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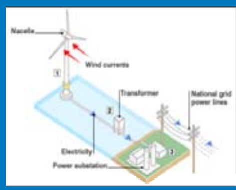
Developing offshore grids : An integrated approach

cigré



Andrew Hiorns

Integrated offshore networks: the context of our work

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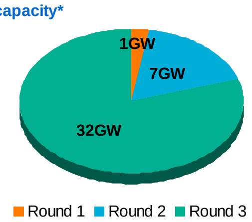
We are interested in establishing workable arrangements at the lowest costs for UK consumers such that:

- The potential deliverability of offshore wind is maximised
- Security of supply and network resilience are maximised
- The overall cost to consumers is minimised

- The scale of potential offshore a wind necessitates reflection on the delivery challenges:
  - Security of supply
  - European interconnection
  - Technology development
  - Supply chain capability
  - Planning consents
  - Financing
  - Skills

Offshore wind leased capacity*



** Source: DECC website*
http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/offshore/wind_leasing/wind_leasing.aspx

Assumptions: Generation mix scenarios

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Slow Progression

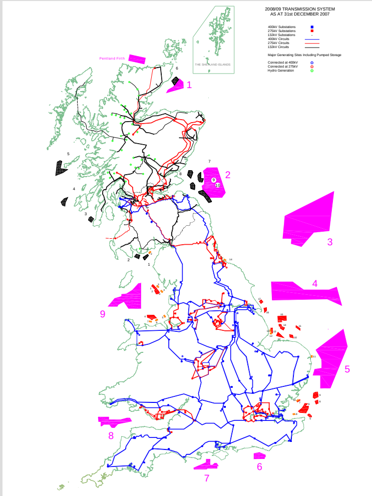
- 9,724MW offshore wind in 2020
- 23,174MW offshore wind in 2030
- 21% renewable electricity generation
- **2020 target missed**

Gone Green

- 16,374MW offshore wind in 2020
- 26,354MW offshore wind in 2030
- 32% renewable electricity generation
- **2020 target hit**

Accelerated growth

- 32,239MW offshore wind in 2020
- 51,552MW offshore wind in 2030
- 43% renewable electricity generation
- **2020 target exceeded**



3

Technology Assumptions:

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New technology is needed under both a radial & integrated solution

HVDC cables

- Technology is still developing
- 2-3 year development lead times for the larger cables
- Cables where lead times exceed 2-3 years not used in our study before 2020

Platform design

- Currently bespoke by project / application
- Scope for standardisation under an integrated solution

AC cables

- Appropriate only over shorter distances
- Capacitive effects increase exponentially over distance
- Reactive compensation required, but ineffective over distance, reducing real power capacity

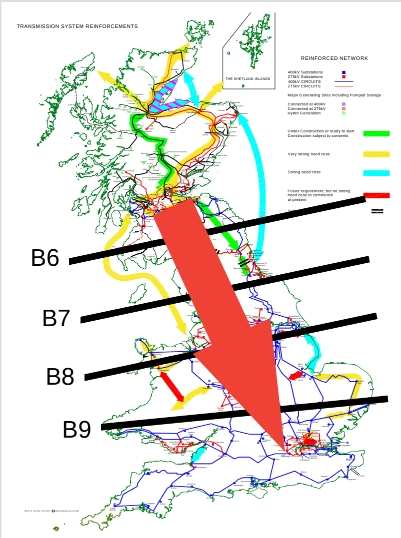
Smart grids

- Could be developed as part of an integrated solution

We have not assumed radical technology solutions pre 2020

4

Interaction with onshore



Power transfers

- North-South will increase
- How might these be managed?

Radial solutions

- Radial connections to the nearest landing point and then additional onshore reinforcements to provide additional capacity (minimum offshore costs v's maximum onshore costs)
- Radial connections extended significantly to avoid onshore reinforcement (maximum offshore costs v's minimum onshore costs)
- Optimum balance sought between radial offshore costs vs onshore costs (ODIS)

Integrated solution

- Designs fully integrated to minimise total cost and impact on environment

Increased supply security by integration

Assuming transmission circuit availability of 95%

Annual load factor of offshore wind generation ~40%

Case 1 -Radial connection

= 5% x 40% = 2% of installed capacity

Total wind generation curtailment = 2%

Case 2 – Integrated, sufficient transmission capacity to accommodate 100% wind generation output

Intact offshore network, Wind generation output curtailment = 0%

Outage of transmission network, Wind generation output curtailment

= 5% x 5% x 40% = 0.1% of installed capacity

Total wind generation curtailment = 0.1%

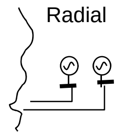
Case 3 – Integrated, sufficient transmission capacity to accommodate 90% wind generation output,

Intact curtailment = 2.3%

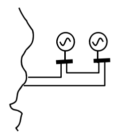
Outage curtailment = 5% x 5% x 40% = 0.1% of installed capacity

Total wind generation curtailment = 2.4%

Radial



Integrated



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Radial and Integrated UK Offshore

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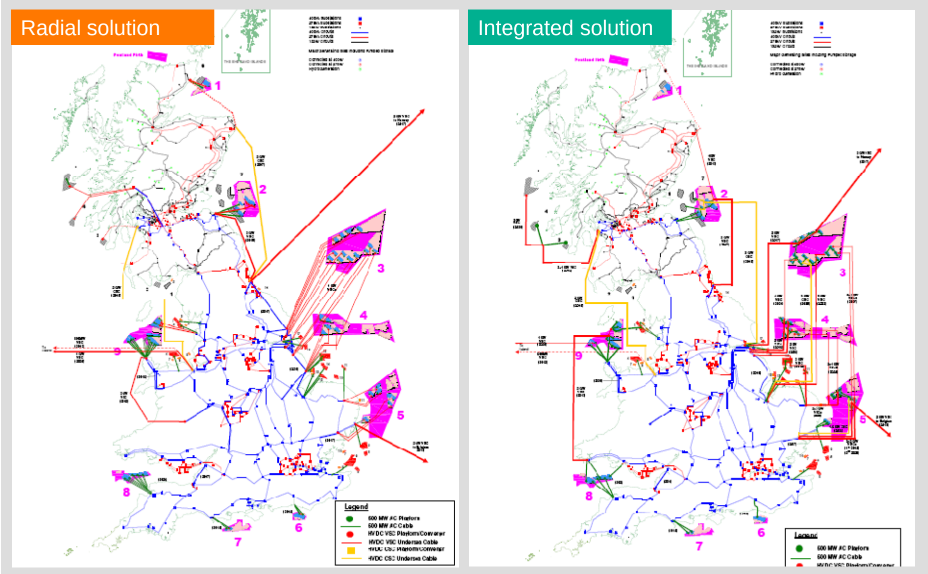

Design Options

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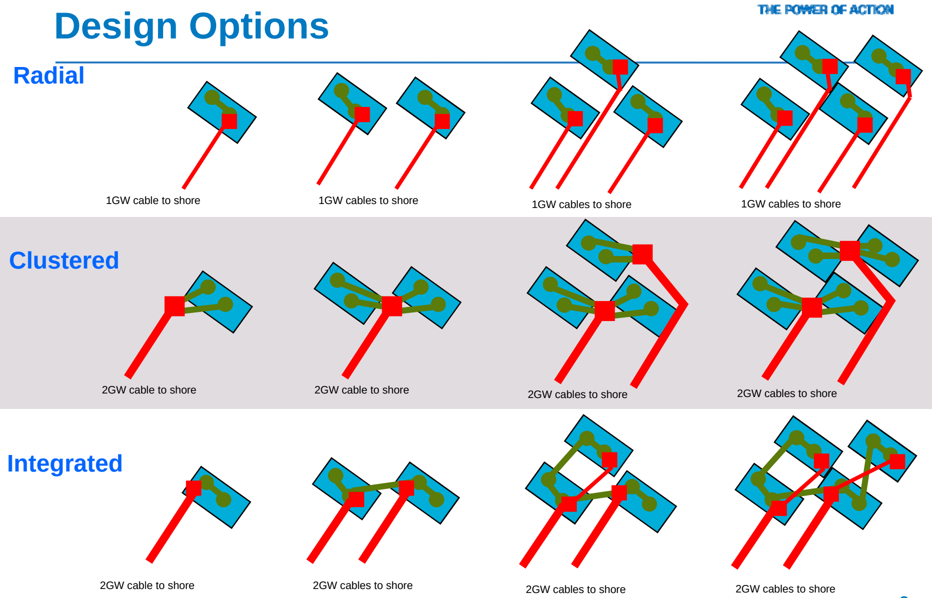

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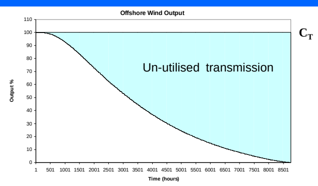
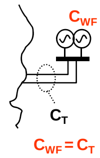
Interaction with interconnectors 1

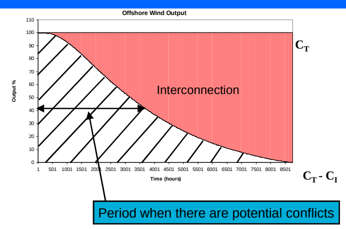
Case 1 – Radial wind with 100% connection transmission capacity



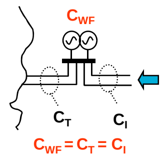
- Very little restriction of wind output
- Transmission utilisation 35-45%



Case 2 – Wind and interconnection at 100% transmission capacity



- Potentially either heavily curtailment of wind generation output or interconnector trading
- Potentially 100% transmission utilisation
- Limitations on ability to use interconnectors exist nearly all times



9

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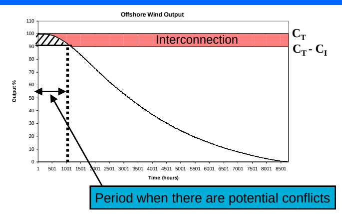
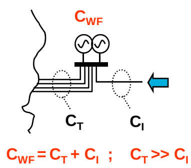
Interaction with interconnectors 2

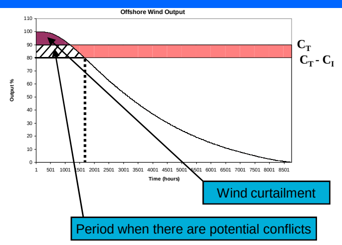
Case 3 – Wind and 10% interconnection



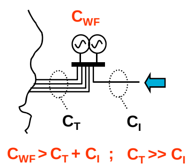
- Very limited curtailment of wind generation output or interconnector curtailment
- Increased utilisation of transmission
- Ability to utilise interconnectors for most periods (only limited with high output across all offshore wind parks



Case 4 –Wind with 90% transmission connection capacity and 10% interconnection



- Limited curtailment of wind generation output or interconnector curtailment
- Increased utilisation of transmission
- Ability to utilise interconnectors for most periods (only limited with high output across all offshore wind parks



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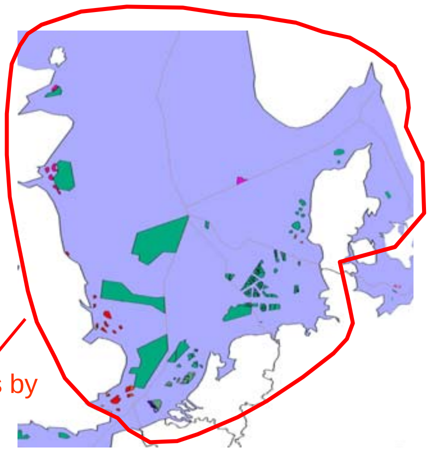
Extending into European waters ?



Potential 50GW plus by 2030

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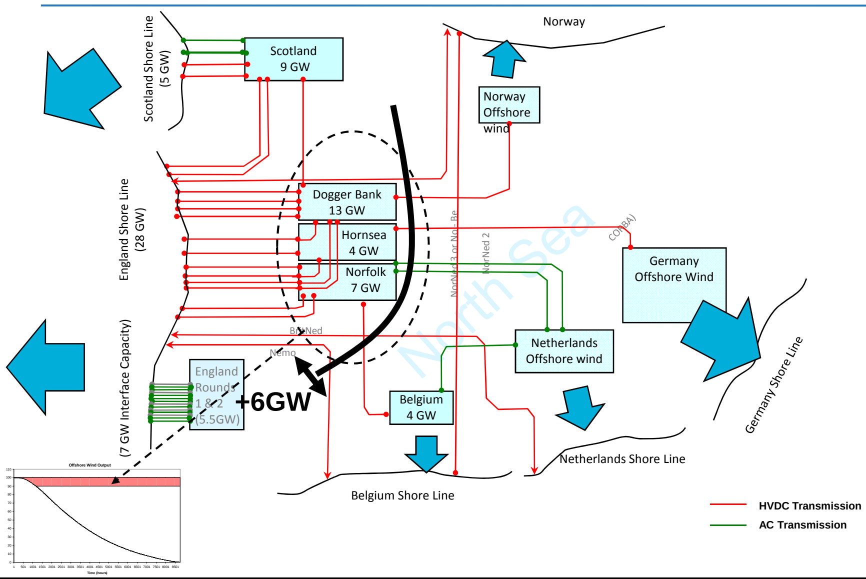
Integrated North Sea Grid ?



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Dogger Bank – Integrated Control Challenge

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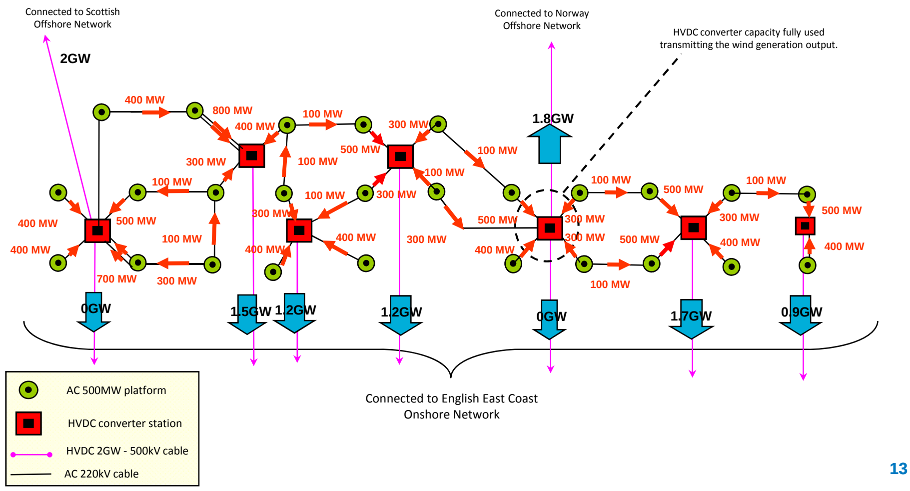
80% Wind Output



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An integrated network solution has multiple benefits

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~25% potential savings for UK consumers

Reduces planning consent issues

Better management & utilisation of valuable resources

“Future proof” for network evolution & greater European integration

Other benefits include:

- Meeting / potentially exceeding developer timelines
- Strengthening security of supply
  - More resilient / reliable network
- Maximising deliverability:
  - Reduces supply chain pressures through lower asset volumes
  - Better secures resources to enable a step-up in UK supply chain capacity
  - Supports vital technology development
  - Facilitates a move towards standardisation
- Minimising environmental impact
- Strengthening UK role in EU energy
  - Enabler of a North Seas grid
  - Increased potential for UK to export excess wind power
  - Step towards engaging and influencing the EU landscape

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Head of Business Development
Siemens Transmission and Distribution Limited
Matthew.knight@siemens.com

Offshore Grid Technology

Technology options and practical issues for offshore networks



CIGRE London

17/01/11

ZERO HARM

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Chuxiong – world first 5GW, ±800kV HVDC link

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China: >104*GW transmission capacity expansion by 2019

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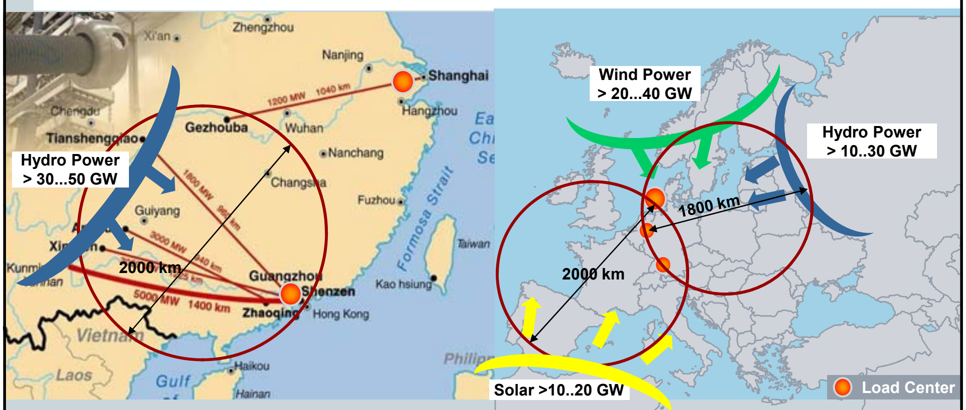
China vs. EU



Similar distances and capacity required
Differently organised
Submarine connections
- OH line technology not available for UK part of the EU supergrid

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What's needed?

