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

Market design for large shares of renewables: time and space

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EPRG Spring Research Seminar

Cambridge 16 May 2008

http://www.electricitypolicy.org.uk

Outline

- Challenge for GB power market
- Suitable market design
  - Congestion management, plant operation
  - Location/type of investment
- Transition
  - Fair treatment of existing assets
  - avoid discouraging wind
- Consequences of large wind share

The challenge of renewables

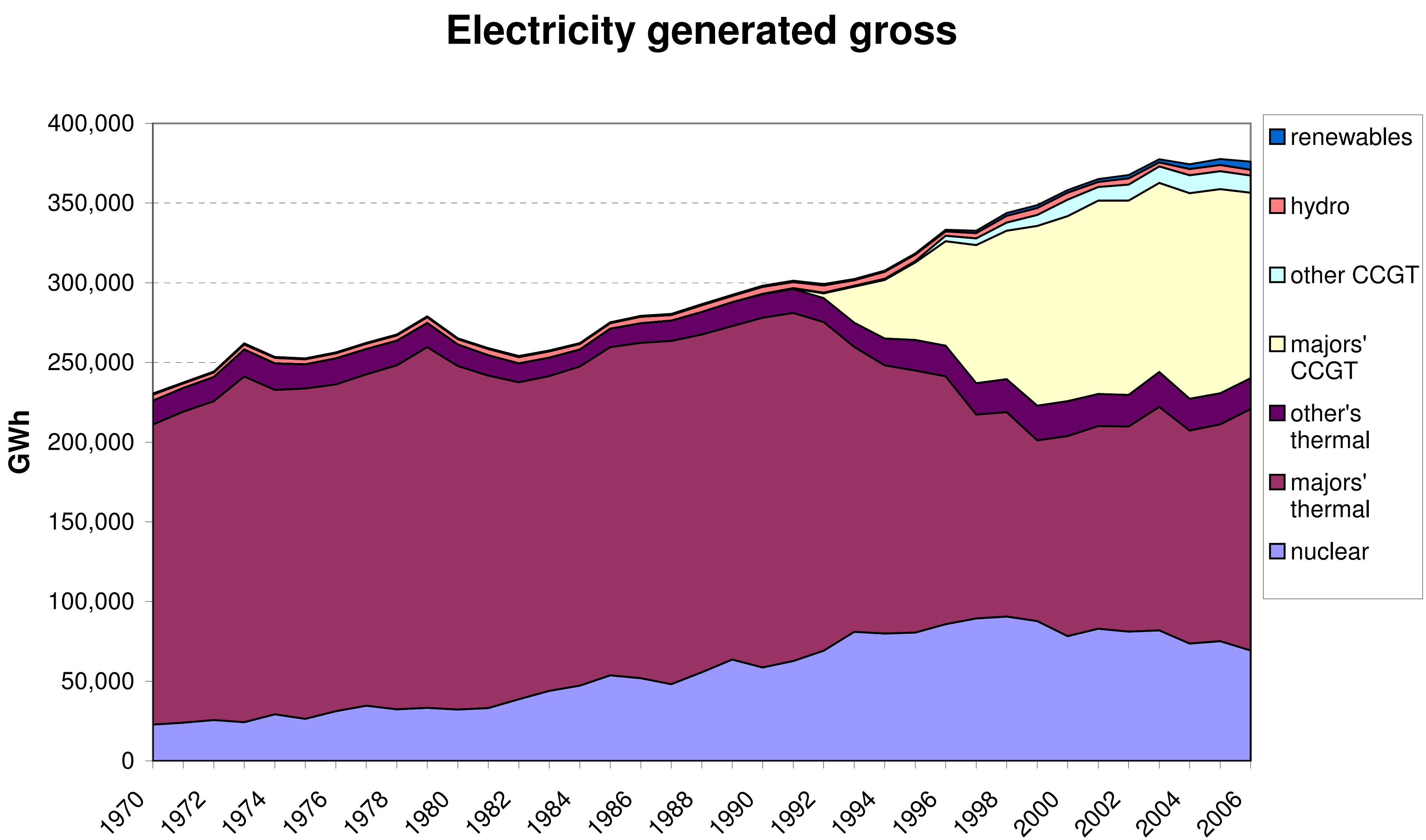
- 20% EU renewables target by 2020 agreed

