NAM

The NAM Gas Well Deliquification Toolbox

How to Achieve the Lowest Possible Reservoir Pressure to Maximize Gas Recovery

KIVI Lecture

On 10 March 2015

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Contents

NAM's mission is to sustainably prospect for and produce oil and gas from deposits within the Netherlands and the Dutch section of the Continental Shelf.

ExxonMobil

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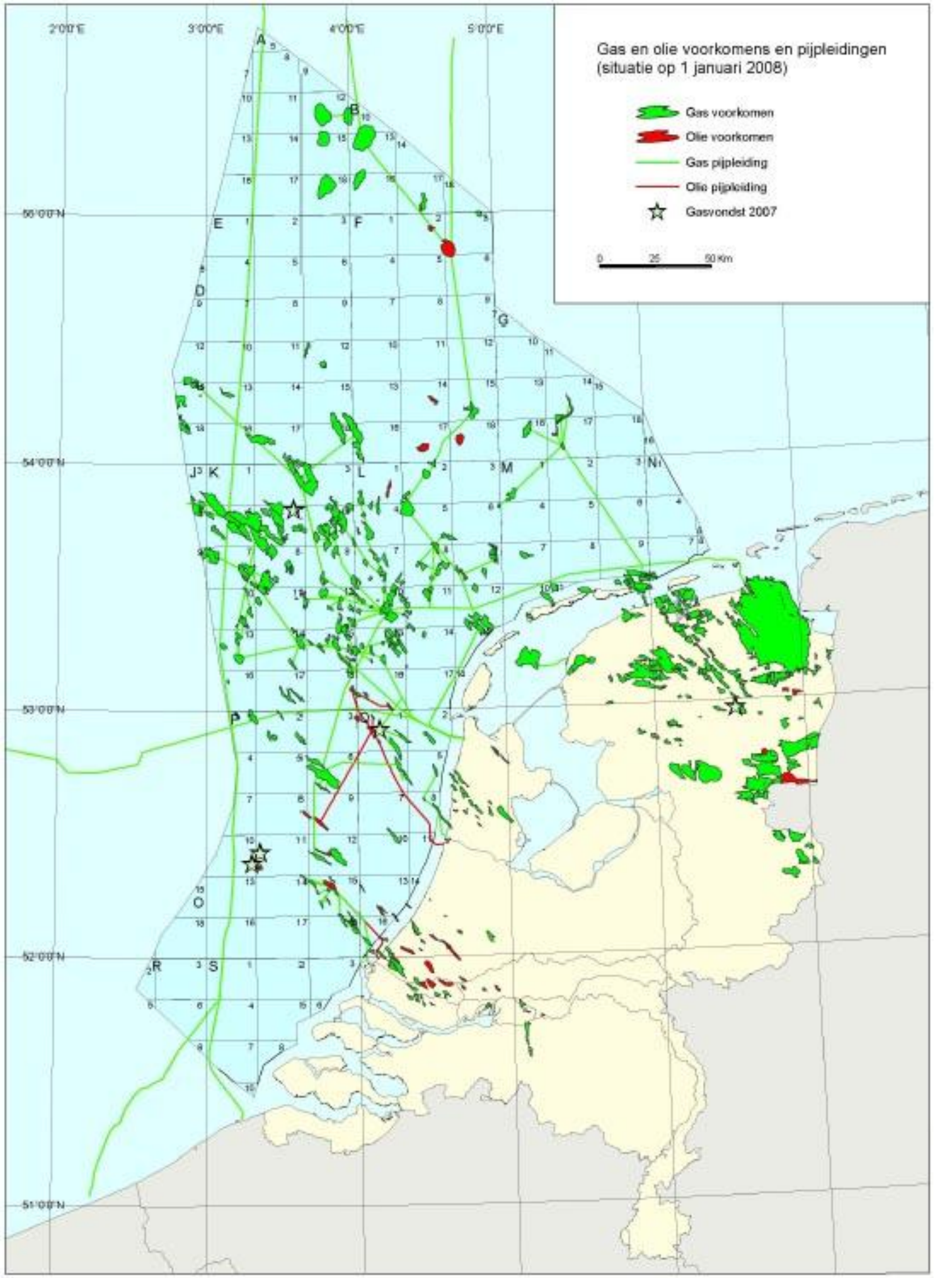
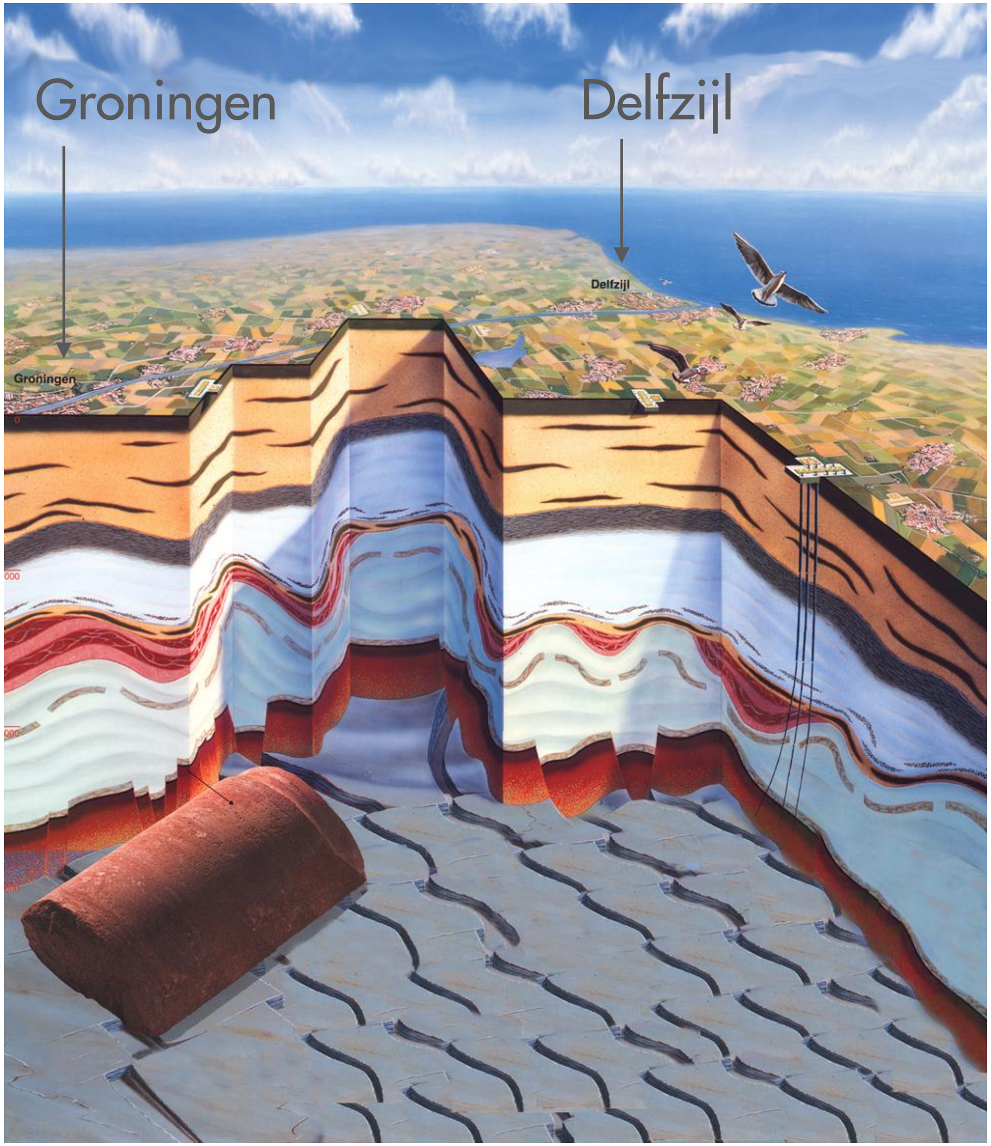
Where is Natural Gas Located?

- The Groningen gas field, one of Europe's largest fields, is located in the Netherlands
- More than 175 onshore and offshore fields are in production
- 56% of all natural gas reserves in the European Union are located in the Netherlands



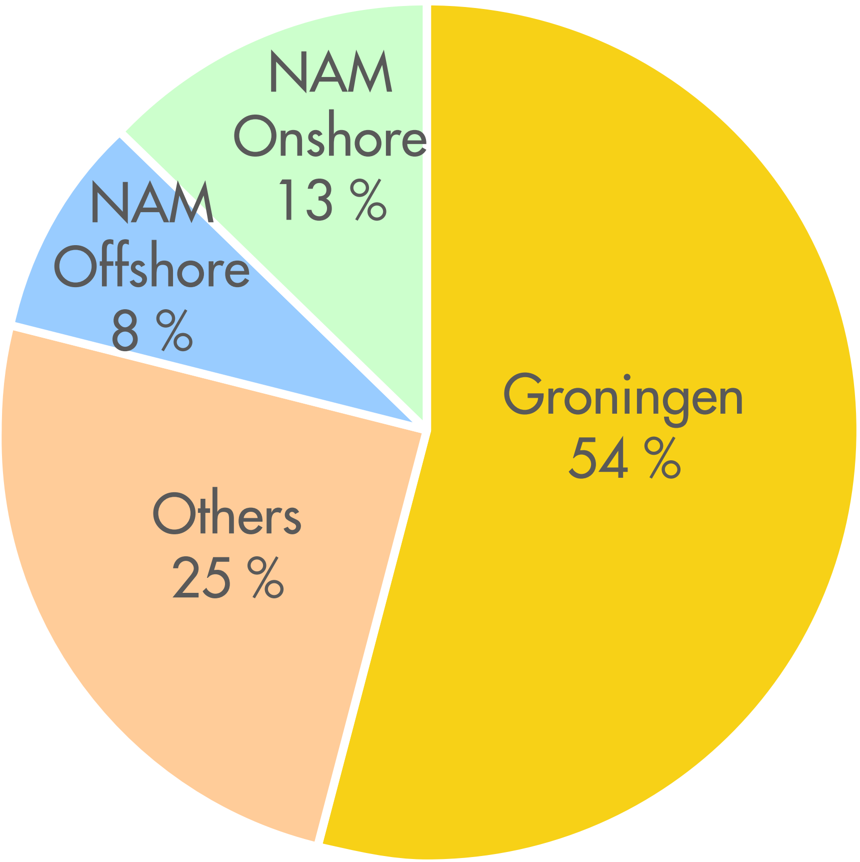
Where is Natural Gas Located?

- Mostly in 3-5 km deep porous Rotliegend sandstone reservoirs
- Some in 1-3 km deep porous Vlieland, Volpriehausen and Bunter sandstone reservoirs
- Some in 2-4 km deep porous and naturally fractured Zechstein carbonate reservoirs
- Porosity 5-25%



NL Natural Gas Production ~70e9 Nm^3 (2009)

- Groningen: 38e9 Nm^3
- NAM Onshore: 9e9 Nm^3
- NAM Offshore: 5e9 Nm^3
- Others: 18e9 Nm^3
- **Total value*: ~14 Billion Euro**
- Daily: 192e6 Nm^3/d
- Gas Wells: ~1000 or ~0.2e6 Nm^3/d/well



* Presentation assumes imaginary gas price of 0.20 Euro/Nm^3

Gas Field = Gas Reservoir = Tank

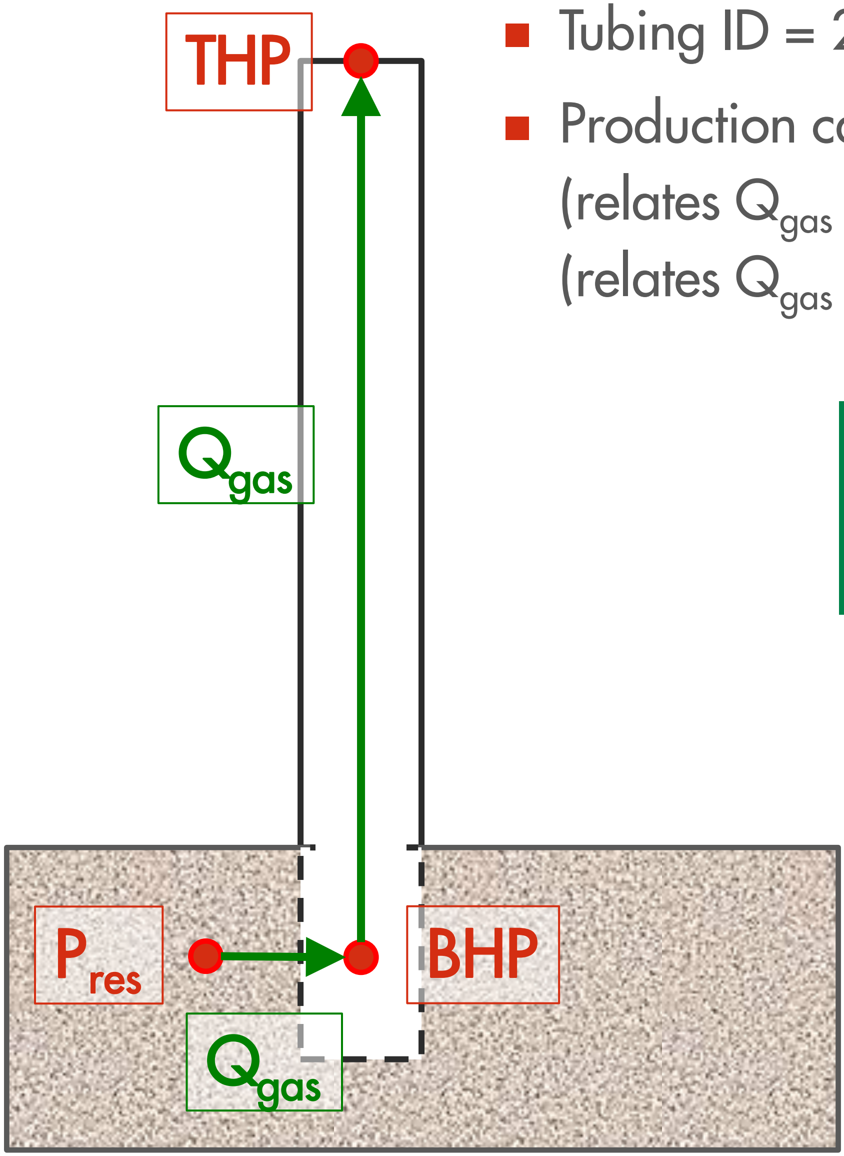
- Depth D= 2500 m
- Initial pressure P_i = 250 bara
- Temperature T_{res} = 100 degC
- Thickness H = 100 m
- Area = 1 km x 1 km
- Porosity ϕ = 10%
- Gas saturation S_g = 80%
- Actual gas volume = $H \cdot Area \cdot \phi \cdot S_g$ = 8.0e6 m^3
- Gas volume @ standard* conditions **OGIP** = $H \cdot Area \cdot \phi \cdot S_g \cdot P_i$ = 2.0e9 Nm^3

1 Nm^3 ~ 40 MJ
1e3 Nm^3 ~ 1 m^3 or 6 bbl oil equivalent
1e6 Nm^3/d ~ 500 MW power plant
1e9 Nm^3 supplies Amsterdam for 1 year

* 0 degC and 1 atm

Range of OGIP: 0.2-2000e9 Nm^3
Few large fields – Many small fields
Revenue: 0.04-400 Billion Euro

Gas Well = Pipe



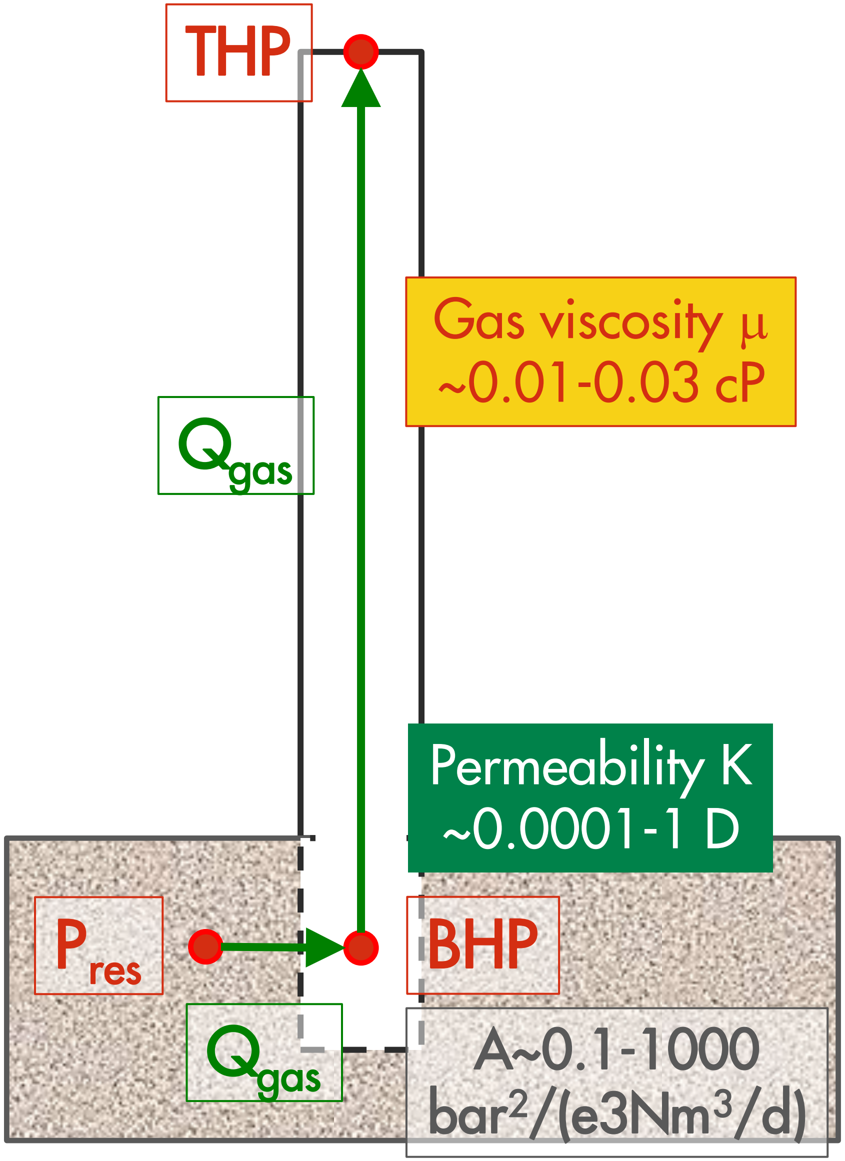
- Tubing ID = 2"-8" (0.05-0.2 m)
- Production capacity Q_{gas} is governed by <u>inflow relation</u> (relates Q_{gas} to P_{res} and BHP) and <u>outflow relation</u> (relates Q_{gas} to BHP and THP)

Range of Q_{gas}: 0.01-10e6 Nm^3/d
High for new wells (high P_{res}) and large ID
Small for old wells (low P_{res}) and small ID

Range of well life: 10-100 years
Depends on OGIP, inflow, outflow <u>and</u> economic limit (operating cost)

Range of OGIP/well: 0.2-10e9 Nm^3
Revenue/well: 0.04-2 Billion Euro

Inflow Relation



- Actual Darcy flow between reservoir and well:

  $$Q_{actual} \sim (P_{res}\text{-}BHP) \cdot (K \cdot H)/\mu$$

  - Where K is permeability, H is reservoir height and μ is fluid viscosity
- Convert to standard conditions by multiplying by average pressure $(P_{res}+BHP)/2$:

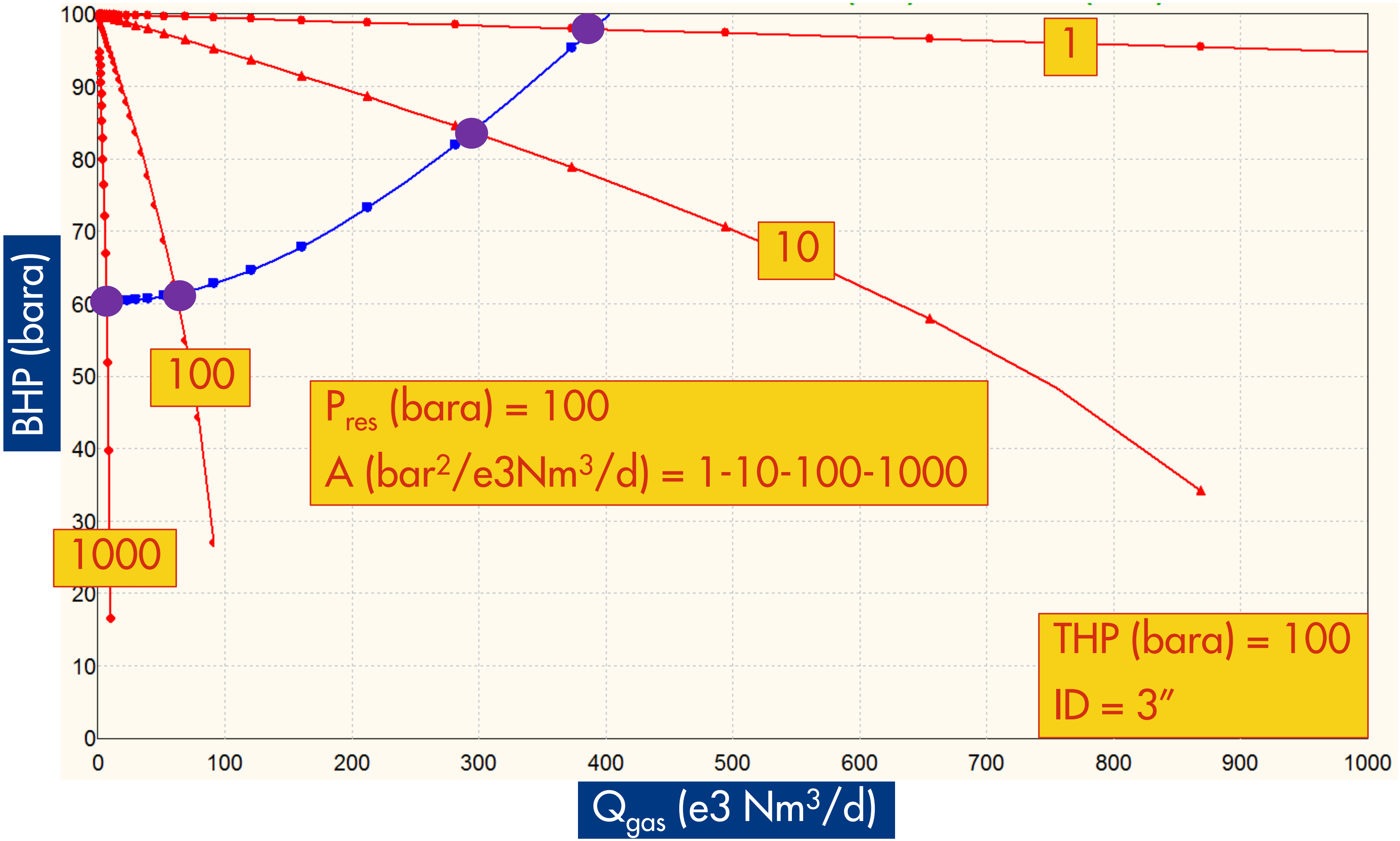
  $$Q_{gas} \sim (P_{res}^2\text{-}BHP^2) \cdot (K \cdot H)/\mu$$

- Which is equivalent to Forchheimer equation:

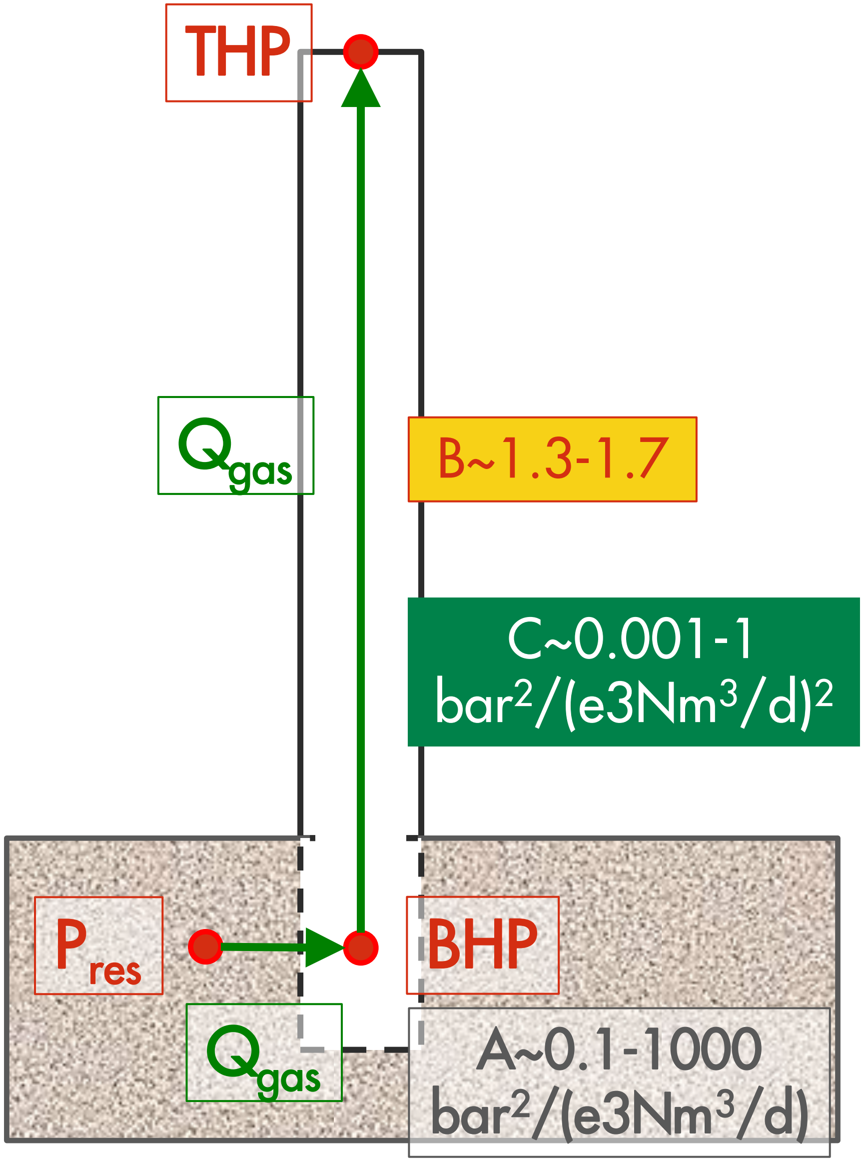
  $$(P_{res}^2\text{-}BHP^2) = A \cdot Q_{gas}$$

  - Where inflow resistance $A \sim \mu/(K \cdot H)$

Inflow Performance



Outflow Relation



- Pressure drop between bottom BHP and surface THP consists of weight of gas column and gas friction:

$$BHP^2 = THP^2 \cdot B + C \cdot Q_{gas}^2$$

- Where B is the hydrostatic parameter:

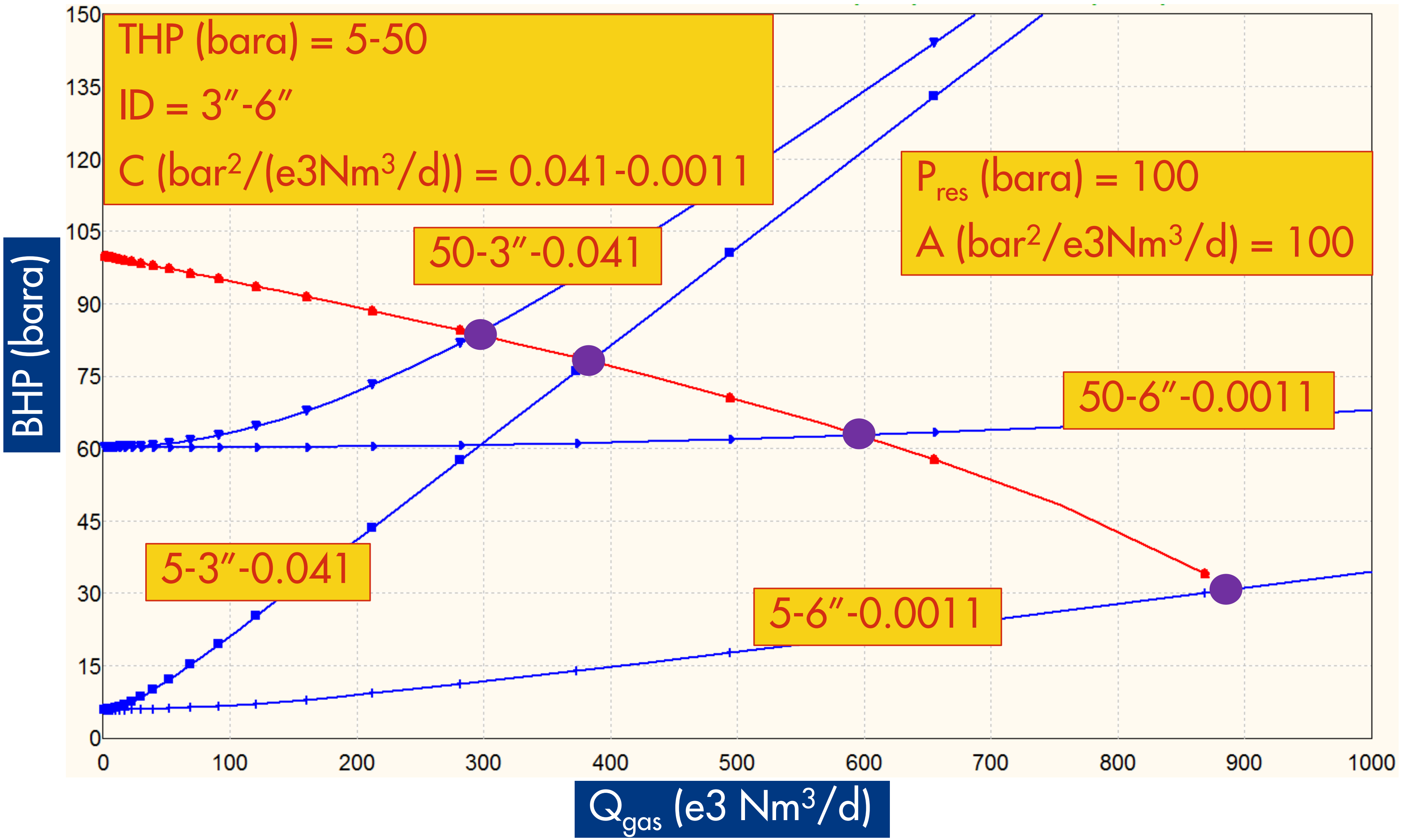
$$B \sim e^{(0.0683 \cdot D \cdot SG)/(Z \cdot T))}$$

  - B increases with depth D and gas density SG
- And C is the friction parameter:

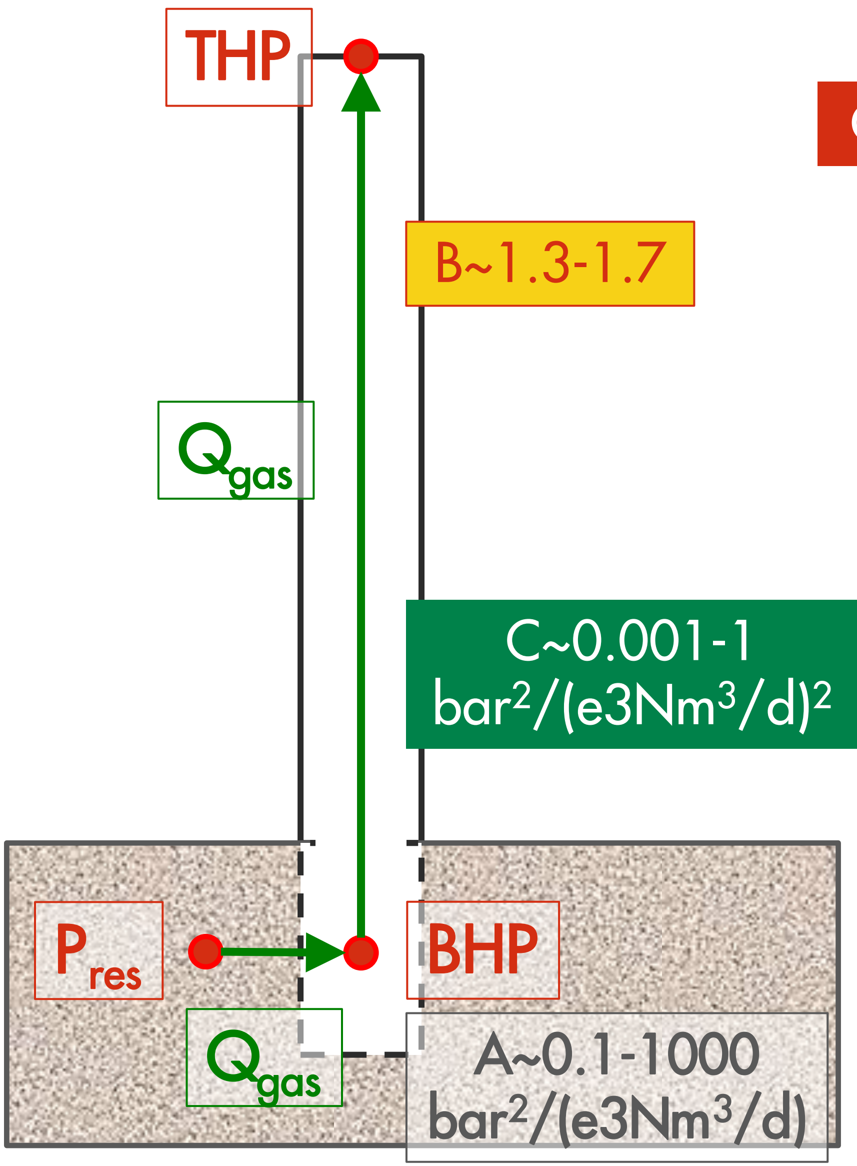
$$C \sim D \cdot (B-1)/ID^5$$

  - C increases with depth D and decreases with tubing ID

Outflow Performance



Production Forecast – Nodal Analysis



- Solution exists for Q_{gas}:

$$Q_{gas} = \{[A^2+4\cdot C\cdot(P_{res}{}^2-THP^2\cdot B)]^{0.5}-A\}/(2\cdot C)$$

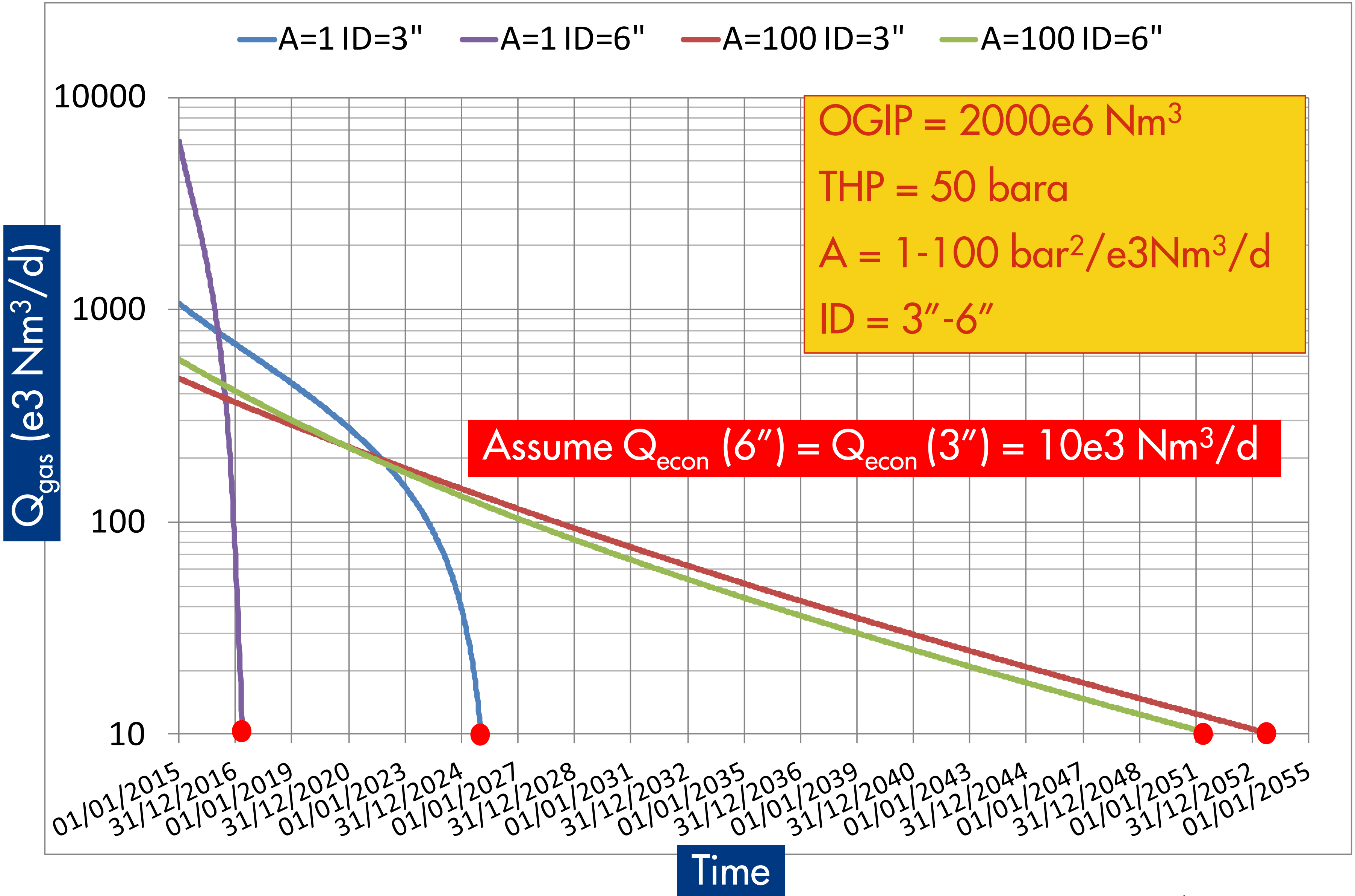
- Solution exists for minimum achievable reservoir pressure P_{min}, assuming economic limit Q_{econ}:

$$P_{min}{}^2 = THP^2\cdot B+A\cdot Q_{econ}+C\cdot Q_{econ}{}^2$$

- For low enough Q_{econ}, P_{min} becomes:

$$P_{min} \approx THP\cdot B^{0.5}$$

Production Forecast – Q_{gas} Vs Time



Ultimate Recovery

- For tank type reservoirs the produced gas volume G_p is proportional to the reduction of the reservoir pressure P_{res} (linear material balance):

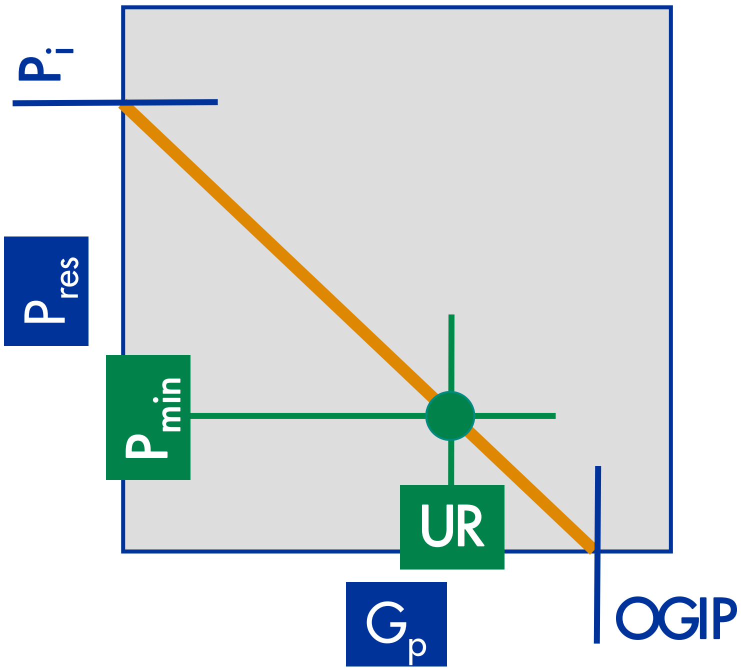
$$G_p = OGIP \cdot (1 - P_{res}/P_i)$$

- The ultimate recovery UR is governed by the minimum tank or reservoir pressure P_{min}:

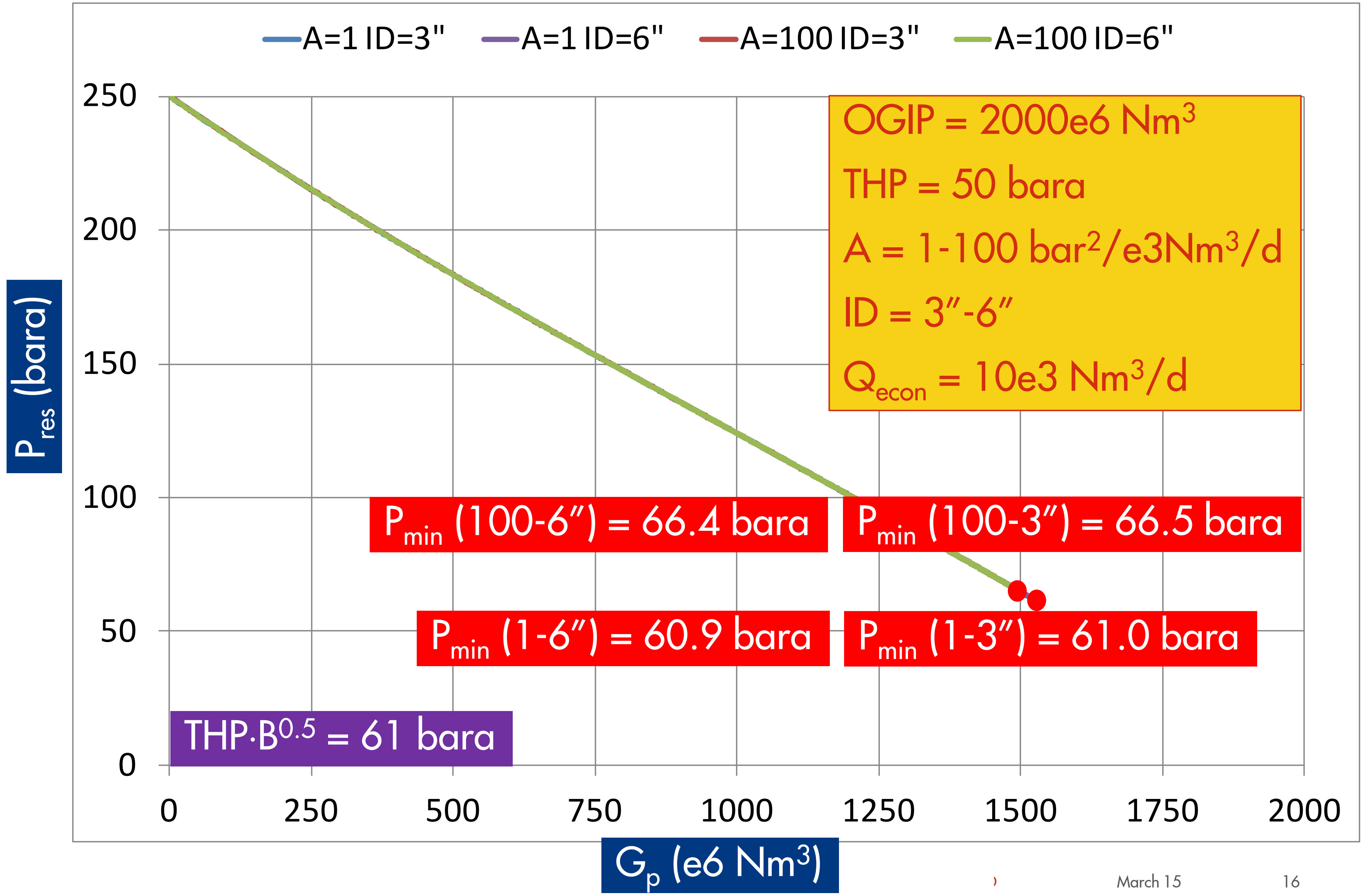
$$UR = OGIP \cdot (1 - P_{min}/P_i)$$

- **Maximize UR by reducing P_{min} as far as economic by reducing THP and Q_{econ}**

$$P_{min}^2 = FTHP^2 \cdot B + A \cdot Q_{econ} + C \cdot Q_{econ}^2$$

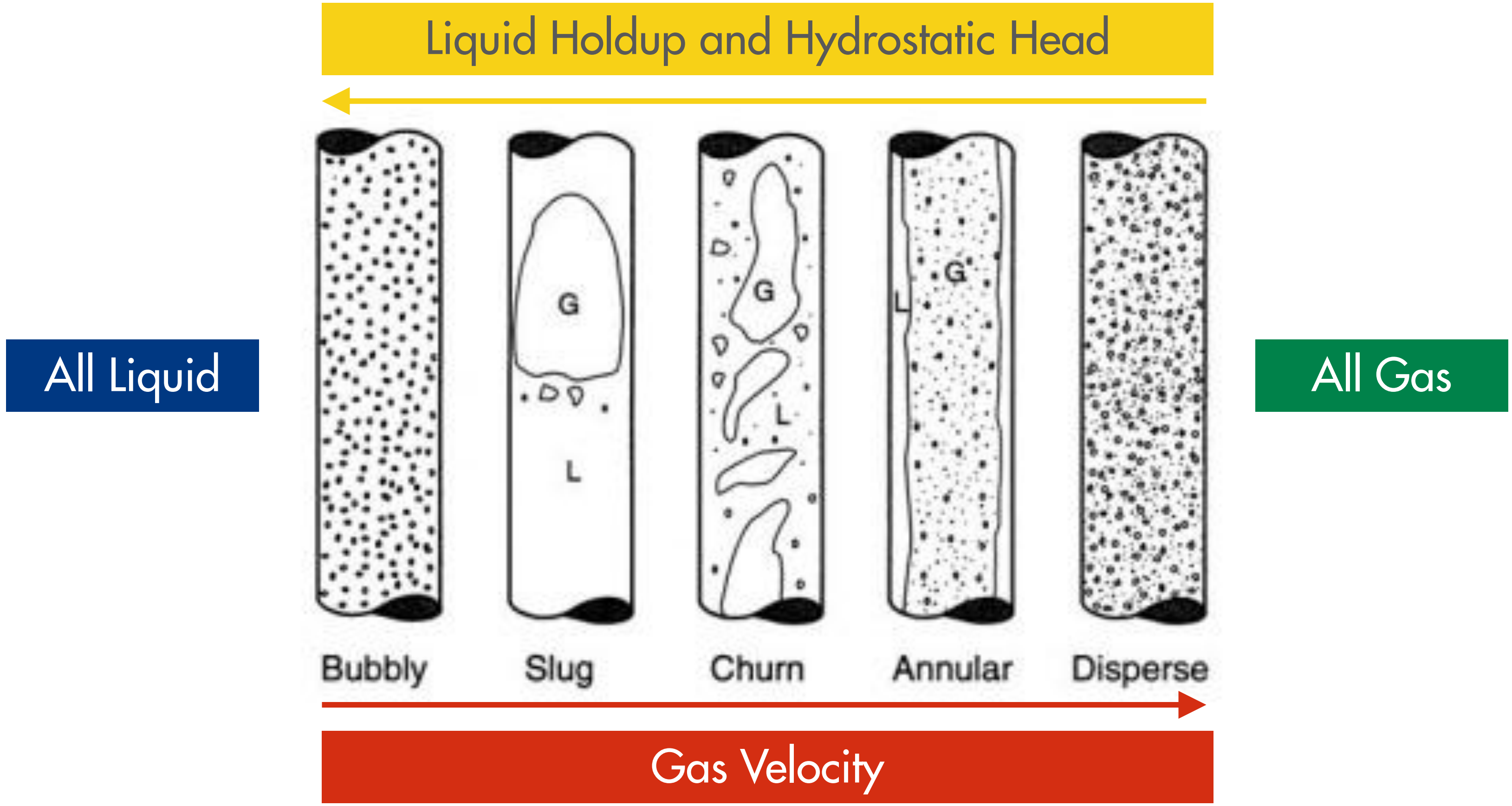


Production Forecast – P_{res} Vs G_p

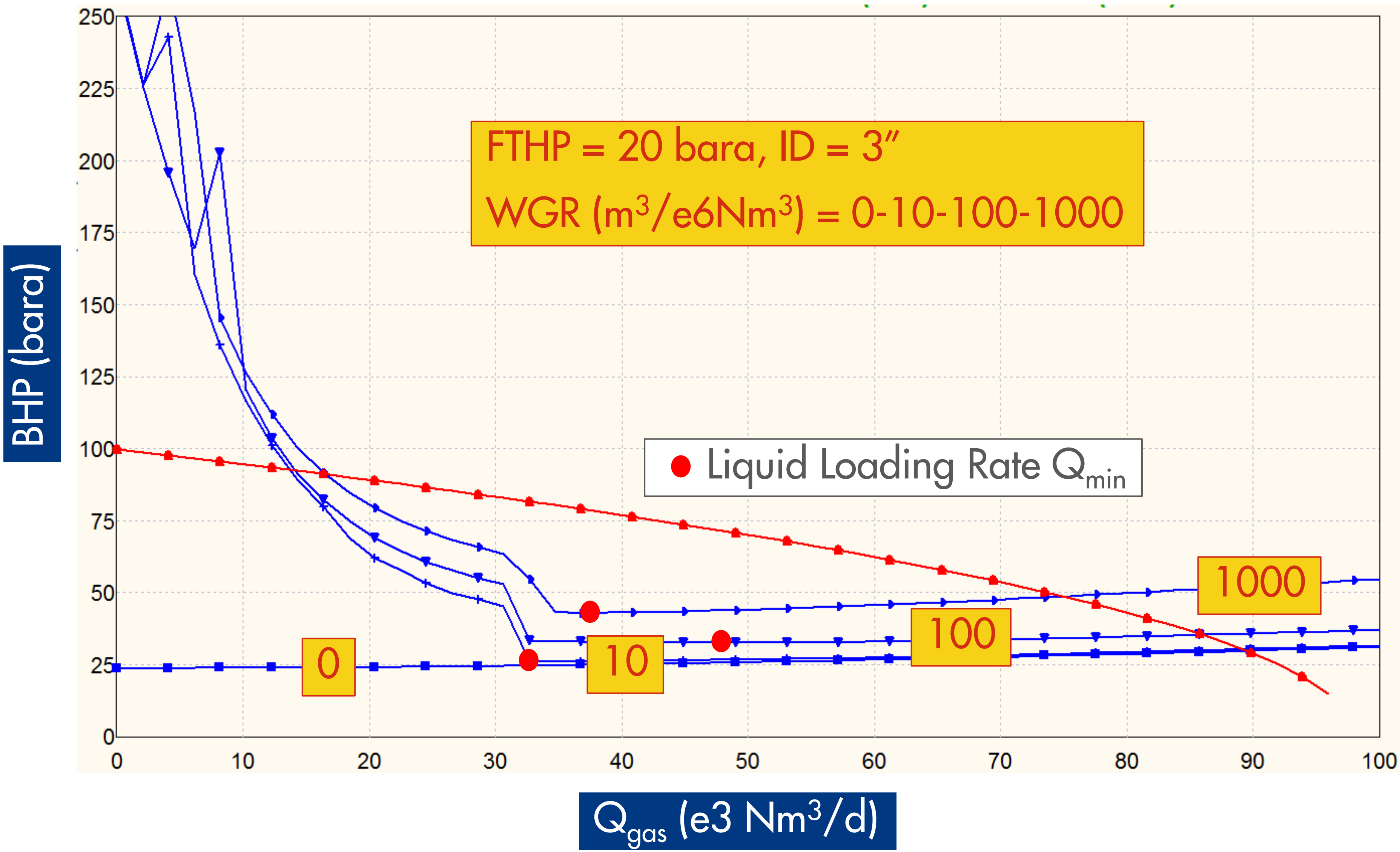


Multiphase Fluid Flow

- Reservoir gas contains heavier hydrocarbons and water in vapor phase
- Part of that vapor condenses into liquid on its way up to surface due to temperature and pressure reduction, resulting in liquid holdup

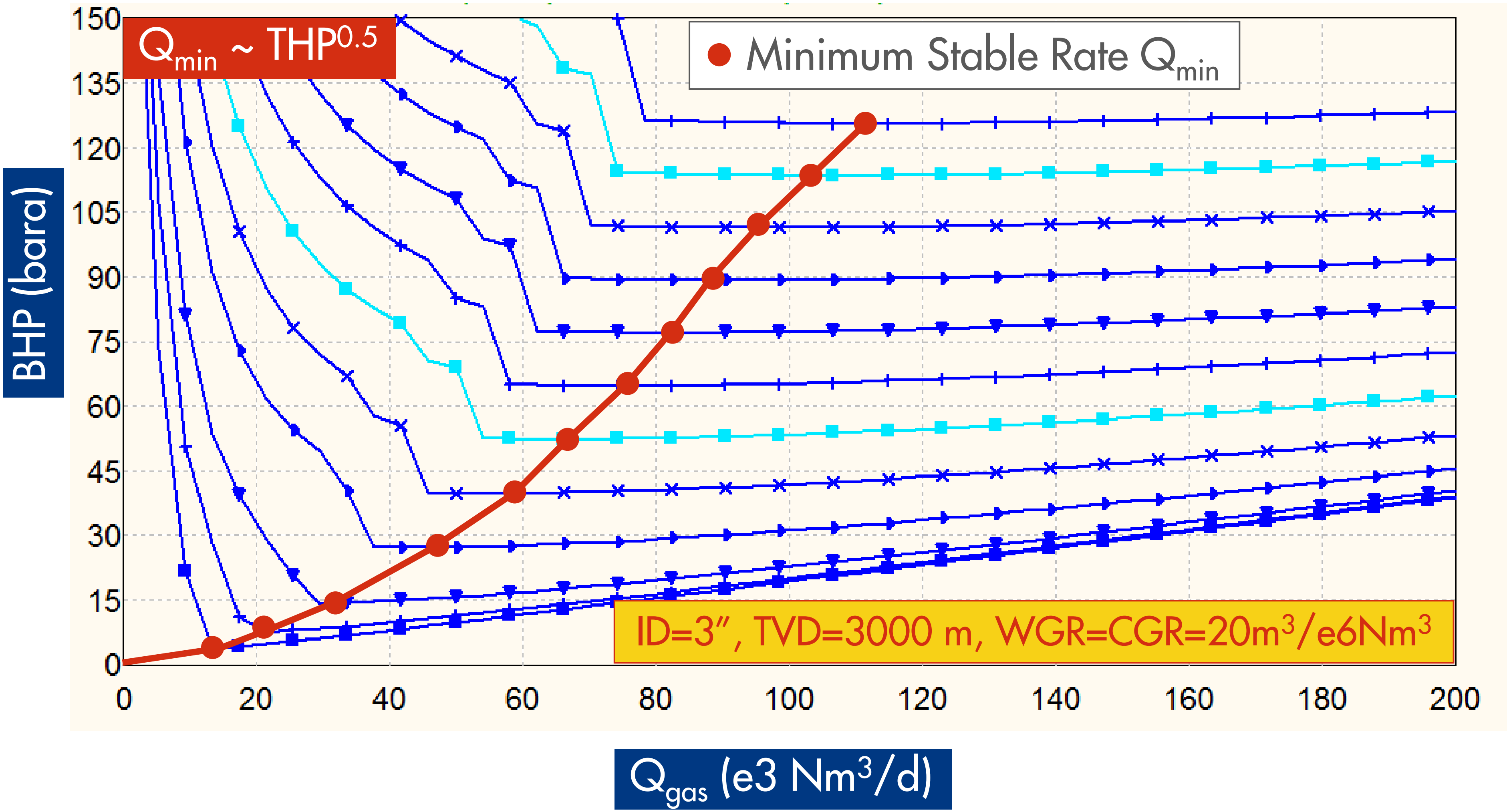


Outflow Performance – Liquid Holdup & Liquid Loading



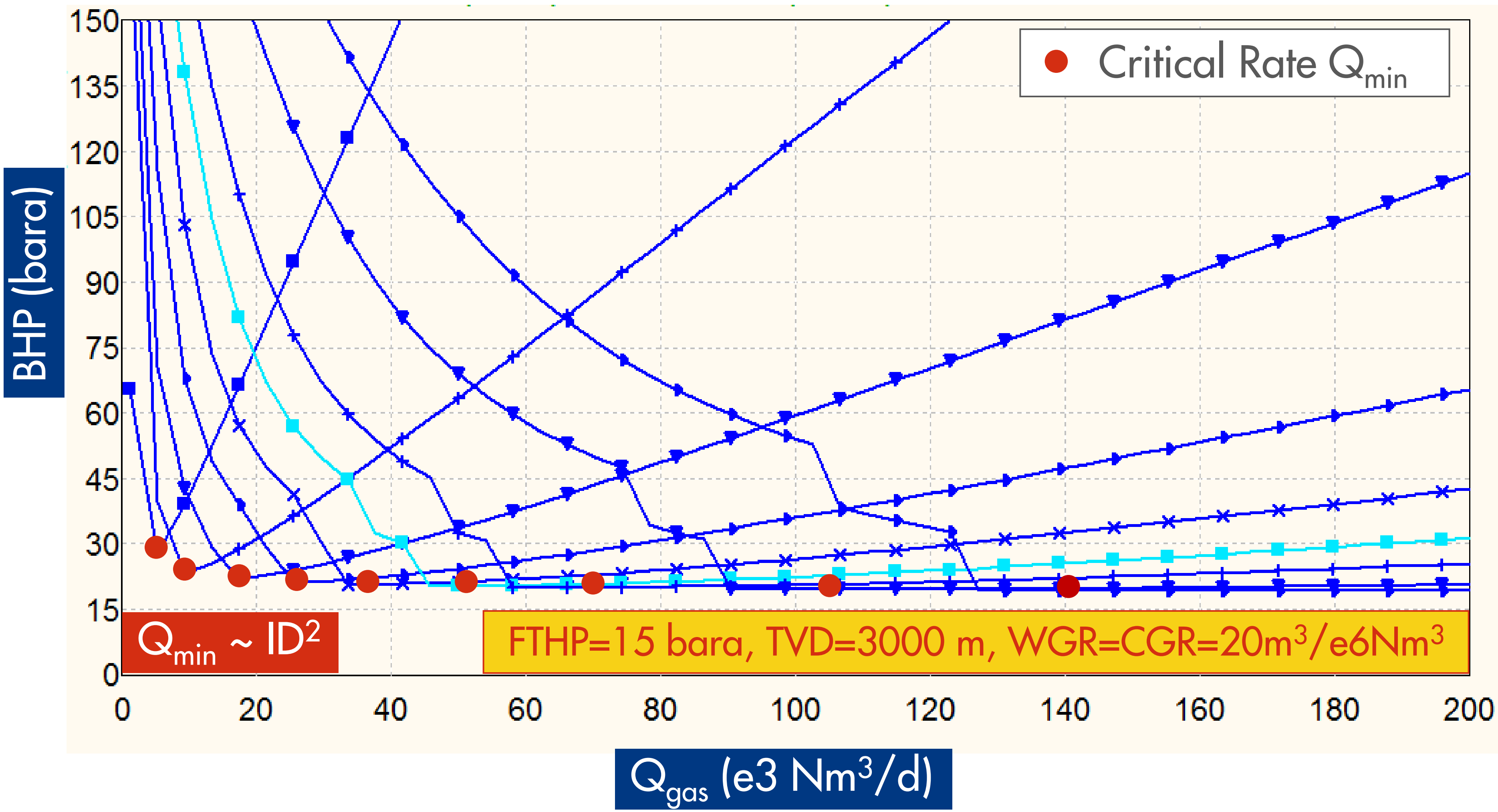
Impact of THP on Outflow and Q_{min}

THP (bara) = 2-5-10-20-30-40-50-60-70-80-90-100



Impact of ID on Outflow and Q_{min}

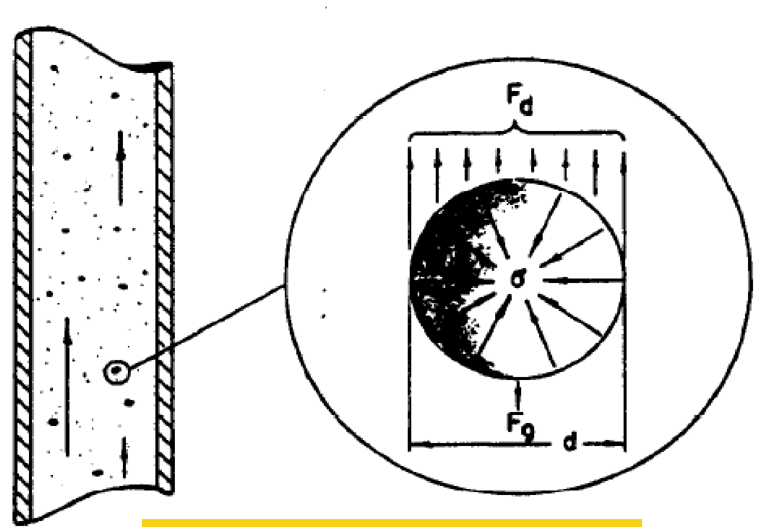
ID = 1″-1.5″-2″-2.5″-3″-3.5″-4″-5″-6″



Turner Criterion: Droplet Reversal*

*Turner, Hubbard and Dukler (1969)

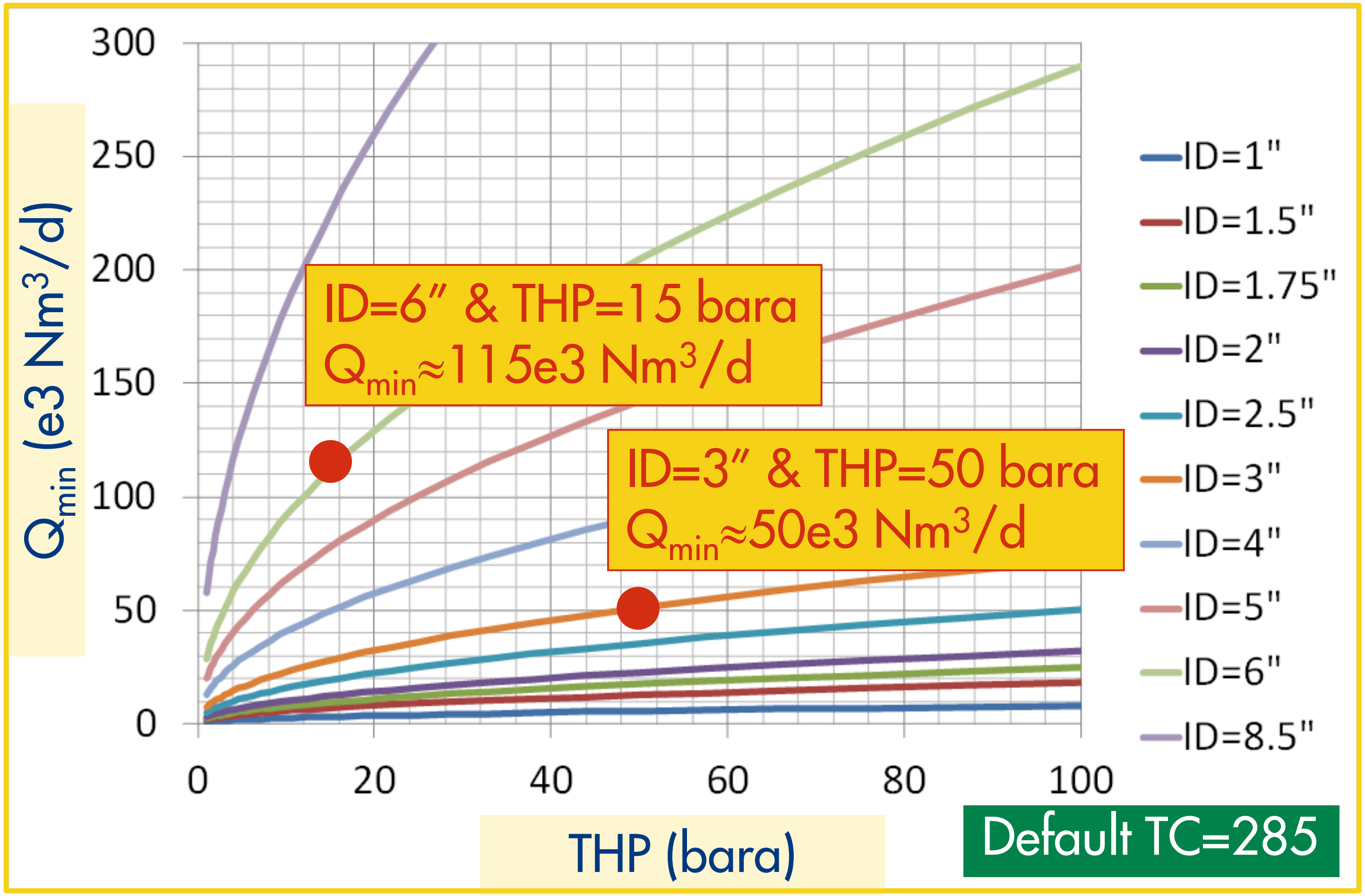
- Liquid loading occurs below the critical gas velocity, at which the friction drag force on the largest liquid droplets becomes less than the gravity force on the droplets.
- However, the largest droplet size required to match the liquid loading data is much larger than the liquid droplet size typically observed in nature.