Offshore transmission technology

- High capacity
- Long distance
- Reliable
- Stable
- Work with existing infrastructure
- And new renewable generation
- Extendable
- Affordable

AC

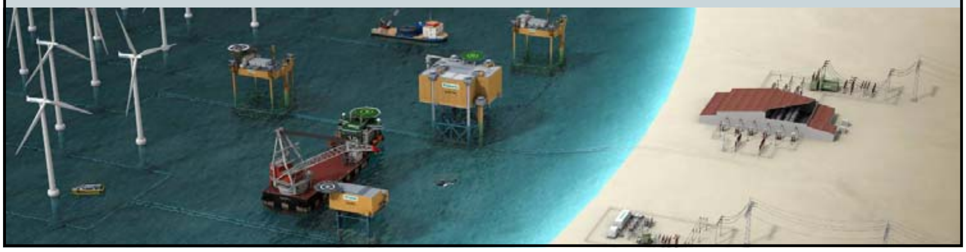
- Cable
- GIL

DC

- CSC
- VSC

Grid Topology

Practical issues



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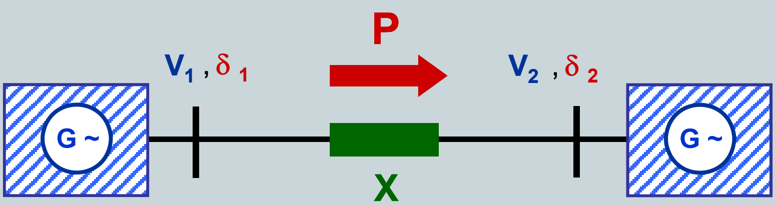
AC Power Transmission - The basic Equation



$$P = \frac{V_1 \; V_2}{X} \sin(\delta_1 - \delta_2)$$

Series Compensation

Parallel Compensation

Power-Flow Control

Each of these Parameters can be used for Load-Flow Control and Power Oscillation Damping

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AC submarine cables

UK offshore wind lessons

Gabbard 500MW wind farm = 3 x 132kV
London Array 630MW = 4 x 150kV

UK 50GW = 300 132kV cable circuits

Feb 2010 NKT awarded Djursland / Anholt Offshore wind farm 400MW connection
- one 245kV cable
- 25km 3x1600sqmm Al
- diameter 260mm

How practical is this size of cable?


InnerGabbard substation


NKT Anholt cable

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Cable rating

Cable rating hot spots
- Solar gain in J tubes
- Heat dissipation – burial depth, landfall
- Landfall section in ‘dry’ ground
- Reactive power

can de-rate by half from wet sea bed rating

Transition joint offshore to larger landfall section
- also allows deeper draft vessel to lay in deep water

Distributed temperature sensing
Dynamic ratings

132kV ~ 200MW 220kV ~ 300MW

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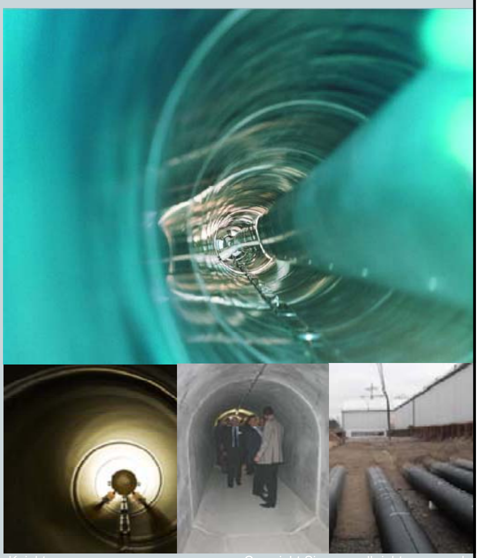
GIL Gas Insulated Line

High power transmission capacity

Lower losses than cable
- Less / no reactive compensation (<70km)

High safety (no fire hazard)
High reliability
- Sealed for lifetime continuous welded construction
- No ageing of insulating gas
- Automatic reclosure functionality

Low external electromagnetic fields



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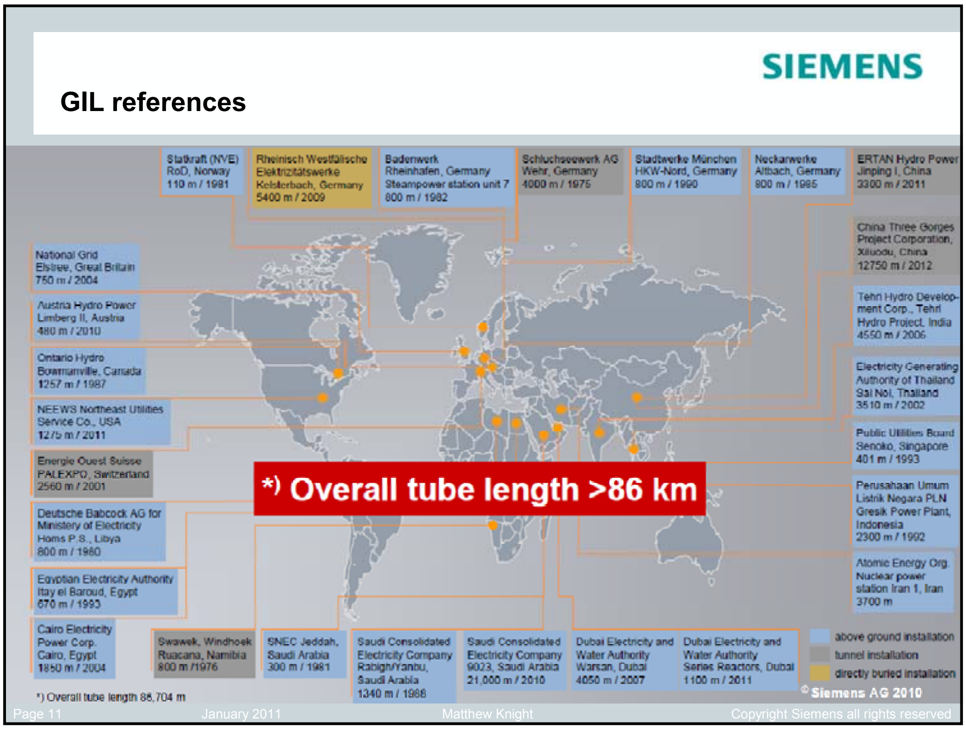
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GIL references
Statkraft (NVE) RoD, Norway 110 m / 1981
Rheinisch Westfälische Elektrizitätswerke Kelsterbach, Germany 5400 m / 2009
Badenwerk Rheinhafen, Germany Steampower station unit 7 800 m / 1982
Schluchseewerk AG Wehr, Germany 4000 m / 1975
Stadtwerke München HKW-Nord, Germany 800 m / 1990
Neckarwerke Altbach, Germany 800 m / 1985
ERTAN Hydro Power Jinping I, China 3300 m / 2011
National Grid Elstree, Great Britain 750 m / 2004
Austria Hydro Power Limberg II, Austria 480 m / 2010
Ontario Hydro Bowmanville, Canada 1257 m / 1987
NEEWS Northeast Utilities Service Co., USA 1275 m / 2011
Energie Ouest Suisse PALEXPO, Switzerland 2560 m / 2001
Deutsche Babcock AG for Ministery of Electricity Homs P.S., Libya 800 m / 1980
Egyptian Electricity Authority Itay el Baroud, Egypt 670 m / 1993
Cairo Electricity Power Corp. Cairo, Egypt 1850 m / 2004
China Three Gorges Project Corporation, Xiluodu, China 12750 m / 2012
Tehri Hydro Development Corp., Tehri Hydro Project, India 4550 m / 2006
Electricity Generating Authority of Thailand Sai Noi, Thailand 3510 m / 2002
Public Utilities Board Senoko, Singapore 401 m / 1993
Perusahaan Umum Listrik Negara PLN Gresik Power Plant, Indonesia 2300 m / 1992
Atomic Energy Org. Nuclear power station Iran 1, Iran 3700 m
*) Overall tube length >86 km
Swawek, Windhoek Ruacana, Namibia 800 m /1976
SNEC Jeddah, Saudi Arabia 300 m / 1981
Saudi Consolidated Electricity Company Rabigh/Yanbu, Saudi Arabia 1340 m / 1988
Saudi Consolidated Electricity Company 9023, Saudi Arabia 21,000 m / 2010
Dubai Electricity and Water Authority Warsan, Dubai 4050 m / 2007
Dubai Electricity and Water Authority Series Reactors, Dubai 1100 m / 2011
above ground installation
tunnel installation
directly buried installation
© Siemens AG 2010
*) Overall tube length 86,704 m
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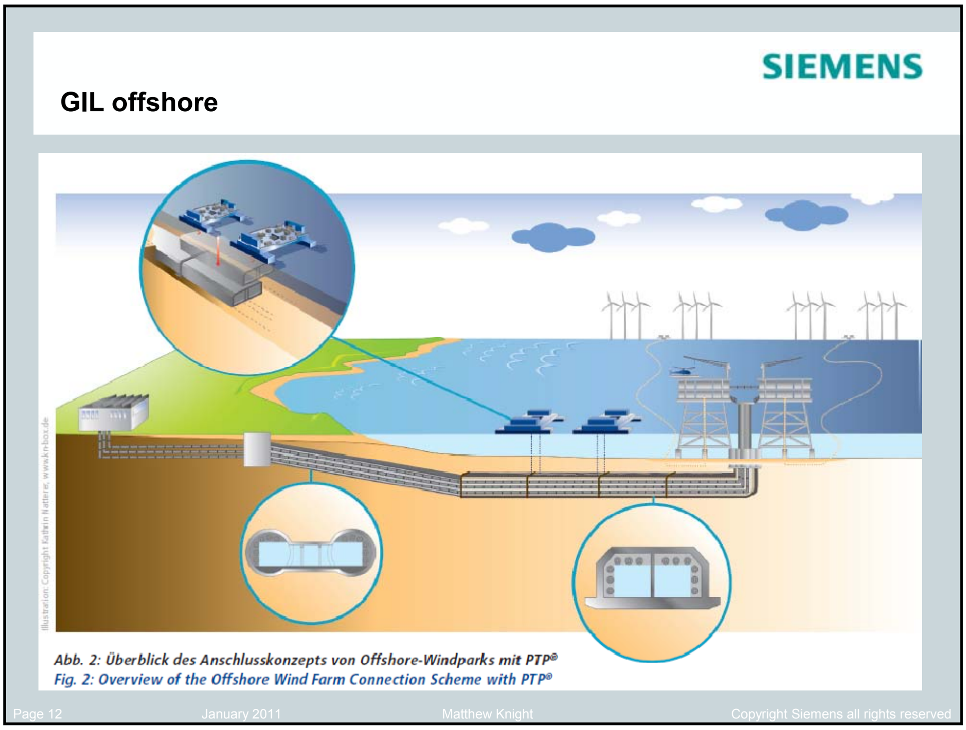
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GIL offshore
Abb. 2: Überblick des Anschlusskonzepts von Offshore-Windparks mit PTP®
Fig. 2: Overview of the Offshore Wind Farm Connection Scheme with PTP®
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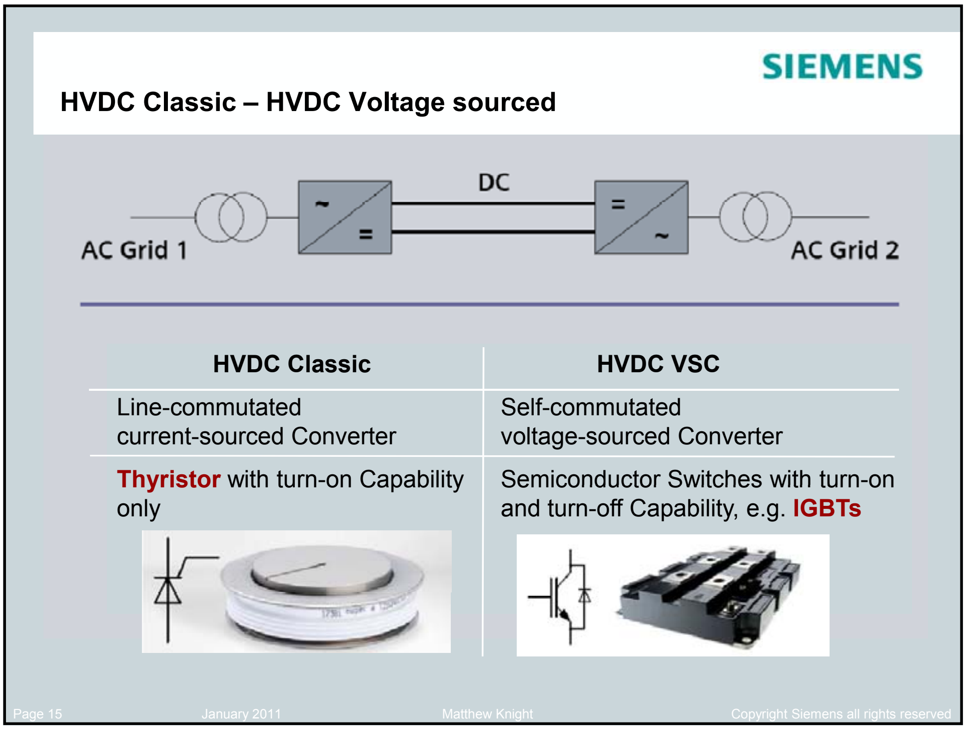
HV DC transmission

