IPTC
International Petroleum Technology Conference
Innovation and Efficiency Excellence for our Energy Future

14 - 16 November 2016
BANGKOK, THAILAND
Bangkok Convention Centre
at CentralWorld

IPTC-18732-MS
A Technical Evaluation of Hybrid Membrane-Absorption Processes for Acid Gas Removal

Michael Schlierf, Technischen Universität Müchen, Germany

Tom Rufford, The University of Queensland, Australia

Contact: t.rufford@uq.edu.au

The University of Queensland
AUSTRALIA
Create change

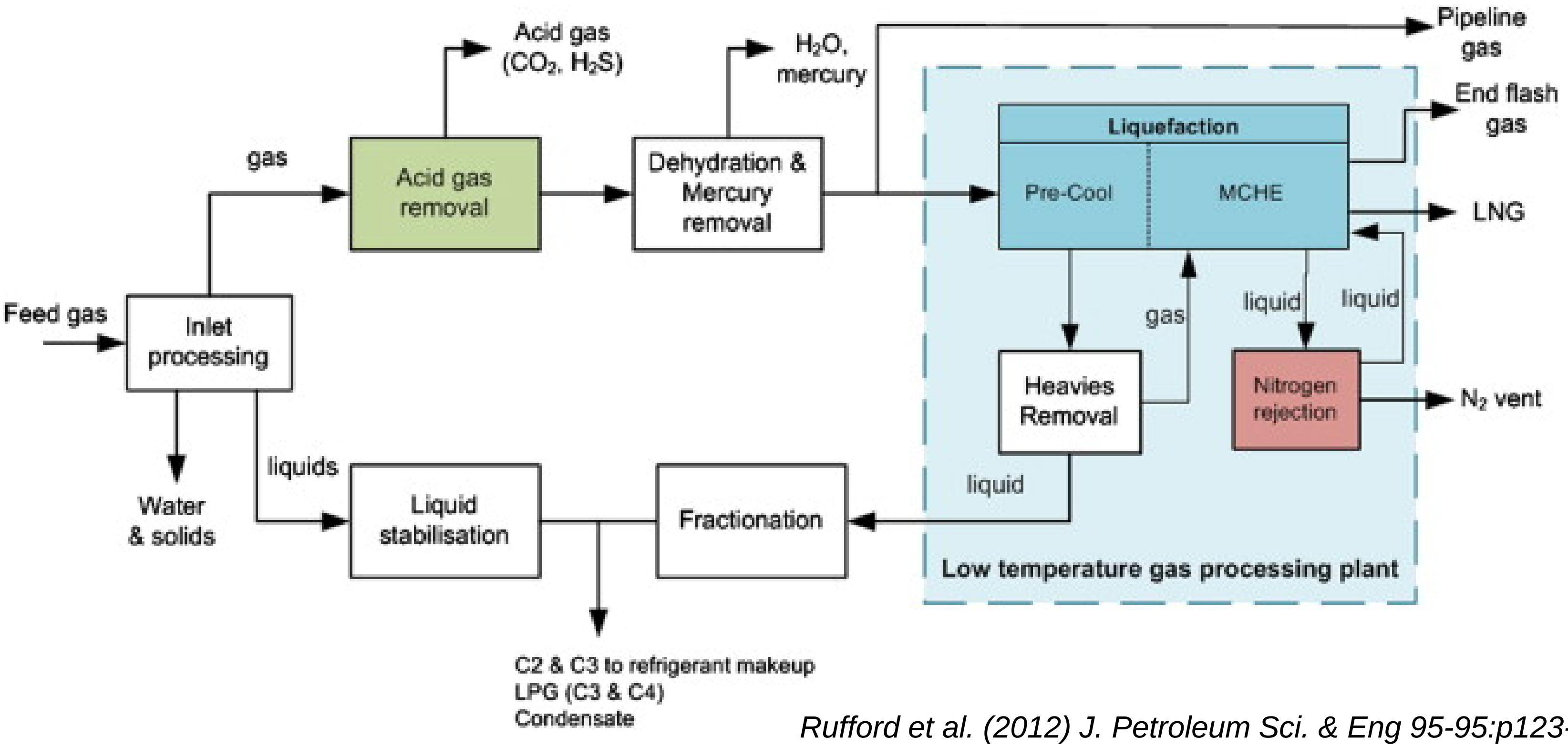
Highlights

Comparison of (1) conventional MDEA amine absorption and (2) hybrid membrane + amine process to treat sour gas for feed to an LNG plant.

Feeds with 10%mol CO_2 → no apparent benefits of a hybrid system.

