Low and volatile oil price environment. Technical responses in the Pannonian basin

Workshop
Monobore completion – is it really cheap?

Szolnok, 17 November 2016
Society of Petroleum Engineers

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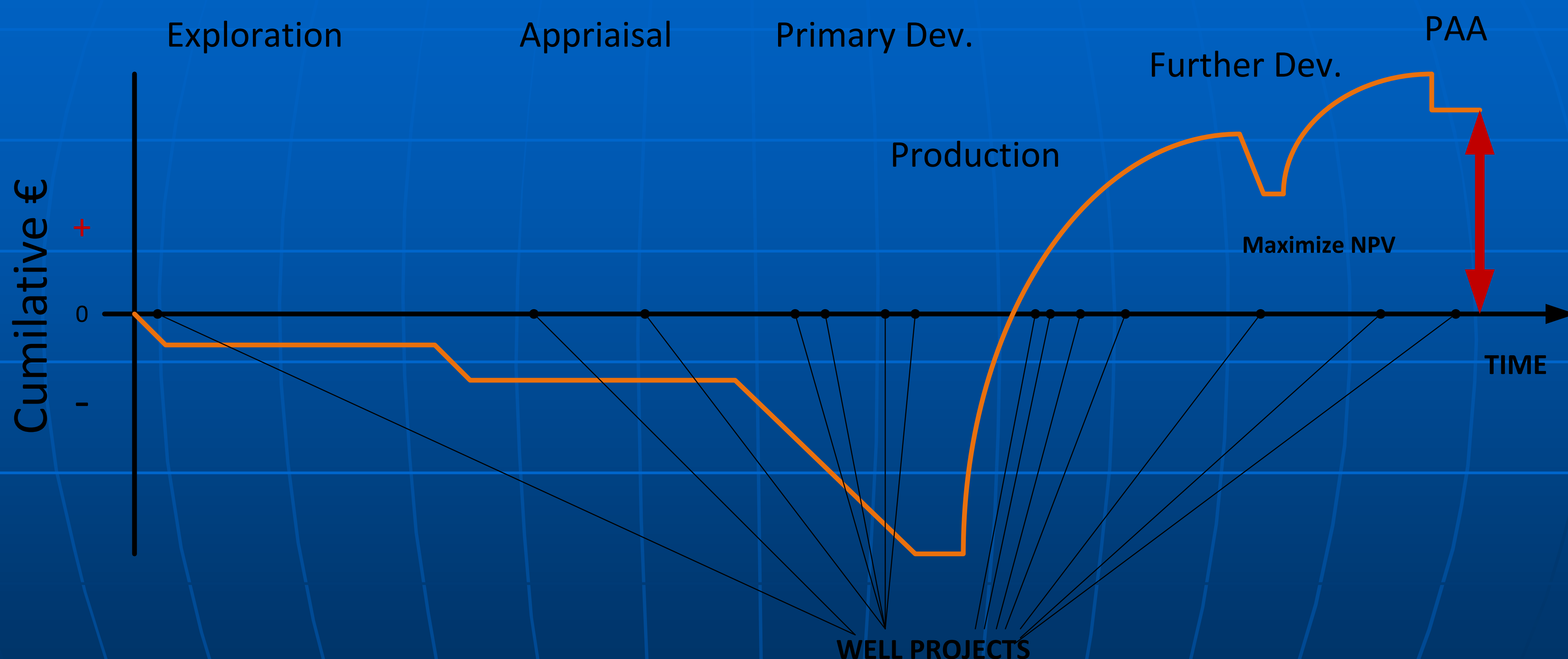
Agenda

1. Well Planning– well lifecycle as a holistic approach
2. What is the monobore (MB) well?
3. Benefits & limitations of MB wells
4. Real example

Lifecycle of a well & fundamentals of well planning:



Key objective of well planning through well life cycle:

Maximize profitability:

- By maximizing well hydrocarbon **recovery**
- By **optimizing** data gathering & interpretation
- By considering the **full petroleum resource life cycle**
- By **balanced management of risks**
- Without compromising **HSE standards**
- Through the earliest possible input of **key staff** & **correct technology**
- Through **effective multi disciplinary teams**
- Through **optimum business processes**
- Through **planned change**

Key objective of well planning through well life cycle - II

- Conventional well planning & completion
  - Several casing strings or liners
  - Completion is usually using different string than last production casing string
  - Different OD’s & ID’s are in completion thru entire well
- Monobore well design & completion
  - Several casing strings or liners
  - Completion is usually using the same string as the production casing string
  - Same OD’s & ID’s in compl. Thru entire well

What is the monobore wellbore design?

