International Network for CO_2 Capture: Report on 9th Workshop

(16th June 2006, Copenhagen, Denmark)

Report Number: 2006/11

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ACKNOWLEDGEMENTS AND CITATIONS

The IEA Greenhouse Gas R&D Programme supports and operates a number of international research networks. This report presents the results of a workshop held by one of these international research networks. The report was prepared by the IEA Greenhouse Gas R&D Programme as a record of the events of that workshop.

The international research network on post combustion capture is organised by IEA Greenhouse Gas R&D Programme. For the 9th meeting we wish to acknowledge the support and hospitality provided by Energie E2 who acted as hosts for the meeting in Copenhagen.

The series of workshops is co-ordinated for the IEA Greenhouse Gas R&D Programme by Dr J M Topper, who is the managing director of the Operating Agent for the Programme Johnmtopper@aol.com or john.topper@iea-coal.org.uk. An alternative contact is John Gale, IEA Greenhouse Gas R&D Programme johng@ieaghg.org.

The report should be cited in literature as follows:

"IEA Greenhouse Gas R&D Programme (IEA GHG), International Network for CO_2 Capture: Report on 9th Workshop, 2006/11, June 2006".

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INTERNATIONAL NETWORK FOR CO_2 CAPTURE: REPORT ON 9^{th} WORKSHOP

(16th June 2006, Copenhagen, Denmark)

1. Overview of the network and past workshops

This workshop was the ninth in a series to discuss co-operation in development of MEA and related solvents to capture CO_2 from power plant flue gases. The previous events were, in Gaithersburg, Calgary, Apeldoorn, Kyoto, Pittsburgh, Trondheim, Vancouver and Austin. Copies of previous reports after the Apeldoorn meeting are available on CD (contact louise@ieaghg.org).

Carbon dioxide capture and storage is now established in OECD countries' energy policies and R&D programmes as a potential contributor to climate mitigation strategies. Post combustion capture allied to improved efficiency power plant looks likely to be a major element for new plant as markets develop – particularly so in developing countries where there is a clear preference for using the best established technologies for power generation. Retrofit to established plant is also technically feasible although less economically attractive for ageing, less efficient assets. Since the previous workshop a number of generators in Europe and Canada have expressed interest in the possibilities of demonstrating the technology at full scale and a major pilot plant operation under the EU CASTOR programme has commenced at a power station near Esbjerg in Denmark. About a quarter of the workshop participants used the opportunity to visit this new facility on the day previous to the workshop – thanks from all participants to Elsam for hosting this visit.

Over the six years in which this workshop series has existed, we are seeing more and more researchers coming into the field and some exciting new developments covering new solvent formulations, process engineering innovation and increasingly sophisticated process economic modelling. This report contains presentations on a variety of fundamental developments including for the first time a presentation on the opportunities of using spray absorption of CO_2. There is also our first report on possible environmental impacts, although it must be borne in mind that this arises from experience at Statoil's Sleipner capture operations in the North Sea.

Some background on the most recent workshops in this series:-

Trondheim

Norwegian University of Science and Technology (NTNU), Department of Chemical Engineering were the hosts. The thirty-eight registrants who attended included several post-grads and post-docs from NTNU itself. Drawn from eleven countries, the majority were understandably from Europe and for the first time the Network was glad to be able to welcome a delegate from Singapore.

The content showed a notable shift from previous workshops with more on fundamental laboratory investigations and a little less on process modelling.

Vancouver

This workshop was associated with the GHGT-7 conference and was for one day only. The opportunity was taken to allow students to present their work, in particular those who were unable to get a paper accepted for the conference platform. Thus, the majority of presentations dealt with studies of a fundamental nature. Numerically it was the best yet with around 60 attendees on the day. About half were graduate students or post doctoral workers. Ten countries were represented – Australia, Brazil (for the first time), Canada, Denmark, France, Japan, the Netherlands, Norway, UK and USA.

Austin

This workshop was notable for the visit to a substantial pilot plant used to investigate CO_2 capture by solvents – centred on an absorber-stripper combination. There were 16 technical presentations ranging about half of which were devoted to laboratory research and modelling including three from the "home" team. There were several on process economics – including material looking at "top-down" predicting of future capture costs and an attempt to model some of the effects of uncertainties in power plant systems operation on CO_2 capture economics.

2. Copenhagen Workshop

The agenda and delegate list are appended as Annexes I and II, respectively.

3. Presentations by Attendees

Presentations were made as listed below. Copies of slides appear in the same order in Annex III.

1	John Topper - for the IEA GHG R&D Programme	Introduction to 9th Workshop
2	Ole Biede - E2 and Jacob Knudsen - Elsam, Denmark	Carbon Dioxide Capture and Storage activities in Denmark
3	J P Brouwer, P H M Feron, N A M ten Asbroek - Department of Separation Technology, TNO-Science and Industry, The Netherlands	CO_2 absorption using precipitating amino acids in a spray tower
4	Kazuya Goto - RITE, Japan	Novel Absorbents for CO_2 Capture from Gas Stream
5	Marcus Hilliard, John McLees and Gary T Rochelle - University of Texas, USA	Volatility of MEA and Piperazine
6	Babatunde A Oyenekan and Gary T Rochelle - University of Texas, USA	Rate modeling of Stripper Performance
7	Amy Veawab and Andy Aroonwilas - University of Regina, Canada	Energy Requirement for Solvent Regeneration in CO_2 Capture Plants
8	Jon Gibbins - Imperial College, UK	Making New Power Plants 'Capture Ready'
9	Louis Wibberley - CSIRO, Australia	Australian National Post Combustion Capture and Storage Demonstration Project

10	Barry Hooper - CO2 CRC, Australia	Dwarfing Sleipner! Large Scale CCS projects and other CO2CRC activities
11	Gelein de Koeijer - Statoil, Norway	Increased Interest in Environmental Impacts of Amines
12	Nick ten Asbroek - TNO, The Netherlands	Overview of activities in CASTOR, ENCAP, CATO and Dynamis at TNO
13	Dick Rhudy - EPRI, USA	CO_2 Testing Program: An Industry/EPRI Initiative to Develop CO_2 Capture and Storage Test Capabilities
14	Dennis Leppin - Gas Technology Institute, USA	GTI's Acid Gas Treating Pilot Plant (AGTPP) Relocation and Integration with FlexFuel Facility
15	Tsuyoshi Oishi,- MHI, Japan	Mitsubishi CO_2 Recovery Technology from Flue Gas: Experience and R&D Facilities

4. Next Meeting(s)

The 10th Network meeting will be as guests of IFP, Institute Français du Pétrole, in Lyon in May or June of 2007. In 2008 GHGT9 conference will be in Washington DC, provisionally in early November. It is expected that the 11th Network meeting will be either before or after this conference.

5. Thanks and Acknowledgements

All participants wish to thank Ole Biede of E2 for all the hard work of co-ordinating the event and the pilot plant visit on the previous day. The Danish power industry will have been reorganised by the time this report is made generally available and Ole will be in Dong. We wish him well under new ownership. The E2 offices were an excellent venue for the meeting and we all enjoyed further E2 hospitality at the dinner in the Tivoli area on the evening of 16th June.

6. Contacting the Co-ordinator

The IEA Greenhouse Gas R&D Programme co-ordinates the development of this network and arranges the workshops.

Queries about or copies of this report can be obtained by contacting:-

John Topper john.topper@aol.com
or via the "feedback" facility in the IEA GHG website's home page http://www.ieagreen.org.uk

ANNEX I

Workshop Agenda

9th International Network for CO_2 Capture
Copenhagen Workshop

Friday, 16th June 2006

0900 Welcome, Round the Table Introductions, Today's Agenda
– John Topper for IEA Greenhouse Gas R&D Programme

0915 Hosts Address – "Carbon Dioxide Capture and Storage activities in Denmark" including description of pilot plant and it's programme of work

Morning Chair – Gary Rochelle

0950 Jan-Peter Brower – TNO, Netherlands: "CO_2 absorption using precipitating amino acids in a spray tower"

1015 Coffee Break

1045 Kazuya Goto – RITE: "Novel absorbents for CO_2 capture from gas streams"

1110 Marcus Hilliard – University of Texas, USA: "Volatility of monoethanolamine and piperazine"

1135 Babatunde Oyenekan, – University of Texas, USA: "Rate modelling of stripper performance"

1200 Amornvadee Veab and Adisorn Aroonwilas – University of Regina, Canada: "Energy requirements for solvent regeneration in CO_2 capture plants"

1225 Lunch and Group photo

Early Afternoon Chair – Jon Gibbins

1345 Jon Gibbins – Imperial College, UK: " Capture ready design and facilities"

1410 Louis Wibberley – CSIRO, Australia: "Proposal for LETF funding from Australian Government on Post Combustion Capture"

1435 Barry Hooper – CO2CRC, Australia: "Dwarfing Sleipner! Large scale CCS and other CO2CRC projects"

1500 Coffee Break

Late Afternoon Chair – John Topper

1530 Gelein de Koeijer – Statoil, Norway: "Increased interest in Degradation of

	Amines”
1555	Nick ten Asbroek – TNO, Netherlands: “An overview of activities in CASTOR, CATO, ENCAP and DYNAMIS”
1620	Richard Rhudy – EPRI, USA “Plans for post combustion pilot plant at EPRI
1635	Denis Leppin – GTI, USA: “The GTI Flex Fuel test Stand”
1650	Tsuyoshi Oishi – MHI, Japan: “KS 1 solvent – Commercial Experiences”
1705	Wrap up, conclusions, next meeting – John Topper

ANNEX II

9th International Network for CO_2 Capture

16th June 2006, Copenhagen, Denmark

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ANNEX III

PRESENTATIONS

The powerpoint presentations follow in the same order as listed in section 3 of this report and can be accessed from the bookmark list

International Network for CO_2 Capture

Introduction to 9th Workshop, Copenhagen

By

J M Topper

Managing Director IEA Environmental Projects Ltd

IEA Greenhouse Gas R&D Programme

- A collaborative research programme which started in 1991.
- Its main role is to evaluate technologies that can reduce greenhouse gas emissions.
- Aim is to:

Provide our members with informed information on the role that technology can play in reducing greenhouse gas emissions

Current Membership

OPEC Organization of the Petroleum Exporting Countries

ALSTOM B&W BG GROUP bp Chevron EniTecnologie e·on EPRI

ExxonMobil REPSOL YPF RWE Schlumberger STATOIL TOTAL VATTENFALL

International Network for CO_2 Capture

- ***AIM*: *To establish a forum that will encourage practical work on CO_2 capture. Emphasis on use of MEA and derivative solvents***

- ***WHY CO-OPERATE?:***
    - ***avoid duplication of effort***
    - ***encourage development***
    - ***minimise cost of participation***
    - ***enhance technology credibility***
    - ***share risks***

International Network for CO_2 Capture

Four Tasks Established **(Gaithersburg 2000)**

- A – Process Simulation
- B – Economic Assessment
- C – Process Innovation at Test Facilities
- D – Feasibility Study

IEA GHG to facilitate

International Network for CO_2 Capture

- 1st Workshop in Gaithersburg, USA (Spring 2000)
- 2nd Workshop, Calgary, Canada(November 2001)
- 3rd Workshop in Apeldoorn; Netherlands (Spring 2002)
- 4th Workshop in Kyoto, Japan (Autumn 2002)
- 5th Workshop in Pittsburgh, USA (June 2003)
- 6th Workshop in Trondheim, Norway, (Spring 2004)
- 7th Workshop in Vancouver, Canada, (Sept 2004)
- 8th Workshop in Austin, USA (Autumn 2005)
- 9th Workshop at offices of E2, Copenhagen

International Network for CO_2 Capture

- We are now a well established club; 2/3 of the non-Danish registrants have been to two or more workshops
- Of those almost 1/2 from N America; 1/3 from Europe + 2 from Japan, 6 or 7 from Australia.
- 10 different countries here today
- Excellent networking

International Network for CO_2 Capture

Today: Housekeeping Points

- Coffee breaks around 10.15 and 15 00
- Lunch, 12.30 – 13 30 followed by photos
- Afternoon session will finish at around 17 30 and by bus back to hotel(s)
- Dinner this evening in the Tivoli area – E2 to provide details. Need to check numbers & partners
- ALL PRESENTERS ensure I get a copy of their presentation on data storage stick if you want it on the GHG website next week
- Mobile phones off or on vibrating alert

And one issue that IEA GHG would like raised now and in future workshops

ENVIRONMENTAL IMPACTS OF AMINE SOLVENTS USAGE AND THE BY PRODUCTS OF CAPTURE

Thanks to E2 and Elsam

- To E2 for local organisation
- And for Sponsoring the Dinner this evening
- To Elsam for the pilot plant and power station visit yesterday

9th International CO_2 Capture Network
ENERGI E2, Copenhagen, June 16, 2006

Carbon Dioxide Capture and Storage activities in Denmark

Ole Biede, ENERGI E2 A/S

Jacob Knudsen, Elsam Engineering

Elsam Engineering

ENERGI E2

- **Practical details**
- **ENERGI E2 and Reorganization of the Danish Power Companies**
- **CO_2 Capture and Storage activities in Denmark**
- **CASTOR Project (Capture and Storage of CO_2)**
- **Pilot Plant**
- **Results from the Pilot Plant**

9th Int. CO_2 Capture Network, Copenhagen 2006
Practical details - overview

- **Coffee breaks – 10.15 and 15.00**
- **Lunch buffet – 12.30**
- **Restrooms**
- **Dinner in Tivoli, Restaurant Påfuglen 19.30**
  - **Number of participants**
    - **Accompany: Keith Harrison, Bob Stobbs, John Topper**
  - **Dietary requirements**
    - **No beef: Andy Aroonwilas, Amy Weawab**
  - **Tickets**
  - **Map**
  - **Tivoli closes at 00.30**

9th Int. CO_2 Capture Network, Copenhagen 2006
Practical details - maps

Tivoli

Kong Frederik

Absalon

Elsam Engineering

ENERGI E2

9th Int. CO_2 Capture Network, Copenhagen 2006
Practical details - Tivoli

Dinner at Påfuglen **19.30**

Entrance

9th International CO_2 Capture Network
E2, Copenhagen, June 16, 2006

ENERGI E2 and Reorganization of the Danish Power Companies

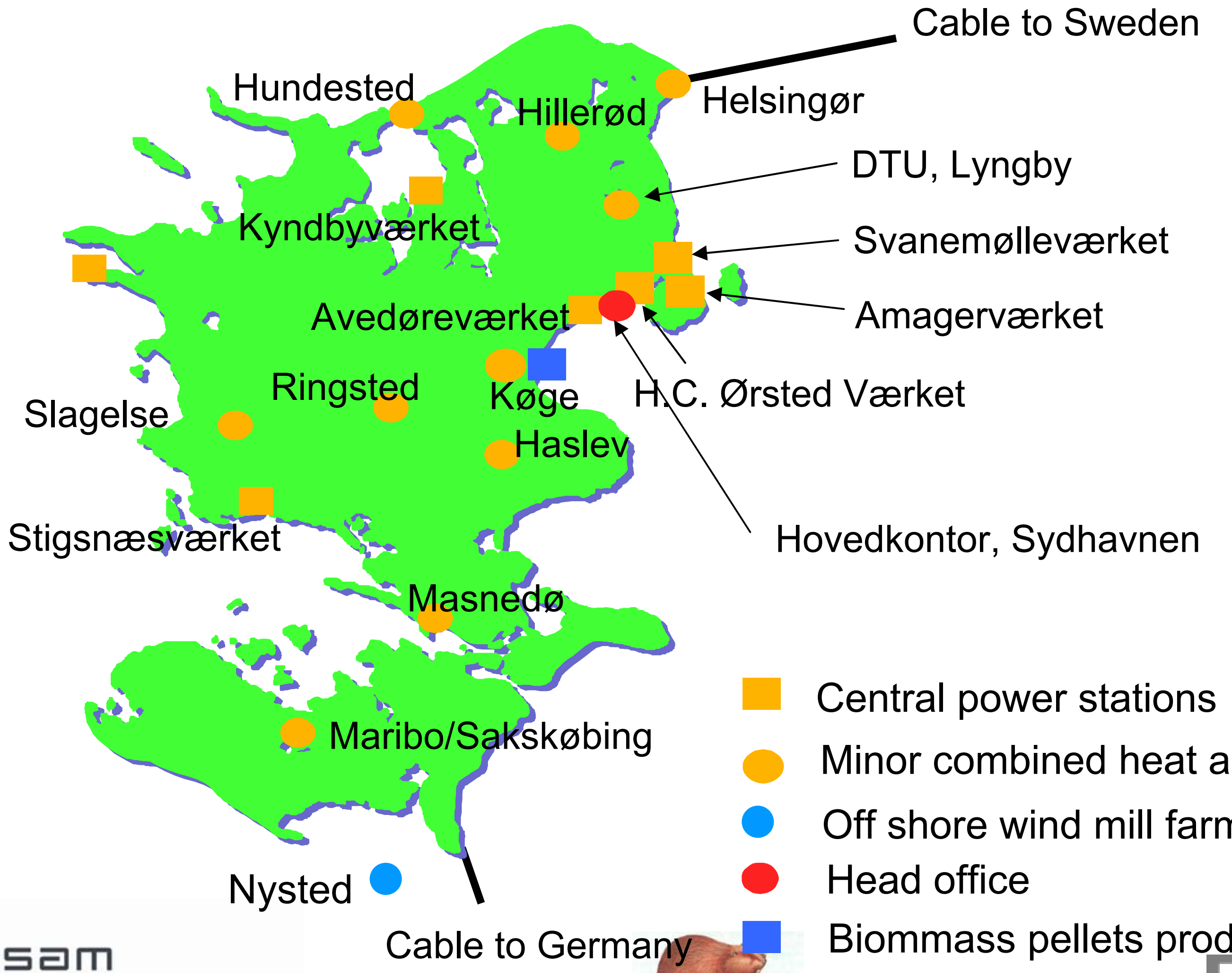
Elsam Engineering

ENERGI E2

9th Int. CO_2 Capture Network, Copenhagen 2006
ENERGI E2

- ENERGI E2 is a leading Danish energy production and trading company
- E2 owns and operates 17 power and combined heat and power plants in Eastern Denmark and has several activities internationally
- E2's head office is located in Copenhagen with approximately 400 employees
- In total E2 has 1450 employees
- Total production capacity:
  4.800 MW electricity, 2.850 MJ/s heat and 1.800 MJ/s steam.

9th Int. CO_2 Capture Network, Copenhagen 2006
ENERGI E2 – power plants



🟧 Central power stations

🟠 Minor combined heat and power plants

🔵 Off shore wind mill farm

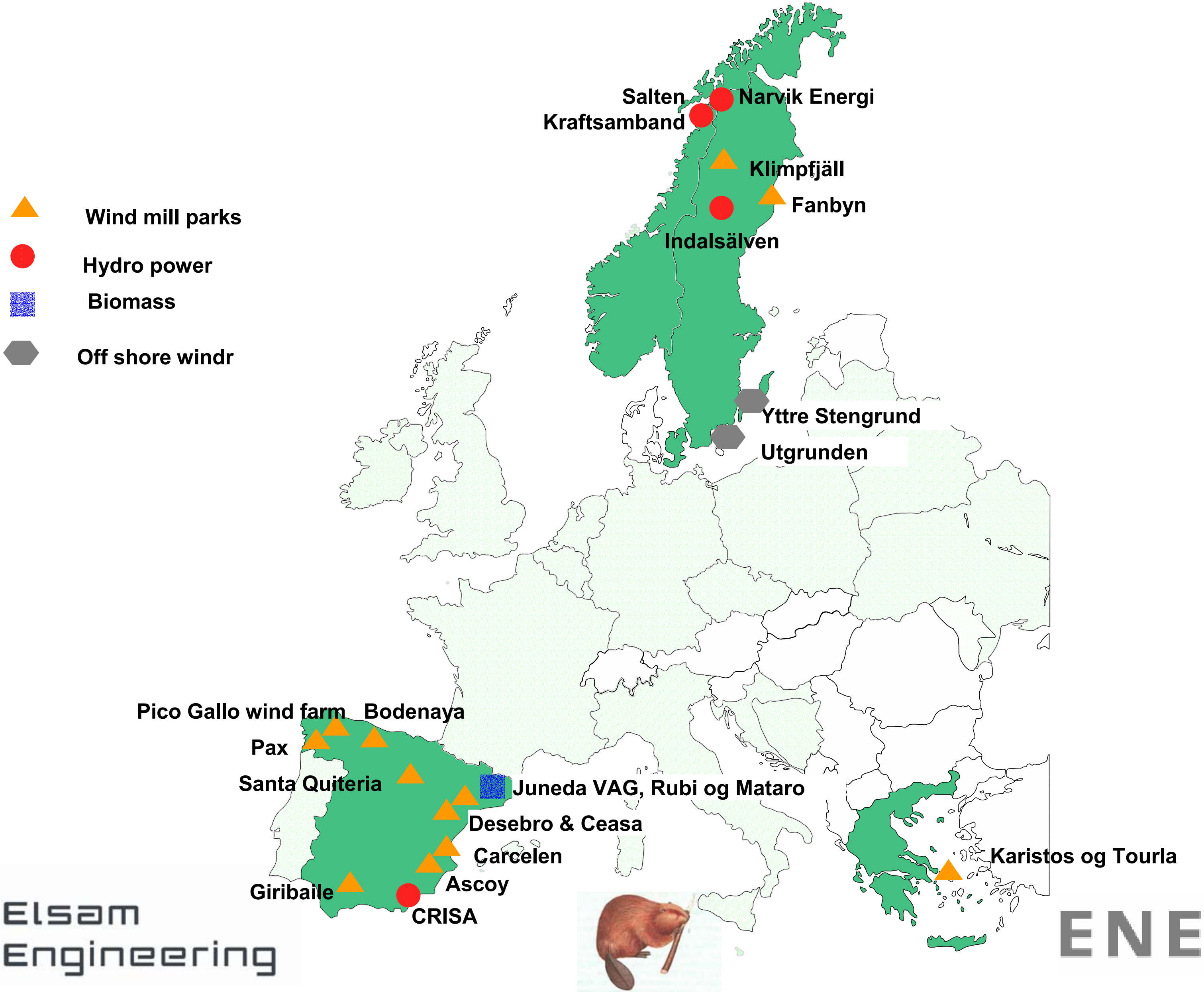
🔴 Head office

🟦 Biommass pellets production

Elsam Engineering

ENERGI E2

9th Int. CO_2 Capture Network, Copenhagen 2006
ENERGI E2 - international



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ENERGI E2

9th Int. CO_2 Capture Network, Copenhagen 2006
ENERGI E2, Avedøre Power Station

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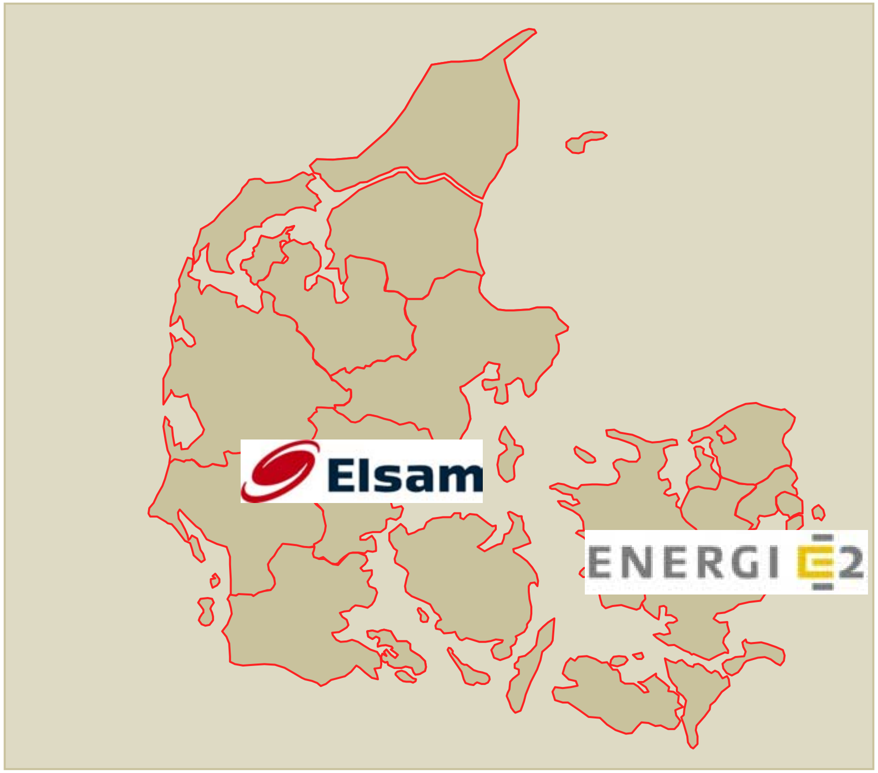
ENERGI E2

9th Int. CO_2 Capture Network, Copenhagen 2006
Reorganization of the Danish Power Companies

1. July 2006

Before



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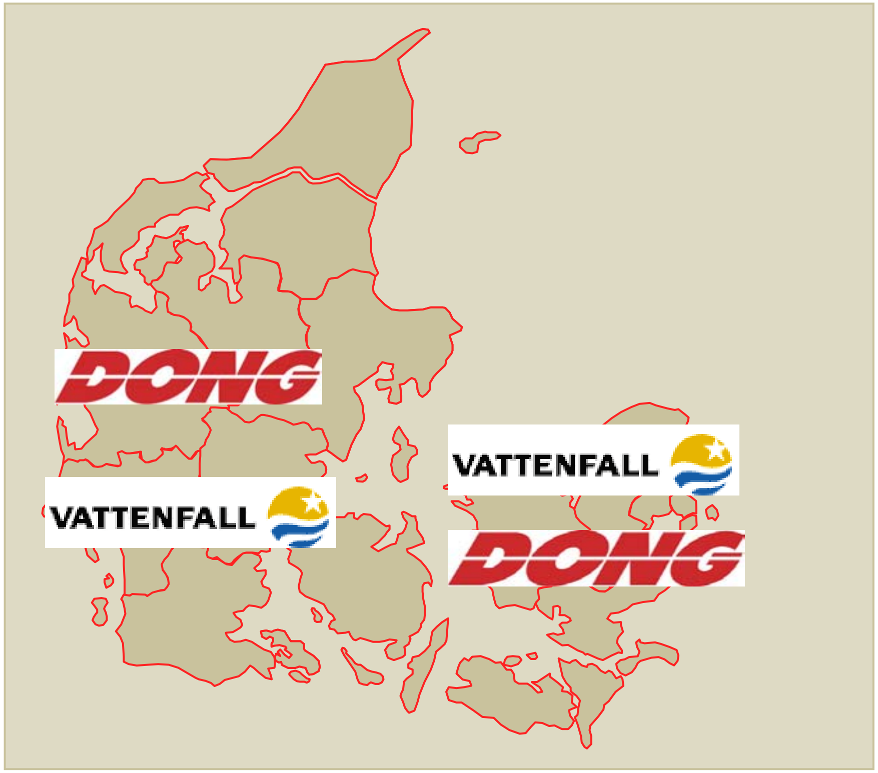
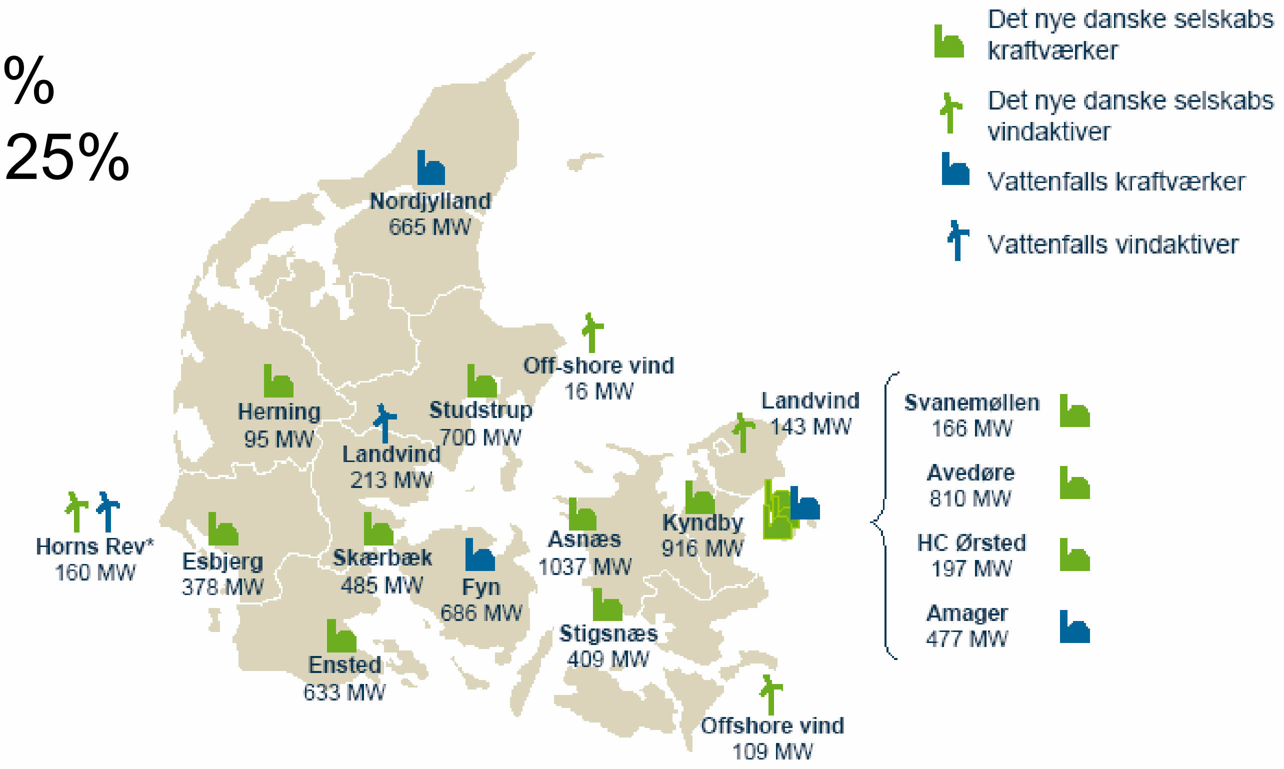


9th Int. CO_2 Capture Network, Copenhagen 2006
Reorganization of the Danish Power Companies

Fordeling af produktionsanlæg i Danmark

DONG: 75%
Vattenfall: 25%



Øvrige værker 298 MW **Hillerød og Helsingør 135 MW**

* *Vattenfall overtager 60% af Horns Rev inkl. driftsansvar*

9th International CO_2 Capture Network
E2, Copenhagen, June 16, 2006

CO_2 Capture and Storage activities in Denmark

- **Kalundborg**
- **CENS**
- **EU-projects: CO2store, ENCAP, Castor**

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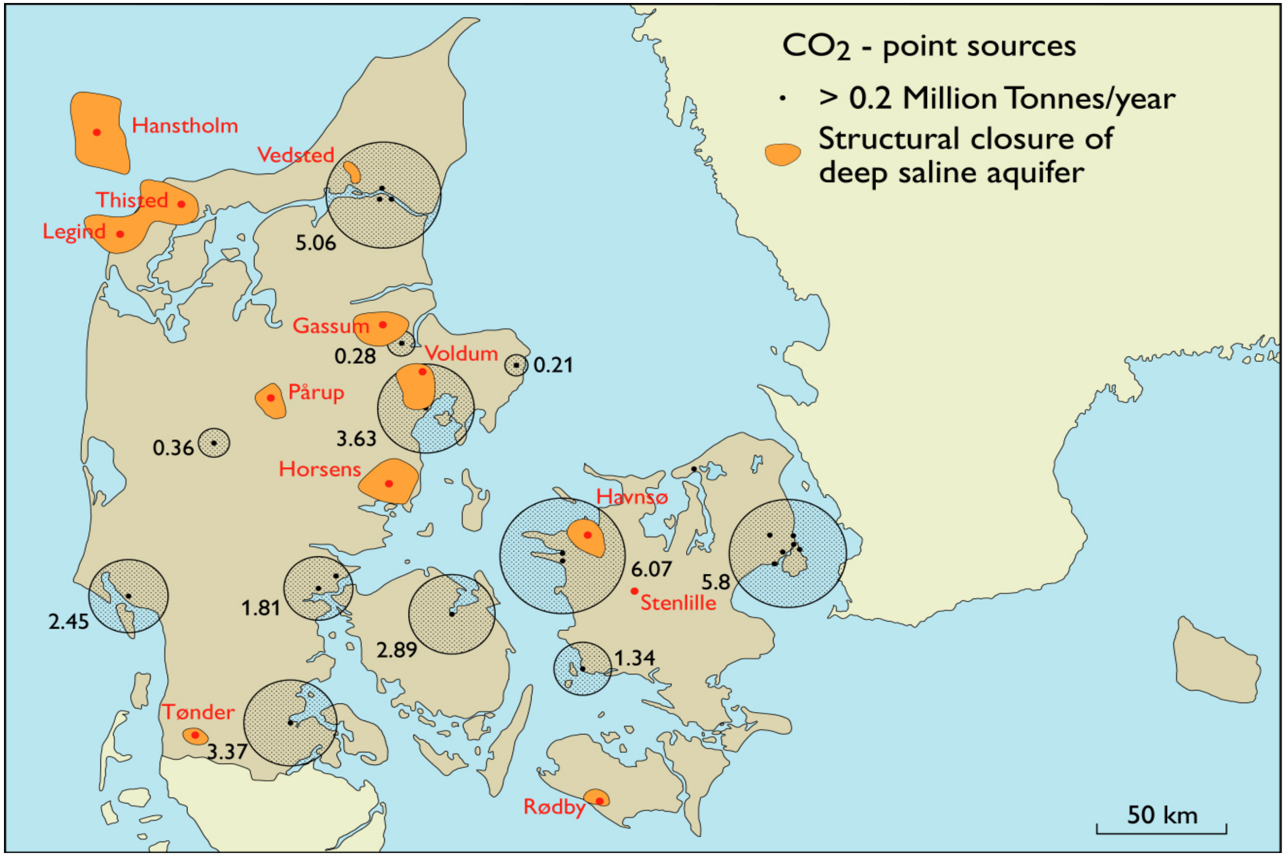
Geological Survey of Denmark and Greenland, GEUS

Saline aquifer storage of CO_2 from major point sources – a Danish case study



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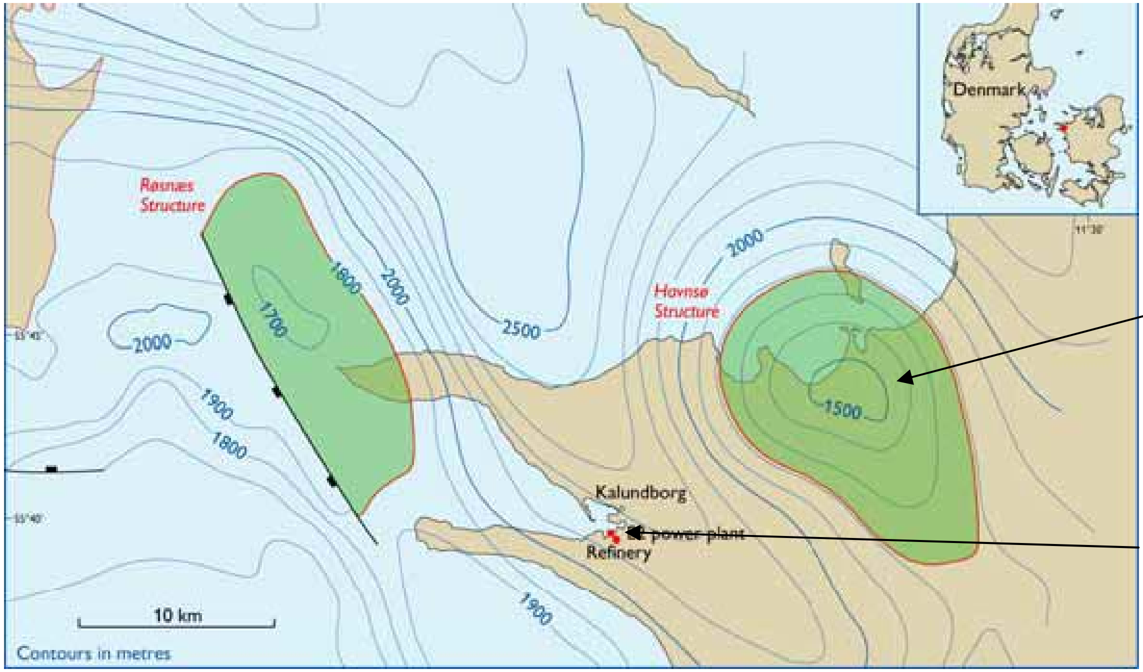
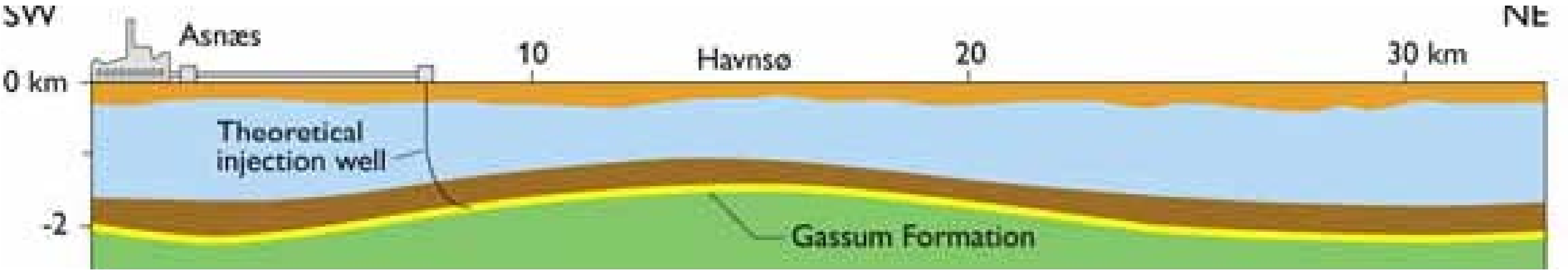
9th Int. CO_2 Capture Network, Copenhagen 2006
Carbon Dioxide Capture & Storage activities in Denmark - Kalundborg



Havnsø
Saline aquifer

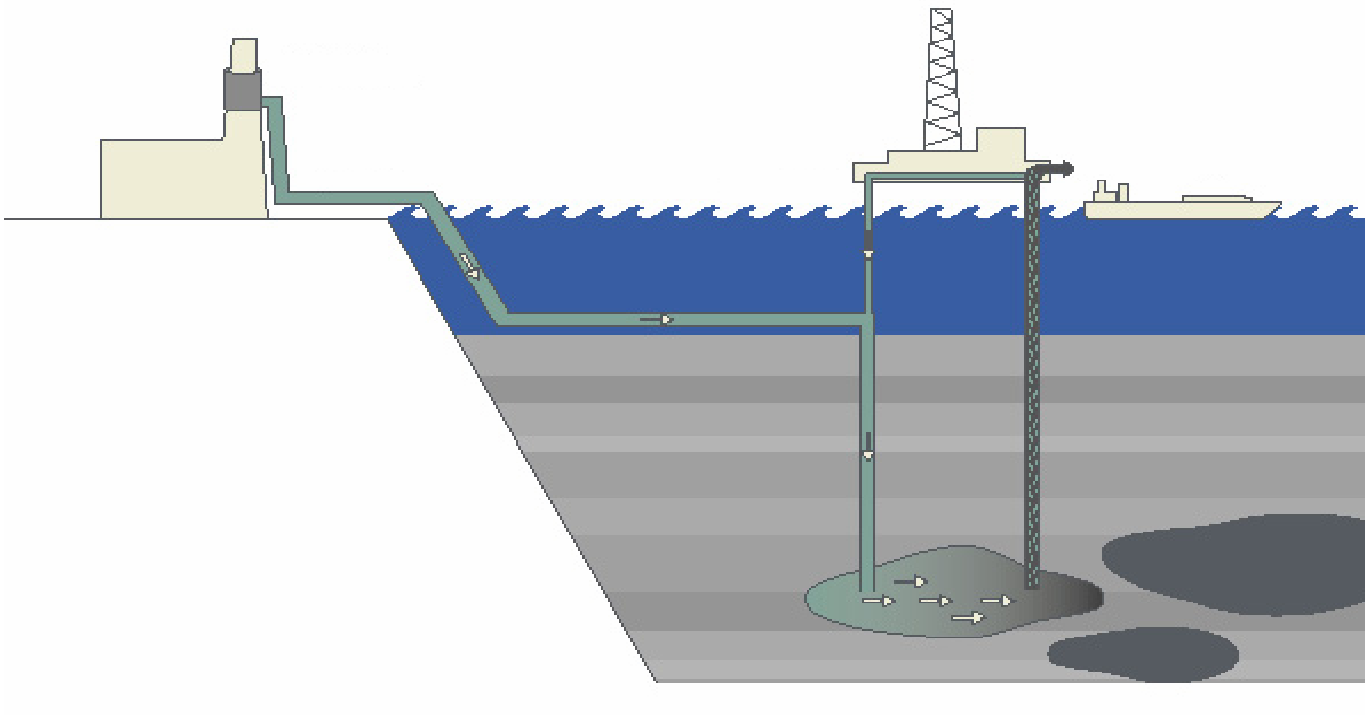
Asnæs Power
Station



9th Int. CO_2 Capture Network, Copenhagen 2006
Carbon Dioxide Capture & Storage activities in Denmark - CENS

Elsam–project:

CENS: $\underline{C}O_2$ for $\underline{E}$nhanced Oil Recovery in the $\underline{N}$orth $\underline{S}$ea



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Esbjergværket today

Esbjergværket with CO_2 capture

- **Conclusions from the CENS-study:**
-
- **Technology for CO_2-capture is commercially available**
- **No economic basis for EOR (2001)**
- **Lack of experience from coal-fired full-scale power plants**
- **Pilot / demonstration plants on coal flue gas needed**

Participation in CASTOR

9th International CO_2 Capture Network,
ENERGI E2, Copenhagen, June 16, 2006

CASTOR Project
”Capture and Storage of CO_2”

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ENERGI E2

CASTOR – Objectives / Targets

- **Reduce the cost of CO_2 post-combustion capture**
- **Contribute to the feasibility & acceptance of the geological storage concept**
- **Validate the concept on real site(s)**
  - **Pilot plant testing for capture**
  - **Detailed studies of future storage projects**
- **Duration: 4 years (February 2004 – January 2008)**
- **Budget: ~16 M€ (EU funding: 8.5 M€)**

9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Main Components

Budget: 0,75 M€

Strategy for CO_2 Reduction

WP1.1 Development of CO_2 reduction strategies

WP1.2 Geological storage options for CO_2 reduction strategy

Management Dissemination

WP0.1 Project Management

WP0.2 Dissemination & Training

Budget: 10,3 M€

CO_2 Post-Combustion Capture

WP2.1 Evaluation, optimisation & integration of post-combustion capture processes

WP2.2 Identification of most promising liquids

WP2.3 Designed of membrane based processes

WP2.4 Advanced processes

WP2.5 Process validation in pilot plant

Budget: 3,8 M€

CO_2 storage performance & risk assessment studies

WP3.1 Field case "Casablanca"

WP3.2 Field case "Lindach"

WP3.3 Field case "K13b"

WP3.4 Field case "Snohvit"

WP3.5 Preventive & corrective actions

WP3.6 Criteria for site selection and
site management

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CASTOR – Consortium Participants

28 participants from 11 countries

R&D

IFP (FR)
TNO (NL)
SINTEF (NO)
NTNU (NO)
BGS (UK)
BGR (DE)
BRGM (FR)
GEUS (DK)
IMPERIAL (UK)
OGS (IT)
TWENTE U. (NL)
STUTTGARTT U. (DE)

Oil & Gas

STATOIL (NO)
GDF (FR)
REPSOL (SP)
ENITecnologie (IT)
ROHOEL (AT)

Power Companies

VATTENFALL (SE)
ELSAM (DK)
ENERGI E2 (DK)
RWE (DE)
PPC (GR)
POWERGEN (UK)

Manufacturers

ALSTOM POWER (FR)
MITSUI BABCOCK (UK)
SIEMENS (DE)
BASF (DE)
GVS (IT)

Co-ordinator : IFP

9th International CO_2 Capture Network,
ENERGI E2, Copenhagen, June 16, 2006

Castor Pilot Plant

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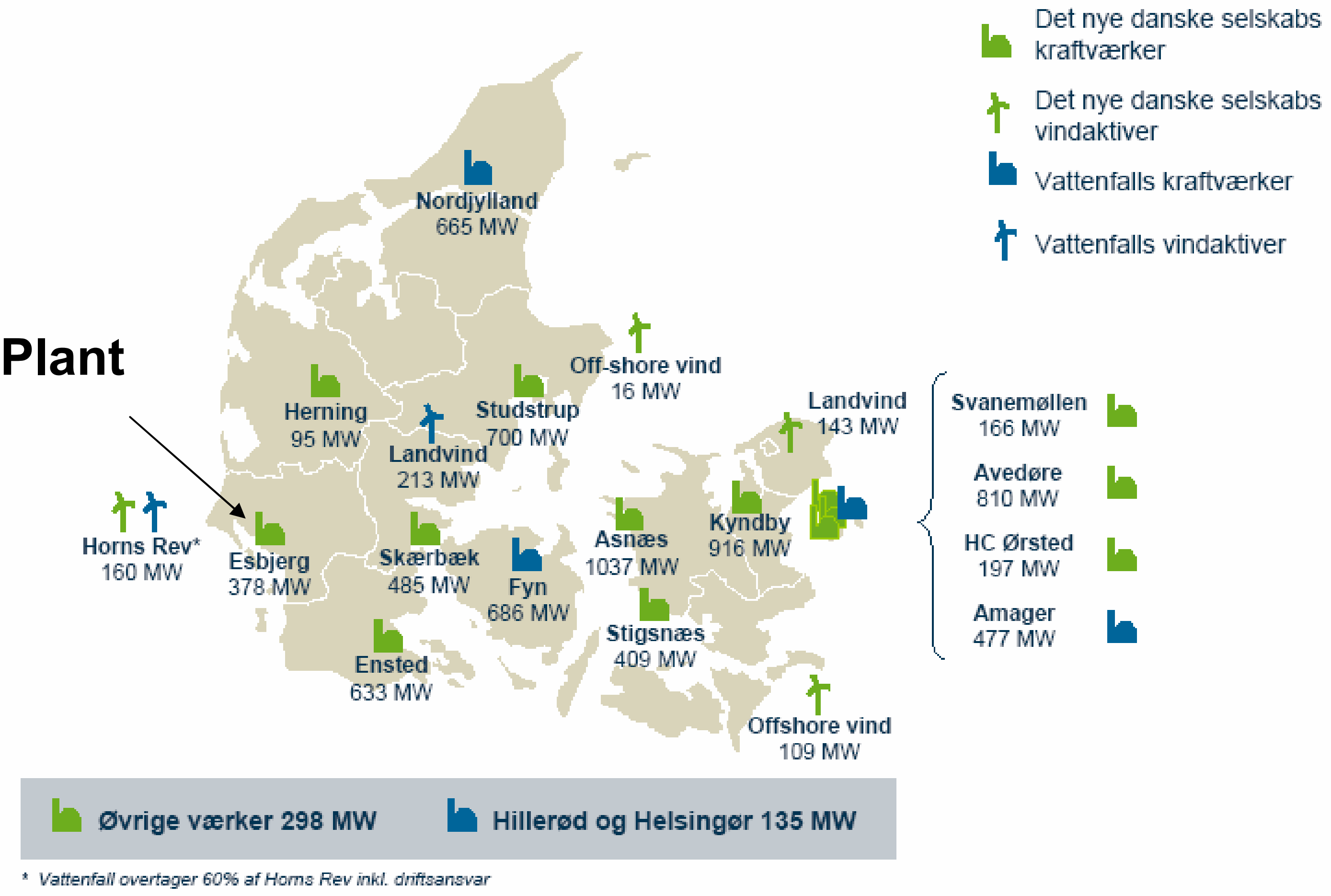
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Time schedule

- February 2004 : Castor project starts
- September 2004 : Invitation for tender issued
- February 2005 : Contract awarded – TPI, Italy
- July 2005 : Erection start
- October 2005 : Commissioning start
- January 2006 : Start Test Phase 1, 1000 h on 30% MEA
- March 2006 : End Test Phase 1
- August 2006 : Start Test Phase 2, 1000 h on 30% MEA
- Fall 2006: : Start Test Phase 3, 4000 h on Castor1
- Summer 2007 : Start Test Phase 4, 4000 h on Castor2
- January 2008 : End of Castor

9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant at Esbjergværket

Fordeling af produktionsanlæg i Danmark

Castor Pilot Plant



* *Vattenfall overtager 60% af Horns Rev inkl. driftsansvar*

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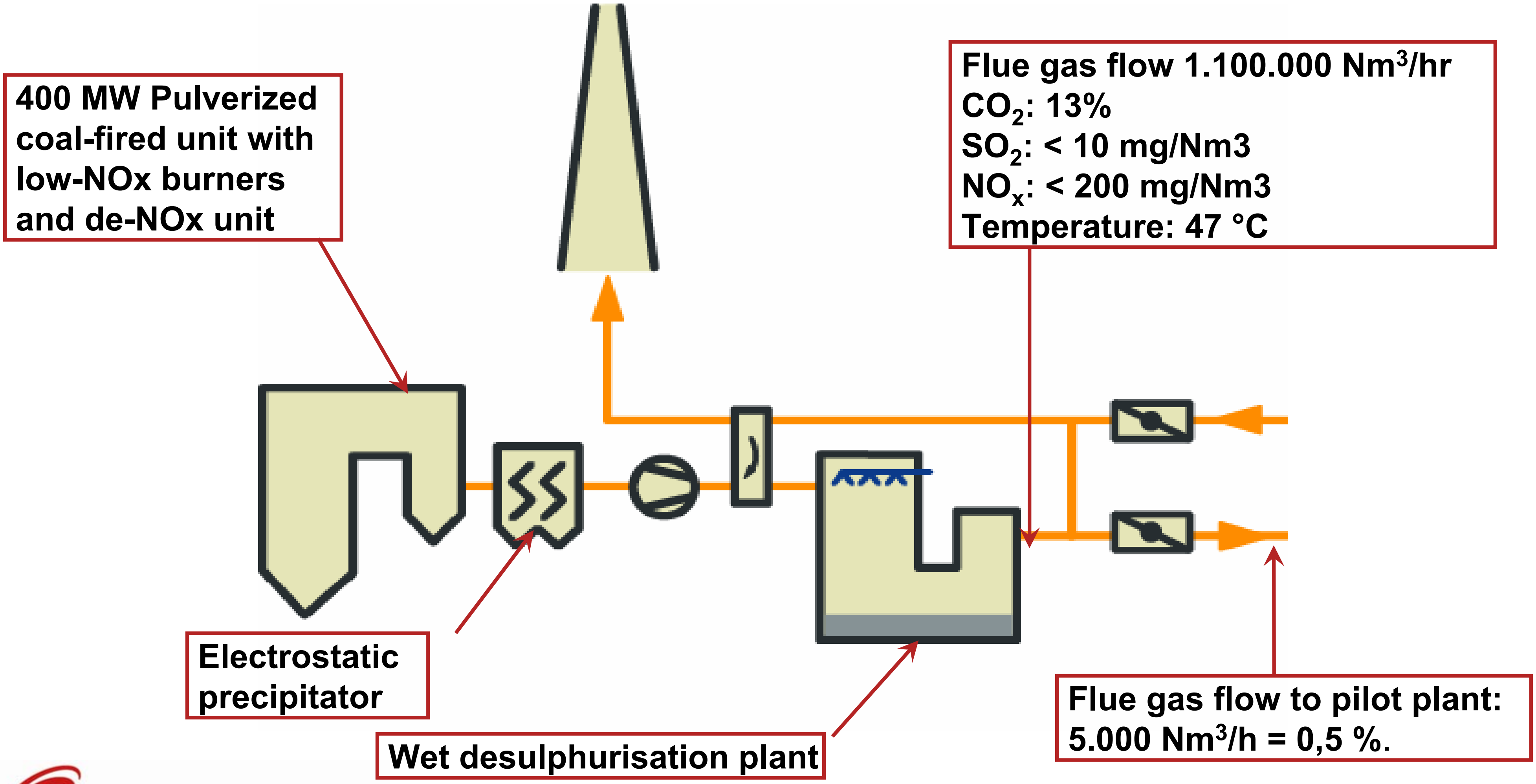
CASTOR – Esbjergværket unit 3



400 MW Pulverized coal-fired unit with low-NOx burners and de-NOx unit

Flue gas flow 1.100.000 Nm^3/hr
CO_2: 13%
SO_2: < 10 mg/Nm3
NO_x: < 200 mg/Nm3
Temperature: 47 °C

Electrostatic precipitator

Wet desulphurisation plant

Flue gas flow to pilot plant: 5.000 Nm^3/h = 0,5 %.

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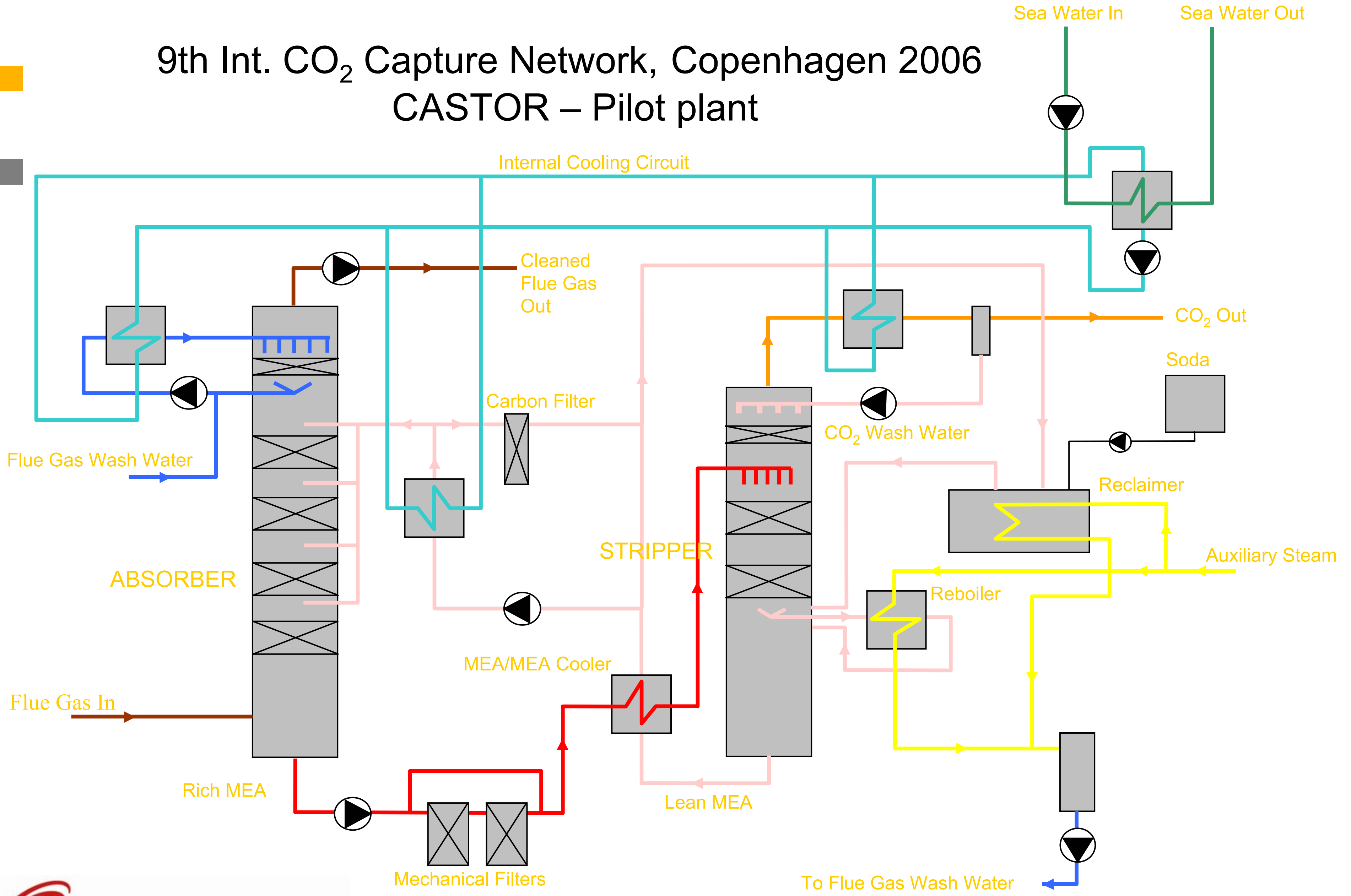
CASTOR – Pilot plant



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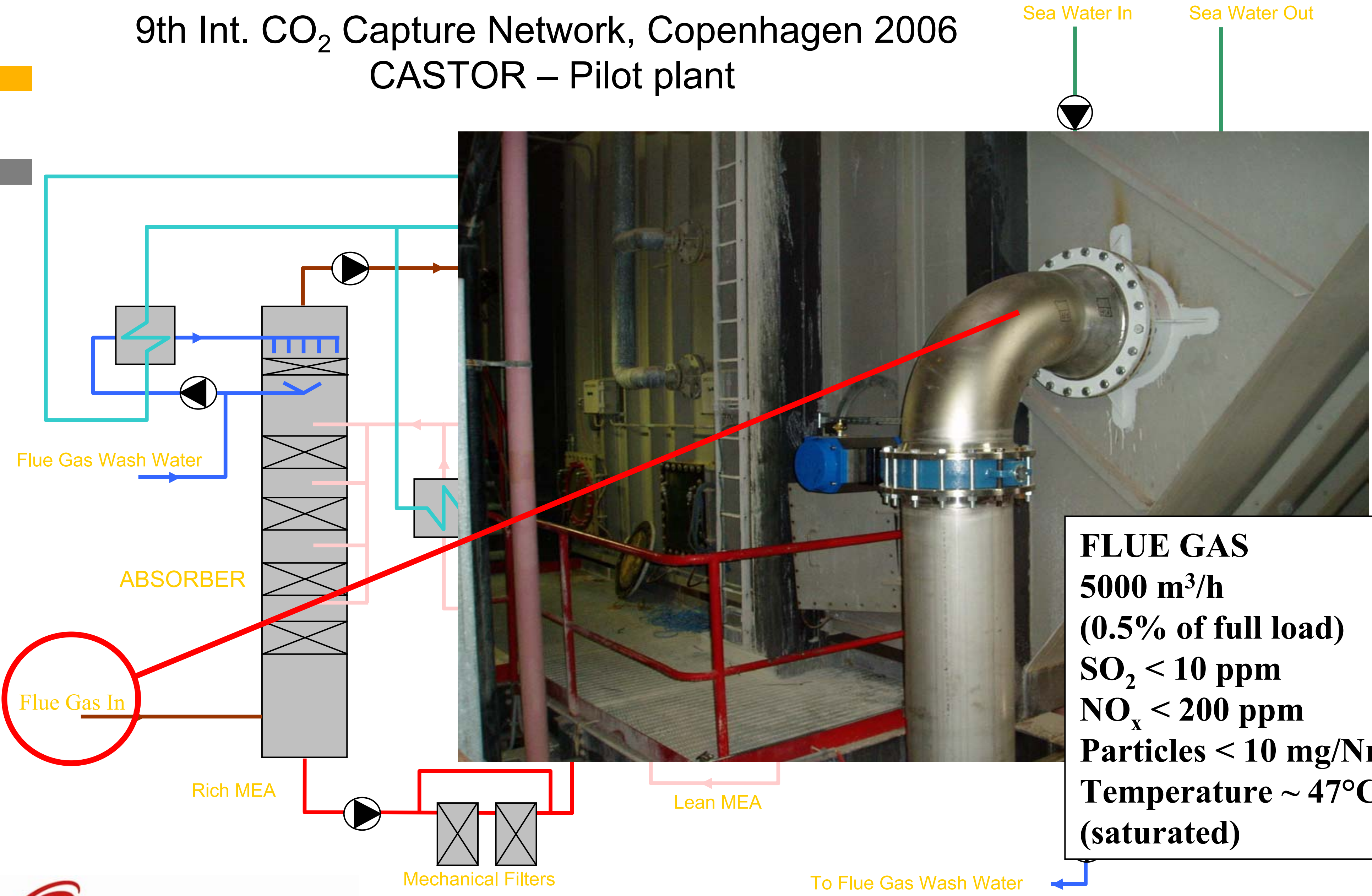
9th Int. CO$_2$ Capture Network, Copenhagen 2006
CASTOR – Pilot plant



FLUE GAS
5000 m^3/h
(0.5% of full load)
SO$_2$ < 10 ppm
NO$_x$ < 200 ppm
Particles < 10 mg/Nm^3
Temperature ~ 47°C
(saturated)

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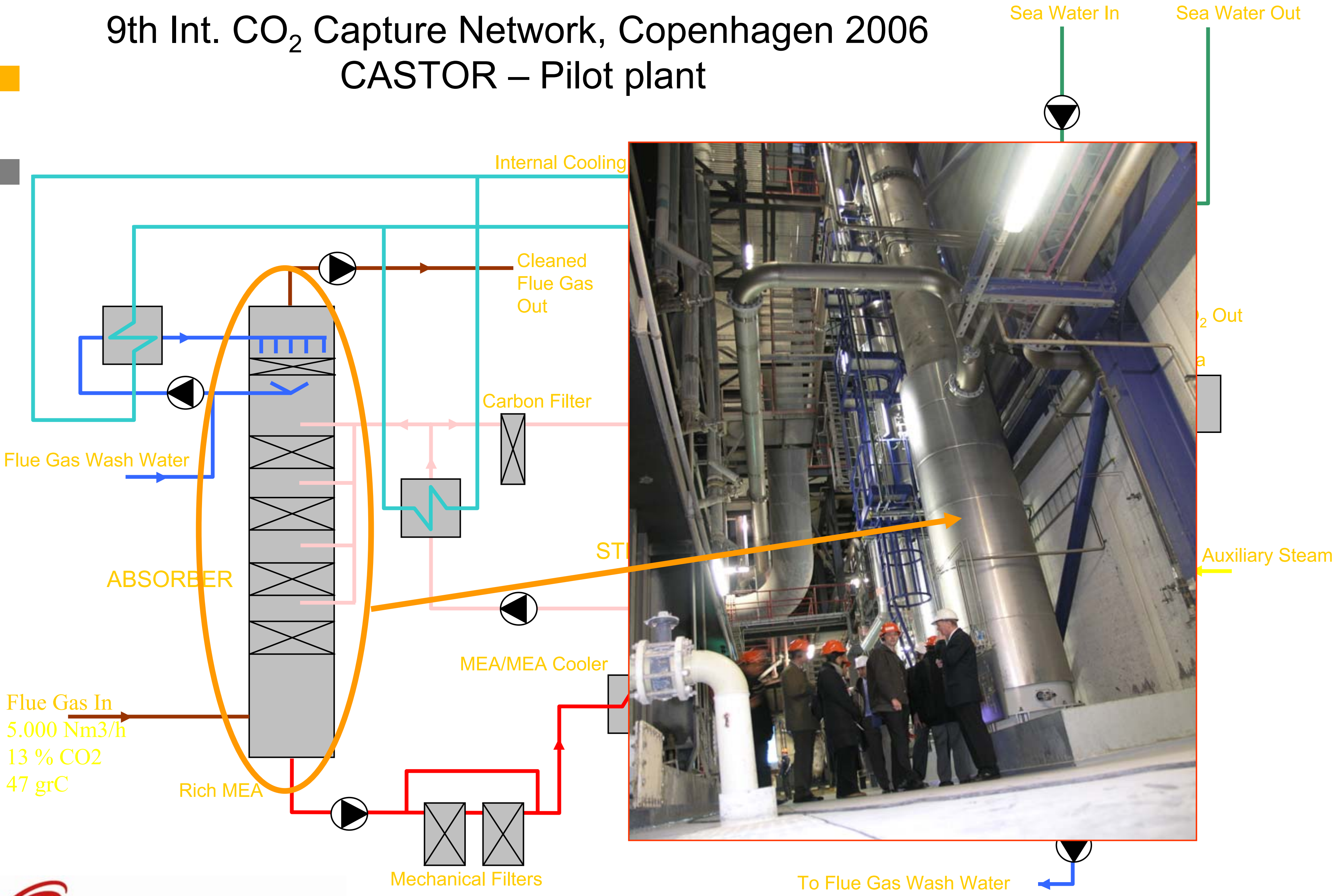
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



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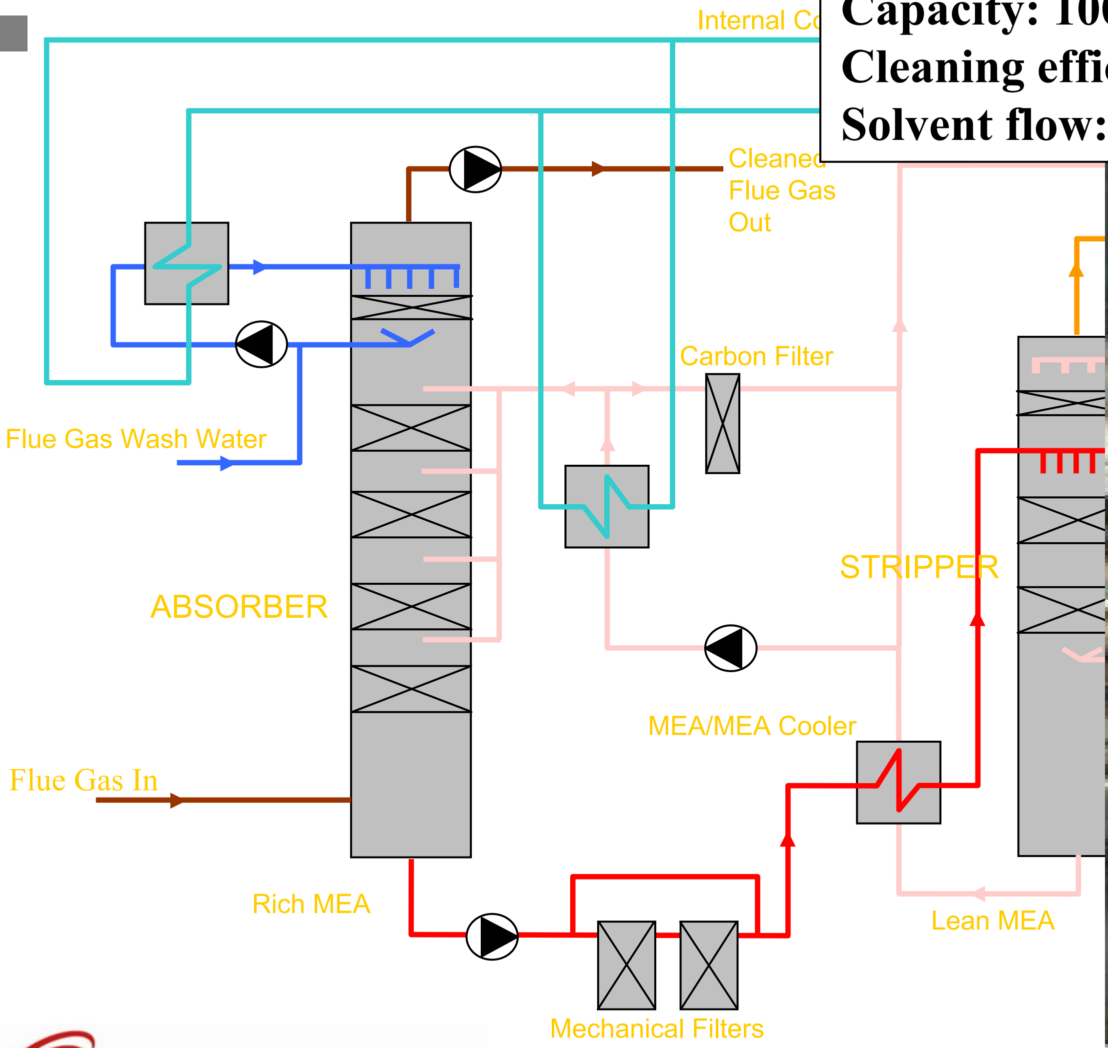
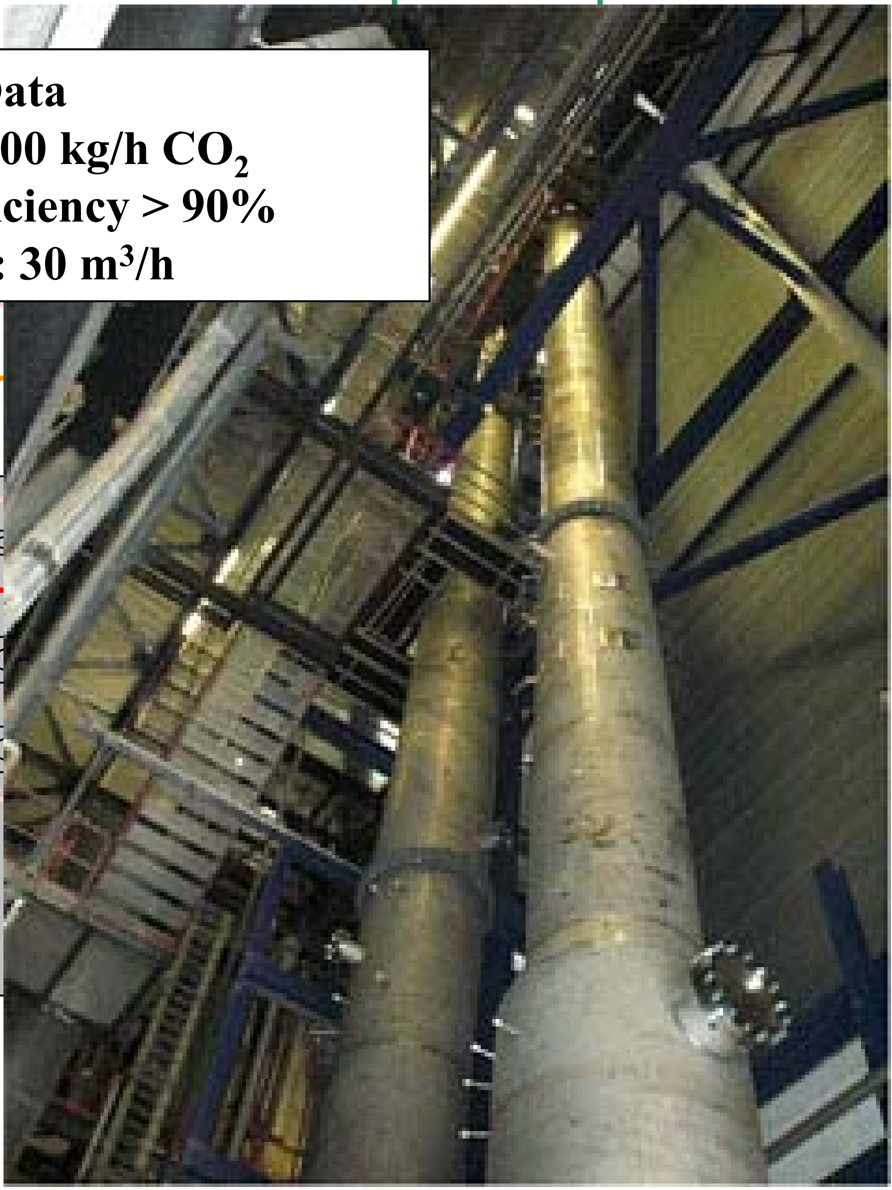
9th Int. CO_2 Capture Network, Copenhagen 2006

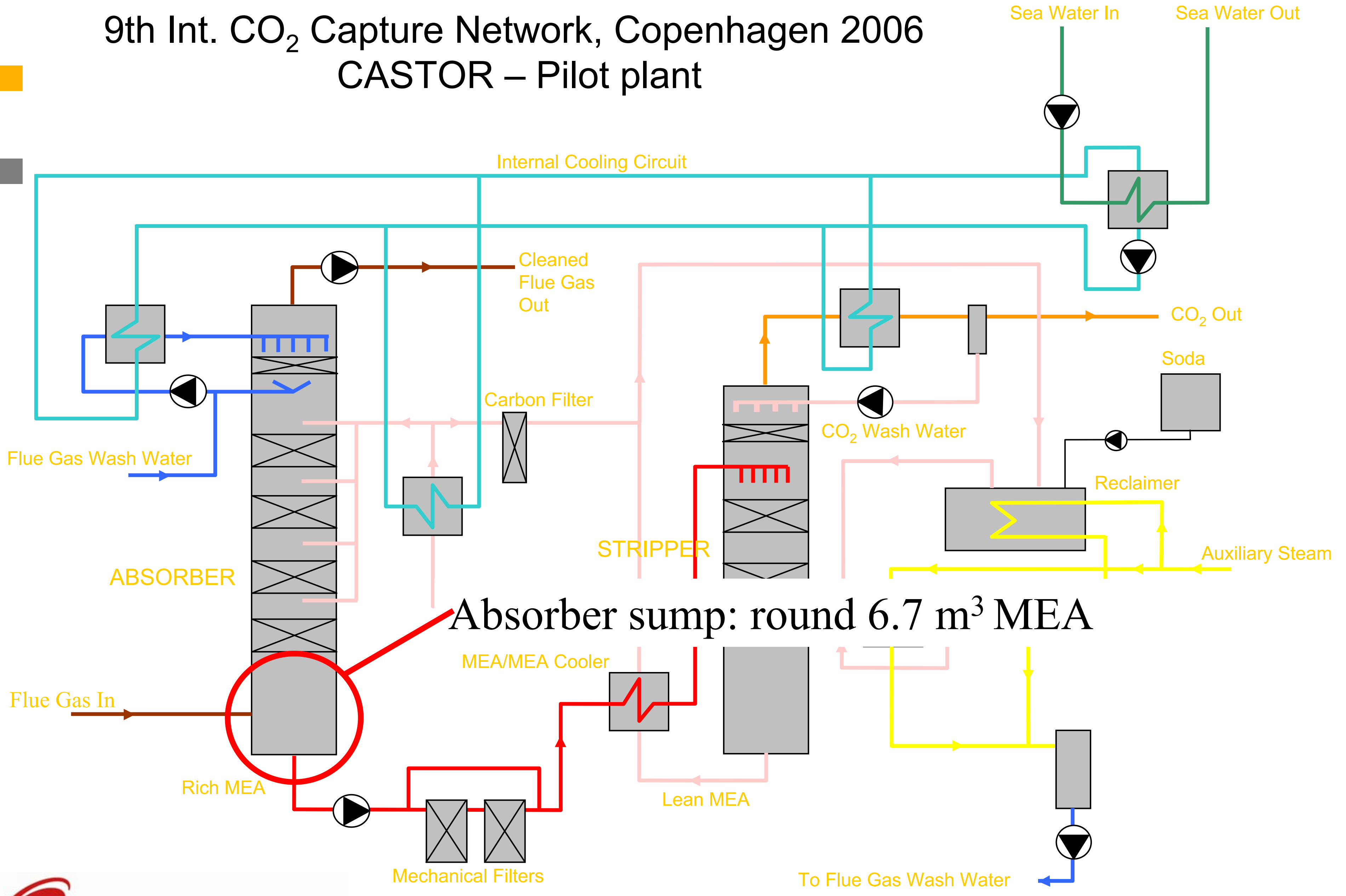
CASTOR – Pilot plant



Pilot Plant Data
Capacity: 1000 kg/h CO_2
Cleaning efficiency > 90%
Solvent flow: 30 m^3/h



9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



Absorber sump: round 6.7 m^3 MEA

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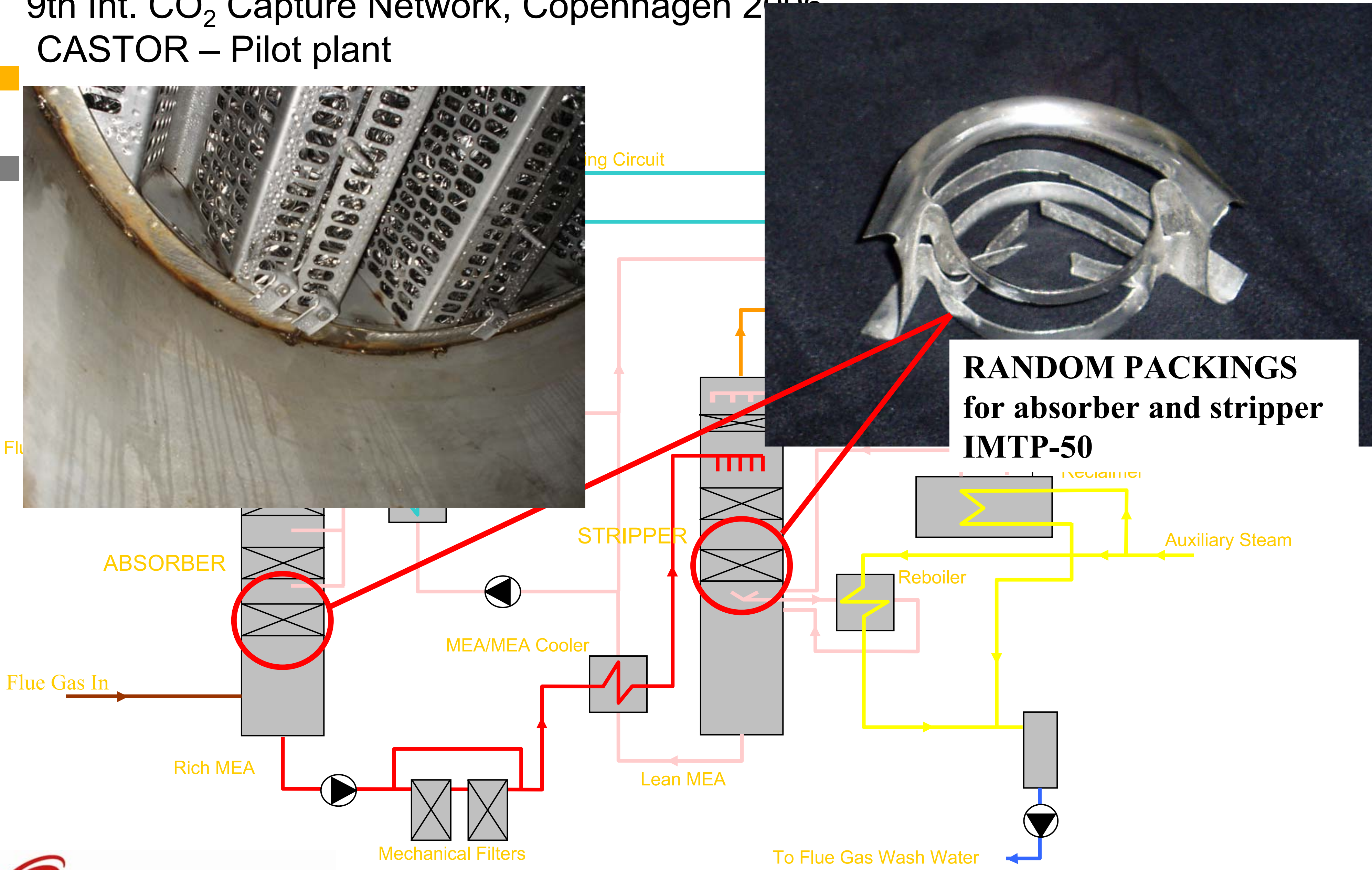
9th Int. CO$_2$ Capture Network, Copenhagen 2006

CASTOR – Pilot plant



RANDOM PACKINGS
for absorber and stripper
IMTP-50

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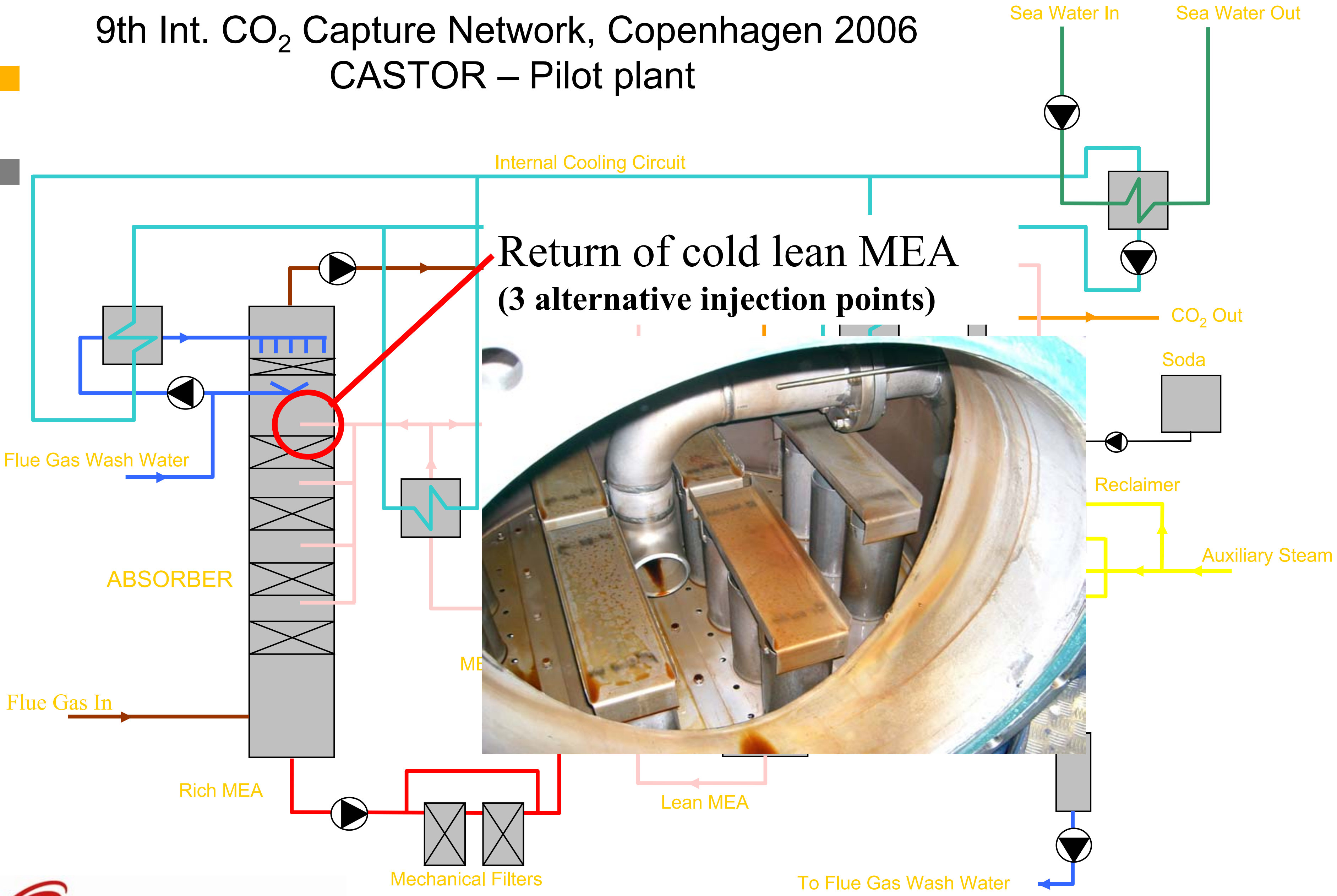
CASTOR – Pilot plant



Return of cold lean MEA

(3 alternative injection points)

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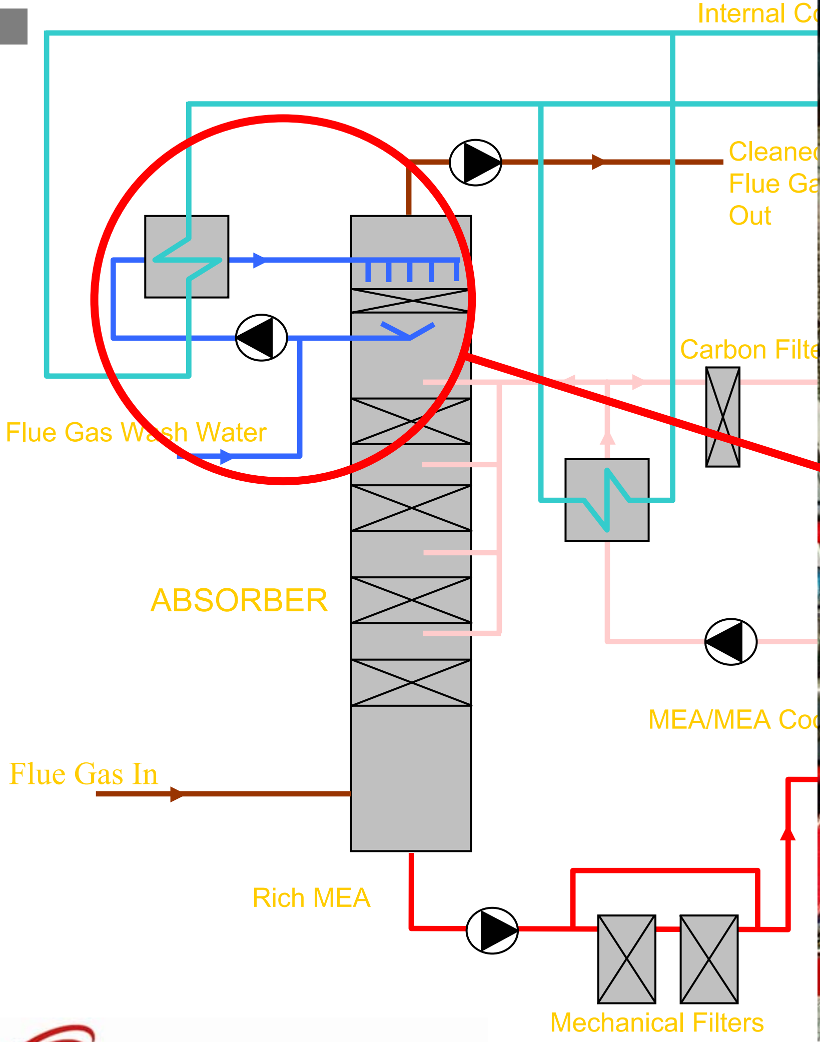
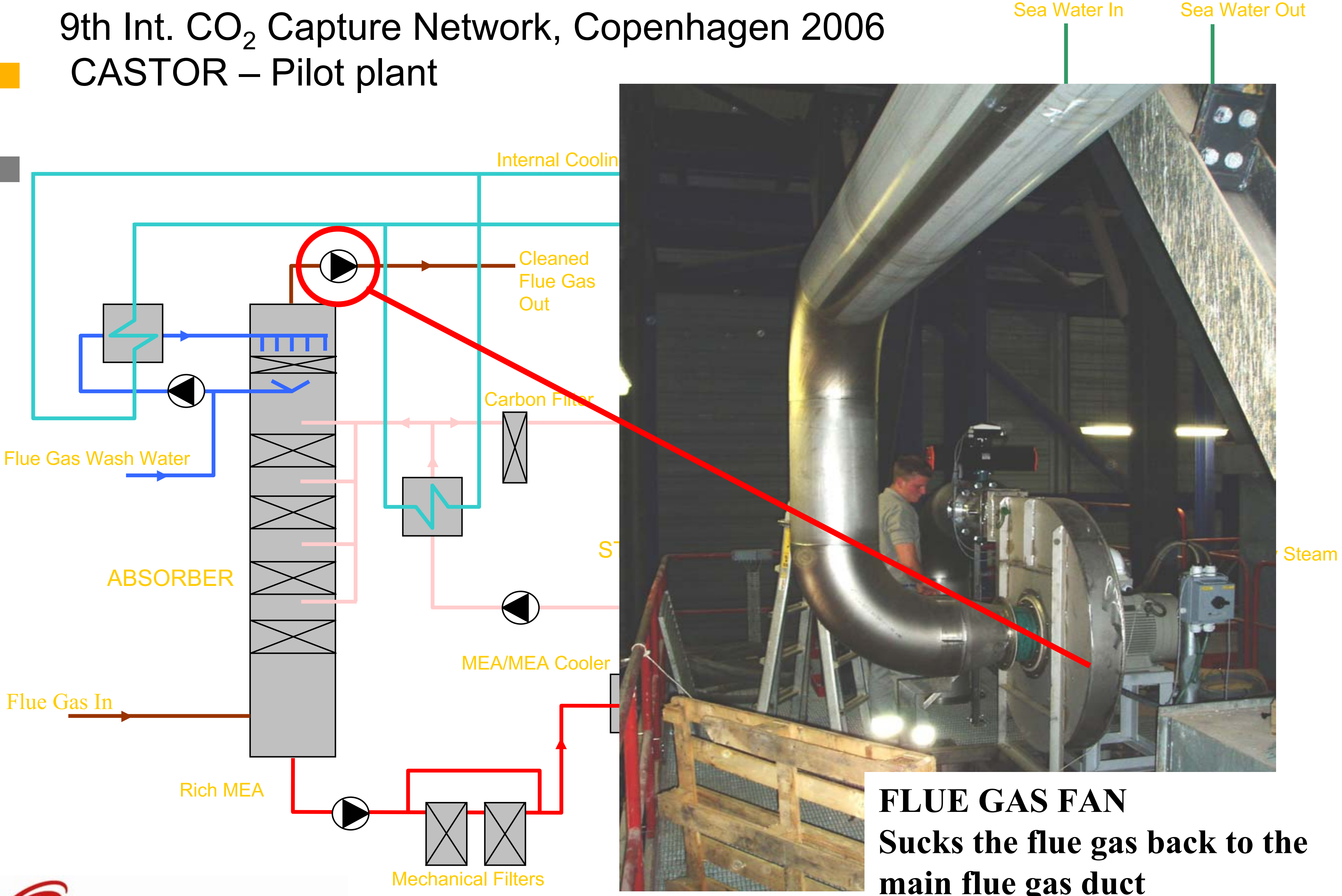
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



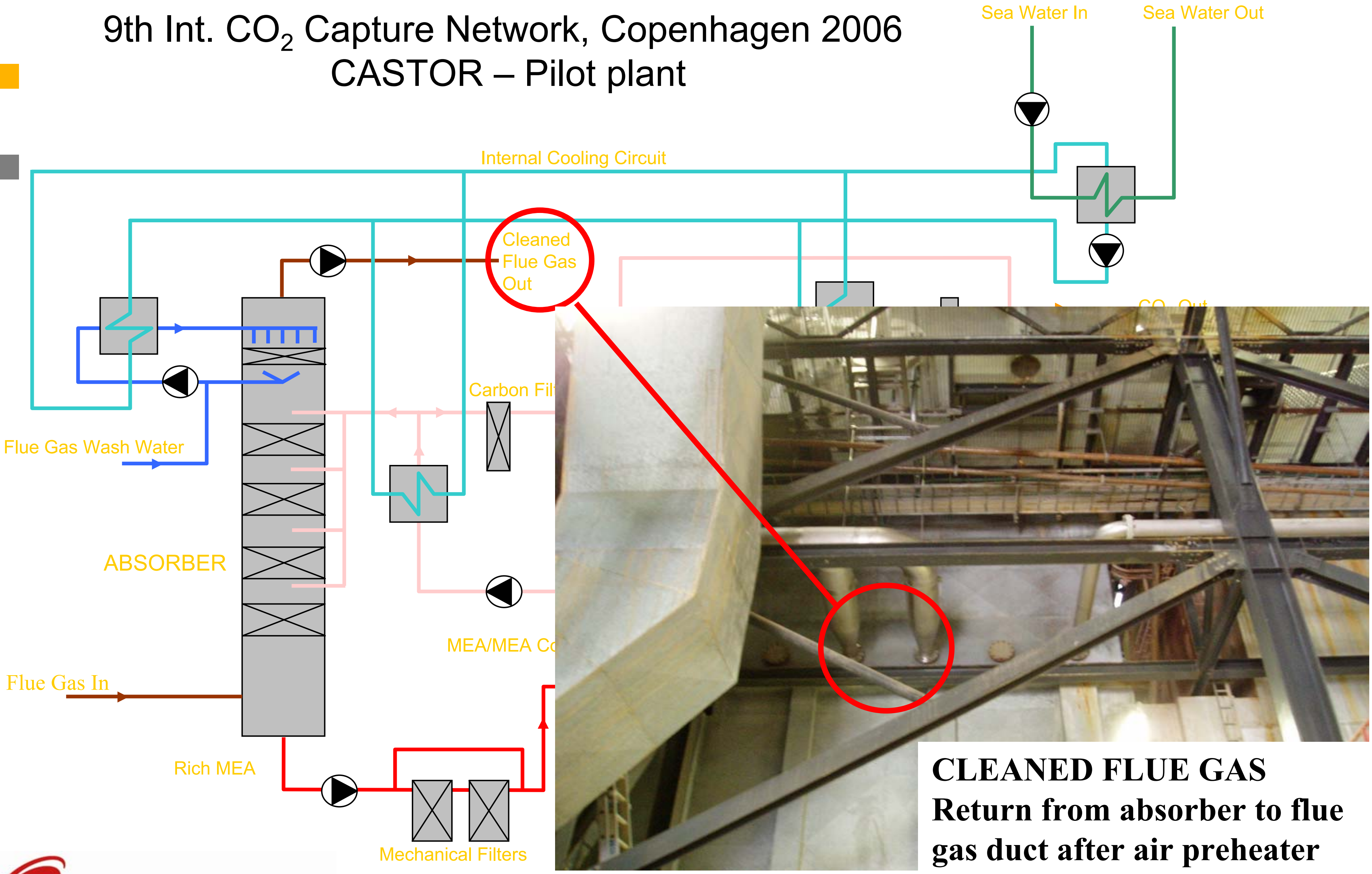
ABSORBER WASH SECTION
Cleans the flue gas for MEA carry over

9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



FLUE GAS FAN
Sucks the flue gas back to the main flue gas duct

9th Int. CO$_2$ Capture Network, Copenhagen 2006
CASTOR – Pilot plant



CLEANED FLUE GAS
Return from absorber to flue gas duct after air preheater

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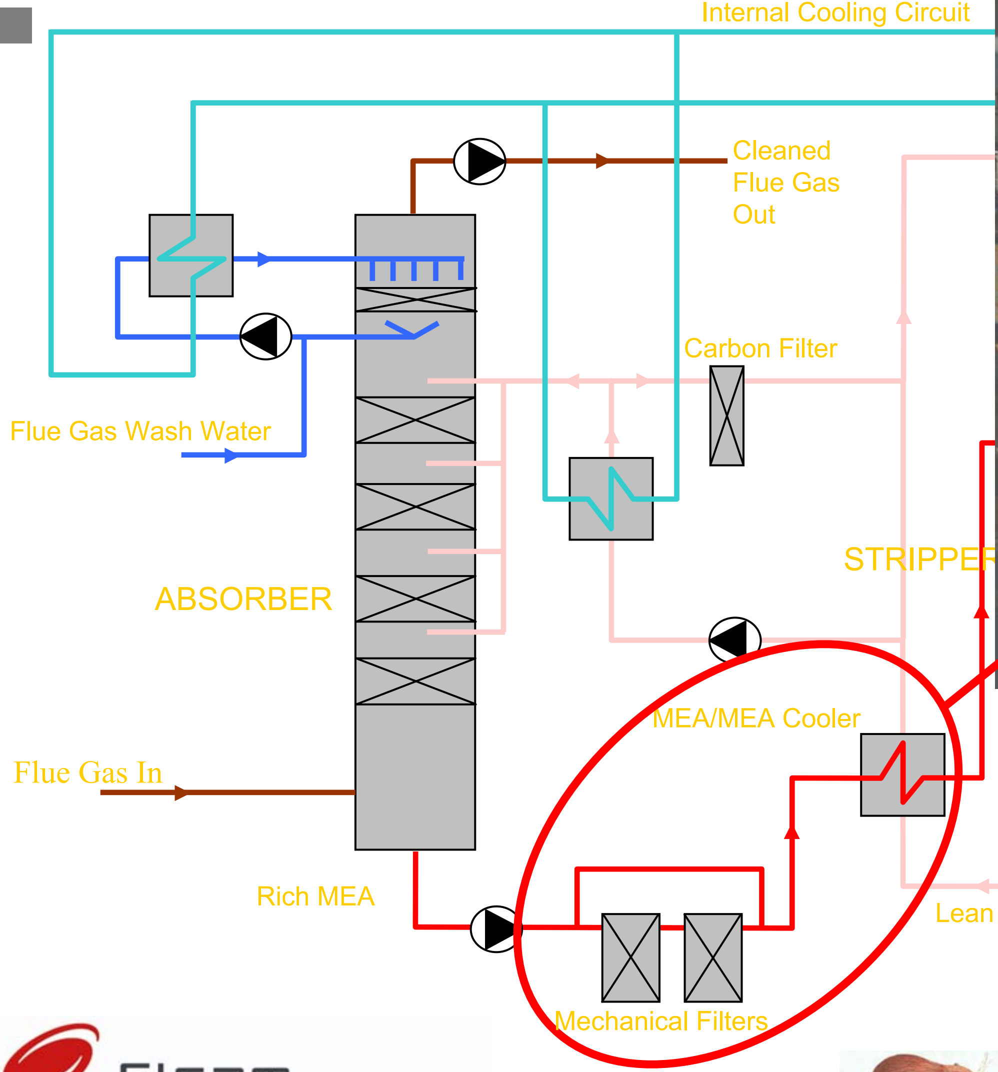
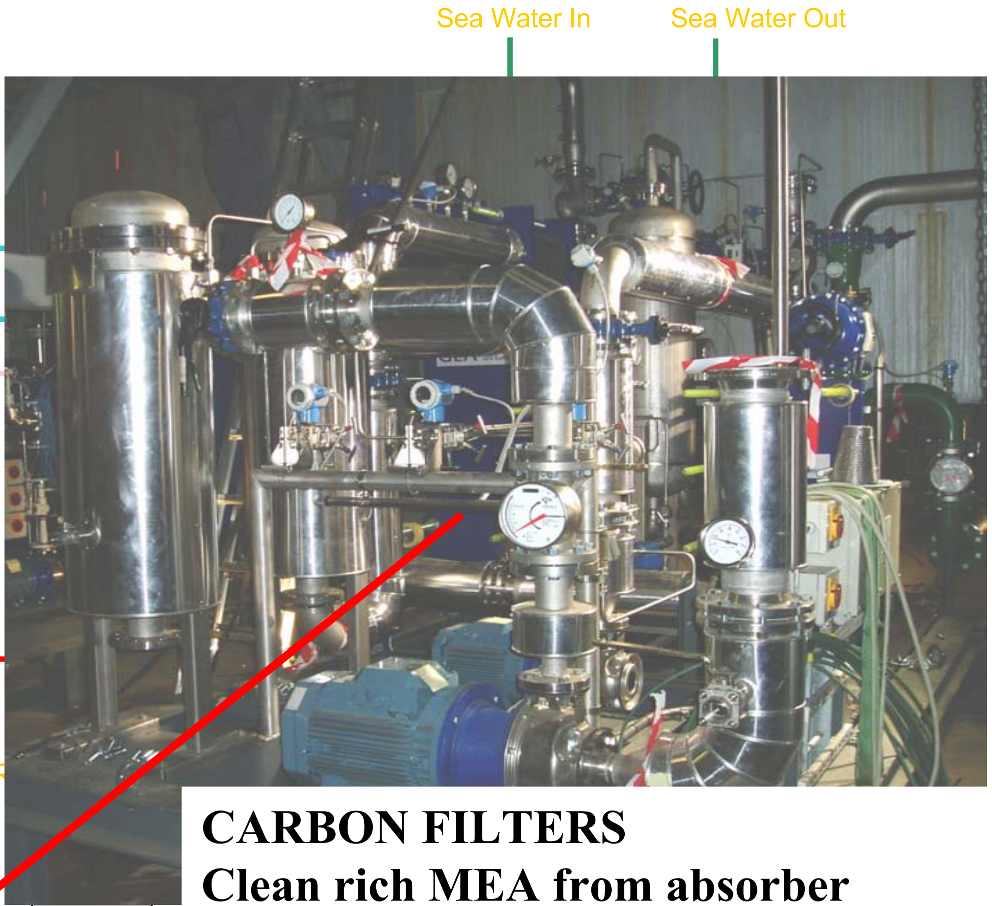
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant





