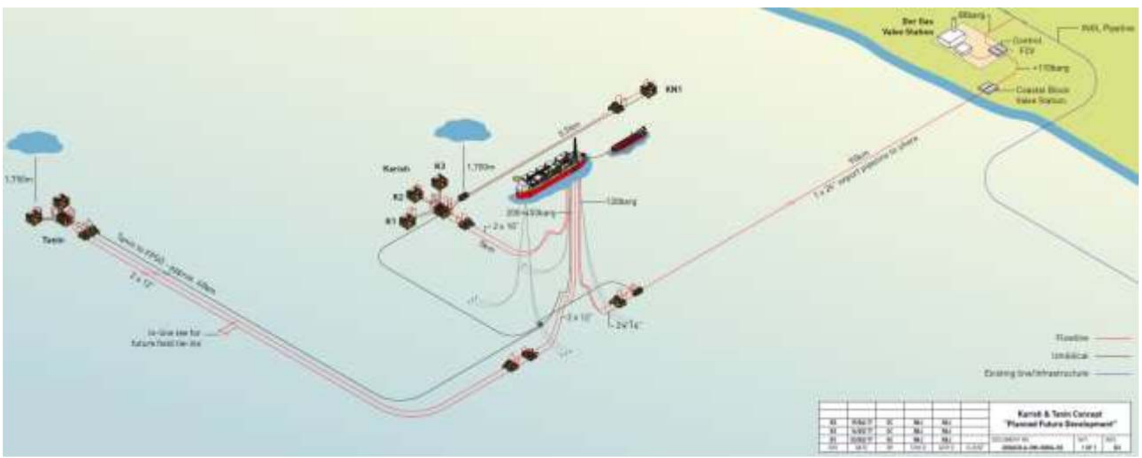
<u>Problem 2:</u> Model development and production scheduling for the dry gas field Karish and Tanin, offshore Israel.

The Karish and Tanin fields are undeveloped assets discovered by the company Noble in the Levantine Basin in 2013 and 2011 respectively. The reservoirs are located north of Israel's exclusive economic zone, approximately 110 km offshore Israel. The water depth is about 1 700 m. Tanin is located approximately 40 km from the Karish field. The combined discoveries sum up to 2.30 trillion cubic feet of gas in reserves.

Energean, a London-based independent E&P company focused on developing resources in the Mediterranean is the operator.

Energean has established gas sales and purchase agreements (GSPAs) with several companies in Israel: Dalia Power Energies, Dorad Energy, Edeltech, Israel Chemical, Bazan oil refineries, OPC, Rapac group, IPM Beer Tuvia, MRC Along Tavor, Ramat Hovav power plant, among others. The gas will be used mainly for power generation. All contracts contain provisions for take-or-pay[1] and/or exclusivity, and floor pricing[2], ensuring that Energean's revenue stream in Israel is secured, predictable and largely insulated from global commodity price fluctuations. The agreed gas price is, in average, \$4 per million Btu (approximately 0.05 USD/Sm3)[3].



