Between 2001 and 2011, I used to tell my students at the University of Western Australia that Floating LNG would never happen.

And then I had an epiphany… which I will tell you about later.

FLNG is coming, it is a game changer, and I believe it changes the game for us in subsea too.

In fact, just as Floating LNG is a game changer, so the subsea part has to be re-engineered too:

• Firstly, to take advantage of the new opportunities that come from having the LNG plant right next to the gas reservoirs, instead of hundreds of kilometres away,

• And secondly, to avoid the pitfalls that can come with this new technology.

FLNG represents a truly revolutionary technique that avoids expensive and vulnerably long export pipelines plus politically, socially and environmentally sensitive land-based facilities, by placing the LNG plant offshore, right above the subsea wells. This emergent opportunity has the potential to substantially revitalise Western Australia's outlook for development of natural gas reserves, steering clear of some of the major challenges encountered during recent developments. Where does the future lie without this opportunity? However, the viability of FLNG in Australia may hinge on the ability of our underwater technologies to address anticipated and unanticipated challenges. So, what about the subsea equipment? Does it need to change? Can it be optimised for FLNG? With a theme of "Smaller, Smarter, More Dangerous", this presentation looks first at how FLNG can use the existing suite of underwater technologies for developing remote gas fields. It then focuses on "smarter" subsea infrastructure which could help to give technical, economic and operational edge needed to establish FLNG as a new means to open up Western Australia's untapped gas. However, the uncertainties and dangers associated with FLNG should not be underestimated and our industry needs to be smart, agile and responsive. Casting a critical eye over public domain information on existing and upcoming FLNG developments, this presentation poses some questions but also give some answers to the key question – FLNG is coming, what does this mean for our industry?

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2

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EcoNomics

But first, a disclaimer. This presentation is my personal opinion, and uses information in the public domain.
Another disclaimer is that I've never worked on a "real" FLNG project. But that's good, because I'm not bound by any confidentiality agreements.
I ***have*** studied the subject in some detail, and I've had 120 students and engineers working on this in my Subsea Technology course at the University of Western Australia:

- The course was actually established by Chris Lawlor back in 1996, but I've helped to keep it running, and brought in new developments such as FLNG.
- In 2012, the student project was the Scarborough field, and in 2013, the Browse LNG development, and I'll be revealing some of their work shortly.

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3

Some justification for all this

▸ What about subsea?

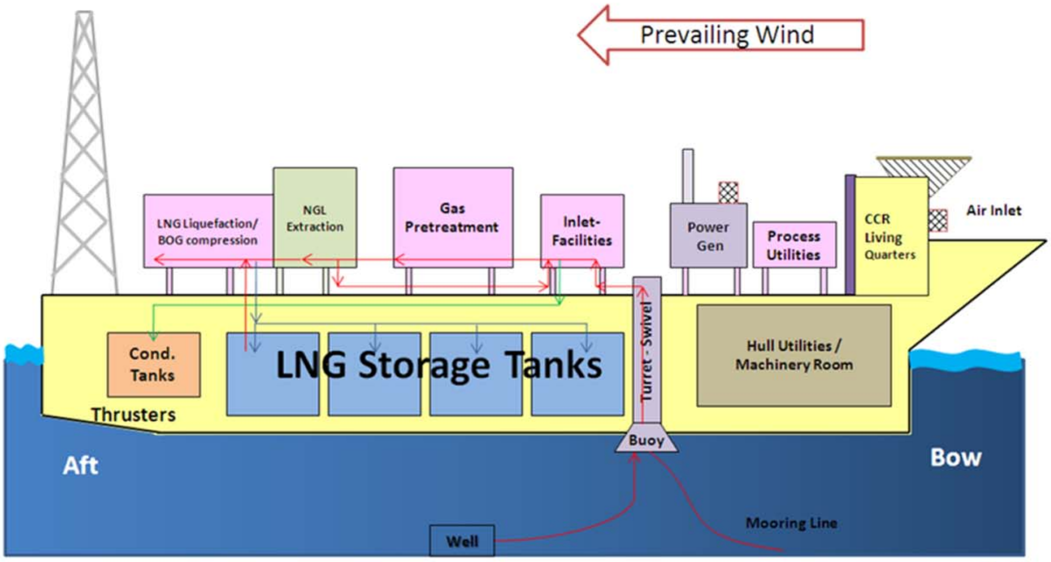

Image: IPTC 14548 EcoNomics

So why am I talking to the Society for Underwater Technology about Floating LNG ?
Well, this picture tells it all! Most of the information on Floating LNG is about the vessel and the technology used on it.
The subsea aspects (like this poor little well here) get no attention at all.
And another aspect is not even shown here – the geopolitical socioeconomic landscape in which LNG is developed.
So I want to talk about what goes on underneath the waterline, and also the big picture of Floating LNG.

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Agenda

- Subsea Developments for FLNG Production
- Smaller, Smarter, More Dangerous
  - Turning constraints of FLNG to advantage
  - Impact of FLNG on subsea field layout
  - New subsea technologies for FLNG
  - Risks to FLNG from subsea developments
- Case studies

EcoNomics

The context in which I'm speaking is the Browse LNG type developments, with massive offshore infrastructure, long distance subsea pipelines, and onshore LNG plants, being developed instead with Floating LNG.
My theme is "Smaller, Smarter, More Dangerous".
I'll explain what I mean by that, and then give some case studies.
So why do I say it's smaller? After all, Prelude is huge, the biggest vessel ever floated.

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Smaller, Smarter, More Dangerous

- Australian LNG projects, capital costs and unit costs
  - FLNG is small – single train
  - Typical fields will require several FLNG
  - Prelude: 3.6 – 5 MTPA LNG

Project	State	Year completed	Capital cost A$b	Capacity Mtpa	Unit cost $/t
North West Shelf 4th train	WA	2004	2.5	4.4	568
Darwin LNG	NT	2006	3.3	3.2	1031
North West Shelf 5th train	WA	2008	2.6	4.4	591
Pluto LNG	WA	2012	14.9	4.3	3465
Gorgon LNG	WA	2015	43	15	2867
Queensland Curtis LNG	QLD	2015	19.4	8.5	2353
Gladstone LNG	QLD	2015	15.5	7.8	1987
Prelude	Floating	2016	10+	3.6	>2777
APLNG	QLD	2015	13.6	4.5	3022
Wheatstone	WA	2016–17	29	8.9	3258
Ichthys	NT	2016–17	33.3	8.4	4048

Source: BREE

EcoNomics

We can see here how Prelude compares with typical LNG developments.
Prelude is only 3.6 MTPA. Typical fields would require 2 or 3 FLNG vessels. Woodside say they will need 3 for Browse.
Prelude is designed for 3.6 MTPA of LNG, but for a field with no liquids, Prelude could handle 5 MTPA of LNG.

At this point, you may be beginning to see some cracks in the concept of the one-size-fits-all FLNG approach. Reservoirs are different sizes, and contain different amounts of gas and liquids. It’s unlikely that you can just move an FLNG from one field to another, the processing equipment on board would have to be changed.

To look at the small size of Prelude another way, you can see that Prelude only makes a small impact on the total LNG volume produced in Australia.
To do all of this with FLNG, you would need 20 or 30 Prelude size vessels.

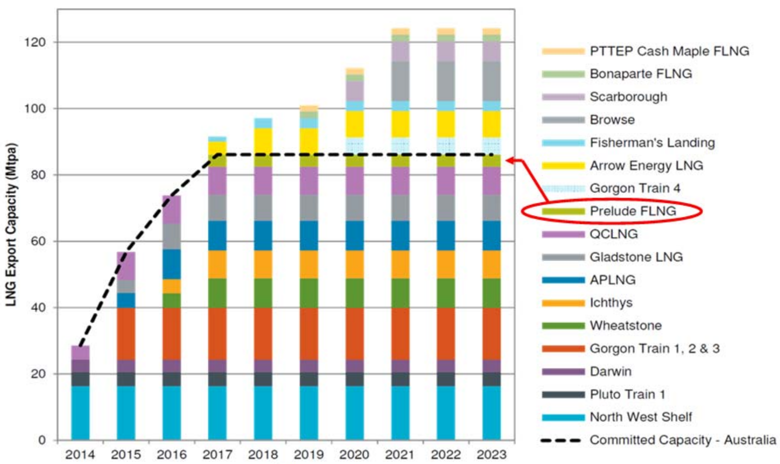

Chart: imo Gas Statement of Opportunities

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Smaller, Smarter, More Dangerous

- Mini and micro FLNG
- The constraint is LNG tankers
  - Up to 266,000 m^3, the majority are 120,000-140,000 m^3