Entrained Drop Movement

Turner Criterion $Q_{min} \sim TC \cdot FTHP^{0.5} \cdot ID^2$

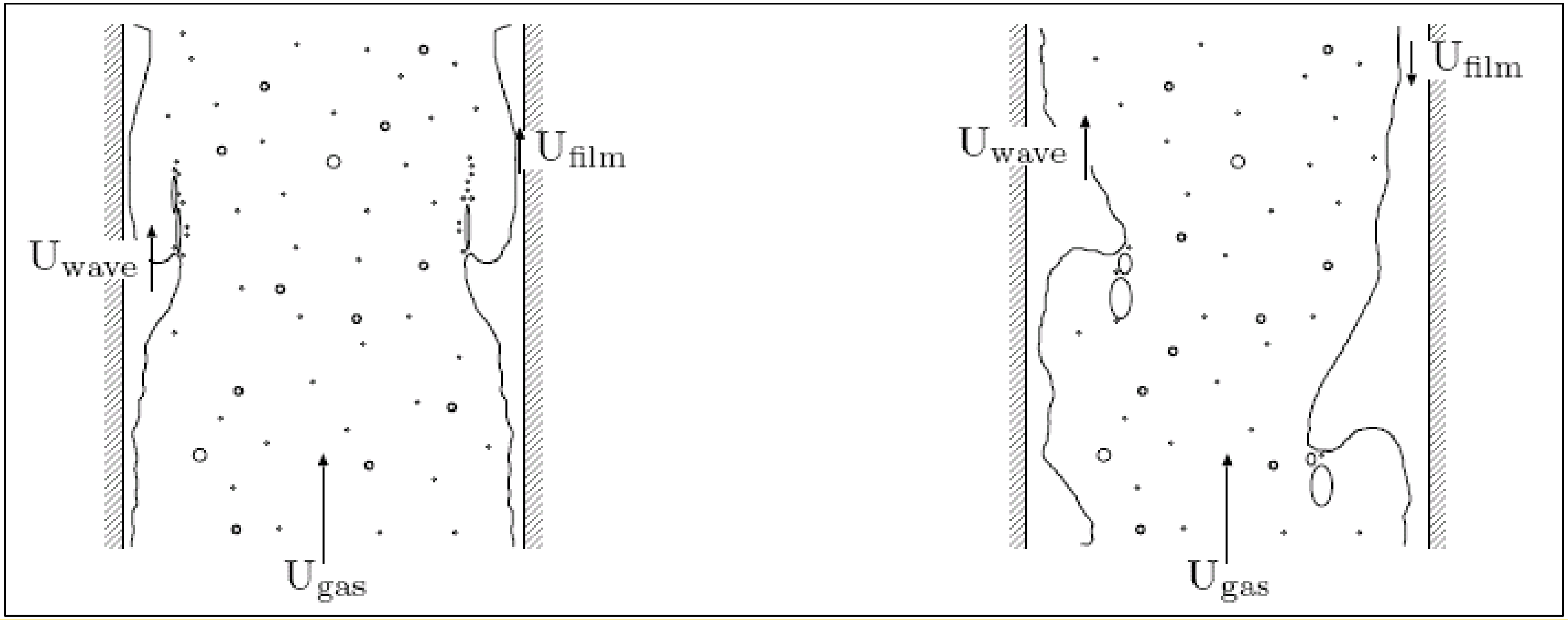
- Translates minimum gas velocity at wellhead into minimum gas rate
- Independent of WGR i.e. water of condensation is sufficient!



Air-Water Flow Loop: Film Reversal

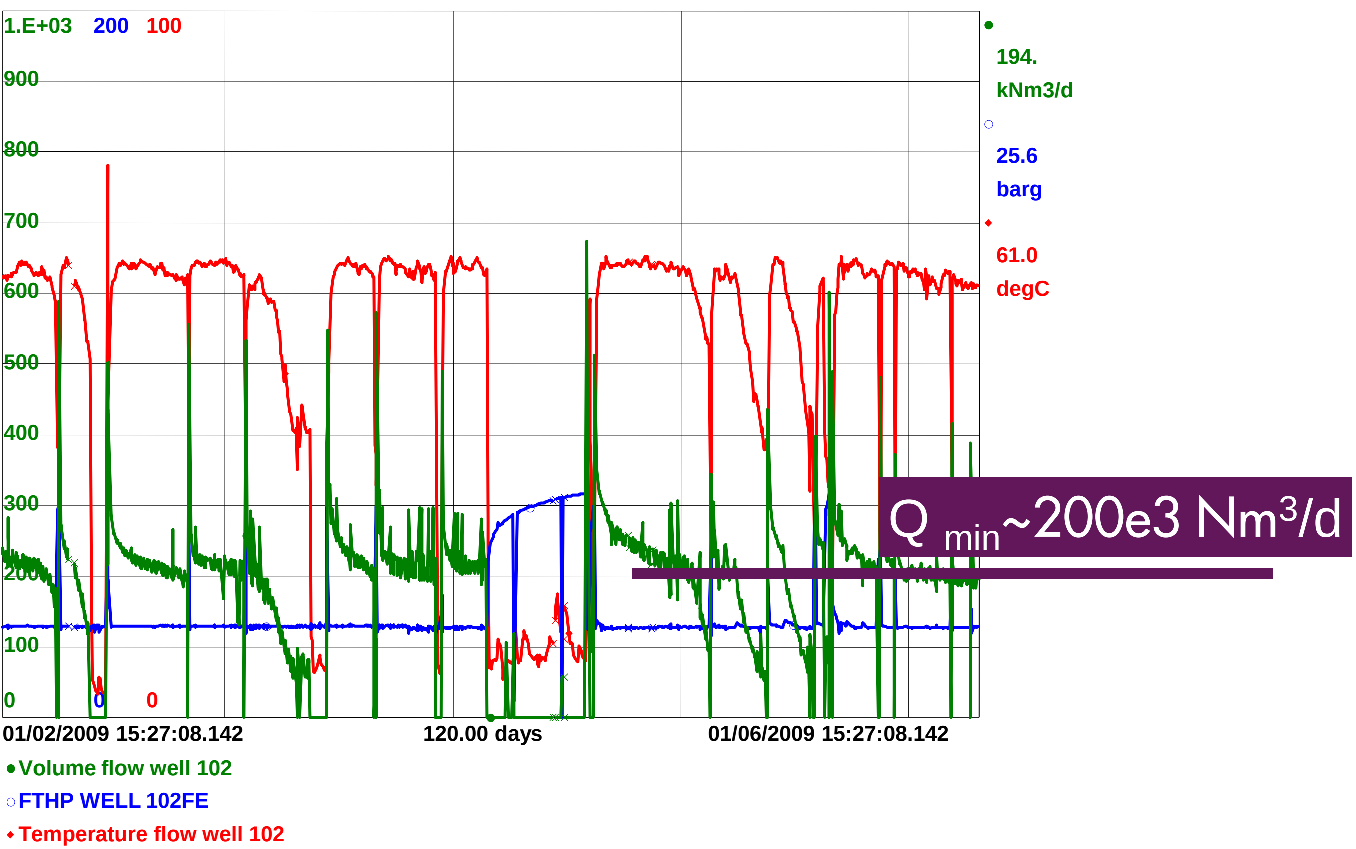
Film Reversal

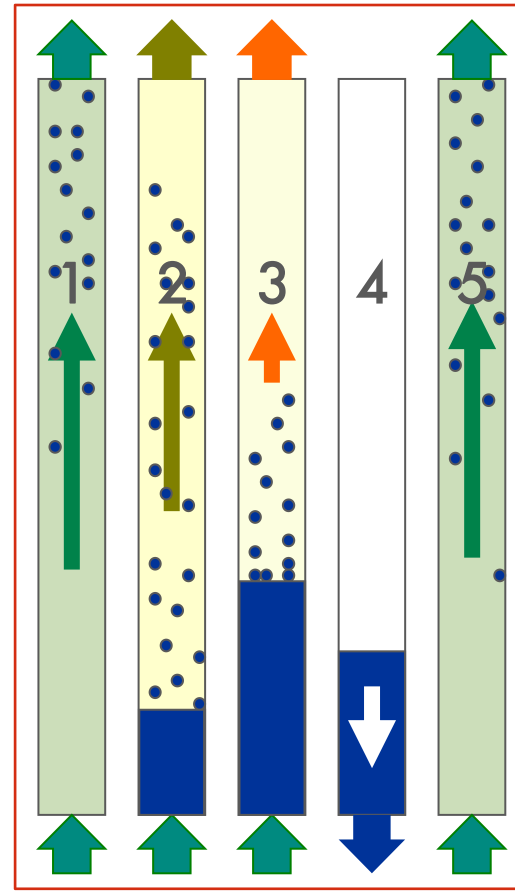
- In a stable flow regime, liquid moves upward in the form of droplets and film
- Onset of liquid loading is governed by film flow reversal, both observed and modelled
- Nonetheless, **Turner** provides a practical and adequate engineering tool



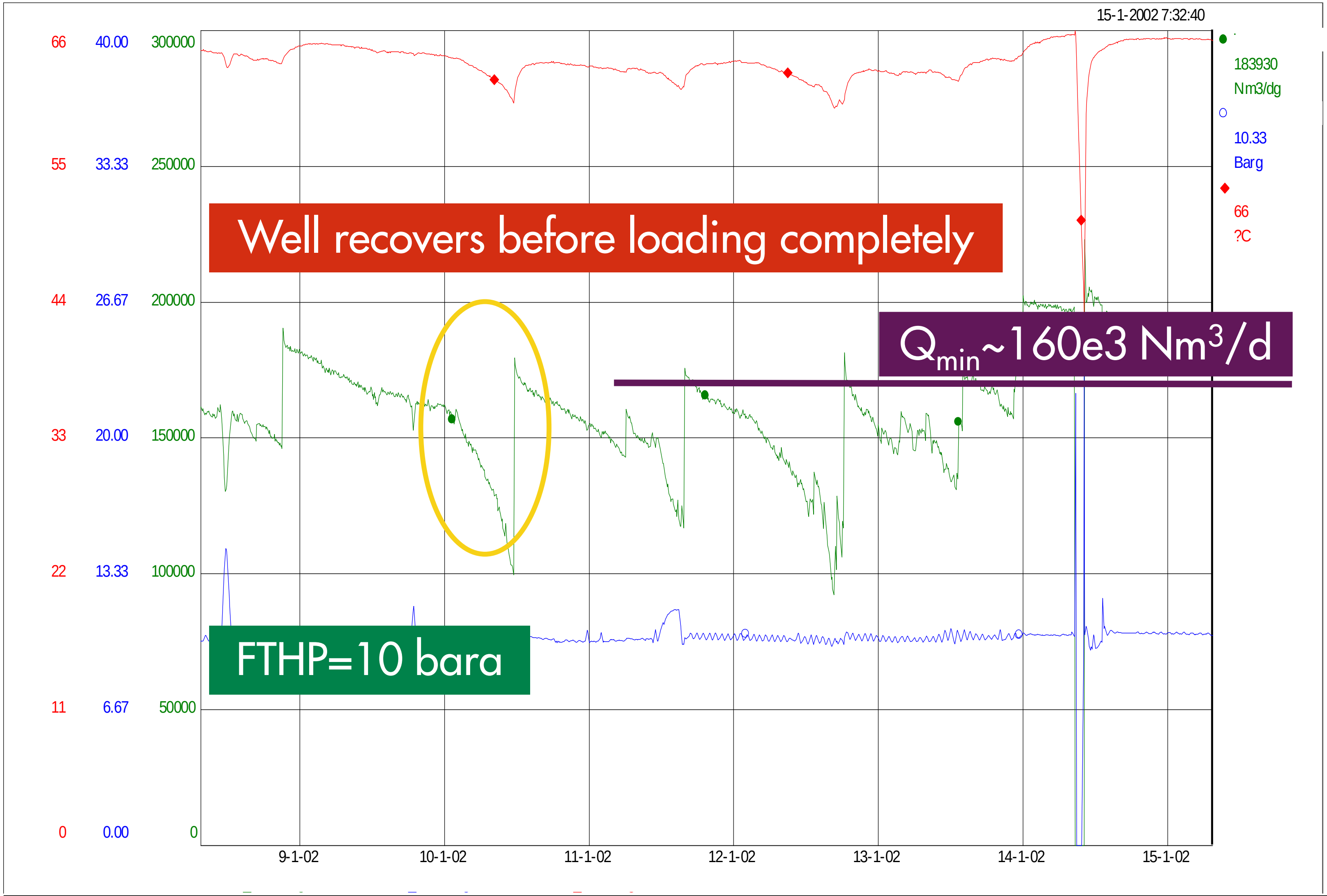
Liquid Loading Cycle

- As reservoir pressure (P_{res}) declines due to depletion, well production (Q_{gas}) decreases
- When Q_{gas} decreases below Q_{min}, the liquid loading cycle starts and average production drops