CARBON FILTERS
Clean rich MEA from absorber

MEA/MEA HEAT EXCHANGER
Heats rich MEA from absorber before entering stripper

Cools lean MEA from stripper before entering trim cooler and absorber

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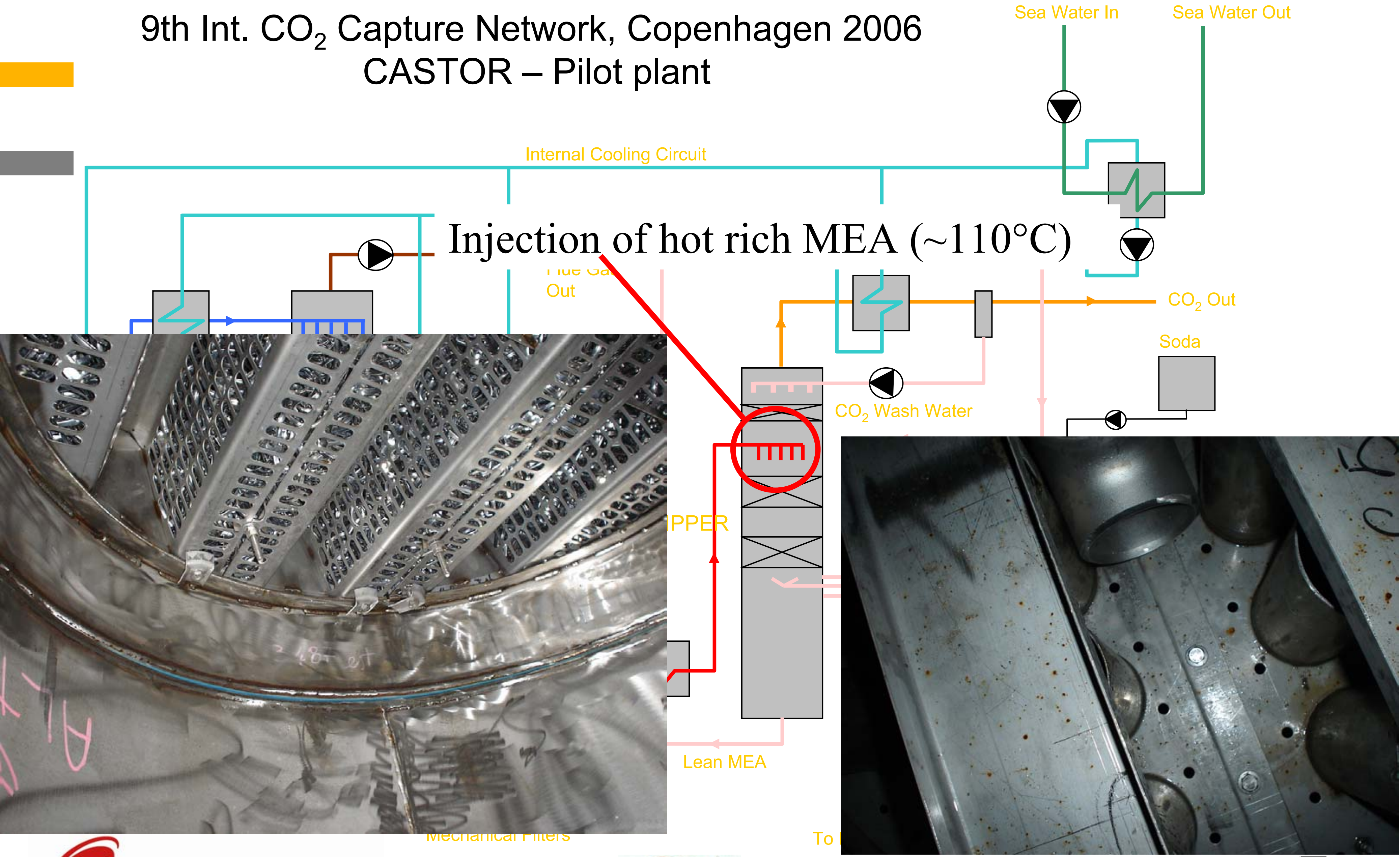
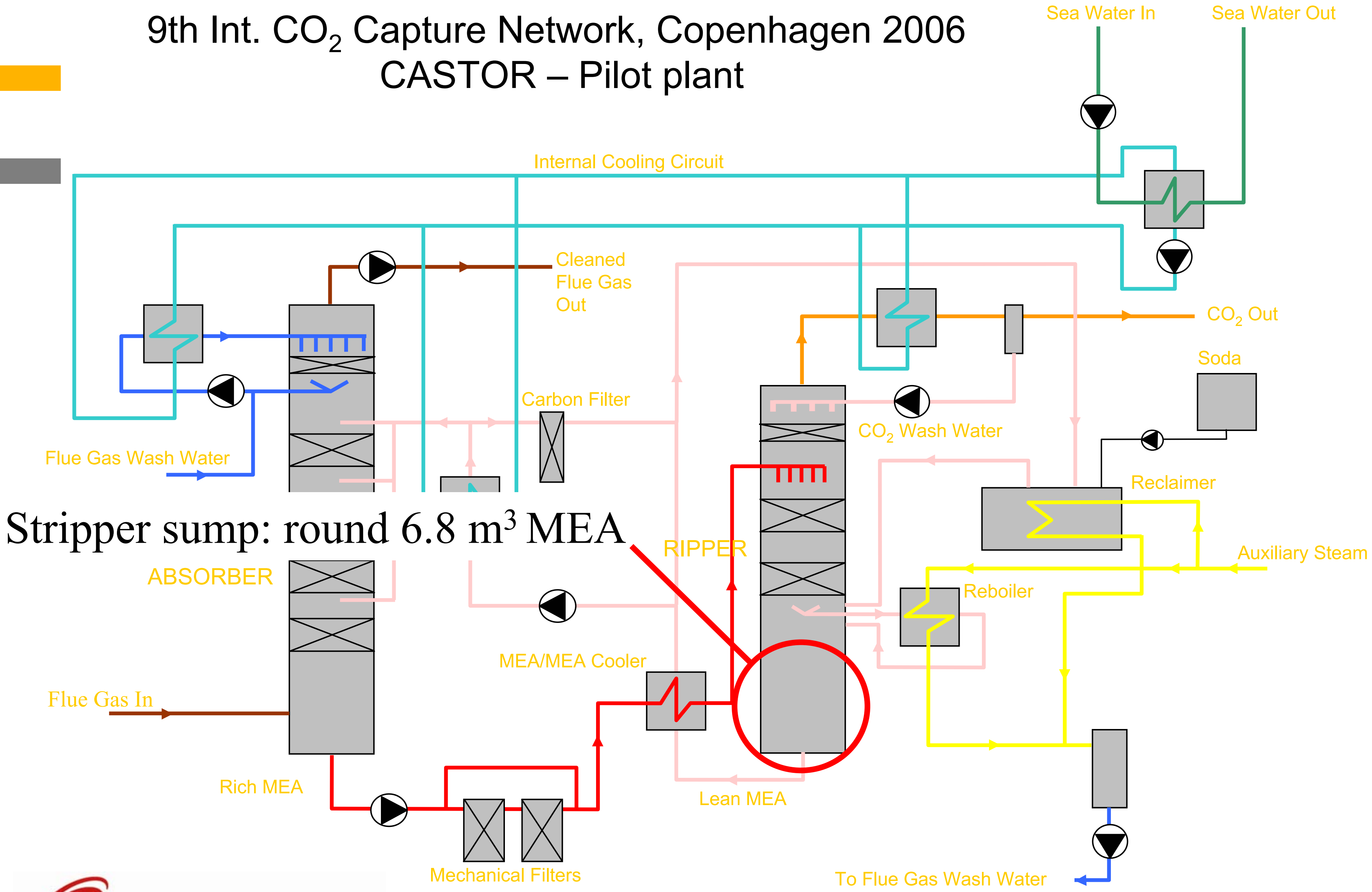
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



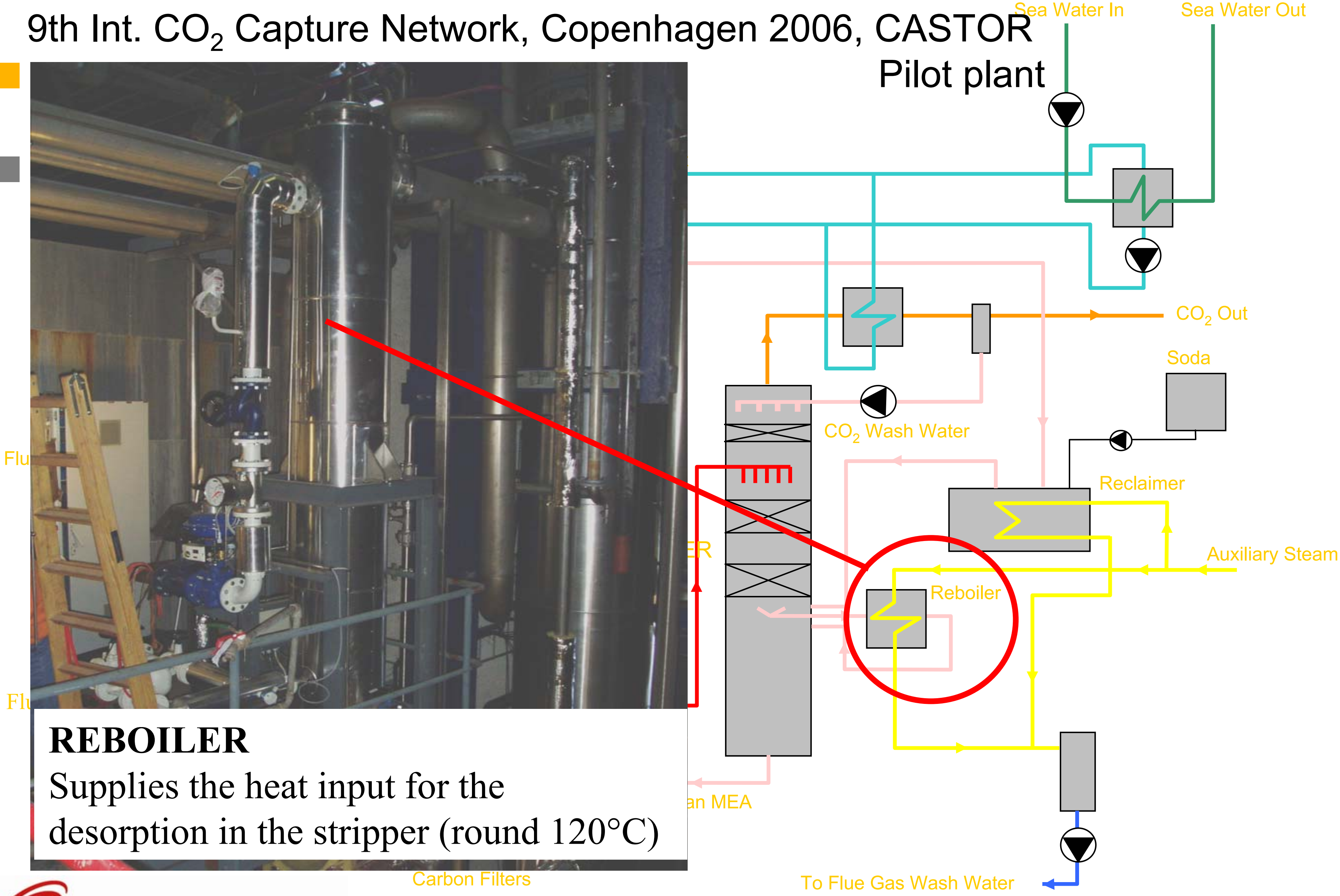
Injection of hot rich MEA (~110°C)

9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



Stripper sump: round 6.8 m^3 MEA

9th Int. CO_2 Capture Network, Copenhagen 2006, CASTOR Pilot plant



REBOILER
Supplies the heat input for the desorption in the stripper (round 120°C)

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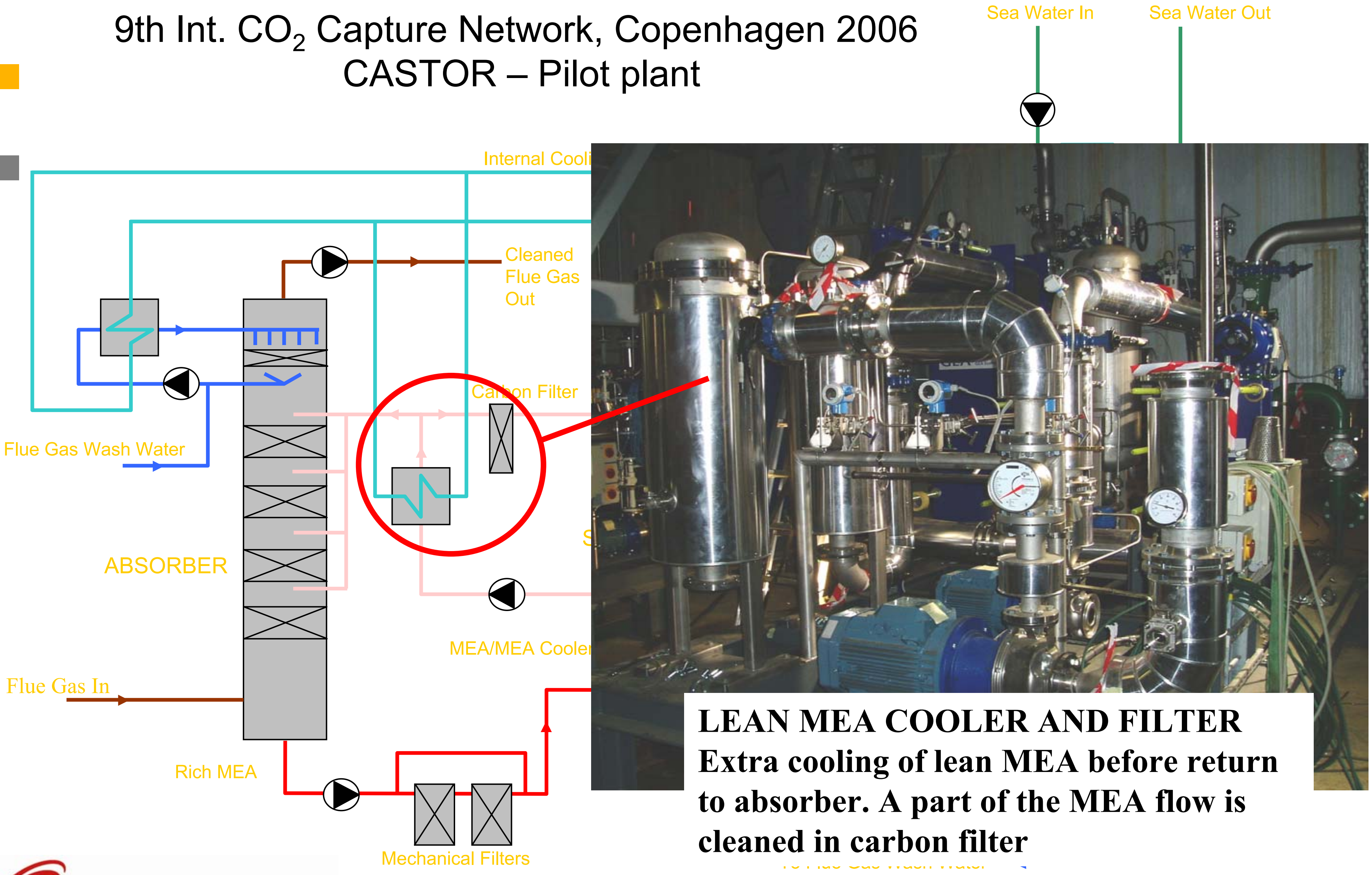
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



LEAN MEA COOLER AND FILTER

Extra cooling of lean MEA before return to absorber. A part of the MEA flow is cleaned in carbon filter

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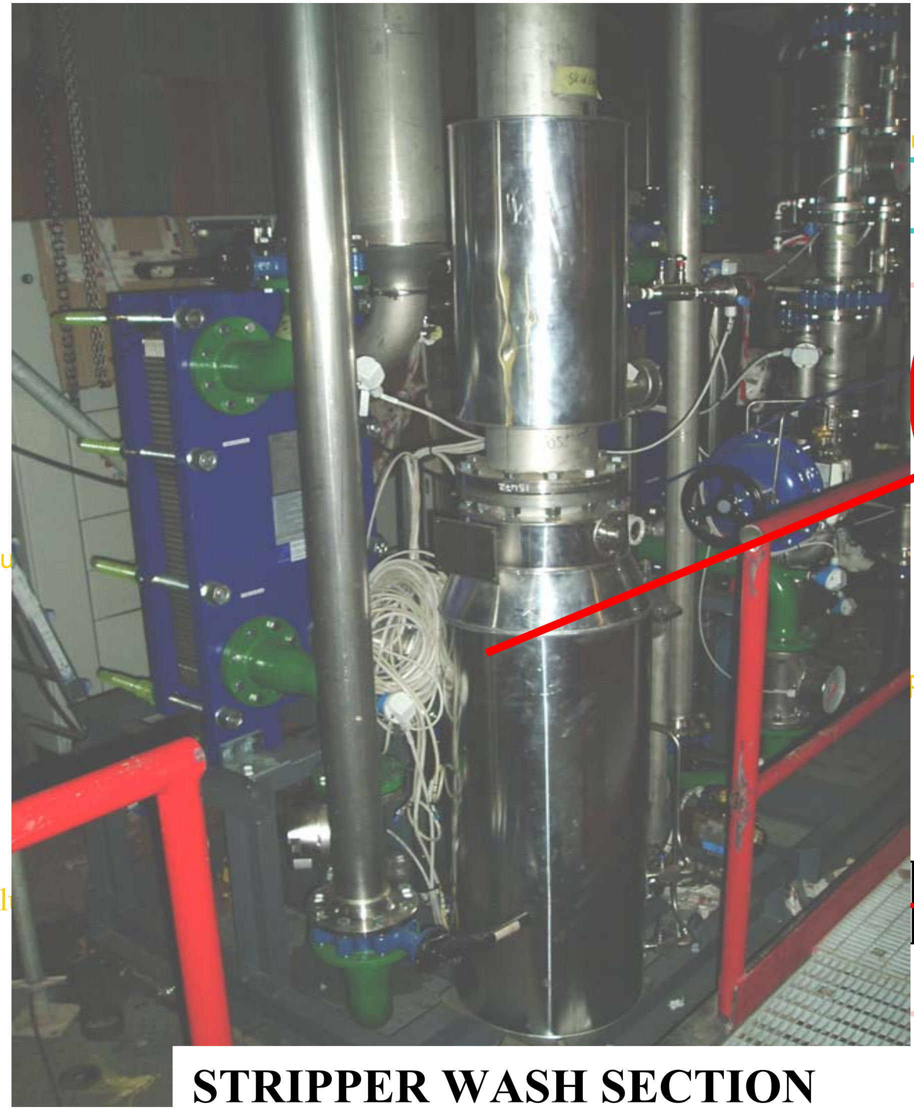
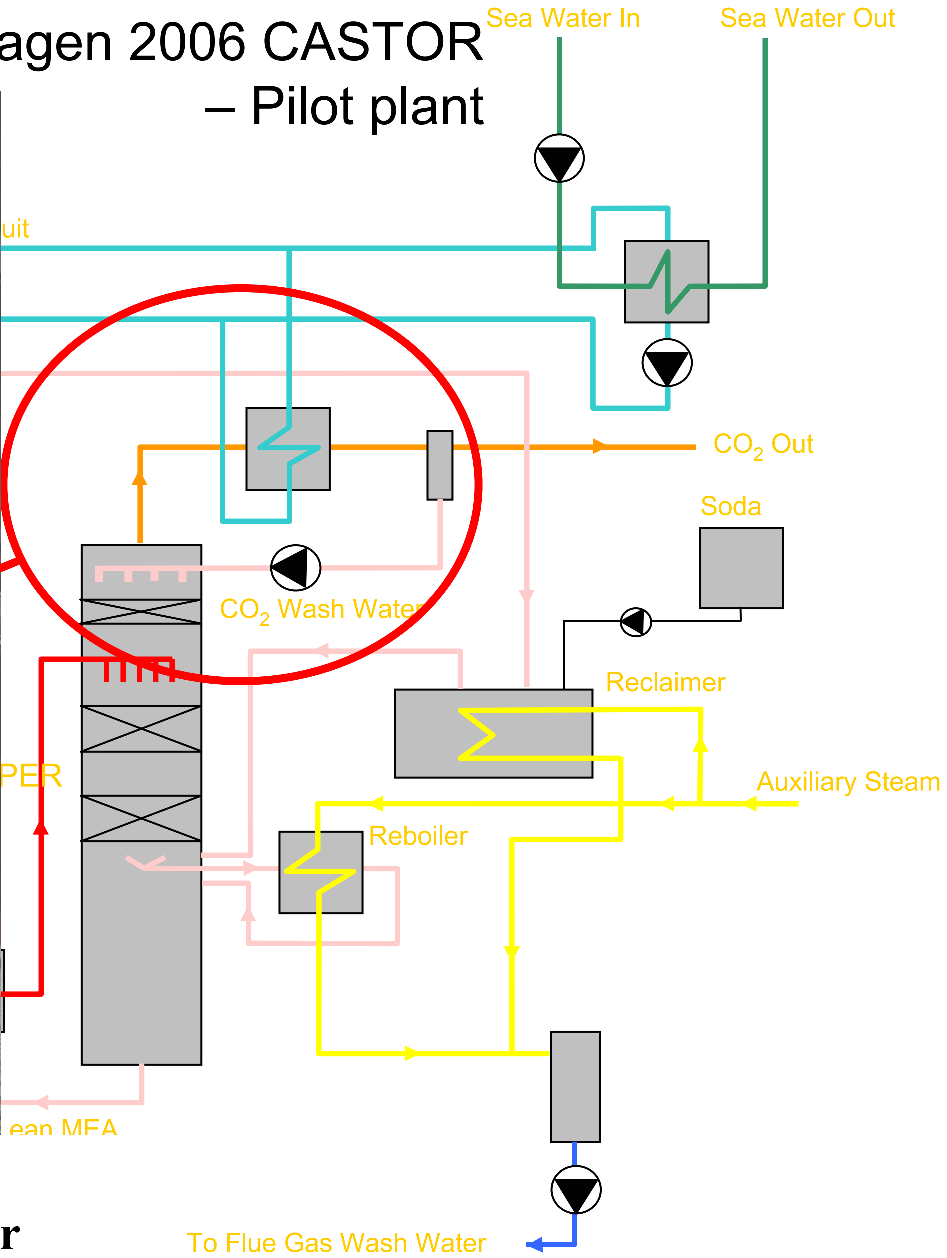
9th Int. CO_2 Capture Network, Copenhagen 2006 CASTOR – Pilot plant





STRIPPER WASH SECTION
Cleans CO_2 gas for MEA carry over

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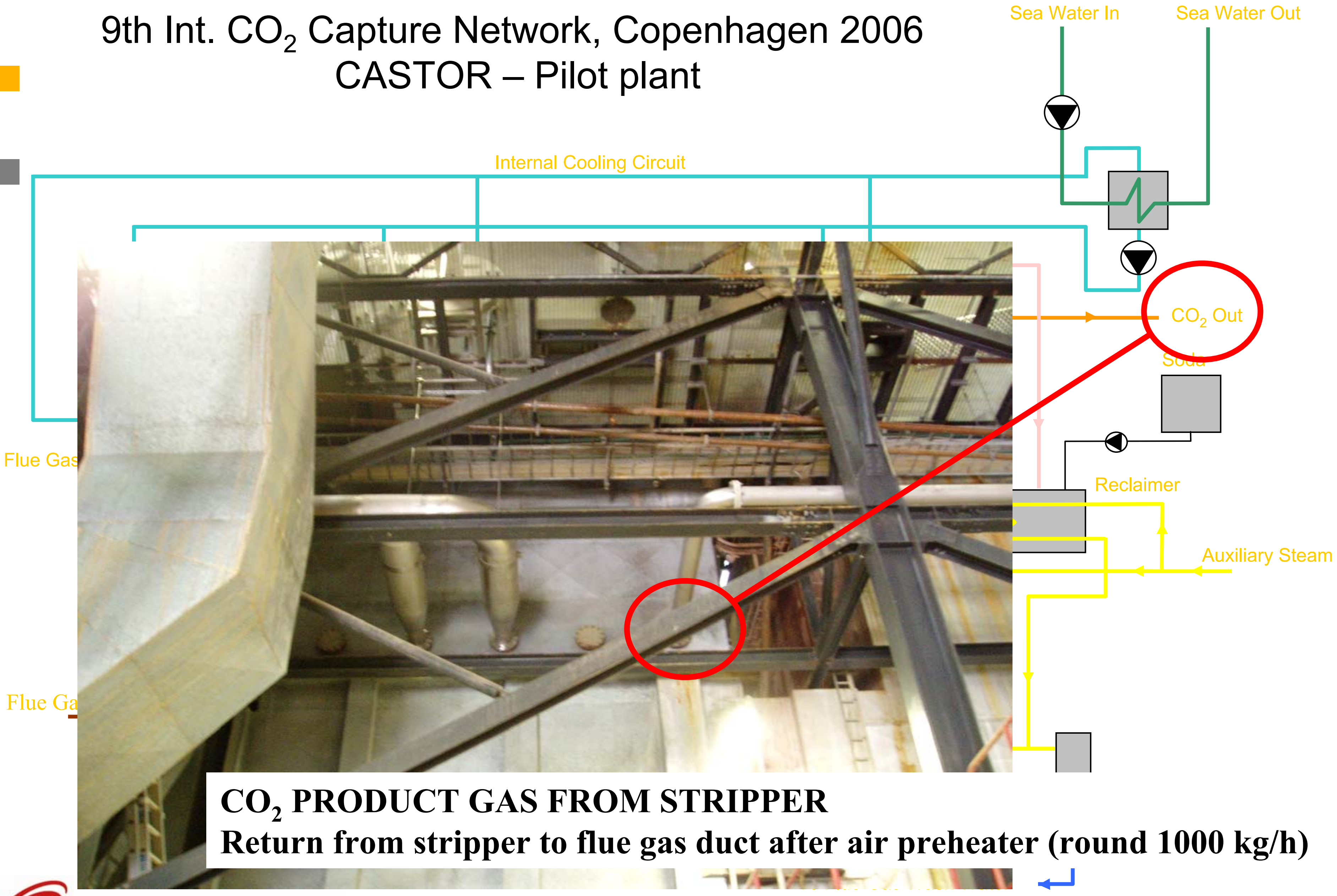
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



CO_2 PRODUCT GAS FROM STRIPPER

Return from stripper to flue gas duct after air preheater (round 1000 kg/h)

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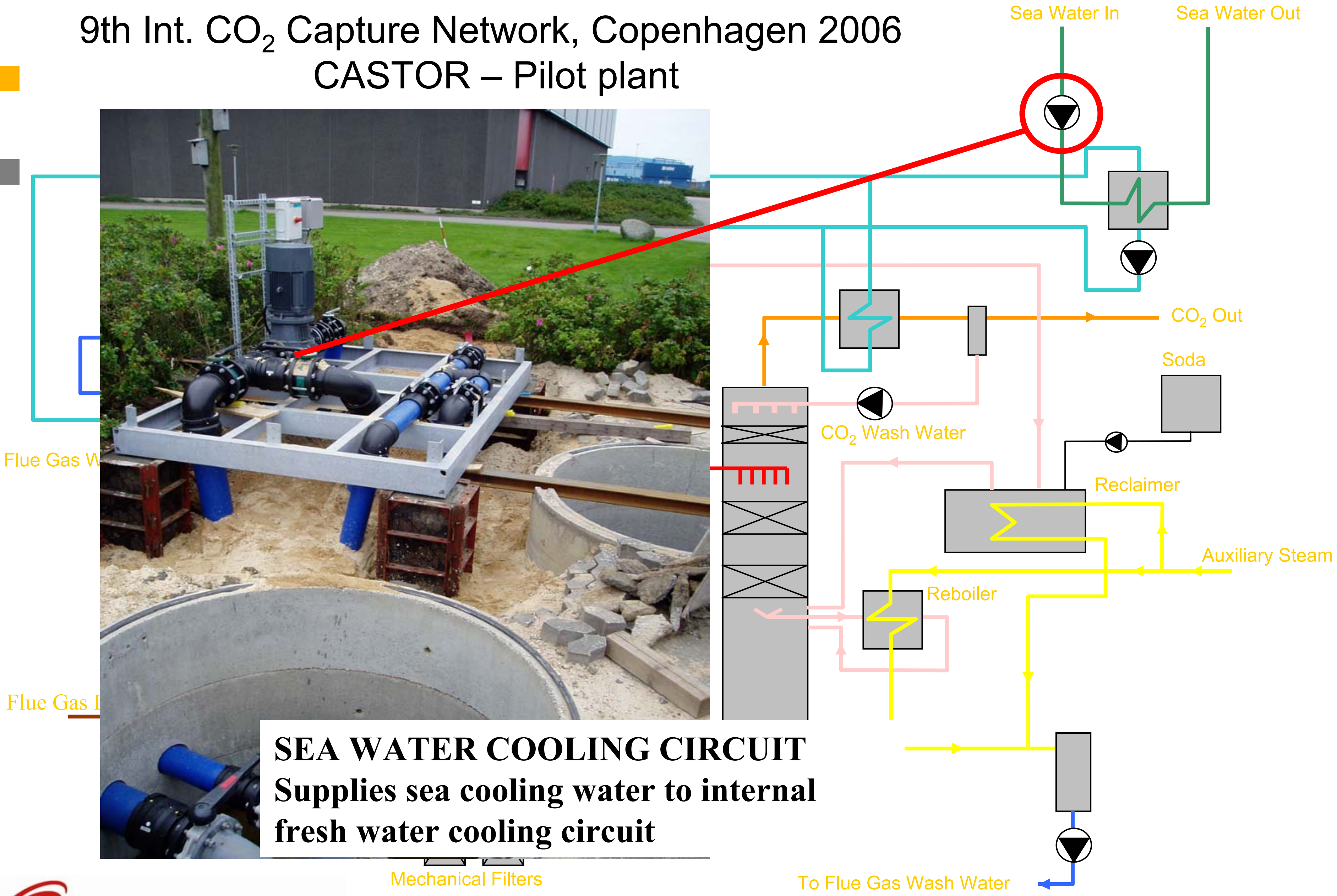
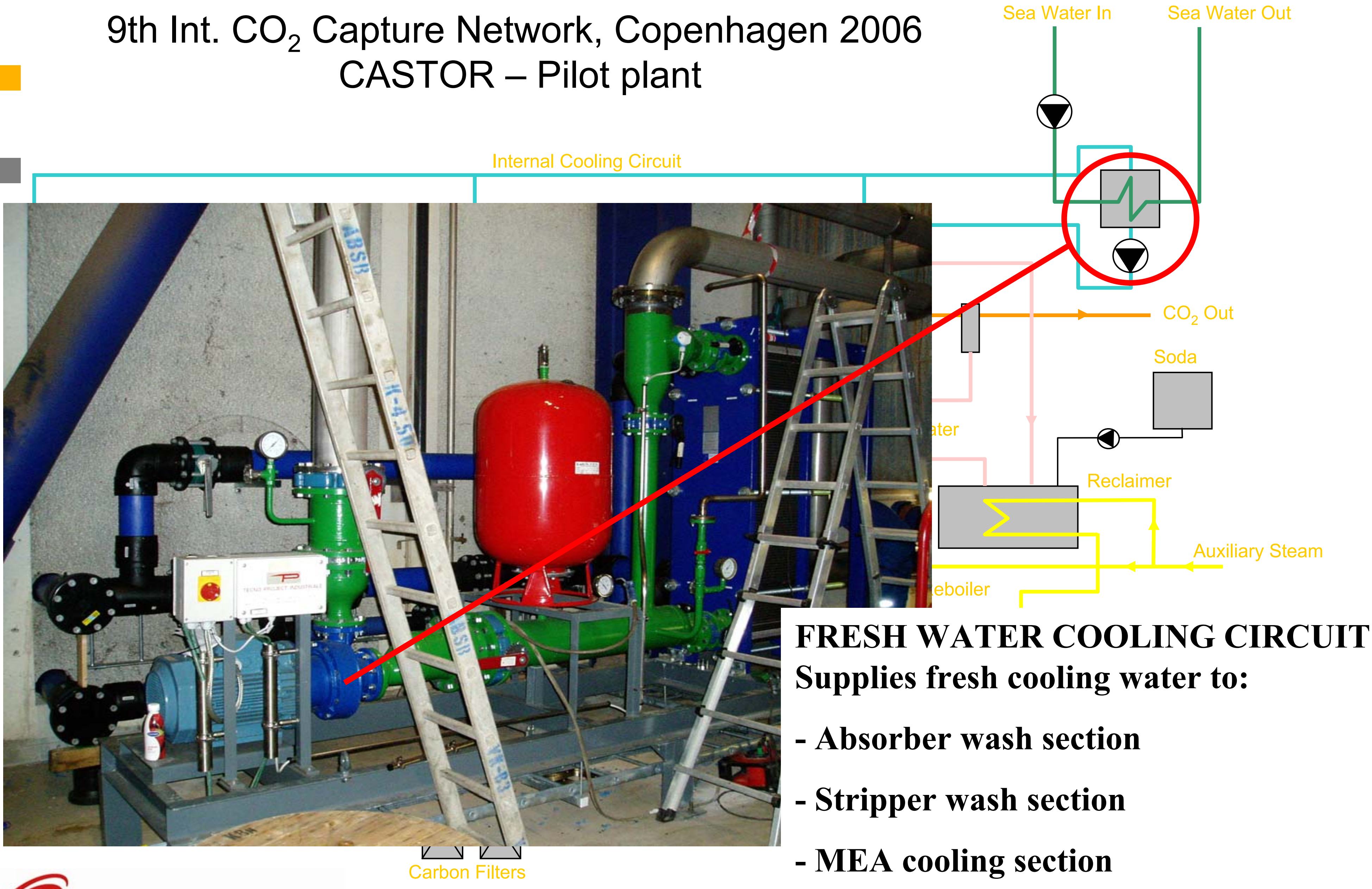
CASTOR – Pilot plant



SEA WATER COOLING CIRCUIT
Supplies sea cooling water to internal fresh water cooling circuit

9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant



FRESH WATER COOLING CIRCUIT
Supplies fresh cooling water to:

- **Absorber wash section**
- **Stripper wash section**
- **MEA cooling section**

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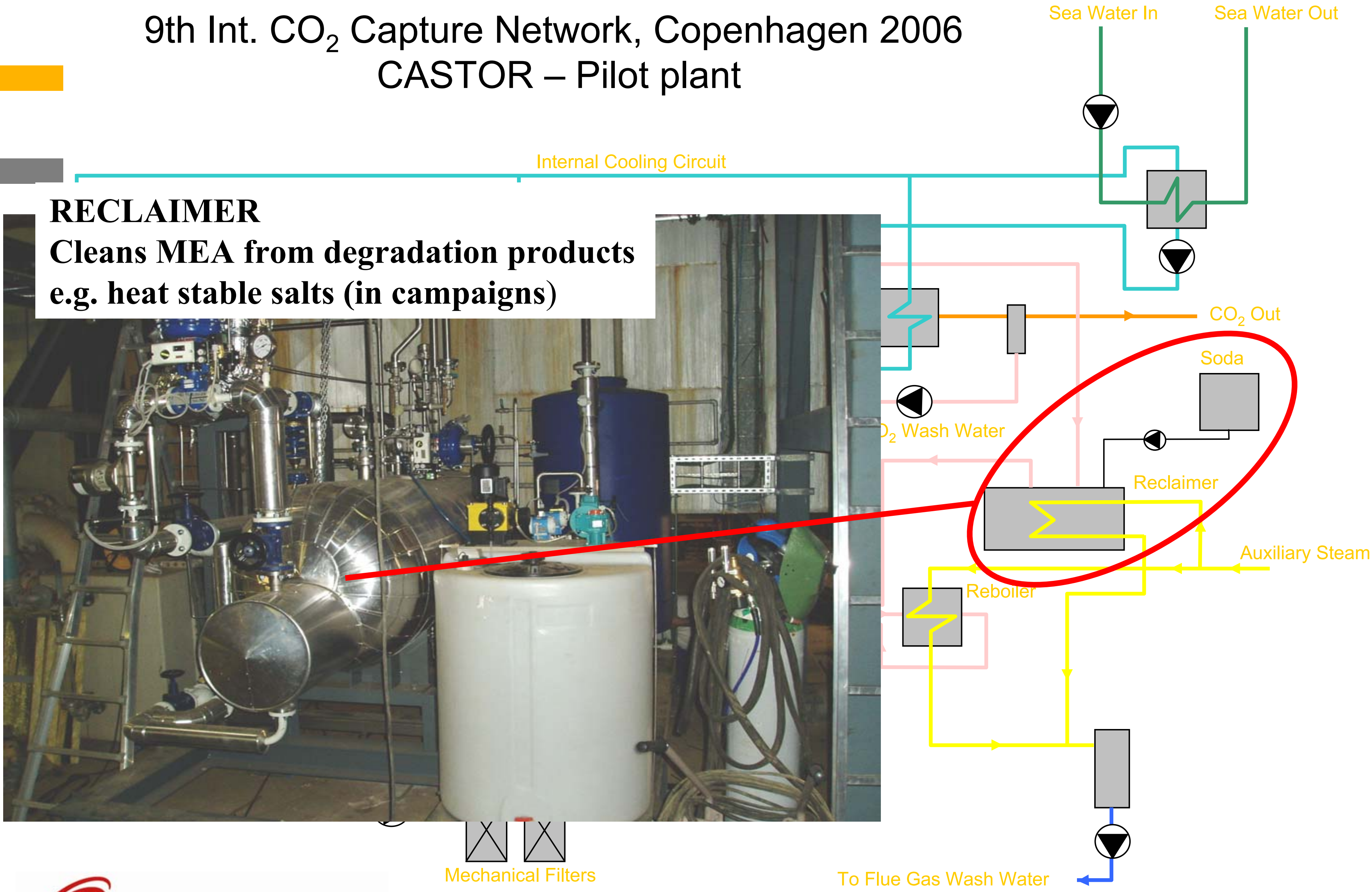
9th Int. CO_2 Capture Network, Copenhagen 2006
CASTOR – Pilot plant

RECLAIMER
Cleans MEA from degradation products e.g. heat stable salts (in campaigns)



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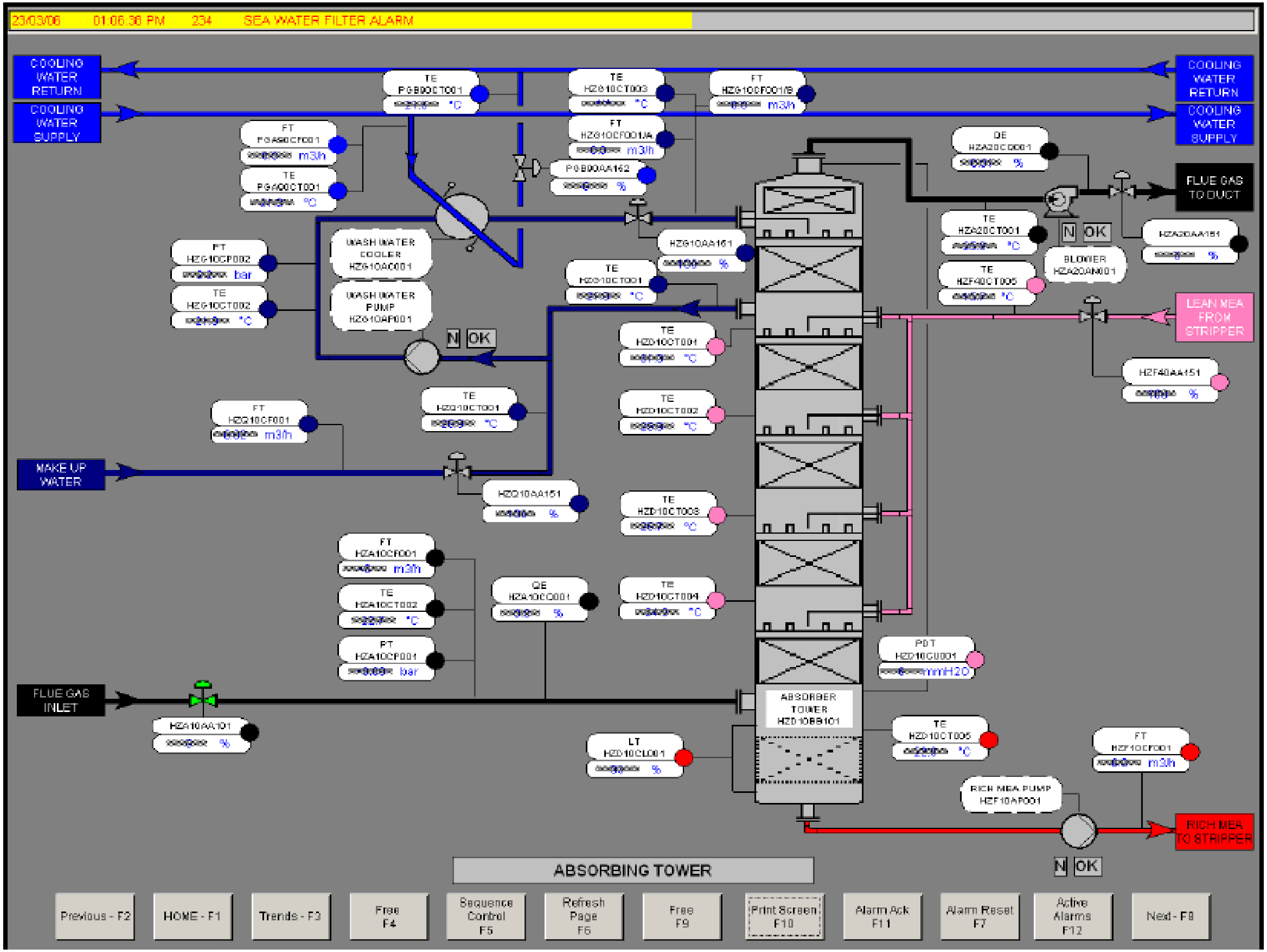
9th Int. CO2 Capture Network, Copenhagen 2006, CASTOR – Pilot plant



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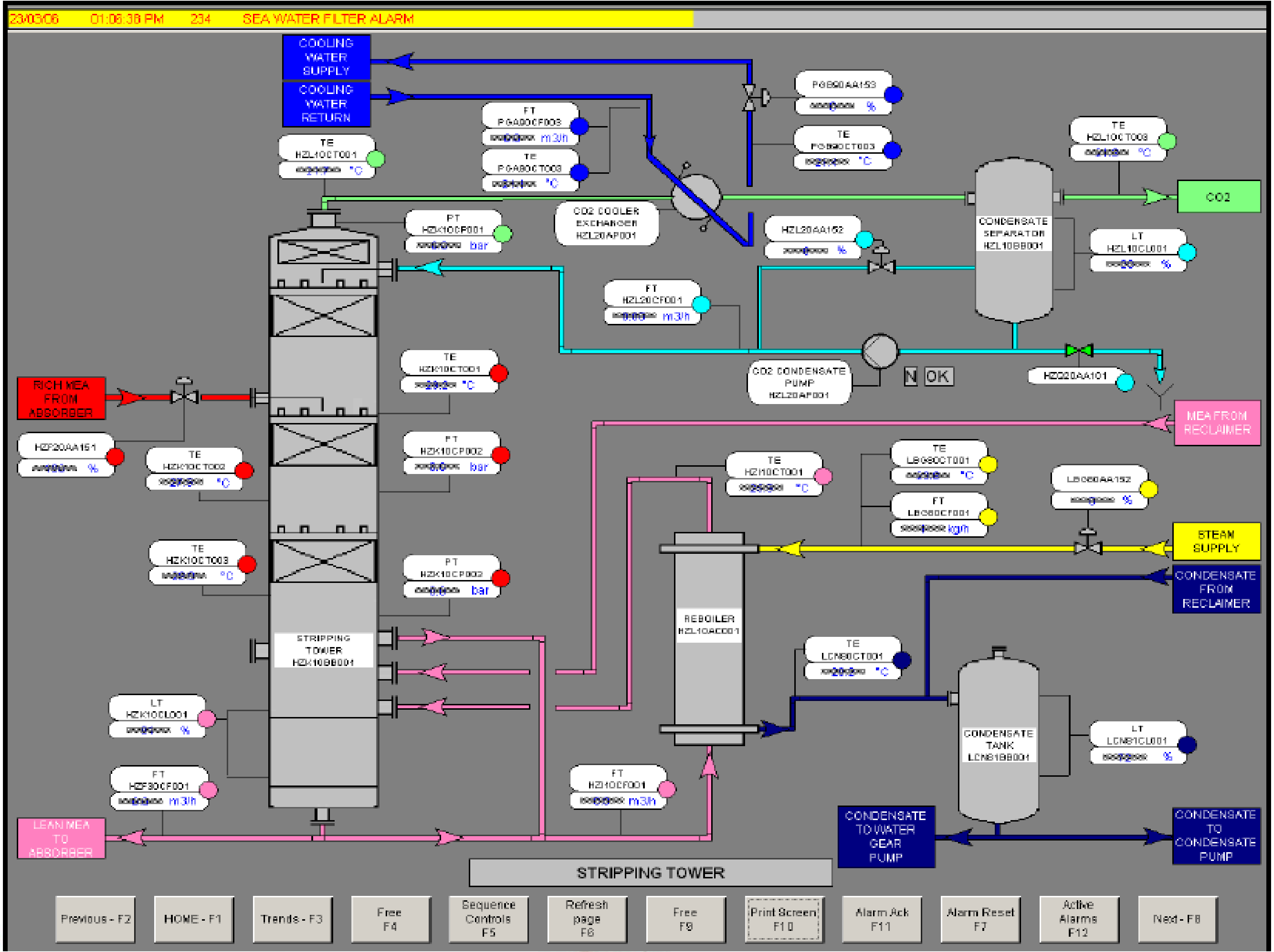
ENERGI E2



23/03/06 01:06:38 PM 234 SEA WATER FILTER ALARM

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ENERGI E2

- **Results from the Pilot Plant**

Objectives - 1000 hours MEA campaign

- Functional test of the pilot plant
- Gain of operating experience
- Information on operating costs (e.g. energy & solvent consumptions)
- Verification of theoretical models

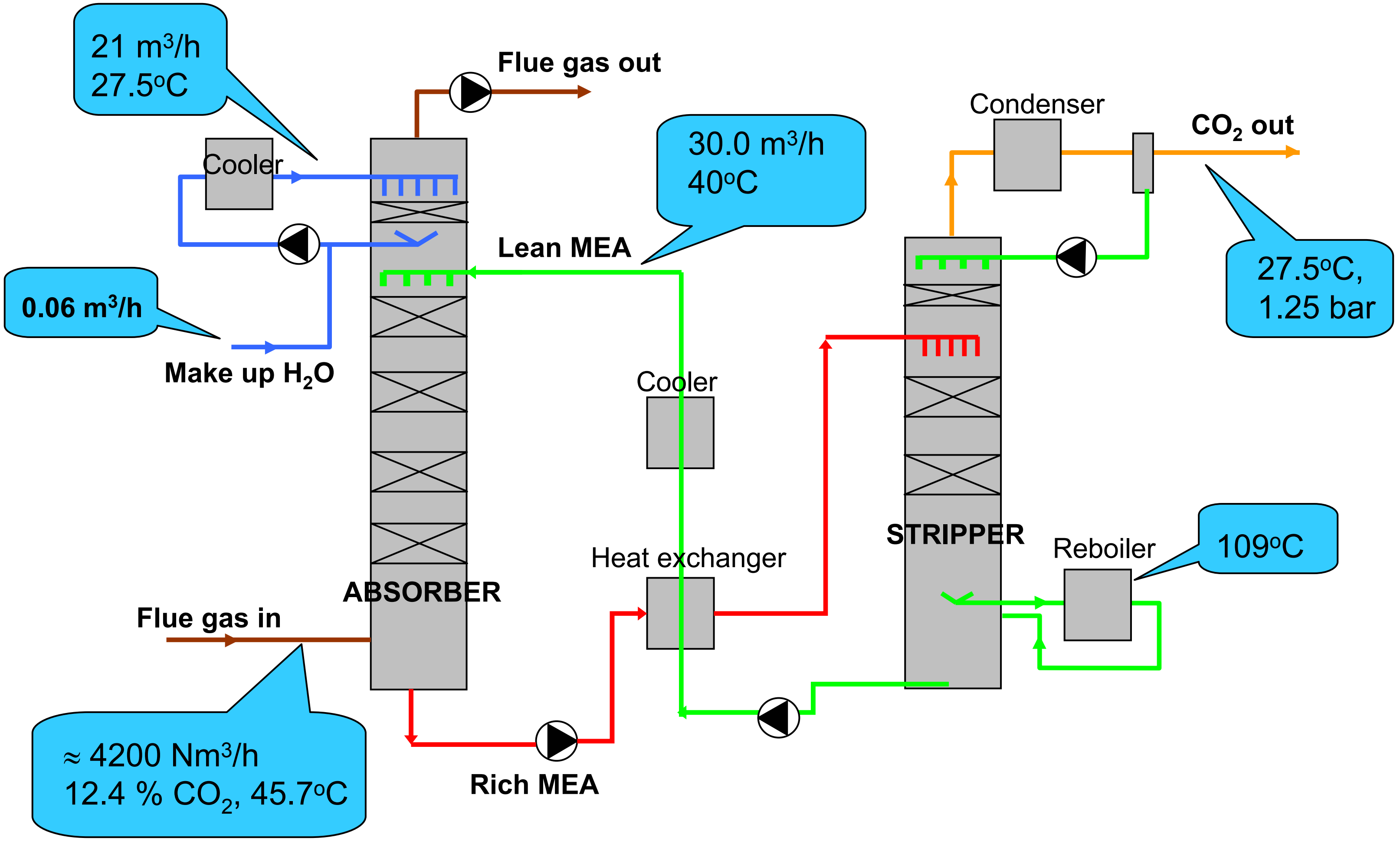
Test program – 1000 hours MEA campaign

- Test 1 – 500 hours of continuous operation (10/01/06 - 01/02/06)
  - Continuous operation at the nominal conditions, achieving 90% CO_2 capture
  - Corrosion tests (IFP)
- Test 2 – Parametric study (07/02/06 -15/02/06)
  a) Load following capability
  b) Minimizing the solvent flow
  c) Changing the regeneration temperature
  d) Optimizing the regeneration conditions
- Test 3 – Special interest experiments (20/02/06 - 02/03/06)
  a) Absorber pressure drop (IFP)
  b) SO_2 injection incl. extended gas and solvent analyses (RWE & TNO)

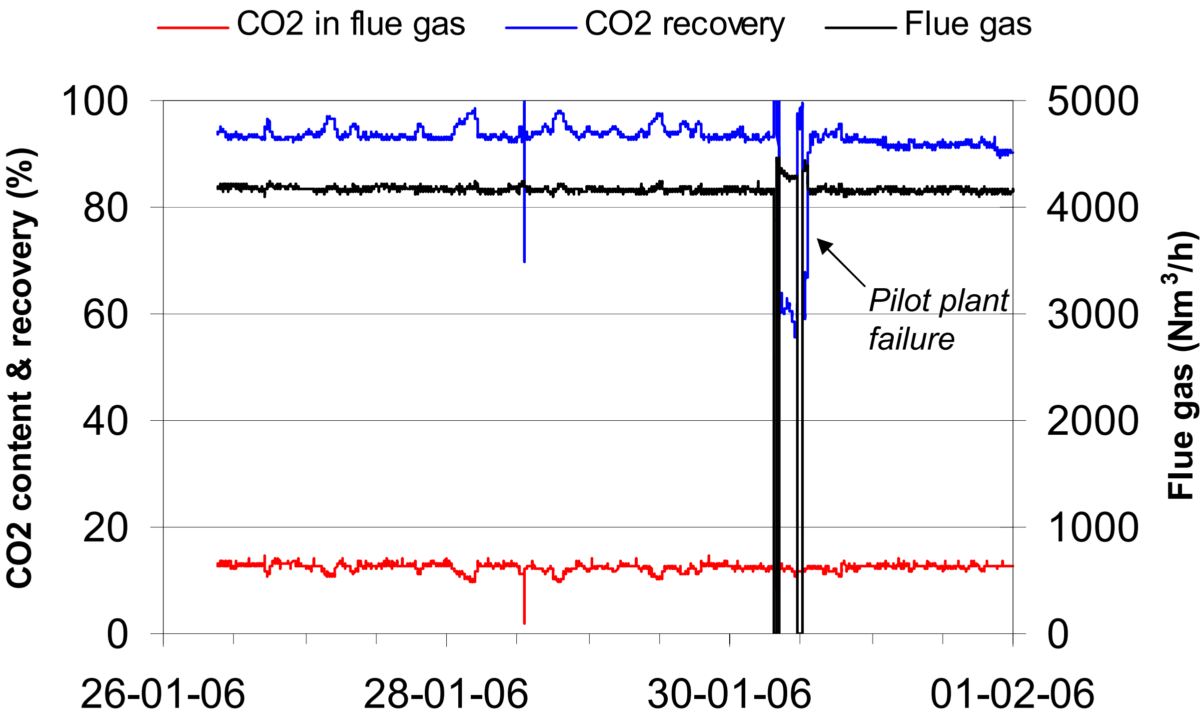
Test 1 - Summary

- Continuous operation from Jan 10th to Feb 1st
- Plant operated at settings recommended by the contractor:
- 18 outages during the test. Total down time: ≈20 hours
- Causes: High SO_2, high levels, plugging of sea water filter
- Frequent plugging of solvent filter (gypsum, fly ash)
- Fresh MEA added to compensate for losses
- No reclaiming during the test

Test 1 – Settings



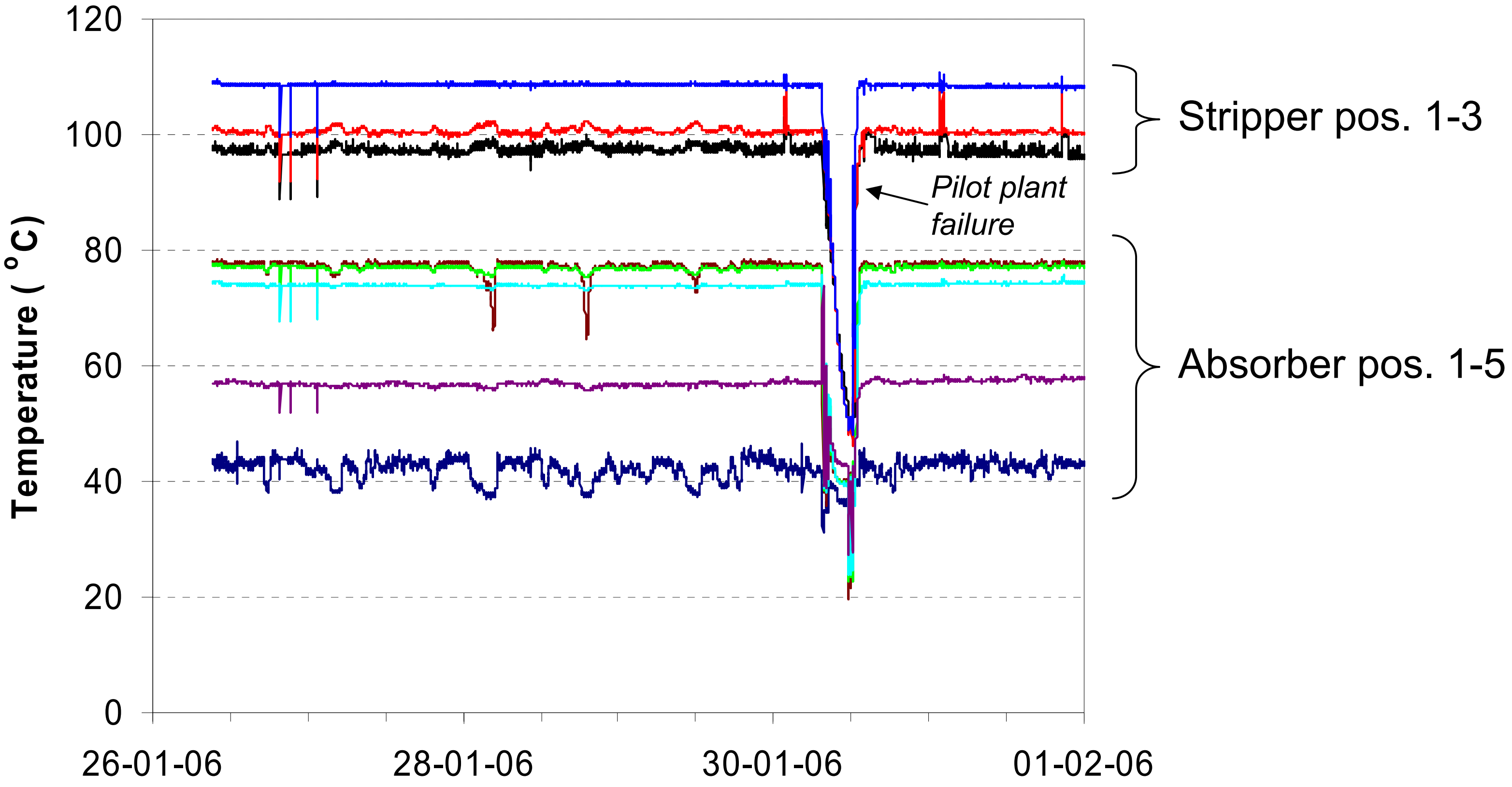
Test 1 – CO_2 recovery



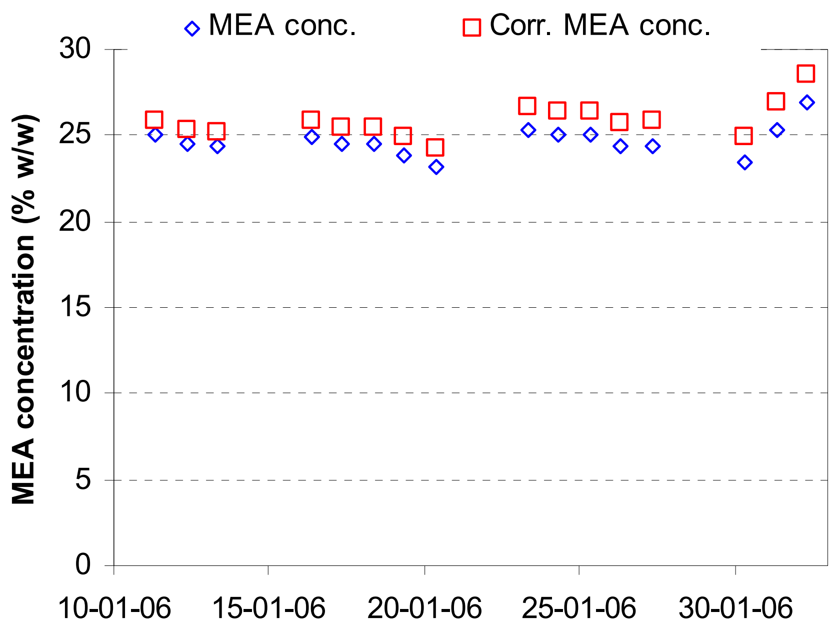
Average (26/01/06 - 01/02/06):

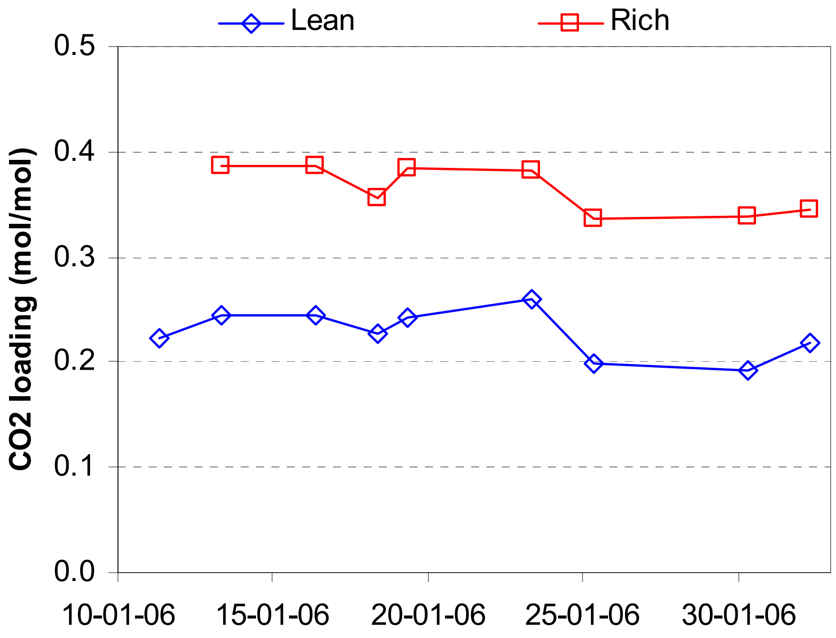
- Flue gas flow: 4170 Nm³/h (12.4% CO_2)
- CO_2 recovery: 92.5%
- CO_2 production: 850 kg/h

Test 1 – Absorber & Stripper temperatures



Test 1 – MEA % and CO_2 loadings





Average value:

- MEA: 25.7 %
- Lean loading: 0.24
- Rich loading: 0.37 (not reliable)

Test 1 - Balances

Material balances (26/01/06 - 01/02/06)

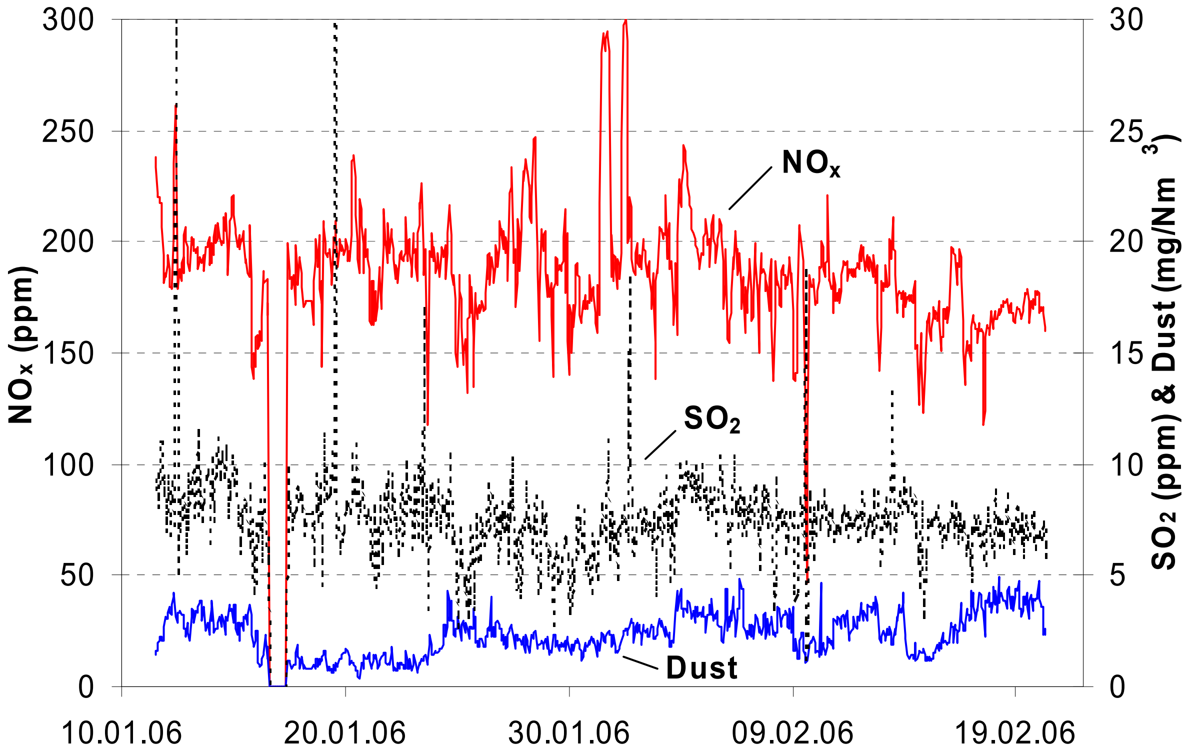
	Stream	*avg. value*
CO_2 balance:	CO_2 absorbed - gas side	**846**
(kg/h)	CO_2 desorbed - gas side	**885**
	CO_2 absorbed - solvent	**687**
H_2O balance:	H_2O condensed from flue gas	**246**
(kg/h)	Make up H_2O to abs. wash	**60**
	H_2O input with CO_2 product	**-12.3**
	Drain of stripper condensate	**n.d.**
	Total:	**+ 294**

Energy balance (26/01/06 - 01/02/06)

Heat (MJ/ton CO_2)	*avg. value*
Heat input from steam	**4400**
Heat from flue gas	**720**
Cooling water	**-4930**
Distribution of cooling duty (%)*	**7.5 / 67 / 25.5**
Total energy balance	**+170 (3.3 %)**

*Distribution of cooling duty between abs. wash, MEA/H_2O cooler, and condenser

Flue gas pollutants - 1000 hours MEA Test



	O_2 (% vol)	NO_x (ppm)	SO_2 (ppm)	Dust (mg/Nm^3)
Average – 10. Jan. - 20. Feb.	6,0	187	7,6	3,5
Design criteria	-	65	10	10

Elsam Engineering

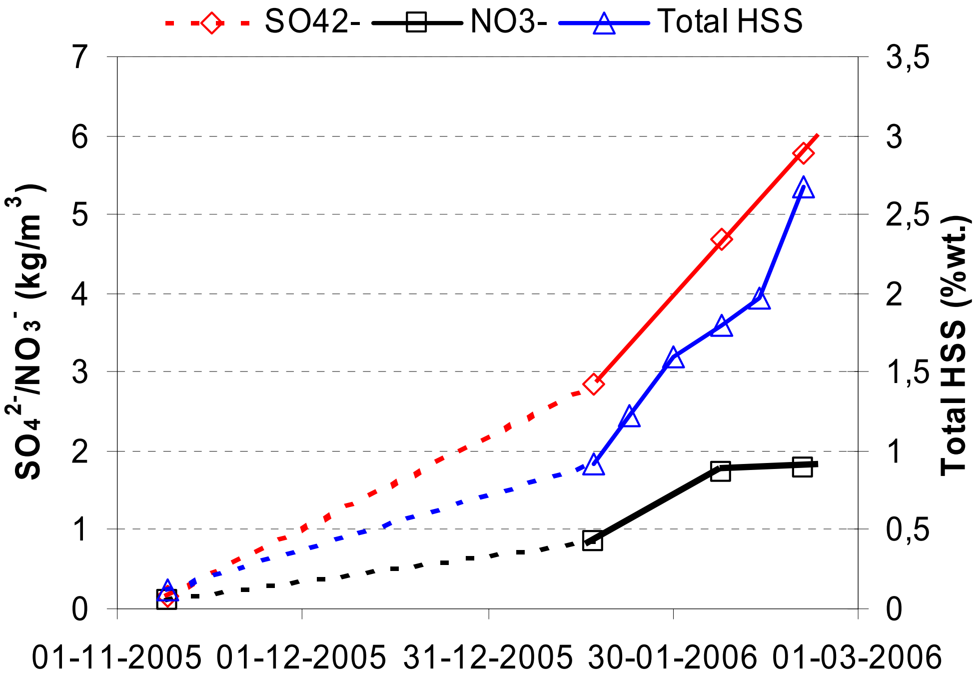
ENERGI E2

Solvent consumption & degradation

Findings

- MEA consumption during Test 1: 2.4 kg/ ton CO_2
- Nearly complete absorption of SO_2 (50% as SO_4^{2-})
- ≈1 % of NO_x absorbed ad NO_3^-
- Solvent saturated with gypsum
- MEA loss by degradation probably more significant than slip

Degradation & absorption of NO_x & SO_2



Upcoming activities at Esbjerg pilot plant

- Additional campaign with MEA (Summer 2006)
- Campaign with new solvent ”Castor 1” (Autumn 2006 - 2007)
- Campaign with new solvent ”Castor 2” (2007)

CO_2 absorption using precipitating amino acids in a spray tower

J.P. Brouwer, P.H.M. Feron, N.A.M. ten Asbroek
Department of Separation Technology
TNO-Science and Industry, Apeldoorn, The Netherlands

9th International CO_2-Capture Network Meeting
16 June 2006

Overview

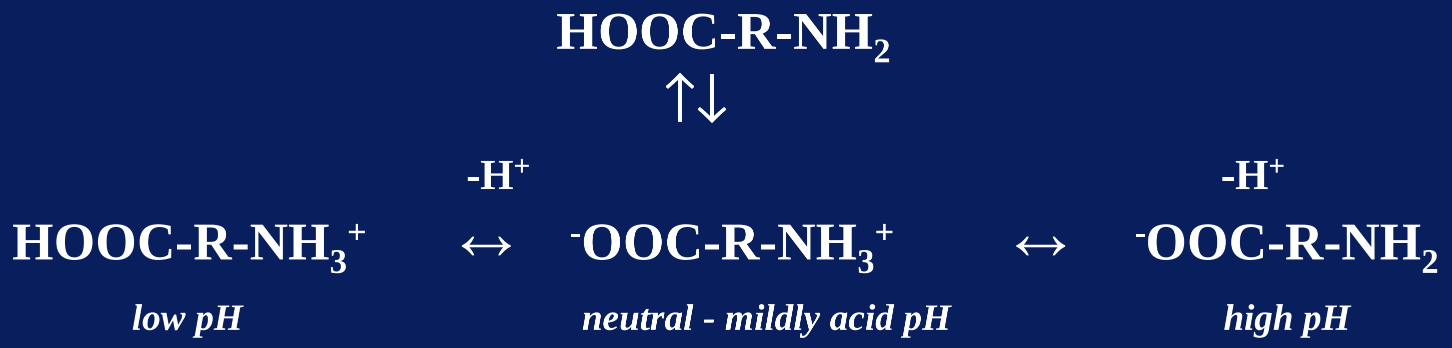
- Introduction to the Decab process
- Selection of contactor type
- Experimental set-up
- First results
- Preliminary design considerations
- Conclusions + future work

Introduction to the Decab process

- CORAL = $\underline{CO}_2$-$\underline{R}$emoval $\underline{A}$bsorption $\underline{L}$iquid
- Mixtures of amino-acids, alkali salts and amines
- Stable operation with polyolefin membranes
- Better oxygen stability
- Less corrosive
- No losses of active components
- Neutralized amino acids: very suitable for membrane gas absorption (no leakage through membrane, no vapour pressure, good thermal stability)

Chemistry

- Preparation by neutralization of amino acid with KOH (up to 6 M, thus high loadings possible), equilibria:



$$\begin{array}{ccccc} & & HOOC\text{-}R\text{-}NH_2 & & \\ & & \uparrow\downarrow & & \\ HOOC\text{-}R\text{-}NH_3^+ & \xleftrightarrow{-H^+} & {}^-OOC\text{-}R\text{-}NH_3^+ & \xleftrightarrow{-H^+} & {}^-OOC\text{-}R\text{-}NH_2 \\ \textit{low pH} & & \textit{neutral - mildly acid pH} & & \textit{high pH} \end{array}$$

- Solubility of neutral species is limited → salt formation during absorption

Reactions with CO_2 (similar to "normal" amine systems):

Carbamate formation (primary and secondary amines)

$CO_2 + 2\ {}^{-}OOC\text{-}R\text{-}NH_2 \leftrightarrow {}^{-}OOC\text{-}R\text{-}NH\text{-}COO^{-} + {}^{-}OOC\text{-}R\text{-}NH_3^{+}$ (1)

amine *carbamate* *protonated amine*

Carbamate hydrolysis

${}^{-}OOC\text{-}R\text{-}NH\text{-}COO^{-} + H_2O \leftrightarrow {}^{-}OOC\text{-}R\text{-}NH_2 + HCO_3^{-}$ (2)

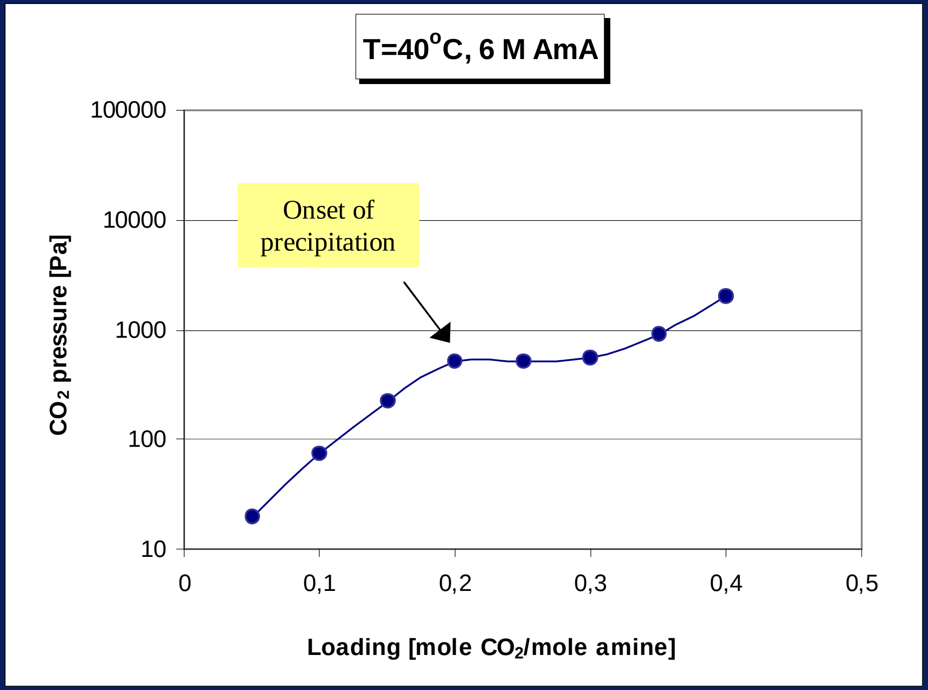
carbamate *amine* *bicarbonate*

Bicarbonate formation (tertiary amines, sterically hindered secondary amines)

$CO_2 + {}^{-}OOC\text{-}R\text{-}NH_2 \leftrightarrow {}^{-}OOC\text{-}R\text{-}NH_3^{+} + HCO_3^{-}$ (3)

amine *protonated amine* *bicarbonate*

Equilibria may be positively influenced by precipitation during absorption (removal of acid from solution)

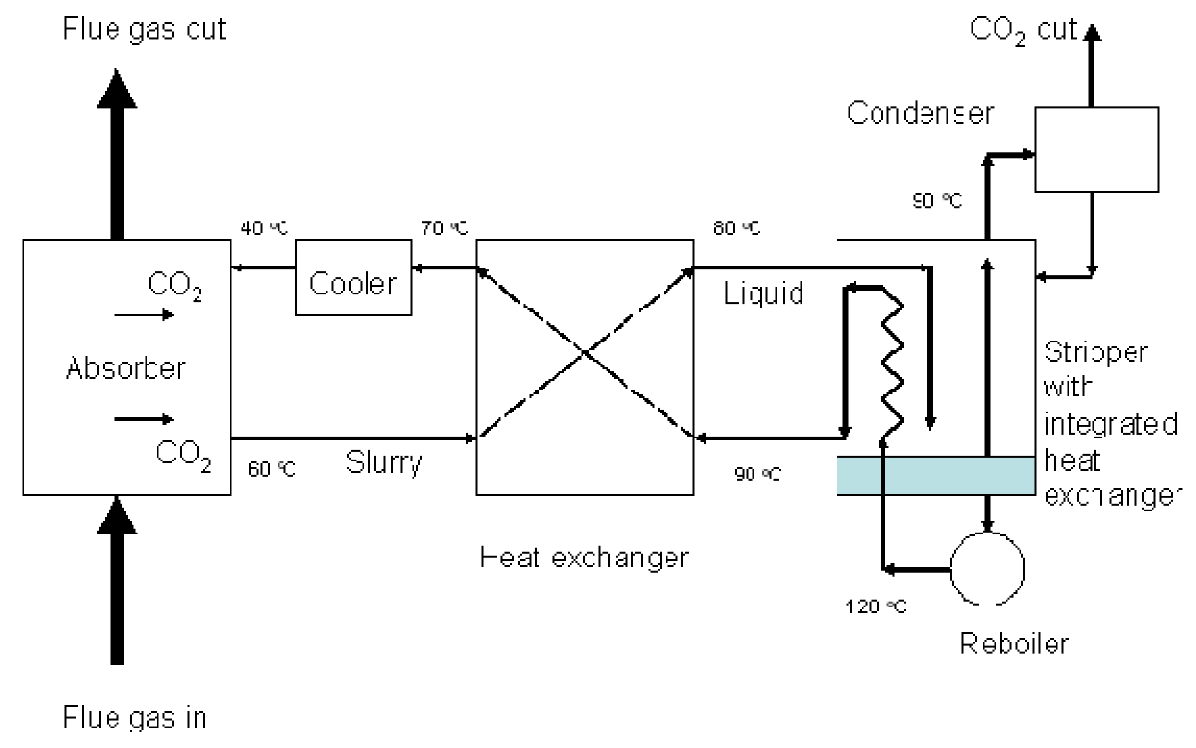


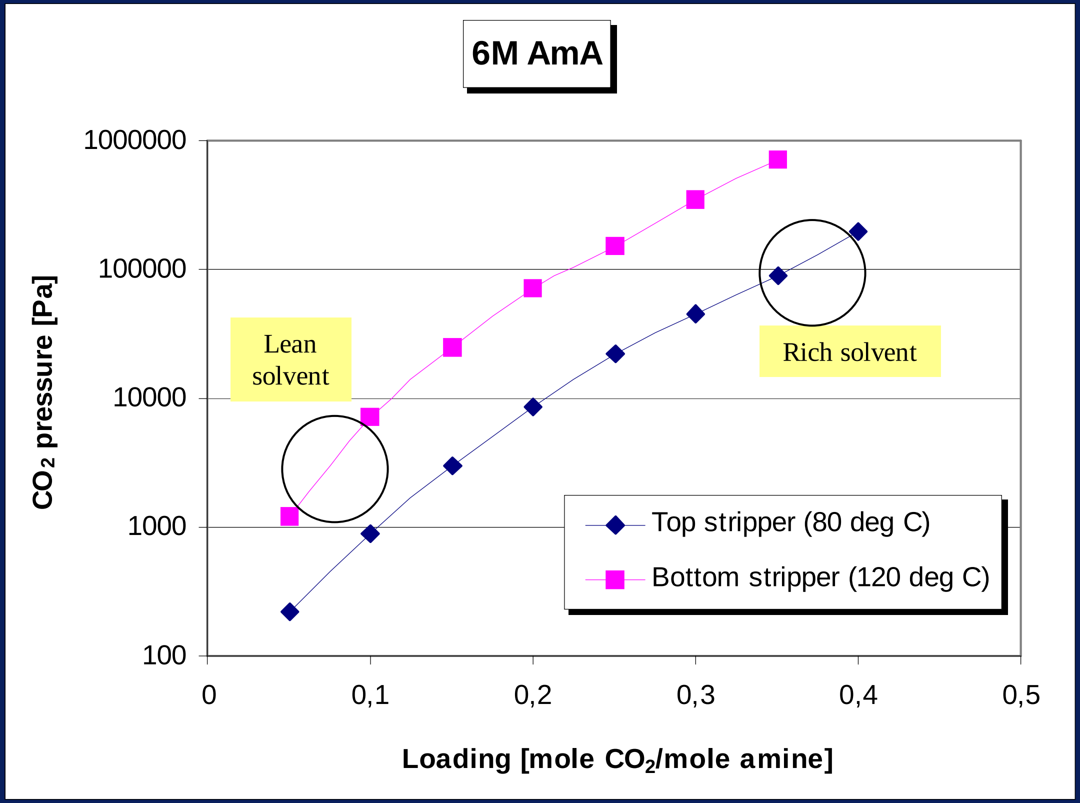
By increasing temperature, amino acid redissolves, effectively driving out CO_2

⇒ lower top temperatures in stripper may be applied

This necessitates use of an integrated heat exchanger though

Conceptual process design:





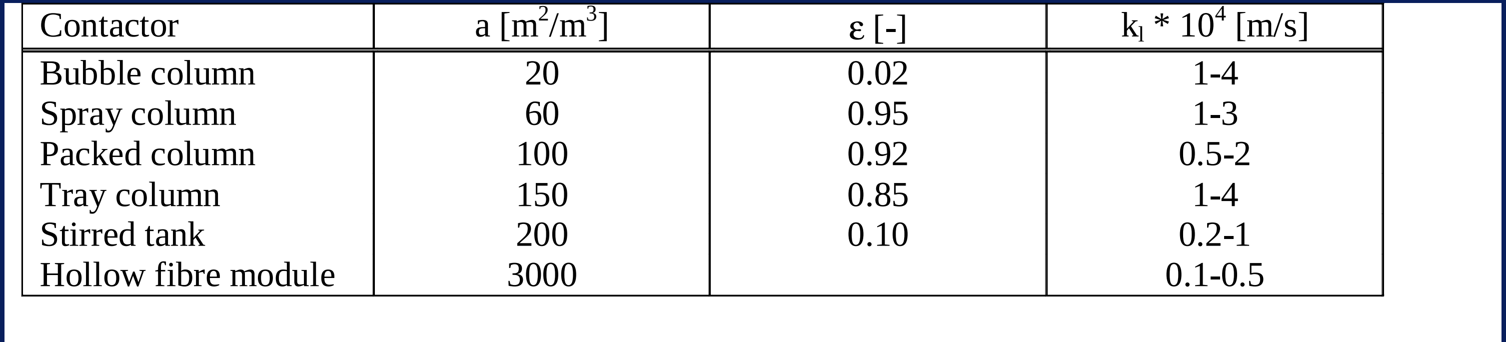
High cyclic loadings and low stripper top temperature are possible

→ Possible 40-50% reduction of energy consumption (compared to MEA)

→ Reduction of capital costs

What contactor?

- Contactor must be able to handle slurries!



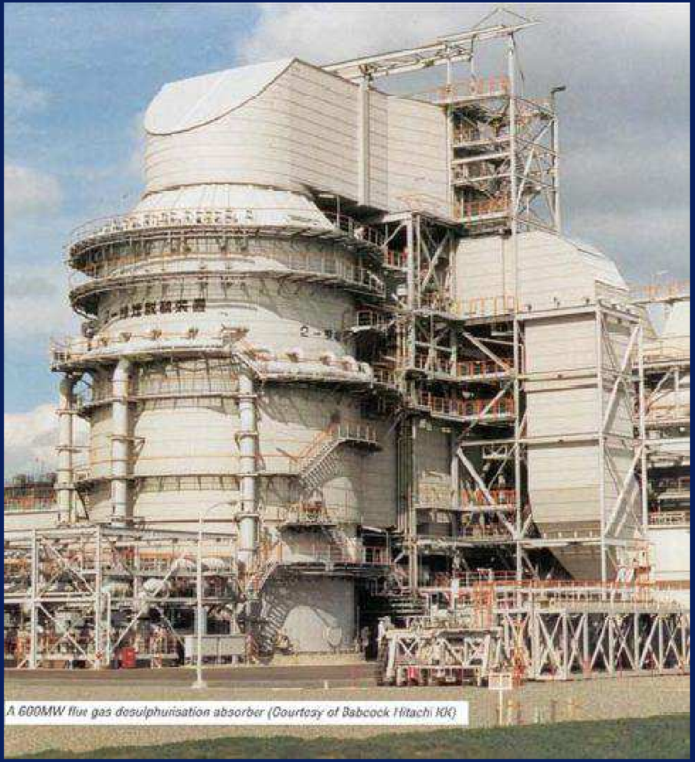
Contactor	a [m^2/m^3]	ε [-]	k_l * 10^4 [m/s]
Bubble column	20	0.02	1-4
Spray column	60	0.95	1-3
Packed column	100	0.92	0.5-2
Tray column	150	0.85	1-4
Stirred tank	200	0.10	0.2-1
Hollow fibre module	3000		0.1-0.5

- Interfacial area is important for efficiency
- Typical absorption regime for Coral: chemical enhancement (E=Ha), thus k_L not very important for flux
- MEA at high CO_2-concentrations: amine diffusion control, i.e. $E=E_\infty$

- **Spray columns are widely used in flue gas desulphurization**

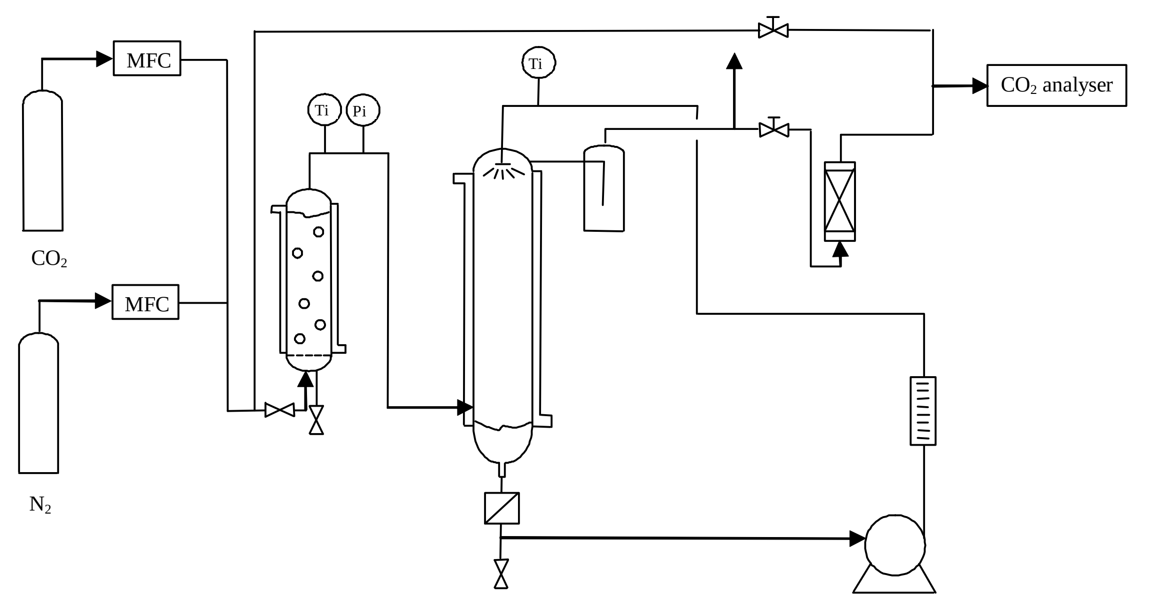
- **Advantages:**
  - Low pressure drop
  - High capacities, suitable for power plants
  - Robust system, capable of handling slurries

- **Drawbacks:**
  - Backmixing
  - Recycle of solvent may be required for high G-L interface. This is unwanted! We want countercurrent flow!



A 600MW flue gas desulphurisation absorber (Courtesy of Babcock Hitachi KK)

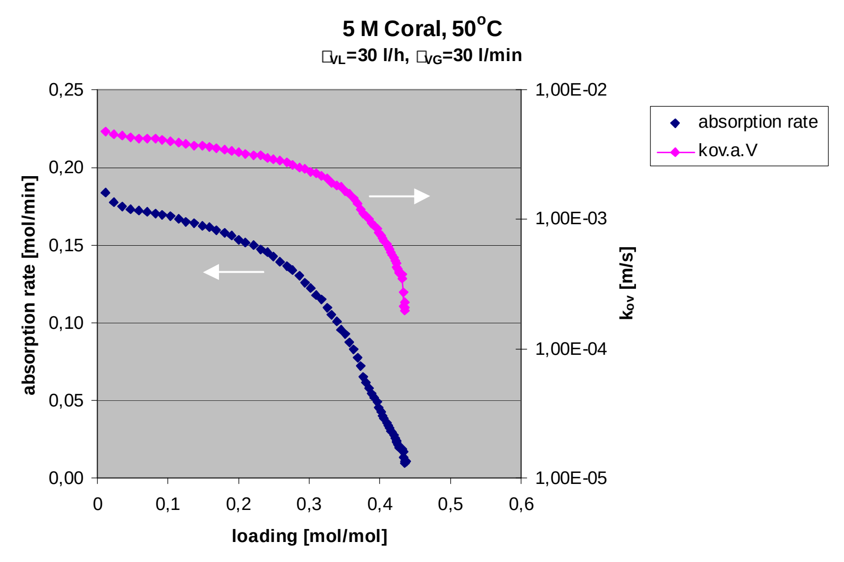
Experimental set-up (absorption)



First results

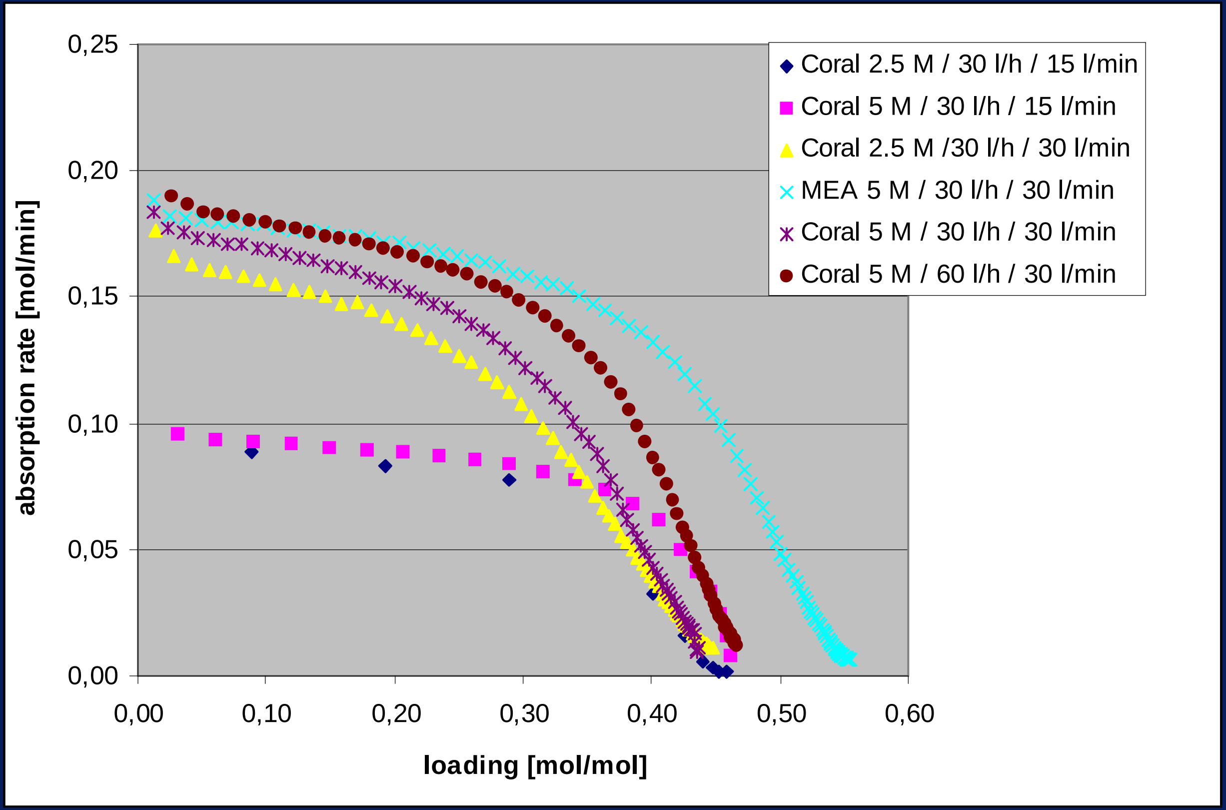
- **Absorption at 50-55^{o}C; feed gas = 15% CO_2**
- **Variation of**
  - Coral concentration
  - Gas flworate
  - Liquid flowrate

$$k_{ov} = \frac{r_{abs}}{aV\left(\frac{P_{CO_2} - P^*_{CO_2}}{RT}\right)}$$

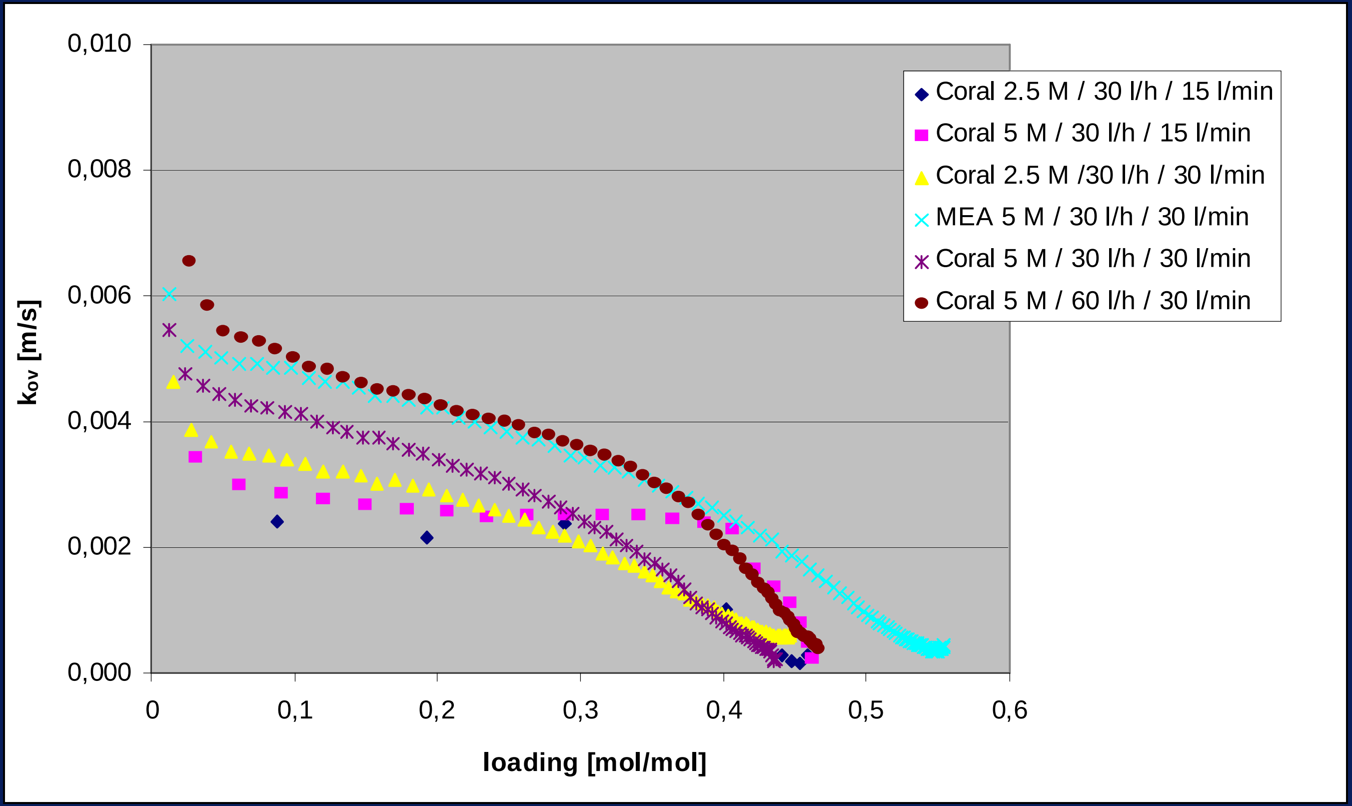


- **K_{ov} based on interpolated equilibrium pressures and estimated GL-surface area (including wetted wall!)**

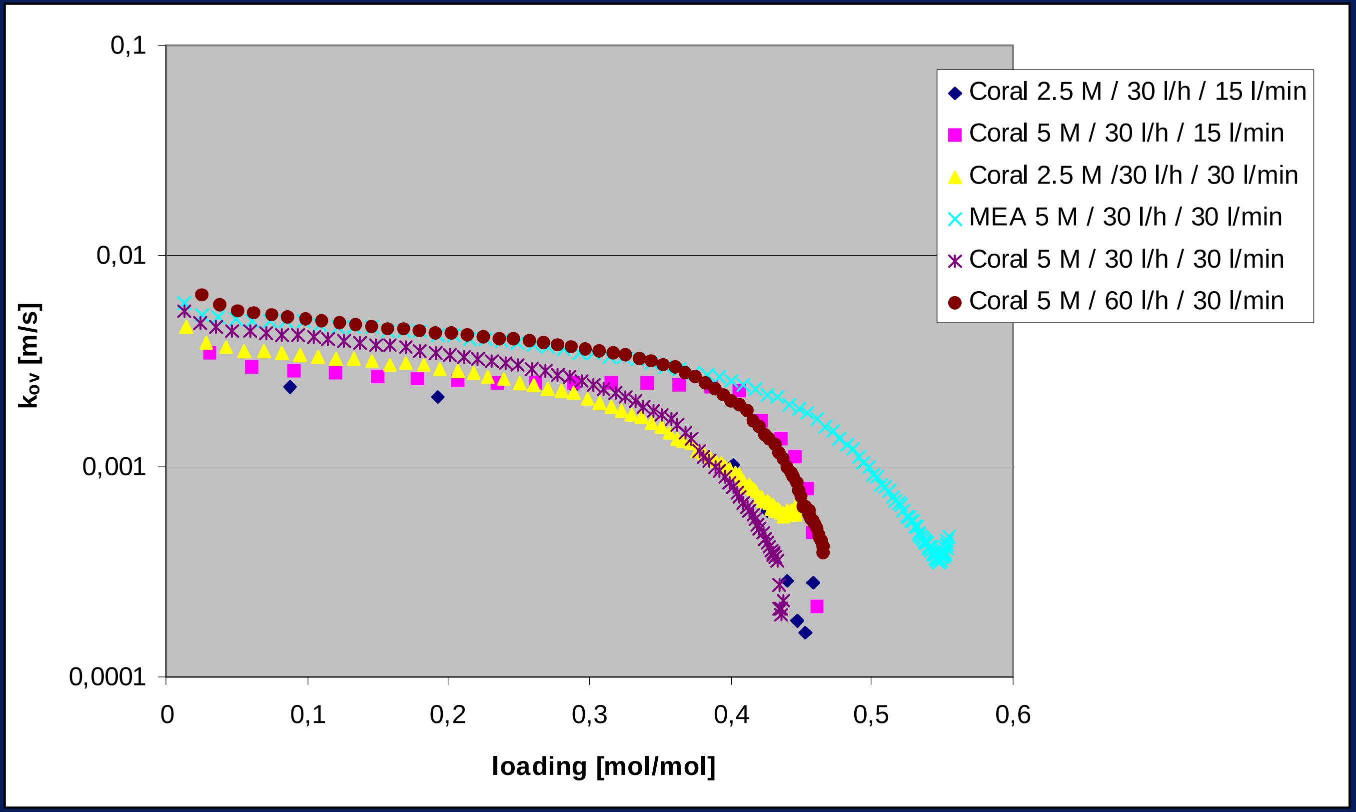
Absorption rates



Overall mass transfer coefficients

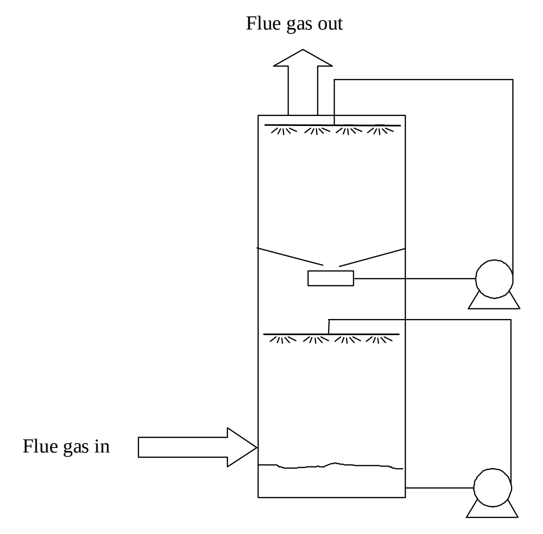


Overall mass transfer coefficients



Preliminary design considerations

- **Liquid recycling is detrimental to driving force! (increase of top loading)**
- **There exists an optimum recycling rate (increasing rate gives increasing a, but also increasing α_{top} and thus $P_{CO2,eq}$)**
- **Ways to deal with this:**
  - Accept lower removal, i.e. an estimated efficiency of 70-80% instead of 90% (based on H=40 m, 12% CO_2 in feed gas and measured k_{ov} as function of loading for countercurrent column)
  - Dual loop system: two column sections with separate absorbent circuits. Leads to loss in loading (not yet quantified).



