Integration of Reservoir Modelling with Oil Field Planning and Infrastructure Optimization

Nirmal Mundhada[1], Mériam Chèbre[2], Philippe Ricoux[2] , Rémy Marmier[3] & Ignacio E. Grossmann[1]

[1] Center for Advanced Process Decision-making
Department of Chemical Engineering
Carnegie Mellon University

[2] TOTAL S.A. [3] TOTAL E&P

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Motivation for Integration

TOTAL COMMITTED TO BETTER ENERGY

- **Goal:** To optimize the investment and operations decisions for oil and gas field development problem with computational ease and sufficient accuracy.

- Recent simultaneous models assume fixed linear reservoir production profiles or piecewise linear approximations that led to suboptimal solutions.

- **Objective:** Develop models to incorporate detailed reservoir profile for accurate planning.

Operations Problem: Multiperiod NLP for Production Planning

❖ **Given information:**

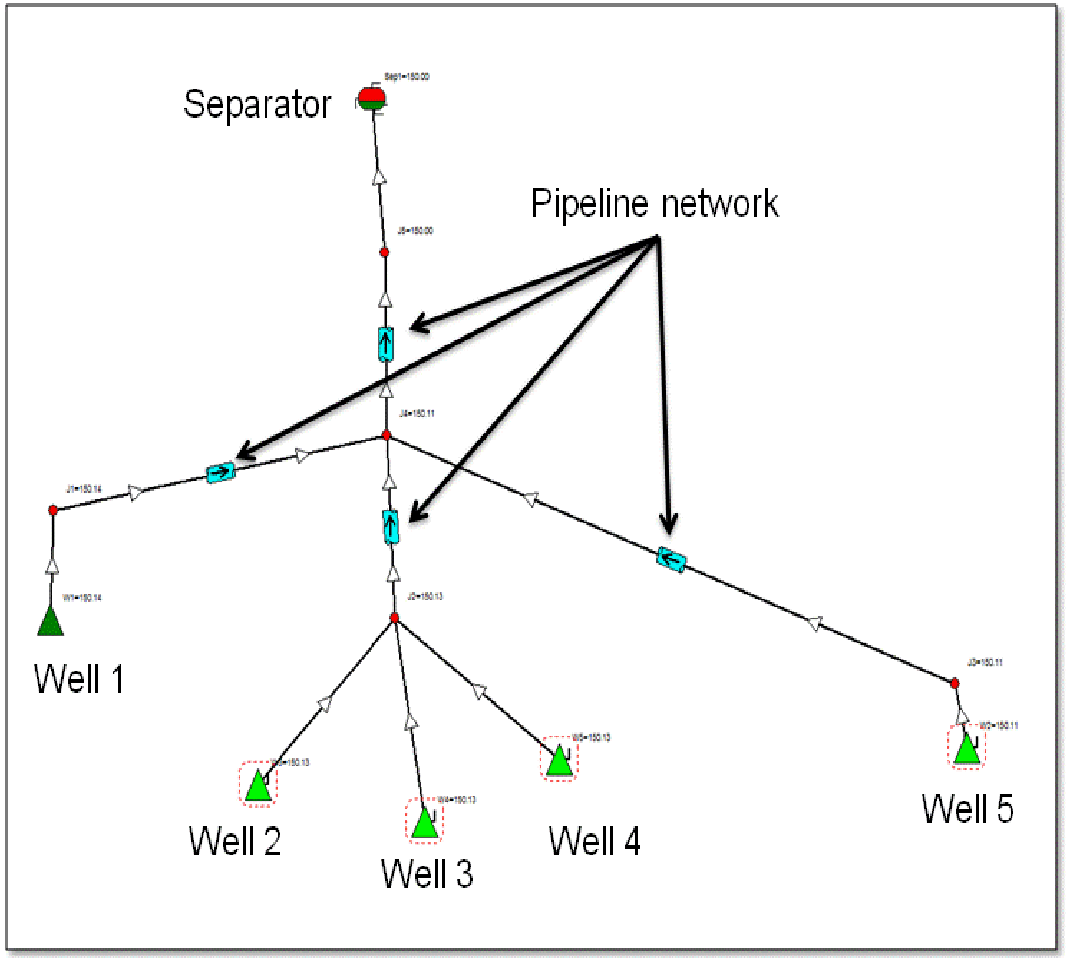
- ✓ Number and location of wells.
- ✓ Productivity indices and Pressure Profiles.
- ✓ Variation of GOR and WOR.
- ✓ Maximum Separator Capacity of 8000 bbl./year.
- ✓ Selling prices and Costs.