By definition –according to Tullow Oil:

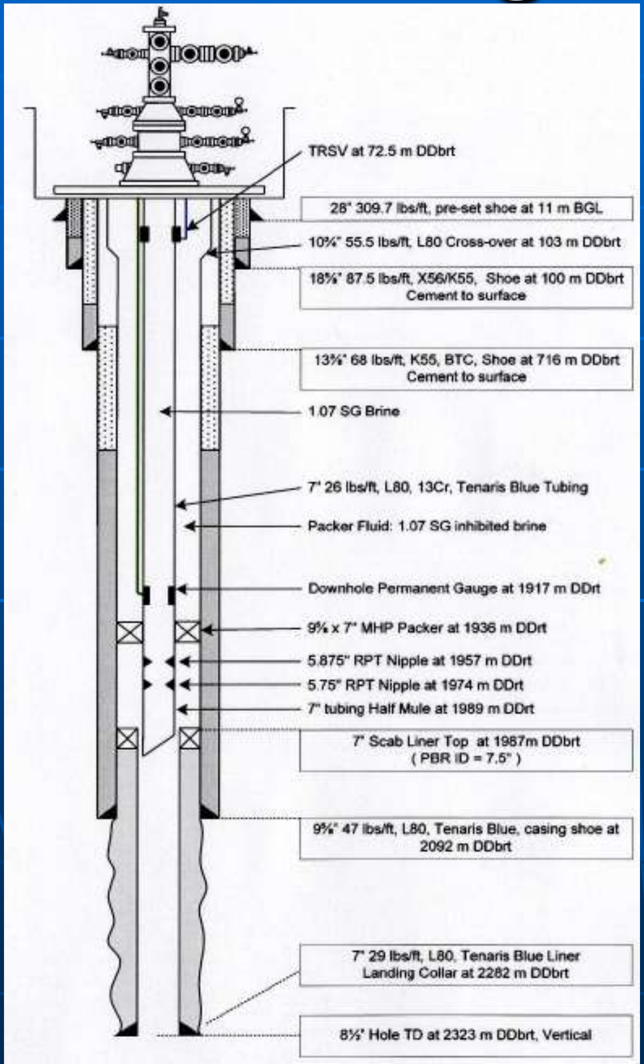
- “Monobore” describes a well where the diameter of the production conduit is *uniform* from the reservoir to surface.

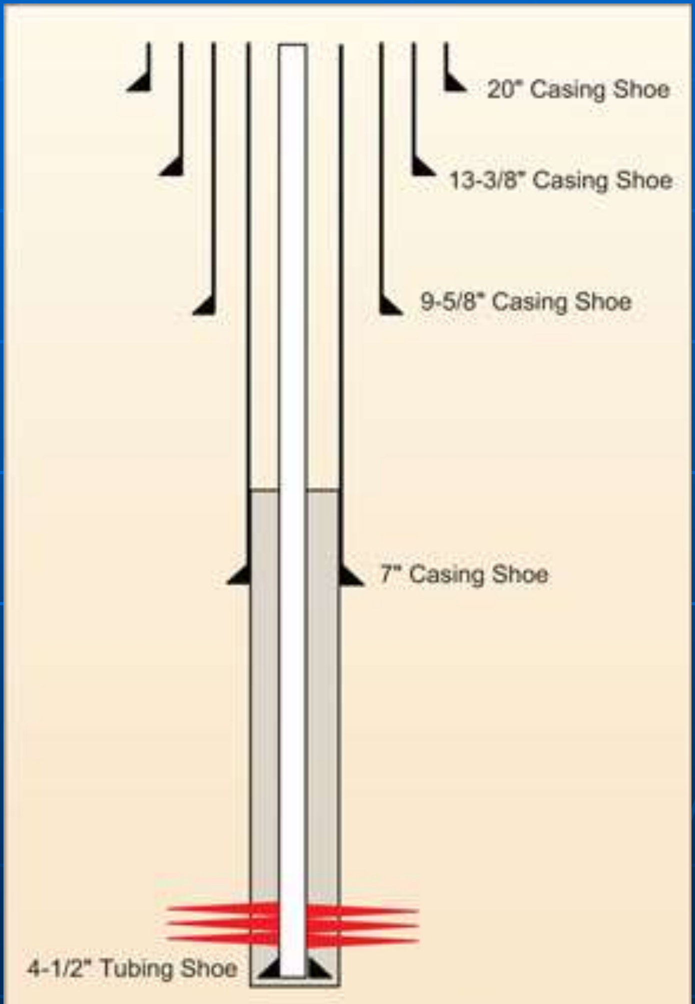
By definition –according to SHELL:

- A monobore (MB) completion is a completion with fullbore access across the payzone, without diameter restriction.

