Carbon Storage and Management

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Sustainable Development of CO_2 Transport and Injection System for 1st Large-Scale CCS Project in Korea

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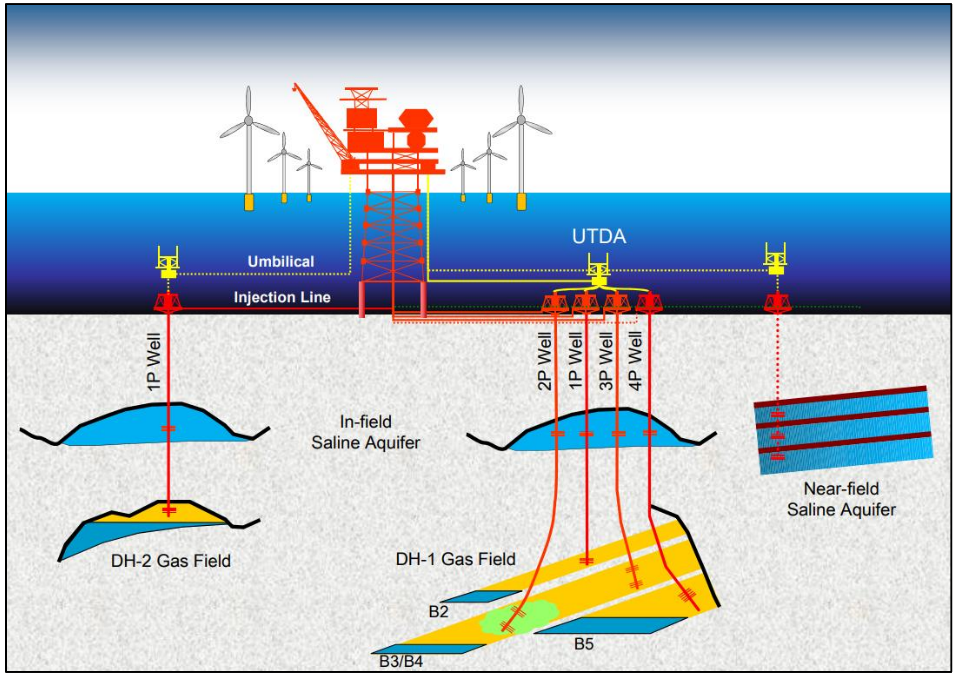
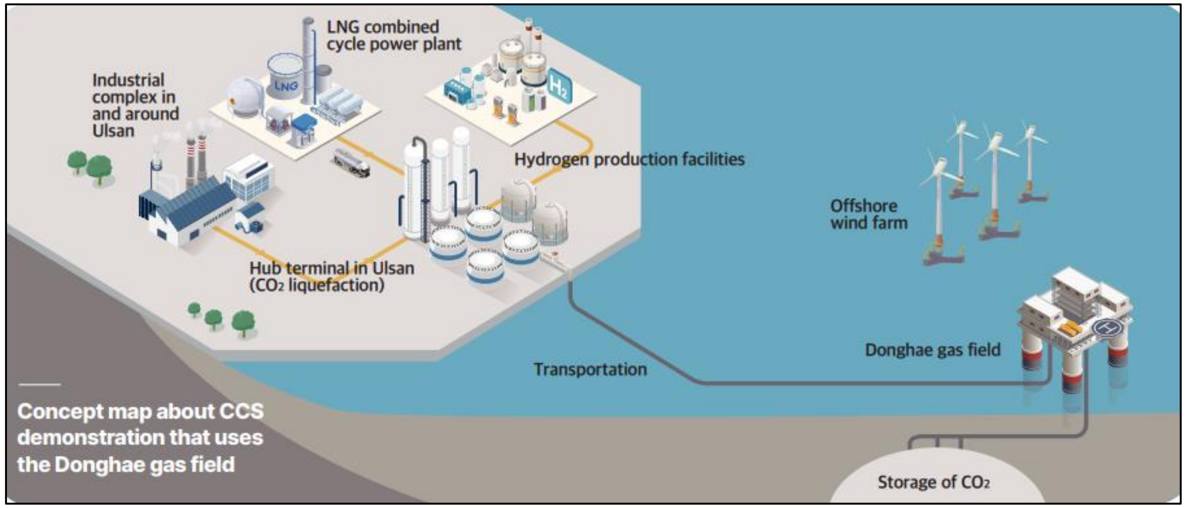
DONGHAE GAS FIELD OVERVIEW