❖ **Objective** is to maximize the NPV in the long term horizon.

❖ Initial investment of 150 MUSD is not included in the objective function since it is constant and is paid up-front.

❖ **Assumptions:**

- Natural Depletion of the reserves.
- Pipeline network is already established.
- Planning horizon is discretized into a number of time periods 't' , typically 1 year.
- Water is re-injected into the well after separation and gas is sold.



Multi-period NLP model

- Objective function: Maximize NPV, **NPV = $\sum_{\mathrm{time}}[\mathbf{REV(t)} - \mathbf{COST(t)}] * \boldsymbol{disc(t)}$**
- Total Revenue: **REV(t) = del(t) * (oil price(t) * oil produced(t)) + (gas price(t) + gas produced(t))**
- Total costs:

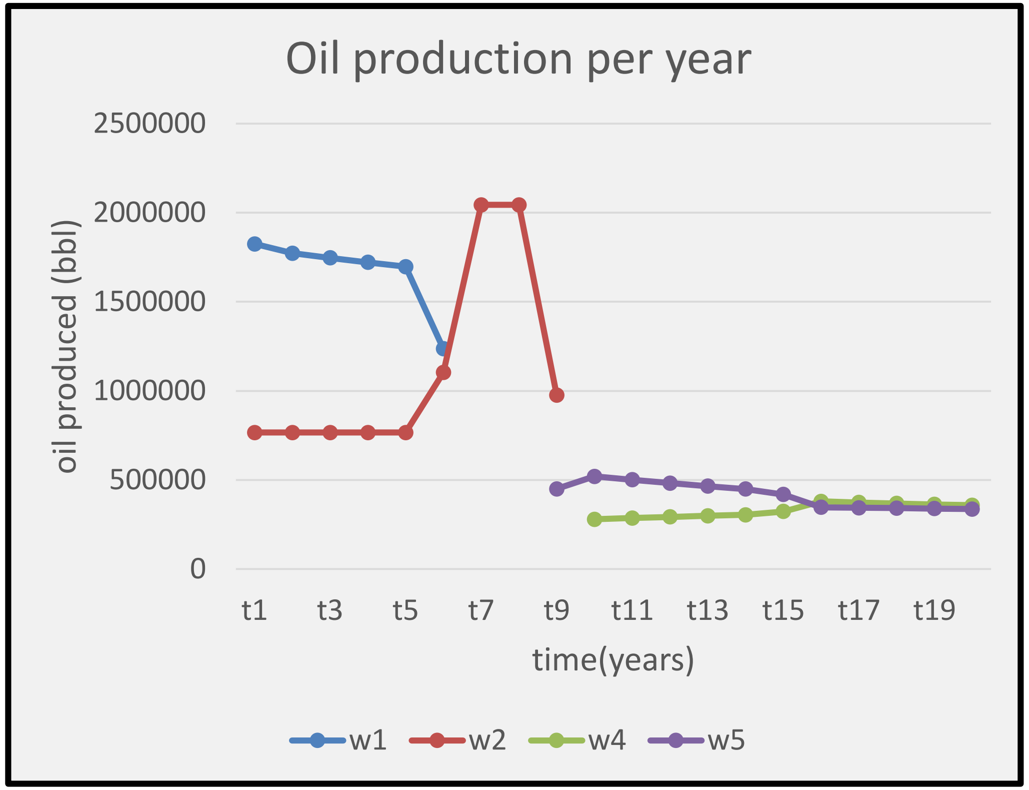
  COST(t) = del(t)*(gas compression cost * gas produced(t)) + (water treatment * water produced(t))
- Total Liquid Produced:

  Liquid produced (well, time) = Productivity index (well) * Pressure variation(well, time)
- Oil produced(well, time) = **Liquid produced * (1 – wct%(well, time))**

  Nonlinearity
- Gas produced(well, time) = **Oil produced(well, time) * GOR(well, time)**
- Total liquid produced(time) = $\sum_{\mathrm{well}} \mathbf{Liquid\ prodcued(well, time)}$
- Upper bound for liquid produced: **Total liquid produced(t) ≤ Maximum separation capacity(t)**
- Upper bound for Oil production: $\sum_{\mathrm{well}} \mathbf{Oil\ recovered(well, time)}$ **≤ Cumulative Oil produced (well)**

Results & Statistics of the Multi-period NLP model

❖ NPV = 1119 MUSD



❖ **Model Statistics (BARON 14.4):**

✓ **Number of wells:** 5

✓ **Number of time periods:** 20 time periods of 1 year each.