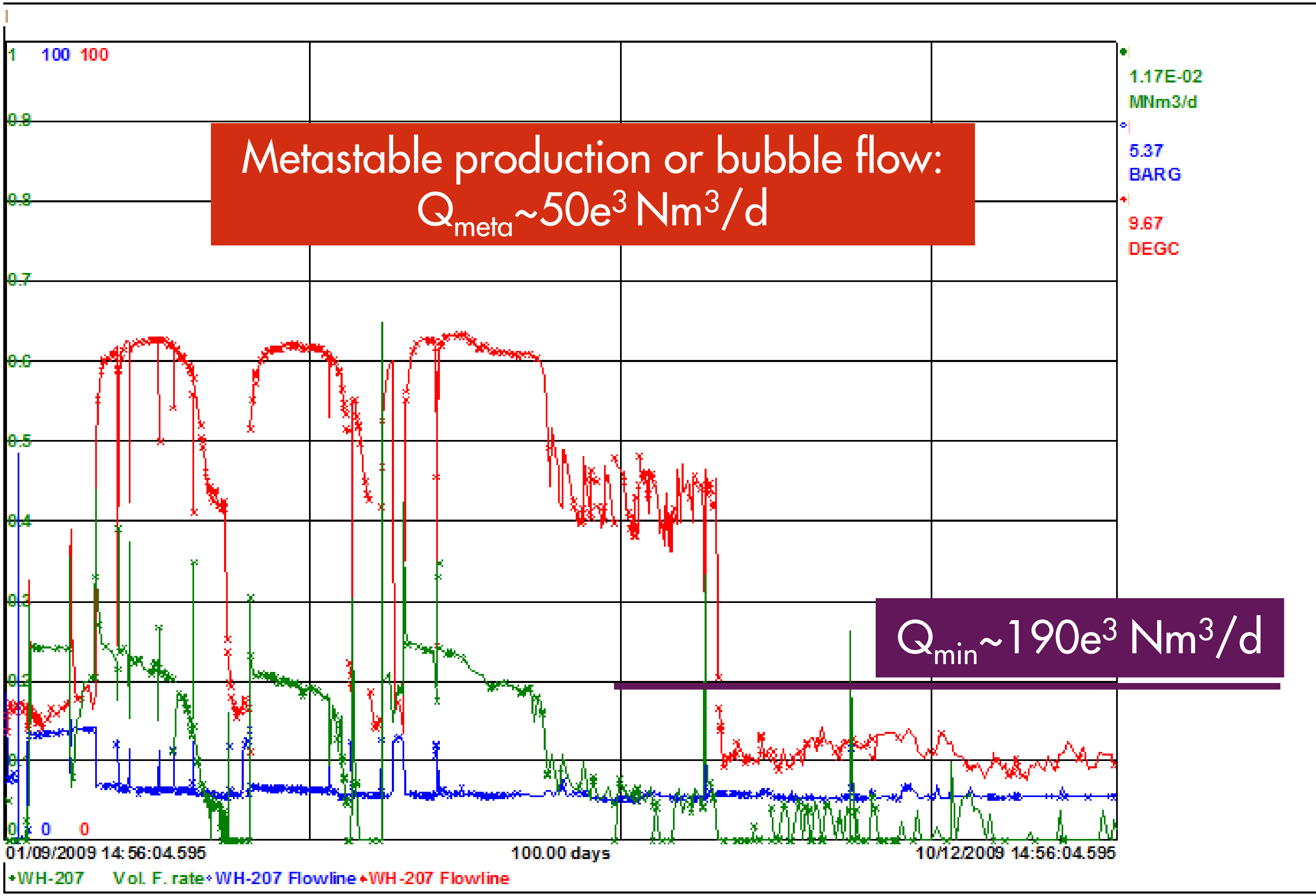




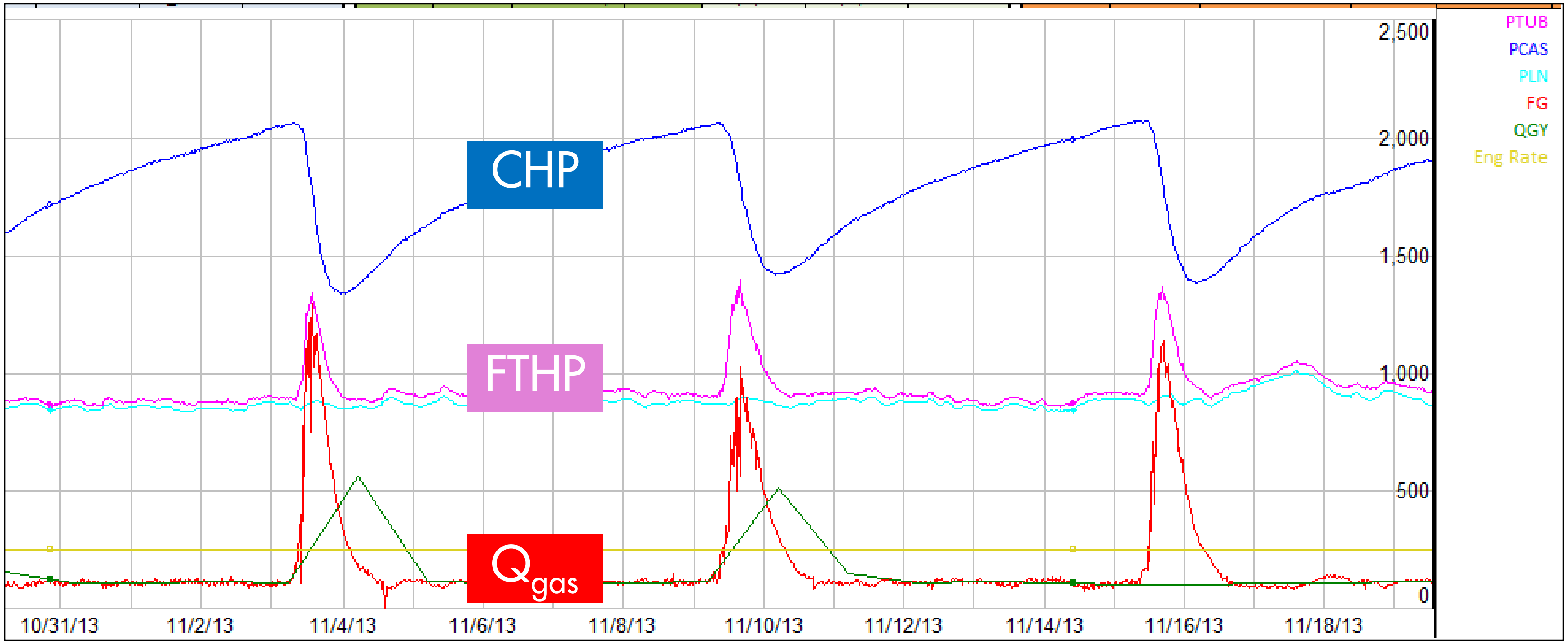
Close to Liquid Loading



Metastable Flow a.k.a. Bubble Flow

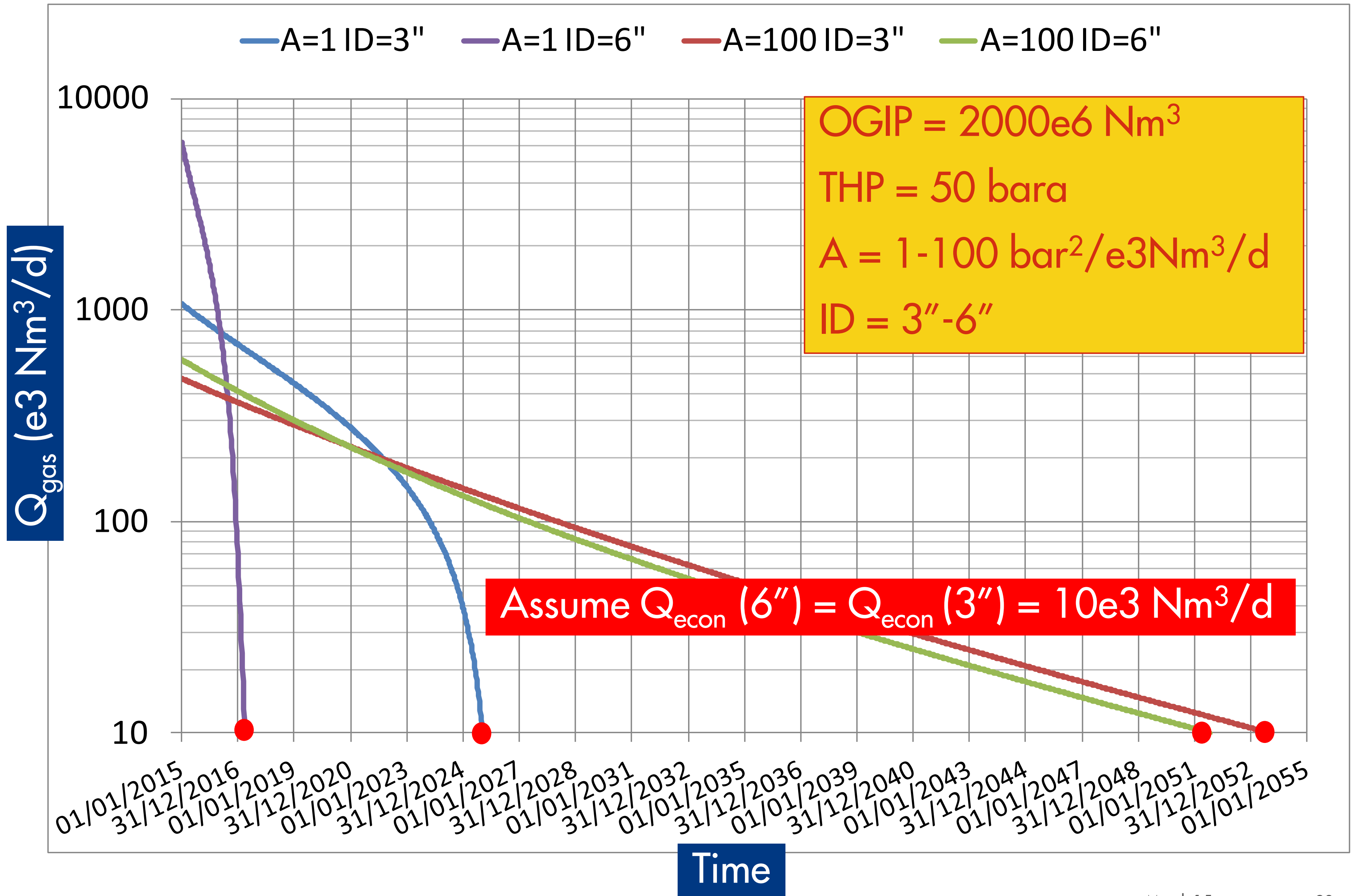


Self-Intermitting Shale Gas Well

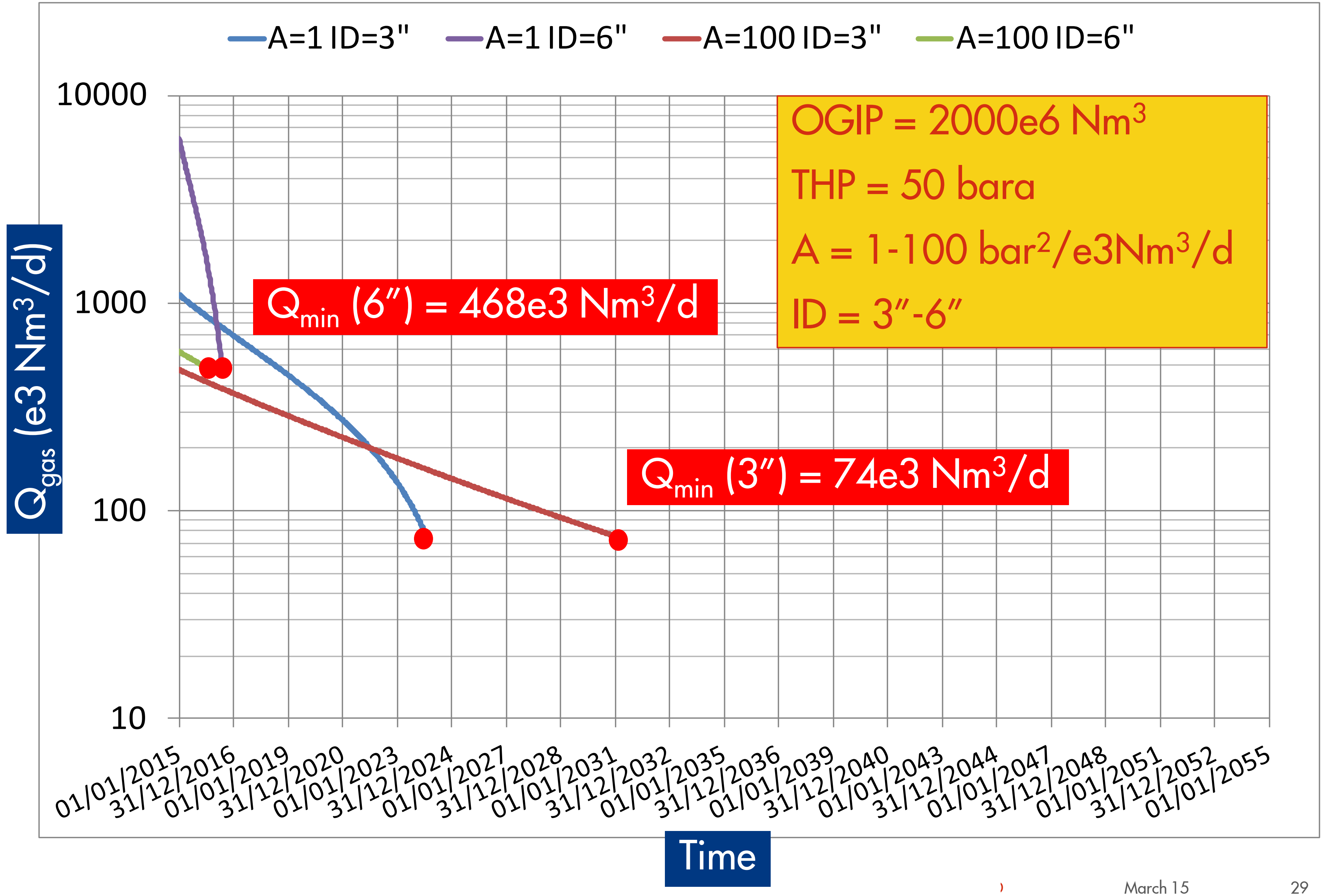


Natural LL Cycle Period ~1 Week

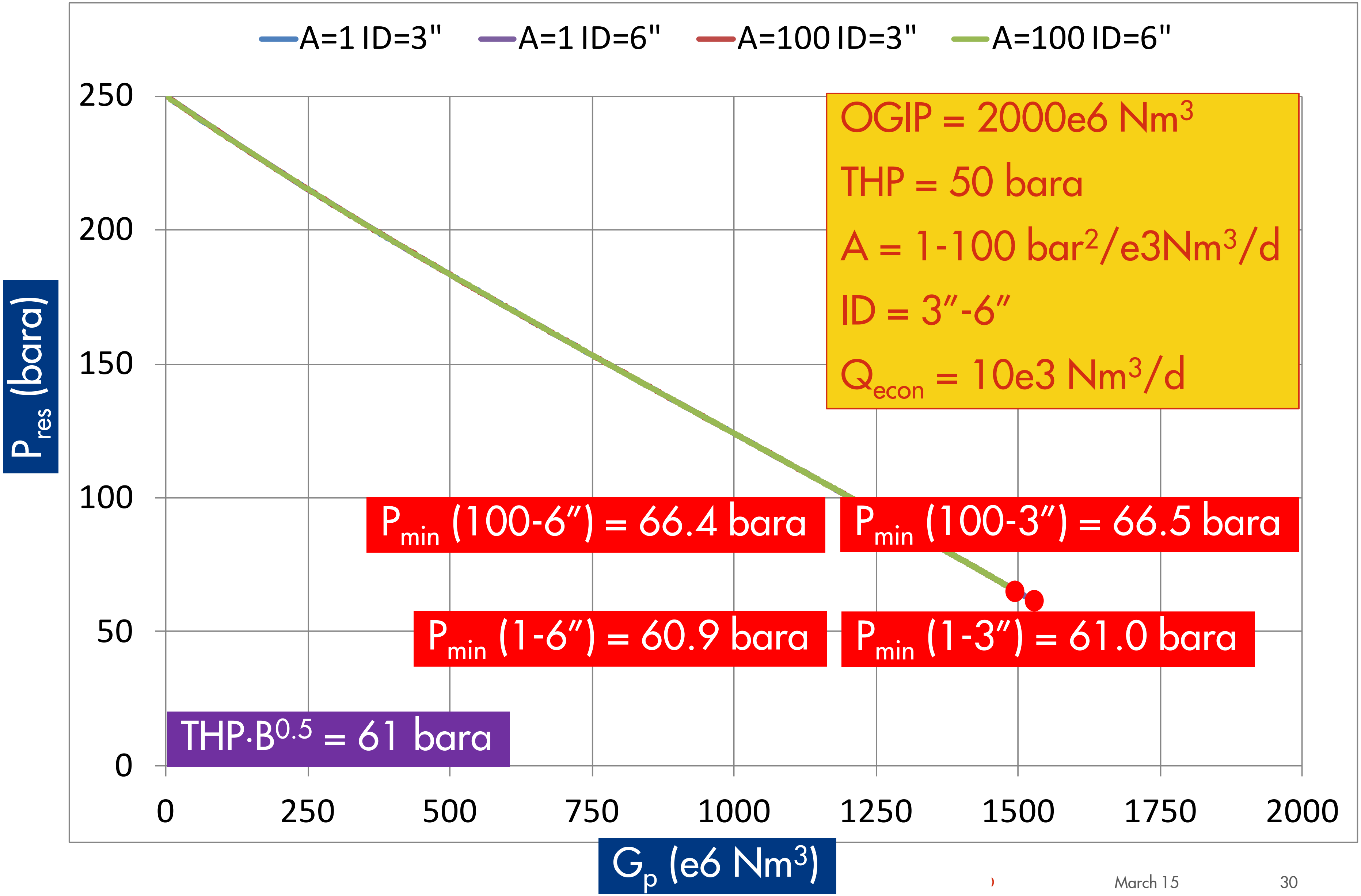
Production Forecast – Q_{gas} Vs Time



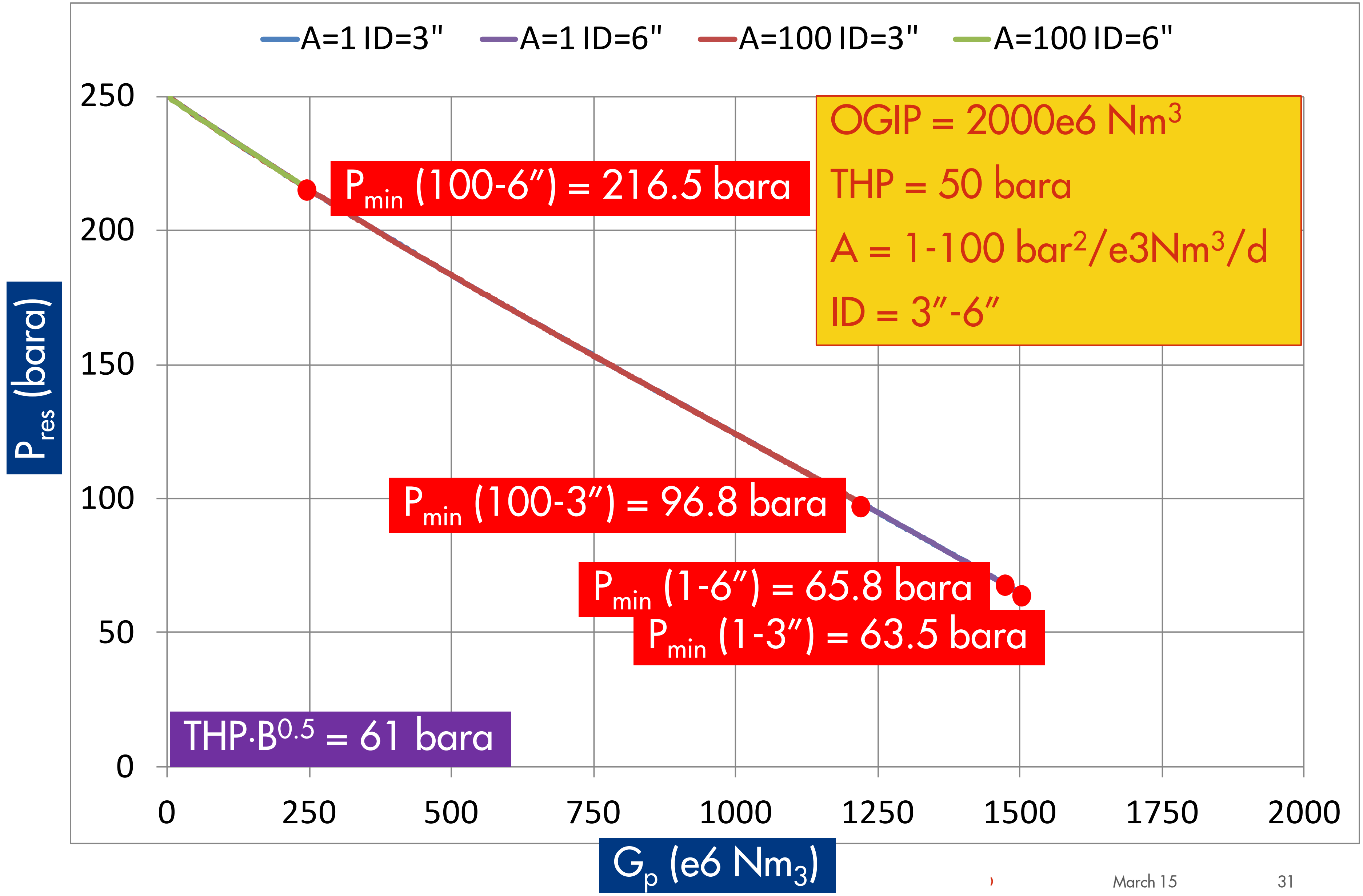
Production Forecast – Q_{gas} Vs Time



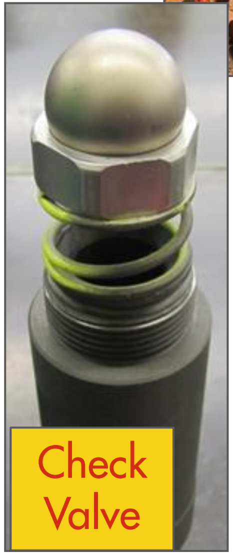
Production Forecast – P_{res} Vs G_p



Production Forecast – P_{res} Vs G_p



Gas Well Deliquification Toolbox



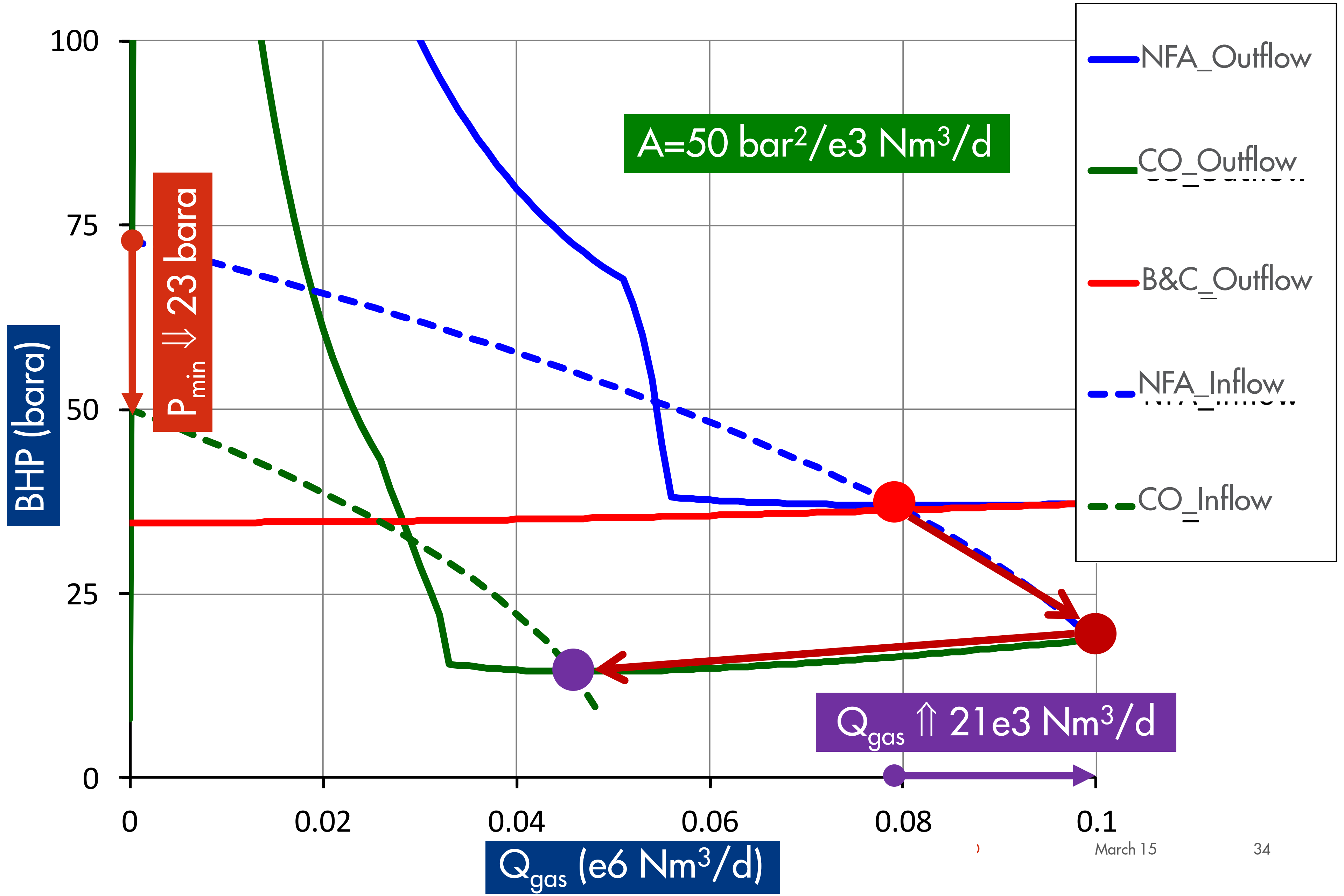
Gas Well Deliquification = Reducing P_{min} = Increasing UR

- Reduce THP and hydrostatic head
  - E.g. compression, water shut-off and downhole pumping
- Reduce critical rate (Q_{min})
  - E.g. compression, velocity string, foam assisted lift, plunger lift and gas lift
- Increase well capacity (Q_{gas})
  - E.g. compression, stimulation, intermittent production, plunger lift and check valve

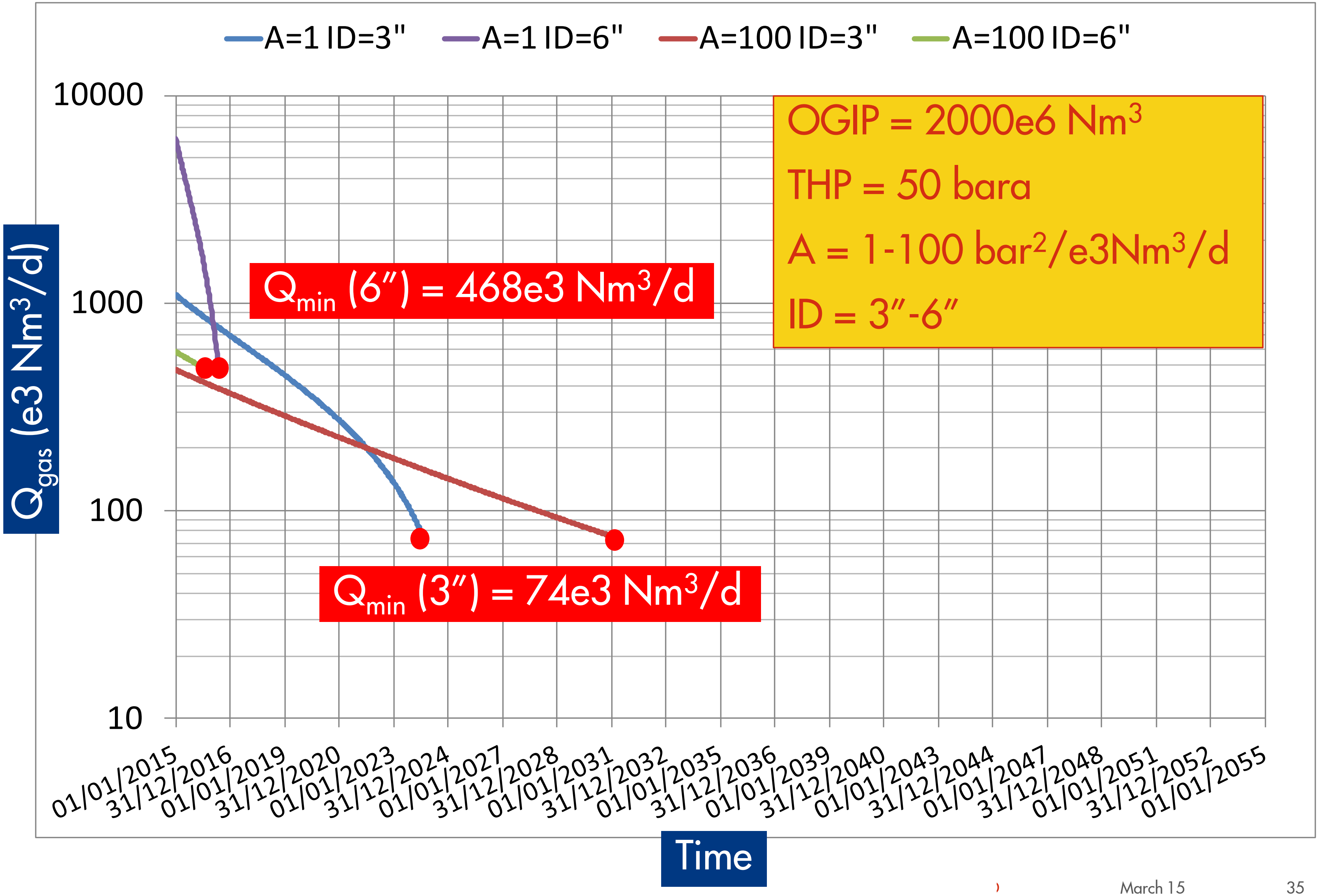
Wellhead compressor

Continuous foam

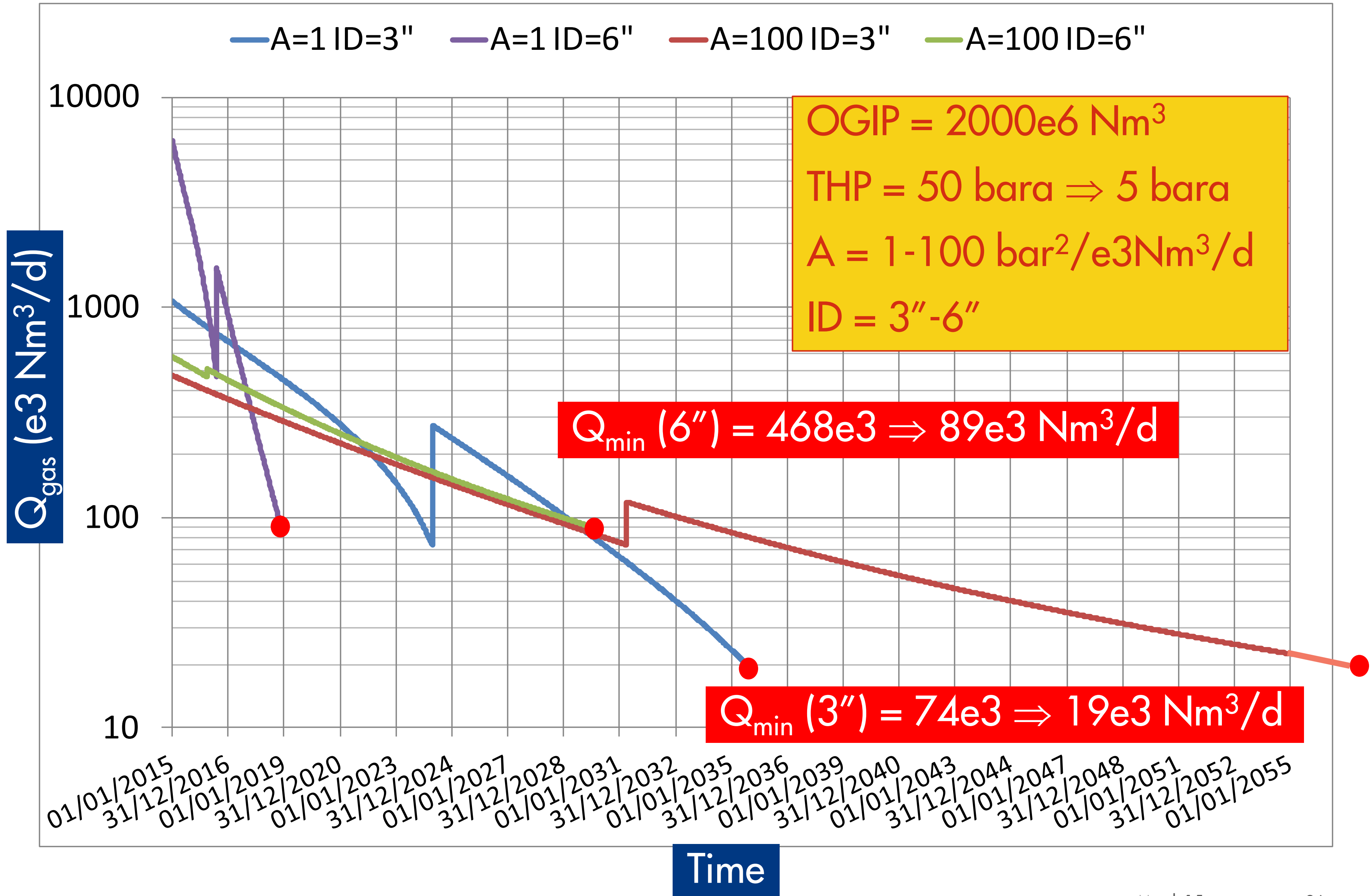
Reduce THP to Reduce Q_{min} and P_{min}



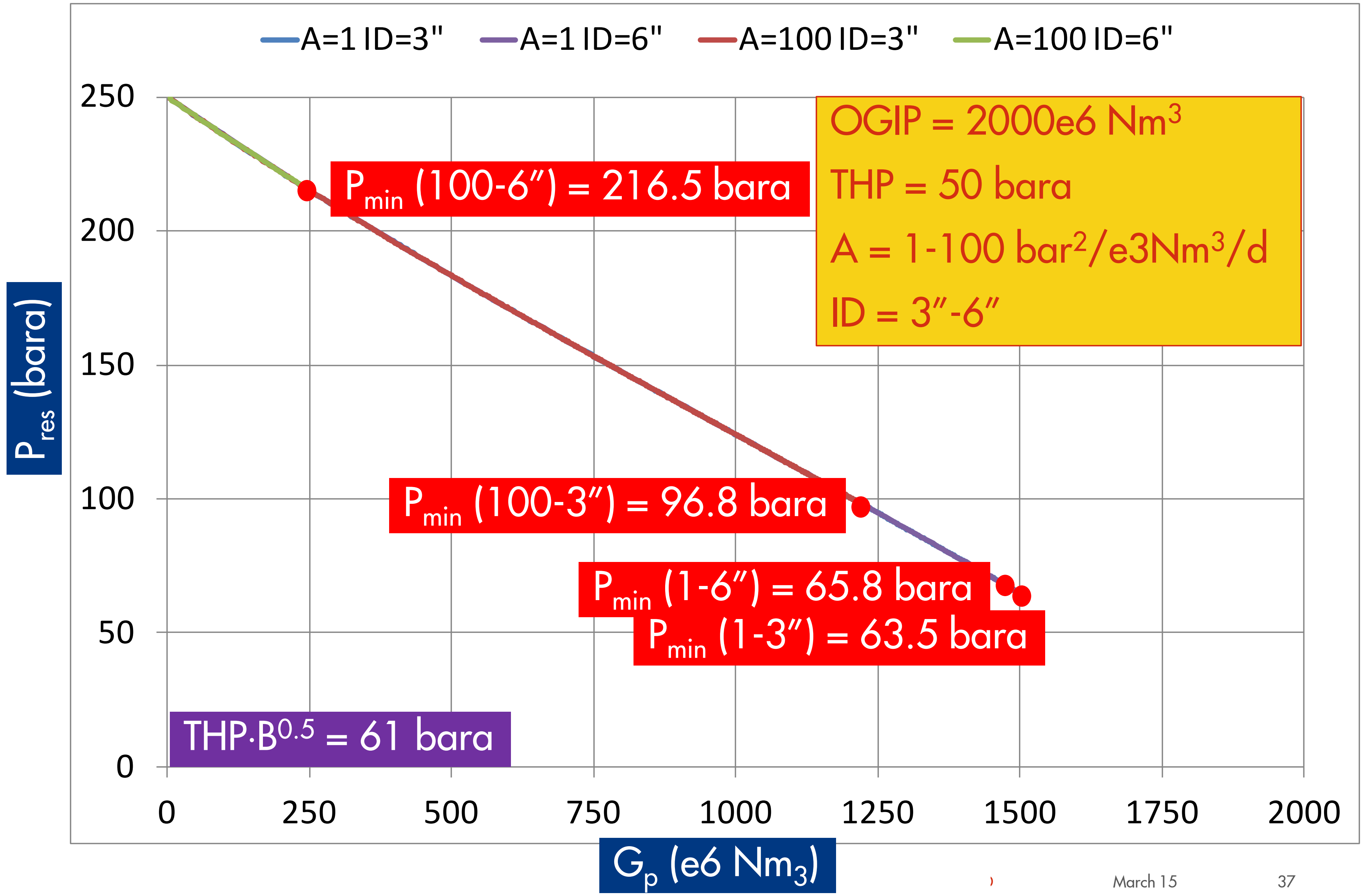
Q_{gas} Vs Time – Base Case



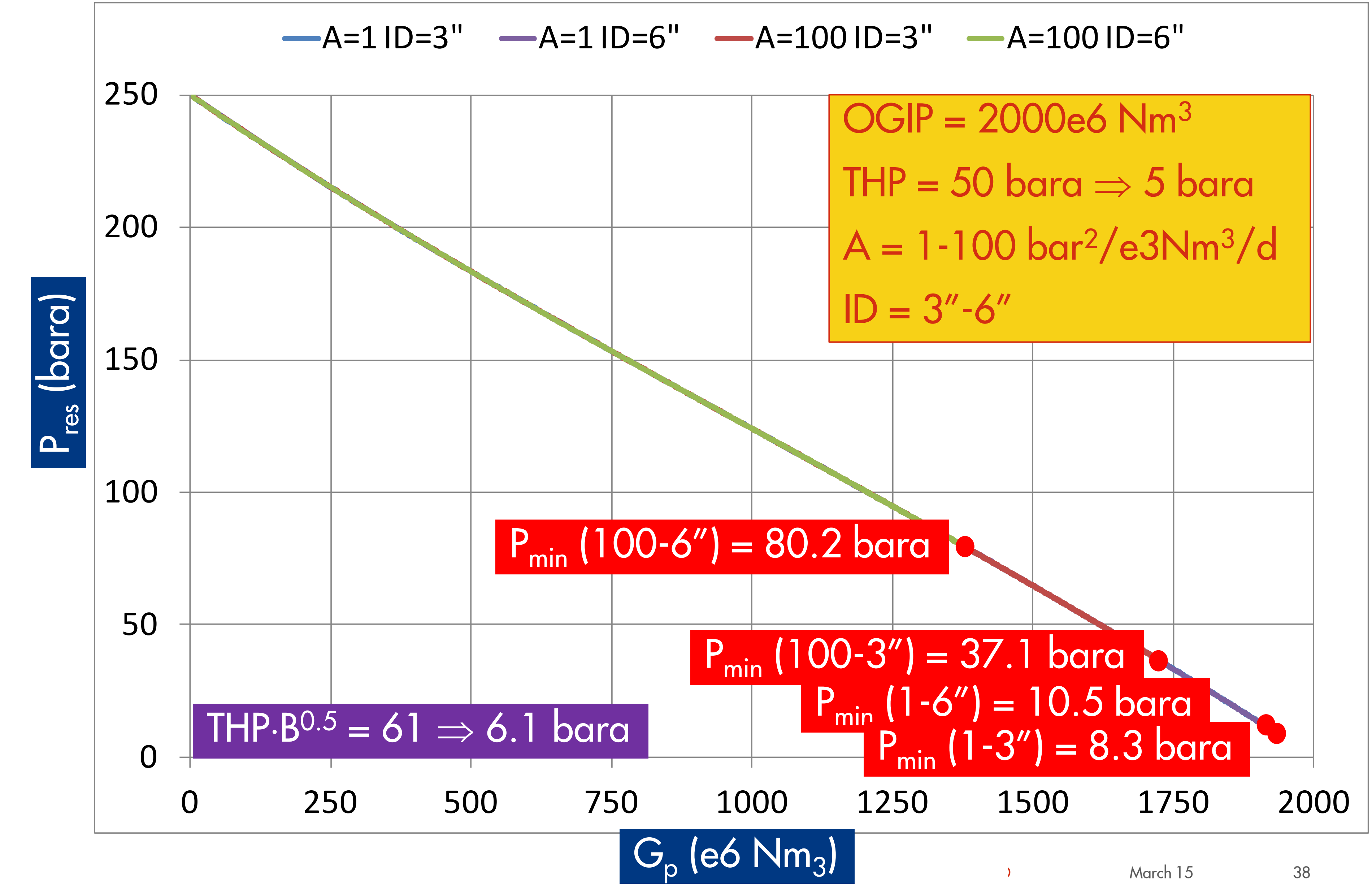
Q_{gas} Vs Time – Compression



P_{res} Vs G_p – Base Case



P_{res} Vs G_p – Compression

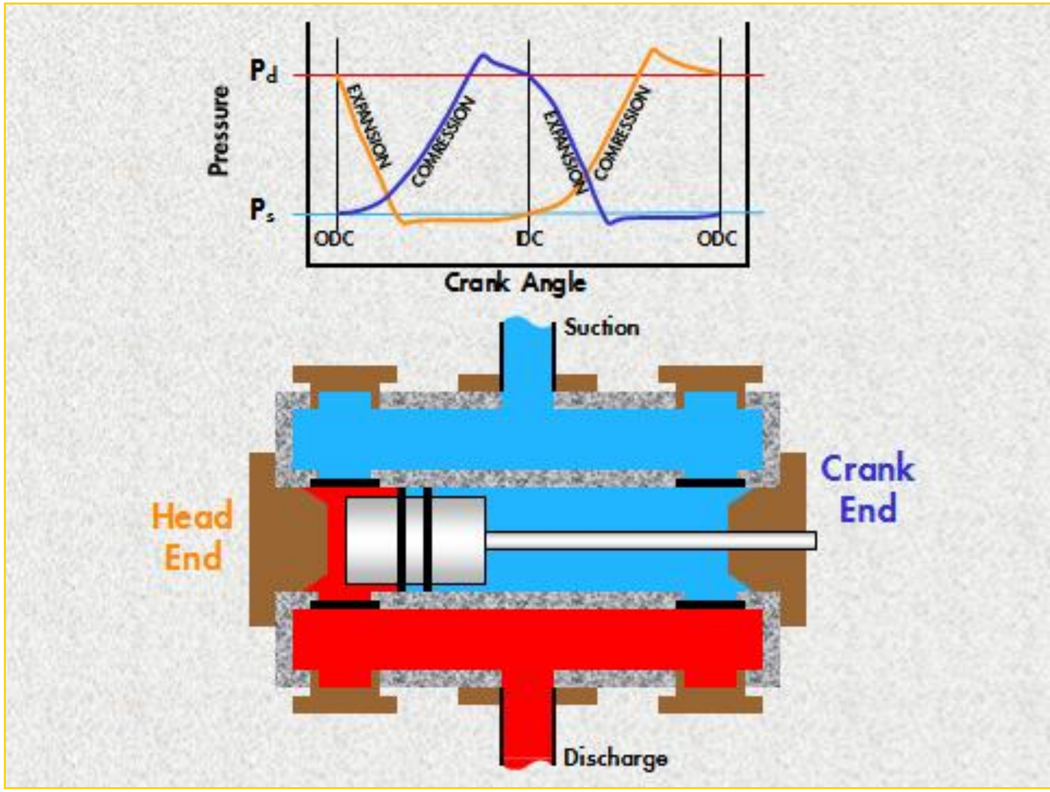


Compressor Types

- Centrifugal
- Reciprocating
- Screw
- Surface gas eductor
- Piston
- Liquid ring
- Sliding vane
- Rotary lobe
- Twin screw multiphase (for wet gas)
- Downhole gas eductor
- Downhole ESP for gas

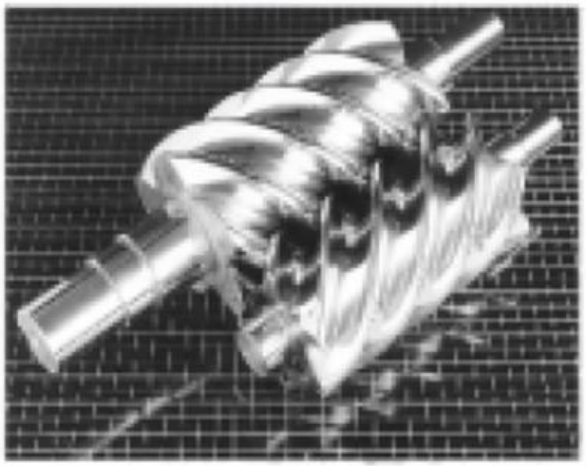
Reciprocating Compressor

- Most commonly used compressor; flexible in terms of varying suction and discharge pressure; high efficiency, up to 85%
- Staged setup of two, three or four; thereby allows very high compression ratio from a single machine, if necessary
- Relatively easy maintenance
- No tolerance for liquids
- Limited to compression ratio of four per stage
- Lower efficiencies at low suction pressure or compression ratio