  (But *not necessarily with a constant diameter* from top to bottom!)

What is the monobore wellbore design? Differences





Simple Monobore Design

Application of MB wellbores:

- Both on and off shore,
- In high rate gas wells – no ID restriction in completion for higher PI
- Disposable wells, where the aim to save on tangibles and logistic costs
- In most cases where the field development cost is crucial, eg. where the reservoir can be drained within short period therefore operating companies want to increase the project NPV.

Advantages

- For the same size of surface casing strings, the monobore design allows a larger production conduit than a conventional well without having to utilize underreaming, bi-centre bits or expandable tubulars, for example.
- May eliminate one casing/liner string compared with a conventional wellbore design.
- If the well can be downsized (while still achieving the same size of production conduit), then the reduction in hole sizes may result in a significant saving in wellhead equipment, mud, casing, cement and drill bit costs.
- The number of specialist completion services can be significantly reduced, saving on well construction costs and logistical issues.
- The simplicity of design and reduced number of services required can allow the wells to be brought online as rapidly as possible, e.g., all operations can be performed with the drilling rig, potentially eliminating the need for a workover rig.

Advantages – cont'

- May enable fracture stimulation to be performed without the need for installation of a frac string.
- Reduced number of components required in monobore well construction can lead to significant inventory management savings
- May allow a smaller drilling rig to be utilized to drill a smaller wellbore, which may save on rig costs. This may also have the added benefit of reducing lease size, reducing chemical and material consumption to result in reduced environmental impact.
- May allow a larger number of wells in a development or exploration program for the same capital expenditure.
- When recovery factor, deliverability and reservoir characterization are taken into consideration, it may be more cost-effective to drill a new monobore than to work over a conventional well.