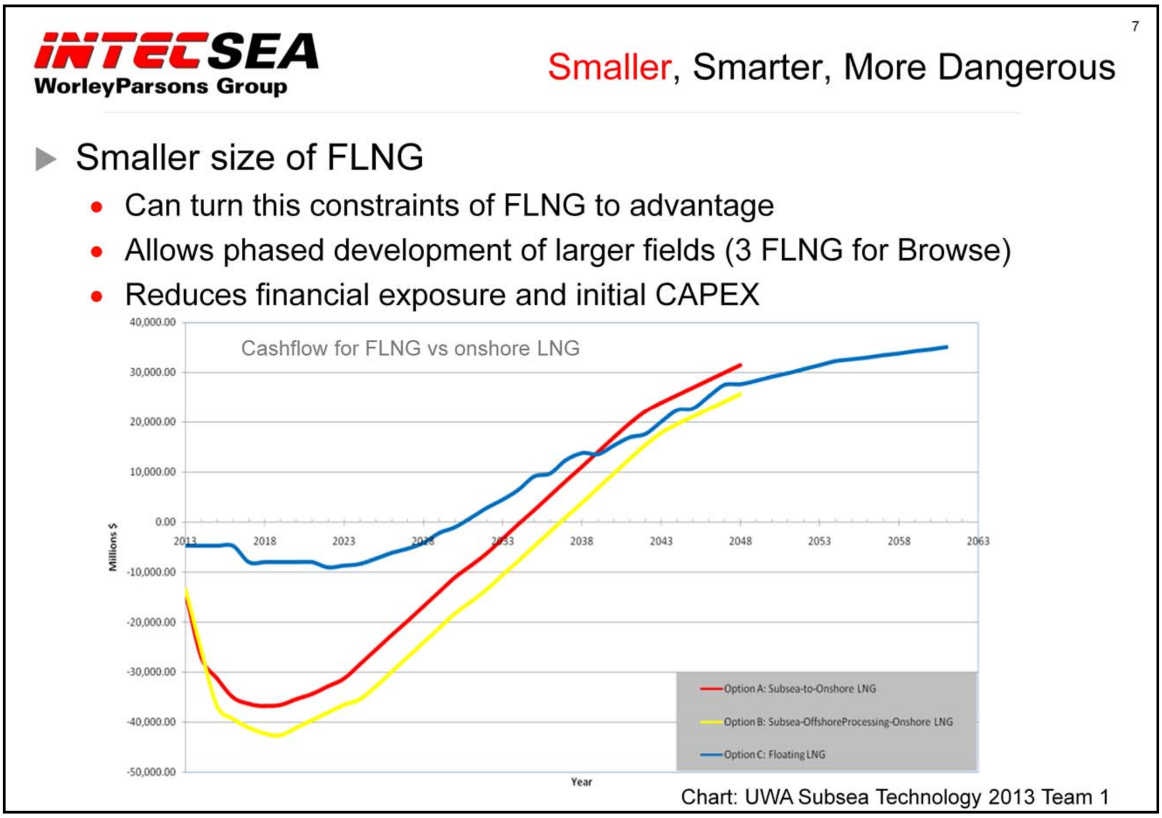
FLNG Facility	Capacity	Length	Storage	Storage	Weight
Shell Prelude	3.6 MTPA	488 m	220,000 m^3	10 days	600,000 tonnes
Petronas Kanowit	1.0 MTPA	365 m	177,000 m^3	29 days	125,000 tonnes
Exmar Pacific Rubiales	0.5 MTPA	144 m	16,000 m^3 *	5 days	

*Exmar Pacific Rubiales FLNG has 144,000 m^3 FSU alongside

EcoNomics

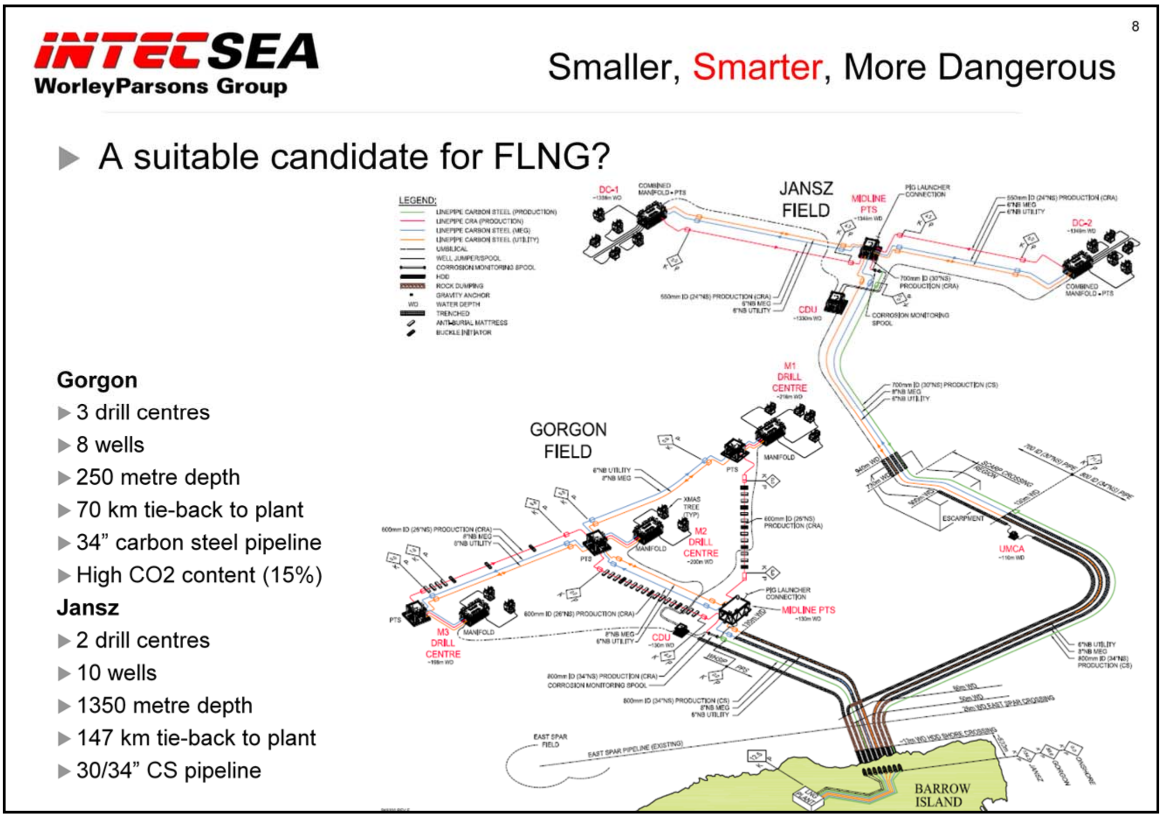
There ***are*** other FLNG developments currently being constructed, but Prelude is the biggest.
The LNG has to be stored and then offloaded into an LNG tanker which puts constraints on the size and production rates of the vessels.
But the smaller size of FLNG can actually be turned to advantage.

The Petronas Kanowit development is smaller at only 1 MTPA but it's interesting to note that they are already developing a second at 2 MTPA.
Pacific Rubiales is different, it is much smaller, and takes gas from an onshore field. It processes the gas on a barge with minimal onboard storage, and relies on having a tanker moored alongside.
Mind you, Exxon Mobil are talking about a 7 MTPA facility for Scarborough, though I think that's a bit ambitious.



Big LNG developments need huge capital outlay before any gas starts to flow and any revenue starts coming in. You can see this in the red and yellow curves, where the CAPEX is 40 billion dollars.
If we develop these fields instead with FLNG, we don't need all three FLNG vessels coming online at the same time. They would be built and installed in phases, so the initial outlay is only for a single FLNG, not three.
Once the first FLNG is installed and producing, it starts generating revenue, so a second and then a third can be brought into service, using revenue to fund the later phases.
The benefit of the phased development is that the financial exposure is far less than for conventional developments, where the entire system has to be built before any LNG can be produced.

CAPEX could be 60 billion dollars for Gorgon, and possibly 80 billion dollars for Browse at James Price Point according to Woodside figures.



The big offshore developments that we see at the moment have long trunklines to bring the gas to shore, with MEG injection to prevent hydrate formation.

- Are these developments suitable for Floating LNG?
- Is it just a case of mooring a Floating LNG vessel over the field and producing, or does the subsea architecture and equipment need to change?

I believe that it does.

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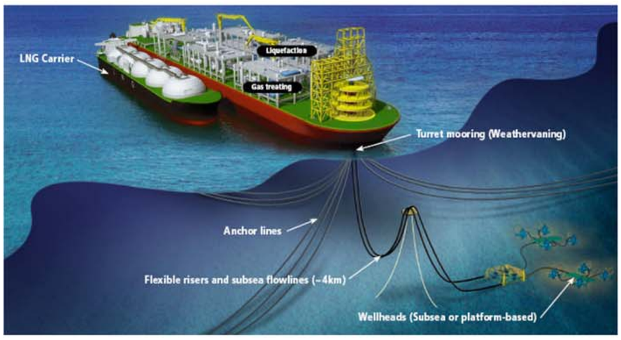
9

Smaller, Smarter, More Dangerous

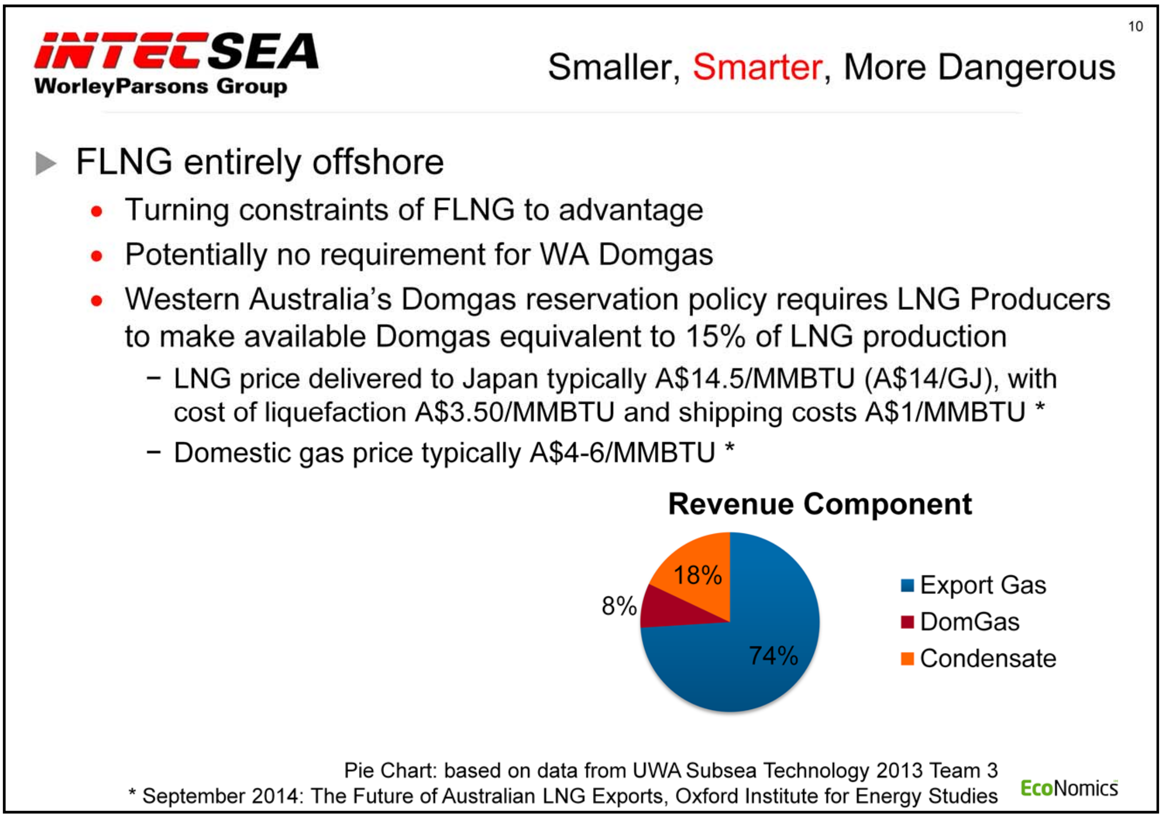
- Having FLNG close to wells is an enabler
  - Allows pipeline heating
  - Reduces dependence on chemicals (MEG)
- Shorter distance to wells
  - Slugs and liquid hold-up in flowlines is less of a problem
  - No need for compression or boosting
  - Less failure-prone equipment on the seabed



Courtesy: Referral of proposed action – Shell Prelude FLNG facility, 2008

EcoNomics

Bringing the LNG facility to the wells dramatically changes the technologies that can be used subsea.
Technologies that can't be used over long distances such as pipeline heating are now back on the table.
That can reduce the need for hydrate inhibitors. You might only need them for startup, rather than continuous injection.
Slugging and liquid build-up in the lines is less because the flowlines are shorter.
Another massive benefit of shorter distances is that subsea compression and boosting and separation are not needed, which means there is less equipment on the seabed which can fail. As we know, getting rid of that stuff is one of the smartest things you can do!
But the smart things are not just on the seabed…



By locating the FLNG entirely offshore, there is a possibility of avoiding the need for Domgas in WA.
Estimates for Browse show that Domgas comprises 15% of LNG production but may only gets 8% of the revenue due to the lower sales price of Domgas.