For distances >100km DC becomes best / only option

Negligible reactive losses in the DC circuit

Conversion losses:
- 0.75% CSC
- 1% MMC VSC

Power flow is set by the control system
- 5th Nov 2006 – Major outage across Europe
- France – UK link continued to export 1GW while 5m French customers left in the dark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HVDC Classic – HVDC Voltage sourced
DC
AC Grid 1
AC Grid 2
HVDC Classic
HVDC VSC
Line-commutated current-sourced Converter
Self-commutated voltage-sourced Converter
Thyristor with turn-on Capability only
Semiconductor Switches with turn-on and turn-off Capability, e.g. IGBTs
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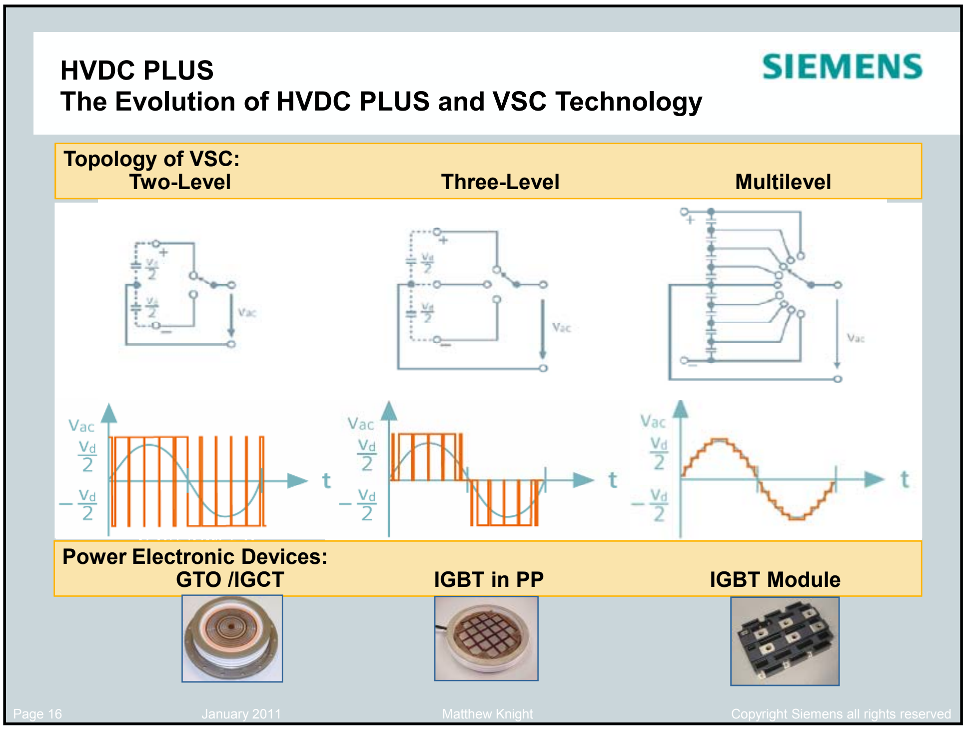
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HVDC PLUS
The Evolution of HVDC PLUS and VSC Technology
Topology of VSC:
Two-Level
Three-Level
Multilevel
Vac
t
Power Electronic Devices:
GTO /IGCT
IGBT in PP
IGBT Module
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HVDC PLUS Converter
AC Voltage Generation

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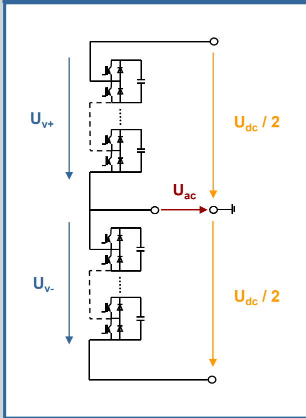
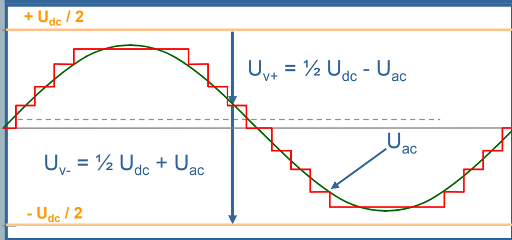
Simplified Block Diagram



Multilevel Topology



Characteristics

- Switching of individual Power Modules:
  1. Tolerance Band of AC Voltage
  2. Voltage Balance of Power Modules
- No fix Pulse Pattern
- 200 steps ≈ “7½ bit” resolution

BritNed, UK 2010

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Costumer	BritNed Development Ltd
Project Name	BritNed
Location	Isle of Grain, UK Maasvlakte, NL
Power Rating	1000 MW
Type of Plant	HVDC Classic Bipolar 200 km Submarine Cable
Voltage Levels	± 450kV DC 400 kV AC, 50 Hz
Type of Semi-conductors	LTT 8 kV

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Trans Bay Cable Project, USA 2010

Costumer	Trans Bay Cable LLC
Project Name	Trans Bay Cable Project
Location	Pittsburg, CA San Francisco, CA
Power Rating	400 MW
Type of Plant	85 km HVDC PLUS Submarine Cable
Voltage Levels	± 200 kV DC 230 kV/138 kV AC, 60 Hz
Type of Semi-conductors	IGBT

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HVDC Capacity

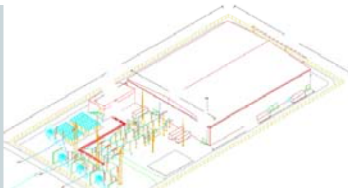
Commercially sensitive

DC power ≈ Volts x Amps

Volts limited by cable
- Polymeric 300/ 320kV
- Future?
- Issues for rapid power reversal
- MI 500kV in service

Amps limited by converter design various options different capacity vs. footprint, losses etc.

NG's assumed available technology dates in ODIS - Mfrs don't disagree



1,000MW HVDC PLUS converter

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DC Network Topology

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HVDC networks - Supernode

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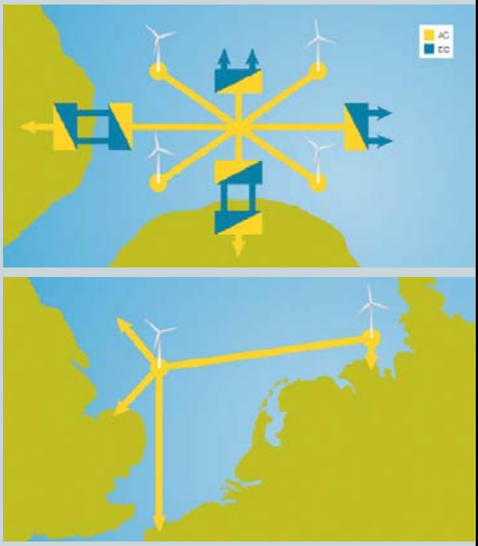
Grid is made up of 2 ended HVDC links that meet at AC supernodes

- Requires no new technology
- AC transformers allow mix of voltages and manufacturers
- Easily extended
- Impedance of the AC parts helps with control

Serial transformer losses where power flows pass through a node



HVDC networks – Multi terminal

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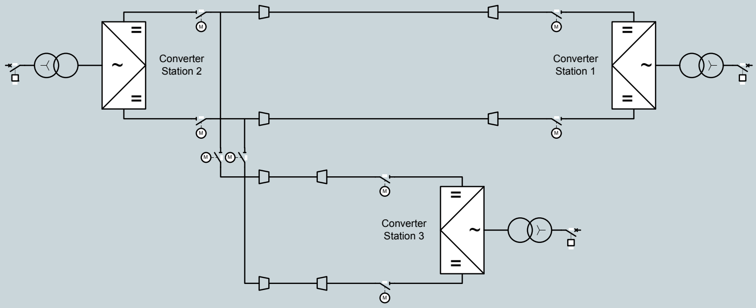
Wudqvp lvvlrq#ehwz hhq#vhyhudo#srlqw#lq#D F#J ulg+v,
- 0 Rqh#vwdwlrq#ghwhup lqhv#wkh#GF#yrowdjh
- (Srz hu#lv#ghwhup lqhg#e|#do#exw#rqh#vwdwlrq
- 0 Frqwuro#frqfhsw#ghhgv#wr#eh#ghwhup lqhg#dqg#yhulilhg#e|#vwxglhv

P xowl0yhqgru#lvvxhv
- 0 z rxog#lw#z run/#dqg#z kr*v#idxow#li#lw#grhvq*wB



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HVDC networks – Fully DC grids

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"HV DC circuit breakers needed for Supergrid"
- Several recent reports make this claim

But technology is not the issue
- Siemens (and probably our competitors) could have a DC breaker in 18-24 months
- We have concept designs and patents for at least 4 ways to make a DC breaker
- When will someone want to buy one?
- What Voltage does it have to switch?
- How fast, etc?

All 3 topologies have to deal with Kirchov's Current Law

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Standards for DC grids

Who is best placed to agree the basics?
- ABB
- Alstom
- Nexans
- Prysmian
- Siemens

Under the auspices of
- A standards body e.g. CENELEC
- With TSO representation – ENTSO-E

with the blessing of
- 9 country North Seas Grid Initiative

If we do it fast enough UK R3 can benefit

WANTED!

STANDARDS BODY

GSOH
ABILITY TO
FAST TRACK

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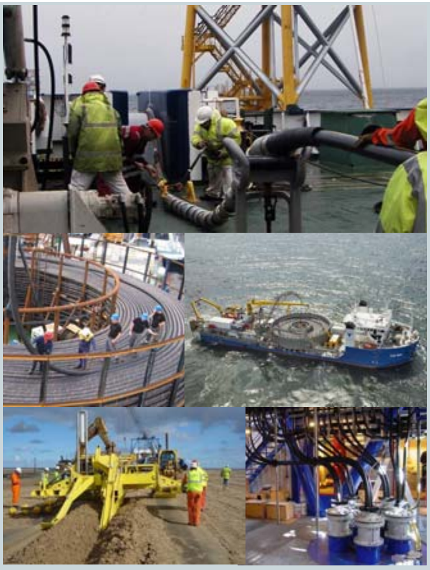
Laying offshore cables

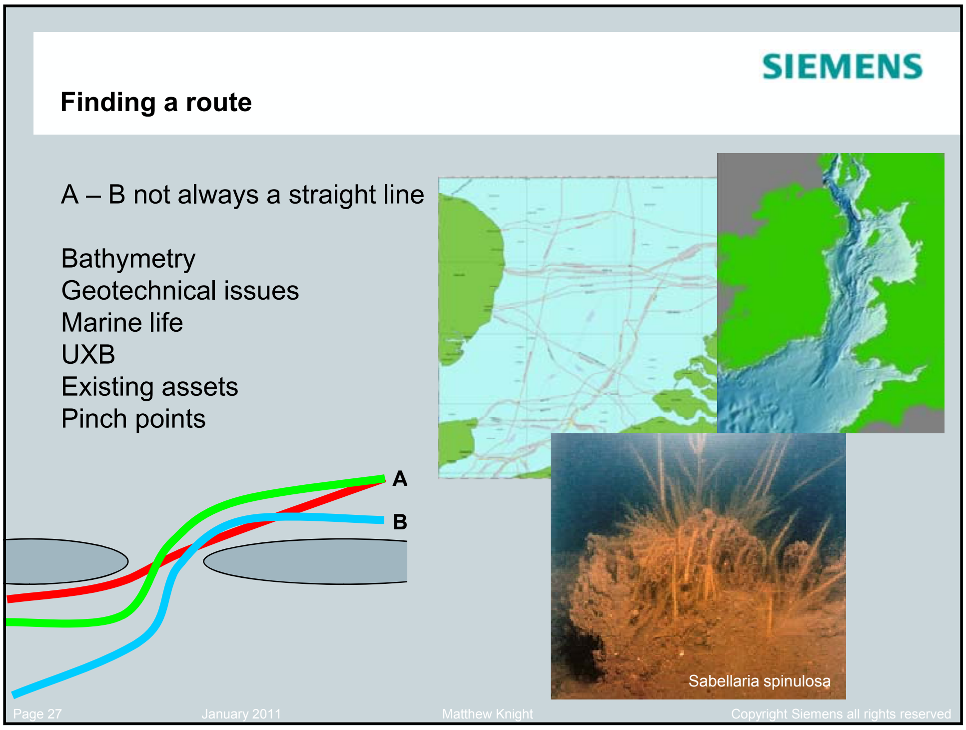
Export or interconnectors not like Array cables

Specialist vessel and crew
Turntables up to 7,000 t

Plough burial
Grapnel recovery?

Special consideration for last few metres

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Finding a route
A – B not always a straight line
Bathymetry
Geotechnical issues
Marine life
UXB
Existing assets
Pinch points
A
B
Sabellaria spinulosa
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Not all mud is the same
Morecambe Bay West Coast
Humber East Coast
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Landfall - Beaches vary
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HDD under sea defences
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Onshore Cable

Onshore drum length is main driver

- 3 separate cores
- Use of ducts allows minimum open time
- Security
- Land requirement includes construction width
- Seasonal issues

132kV AC cable installation on Lincs wind farm connection

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Offshore substations

AC collector substations

- UK now has a dozen
- Jacket / monopile & topsides
- 750t up to >2,000t
- Installed with heavy lift vessel @£250k per day

DC converter stations

- Topsides much heavier
- Self installing

Manned?
Access?
SCADA

SIEMENS

3 ways to reduce cost

Standardisation
- Consistent block sizes for wind farms
- Allow suppliers to compete head to head

Best practice design
- Involve those who actually know the answer
- (even / especially if they come from the Oil and Gas industry)

Agree future DC basics

With the scale planned by UK we can significantly reduce costs

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SIEMENS

Siemens investment in UK offshore programme

- Purpose built Renewable Energy Engineering Centre; on stream December 2012.
- Will incorporate HVDC Plus emulation / verification facility.
- Commitment to UK Wind Turbine Production Facility.
- State of the Art Wind Turbine Technology will be built in UK

ZERO HARM

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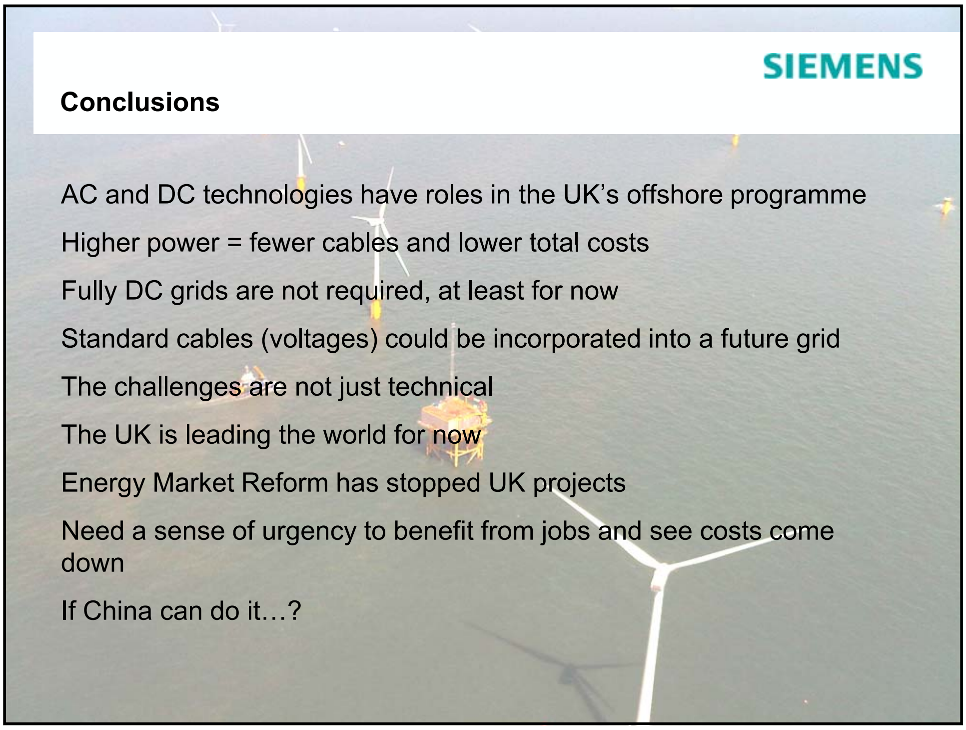

SIEMENS
Conclusions
AC and DC technologies have roles in the UK’s offshore programme
Higher power = fewer cables and lower total costs
Fully DC grids are not required, at least for now
Standard cables (voltages) could be incorporated into a future grid
The challenges are not just technical
The UK is leading the world for now
Energy Market Reform has stopped UK projects
Need a sense of urgency to benefit from jobs and see costs come down
If China can do it…?