=15% renewable **ENERGY** for UK

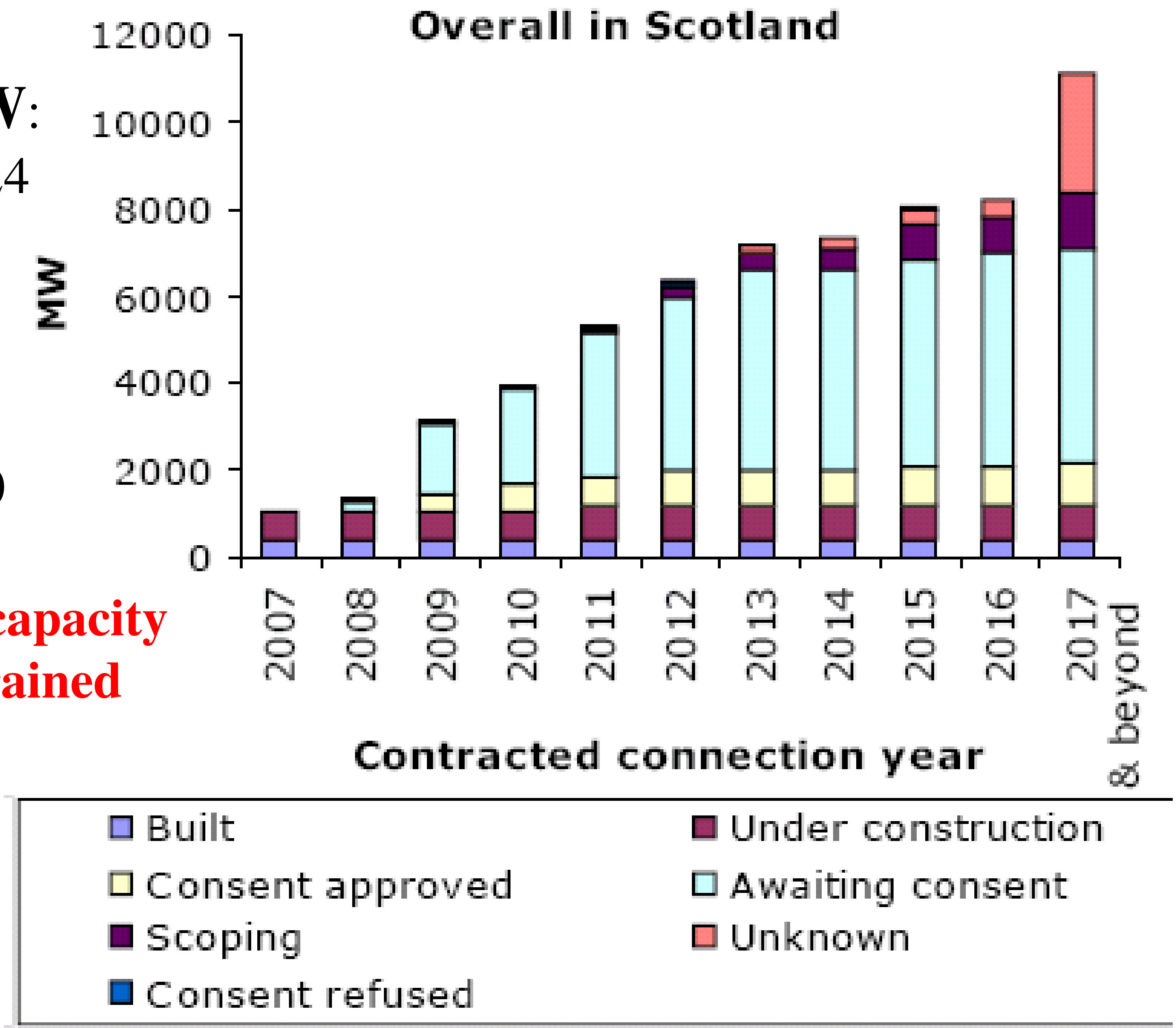
=30-40% renewable **ELECTRICITY**

- likely to be large shares of wind
  - Much in Scotland: queue of 11 GW, 9GW Wales
- At 25% capacity factor, 25% wind
  - = 100% peak demand

=> volatile supplies, prices, congestion, ….


Electricity generated gross
GWh
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
renewables
hydro
other CCGT
majors' CCGT
other's thermal
majors' thermal
nuclear

Existing MW:
Thermal = 1,524
Hydro = 1,100
Wind = 650
pump
storage = 300
demand = 1650