- Discovered in 1998 and produced 46 MMboe of gas/condensate from 2004 to 2021
- Located 58 km south-east of Ulsan, 152 m MSL/ 2,300 to 2,600 m TVDSS
- Now, ready for **New Low Carbon Energy Projects**



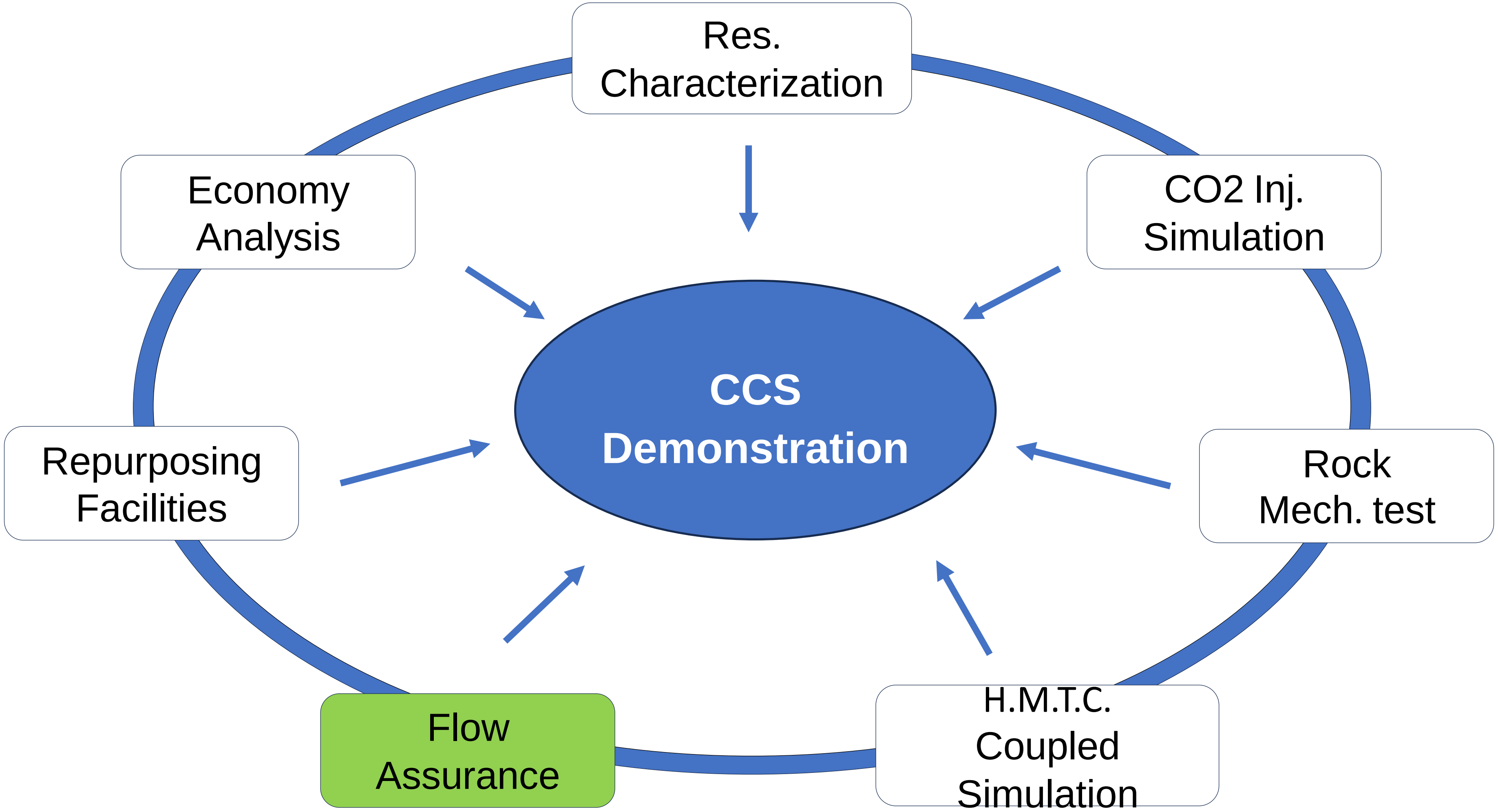
DONGHAE CCS PROJECT OVERVIEW

CAPTURE	TRANSPORTATION	STORAGE	MONITORING
▪ Capture from regional **H_2 manufacturer and power plants** ▪ Accepting the multiple sources when expanding Donghae gas field	▪ Gathering captured CO_2 at Hub Terminal ▪ Offshore transport by **pipeline** ▪ Considering future expansion for ship transportation	▪ CO_2 Injection and storage in **depleted