Conclusions

- CO_2-absorption using precipitating amino acids in a spray tower is technically feasible (~75% CO_2 removal)
- Existing tower designs (for desulphurisation) can be used
- Potential for large capital and energy savings
- Liquid recycling may be required to obtain sufficient interfacial area; possibly dual loop system improves performance

To do

- More flux measurements at increased flowrates
- Equilibrium measurements at absorption temperature
- Desorption experiments

Novel Absorbents for CO_2 Capture From Gas Stream

Copenhagen, Denmark
16 June, 2006

RITE
Research Institute of Innovative Technology for the Earth
Kyoto, Japan (URL: http://www.rite.or.jp)

Today’s Contents

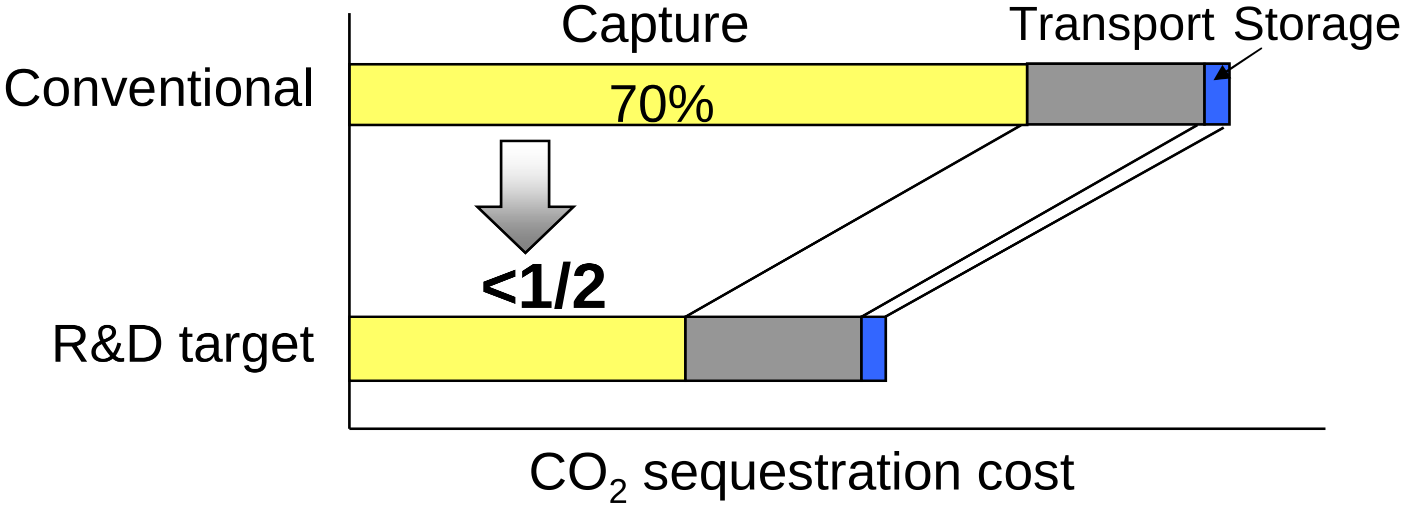
1. Outline of COCS Project

- **COCS Project:(Cost-Saving CO_2 Capture System)**
  - **Financial Support by METI**
  - **Collaboration with 3-Japanese Companies**

- **Target of COCS Project**

  CO_2 Separation by Chemical Absorption and Storage

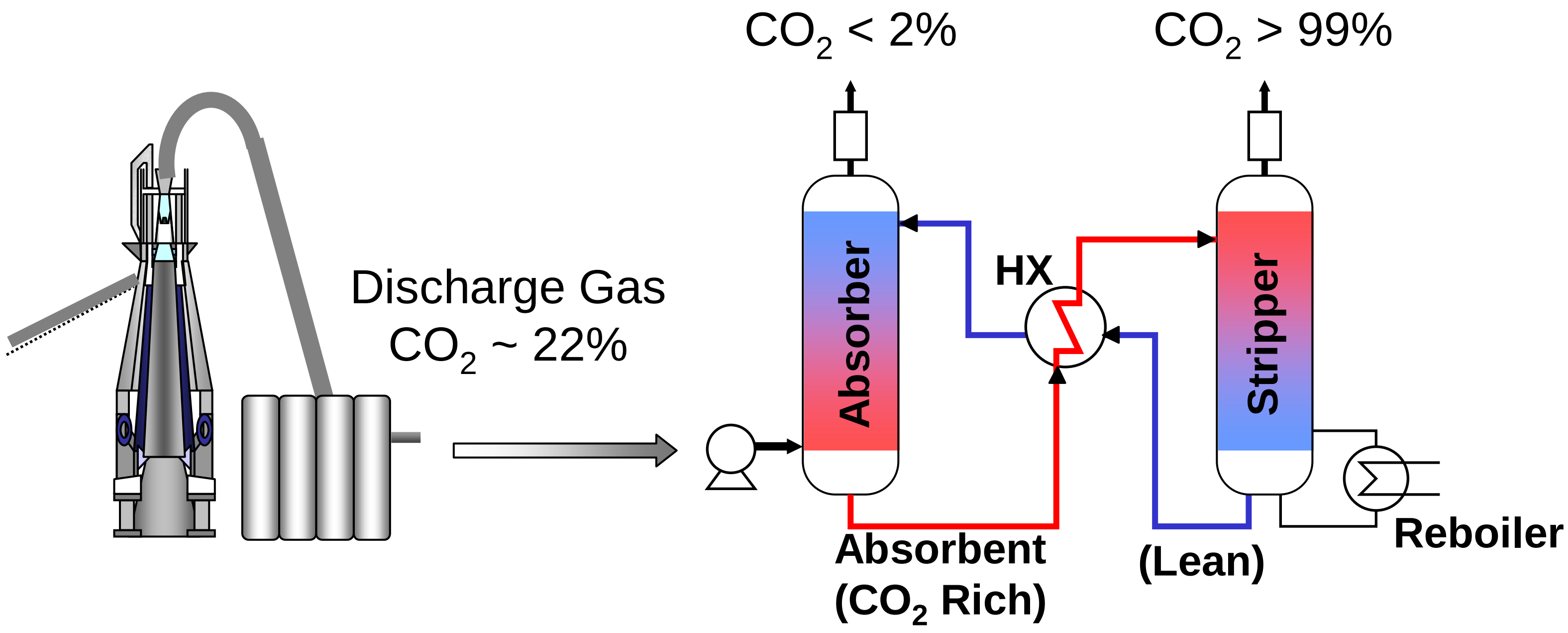
  - Reduce CO_2 Capture Cost by less than 1/2



Concepts of COCS Project

Steel plant, etc.

Chemical absorption



$CO_2 < 2\%$

$CO_2 > 99\%$

Discharge Gas
$CO_2 \sim 22\%$

Absorber

HX

Stripper

Reboiler

Absorbent
(CO_2 Rich)

(Lean)

- High CO_2 conc.

- New absorbents

- Utilization of low-grade waste heat

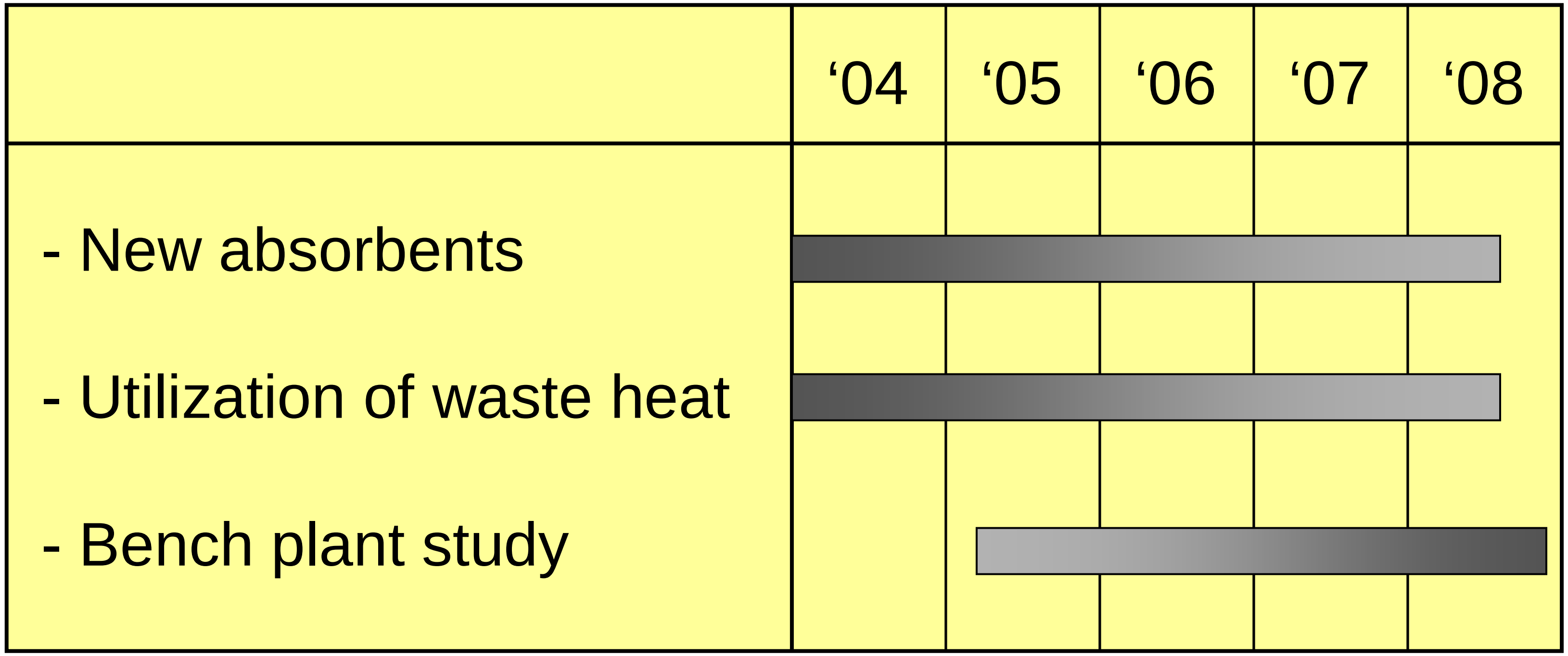
Reduction of Capture Cost

Objectives of COCS Project

1. Develop new absorbents and absorption system for lower-energy CO_2 capture

2. Evaluate new CO_2 capture system for steel plant
   1) Utilization of low-grade waste heat
   2) Removal of CO_2 from high CO_2 concentration discharged gas by bench plant study

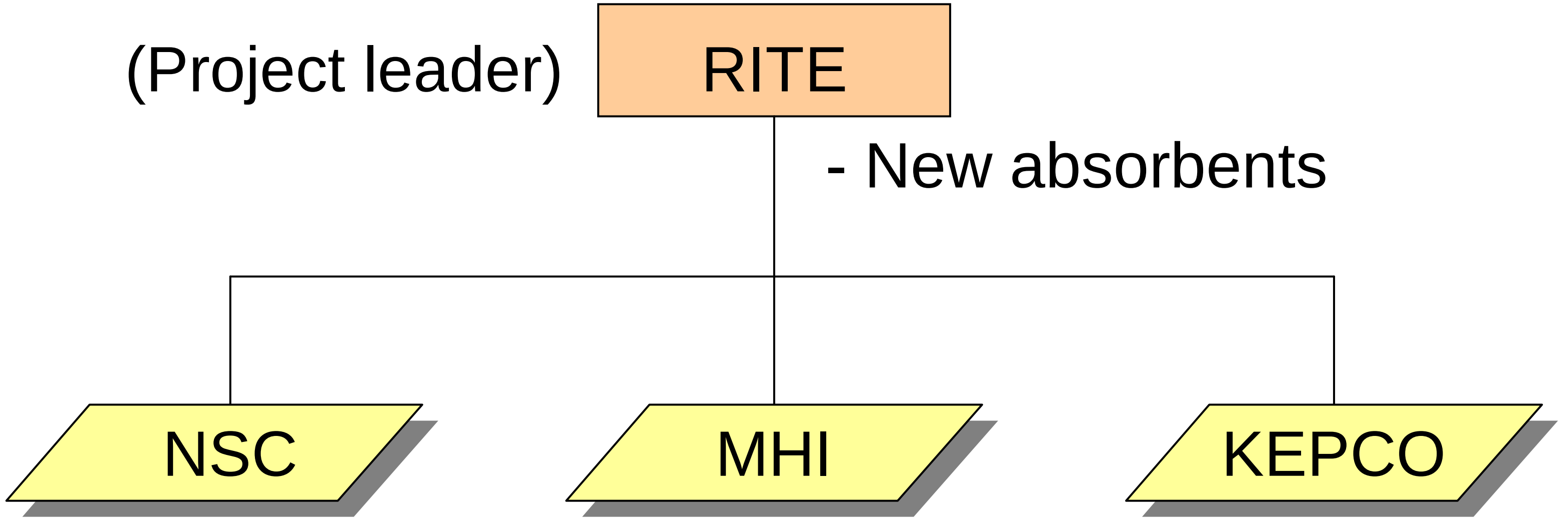
Schedule of COCS Project



‘04 ‘05 ‘06 ‘07 ‘08

- New absorbents
- Utilization of waste heat
- Bench plant study

Collaboration with 3 Japanese Companies



(Project leader) **RITE**

- New absorbents

NSC

- CO2 capture system

- Utilization of waste heat

MHI

- CO2 capture system

KEPCO

- New absorbents

Next Topics

Research Institute of Innovative Technology for the Earth

Today's Contents

1. **Outline of COCS project**

2. **Development of new absorbents**

   1) Ideas to find new absorbents

   2) Fundamental research

   3) Evaluation of new absorbents

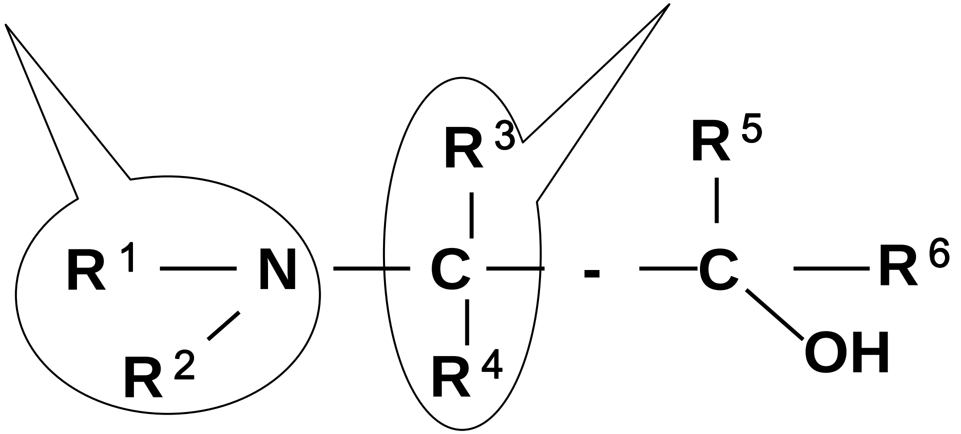
1) Ideas to Find New Absorbents

Desirable characteristics:

- Low energy use for CO_2 capture
- High absorption/desorption rate
- High capacity of CO_2 capture
- Low volatility and high stability

Keys to Exploring New Absorbents (1)

1. Low energy use for CO_2 capture
2. High absorption/desorption rate



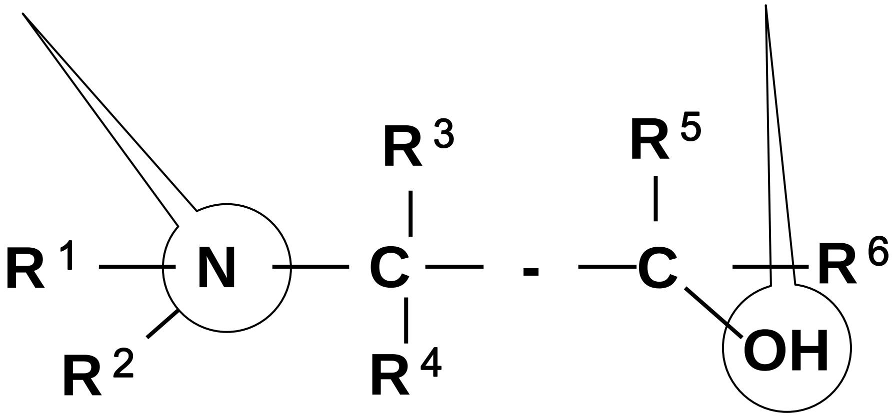
(1) Secondary/Tertiary amine

(2) Effect of steric hindrance

Keys to Exploring New Absorbents (2)

1. High capacity of CO_2 capture
2. Low volatility and high stability

(1) High density of amino group　　**(2) Position and number of OH-**



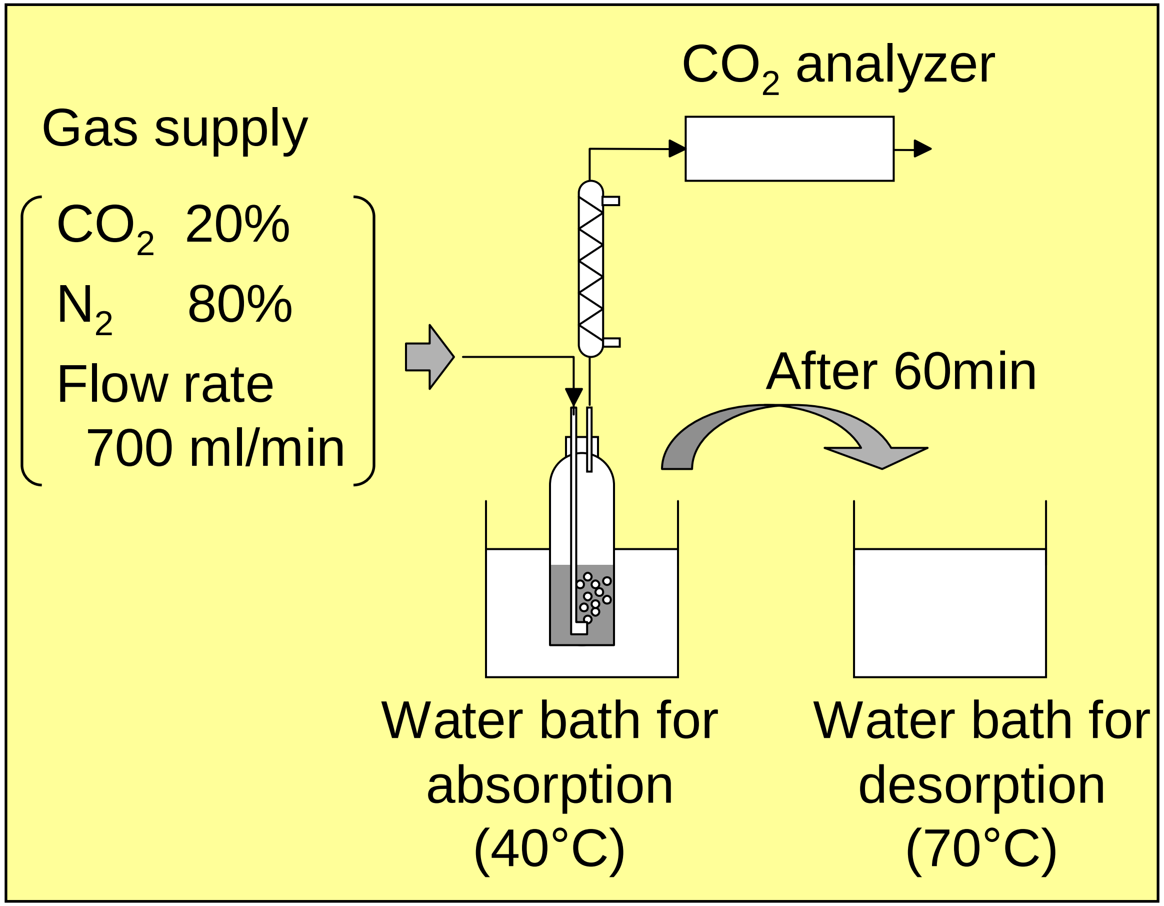
2) Fundamental Researches on New Absorbents

(First stage)
- **Screening**
- **Vapor-liquid equilibrium**
- **Heat of absorption**

(Second stage)
- Corrosion
- Kinetics
- Volatility

etc.

Screening


Gas supply

CO_2 20%
N_2 80%
Flow rate
700 ml/min

CO_2 analyzer

After 60min

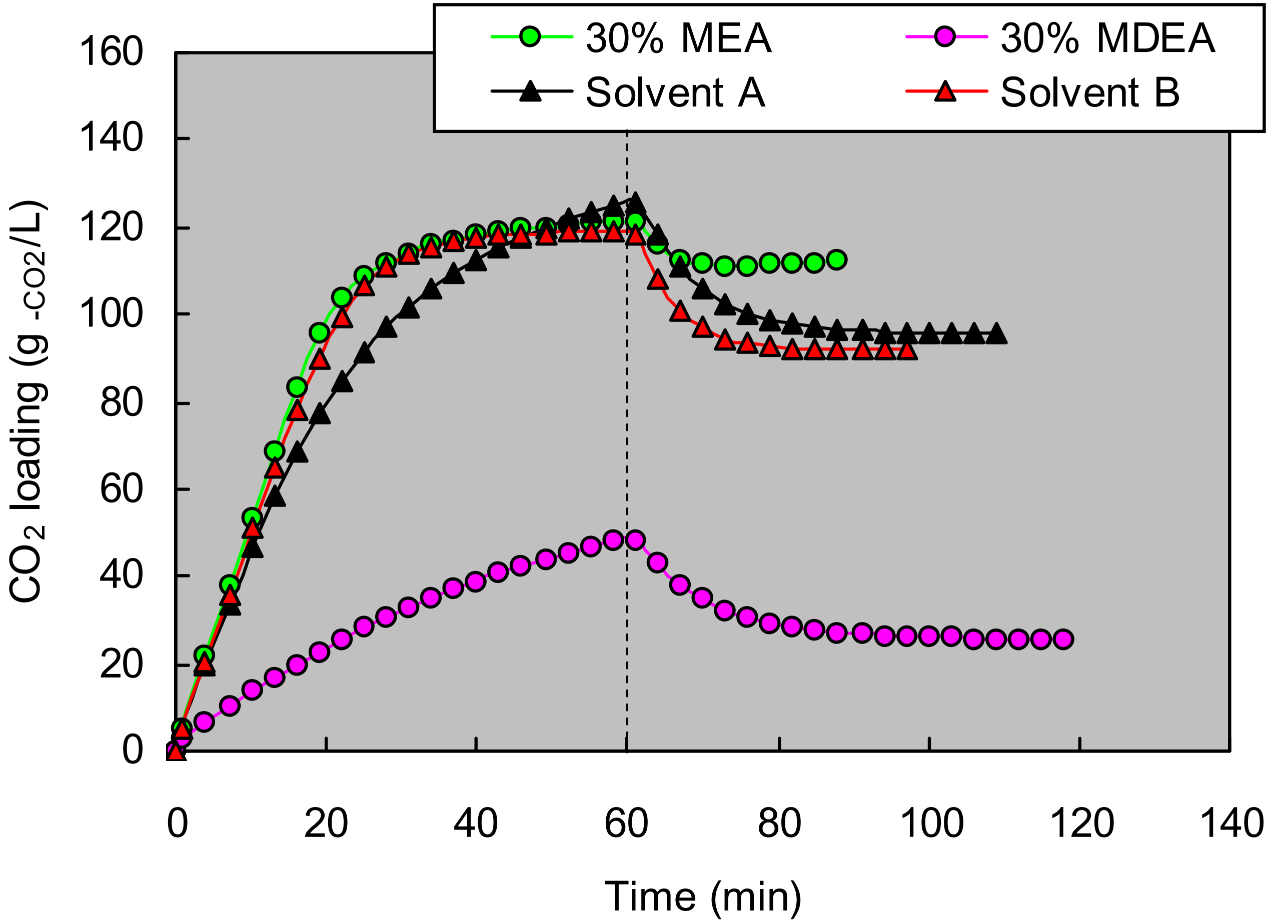
Water bath for absorption (40°C)

Water bath for desorption (70°C)

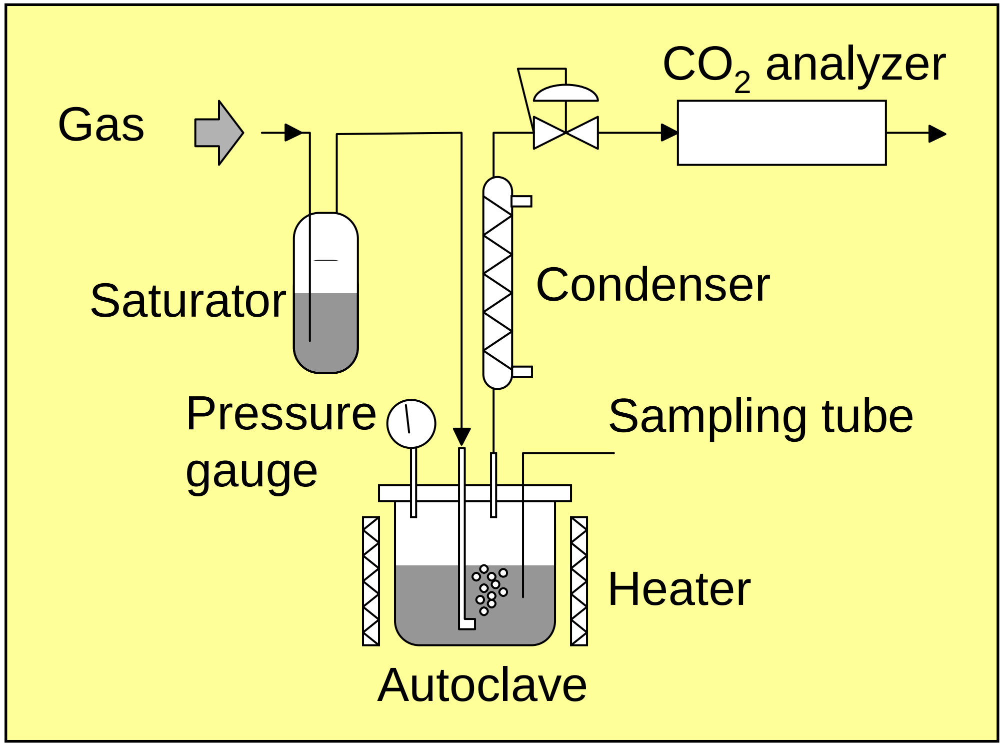
Absorbent : 50 ml
Absorption time : 60 min

Photo. Screening apparatus with six glass reactors

Results of Screening Tests



Vapor-liquid Equilibrium



Gas

CO_2 analyzer

Saturator

Condenser

Pressure gauge

Sampling tube

Heater

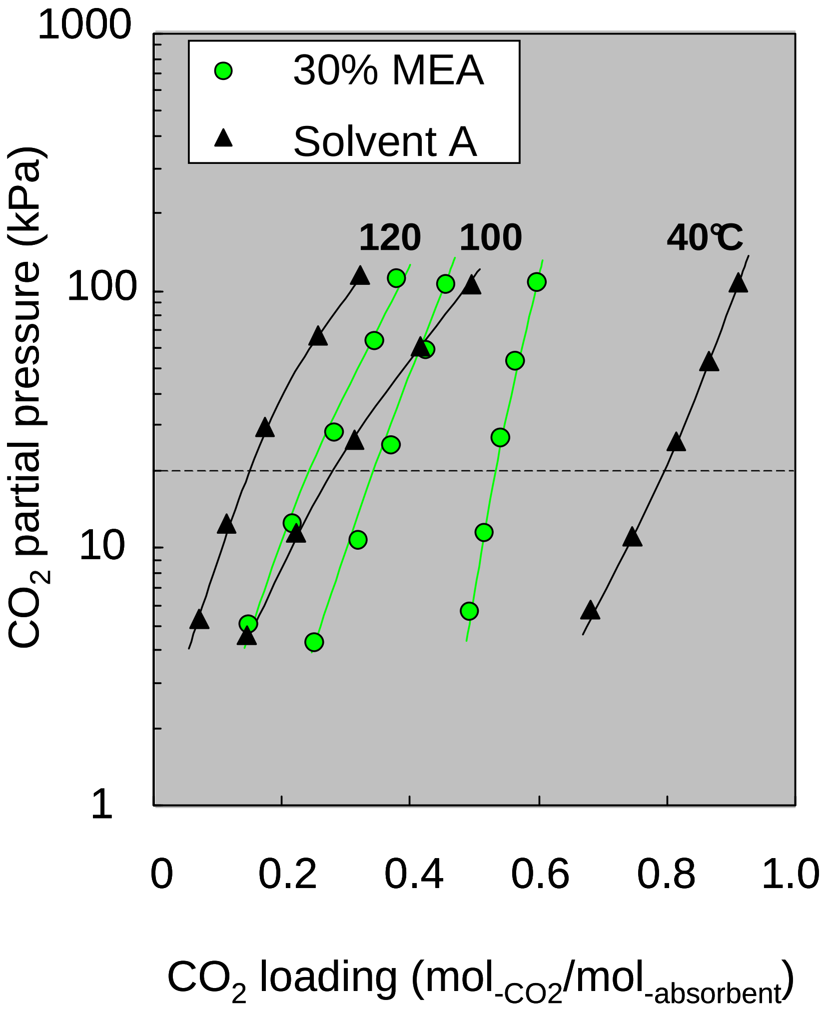
Autoclave

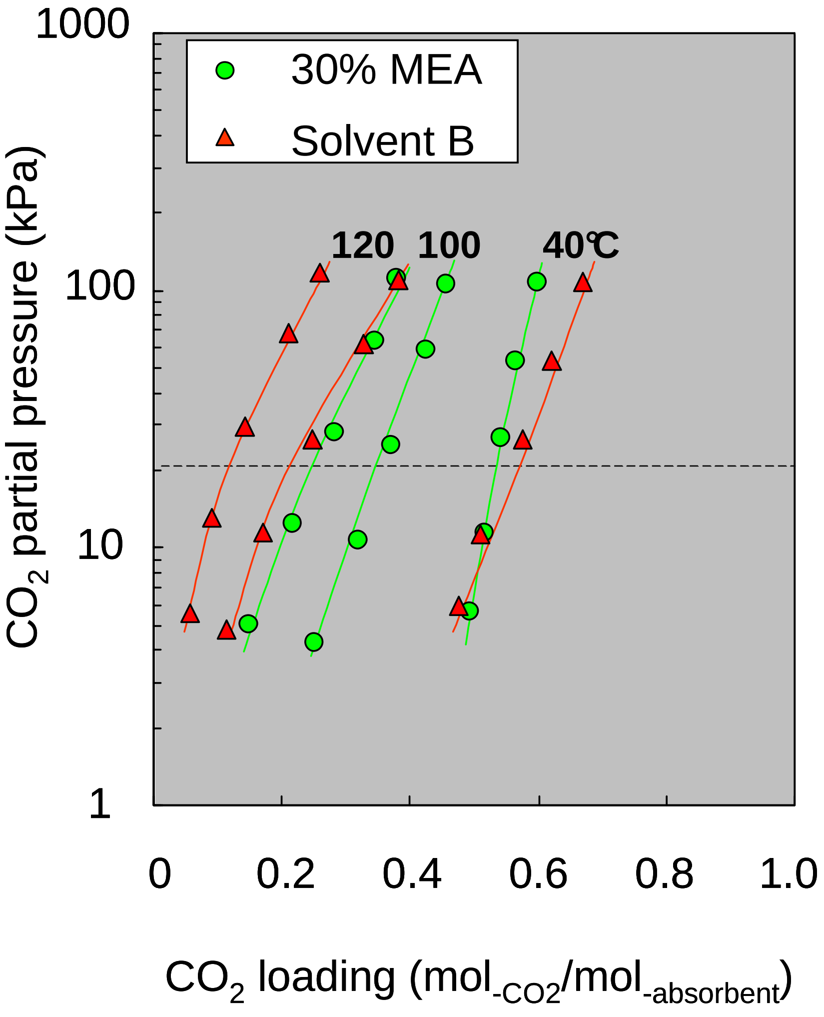
CO_2/ N_2 gas:	20/80 %
Gas flow rate:	700 ml/min
Absorbent :	700 ml
Temperature :	40 - 120 °C
Pressure :	0.1 - 1 MPa

CO_2 conc. in liquid phase:

TOC (Total Organic Carbon analyzer)

Results of Vapor-liquid Equilibrium test

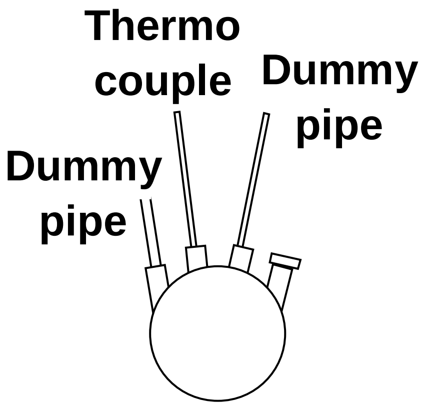




Heat of Absorption

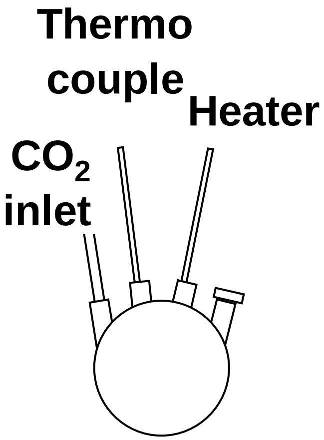
Measurements:

- Differential reaction calorimeter
- Semi-batch process
- 250ml reactor



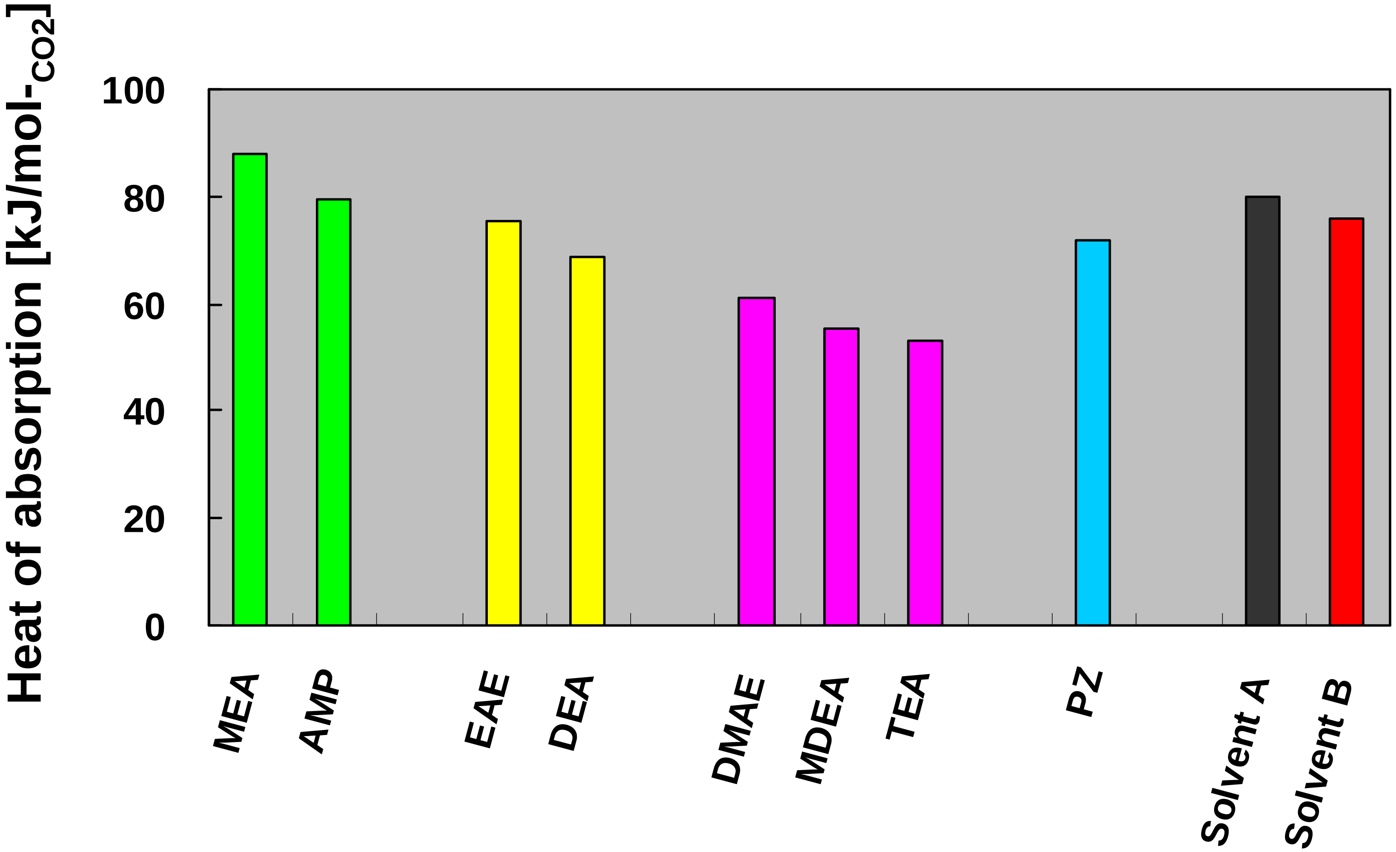
Reference

(SETARAM DRC)



Reactor

Experimental Results of Heat of Absorption



Mathematical Estimation of Reaction Heat

Theoretical study:

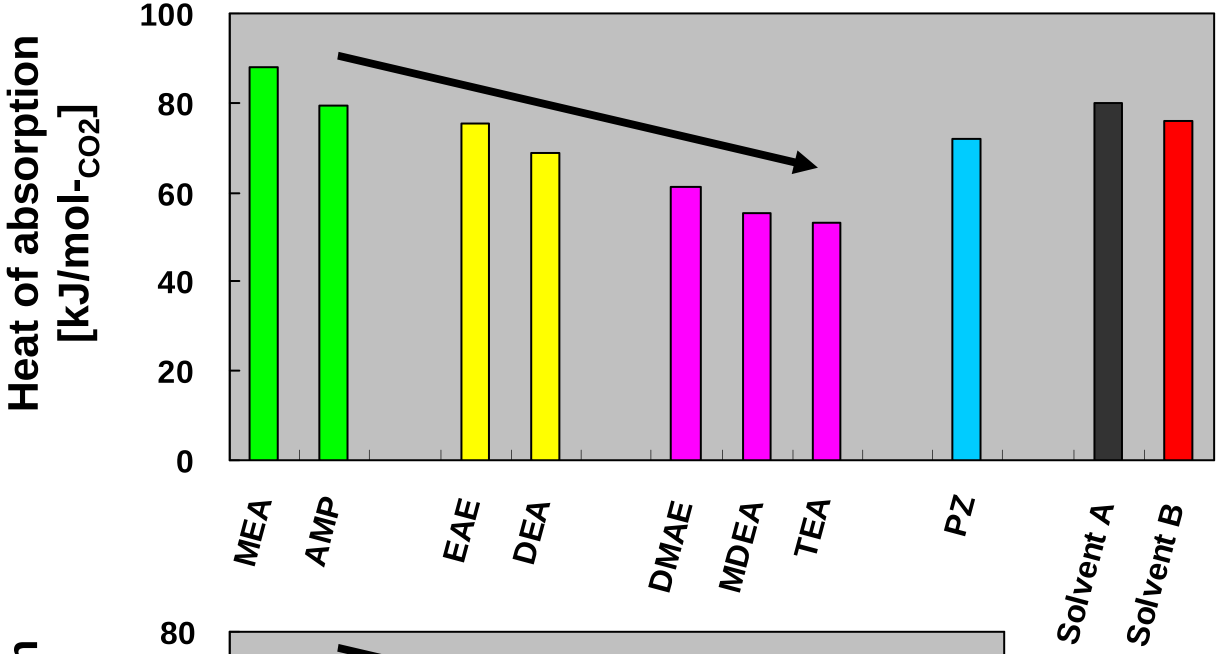
- Analysis of reaction energy of the following reaction as heat of absorption

$$Amine + CO_2 + H_2O \rightarrow Protonated\ Cation + HCO_3^-$$

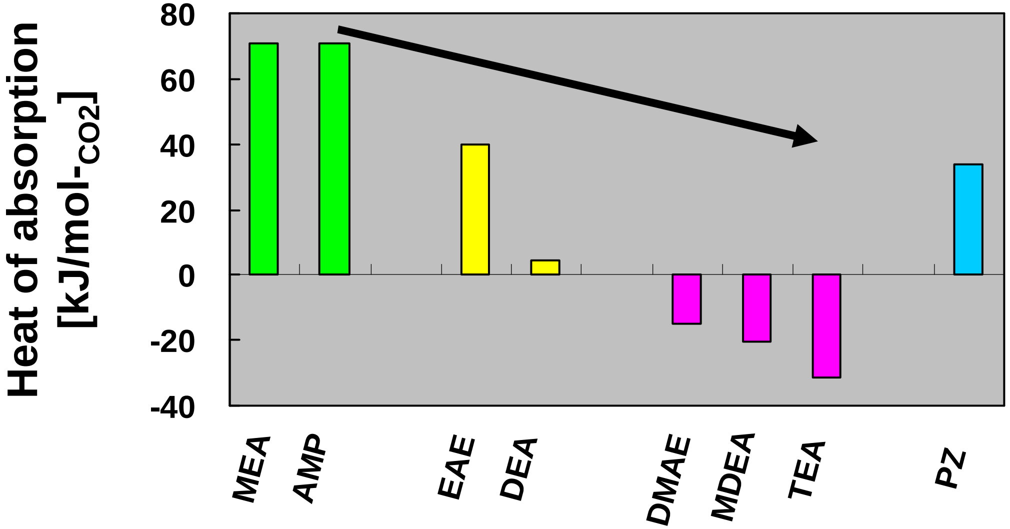
- Semi-empirical molecular orbital model,
  PM3 (Spartan ’04 for Windows)
- Solvation energy
  Cramer/Truhlar SM5.4 model

Results of Heat of Absorption

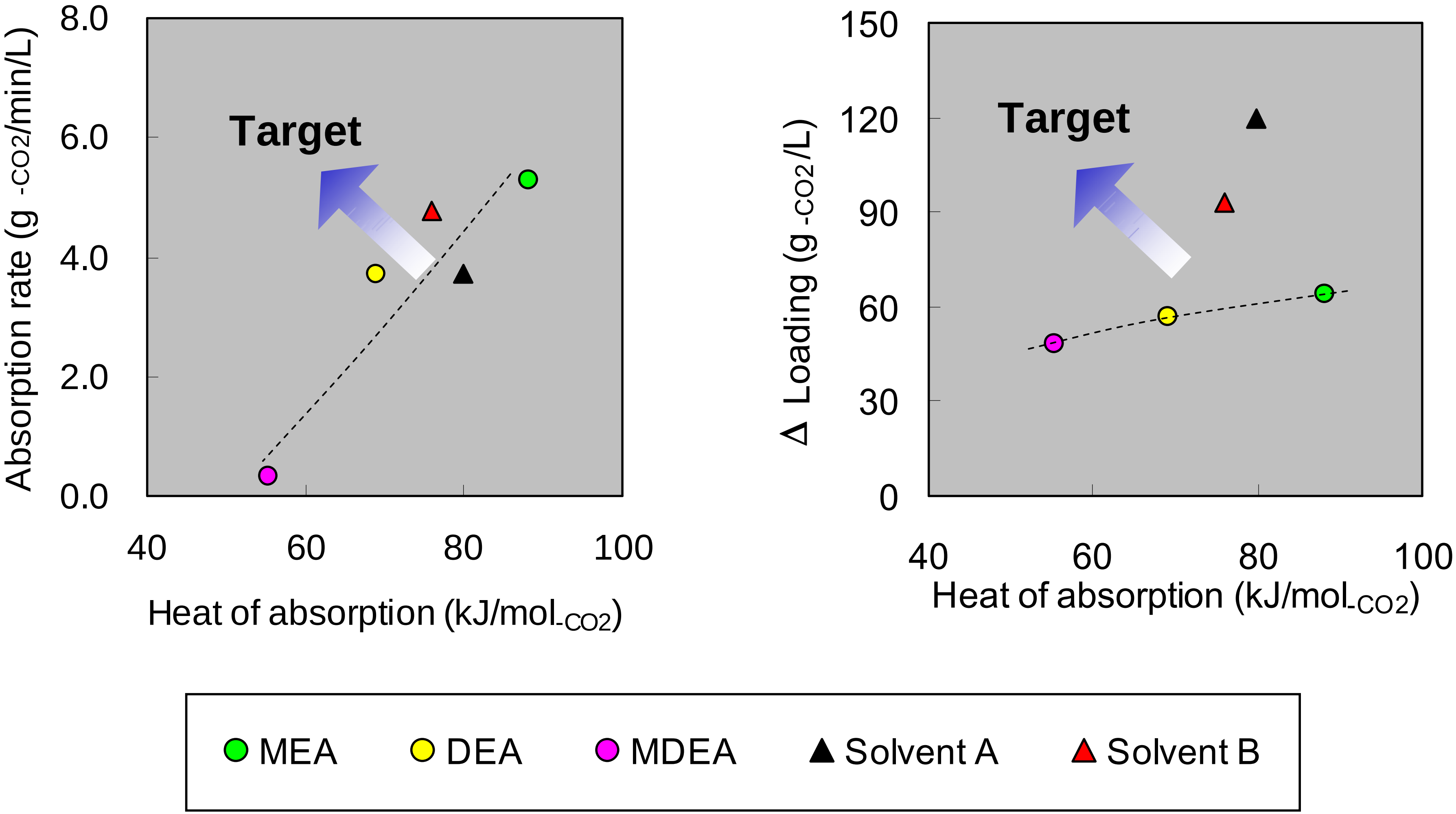
Exp.



Cal.



Direction for Developing New Absorbents



3) Evaluation of Absorbents in the First Stage

(First stage)

- Screening
- Vapor-liquid equilibrium
- Heat of absorption

(Extensive research for absorbent evaluation)

- Estimation of CO_2 capture energy

Estimation of CO_2 Capture Energy

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CO_2 capture energy:

$$Q = Q_R + Q_H + Q_V$$

Heat consumption in stripper:

(1) Reaction heat of stripping CO_2

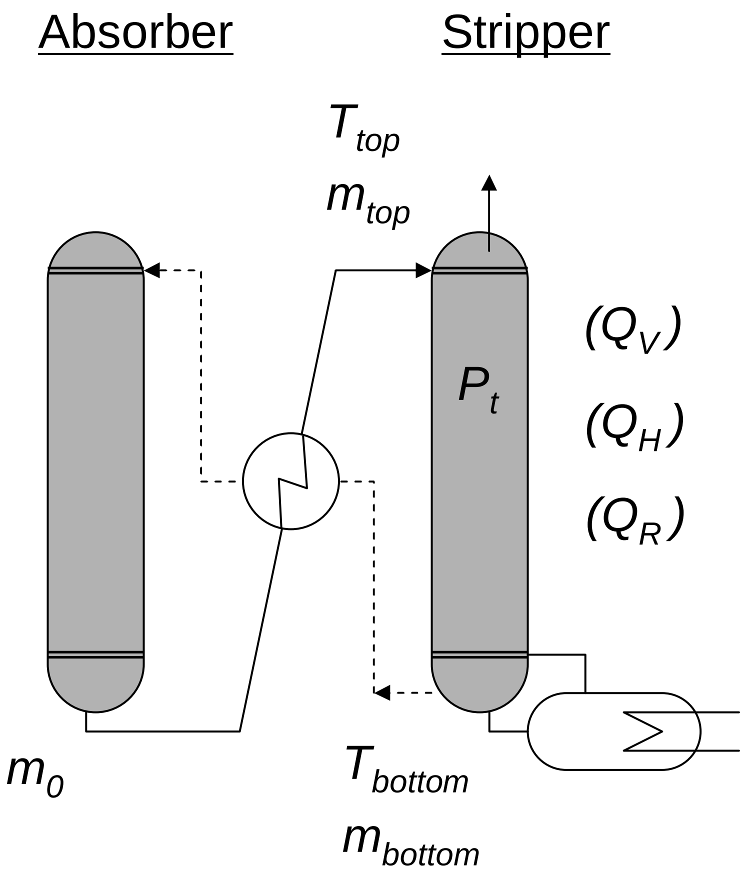
$$Q_R = f1(m_{top}, m_{bottom}, H_R)$$

(2) Sensible heat of absorbent

$$Q_H = W_S \cdot Cp(T_{top} - T_{bottom})$$

(3) Latent heat of vapor at stripper top

$$Q_V = f2(W_{H2O}, H_{H2O}, T_{top})$$



m : CO_2 loading of absorbent
[$mol_{-CO2}/mol_{-absorbent}$]

Calculation under Equilibrium Condition

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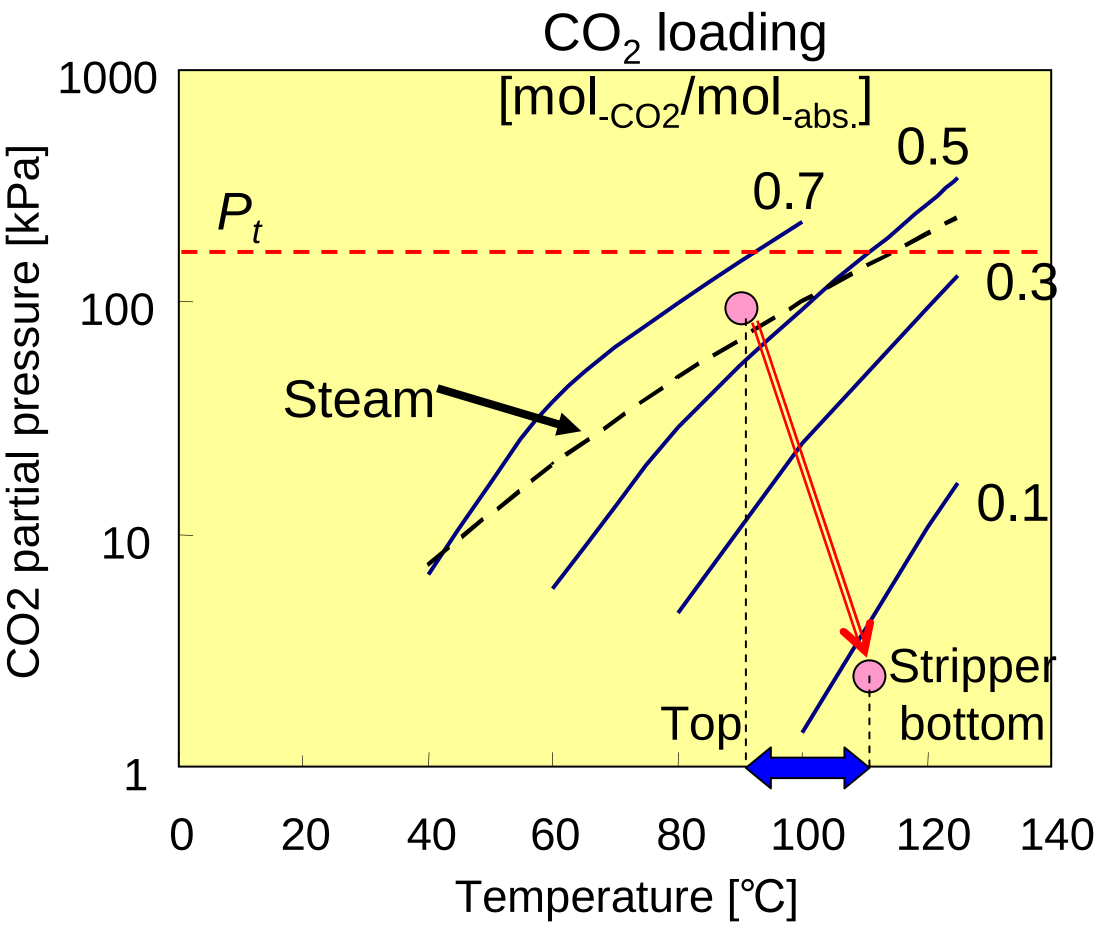
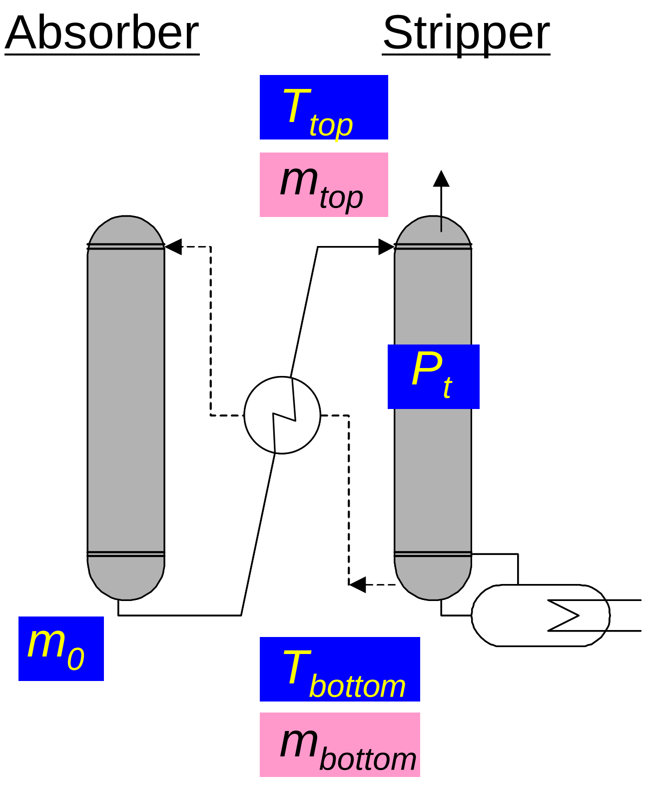


Fig. Liquid-vapor equilibrium of Solvent A



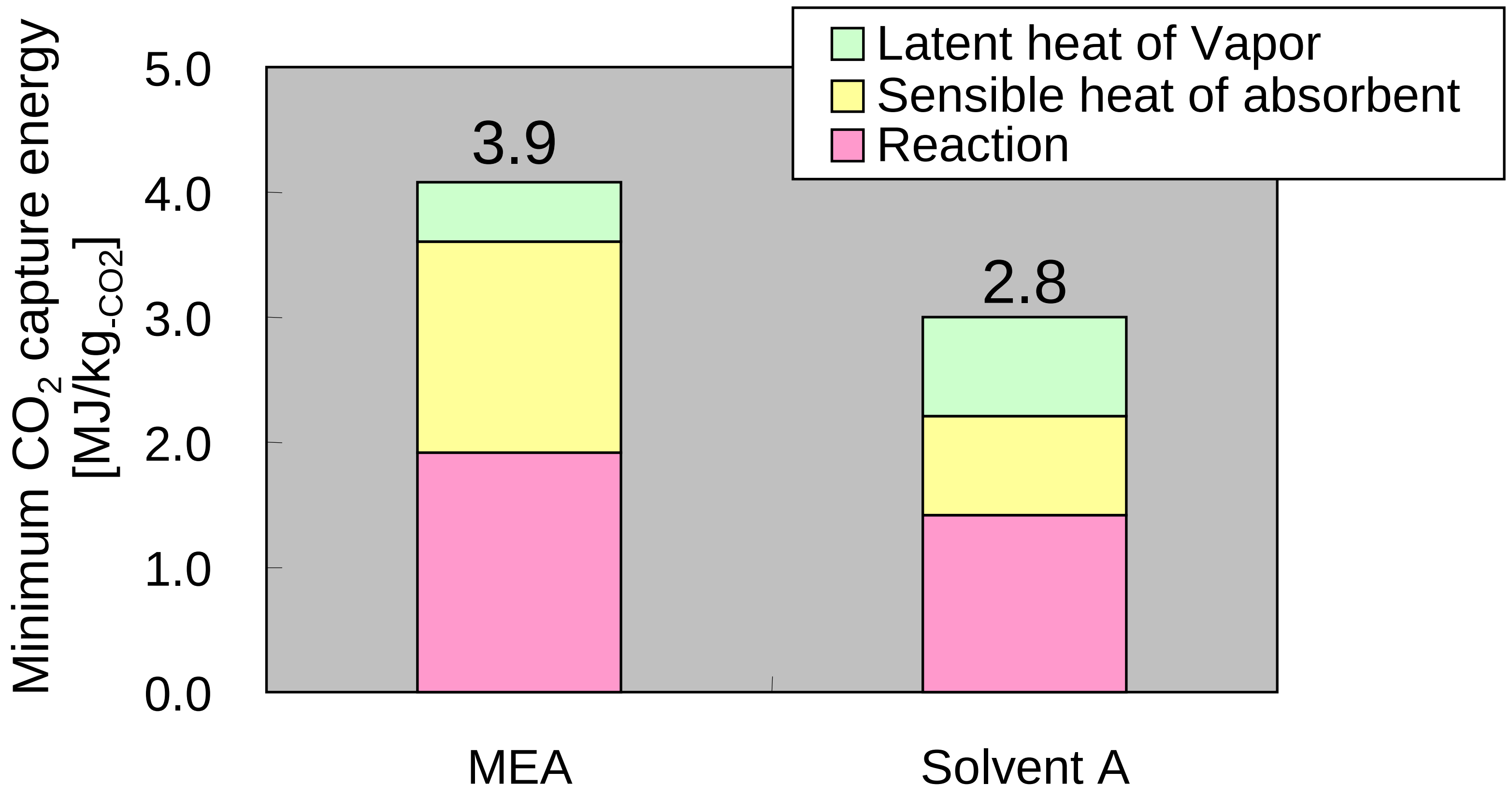
Initial condition

Analysis object

Analytical Data

Absorbent	**Solvent A**	**MEA30%**
Heat of absorption H_R [kJ/mol-CO_2]	**84**	**91**
CO_2 loading at absorber bottom m_0 [$mol_{-CO2}/mol_{-absorbent}$]	**0.64**	**0.50**
Total gas pressure in stripper P_t [kPa]	**186**	**186**
Temp. at stripper top T_{top} [˚C]	**90**	**90**
Temp. at stripper bottom T_{bottom} [˚C]	**110**	**120**

Potential Performance of Absorbents



Bench Plant (2kg$_{\text{-CO2}}$/h) Study

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Bench-scale plant facility with mixed gas (KEPCO)

	Diameter (m)	Height (m)
Absorber:	0.1	2.3
Stripper:	0.1	1.8

Experimental condition

Gas volume	6.5 m^3/h
L/G	3.0 L/m^3

CO_2 capture energy [MJ/kg$_{\text{-CO2}}$]

	Solvent A	**30% MEA**
Experiment	3.0	4.0
Calculation	2.8	3.9

Summary

Results :

1) Definition of the target absorbent.
2) Development of the new absorbents with higher-performance than MEA.

Future Work :

- Develop higher-performance absorbents.
- Utilize low-grade waste heat.
- Study on process research with bench plant facility.

Acknowledgement

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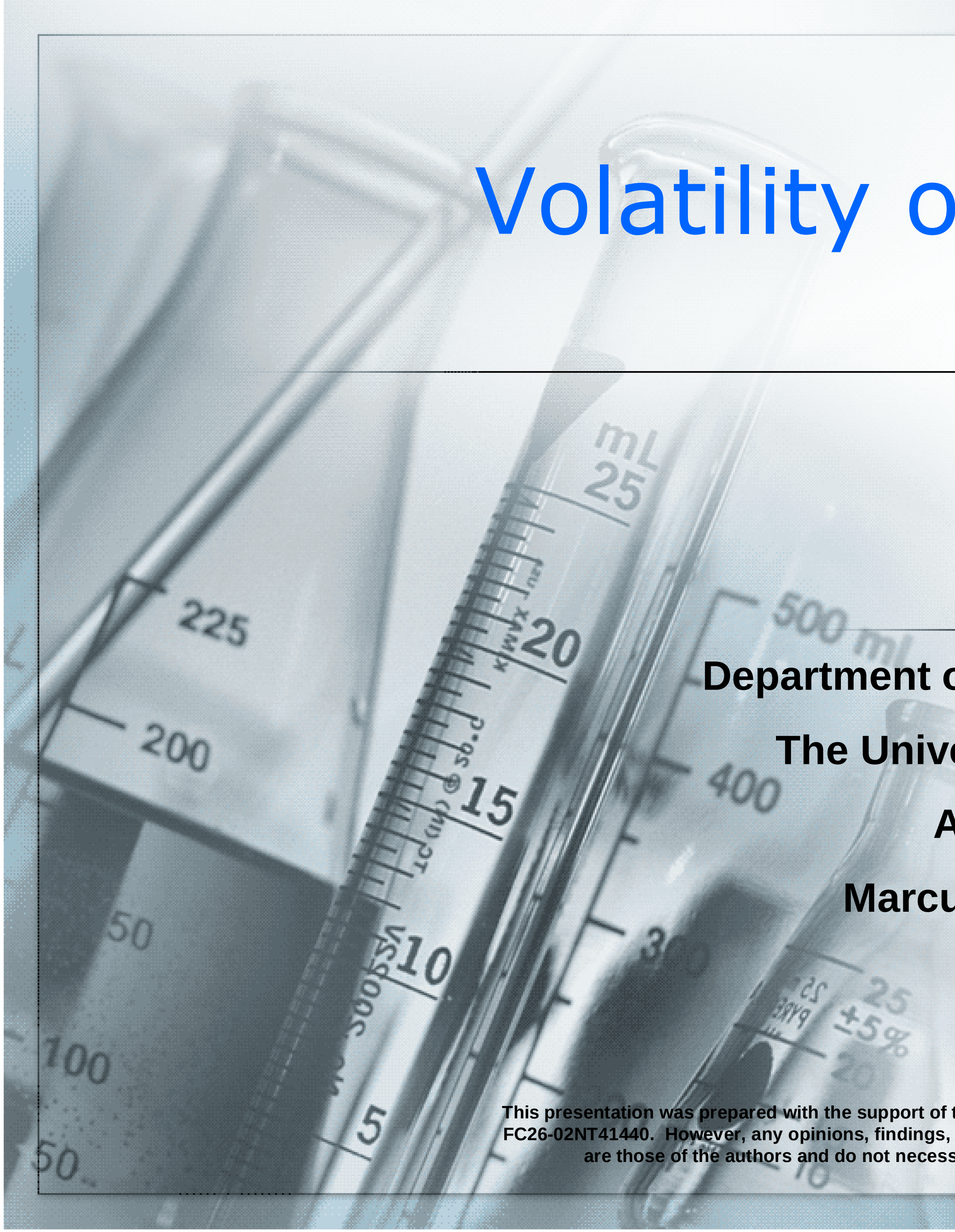
and carried out with collaboration from three Japanese companies:

- Nippon Steel Co.
- Mitsubishi Heavy Industries, Ltd.
- The Kansai Electric Power Co., Inc.

Volatility of MEA and Piperazine



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Dr. Gary T. Rochelle

June 16, 2006

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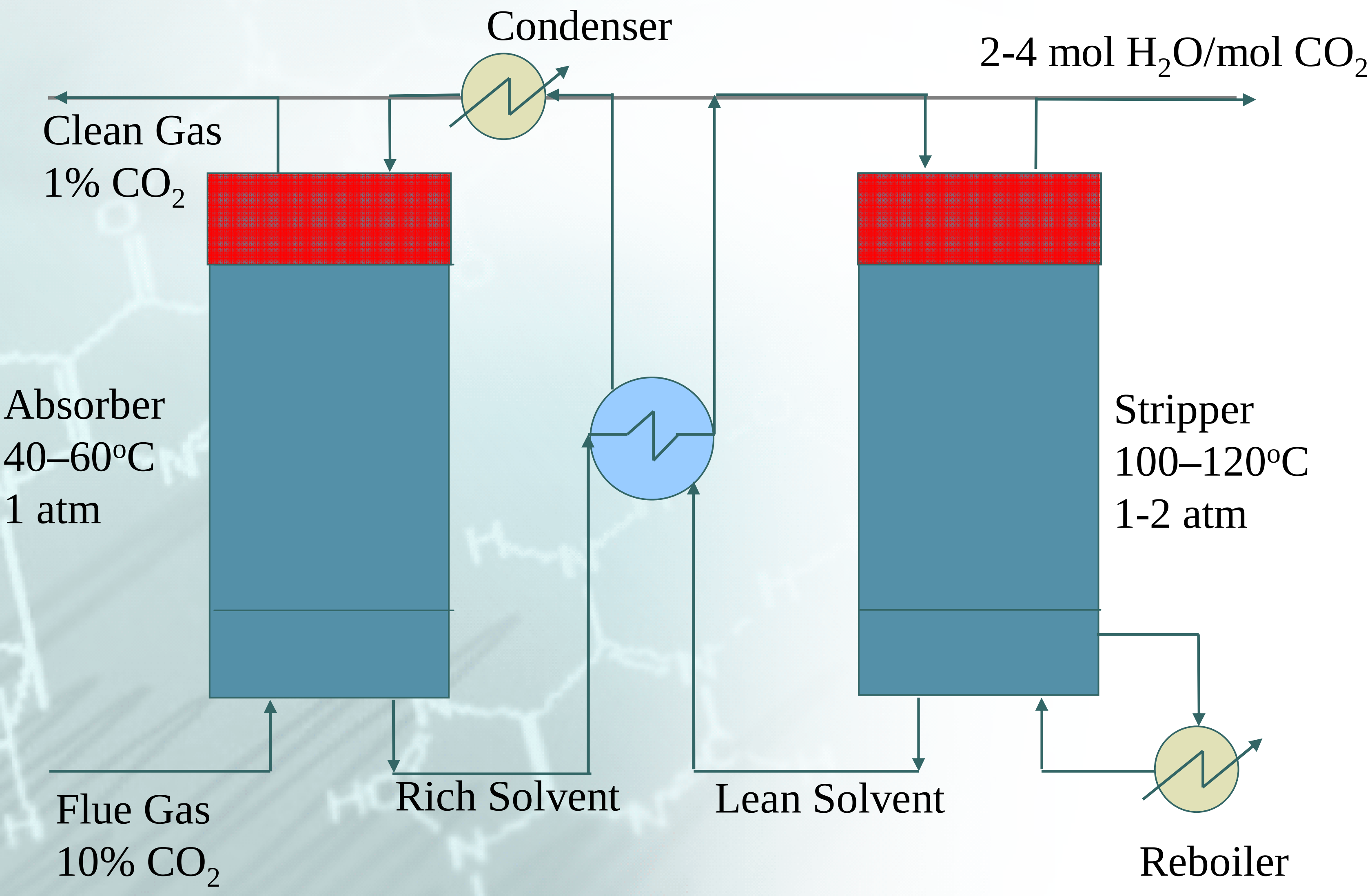
Outline

- Background
- Method: Multi-component VLE
- Analysis: FT-IR
- Modeling: NRTL
- Results: Amine Volatility and γ_i

Background

- Why is Amine Volatility Important in CO_2 Capture?
- What is the Motivation for Studying Amine Volatility in Blended Amine Systems?

Absorption/Stripping Process



Condenser

2-4 mol H_2O/mol CO_2

Clean Gas
1% CO_2

Absorber
40–60°C
1 atm

Stripper
100–120°C
1-2 atm

Flue Gas
10% CO_2

Rich Solvent

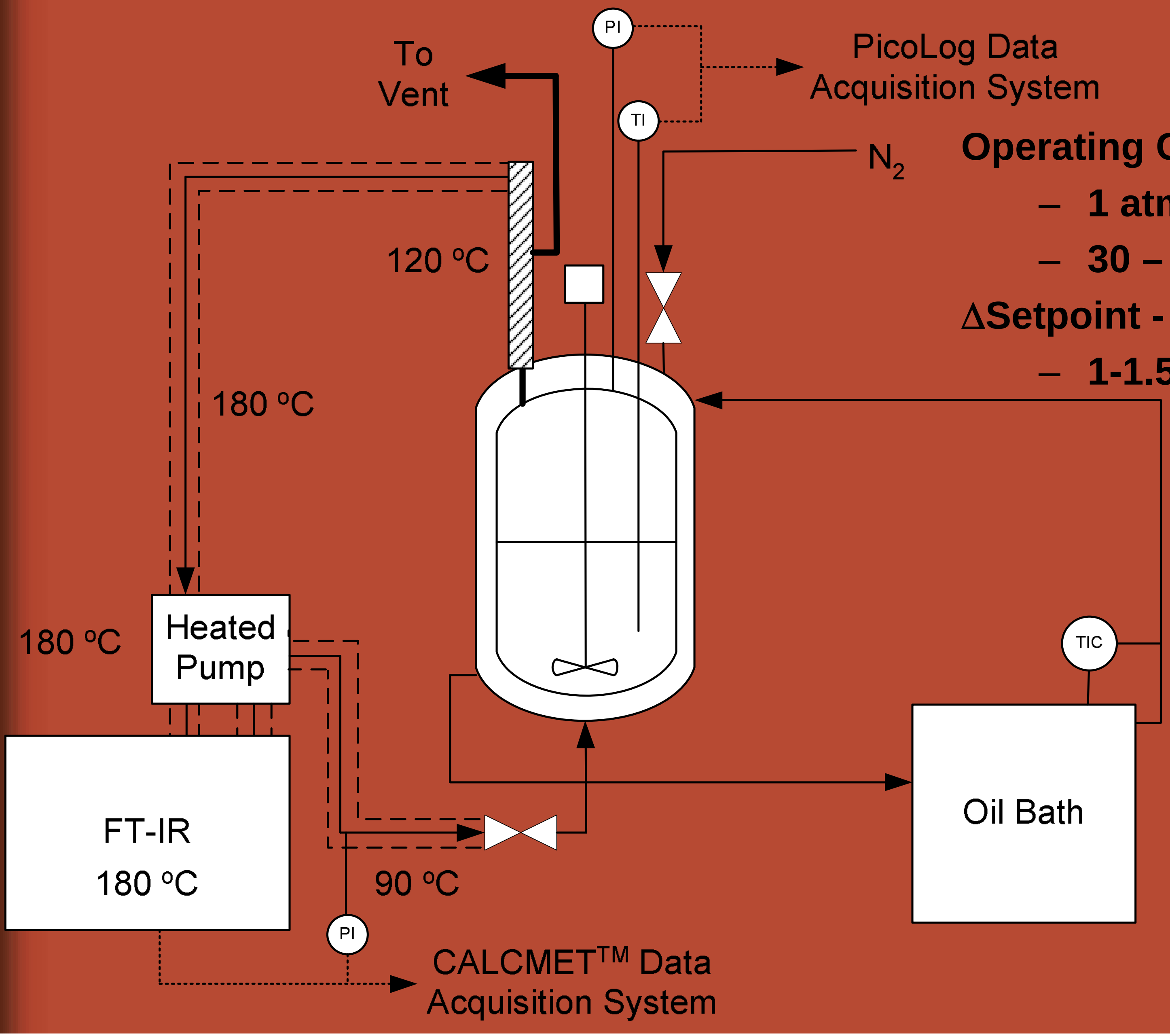
Lean Solvent

Reboiler

Solvent - CO_2 Capture

- 30 wt% MEA - Mature technology
  - K_2CO_3/PZ
  - MEA/PZ
    - Increased in capacity and faster rates
- Hilliard (2005) – Aspen Plus ENRTL Model
  - ➢ Motivation for Modeling
    - Capacity
    - Heat of Desorption
    - Complex MT with Chemical Reactions – Speciation
    - Cost of Amine Make-up or Recovery - Amine Volatility

Apparatus for Vapor Speciation



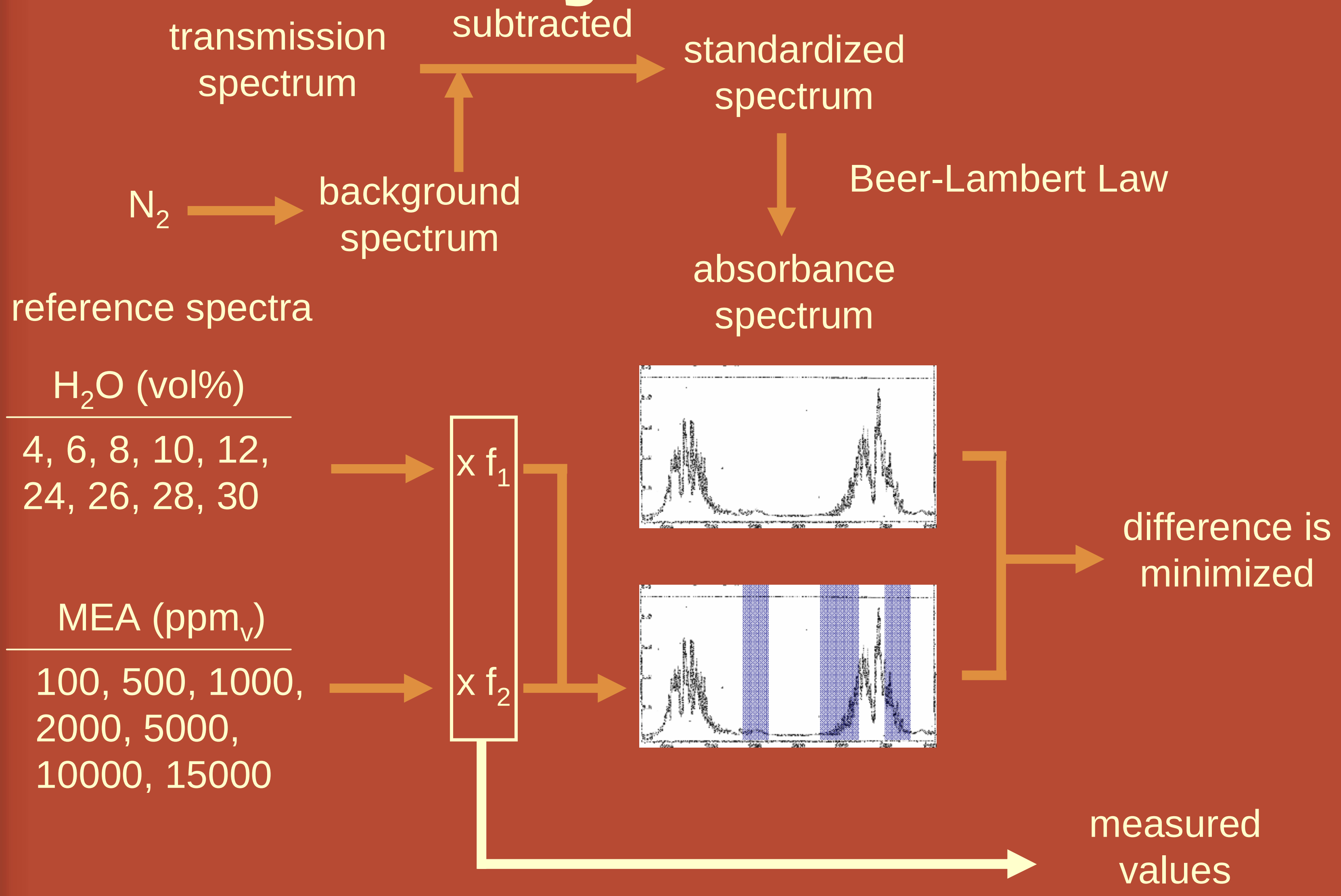
Operating Conditions:

- **1 atm**
- **30 – 70 °C**

ΔSetpoint - Equilibrium

- **1-1.5 hr**

FT-IR Analysis



transmission spectrum

subtracted

standardized spectrum

N_2 → background spectrum

Beer-Lambert Law

absorbance spectrum

reference spectra

H_2O (vol%)
4, 6, 8, 10, 12, 24, 26, 28, 30

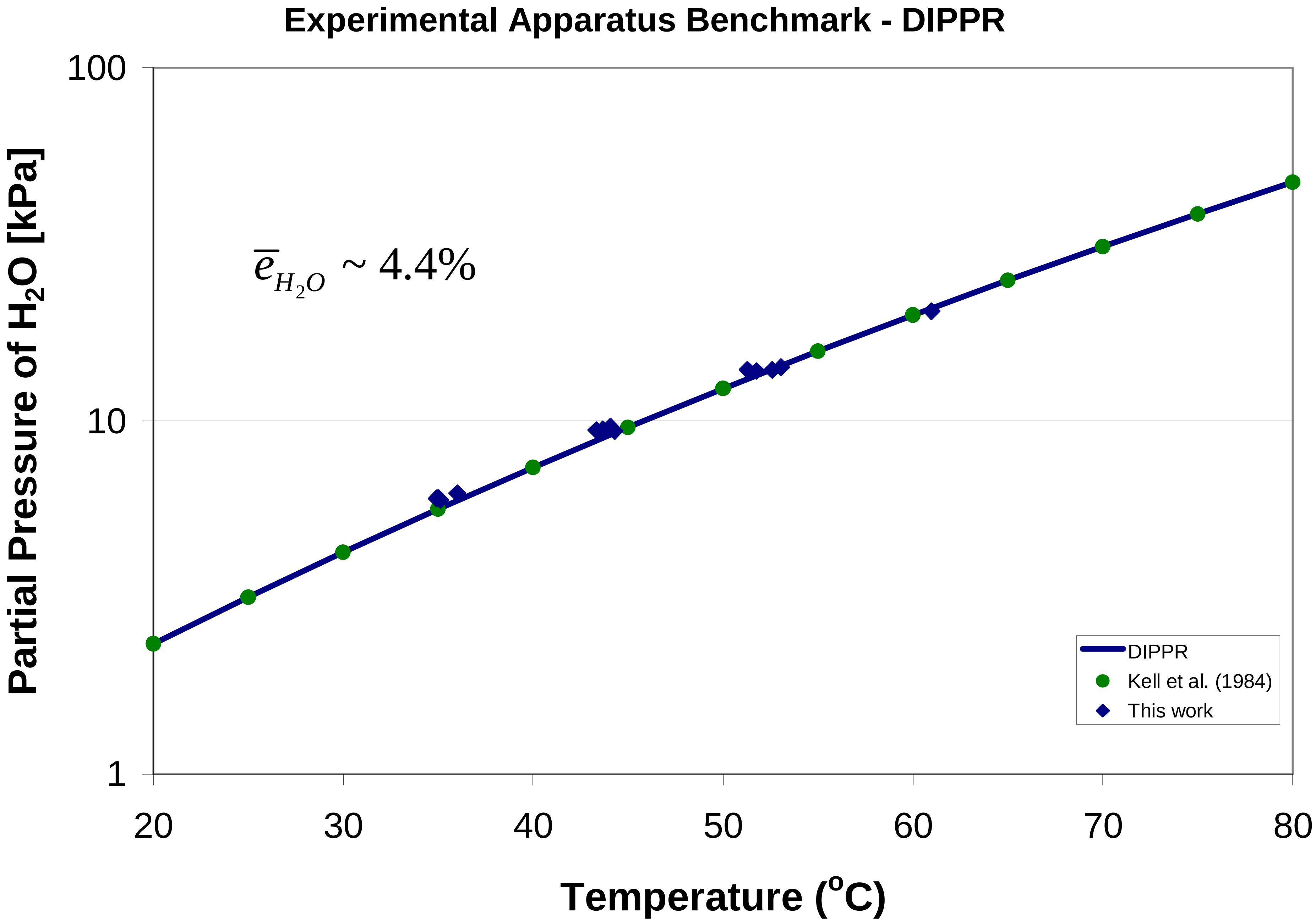
MEA (ppm_v)
100, 500, 1000, 2000, 5000, 10000, 15000

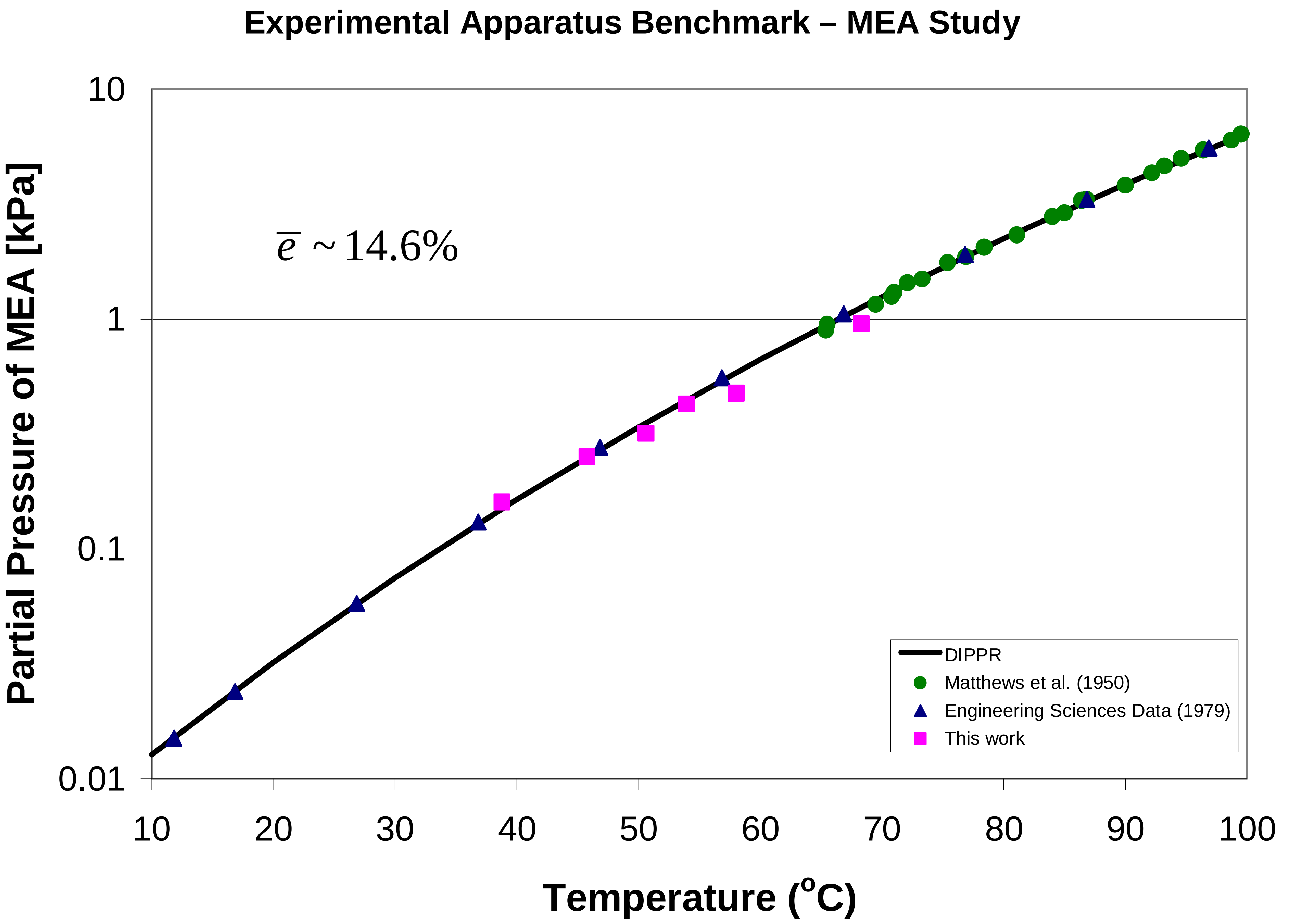
$x\ f_1$

$x\ f_2$

difference is minimized

measured values


Experimental Apparatus Benchmark - DIPPR
Partial Pressure of H_2O [kPa]
100
10
1
20
30
40
50
60
70
80
Temperature (^oC)
$\overline{e}_{H_2O} \sim 4.4\%$
DIPPR
Kell et al. (1984)
This work


Experimental Apparatus Benchmark – MEA Study
$\overline{e} \sim 14.6\%$
Partial Pressure of MEA [kPa]
10
1
0.1
0.01
10
20
30
40
50
60
70
80
90
100
Temperature (°C)
DIPPR
● Matthews et al. (1950)
▲ Engineering Sciences Data (1979)
■ This work

Aspen Plus - NRTL Model

- c_{ion}→0: ENRTL reduces to NRTL
- Developed by Renon and Prausnitz (1968)

$$\frac{G^E}{RT} = x_1 x_2 \left(\frac{\tau_{21} e^{-\alpha_{21}\tau_{21}}}{x_1 + x_2 e^{-\alpha_{21}\tau_{21}}} + \frac{\tau_{12} e^{-\alpha_{12}\tau_{12}}}{x_2 + x_1 e^{-\alpha_{12}\tau_{12}}} \right)$$

1 = H_2O

2 = Amine

$$\tau_{ij} = A_{ij} + \frac{B_{ij}}{T} + C_{ij} \ln T + D_{ij} T \qquad \tau_{ii} = \tau_{jj} = 0$$

$$\ln \gamma_2 = x_1^2 \left[\tau_{12} \left(\frac{e^{-\alpha_{12}\tau_{12}}}{x_2 + x_1 e^{-\alpha_{12}\tau_{12}}} \right) + \frac{\tau_{21} e^{-\alpha_{21}\tau_{21}}}{\left(x_1 + x_2 e^{-\alpha_{21}\tau_{21}} \right)^2} \right]$$

Aspen’s Data Regression Package
- Maximum Likelihood Principle

- Determining the parameter values were carried out using an algorithm derived by Britt and Luecke (1973)
- Objective function based on the following assumptions:
  - Where all variables are adjusted and weighted by the standard deviation (i.e. experimental data are not error free)
  - Not Simple least squares regression.

$$Q = \sum_{i}^{N_i} \sum_{j}^{N_j} W_{U_j} \left(\frac{U_{j,adj} - U_{j,obs}}{\sigma_{U_j}} \right)^2$$

where the summation is over all of the measured variables, N_i, for all of the data points, N_j.