However this situation may change shortly as Domgas contract prices are re-negotiated. Another interesting thing to note is that condensate and LPG can generate a large revenue stream in addition to LNG sales, which can significantly change the economics of an installation.

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11

Smaller, Smarter, More Dangerous

- FLNG entirely offshore
  - Turning constraints of FLNG to advantage
  - Out of reach of environmental activists
  - Greenpeace vessel Arctic Sunrise arrested by Russia
  - Piracy charges for boarding the Gazprom drill rig Prirazlomnaya, downgraded to hooliganism



EcoNomics

Another “big picture” item is that offshore FLNG reduces exposure to environmental direct action.
The onshore protest activity (at James Price Point) may have had something to do with Woodside’s decision to pull out and propose FLNG for Browse - thought they said it wasn’t. We do know that onshore protests have delayed the development of Shell’s Corrib field in Ireland for ten years.
There is still some risk of offshore activism, but there are signs that the tolerance of oil companies and society for eco-hooliganism is waning, and Greenpeace might get a blood nose if they try these stunts again.

12

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Smaller, Smarter, More Dangerous

- Heating of flowlines for hydrate prevention
  - Direct electric heating or trace heating or heated water pipes
  - Reduce need for MEG
  - Reduce need for MEG reclamation on FLNG vessel
- Why?
  - Shell Prelude has 800 m^3/day MEG regeneration system to provide buffer storage, collection and regeneration of MEG
  - MEG facilities including MEG storage tanks, MEG desalination package, MEG regeneration and MEG booster pumps

MEG module for offshore Brazil application
Rich MEG flow 120 m^3/day
300 tonne module

Image: Cameron

But back to subsea…
Flowline heating may take the place of MEG for hydrate inhibition.
Prelude has a massive MEG reclaim package and eliminating anything on its crowded deck would be welcome.

13

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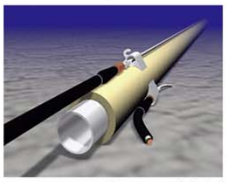
Smaller, Smarter, More Dangerous

- Direct Electrical Heating (DEH)
  - AC current to pipe
  - Field Proven: Single phase required
  - High voltage and power required (100-150 W/m)
- Integrated Production Bundle (IPB)
  - Heating cables/hot water tubes between pipe and insulation
  - Use spare heat from compression / power generation
  - Use for risers
- Electrical Heat Tracing (EHT)
  - Heating cables between pipe and insulation
  - Pipe in Pipe (PIP)
  - AC three phase power
  - Low voltage, low power (4-30 W/m)
  - Higher safety, less dielectric ageing
  - Qualified wire traces and subsea connectors
  - Allows redundancy



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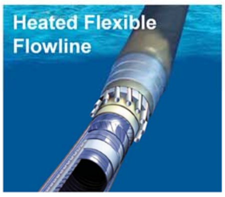

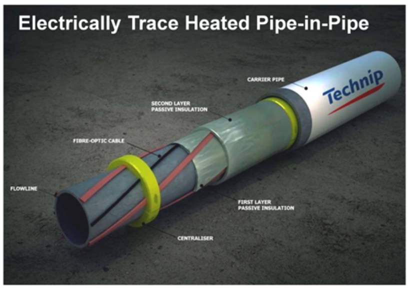

Images: Technip

The heating technologies are shown here:

- Direct Electrical Heating and the Integrated Production Bundle are both well-proven.
- But there is a newly introduced technology, Electrical Heat Tracing for subsea pipelines. This has the potential to change what we do in our industry.

- Direct Electrical Heating uses AC current through the pipe, with a return through the pipe or an external cable. It is field proven: NaKika (Shell, GOM) – 5 cases in Norway (Statoil), but requires a lot of electrical power.
- The Integrated Production Bundle is also field proven has been used successfully for risers on Dalia, Pazflor and the Papa-Terra project

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14

Smaller, Smarter, More Dangerous

- Electrical Heat Tracing (EHT)
  - Low voltage, low power (4-30 W/m)
  - Redundant trace heating cables
  - Fibre optic for thermal monitoring

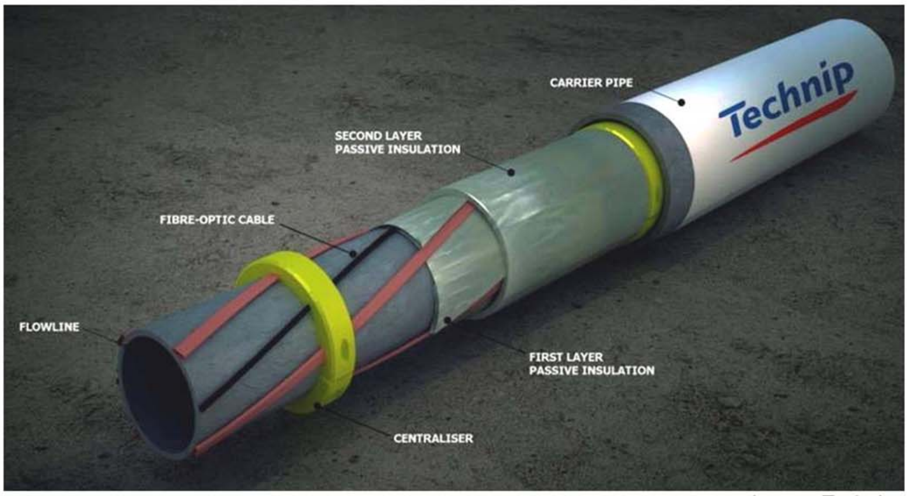

Image: Technip

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The power required is relatively small thanks to the insulation and the pipe-in-pipe. You can even monitor the temperature with the imbedded fibre optic cable.

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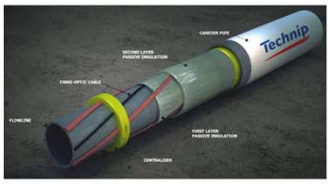
15

Smaller, Smarter, More Dangerous

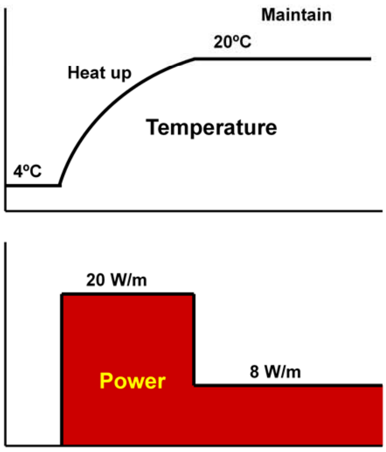
- Electrical Heat Tracing (EHT)
  - Low voltage, low power (4-30 W/m)
  - Redundant trace heating cables
  - Fibre optic for thermal monitoring



Power requirements for Islay EHT

	Power required per metre	Overall power required
Maintain temperature above HAT (ca 20°C)	4 to 8 W/m	Ca. 50 kW
Heat up pipeline from 4 to 20°C in 24 hours	15 to 20 W/m	Ca. 120 kW
Heat up pipeline from 4 to 20°C in 30 hours with 15% of hydrates	30 W/m	Ca. 180 kW