✓ **Number of Variables:** 1303

✓ **Number of single equations:** 1408

✓ **Solver CPU time:** 67.54 seconds (1% relative optimality gap)

Design problem: Optimal placement of wells

❖ *Allowing:*

- Reservoir may have arbitrary and irregular shapes.
- Existing manifolds and centers can make/receive new connections.
- Processing centers can receive fluids from wells directly or through manifolds.

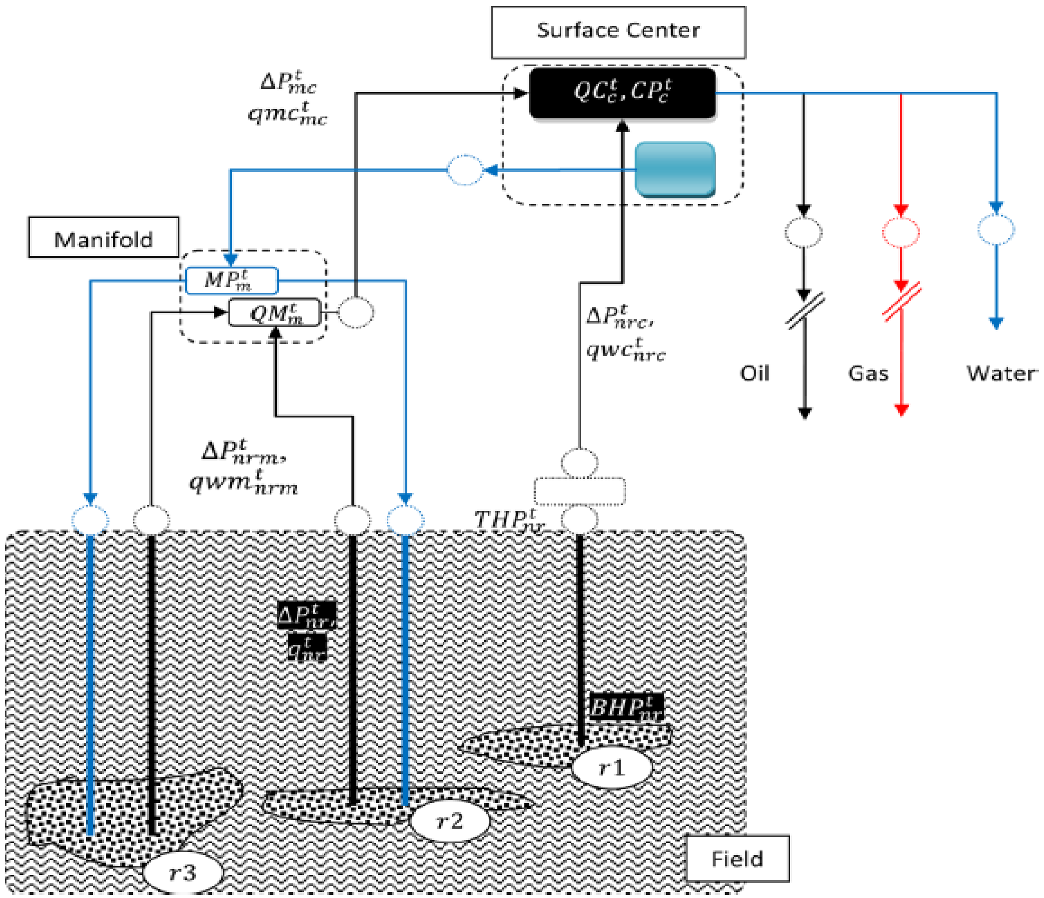
❖ *Following:*

- Each well must be beyond some minimum distance from all other wells.
- A well that hits its water-cut limit is shut in.