Absolute Average Relative Deviation for the H_2O-MEA-PZ systems

- MEA/H_2O: 3 parameters

  $A_{H_2O/MEA}$ $B_{H_2O/MEA}$

  A_{MEA/H_2O}

- PZ/H_2O: 4 parameters

  $A_{H_2O/PZ}$ $B_{H_2O/PZ}$ $C_{H_2O/PZ}$

  A_{PZ/H_2O}

- MEA/PZ/H_2O: 2 parameters

  $A_{MEA/PZ}$

  $A_{PZ/MEA}$

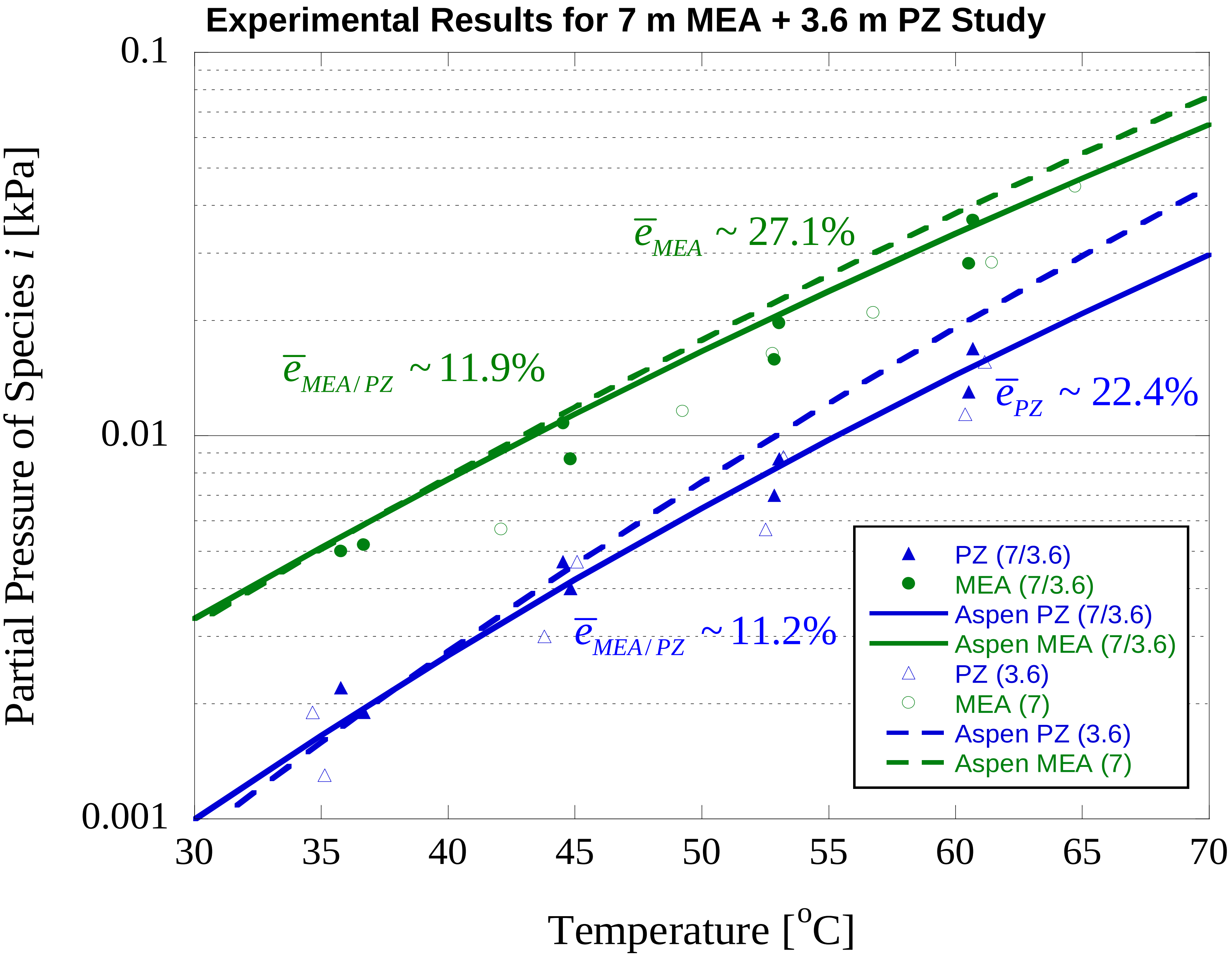
No.	Name	Data type	# Papers	AARD (%)
1	MEA/H_2O	TPx	3	3.0
		Y_{MEA}	4	6.4
			This work	*17.6**
		Y_{H2O}		*10.6**
		ΔT_f	1	5.9
		ΔH_{mix}	2	7.1
		C_p	3	6.2
2	PZ/H_2O	Y_{PZ}	This work	*23.0**
		Y_{H2O}		*5.4**
		TPx	1	0.4
3	MEA/PZ/H_2O	Y_{MEA}	This work	*11.1**
		Y_{PZ}		*13.0**
		Y_{H2O}		*3.0**

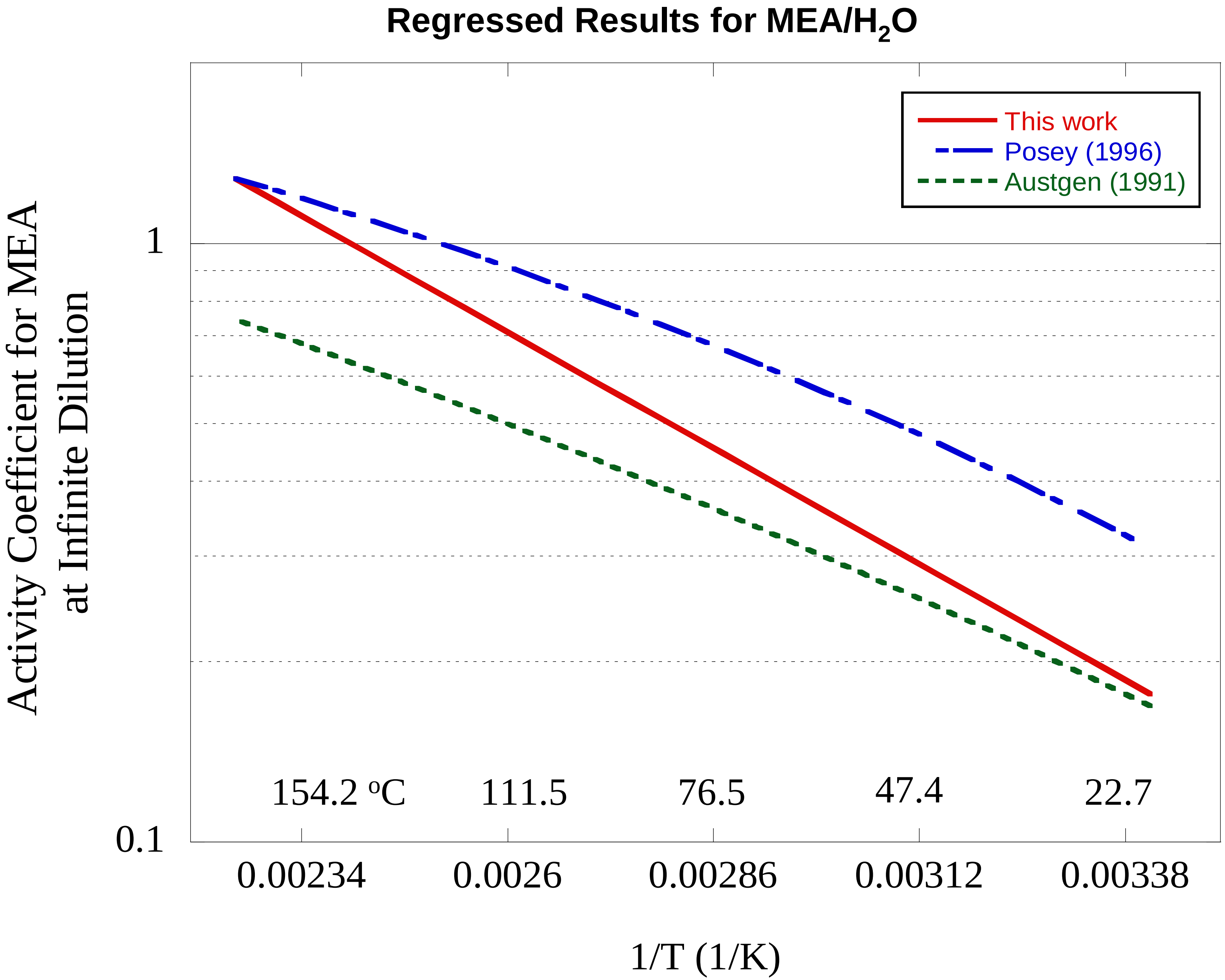
Measured multi-component VLE

- MEA-H_2O Study
  - 3.5, 7, 23.8 m MEA

- PZ-H_2O Study
  - 0.9, 1.8, 2.5, 3.6, 5.0 m PZ

- MEA-PZ-H_2O Study
  - 3.5, 7 m MEA + 1.8, 3.6 m PZ


Experimental Results for 7 m MEA + 3.6 m PZ Study
Partial Pressure of Species i [kPa]
0.1
0.01
0.001
Temperature [°C]
30
35
40
45
50
55
60
65
70
$\overline{e}_{MEA} \sim 27.1\%$
$\overline{e}_{MEA/PZ} \sim 11.9\%$
$\overline{e}_{PZ} \sim 22.4\%$
$\overline{e}_{MEA/PZ} \sim 11.2\%$
▲ PZ (7/3.6)
● MEA (7/3.6)
Aspen PZ (7/3.6)
Aspen MEA (7/3.6)
△ PZ (3.6)
○ MEA (7)
Aspen PZ (3.6)
Aspen MEA (7)

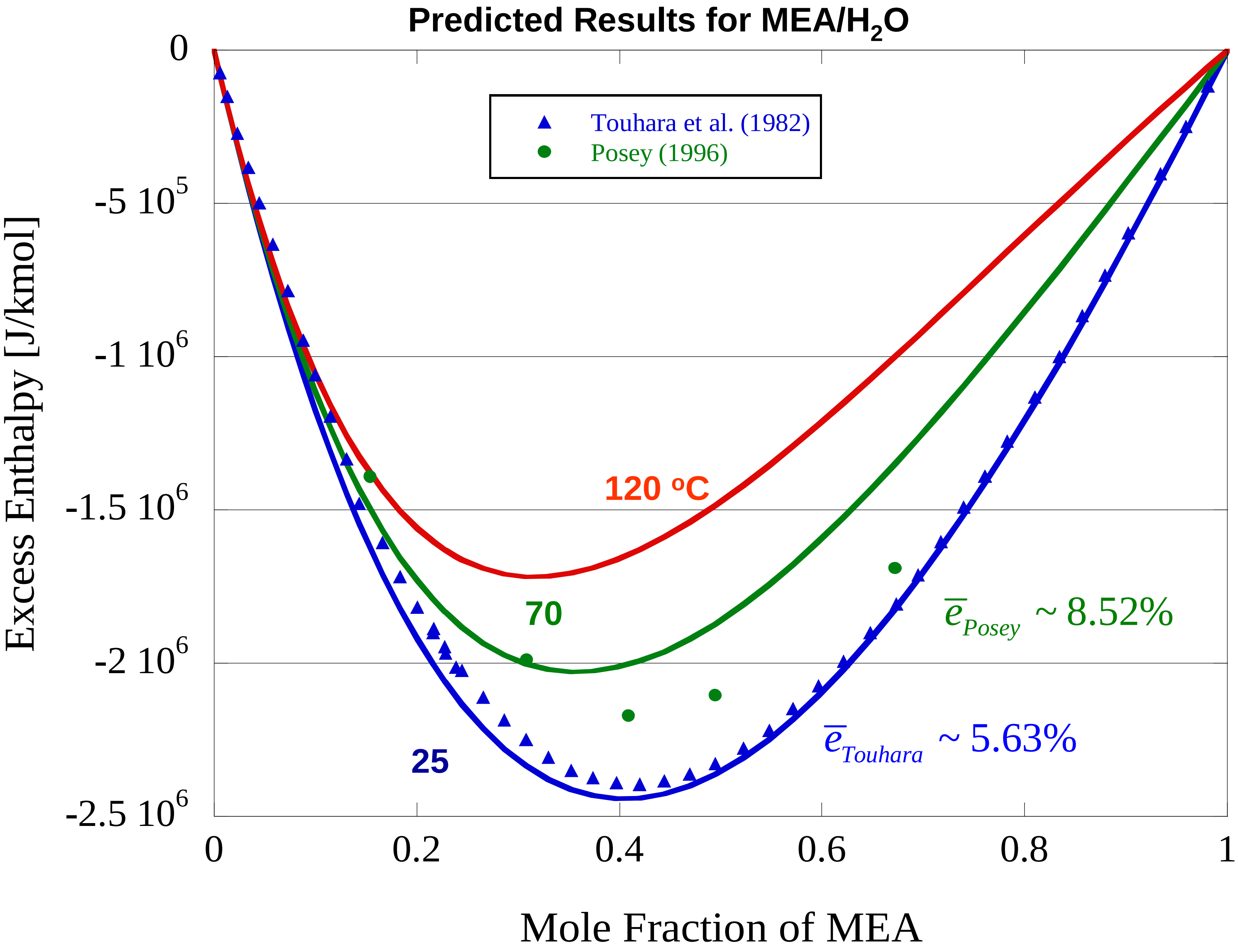

Regressed Results for MEA/H_2O
This work
Posey (1996)
Austgen (1991)
Activity Coefficient for MEA at Infinite Dilution
1
0.1
154.2 °C
111.5
76.5
47.4
22.7
0.00234
0.0026
0.00286
0.00312
0.00338
1/T (1/K)

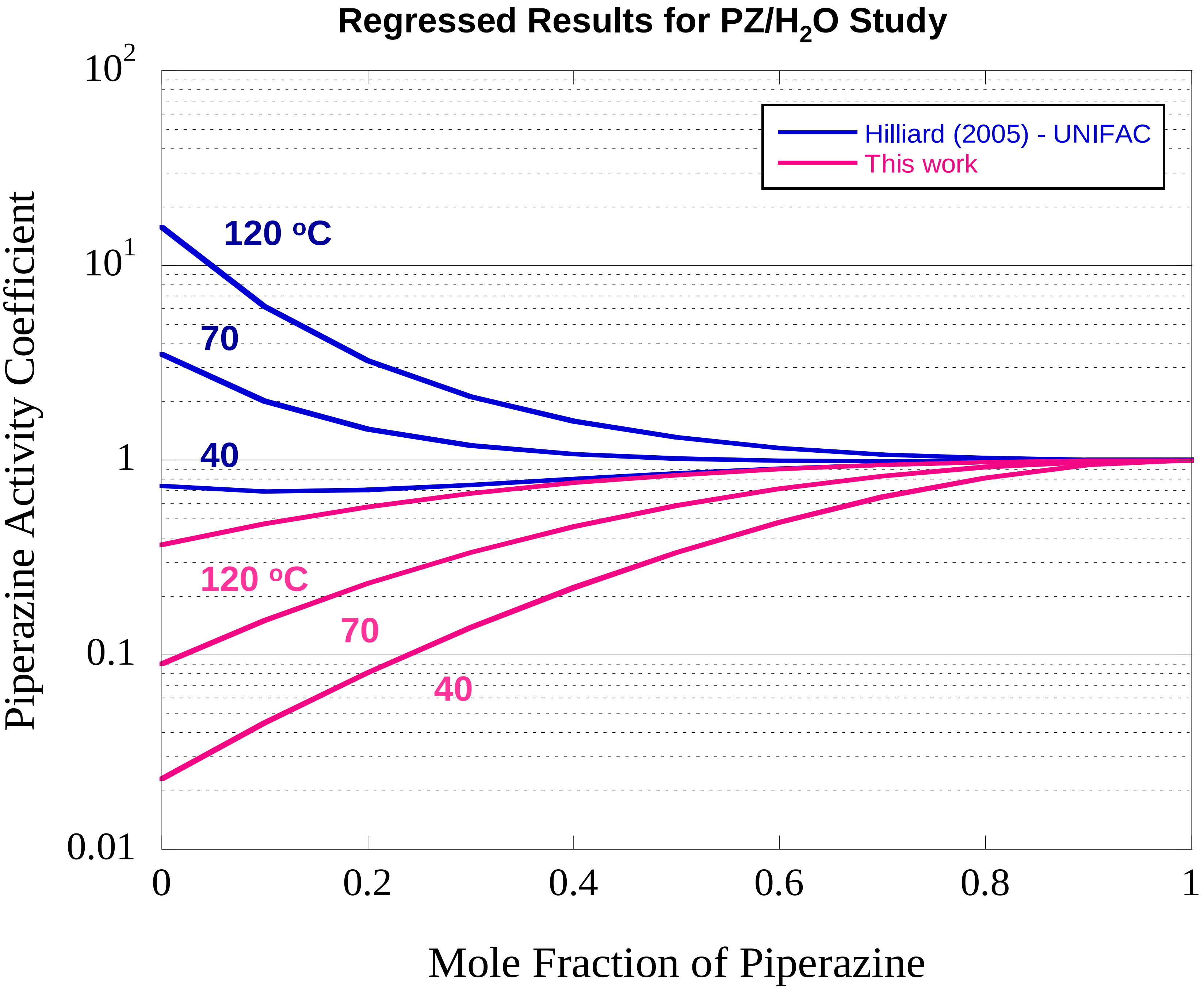
Excess Enthalpy (kJ/mol) for MEA at Infinite Dilution in Water

$$\Delta H^E = R\frac{d\ln\gamma_{MEA}^{\infty}}{d1/T}$$

For a temperature range from 25 to 80 °C:

ΔH^E	Source
-12.61	Touhara (1982)
-11.43	Kim et al. (1987)
-11.92 to -10.66	Austgen (1991)
-12.79 to -10.13	Posey (1996)
-14.28 to -14.28	This work


Predicted Results for MEA/H_2O
Excess Enthalpy [J/kmol]
0
-5 10^5
-1 10^6
-1.5 10^6
-2 10^6
-2.5 10^6
Mole Fraction of MEA
0
0.2
0.4
0.6
0.8
1
▲ Touhara et al. (1982)
● Posey (1996)
120 °C
70
25
$\bar{e}_{Posey} \sim 8.52\%$
$\bar{e}_{Touhara} \sim 5.63\%$



Regressed Results for PZ/H_2O Study

Excess Enthalpy (kJ/mol) for PZ at Infinite Dilution in Water

$$\Delta H^E = \Delta H_{sol} = \left(\Delta H_{dis} - \Delta H_{fus}\right)$$

$$\Delta H^E = R\frac{d\ln\gamma_{PZ}^{\infty}}{d1/T}$$

For a temperature range from 25 to 80 ^{o}C:

ΔH^E	Source
-44.1 to -38.5	ΔH_{dis} - ΔH_{fus}
-55.54 to -39.25	Hilliard (2005)
-47.28 to -34.71	This work

Conclusions

- Relative Volatility of MEA & PZ is ~ unity
- PZ activity coefficients are 567% lower than UNIFAC predictions
- Simultaneous regression may help improve Sequentially regressed parameters
- In 7 m MEA/3.6 m PZ at 40 ^{o}C
  - P_{PZ} = 2.676 Pa
  - P_{MEA} = 7.708 Pa
- ΔH^{E} at Infinite Dilution from 25 to 80 ^{o}C
  - PZ: -14.28 kJ/mole
  - MEA: -47.28 to -34.71 kJ/mole
- Confident in this apparatus to generate new VLE data

Thank you for your attention.

Any questions?

Rate Modeling of Stripper Performance

By

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The University of Texas at Austin

9th International Post Combustion CO_2 Capture Network Meeting
Copenhagen,Denmark
June 16, 2006.

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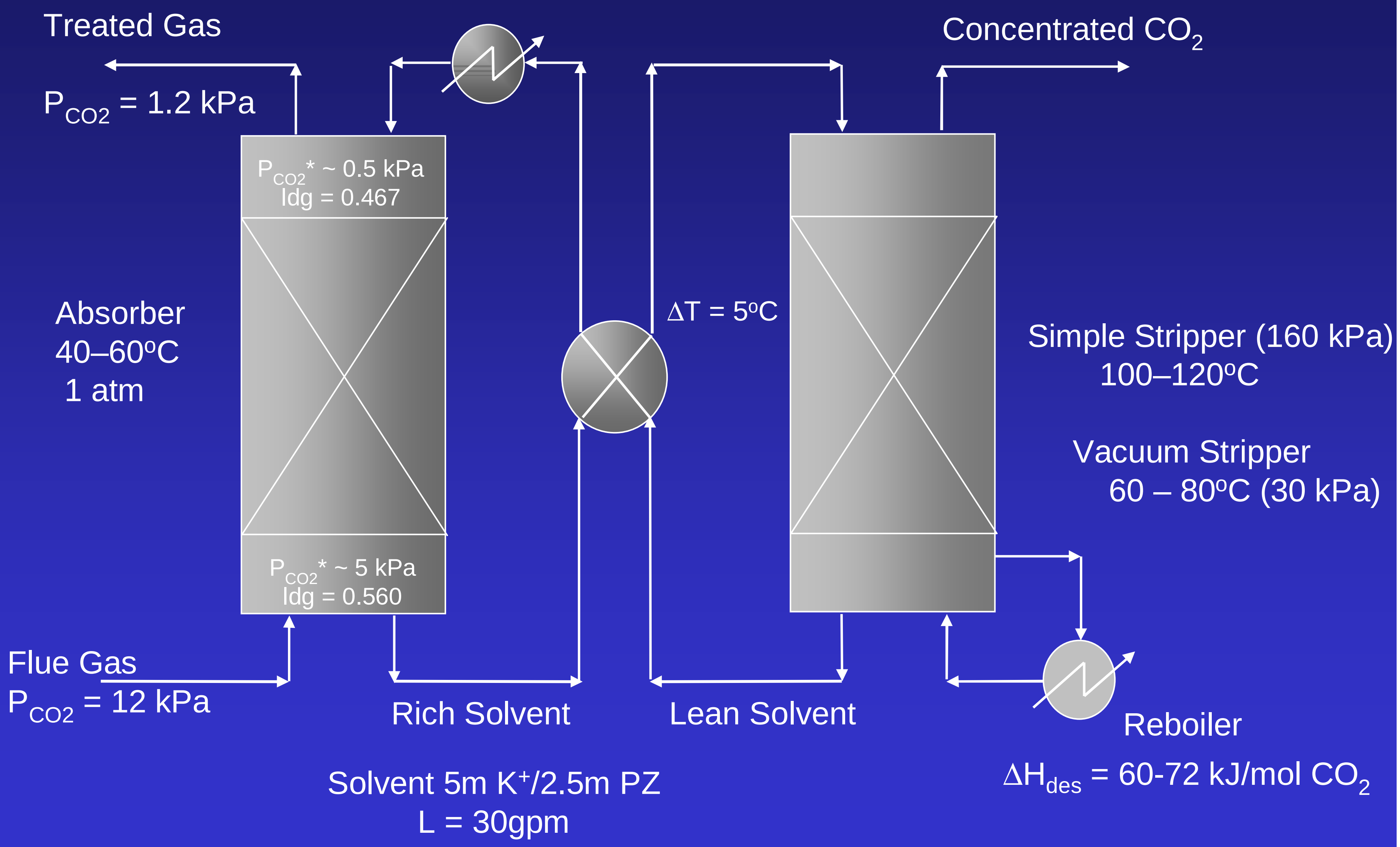
Outline

- Introduction
- Scope of work
- Rate Modeling
  - Mass transfer mechanisms
  - Aspen Custom Modeler Model Description
- Results
- Conclusions

Typical Absorber/Stripper Configuration



Treated Gas

P_{CO2} = 1.2 kPa

P_{CO2}* ~ 0.5 kPa
ldg = 0.467

Absorber
40–60ºC
1 atm

P_{CO2}* ~ 5 kPa
ldg = 0.560

Flue Gas
P_{CO2} = 12 kPa

Rich Solvent

ΔT = 5ºC

Lean Solvent

Concentrated CO_2

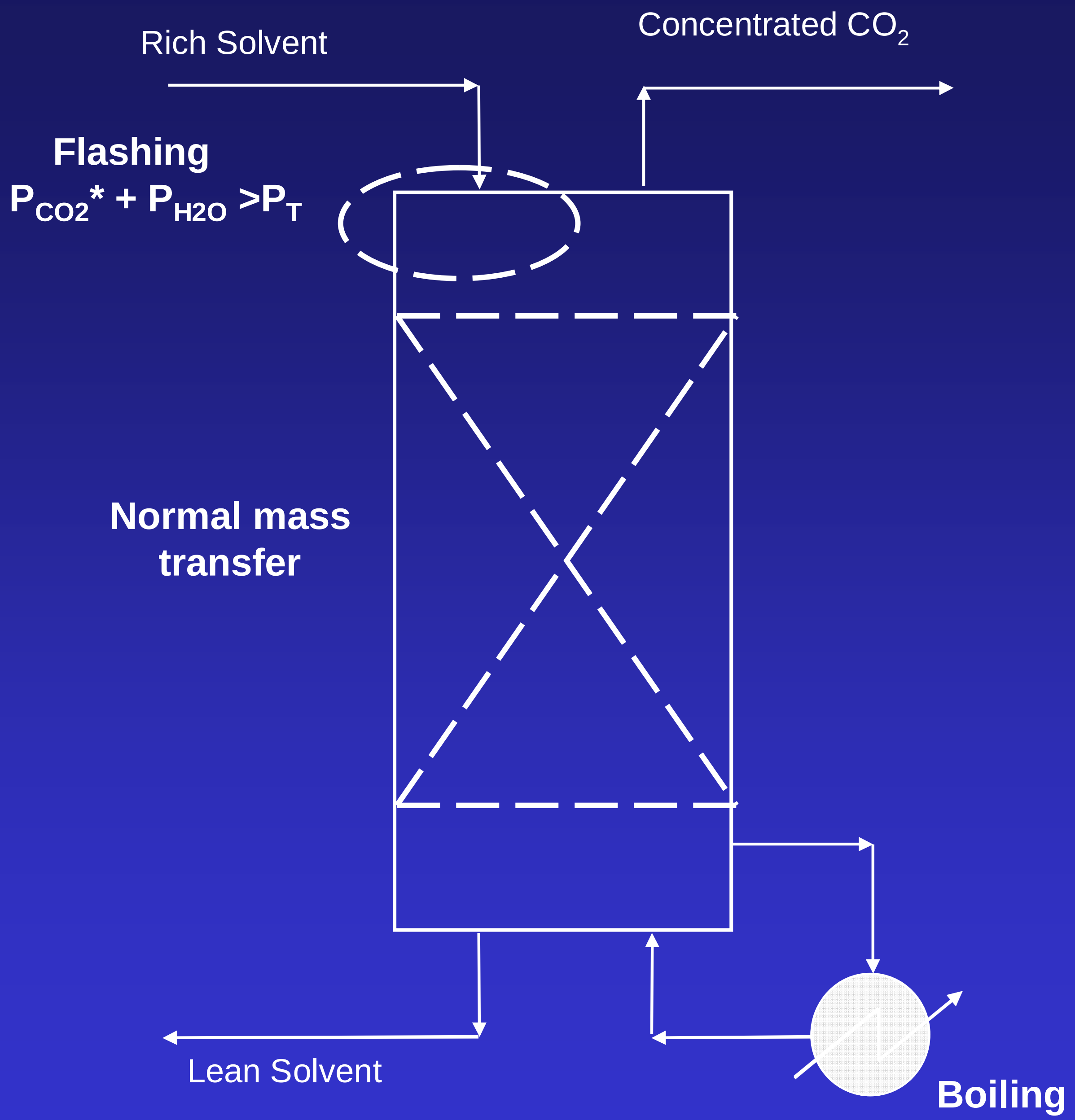
Simple Stripper (160 kPa)
100–120ºC

Vacuum Stripper
60 – 80ºC (30 kPa)

Reboiler

ΔH_{des} = 60-72 kJ/mol CO_2

Solvent 5m K^+/2.5m PZ
L = 30gpm



Rich Solvent

Concentrated CO_2

Flashing

$P_{CO2}^* + P_{H2O} > P_T$

Normal mass transfer

Lean Solvent

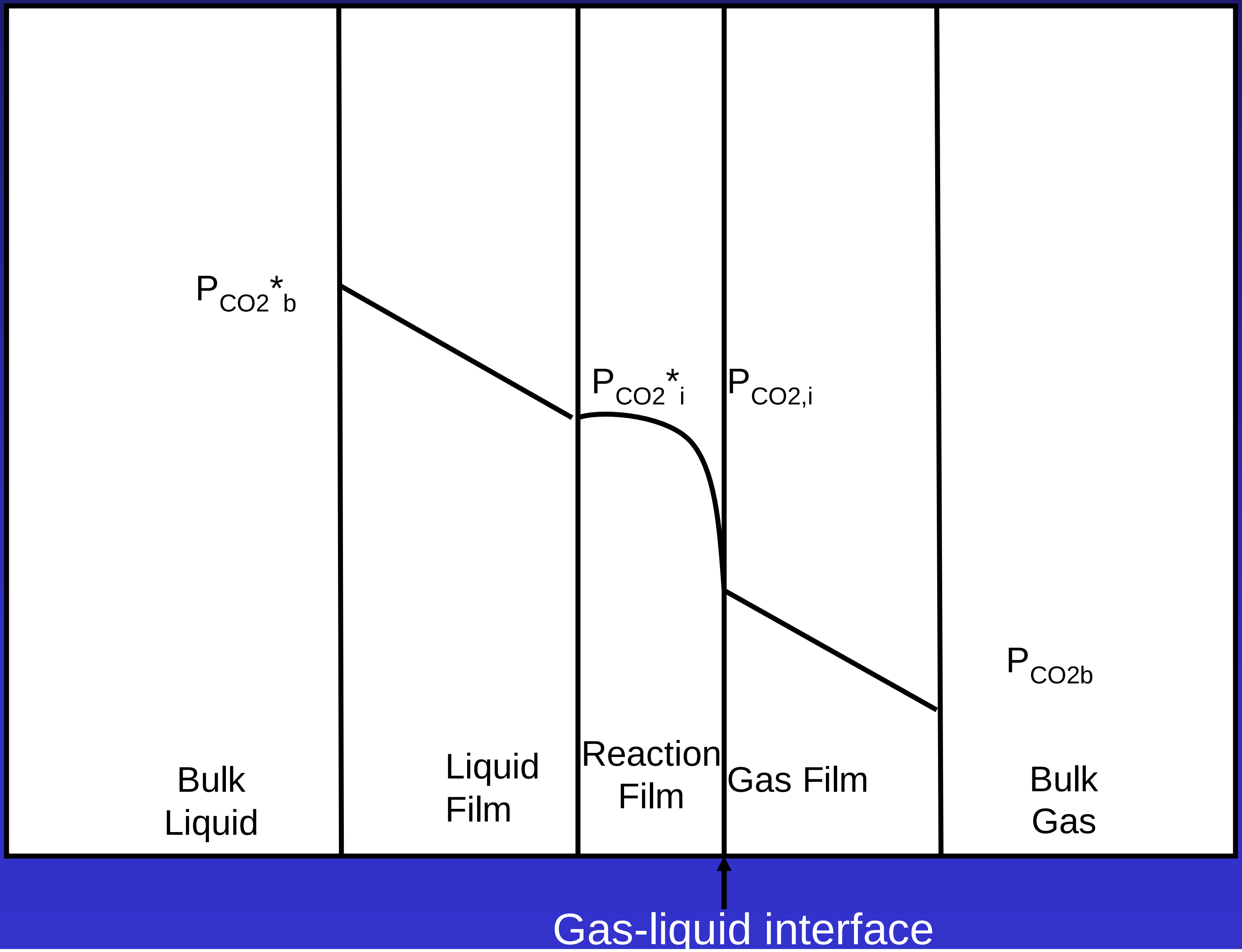
Boiling

Modeling approaches

- Equilibrium Stage Model
  (Oyenekan & Rochelle, 2006)
- **Mass transfer with reaction in boundary layer and liquid diffusion (This work)**
- Mass transfer with equilibrium reactions
  Weiland et al. (1982), Freguia & Rochelle (2002), Tobiesen et al. (2005)

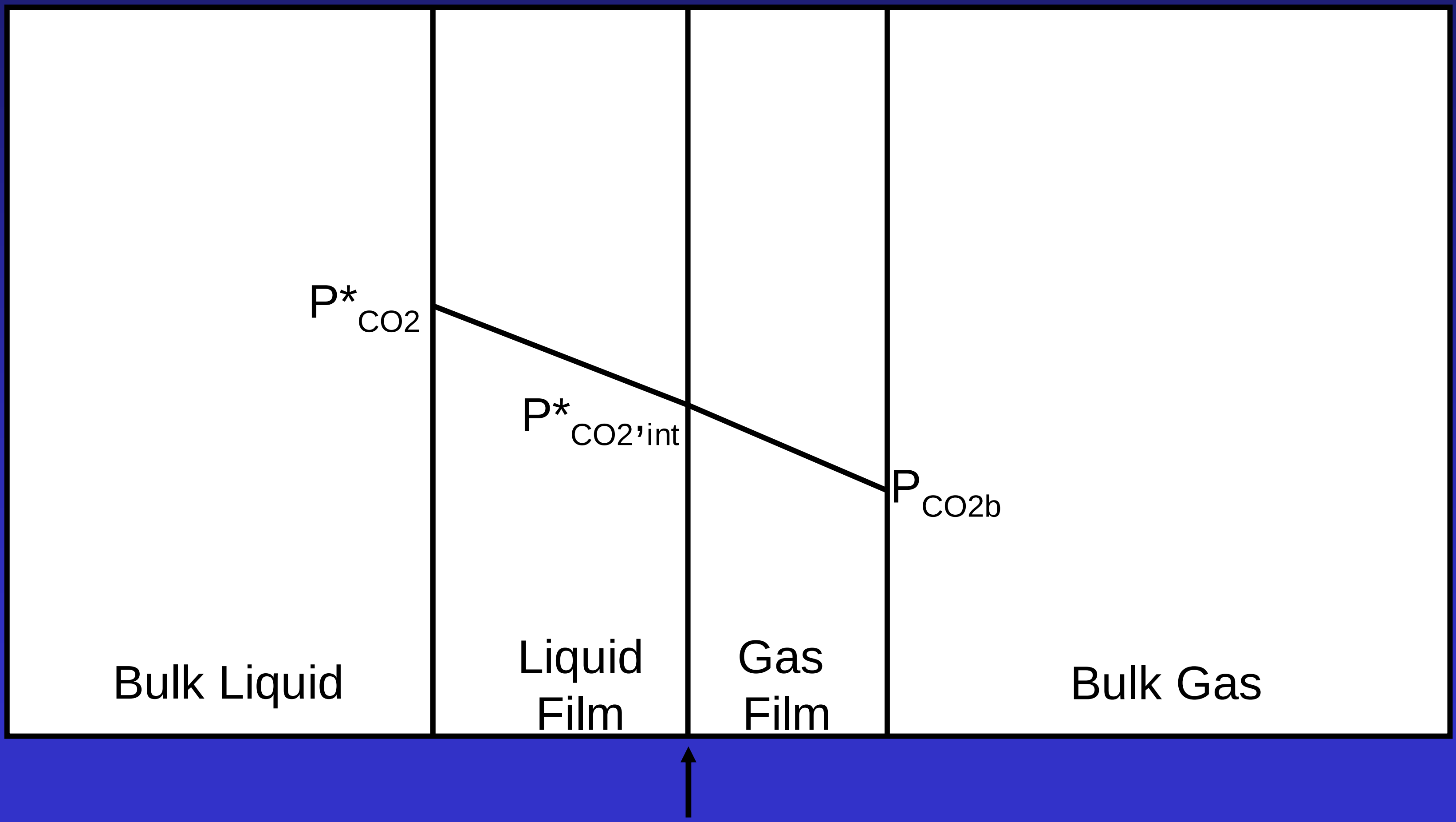
Mass transfer with reaction in boundary layer and liquid diffusion

(CO_2 in amines, K_2CO_3,PZ/K_2CO_3)



Mass transfer with equilibrium reactions

(Stripper conditions – CO_2 in amines ??)



Gas-liquid interface

Flux of CO_2
from bulk liquid
to bulk gas

Overall m.t. coefficient
f(equipment,fluid properties,
hydraulics,composition,chemistry)
- accounts for reaction and diffusion

$$N_{CO2} = K_G\ (P_{CO2}^* - P_{CO2b})$$

Driving force
f(thermodynamics i.e. VLE)

$$\frac{1}{K_G} = \frac{1}{k_g} + \frac{1}{k_g'}$$

Hydraulics – $k_l a, k_g a, a = f(\text{internals}, L, G, \rho, \mu, \sigma)$
($k_l a, k_g a$ - ONDA (1968); a – SRP tests

Overall mass transfer coefficient, K_G

Combined reaction

$$\frac{1}{K_G} = \frac{1}{k_g} + \frac{H_{CO2}}{\sqrt{k_2[Am]_i D_{CO2}}} + \frac{1}{k_{l,prod}} \left(\frac{\Delta P_{CO2}}{\Delta [CO_2]_T} \right)^*$$

Equilibrium reaction

$$\frac{1}{K_G} = \frac{1}{k_g} + \frac{1}{k_{l,prod}} \left(\frac{\Delta P_{CO2}}{\Delta [CO_2]_T} \right)^*$$

Rate Model for k_g'

Rigorous rate model (Bishnoi,2000) based on eddy diffusivity theory.

Model integrates the series of differential equations

- Thermodynamics in bulk liquid
- Diffusion across liquid film
- Reaction in the boundary layer

Non-linear regression (Cullinane,2005)

- Rate constants
- Diffusion coefficients

Aspen Custom Modeler (ACM) Model Features

- 10 segments, IMTP #40,equilibrium reboiler
- Rigorous thermo (E-NRTL, Chen et al. 1986) VLE (regressed from Cullinane,2005)

- Mass transfer with combined reaction (approx.)
- Account for flash and reboiler mass transfer
- Well mixed L & V phases
- Negligible vaporization of solvent
- Reaction takes place in the liquid phase
- Accounts for unequal flux of CO_2 and H_2O

Performance of Strippers
Concept of Equivalent Work (W_{eq})

Why W_{eq} ?

- Compare stripper configurations on same basis.
- Compare Q and W.

$$= 0.75 Q_{reb} \left[\frac{(T_{reb} + 10) - 313}{(T_{reb} + 10)} \right] + W_{comp} + W_{pump}$$

75% Adiabatic Efficiency in Compressor

Wcomp to 1000 kPa

65% Efficiency in Pumps

Conditions

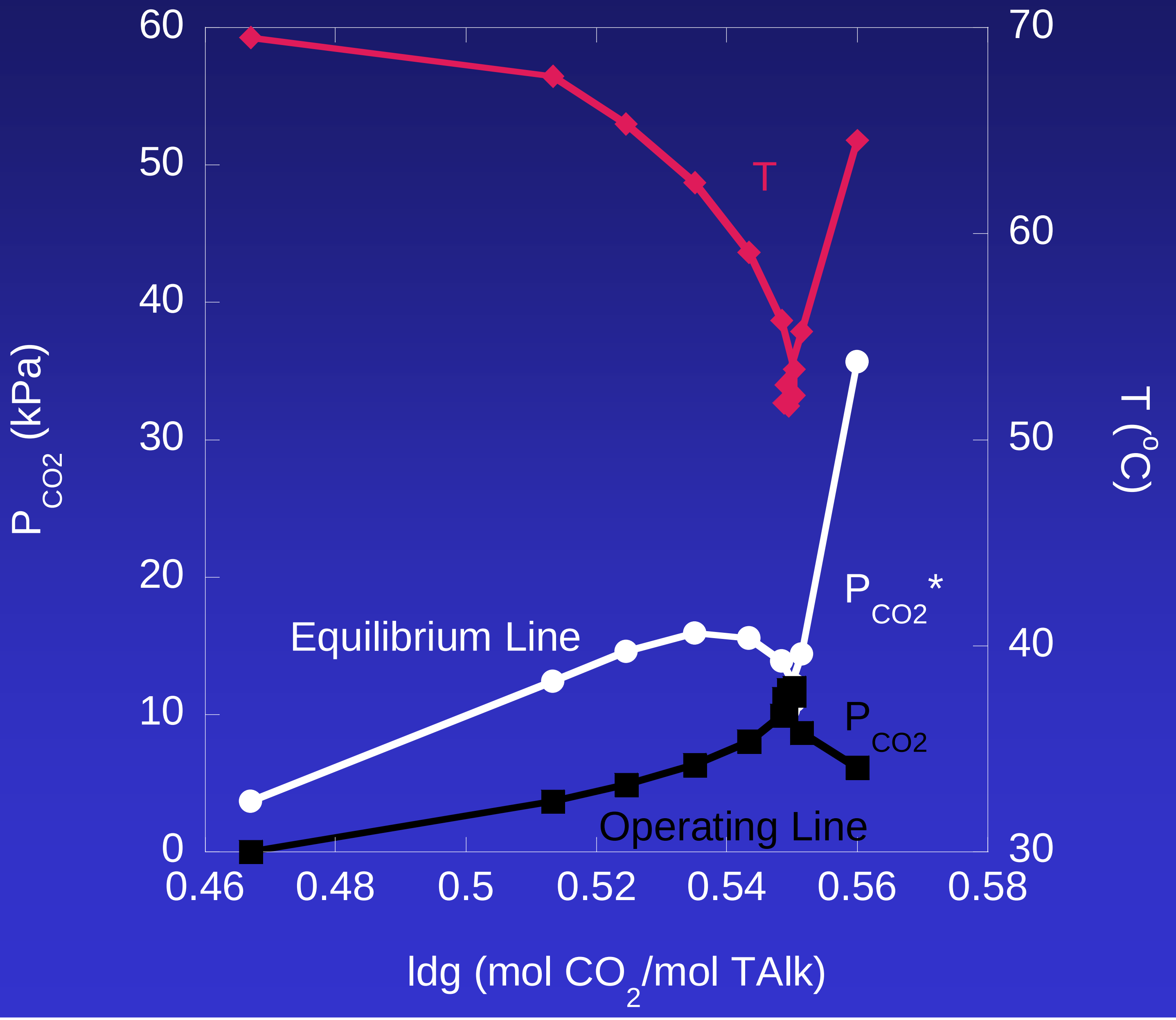
- 5m K^+/2.5m PZ
- L = 30 gpm
- Loading (mol CO_2/mol TAlk)
  Rich = 0.560 , Lean = 0.467
- 80% flood

“Short & Fat” vs “Tall & Skinny” Column

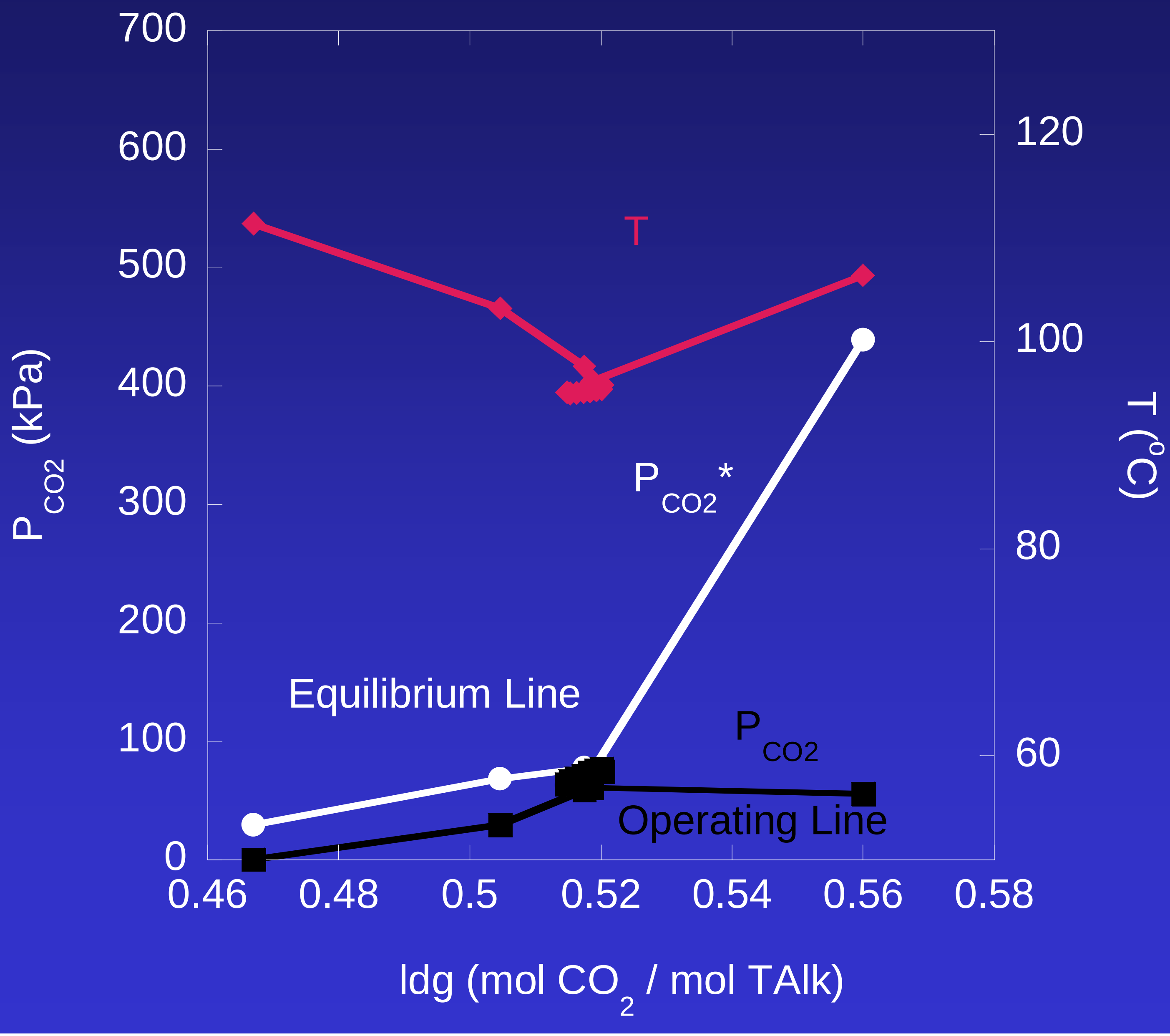
(Fixed volume of packing = 0.858 m^3)

Reboiler P	% flood	D	H	Q_{reb}	W_{comp}	Total W_{eq}
kPa		m		kJ/mol		
30	80	0.33	9.8	190	18	33.7
	30	0.51	4.2	155	15	30.9
160	80	0.20	26.8	138	7.6	35.3
	30	0.33	10.2	128	7	33.3

McCabe-Thiele Plot for Vacuum Stripper



McCabe-Thiele Plot for Simple Stripper



Mass Transfer Mechanisms In Simple Stripper

Mole fraction units (x 10^5) kmol/m^2-s	P = 30 kPa		P = 160 kPa	
	Rich End	Lean End	Rich End	Lean End
k_y'	1.5	3.7	22.8	37.7
K_y	1.5	3.5	19.8	28.0
Gas res.(%)	2	3	14	25
Kinetic res.(%)	89	60	17	25
Diffusion res.(%)	9	37	69	50

Conclusions

- Stripper operation is liquid film controlled.
- The stripper operation is kinetics controlled at 30 kPa and diffusion controlled at 160 kPa.
- For vacuum operations, a ‘short and fat’ stripper may be more attractive than a ‘tall and skinny’ one. The ΔP is also less with a ‘short and fat’ stripper.
- A vacuum (30 kPa) stripper requires less W_{eq} (~ 7 %) when run at the same % flood than a simple (160 kPa) one.

Energy Requirement for Solvent Regeneration in CO_2 Capture Plants

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Presented at the 9th International CO_2 Capture Network, Copenhagen.
June 16, 2006

Outline

- ❑ Introduction/ motivation
- ❑ Research Objective
- ❑ Methodology
- ❑ Results & Discussion
- ❑ Conclusions
- ❑ Acknowledgement

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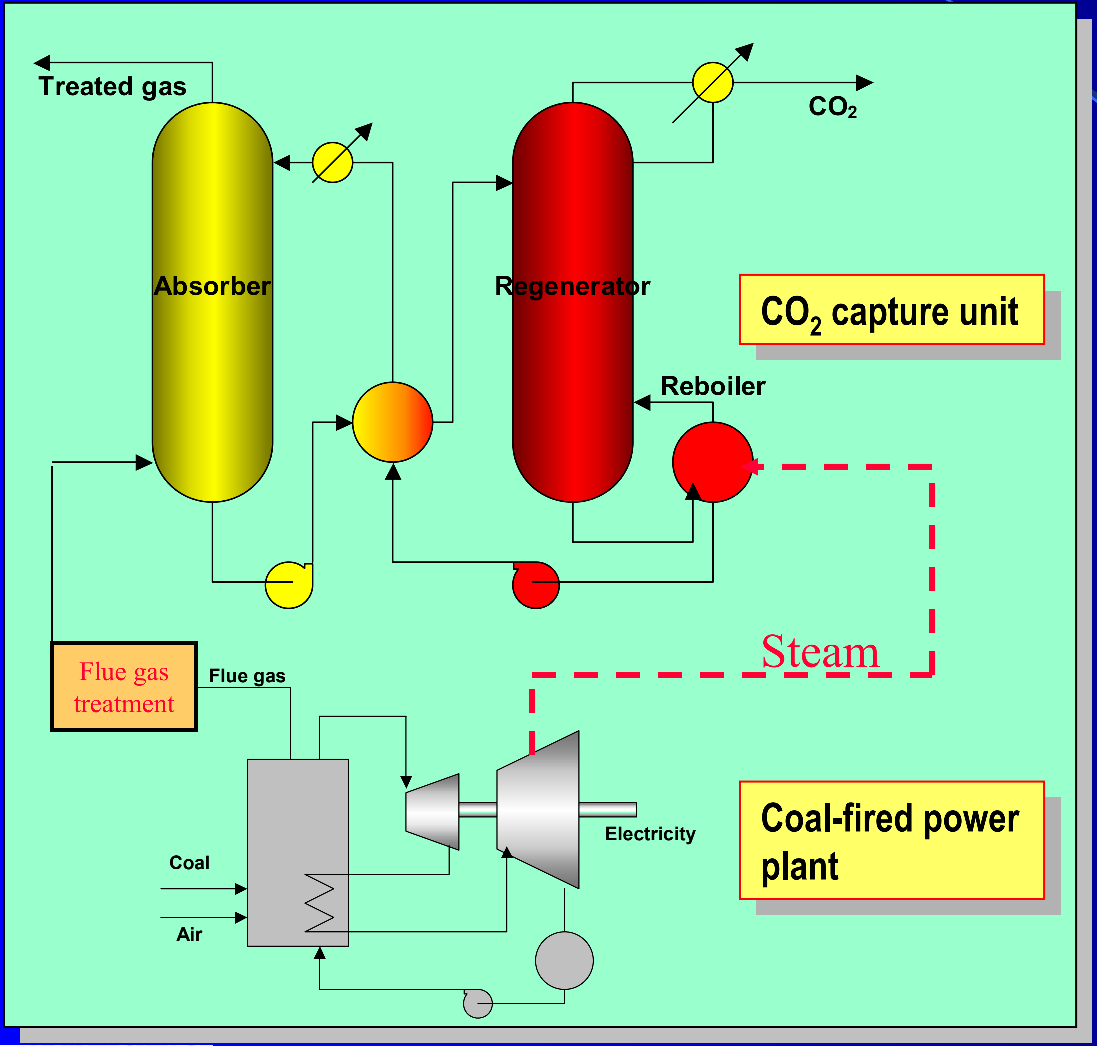
Amine Treating Plant for CO_2 Capture



Plant feature:

- Absorption process
- Chemical reaction
- Monoethanolamine (MEA)

  $HO\text{-}CH_2\text{-}CH_2\text{-}NH_2$
- Energy input for solvent regeneration

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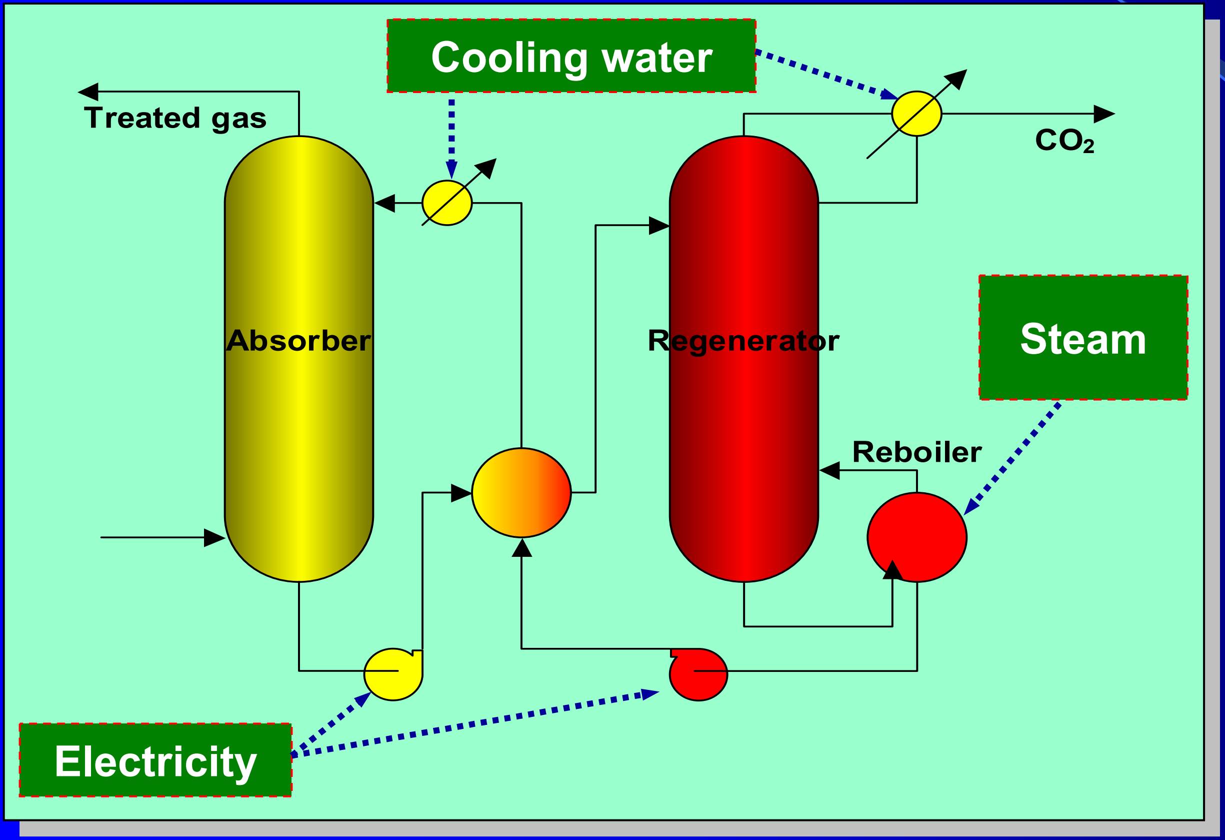
Utility & Energy Consumption



Steam consumption:

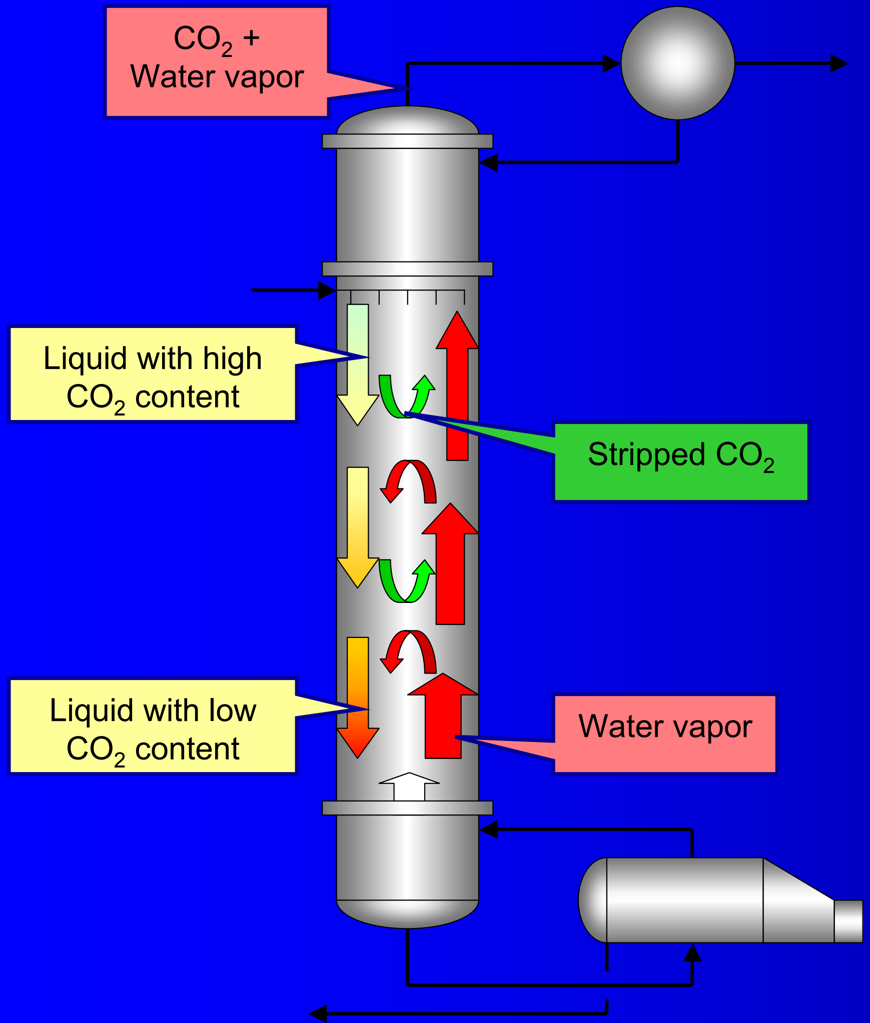
- 4,000-5,000 kJ/kg CO_2

Steam cost:

- 70-80% of operating cost

$CO_2 + 2RR'NH \leftrightarrow RR'NH_2^+ + RR'NCOO^-$

Solvent Regeneration



Energy utilization: **(Steam)**

- Heat of reaction (CO_2 – Amine)
- Heat capacity (increase in Temp.)
- Heat of water vaporization

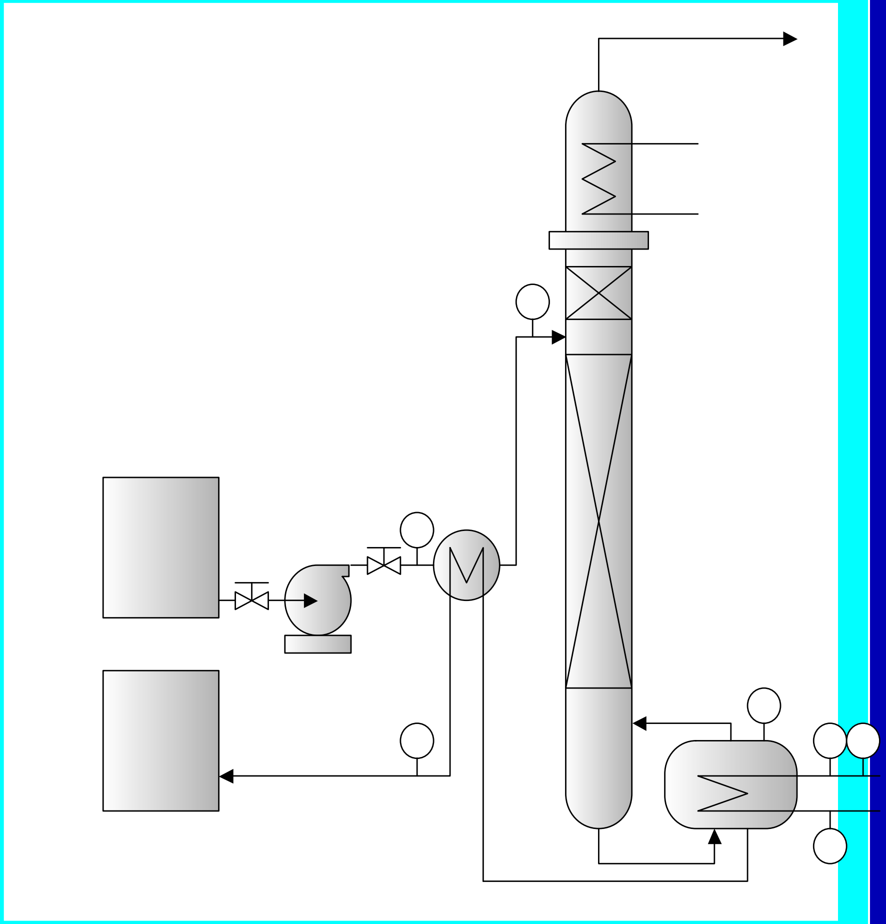
Cost reduction:

- Energy-efficient solvents
- Process modifications

Research Objectives

- To evaluate reboiler heat duty of different solvent types under different operating conditions
- To correlate relationships between process parameters and reboiler heat-duty
- To establish a strategy for process cost reduction

Experiments (Flow-Through Gas Stripping System)



Experiments

Single Alkanolamine	❑ MEA (Monoethanolmine) ❑ DEA (Diethanolamine) ❑ MDEA (Methyldiethanolamine)
Blended Alkanolamine	❑ MEA-MDEA ❑ DEA-MDEA
Mixing Ratio (mol : mol)	❑ 1 : 2 ❑ 1 : 1 ❑ 2 : 1
Rich CO_2 Loading	❑ 0.3 mol/mol ❑ 0.5 mol/mol
Solvent Concentration	❑ 4.0 $kmol/m^3$ ❑ 5.0 $kmol/m^3$ ❑ 7.0 $kmol/m^3$

Experimental Validation

Reboiler heat-duty (kJ/kg CO_2)	lean CO_2 loading (mol/mol)	
	literature [a] (1-4 tonnes/day units)	this study
3,800	0.28 – 0.35	0.30 (at 3,767 kJ/kg CO_2)
4,800	0.23 – 0.29	0.25 (at 4,849 kJ/kg CO_2)
5,400	0.20 – 0.24	0.23 (at 5,203 kJ/kg CO_2)

[a] Estimated values from the work by Wilson et al. (2004)

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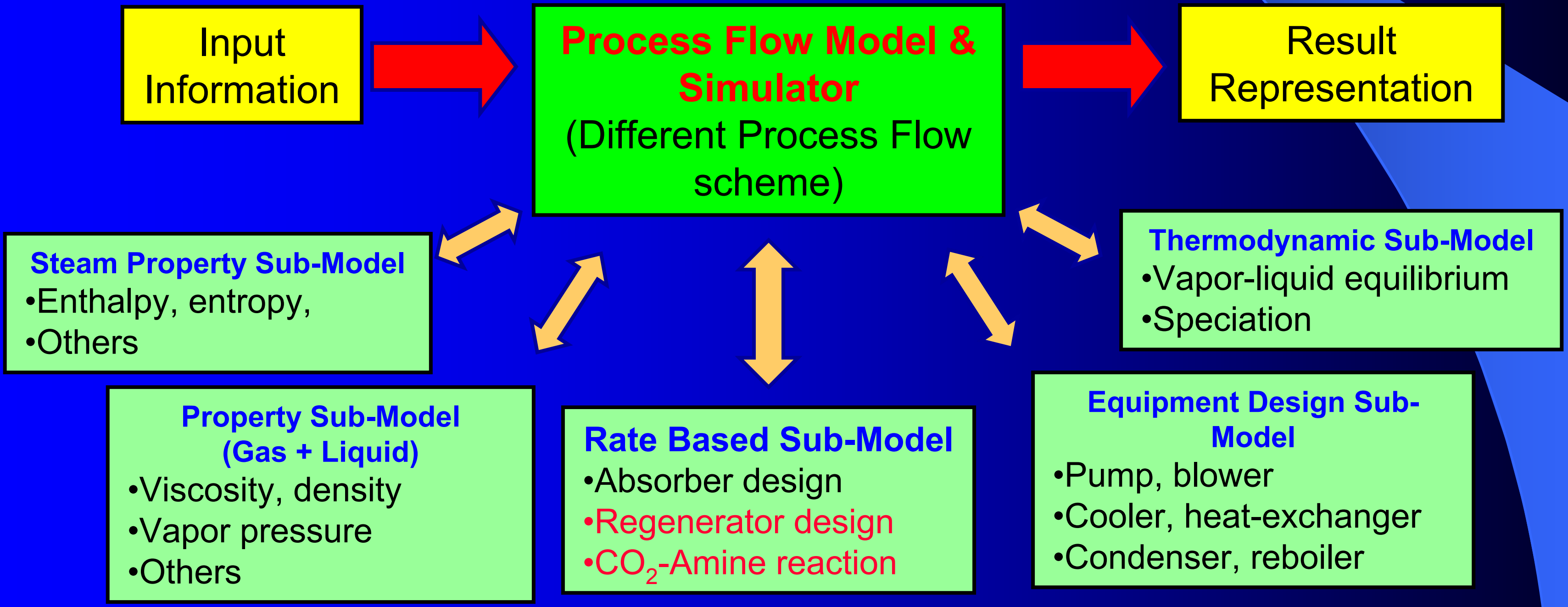
Methodology (Energy model simulation)

- Process flow model
- Design & property sub-models



Input Information

Process Flow Model & Simulator
(Different Process Flow scheme)

Result Representation

Steam Property Sub-Model
- Enthalpy, entropy,
- Others

Property Sub-Model (Gas + Liquid)
- Viscosity, density
- Vapor pressure
- Others

Rate Based Sub-Model
- Absorber design
- Regenerator design
- CO_2-Amine reaction

Equipment Design Sub-Model
- Pump, blower
- Cooler, heat-exchanger
- Condenser, reboiler

Thermodynamic Sub-Model
- Vapor-liquid equilibrium
- Speciation

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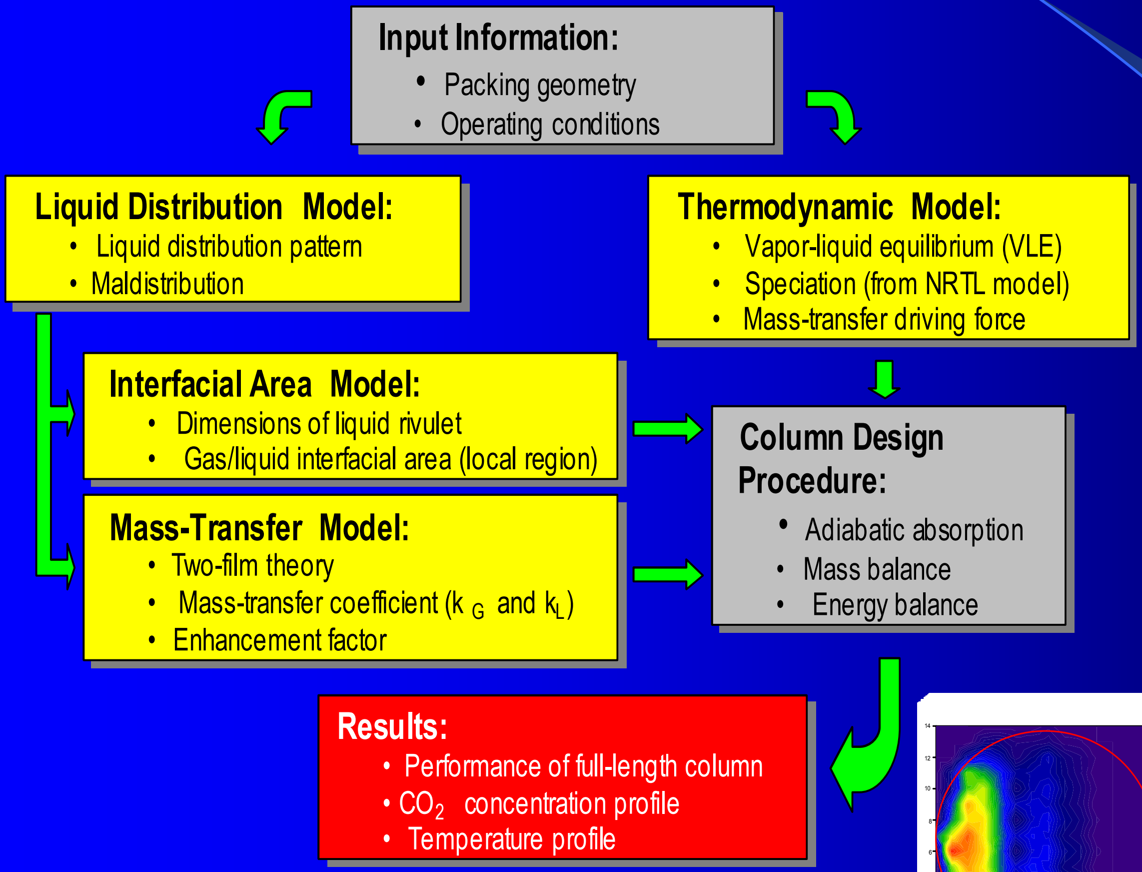
Mechanistic Model

(Mass-transfer & Hydrodynamics)



Input Information:
- Packing geometry
- Operating conditions

Liquid Distribution Model:
- Liquid distribution pattern
- Maldistribution

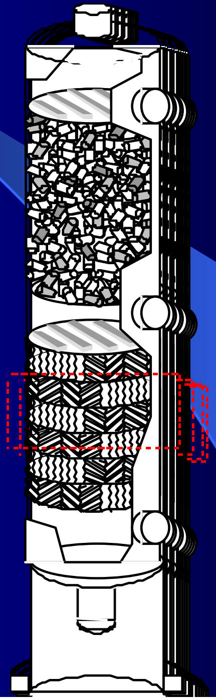
Thermodynamic Model:
- Vapor-liquid equilibrium (VLE)
- Speciation (from NRTL model)
- Mass-transfer driving force

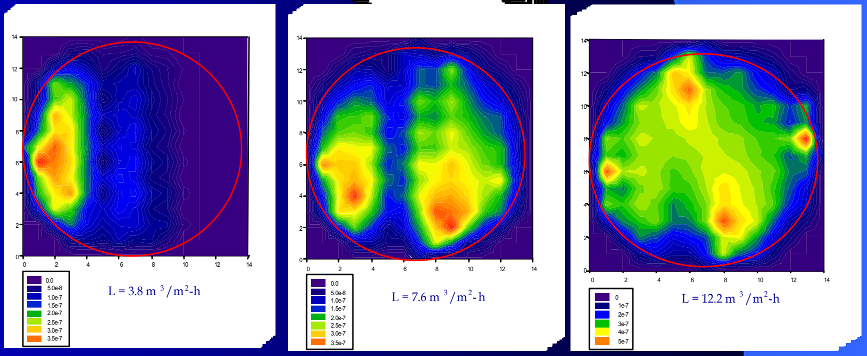
Interfacial Area Model:
- Dimensions of liquid rivulet
- Gas/liquid interfacial area (local region)

Mass-Transfer Model:
- Two-film theory
- Mass-transfer coefficient (k_G and k_L)
- Enhancement factor

Column Design Procedure:
- Adiabatic absorption
- Mass balance
- Energy balance

Results:
- Performance of full-length column
- CO_2 concentration profile
- Temperature profile





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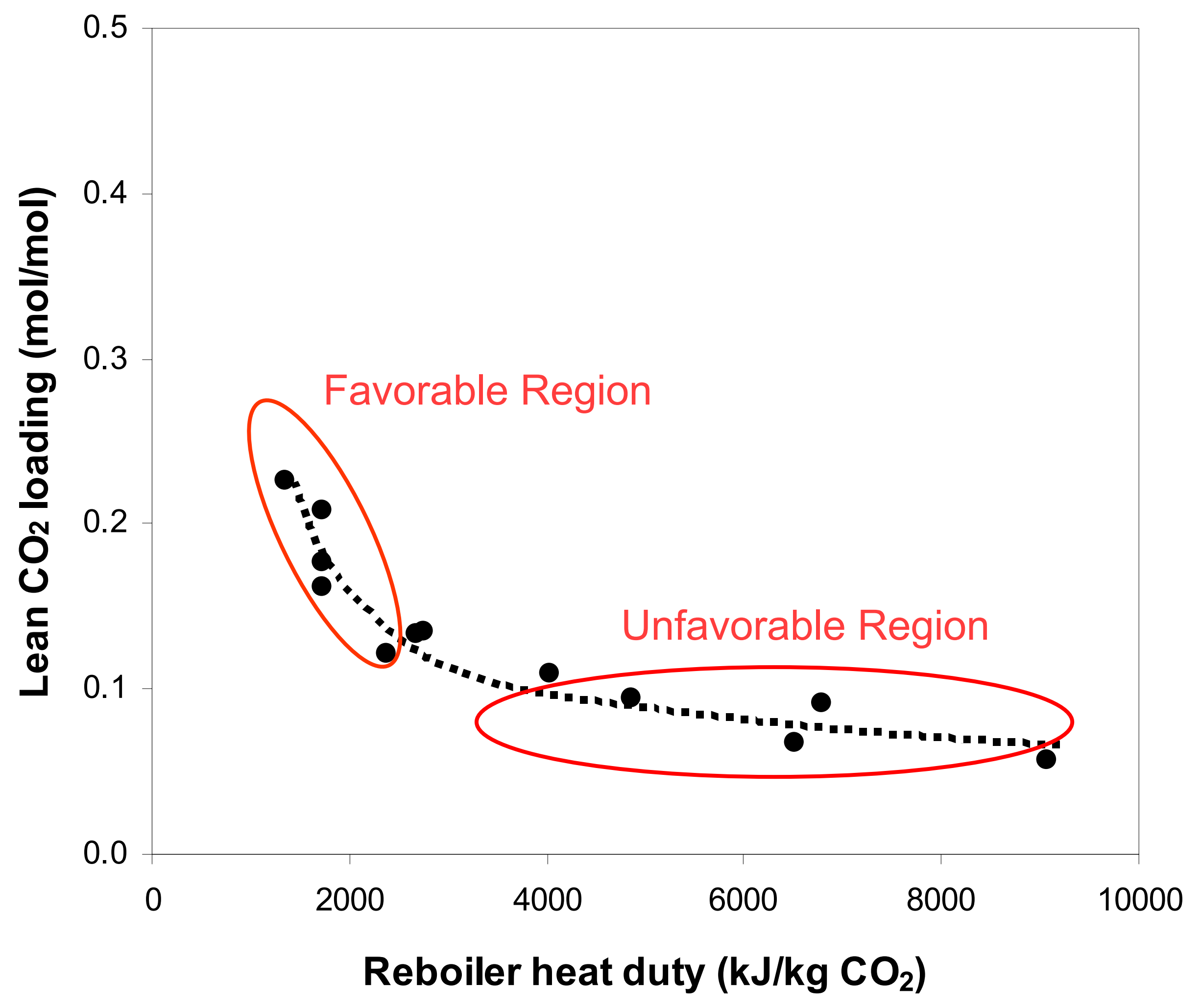
- section at various liquid loads.

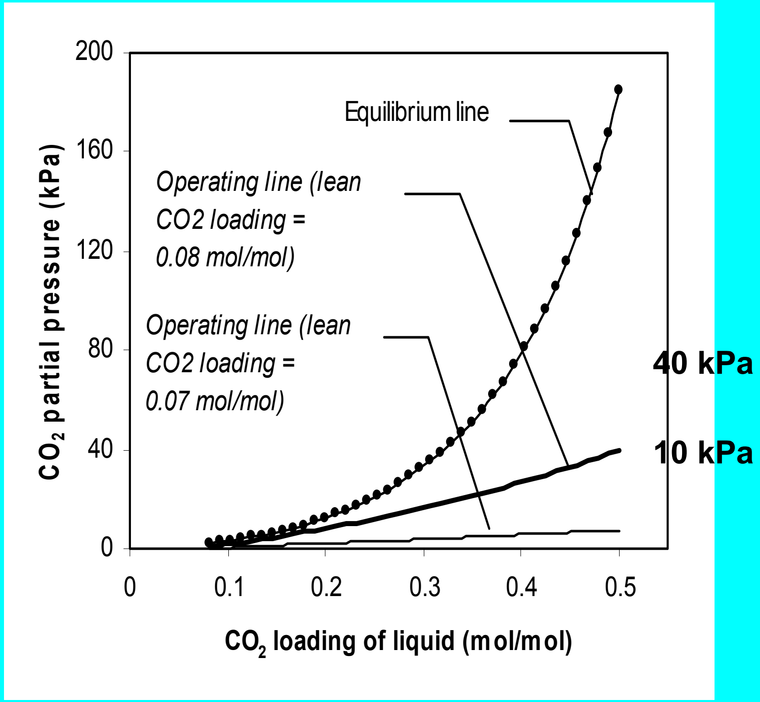
Effect of Lean-CO_2 Loading



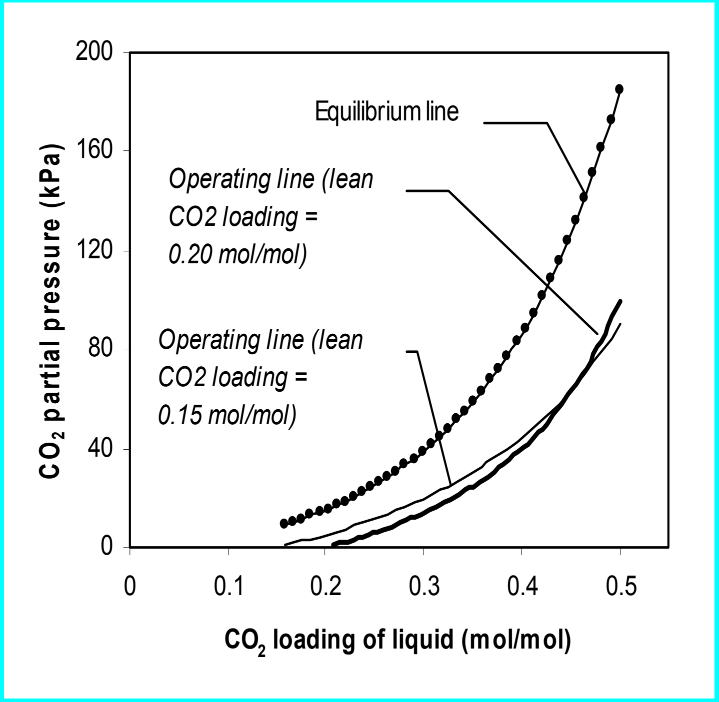
Rich Loading: 0.5 mol CO_2 / mol DEA, Concentration: 4 kmol/m^3

Effect of Lean-CO_2 Loading (con't)

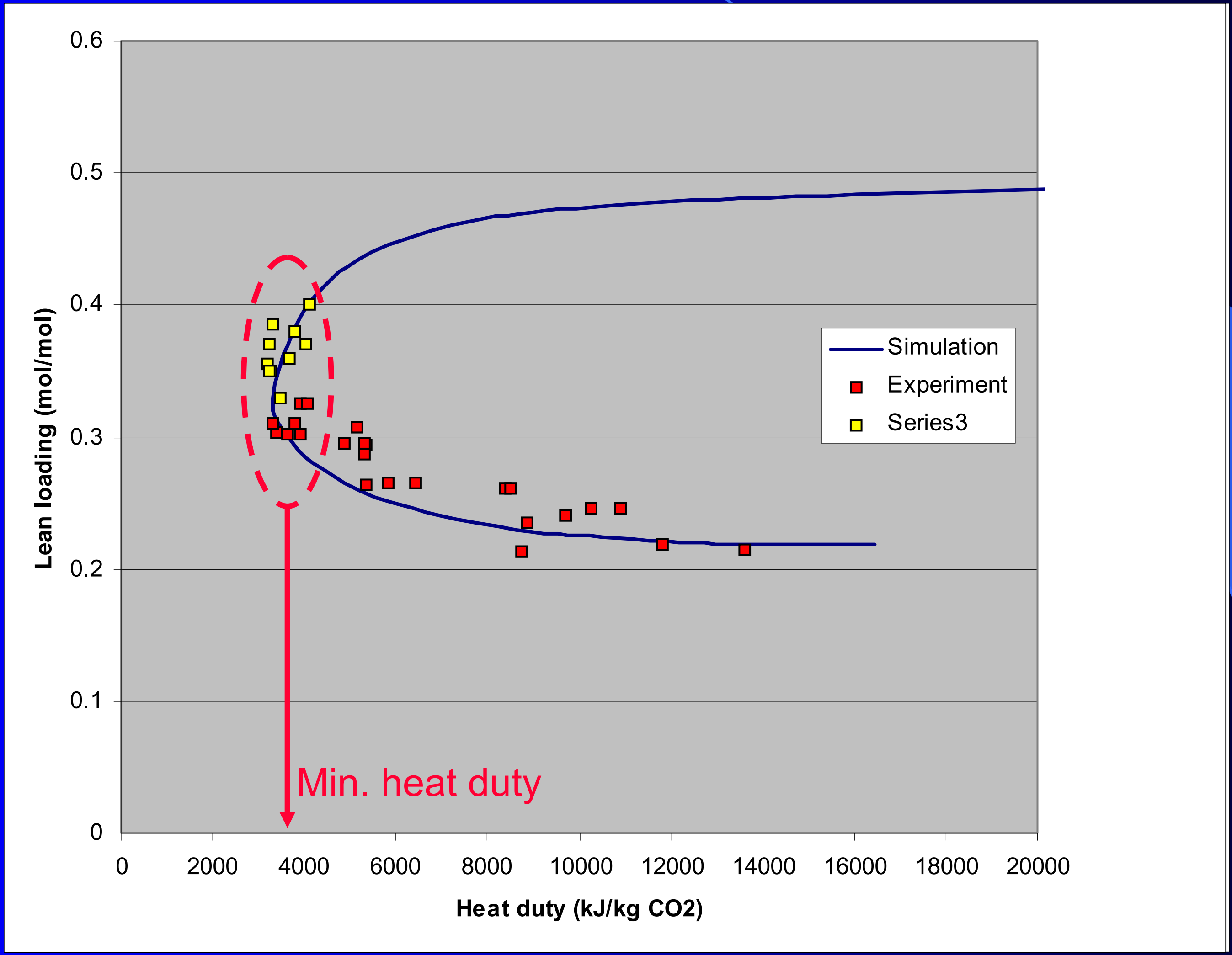
Unfavorable Region



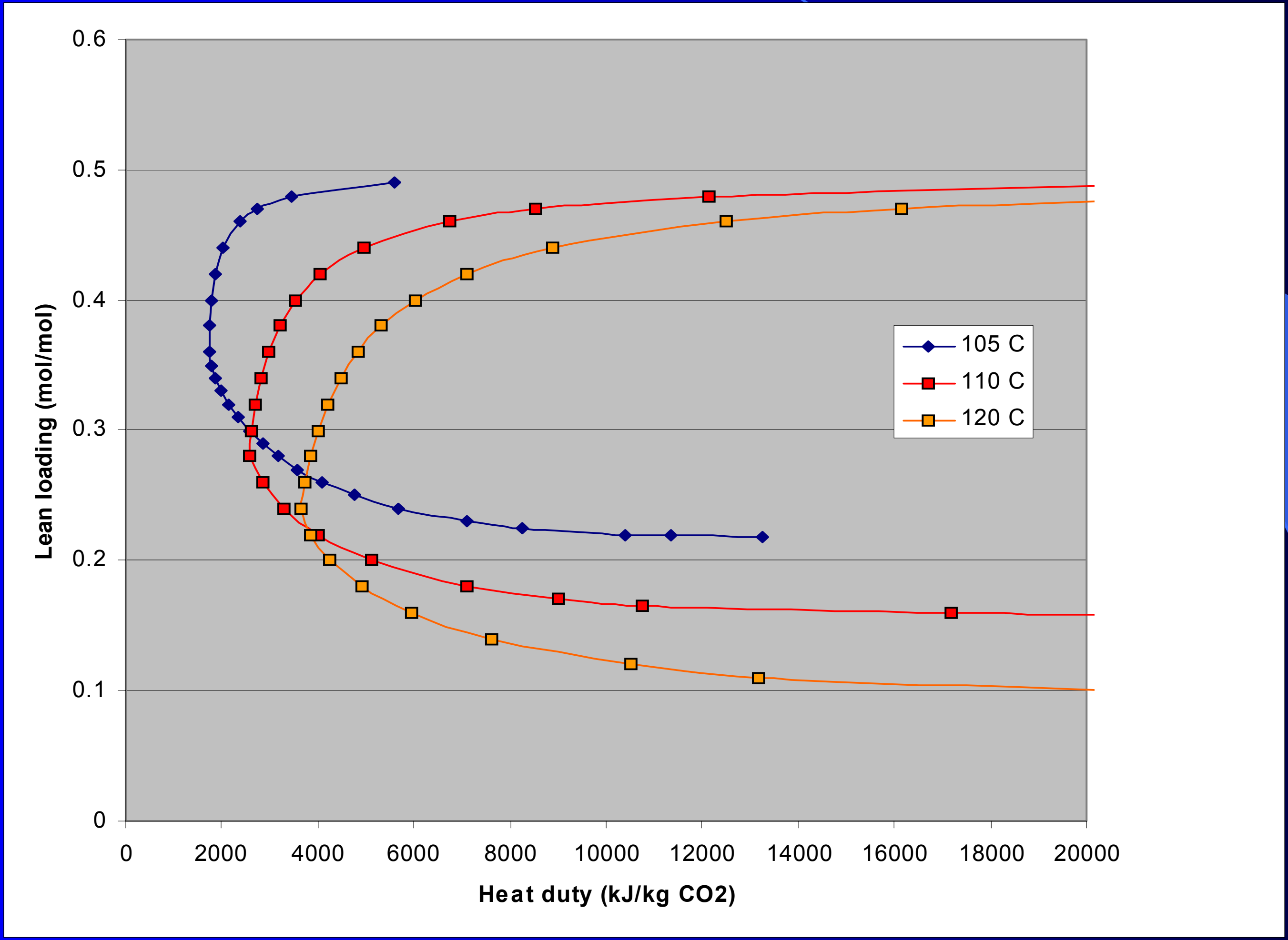
Favorable Region



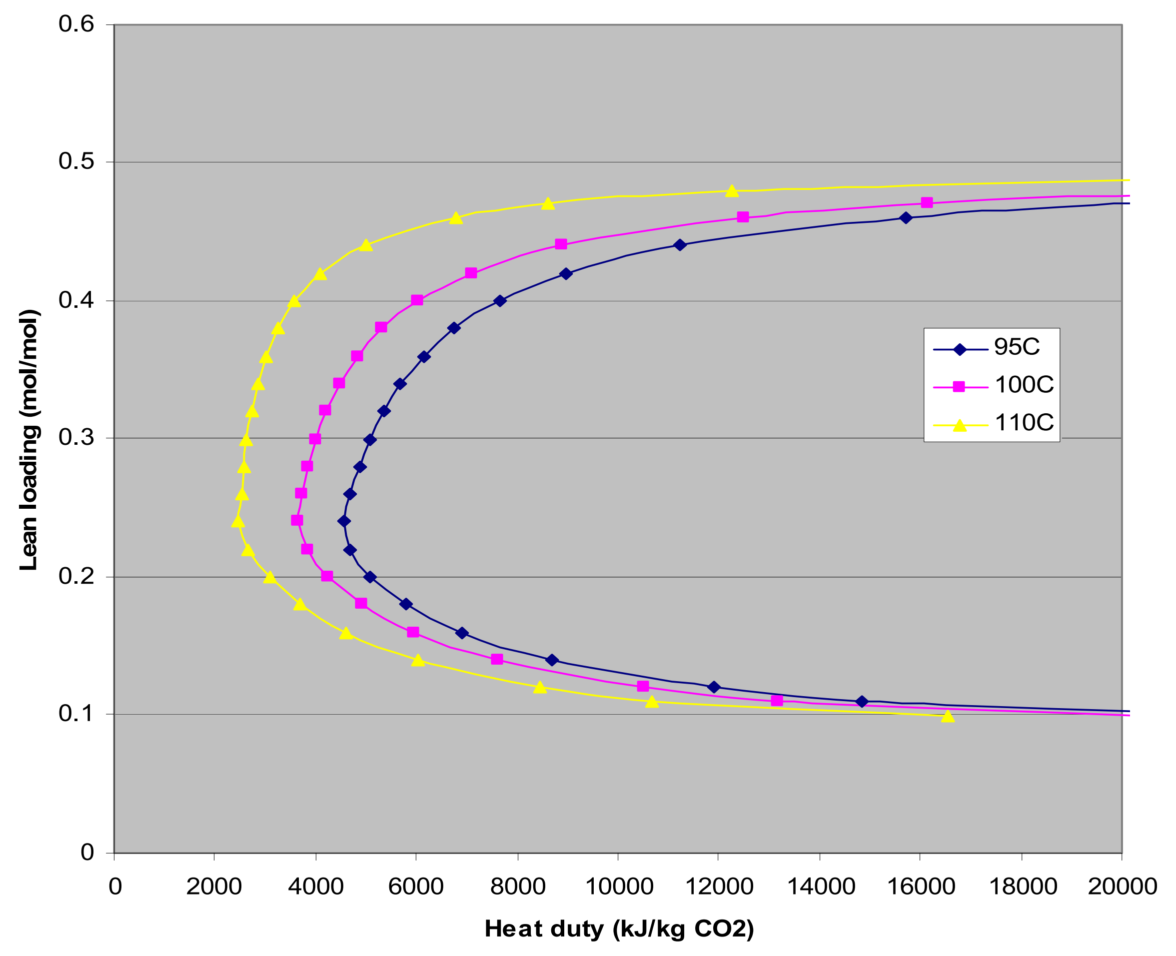
Simulation Results



Simulation Results
(Effect of Reboiler Temp.)



Simulation Results (Effect of Regen Feed Temp.)



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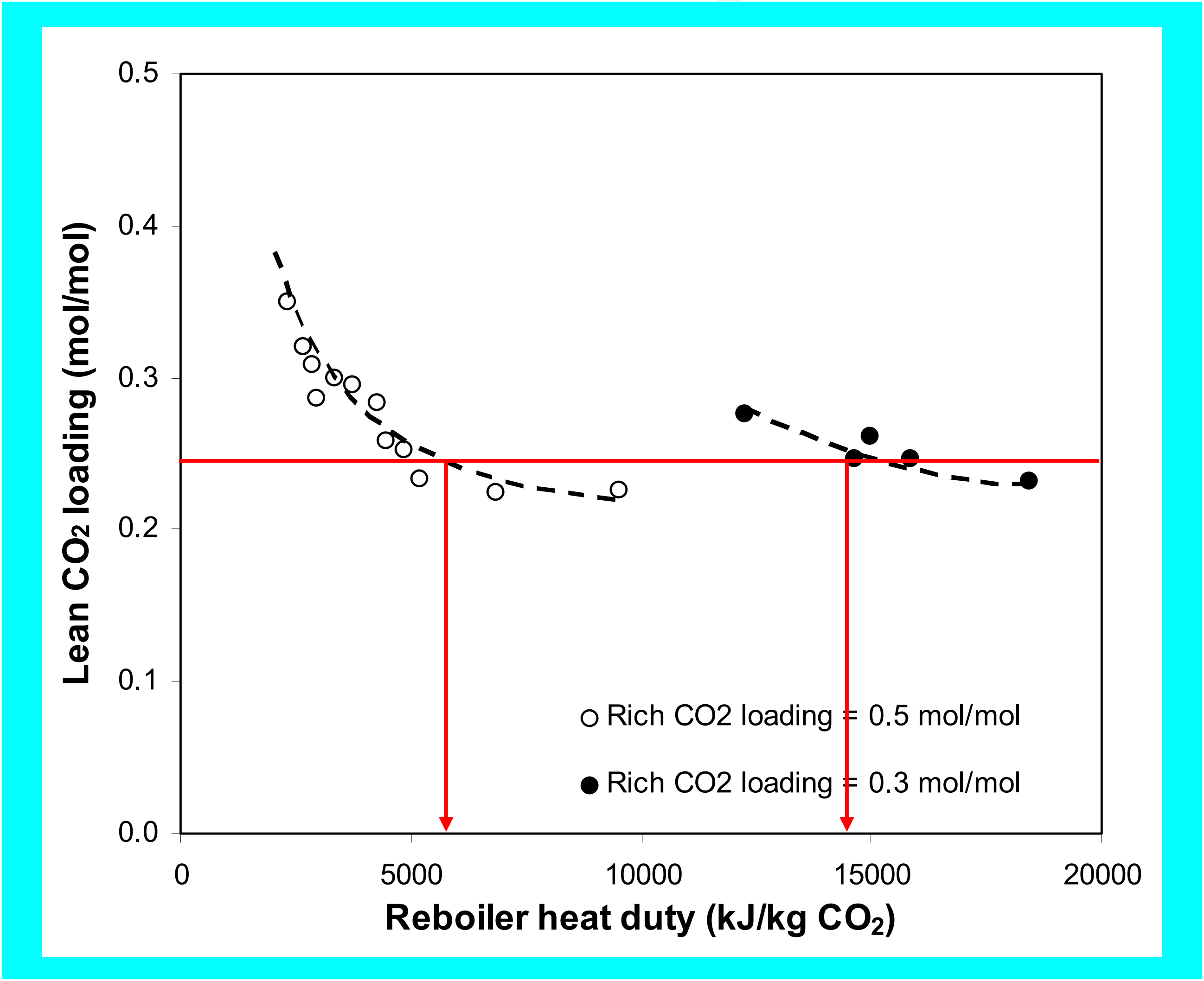
Effect of Rich-CO_2 Loading

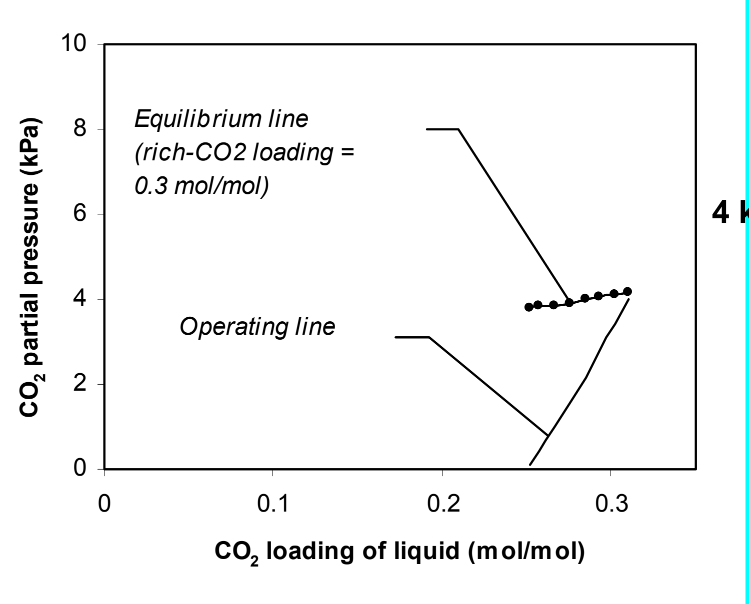


0.3 mol/mol Rich CO_2 Loading > 0.5 mol/mol Rich CO_2 Loading

Solution: MEA, Concentration: 5 kmol/m^3

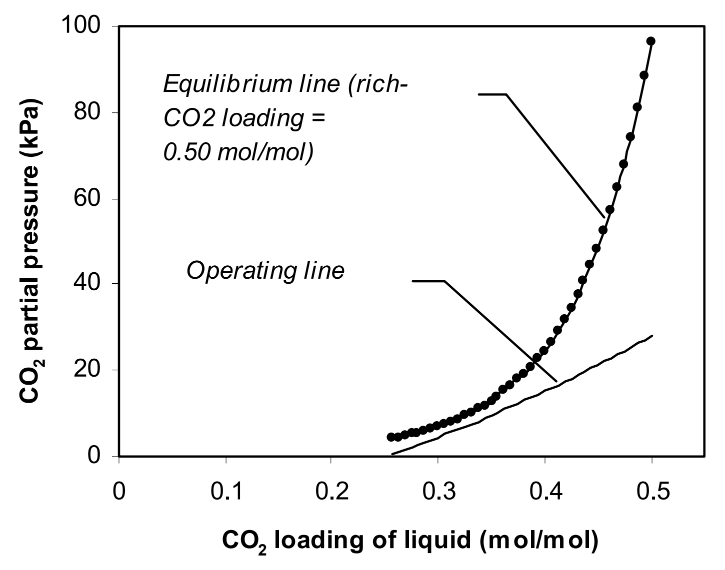
Effect of Rich-CO_2 Loading (con't)

Rich Loading : 0.3 mol/mol

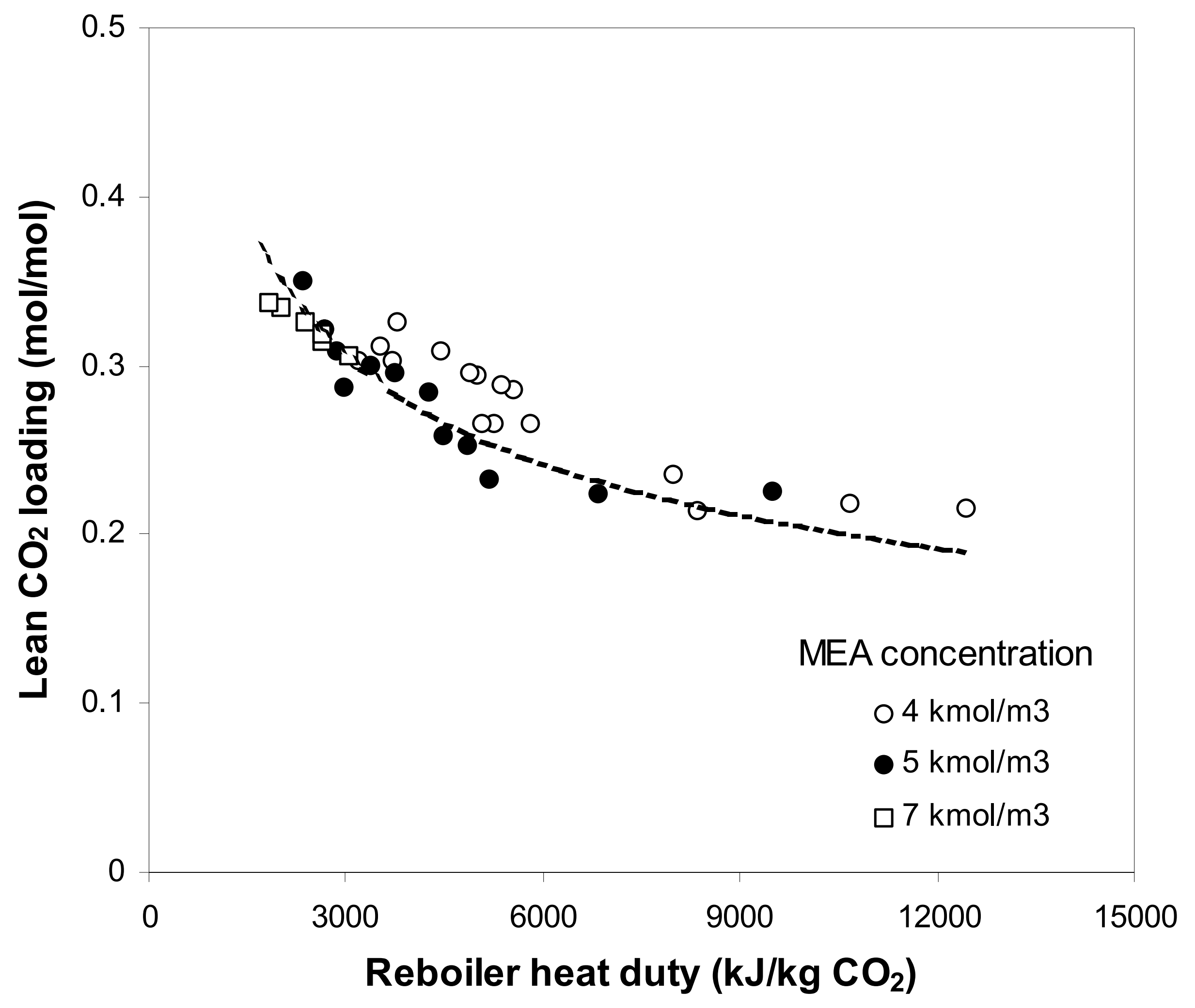


4 kPa

Rich Loading : 0.5 mol/mol

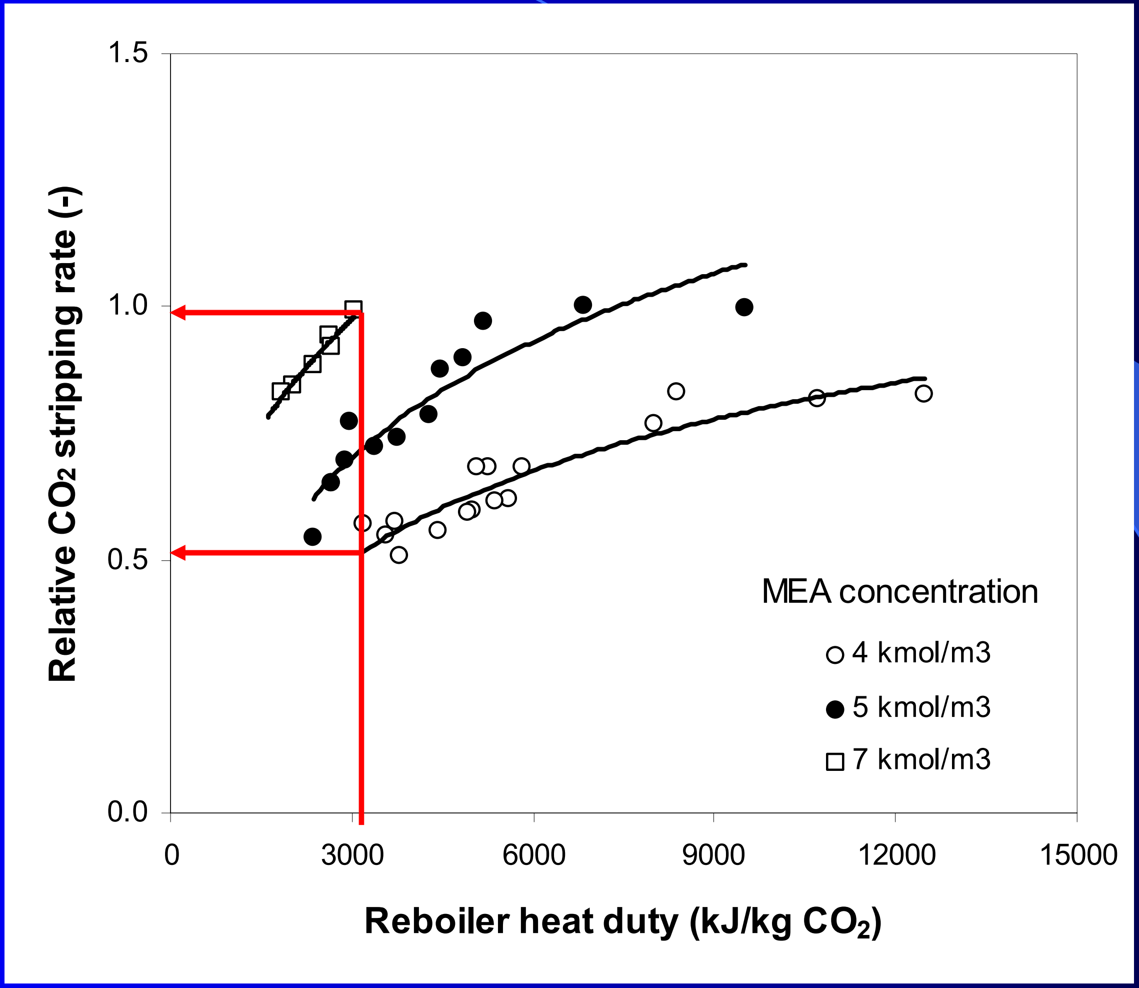


Effect of Solvent Concentration



Solution: MEA, Rich Loading: 0.5 mol CO_2 / mol solution

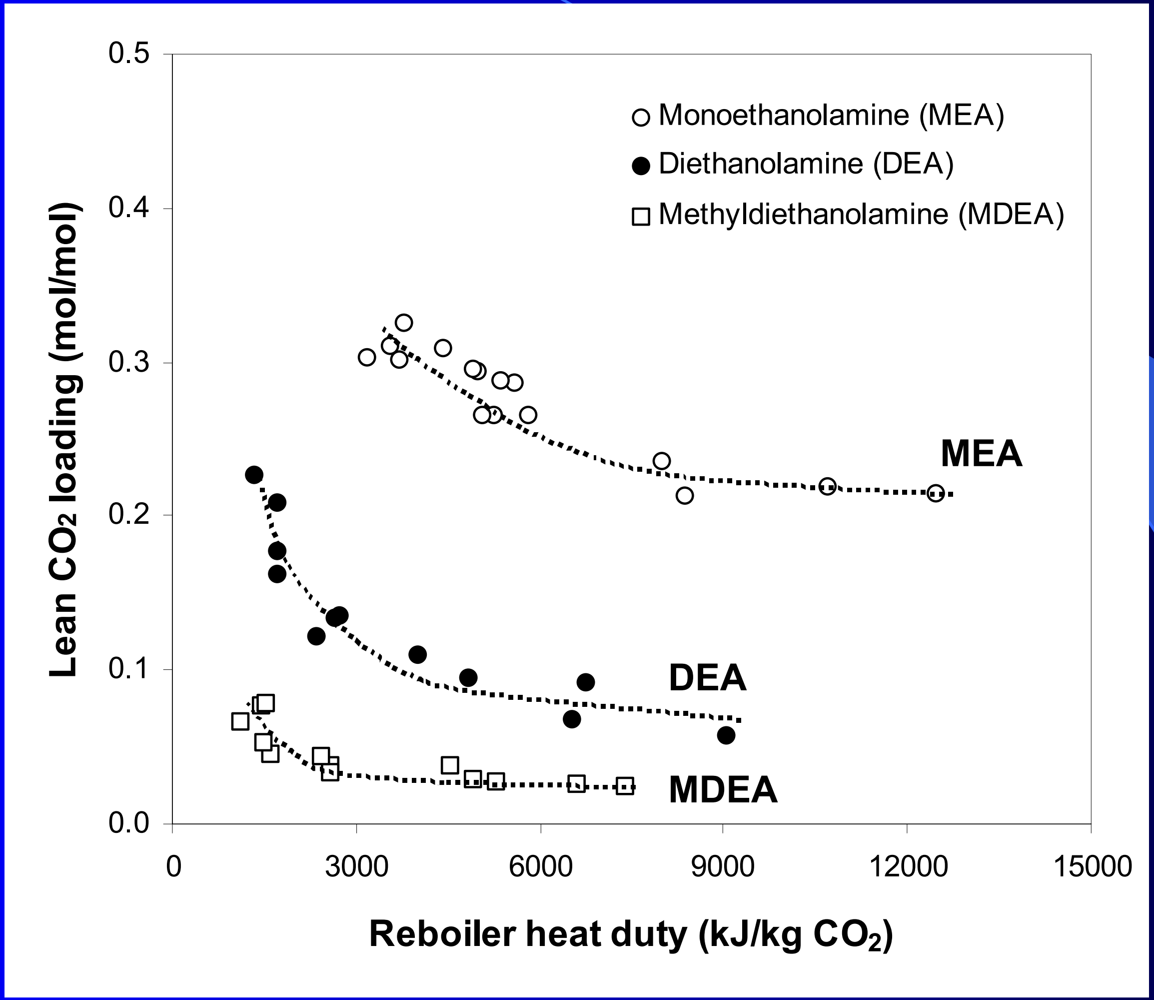
Effect of Solvent Concentration (con't)