2 GW export capacity already constrained

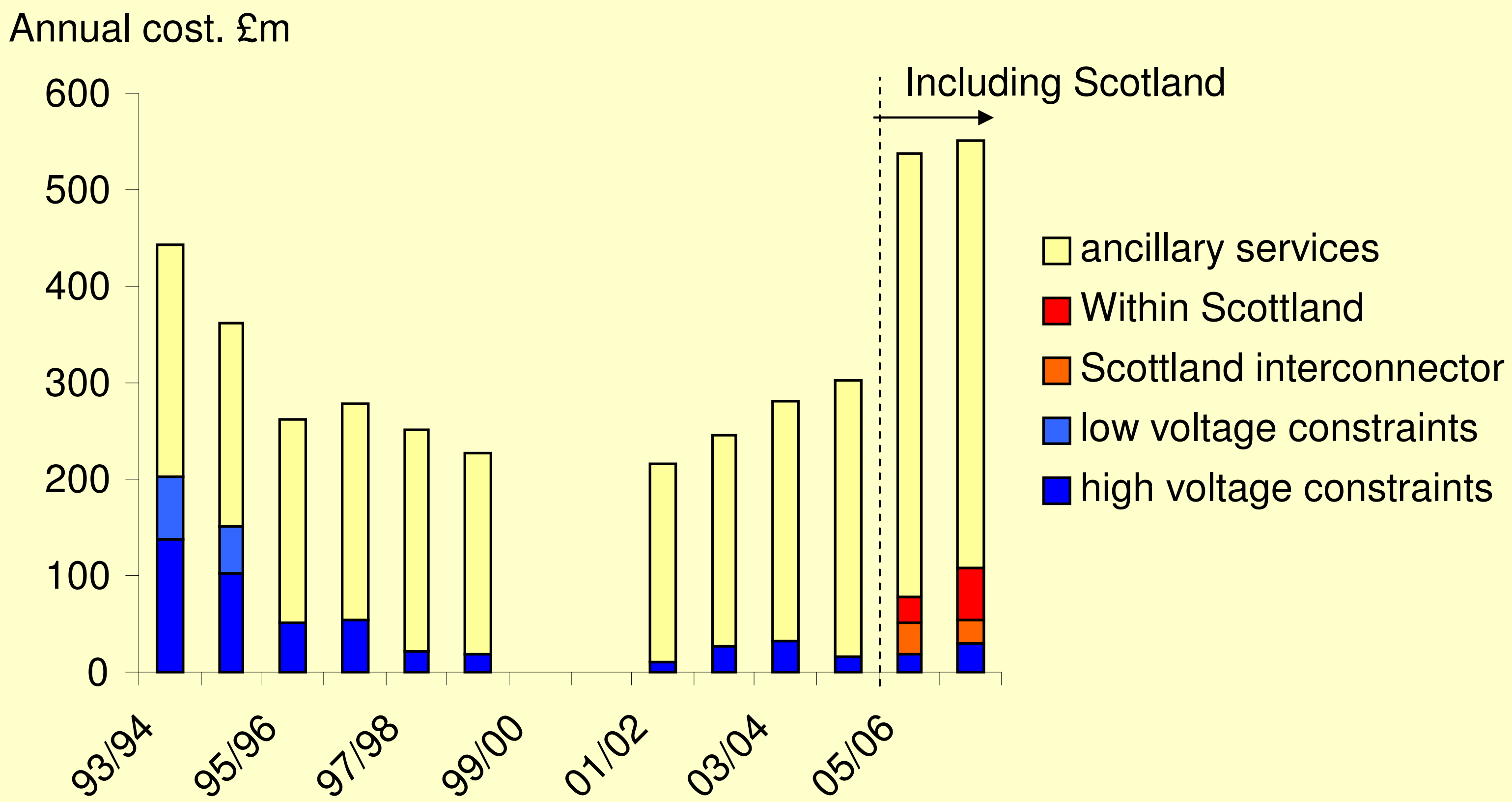
Current transmission access

- Connect for firm access
  - delay until reinforcements in place

=> excessive T capacity for wind
  - excessive delays in connecting wind

- TSO uses contracts and Balancing Mechanism to manage congestion
  - weak incentives on G to manage output
  - costly to deal with Scottish congestion