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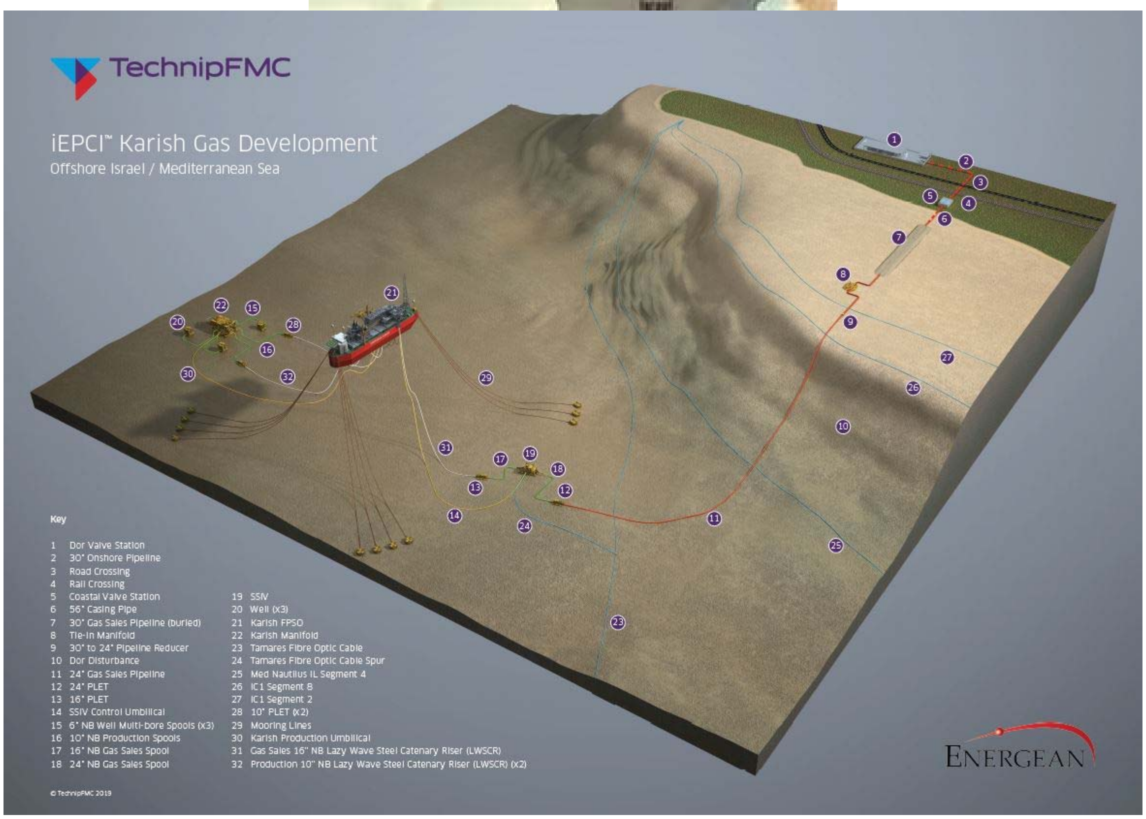
[1] A take-or-pay clause usually requires a supplier to make a minimum amount of product available to a buyer on an annual basis. The buyer must either take delivery of the product or pay for a minimum amount at a contractually agreed price. https://www.lexology.com/library/detail.aspx?g=4b4b5af2-4514-48cb-83b6-7085aa8bde68

[2] In floor pricing, there is an agreement on a value below which gas prices cannot fall

[3] Out of curiosity, check how much does natural gas cost in the US https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm



According to the reference case[4] presented in the field development plan, the field will be produced for most time in plateau rate to give a constant and reliable supply of gas to customers of 8.3 E06 Sm3/d. The total production horizon is approximately 31 years. For the first 17 years, only Karish will be produced and then rate from Karish will be reduced to 2.7 E06 and the rest will be compensated with production from Tanin.

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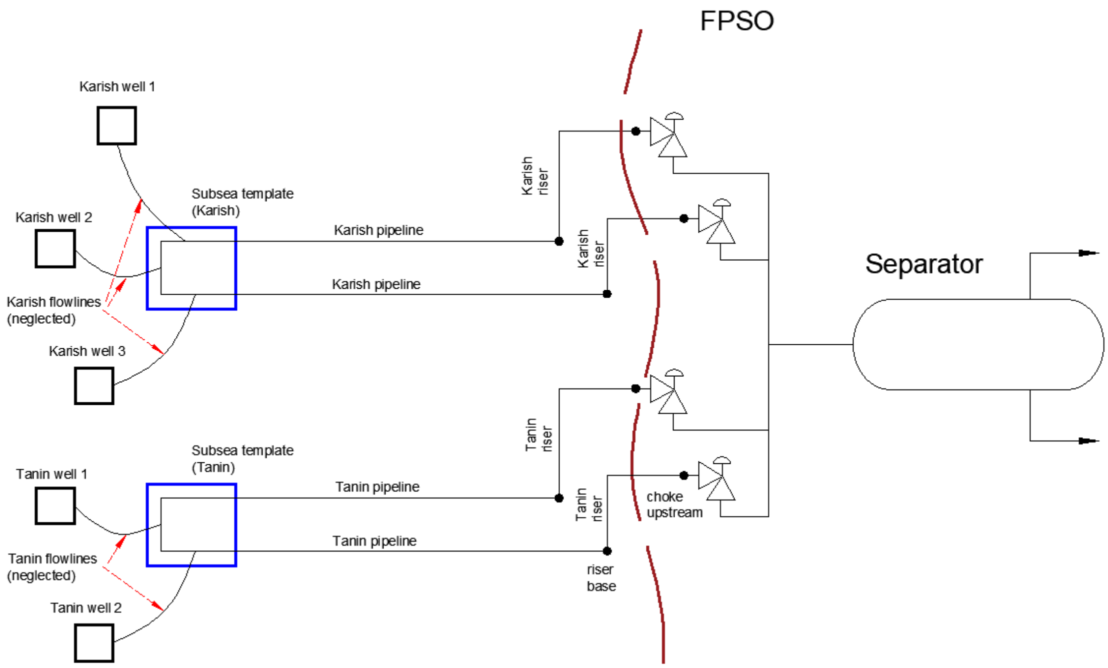
[4] FDP Fig. 1-10 and Fig. 6-64.