❖ *Assumptions:*

- Reservoirs are horizontal and planar. Field surface elevation may vary from point to point.
- Wells are vertical, can pass through multiple reservoirs, but can be perforated to access only one reservoir.
- A wellhead may be connected to one or more manifolds/ centers.
- Each well(existing or potential) is preallocated to some manifolds/centers (existing or potential) based on distance, from which best allocations will be selected.
- Each reservoir may have different pressure and saturation distribution.

Schematic of the Model



Schematic of a hydrocarbon field, with three different reservoirs in the same field. *Blue lines* are injector wells and *black lines* are producer wells.

Well placement model

❖ *Given:*

- Geological information such as dimensions, porosity, permeability.
- PVT information such as formation volume factor and fluid properties.
- Existing wells and their types.
- Minimum allowable well to well distance.
- Operational data such as water cut limits, max injection pressure, capacity expansion plans for surface facilities.
- Production horizons for ‘H’ years.
- Demand curve, drilling budget and costs.

❖ *Obtain:*

- **Number and location of new producer wells and their production profiles.**
- Number and location of manifolds and processing centers and incremental capacity expansion plan for surface processing centers.
- Potential well-to-manifold, well-to-surface, and manifold-to-surface-center allocations.
- Dynamic pressure profiles along the network at processing centers, manifolds, wellheads, well bore holes.
- Dynamic pressure and saturation profiles for each reservoir.

Model:

❖ Maximize NPV

considering

- Reservoir Dynamics and spatial discretization
- Drilling and infrastructure Design Decisions
- Well and surface Network flow management

❖ Solution Strategy: Using the Modified Outer Approximation Algorithm

The Mass Balances Equation

Dynamic multiphase flow in a reservoir

$$\frac{\partial}{\partial t}\left[\varepsilon \frac{S_f}{B_f}\right] + q_f - \nabla\left[\frac{kr_f}{\mu_f B_f}\mathbf{K}\left(\nabla P_f - \rho_f \frac{g}{g_c}\nabla z\right)\right] = 0$$

Backward finite difference approximation

$$\begin{aligned}&\left(\frac{V_n}{dh^t}\right)\{d^t_{o,1,n}[P^t_n - P^{t-1}_n] + d^t_{o,2,n}[S^t_n - S^{t-1}_n]\} + q^t_{0,n\notin \mathbf{IW}}\\&+(\{M^t_{o,x-}\cdot T^x_{n-1}\cdot[P^t_n - P^t_{n-1}]\}_{(n-1)\in\mathbf{IX}} + \{M^t_{o,x+}\cdot T^x_n\cdot[P^t_n - P^t_{n+1}]\}_{n\in\mathbf{IX}}\\&+\{M^t_{o,y-}\cdot T^y_{n-l}\cdot[P^t_n - P^t_{n-l}]_{(n-l)\in\mathbf{IY}} + \{M^t_{o,y+}\cdot T^y_n\cdot[P^t_n - P^t_{n+l}]\}_{n\in\mathbf{IY}})\\&= 0\end{aligned}$$