Screw Compressor

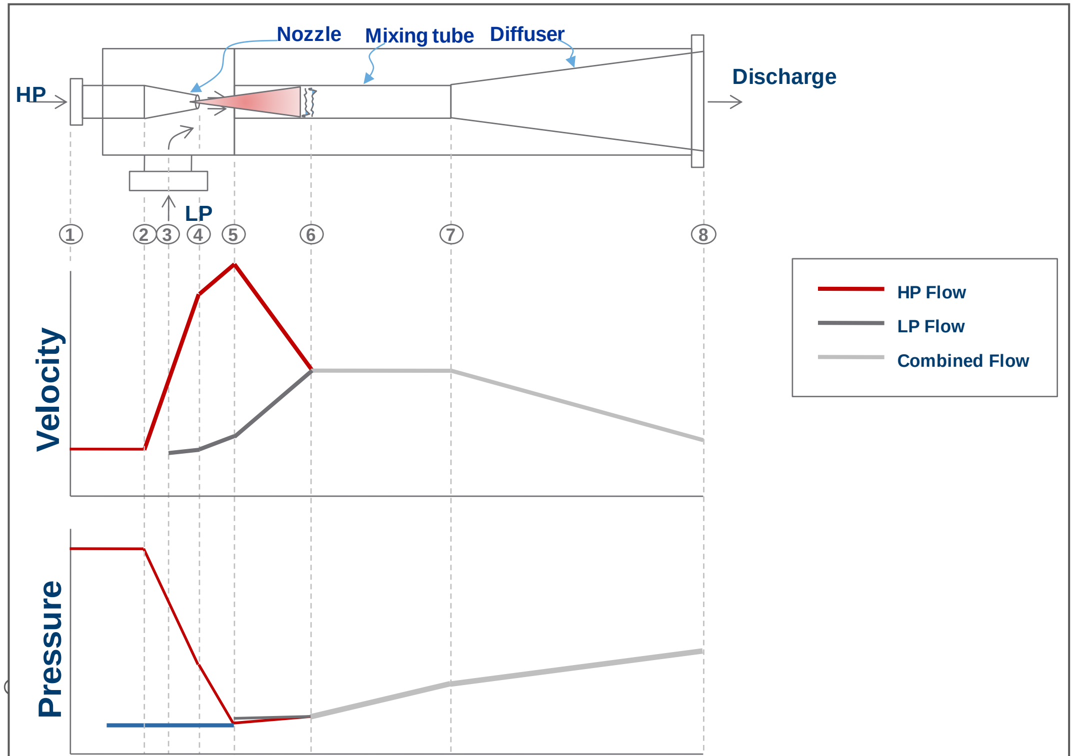
- Second most commonly used compressor in North America; up to high compression ratio, 6 to10
- Operates down to low suction pressure (near vacuum); efficiency can be high, typically 65 percent, if it is run at design conditions
- Very few moving parts
- Not very flexible and loses efficiency when operated outside the envelope, e.g. at low suction pressure or compression ratio
- Oil cooled, oil contamination can be an issue; best used in dry gas environment.
- Limited to 24 bar discharge pressure
- Higher cost than reciprocating compressor

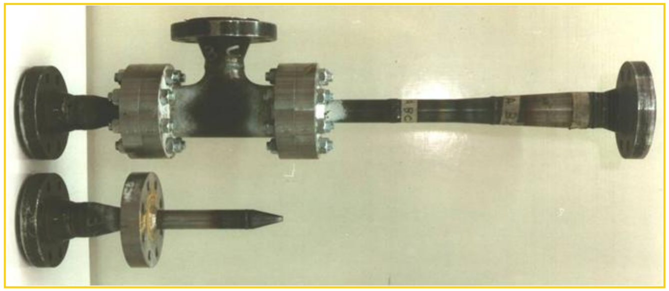


Surface Gas Eductor

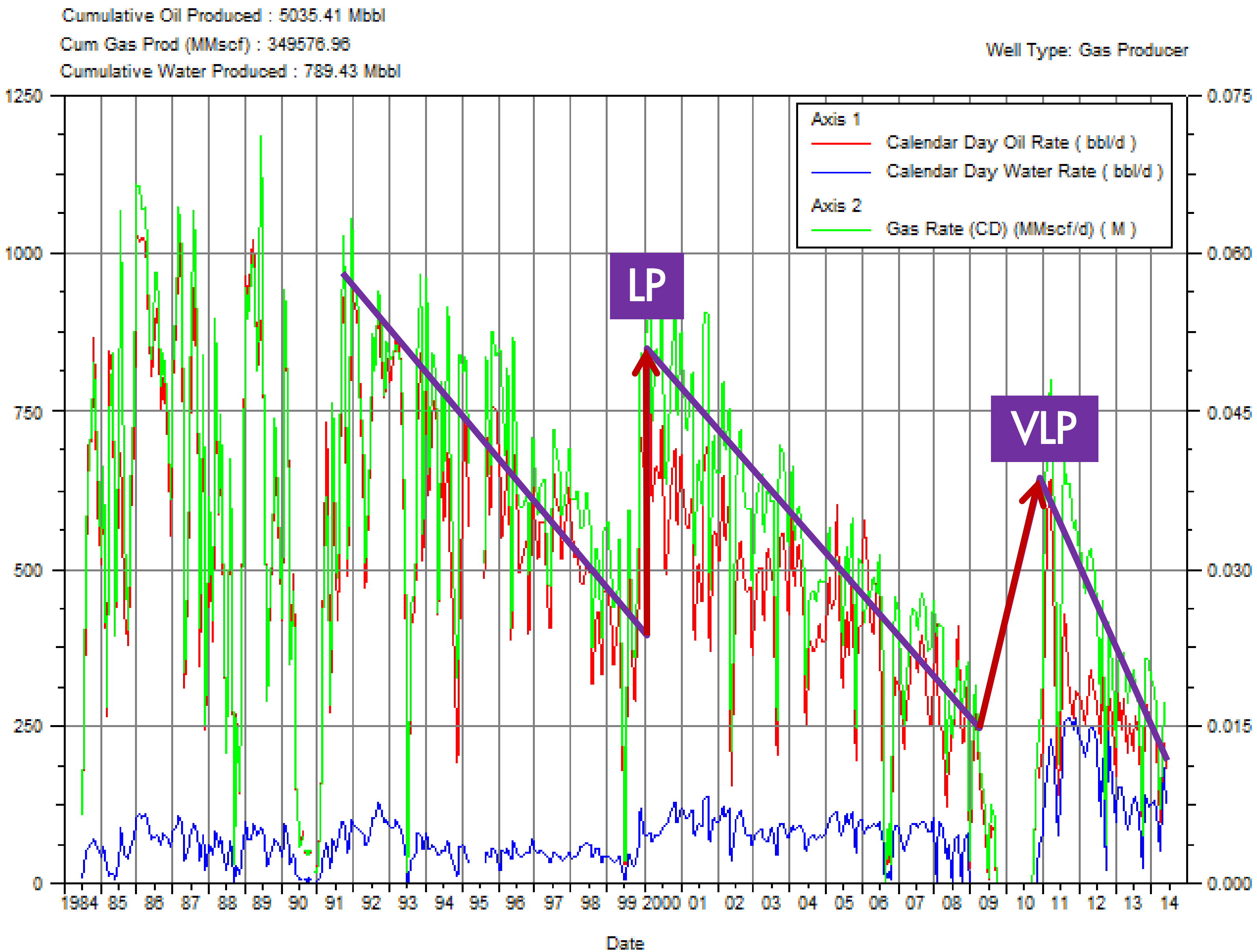
Use ‘surplus’ high pressure gas:

- From new wells where low FTHP makes no difference
- From compressors on recycle
- Not energy efficient but often economically attractive

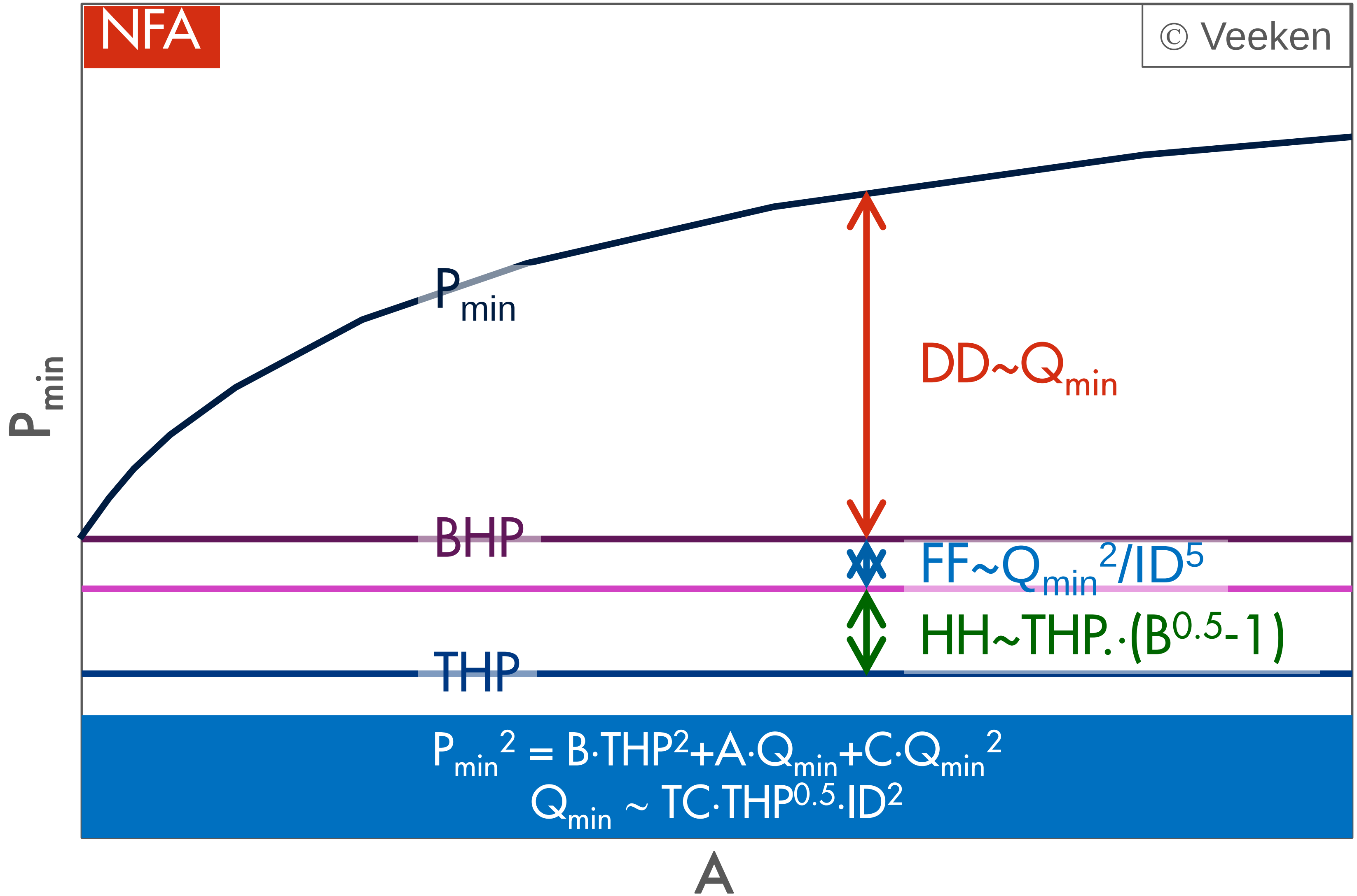




Compression in Action



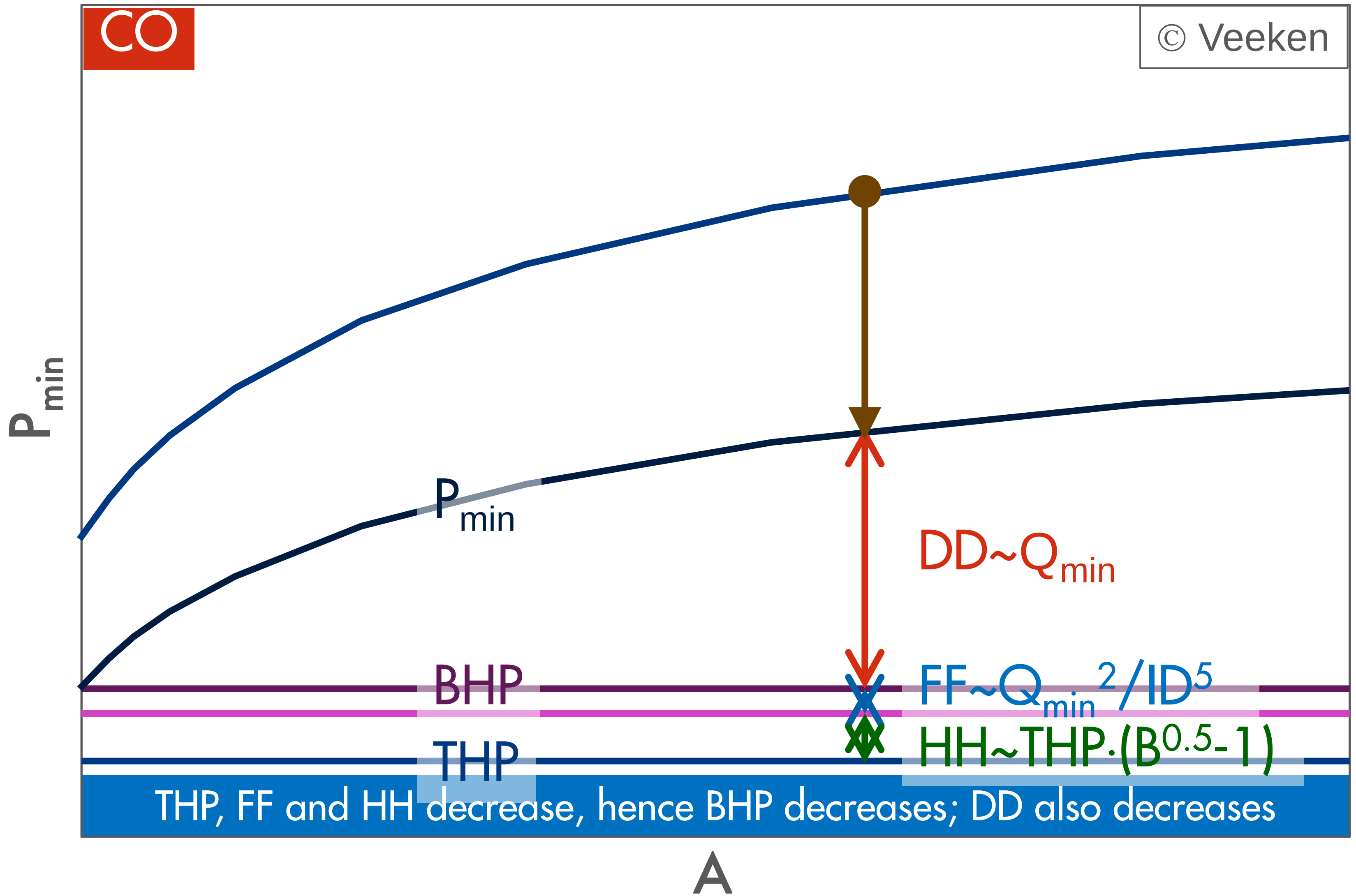
Base Case



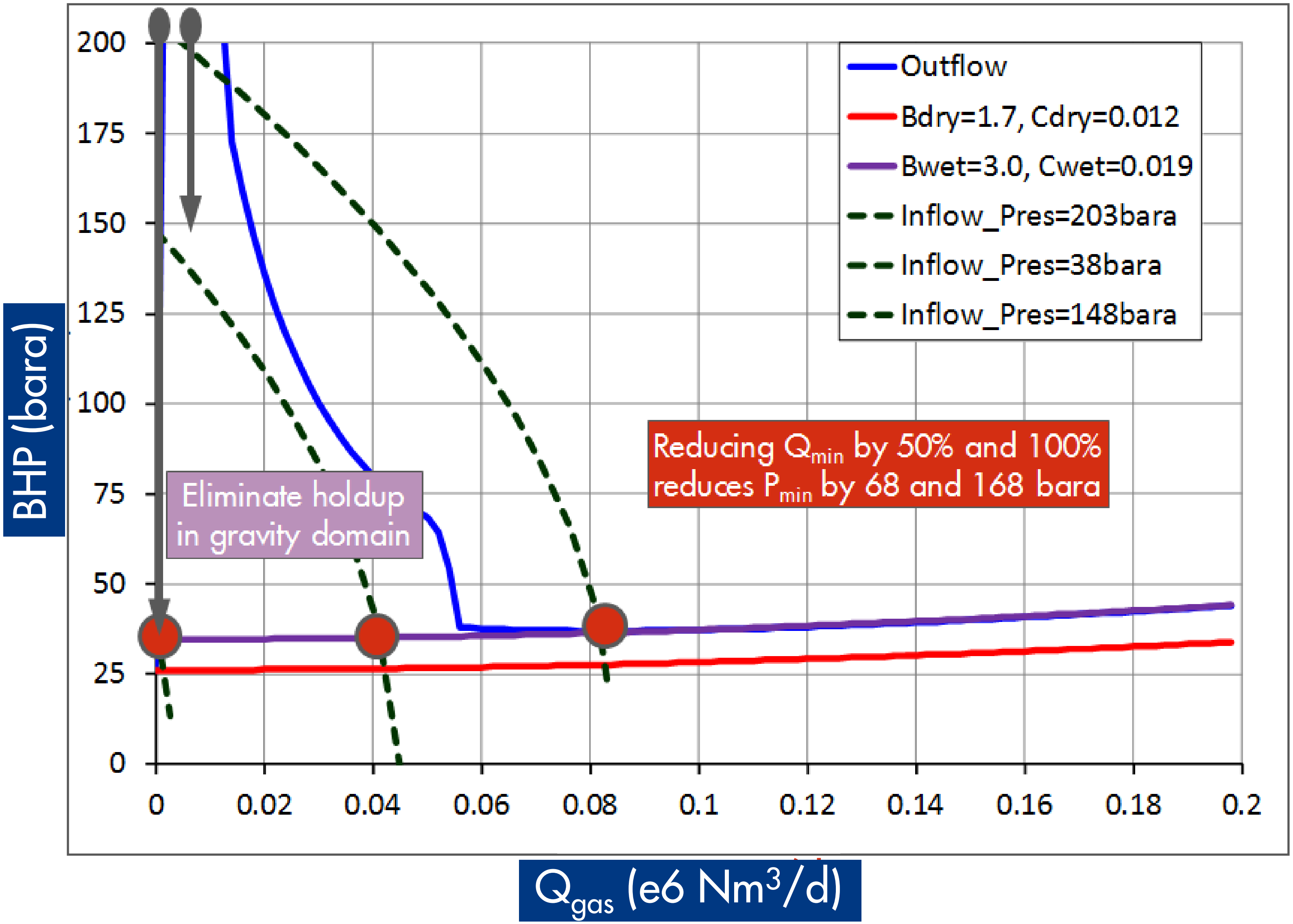
$$P_{min}^2 = B \cdot THP^2 + A \cdot Q_{min} + C \cdot Q_{min}^2$$

$$Q_{min} \sim TC \cdot THP^{0.5} \cdot ID^2$$

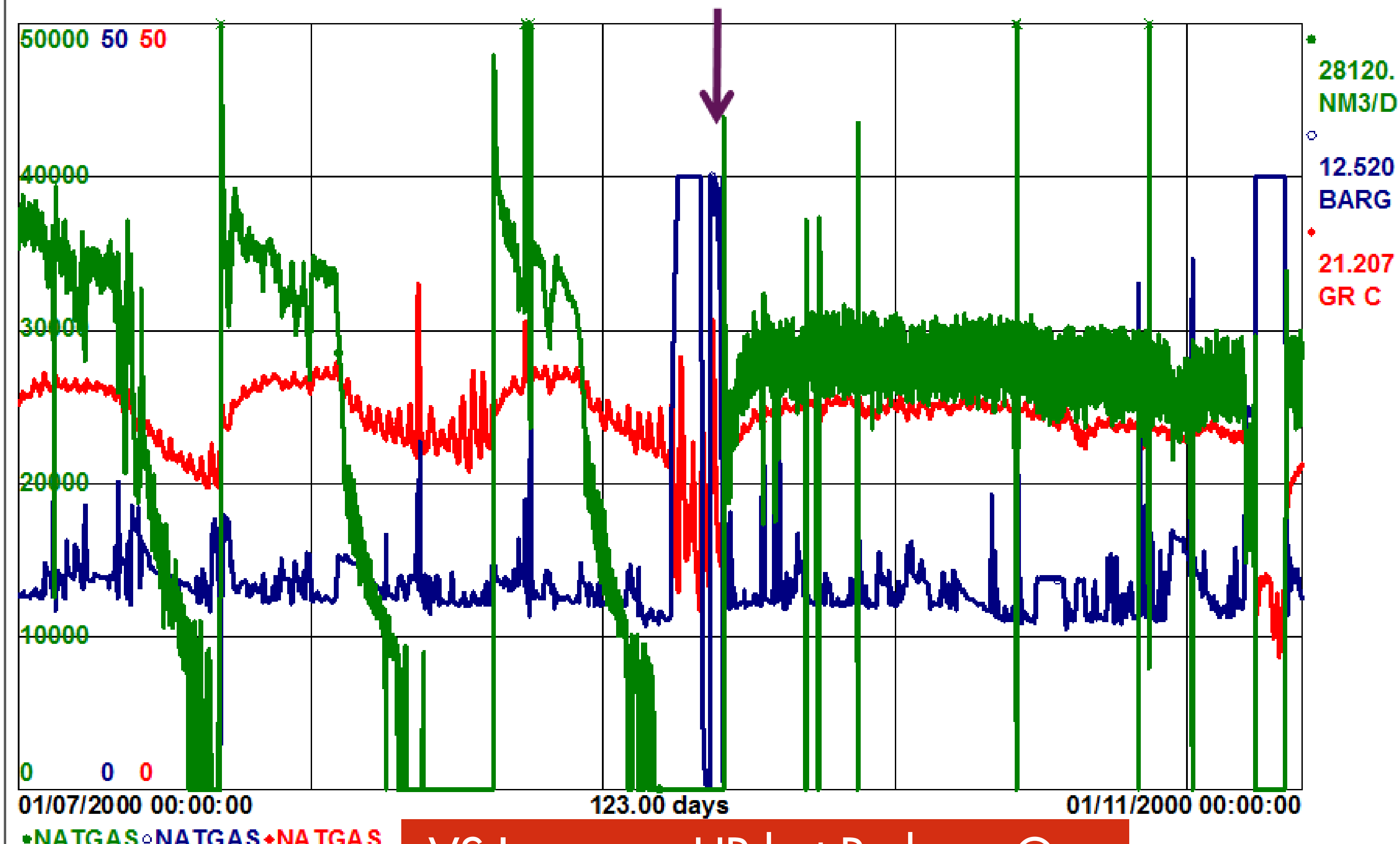
Compression



Reduce Q_{min} to Reduce P_{min}



Velocity String in Action: 2" CT inside 3½" Tubing



VS Increases UR but Reduces Q_{gas}

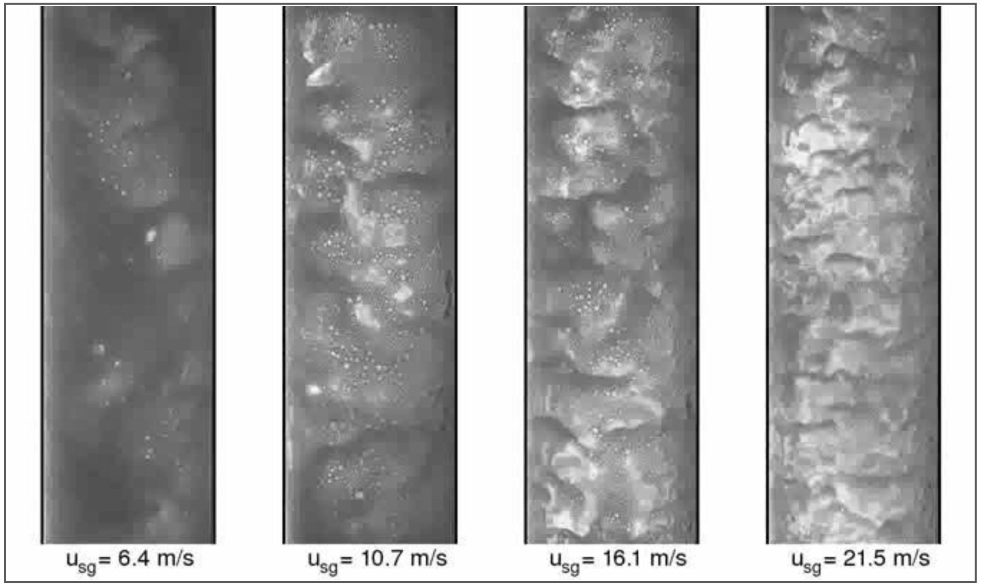
Offshore Velocity String Installation

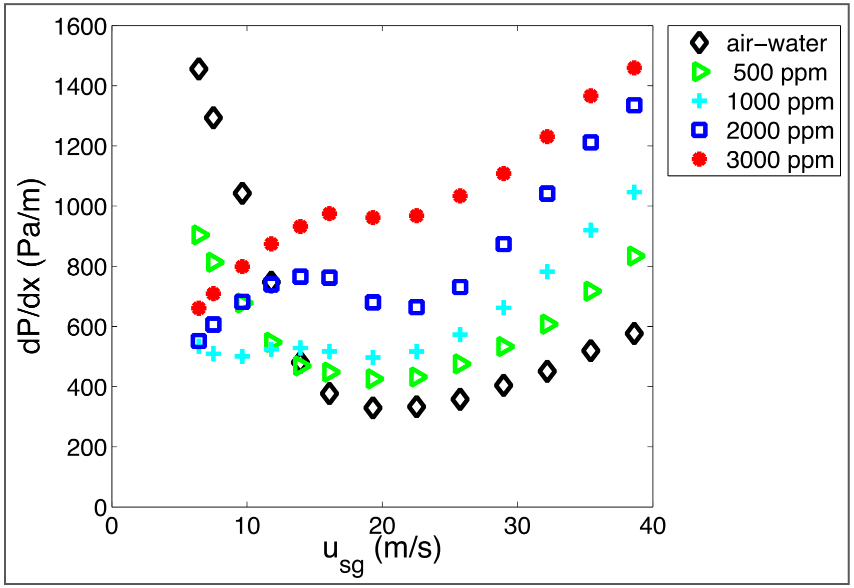
Installing 3800 m (12,500′) of $2^{7}/_{8}$″ Cr16 CTVS

Foam Assisted Lift: How Does It Work?

- Downhole agitation of gas, water and surfactant creates foam
- Old school: Foam is easier to lift because of reduction of density and surface tension
- New school: Foam stabilises liquid film and delays film reversal
- Lab testing of foamer performance and compatibility is critical

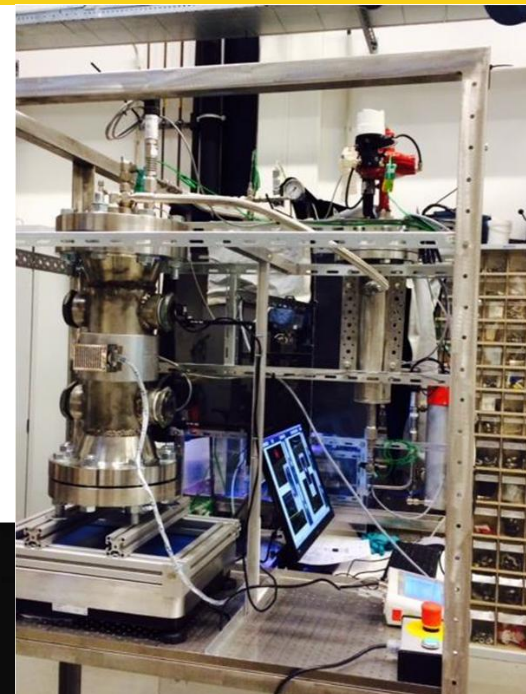
Foam is only present on the tubing wall

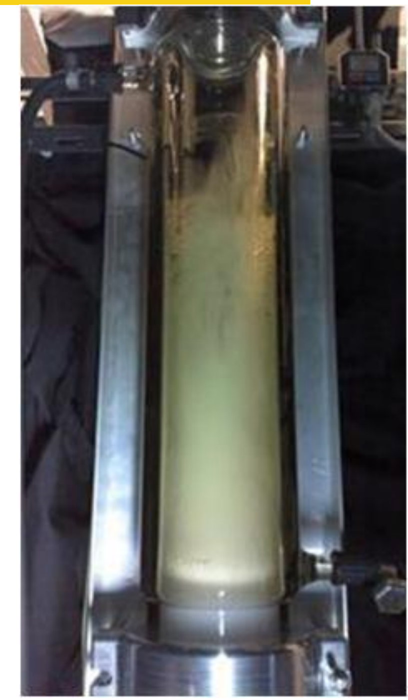




Foam Performance Testing

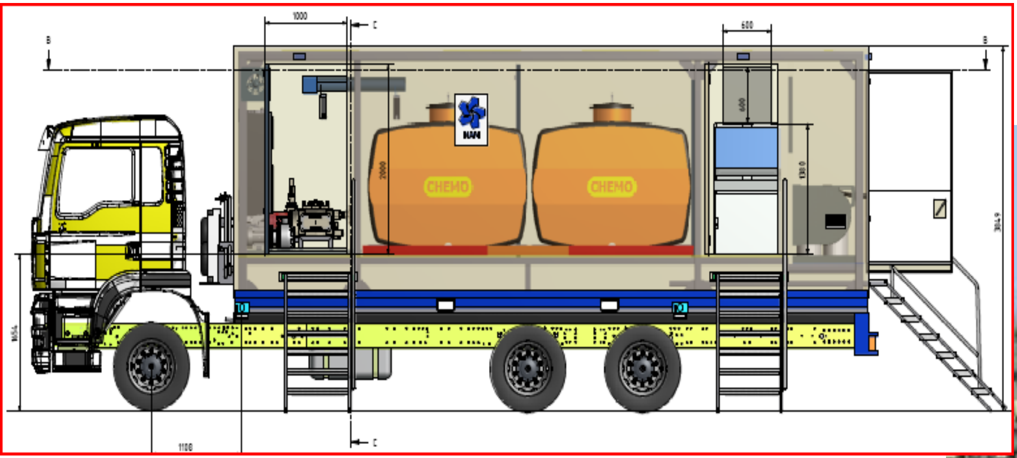
- TNO JIP: table top sparging ⇒
  - High temperature & pressure
- TUD PhD: air-water flow loop ⇓
  - 1.3″-2.0″-3.2″ tubing





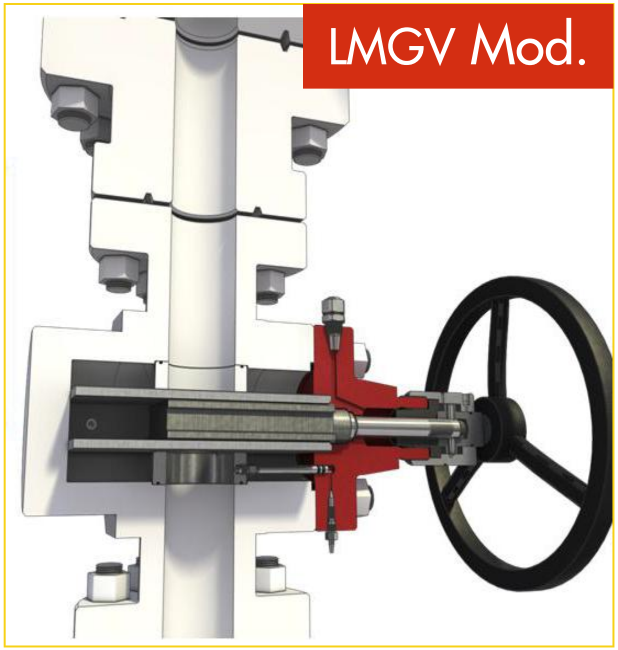
Batch Surfactant: Drop Stick or Pump Liquid