Introduction
Study Background

- Offshore generation in the UK is expected to make a significant contribution to helping the UK achieve its 2020 renewable energy target, with 12.5 GW of offshore wind anticipated by 2020 in the lead scenario of the 2009 Renewable Energy Strategy.
- Major investment required in
  - offshore wind turbines
  - offshore grid
  - conventional plant for balancing and ensuring security of supply is maintained on a system with large volumes of intermittent generation
  - onshore grid reinforcements
- As the number of renewable projects across Europe grows, it may be technically feasible and economically beneficial for the UK to enter into some joint renewable generation projects that, connected to the UK and/or to another member state, may allow the UK to reduce the costs of achieving its 2020 target.
- Allowed under the EU Renewables Directive

Introduction

Project Objectives

- Study commissioned by DECC to inform UK view whether:
  - Joint Project development and
  - combining offshore projects with interconnection

  are likely to provide a positive benefit to UK electricity consumers and the wider economy
- “to provide robust information on the potential, likely costs and benefits and technical feasibility of
  - combining offshore renewable projects in the Irish Sea, North Sea, English Channel and Iceland with interconnection, and of
  - connecting the GB grid to onshore renewable energy and storage/balancing sources outside GB.
- Some key questions
  - Is it viable for offshore generation to offer a vehicle for cost effective interconnection?
  - Does Joint Project development offer a cost effective route to help the UK meet its renewable and carbon targets and possibly also interconnection?
- Conducted high level CBA of offshore wind and interconnections together with potential JP development in other countries

Introduction

Joint Projects examples

Connection to the UK of offshore generation located in territorial waters of other countries. This generation may be closer to the UK and/or in shallower waters, and hence lower in costs, than alternative developments in UK territorial waters.

Connection to the UK of an offshore project connected to other country, effectively providing an interconnection between the two countries.

Offshore projects in UK territorial waters connected to continental Europe (UK export) with or without interconnection to the UK onshore grid.

Offshore grid connections to onshore renewable projects in third countries, including neighbouring non-EU members (e.g. Iceland, Norway).

4

Introduction

CBA – the UK perspective

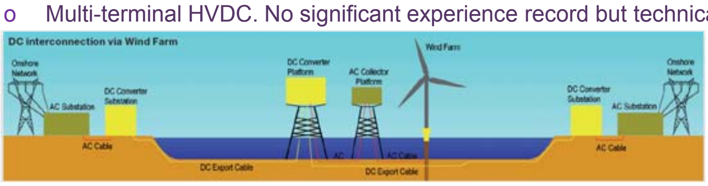
- 2009 RES Lead Scenario as the basis for comparison –
  - Annual values to 2030, robustness and consistency with DECC policy.
  - Consistent assumptions to determine savings
  - Consistent future ROC values to determine subsidy costs
- CBA undertaken in two ways to identify the best alternatives:
  - Potential JPs **contained** in the RES Lead scenario:
    are JPs a more cost effective way of meeting the 2020 target?
  - Potential JP **in addition** to the RES Lead scenario:
    are JPs an effective way of achieving more renewable generation, carbon savings etc?
- NPV of benefits/(costs) streams calculated to 2020 and 2030.
- Benefits from a UK perspective
  - Renewable Subsidy
    - Reduction of ROC funding
  - Wholesale Price Reduction
    - Impact on market prices, competition
  - Balancing Costs
    - Using 2009 RES Lead Scenario assumptions
  - Security of Supply
    - Reduction in need for shadow plant and thermal displacement
  - Carbon Emissions
    - Over the counterfactual
  - Others unmonetised: Jobs, Exchequer benefit etc.

5

Introduction

How can it be done?

- Link from an offshore site with a direct connection with GB:
  - Two DC onshore converter plus one offshore converter.
  - VSC technology. Current technology limits to about 1 GW per DC link module.
  - Multi-terminal HVDC. No significant experience record but technically feasible



- Direct interconnection
  - DC with both converters onshore, likely CSC Technology.
  - Lower capital cost and losses
  - Higher voltages, higher carrying capacities
  - Long experience record

Introduction

Scope for integrating offshore grids

- Offshore Wind Farms
  - For connections <= 90 km to shore HVAC most effective.
  - For connections 90 km to 115/120 km HVAC could still be attractive.
  - For connections >= 120 km the HVDC is most effective technology
- For HVAC little benefit in offshore interconnections based on availability and cost of lost generation analysis.
- For HVDC there is benefit in having offshore interconnections due to high unavailability of offshore HVDC converters, largely single circuit connections, and long connection distances.

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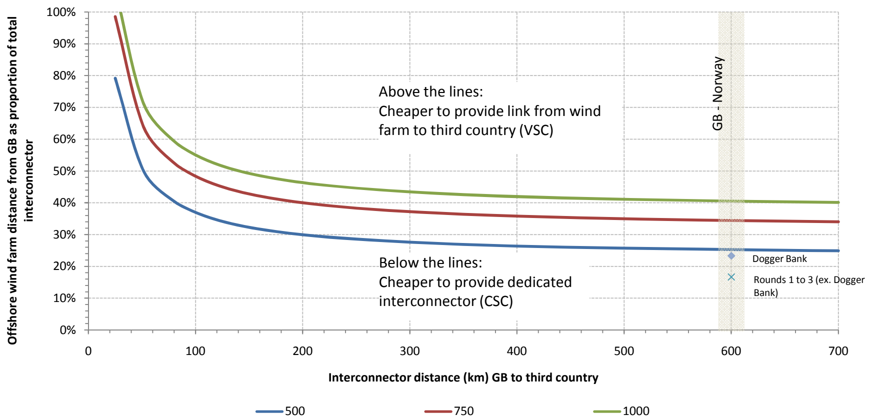
Introduction

Interconnectors: Cheaper direct or from wind farm?



- For long interconnectors, a direct interconnection between two countries is cheaper than the link from an offshore wind farm to another country if the wind farm is below about 30% to 40% of the distance between the two countries.
- Distance required from wind farm for additional link to be cheaper than direct interconnector grows with link capacity

8

Introduction

How will an interconnector be used?

- Interconnectors are primarily justified based on their utilisation (Power flows)
- One way of estimating utilisation is to assess the arbitrage opportunities between two markets.

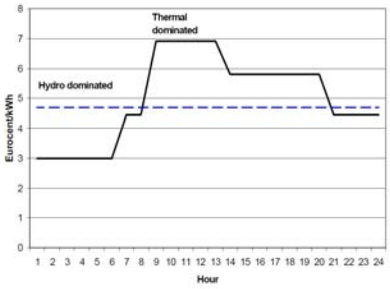
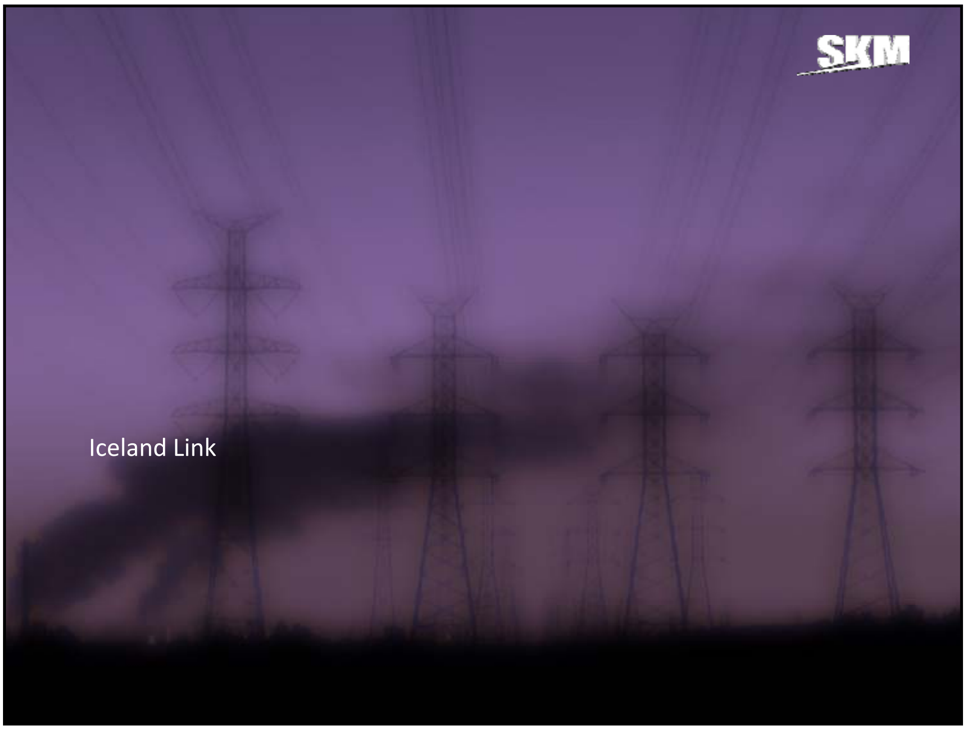


Figure 2.1: Illustration of price structure on the Nordic (hydro) and the Continental market (thermal)

Source: Nordic Grid Master Plan 2008

- In order to estimate the benefits that might accrue from interconnection is it necessary to undertake the following:
  - o Examine historic price differentials between the relevant markets and calculate theoretical arbitrage opportunities, allowing for losses and balancing costs;
  - o Calculate the likely impact on arbitrage revenues of the flows produced by the offshore wind generation; and
  - o Estimate likely future revenues from the historic values.
- Arbitrage revenue calculations in turn for GB (UKPX) in relation to Ireland (SEM), Netherlands (APX-NL) and Norway (Nordpool).



Iceland

– why consider a JP with Iceland?

- Geothermal is a competitive renewable source compared to offshore renewables
- There is an abundant resource to be exploited
- Iceland system has grown significantly in the last few years. It can allow more significant generation exports to other countries without jeopardising it own reliability and also facilitating the use of conventional DC technology.
- Expected capacity factor: 91%
  - o 500 MW of geothermal plant at a load factor of 90% could provide as much renewable energy as:
  - o some 1.1 GW offshore wind with a load factor of around 40% .
- ... but a number of significant challenges still remain.

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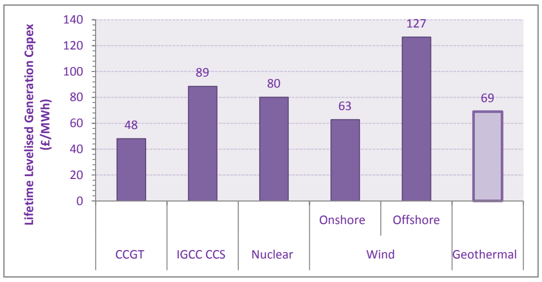
Iceland

Geothermal– lifetime levelised capex comparison



> Geothermal generation costs are
>> of the same order as onshore wind costs
>> almost half of the offshore wind costs

> But connections to Iceland will add onto those costs hence need for further analysis.

	CCGT	IGCC CCS	Nuclear	Onshore Wind	Offshore Wind	Geothermal
Capex (£/kW)	646	1,992	2,375	1,200	2,600	2,875
FOC (£/kW/yr)	20	100	56.6	25.1	52.5	28.1
VOC (£/kWh)	0.002	0.004	0.003	0.0005	0.0005	0.0060
Discount rate	12%	12%	12%	12%	12%	12%
Planning lead time years	3	5	9	3	3	5
Load factor	80%	80%	80%	30%	38.8%	91%
Amortisation period	20	30	30	20	20	20
Fuel costs	50p/thm	$100/te				
Carbon	€20/te CO2					
Lifetime levelised cost (£/MWh)	48.1	88.6	80.2	62.8	126.7	69.0

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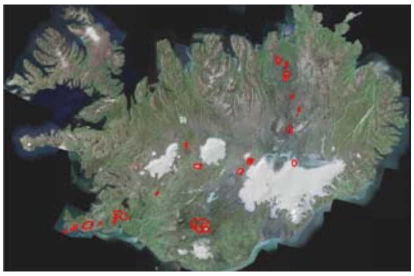
Iceland

Geothermal Resource

- The Energy Authority of Iceland (Orkustofnun) estimated (2009) the usable geothermal resource base for electricity generation.
- The authority estimates that it is possible to develop 4,300 MW for geothermal electricity generation within the next 50 years from known high temperature areas in Iceland.
- This translates to around 35 TWh in annual electricity production. In comparison, in 2008 electricity of 4 TWh was generated from geothermal power plants in Iceland.



Svæði	Stærð [km²]	Hágildi	Miðgildi	Lággildi
		$[MW_{50}]$		
Reykjanes	9	81	45	27
Svartsengi-Eldvörp	30	270	150	90
Krýsuvík	89	801	445	267
Brennisteinsfjöll	5	45	25	15
Hengill	142	1278	710	426
Geysir	5	45	25	15
Kerlingarfjöll	39	351	195	117
Hveravellir	14	126	70	42
Torfajökull	253	2277	1265	759
Hágöngur	43	387	215	129
Vonarskarð	29	261	145	87
Kverkfjöll	31	279	155	93
Askja	27	243	135	81
Hrúthálsar	4	36	20	12
Fremrinámar	10	90	50	30
Krafla-Námafjall	62	558	310	186
Gjástykki	11	99	55	33
Þeistareykir	48	432	240	144
Samtals	**851**		**4255**	

Source: Energy Authority of Iceland (Orkustofnun)

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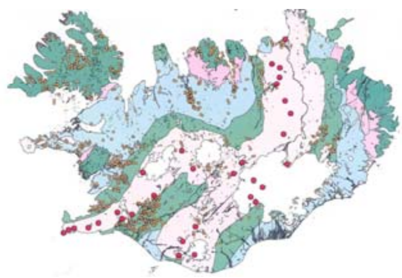
Iceland

Realisable Geothermal Resource

- 500 MW of new geothermal development in Iceland possible by 2020.
- 500 MW from developments at five new 100 MW geothermal resource locations
- Developments greater than 100 MW unlikely before 2020
- New developments, are likely to be *'high temperature'*. The biggest unknowns are
  - o *well productivity* and
  - o *fluid enthalpy*

  which drives how many production and injection wells need to be drilled – and wells are expensive



Source: Geothermal and Hydro power Master Plan 2007

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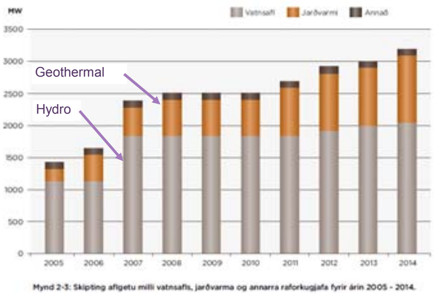
Iceland
Generation overview

Hydro	Total Capacity (MW)	Geothermal	Total Capacity (MW)
Fljótsdalsstöð	690	Kröflustöð	60
Búrfellsstöð	270	Hellisheiðarvirkjun	210
Hrauneyjafossstöð	210	Reykjanesvirkjun	100
Sigöldustöð	150	Svartsengisvirkjun	75
Blöndustöð	150	Nesjavallavirkjun	120
Sultartangastöð	126		
Vatnsfellsstöð	90		
Írafossstöð	48		
Lagarfossstöð	28		
Laxárstöðvar	27.5		
Steingrímsstöð	27		
Ljósafossstöð	15		
Mjólkárvirkjun	8.1		
Andakílsárvirkjun	8		
Total	1847.6		565

GANGSETNING	VINNSLUSVÆÐI	UPPSETT AFL [MW]
2011	Hellisheiðarvirkjun	90
	Reykjanesvirkjun	100
2012	Reykjanesskagi	50
	Hellisheiðarsvæði	90
	Búðarhálsvirkjun	80
2013	Hvammsvirkjun	82
2014	Reykjanesskagi	95
	Holtavirkjun	53
	Hellisheiðarsvæði	45

Tafla 2-3: Aukning í raforkuframleiðslu inn á flutningskerfi Landsnets árin 2010- 2014.