4 kmol / m^3 > 5 kmol / m^3 > 7 kmol / m^3

Solution: MEA, Rich Loading: 0.5 mol CO_2 / mol solution

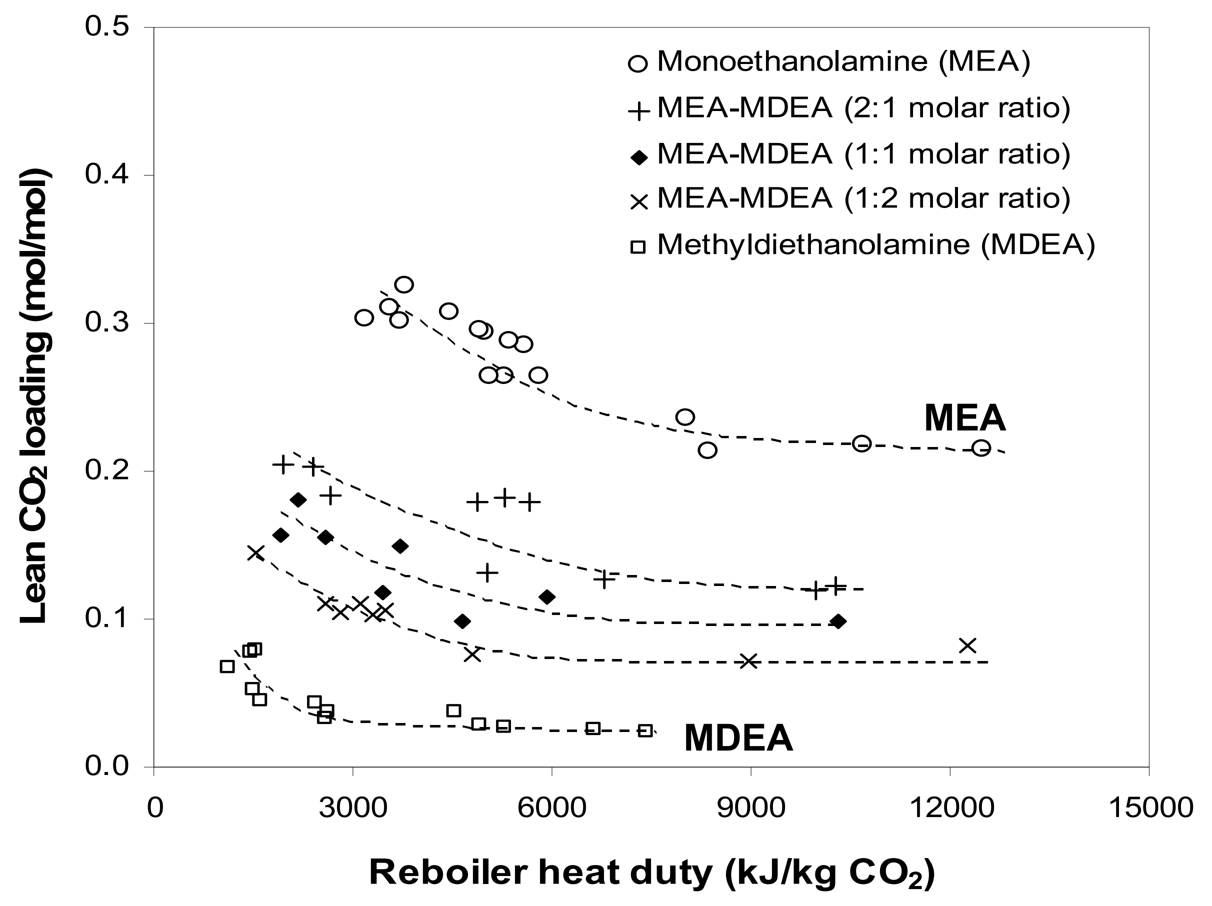
Effect of Single Alkanolamine



MEA > DEA > MDEA

Rich Loading: 0.5 mol CO_2 / mol solution, Concentration: 4 kmol/m^3

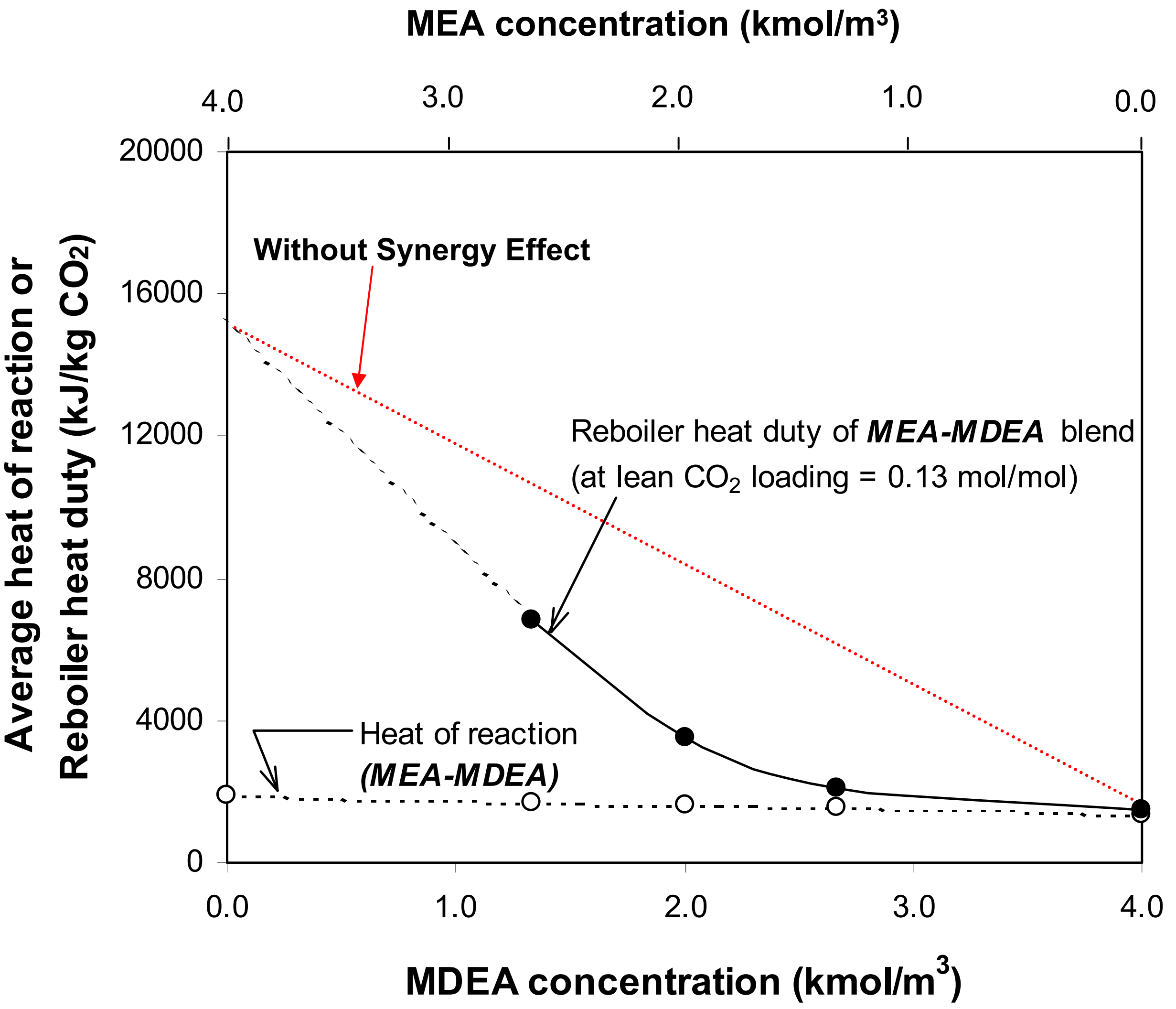
Effect of Blended Alkanolamine



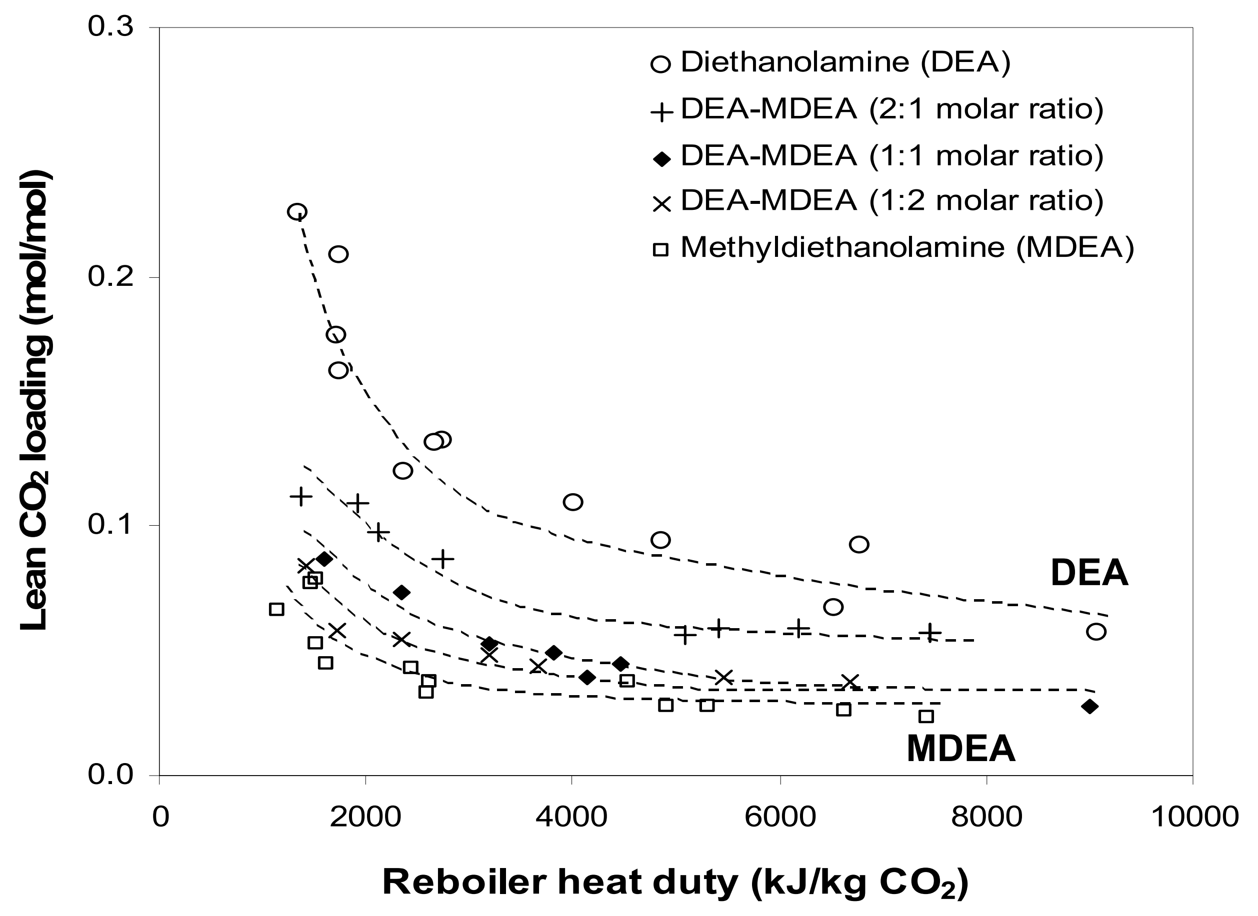
MEA > MEA-MDEA (2:1) > MEA-MDEA (1:1) > MEA-MDEA(1:2) > MDEA

Rich Loading: 0.5 mol CO_2 / mol solution, Concentration: 4 kmol/m^3

Effect of Blended Alkanolamines (con't)



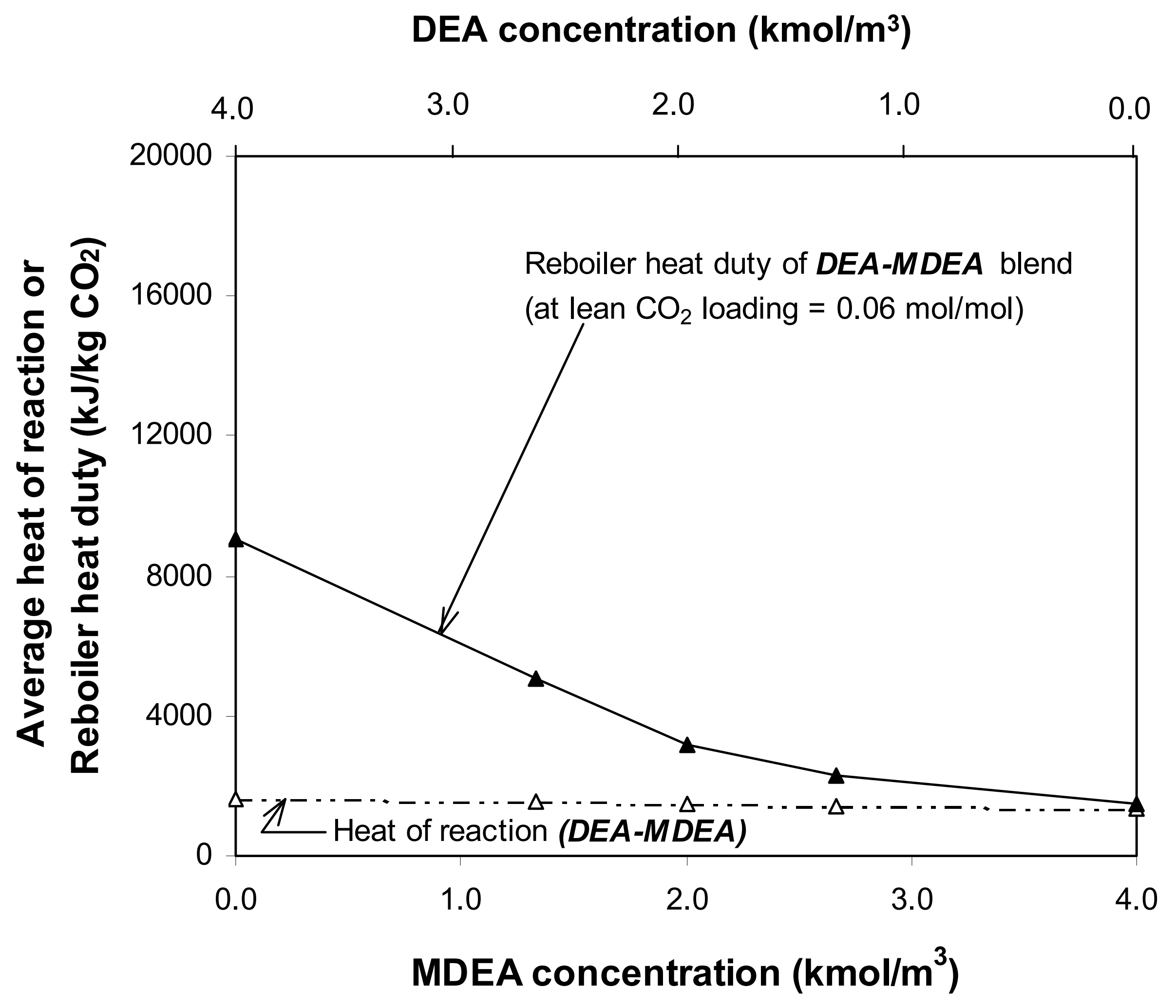
Effect of Blended Alkanolamines (con't)



DEA > DEA-MDEA (2:1) > DEA-MDEA (1:1) > DEA-MDEA (1:2) > MDEA

Rich Loading: 0.5 mol CO_2 / mol solution, Concentration: 4 kmol/m^3

Effect of Blended Alkanolamines (con't)



Conclusions

- Reduction in reboiler heat-duty can be achieved by operating the plants at:
  - High rich-CO_2 loading
  - Favorable range of lean-CO_2 loading
  - Low reboiler temperature
  - High lean-regen. feed temperature
  - Blended MDEA-based solvents

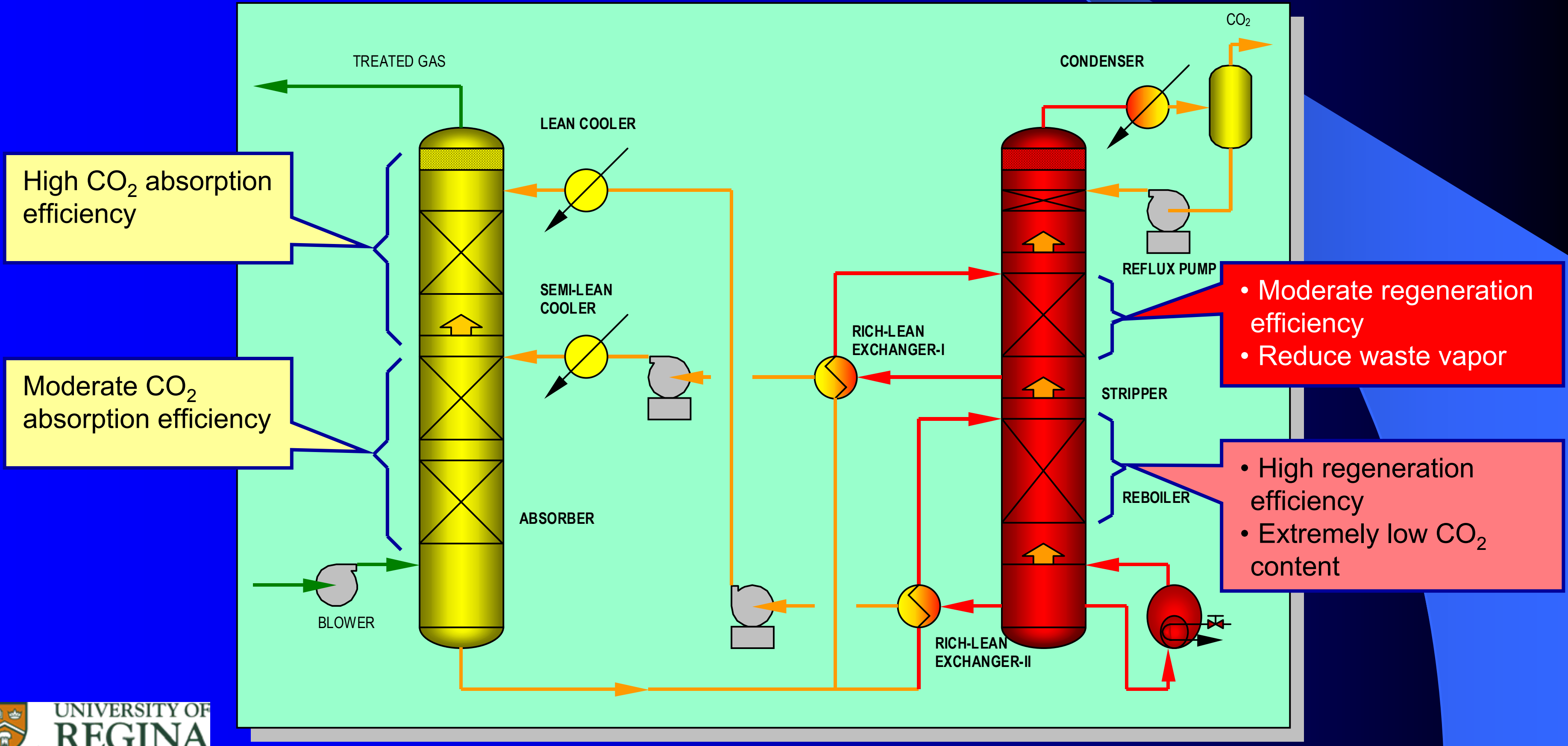
Reduce excess water vapor at the regenerator top

Approach heat of reaction

Split-Flow Configuration

Scheme feature:

- **Division of rich-solution from the absorber into two streams.**
- **Reduce the associated latent heat required during solvent regeneration.**



High CO$_2$ absorption efficiency

Moderate CO$_2$ absorption efficiency

- Moderate regeneration efficiency
- Reduce waste vapor

- High regeneration efficiency
- Extremely low CO$_2$ content

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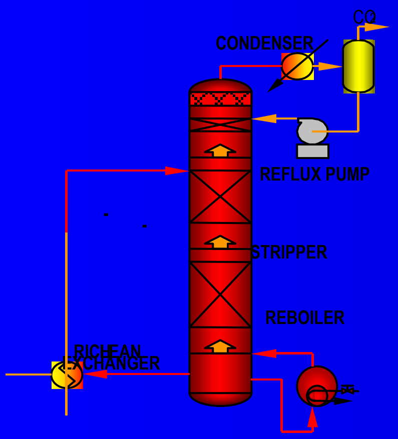
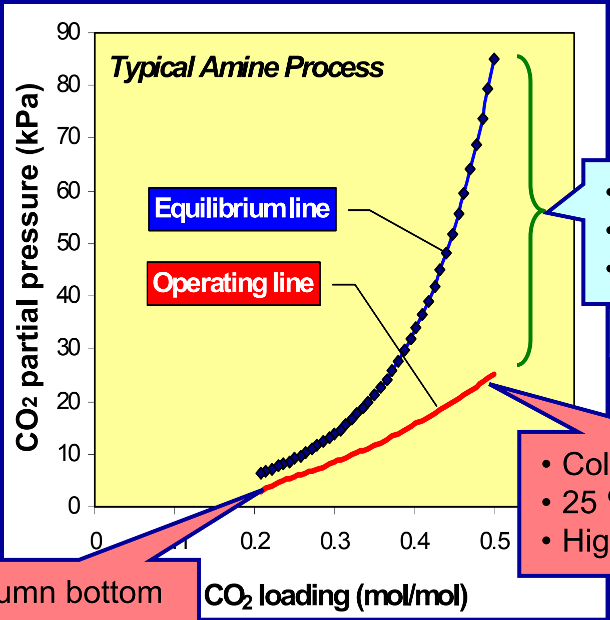
McCabe-Thiele Diagram (Typical Process)

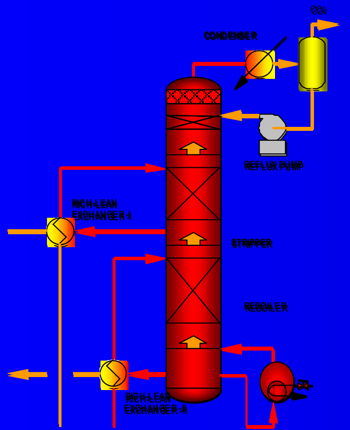


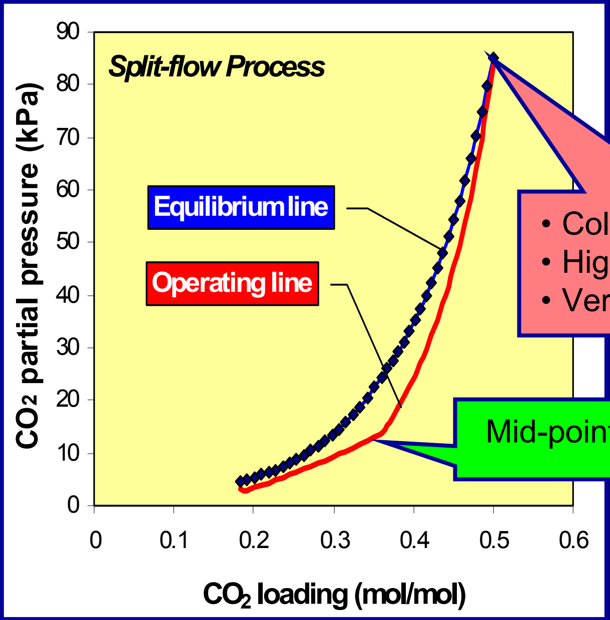


- Large driving force
- Small NTU
- Short column

- Column top
- 25 % CO_2
- High water vapor

Column bottom





- Column top
- High % CO_2
- Very low water vapor

Mid-point

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Process Simulation

Simulation conditions:

Column	Packed type
Process capacity	1,000 tonne CO_2/day
CO_2 capture efficiency	95%
Absorption solvent	Aqueous MEA solution
Solvent concentration	5.0 kmol/m^3
CO_2 content before regen.	0.50 mol CO_2/mol MEA
CO_2 content after regen.	0.17-0.22 mol CO_2/mol MEA
Reboiler temperature	up to 120°C

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REGINA

Simulation Results (Case I)

Result representation:

- Dimension of absorption column
- Height of regeneration column
- Reboiler heat duty (energy input)

Case I: Reboiler temp. = 110°C, CO_2 content after regen. = 0.17 mol/mol

Process	Specific absorber size	Specific NTU_{Regen}	Reboiler heat duty (Btu/lb mol CO_2)
Typical amine process	1.00	1.0	144,000 (7,600 kJ/kg)
Split-flow (Operation I-CI)	1.05	4.2	55,000 (2,900 kJ/kg)
Split-flow (Operation II-CI)	1.01	3.4	59,000 (3,100 kJ/kg)
Split-flow (Operation III-CI)	0.99	2.0	67,000 (3,500 kJ/kg)

Split-flow: 53 - 62 % energy saving

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Simulation Results (Cases II & III)

Case II: Reboiler temp. = 110°C, CO_2 content after regen. = 0.22 mol/mol

Process	Specific absorber size	Specific NTU_{Regen}	Reboiler heat duty (Btu/lb mol CO_2)
Typical amine process	1.00	1.0	83,000 (4,400 kJ/kg)
Split-flow (Operation I-CII)	0.73	3.0	68,000 (3,600kJ/kg)
Split-flow (Operation II-CII)	1.09	2.0	69,000 (3,600 kJ/kg)

Case III: Reboiler temp. = 120°C, CO_2 content after regen. = 0.17 mol/mol

Process	Specific absorber size	Specific NTU_{Regen}	Reboiler heat duty (Btu/lb mol CO_2)
Typical amine process	1.00	1.0	78,000 (4,100 kJ/kg)
Split-flow (Operation I-CIII)	1.01	1.9	64,000 (3,400 kJ/kg)

Split-flow: 18 % energy saving

Acknowledgement

- Natural Sciences and Engineering Research Council of Canada (NSERC)
- Roongrat Sakwattanapong

Imperial College
London

9th International CO2 Capture Network – Agenda
16 June 2006
Offices of E2, Copenhagen, Denmark

MAKING NEW POWER PLANTS ‘CAPTURE READY’

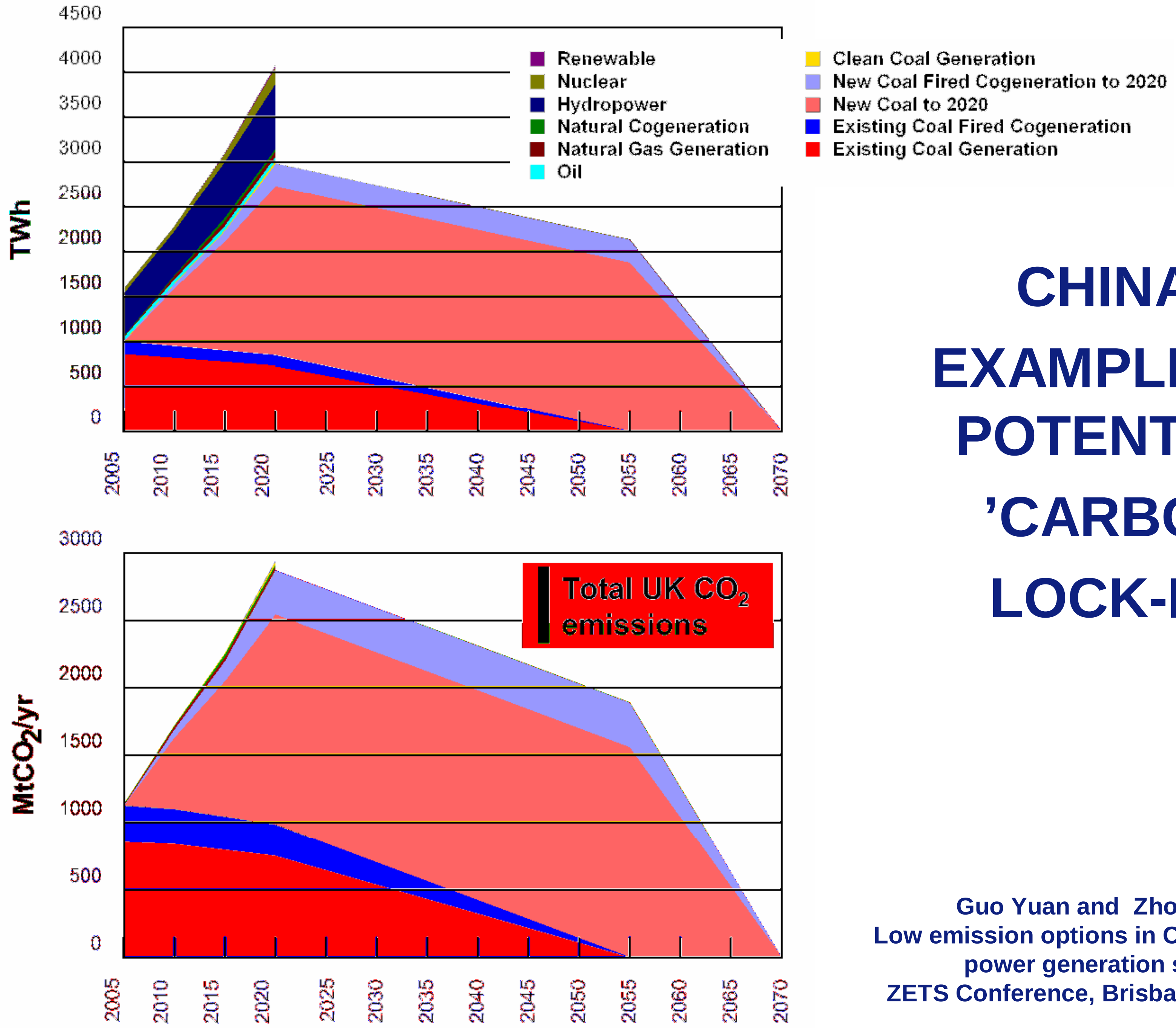
Jon Gibbins

Energy Technology for Sustainable Development Group

Mechanical Engineering Department

Imperial College London

BCURA, DTI, IEA GHG, TSEC Programme - UKCCSC



CHINA:

EXAMPLE OF POTENTIAL 'CARBON LOCK-IN'

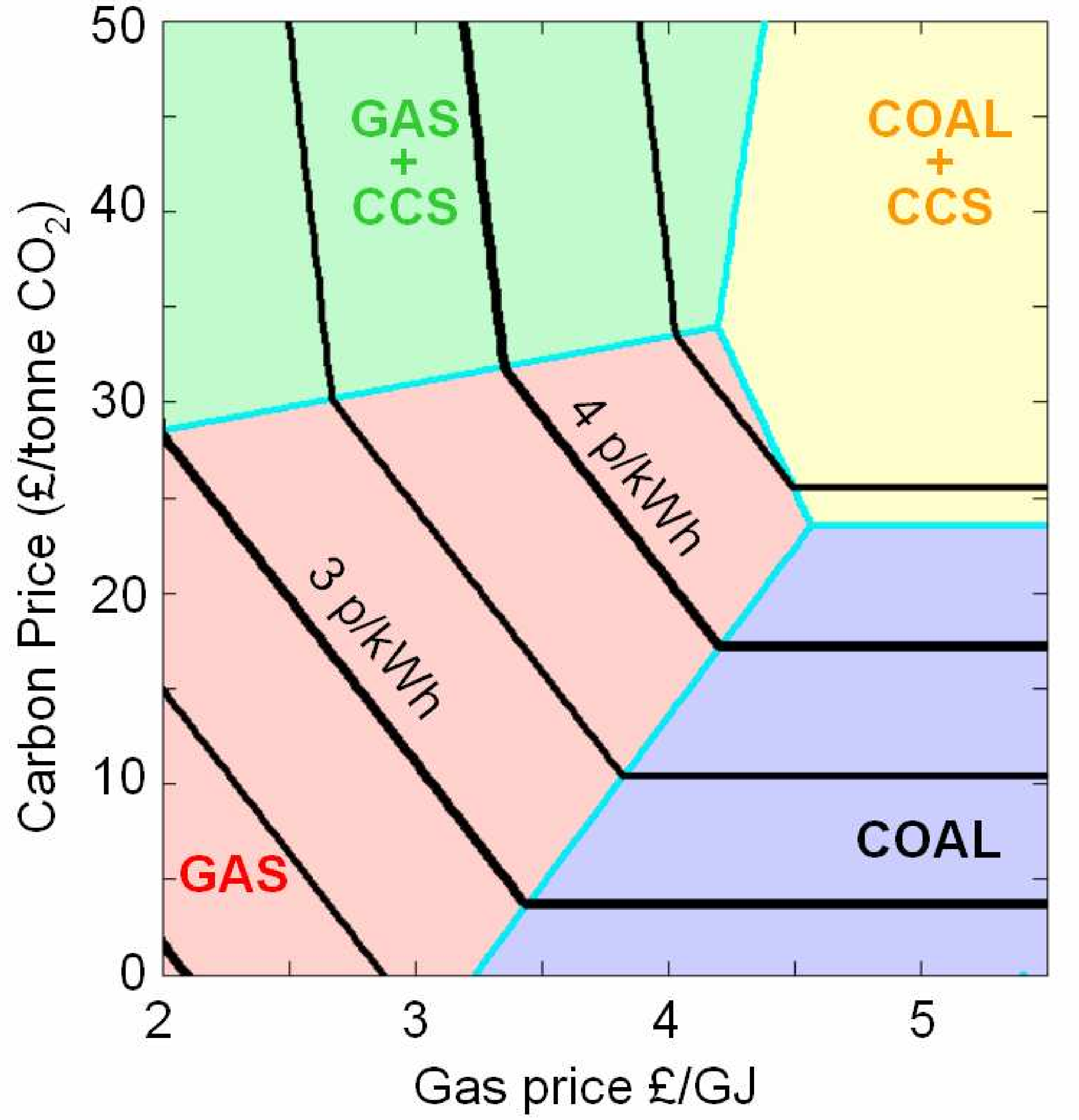
Guo Yuan and Zhou Dadi,
Low emission options in China's electric power generation sector,
ZETS Conference, Brisbane, Feb 2004.

UK:

EXAMPLE OF POTENTIAL 'CARBON LOCK-IN' AND 'GAS LOCK-IN'

Lowest cost generation as a function of gas and carbon prices

Coal price: £1.4/GJ
25 year plant life,
10% IRR



THE GLENEAGLES COMMUNIQUÉ

14. We will work to accelerate the development and commercialization of Carbon Capture and Storage technology by:

(a) endorsing the objectives and activities of the Carbon Sequestration Leadership Forum (CSLF), and encouraging the Forum to work with broader civil society and to address the barriers to the public acceptability of CCS technology;

(b) inviting the IEA to work with the CSLF to hold a workshop on short-term opportunities for CCS in the fossil fuel sector, including from Enhanced Oil Recovery and CO_2 removal from natural gas production;

(c) inviting the IEA to work with the CSLF to study definitions, costs, and scope for 'capture ready' plant and consider economic incentives; (E.ON, Mitsui Babcock, Imperial IEA GHG project)

(d) collaborating with key developing countries to research options for geological CO_2 storage; and

(e) working with industry and with national and international research programmes and partnerships to explore the potential of CCS technologies, including with developing countries.

UK PARLIAMENT SCIENCE & TECHNOLOGY SELECT COMMITTEE, 2006

"We recommend that Government makes capture readiness a requirement for statutory licensing of all new fossil fuel plant. This would compel the developer to demonstrate that consideration has been given in the planning and design of the plant to facilitating subsequent addition of suitable carbon dioxide capture technology, as and when it becomes available and economic."

GENERAL PRINCIPLES FOR CAPTURE READY

Easy requirements:

a) Space on site and in critical access locations to build CO_2 capture plant and make connections.

b) Design study for adding CO_2 capture.

Challenging requirements:

c) Optional pre-investments to reduce future costs, improve performance etc.

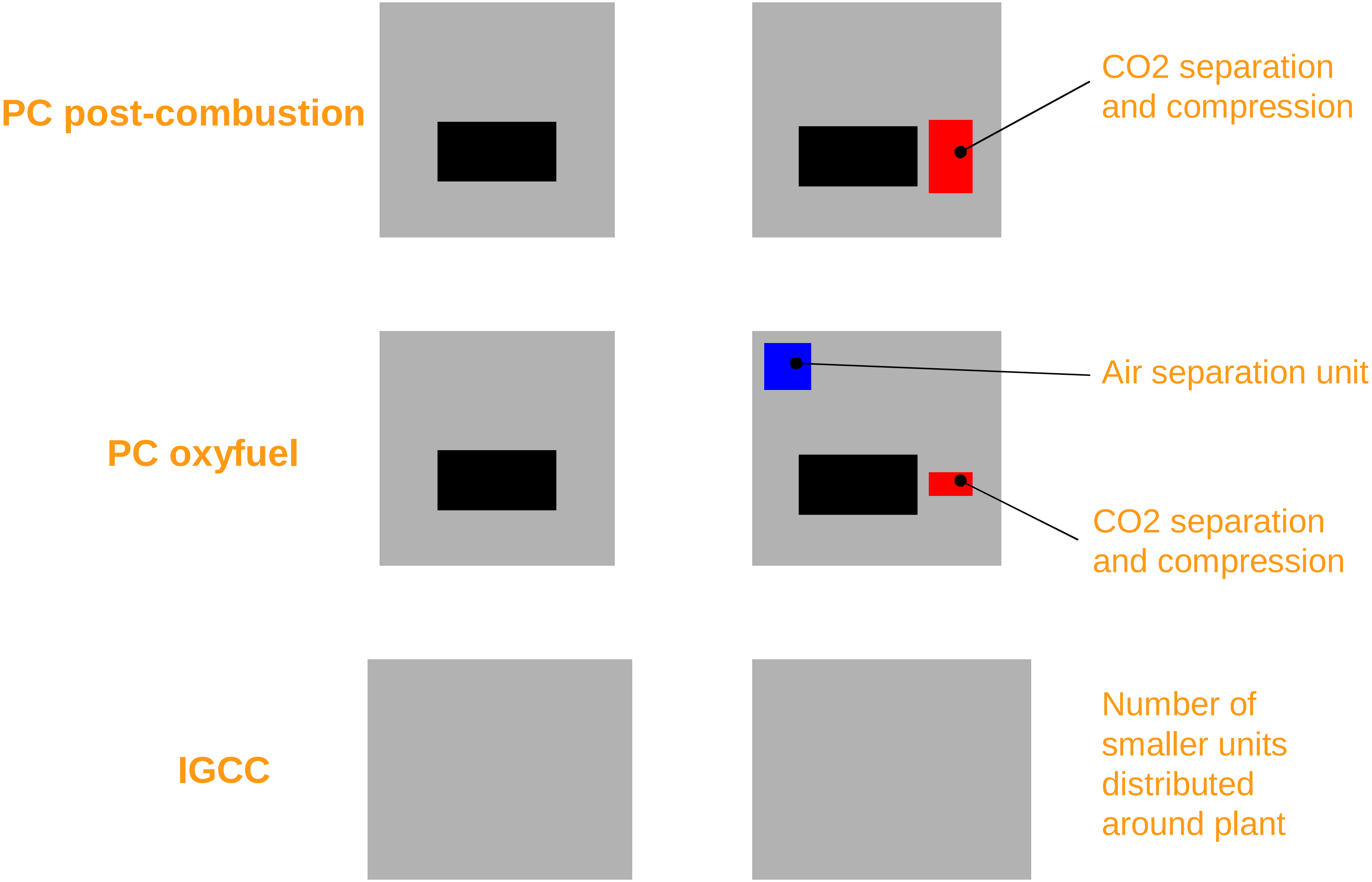
- Extra/modified equipment
- Plant siting to reduce storage costs
- Choice of base plant

Statoil/Shell 860 MW gas fired power plant, Draugen, Norway

STATOIL

INDICATIVE AREAS FOR 500 MW PLANTS WITH AND WITHOUT CAPTURE

(based on IEA GHG 2008-6)



PC post-combustion

CO2 separation and compression

PC oxyfuel

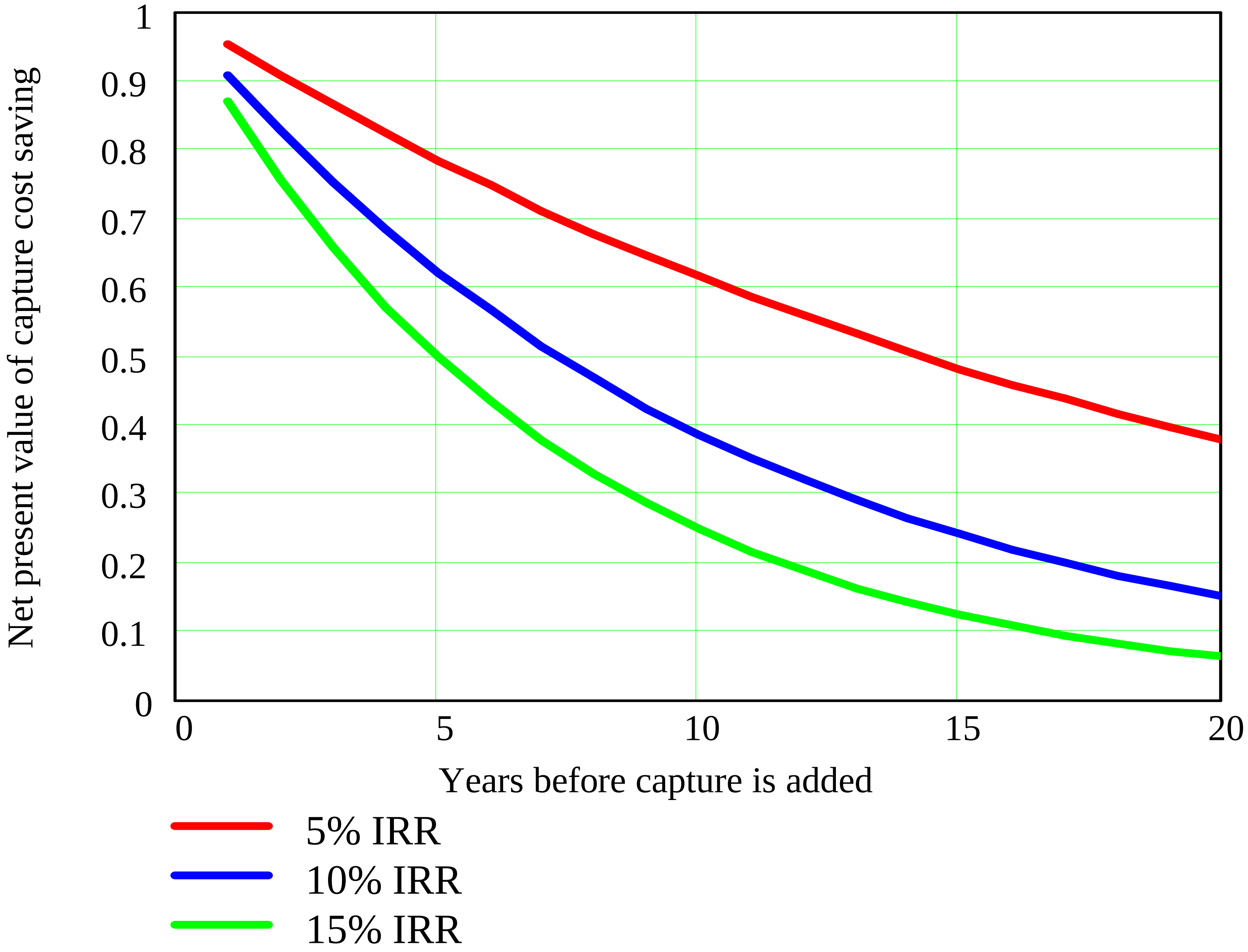
Air separation unit

CO2 separation and compression

IGCC

Number of smaller units distributed around plant

HOW MUCH MONEY IS IT WORTH SPENDING NOW TO SAVE MONEY WHEN CAPTURE IS ADDED?



When uncertainty is taken into account future cost savings of 2:1 - 10:1 required

i.e. Capital cost can be 2-10 times as much, if it is not incurred until capture is fitted

IDEAL CAPTURE READY FOSSIL FUEL PLANT

1. **Prior to capture:**
   no additional expenditure,
   no performance penalties
   vs. industry standard plant.

2. **After capture added:**
   no additional expenditure,
   no performance penalties
   vs. industry standard plant.

3. **Sited with access to viable CO_2 storage.**

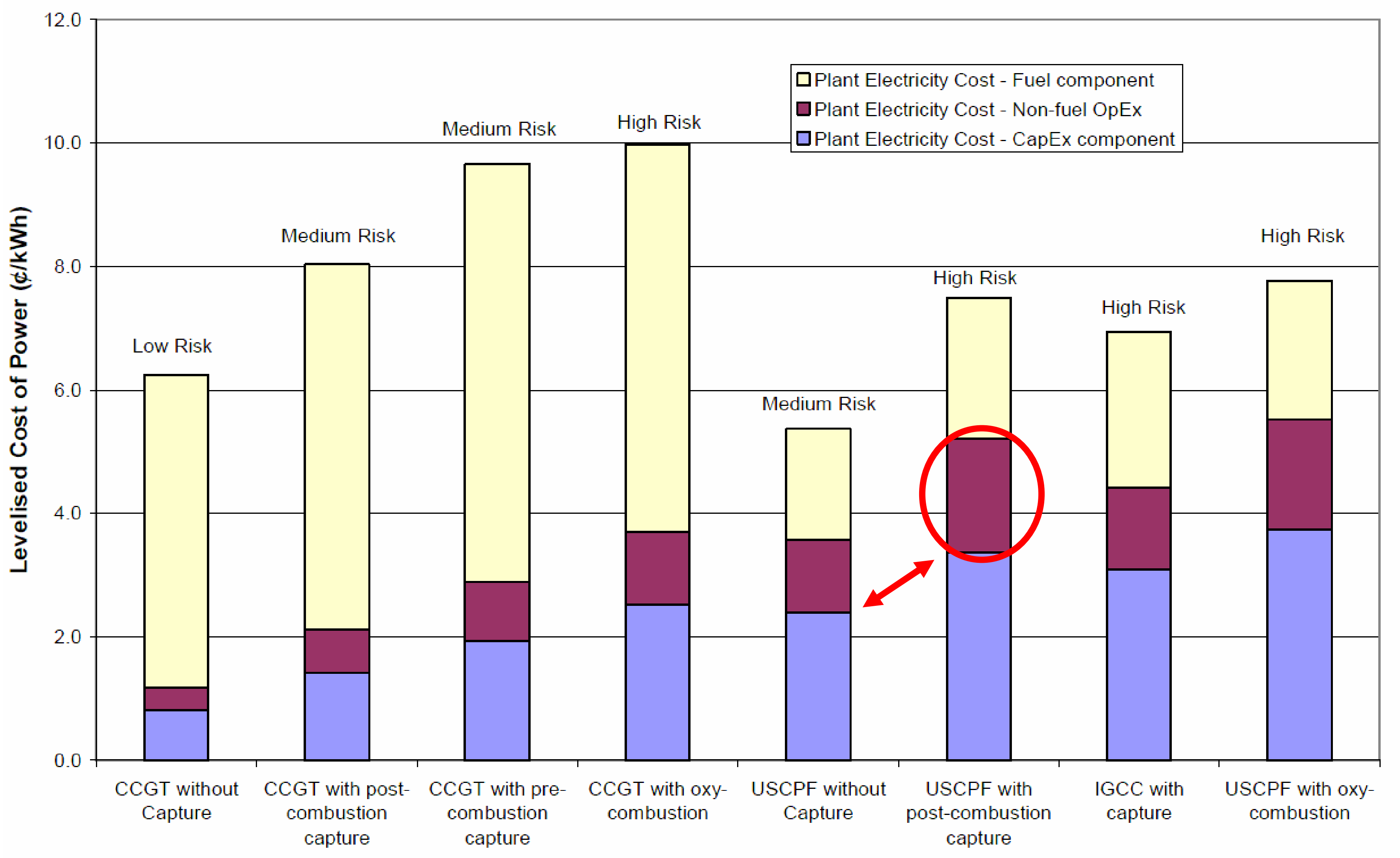
NO CHOICE FOR BASE PLANT:

- Gasifier-based polygeneration plants
  e.g. electricity + hydrogen, liquid fuels
- Natural gas combined cycle plant (NGCC)
  can be capture ready and gasifier ready

CHOICE FOR BASE PLANT:

- Coal power plants
  - IGCC
    higher cost & risk without capture,
    some cost penalty to be capture ready
    industry standard with capture
  - Supercritical PC
    industry standard without capture
    minimal cost to be capture ready
    higher capture cost & risk

COMPARISON OF ELECTRICITY COSTS FOR POWER PLANTS BUILT WITH CAPTURE
IEA GHG 2006-8



Plant type (net electrical output approx. 800MW)		**Supercrit Pulverised Coal**	**IGCC + precom**	**Supercrit + retrofit postcom**	**New IGCC + precom**
Total plant cost	£/kW	880	1258	317	700
	£/kW			1408	
Efficiency (LHV)	% LHV	44.0%	33.5%	35.5%	42.0%
% CO2 captured		0%	85%	85%	85%
Fuel cost (LHV)	**£/GJ**	**1.4**	**1.4**	**1.4**	**1.4**
Operating hours	hrs/yr	8000	8000	8000	8000
Discount rate	%	10%	10%	10%	10%
Plant life	years	25	25	15	25
CO2 storage cost (part of 10MtCO2/yr aquifer/gas field storage system)	£/tonne CO2	5.5	5.5	5.5	5.5
EU ETS CO2 Emission Allowance cost	£/tonne CO2	25	25	25	25
Cost of electricity					
Capital	p/kWh	1.21	1.73	0.52	0.96
Operating expenditure	p/kWh	0.38	0.44	0.56	0.44
Fuel	p/kWh	1.15	1.50	1.42	1.20
CO2 storage costs	p/kWh	0.00	0.45	0.43	0.36
Emission allowance costs	p/kWh	1.85	0.36	0.34	0.29
Cost of electricity inc. EU ETS	**p/kWh**	**4.58**	**4.49**	**3.27**	**3.25**
Marginal cost of generation	**p/kWh**	**3.18**	**2.54**	**2.47**	**2.07**

CAPTURE READY REQUIREMENTS

- Post-combustion ready (PC and NGCC)
  - space for absorber (plus FGD if needed)
  - suitable IP/LP crossover steam pressure
  - allow for rapid technology changes
- Gasifier ready NGCC gas turbine for H_2
  - space on site? or pipeline to remote site
- Capture ready IGCC layout and space
  - but cannot integrate before and after capture,
  - unless other uses for gas, steam, etc.
- Oxyfuel PC space for ASU
  - duct access, air heater & fan capacity

CONCLUSIONS AND ISSUES

- **Capture ready not a substitute for capture.**

Proposed full-scale (~300 MWe and above) CCS projects

(Based on media reports, press releases and personal communication so indicative only!)

Company/ Project Name	Fuel	Plant output/cost	Capture technology	Start
Progressive Energy, Teeside, UK	Coal (petcoke)	800 MW (+ H2 to grid) ($1.5bn)	IGCC + shift + precombustion	2009
BP/SSE DF1, Peterhead/Miller, Scotland	Natural gas	350 MW, ($600M)	Autothermal reformer + precombustion	2010
Powerfuel/Kuzbassrazrezugol Hatfield Colliery, UK	Coal	~900 MW	IGCC + shift + precombustion	2010
BP DF2, Carson, USA	Petcoke	500 MW, ($1bn)	IGCC + shift + precombustion	2011
Statoil/Shell, Draugen, Norway	Natural gas	860 MW	NGCC+ Post-combustion amine	2011
SaskPower, Saskatchewan Canada	Lignite coal	300 MW	PC+ Post-combustion or oxyfuel (to be determined Q3 2006)	2011
E.ON, Killingholme, Lincolnshire coast, UK	Coal (+petcoke?)	450 MW (£1bn)	IGCC + shift + precombustion? (may be capture ready)	2011
Stanwell, Queensland, Australia	Coal	275 MW	IGCC + shift + precombustion	2012
Futuregen, USA	Coal	275 MW	IGCC + shift + precombustion	2012
RWE, Germany Germany	Coal	450 MW (€1bn)	IGCC + shift + precombustion	2014
RWE, Tilbury, UK	Coal	~500 MW (£800m)	PC (supercritical retrofit) + post-combustion (may be capture ready)	2016

CONCLUSIONS AND ISSUES

- **Capture ready not a substitute for capture.**
- **Flexible approach needed for capture ready.**
- **Show-stoppers must be avoided:**
  space, access to storage or H_2 supply;
  but significant expenditure not justified.
- **Often no choice in base plant, or capture method**
  but technology changing rapidly.
- **Choice between IGCC and PC as capture ready;**
  depends on technical developments.
- **Choice between pre- and post-com for NGCC;**
  depends on future gas and coal prices.
- **'Plan capture ready, build capture' also an option.**

APPENDIX

CAPTURE READY IGCC PLANT FOR THE PURPOSES OF US GOVERNMENT SUPPORT:

“Qualifying IGCC projects must use coal, petroleum coke, or biomass for at least 65% of annual heat input, produce electricity for 65% of their useful output, <u>have a design determined by the Secretary to be capable of accommodating equipment for capturing carbon dioxide,</u> have an assured revenue stream to cover capital and operating costs approved by the Secretary and relevant PUC, and commence construction within 3 years of receiving a guarantee commitment.” **(EPACT, 2005)**

Parsons Corporation Capture Ready IGCC

	Baseline CVX IGCC Plant Dual Train	Operating CVX IGCC Plant Retrofitted for CO_2 Capture Derated 90% Capture	Pre-investment CVX IGCC Plant Oversized Dual Train	Pre-investment CVX IGCC Plant Retrofitted for CO_2 Capture 90% Capture
Performance				
Coal Flow, lb/hr	370,663	370,663	370,663	390,950
Total Oxygen Flow, lb/hr	375,574	375,574	375,574	393,747
Gas Turbine Power, kW	394,000	374,480	394,000	394,000
Expander Power, kW	13,950	11,090	13,950	11,600
Steam Power, kW	206,950	191,260	206,950	201,870
Total, kW	614,900	576,830	614,900	607,470
Total Auxiliaries, kW	105,620	152,000	105,620	158,620
Net Power, kW	509,280	424,830	509,280	448,850
Efficiency, %HHV	35.4	29.5	35.4	29.5
Heat Rate, Btu/kWh HHV	9,653	11,569	9,653	11,550
CO_2 Captured, lb/hr	N/A	839,372	N/A	885,381
Cost				
Total Plant Cost, 1,000 $	$589,896	$678,196	$619,600	$682,953
Total Plant Cost, $/kW	$1,158	$1,596	$1,217	$1,522
Delta Cost of Retrofit, 1,000 $		$88,300		$63,353
Fixed Operating	$10,806	$11,560	$11,055	$11,586
Variable Operating	$13,837	$14,878	$14,547	$15,173
Fuel @$1.35/MMBtu)	$51,157	$51,144	$51,157	$53,947
COE, $/Mwh[a)]	$45.74	$59.32	$47.09	$57.23

HHV basis

COE based on TPC plus owners costs annualized at a rate of 15% and a 90% capacity factor

+5% capital for capture ready before capture

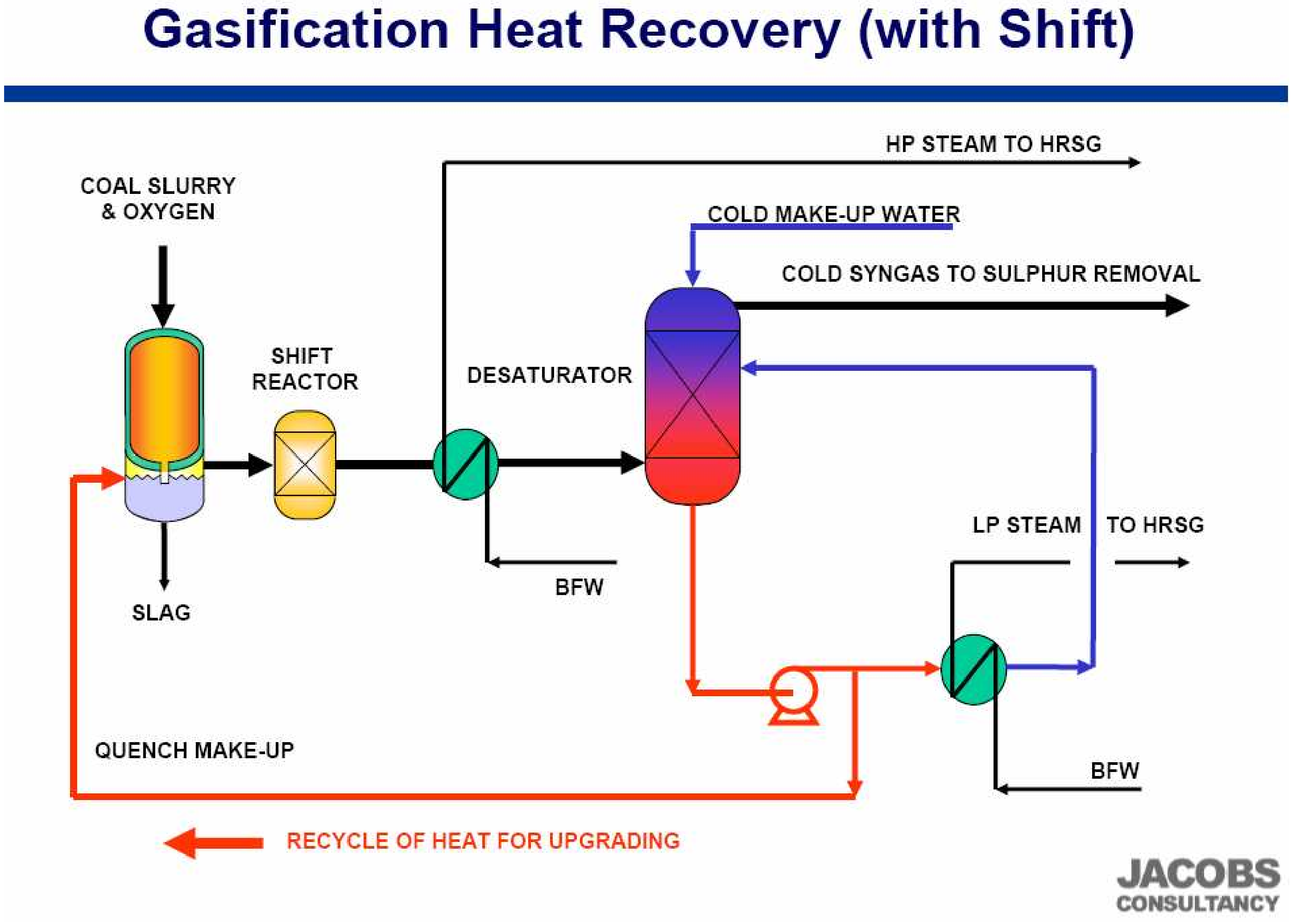
+5% capital for capture un- ready after capture

Rutkowski, M., Schoff, R., Holt, N. and Booras, G., 2003, *Pre-Investment of IGCC for CO_2 Capture with the Potential for Hydrogen Co-Production*, Gasification Technologies 2003, San Francisco, CA, October 12-15, 2003. (http://www.gasification.org/Docs/2003_Papers/29RUTK_paper.pdf)

PRE-COMBUSTION CAPTURE READY

Problem for IGCC, if gas turbine is matched to gasifier and oxygen plant before shift and capture is added.

Possible alternative for IGCC – have shift from the start and recover the losses



Jacobs Engineering Capture Ready IGCC

	1A	1B	2A	2B
Coal Feed rate AR (t/h)	160	172	173	168
Steam Turbine (MW)	246.9	241.3	254.6	233.4
Gas turbine (single) (MW)	197.0	194.4	197.0	197.0
Power Output (nett) (MW)	559	489	576	472
Efficiency (%) **LHV basis**	42.2	34.3	40.3	34.0
Heat Rate (HHV) (Btu/kWh)	8384	10296	8777	10395
Capex $MM	650.8	739.5	672.9	728.1
Capex $/kW	1164	1511	1169	1542

5% extra fuel
for capture
ready IGCC

+2% capital for capture ready plant
compared to plant built with
capture

Griffiths, J. and Scott, S., 2003, *Evaluation of Options for Adding CO_2 Capture to ChevronTexaco IGCC*, Gasification Technologies 2003, San Francisco, CA, October 12-15, 2003. http://www.gasification.org/Docs/2003_Papers/28GRIF.pdf)

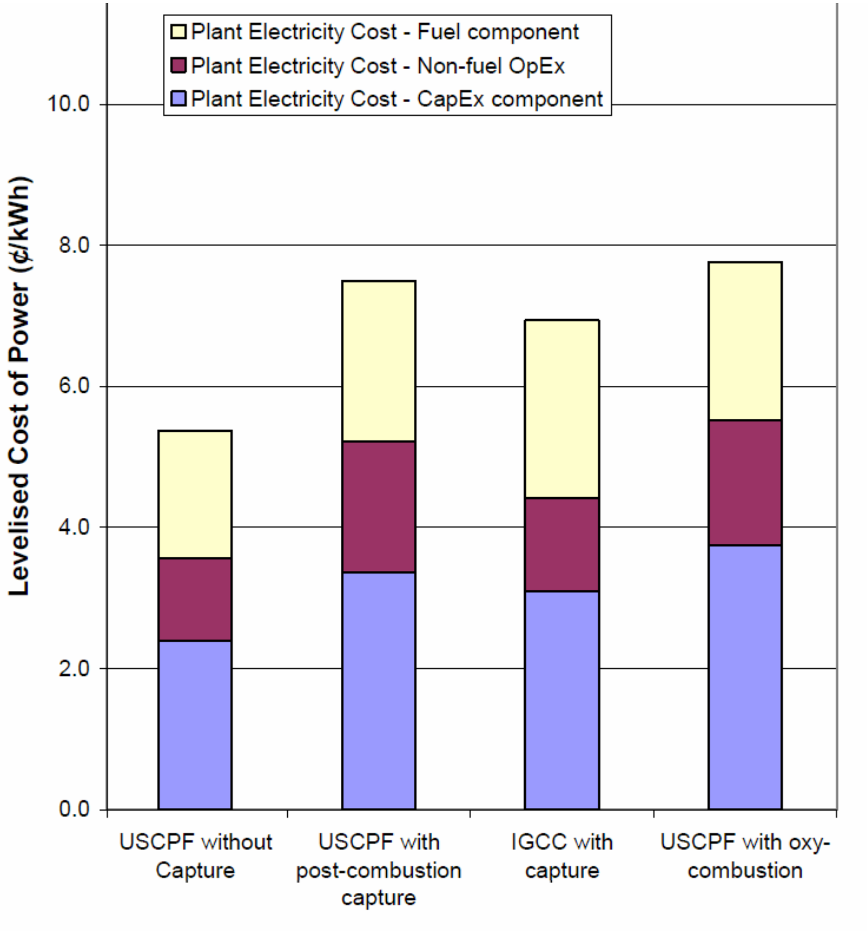
COMPARISON OF ELECTRICITY COSTS FOR POWER PLANTS BUILT WITH CAPTURE

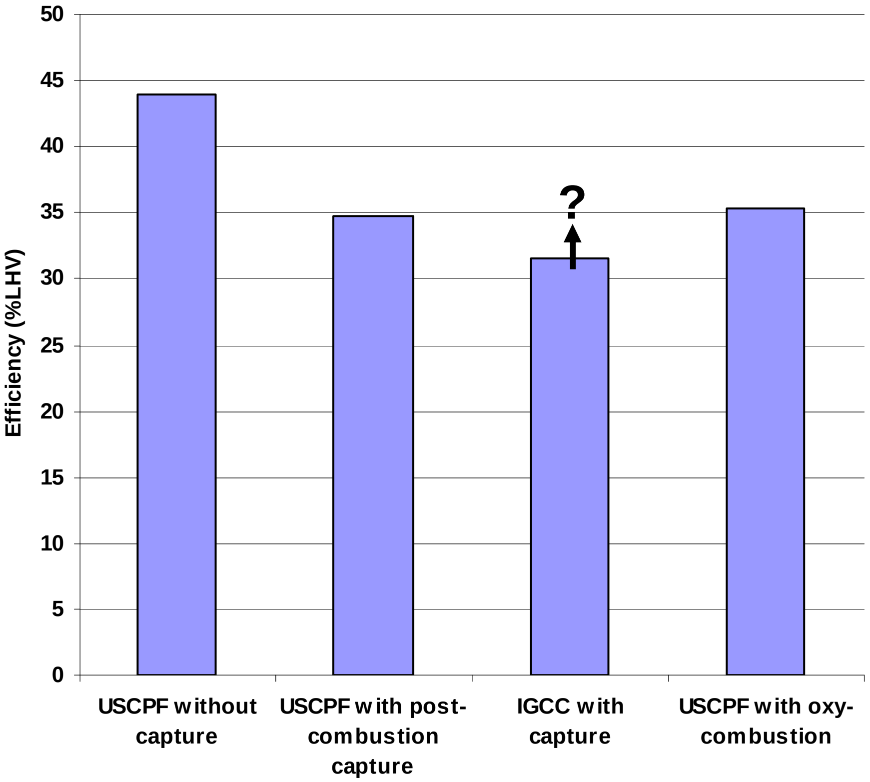
IEA GHG 2006-8

- USCPC industry standard without capture – best efficiency, lowest capital cost
- IGCC without capture – higher capital cost, availability issues

- USCPC with capture - higher capital and operating costs
- IGCC with capture - lowest capital and operating costs, lower efficiency (for lowest COE)

- USCPC with capture - no experience
- IGCC with capture - some chemical plant experience





PCC Ltd

RIO TINTO

Australian COAL Association

CSIRO

Australian National Post Combustion Capture and Storage Demonstration Project

Louis Wibberley
Principal Technologist
CSIRO Energy Technology

Presentation outline

- What's changed since Austin Oct 2005
- Australian context
  - different flue gases, water issues, brown coals
- Why PCC?
  - initially rejected in Australia in favour of IGCC and oxy-pf
- CSIRO's National PCC R&D Program
  - led to a proposal to Government and Industry for a National Demonstration Program
- PCC Ltd and the demonstration program
  - formed to enable large scale demonstration of PCC and storage, with the assistance of LETDF
  - combines the National R&D activities
- Current status

Changes since Austin 10/2005

- CSIRO now has an established a PCC laboratory and pilot plant, with a number of research programs
  - joined University of Texas IRA
  - research programs established with RITE/MHI and University of Newcastle (others under development)
- CSIRO's proposal for a National PCC and storage RD&D program has been endorsed by industry, with PCC Ltd established as the entity to progress the National RD&D program
  - currently consists of Rio Tinto (lead organisation), Australian Coal Association and CSIRO, with other industry participants expected
  - developing consolidated program, including engineering for the demonstration phase
- Also several other projects involving PCC for gas and brown coal-based generation
  - PCC R&D is not the primary focus

Why PCC?

- PCC concept now fully endorsed by Australian Utilities and State/Federal Governments mostly due to:
  - potential retrofit to existing plants (near ZETS)
  - can be integrated into new SCPF plants (near ZETS)
- Generators like high adaptability and resilience
  - partial retrofit, zero to full operation (market matching)
    - Australia has an increasing peak demand
    - provides a discretionary load
  - ability to use solar thermal energy
  - unique options for application to Victorian brown coal generation
- Low technology and commercial risk (vs IGCC and oxy-pf)
  - cost of electricity is broadly comparable with other LET options
  - reduced multiplier effect
- Cooling water and storage uncertainties are significant issues
- Strategic importance to developing nations with emerging large pf capacity, and for Australia’s contribution to AP6

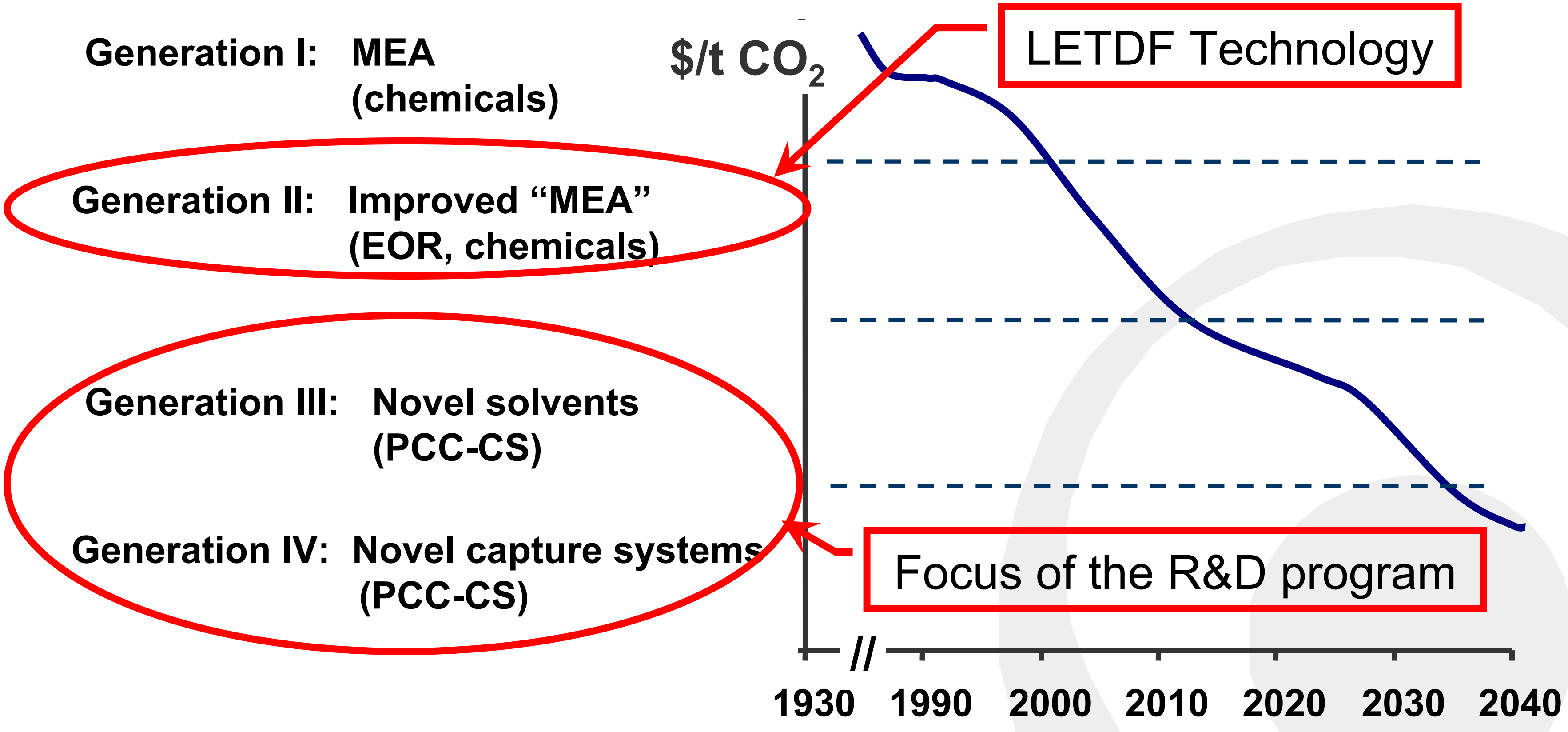
CSIRO – National PCC Program Concept

- Five concurrent phases
  - semi-commercial scale facility (50,000 tpa) at host site
  - geo-sequestration demonstration into coal & adjacent strata (based on existing CSIRO studies)
  - pilot plant research and development
  - applied laboratory research and test capability for sorbent and membrane development, and energy integration (CSIRO, CO2CRC, CCSD, LigniteCRC)
  - international collaboration (AP6, CASTOR, MHI & RITE, Uni Texas, IEA, IPHE, CSLF)
- Managed by an industry-led consortium over 7 years (LETDF funding)
  - commencing in 2007
  - R&D supporting the demonstration, which will use best commercial technology

PCC Ltd project overview

- PCC Ltd formed, led by Rio Tinto
- PCC demonstration at an Australian coal fired power station
  - 50,000 tpa CO_2 capture
  - 10,000 tpa CO_2 storage
- Total project cost = A$61M
- Based on best commercially available solvent technology at the proposed scale.
- CO_2 storage into deep un-mineable coal or other geological formations
- Concurrent (separately funded) R&D and pilot program
  - integrated approach between R&D, pilot and demonstration programs

Development pathway for PCC



Generation I: MEA (chemicals)

Generation II: Improved "MEA" (EOR, chemicals)

Generation III: Novel solvents (PCC-CS)

Generation IV: Novel capture systems (PCC-CS)

LETDF Technology

Focus of the R&D program

Project development process – milestones

- Engagement with domestic coal and utility industry
  - technical scope to be broadened
  - consideration of international activities and domestic fit
  - integrated National PCC Program concept
- Technical Review Meeting convened (3-5-2006)
  - 20 organisations represented
  - Australian coal suppliers
  - Australian black coal utilities
  - Australian based researchers
  - International PCC experts/researchers
- Project development Action Plan developed
- Formation of an Industry Advisory Group
  - coal supplier representation
  - Qld/NSW utility representation

Project development process – overview

- Three initial areas of work:
  - complete a state of the art review of PCC in the Australian context
  - develop industry drivers and success criteria for PCC
  - assess other carbon capture and storage activities for linkages and fit
- Outputs will be consolidated to form the basis of an integrated national plan for PCC that covers R&D, pilot scale and demonstration scale components
- EPC company to develop pre-feasibility study for demonstration activity
- Continued engagement with potential sponsors – move from technical engagement to commercial engagement

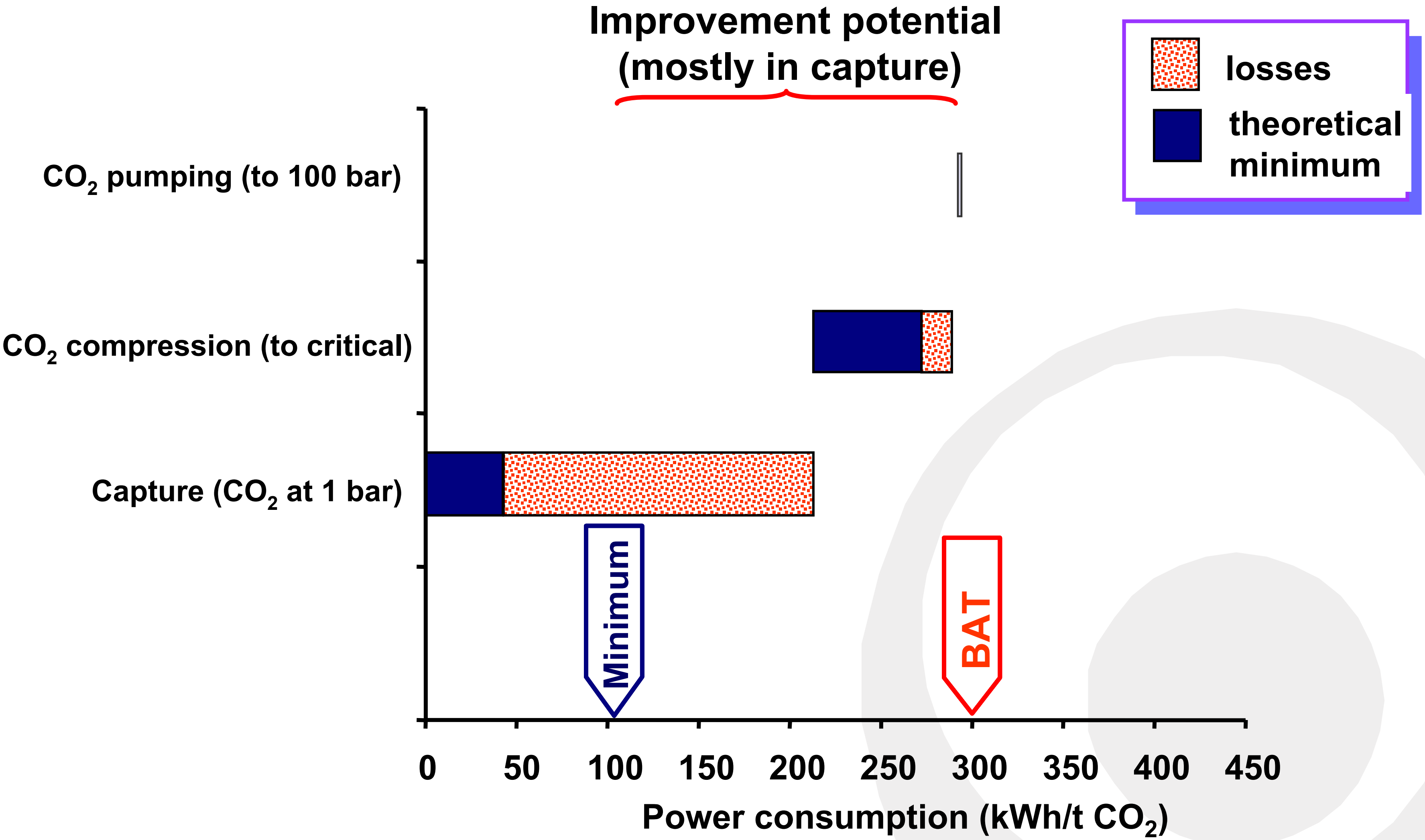
Project development process – status

- State of the Art Review underway
  - scope developed from output of Technical Review Meeting and Industry Advisory Group
  - work being undertaken jointly by CSIRO and CO2CRC with IAG review (completion by early July)
- Industry drivers and success criteria to be documented during June
- Assessment of other capture and storage activities to be completed by end of June
- AusIndustry assessment process has gone well so far – timing remains the challenge
- R&D led by CSIRO is progressing

Pilot plant and R&D – overall objectives

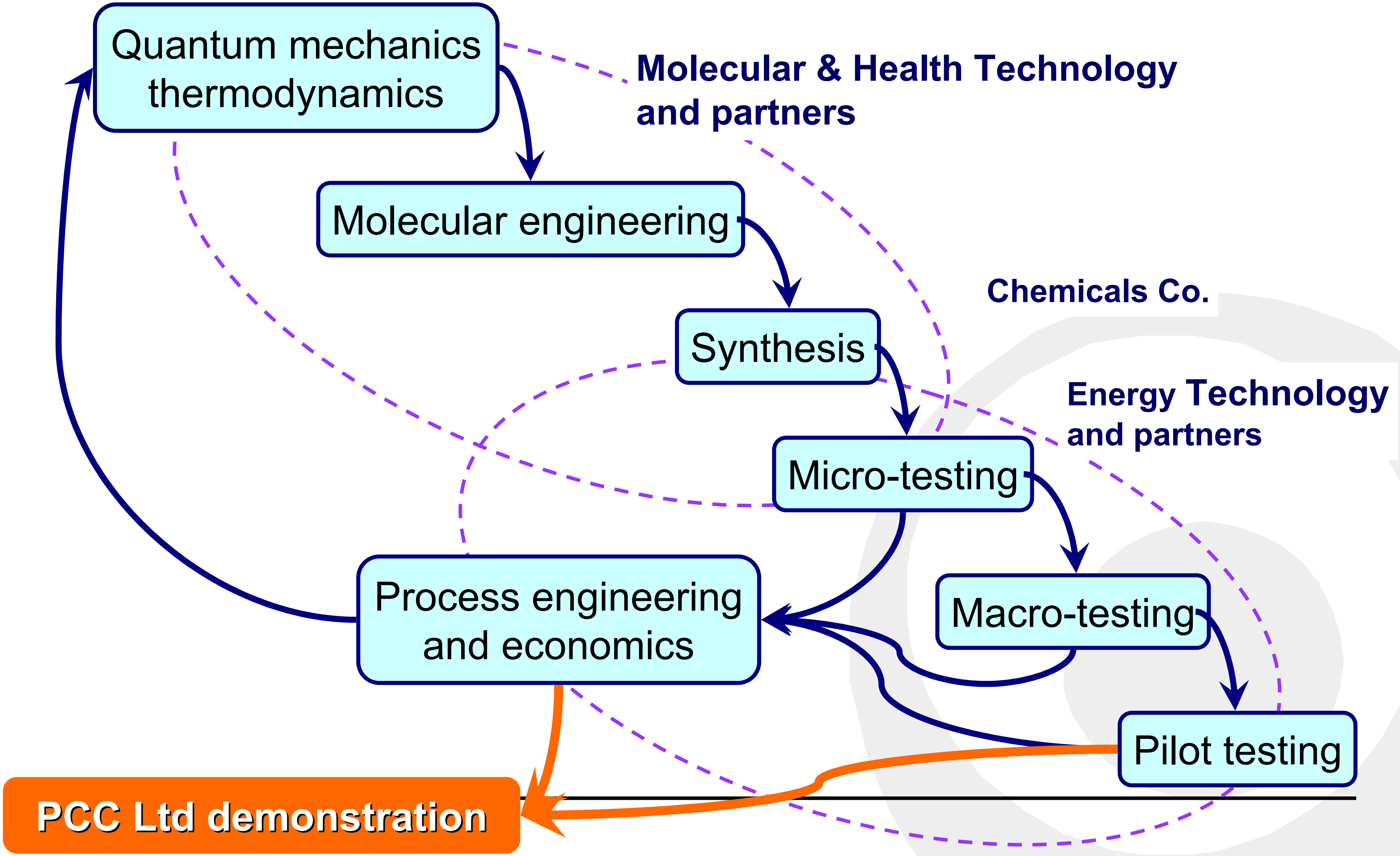
- To support the demonstration program
  - pilot plant, laboratory and technical support (new solvents towards end of program)
- Goal - science and engineering to reduce the cost of capture by 50%
  - costs need to be lower than the value of the avoided emissions (or use of alternative generation technologies)
  - incremental and step improvements needed at all stages:
    - reducing the amount and value of the energy used for capture
    - reducing the need for separate deNOx and deSOx plant
    - reducing overall equipment cost
    - production of by-products (Australia is sulphur impoverished)
    - inherent high adaptability/flexibility should be maintained
    - benefiting from the synergies with renewables
  - leverage from, and contribute to, international efforts in PCC (from all forms of capture and gas processing)

Large improvement potential for the capture stage



PCC Ltd

Iterative R&D methodology



Quantum mechanics thermodynamics

Molecular engineering

Synthesis

Micro-testing

Macro-testing

Pilot testing

Process engineering and economics

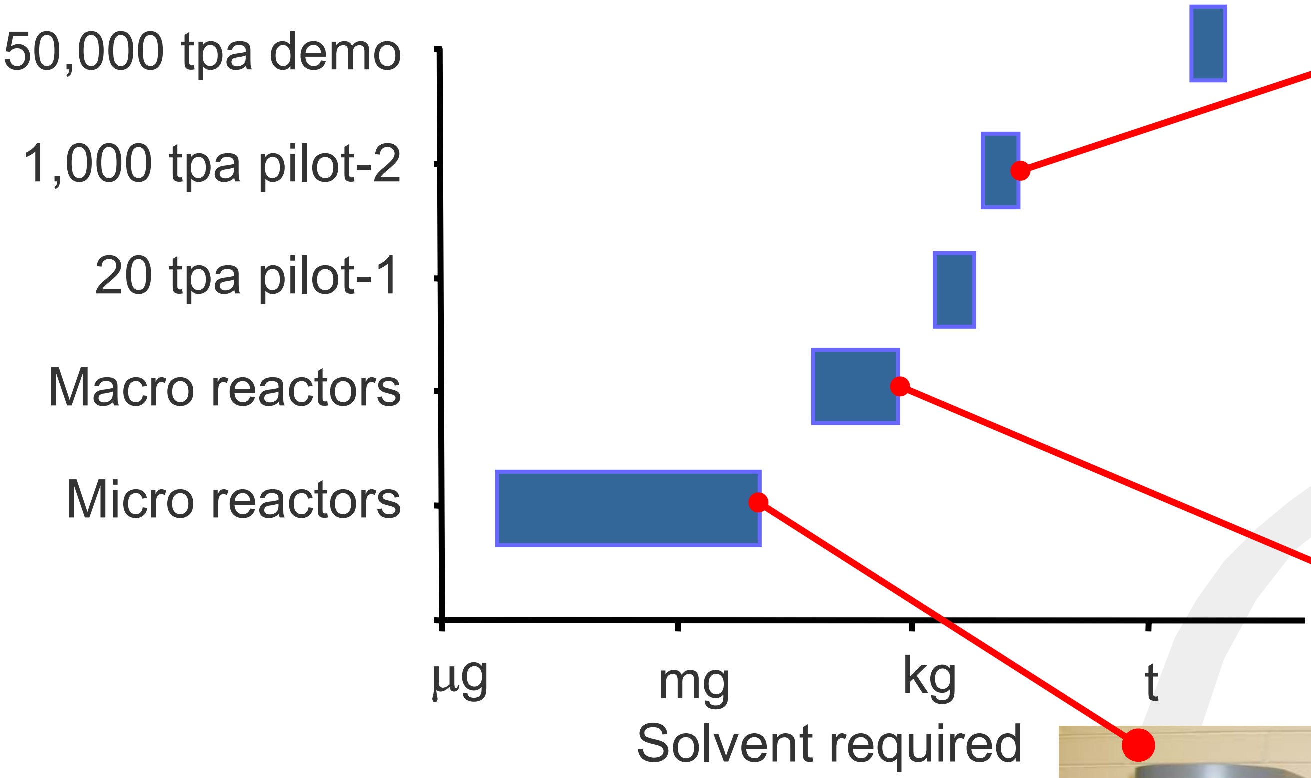
PCC Ltd demonstration

Molecular & Health Technology and partners

Chemicals Co.

Energy Technology and partners

Screening & testing tools (50:1)



Research program next 5 years

- Developing novel amines (and RTILs and other solvents) using molecular science
  - regeneration with low energy use
  - high absorption/desorption rate and regeneration at low temperature
  - tolerant of NOx, SOx, oxygen and ash trace elements
  - low volatility and high stability
  - low corrosiveness and toxicity
- Developing novel systems for Generation IV capture
  - expected to include a range of liquid and solid systems (*eg* ionic liquids with polymer support networks)
- Scaling up research results, using the transportable pilot plant on real flue gases

Summary

- PCC offers a resilient strategy for coal-fired generation
  - near zero emission for coal fired plant (both existing and new)
  - high operational flexibility
  - low technology risk
  - competitive cost
- Therefore, a high degree of buy-in by power industry on the technical way forward has been achieved
  - technical challenges (but we know how to address them)
  - major blockers are political, as well as the fragmented nature of power generation industry
- Success with PCC development and demonstration for pf power generation is necessary to ensure the role of coal in Australia’s fuel energy mix

Dwarfing Sleipner!