Re-dispatch to resolve constraints in England and Wales

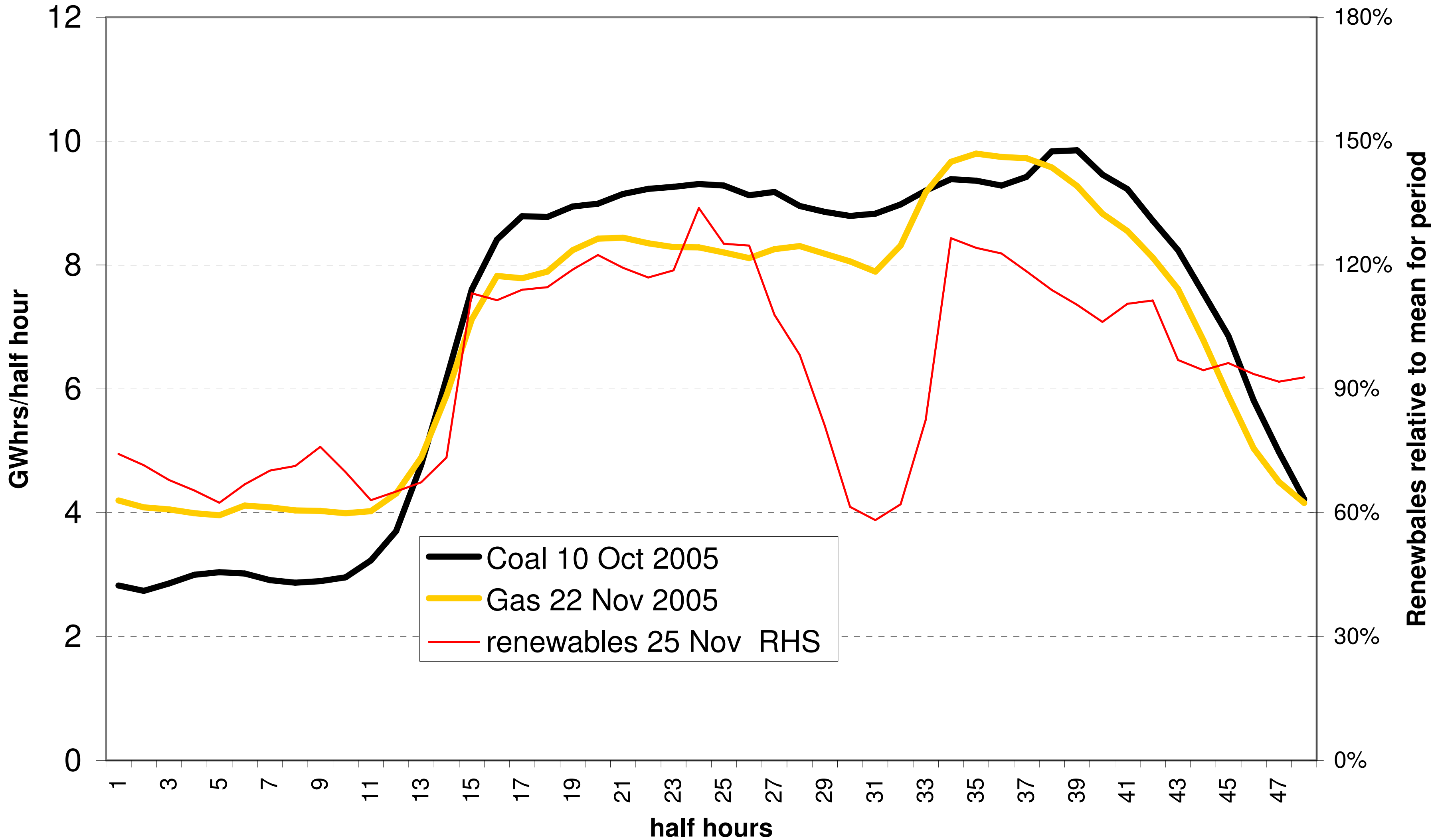


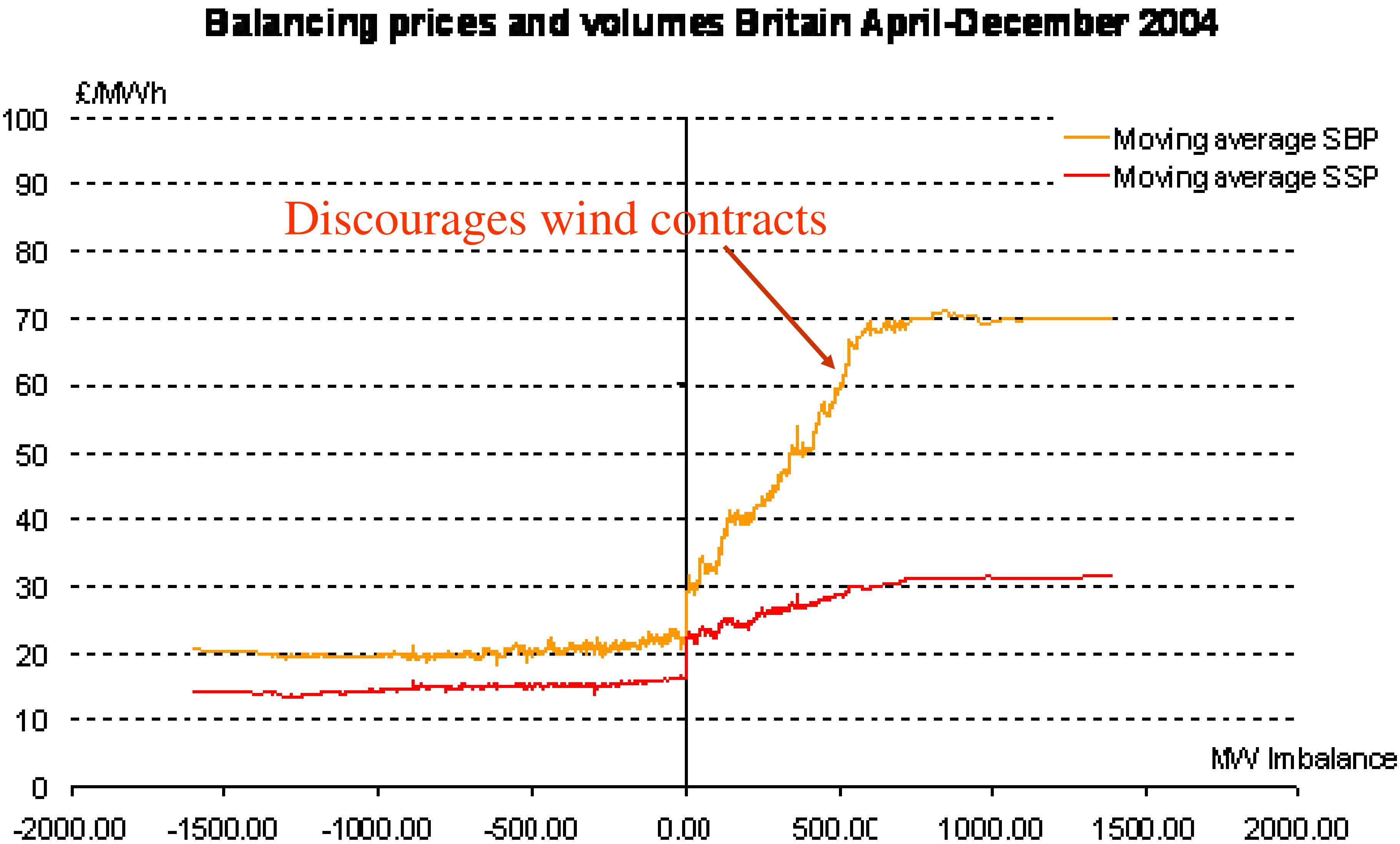
Costs rise rapidly with constrained links to Scotland

Balancing - problems and requirements

- efficient dispatch: schedule ahead of time
  - to allow for warm-up, ramping, etc
- wind forecasts increasingly accurate at -4hrs
- day-ahead market bad for wind contracting
- etc?

Ability to vary thermal output




Balancing prices and volumes Britain April-December 2004
£/MWh
100
90
80
70
60
50
40
30
20
10
0
Moving average SBP
Moving average SSP
Discourages wind contracts
MW Imbalance
-2000.00
-1500.00
-1000.00
-500.00
0.00
500.00
1000.00
1500.00
2000.00

Summary of problems

- Losses not reflected in dispatch
- T access is firm - all or nothing
- Constraints only reflected through BM
  – may be OK if BM efficient and competitive, but is it? thin market? Dual pricing?
- Intertemporal dependencies may not be efficiently handled
  – would short run wind output forecasts allow more efficient scheduling of fossil plant?