Mynd 2-3: Skipting afligetu milli vatnsafls, jarðvarma og annarra raforkugjafa fyrir árin 2005 - 2014.

- > Islanded small system, about 3% of GB
- > About 2.4 GW installed capacity with over 76% hydro and the rest geothermal
- > Plans to reach over 3,000 MW by 2014 mainly through the addition of Geothermal plants mainly for energy intensive industries
- > About 1.2 GW of new hydro and geothermal specific projects (12) at various stages through the planning process. Majority geothermal.

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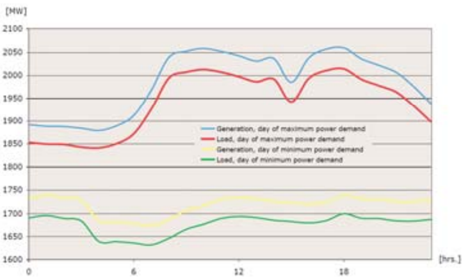
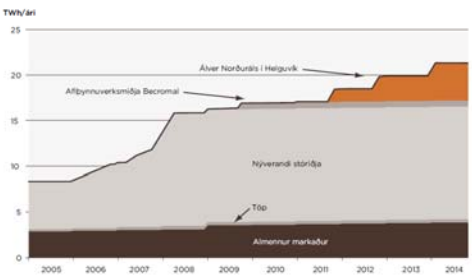
Iceland
Iceland demand

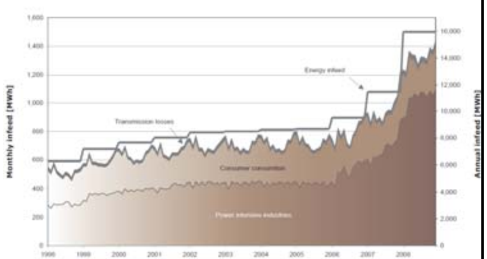
Generation and load curves at day of max. (02.12.2008) and min. (04.08.2008) demand





Source: Landsnet annual report 2009

The graph shows trends in the volume of power fed monthly and annually into Landsnet's grid in the past 11 years



- > Demand 16 GWh, fast growth over last three years driven by energy-intensive industries
- > Peak demand over 2.1 GW with annual energy and minimum around 1.7 GW.
- > Relatively low winter summer variability (+/- 300 MW or 15%)
- > Spare capacity could be used for export reducing need for new plants, however,
- > Growth forecast despite economic crisis reaching over 20 TWh by 2014.

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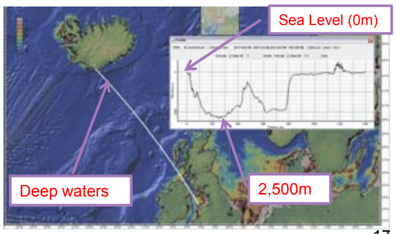
Iceland
Outline routes

- Direct Iceland-GB Interconnection
  - o Access to renewable geothermal dispatchable resource
- Long connection required
  - o About 1,700 km if connected to north Wales
  - o About 1,200 km if connected to north of Scotland
- Route selection required to avoid deep areas >1,650m (state of the art cable laying depth)



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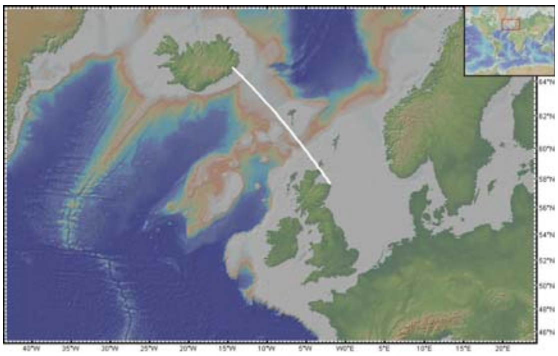
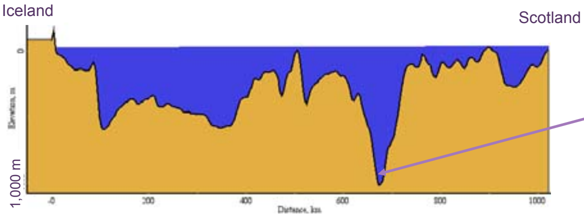
Iceland
Managing depth-realisable South East route



> Example trace to demonstrate feasibility of "shallow" route.

> South East routing from Iceland to the UK would keep water depth well within capability of current state of the art submarine cable laying demonstrated technology (about1650 m)

> If plants located in the south west cable route likely to go East first to avoid deep water areas, adding length to cable route.



Cable routing example showing deepest point about 1,000 m

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Iceland

Iceland – UK – a very long connection-

- 1700 km radius from London (similar distance to Iceland-Wales cable route) covers most of Western Europe
- Longest HVDC submarine cable installed to date is NorNed 580 km (34%) with second circa 250 km (15%) Sweden-Poland
- Potential reliability issues
- Financing and risk issues
- Too long?

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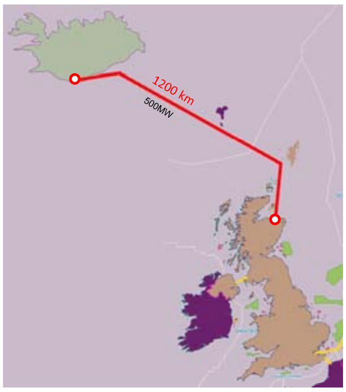
Iceland

Iceland-UK. Direct links



- DC links:
  - CSC converters with MIND cables
  - VSC with XLPE cables
- East route length much shorter but potentially affected by onshore network constraints in Scotland.

Option	Capital (£m)	Losses (%)
East 1200 km	782	8.2
West 1700 km	1,058	10.9
East VSC	936	12.9

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Iceland

Iceland-UK. Link via Shetlands

- Shetland Wind farm (540 MW) strategic location between UK, Norway and Iceland. Very high load factor around 50%.
- Shetland connection would require use of VSC technology, then all links VSC.
- "Current" VSC technology only up to about 300 kV (vs up to 500 kV CSC). Impact on losses.
- **Incremental** costs **over radial Shetland**

Option	Capital (£m)	Losses (%)
500 + 500	670	7.9
500 + 1000	866	5.5

> Shetland connection assets costs are considered sunk (500 MW) but would result in constraints to the high load factor geothermal

> If Shetland link capacity increases to 1000 MW then capital costs increase but constraints and losses reduce. Optimisation of cable capacity required.

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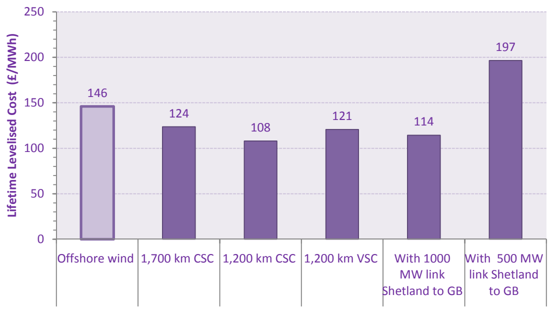
Iceland

500 MW link with Iceland: Options analysis



> Geothermal Levelised costs for best options range between £108/MWh to £124/MWh

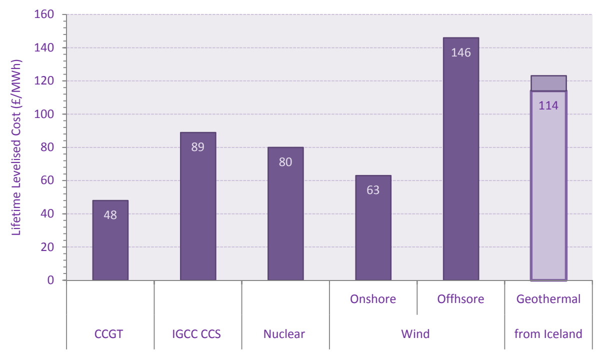
> Geothermal power from Iceland could be substantially cheaper than offshore wind (up to about 25%).

> Both the direct link Iceland-GB and indirect link via Shetland wind farm are attractive.

		Direct Link			Iceland link via Shetland linking with 500 MW wind farm	
	Offshore wind	1,700 km CSC	1,200 km CSC	1,200 km VSC	With 1000 MW link Shetland to GB	With 500 MW link Shetland to GB
Capex (£/kW)	3,050	4,990	4,439	4,747	4,652	4,214
Losses	3.9%	10.9%	8.2%	12.9%	9.7%	6.5%
Load factor	37.3%	81.1%	83.5%	79.2%	82.1%	42.5%
Lifetime levelised cost	146.0	123.6	108.0	120.7	114.4	196.5
Resulting ROC support	2	1.5	1	1.5	1.25	3.25

Iceland

Comparative lifetime levelised costs – including connection costs



- Geothermal from Iceland competitive with offshore wind – but twice the cost of onshore wind
- Feasible with current geothermal ROC support
- However – uncertainties abound:
  - o highly front loaded capex
  - o cable length and associated risk
  - o Issues with development in Iceland re grid access, location and environment
- Higher IRR required for project?

	CCGT	IGCC CCS	Nuclear	Onshore Wind	Offshore Wind	Geo-thermal
Capex (£/kW)	646	1,992	2,375	1,200	2,900	4,652
Load factor	80%	80%	80%	30%	38.4%	82.4%
Lifetime levelised cost (£/MWh)	48	89	80	63	146	114

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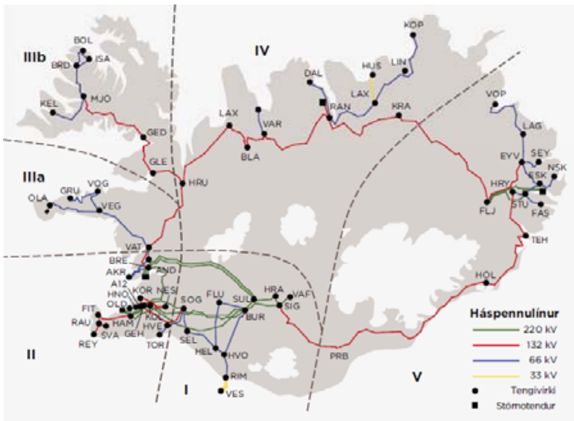
Iceland

Onshore network impact: Iceland network



> Relatively weak transmission system. Fundamentally two main load areas with weak 132kV interconnection ring. Some 220 kV lines already built to 400 kV specs.

> Any large joint project significantly increasing East-West power transfers would require onshore reinforcements.

> South West and East are strongest areas for connection. East would be best also to avoid deep water areas to the south of Iceland, would reduce submarine cable lengths.

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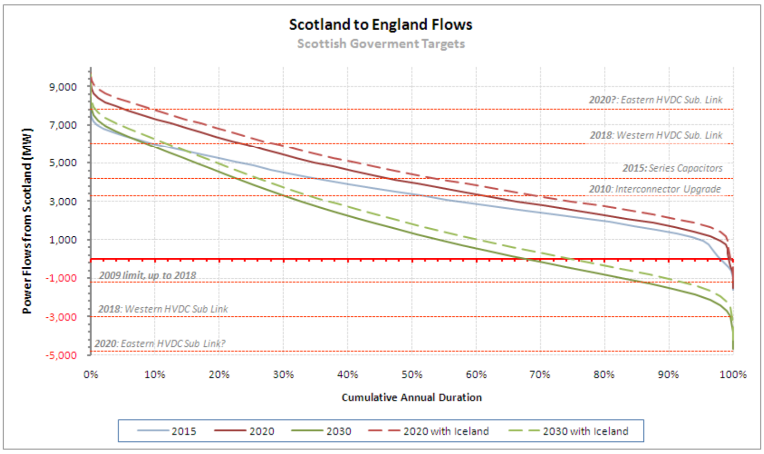
Iceland

Onshore network impact – England-Scotland Boundary

Flows Scotland to England without the energy from the 500 MW link to Iceland and with it (dashed coloured lines).



- Without Iceland link: By 2020 constraints may occur for about 5% of the time, even following second of the ENSG planned offshore links (Eastern link).
- With the 500 MW Iceland link by 2020 constraints will increase to around 10% of the time. However, priority access for renewables?
- Also post 2020 constraints will disappear as thermal plant closes in Scotland.

Iceland

5 new geothermal plants? it's already happened before.

News

Jun 13, 2008

Iceland Orders Five Geothermal Power Generation Plants

Iceland continued its world leadership in geothermal power generation by ordering five more geothermal power plants. Iceland purchased five 45 MW geothermal plants that will produce 225 MW of clean, renewable electricity in total. The new power plans will be built in a field outside of Reykjavik. Iceland generates nearly all of its power through renewable resources.

Reykjavik Energy (Orkuveita Reykjavikur) of Iceland has issued a turnkey order to Mitsubishi Heavy Industries, Ltd. (MHI), in a consortium with Balcke-Dürr GmbH, to build five 45 MW (megawatt) geothermal power plants, 225 MW in total, in the suburbs of Reykjavik. Deliveries of the plants will begin in October 2010 and be completed by February 2012. MHI has previously received several orders for geothermal plants for Iceland and the latest order brings the total number of the plants to the country to 15.

- 5 geothermal plants ordered in 2008
- Appear in 2009 development plan
- 4 plants will be delivered within 4 years of contract
- Iceland link decision would need to be made not later than 2015 for 2020 commissioning. Challenging supply-chain.

GANGSETNING	VINNSLUSVÆÐI	UPPSETT AFL [MW]
2011	Hellisheiðarvirkjun	90
	Reykjanesvirkjun	100
2012	Reykjanesskagi	50
	Hellisheiðarsvæði	90
	Búðarhálsvirkjun	80
2013	Hvammsvirkjun	82
2014	Reykjanesskagi	95
	Holtavirkjun	53
	Hellisheiðarsvæði	45

Tafla 2-3: Aukning í raforkuframleiðslu inn á flutningskerfi Landsnets árin 2010- 2014.