Donghae gas field** ▪ Additional CO_2 injection into **saline aquifers** in future	▪ Confirming storage conditions on sealing and environmental impact by **4-D seismic**



Concept map about CCS demonstration that uses the Donghae gas field

STUDIES FOR CCS DEMONSTRATION



CCS FLOW ASSURANCE STUDY

- Flow Assurance challenges
  - Multiphase flow in flowline/ Hydrate, salt / Slugging, corrosion and erosion
- Boundary condition
  - Transport 1.2Mtpa of dense CO_2 via 60km subsea pipeline and 2km flowline/ Inject into 3 res.

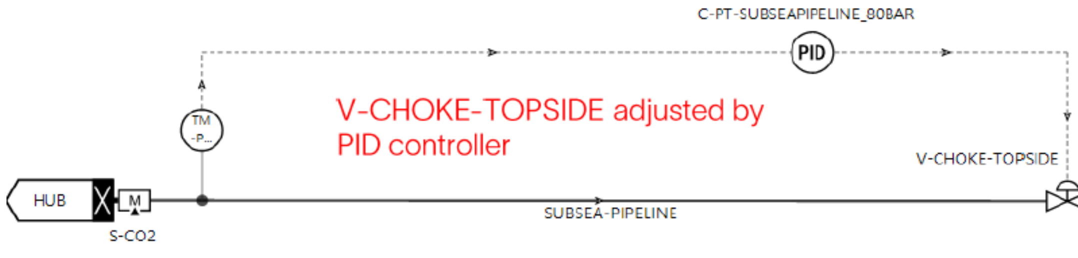
Well	Pr, Bara	Qinj, Mtpa
1P	54	0.1
2P	33	0.8
4P	92	0.3