- Optimum batch frequency depends on LGR, can be multiple times per day
- Optimum liquid foamer volume depends on the well, 10-100 L

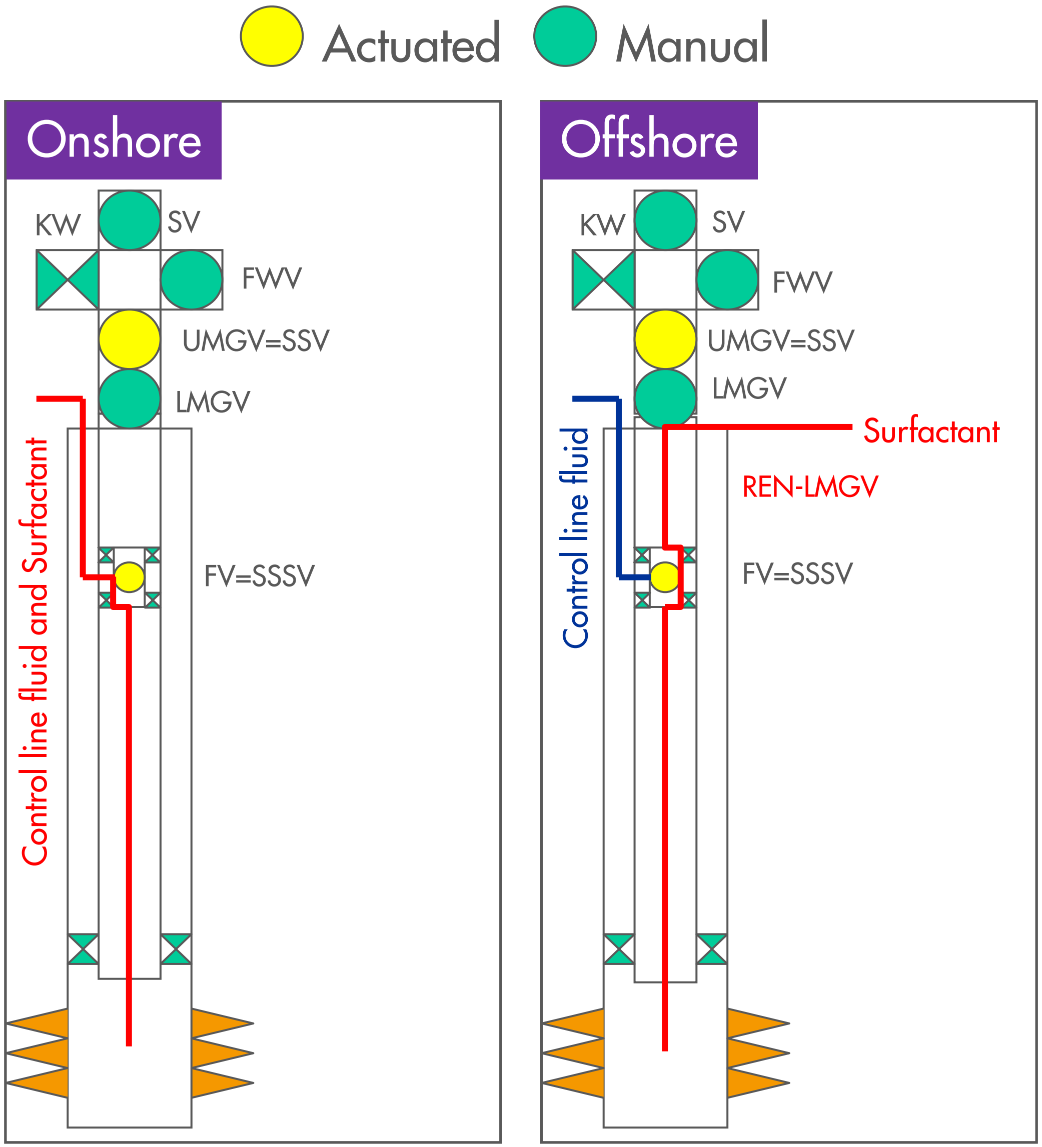


“Well Extender” Dedicated Truck

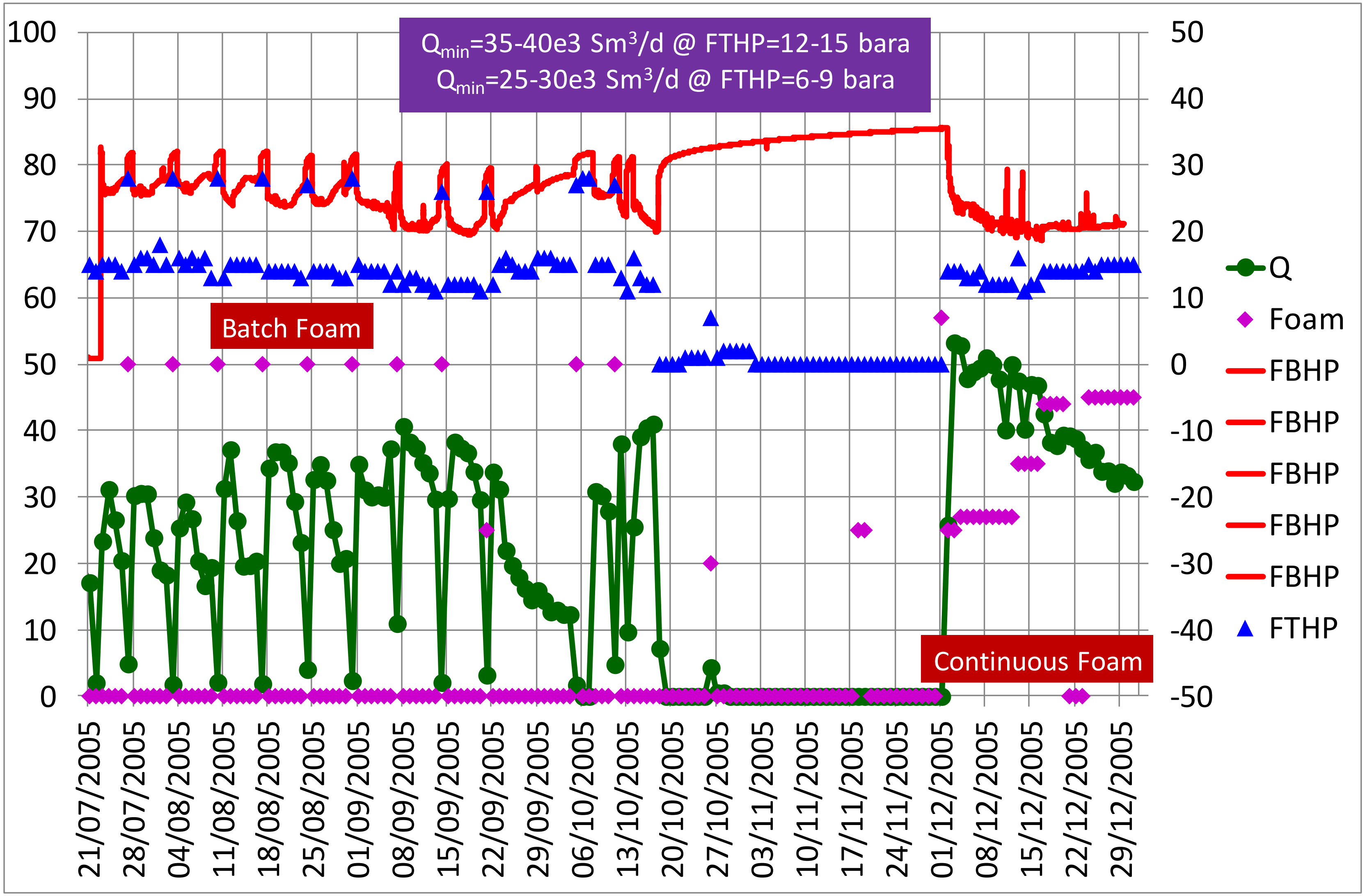
Accommodate SC-SSSV



- Onshore system is available from Halliburton and Weatherford
- Offshore system is available from Weatherford



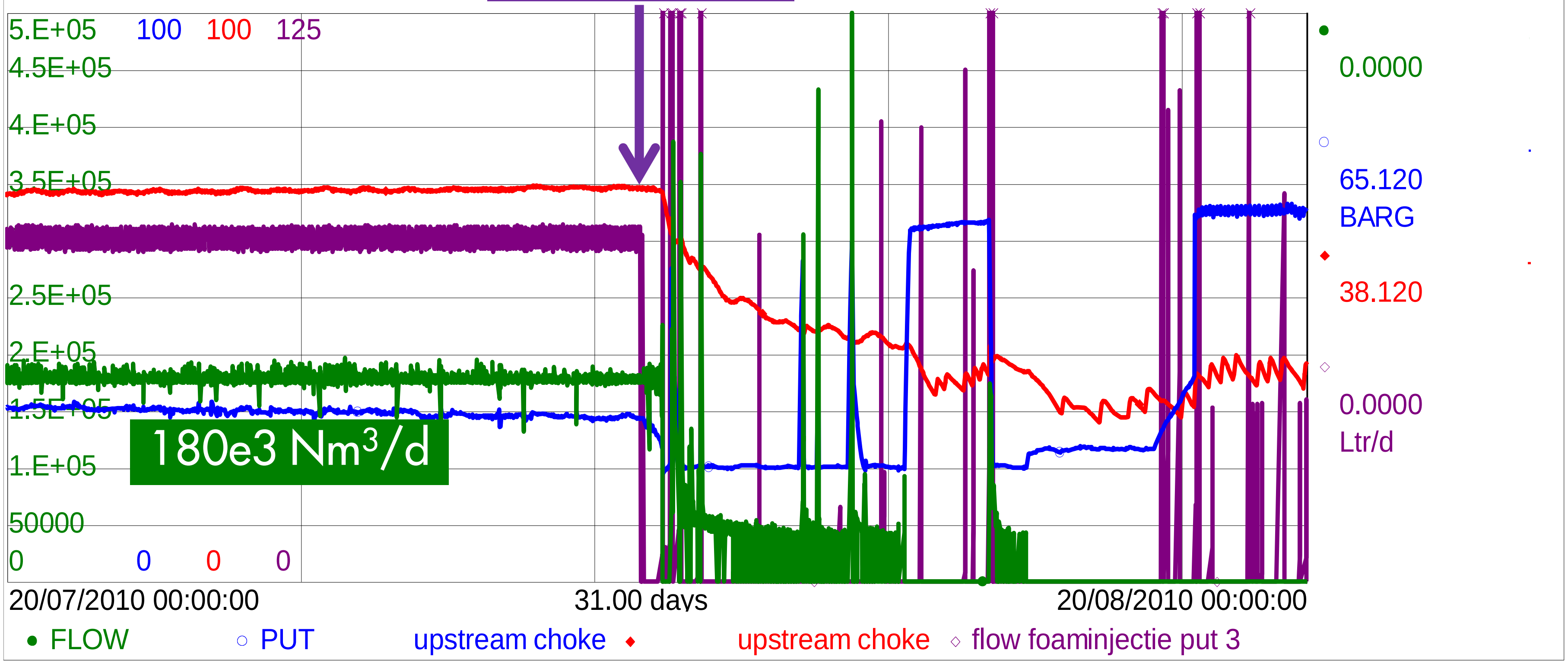
From Batch Foam to Continuous Foam



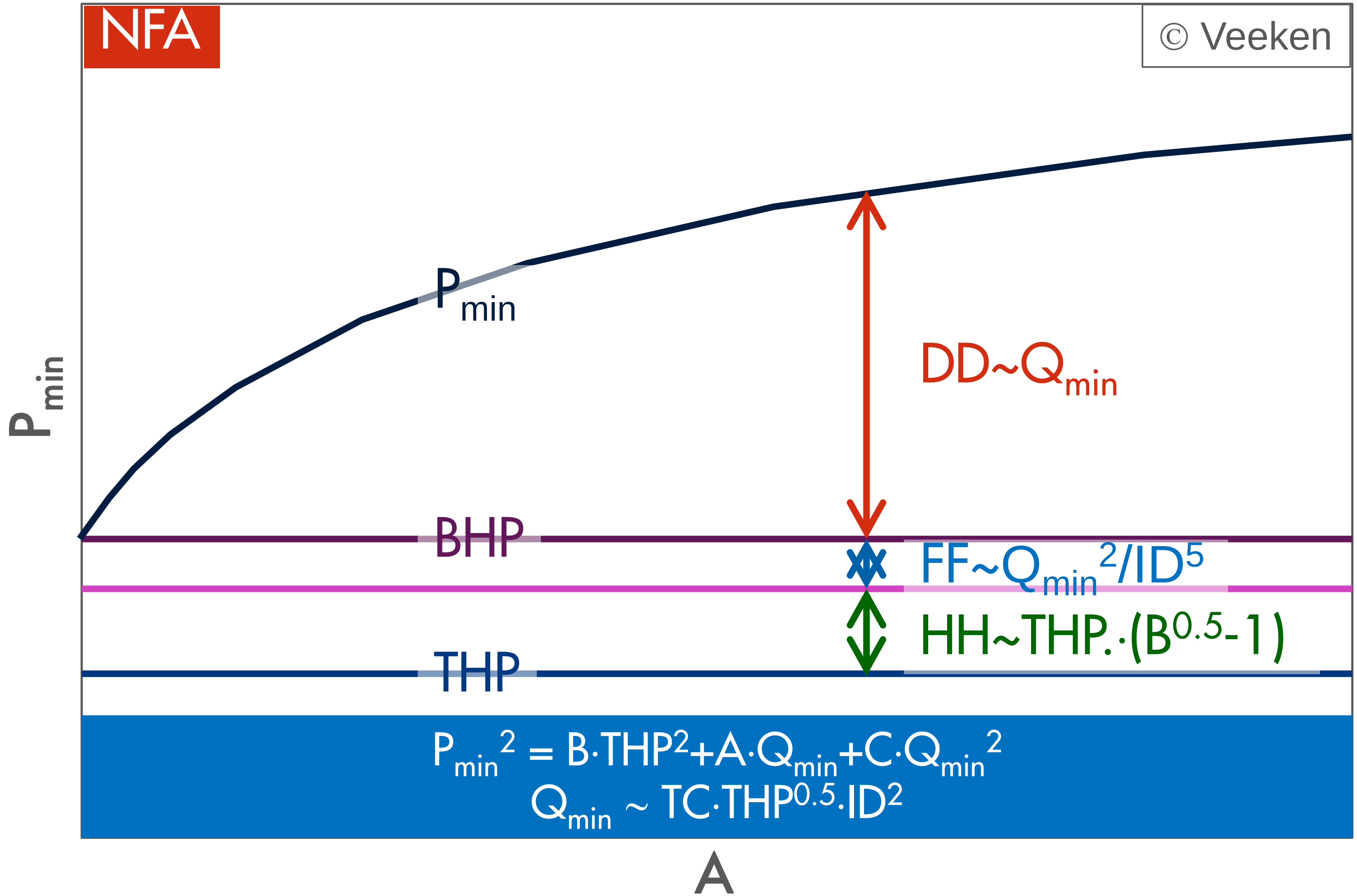
Foam Assisted Lift in Action

- 8 yrs continuous downhole injection of surfactant increased ultimate recovery by 200e6 Nm^3

Injection stops

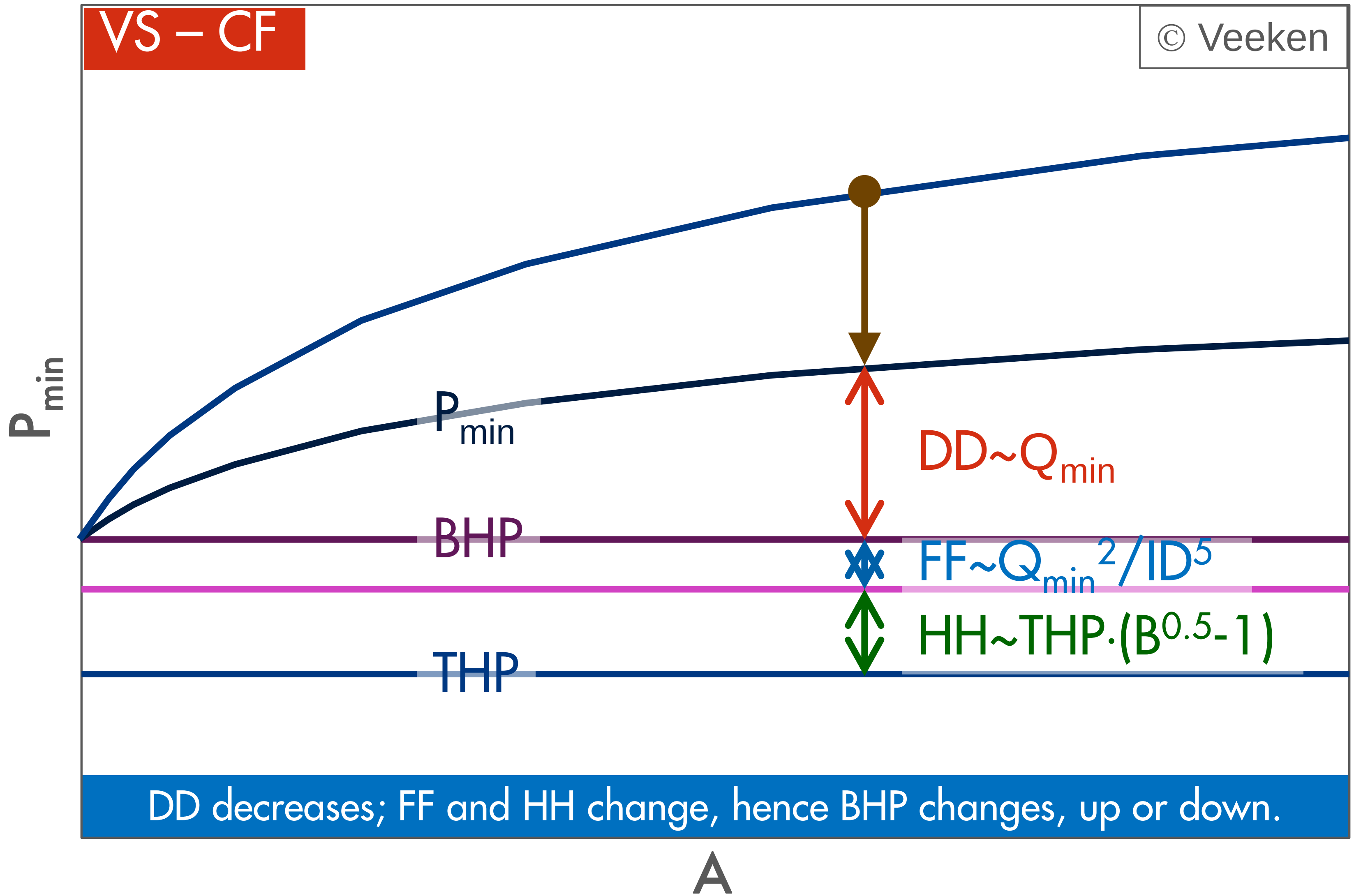


Base Case



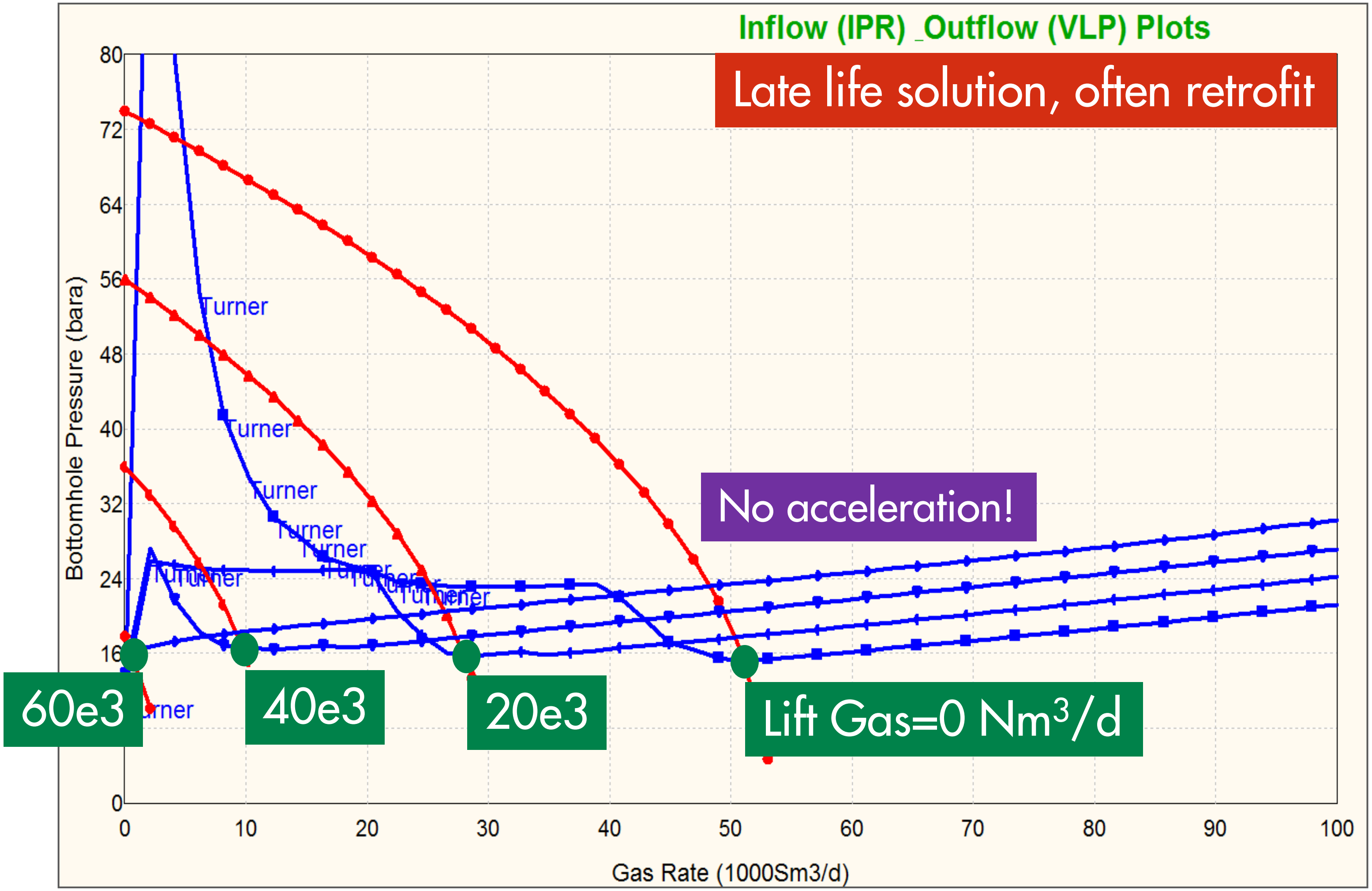
NFA
© Veeken
P_{min}
P_{min}
$DD \sim Q_{min}$
BHP
$FF \sim Q_{min}^2 / ID^5$
$HH \sim THP \cdot (B^{0.5}-1)$
THP
$P_{min}^2 = B \cdot THP^2 + A \cdot Q_{min} + C \cdot Q_{min}^2$
$Q_{min} \sim TC \cdot THP^{0.5} \cdot ID^2$
A

Velocity String or Continuous Foam



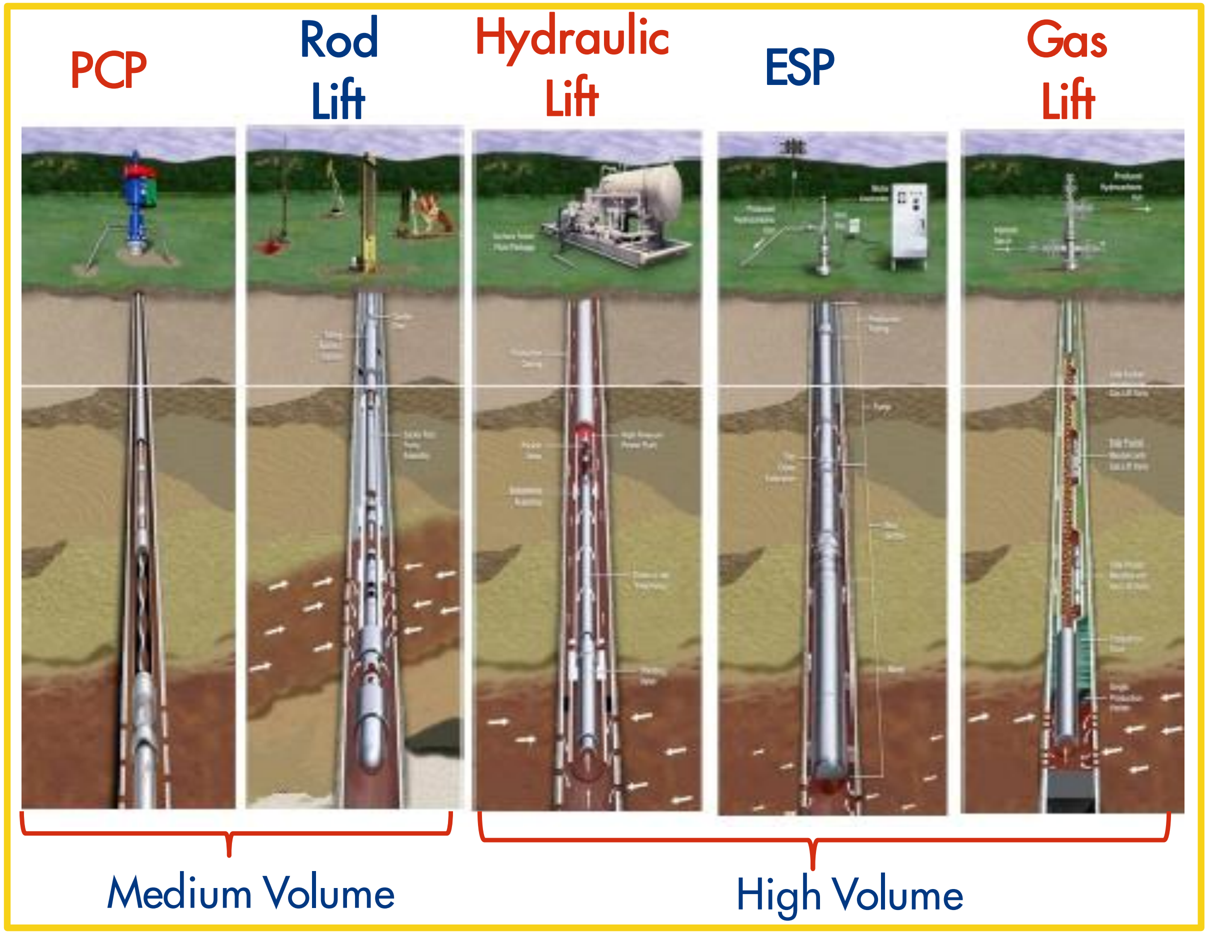
Continuous Gas Lift in Gas Well

- Key target is reduction of Q_{min} and P_{min}



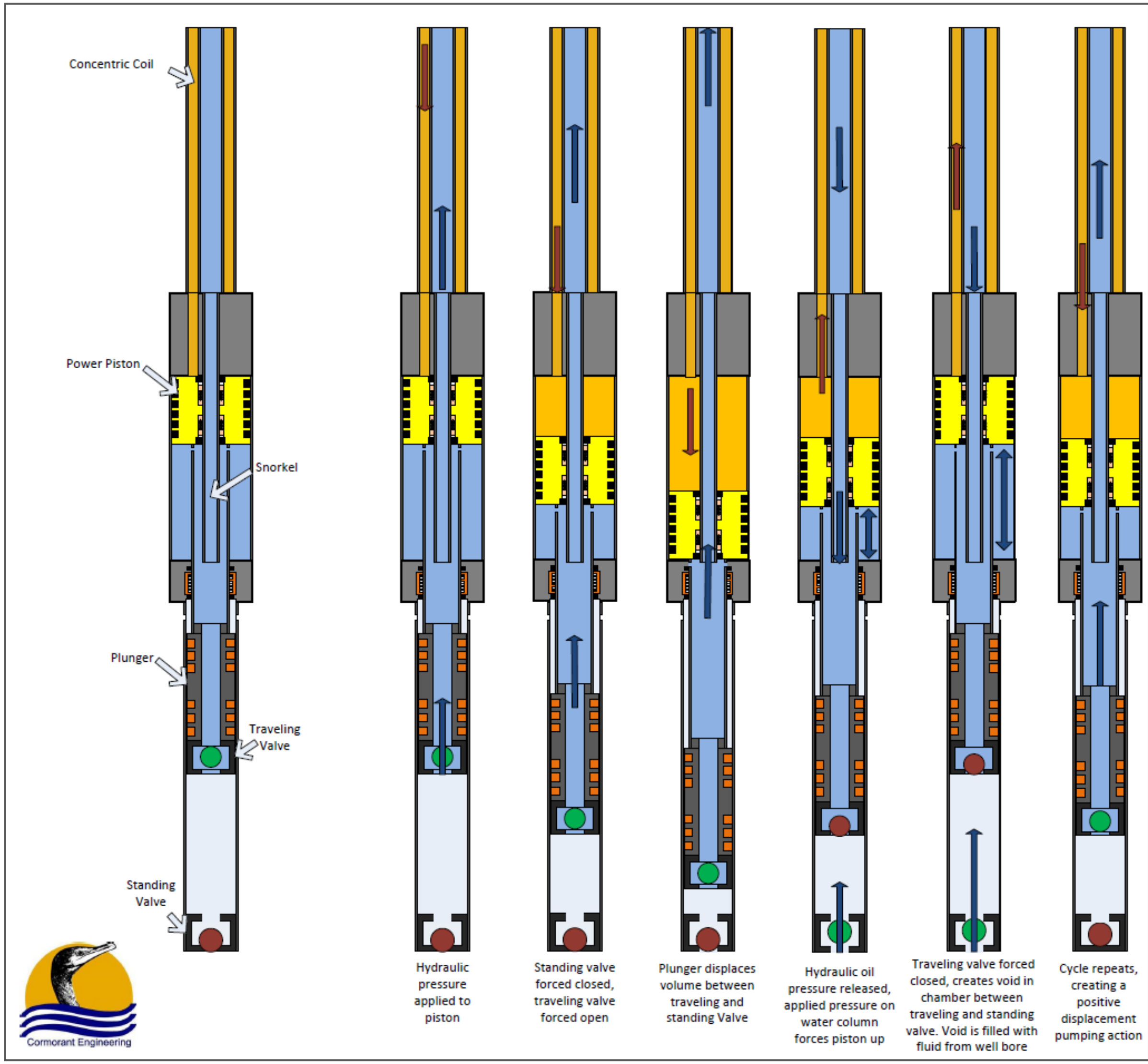
Pumping Options

- Positive displacement pump
  - Progressive Cavity Pump (PCP)
  - Beam pump
  - Hydraulic piston pump
- Dynamic pump
  - Hydraulic jet pump
  - Electrical Submersible Pump (ESP)