Very sour feed gas with 50%mol CO_2 the hybrid system has potential for significant reductions in equipment weight, plant volume, investment costs, and operating costs.

Typical process flow scheme for LNG production



Rufford et al. (2012) J. Petroleum Sci. & Eng 95-95:p123-154

Challenges for gas processing in remote or stranded fields

Feed to LNG plant has tight specification, e.g.:

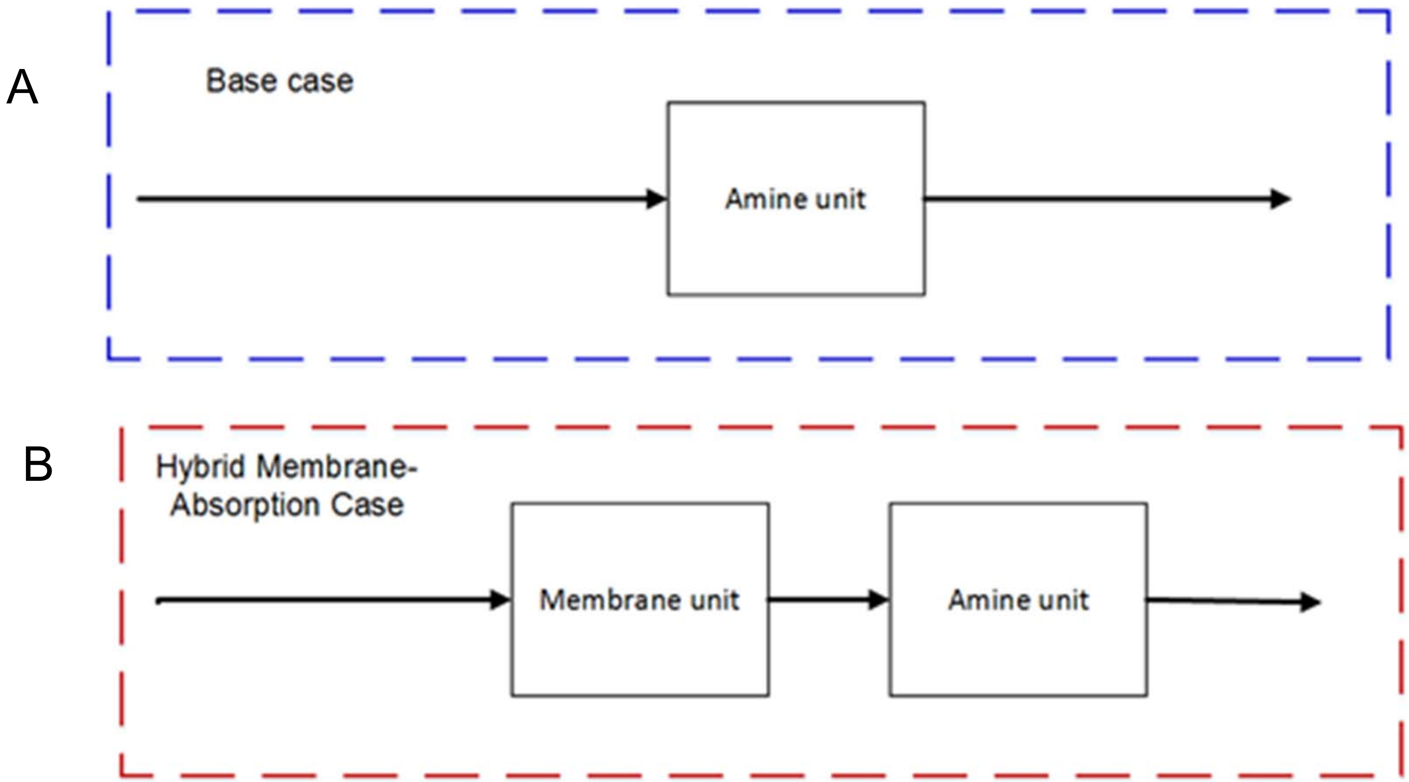
- $CO_2 \leq 50$ppmv
- $H_2S \leq 4$ppmv

To meet these specifications amine plants require large columns, large solvent inventories, high demand for energy.

Floating LNG (FLNG) and micro-LNG plants may need significant reductions in weight, cost, and energy demand.

This project seeks to evaluate the potential of a hybrid membrane + absorption process to treat sour gas onboard FLNG plants.