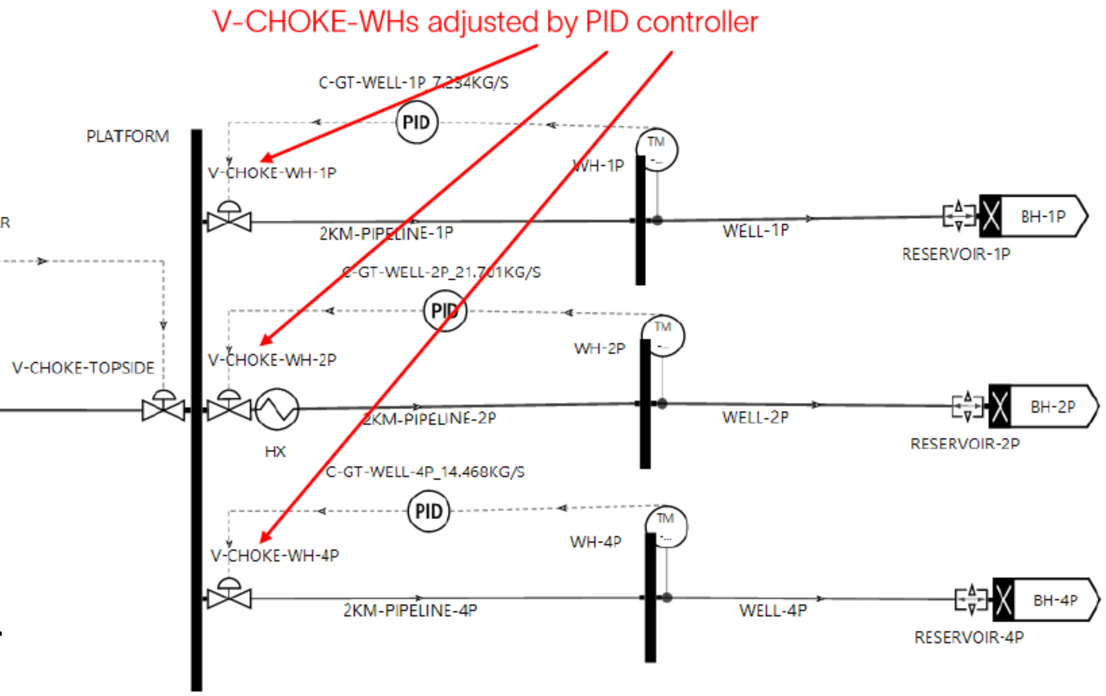
Pipeline Op. P	P, Bara
Min	80
Max	150

Fluid	%
CO_2	99.26
H_2	0.60
CH_4	0.12
CO	0.01
H_2O	0.01

- Tested cases to predict hydrate precipitation
  - Flow rate control
  - Heating / flowline insulation
  - Reservoir pressure