Iceland

Benefits from a UK perspective

Benefit NPV (£m)	'contained' renewables		'additional' renewables	
	2020	2030	2020	2030
Carbon	0	0	220	897
Balancing cost	83	242	0	0
Back up/Thermal plant	54	138	122	309
Renewable subsidy	359	993	-689	-1,750
Subtotal	**496**	**1,372**	**-347**	**-544**
Wholesale price	*44*	*116*	*13*	*40*
Total	**540**	**1,488**	**-334**	**-504**
Additional contribution to renewables target?	No	No	Yes	Yes

- Balancing cost and back up plant benefits
- Assume mainly importing

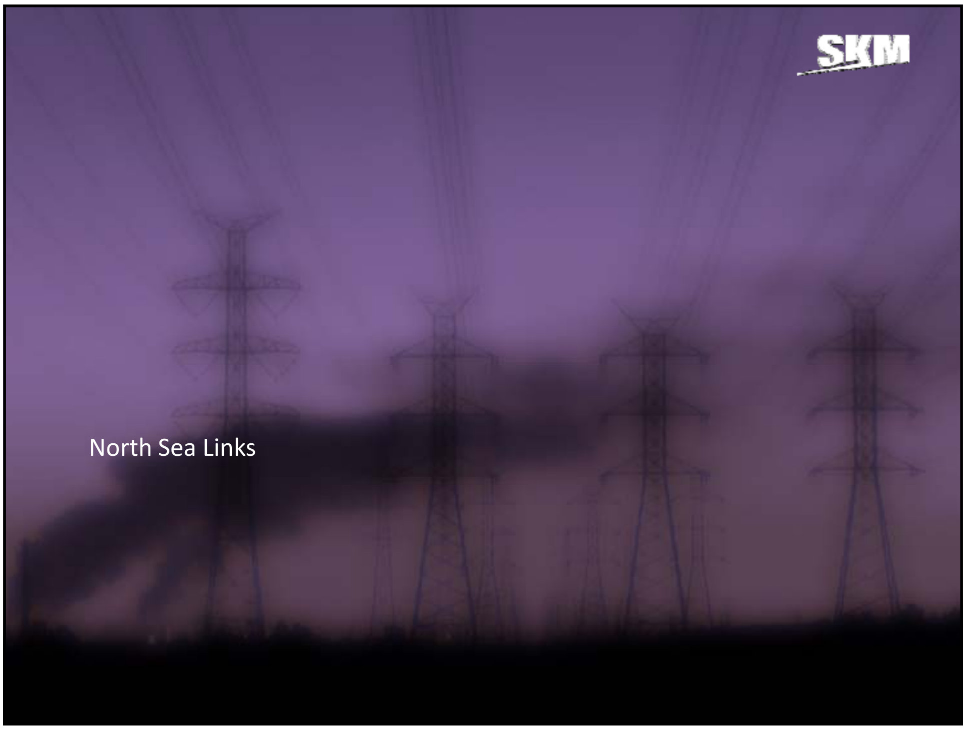
> Carbon saved, but ROC support required

> Increases renewable contribution by 4 TWh – raises renewable generation by about 4% by 2020

Iceland

Icelandic link – summary

- Geothermal potential cost effective JP option – although probably limited to around 500 MW by 2020
- Likely to require 5 * 100 MW plants – with associated risk
- Most attractive options are:
  - o The shorter 1200 km cable landing at NE Scotland
  - o Link to Shetlands, then 1000 MW from Shetlands to NE Scotland
- Geothermal capital cost (£/kW) greater than offshore wind, high load factor leads to lower costs/kWh
- Feasible with current Geothermal ROC
- Very long cable
- A high risk project – but figures suggest it may be cost effective way of achieving additional renewable generation.
- This indicates that savings in offshore generation costs can fund substantial investments in network (gearing of costs but also of savings)



Norway

Why investigate a link with Norway?

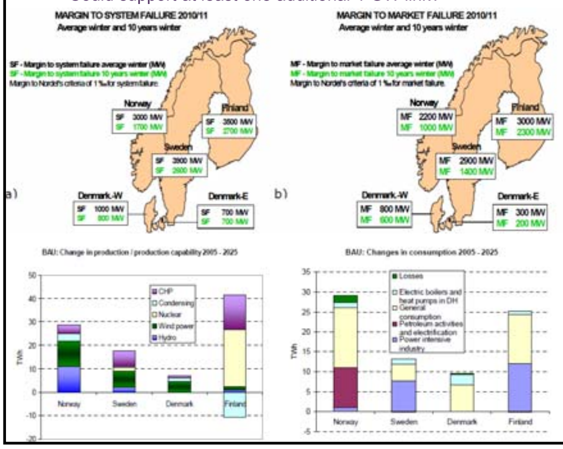
- Potential for JP development in Dogger Bank
- Resulting potential for interconnection with Norway
- Norway has deregulated power market – although over 85% electricity produced by state owned companies
- 98% electricity produced from hydro – relatively stable Nordpool price – likely to increasingly complement more volatile GB wholesale prices
- Also potentially assist with balancing

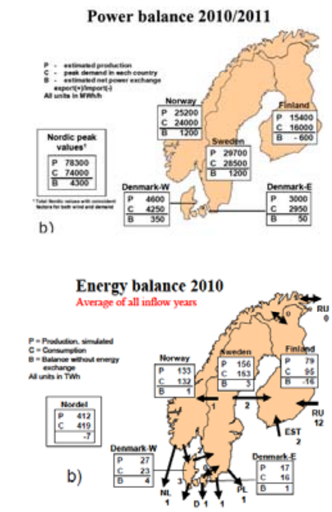
However,

- Norway hydro output dependent on rainfall – low in 2003 and 2004, Norway became net importer in these years
- Little large new hydro development expected - most new generation development expected is wind
- Interconnection with rest of Northern Europe expanding apace

Norway
Generation-Demand Overview

- Norway has some 26.5GW of available winter generating capacity and on 6 Jan 2010 the demand hit 24GW at 8am.
- Small remaining capacity in Norway 1-3 GW (2010)
- Planned Norway-Germany interconnector 1.4GW (2015?)
- Growth in expected demand matched by planned generation growth
- Uncertainty about energy surplus in the long term
- Could support at least one additional 1 GW link?





Source: Nordic Grid Master Plan 2008

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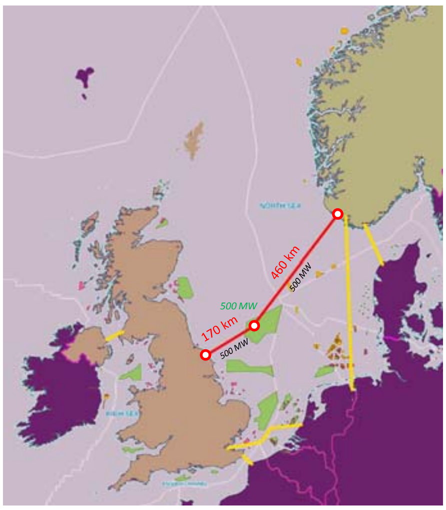
Norway
UK-Norway via Dogger Bank



- VSC Technology module compatible size (around 1000 MW max transfer)
  - o 500 MW from Norway
  - o 500 MW Wind Farm in Dogger bank connected to the UK and Norway
  - o 1000 MW wind farm in DB would have same incremental capital costs for Norway link but reduced benefits due to constraints
- GB-Dogger Bank link capacity options:
  - o 500 MW, using spare capacity with low wind
  - o 1,000 MW, unconstrained
- Incremental costs over radial Dogger connection

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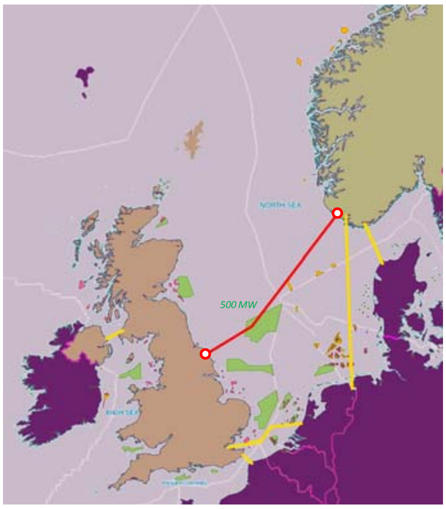
Norway

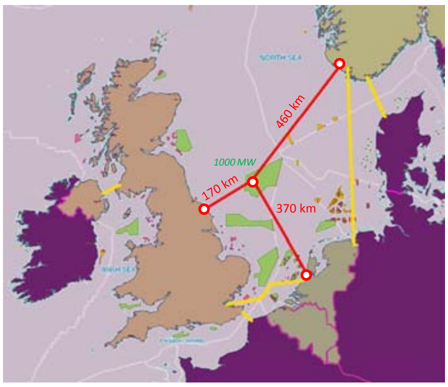
UK-Norway Direct Link



- CSC Technology
  - o Lower capex
  - o Less losses
- Two alternatives considered to ease comparison
  - o 500 MW link
  - o 1000 MW link

Norway

Variations: UK-Norway-Benelux via Dogger



- Link from Dogger to Benelux/France unlikely on cheaper alternative basis
- Potential for Germany link as they exploit further afield sites in the North Sea (e.g. Bard 1 already has over 200km DC connection)
- However there are potential competing connections in the Baltic Sea involving shorter lengths and,
- NorGer interconnector under development directly linking Norway and Germany (1,400 MW)

Norway

Norway Costs

- Direct interconnector significantly cheaper way of providing an interconnection with Norway
- 1000 MW direct link most cost effective option from a 'UK' perspective

	Offshore wind (500 MW)	Direct Link GB-Norway		GB-Norway (500 MW) via WF	
		500 MW	1000 MW	Dogger-GB 1000 MW	Dogger-GB 500 MW
Cable costs	50	347	451	505	413
Converters	170	120	180	254	227
Total	**220**	**467**	**631**	**759**	**640**
Energy delivered	1.63	3.8	7.6	5.3	3.8

- Options Considered:
  - Link from GB to Dogger Bank wind farm (500 MW) - 2 alternatives- and from wind farm to Norway (500 MW). Capacities limited by VSC module sizes.
  - Direct interconnection to Norway, 500 and 1000 MW links.

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Norway

Norway Benefits

Benefit NPV (£m)	500 MW link via Dogger wind farm (500 MW) with 1000 MW link Dogger-GB				Direct Interconnector (1000 MW)	
	'contained' renewables		'additional' renewables			
	2020	2030	2020	2030	2020	2030
Carbon	98	400	342	1,395	440	1,794
Balancing cost	12	35	-28	-81	24	70
Back up/Thermal plant	106	270	80	203	213	540
Renewable subsidy	0	0	-447	-1,171	0	0
Subtotal	**216**	**705**	**-53**	**346**	**677**	**2,404**
Wholesale price	*20*	*60*	*20*	*60*	*27*	*80*
Total	**236**	**765**	**-33**	**406**	**704**	**2,484**
Additional contribution to renewables target?	Maybe	Maybe	Yes	Yes	Maybe	Maybe

- Link via Dogger shows less benefits than direct interconnector
- Interconnector assumed importing to UK about 70% of time
- Substantial direct interconnector benefits

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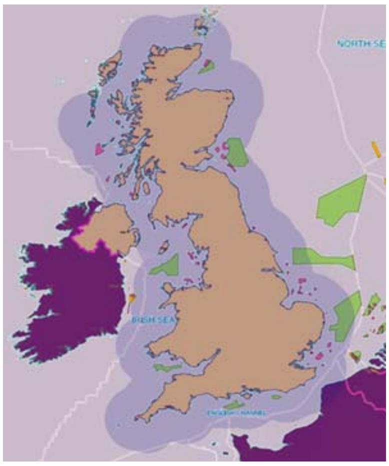
Norway

CBA Summary

- The CBA shows that the direct link is more effective than the link via Dogger Bank from a UK perspective
- Only new Norwegian hydro built after the EU Renewables Directive would count towards the target
- Benefits highly dependant on direction of power flows. Interaction with other links and future generation profile may constraint use.

Ireland
Irish Offshore



- Joint Project development opportunities also exist in the Irish Sea with the potential development of offshore wind close to shore in Irish territorial waters
- However more cost effective for the offshore wind developer in Ireland to connect such wind farms to Ireland rather than GB
- But may require substantial network reinforcements in Ireland with expected connection dates well into the future.
- An earlier connection date may be possible in some cases if connected to the UK.
- Benefits from Irish offshore wind farms connecting to GB similar to any other R3 wind farms

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Ireland
Ireland Benefits

Benefit NPV (£m)	500 MW link via wind farm (500 MW) with 500 MW link Wind farm-GB				Direct Interconnector (500 MW)	
	'contained' renewables		'additional' renewables			
	2020	2030	2020	2030	2020	2030
Carbon	0	0	40	166	0	0
Balancing cost	5	13	-20	-58	20	58
Back up/Thermal plant	38	96	12	30	76	193
Renewable subsidy	0	0	-447	-1,171	0	0
Subtotal	**42**	**110**	**-415**	**-1,033**	**96**	**251**
Wholesale price	*7*	*19*	*7*	*19*	*13*	*38*
Total	**88**	**225**	**-408**	**-1,014**	**109**	**289**
Additional contribution to renewables target?	No	No	Yes	Yes	No (?)	No (?)

- Interconnector importing to UK 25% of time – rising to 45% by 2030
- UK providing ROC support
- Main savings CO_2 and thermal plant reduction to maintain security of supply

> Potential to add to UK renewables via onshore JP in Ireland?

> Balancing cost and reduction in UK thermal plant requirement

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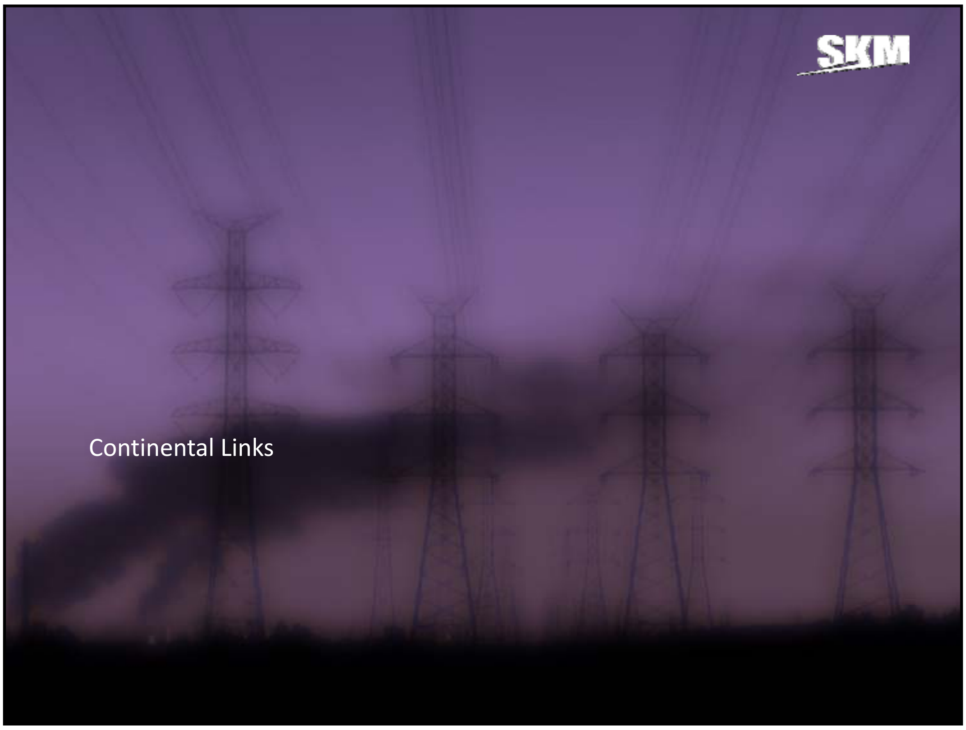
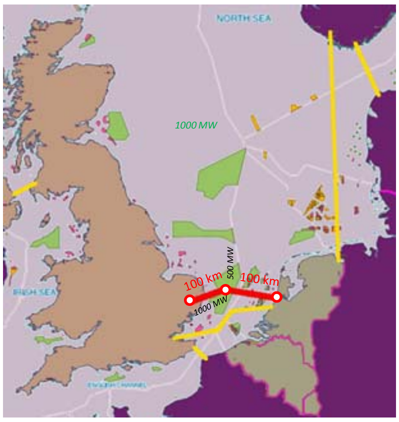
Ireland

Ireland summary

- Current interconnector between GB and NI is dominated by exports to NI
- This will change as wind increases in Ireland – expect beyond 2020 for Ireland to become net exporter in the winter, when wind is high, and importer in the summer when wind is lower.
- With less interconnection Irish wind will become increasingly ‘curtailed’ and prices in the SEM increasingly volatile
- Increased interconnection allows Ireland to export excess wind
- Little benefit for GB wholesale prices as when windy in Ireland higher likelihood of wind in GB
- Benefit to the UK in the form of reduced CO_2 emissions
- UK will pay renewable subsidy
- Building onshore wind in Ireland and exporting to the UK – better deal for the UK?