Overview of the processes compared



Membrane unit alone ***could not*** achieve 50ppmv CO_2

Summary of methodology

Two feed cases developed based on Roussanaly et al. (2014)

	Feed1	Feed2
	Feed compositions in mole %	
Methane	83	41
Ethane	5	4.5
Propane	2	3.5
CO_2	10	50
H_2S	0	1
H_2O	0	0
N_2	0	0
Temp., °C	40	40
Pressure, bar	70	70
Flow Nm^3/h	590,000	590,000

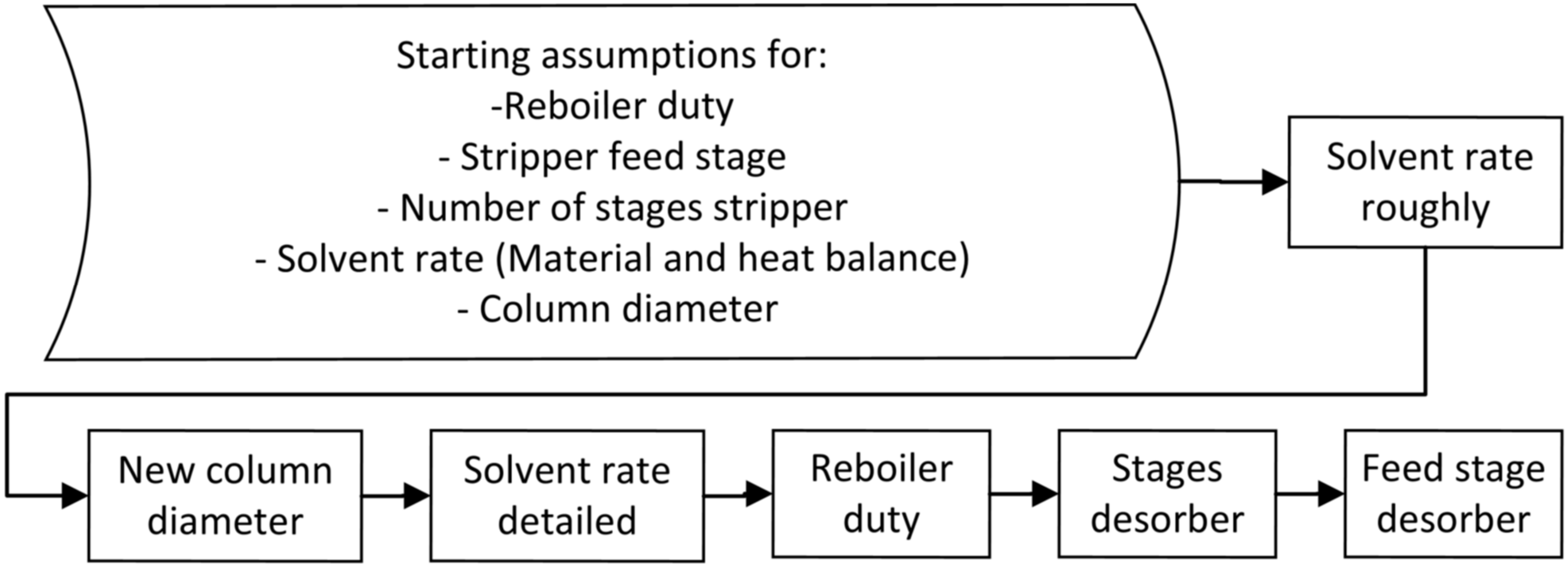
Simulations in *Aspen Hysys V8.6*

Process metrics considered:

- Methane slip (MS)
- Relative energy demand (RED)
- Dry equipment weight
- Dry installed weight
- Total plant volume
- Equipment cost & installed cost
- Operating cost

Aspen Process Economic Analyzer

General simulation strategy



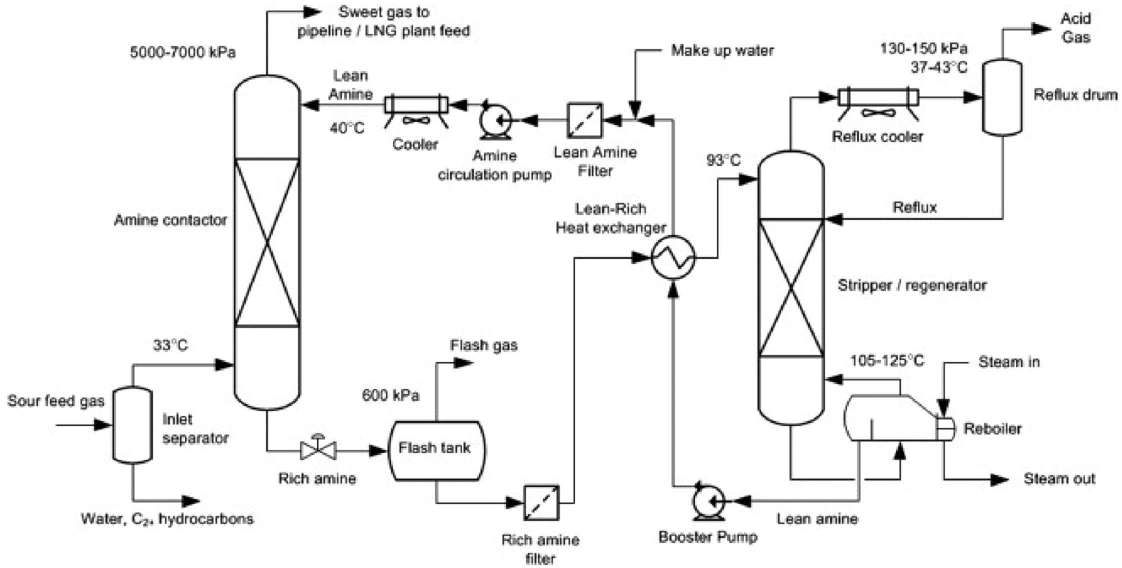
Summary of Base Case: 50% MDEA absorption