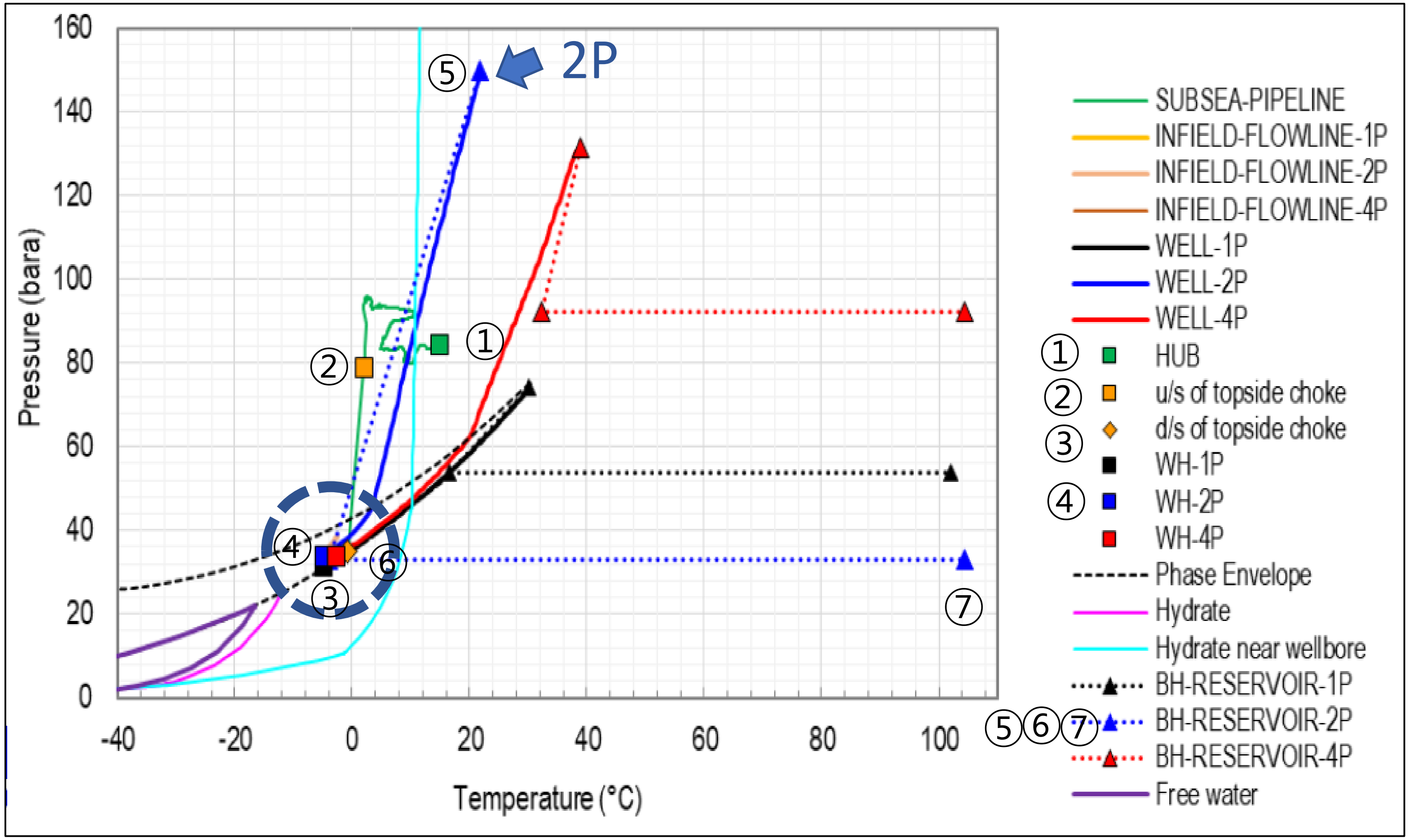
DONGHAE OLGA MODEL DIAGRAM





- Case 1: P_r at start of injection
- Case 2: P_r at start of injection & Heater
- Case 3: P_r 1 year after injection