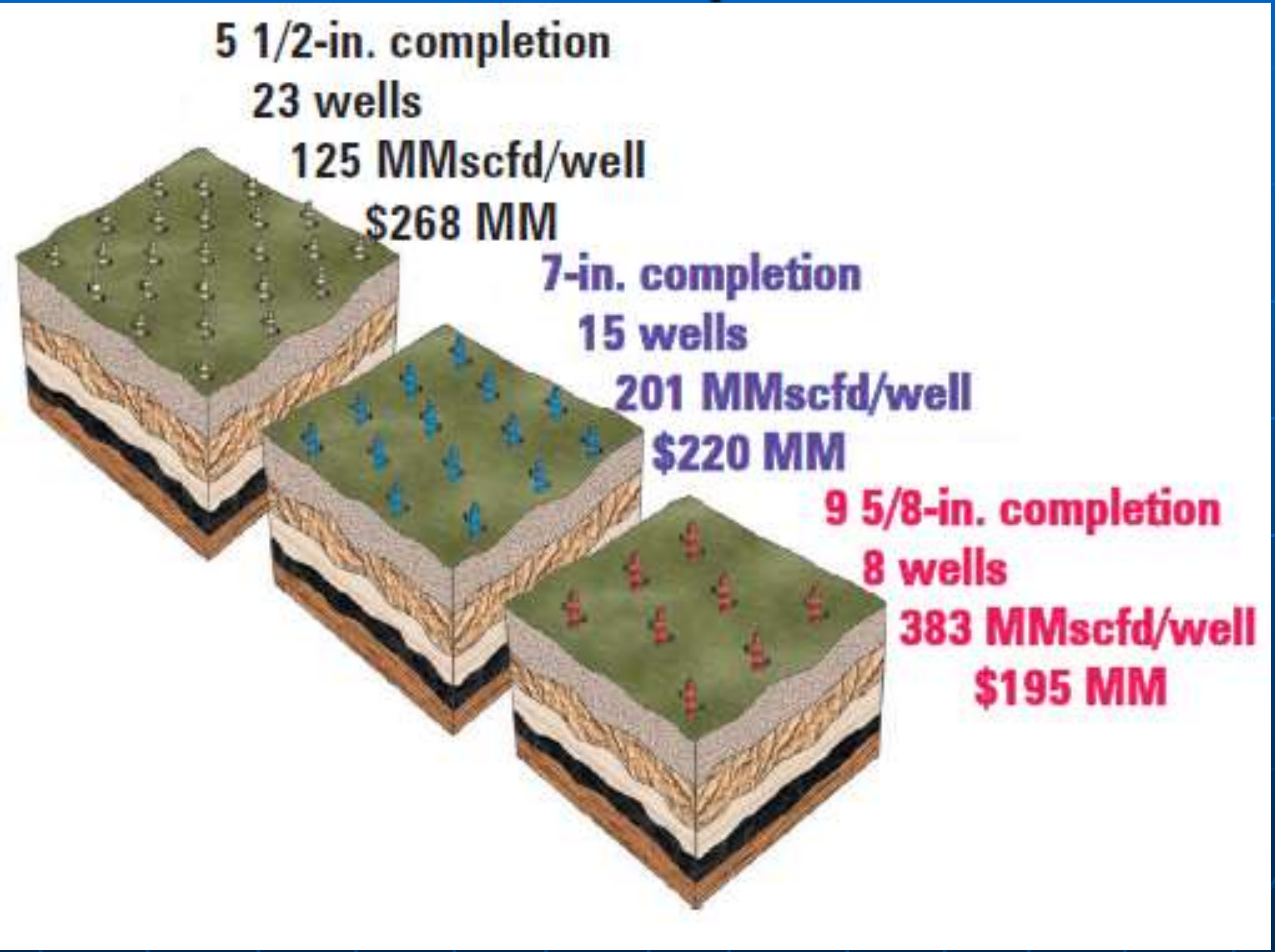
Limitations

- If the upper casing strings are downsized to minimise costs, then contingency string options may be limited in the event that drilling difficulties are encountered.
- As the monobore production string will be cemented through, installing completion components such as sliding sleeves, subsurface safety valves, nipples and gas lift mandrels may not be possible or practical.
- The options available for re-entry and sidetracking a monobore well are more limited than for conventional wells.
- Selection of the monobore material may have to be made before the composition of the reservoir fluid is known. This can lead to problems if CO_2 or H_2S is present in wells to be tested for an extended period or ones that will eventually be put on production.
- The specification and cost of the monobore production string may have to be higher than in the conventional well in order for the monobore design to achieve a wellbore life similar to a conventional well, where the completion string can be changed out when required.

Limitations – cont'

- Isolation of perforations while maintaining access to deeper zones can be achieved by installing a tubing patch, but this leads to a restriction in internal diameter, which may compromise the ability to perform zonal isolation operations deeper in the well.
- If intervention operations are required, the diameter of the monobore (compared with the larger diameter of the production string in a conventional well) may restrict workstring size to small-diameter tubing/drill pipe, coiled tubing, e-line or slickline. These options are not always readily available or suitable.
- The monobore internal diameter may limit the type of tools available to be run, especially for logging tools, although slimmer tools are continually coming on the market.
- Cannot optimize fluid lift capabilities by selecting the tubing size to suit the well deliverability or liquid gas ratio. This may be partially overcome by running acceleration strings or capillary strings for gas lift or surfactant injection.
- Hydraulic performance during drilling operations may be compromised (e.g., higher circulating pressures, lower HSI and higher ECD) through use of smaller drillstrings and reduced hole diameter.

Application of MB wellbores example:



Real Example

- Few MB wells had been drilled in Hungary between 2005 to 2009
- Shallow and deep wells were drilled. Targeted for gas.
- Using 4-1/2” completion for the deeper one
- Using 2-7/8” tubing thru cement compeltion for the shallow well.

Tecnical cosnideration of cement thru tubing monobore wells:

- Equipment must be met with cement thru compliance. (SCSSSV, flow couplings, blast joints, etc)
- Completion equipment must be defined in advance (CO_2 and/or H_2S resistance)
- Slurry design – needs to be rheology designed
- Cement unit – required high horsepower
- Spacer volumes & density: relative large amount of spacer, while keep the density close to the mud weight.
- Puming rate: important not to make dramatic changes in pump rate during displacement
- All lines must be flushed clean while dropping plug. Small amount (1-2 bbl) of cement can cause big problem

Real Example

Well A:

- Drilled in 2006
- TD: 1025m TVDRT
- Drilling time: ~14 days without test
- Deviated