2-D discretization of reservoir

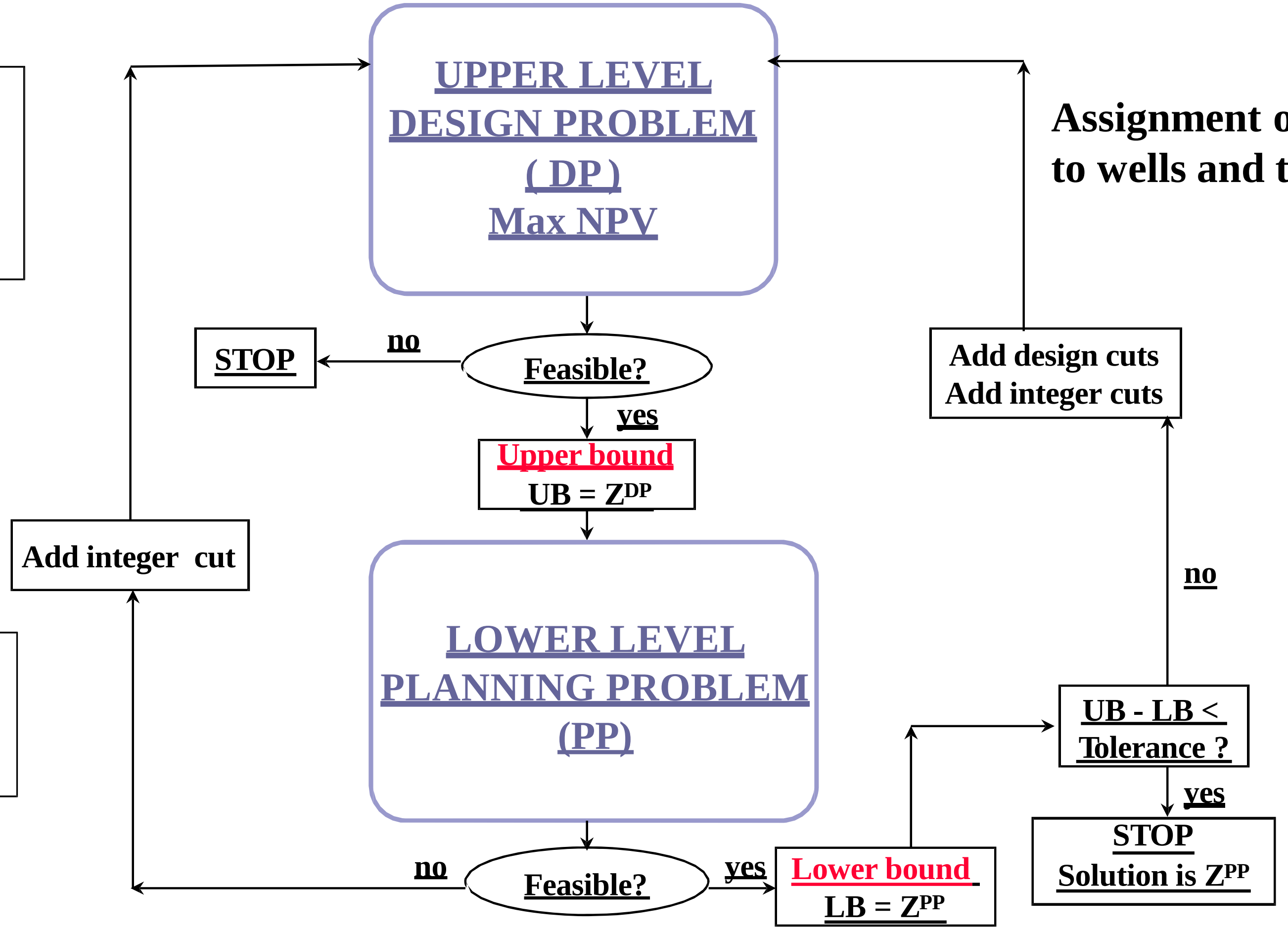
N1	**N2**	**N3**	**N4**
N5	N6	N7	N8
N9	N10	N11	N12
N13	N14	N15	N16

- Binary variable : y(n) → 1 if a well should exist in cell 'n'
- Empirical equations for estimating BHP.
- Allow upstream mobility values for convective flows to be chosen dynamically based on pressure time map at time (t-1).

STRATEGY : Bi-Level Decomposition

DP : Vijay Gupta and Grossmann (2012)

PP : Tavallali, Karimi et al. (2012)



Assignment of platforms to wells and their installation

Selection of wells and production planning

GRID BASED

Incorporating field data

- Two-level Optimization approach

- Upper level minimization of error (with data)

  min $\phi(u,v,\Theta)$

  s.t. max NPV(u,v,Θ) Lower level maximization NPV

  s.t. $g(u,v,\Theta) \leq 0$

  Fitting error $\phi(\Theta) = \frac{1}{2}(u-u^{\alpha})^2$

  select Θ to minimize the error function.

- Lower level optimization of model (as shown in previous slide)

This approach ensures that we are not compromising on the number of degrees of freedom.

Conclusion and Future work

- **Model development for Production planning:**
  - Add Gas lift operations to the model.

- **Well placement model:**
  - Implementation of an improved optimization approach in the well placement model.
  - Validation of the results from historical production data and ECLIPSE simulation.
  - Integration of PETEX suite for well simulations.