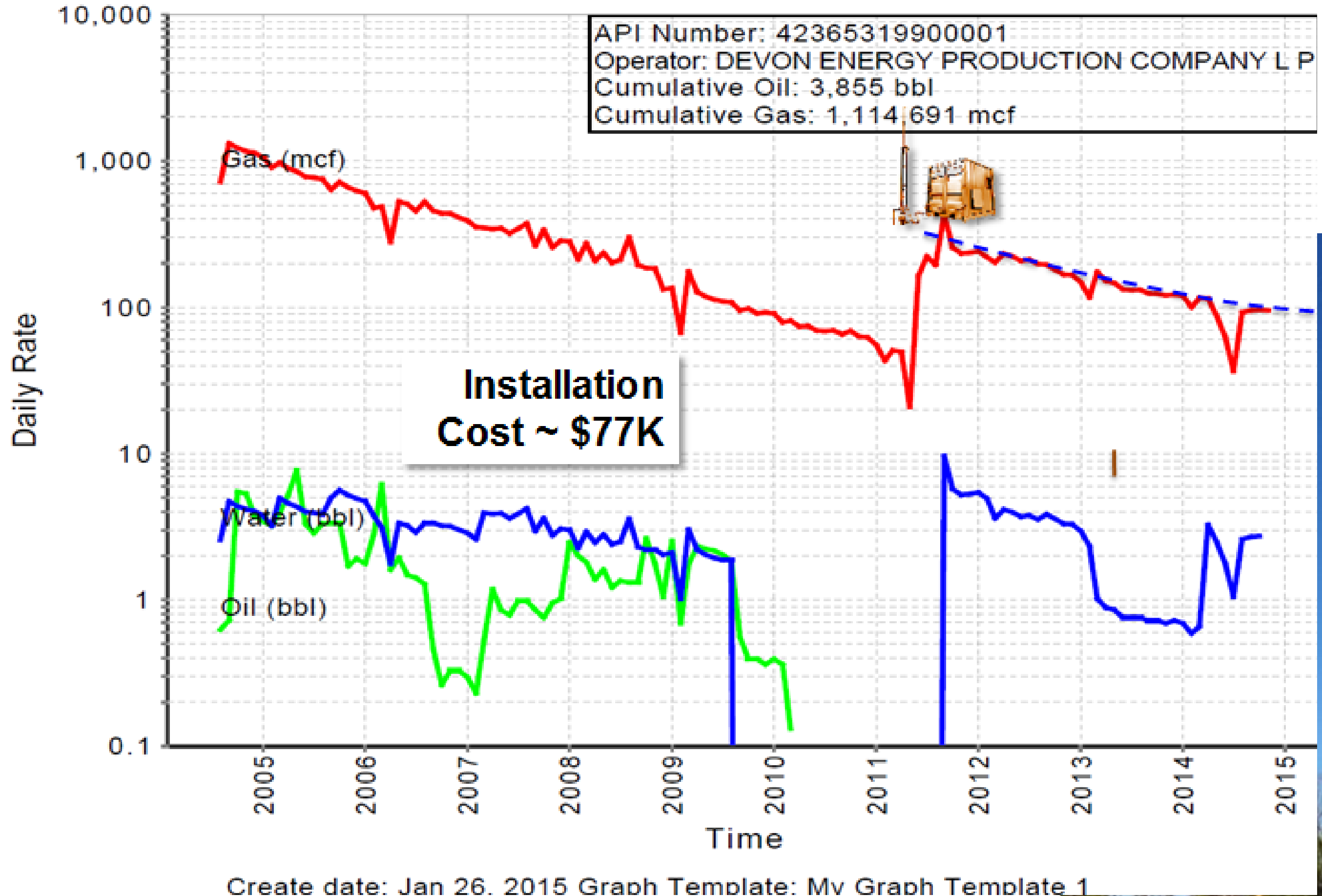


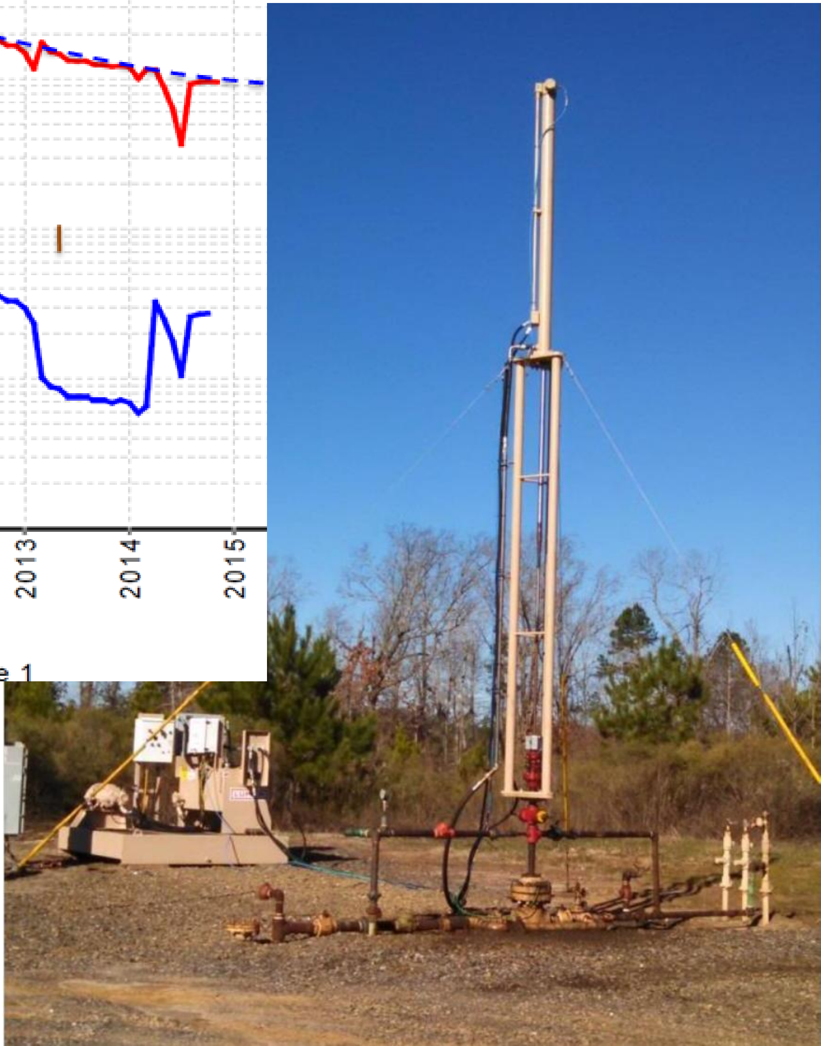
Hydraulic Piston Pump

- 3″ OD hydraulic driven piston pump
- Deployed on 1-1/2″ x 7/8″ concentric coiled tubing (CCT), annulus contains hydraulic oil, inside contains produced liquid
- Hydraulic power is applied on both conduits
- Pumping 1-2 m^3/d

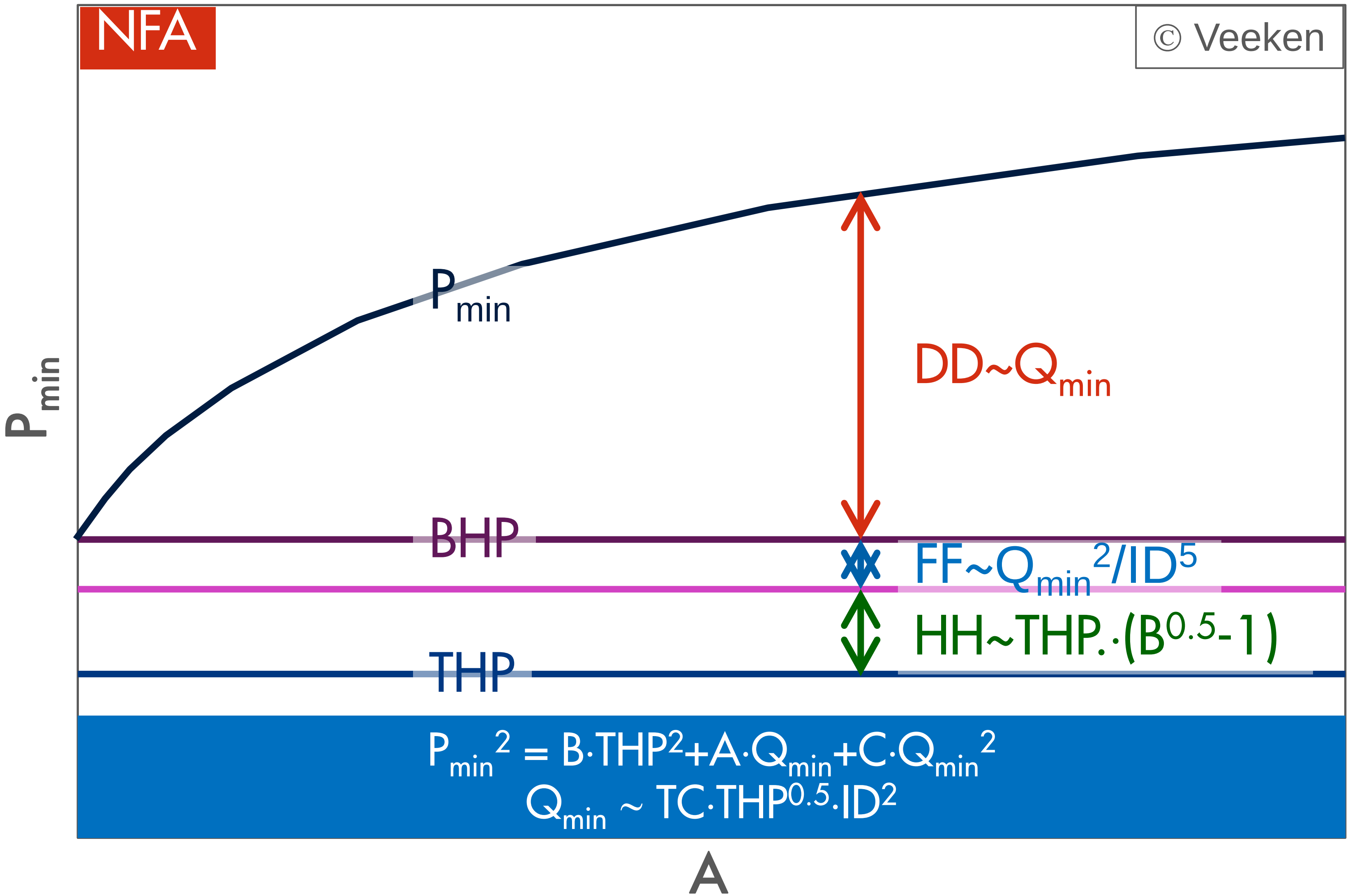


Hydraulic Rod Pump





Base Case



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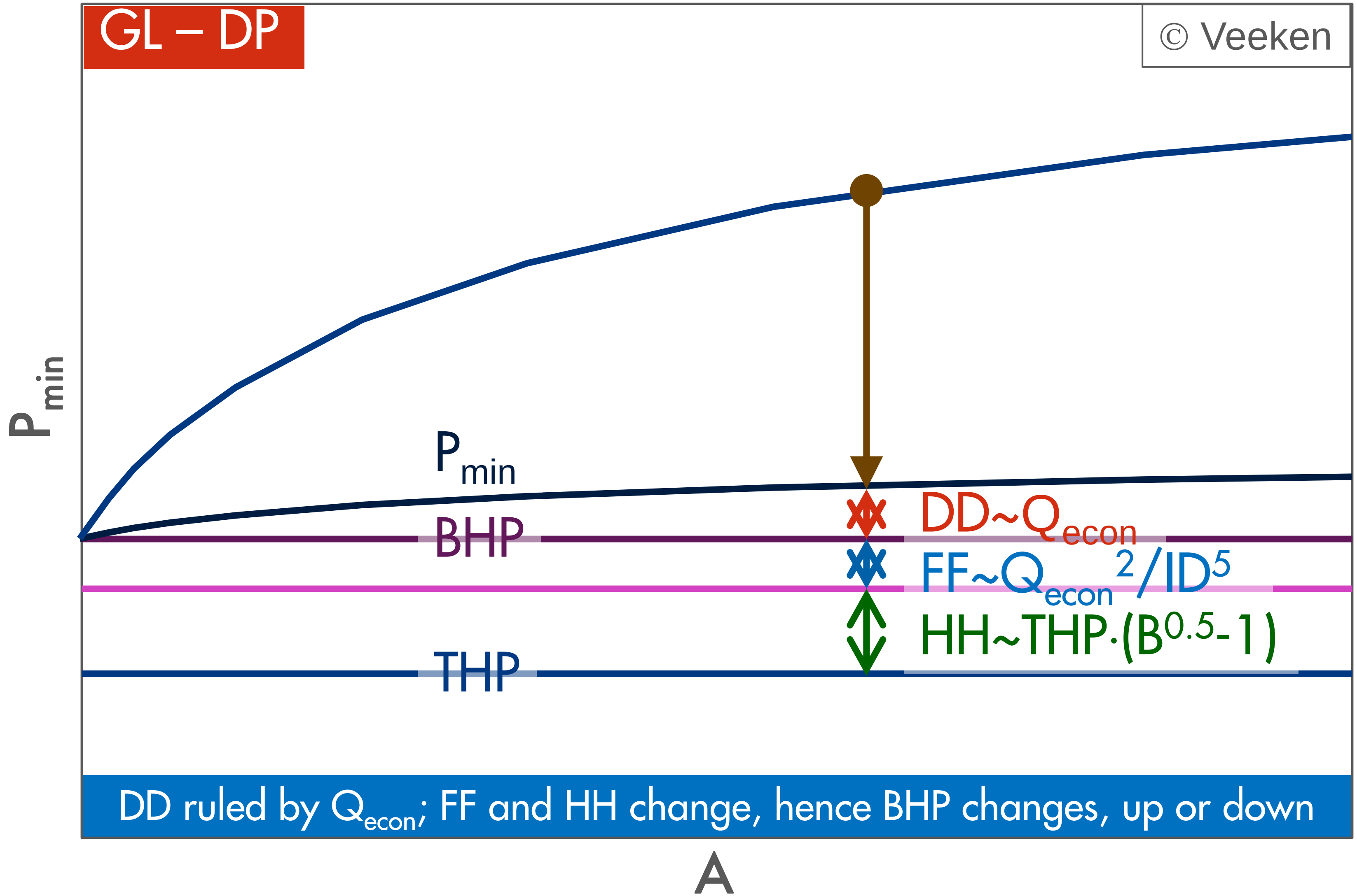
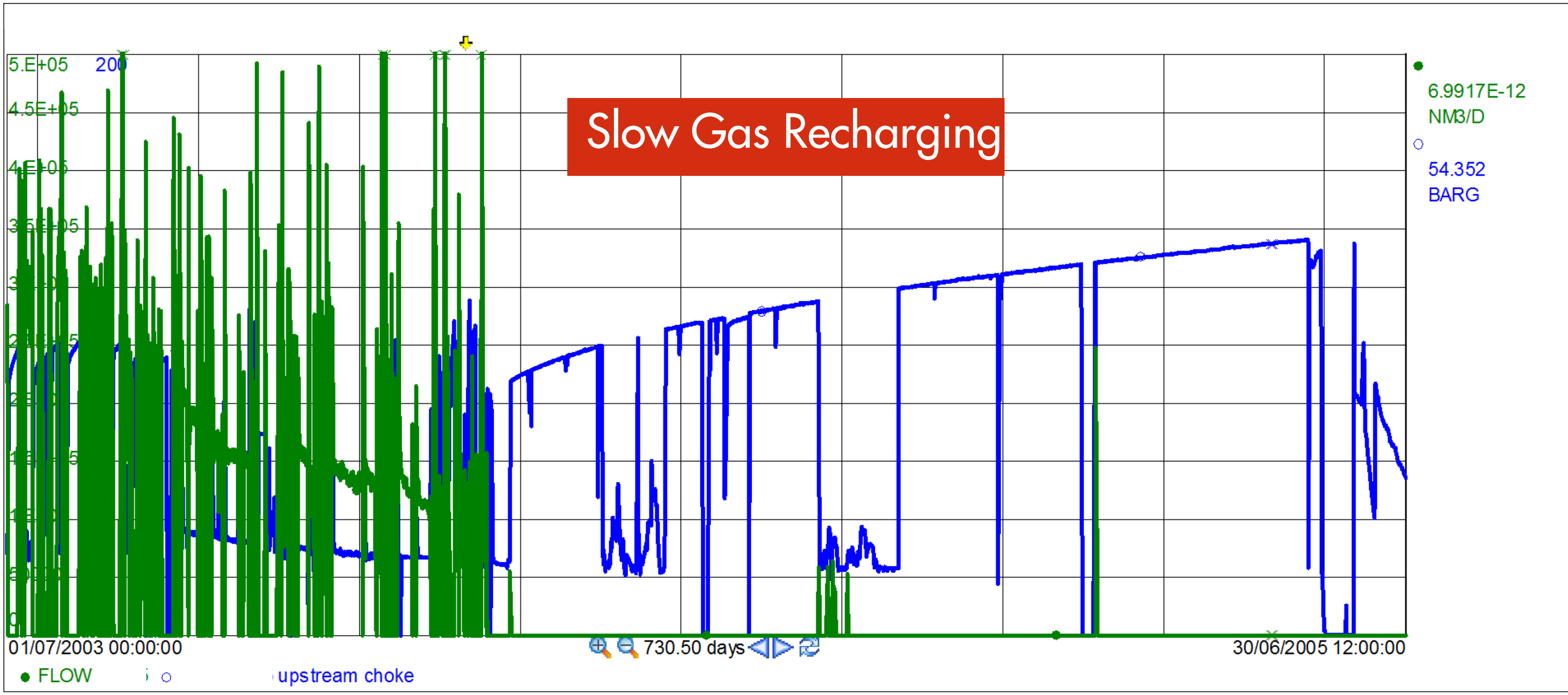
$Q_{min} \sim TC \cdot THP^{0.5} \cdot ID^2$
P_{min}
A

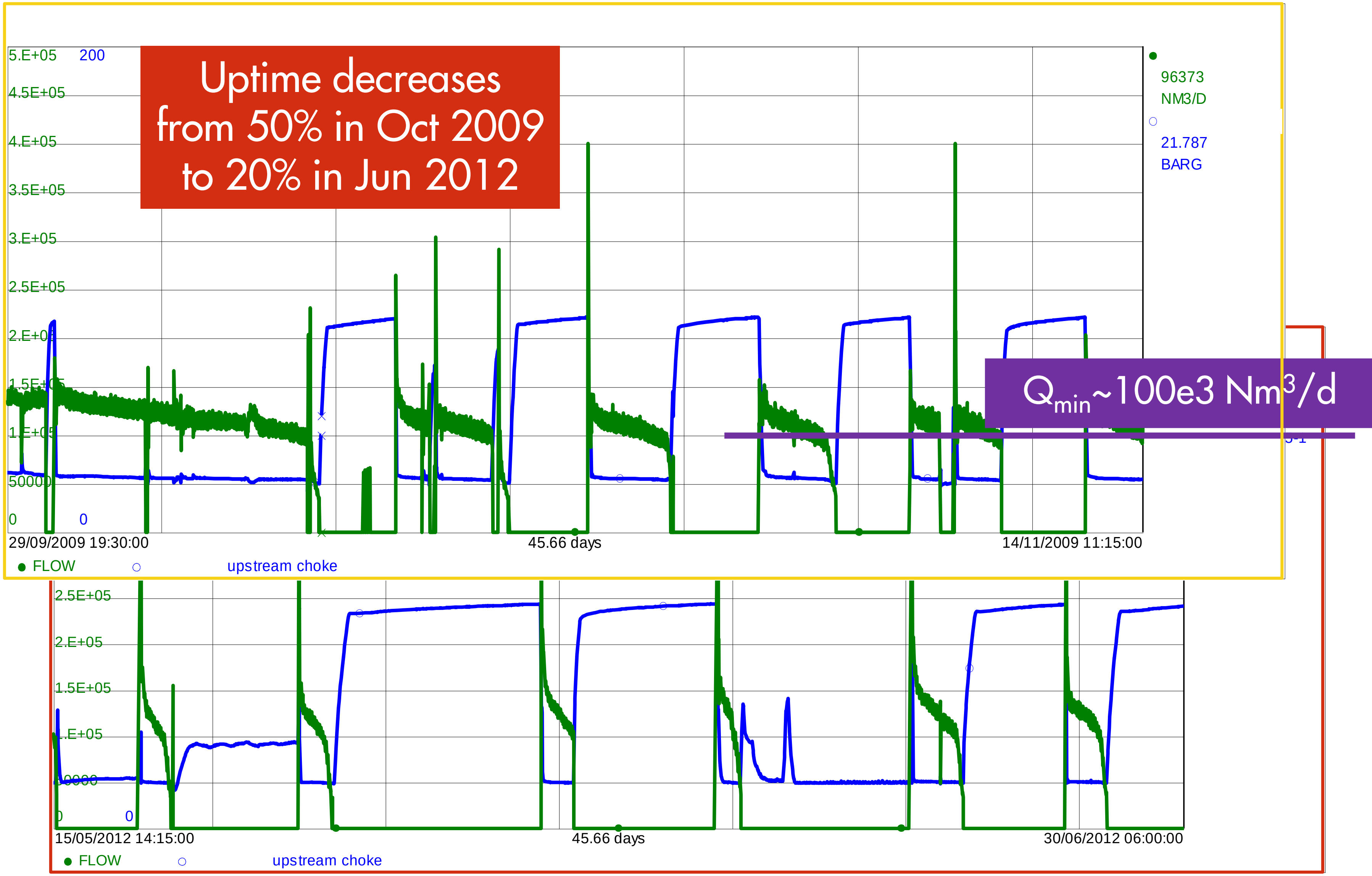
Gas Lift or Downhole Pump



Gas Reservoir ≠ Single Tank

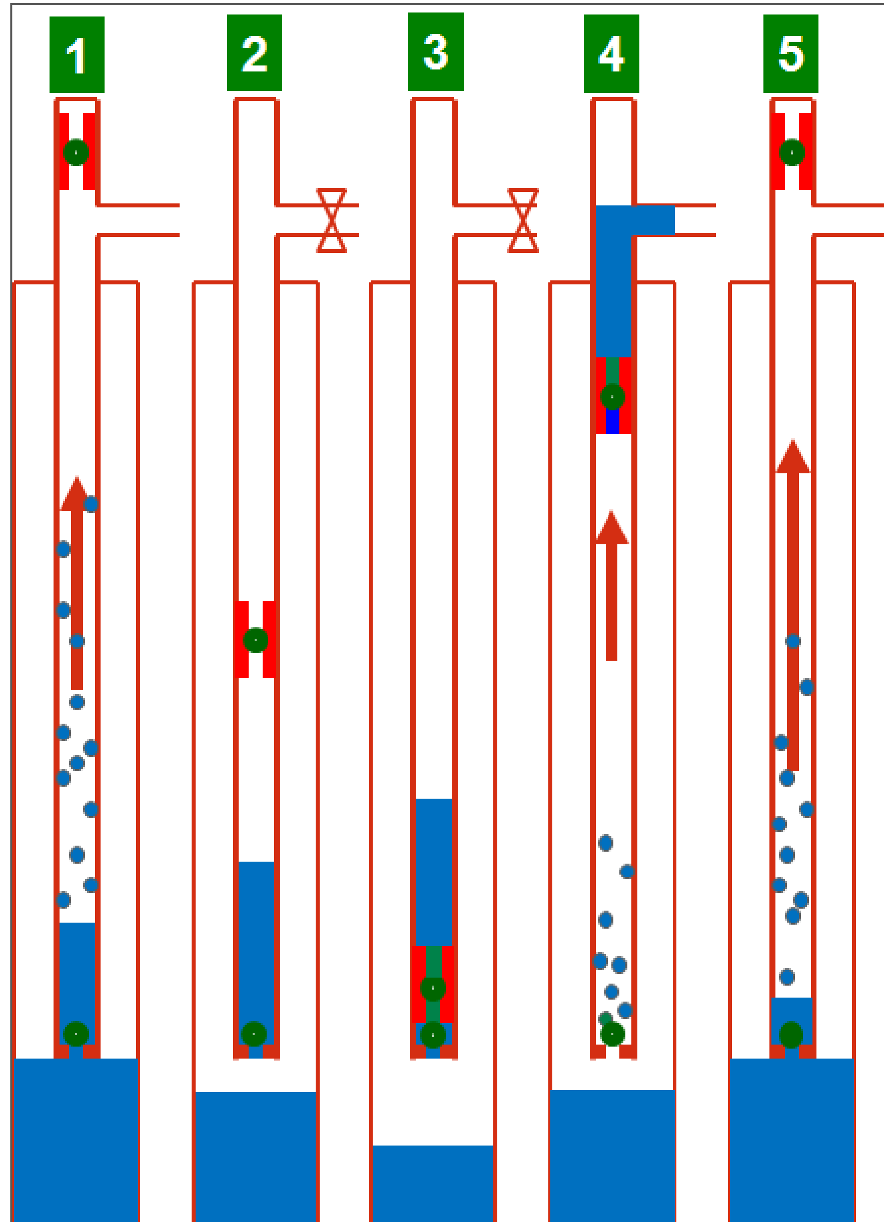


Intermittent Production Can Continue for Years

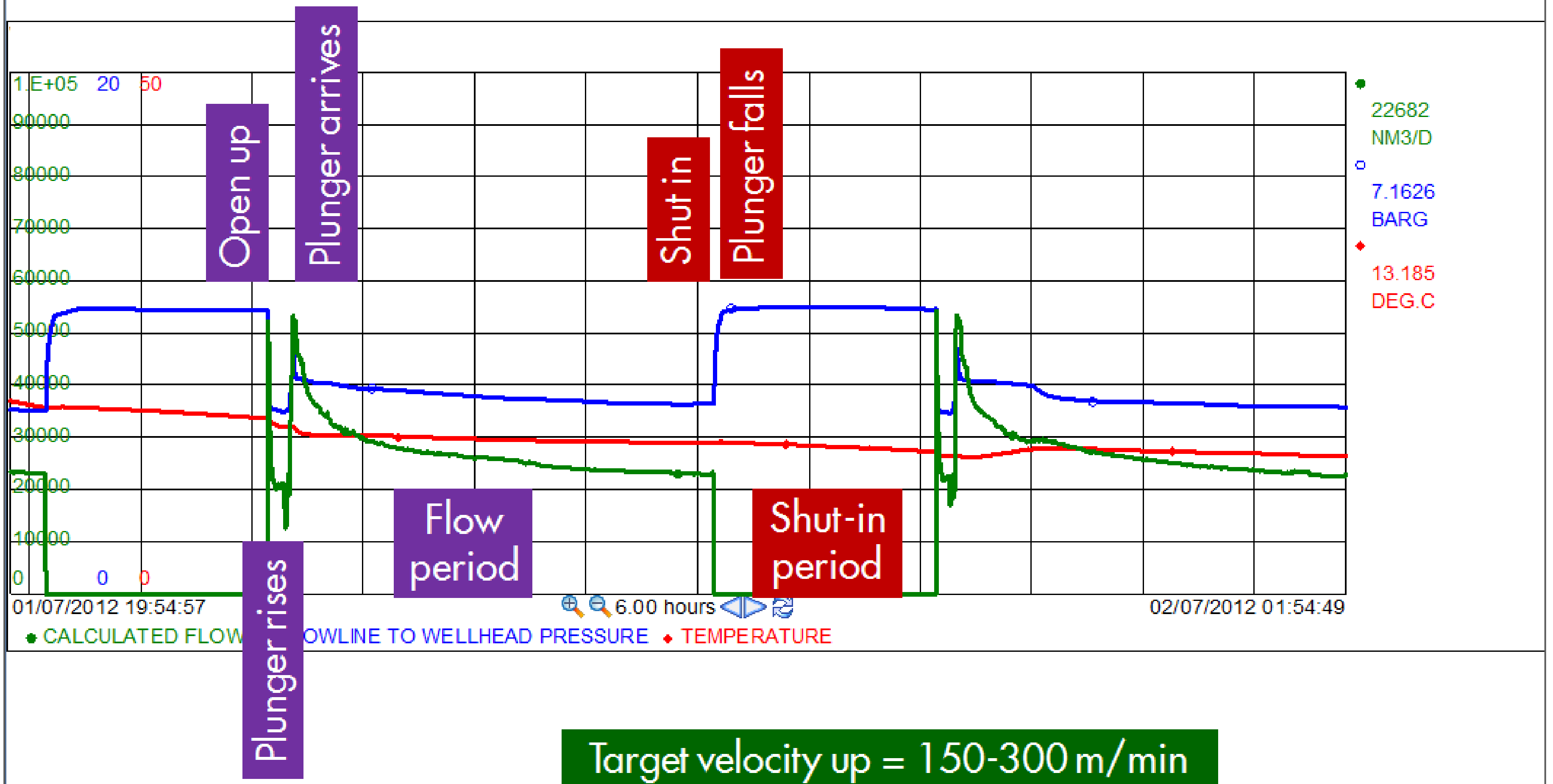


Plunger Lift

1. Plunger at surface, well open: Gas is produced, liquid accumulates on top of standing valve
2. Well shut-in: Plunger drops to bottom
3. Plunger on bottom with liquid slug on top: Casing pressure builds up
4. Well open: Casing gas expansion pushes plunger plus liquid to the surface
5. Plunger at surface, well open: Gas is produced, liquid accumulates