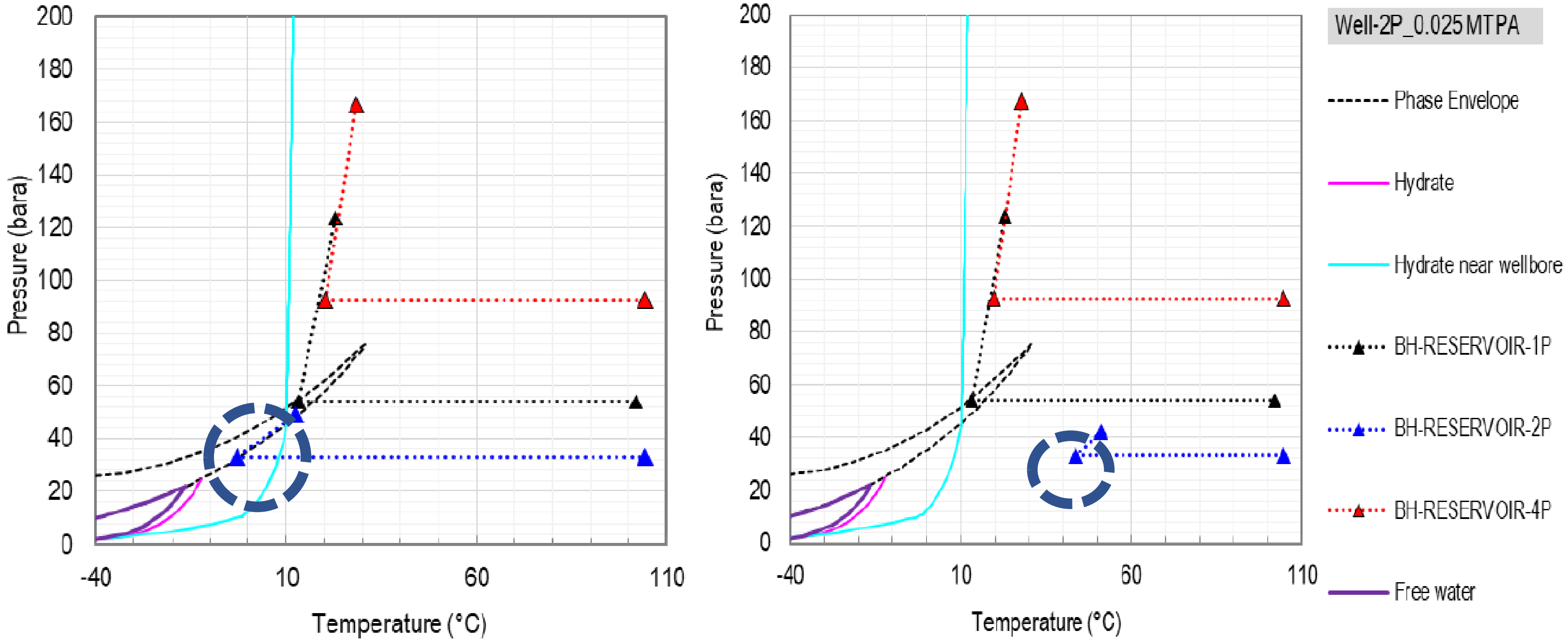
Case 1: P_r - START OF INJECTION



Well	Pr, Bara	Qinj, Mtpa
1P	54	0.1
2P	33	0.8
4P	92	0.3