Large Scale CCS projects and other CO2CRC activities

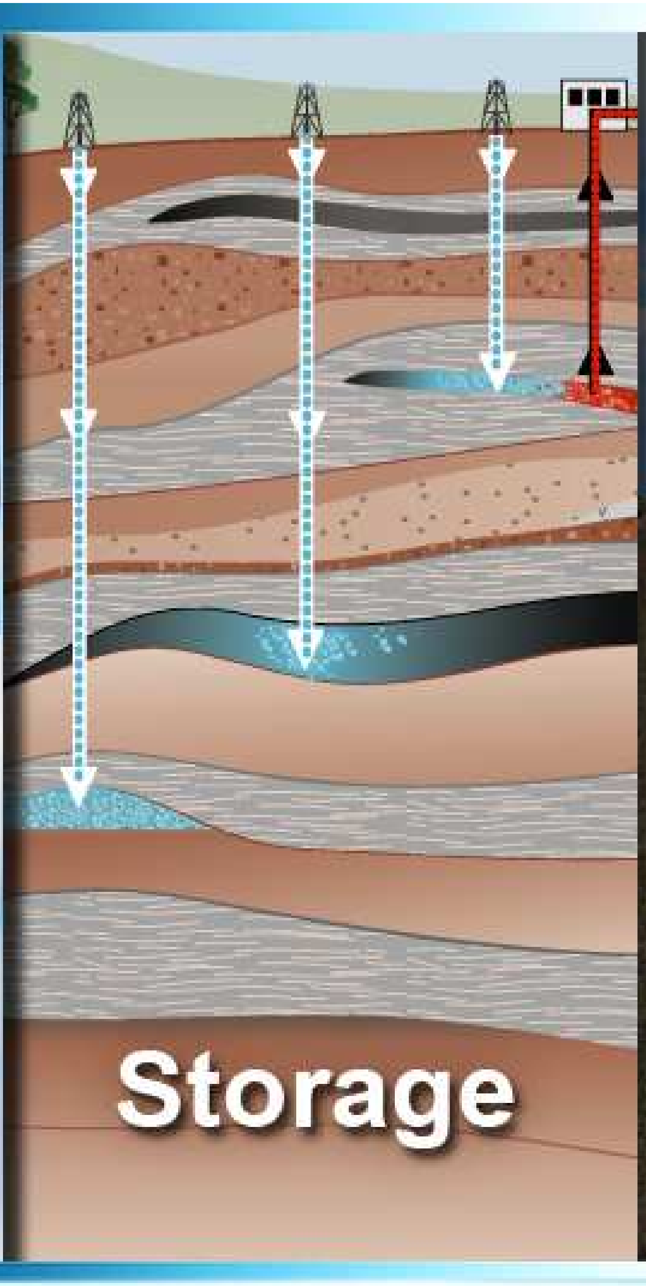
Barry Hooper

IEA
Capture Test Network
Copenhagen
16th June 2006

Presentation Outline

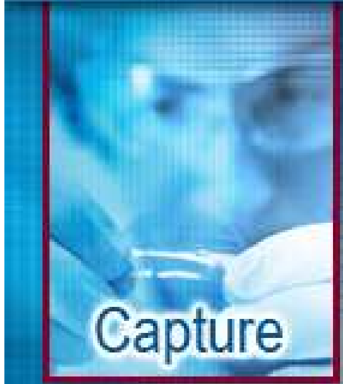
- Background to the Cooperative Research Centre for Greenhouse Gas Technologies – aka CO2CRC
- CO2CRC Capture Program
- Review of Large Scale CCS Project Development
  - Background to LVCSA
  - Earth Science Studies
  - Reservoir Modelling
  - Techno-Economics
  - Storage Risk Assessment
  - Infrastructure Risk Assessment
  - Conclusion

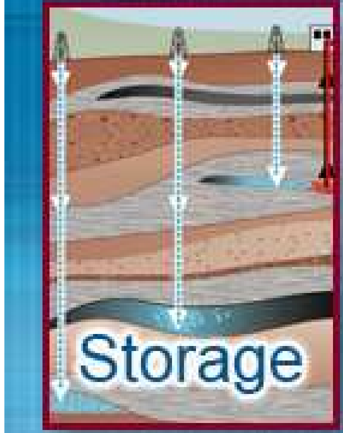
Capture



Storage

Pilot projects





CO2CRC Participants:

CRC AUSTRALIA

Australian Government

Geoscience Australia
Australian Greenhouse Office
Department of Industry, Tourism and Resources

RIO TINTO

xstrata coal

CSIRO

bp

SOLID ENERGY
Coals of New Zealand

STANWELL
CORPORATION LIMITED

THE UNIVERSITY OF ADELAIDE AUSTRALIA

NZ RESOURCE CONSORTIUM

Chevron

ACARP
Australian Coal Association Research Program

curtin
University of Technology
Western Australia

Victoria
The Place To Be

ANGLO COAL

Schlumberger

MONASH University

UNSW

THE UNIVERSITY OF MELBOURNE

WOODSIDE
AUSTRALIAN ENERGY

bhpbilliton

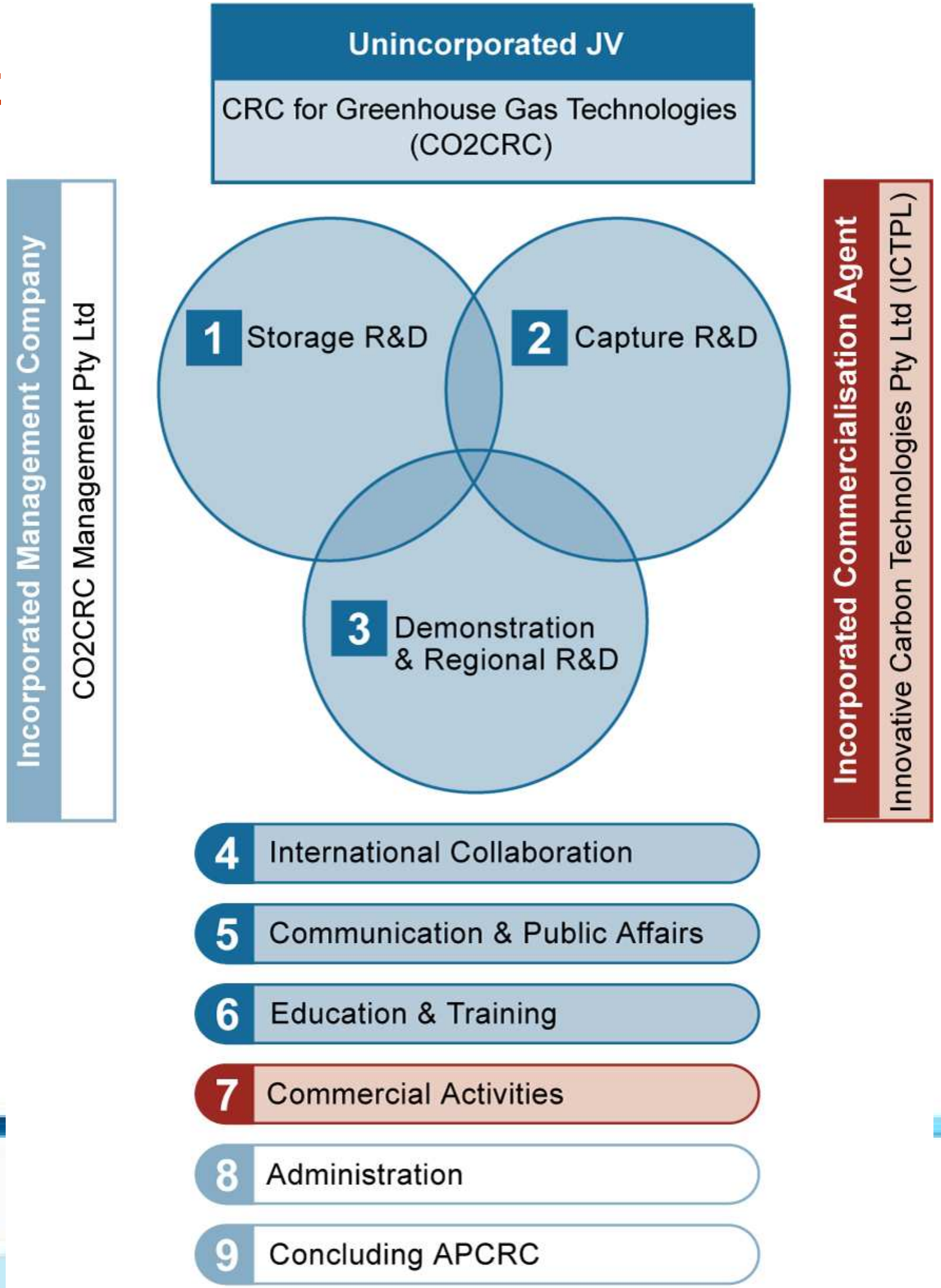
Supporting participants: **Australian National University** | **CANSYD** | **Meiji University** | | **The Process Group** | **University of Queensland** | **Whistler Research** |

CO2CRC

CO2CRC
Research Providers

Collaborating with
- Canada
- China
- EU
- Japan
- UK
- USA

Centre Management Structure



Unincorporated JV

CRC for Greenhouse Gas Technologies (CO2CRC)

Incorporated Management Company

CO2CRC Management Pty Ltd

1 Storage R&D

2 Capture R&D

3 Demonstration & Regional R&D

Incorporated Commercialisation Agent

Innovative Carbon Technologies Pty Ltd (ICTPL)

4 International Collaboration

5 Communication & Public Affairs

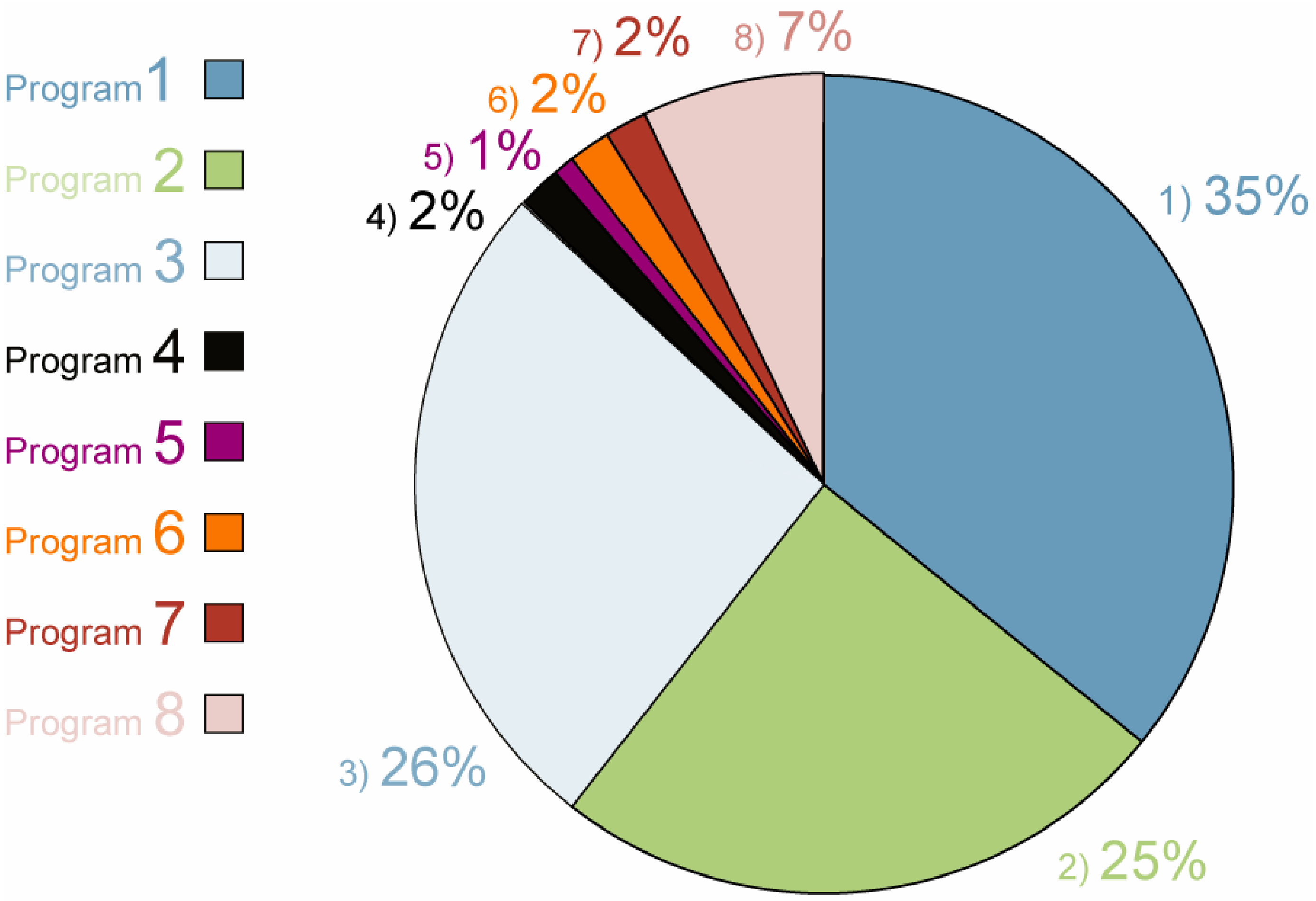
6 Education & Training

7 Commercial Activities

8 Administration

9 Concluding APCRC

Budget Summary



Total budget approximately $140 million

CO2CRC Capture Program research teams

PROGRAM 2: CAPTURING CO_2

PROGRAM MANAGER: Barry Hooper

CO2CRC Programs

2.1 Characterising Australian Emissions
Project Leader: Luke Murray

2.2 Enhanced Solvent – Based Systems
Project Leader: Prof G Stevens, Melbourne University

2.3 Innovative Membrane Systems
Project Leader: Dr S Kentish, Melbourne University

2.4 Innovative Pressure Swing Adsorption Systems
Project Leader: Dr A Chaffee/Dr Paul Webley, Monash University

2.5 Hydrate Formation & Cryogenic Distillation Systems
Project Leader: Prof R Amin, Curtin University of Technology

2.6 Capture of CO_2 in Brines and Minerals
Project Leader: Dr G Sparrow, CSIRO Minerals

2.7 Metal Activated Conversion of CO_2
Project Leader: A/Prof M Buntine, University of Adelaide

2.8 Economic Modelling of Capture & Storage Systems
Project Leader: G Allinson, UNSW

2.9 LDH Membranes
Project Leader: J da Costa, U of Qld

CO2CRC Capture Program

Capture

Extensive Collaboration

Separation Processes

Fuels

Applications

Techno-economic Modeling

Risk Assessment

Pilot / Demonstration Projects

Projects Critically Assessed

GHGT 8 Presentations

- Papers
  - CO2CRC Capture Program
  - CCS Economics
  - GAM Membranes
  - Adsorbents Research
  - LVCSA Geoscience
  - LVCSA Risk Assessment

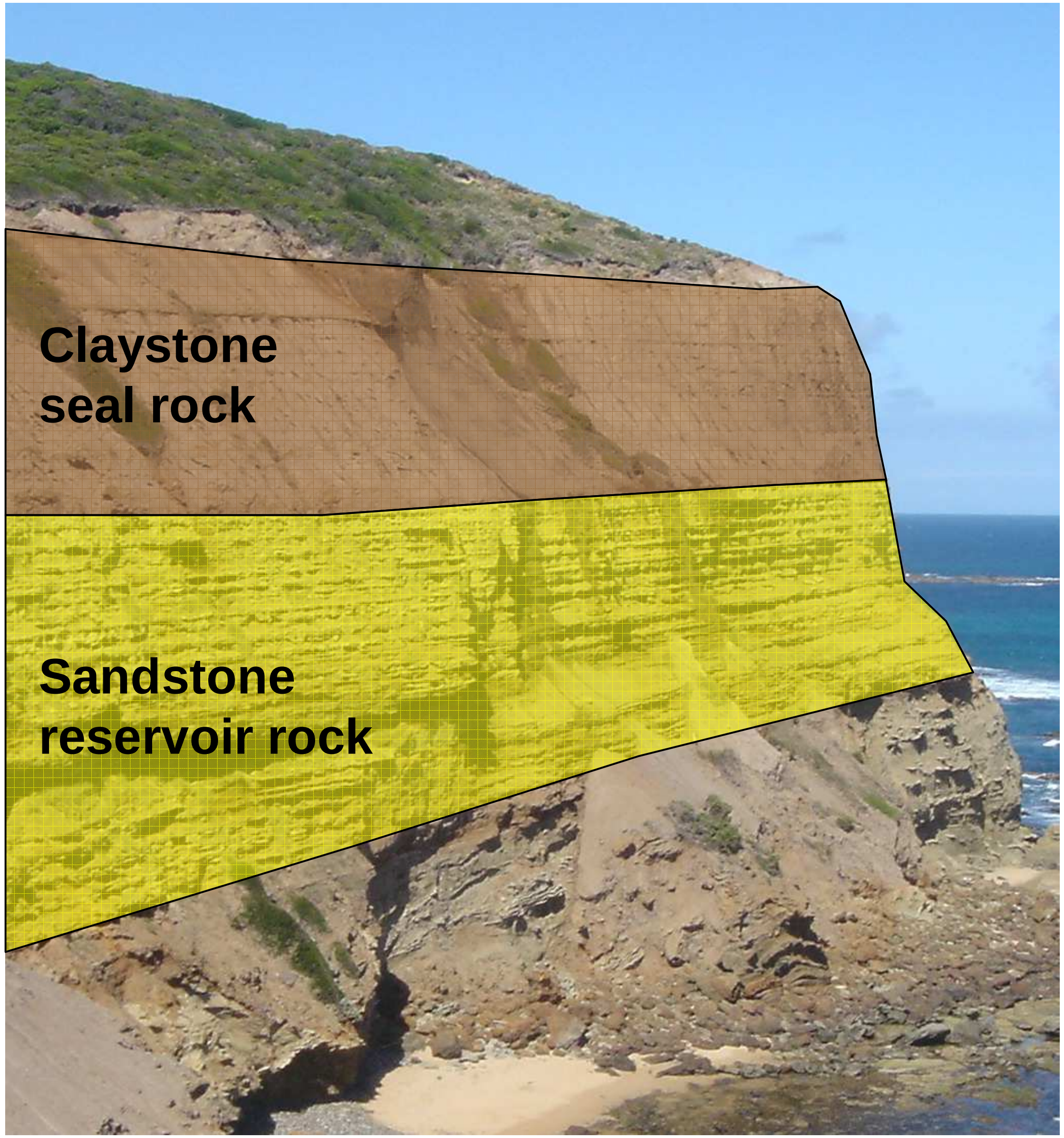
- Posters
  - Capture Economics
  - LVCSA Economics
  - Solvent Packings
  - VSA for CO2 Capture
  - Novel Materials for ESA
  - OBPP Pilot Plant – Capture
  - LDH Material Development

LVCSA Background

- **The Problem**
  - New brown coal developments in Latrobe Valley, Victoria
  - CO_2 emissions up to 50 Million tonnes/year
- **Potential Solution**
  - Offshore Gippsland Basin
  - Existing oil and gas fields (once depleted)
  - Deeper saline formations
- **Injection Scenarios**
  - Injection at several sites along regional migration pathways, sequentially & simultaneously, ramping up volume to 50 Mt/y

1. Kingfish Field: 15 Mt/y for 40 years ← **This presentation**
2. Fortescue Field: 15 Mt/y for 40 years
3. Basin centre & northern gas fields: 20 Mt/y for 40 years

Geological Storage of CO_2



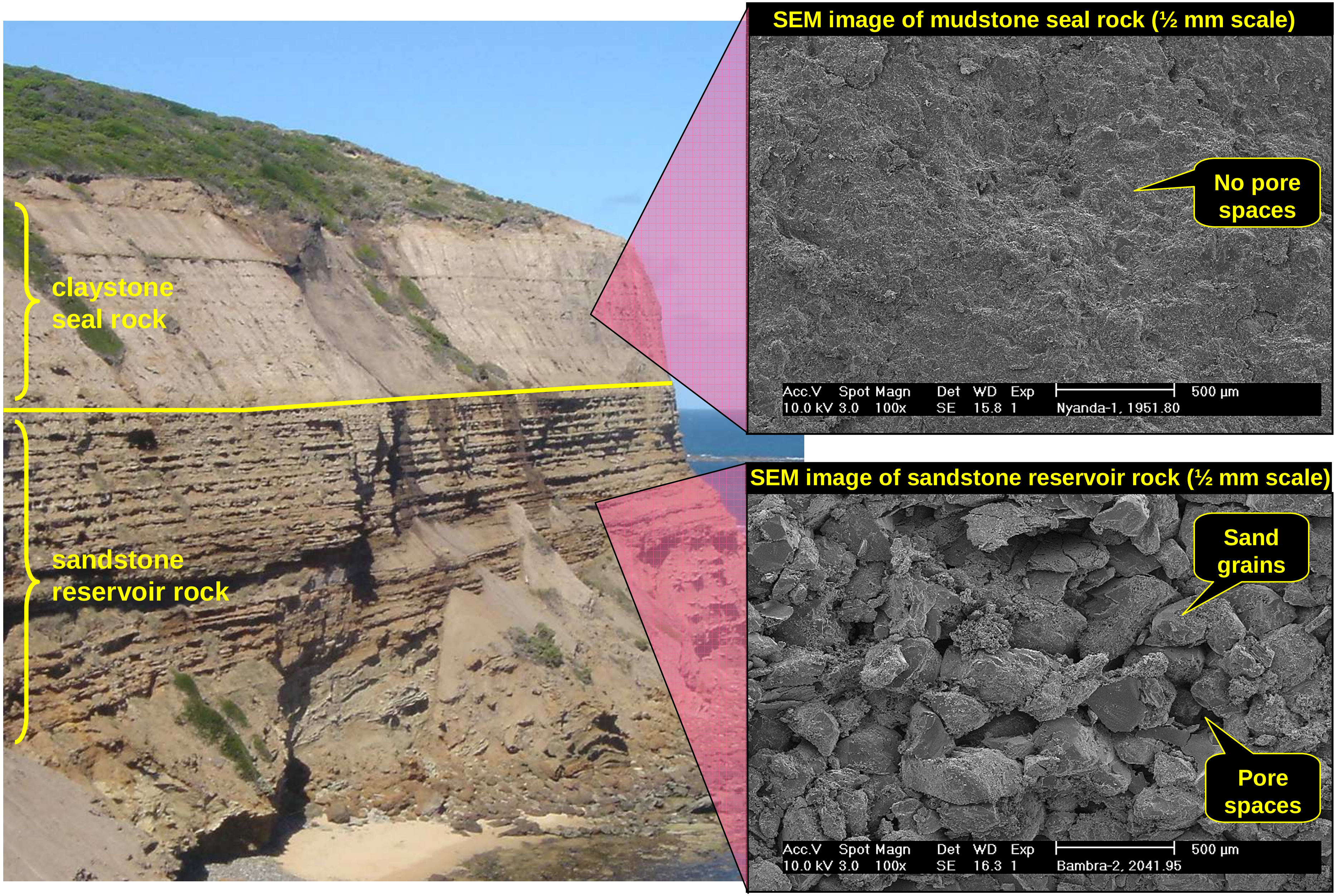
What do we need?

- **RESERVOIR ROCK – porous, e.g. sandstone**
- **SEAL ROCK – non-porous, e.g. claystone**

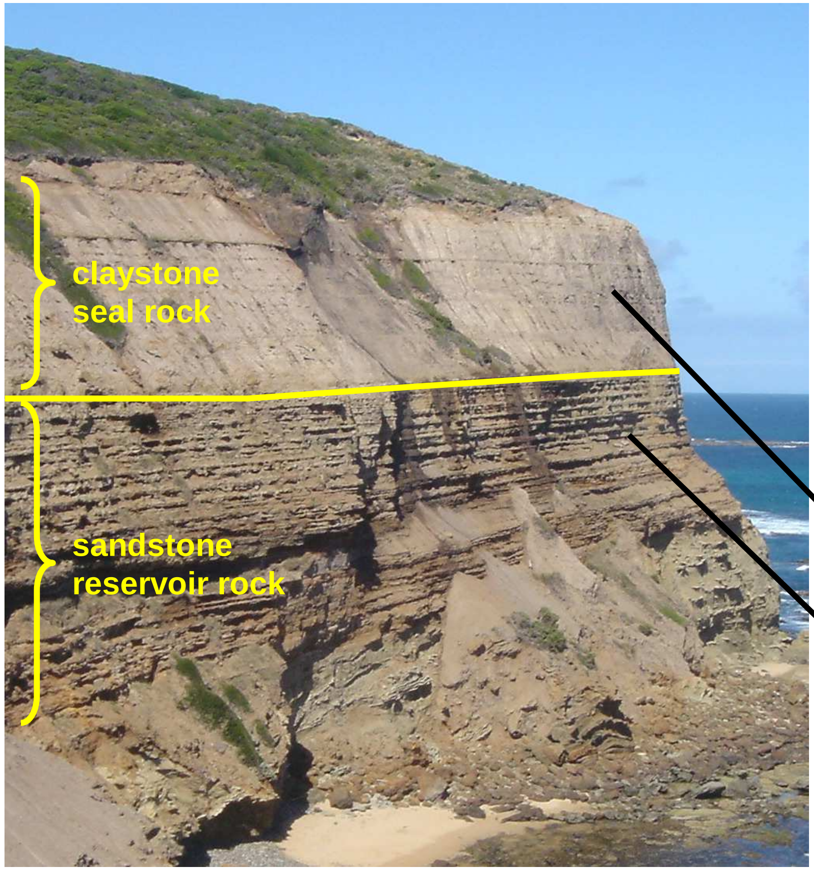
How does it work?

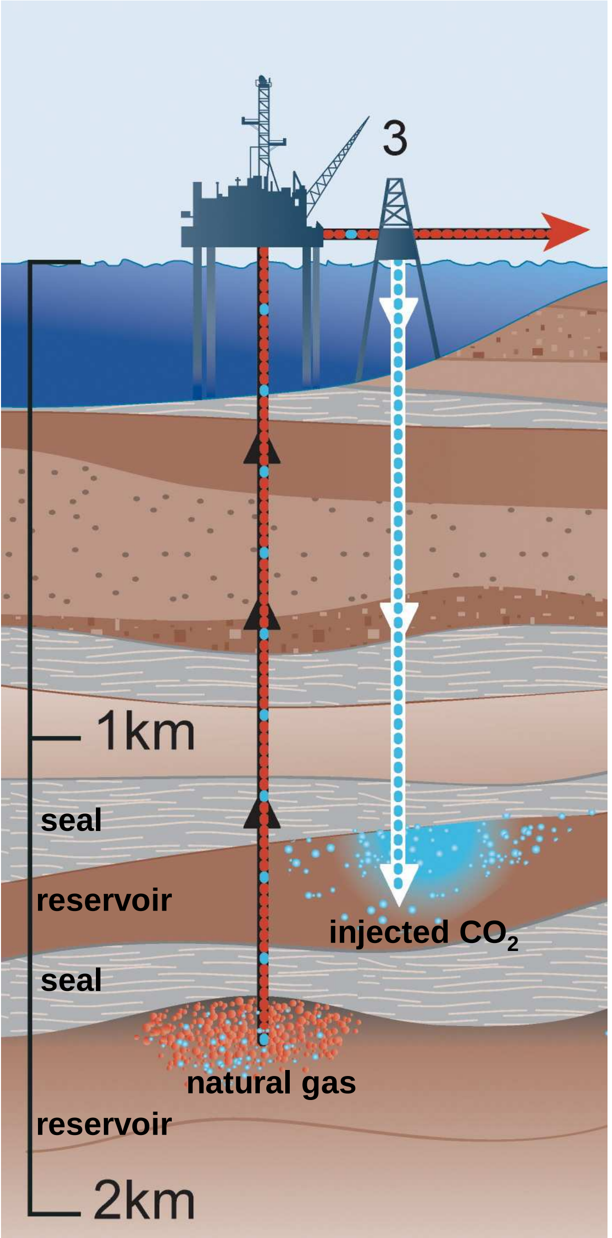
- **CO_2 injected into porous reservoir rock**
- **CO_2 held in place by overlying non-porous seal rock**

Geological Storage of CO_2



Geological Storage of CO_2

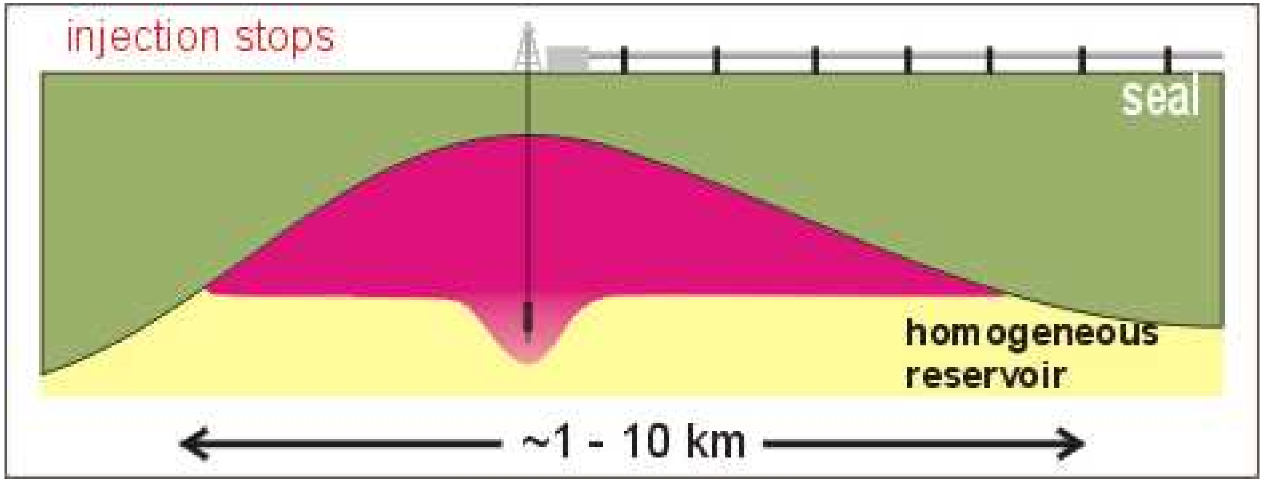




CO_2 storage sites:

- **Several kilometres below surface**
- **Similar locations to oil and natural gas**

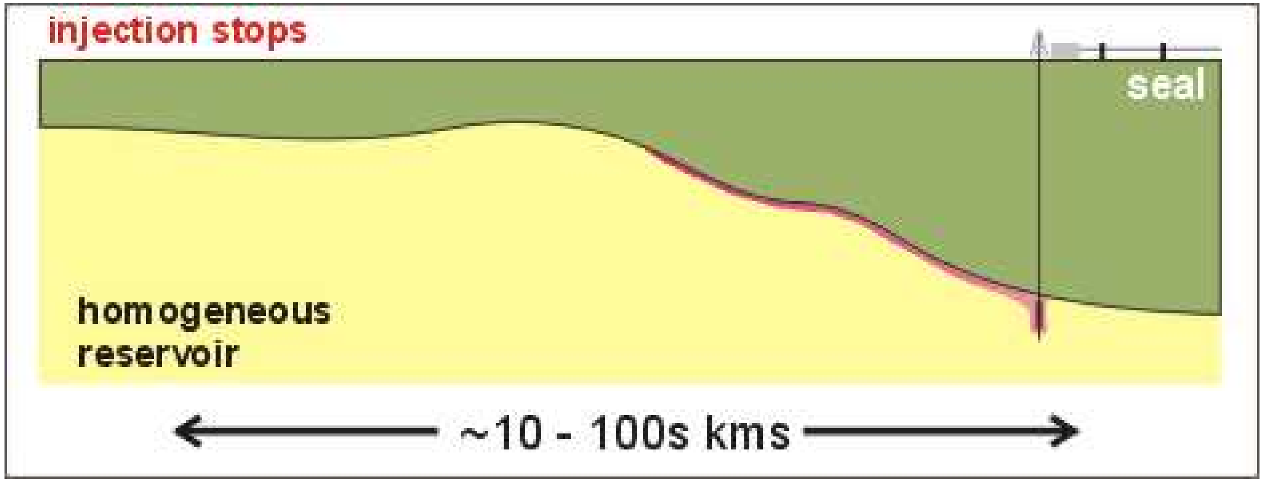
Conceptual CO_2 Storage Scenario



NOTE: Supercritical CO_2 less dense than water. Post-injection, CO_2 will move upwards through reservoir rock until trapped by impermeable seal rock

<u>Conventional Structural Trap / Depleted Field</u>

- **Proven seal potential**
- **Few opportunities in Australia at present; more expected in next 20 years**
- **Relatively small volume opportunities at present; larger potential volumes in next 20 years**



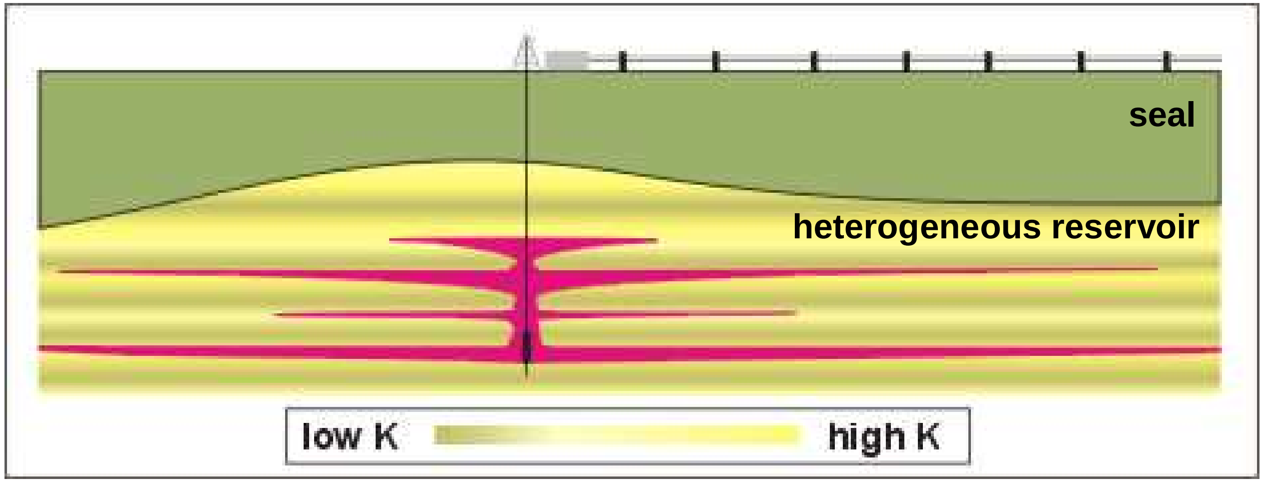
<u>Large, Open Structure (Hydrodynamic/Residual Gas Saturation Trapping)</u>

- **Long migration path**
- **Large total capacity**
- **Extensive opportunity in Australia presently**
- **Seal potential (?)**

(CO_2 concept models courtesy of Robert Root)

UNSW CSIRO ASP Australian School of Petroleum THE UNIVERSITY OF ADELAIDE AUSTRALIA CO2CRC

Conceptual CO_2 Storage Scenario



Heterogeneous Reservoir

Flow 'channeling'

Amount of CO_2 geologically stored influenced by:

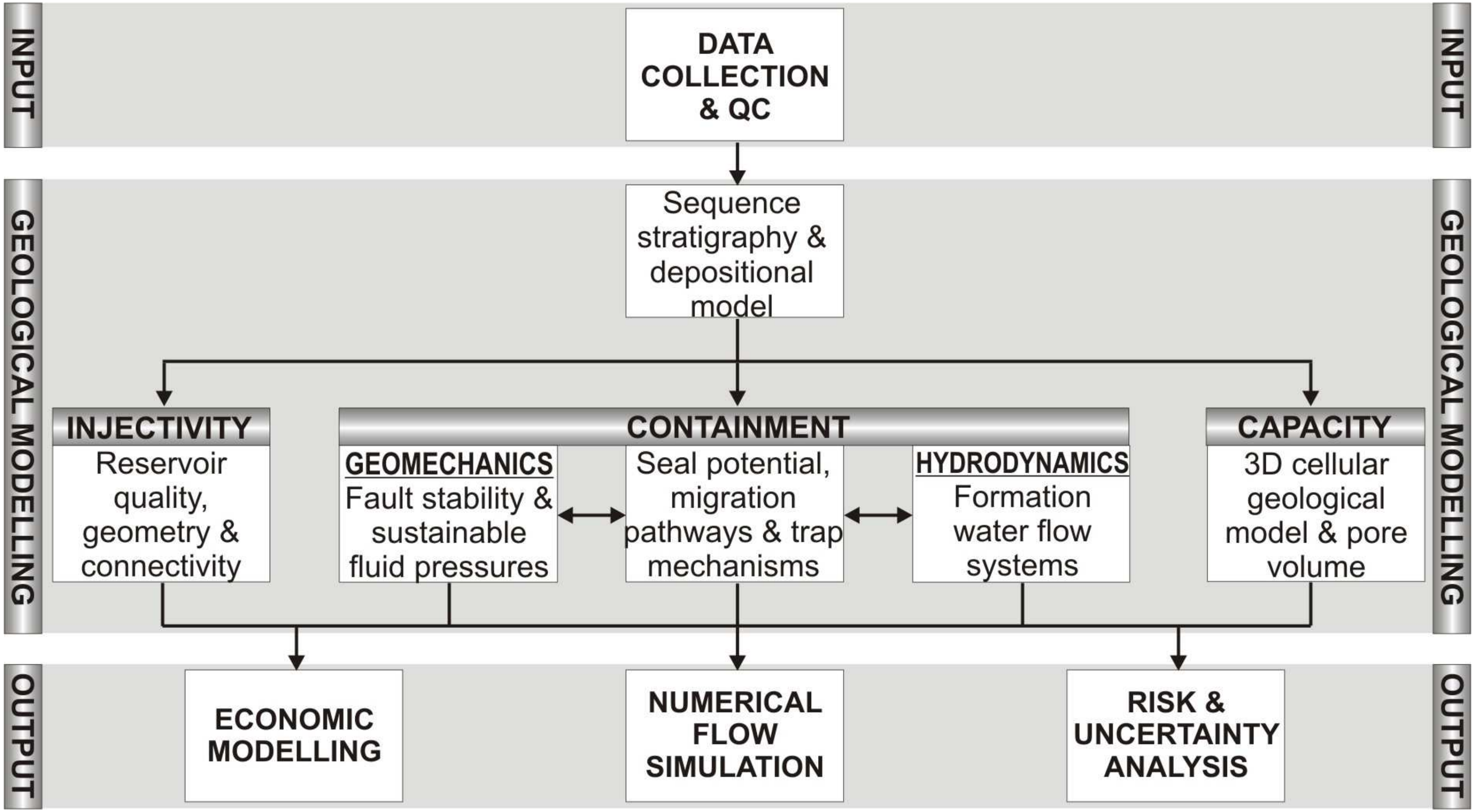
- **Rate of CO_2 migration**
- **Style of multiphase flow**
- **Rate of CO_2 dissolution**
- **Rate of chemical reaction with minerals**

Controlled by many variables, including:

- **Reservoir and seal structure**
- **Stratigraphic architecture**
- **Reservoir heterogeneity**
- **Faults/fractures**
- **Pressure/temperature conditions**
- **Hydrodynamics and chemistry of *in situ* formation fluids**

(CO_2 concept models courtesy of Robert Root)

Site Characterisation Workflow



INPUT

DATA COLLECTION & QC

GEOLOGICAL MODELLING

Sequence stratigraphy & depositional model

INJECTIVITY

Reservoir quality, geometry & connectivity

CONTAINMENT

GEOMECHANICS

Fault stability & sustainable fluid pressures

Seal potential, migration pathways & trap mechanisms

HYDRODYNAMICS

Formation water flow systems

CAPACITY

3D cellular geological model & pore volume

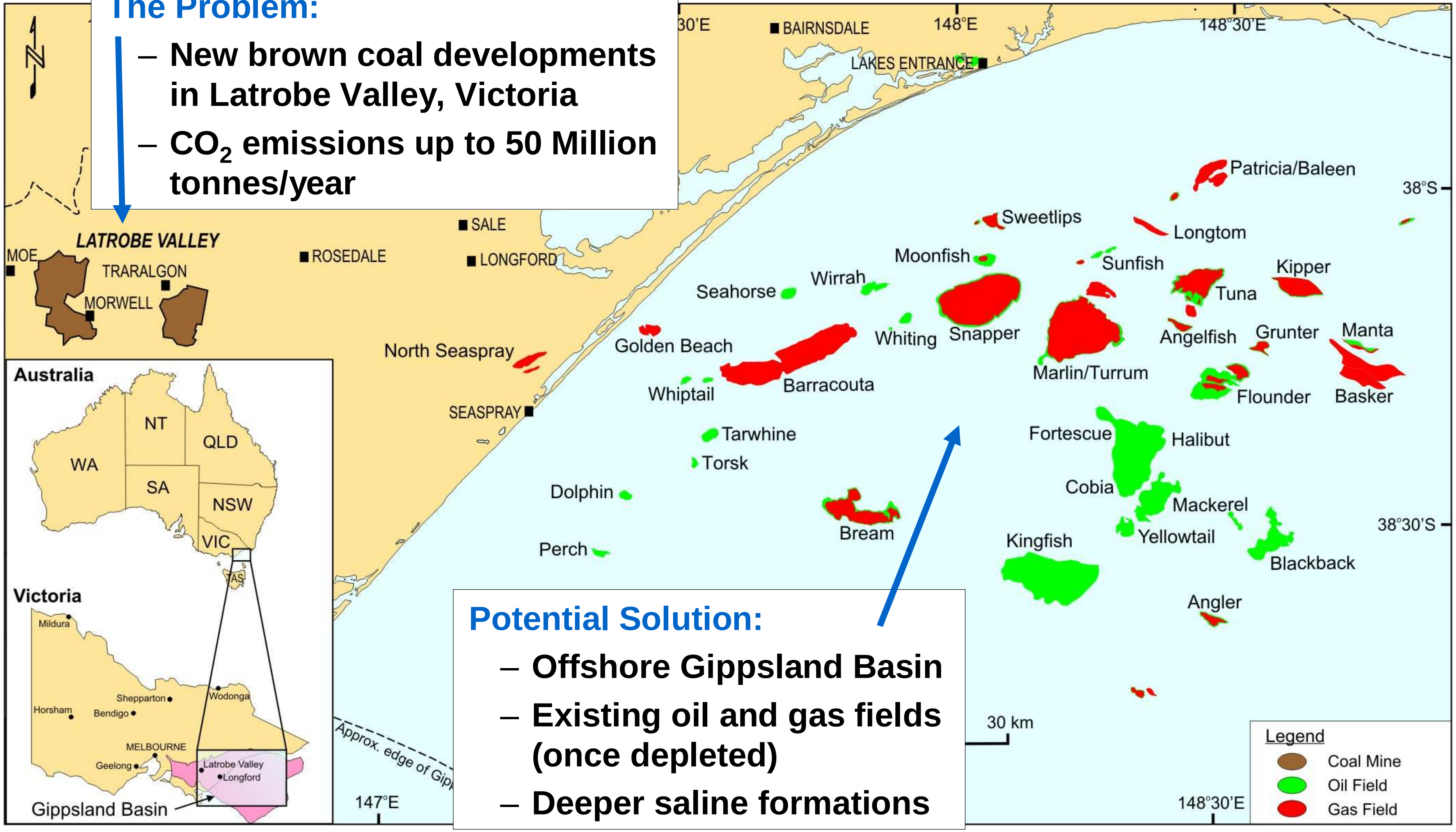
OUTPUT

ECONOMIC MODELLING

NUMERICAL FLOW SIMULATION

RISK & UNCERTAINTY ANALYSIS

Gippsland Basin, Southeast Australia



The Problem:

- New brown coal developments in Latrobe Valley, Victoria
- CO_2 emissions up to 50 Million tonnes/year

Potential Solution:

- Offshore Gippsland Basin
- Existing oil and gas fields (once depleted)
- Deeper saline formations

Selected Site Scenarios

Injection Scenarios:

Injection at several sites along regional migration pathways, sequentially & simultaneously, ramping up volume to 50 Mt/y

1. **Kingfish Field: 15 Mt/y for 40 years**
2. **Fortescue Field: 15 Mt/y for 40 years**
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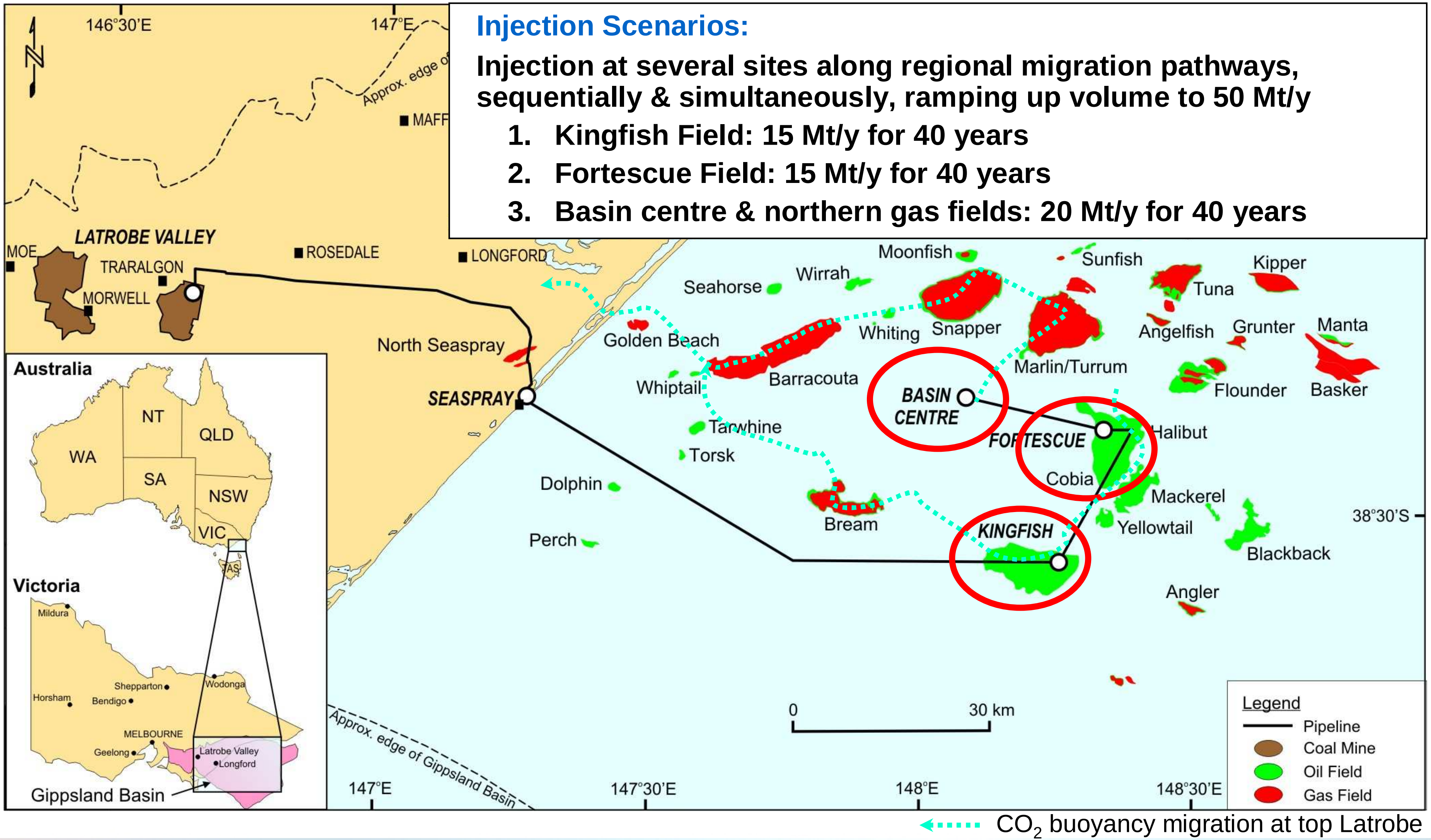
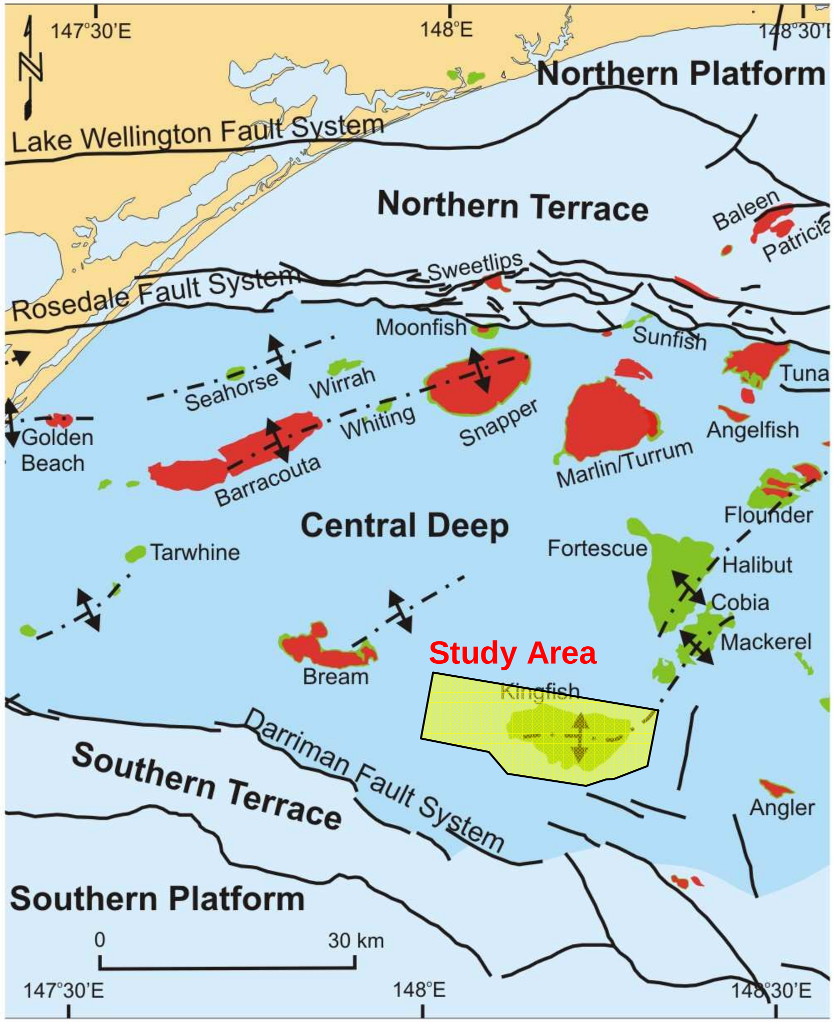


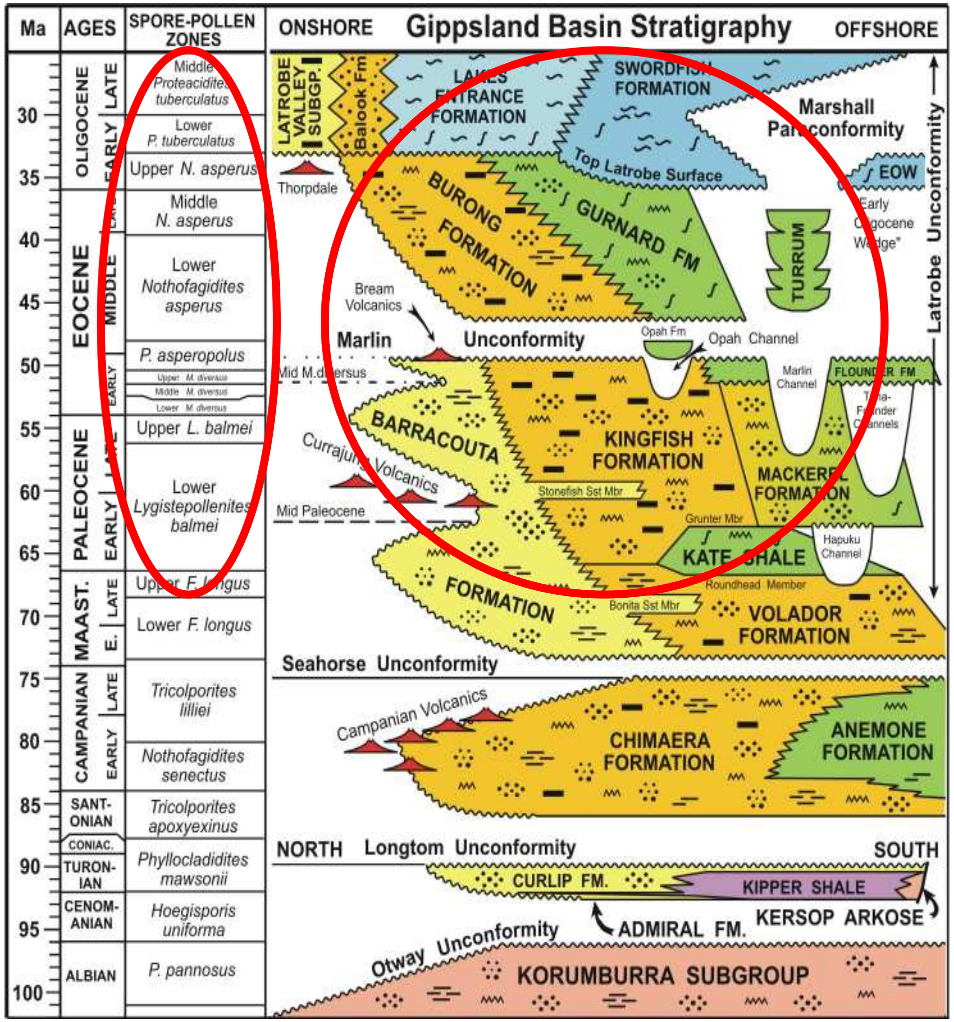
Detailed Characterisation: Kingfish Field

Location map of Gippsland Basin



(modified after Power et al., 2001)

Stratigraphic column



(after Bernecker & Partridge, 2001)

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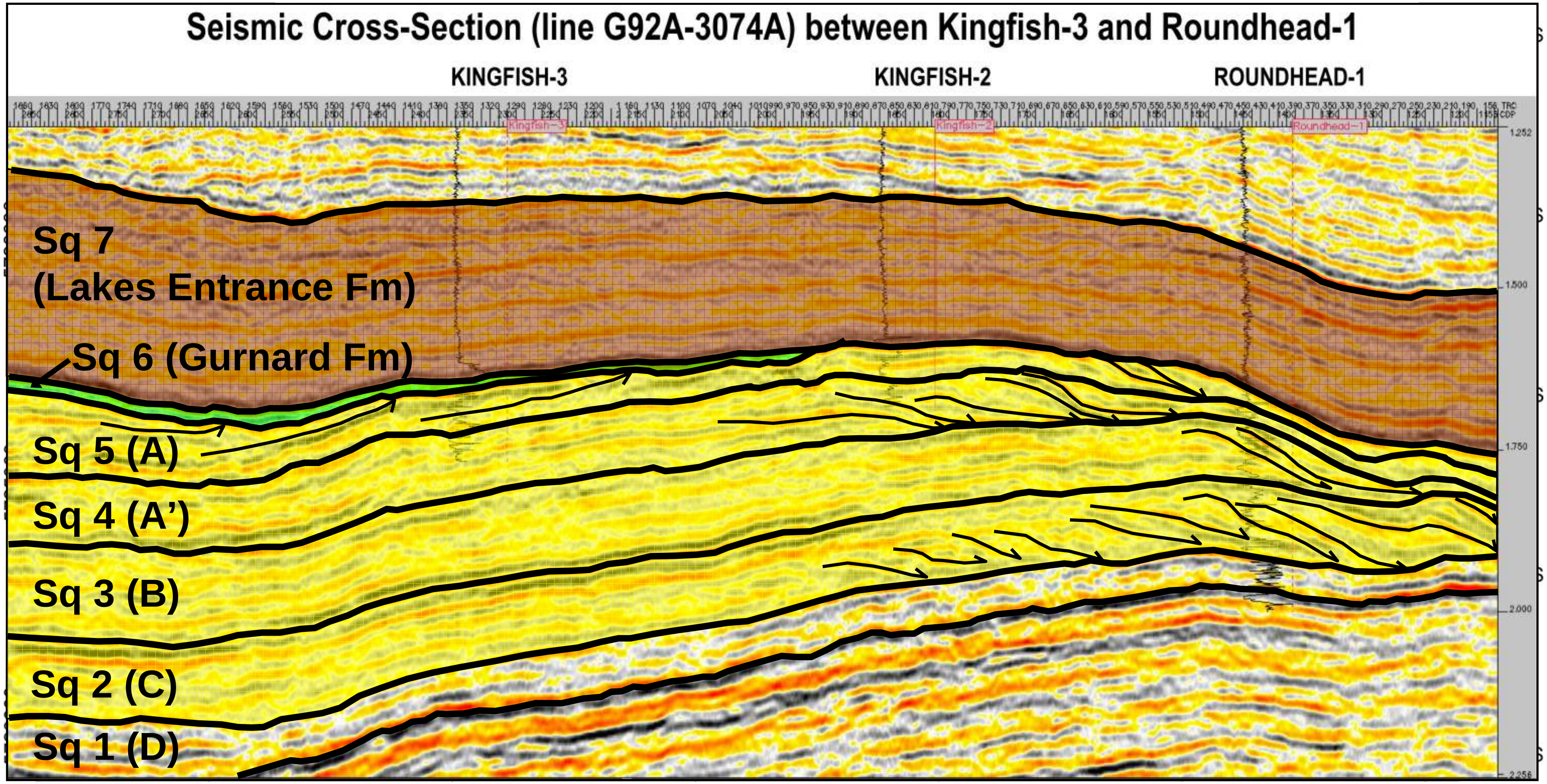
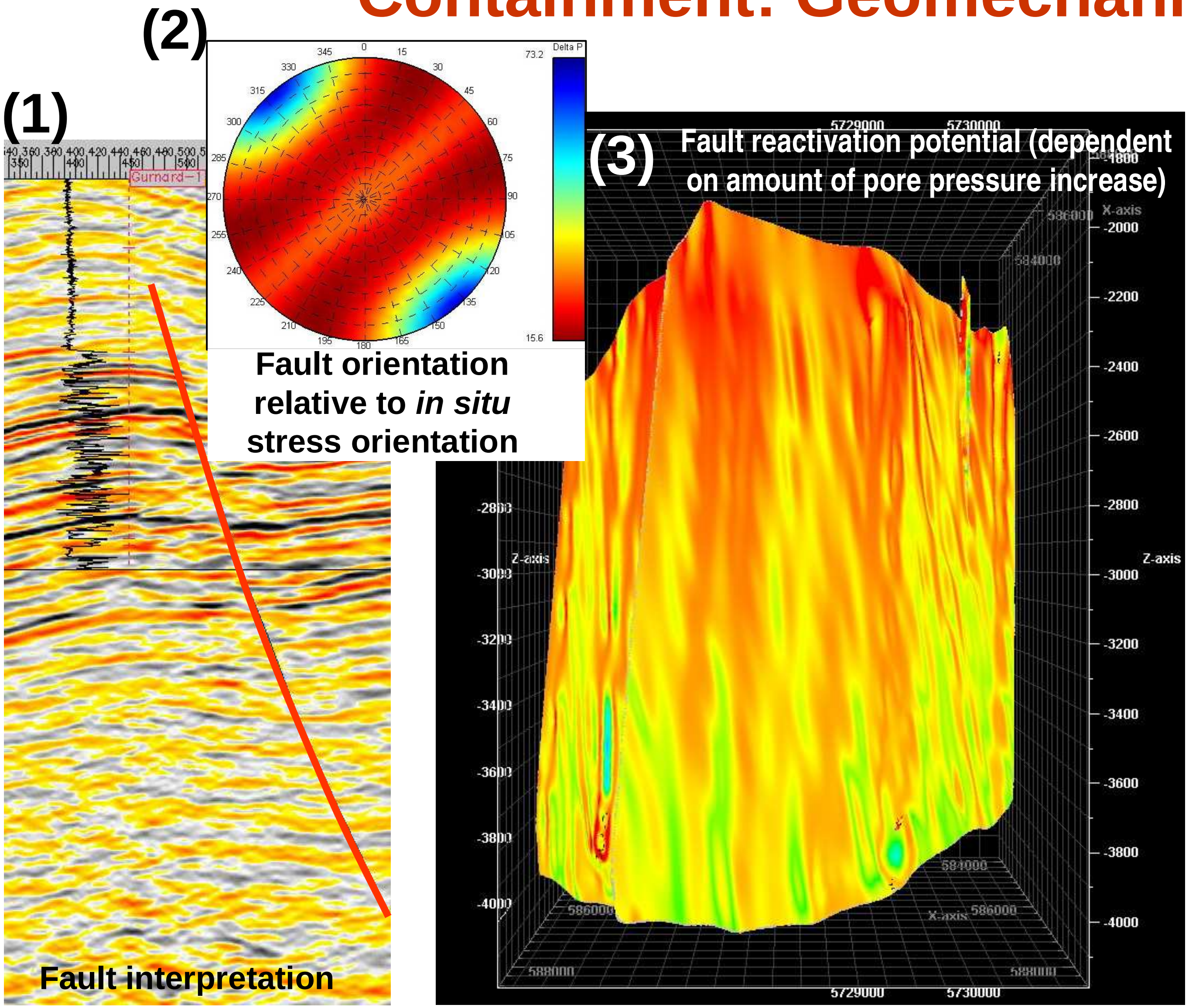
Sequence Stratigraphy



Containment: Geomechanics



Fault interpretation

Fault orientation relative to *in situ* stress orientation

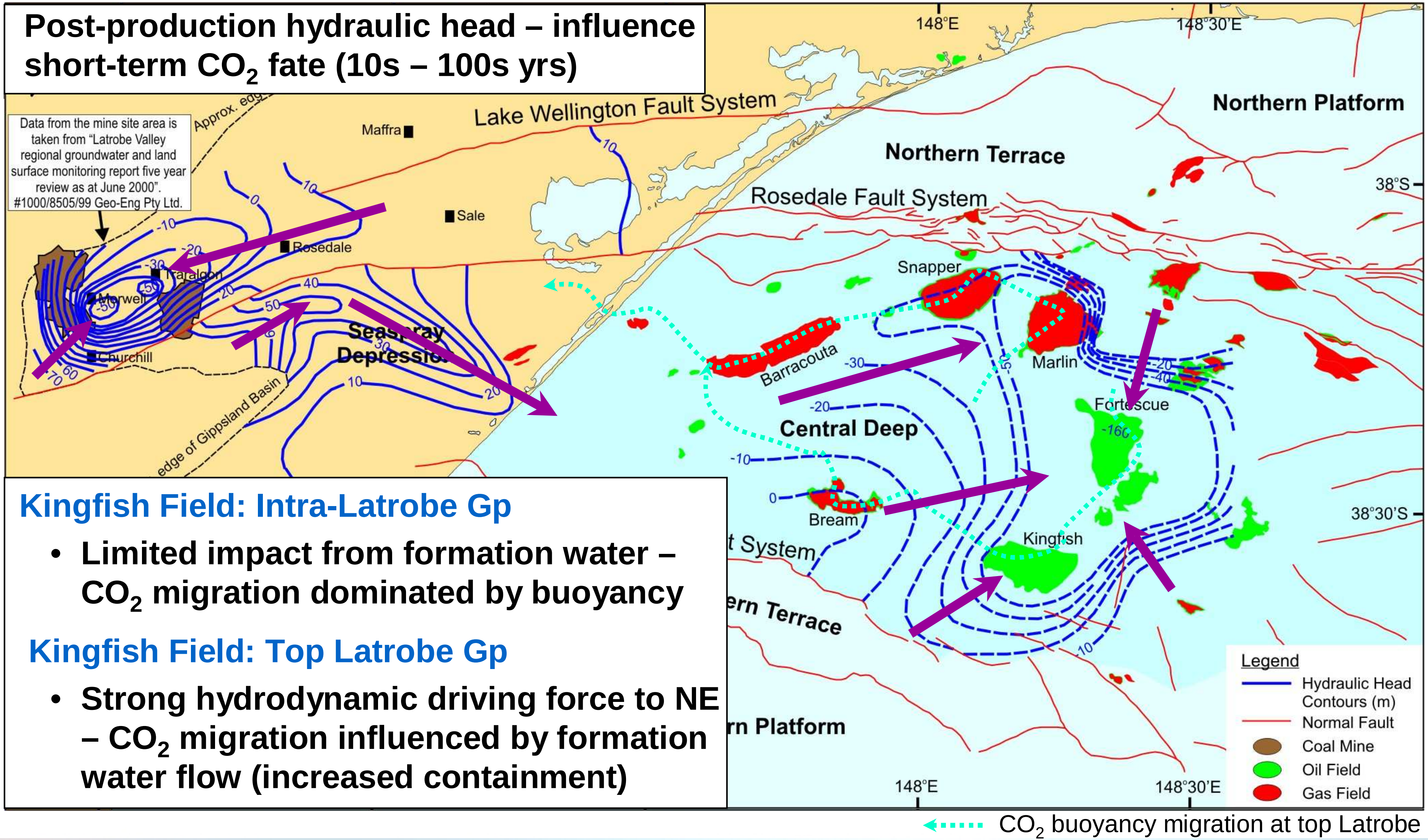
Fault reactivation potential (dependent on amount of pore pressure increase)

Seismically-resolvable faults

- 3 cut the top Latrobe unconf.
- 7 terminate within Latrobe Gp
- Most have moderate to high fault reactivation potential
- However, most not in immediate migration pathway

Containment: Hydrodynamics

Post-production hydraulic head – influence short-term CO_2 fate (10s – 100s yrs)



Data from the mine site area is taken from "Latrobe Valley regional groundwater and land surface monitoring report five year review as at June 2000". #1000/8505/99 Geo-Eng Pty Ltd.

CO_2 buoyancy migration at top Latrobe

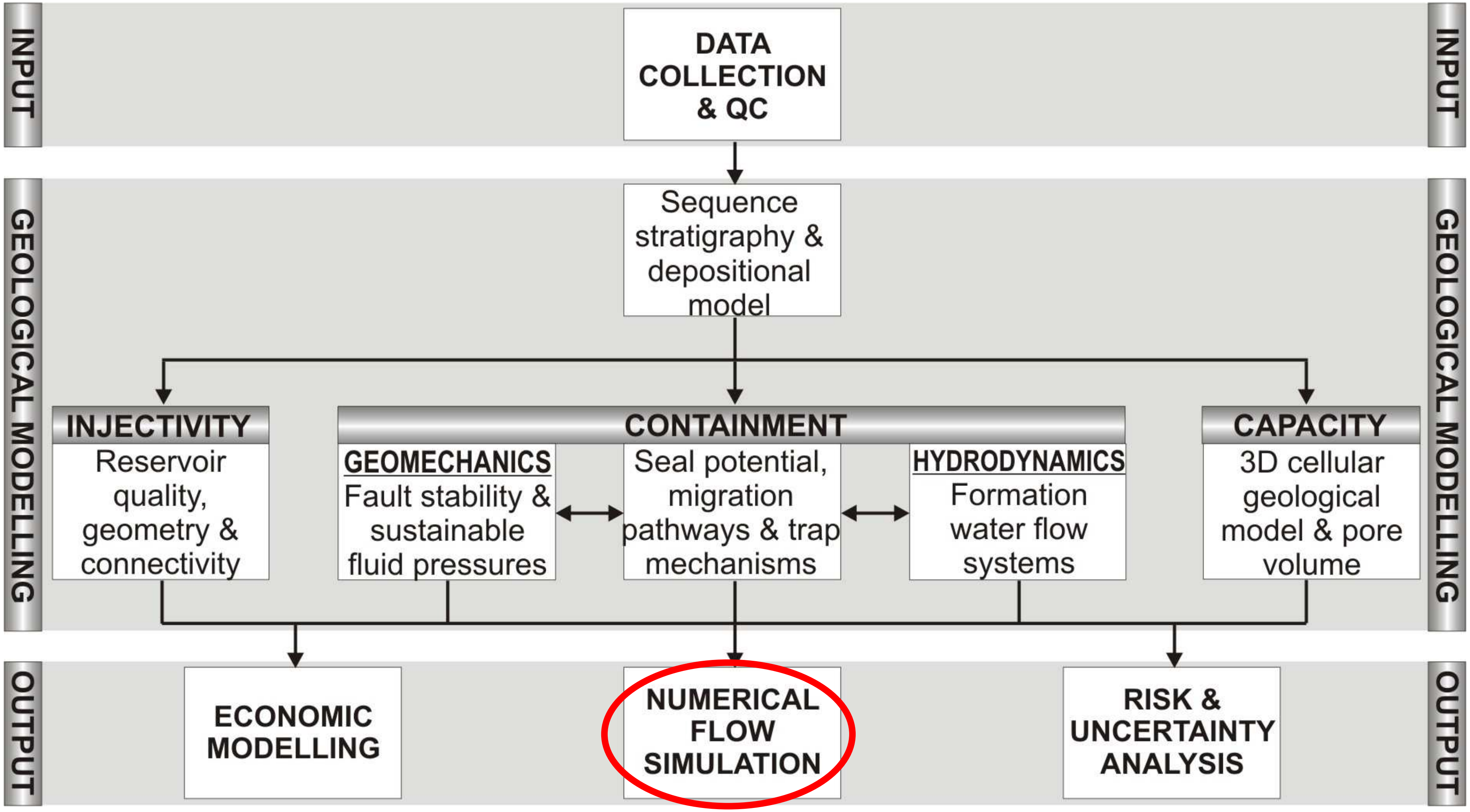
Kingfish Field: Intra-Latrobe Gp

- Limited impact from formation water – CO_2 migration dominated by buoyancy

Kingfish Field: Top Latrobe Gp

- Strong hydrodynamic driving force to NE – CO_2 migration influenced by formation water flow (increased containment)

Numerical Flow Simulation



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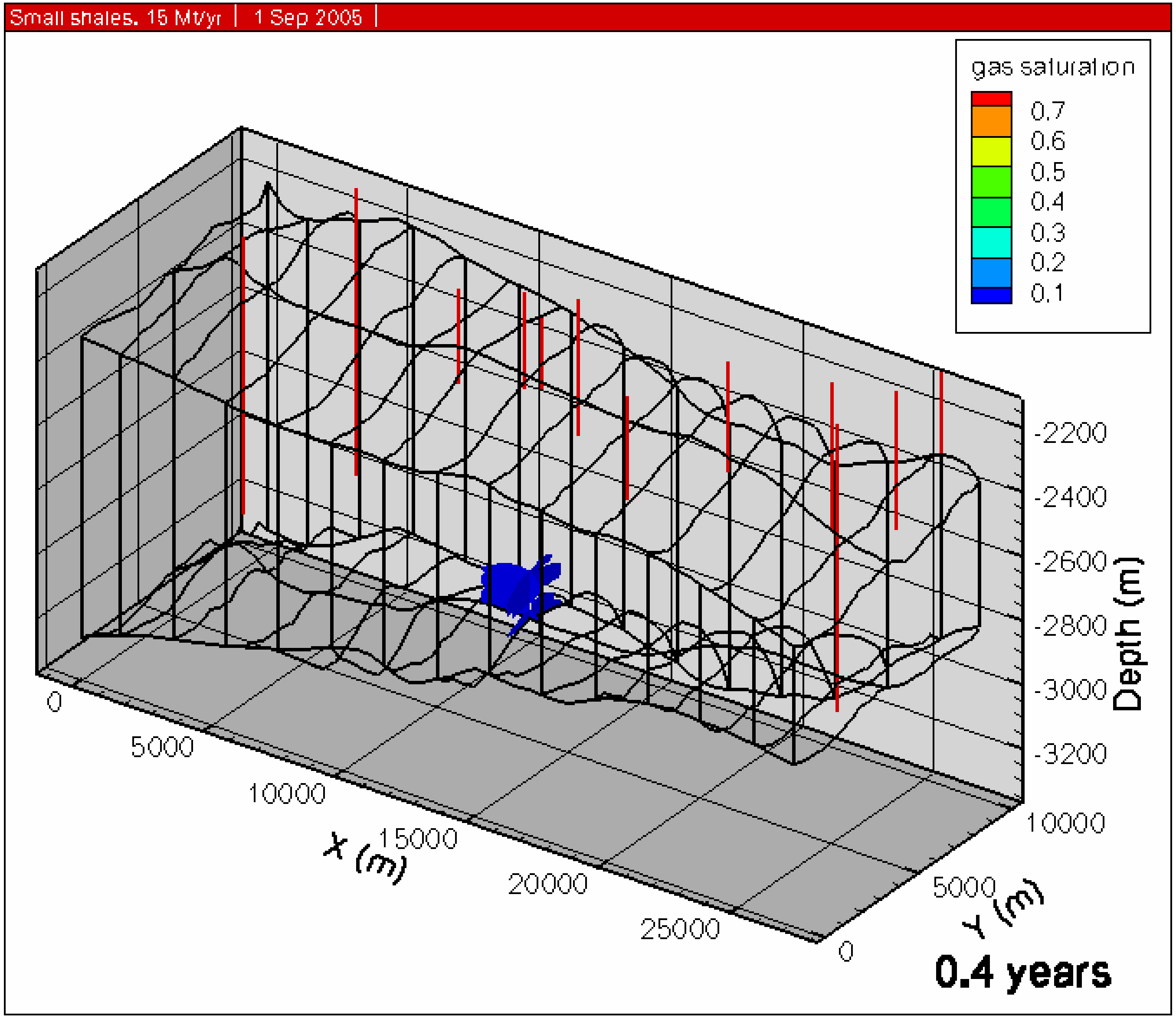
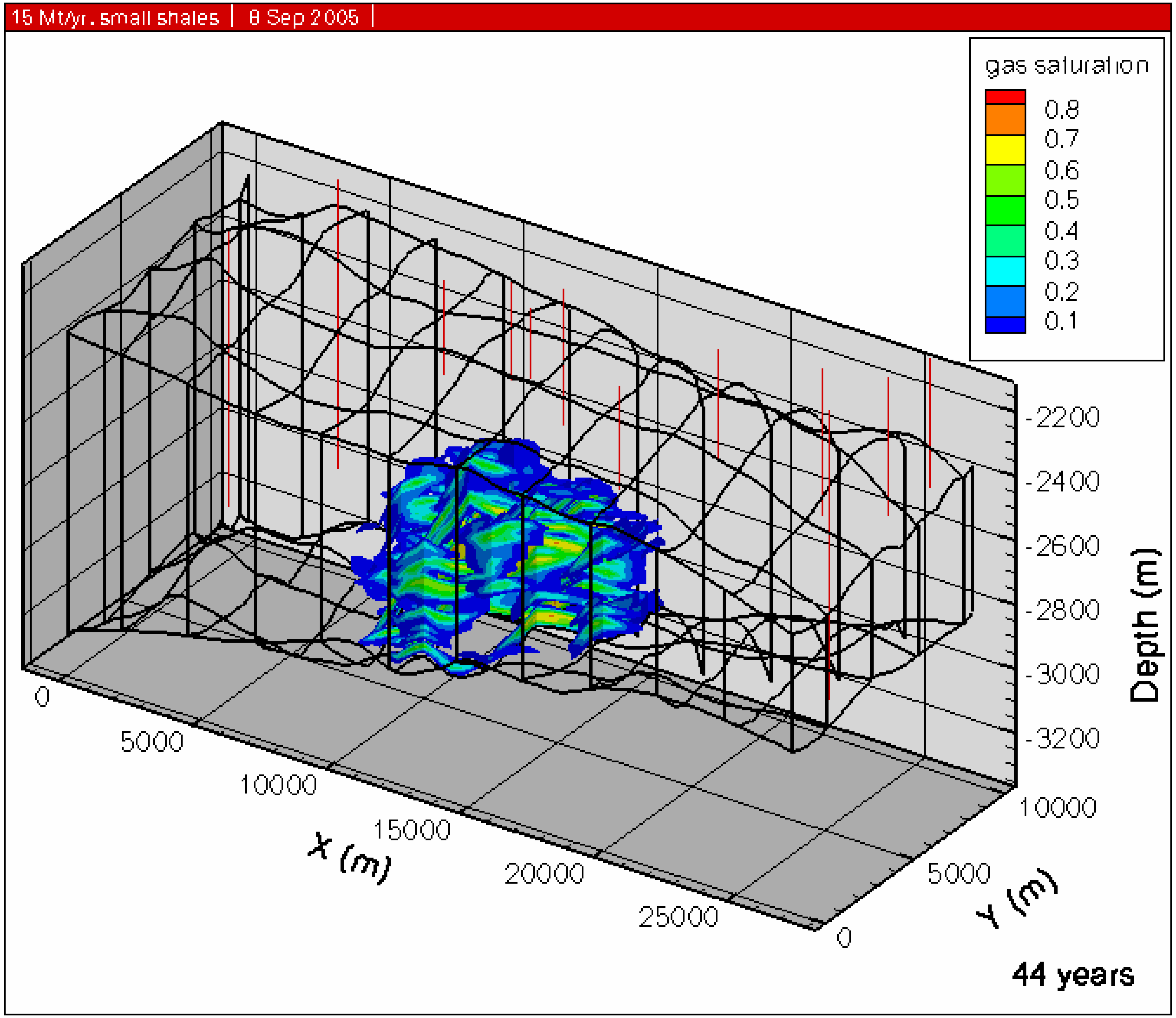
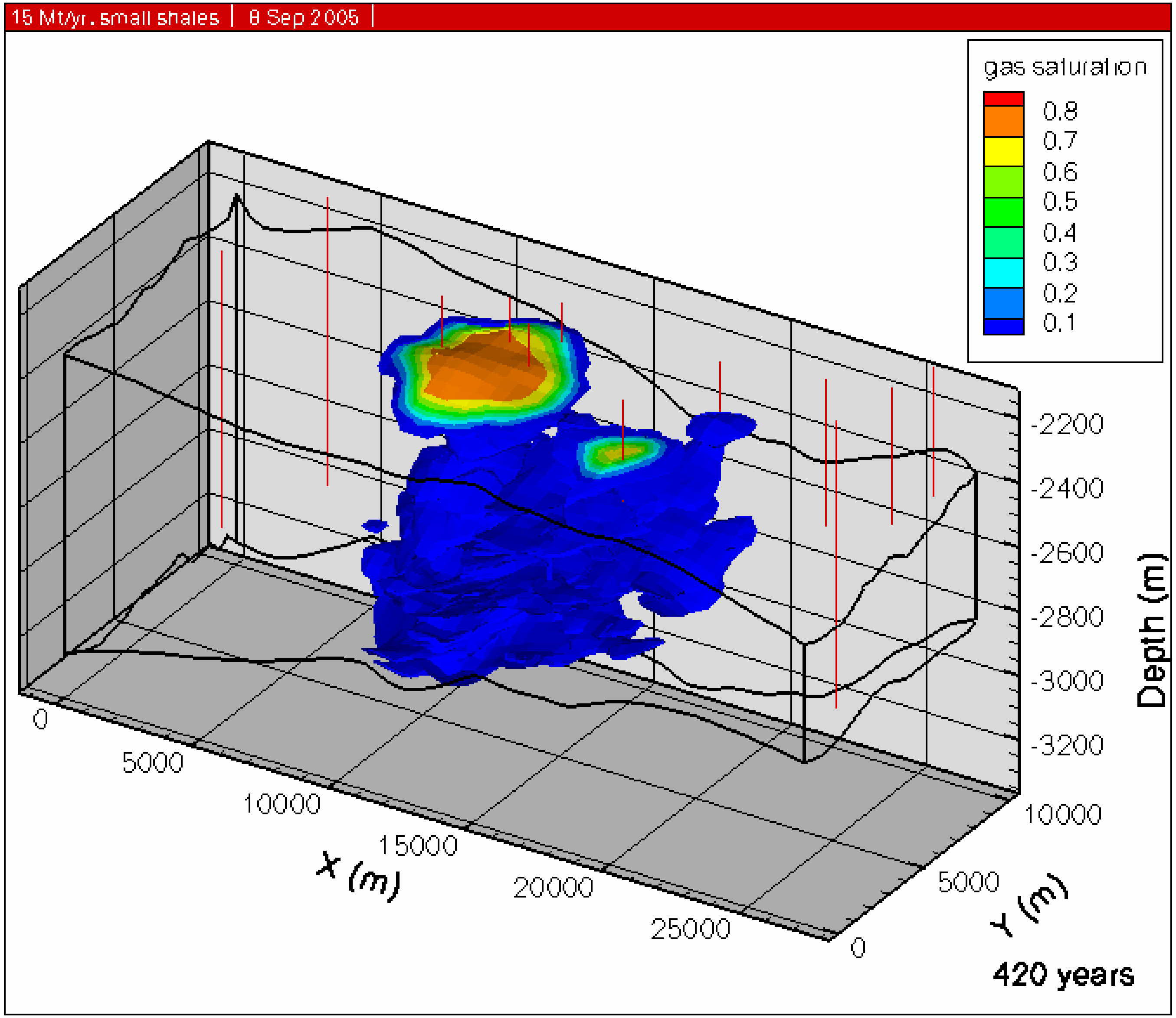


- **15 Mt/y for 40 years**
- **Post-injection small shales 0–40 yrs**



- **15 Mt/y for 40 years**
- **Post-injection small shales 40–400 yrs**



- **15 Mt/y for 40 years**
- **Post-injection small shales 400–1140 yrs**

Simulation results:

- **Injection rate achievable – lower permeability or extensive shale barriers require more wells**
- **Migration time to the oil-bearing zone is 40–200 years for deep injection – less for shallow injection, more for wider shale barriers**
- **Storage capacity sufficient with deep injection – more CO_2 trapped as residual gas**

Geoscience Conclusions

Suitability of Kingfish Field/Gippsland Basin as CO_2 storage site:

- Complex stratigraphic architecture which slows vertical migration and increases residual gas trapping
- Non-reactive reservoir units with high injectivity
- Geochemically-reactive, low permeability reservoir just below regional seal to provide additional mineral trapping
- Several depleted oil fields to provide storage capacity coupled with transient flow regime that enhances containment
- Long migration pathways beneath competent regional seal
- Kingfish Field, in conjunction with other sites (e.g. Fortescue, northern gas fields), indicate that Gippsland Basin has sufficient capacity to store very large volumes of CO_2.

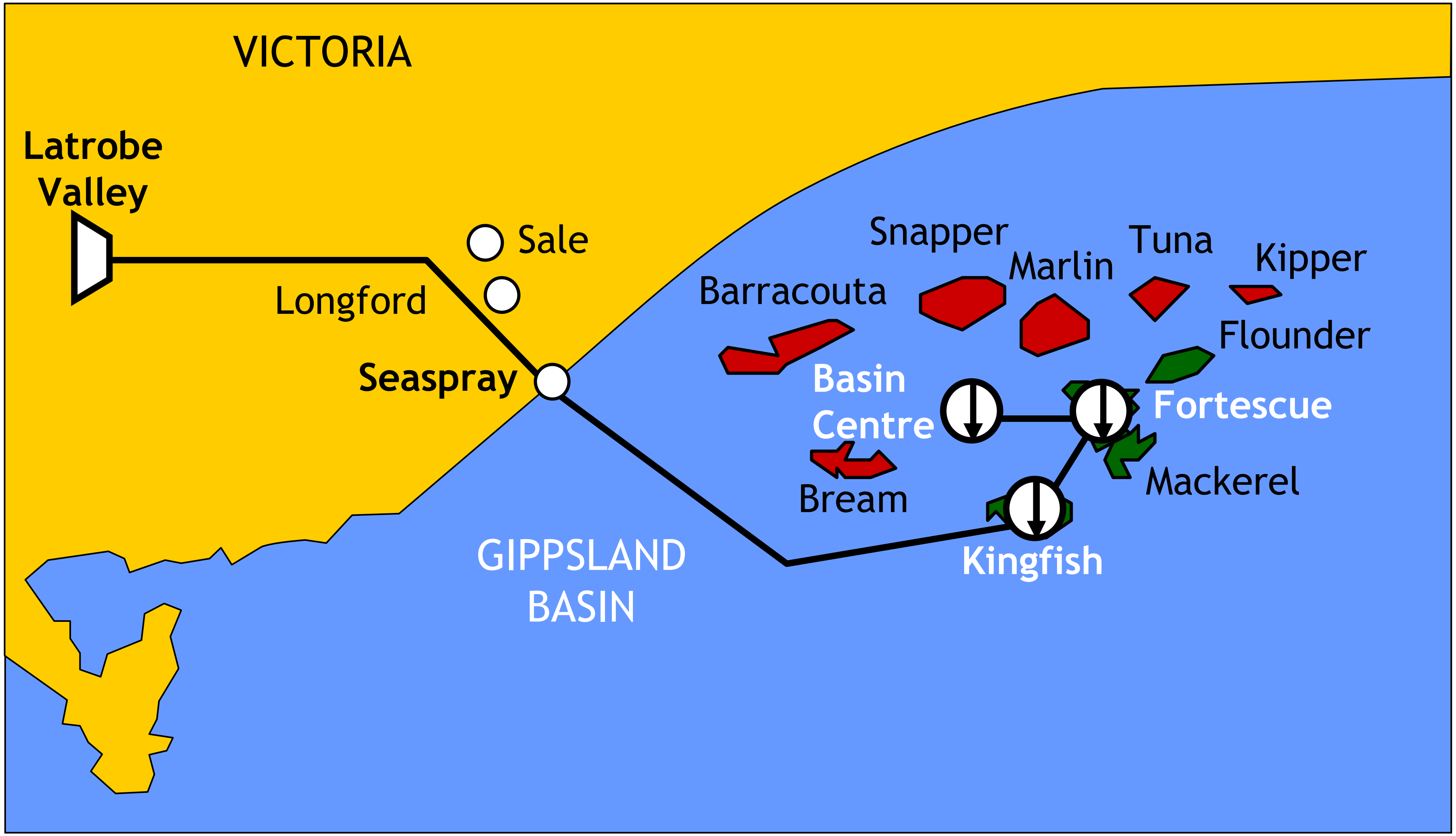
Latrobe Valley Storage Economics

Base Cases

Five cases are examined -

A	Constant 2 MMtpa for 5 years
B1	Constant 15 MMtpa for 40 years
B2	= B1 with onshore capacity for 50 MMtpa
C1	Ramp up from 15 MMtpa to 50 MMtpa for 40 years
C2	Constant 50 MMtpa for 40 years

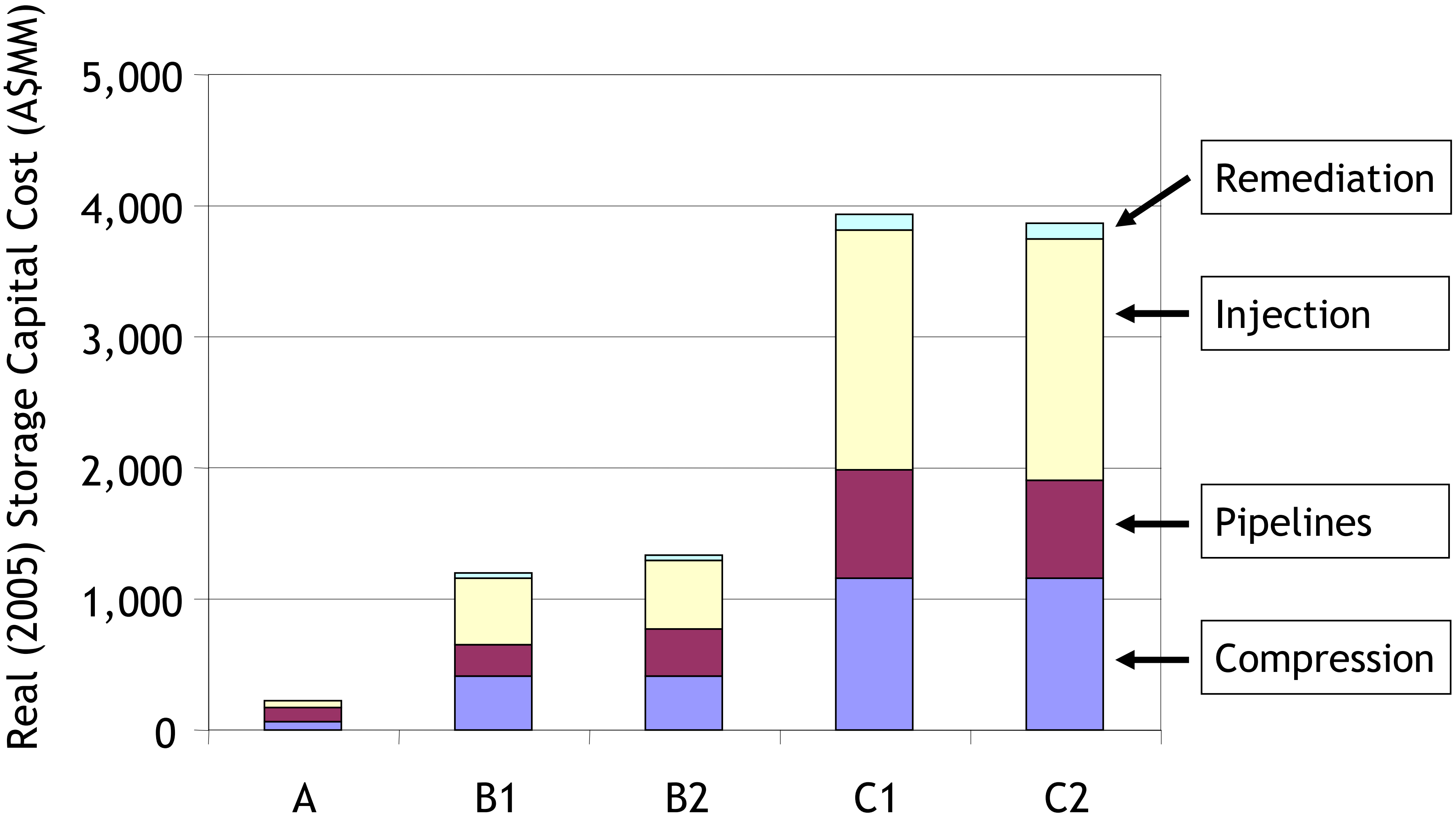
Study Area & Storage Process



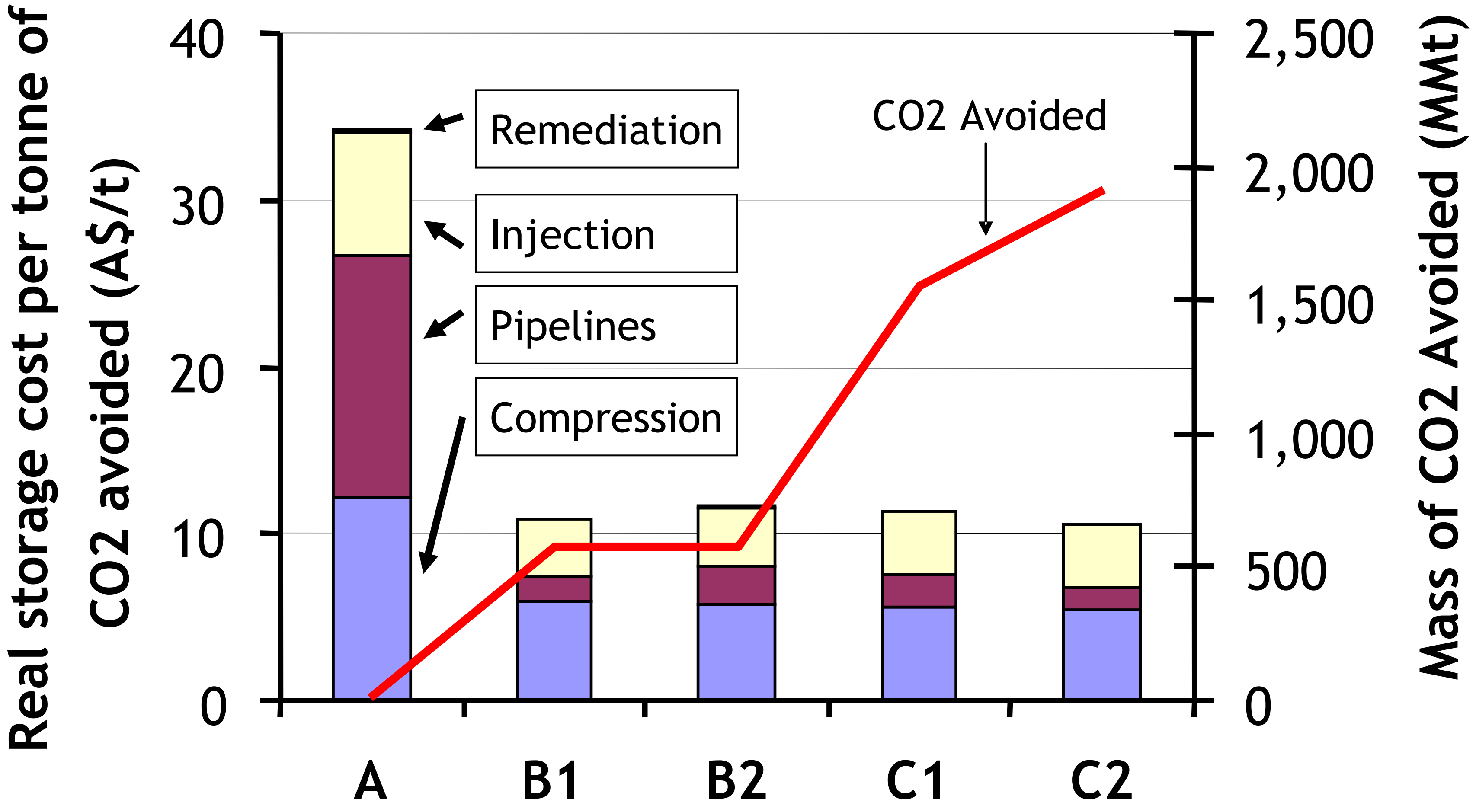
Assumptions

- Costs as at Q1 2005.
- Real discount rate = 7%
- Project Life = 40 yrs
- Spare compressor trains (cycled)
- Capture not modelled
- New platforms for A, B and C cases
- Permeability = 150 millidarcies
- Fortescue and Central Deep properties the same as Kingfish

Capital Cost of Base Cases



Real (2005) Storage Cost and CO2 Avoided



UNSW

CSIRO

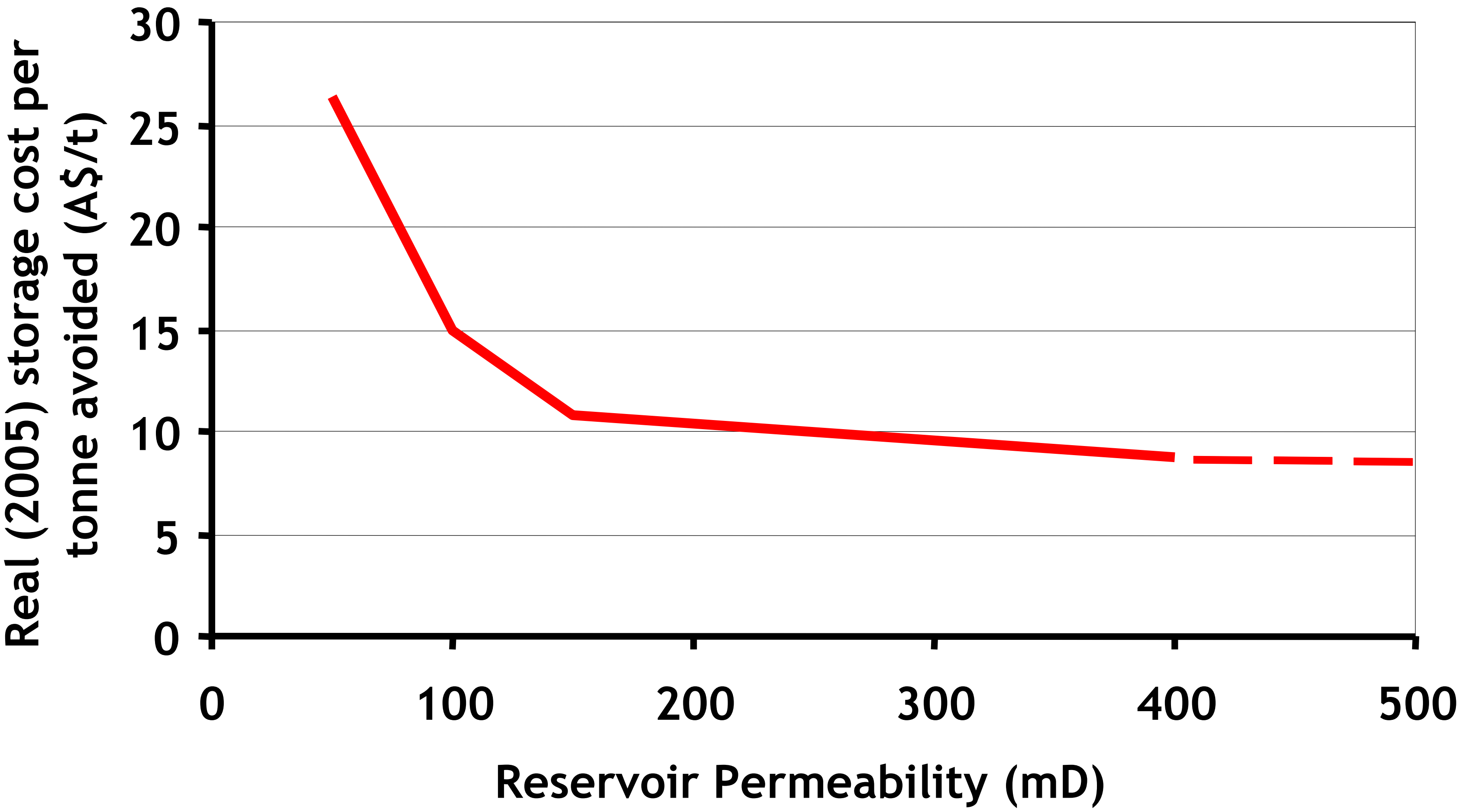
ASP Australian School of Petroleum

THE UNIVERSITY OF ADELAIDE AUSTRALIA

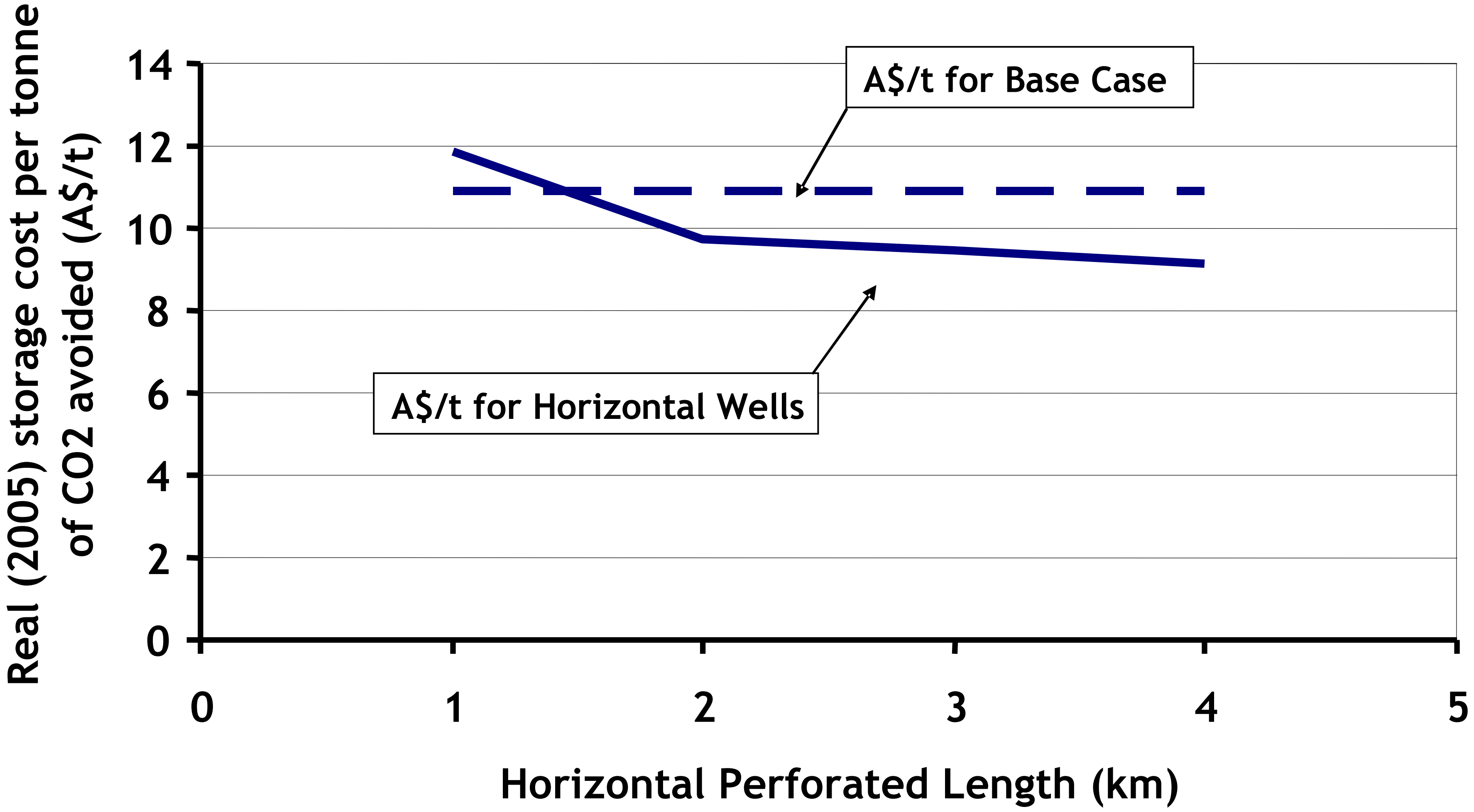
CO2CRC

Sensitivity Analyses

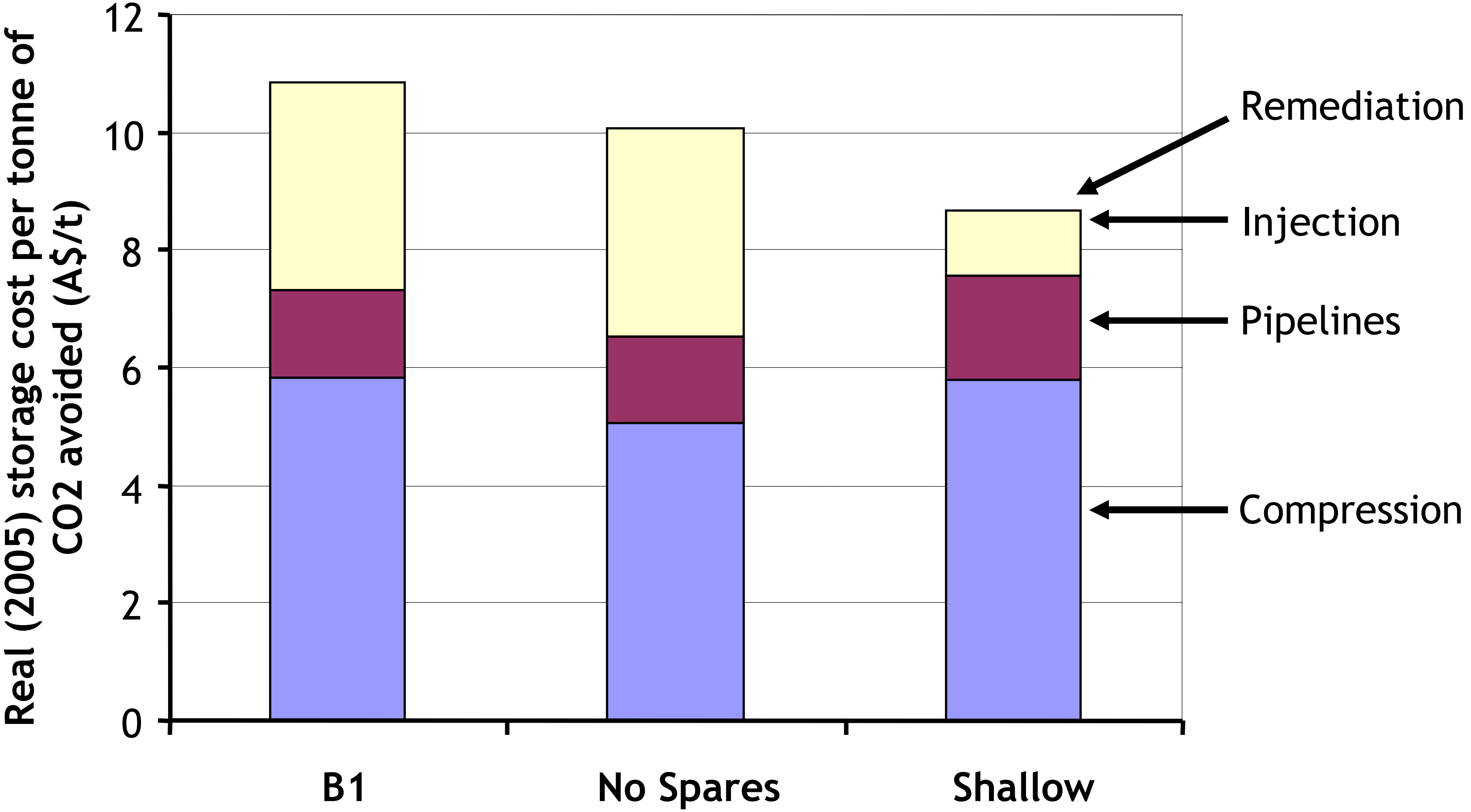
Permeability



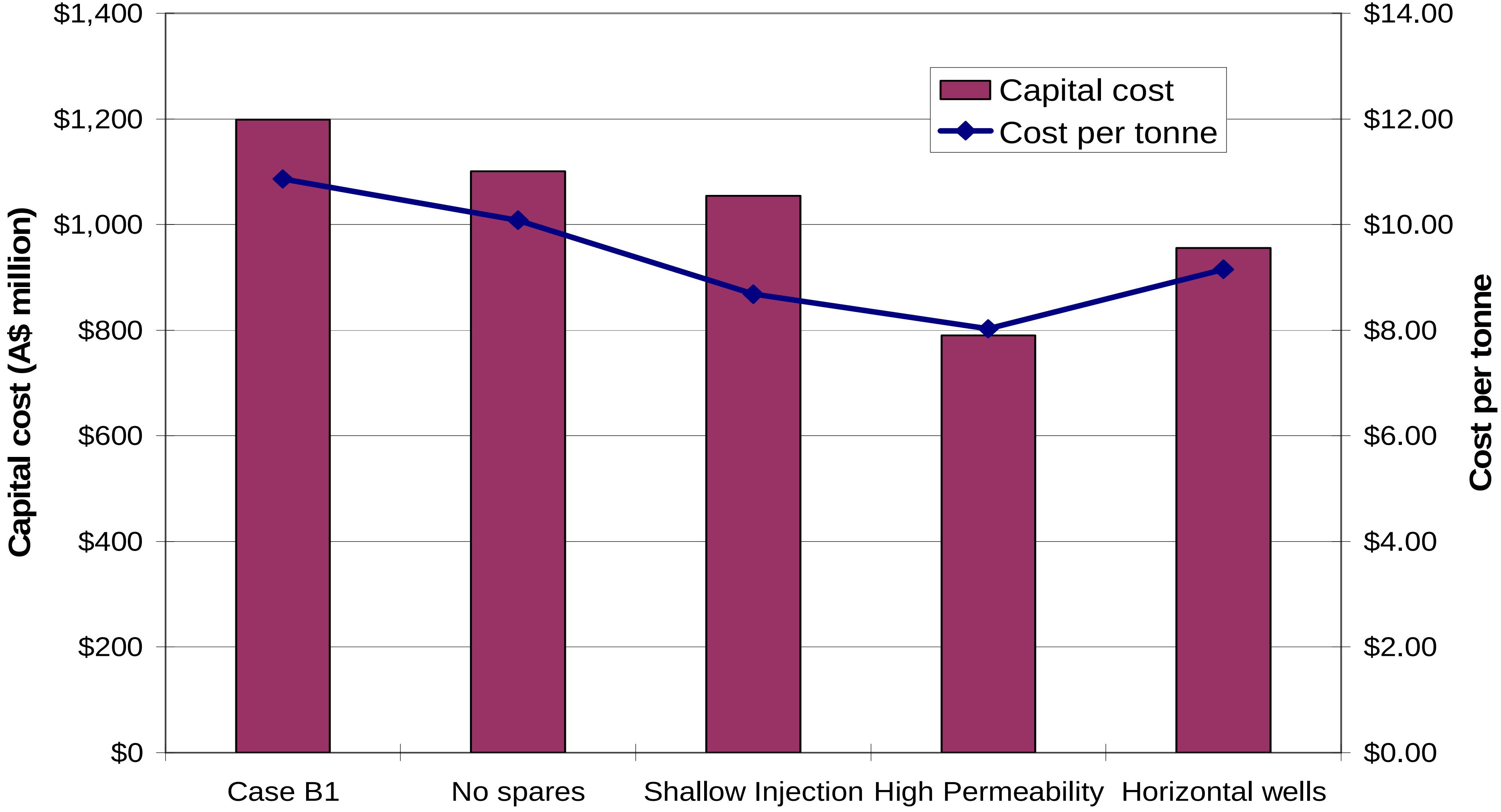
Horizontal Wells



Sparing Philosophy & Shallow Injection



Sensitivities



Summary

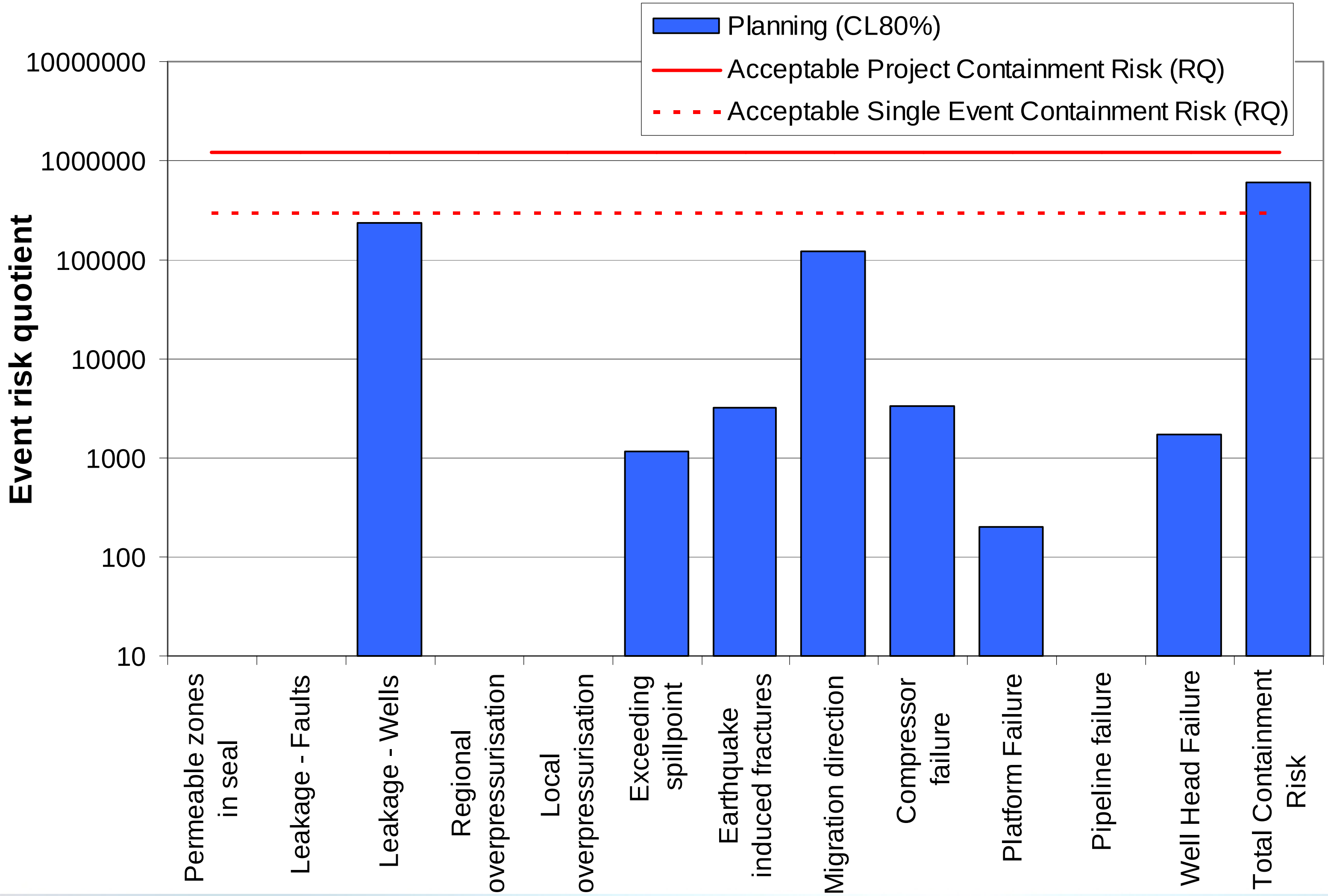
- Base case (40 year) storage cost A$10–12/t CO2 avoided
- Storage cost highly sensitive to permeability
- Costs can be reduced by -
  - Using horizontal wells
  - Not installing spare compressors
  - Injecting in shallower, higher permeability layers

Storage Risk Assessment

GEODISC
KPI 1 Reservoir performance

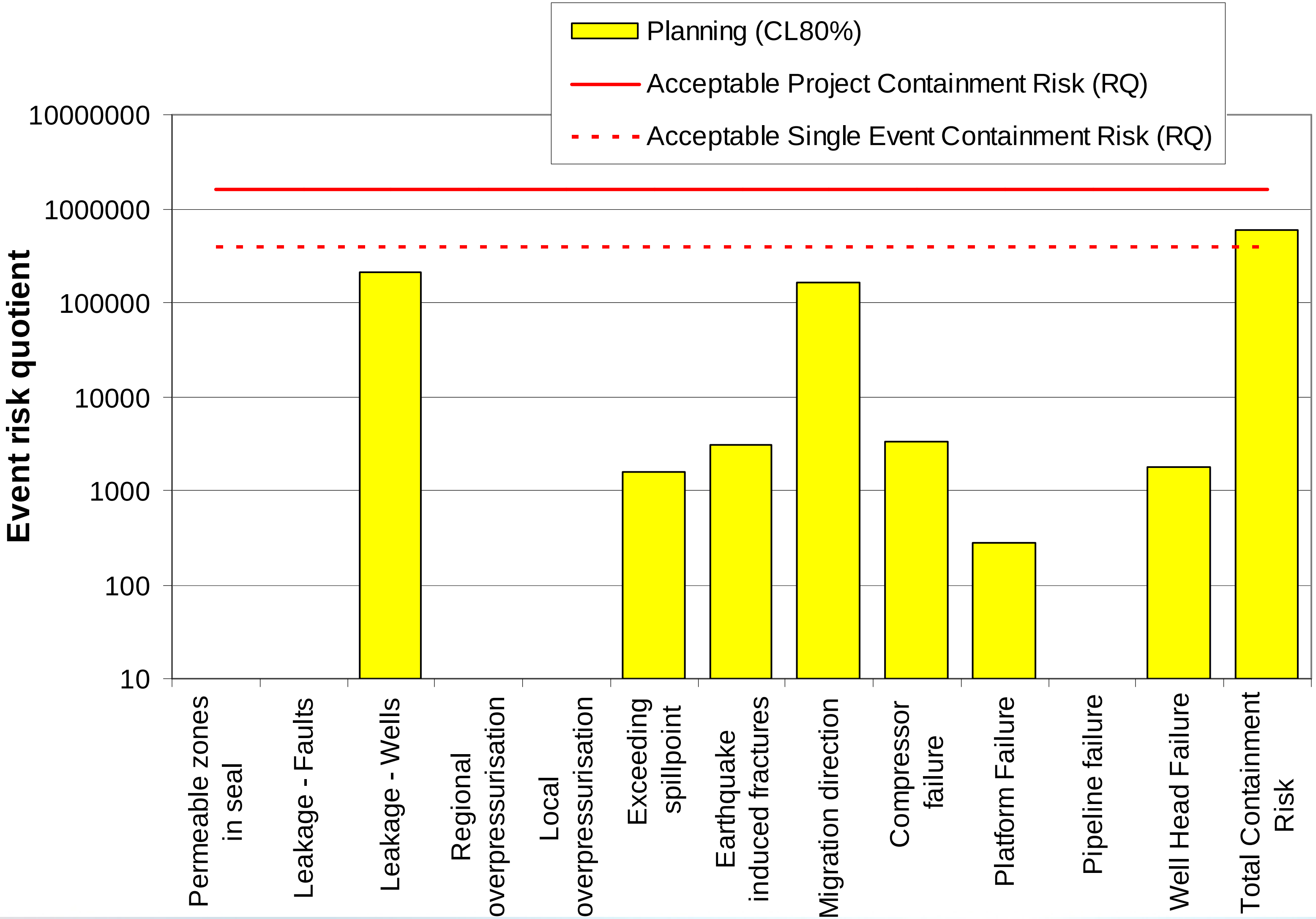
- **The following risk events could potentially affect containment:**
  - leakage via permeable zones in seal,
  - leakage via faults,
  - leakage via wells,
  - regional scale over-pressurisation,
  - local scale over-pressurisation,
  - exceeding spillpoint,
  - earthquake,
  - misidentification of migration direction,
  - well-head failure, pipeline failure, compressor failure, and platform failure.