Courtesy: Total



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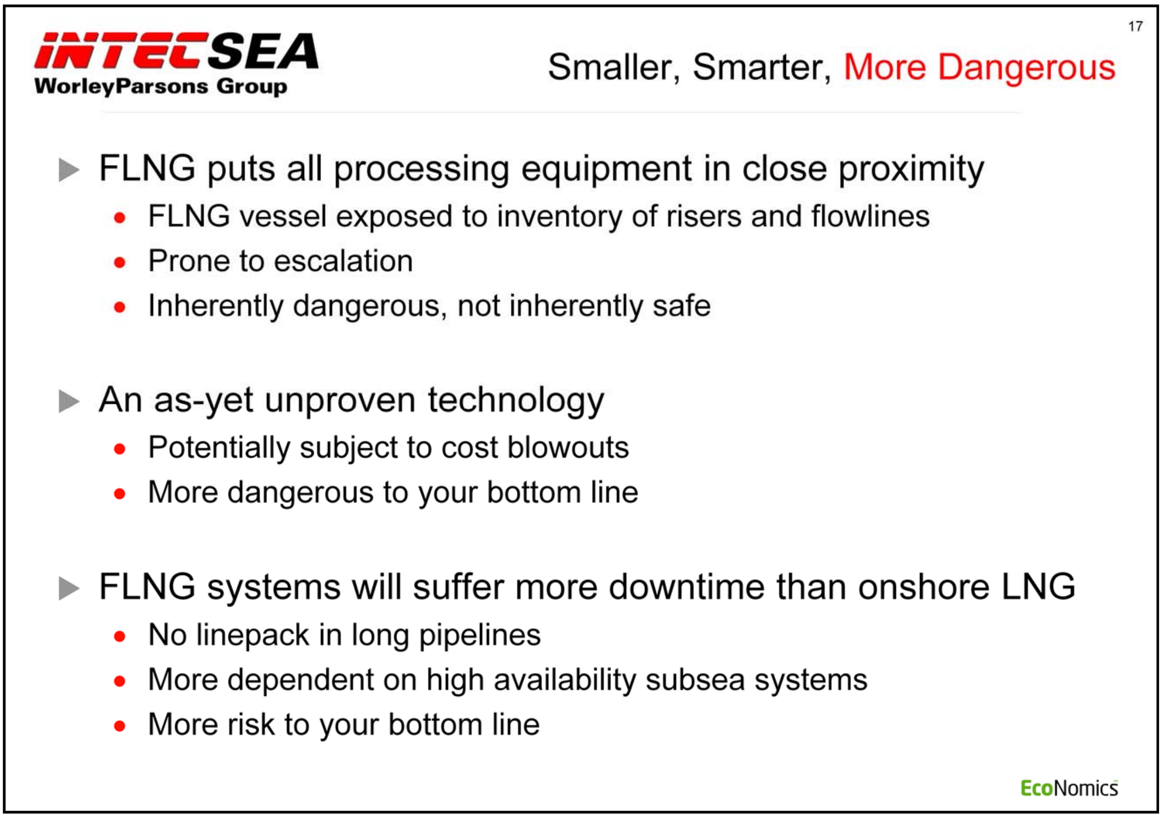
The highest power demand is during pipeline warm-up, when the wells are not producing, and power is ***not*** needed for processing and liquefaction.
Once the lines have warmed up, the power demand is less. It just fits in beautifully with the power demand for FLNG.
But there’s more!

The Electrical Heat Traced Pipe in Pipe can be installed by reel lay. They did this on the Islay project where they achieved faster installation than conventional pipelay methods such as S-lay.
So we can use spare power or waste heat, and use reel installation.
It gets rid of the MEG recycling equipment and frees up space on the vessel.
It's like the planets coming into alignment, everything is right for this new technology.

A complete reel length is fabricated onshore in controlled conditions, and reeled onto the installation vessel, taken out to the field, and unreeled onto the seabed. Lay rates of up to 16 kilometres per day can be achieved with reel lay.
The Electrical Heat Traced Pipe in Pipe is qualified for sizes up to 12" which makes it ideally suited for FLNG developments. These don't have the 40" export pipelines need by the Gorgon and Ichthys type projects.



More dangerous? This has three aspects.
First, putting explosive or inflammable things close together is a recipe for disaster.[1]
FLNG vessels are big – very big – and they use air gaps between modules. But putting all that equipment close together must increases the risk of escalation. Also, hooking the FLNG up to the subsea system increases the risk.

We've also got the issue of technical risk. Ann Pickard of Shell described FLNG as the potential "saviour" of Australian LNG, in the light of cost blowouts suffered by current projects.
But is that realistic, for an as-yet unproven technology?

And another area of concern is the availability and operability of FLNG systems.
Conventional systems have the benefit of long pipelines which act as a buffer and allow LNG production to continue when the subsea system is down.
FLNG systems don't have this buffer. If the subsea system trips, you have to shut down LNG production. Recycling the gas around the process may buy you a bit of time, but eventually you have to shut down. You are totally reliant on a high availability subsea system.

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1. We saw escalation in the pipeline rupture and fire at Varanus Island, where the narrow pipeline corridor resulted in one ruptured pipeline setting off another and then another.

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18

Smaller, Smarter, More Dangerous

- Risk is higher with FLNG than FPSOs
  - Risk = Likelihood x Consequence
  - Likelihood is higher with gas than with oil developments
  - Consequence of loss of FLNG = $13 billion   Shell Prelude
  - Consequence of loss of FPSO = $1.5 billion   UIBC 2012 data

UPSTREAM INDUSTRY UIBC 2012 BENCHMARKING CONSORTIUM

Database Description

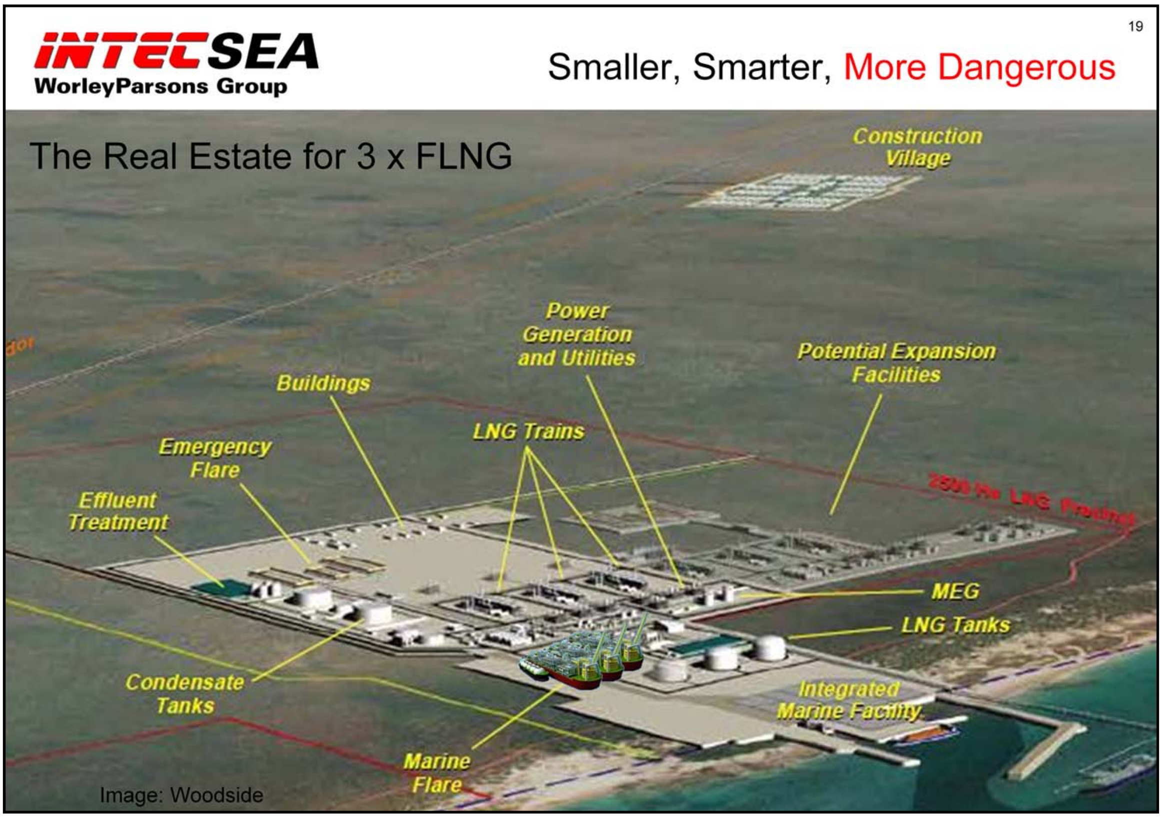
Number of Total FPSs	**134**
Number of FPSO Projects	*78*
Average Floating System Cost *(2012 USD)*	**$1.5 Billion**
Range of Costs (2012 USD)	*Less than $300 million to more than $3 Billion*

- Shell statement in Prelude EIS
  - After comprehensive studies, model testing and in-depth reviews, Shell's FLNG design safety is considered equal to the latest FPSO or integrated off shore facility.

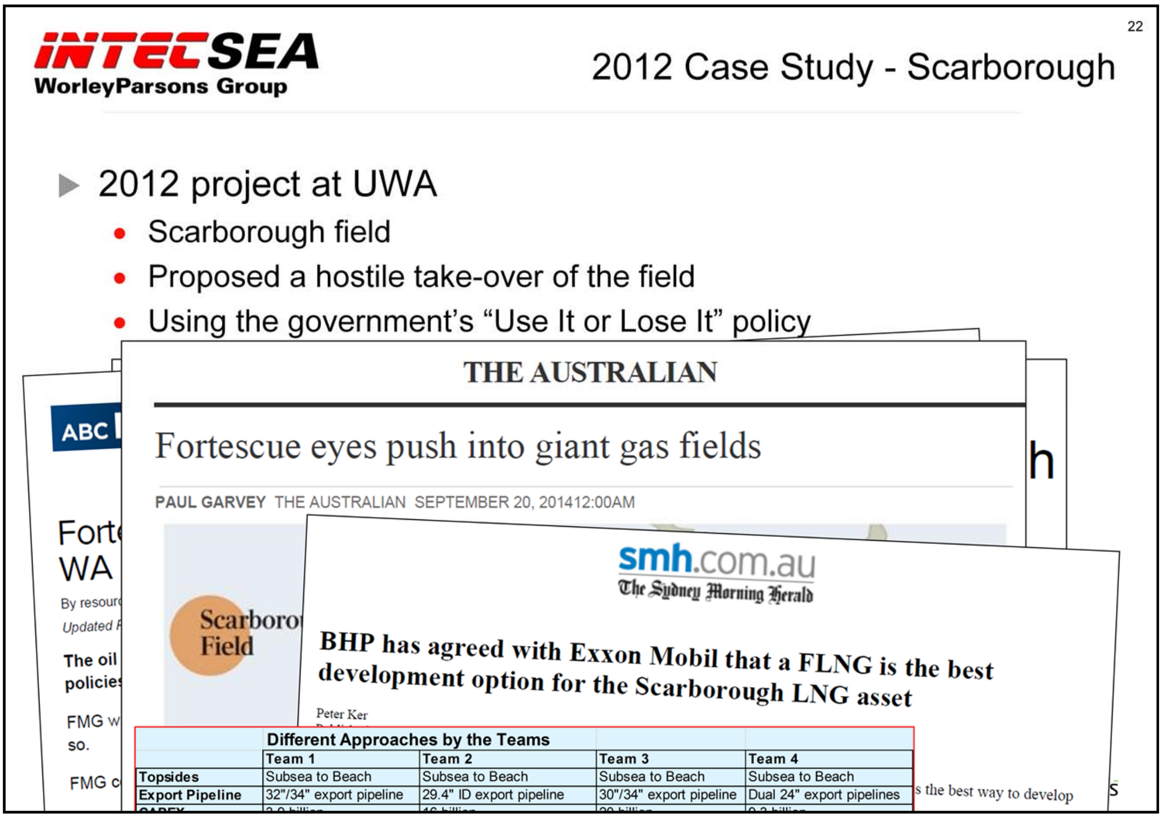
EcoNomics

Shell claims that the safety of their FLNG design is considered equal to the latest FPSOs. I would challenge this. The risk is higher for FLNG than for FPSOs, the two are not comparable at all.
Risk = Likelihood x Consequence:

- The likelihood is higher with a gas-based FLNG than for an oil-based FPSO, gas is inherently more hazardous than oil.
- And the consequences of total vessel loss are much higher for FLNG, as the vessels are more expensive.