The argument for change

- A flawed system can be improved

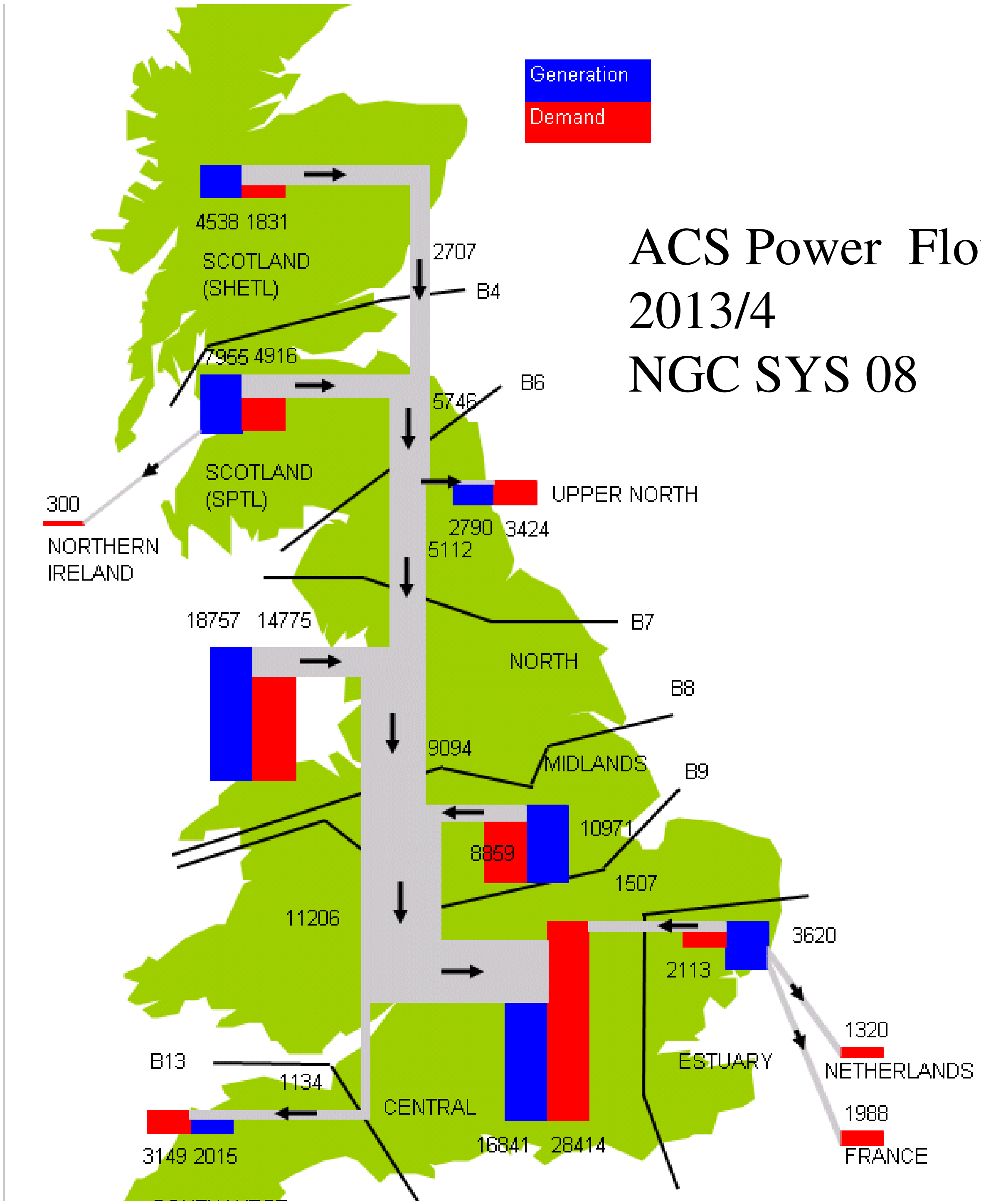
=> potentially everyone can be made better off

- The challenge:
  - identify the efficient long-run solution
  - that can co-exist with an evolving regime for incumbents
  - apply new regime to all new generation
  - which compensates incumbents for any change
  - while encouraging them to migrate

Efficient congestion management

- Nodal pricing or LMP for optimal spatial dispatch
- All energy bids go to central operator
- Determines nodal clearing prices
  - reflect marginal losses with no transmission constraints
  - Otherwise nodal price = MC of export (or MB of import)
- Bilateral energy contracts
  - Can submit firm bids => pay congestion rents
  - Can submit price responsive bids => profit over
- Financial transmission contracts hedge T price risk