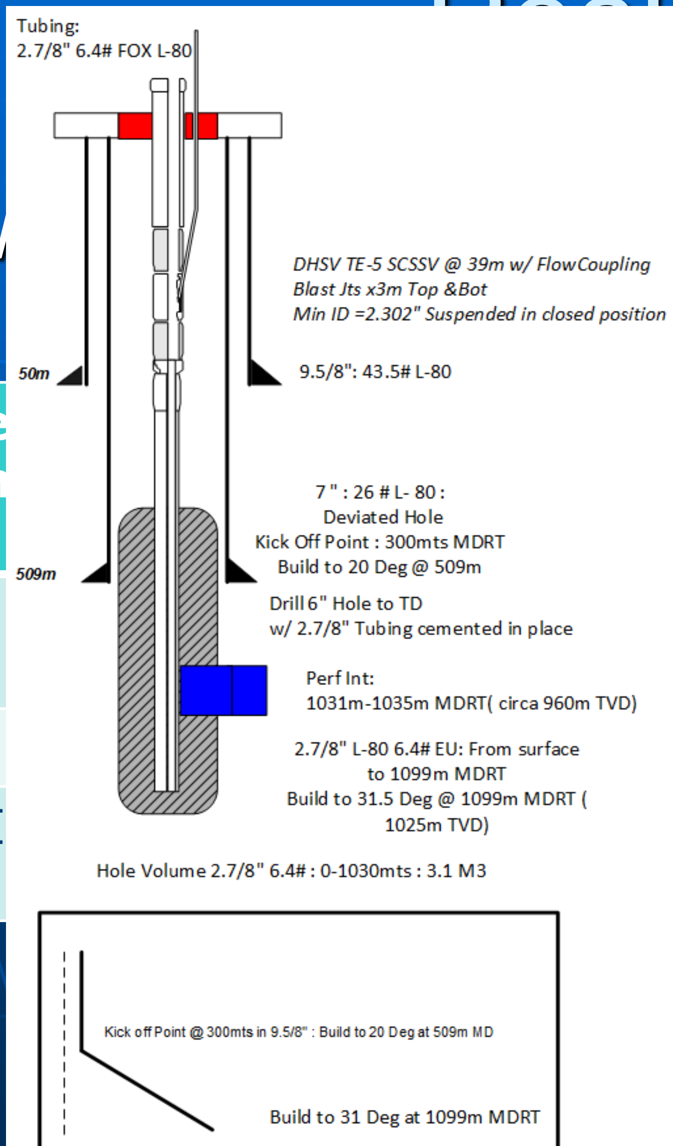
Well B:

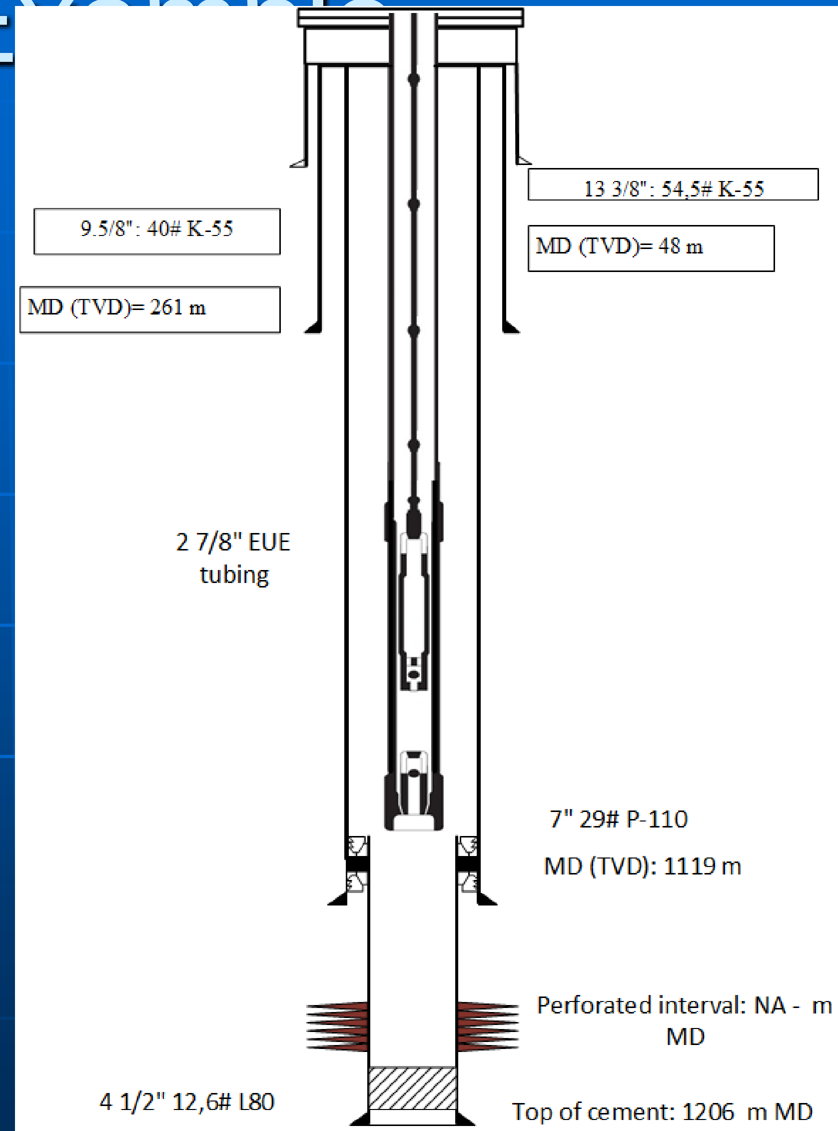
- Drilled in 2016
- TD: 1214 m TVDRT
- Drilling time: ~14 days without test
- Vertical