The field produces some associated condensate. The Condensate Gas Ratio (CGR) is 75.2 $Sm^3/1E06\ Sm^3$ for Karish and 12.4 $Sm^3/1E06\ Sm^3$ for Tanin[5].

According to the base case Scenario[6], there will be 3 wells in Karish and 2 wells in Tanin[7]. The field will have 2 subsea templates (1 for Karish wells and 1 for Tanin wells). Each subsea template is connected by 2 pipelines and 2 risers to the FPSO where the flow is choked and then commingled in a manifold before entering the first stage separator.

The production from Karish and Tanin wells will be controlled with chokes located on topside[8] (one on each riser[9]). Choking at the FPSO minimizes pressure drop in the subsea system and consequently temperature drop and liquid dropout. Additionally, it minimizes wear to the wellhead chokes (thus less frequent well intervention is needed). However, due to this, the topside chokes split the system in two, with different pressure ratings. Upstream the choke, the system is designed for a maximum pressure of 420 bar. Downstream the choke, the system is designed for a maximum pressure of 260 bar[10].

Wellhead chokes will be used to control production from each well and ensure the planned reservoir production targets per well are achieved.



[5] Values taken from FDP, section 6.1.4.3. Before table 6-9

[6] Presented in sections 7.2 and 7.3 in the FDP

[7] According to the FDP, more wells could be drilled once the aquifer floods the reservoir zones of existing wells.

[8] Presented in section 7.5.4.1. and section 7.6.2.

[9] Ref. Fig. 7-46 on the FDP.

[10] FDP, section 7.5.6.1. “Potential future Inlet facilities”

Separator pressure is set initially to 200 bar[11] and will be reduced to 130 bar[12] after 25 years of production. After the separator, the gas is expanded sequentially in two Joule-Tompson valves, from 200 – 130 bar and from 130 bar to 75 bar. Liquids are removed with scrubbers.

The gas is then compressed and sent to a subsea export template via two risers. Afterwards, there is a 24” pipeline of 90 km of that transports the gas to a gas terminal onshore.

To perform your calculations, assume all wells within a reservoir are identical (in structure and productivity and all other design and operation parameters). Furthermore, assume that wellhead chokes are always open, and that the flowlines from wellhead to template are short and can therefore be neglected. **Therefore, wellhead pressure is equal to template pressure.**

Due to the fact that all wells within a reservoir are identical and located symmetrical with respect to the subsea template, it is possible to perform flow equilibrium calculations considering only the flowpath:

reservoir →	bottom-hole →	wellhead →	riser base →	upstream choke →	separator
formation	tubing	pipeline	riser	choke	
well rate	well rate	well rates/2	well rates/2	well rates/2	

Task 1: Calculate the production profile of the field using the production strategy suggested by Energean in the Field Development plan. Report plateau duration.

Task 2: As described in the field development plan, there are big uncertainties in the support from the aquifer and in the in-place gas volumes. Compute the production profile for two extreme cases (e.g., small Gs, poor aquifer support, and big Gs, aquifer support as initially estimated).

Guidelines and recommendations

- Assume that all wells within a reservoir are identical (in structure and productivity and all other design and operation parameters).
- You can assume that all reservoir units in Karish behave as a single reservoir unit and that a simple gas material balance with pot aquifer is good enough to represent its behavior.
- You can assume that all reservoir units in Tanin behave as a single reservoir unit and that a simple gas material balance with pot aquifer is good enough to represent its behavior.
- Assume dry gas flow equations, dry gas tank model material balance with pot aquifer, and no condensation in the entire production system. Use the pre-programmed VBA functions to calculate flow in tubing, pipeline and riser, for the dry gas material balance, for the Z factor and for the inflow performance relationship.