ACS Power Flow 2013/4 NGC SYS 08



Effects of efficient nodal pricing

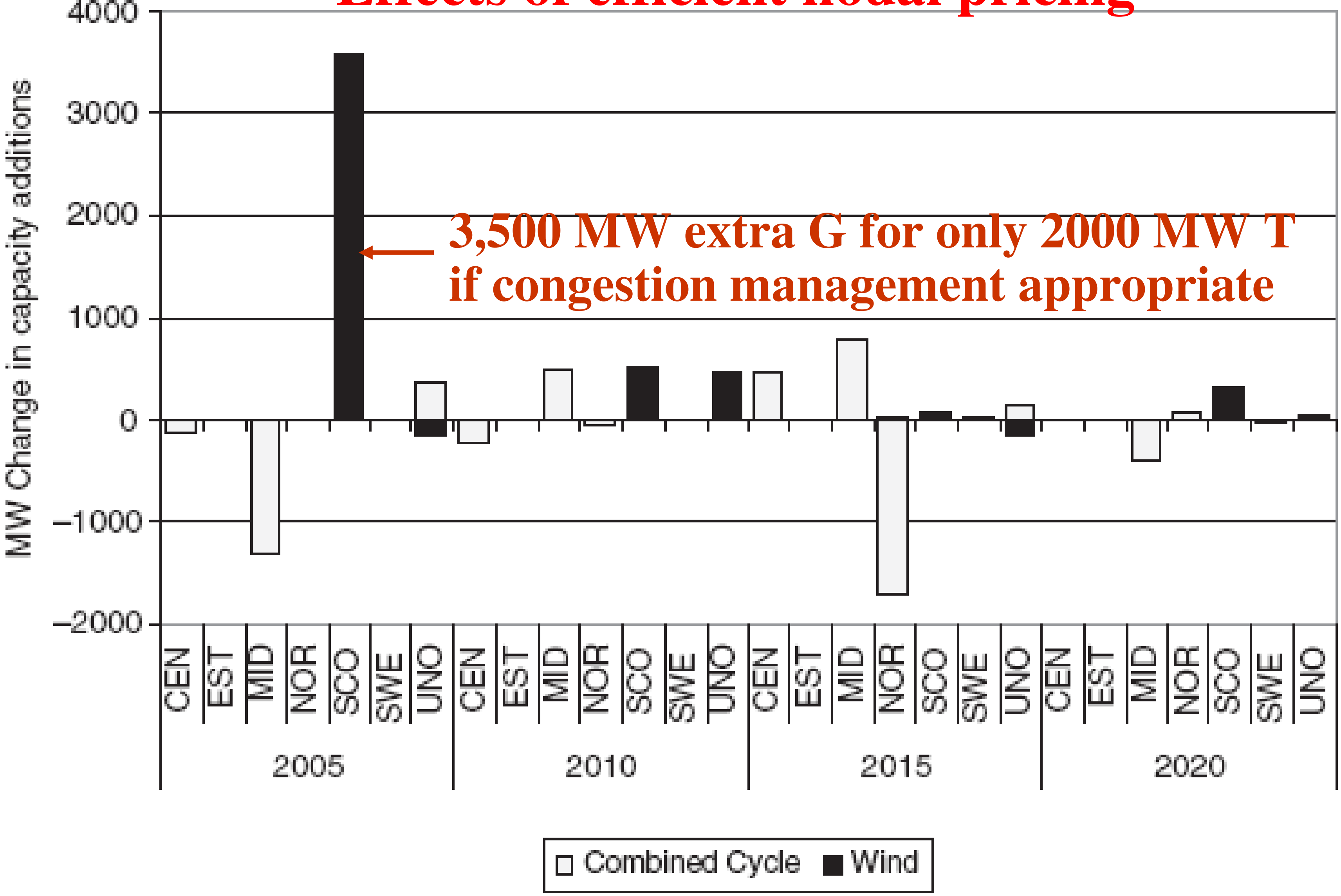


Figure 6.6. Change in investment relative to Scenario M2 with 2GW transmission expansion

Efficient balancing market

- Use right combination of plants to
  - provide spinning reserve
  - provide flexibility to vary output over periods of mins - 4 hours (i.e. are warm, and given ramping constraints)
  - meet next demand peak and demand low
  - handle varying transmission constraints

=> inter-temporal optimisation, updated with new wind/demand forecasts

- Market participants submit multi-part bids
  - Start up cost/time, Ramping rates, etc
  - Marginal generation cost
  - Part load constraint, etc

=> POOL type approach

Spatial and temporal optimisation

=> nodal pricing + central dispatch

- Nodal price reflects congestion & marginal losses
  - lower prices in export-constrained region
  - efficient investment location, guides grid expansion
- Central dispatch for efficient scheduling, balancing
- Market power monitoring – benchmark possible
- PJM demonstrates that it can work
  - Repeated in NY, New England, California (planned)

Objections to nodal pricing

- Disadvantages Scottish generators
  - but would benefit voting Scots consumers!

=> Large revenue shifts for small gains

- All earlier attempts thwarted by courts

=> need to compensate losers

Need to make change ***before*** large investments made (wind + transmission)

Other options?

- Can the present system be made to work?
  - Allow G entry - connect and manage?
  - but what about efficient spatial and temporal dispatch?

=> Trading of firm access rights? (OK in theory?)
  - Liquidity – does not even exist at UK level
  - Loop flows –require complex reconfiguration
  - cannot address efficient intertemporal dispatch/balancing

- Liquid competitive markets => efficiency (if externalities reflected in prices)

Hard to imagine trading can achieve all this

Transition for existing plant

- Existing G receives long-term transmission contracts but pays grid TEC charges
- for output above TEC, sell at LMP

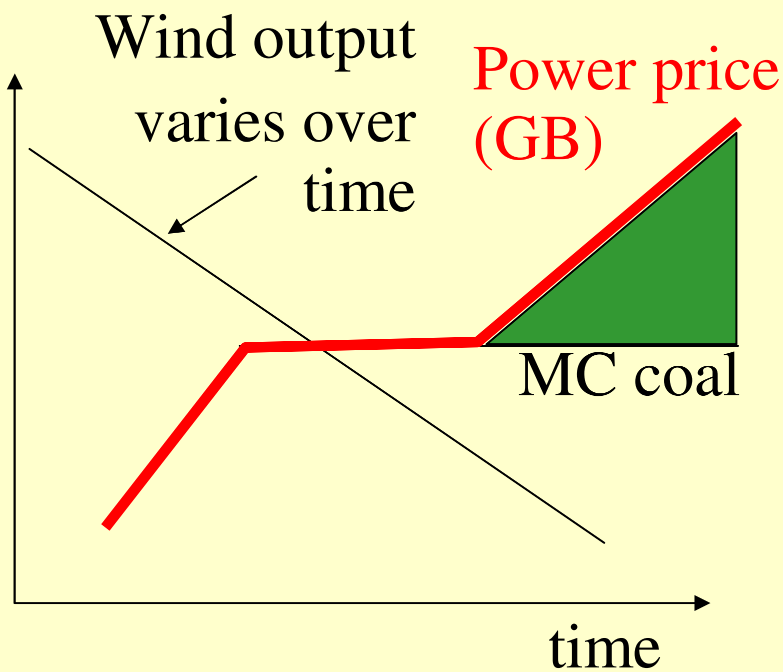
$\Rightarrow$ G significantly better off than at present