Kingfish



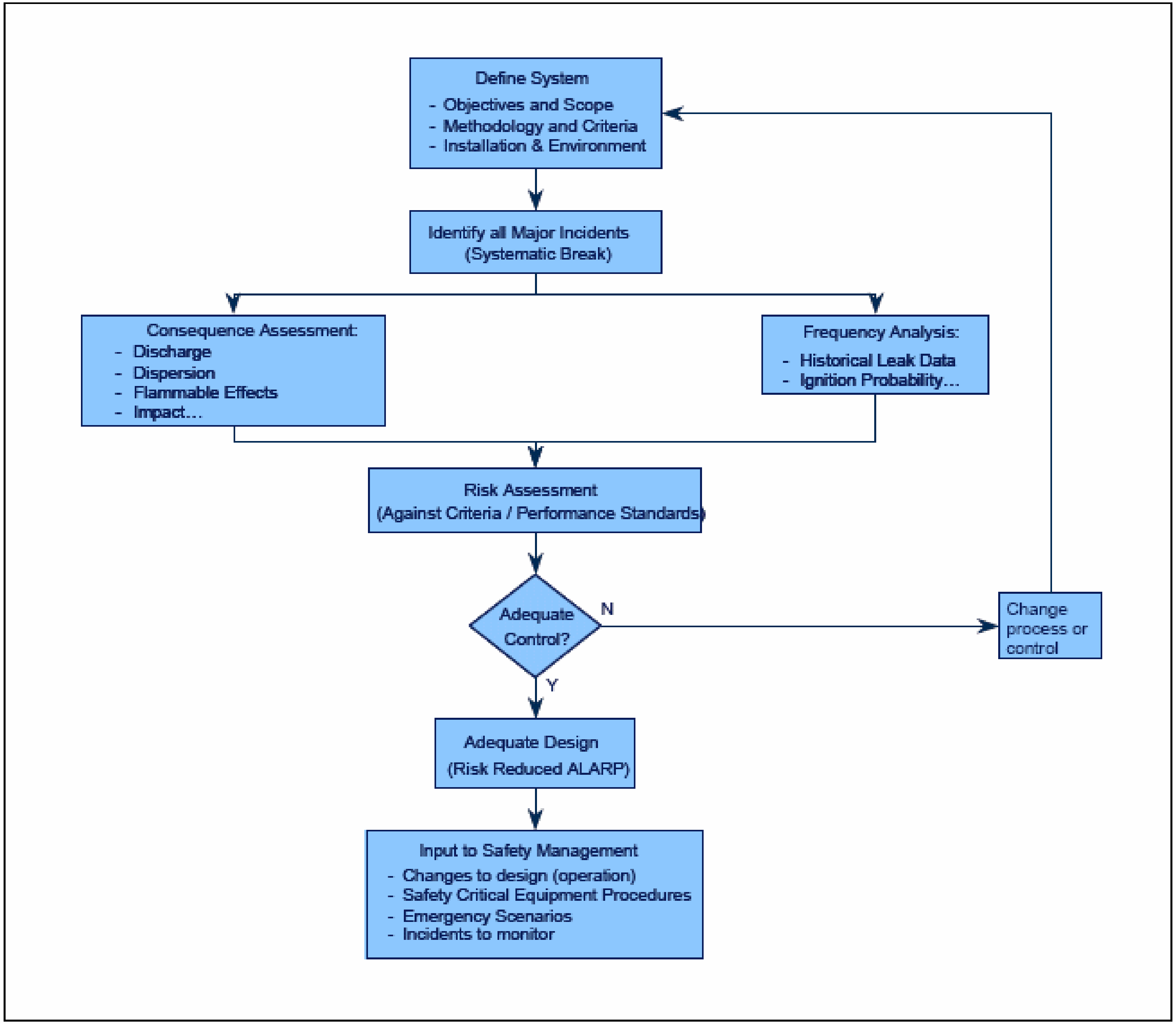
Planning (CL80%)
Acceptable Project Containment Risk (RQ)
Acceptable Single Event Containment Risk (RQ)
Event risk quotient
10000000
1000000
100000
10000
1000
100
10
Permeable zones in seal
Leakage - Faults
Leakage - Wells
Regional overpressurisation
Local overpressurisation
Exceeding spillpoint
Earthquake induced fractures
Migration direction
Compressor failure
Platform Failure
Pipeline failure
Well Head Failure
Total Containment Risk

Basin Centre



Infrastructure Risk

Figure 2-1 The QRA Process



Define System
- Objectives and Scope
- Methodology and Criteria
- Installation & Environment

Identify all Major Incidents (Systematic Break)

Consequence Assessment:
- Discharge
- Dispersion
- Flammable Effects
- Impact…

Frequency Analysis:
- Historical Leak Data
- Ignition Probability…

Risk Assessment (Against Criteria / Performance Standards)

Adequate Control?

N

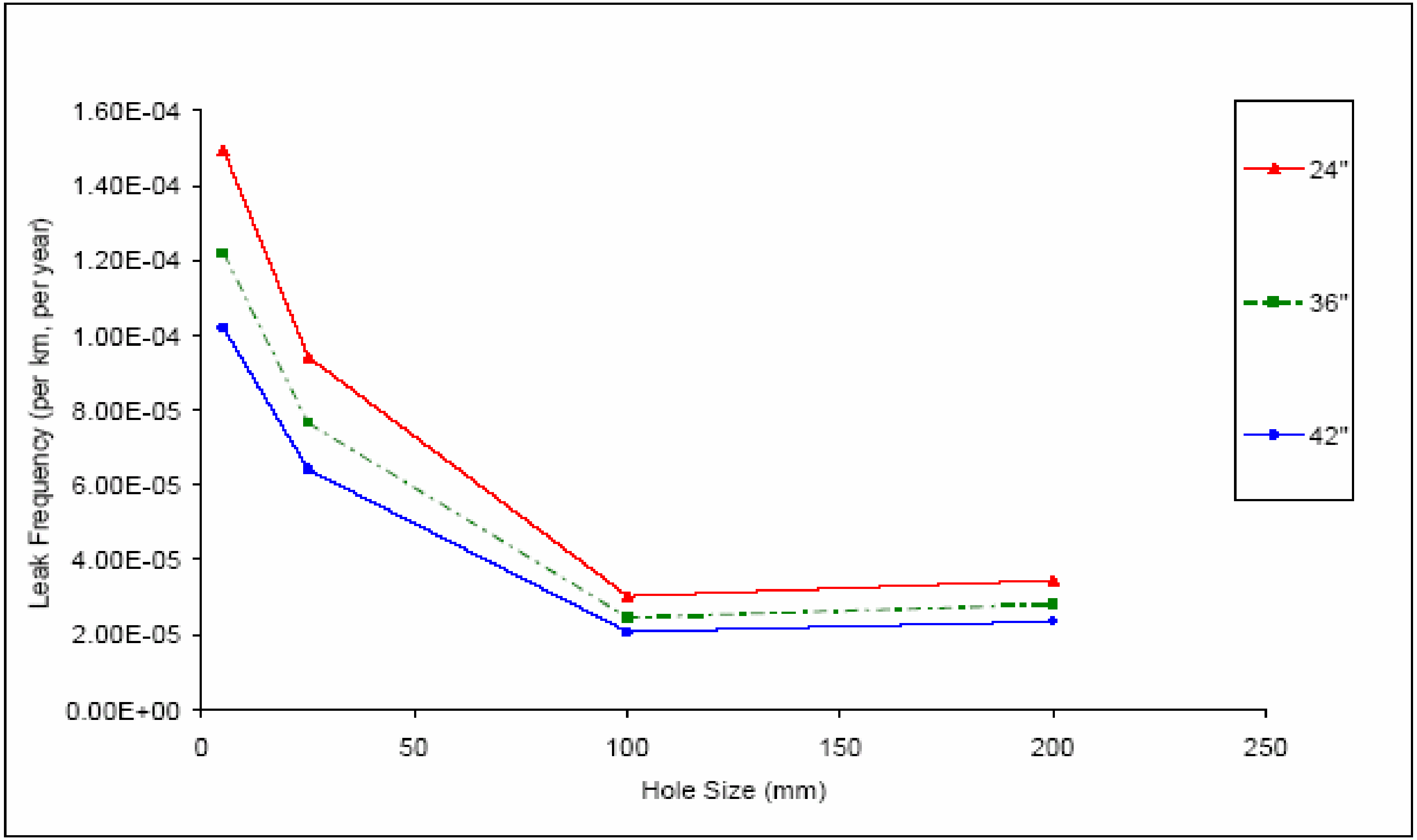
Change process or control

Y

Adequate Design (Risk Reduced ALARP)

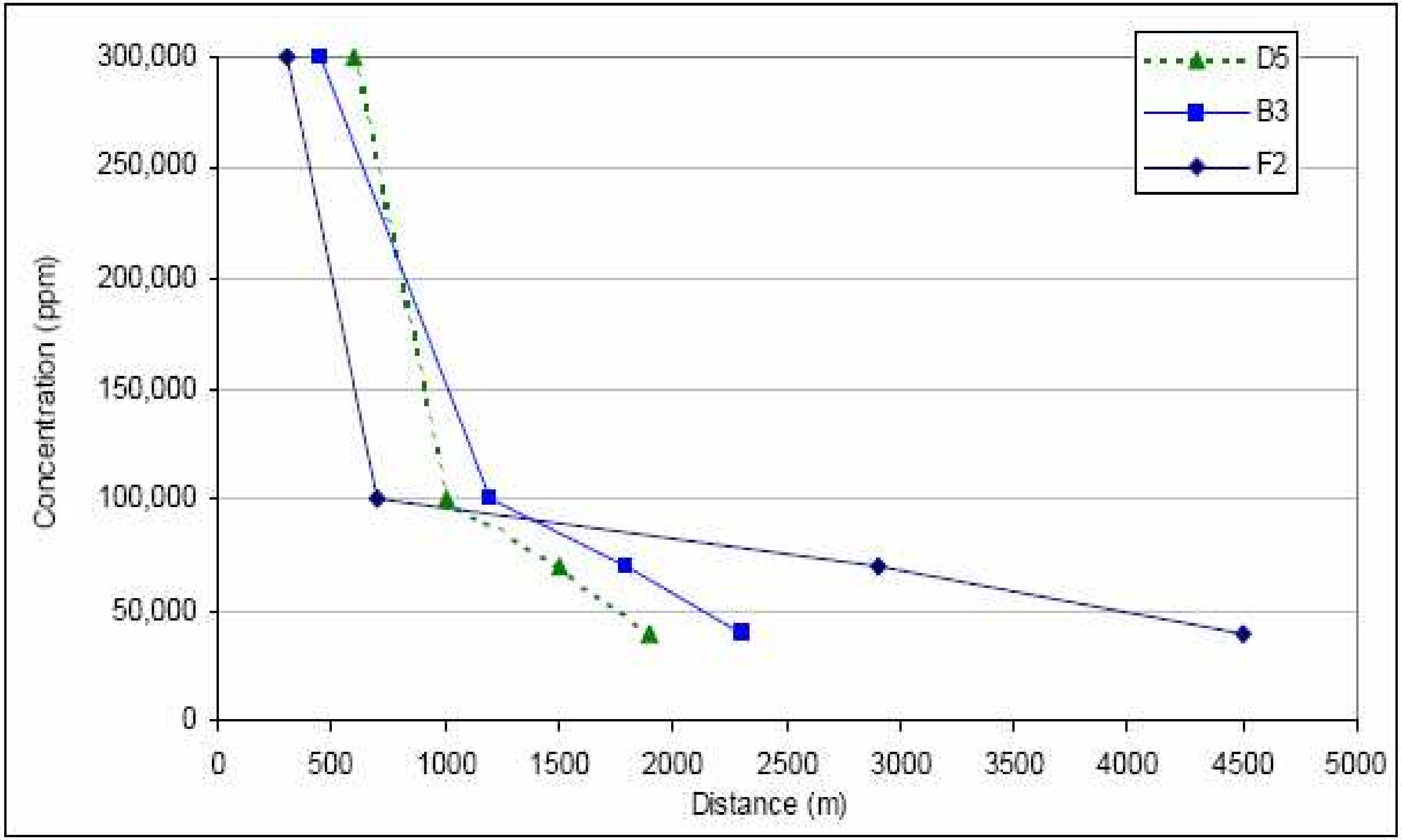
Input to Safety Management
- Changes to design (operation)
- Safety Critical Equipment Procedures
- Emergency Scenarios
- Incidents to monitor

Frequency Analysis

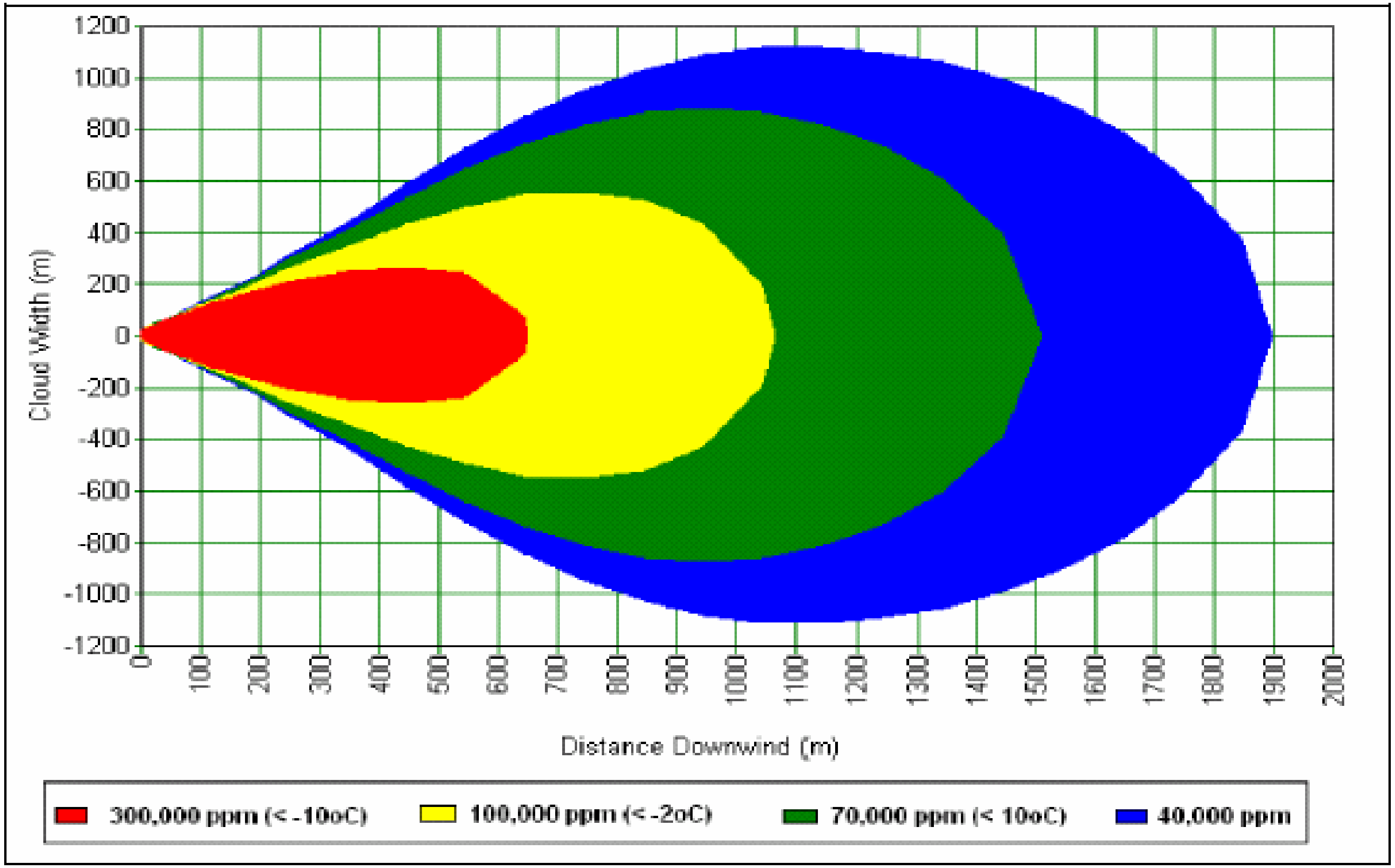


Consequence Analysis

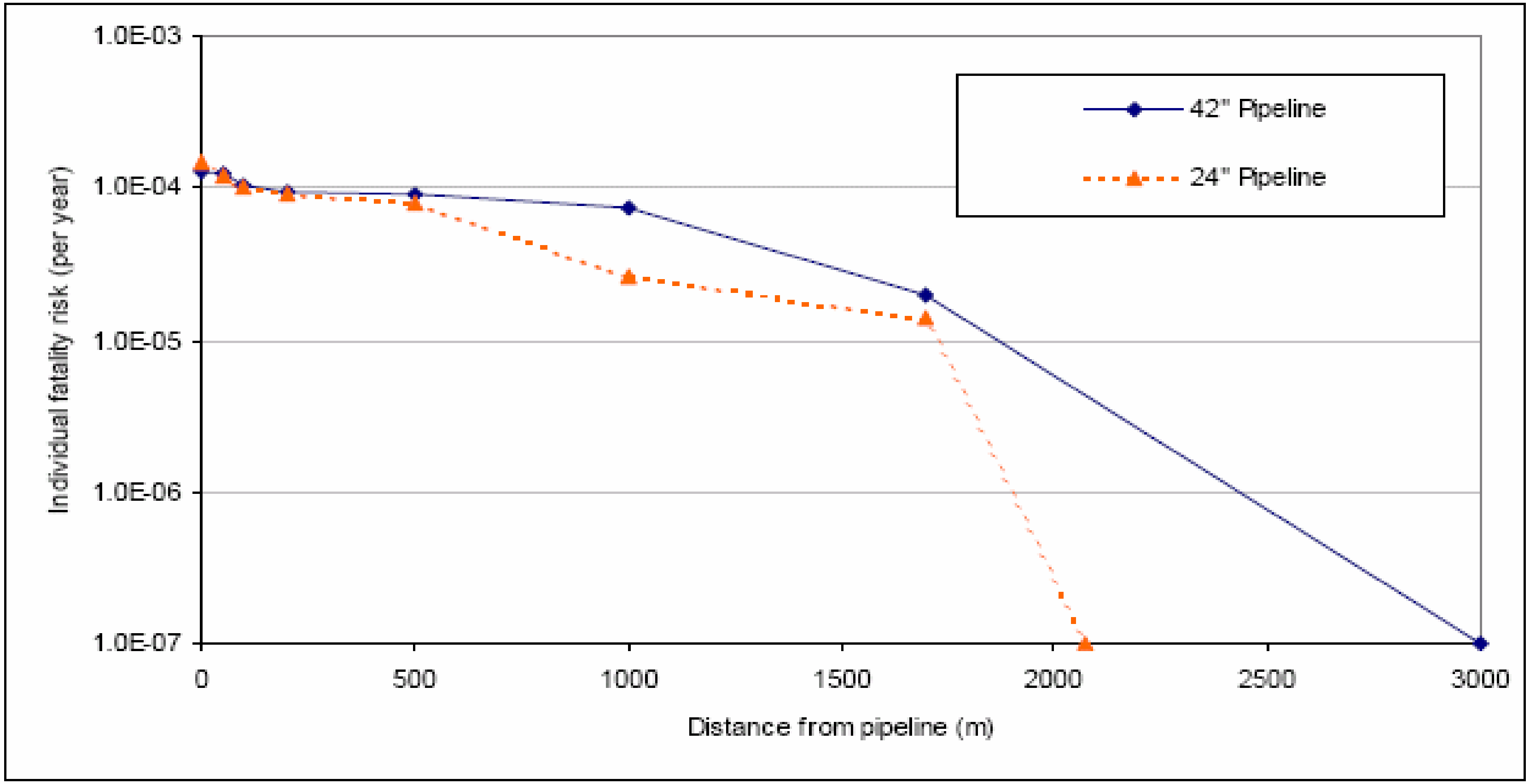
Downwind Dispersion Distances for Three Pasquil Atmospheric Stability Classes



Plume Calculations



Risk Analysis



Infrastructure Risk Findings

- Demonstrated infrastructure risk for major CCS installation
- Installation poses no greater risk than similar pipeline facilities currently in operation in Australia
- All risks are considered manageable with conventional pipeline safety and mitigation methods incorporated into the design
- Examined the sensitivity of several pipeline parameters
  - Pressure
  - Impurities

Conclusions

- The findings from the project indicate that:
  - the existing oil and gas fields could store more than two billion tonnes of CO2 once depleted;
  - the regional seal rock is of good quality to store CO2;
  - the geology, chemistry and hydrology are favourable for CO2 storage;
  - CO2 will migrate very slowly through the reservoir rock over tens to hundreds of years;
  - the unit cost of storage is low by world standards;
  - risks are low and can be readily managed by proponents; and
  - the targeted offshore injection sites are favourable for geosequestration.

Thank you

I’d be pleased to take questions

Increased Interest in Environmental Impacts of Amines

Gelein de Koeijer

9th IEA GHG International CO_2 Capture Network

Copenhagen, 16-6-2006

STATOIL

Reasons for increased interest

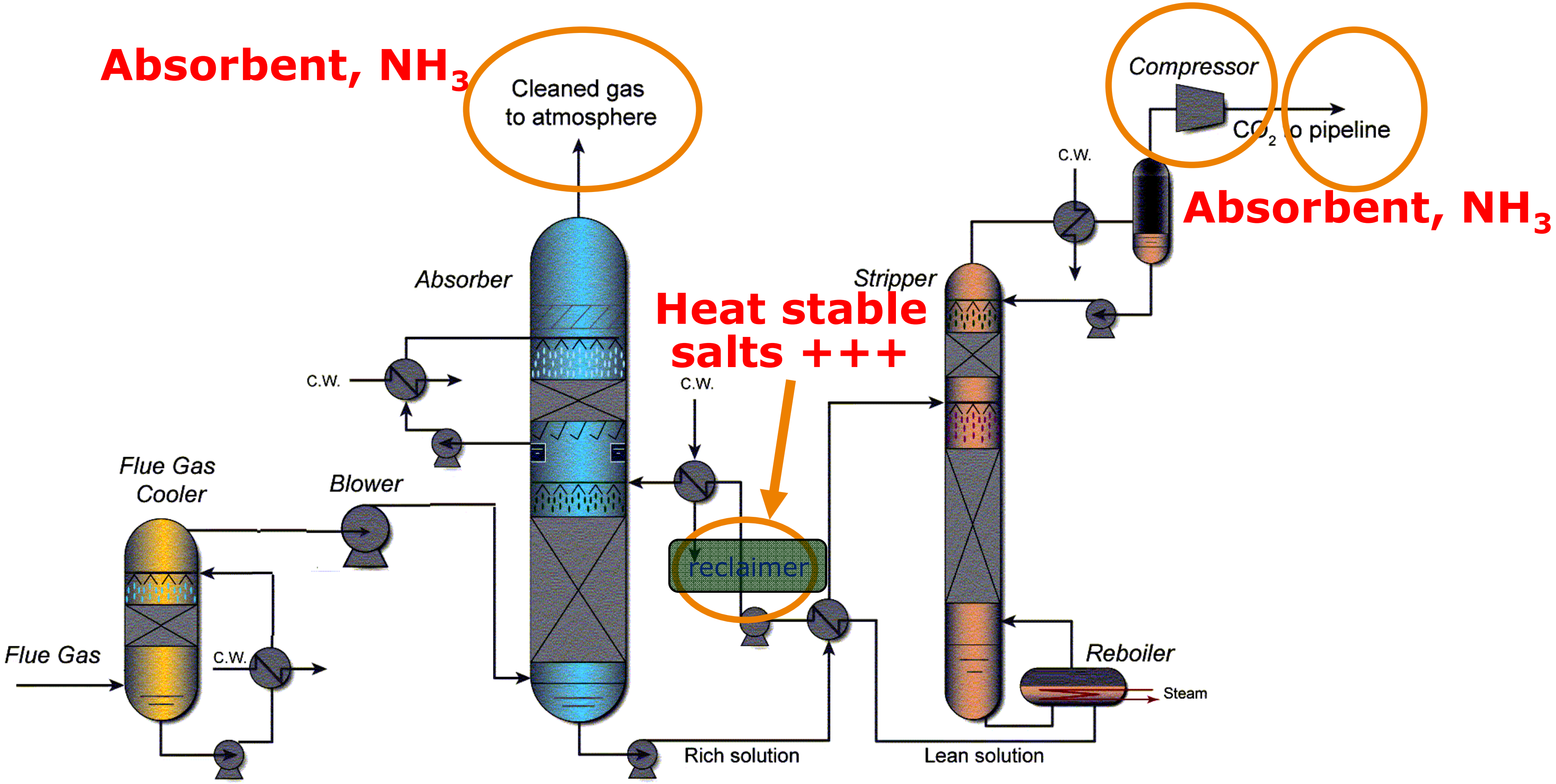
- Norwegian pollution control authorities required Statoil to give an assessment on possible substitutes for MDEA at the Snøhvit CO_2 capture site[1]

- Statoil and Shell are assessing the possibilities for building a CO_2 capture plant at Tjeldbergodden (Norway)

- Statoil's aim to produce oil & gas with zero harmful emissions

[1] http://www.sft.no/nyheter/brev/snohvit_klager_md230505.htm

Emissions from CO_2 capture plants



Absorbent, NH_3

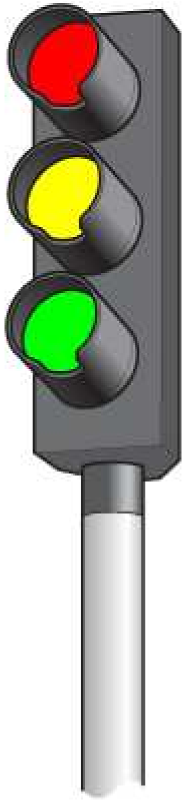
Absorbent, NH_3

Heat stable salts +++

Source figure: SINTEF

Classification chemicals offshore Norway

	Classification
Water	Green
Chemicals on PLONOR list	Green
Hormone disturbing chemicals	Black
List over prioritised chemicals that are contained in ”resultatmål 1 (prioritetslisten) St.meld. nr 25 (2002-2003)”	Black
Biodegradibility < 20 % and log Pow ≥ 5	Black
Biodegradibility < 20 % and toxicity EC50 or LC50 ≤ 10 mg/l	Black
Two out of three categories: Biodegradability < 60 % log Pow ≥ 3, lEC50 or LC50 ≤ 10 mg/l	Red
Inorganic and EC50 or LC50 ≤ 1 mg/l	Red
Biodegradability < 20 %	Red
Other chemicals	Yellow



Translated from Miljørapport 2004 Oljeindustriens Landsforening, http://www.olf.no/miljo/miljorapporter/?27220.pdf

Amine based absorbents: general behaviour

Red:

Most tertiary amines (e.g. MDEA)

Some common activators (e.g. Piperazine, AEEA)

Some foam and corrosion inhibitors

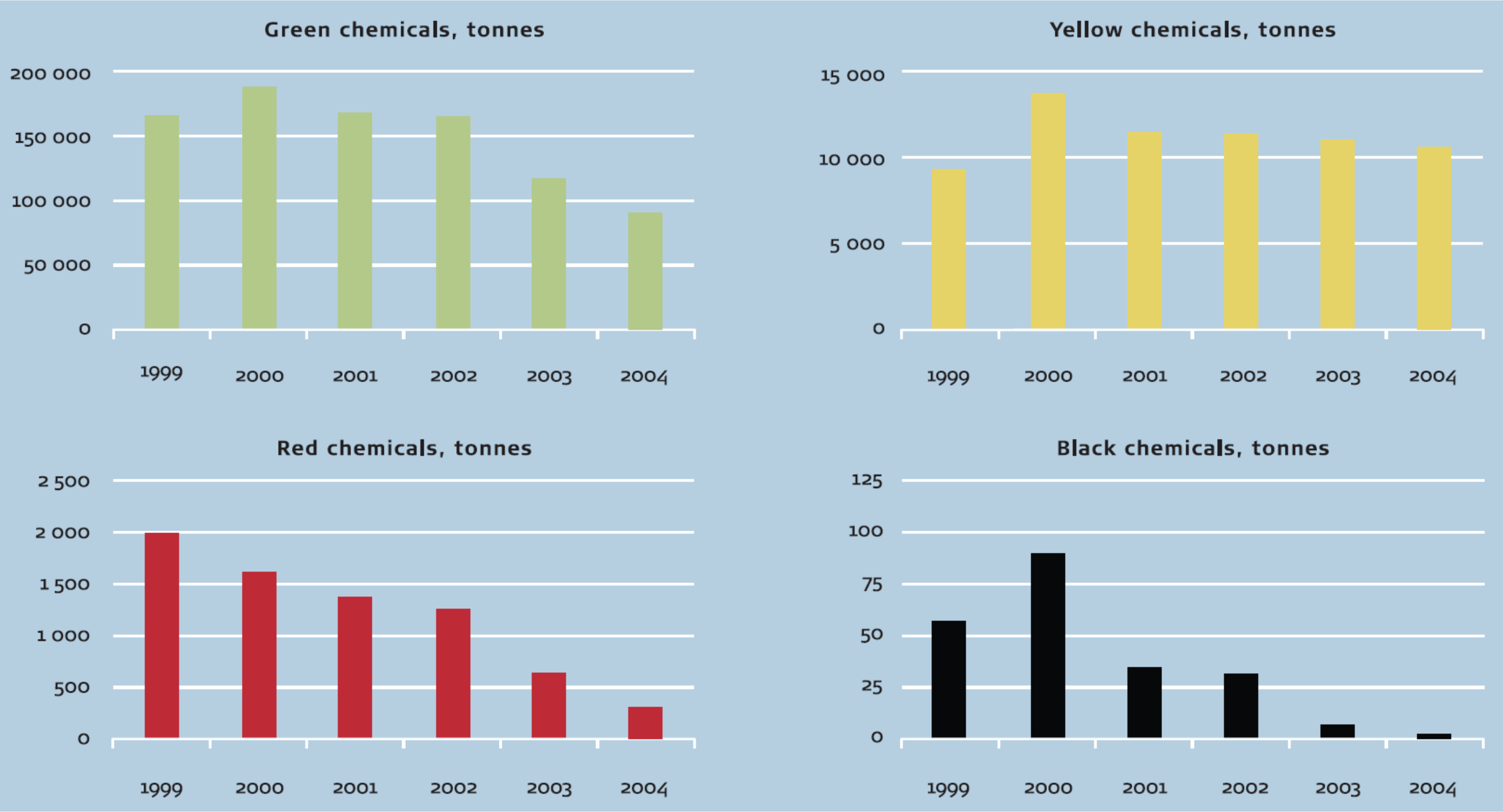
Yellow:

Most primary and secondary amines (e.g. MEA)

Some sterically hindered amines (e.g. Flexsorb)

Some foam and corrosion inhibitors

Historic emissions



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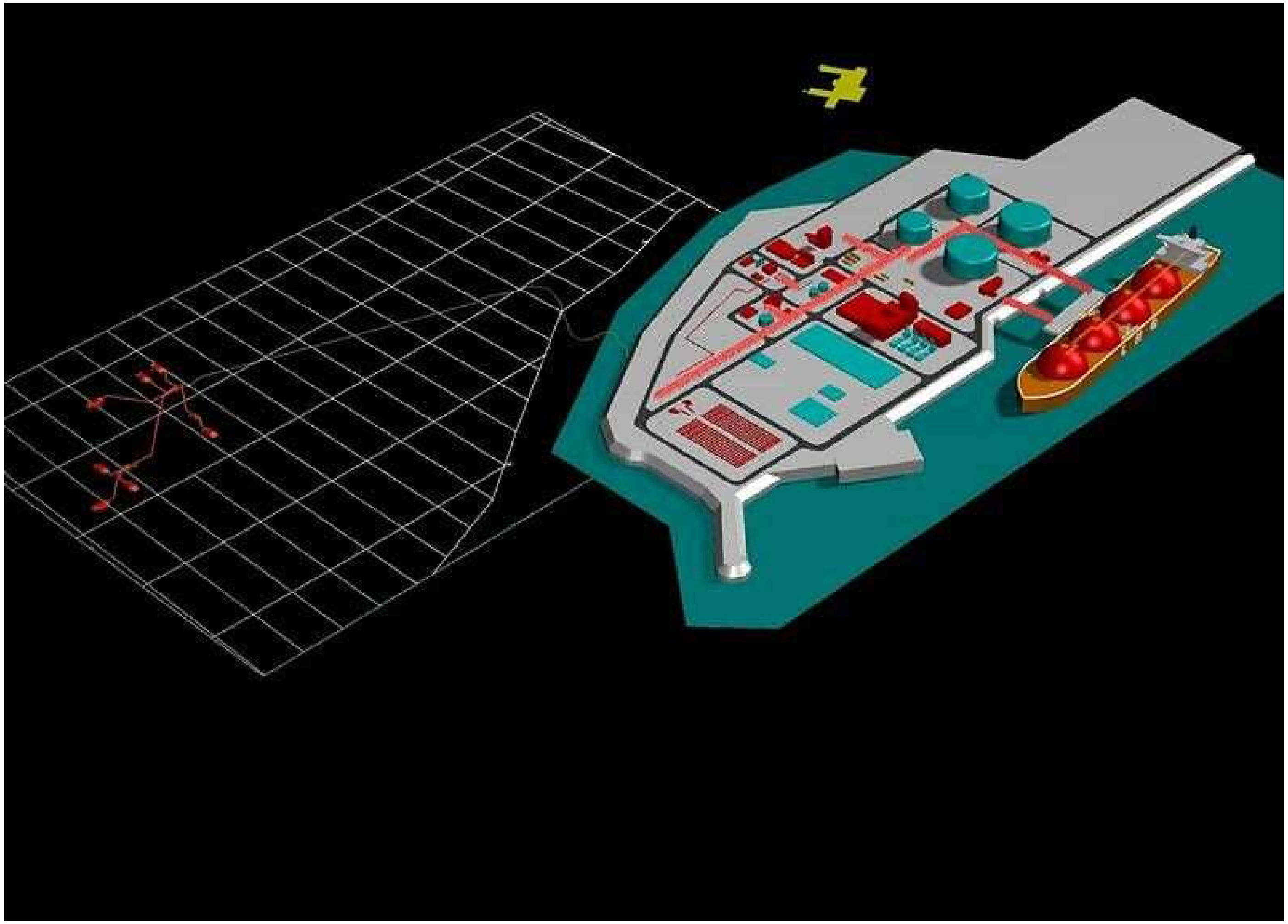
Uncertainties

- Are the current classifications based on the latest results and correct test method?
- Are all aspects of bio-degradibility and eco-toxicity taken into account in the classification tests?
- Are all emissions fairly assessed?
- Are the classification tests valid for the specific site?

Answer: Integrated HSE tools

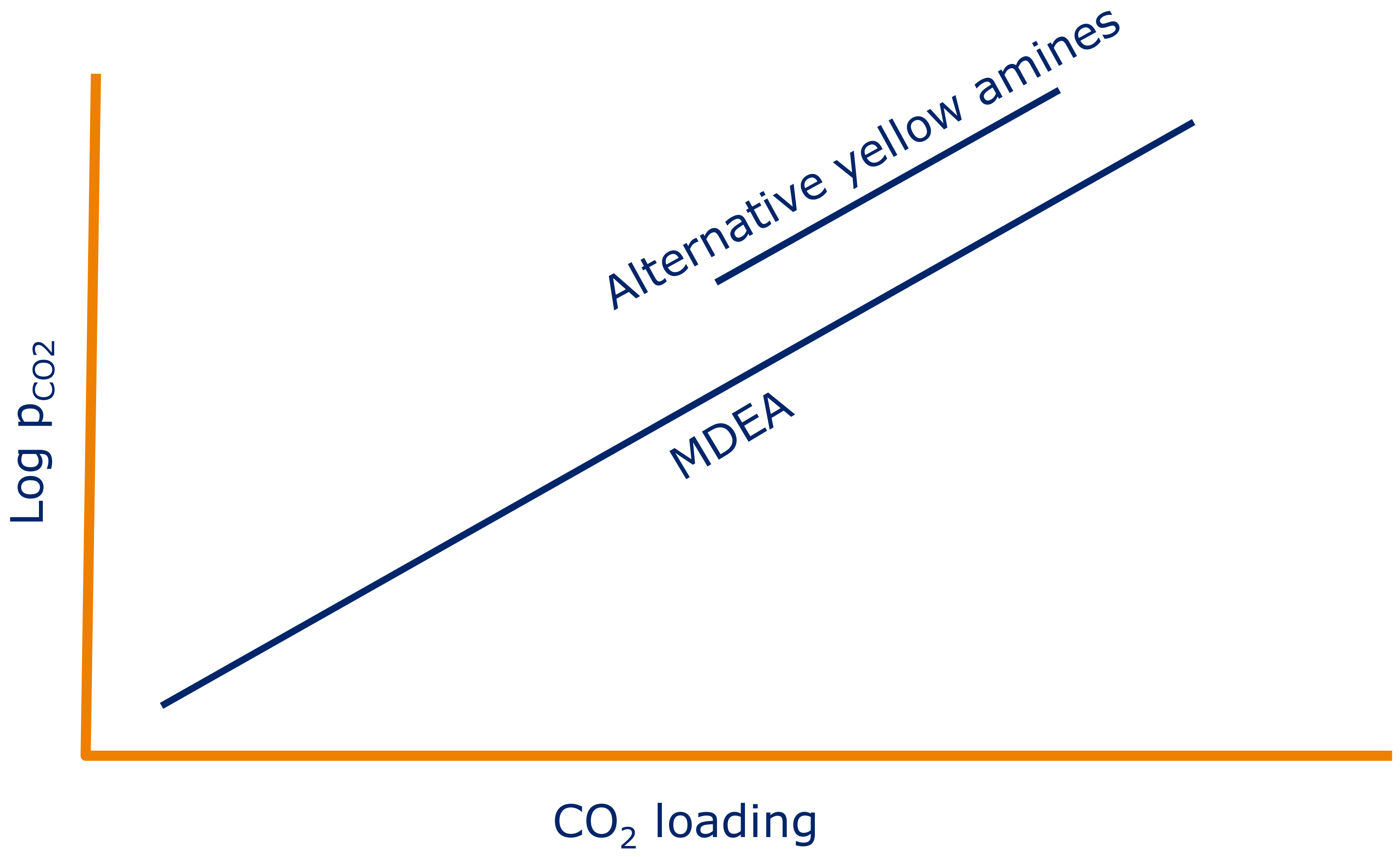
Snøhvit LNG



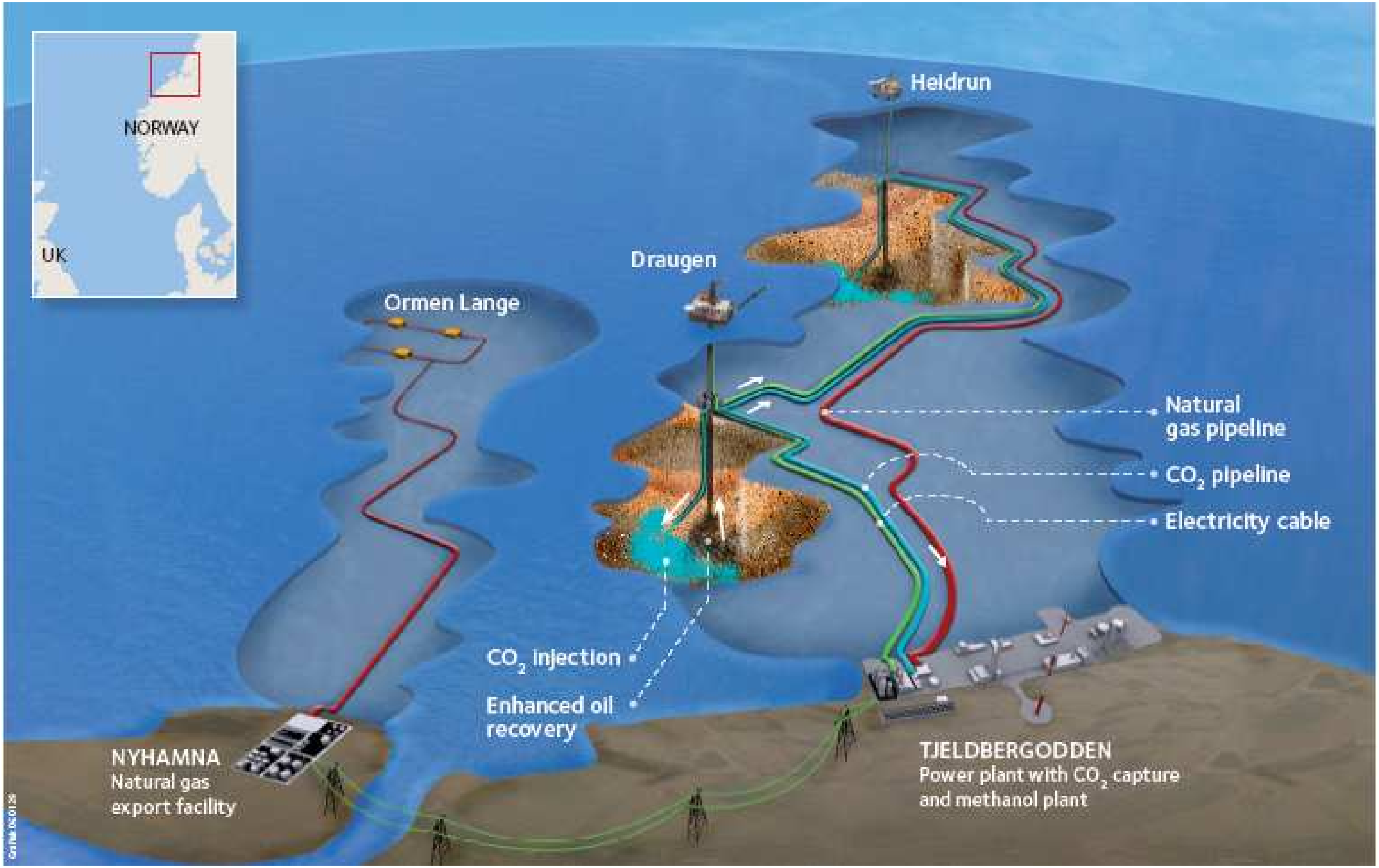
Assessing alternatives to MDEA

- Maximum loading of MDEA and alternative yellow amines
- Kinetics of MDEA and and alternative yellow amines
- Environmental tests of alternative yellow amines
- Test alternative yellow foam inhibitors

Preliminary results: MDEA vs alternatives



An industrial model for a CO_2 value chain in Norway



Summary

- Knowledge on environmental aspects of CO_2 capture with amines is increasing at authorities

- Stricter requirements on environmental aspects for operators and suppliers

- Legislation is becoming clearer

- Statoil R&D will increase activity on environmental aspects of CO_2 capture with amines

- Integrated HSE tools are needed, and under development

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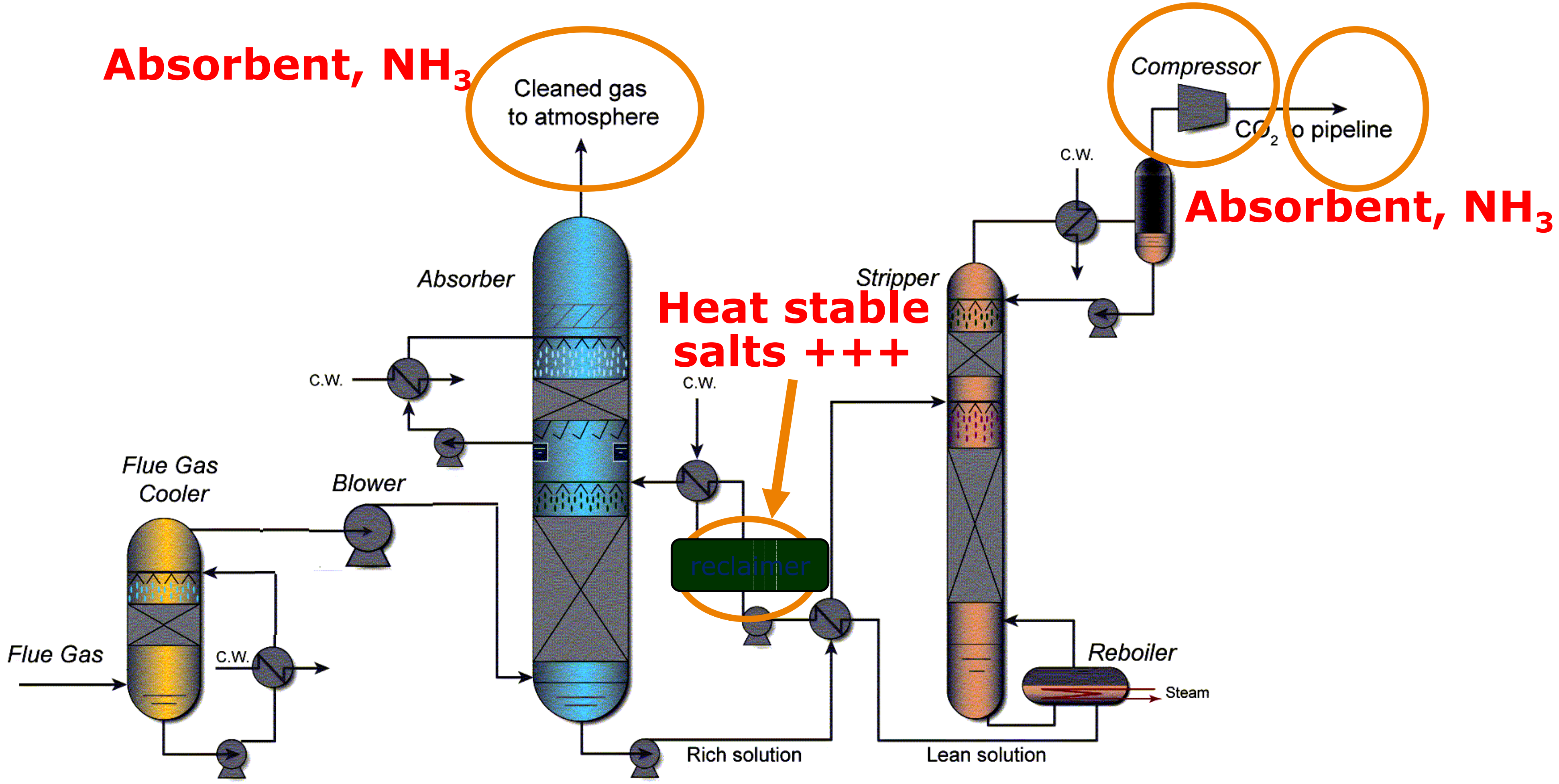

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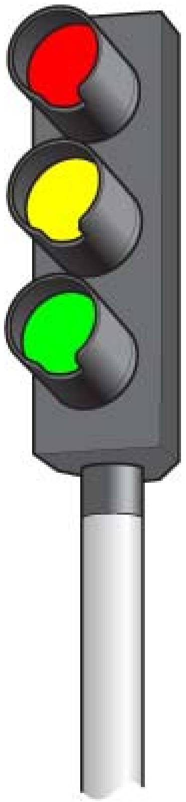

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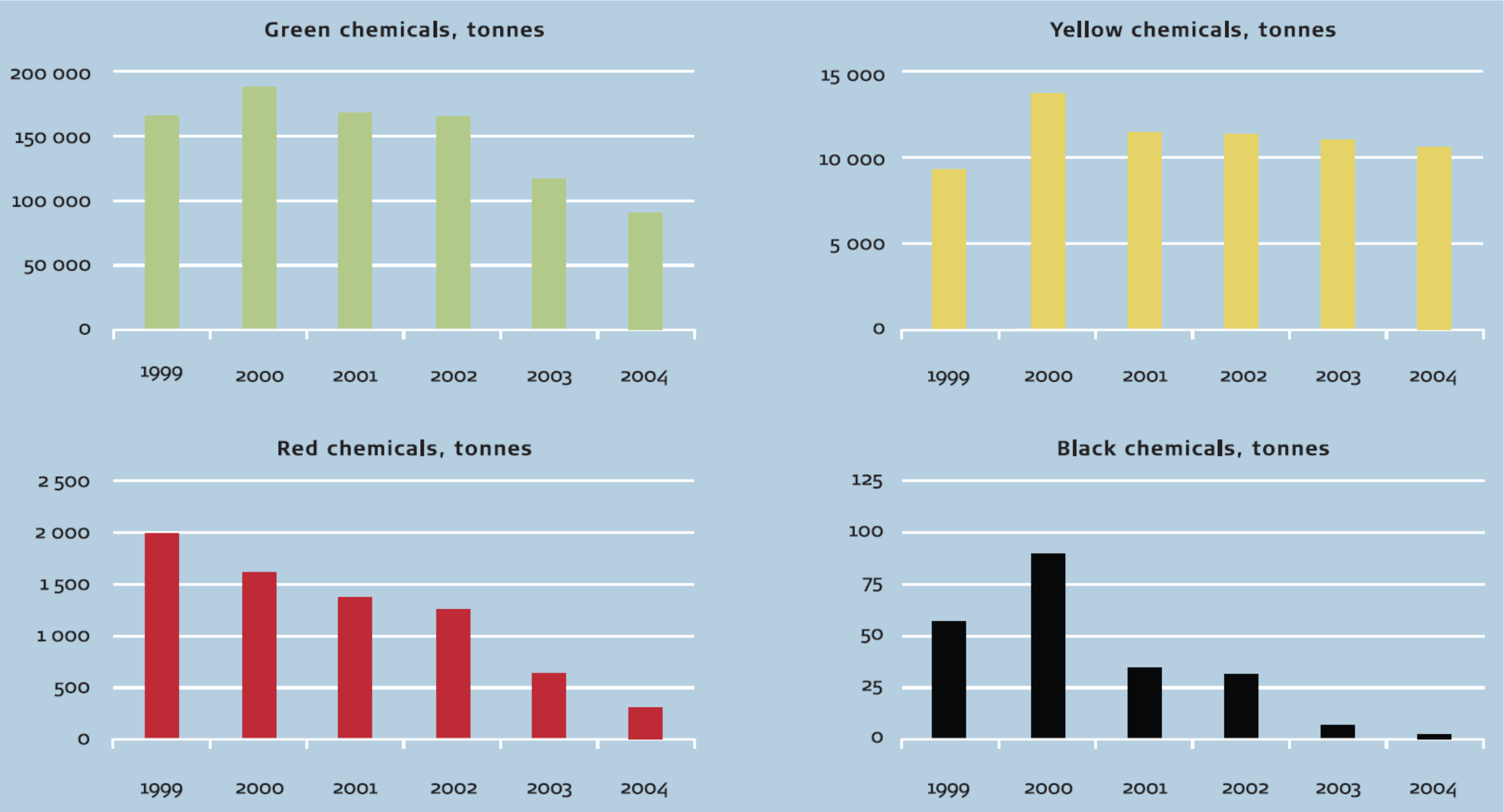

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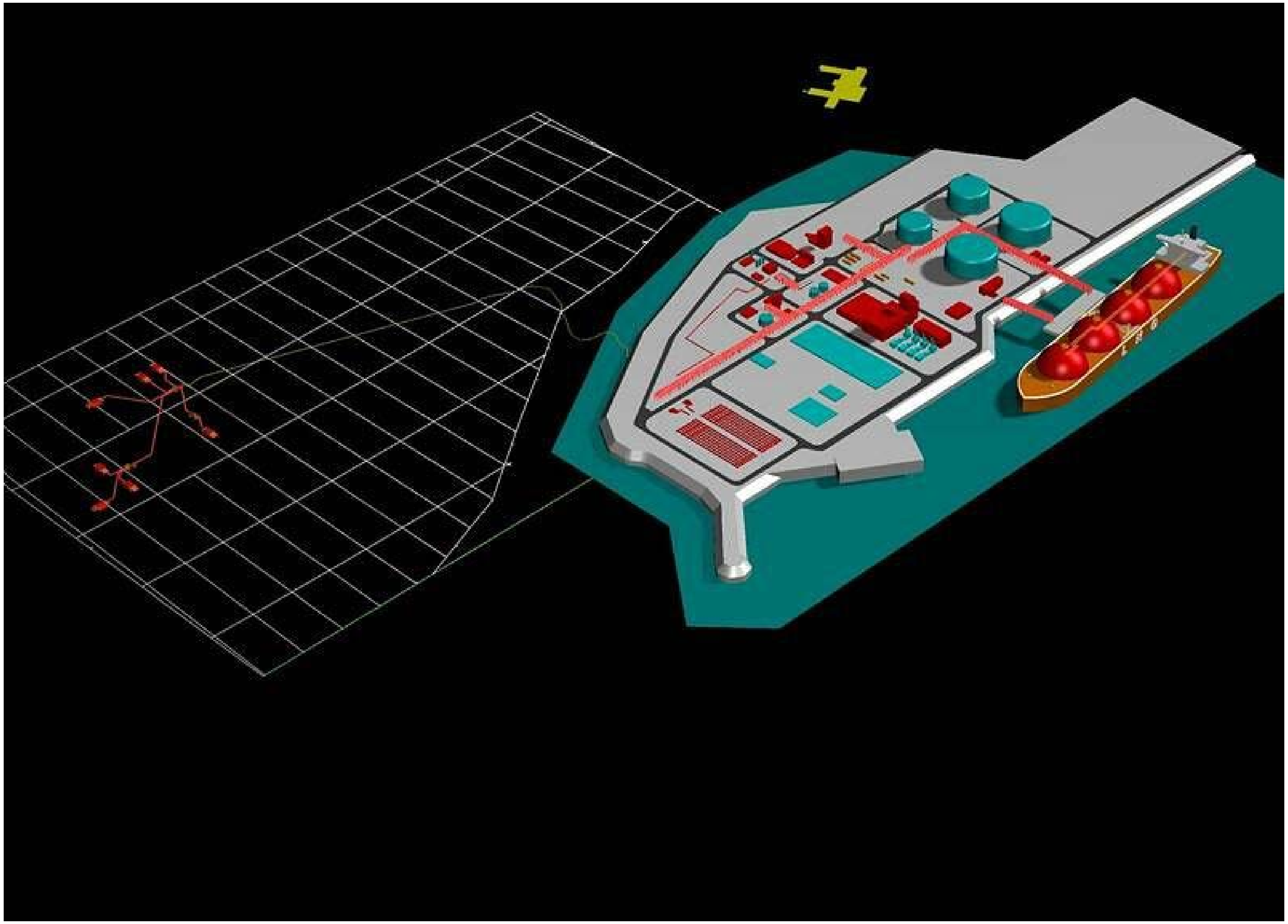

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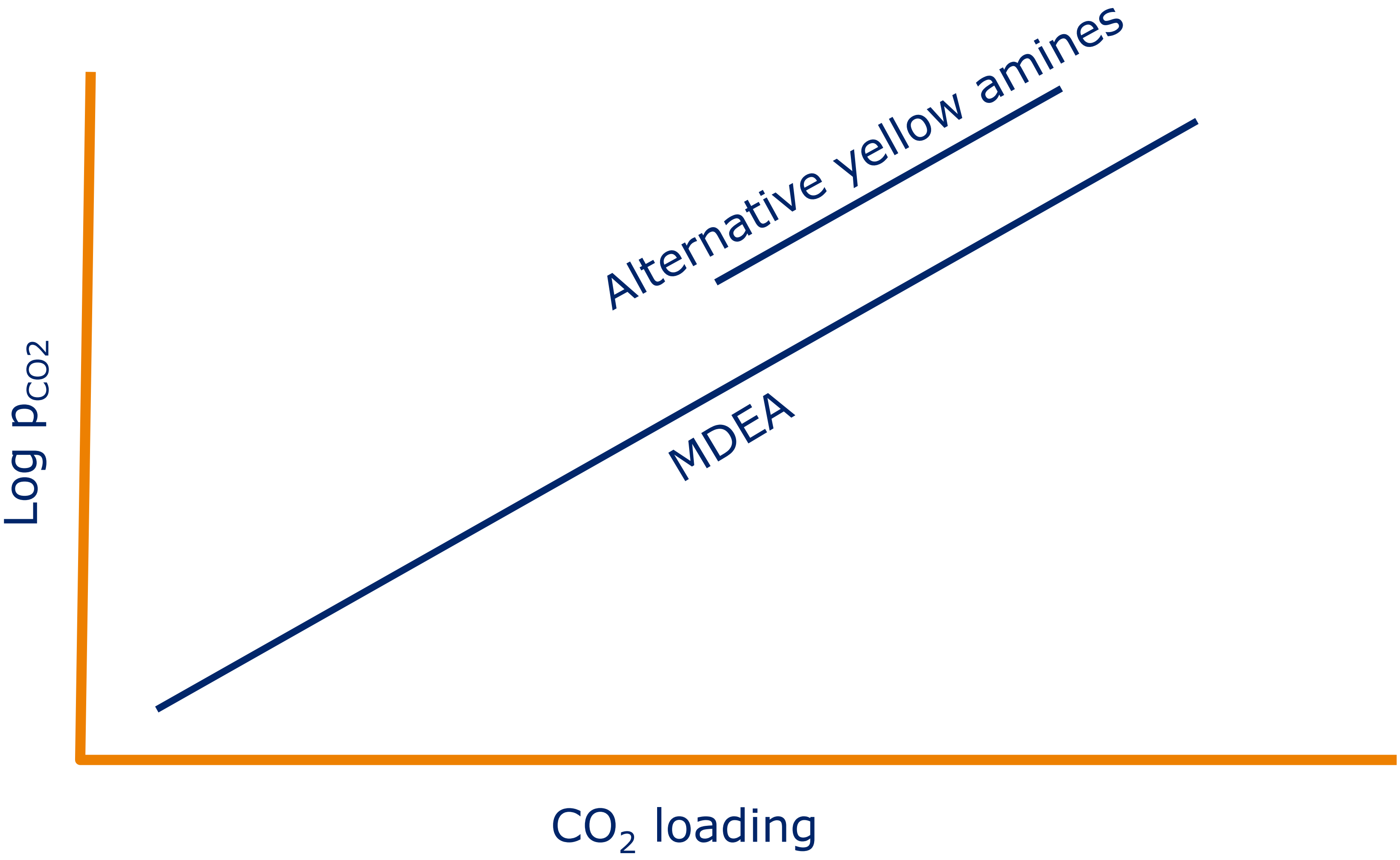

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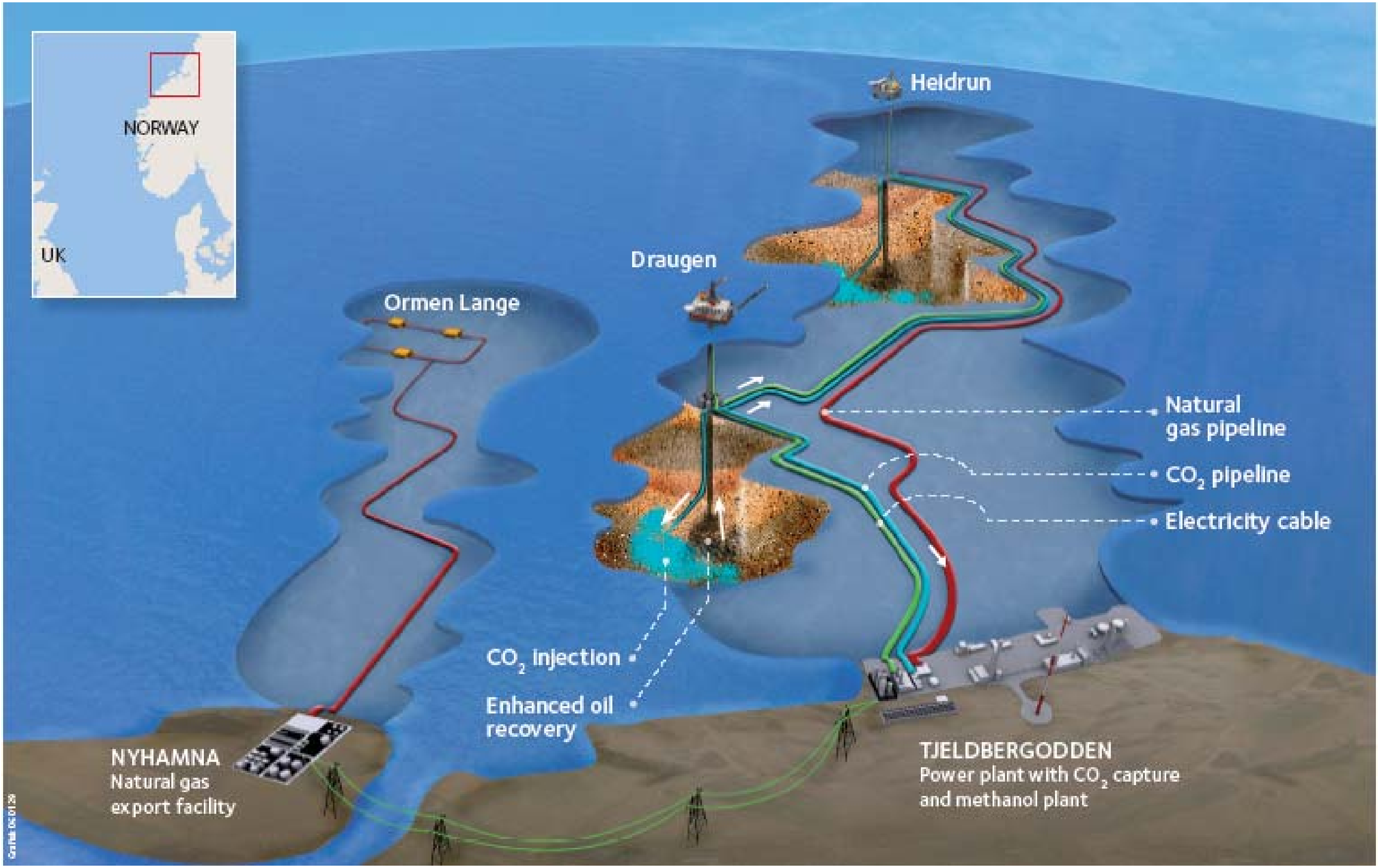

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- Integrated HSE tools are needed, and under development

Overview of activities in CASTOR, ENCAP, CATO and Dynamis at TNO

TNO | Knowledge for business

TNO Science & Industry
Department of separation technology
e-mail: Nick.tenAsbroek@tno.nl
Internet: www.tno.nl

Overview

Post-combustion related activities:

- MGA Developments in CASTOR/CATO
- Post combustion CO_2 capture in EU-Dynamis
- Caprice
- Construction of hybrid-pilot in CATO

Chemical Looping Combustion related activities:

- Development of fixed bed CLC reactors in ENCAP and CATO

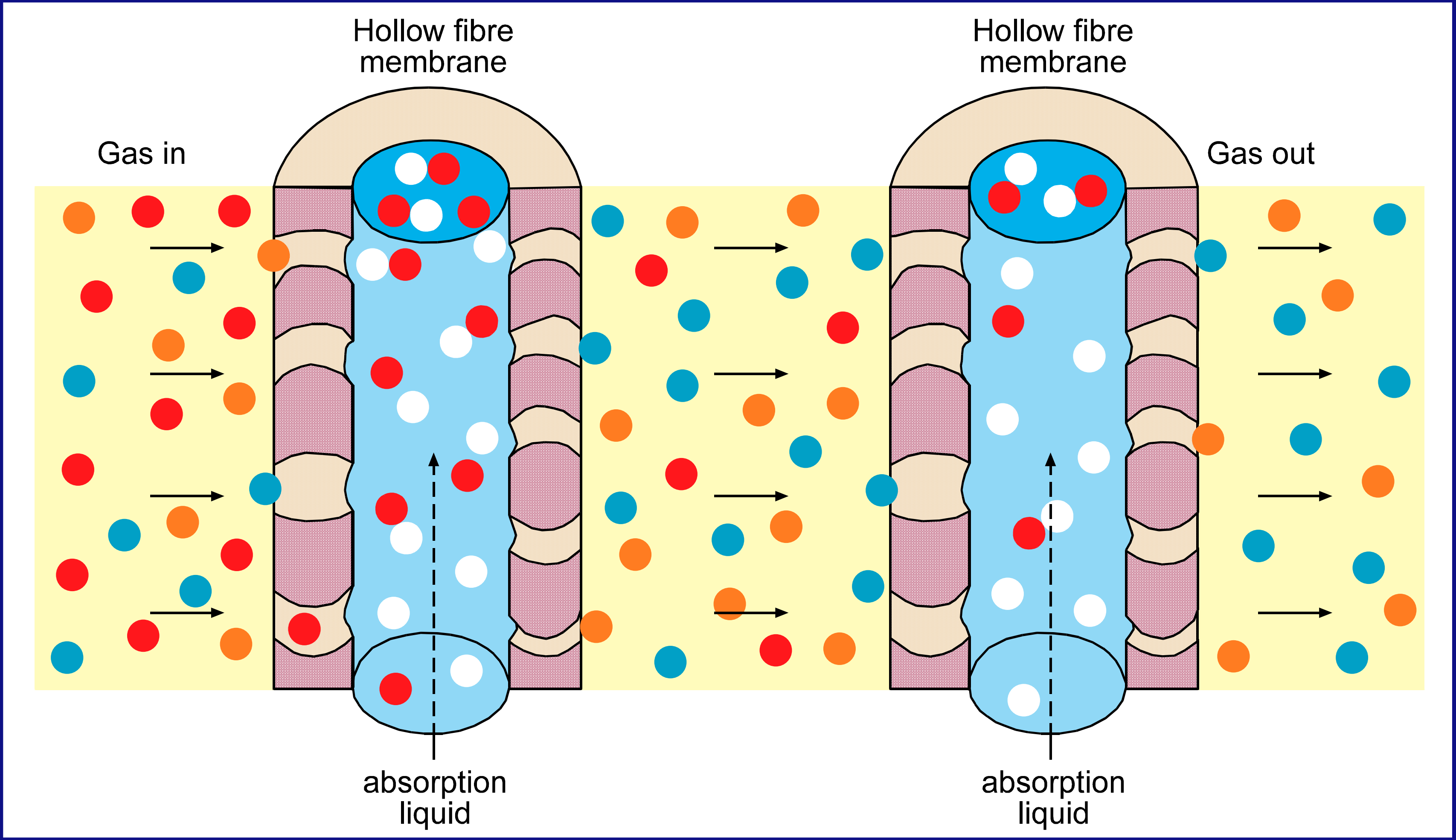
CASTOR

CO_2 CApture and STORage

Main activities

- CO_2-storage, verification and monitoring (TNO NITG)
- Esbjerg pilot plant experimental program (TNO I&T)
- System modelling and economic optimalisation (TNO I&T)
- Development of MGA for absorption/desorption (TNO I&T)
    - Membrane selection (absorption/desorption)
    - MGA contactor development (absorption/desorption)
    - Basic design of absorption MGA installation

Principle CO_2 Membrane Gas Absorption

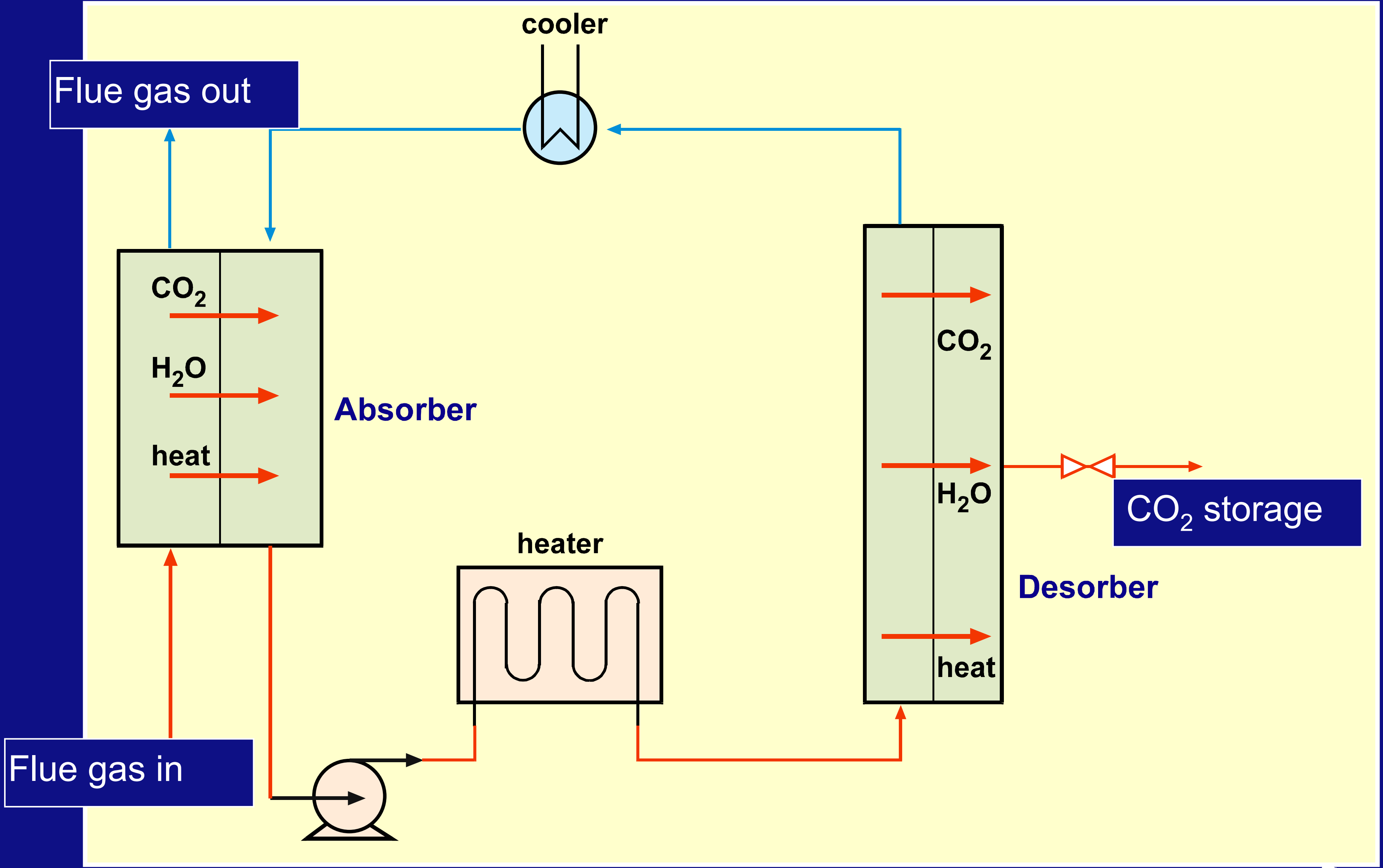


CO_2, present in the flue gas, is selectively absorbed into a proprietary absorption liquid through a porous membrane

Advantages CO_2 MGA

- High selectivity
- Compact equipment
- Independent flow control
- No entrainment, flooding, channelling, foaming
- Not influenced by tilt
- Low liquid pumping power
- Flexibility in scale-up

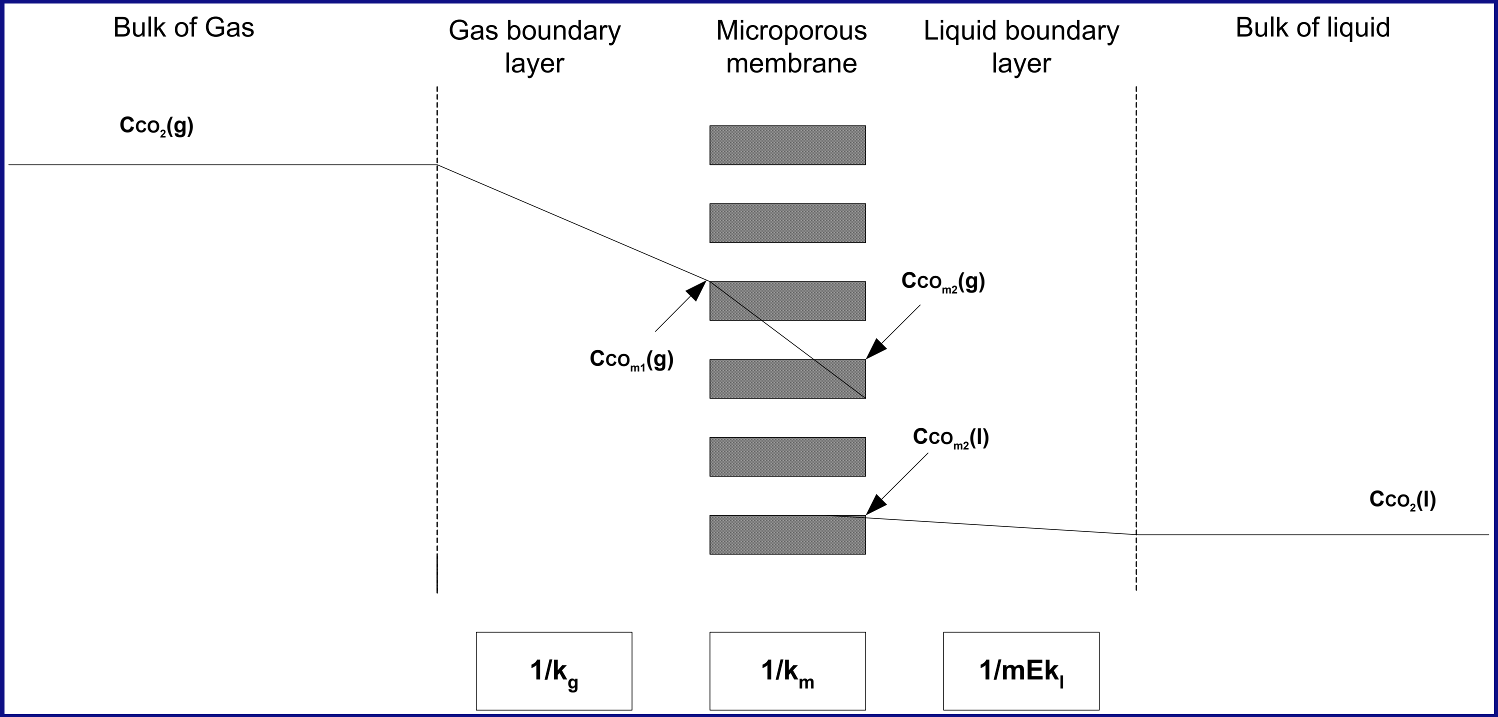
Future - Membrane Gas Absorption/Desorption



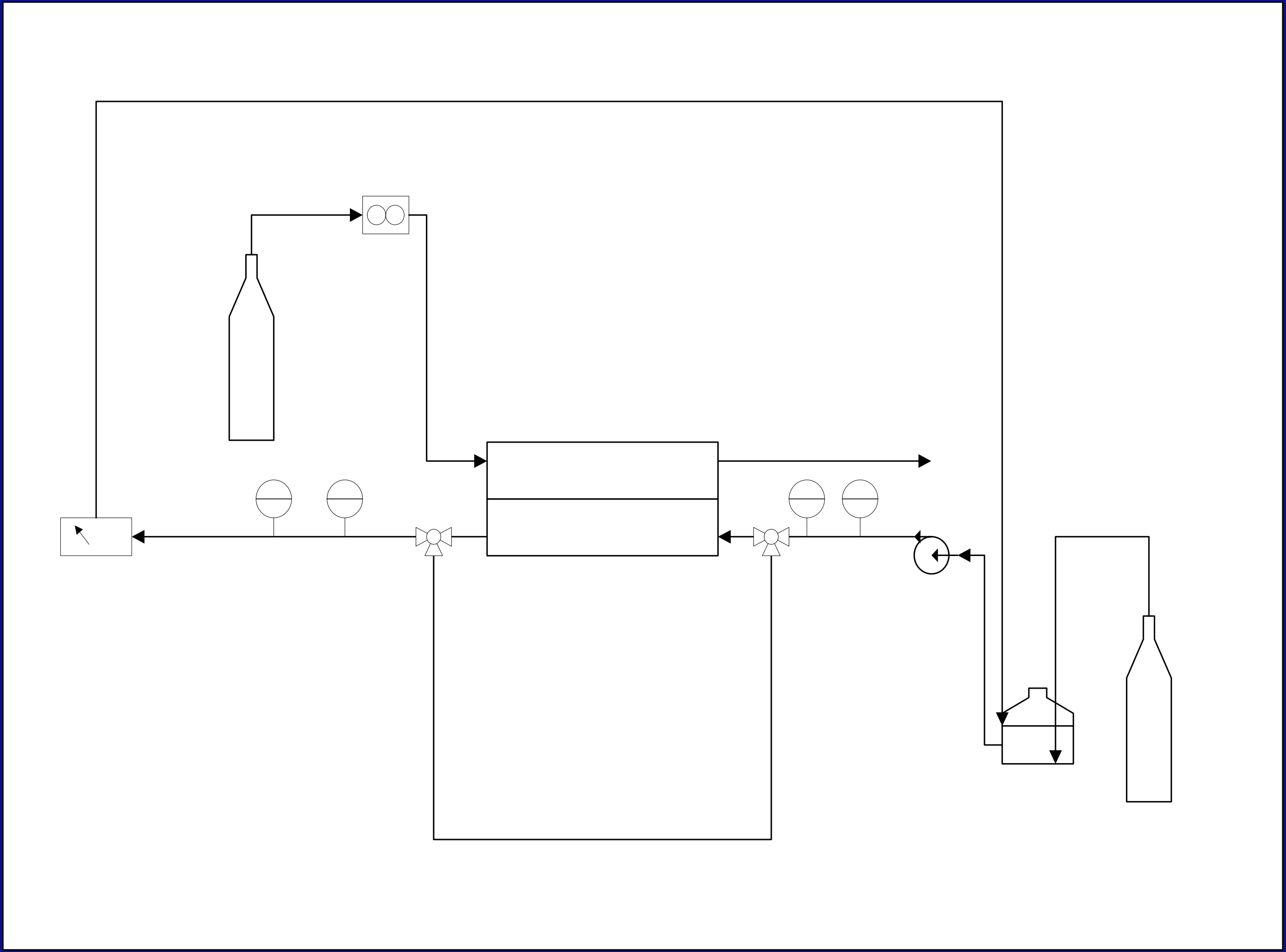
MGA process development

- Breakthrough pressures of membranes with absorption liquids
- Liquid site mass transfer (with spacer)
  - Oxygen desorption tests →kL
- Membrane characterisation
  - SO_2 experiments → km and kg

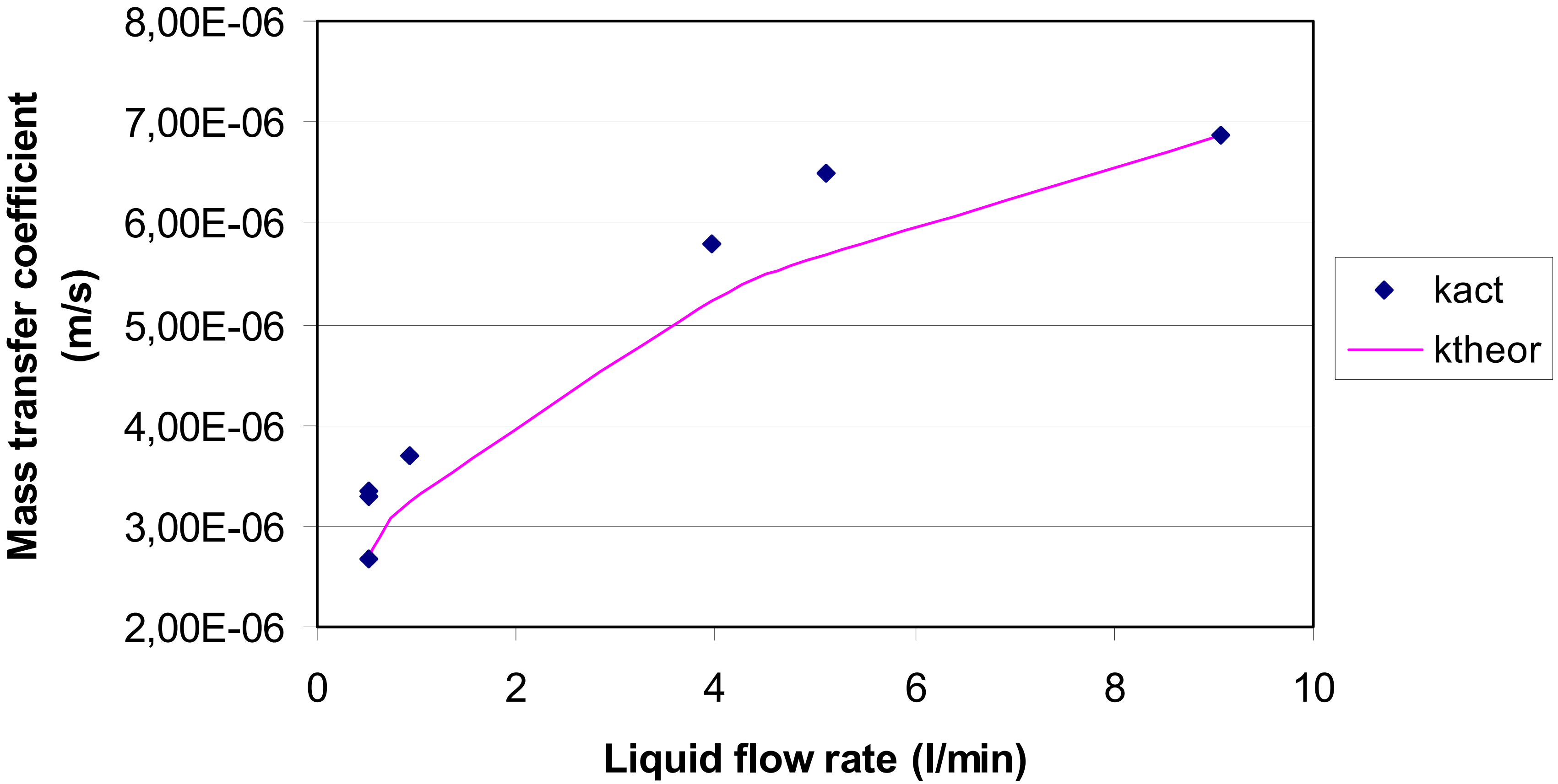
$$\frac{1}{K_{ov}} = \frac{1}{k_{gas}} + \frac{1}{k_{membrane}} + \frac{1}{k_{liquid}}$$



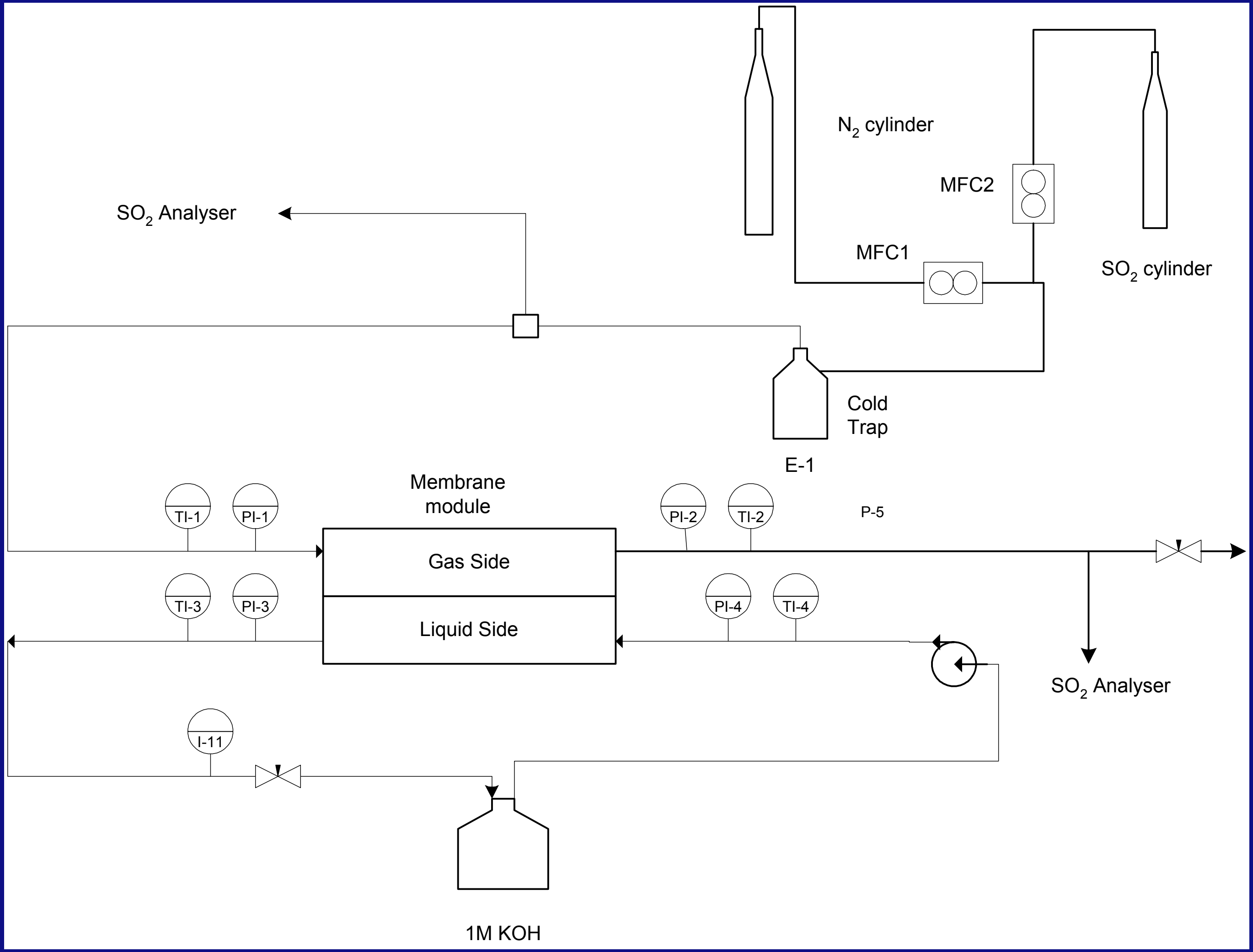
Liquid-side mass transfer of membrane channel (kL) Oxygen-setup



Liquid-side mass transfer of membrane channel (kL)



Gas and membrane mass transfer resistance SO_2-setup



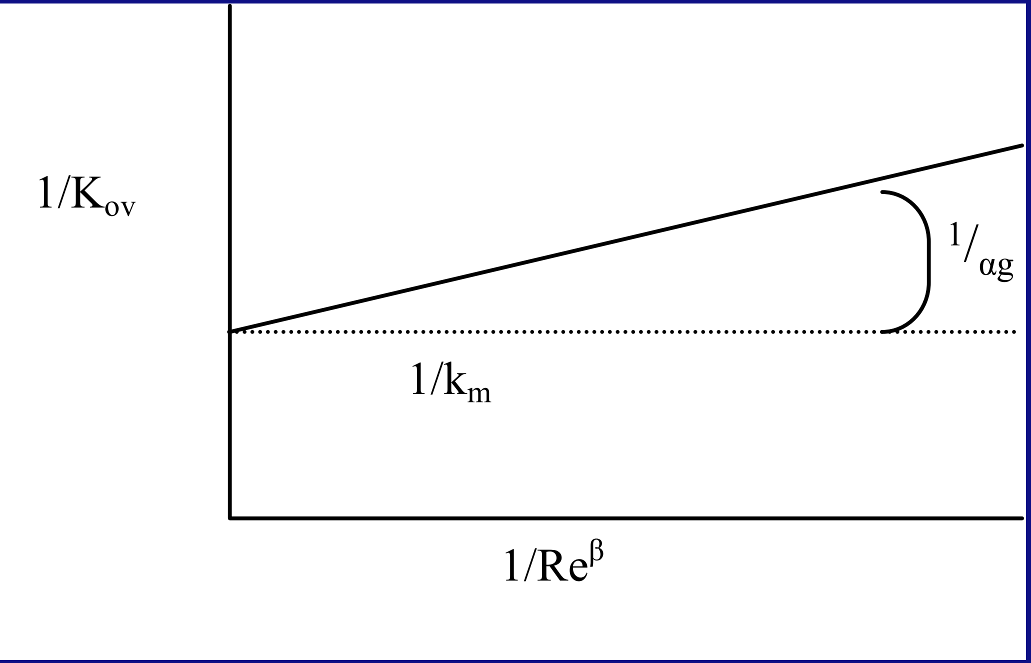
SO_2-experiments

- Overall mass transfer coefficient
  - SO_2 reaction with KOH very rapid
    - $mk_L E_{CO2} >> k_m$, k_g