Real Example

W

Se
on





I

II

III

Real Example

Well A:

Rig type:

Hungarian contractor modified medium WO rig

Wellhead:

- Claxton made

Well B

Rig type:

Hungarian contractor modified medium WO rig

Wellhead:

- Claxton made

Real Example – Drilling cost

Well A:

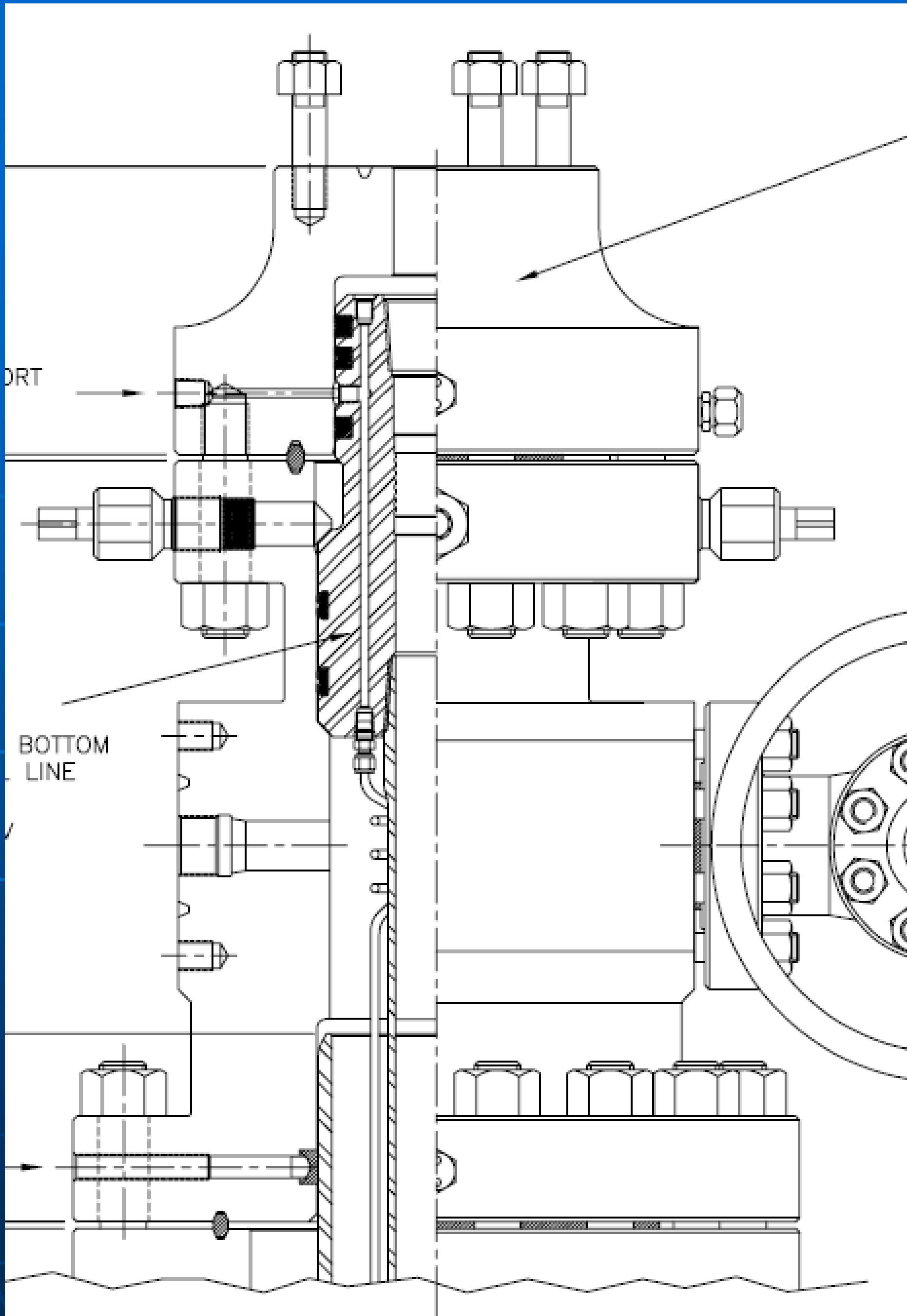
- Location prep: ~€135,000
- Rig mobilization & operating cost: ~€378,000
- Drilling fluid & service cost:

  ~€52,000
- Cementing: ~ €67,000
- WL evaluation: ~€45,000

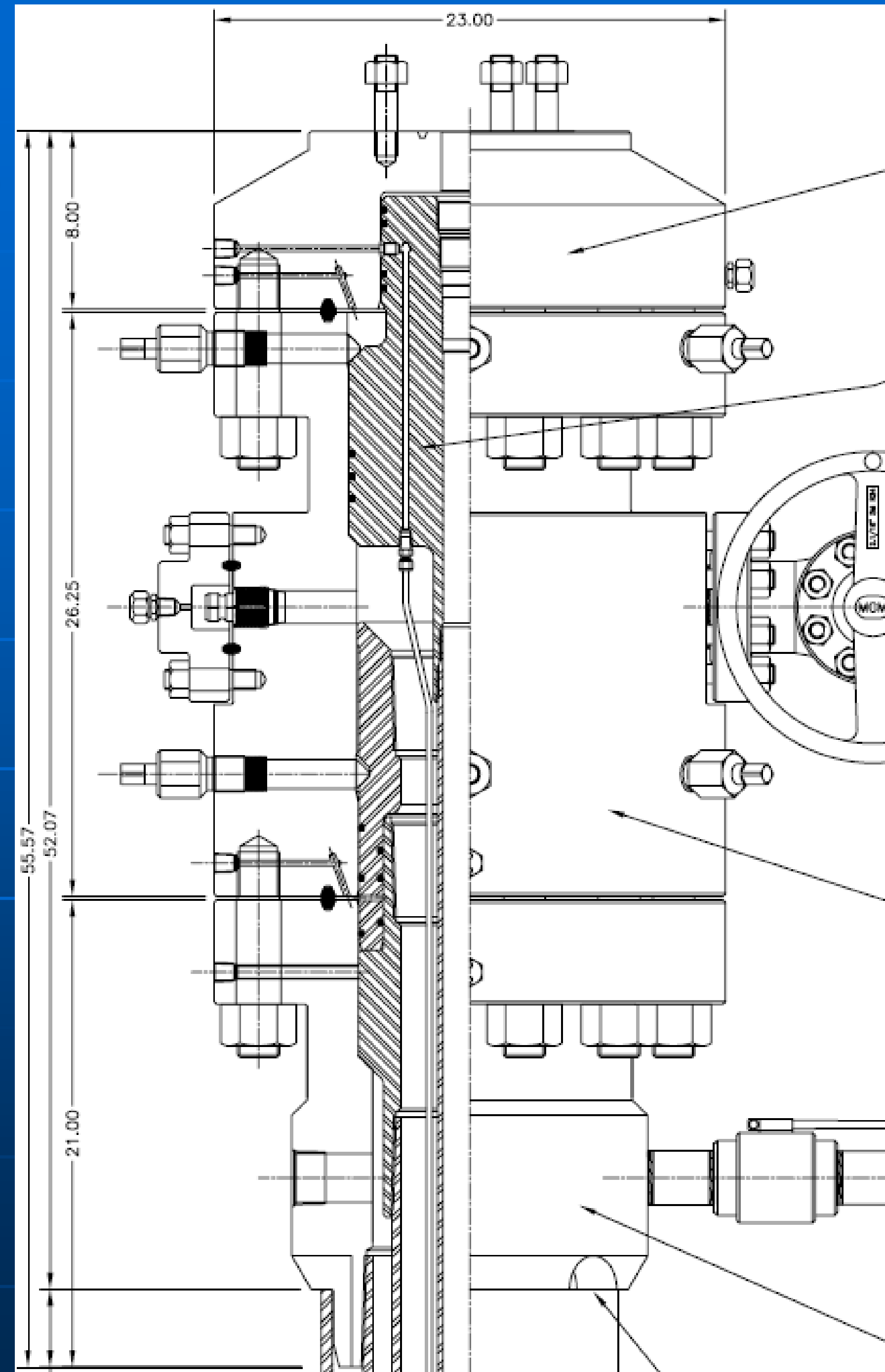
Well B

- Location prep: ~€150,000
- Rig mobilization & operating cost: ~€335,000
- Drilling fluid & service cost:

