Muddy bioturbated sandstone	Muddy bioturbated sandstone overlain by thick bedded sandstone
RESERVOIR PROPERTIES	Net Pay 6.5m	Net Pay 5.0m (7.0m -Vsh)	Net Pay 5.0m
	Average Porosity 9.8%	Average Porosity 7.2%	Average Porosity 9.0%
	PhiH 0.64	PhiH 0.36	PhiH 0.45
	Sw 15%	Avg. Sw 33%	Avg. Sw 24.6%
	Permeability 0.1-2.5mD	Permeability 0.05-1.36mD	Permeability 0.02-2.0mD
		High shale volume in reservoir	High shale volume in bioturbated
DRILLING	Lateral drilling days 5.2	Lateral drilling days 3.9	Lateral drilling days 4.7
	16% average sliding in lateral	8% average sliding in lateral	12% average sliding in lateral
	1.7 bits to drill lateral	Lateral drilled with one bit	1.5 bits to drill lateral
COMPLETIONS	Higher treating pressures (>50MPa)	Low treating pressures (45-50MPa)	Low treating pressures (35-45MPa)
	Lowest pump rates (5-6m3/min)	High pump rates (7-9m3/min).	High pump rates (7-9m3/min).
	Scours commonly be required	Rarely requires scour	Rarely requires scour
	High risk of screen outs		
PRODUCTION & ECONOMICS	**Thick bedded sandstone highest oil cum. over time**	**Lowest overall cumulative production offset by more efficient drill and completions**	**Highest IP rates Highest reservoir pressures**

ACKNOWLEDGEMENTS

- LIGHTSTREAM RESOURCES
- DON KEITH
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