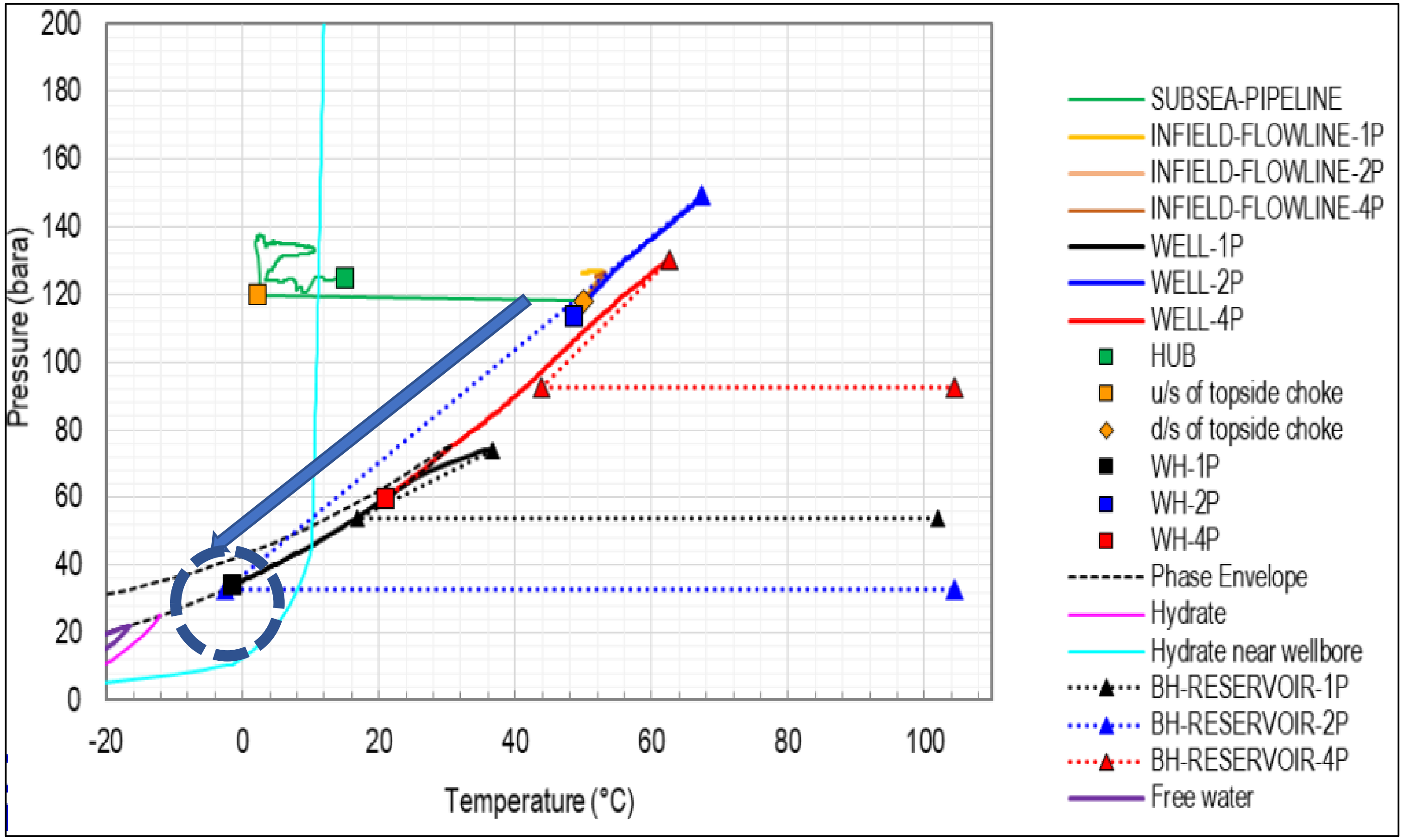
- No hydrate risk in subsea pipeline in normal op. cond.
- Hydrate risk at 2P
  - dP ~ 120bar
  - Required mitigation method