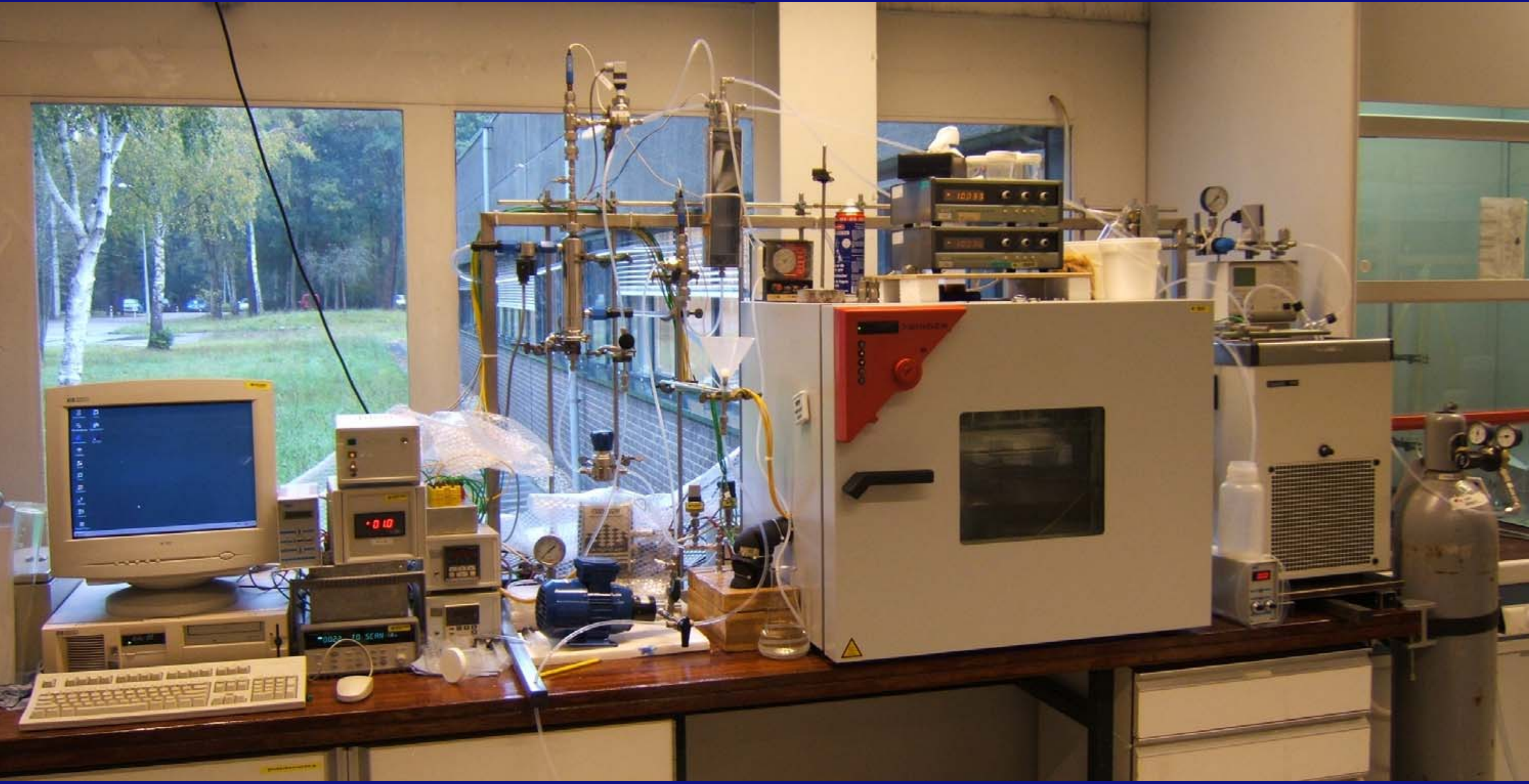
→

$$\frac{1}{K_{ov}} = \frac{1}{k_g} + \frac{1}{k_m}$$

$$\frac{1}{K_{ov}} = \frac{1}{\alpha_g \cdot Re^{\beta}} + \frac{1}{k_m}$$

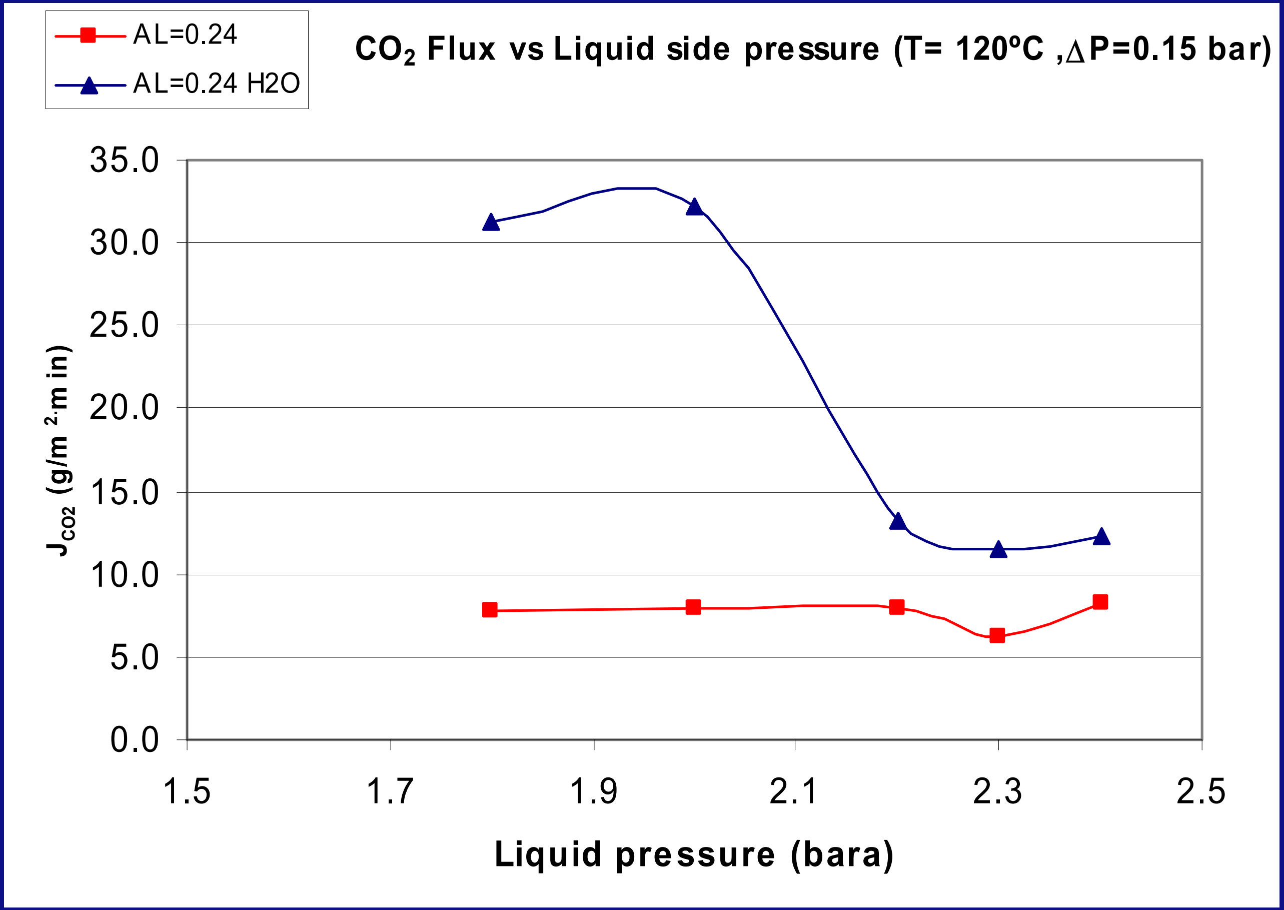


Membrane desorption set-up at TNO



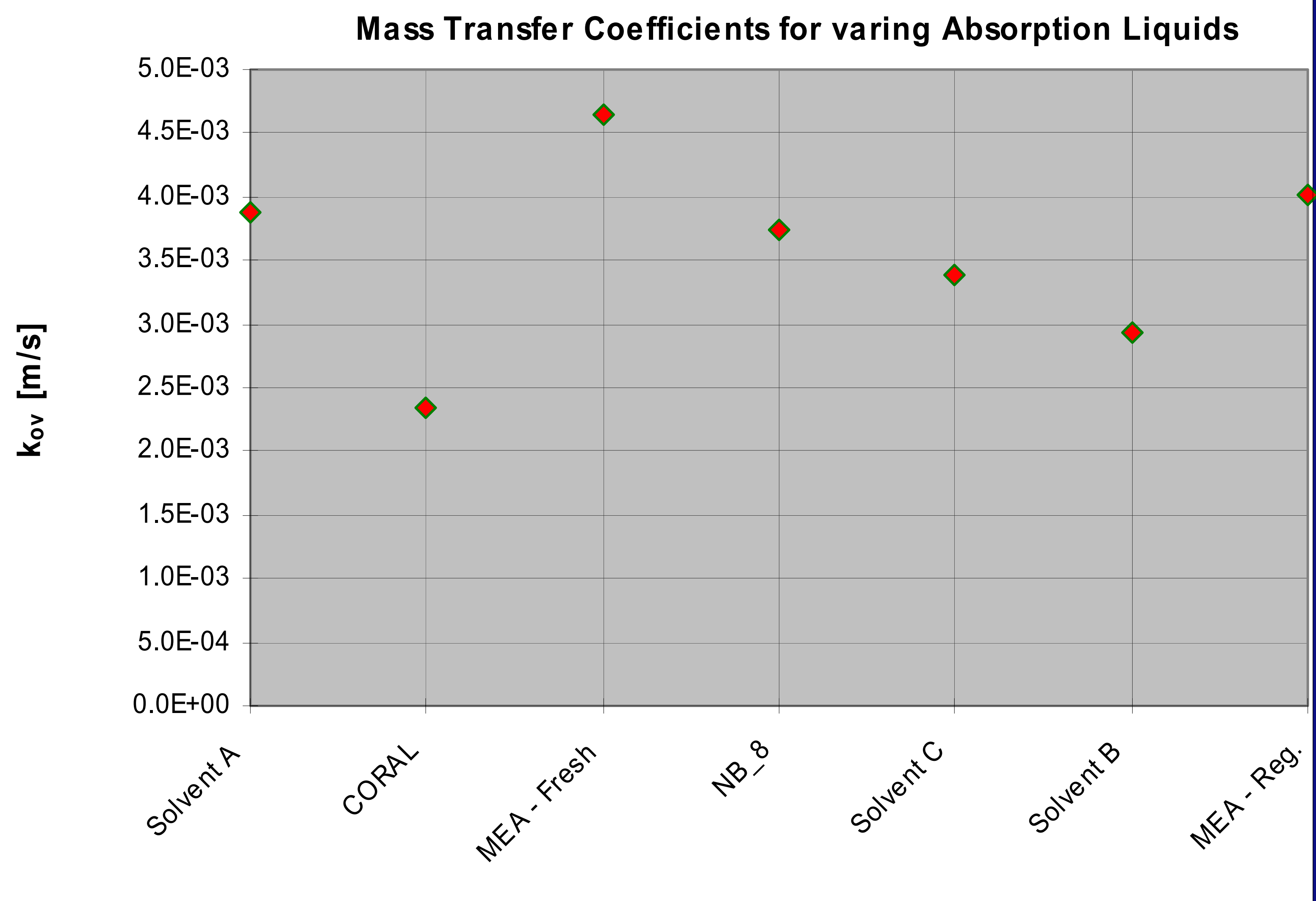
Membrane desorption

- Membrane testing at various temperatures and pressures
- Membrane desorption process development



Membrane absorption set-up at TNO

Preliminary results of membrane absorption/desorption



Membrane contactor development

Boundary conditions and choices for a membrane contactor

Module channel wide	1.0 meter
Module channel length	3.0 meter
Module total height	Approx. 1 meter
Module gas channel height	2.0 mm (spacer filled)
Module liquid channel height	1.0 mm (spacer filled)
Number of gas channels	322
Number of liquid channels	322
Number of baffles liquid side	5 x (approach counter current)
Gas speed	2.0 m/s
Liquid speed	0.02 – 0.07 m/s
Gas side pressure drop	3 – 4 kPa
Liquid side pressure drop	20 - 60 kPa
Membrane area per feed gas	Approx. 0.5 m^2 per m^3/hour
CO_2 capture ratio	90 %
CO_2 content in flue gas	5 – 25 %
Flue gas mass flow single channel	18 - 19 kg/h (at 2 m/s gas speed)
Total module gas side mass flow	Around 6000 kg/h (at 2 m/s)
Total module liquid side mass flow	15000 - 45000 kg/h (at 2 m/s) (depending on CO_2 inlet conc.)
Weight module empty (approx.)	1400 kg (incl. heavy support mounting)
Weight module filled (approx.)	2500 kg

Results CASTOR conventional absorber and MGA

Power plant		**Gas fired combined cycle [393 MW_e] Conventional column**	**Gas fired combined cycle [393 MW_e] MGA**	**Bituminous coal fired power plant [600 MW_e] conventional column**	**Bituminous coal fired power plant [600 MW_e] conventional column**
CO_2 product capacity	**ton CO_2/hr**	**131**	**131**	**410**	**410**
Equipment	**Parameter**				
Absorber column	**Columns**	**2**	**1**	**2**	**1**
	Dimension	**Φ 10.7m x 29.5m**	**Φ 11.4m x 17.0m**	**Φ 10.9m x 28.1m**	**Φ 11.2m x 16.0m**
	Packing	**1605 m^3**	**1.01 E^6 m^2**	**1448**	**9.31 E^5 m^2**

- Radial flow profile with flat sheet contactor
- Based on in-house measured data with Coral liquids

Conclusions:

- Significant lower footprint possible (drive for improved liquids)

Large scale flat sheet modules by Keppel Seghers and TNO

DYNAMIS
Towards hydrogen production with CO_2 management

Program

- The EU HYPOGEN initiative for hydrogen economy
- Started march 2006
- To asses the options for full scale HYPOGEN Power Plant
- Full scale pilot to be build by industry post-2008
- Full production HYPOGEN Power Plant to go on stream by 2012

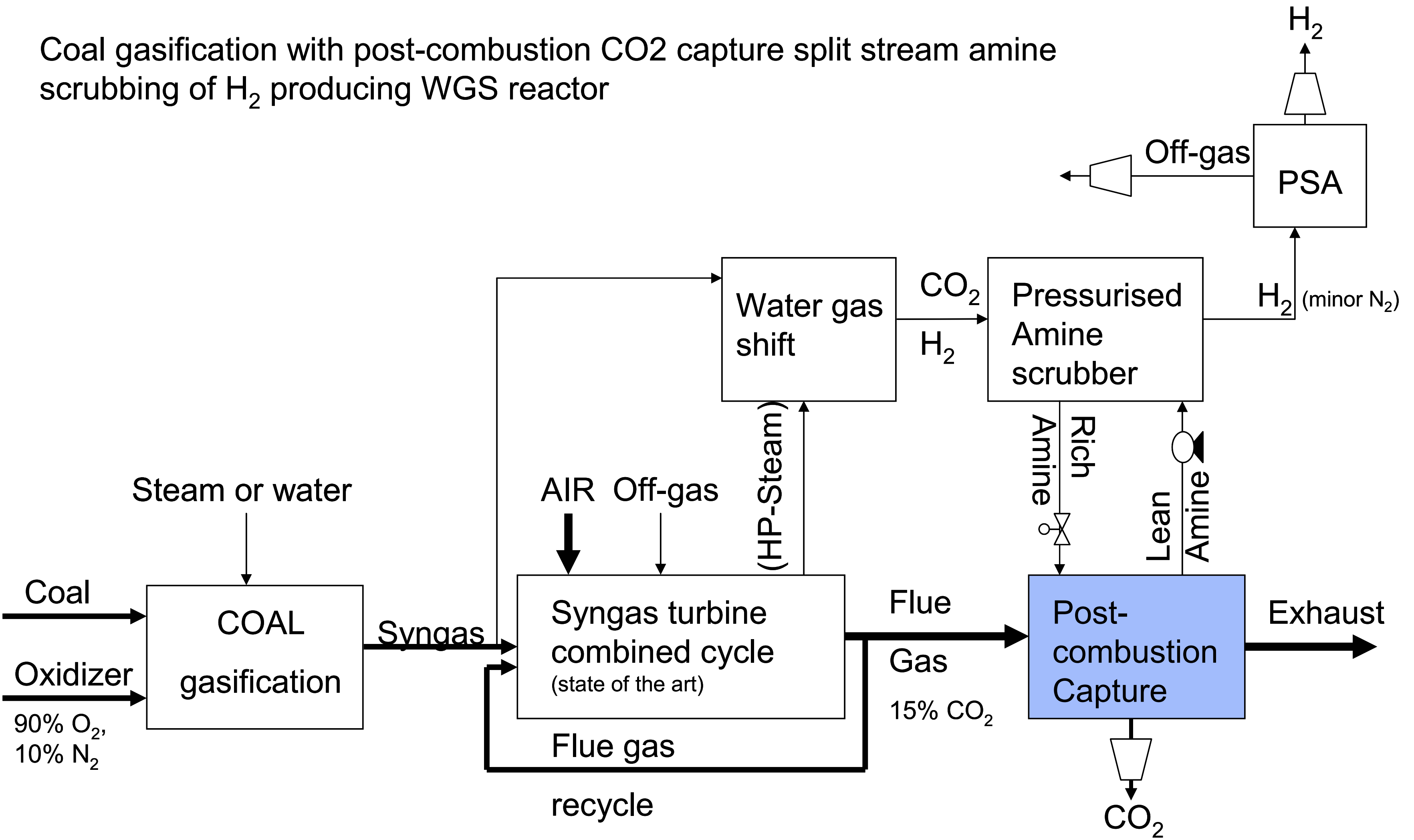
Boundary conditions

- Combined cycle power generation 400 MWe (approx. 700 MW)
- Hydrogen production 25-50 MW (flexible 0-100% hydrogen????)
- Hydrogen spec’s according EU hydrogen infrastructure (2010)
- 90% CO_2 capture
- CO_2 capture cost of €25-30 per tonne CO_2

DYNAMIS

Post-combustion CO_2 capture options researched by TNO

Coal gasification with post-combustion CO2 capture split stream amine scrubbing of H_2 producing WGS reactor



CAPRICE

CO_2 capture using Amine Processes: International Cooperation and Exchange

- STREP currently under negotiation with EC
- Cooperation between CASTOR-partners and consortium around International Test Centre on CO_2 capture (University of Regina, Canada)
- Extending research efforts to other CSLF countries (China, Russia, Brasil)
- Partnership
  - EU - linked: TNO, NTNU, Stuttgart University, IFP, Elsam, E2, E.ON-UK, TIPS, Tsinghua University
  - Canada - linked: Energy Inet, ITC, Un. of Regina, Alberta Research Council, Unifacs

Caprice

Project activities:

1. Benchmarking and validation of amine processes
2. Membrane contactor validation studies
3. Development of tools for integration

Budget:

- Total 1.1 MEuro
- EC-contribution: 0.38 MEuro
- Equal effort by EU and CDN partnership

Key deliverables:

- Input to CSLF
- Action plan for further post-combustion R,D&D on global scale

Construction of hybrid-pilot in CATO

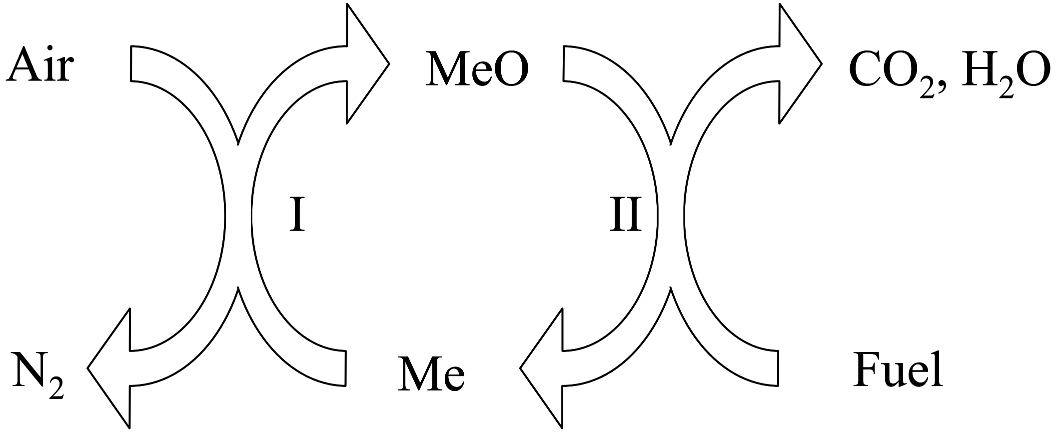
Dutch post-combustion CO_2 capture pilot plant (250 kg/h)

- Budget around K€ 1000
- Start construction expected third quarter of 2006, finished second quarter 2007
- Location? (planned at a coal-fired power plant)
- First operation with conventional columns but with CORAL liquids
- Pilot to be upgraded with membrane contactors for SO_2 and CO_2 removal.

Chemical Looping Combustion (CLC) in ENCAP and CATO

Important features of CLC

- Air and fuel are only contacted via an oxygen carrier (a metal/metal oxide, e.g. Ni/NiO, Fe/Fe_2O_3)
- No NOx formation (absence of flame)
- No dilution of CO_2 with N_2 → no energy penalty for separation



$$\text{I:}\quad 4\,\text{Me} + 2\,O_2 \rightarrow 4\,\text{MeO}\ (\Delta H < 0)$$

$$\text{II:}\quad 4\,\text{MeO} + CH_4 \rightarrow 4\,\text{Me} + CO_2 + 2\,H_2O\ (\Delta H > 0)$$

Chemical Looping Combustion (CLC) in ENCAP and CATO

CLC has in theory high potential for Zero Emission Power Production:

- Theoretical high thermal efficiency
- Low CO_2 separation cost
- Fluidising Circulating Bed technology close to current standard

Current development status of CLC:

- Only applicable for gaseous/liquid fuels
- No integration with gas turbine
  - Risk of particle carry-over
  - Limited intermediate temperature stability
  - High particle cost (environmental concerns)

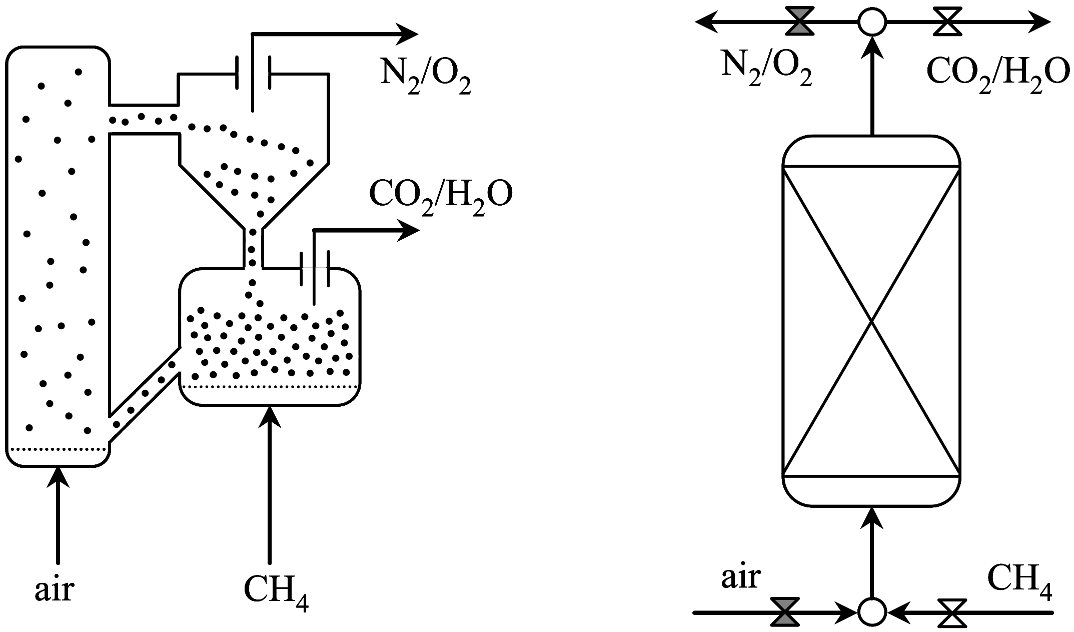
CLC is more expensive then post-combustion CO_2capture

Chemical Looping Combustion (CLC) in ENCAP and CATO

New developments on CLC:

- Integration of CLC-reactor with Combined Cycle Power Plant

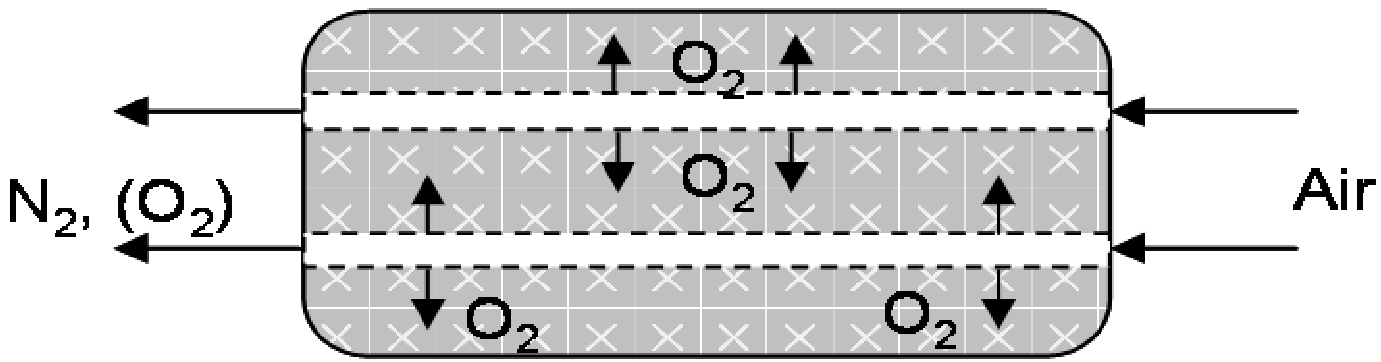
Reactor concept for CLC:



Recirculation or stationary solids?

Chemical Looping Combustion (CLC) in ENCAP and CATO

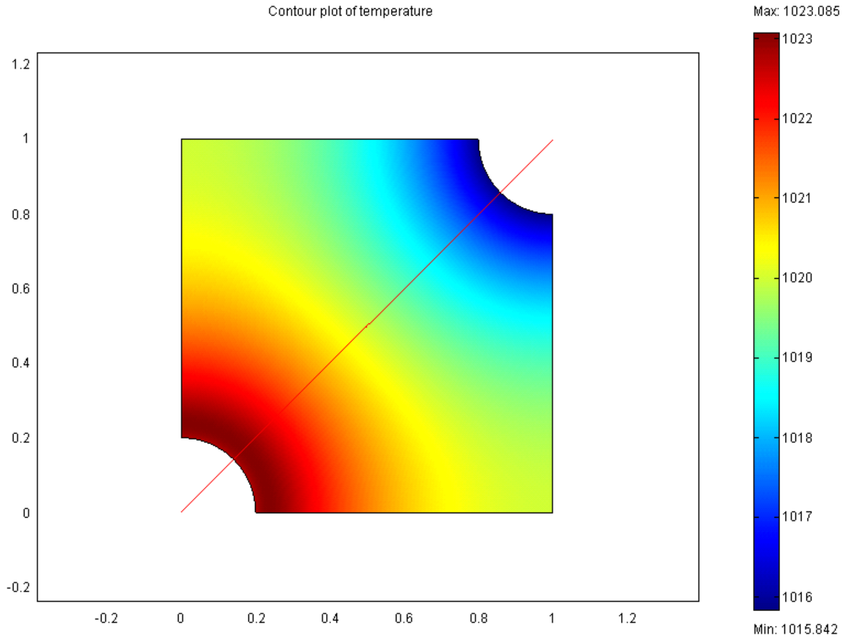
Fixed bed diffusive reactor



Chemical Looping Combustion (CLC) in ENCAP and CATO

Results of modelling work

The formation of a reaction front in the packed bed around an active membrane based on diffusion



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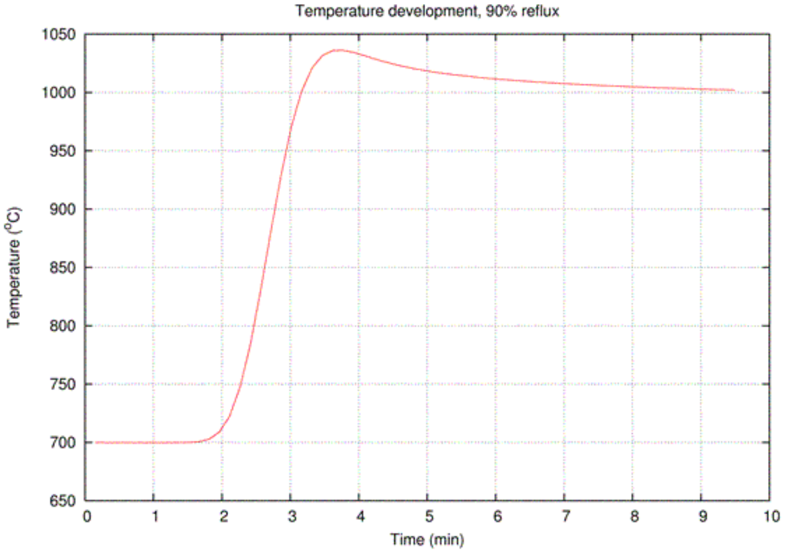
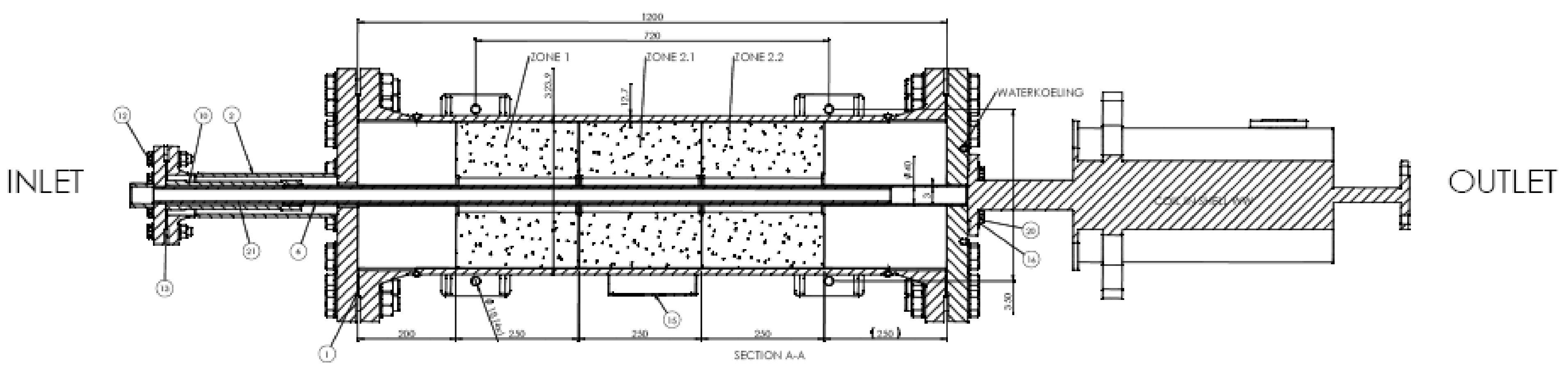


Chemical Looping Combustion (CLC) in ENCAP and CATO

Future work on CLC

- Further development of fixed bed CLC reactors integrated with combined cycle power plant
- Development of new temperature stable intermediates
- Modelling of complete process
- Testing of pilot installation



Conclusions

TNO focuses on CO_2 post-combustion capture!

1. Most developed CO_2 capture technology
2. High potential for further improvement
    - Development of improved liquids
    - Process integration and novel processes steps
    - Optimized and new contactors
    - Process modelling and economic optimisation

Future development includes fixed bed CLC processes!

ELECTRIC POWER RESEARCH INSTITUTE

CO_2 Testing Program

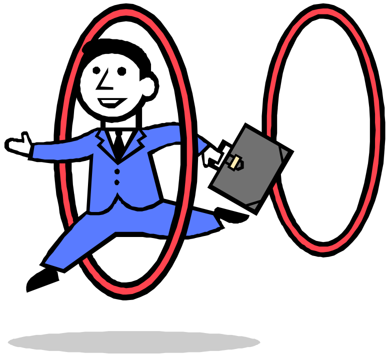
An Industry/EPRI Initiative to Develop CO_2 Capture and Storage Test Capabilities

Dick Rhudy

CO_2 Capture Network Meeting
June 16, 2006

History of the CO_2 Testing Issue

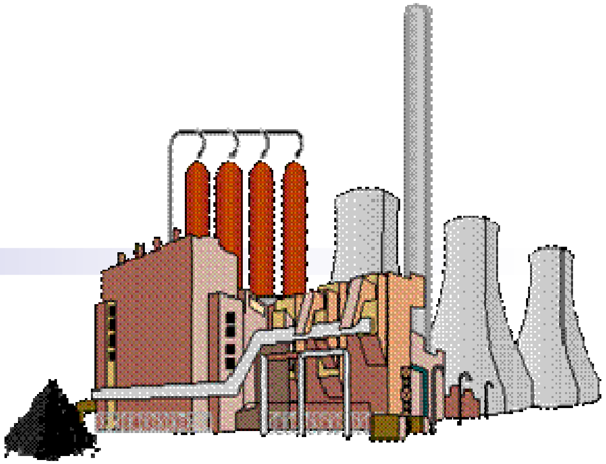
- Conceived of need for regional CO_2 Capture and Storage Test Centers as a necessary RD&D step
  - Several across country
  - Different power generation and storage depending on region
  - 10 MW (150 t CO_2/d)
- Conducted engineering cost and site selection study on pulverized coal (PC) power plant systems
  - PC is the only type of generation available in near-term
  - 4 sites identified
  - High cost



History of the CO_2 Testing Issue (cont.)

- Reviewed with EPRI BoD and Technical Review Committee
  - Identified need for better capture processes
- Decided to conduct study in two steps
  - 1-MW CO_2 capture pilot
  - 10-MW CO_2 capture and storage test facility
- Selected chilled ammonia process to test
- Alstom interest and collaboration
- Currently soliciting participation in 5-MW CO_2 capture pilot of chilled ammonia process

CO_2 Test Centers Current Plan



A multi-phase testing program to develop cost-effective and practical capture technologies

Phase 1

- **1-MW pilot plants**
- **Test solvent, solid and membrane capture technologies**
- **Test materials to be used for compression, transport and injection of flue-gas CO_2**

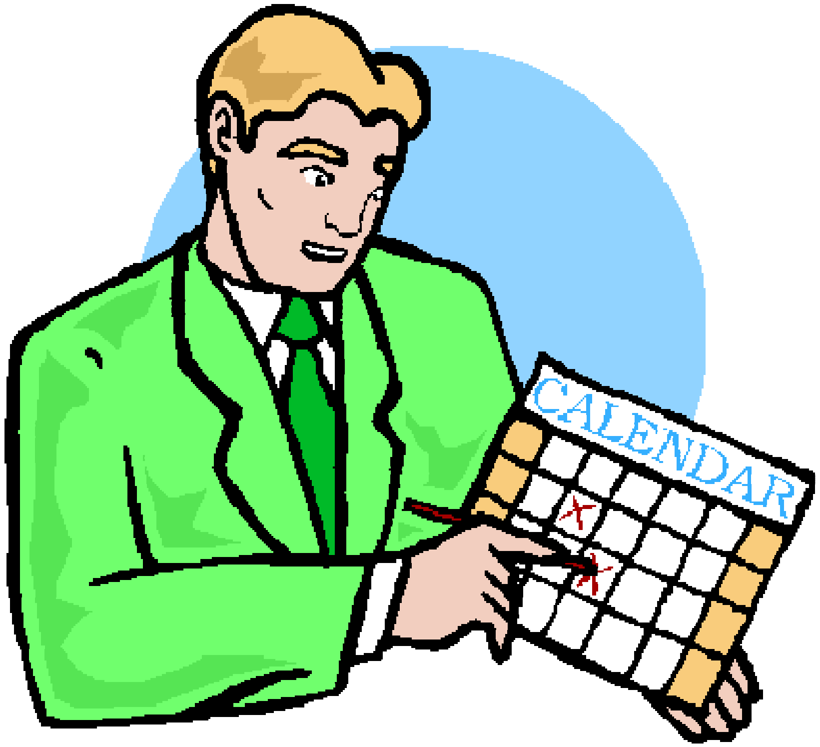
Phase 2

- **10-MW CO_2 Test Center (150 Tonnes/day)**
- **Capture and store CO_2 at substantial scale and real operating environments**
- **Future phases – larger demos to scale-up to full plant**

Determine the viability of combustion-based coal plants in a carbon constrained future

Project Schedule

- Assembling funding in early 2006
- Start on engineering/ procurement in 2006
- Operation of pilot starting in 2007

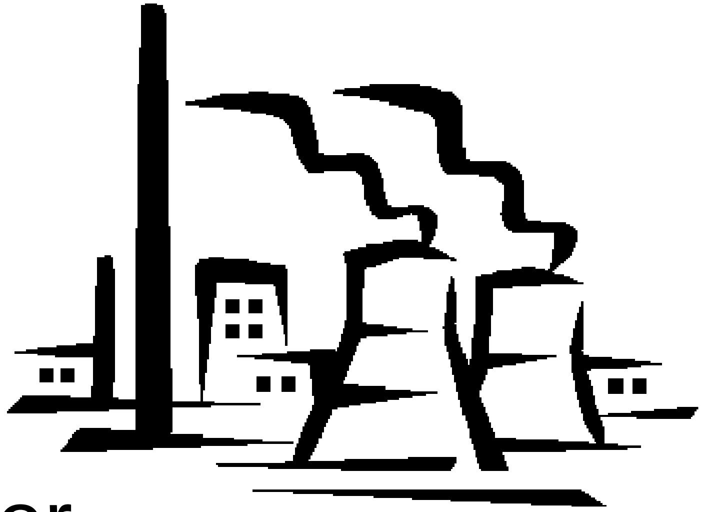


First Capture Process to be Tested

- Chilled ammonia
  - Under development by EPRI

Conventional Ammonia Scrubbing

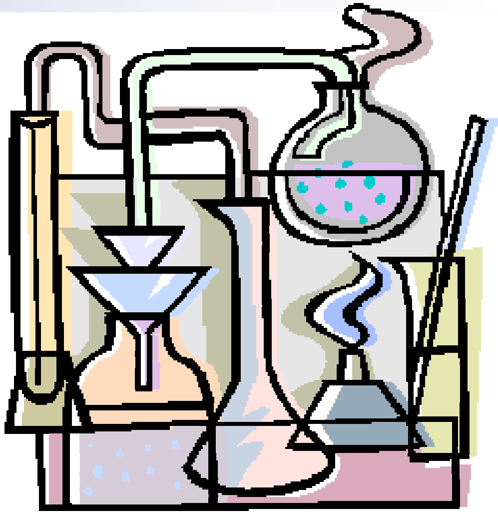
- Advantage
  - Potentially lower regeneration energy
- Challenges
  - Ammonia volatility
  - Poor kinetics in absorber



Chilled Ammonia Process: Key Design Features

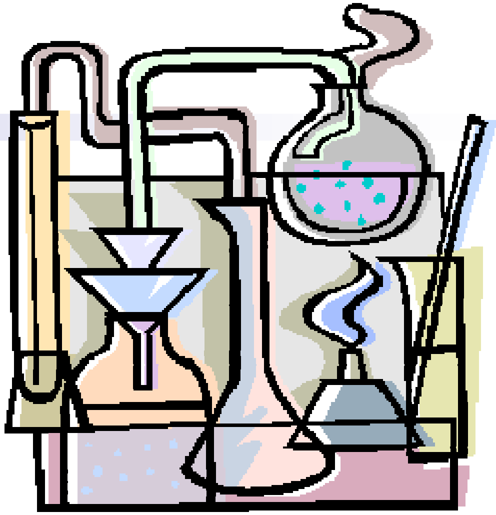
- Low temperature CO_2 Absorption--minimize NH3 emissions
  - Absorber operation at optimal temperature of 2-16C (35-60F)
- High concentration of Ammonium Carbonate/Ammonium Bicarbonate (AC/ABC)--improve CO_2 removal
  - High CO_2 loading per recycled slurry
- High pressure regeneration--saves energy

Chilled Ammonia Lab Tests



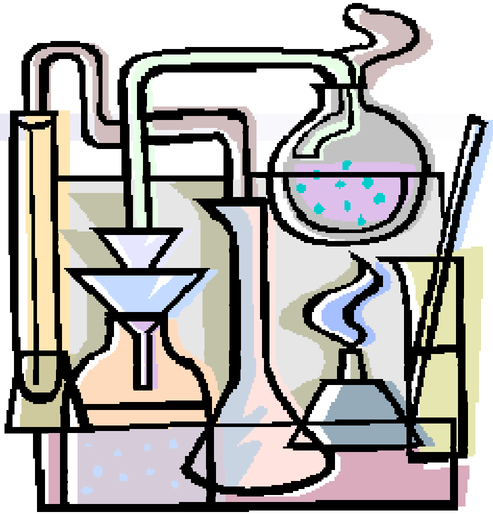
- Phase 1 (2004)
  - Ammonia emission not an issue during absorption at 0-5C (32-40°F)
  - High CO_2 absorption efficiency can be achieved in bubbler absorber
  - High pressure regeneration—at least 20 Bar (300psi) is feasible
  - NH_3 and H_2O concentration in regeneration gas stream is very low

Chilled Ammonia Lab Tests



- Phase 2 (2005)
- Absorption
  - Measurements of absorption rates were completed
  - CO_2 removal in the 2” flow reactor was limited by mass transfer
  - A large scale absorber (1-2 ft) diameter needs to be built and tested to demonstrate high efficiency and high mass transfer rates

Chilled Ammonia Lab Tests (cont.)



- Phase 2 (2005)
- Regeneration
  - 800 psig was measured with regeneration simulation from ammonium bicarbonate
  - High pressure regeneration can be designed to regenerate ammonium carbonate at 125℃

Chilled Ammonia Process Cost Prediction (Early Data Only)

Used Parsons Study for basis	Supercritical PC without CO_2 Removal	Supercritical PC with MEA CO_2 Removal	Supercritical PC with NH_3 CO_2 removal
Levelized cost of Power, c/KWh	5.15	8.56	6.50
% increase		66	26
Avoided Cost, \$/ton CO_2	Base	51	20

Source: Nexant

Chilled Ammonia Process Performance Prediction (Early Data Only)

Used Parsons Study for Basis	**Supercritical PC Without CO_2 Removal**	**Supercritical PC With MEA CO_2 Removal**	**Supercritical PC With NH_3 CO_2 Removal**
LP Steam extraction, lb/hr	0	1,220,000	**270,000**
Power Loss, KWe	0	90,000	**20,000**
GROSS POWER, KWE	491,000	402,000	**471,300**
AUXILIARY LOAD, KWE			
Induced Draft Fan	5,000	19,900	**10,000**
Pumping CO_2 system,	0	1,900	**5,000**
Chillers	0	0	**8,900**
CO_2 compressor	0	30,000	**9,500**
NET POWER OUTPUT	462,000	330,000	**415,000**
% POWER REDUCTION		29	**10**

Source: Nexant

Chilled Ammonia Looks Good to Test at 1 MW

- Data from Technology Innovation bench-scale work looks good
- Economics are very preliminary and supplier derived
- Appropriate for scale-up

CO_2 Capture Pilot Project Launch

- In early February, PON released and participation solicitation initiated
- Initial calls made to potential anchor tenant members
- 16 companies have agreed to participate
- Funding from these members represents about 2/3 of the project funding

Alstom Discussions

- Based on
  - Common interests (e.g., we jointly bid the chilled ammonia project to DOE but was not selected)
  - Alstom's desire to push scale-up and commercialize the chilled ammonia process
- Organizations agreed to collaborate on the construction and testing of a 5-MW pilot CO_2 test unit of this process
- Could accelerate our currently proposed scale-up at no cost to the EPRI funders
- Could move us to scale for CO_2 storage

Alstom Collaboration Benefits

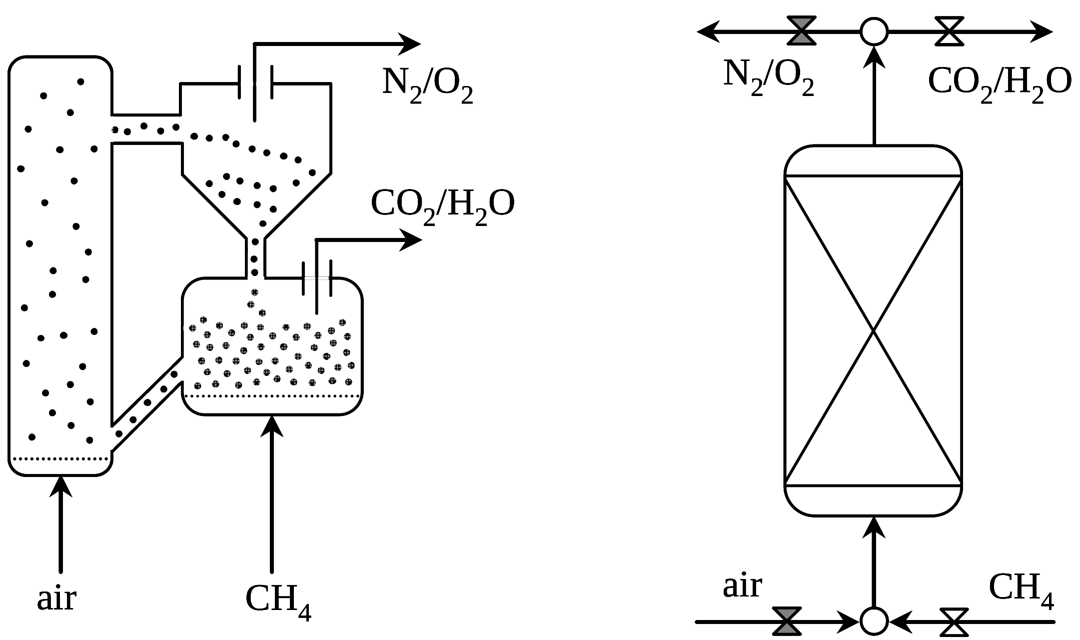
- Enables us to leverage our funder's investment even more
- Allows us to accelerate both the development and commercialization path
  - A 5-MW pilot is big enough to use commercial components (e.g., slurry pumps) designed for such an application
  - Teaming with the company that views this technology as their offering of choice will accelerate its commercialization
  - Can move into a size which allows CO_2 storage testing at least 2-3 years faster

Chemical Looping Combustion (CLC) in ENCAP and CATO

New developments on CLC:

- Integration of CLC-reactor with Combined Cycle Power Plant

Reactor concept for CLC:



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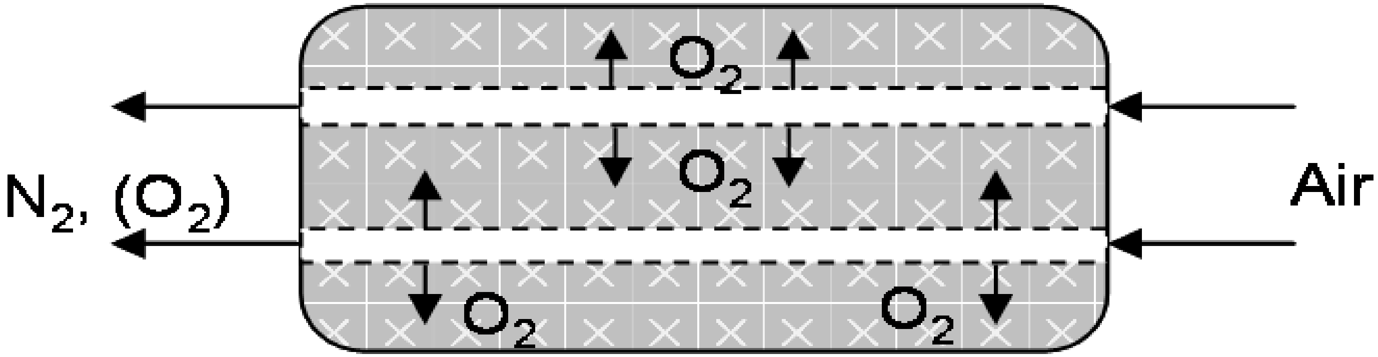
Fixed bed diffusive reactor



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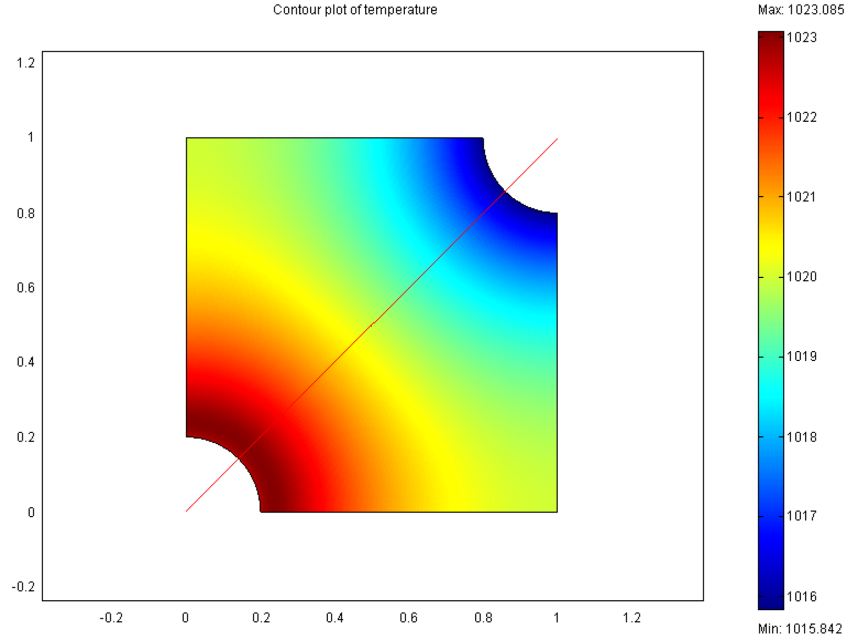

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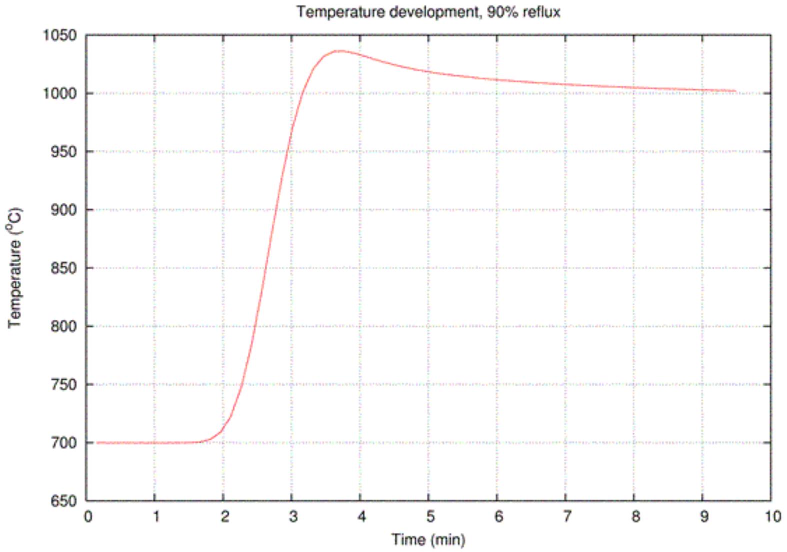

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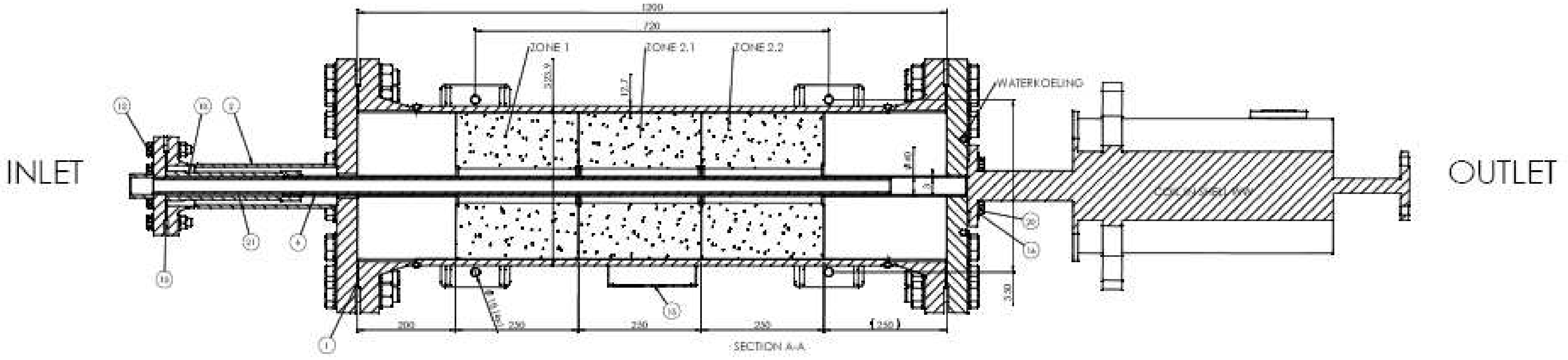

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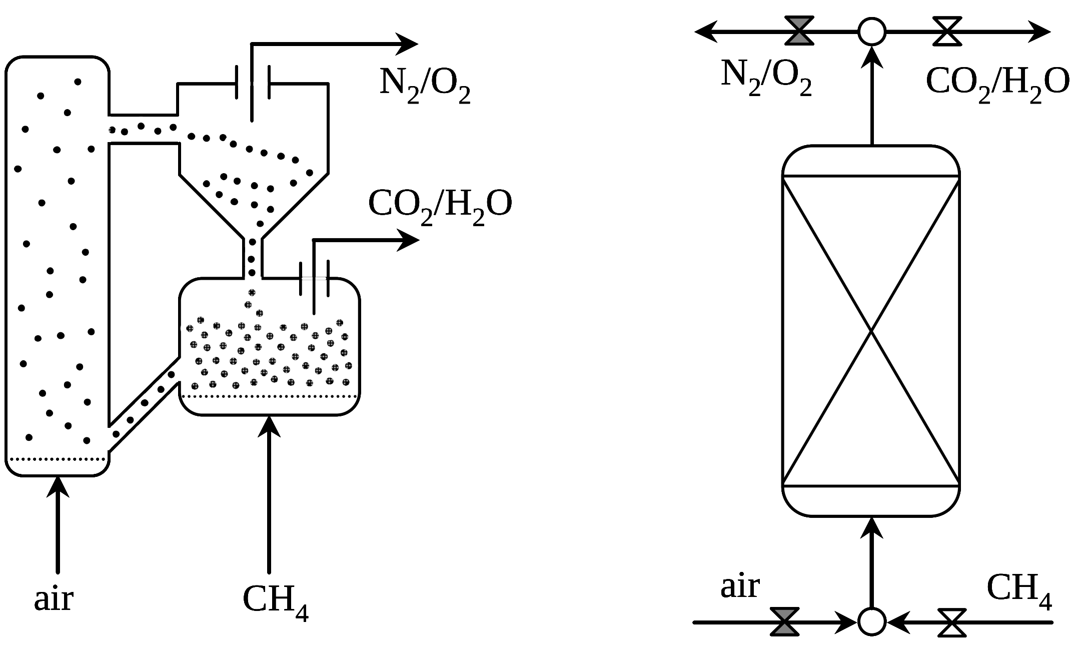

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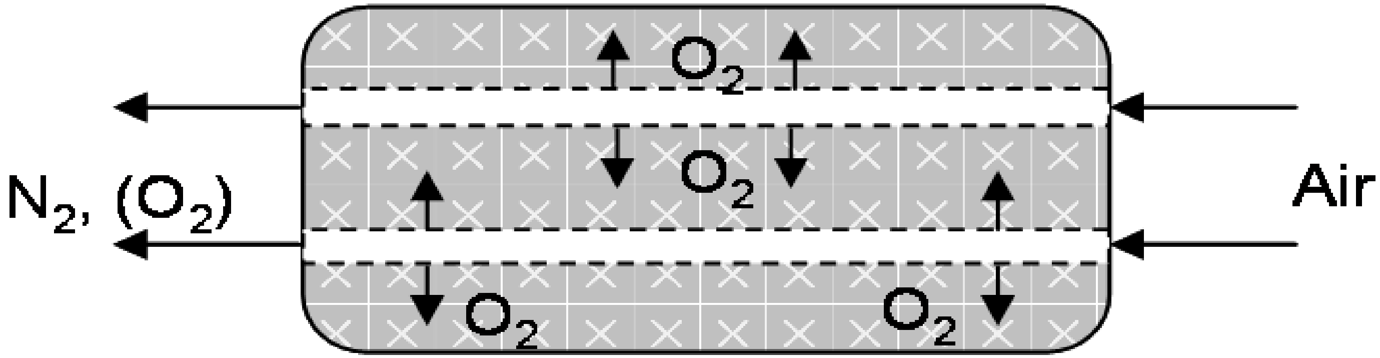

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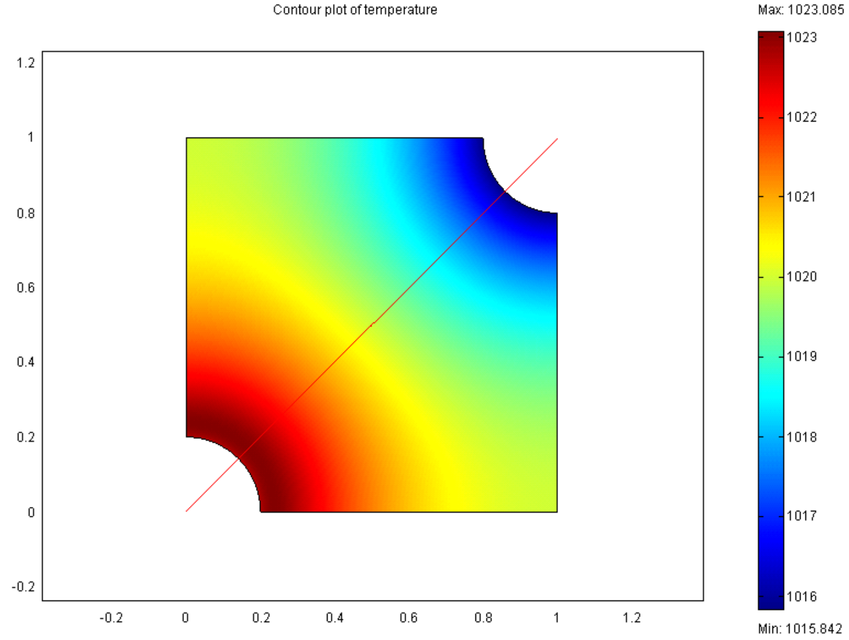

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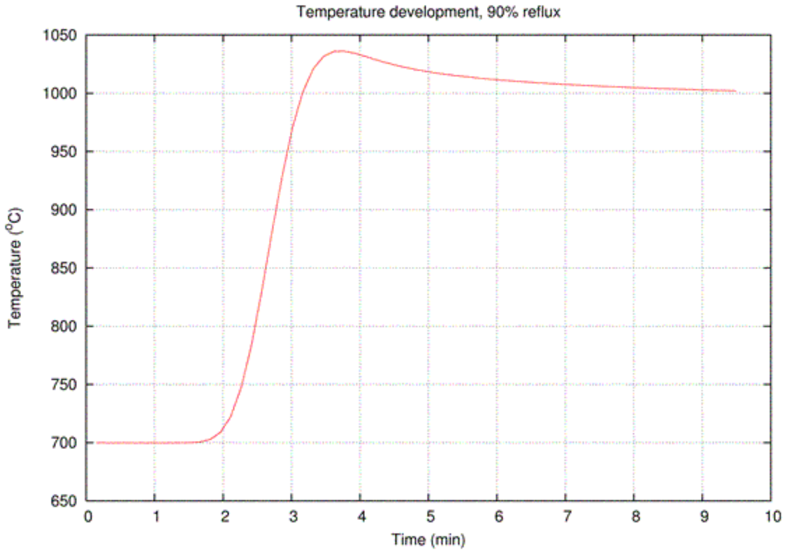

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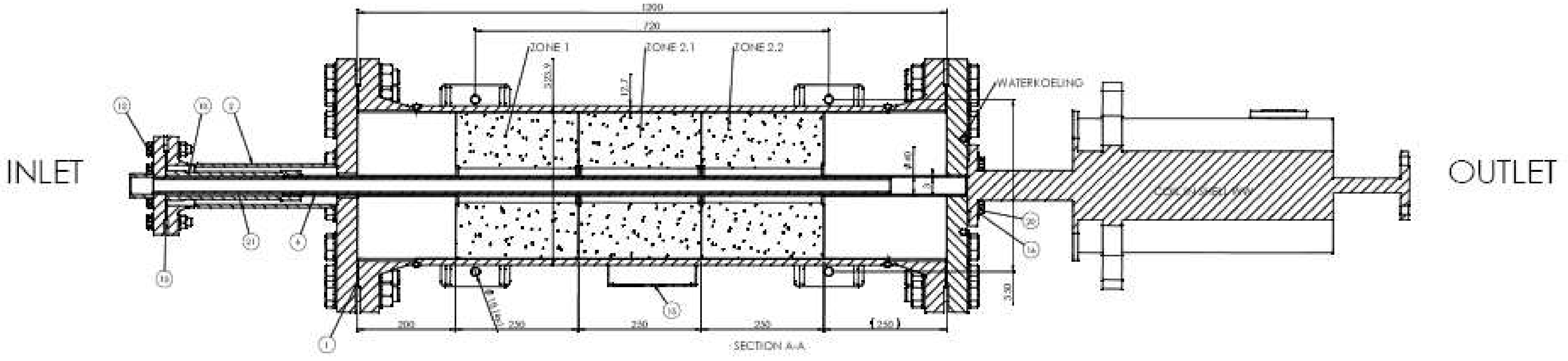

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GTI's Acid Gas Treating Pilot Plant (AGTPP) Relocation and Integration with FlexFuel Facility

> **Dennis Leppin, P.E.**
Gas Technology Institute

Presentation to 9th Int'l. CO_2 Capture Test Network Meeting

Copenhagen, Denmark

June 16, 2006

Objective

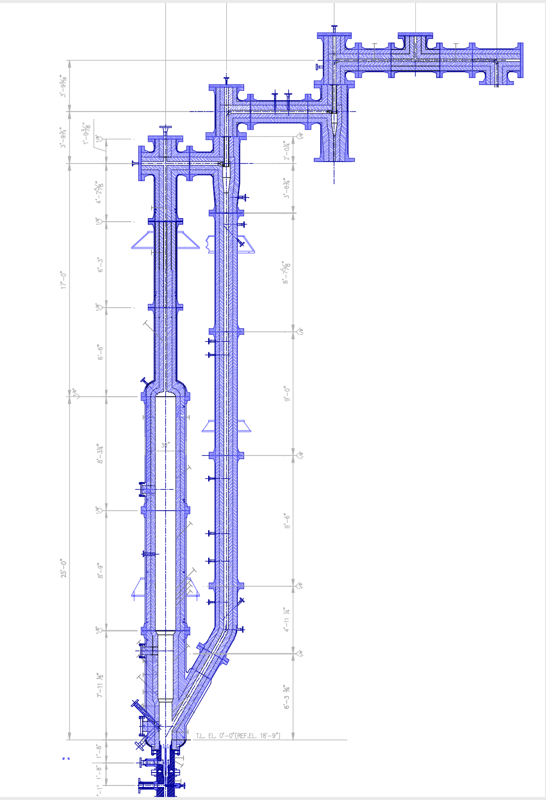
- Develop a research capability for pre-combustion CO_2 removal
- Integrate an existing plant with a new coal gasifier test facility (“GTI Flex Fuel”)
- Test new technology applicable to IGCC acid gas removal
  - Solvents
  - Contactor devices, packing etc.

GTI’s Pilot Plant Unit

- Built in 1994 by Gastech Engineering, Tulsa, OK
- Used extensively for the development of the Morphysorb process - last used in 1999
- Needs reconditioning and modifications to meet syngas application requirements
- Solvent Chillers need to be replaced/rented
- 2005 – State of Ilinois IDCEO has funded relocation/refurbishment project

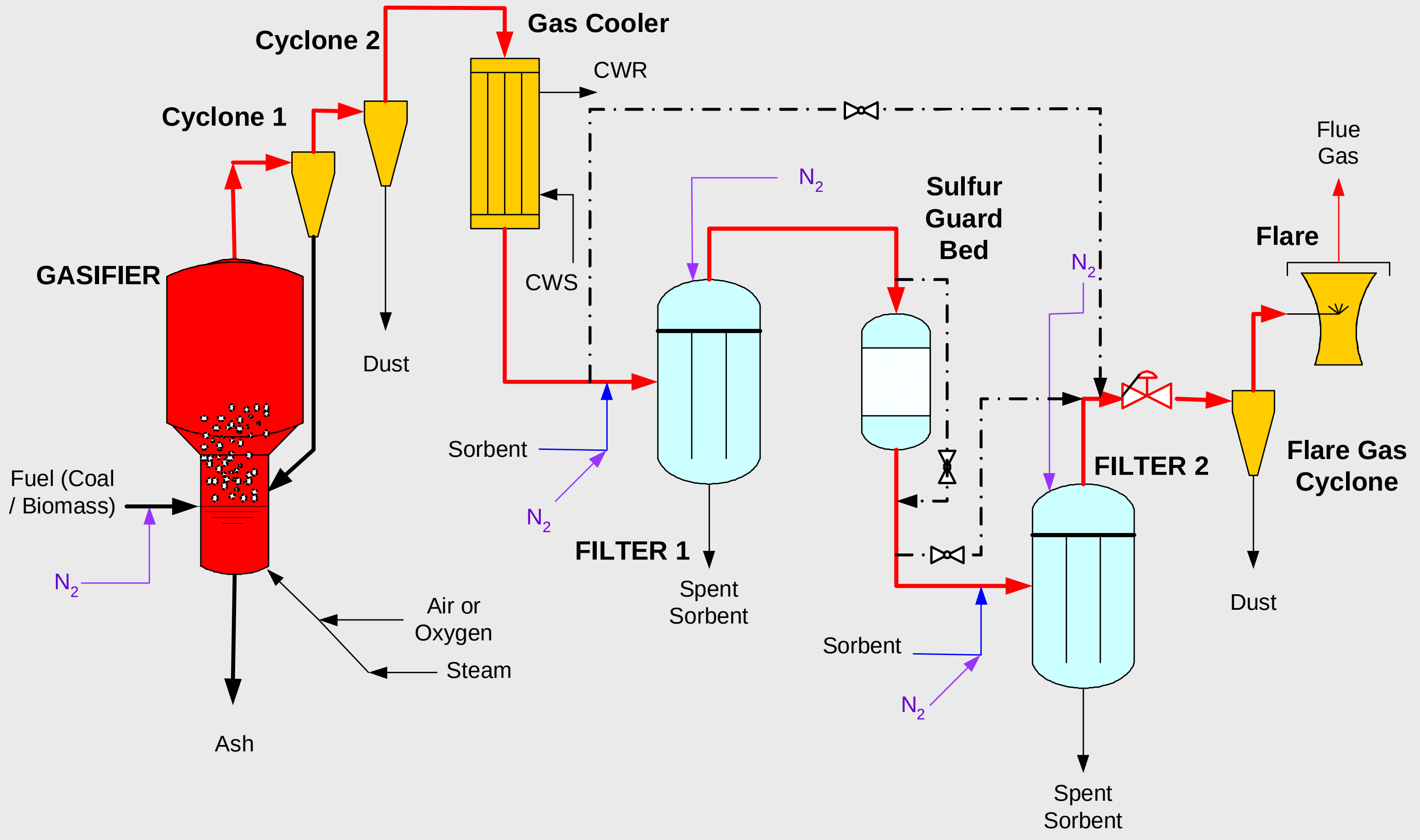
GTI Flex-Fuel Gasification Test Facility

Capacity: ~10 – 20 tpd coal



Currently has a fluid bed gasifier, lock hopper fed using pre-sized and dried feedstocks

Flex Fuel PFD



Flex Fuel

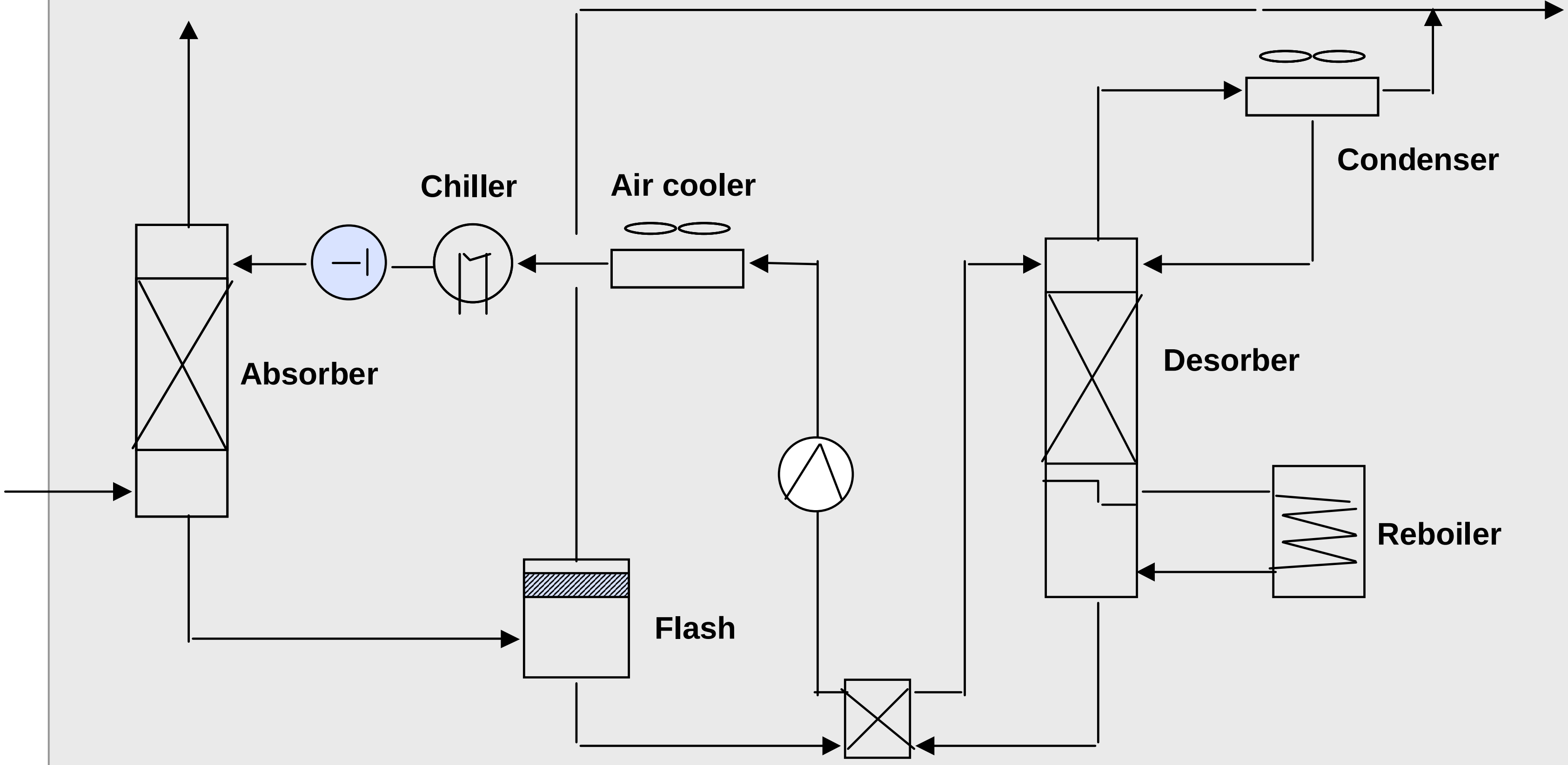
- Various capabilities will be added in planned programs:
  - Entrained gasification (third party)
  - Acid gas removal (AGTPP)
  - Gas quench/gas cooling
  - Sulfur Capture (SulfaTreat)
  - Shift/COS Hydrolysis
  - Oxygen feed
  - Higher-pressure operation
- Using syngas from ongoing tests will be best option if cost is major factor

AGTPP Pilot Plant Unit

Pilot Plant Specifications:

- **Pressure, 1200 psig**
- **Circulation Rate, 5-15 gpm**
- **Feed Gas Flow Rates Up to 1 MMSCF/d**
- **Reboiler Capacity, 600,000 Btu/h**
- **Overall Dimensions, 12 x 12 x 60 ft.**
- **Contract to move this to GTI Fall 2006 – integrate with FlexFuel gasifier - underway**

GTI Pilot Plant Unit

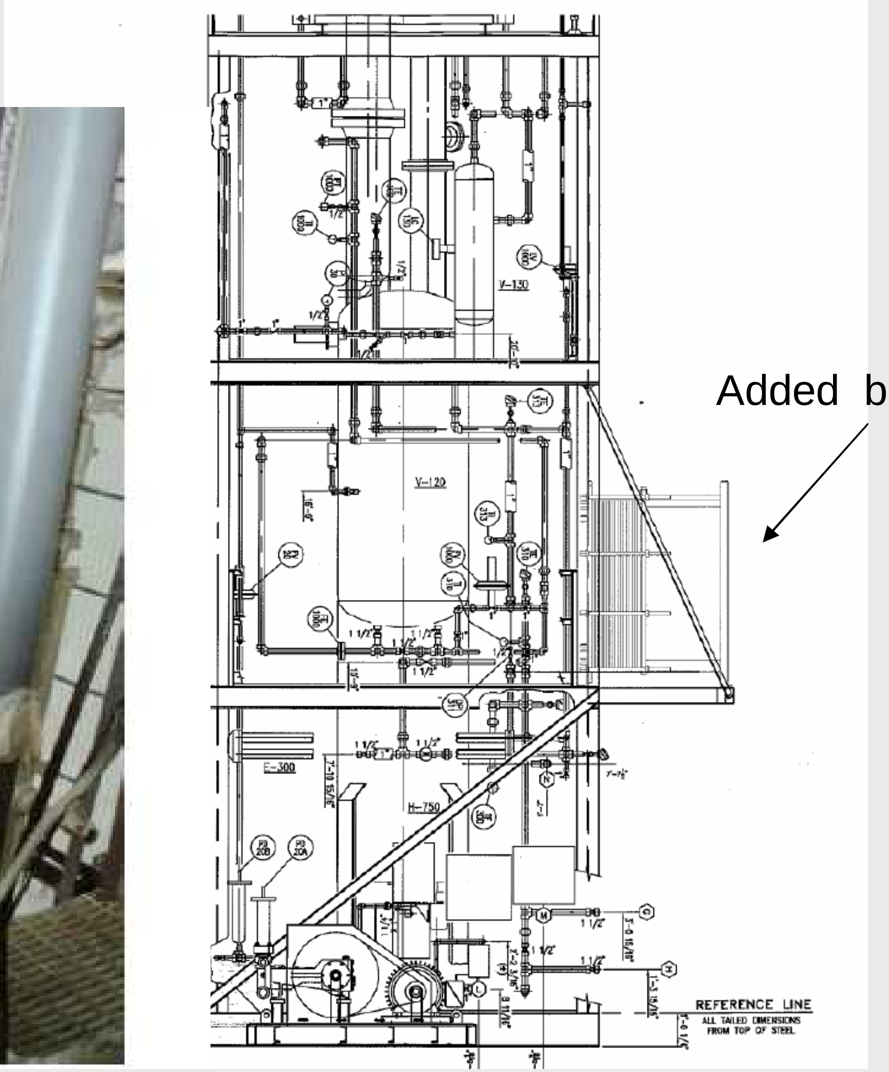


Moving the Plant from Kinder Morgan’s Zapata Plant

Site Preparation at GTI

Unit at GasTech Shop in Tulsa

New Rich/Lean Exchanger



Added balcony

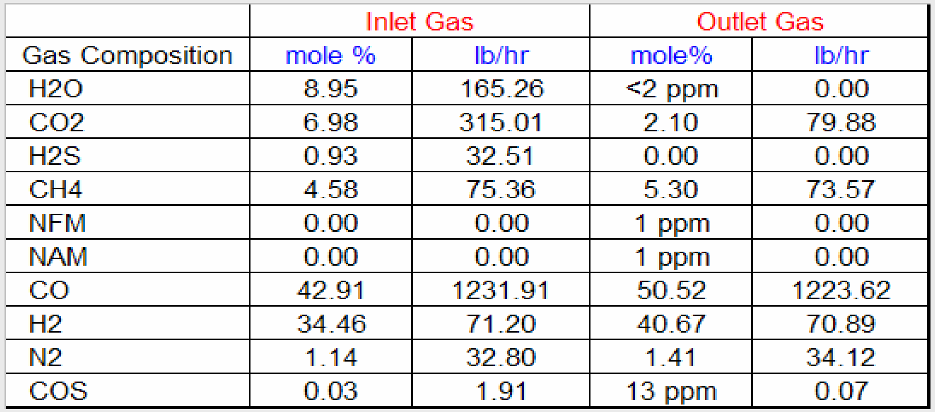
Case 1: High CO_2

- Gas pressure: 400 psig
- Gas Temperature: 90 F
- Total gas flow:1925 lb/hr
- Solvent Circulation: 30 gpm
- Gas Composition

	Inlet Gas		Outlet Gas	
Gas Composition	mole %	lb/hr	mole%	lb/hr
H2O	0.76	11.48	2 ppm	0.00
CO2	23.54	867.61	3.38	94.97
H2S	1.37	39.09	1 ppm	0.00
CH4	4.67	62.76	5.92	60.61
NFM	0.00	0.00	0.00	0.00
NAM	0.00	0.00	0.00	0.00
CO	30.19	708.19	39.25	702.09
H2	31.71	53.54	41.34	53.23
N2	7.71	180.99	10.12	181.04
COS	0.05	2.30	20 ppm	0.01

Case 2—Low CO_2 in Feed Gas

- Gas pressure: 400 psig
- Gas Temperature: 90 F
- Total gas flow:1925 lb/hr
- Solvent Circulation: 30 gpm
- Gas Composition

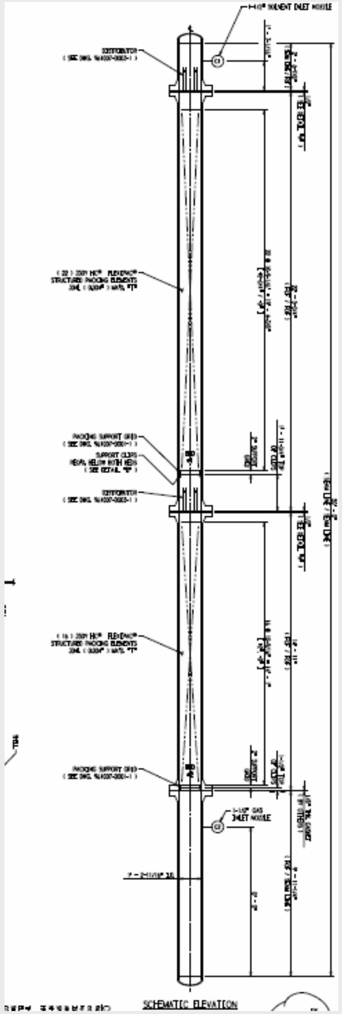


	Inlet Gas		Outlet Gas	
Gas Composition	mole %	lb/hr	mole%	lb/hr
H2O	8.95	165.26	<2 ppm	0.00
CO2	6.98	315.01	2.10	79.88
H2S	0.93	32.51	0.00	0.00
CH4	4.58	75.36	5.30	73.57
NFM	0.00	0.00	1 ppm	0.00
NAM	0.00	0.00	1 ppm	0.00
CO	42.91	1231.91	50.52	1223.62
H2	34.46	71.20	40.67	70.89
N2	1.14	32.80	1.41	34.12
COS	0.03	1.91	13 ppm	0.07

AGTPP Modifications

- Replace high-pressure pump
- Replace Column with 16” diameter and need minimum of 30 ft. packing height
- Extend Regenerator Column (12” dia) to 50 ft. to increase number of stages to meet the lean solvent specification
- Some piping changes to accommodate higher solvent rates
- Replace lean/rich heat exchanger
- Procure/rent solvent chiller
- Replace Data acquisition/PLC

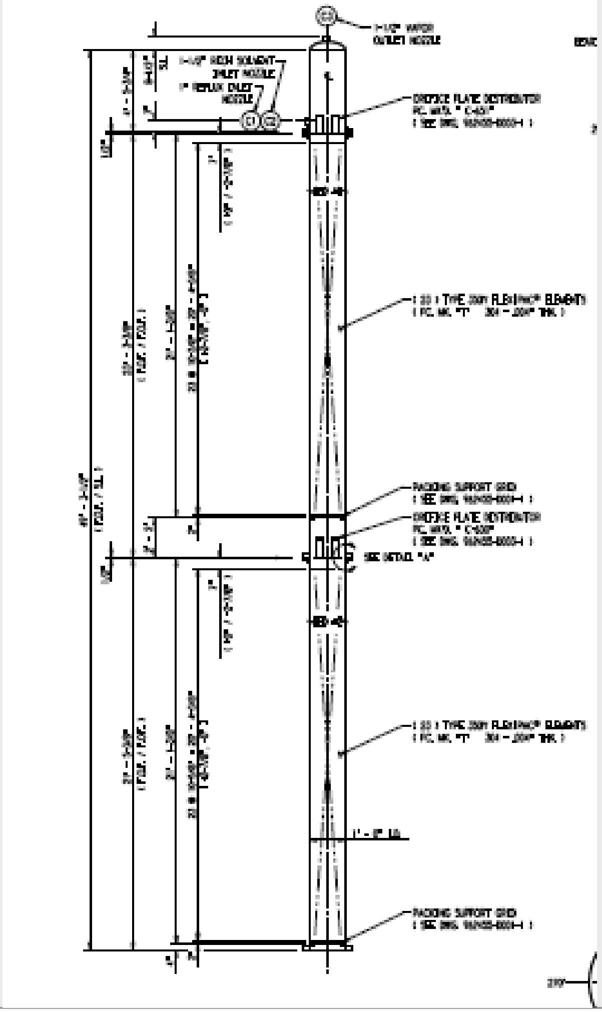
AGTPP Absorber Column Details



- 16” diameter column
- ~35 ft packing
- Structured Packing
- Solvent Redistributor after 20 ft
- Total Column height 50 ft

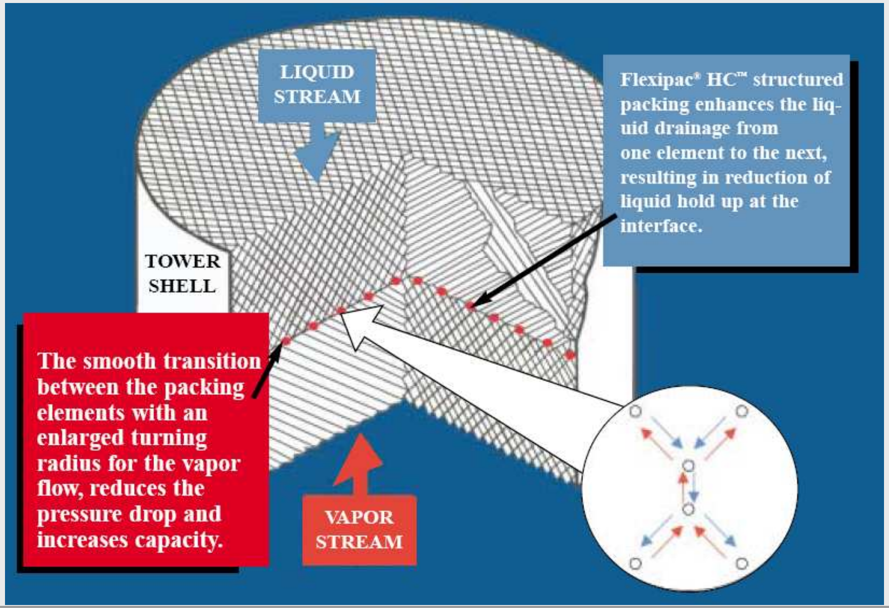
Regenerator Column (12” Dia)

- Structured packing
- Column height ~50 ft
- 45’ of packing (two beds with redistributor)



Koch’s Structured packing

- The new style FLEXIPAC® HC® (High Capacity) structured packing, incorporates a patented modification to the bottom and top edge of each individual corrugated sheet.
- Lower Pressure Drop and up to 40% Higher Capacity than Conventional Structured Packing



Flexipac® HC™ structured packing enhances the liquid drainage from one element to the next, resulting in reduction of liquid hold up at the interface.

The smooth transition between the packing elements with an enlarged turning radius for the vapor flow, reduces the pressure drop and increases capacity.

Relocation of AGTPP to Flexfuel Test Facility –Major Tasks

- Task 1 – Relocation & Erection of Acid Gas Treating Pilot Plant Unit
- Task 2 – Installation of Acid Gas Treating Unit with Flex Fuel Testing Facility
- Task 3 – Acid Gas Treating Pilot Plant Unit Shakedown and Testing

Task 1: Relocation & Erection of AGTPP

> Task 1.1 -- Prepare Site at Flex-Fuel

> Task 1.2 – Prepare and Submit Permits

> Task 1.3 -- Prepare Pilot Plant for Transfer

> Task 1.4 -- Transport Pilot Plant to Des Plaines

> Task 1.5 – Install AGTPP at Flex Fuel Facility

Task 2--Installation of Acid Gas Treating Unit at Flex Fuel Testing Facility

- Re-Install process lines and run necessary utility lines
- Install interconnecting gas piping from FFTF to AGTPP
- Install control / data system in FFTF Control Room and run control wires to AGTPP
- Connect AGTPP unit to Flex Fuel electric switchgear
- Check out of Instrumentation and Control System, and shake down unit
- Fill AGTPP unit with chemicals and ready for testing

Task 3 – Acid Gas Treating Pilot Plant Unit Shakedown and Testing

- AGTPP Unit Shakedown
- Prepare the test unit for experiments
- Limited Testing

AGTPP Status (as of June 2006)

- Main module is expected to ready by end of June
- Absorber Column fabrication and packing is complete
- AGTPP Foundation pad is ready at GTI, Des Plaines, IL
- FFTF and AGTPP piping tie-ins will be completed by August ’06
- AGTPP expected to be at GTI by July’06

Conclusion

- Funding will be needed to carryout any testing or development in the AGTPP
- Please contact the author if you have a potential need for carrying out any testing or development

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MITSUBISHI CO_2 Recovery Technology from Flue Gas
<Experience and R&D Facilities>

9th International CO_2 Capture Network

Copenhagen, Denmark

16 June, 2006

Mitsubishi Heavy Industries, Ltd.

MITSUBISHI
HEAVY INDUSTRIES, LTD.

MITSUBISHI CO_2 Recovery Technology from Flue Gas
<Experience and R&D Facilities>

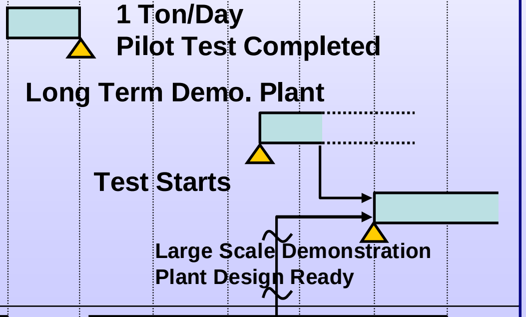
MHI's Evolution Development of Flue Gas CO_2 Recovery Plant

Evolution | 90 | 91 | 92 | 93 | 94 | 95 | 96 | 97 | 98 | 99 | 00 | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09

Coal Fired Flue Gas Application


1 Ton/Day Pilot Plant


Long Term Demo. Plant


1 Ton/Day Pilot Test Completed

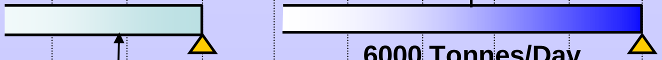
Long Term Demo. Plant

Test Starts

Large Scale Demonstration Plant Design Ready

Enlargement


Large Scale Test Plant


3000 Tonnes /Day Design Completed

FGD Experience

6000 Tonnes/Day Design Completes


3000 Tonnes /Day Plant

Commercial Plant

Start of Development

Nanko Pilot Plant (2 Tonnes/day)

R&D for Process Improvement

Malaysia Kedah (200 Tonnes/day)

Japan, Chemical Company (330 Tonnes/day)

India, Fertilizer Company (450 Tonnes/day x 2)

Abu Dhabi, Fertilizer Company (400 Tonnes/day)


Malaysia kedah Plant


330 Tonnes/day Plant

MITSUBISHI CO_2 Recovery Technology from Flue Gas

<Experience and R&D Facilities>

Commercial Scale Plants

1. CO2 Recovery Plant in Malaysia

Plant Outline

CO2 recovery capacity	**200 ton/day**
Solvent	**KS-1**
Use of CO2	**Urea production**
Start of operation	**October, 1999**
Client	**Petoronas Fertilizer (Kedah) Sdn Bhd**
Location	**Kedah Darul Aman, Malaysia**
Flue gas source	**Stream reformer fluegas**

Process Description

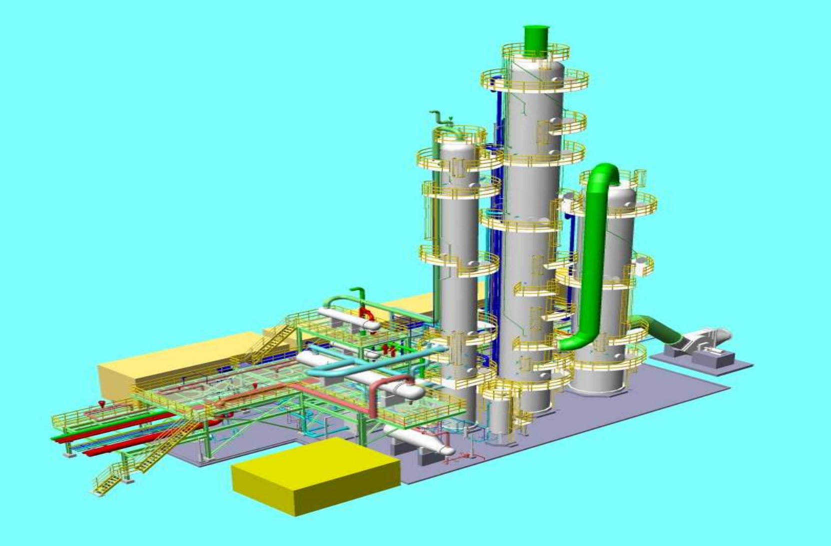
CO_2 is recovered from flue gas of steam reformer of ammonia plant and delivered to CO_2 compressor for urea synthesis. Recovered CO_2 is used to increase urea production. The first commercial plant for flue gas CO_2 recovery using this advance technology has been operating in Malaysia since October 1999 for Urea production. Performance of process is excellent in terms of low steam consumption, very low solvent degradation and low solvent loss.

MITSUBISHI CO_2 Recovery Technology from Flue Gas

<Experience and R&D Facilities>

Commercial Scale Plants

2. Commercial Project in Japan



Plant Outline

Client	A Chemical Company
Capacity	330 T/D (Max.)
Solvent	KS-1
Feed Gas	Natural Gas and Heavy Oil Fired Boiler
Use of CO2	General Use

Process Description

CO_2 is recovered from a natural gas fined boiler and a oil fired boiler. Flue gas is cooled and removed SO_x (When CO_2 is recovered from oil fired boiler) before entering CO_2 absorber. CO_2 is liquefied and used for dry ice, beverages and welding.

MITSUBISHI CO_2 Recovery Technology from Flue Gas
<Experience and R&D Facilities>

Commercial Scale Plants

3. Coal Fired Long Term Demonstration Plant

Plant Outline

Client	Power Station, Japan
Solvent	KS-1
Capacity	10 T/d
Feed Gas	Coal Fired Boiler
Start-up	2006
Location	Nagasaki, Japan

Process Description

This is the demonstration plant for CO_2 recovery from coal fired boiler flue gas. This demonstration plant was constructed 50% cost supported by Japanese Government. The plant is planning a long term operation for coal fired flue gas CO_2 recovery.

Commercial Scale Plants

4. Commercial Project in India

Under Construction

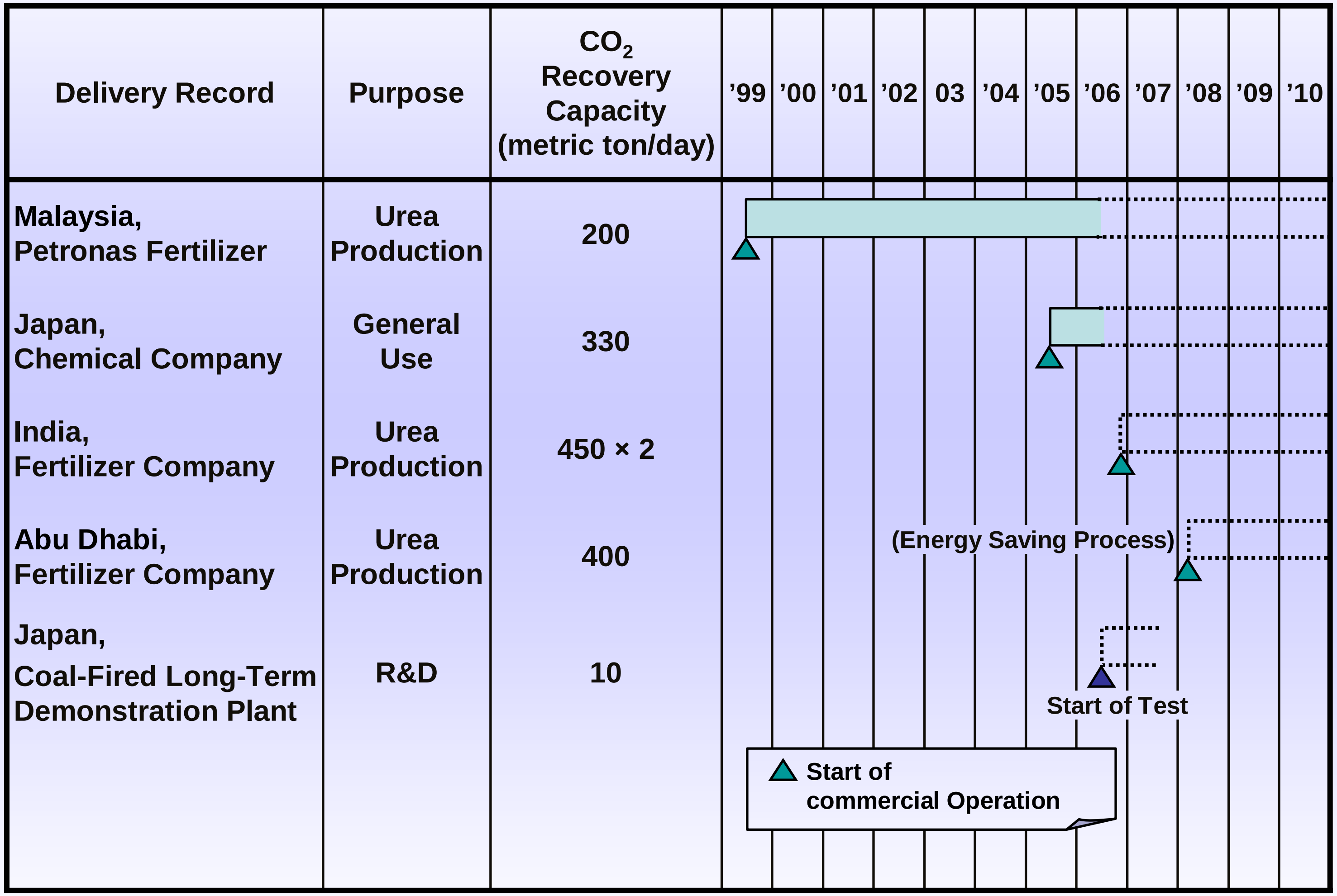
Plant Outline

Client	Indian Farmers Fertilizer Co.
Solvent	KS-1 Solvent
Capacity	450 T/d x 2 units
Feed Gas	Natural Gas and Naphtha Reformer Flue Gas
Use of CO2	Urea Production
Start-up	2007

Process Description

CO_2 is recovered from steam reformer flue gases. CO_2 is compressed and then used for urea synthesis. Flue gas is cooled and then removed SO_X before entering CO_2 absorber.

MITSUBISHI CO_2 Recovery Technology from Flue Gas
<Experience and R&D Facilities>



Delivery Record	Purpose	CO_2 Recovery Capacity (metric ton/day)
Malaysia, Petronas Fertilizer	Urea Production	200
Japan, Chemical Company	General Use	330
India, Fertilizer Company	Urea Production	450 × 2
Abu Dhabi, Fertilizer Company	Urea Production	400
Japan, Coal-Fired Long-Term Demonstration Plant	R&D	10

△ Start of commercial Operation