Onshore LNG plants such as this proposal for Browse at James Price Point have lots of space between the equipment, it is spread out on a 5km by 5km site.
Any leaks, fires or explosions are far enough from neighbouring equipment to not spread.
But with Floating LNG, all these facilities are put together on the vessel, so escalation is possible.
Actually Browse would need three vessels!



But let's look at some case studies.
In 2012, the scenario for my students was a hostile take-over of the Scarborough field, using the government's "Use it or Lose it" policy
The two partners in the field, Exxon Mobil and BHP, had failed to come to agreement on a way of developing it since it had been discovered in 1979.
The hostile takeover did seem far-fetched, I admit…
Last year, Exxon Mobil proposed a FLNG facility for Scarborough, but BHP were non-committal.
In May this year, Fortescue Metals became bullish about WA gas reserves that had been undeveloped for many years.
Last month, Fortescue homed in on Scarborough and Browse – and a week later, BHP announced that they were ***totally*** aligned with Exxon Mobil. The first time in 35 years!
But what did my students come up with for Scarborough? All four teams went for conventional subsea to beach developments.
None of them proposed FLNG, as they perceived it as being too risky.

The following year, we looked at this.
This shows the beauty of the Browse LNG development, viewed by NASA from space.
These coral atolls hide treasure, below the surface, and in the gas reservoirs.

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2013 Case Study – Browse LNG Development

Major gas fields: development status, as of March 2012

Field	Basin	Gas Resources tcf	Condensate Resources mmbbl	Total Resources PJ	Status
Greater Gorgon (including Gorgon, Io/Jansz, Chrysaor, Dionysus, Tryal Rocks West, Spar, Orthrus, Maenad, Geryon and Urania)	Carnarvon	>40	-	>44 000	under construction
Ichthys	Browse	12.8	527	17 179	committed
Woodside Browse project, including Torosa, Brecknock and Calliance	Browse	14	370	17 576	undeveloped
Greater Sunrise (including Sunrise and Troubadour)	Bonaparte	5.13	226	6972	undeveloped
Evans Shoal	Bonaparte	6.6	31	7442	undeveloped
Scarborough	Carnarvon	5.2	-	5720	undeveloped
Pluto (including Xena)	Carnarvon	5.05	72.6	5982	In production
Wheatstone	Carnarvon	4.5	-	4950	under construction
Clio	Carnarvon	3.5	-	3850	undeveloped
Chandon	Carnarvon	3.5	-	3850	undeveloped
Prelude (including Concerto)	Browse	2.5	120	3456	under construction
Thebe	Carnarvon	2, 3	-	2200–3300	undeveloped
Crux	Browse	1.8	66	2368	under construction

Courtesy: Geoscience Australia

Browse comprises three gas reservoirs, and they are big.
Not as big as Gorgon, but bigger than Ichthys which is currently being developed.
And much bigger than Pluto, and dwarfing Prelude.

25

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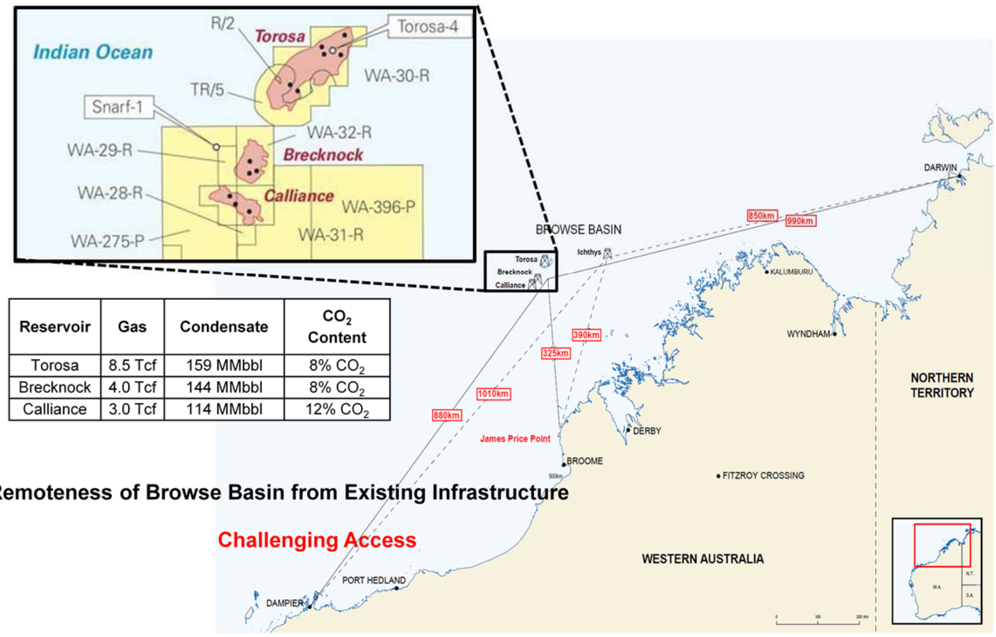
2013 Case Study – Browse LNG Development



Reservoir	Gas	Condensate	CO_2 Content
Torosa	8.5 Tcf	159 MMbbl	8% CO_2
Brecknock	4.0 Tcf	144 MMbbl	8% CO_2
Calliance	3.0 Tcf	114 MMbbl	12% CO_2

Remoteness of Browse Basin from Existing Infrastructure

Challenging Access

Courtesy: UWA Subsea Technology 2013 Team 1

Torosa was discovered in 1971 but the remoteness from existing infrastructure has hampered development.
Another complication is Scott Reef, the coral atoll on top of the Torosa field.

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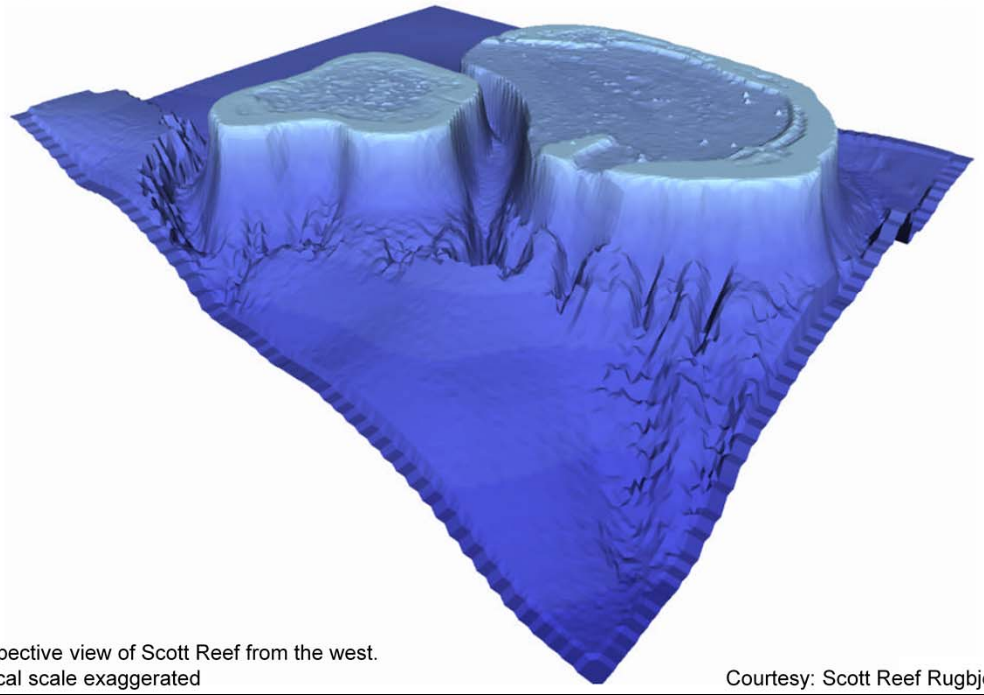
26