50% methyl-di-ethanolamine (MDEA) solvent + piperazine (PZ)

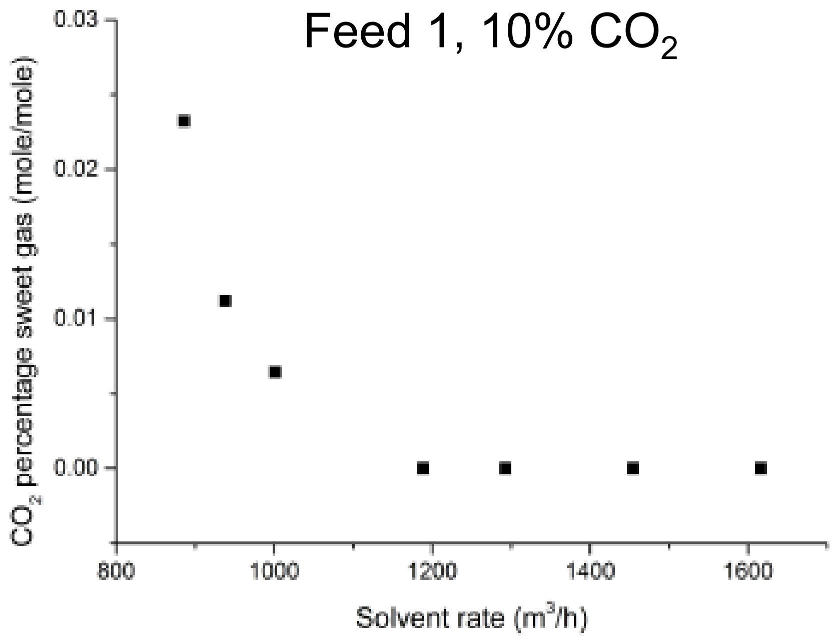
Contactor: P=70bar; Mellapak 250Y structured packing