Continental Links
UK-Benelux via Norfolk



- Norfolk area in close proximity to Belgium and the Netherlands
- Belgium/Netherlands are only about 100km to Norfolk R3 development area, feasible "short" connection.
- However, Belgium has not yet indicated it can not meet targets domestically. Luxembourg needs 0.5-3.5TWh but can trade cheaper renewable sources?
- No apparent significant benefits from wholesale price reductions or renewable generation cost reduction
- Potential benefit in terms of security of supply (e.g. linking of two wind farms connected to two countries) however coincidence issues.
- Cheapest interconnector?

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Continental Links
UK-Benelux via Dogger

- No benefit to Benelux over cheaper "near to their country" alternatives
- For Germany, if Dogger is developed, then again a connection between offshore wind farms may provide a cost effective interconnector

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Continental Links

Continental Benefits

Benefit NPV (£m)	500 MW wind farms linked via 500 MW link				Direct Interconnector (500 MW)	
	'contained' renewables		'additional' renewables			
	2020	2030	2020	2030	2020	2030
Carbon	0	0	40	166	0	0
Balancing cost	5	13	-20	-58	20	58
Back up/Thermal plant	38	96	12	30	76	193
Renewable subsidy	0	0	-447	-1,171	0	0
Subtotal	**42**	**110**	**-415**	**-1,033**	**96**	**251**
Wholesale price	*7*	*19*	*7*	*19*	*13*	*38*
Total	**88**	**225**	**-408**	**-1,014**	**109**	**289**
Additional contribution to renewables target?	No	No	Yes	Yes	No	No

- Fewer carbon savings than Norway – more thermal generation on continent
- UK providing ROC support

> No carbon savings – continental mix similar to UK

> Wholesale price reductions less than Norway – APX/GB arbitrage less

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CBA Key Conclusions

- There are clear benefits to the UK of interconnection – the question is how 'best' to achieve this interconnection. We suggest that:
    - For Norway – a direct point to point interconnection is likely to be the most cost effective option for achieving the benefits of interconnection. Joint project development at Dogger Bank with an interconnection is less attractive – a direct link to the UK could be more cost effective.
    - For continental Europe – linking two offshore wind farms to create an interconnection could be the most cost effective approach. But requires these projects to be built – so achieving the benefits of interconnection may be more readily achieved via a direct onshore to onshore interconnection
    - For Ireland – the most attractive option is a direct interconnection to exploit a potential low cost onshore wind joint project.
    - Geothermal from Iceland is a potentially cost effective joint project development – but will be relatively small scale and high risk

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Other observations

- Limitations of current VSC DC transmission technology could reduce the attractiveness of integrating interconnections involving intermediate offshore wind farms
- In many cases the benefits of interconnection are achieved more efficiently via conventional direct point to point interconnections using conventional CSC DC transmission technology.
- The limitations of VSC DC transmission capacity modules also questions the feasibility and attractiveness of "hubbing" or aggregating multiple offshore wind farms.
- In addition such aggregation would be limited in practice by system operation safety reasons due to the potential simultaneous loss of generation in case of faults within the interconnected DC links somewhat alleviated by developments such as DC circuit breakers.
- Standardisation of voltages, platform designs and compatibility between manufacturers equipment would facilitate potential interconnections between wind farms and lead to potential savings.

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The investor perspective

- For the interconnector options the revenues to the developer will be linked to the flows on that interconnector.
- The arbitrage analysis shows potential interconnector utilisation of around 80% for Norway, continental Europe and Ireland. So there is clearly scope for cost effective interconnection.
- As shown by developer interest in interconnector construction
- Then the question becomes, how can this be achieved most cost effectively for an investor?
- Interconnections between wind farms linking two countries appear highly cost effective but will raise a plethora of contractual and regulatory issues. Not core business of wind generators? Conditional on wind farm construction. Willingness of investors? Higher revenue uncertainty, Higher risk

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Final Remarks

- Offshore grids with integrated offshore generation are not a prerequisite for the development of offshore generation
- Higher benefit but more capital intensive and complicated projects could be difficult and more expensive to finance.
  - At £3 billion/GW or higher, offshore generation projects are very capital intensive and with limited track record: High risk premiums
  - Network connections are a relatively small part of the overall costs for the majority offshore generation developments..
  - Current financial constraints: Financing difficulty, higher risk premiums and complex arrangements for larger capital projects
  - Projects using novel technology and unproven products will also face higher risk premiums
- Higher risk premiums could easily offset any potential benefits from offshore grid interconnections.

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Technology and System Integration Research Challenges

Tim Green

Control & Power Research Group

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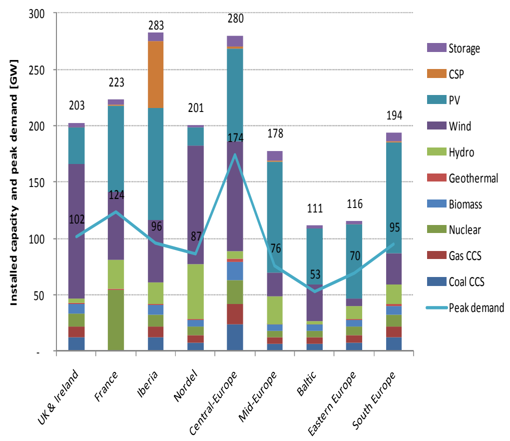
Is UK an island in a low carbon energy future?

EU Roadmap 2050, 80% Renewable Energy



Source: Imperial College and KEMA

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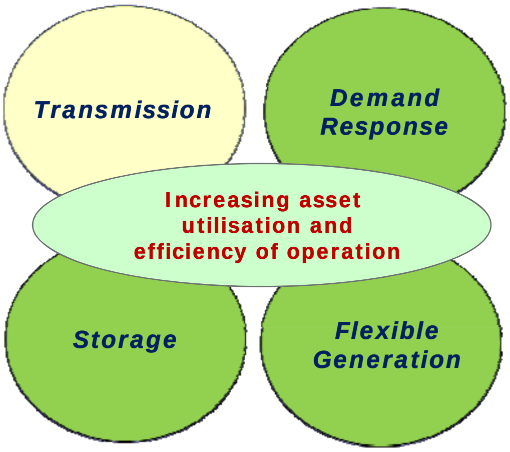
Technology options for efficient integration of low carbon generation



Cost effectiveness of alternative technology options will be system specific

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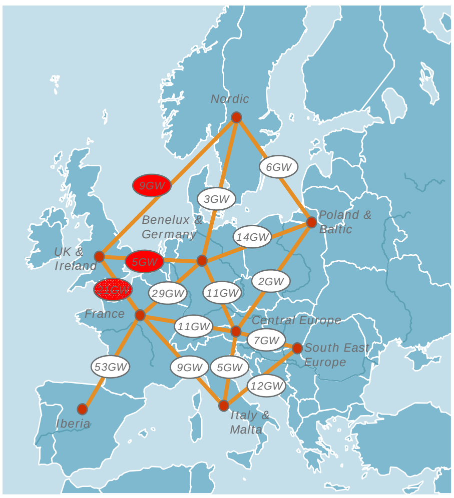
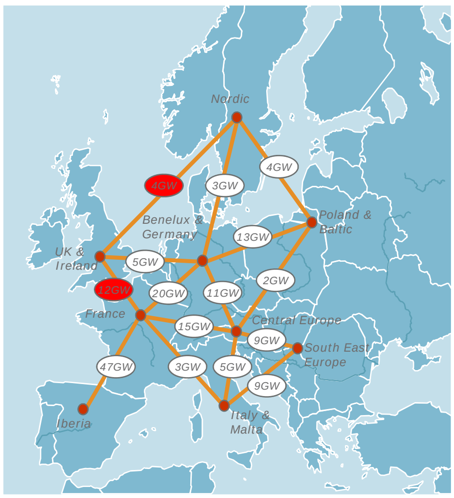
Demand side and storage can substitute for some transmission

Total Net Transfer Capacity Requirements
No Demand Response / Storage



Total Net transfer Capacity Requirements
With Demand Response / Storage



Source: Imperial College and KEMA

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Introductory Remarks

- Offshore HVDC is clearly an expensive capital asset and that fact defines much of how it is used
- Cost-benefit optimisation drives use to the fullest possible extent when used for offshore wind farms
  - Links rated at somewhat less than wind farm capacity (c.f. N-2 provision to onshore thermal generation)
- HVDC interconnection can bring significant value in providing access to diversified renewables but it competes with demand action etc.

- Technology research agenda is driven by desire to
  - Increase ratings
  - Reduce capital cost
  - Reduce operating cost (losses)
  - Reduce cost of downtime

- System integration research agenda driven by need to
  - Understand new system interactions
  - Resolve fault management issues
  - Identify system ancillary service capabilities

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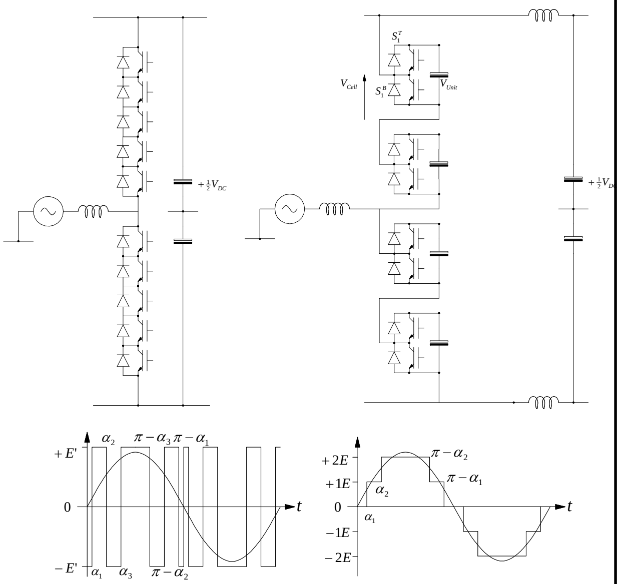
Technology Research

- HVDC based on voltage source converters (self-commutated semiconductors) has made much progress

- Recent announcements by manufacturers indicate convergence on multi-level approach (rather than series valve and PWM)
- Good waveform quality can be achieved with fewer device commutations – less loss, no need for filter



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Power Loss Example

- Typical IGBT of 3.3kV and 1.2kA
- Operate at 1.75 kV DC and 1000 A max with switching of 1kHz

$$V_{RMS} = \frac{1}{2\sqrt{2}} V_{DC} \approx 600V$$

$$I_{RMS} = \frac{1}{\sqrt{2}} I_{Max} \approx 700A$$

$$P_{AC} / IGBT - Pair = 420kVA$$

- Losses using typical figures are about 0.8%
- Switching loss is high and lower frequency would be preferred

$$P_{Loss} = P_{Cond} + P_{Sw}$$

$$P_{Cond-IGBT} = \delta_{IGBT} V_{IGBT} I \approx 0.75 \times 2.5 \times 600 = 1.1kW$$

$$P_{Cond-Diode} = \delta_{Diode} V_{Diode} I \approx 0.25 \times 2.2 \times 600 = 0.3kW$$

$$P_{Sw} = f_{Sw}\left(E_{Off} + E_{On} + E_{RR}\right) \approx 1 \times 10^3 \times 2 = 2kW$$

$$P_{Loss} = 3.3kW$$

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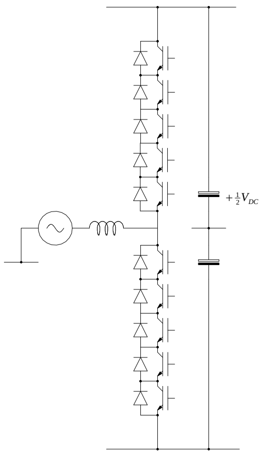
Loss Reduction

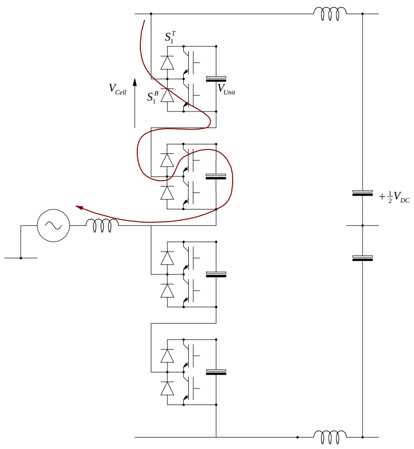
- Large proportion of total loss is direct loss in semiconductors (filter loss very small)
- Switching has been reduced by move to multi-level. Switching for good waveform quality can be 50 Hz in each module. Additional switching needed for capacitor voltage management.
- Trade-off between capacitor size and switching frequency is key. AC filter might have been eliminated but DC capacitors are large.
- Conduction loss reduction has three aspects:
  - How many devices are in the circuit
  - How many are used to form the current path at any one time
  - What semiconductor technology is used

Conduction Loss Reduction



- Higher rated devices leads to fewer devices for a given DC link voltage and in principle this reduces the conduction loss.
- However, there is a limit. The greater is the barrier to off-state voltage; the greater is the challenge in achieving low conduction voltage.
- At the extreme of device design, doubling the voltage rating (say 3.3 kV to 6.6 kV, also doubles forward conduction voltage, say 3.0 V to 6.0 V.
- Conduction loss per unit blocking voltage does not decrease as quickly as expected and may not decrease at all.
- We are in the hands of the device manufacturers

Numbers of Devices in Conduction



- M2C employs twice as many IGBTs for a given voltage rating compared to the simple series valve.
- However, conduction loss is not double since only one device per module conducts at a time.
- Analysis complicated by multiple current paths
- Scope for new topologies exists