$\Rightarrow$ No T rights left for intermittent generation

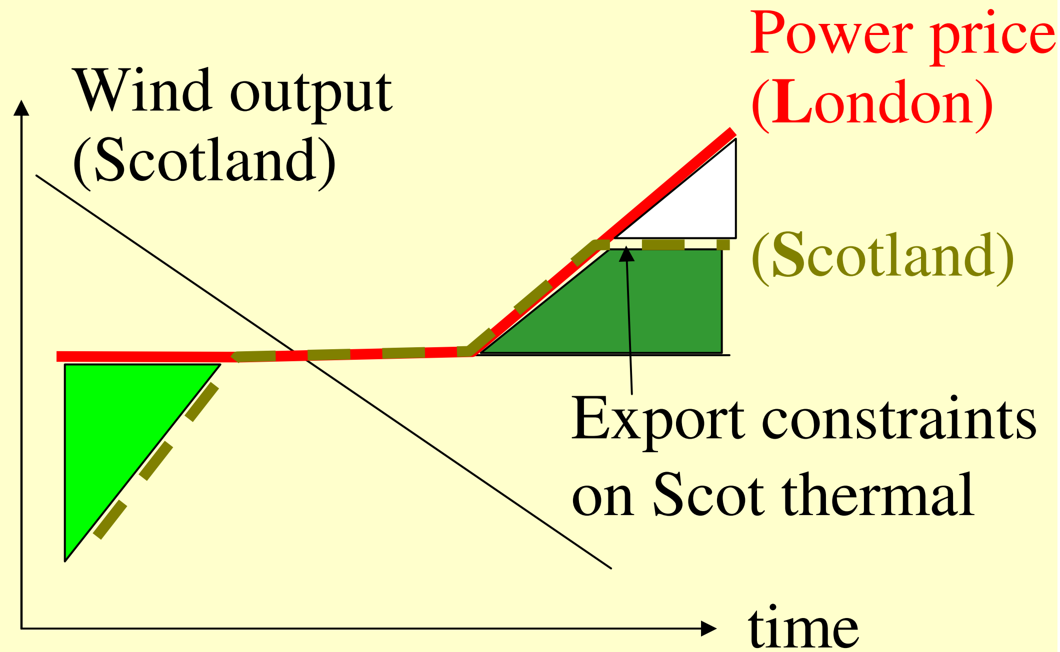
Challenge: devise contracts without excess rents and facilitate wind entry