Stage efficiencies: 0.15 CO_2; 0.8 H_2S

Stripper: 1.9 bar, 50ºC



Solvent rate required to achieve 50 ppmv CO_2 spec



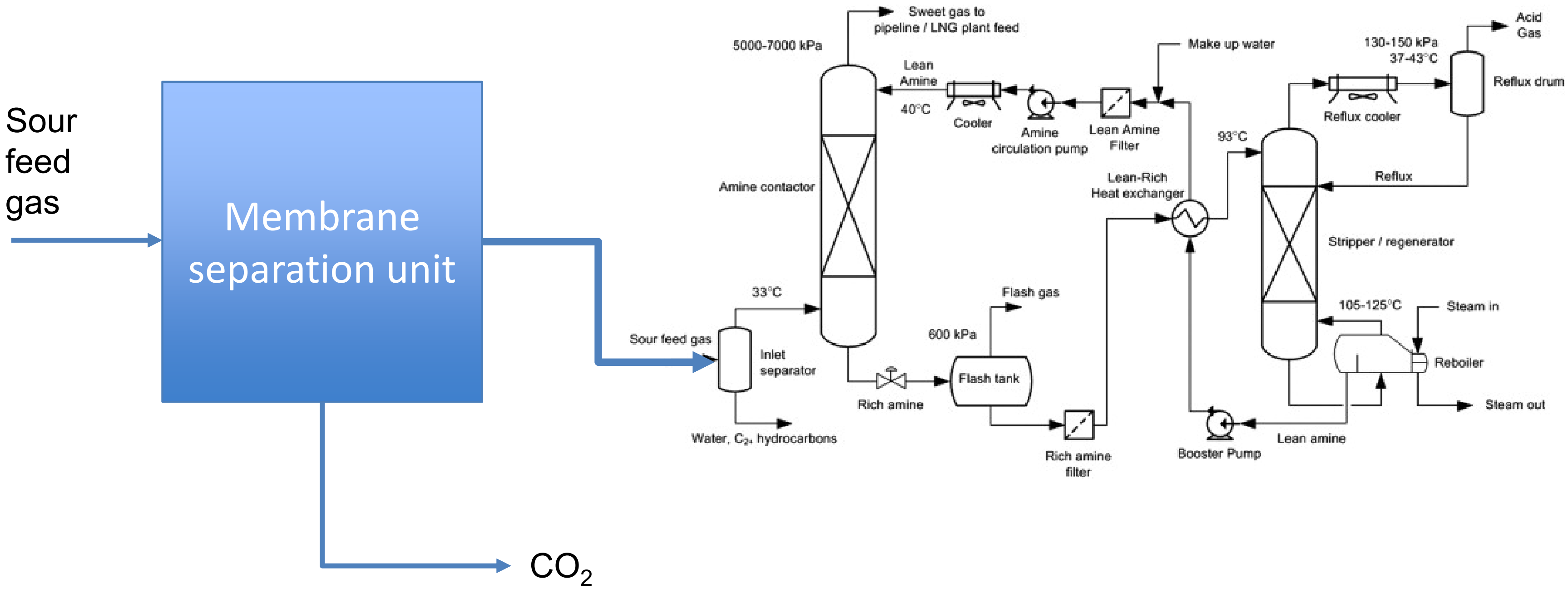
Run absorber hard to get 50 ppmv CO_2 for LNG prep. (vs 2% pipeline gas)

Optimized solvent rate = 1258m^3/h

Summary amine unit requirements for Feed 1 and Feed 2

	Feed1	Feed2
CO_2, %mol	10	50
H_2S, %mol	0	1
Solvent rate m^3/hr	1258	4105
Absorber stages	20	20
Absorber diameter, m	10	15
Stripper stages	7	7
Reboiler duty, Btu/gal lean solvent	880	880

Hybrid membrane-amine unit



Method to model membrane separation unit

Material: cellulose acetate (CA) membrane

Selectivity P_CO_2/P_CH_4 = 15 (Niu and Rangaiah, 2014)
Selectivity P_H_2S/P_CH_4 = 19

Permeate pressure = 1.38 bar

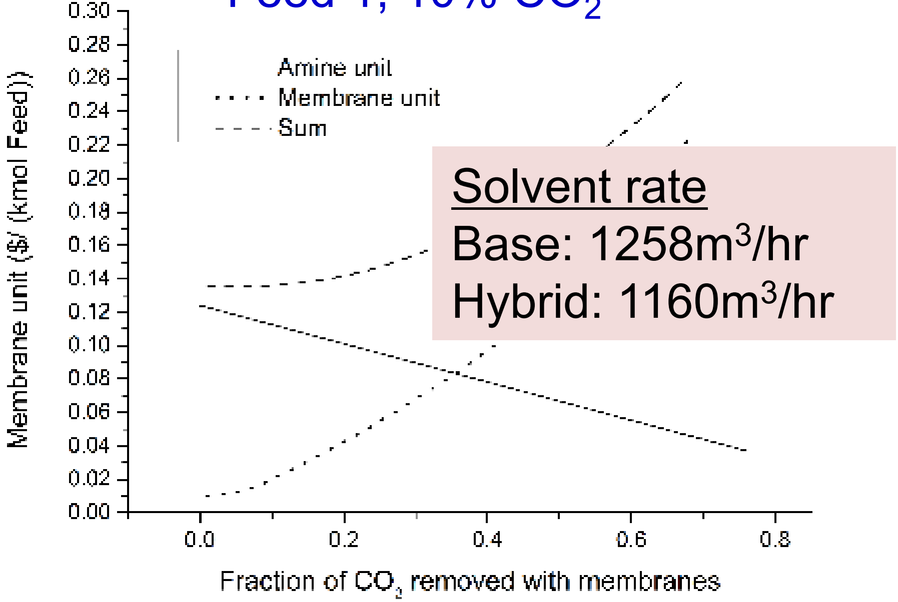
Membrane thickness = 100 nm (i.e. CA thickness on a substrate)