Inflow dry gas equation (valid for high pressure, greater than 200 bara): $$q_{\bar{g}} = C_R \cdot (p_R - p_{wf})^n$$	Production risers equation: $$q_{\bar{g}} = C_{riser} \cdot \left(\frac{p_1^2}{e^{S_{riser}}} - p_2^2\right)^{0.5}$$

[11] FDP, section 7.5.6.1. “Potential future Inlet facilities” and fig. 7-48 and 7-49.

[12] FDP, Fig. 6-64

Tubing dry gas equation $$q_{\bar{g}} = C_T \cdot \left(\frac{p_1^2}{e^S} - p_2^2\right)^{0.5}$$	User defined function for calculating Z factor[13]: Z=f(p_R, T_R, γ_g)
Horizontal pipelines from subsea template to riser base: $$q_{\bar{g}} = C_{FL} \cdot (p_1^2 - p_2^2)^{0.5}$$	

Analytical equation for material balance of dry gas reservoir and pot aquifer

The material balance equation for dry gas with a pot aquifer is:

$$\frac{p_R}{Z_R} \cdot \left(1 - \bar{c}_e \cdot (p_{R,i} - p_R)\right) = \frac{p_{R,i}}{Z_{R,i}} \cdot \left(1 - \frac{G_p}{G}\right) \qquad \textbf{Eq. 1}$$

With $\bar{c}_e$, the effective compressibility:

$$\bar{c}_e = \left[\frac{\bar{c}_f + \bar{c}_w \cdot S_{wc} + \left(\frac{V_{p,AQ}}{V_{p,prod}}\right) \cdot (\bar{c}_f + \bar{c}_w)}{1 - S_{wc}}\right] \qquad \textbf{Eq. 2}$$

Expanding Eq. 1 gives:

$$\bar{c}_e \cdot {p_R}^2 + p_R \cdot (1 - \bar{c}_e \cdot p_{Ri}) - \frac{p_{R,i}}{Z_{R,i}} \cdot Z_R \cdot \left(1 - \frac{G_p}{G}\right) = 0 \qquad \textbf{Eq. 3}$$

Which is a second-degree polynomial function on p_R, that can be solved with the quadratic formula[14].

- To compute the production profile of the field you should use flow equilibrium calculations in every time step.
- Due to the fact that all wells within a reservoir are identical and symmetrical, it is possible to perform flow equilibrium calculations considering only the flowpath: wellbore-tubing, pipeline from subsea template to FPSO. However, use the appropriate flow rate in each pipe segment.
- The accompanying Excel sheets were used to determine the parameters of the dry gas equations presented above,:
  - Tanin_Riser_constants_estimation.xls
  - Tanin_Pipeline_constants_estimation.xls
  - Karish_TPR_fit_with_data.xls
  - Karish_Riser_constants_estimation.xls
  - Karish_Reservoir_MB_dry_Gas_pot_aquifer_fit_with_data.xls
  - Karish_Pipeline_constants_estimation.xls
  - Karish_IPR_fit_with_data_v2.xls

The pipeline and riser constants of both reservoirs were computed analytically, using data from the field development plan.

The parameters of the IPR, tubing and material balance model were determined trying to match the output of the equation with the values reported in the FDP. For example:

[13] Calculated with the procedure proposed by Hall and Yarborough (1973)

[14] https://en.wikipedia.org/wiki/Quadratic_equation

1. The IPR parameters were obtained by varying the backpressure coefficient (C) and exponent (n) to match the curve given in fig. 6.21 in the FDP[15]
2. The TPR parameters were obtained by varying the tubing flow (C) and elevation coefficients (S) to match the VLP curve given in fig. 6.21 in the FDP (for a wellhead pressure of 240 bara)
3. Most of the parameters of the material balance model were obtained using data in the FDP. The "M" ratio between aquifer and pore volumes was obtained by trying to obtain the pressure decline described in the FDP, section 7.6.2: "Based on a 3 BCM/year offtake rate the reservoir pressure is expected to only decline by end life by 100 bar, from 540 bar down to 450 bar".

[15] To extract curve data from the FDP the following tool was used: https://automeris.io/WebPlotDigitizer/ .