  ~€58,000
- Cementing: ~ €70,000
- WL evaluation: ~€120,000



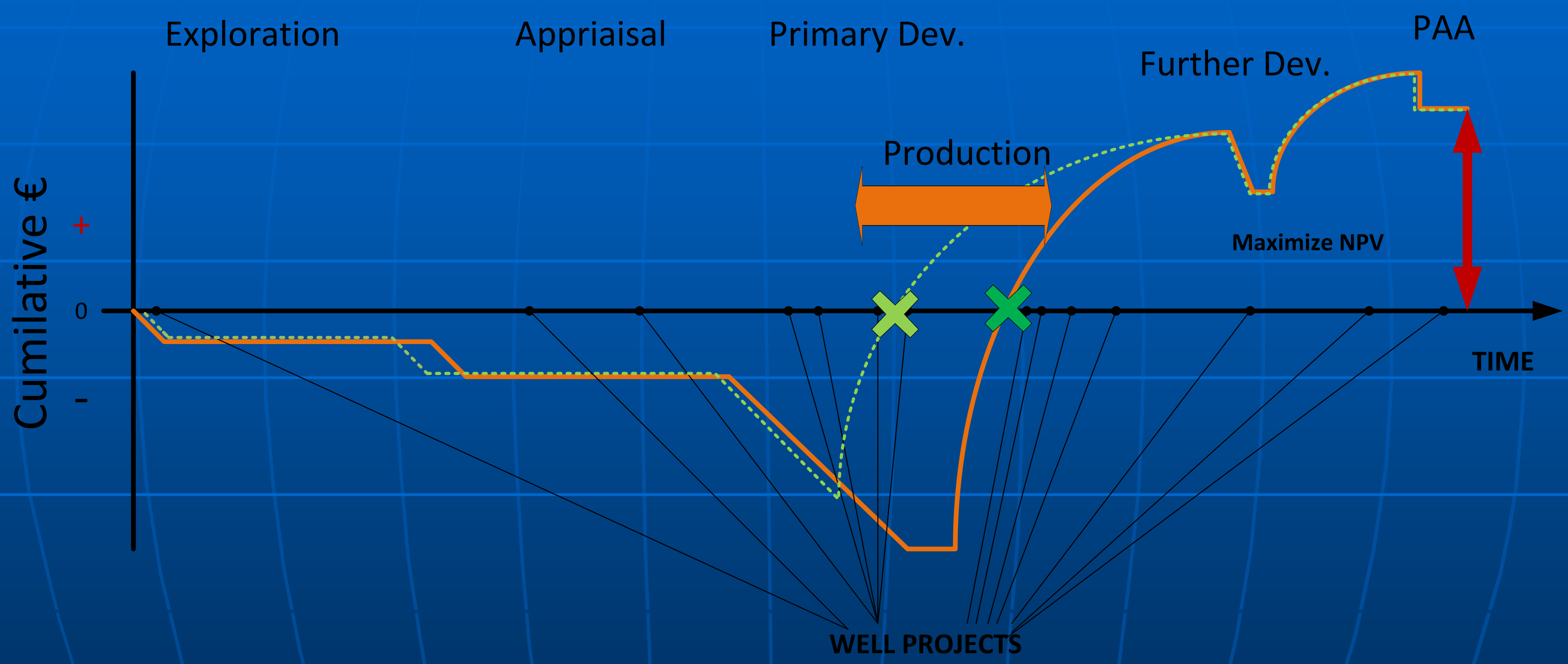
TOREADOR'S EXISTING WELLHEAD EQUIPMENT



Real Example – Conclusion

- Significant saving on tangibles and on some services.
- Calculated saving is:~ **€110,000** for MB well comparing to conventional one. (~€91/m - €120/m)
- Breakeven point is in our case: after the 7th drilled well, the 8th dry well cost will be „free” for the company comparing to conventional one.

Real Example – Conclusion



Real Example – Conclusion

We can save money in the present, but:

- there are limitations on manipulating the wells in the later life cycle. (Close out, remedial works, etc)
- Operations may cost more, comparing to the conventional wellbore
- Risks shall be mitigated first & properly, less chance to do something for second time.

THANK YOU FOR THE ATTENTION!

QUESTION?