2013 Case Study – Browse LNG Development

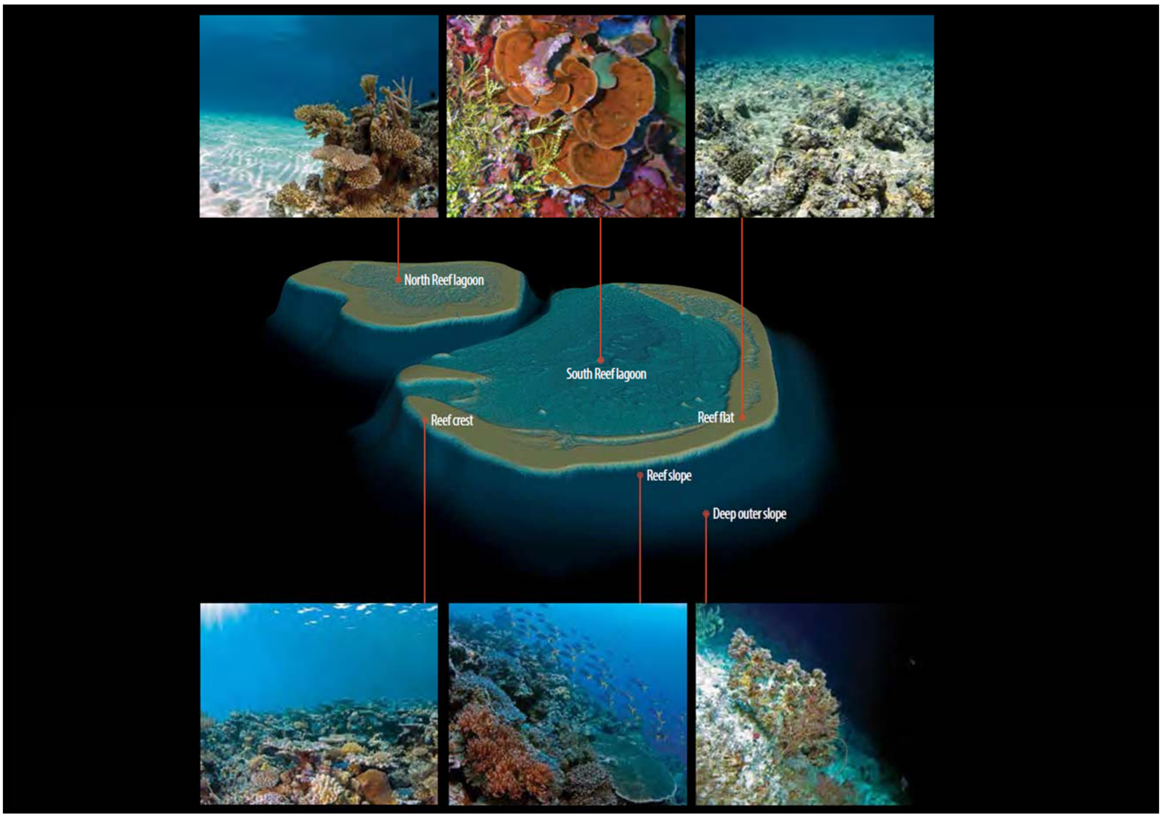


Perspective view of Scott Reef from the west.
Vertical scale exaggerated

Courtesy: Scott Reef Rugbjerg_2009

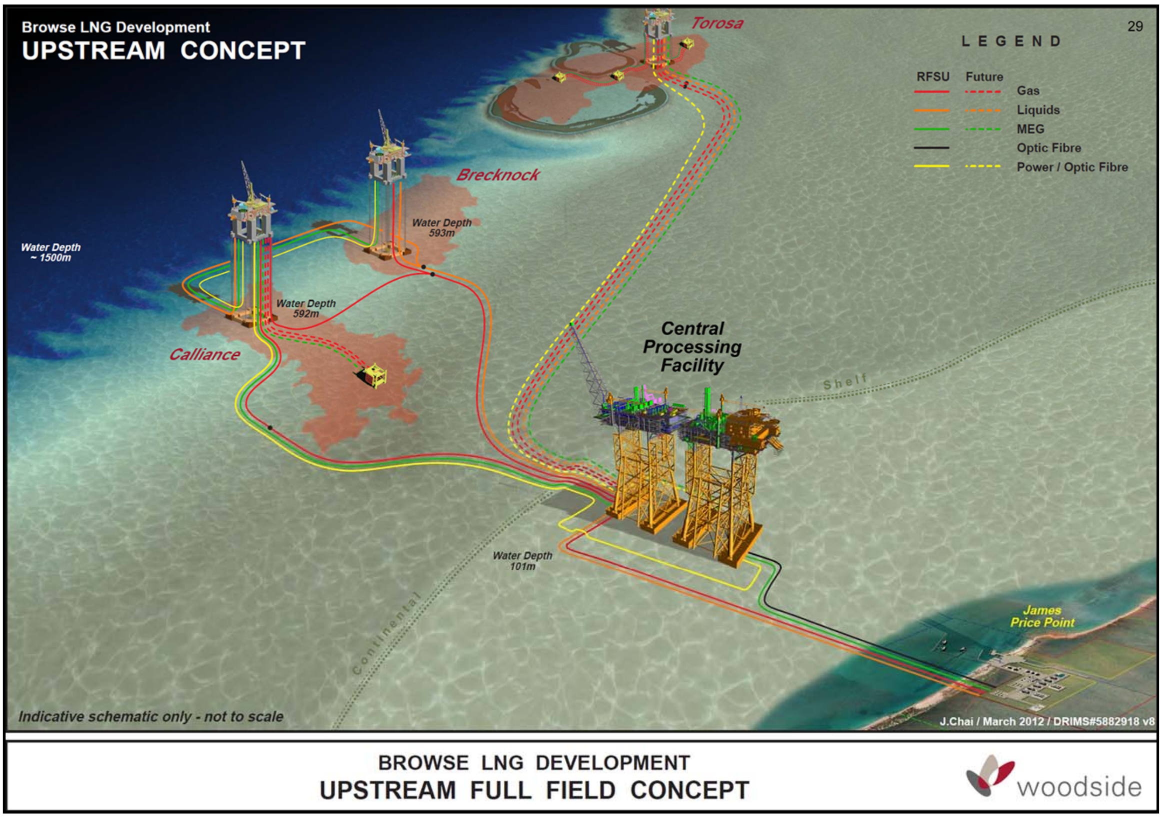
The coral of Scott Reef has grown upwards as the sea level increased over the millennia. It is now located in 500 m water depth on the edge of the continental shelf.

There’s a deep channel with steep sides between the two reefs.



Scott Reef is like a jewel in the Indian Ocean, a hotspot of biodiversity.

Drilling and exploration has taken place outside and inside the reef.



This was how Woodside envisaged the development, before they threw the towel in with James Price Point:

- Dry Tree Units based on Tension Leg Platforms, with some subsea developments to capture outlying parts of the reservoirs.
- All coming back to a shallow water platform providing separation and compression to deliver gas and the hydrocarbon liquids to James Price Point.

My students launched into their study of Browse just as the development erupted.

- Peter Coleman of Woodside declared that developing Browse at James Price Point wasn’t economically viable, and that they were going with FLNG.
- Colin Barnett thundered that it was stark raving mad to lose the jobs and the work to offshore. And the tax.
- Paul Howes of the Unions called it “the great Australian rip-off”.
- Ann Pickard of Shell prophesied that FLNG was a potential "saviour“ for Australian LNG.
- The environmental lobby was delighted that the dinosaur footprints had been saved.
- Rita Augustine of the Jabirr Jabirr tribe was in tears about the benefits lost to her people. She said “These people who were protesting were selfish towards our people, even the protesters that came from overseas. It had nothing to do with them. It is not their country.”

So what did my four teams have to say?

32

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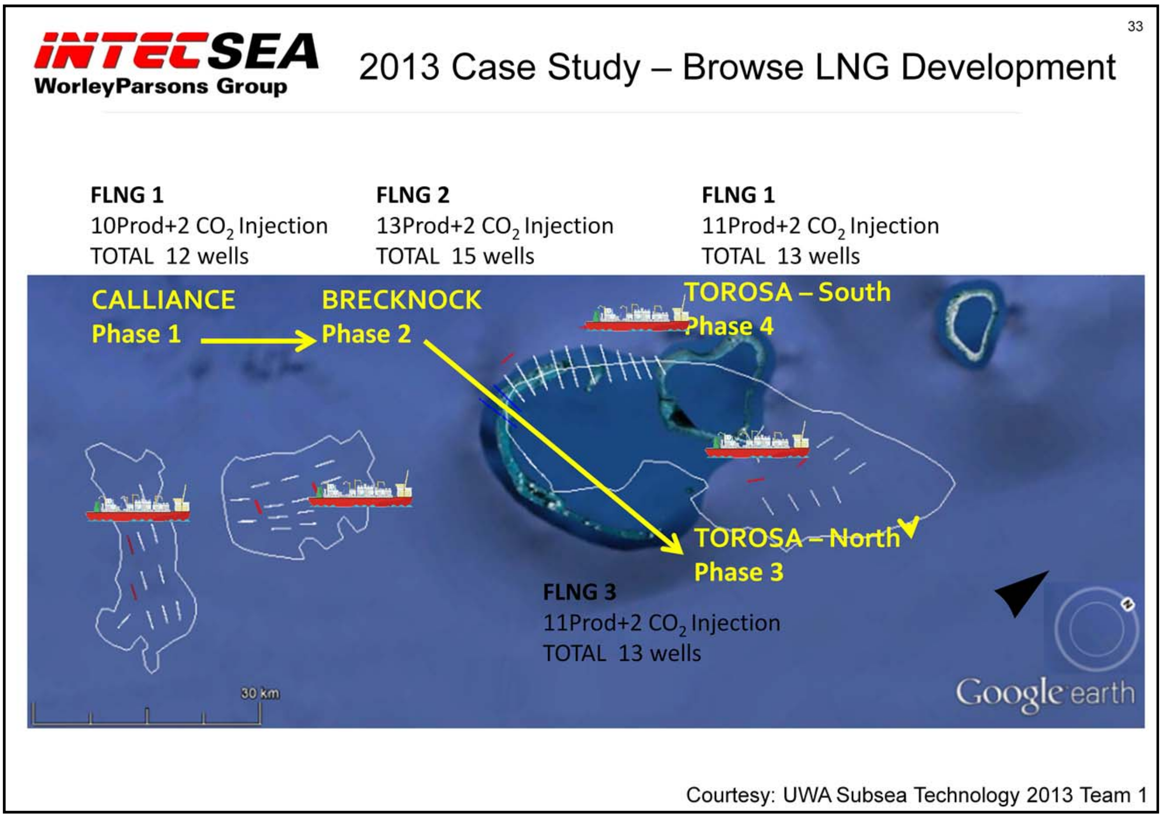
2013 Case Study – Browse LNG Development

	Team 1	Team 2	Team 3	Team 4
Project Analogues	Shell Prelude	Chevron Gorgon (+ Apache East Spar Control Buoy)	Wandoo B	Inpex Ichthys
Topsides	FLNG	LNG trains at JPP LNG Precinct	Concrete Gravity Structure with slug catcher in 45 metre WD, LNG trains at JPP LNG Precinct	Infield Central Processing Facility with compression, LNG trains at JPP
Export Pipeline	N/A	40" CS 310 km pipeline	26" CS x 115 km, 24" CS 240 km export pipeline	36" CS x 325 km export pipeline
CAPEX	Initial CAPEX 13.4 billion, total $45 bn	$47.3 bn	22 billion (*questionable benchmarking*)	36 billion
LNG trains	4.2, 4.3, 4.7 MTPA	3 off 4 MTPA	3 off 4.3 MTPA	2 off 3.65 MTPA
Nominal flowrate	717+740+800 MMSCFD	2200 MMSCFD	1748 MMSCFD	1500 MMSCFD
Field life	39 years	19 years	25 years	36 years
Control of field	Closed loop MUX-EH	Closed loop MUX-EH, via control buoy	MUX-EH (fibre optic), from CGS	MUX-EH from CPF
NPV	35 billion, 10% discount rate	18 billion	12 billion	15 billion
Payback	6.5 years after production	6 years after production	6 years after production	8 years after production
First LNG	2024	2017	2018	2017
Well count	53 wells total	26 wells total	46 wells total	19 wells total
Drilling Phases	6 (9+10+12+13+5+3 wells)	13 (19+1+1+1+1+1+2+5+1+1+1+1+1 wells)	5 (13+8+8+10+7 wells)	7 (6+1+1+1+1+1+1+2+1+1+1 wells)
Trees	7" horizontal	7" vertical monobore trees	7" enhanced horizontal trees	7" horizontal
Completions	7" completions	9 $^{5}/_{8}$" and 7" completions	9 $^{5}/_{8}$" and 7" completions	9 $^{5}/_{8}$" completions
CO_2	Reinject into reservoir	Reinject into reservoir, 18" CS 280 km pipeline		