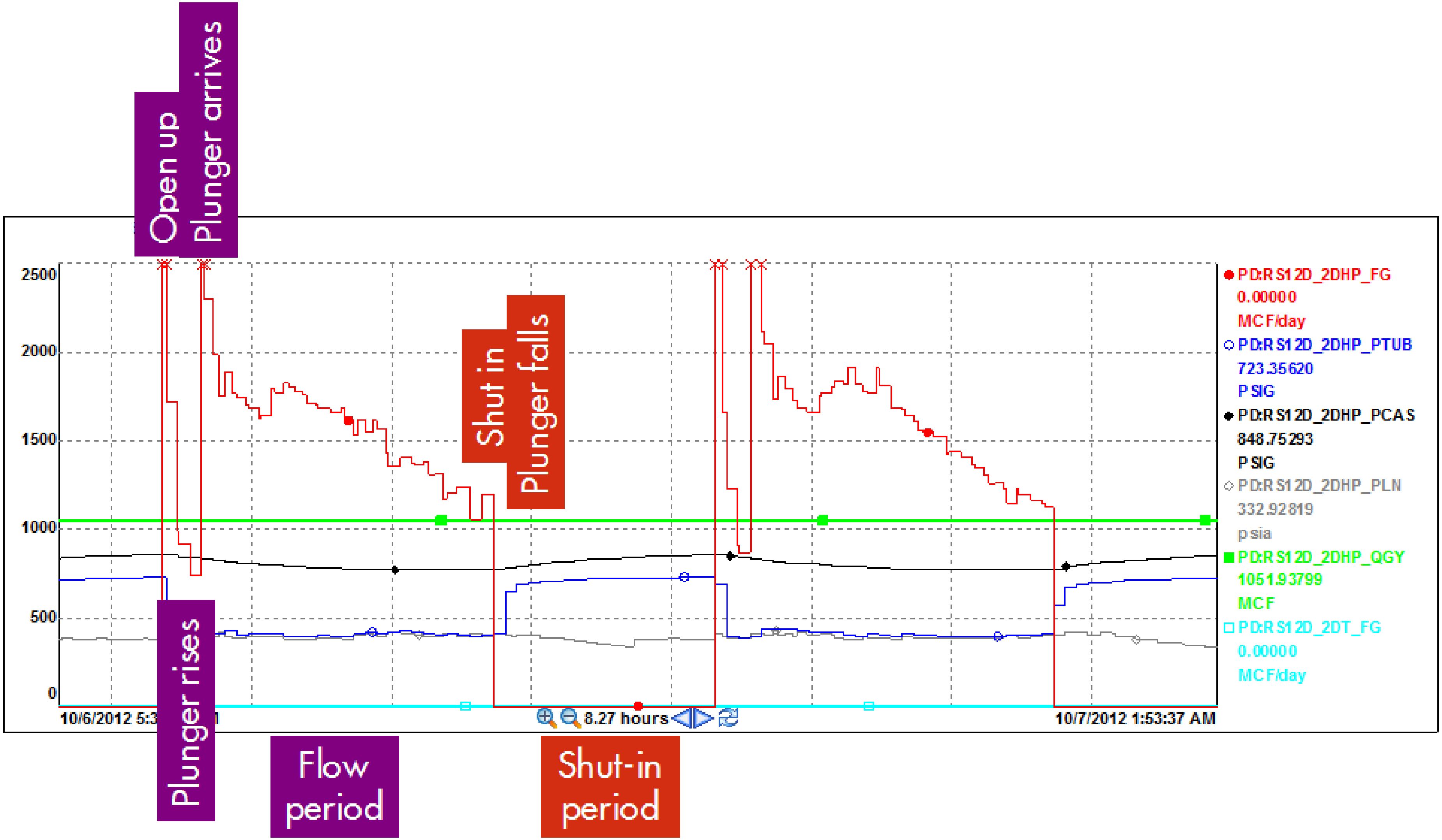


Plunger Lift in Action



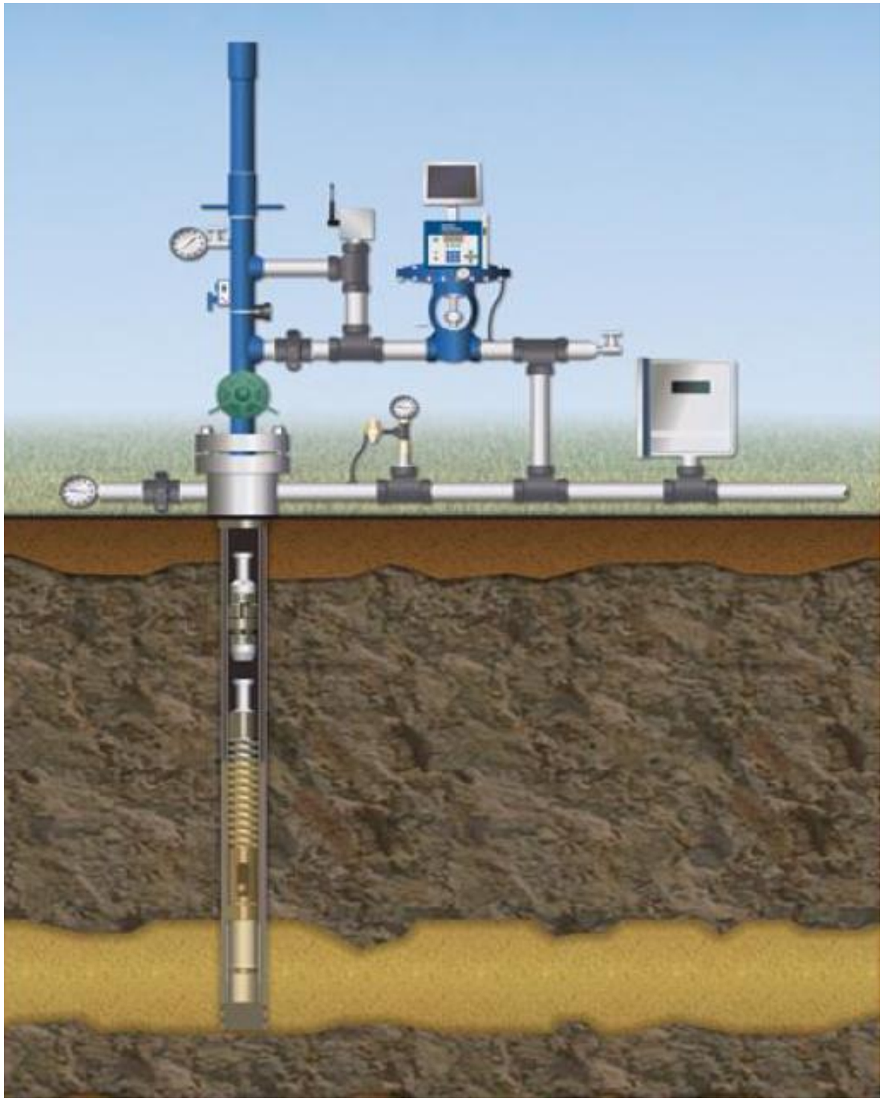
Target velocity up = 150-300 m/min
1200 m AHD in 6 min = 200 m/min

Plunger Lift in Action



Plunger Lift Equipment

- Bottomhole spring
- Plunger
- Arrival sensor
- Lubricator/catcher
- Pressure transducers
- Motor valve(s)
- Gas flow meter
- Wellhead controller

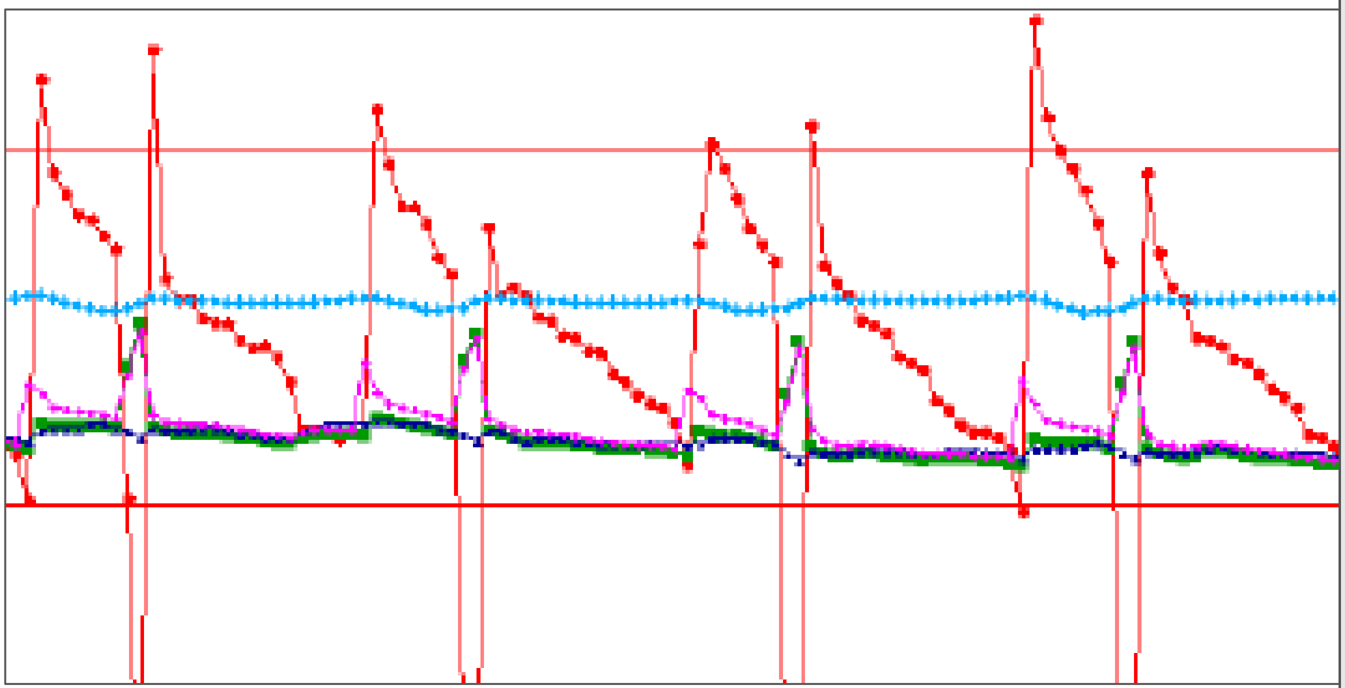


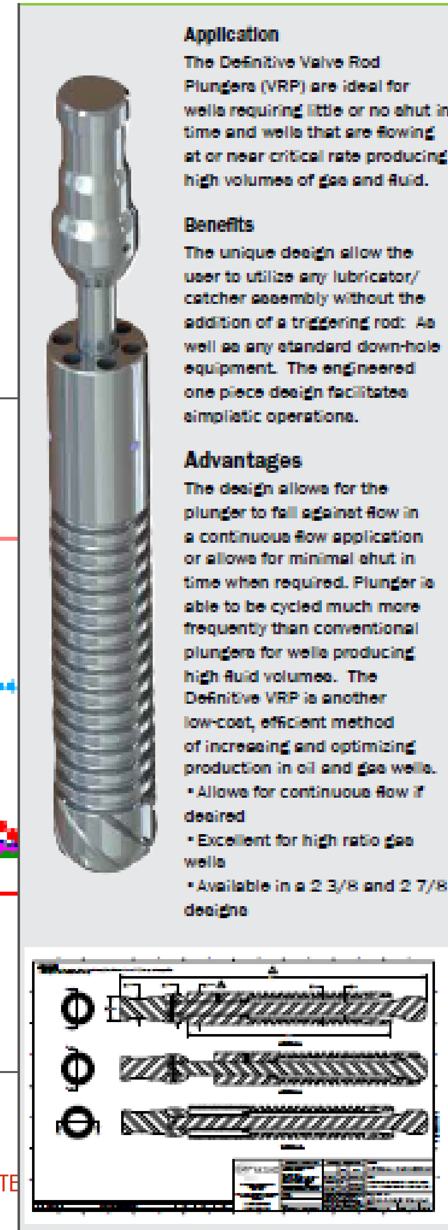
Types of Plungers

Plunger Type	Description	Pros	Cons	Most Use?
Solid	Solid seal face	Low cost Best seal choice for waxy wells	inefficient	Wax, small solids, general use oil or gas
Brush	Flexible surface made of Nylon fibers	Good seal, can run through restricted I.D	Quick wearing seal face loses efficiency High temperature can effect life of seal	Restricted tubing I.D Frac Sand
Pad	Steel pad section that can compress and expand to follow tubing I.D	Good seal long wear life	Solid material like sand can jam pad section Waxy wells are not good candidate for pad plungers	Clean fluid, general use oil or gas Low rate wells requiring improved efficiency
Flow-through/Quick trip/Bypass	Plunger that can fall against flow	Reduces shut-in times Lifts small volumes of fluid multiple times	More dangerous for fast arrivals	Strong wells close to liquid loading rate

Continuous Flow or Two-Piece Plunger

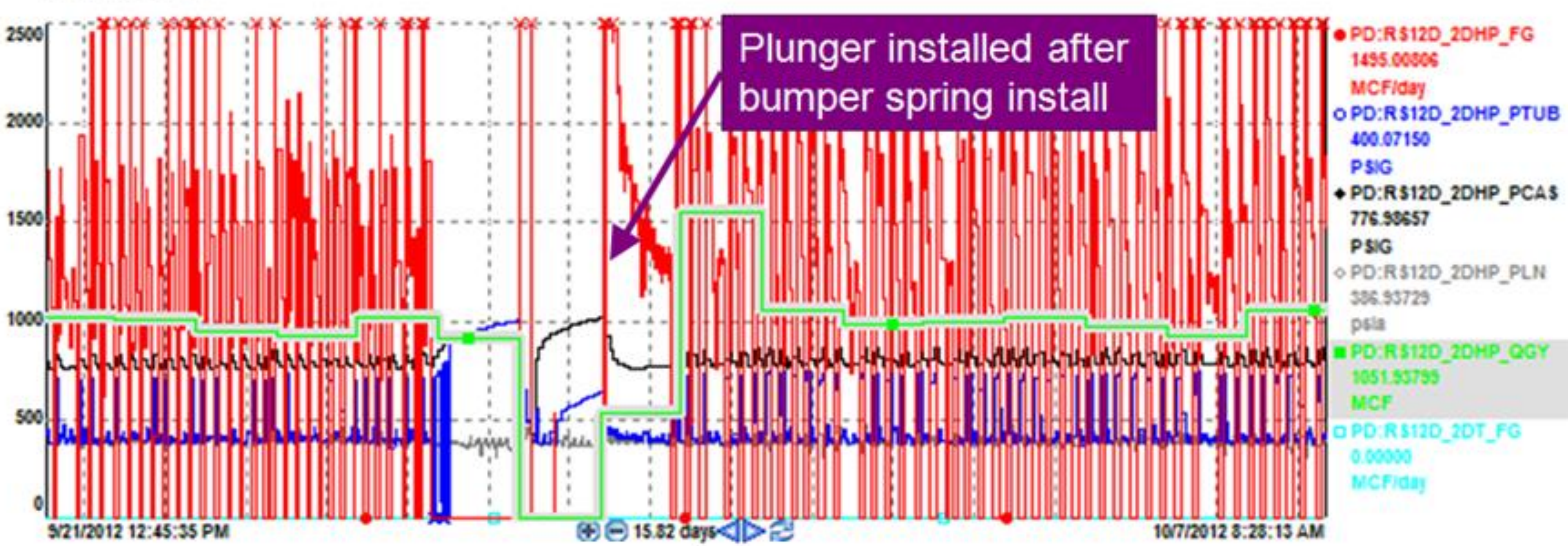
- No shut-in time required in case reservoir gas rate exceeds plunger requirement
- Continuous flow plunger is open to flow while falling down and is closed when travelling up





Plunger Lift in Tight Gas Field

- 508 wells: 387 wells with plunger lift and 31 intermittent wells
- Install the control valve early (with the initial tubing install) to allow intermittent production, before installing bumper spring and plunger
- Ideally, there should be no boost visible in production rate, if plunger is installed on time (production is preserved, not restored)



GWD Selection

- Discuss and rank decision criteria
- Compare GWD lifecycle scenarios, that is, consider all feasible series of GWD measures
- Scheduling lower cost - lower UR - higher profitability options first may jeopardize future higher cost - higher UR - lower profitability options
- Do not discard techniques too quickly as most techniques are technically feasible in most wells (but sometimes costly)

How much money can you spend?

$$\text{Recovery } (Nm^3) \approx (5\text{-}10e6) \cdot OGIP \cdot \Delta P_{min}$$
$$\text{Expenditure* } (\text{Euro}) \approx (0.5\text{-}1.0e6) \cdot OGIP \cdot \Delta P_{min}$$

OGIP in e9 Nm^3, ΔP_{min} in bara, P_i = 200-400 bara
** Assume imaginary 0.10 Euro/Nm^3*

What is Most Important?

Profitability	Look at total cost (instead of installation cost only)
Reserves	As long as profitability is ensured and cost can be absorbed
Production	As long as profitability is ensured, cost can be absorbed and it does not jeopardise reserves ➢ Beware of 'cherry picking' and 'penny-wise but pound-foolish'
Cost	Capital Expenditure (CAPEX) or Operational Expenditure (OPEX) depending on management mood

Lifecycle GWD Strategy

- Lifecycle typically requires multiple measures in series and/or parallel
- Compression is always required at some stage

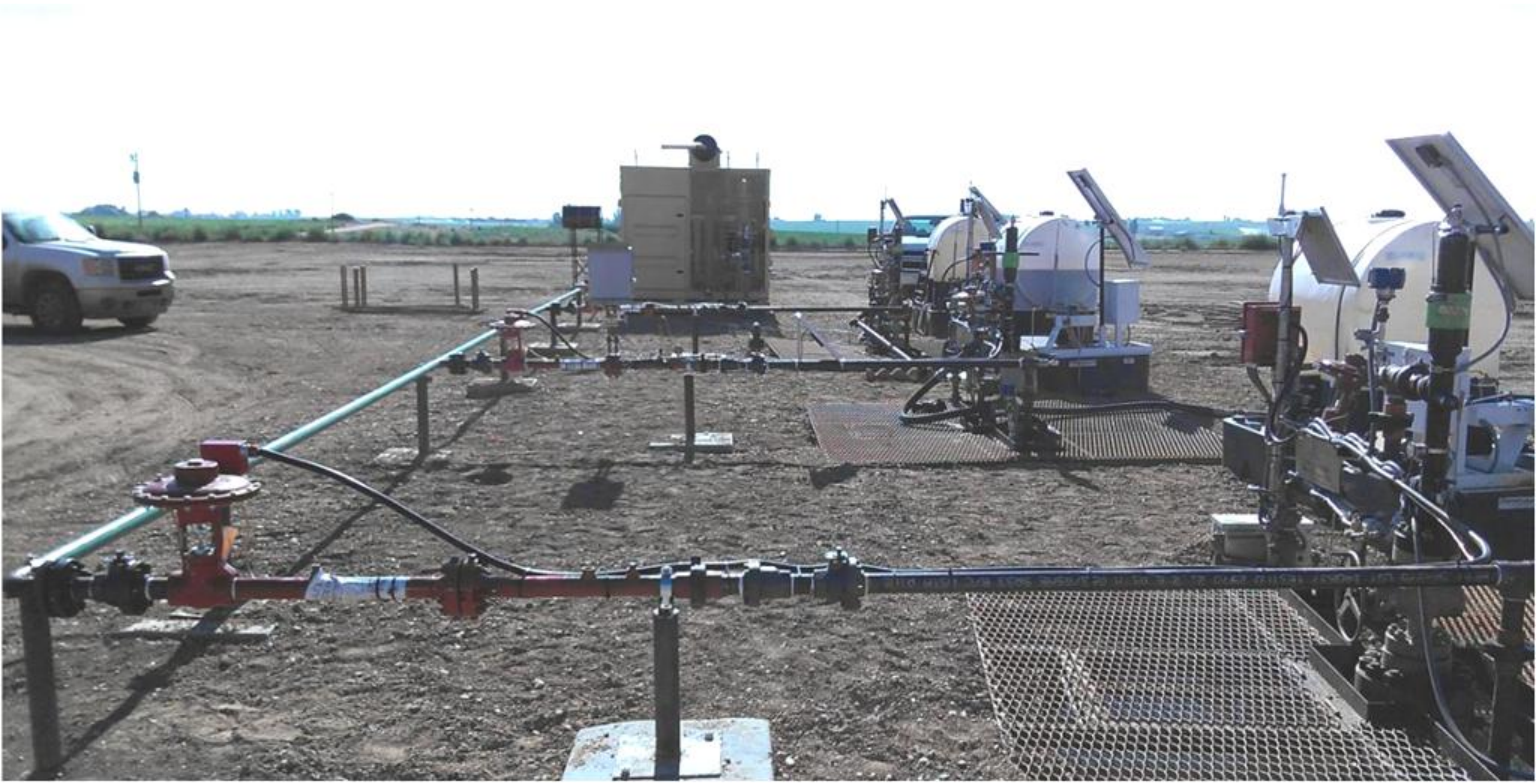
Early Life
- Casing Flow
- Tubing Flow
- Intermittent Production

Mid Life
- Compression
- Velocity String
- Foam Lift
- Plunger Lift

Late Life
- More Compression
- Gas Lift
- Downhole Pump

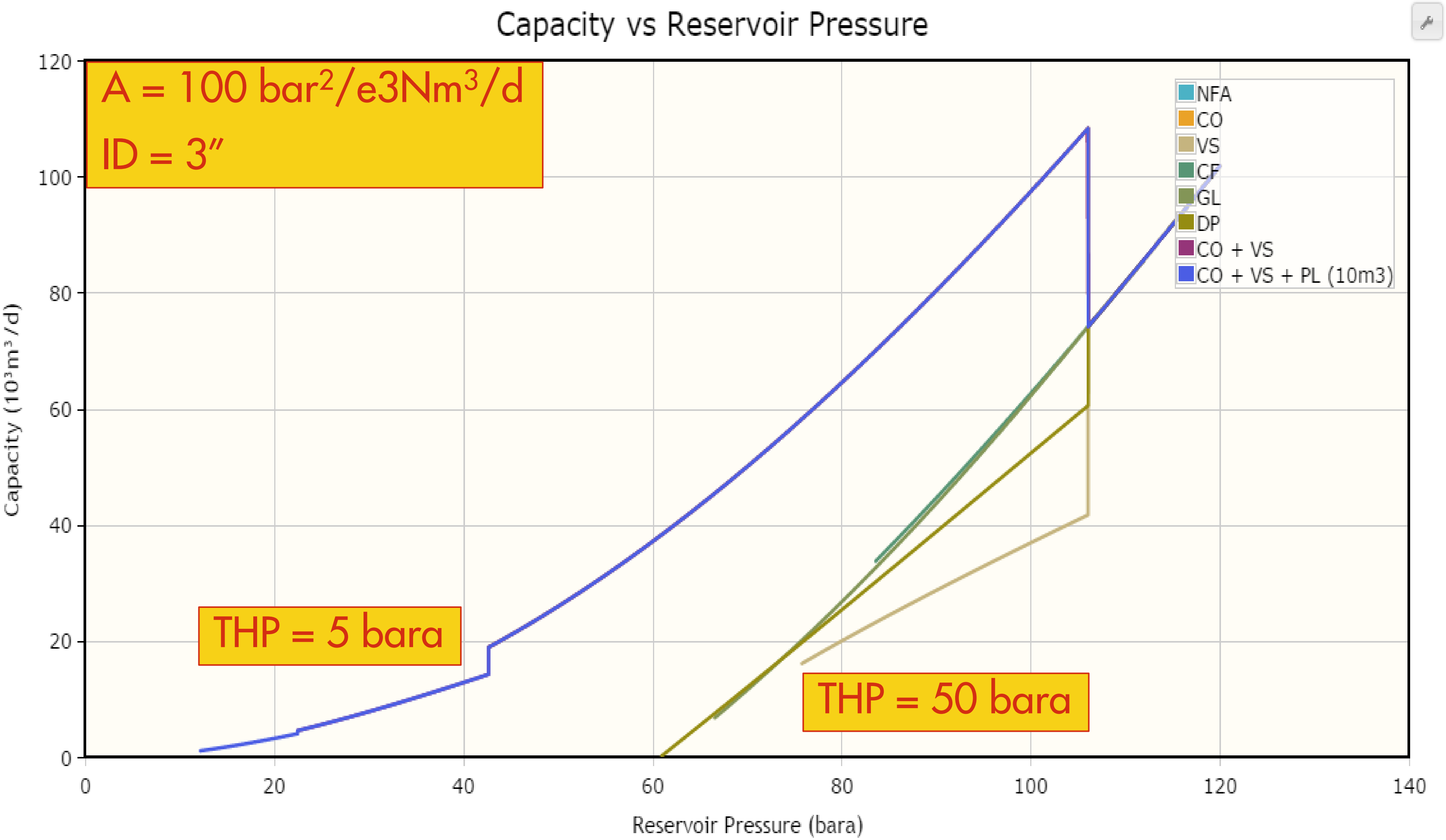
Some GWD Measures Make Great Combinations

- For example, plunger assisted gas lift or foam assisted plunger lift

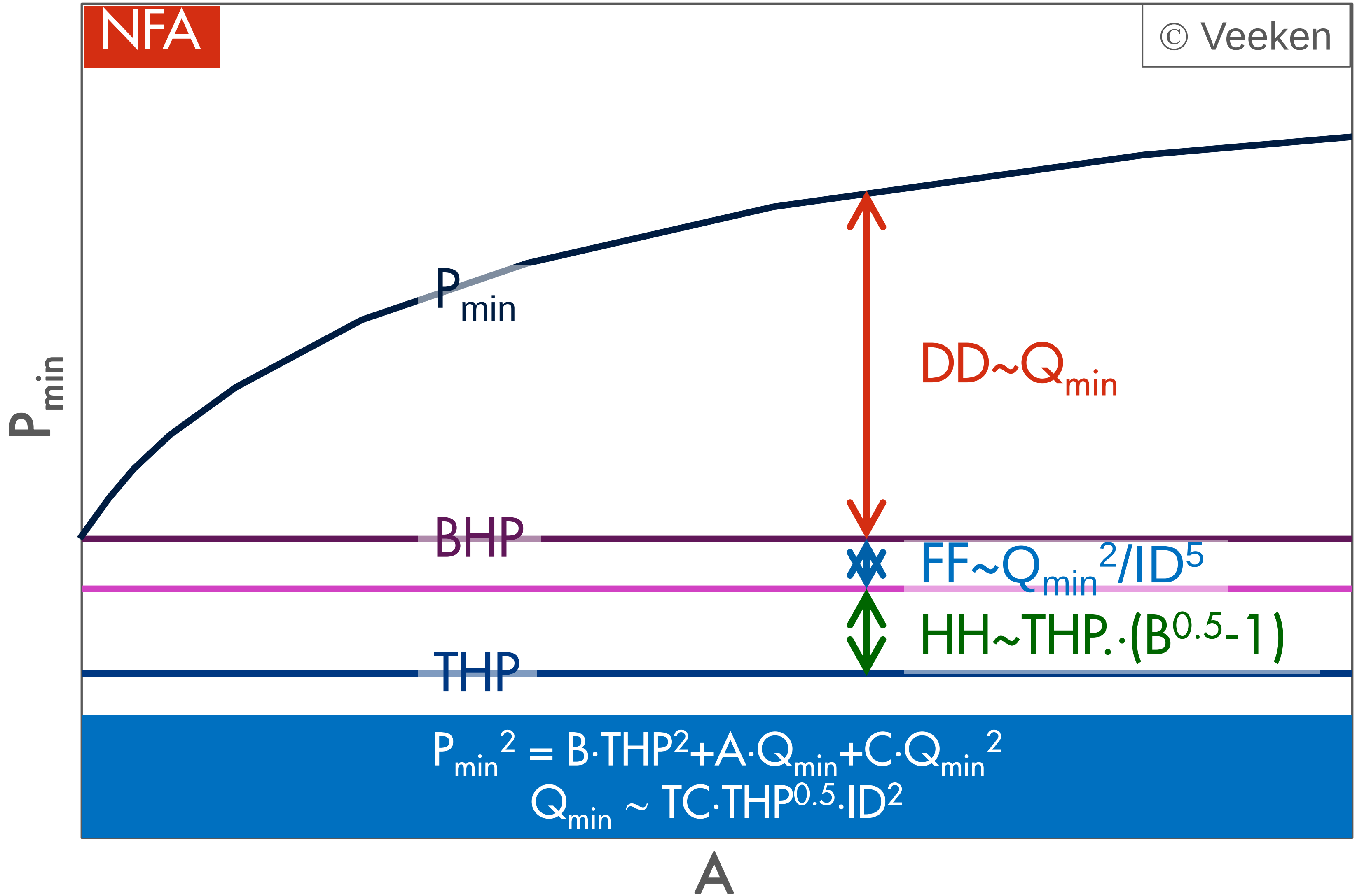


Reducing Q_{min} is Insufficient to Reach Technical Limit

- Need to reduce THP to reach technical limit



Base Case



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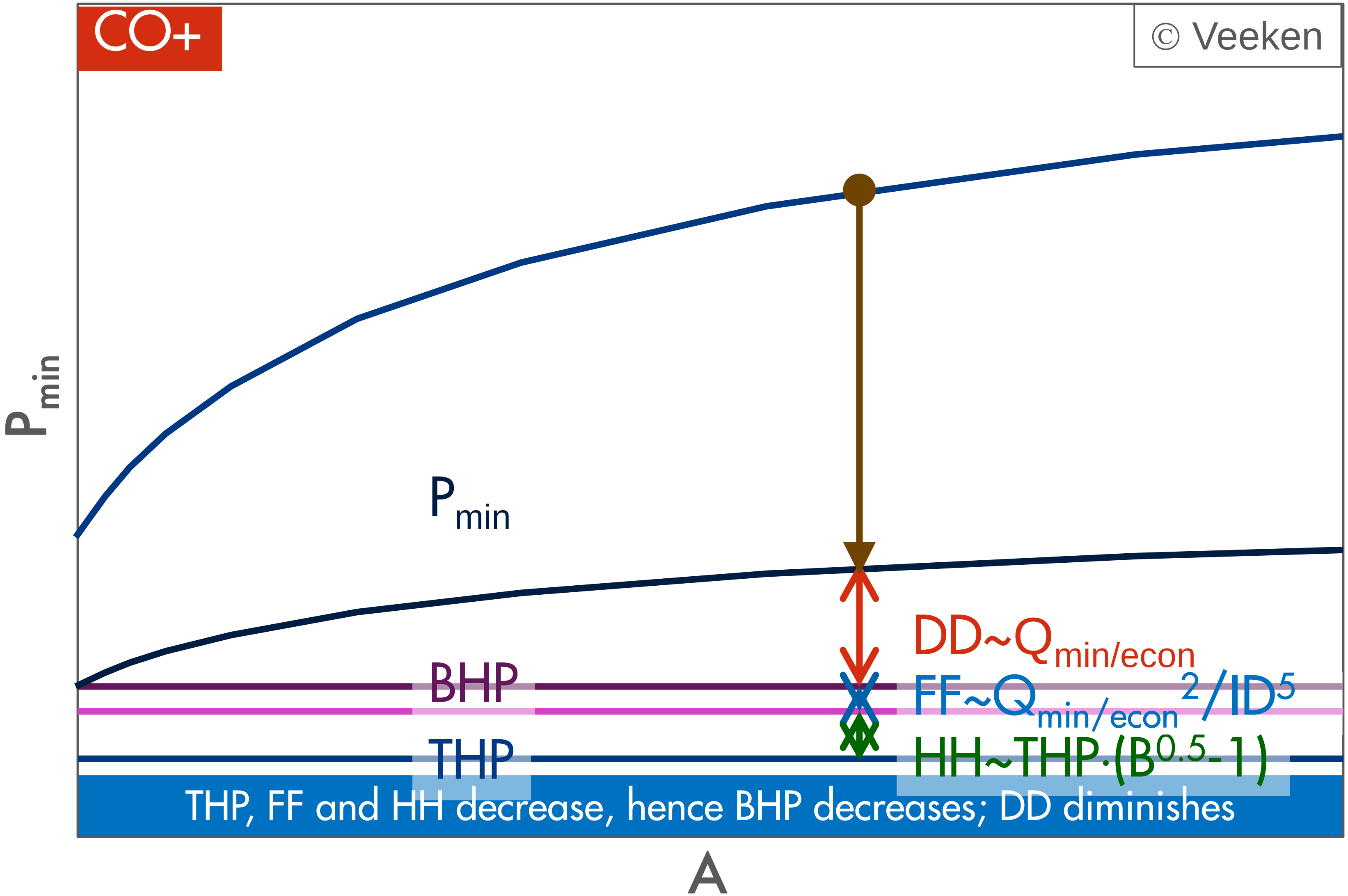
A

Technical Limit Requires Compression



GWD Key Characteristics

- Compression generates reserves and capacity; essential for other GWD measures such as gas lift and plunger lift; only constrained by cost
- Intermittent production buys time in case of a large slow gas component
- Velocity string carries "zero" OPEX; not applicable for prolific inflow
- Foamer injection can harvest significant reserves; can be combined with most other GWD measures
- Plunger lift can be "low cost, high reward" in tight gas and shale gas; scope is constrained by wellbore storage volume and well geometry
- Gas lift maximises reserves; constrained by infrastructure and energy efficiency; excellent combination with plunger lift
- Pumping maximises reserves; constrained by well geometry (size and separation efficiency) and well intervention cost (reliability)

NAM