Modeled membrane unit in a user defined subflowsheet

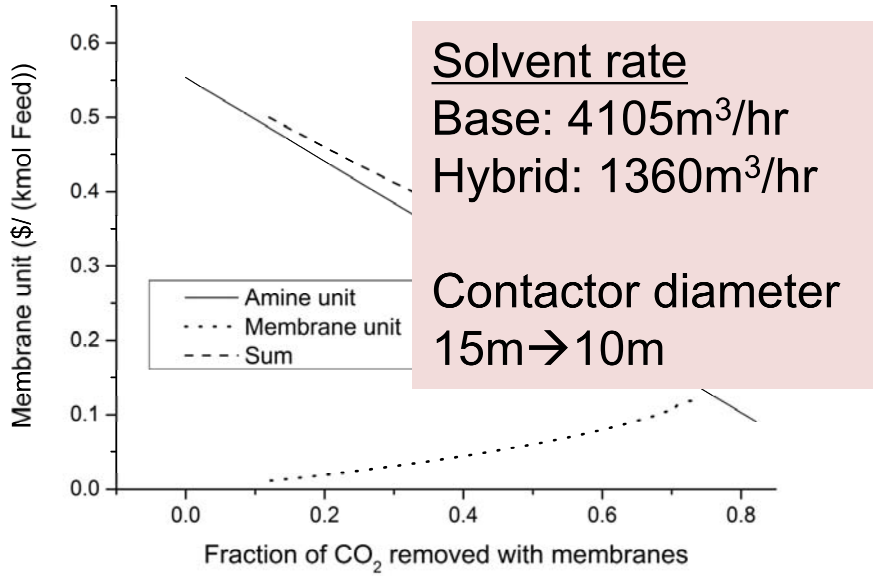
How much CO_2 to remove in the membrane unit?

Each mole of CO_2 removed in membrane unit reduces solvent rate & reboiler duty required in the amine section. *Control = membrane area*.
→ Reducing hydraulic load also effects equipment sizing