New Materials

- New semiconductor materials take a very long time to develop and even longer to reach HVDC scale
- Silicon Carbide has been subject of many promises and is only now beginning to come good
- The prize is to be able to use majority carrier devices in SiC in place of minority carrier devices in Si. These should be faster, less lossy and resistive in conduction.
- SiC diodes available for some time; FETs now on their way
- First commercial SiC JFET is rated at 1200V and 12A
  - Used at 600V and 10A is has switch energy loss of 200uJ and (resistive) voltage drop of 1V
- Conventional silicon IGBT available at 1200V and 12A
  - Used at 600V and 10A is has switch energy loss of 1mJ and voltage drop of 3V

Reducing Downtime

- Normal approach onshore is to mesh the AC networks and use an N-1 or N-2 rule. This is a form of redundancy.
- The same degree of asset redundancy not viable in offshore
- Converters can have internal redundancy by over-providing number of modules.
- For a ±150kV link, 200 modules of 1.5 kV are needed in each limb. Over-providing by 10% allows 20 modules to fail in any limb before converter is forced out of service.
- Cables don't offer the same opportunities
- How would one combat forced outage of a cable?
- Interconnection of DC cables only helps if capacity sharing occurs
- Low load factor of wind provides opportunity to share capacity at times of low production.
- Diversity of closely located wind is small so this helps little

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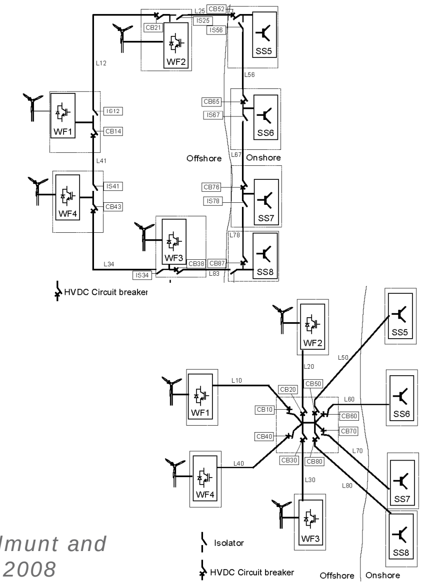
System Integration: Multi-Terminal HVDC

- Any additional cable distance is expensive and needs justification
- Ring topologies are not easy to apply because of high rating of some key branches
- Star topologies may raise single point failure issues
- Meshing can not involve long additional cable routes



Diagrams from presentation by O. Gomis-Bellmunt and N. Jenkins, SEDG HVDC workshop December 2008

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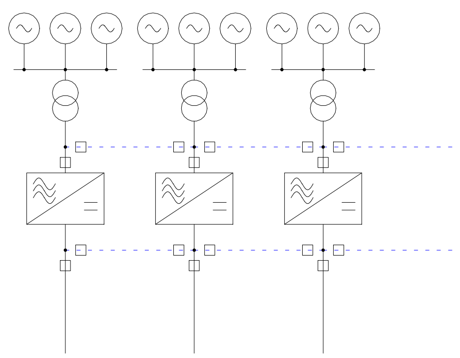
Simple Interconnection

- Cross-linking adjacent routes may have value.
- Aim is to avoid spilling wind during long cable repair times.
  - Fast response is not needed.
  - Loss of in-feed may limit extent of interconnection if fault response is protracted
- This might lead to Design Meshed / Run Radial



- Could interconnect on collector AC network of wind farms or on DC side
- Could perhaps provide N+1 cables for N converters

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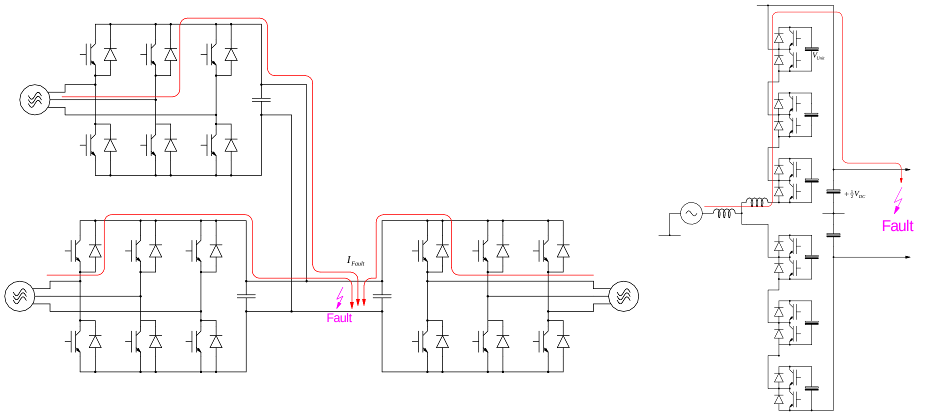
Fault Management

- Management of DC-side faults is know problem in VSC HVDC
  - CSC has ability to block thyristors and di/dt limited by inductance
  - VSC has uncontrolled conduction through diodes – true for M2C and series valve
    - » DC breakers need to be validated
    - » "Run-radial" would help avoid DC breakers: AC-side breakers sufficient for point-to-point



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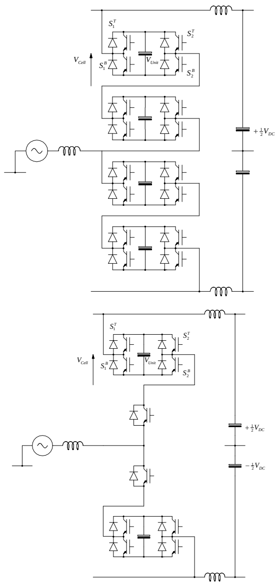
Active Control of DC-Side Faults



- Full-Bridge M2C can bock faults but has twice as many devices (and corresponding increase in devices in current path)
- Heavy price in capital cost and losses
- Alternate Arm Topology reduces device count and losses
- Innovation in circuit topology still occurring
- Process of fault management is now
  - Control or block converters to terminate DC fault current
  - Re-configure DC network using isolators
  - Restart power transfer
- The question is: how fast must this be to satisfy transient stability of main AC network

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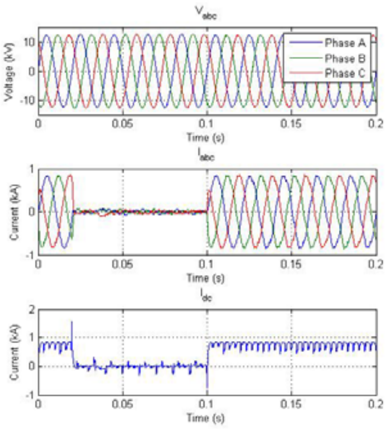
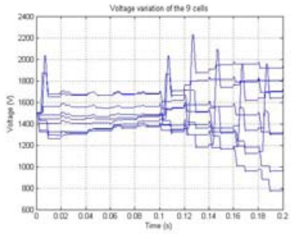
DC Short-Circuit Simulation



- 20MVA, 20kV System with 9 modules per limb
- Modules can continue to switch even when DC-link collapses
- AC-side current can be controlled to zero
- Module capacitors do no feed DC-fault but DC-side filter might
- Large disturbances to capacitor voltages must be controlled



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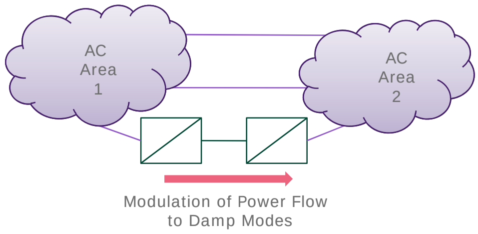
AC-Side Faults

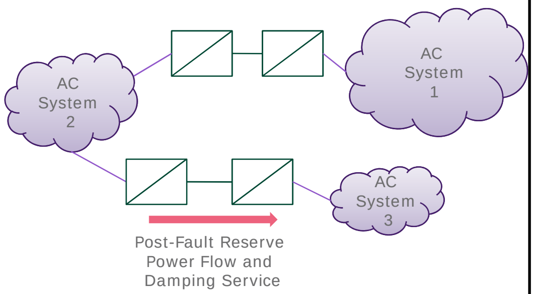
- Response of AC-side faults is crucial for such large contributions to system
  - Opportunity for managed response and set injection of reactive current
  - Limited ability to source fault current
  - Availability of post-fault damping services and reserve provision
  - Need to define response to asymmetric faults and avoid oscillatory real power

System Service Channels v. Firewalls

- Modulation of real power flow and reactive power at each converter station available for AC system control
  - Already shown to be useful to stabilise inter-area modes of a transmission corridor



- DC-links often viewed as firewalls between asynchronous systems
  - Supply of services through the links now couples the systems



Conclusions

- Innovation at circuit topology, semiconductor and cable levels not over yet
- Issues yet to resolve on how to arrange modularity of HVDC links within converters and between cables
- Different value calculations for wind connection and system interconnection may lead to different link interconnections
- Design meshed / run radial may give desired features
- Active control of faults in interconnected HVDC is possible; system impacts unexplored
- Dynamic impacts of system interconnections at high penetration need study

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Developing a Cost Effective Framework for Offshore Grids

Michael Pollitt
Judge Business School

E·S·R·C ECONOMIC & SOCIAL RESEARCH COUNCIL

www.electricitypolicy.org.uk

Theory

- Demsetz, 1968, 'Why Regulate Utilities?, *Journal of Law and Economics.*
- Baumol et al., 1982, 'Contestable Markets: an uprising in the theory of industry structure', *American Economic Review.*

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Rising transmission costs

- Project Discovery *(Ofgem, 9/10/09, pp.94-5)*: E+G Distribution and Transmission investments to 2025 are £47 to £53.4bn
- Electricity transmission and distribution charges rise £49-53 per customer (or 60%), more than proportionately.
- Offshore transmission alone could be £15+bn to 2020 (more than current onshore RAV).
- Cost of capital and competitive sourcing key.

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Key questions for regulatory regime

- What ensures transmission investments are necessary?
- What ensures transmission investments are delivered at least cost?

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A competitive process

- Still need a proposer of investments?
- Tendering processes expensive (vs regulation)
- May lead to duplication of assets
- Capital adequacy problems and non-delivery risks

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Are things changing?

- Investment needs rising sharply
- SO/TO split possible; ISO/ITO model successful elsewhere.
- Scottish arrangements and rise of offshore transmission raise issue about ISO-ITOs.

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UK Offshore Transmission Regime

- 20 year contract, indexed to RPI, de-risked of actual energy flow and existence of wind park
- Round 1 and Round 2 tenders - transitional regime.
- Round 1, projects already built or being built. £1.1bn transfer value.
- Round 2, underway.
- Subsequent rounds - enduring regime (BFOO) or (FOO).

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Offshore Transmission

Source: Ofgem.

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Bidders in Round 1 (Ofgem, 23/09/10)

- Round 1: The bidders that qualified to proceed to the Qualification to Tender stage were (12):
- ABN Amro Infrastructure Capital Management Ltd; Balfour Beatty Capital Limited **(BBCL);** DONG Energy Sales and Distribution A/S **(DESD)**; Equitix (a consortium of Equitix and AMP) **(GET);** ESB International Limited; Frontier Power Consortium (a consortium of Frontier Power Limited and Infracapital Partners LP); 7. Imera Limited; Macquarie Capital Group Limited **(MCGL);** National Grid Offshore Limited **(NGOL);** RWE Npower plc; SSE Offshore Transmission Limited; A consortium of Stakraft UK Limited and StatoilHydro UK Holdings Limited; Transmission Capital Partners (a consortium of International Public Partnerships Limited, Transmission Capital Limited and Amber Infrastructure Limited) **(TCP).**
- *6 Financial; 2 UK incumbents; 3 International energy firms; 1 engineering firm.*

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Shortlisted in Round 1 (Ofgem 14/12/09)

- 6 shortlisted bidders (of which 1 engineering firm, 1 UK incumbent, 3 financials, 1 international energy firm)

Project/MW	Shortlist for each project
Barrow 90 MW	BBCL; DESD; MCGL; TCP
Greater Gabbard 504 MW	GET; MCGL; NGOL; TCP
Gunfleet Sands 1&2 164 MW	BBCL; DESD; MCGL; TCP
Ormonde 150 MW	BBCL; GET; MCGL; TCP
Robin Rigg 180 MW	GET; MCGL; NGOL; TCP
Sheringham Shoal 315 MW	BBCL; GET; MCGL; TCP
Thanet 300 MW	BBCL; GET; MCGL; TCP
Walney 1 178 MW	BBCL; DESD; GET; MCGL; TCP
Walney 2 183 MW	BBCL; DESD; GET; MCGL; TCP
Total MW 2,064	

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Preferred bidders in Round 1

(Ofgem 06/08/10 + 28/10/10)

- TCP (3/8); MCGL (3/8), BBCL (1/8); 1 undeclared; i.e. financials guaranteed 7.
- TCP preferred on Ormonde.

Project/MW	Forecast Transfer Value (£m)	Preferred Bidders	Reserve Bidders
Barrow (90 MW)	36.5	Transmission Capital Partners (TCP)	Macquarie Capital Group (MCGL)
Gunfleet Sands 1&2 (164 MW)	48.2	TCP	MCGL
Robin Rigg (180 MW)	57.3	TCP	MCGL
Sheringham Shoal (315 MW)	182.2	MCGL	TCP
Thanet (300 MW)	163.1	Balfour Beatty Capital Ltd	MCGL
Walney 1 (178 MW)	101.8	MCGL	TCP
Walney 2 (183 MW)	105	MCGL	TCP
Ormonde (150 MW)	101.1	Preferred Bidder to be announced at a later date	
Greater Gabbard 504 MW	316.6	Preferred Bidder to be announced at a later date	

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Lessons from Round 1

- Lots of interest (£4bn vs £1.1bn).
- Low interest rates (19y debt, +200bps).
- Savings of £350m est.
- Potential for greater savings with BOOT.

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The Future – GB ISO?

- RAV of NGET = £7 bn
- RAV of SPT = £1 bn
- RAV of SHET = £0.4 bn
- RAV of Round 1: £1.1 bn
- RAV of Round 2: £2+ bn
- RAV of Enduring Regime: £15 bn?
- This implies we de facto have TO / ISO split emerging.
- This raises issues of NGET – ISO integration.

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The Future – more complex networks?

- Offshore Auctions likely to work well for point-to-point transmission.
- Could have more complicated auctions (multi-criteria) auctions for radial links (f. Kenney and Riaffa 93, and Fang and Morris, 06)
- No evidence of major benefit from meshed offshore networks (e.g. Morton et al. 06).
- Merchant links already being built offshore?
- Storage with renewables?

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Merchant Interconnection (Parail, 10)

- NorNed cable 700 MW.
- Investment in increments of 350MW.
- €11.5/MW/h gives IRR of 10% for NorNed investment with a 20 year life.
- Estimated socially optimal capacity is 3,850MW.
- Lumpiness may stop the last 350MW investment.
- Difference between socially optimal and profit maximising interconnection capacity <10%.

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The Future –Allocating capacity?

- Firm financial transmission rights (FTRs) exist for projects which have initiated connection.
- As more assets exist may be opportunities to sell access to new offshore generation projects.
- May need to have process for allocating unused transmission capacity (Nodal pricing?).
- Large amounts offshore generation raise issues on shore (Nodal pricing?) (see Leuthold et al., 05)
- ISO to do planning for offshore network development and have role in anticipating capacity?

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Conclusions

- Offshore transmission developing well.
- Auction results encouraging.
- Meshed offshore grids challenging and expensive.

- Seem to have a good way forward on cost front.
- Still issue on who decides on network configuration.

- ***Offshore costs still very high.***

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