Case 1: P_r - START OF INJECTION– LOWER INJ. RATE



- Reduced Q_{inj} in 2P to check hydrate formation
  - Required Q_{inj} reduction from 0.8 to 0.025 Mtpa to prevent hydrate formation
  - Too low Q_{inj} to acheive the injection plan

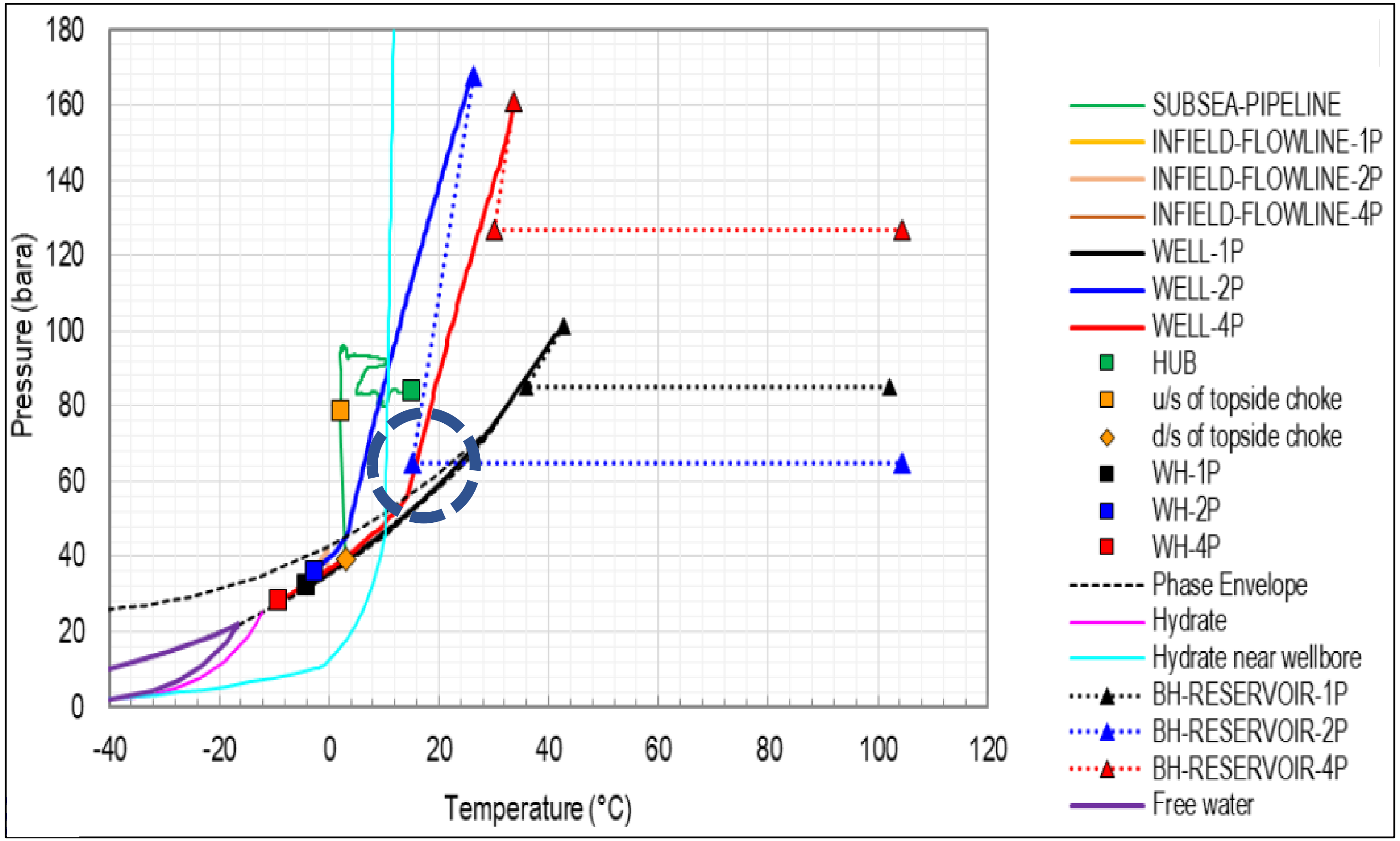
CASE 2 : HEATING & INSULATION



Well	Pr, Bara	Qinj, Mtpa
1P	54	0.1
2P	33	0.8
4P	92	0.3

- Heating CO_2 to 50°C
- Flowline insulation
- Substantial heat loss in flowline due to choke closing
- Hydrate risk at 2P
- Heating is not effective

CASE 3: P_r - 1 YEAR AFTER INJECTION



Well	Pr, Bara	Qinj, Mtpa
1P	54 → 85	0.1
2P	33 → 65	0.8
4P	92 → 127	0.3

- At higher P_r , no hydrate risk exists
- No other hydrate mitigation method is necessary

CONCLUSIONS

- Hydrate risk
  - No risk in subsea pipeline in normal operation at given water concentration
  - Risk in near wellbore
- Hydrate mitigation method
  - Heating: not effective
    - High heat loss due to choking flow valves to meet target rates
    - High platform topside weight
    - Extra CO_2 emission
  - Low rate injection: not effective to achieve injection plan
  - Higher reservoir pressure
  - ➢ methanol injection in early stage of injection is recommended
- Unstable injection
  - ➢ Injection rate adjustment is recommended

RECOMMENDED STUDIES

- Flow Assurance study
  - In depth study for transient conditions (start-up, re-start, turndown)
  - Define optimum injection scenarios

    - Pipe/flowline/tubing sizing, op. procedure, material selections, Q_{inj}
- Integrated flow and reservoir modeling
  - How does cold CO_2 react with hot formation fluid?
  - How does CO_2 interact with formation rock?
  - How does CO_2 effect cap rock integrity?
  - How does CO_2 effect wellbore integrity?