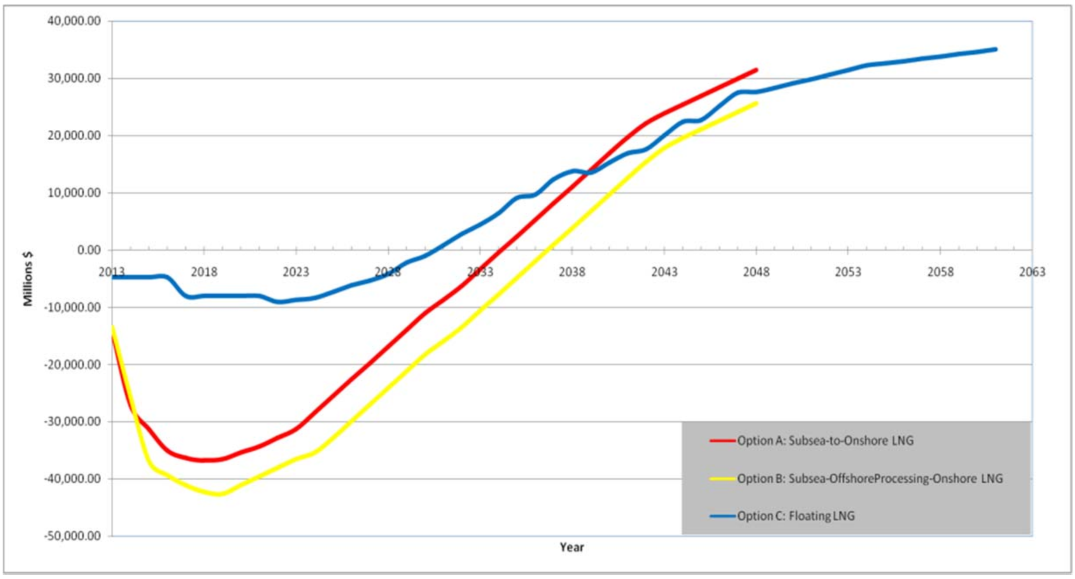
Their proposals were very interesting!
Four very different ways of developing the field.
Only Team 1 went with a FLNG development, the others stayed with more conventional approaches – a Gorgon, a Wandoo B, and an Ichthys.

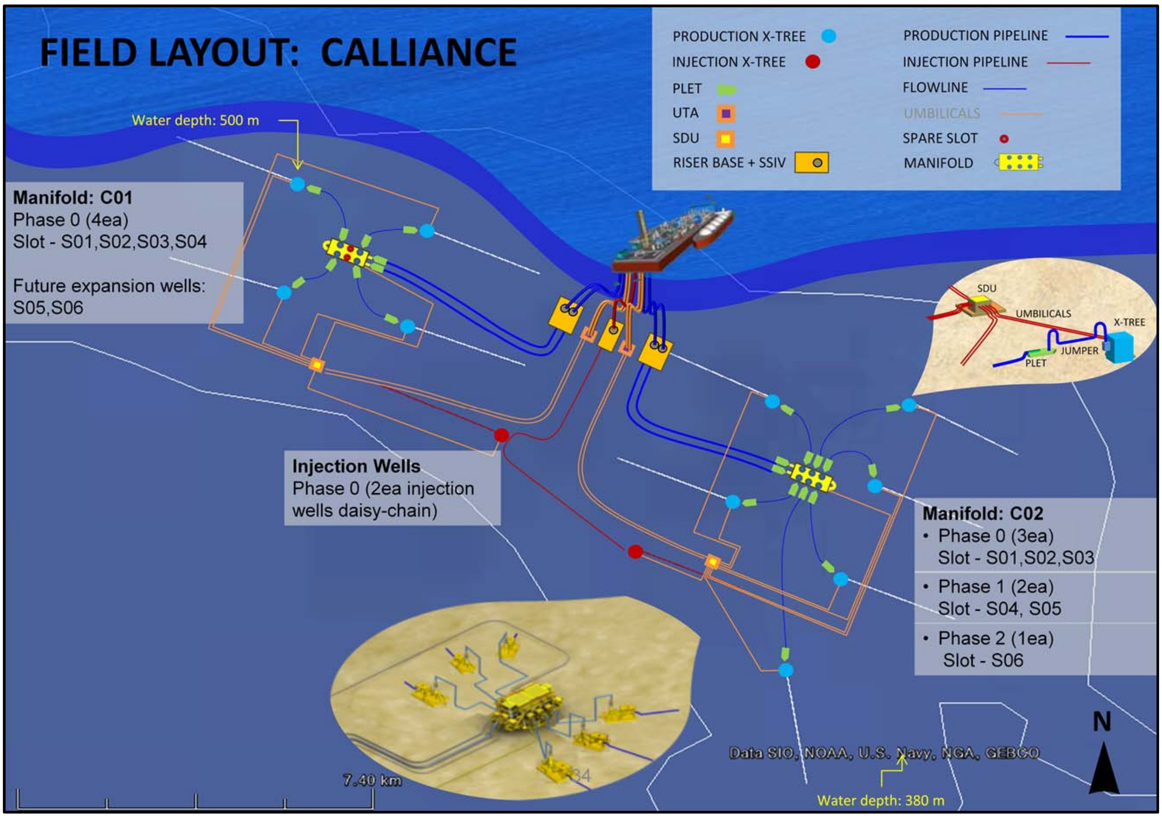
Benchmarking…
The central processing facility Samsung Heavy Industries will build for Ichthys will cost $2.26 billion.
The pipeline for 889 kilometres gas transmission costs $1 billion
The onshore LNG plant near Darwin including two LNG trains with a capacity of 4.2 million tons per year each costs $15 billion .
The Ichthys subsea facilities cost $2 billion.



Team 1 developed the fields with three FLNG vessels in phases.
Phase 1 was the southern-most Calliance field.
Once it was producing, and generating revenue, Brecknock is brought online.
And then Torosa North.
When Calliance depletes, the vessel will be refurbished and come back for Torosa South, the most difficult reservoir to develop.

We've already looked at the implications and the benefits of phased development – the lower, delayed CAPEX, the earlier returns.





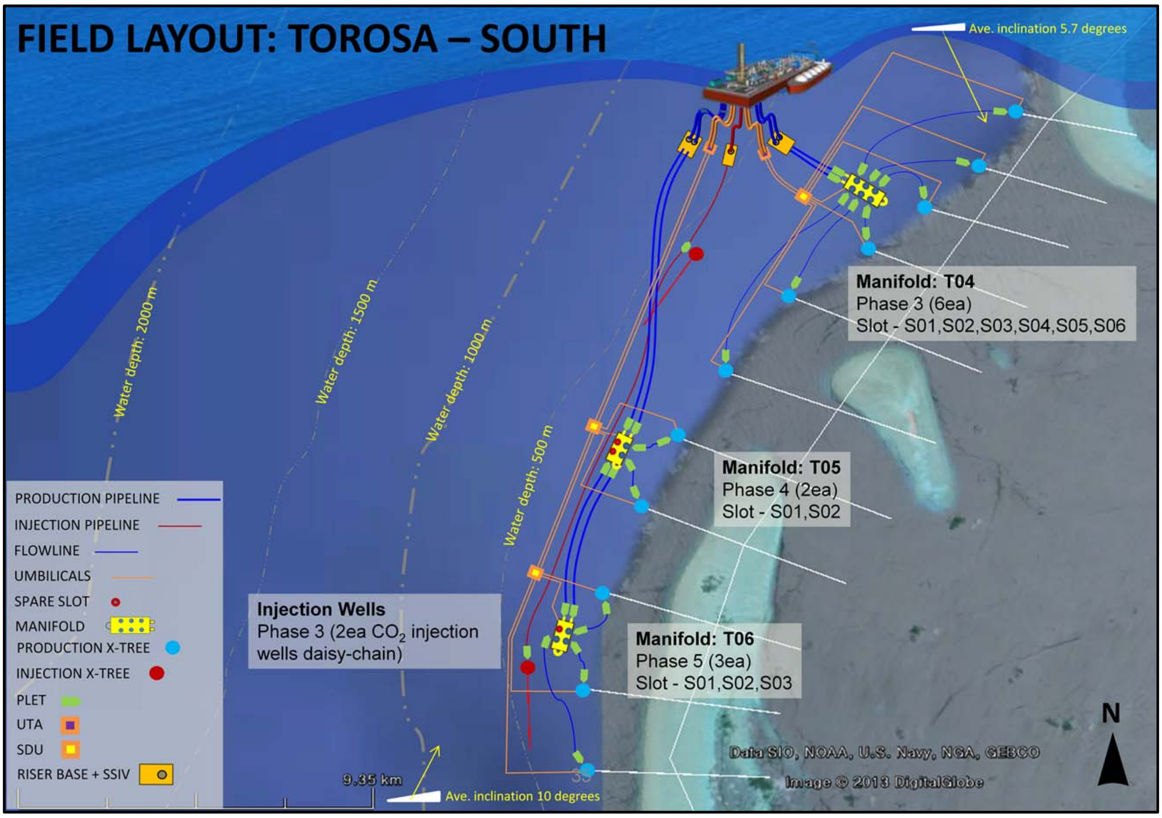
The first phase is Calliance. At first glance, it's similar to Prelude, but there are some significant differences.