Contract design for Scottish FTRs

Current system



Proposed system



FTR option for incumbent

FTR option not given to incumbents

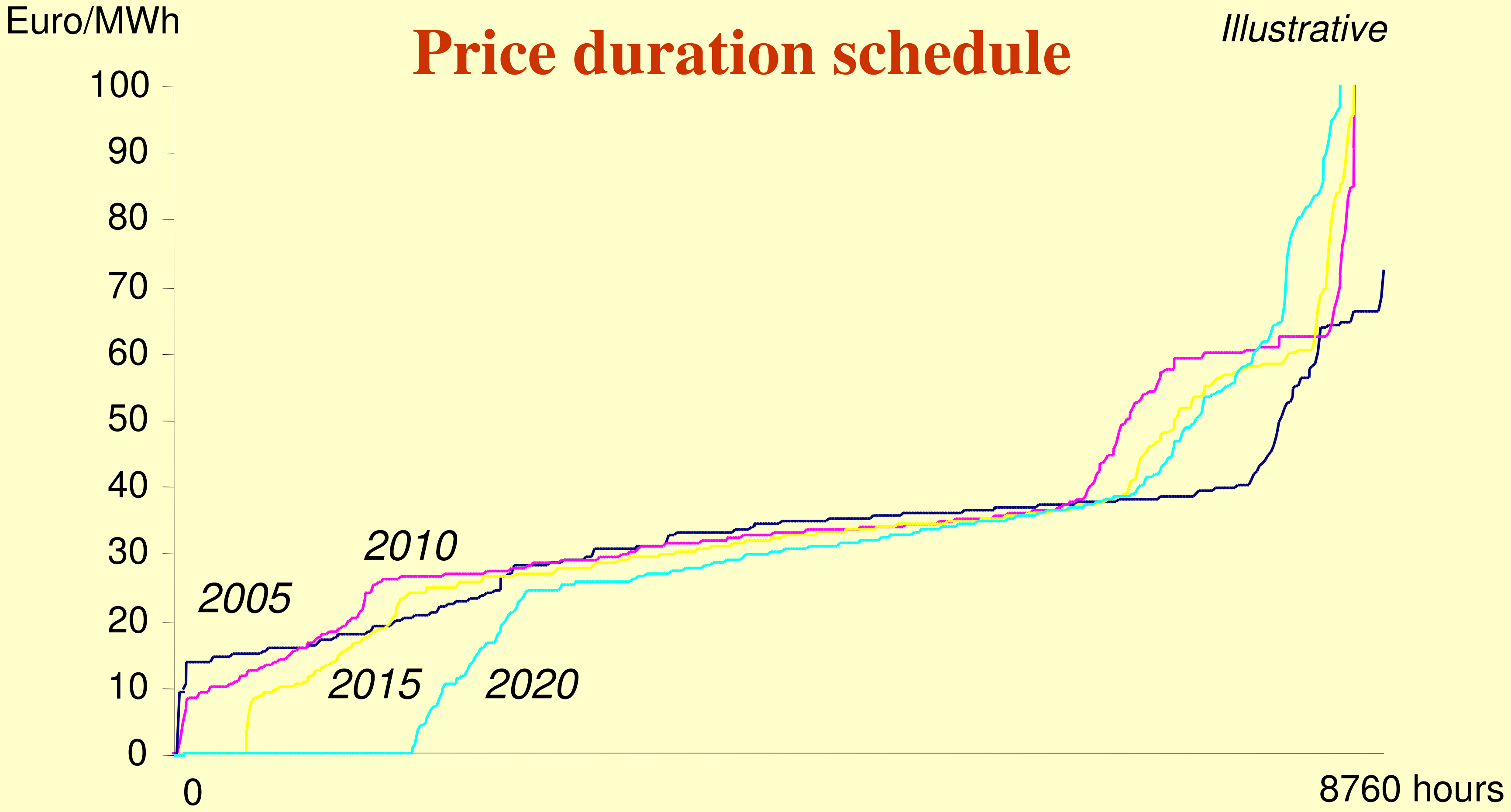
Net profit energy

Caps FTR revenue to incumbents

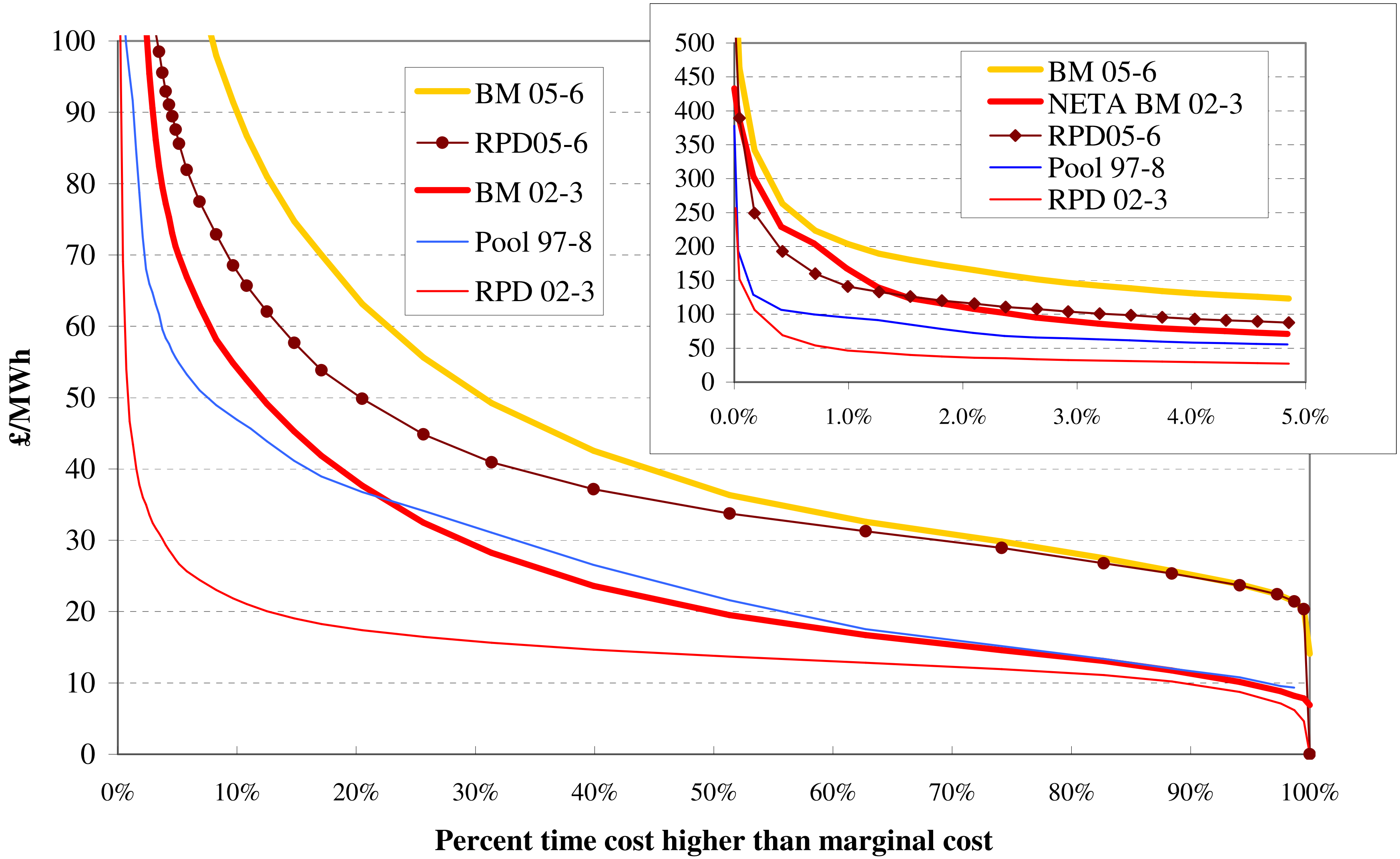
Implications of substantial wind

- Much greater price volatility
  - mitigated by nodal pricing in import zones
  - requires CfDs and nodal reference spot price
- Reserves (much larger) require remuneration
  - VOLL*LOLP capacity payment?
  - or contracted ahead by SO?
  - Or will spot price volatility induce contracts that cover availability costs?

Simulation – more volatility, adequate reward for CCGT



Price duration curves under the Pool and Balancing Mechanism



Implications of volatility

- carbon price - set in expectation of renewables?
- Coal and OCGT for peaking/balancing?
- Encourages interconnectors (esp to Norway)
- Base-load plant margins fall to CCGT level

=> discourages high capital cost plant (nuclear, CCS)

=> increased need for contracting (good)

=> further stimulus to integration? (not so good)

Conclusions

- Renewables target requires *and currently lacks*
  - efficient transmission access regime
  - efficient market design for dispatch and balancing

=> ideal: nodal pricing + pool/SO control

- transition arrangements
  - for new/old Generation

=> careful transition contracts to avoid excess rents

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