Feed 1, 10% CO_2

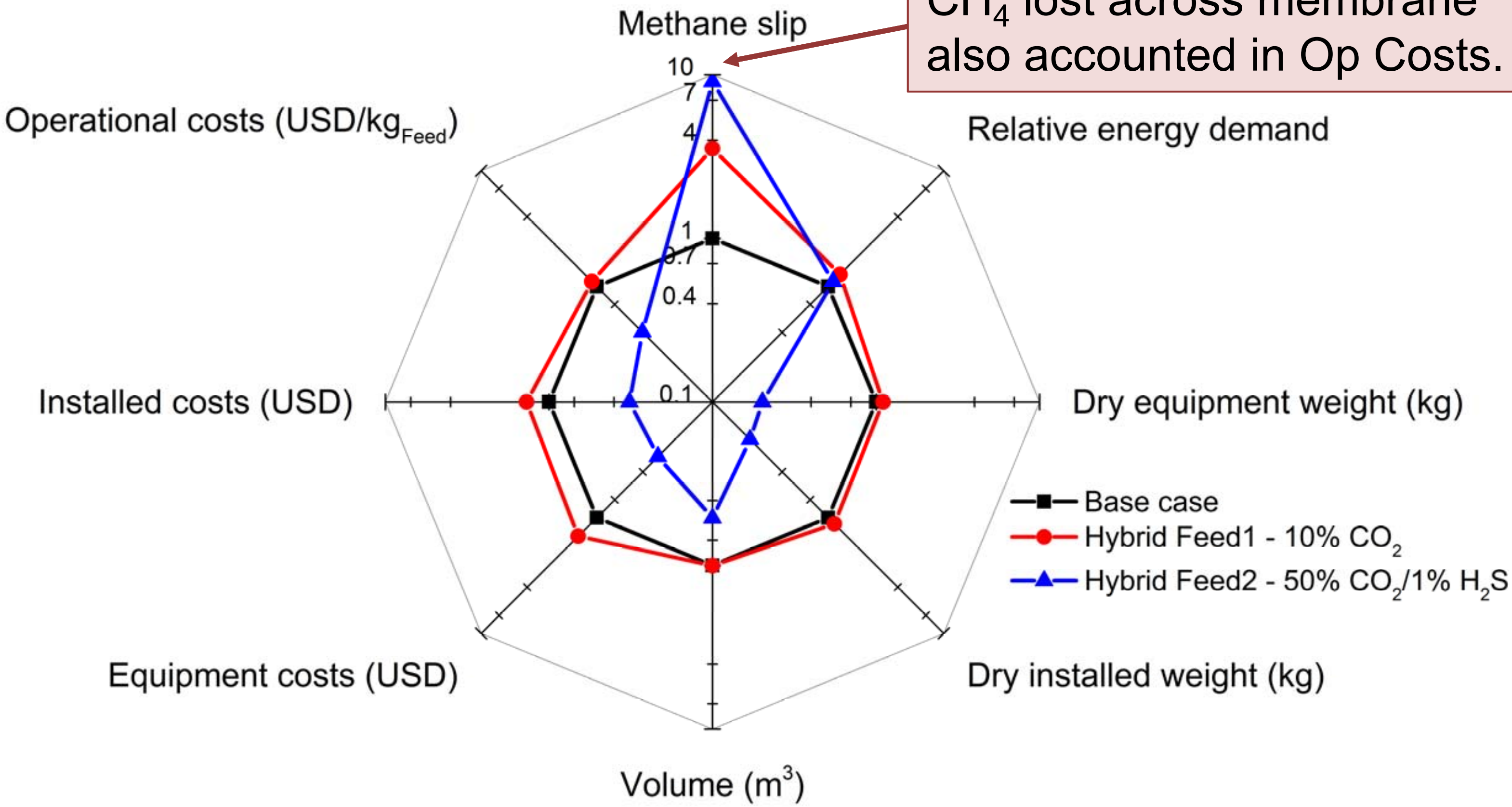


Feed 2, 50% CO_2 + 1% H_2S

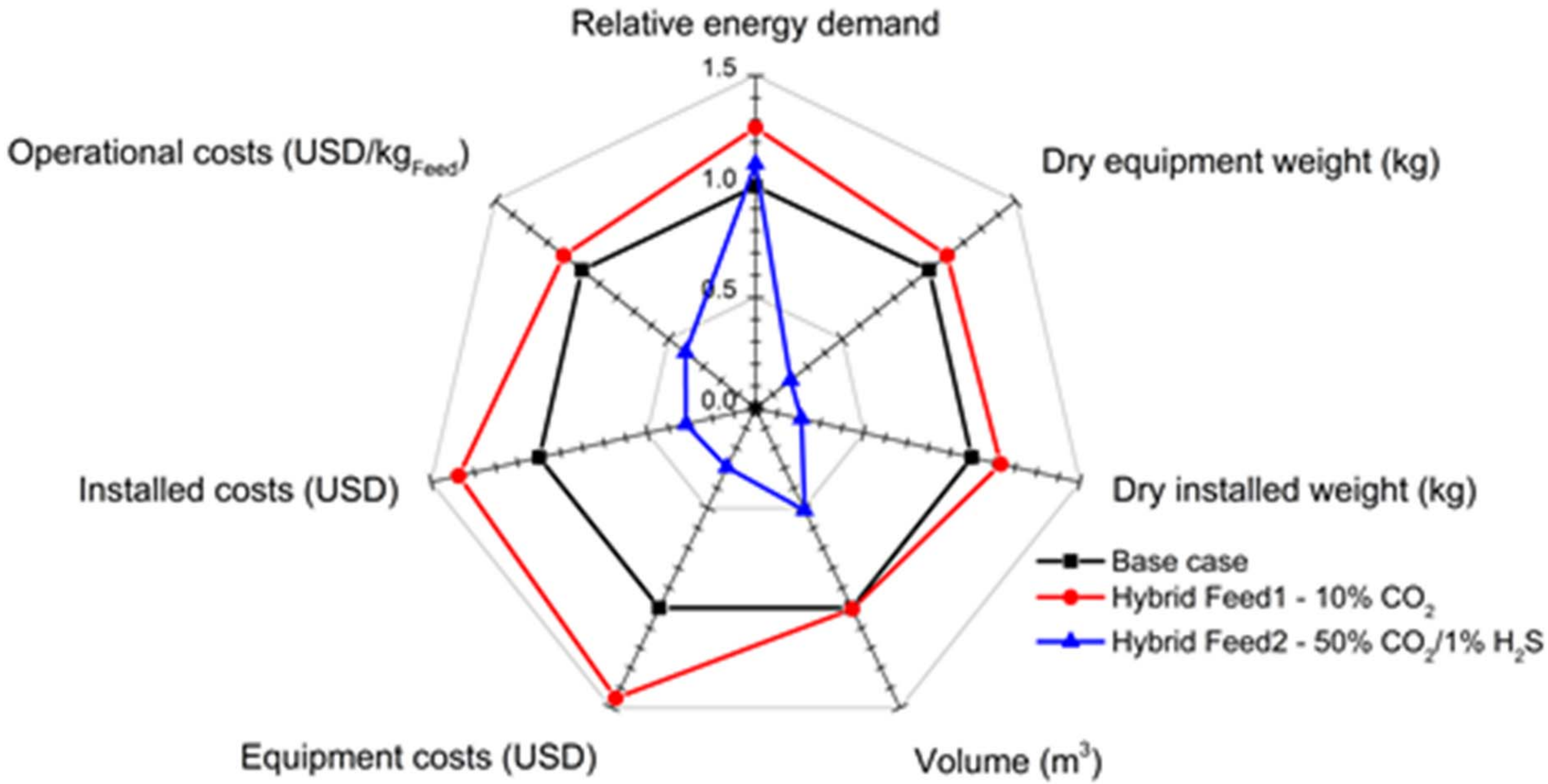


Process metrics spider plot (log scale)

CH$_4$ lost across membrane also accounted in Op Costs.