The single umbilical on Prelude is recognised as a single point of failure, so dual umbilicals are used to each drill centre.

There are two CO_2 injection wells for disposal of the 8-12% CO_2. On Prelude, the 7% CO_2 is simply vented to atmosphere.

Each phase is extended with additional wells to maintain production.

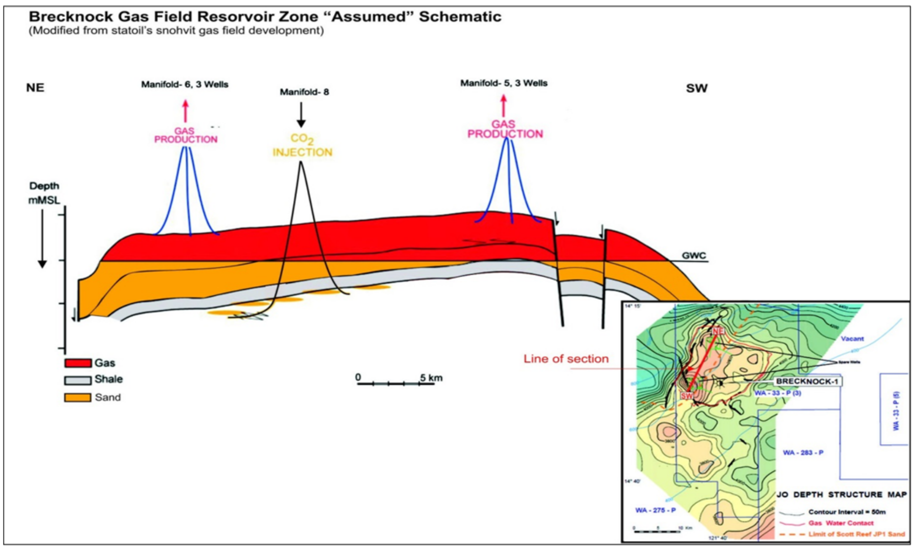
The phases for Brecknock and Torosa North are similar.



Torosa South is different, it uses the FLNG vessel from the depleted Calliance field.

Drilling and production from inside the reef will not be permitted, so all drilling takes place from outside the reef, and outside the reservoir, using deviated drilling to reach in from the wellheads to the reservoir itself. This will need directional drilling with a reach of 6 or 7 kilometres, which is on the edge of current technology, but should be easier in 15 years time.

The Team also planned to use reinjection of the 8-12% CO2 content.



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2013 Case Study – Browse LNG Development

36

Project Economics Key Figures

CAPEX - $46.16B Total Project Cost
FLNG -$42.92B
Subsea -$3.24B
OPEX - $440M per FLNG vessel annually
including fuel, staff, transport assistance

NPV_{10} $35.03B
IRR 10.53%

Courtesy: UWA Subsea Technology 2013 Team 1

Team 1's work shows that the bulk of the cost is in the vessels and the FLNG technology.
The subsea part is as cheap as chips.
They predicted an Internal Rate of Return of 10.5% which is in line with statements from last year's Parliamentary Enquiry.

Statements in last year's Parliamentary Enquiry indicated that FLNG have an internal rate of return of 12.5 - 13 %, with onshore projects around 11.5%.
So Team 1 was in the right ballpark.
Parliamentary Enquiry CALDWELL/METCALFE/ BP - FLNG proposal will likely result in an internal rate of return of somewhere between 12.5 per cent to 13 per cent and that the onshore project would likely have returned somewhere around 11.5 per cent

37

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Closing Remarks

- The Shell Prelude development
  - Single umbilical – single point of failure
  - 9% CO_2 vented up flare stack – 2.3 MTPA
  - Short flowlines – no linepack – high uptime requirement from subsea

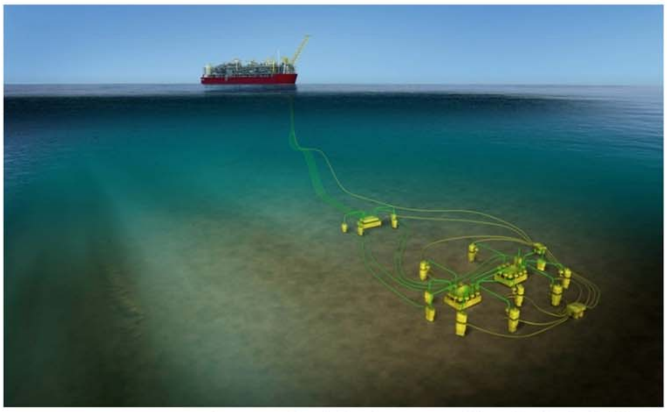

Image: Shell Environment Plan Prelude Drilling

EcoNomics

How does all this compare with Prelude?
You can see some of the concerns here.
It's doubtful if future developments would simply be allowed to vent that much CO2.
There are SSIVs at the riser base leading in to 4 12" flexible risers, so there is some protection against pipeline inventory.
For me, those short flowlines are a major concern as they offer no linepack, which demands high availability from the subsea equipment.
I really think that future developments will have longer flowlines of perhaps 40 or 50 kilometres to provide an adequate buffer against short term interruptions.[1]
The subsea part is as cheap as chips, and improved operability of the FLNG facility can be bought relatively cheaply.

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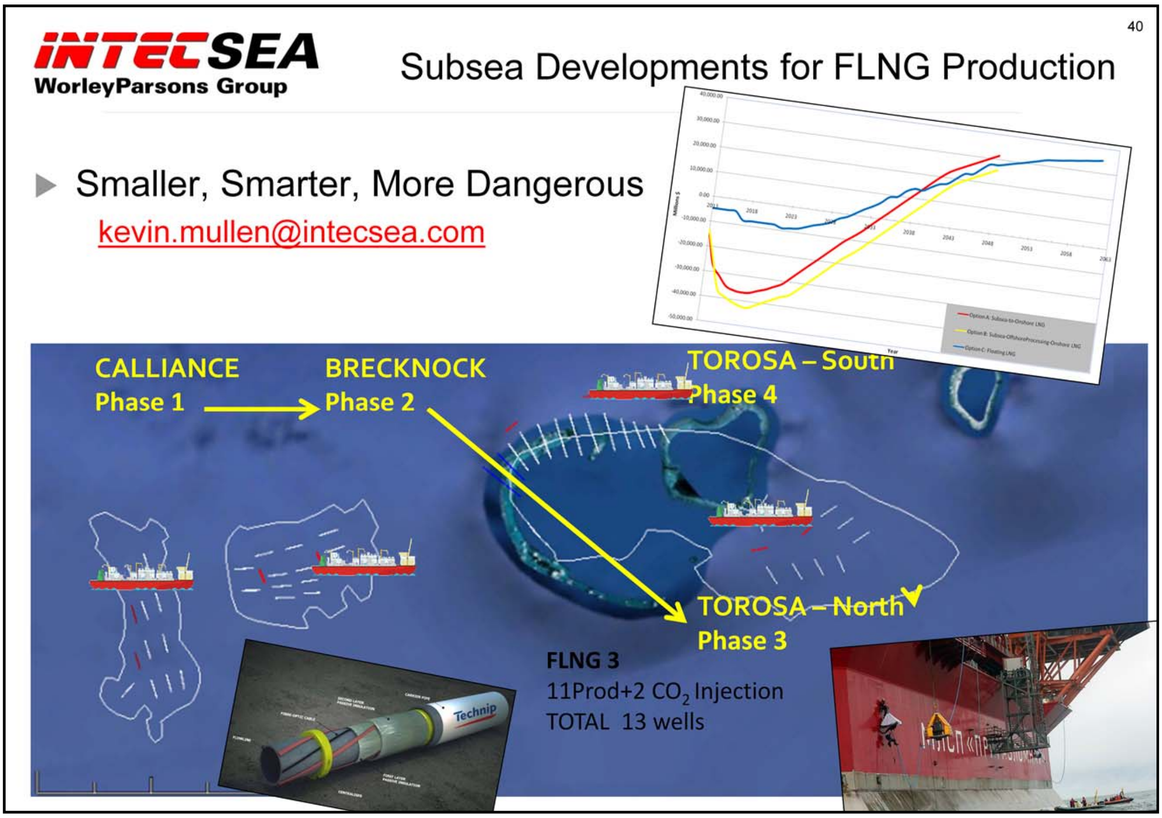
1. The 500 km 24 inch trunkline on Shell Malampaya in the Philippines provides linepack to the three power stations in Luzon, allowing shutdown of the subsea system and platform for intervention/repairs/maintenance for periods of up to 24 hours without loss of supply.
   So, a 50 km flowline to a FLNG vessel could give perhaps 2½ hours of assured supply – a cheap investment that would:
   - Increase operability of the FLNG vessel with fewer shutdowns (restart after shutdown taking typically 24 hours).
   - Allow positioning of the FLNG vessel where you want it, in shallower more benign conditions with easier and cheaper moorings, also allowing easier transfer of LNG to tankers.
   - Allow cooling of flowline contents to extend the life of flexible risers

You've heard my doubts and concerns about Floating LNG, but as I said earlier, I had an epiphany about this in 2011.
I realised that the type of company that would succeed in this would need a solid track record in innovation:

- Innovation going back to '92, that's 1892, sending "Murex" (the first oil tanker), through the Suez Canal.
- Developing Methane Princess (the first LNG tanker), which delivered LNG to the UK from Algeria in 1964.
- Castellon (the first oil FPSO) deployed off Spain in 1977.
- Auger (the first Tension Leg Platform with drilling and production facilities), installed in the Gulf of Mexico in 1994 at a record depth.
- The first subsea completion in 1961, in the Gulf of Mexico, in 17 metres of water. in diver depths but using diverless techniques.
- The Underwater Manifold Centre. In 1982, the most sophisticated system ever installed subsea, embodying the principles used in most modern subsea production systems.
- The Mensa project in the Gulf of Mexico in 1997 breaking records for water depth and tieback distance (1,600 metres, 110 km).

I realised that a company with a track record of innovation like that would be more than capable of successfully delivering Floating LNG.



I've ended this presentation with a tribute to Shell for their boldness in proceeding with Prelude.
But in a way, this presentation is also a tribute to the man who established the Subsea Technology course at the University of Western Australia –
Chris Lawlor, our colleague and friend.