Comparison of process metrics



Feed 1 10% CO_2 summary

No clear advantage of hybrid system for this feed scenario and membrane properties.

- 7.8% lower solvent rate in hybrid process, doesn't impact column size
- 30% drop in energy for reboiler, pumps in amine unit

Those benefits offset by:

- methane slip in membrane unit
- Small increase in equipment weight (MSU + base case amine unit)
- Hybrid process costs all increase

Feed 2 50% CO_2 + 1% H_2S Summary

For very sour gas feed there is potential to use bulk separation properties of the membrane unit.

- 67% reduced solvent rate in hybrid process
- 80% reduced equipment weight, 50% reduced plant volume

Methane slips increases → ~10% CH_4 in feed lost across membrane

- Still energy savings allow 40% reduction in operating costs
- Methane slip has implications on any CO_2 processing/storage plans

Highlights

Comparison of (1) conventional MDEA amine absorption and (2) hybrid membrane + amine process to treat sour gas for feed to an LNG plant.

Feeds with 10%mol CO_2 → no apparent benefits of a hybrid system.

Very sour feed gas with 50%mol CO_2 the hybrid system has potential for significant reductions in equipment weight, plant volume, investment costs, and operating costs.

Acknowledgements / Thank You / Questions

This work was funded in part by:

- The Australian Research Council (DE140100569)
- Technischen Universität Müchen travel support for Michael to UQ

IPTC attendance supported by SPE Faculty Enhancement Travel Award

Cited references

Niu, Mark Wendou, G. P. Rangaiah. 2014. Retrofitting amine absorption process for natural gas sweetening via hybridization with membrane separation (in *International Journal of Greenhouse Gas Control* **29**: 221-230

Roussanaly, S., R. Anantharaman, K. Lindqvist. 2014. Multi-criteria analyses of two solvent and one low-temperature concepts for acid gas removal from natural gas (in *Journal of Natural Gas Science and Engineering* **20**: 38-49.

Rufford, Thomas E., Simon Smart, Guillaume C.Y. Watson et al. 2012. The removal of CO_2 and N_2 from natural gas: A review of conventional and emerging process technologies (in *Journal of Petroleum Science and Engineering* **94-95**: 123-154.

Methane slip (MS) The methane slip depicts the percentage of methane lost during the purification process. It is defined in Equation 5.1.

$$MS = 1 - \frac{CH_4 \ in \ the \ product \ gas}{CH_4 \ in \ the \ raw \ natural \ gas} \tag{5.1}$$

Relative energy demand (RED) This indicator is the ratio of lost and required energy based on the combustion heat of the product gas $\dot{Q}_{Prod}$, depicted in Equation 5.2. The absolute energy demand can be calculated by summing up the differences in the combustion heats of the raw gas $\dot{Q}_{Raw}$ along with the product gas $\dot{Q}_{Prod}$, electrical energy P_{el} and the required heat of the reboiler $\dot{Q}_{Reb}$. The electrical energy P_{el} in the gas facilities is provided by gas turbines. For calculating P_{el} a turbine efficiency of $\eta = 0.4$ is assumed.

$$RED = \frac{\dot{Q}_{Raw} - \dot{Q}_{Prod} + P_{el}/\eta + \dot{Q}_{Reb}}{\dot{Q}_{Prod}} \tag{5.2}$$

Operational costs Table 5.2 provides the information needed for calculating the operational costs. Maintaining costs are neglected in this paper.

Table 5.2: Values for calculating the operational costs of base and hybrid case

	Value	Unit	Source
Cost for reboiler steam	0.0145	\$/kg	[20]
Cost for electricity	0.07	\$/kWh	[20]
Cost for cooling water	0.01	\$/t	[20]
Cost for process water	0.0005	\$/kg	[20]
CH_4 Loss	4	\$/MMBtu	[20],[39]
Lower heating value methane	10	kWh/m^3	[40]
Cost for MDEA	5.5	\$/kg	[41]
Cost for PZ	7.7	\$/kg	[41]
Solvent Degradation	0.25	kg/t_{CO_2}	[20]
Temperature saturated steam	140	°C	
Efficiency of reboiler heating	0.9		