Thoughts on the role of gas and market mechanisms in meeting Peninsular Malaysia's electricity sector challenge

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THE LANTAU GROUP
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This presentation provides an independent perspective on some of the daunting challenges facing the Peninsular Malaysia power sector.

The Lantau Group is an independent, specialist, consultancy based in Asia. Among other things, we focus on the economics, policies, commercial realities and strategies that drive the region's energy sector.

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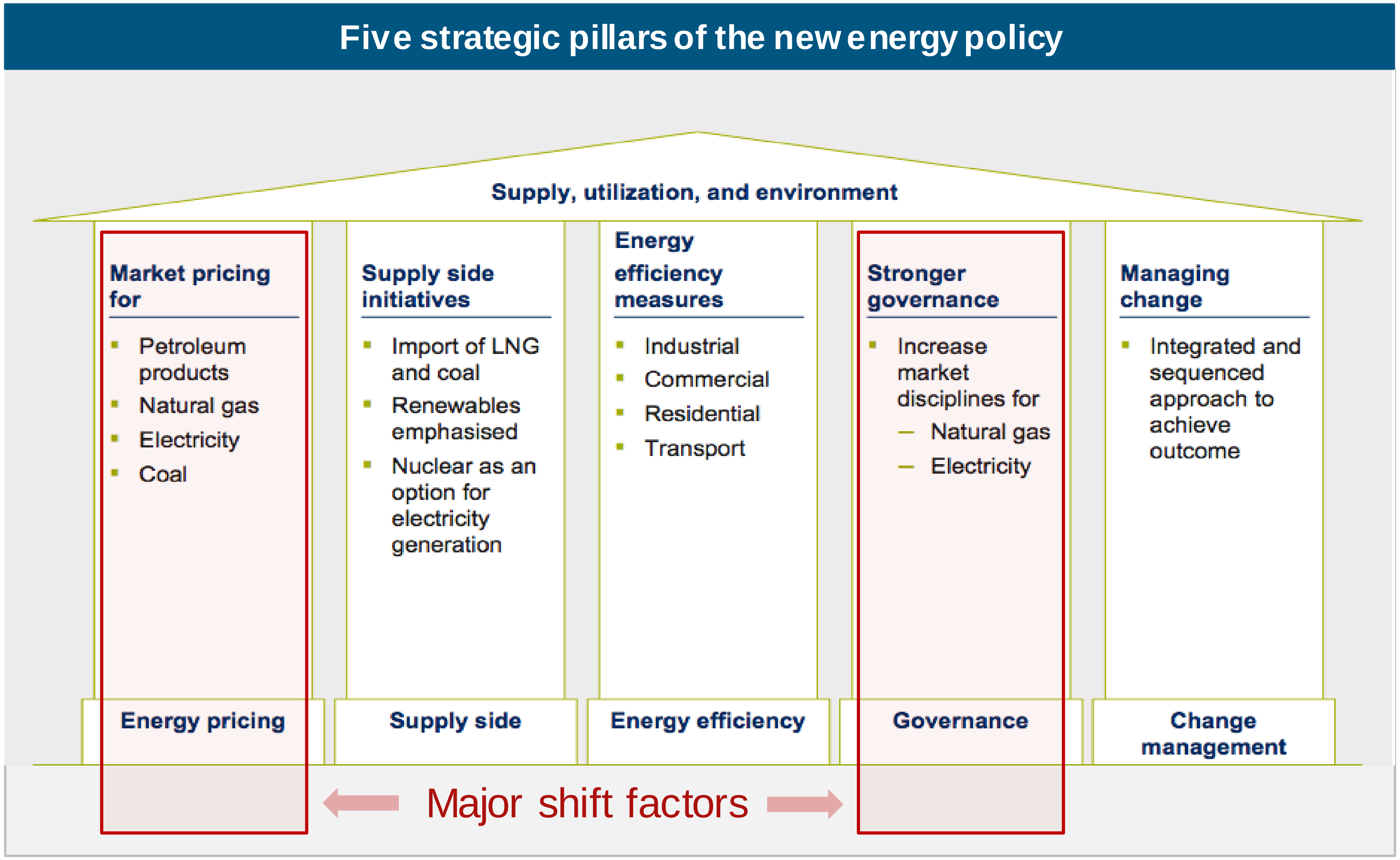
Agenda

1	Is more gas the right choice for Malaysia right now?
2	Isn't it finally time for a power pool?

The 10th Malaysia Plan calls for significant changes to the power sector



Source: Economic Planning Unit

These pillars have significant positive potential, but they are also fraught with complexity

Many complex issues need to be sorted out

- Market-pricing of fuel inputs will require significant increases in costs compared to historical levels
- Depleting existing Peninsular gas resources complicate planning
- Fukushima has complicated near term planning around LNG and longer-term planning around nuclear
- Expiring existing PPAs increase the risk of a future capacity gap
- Environmental concerns complicate the consideration of the type and timing and cost of new capacity additions

Significant upward electricity pricing pressure?

Implications for industry structure (who builds)?

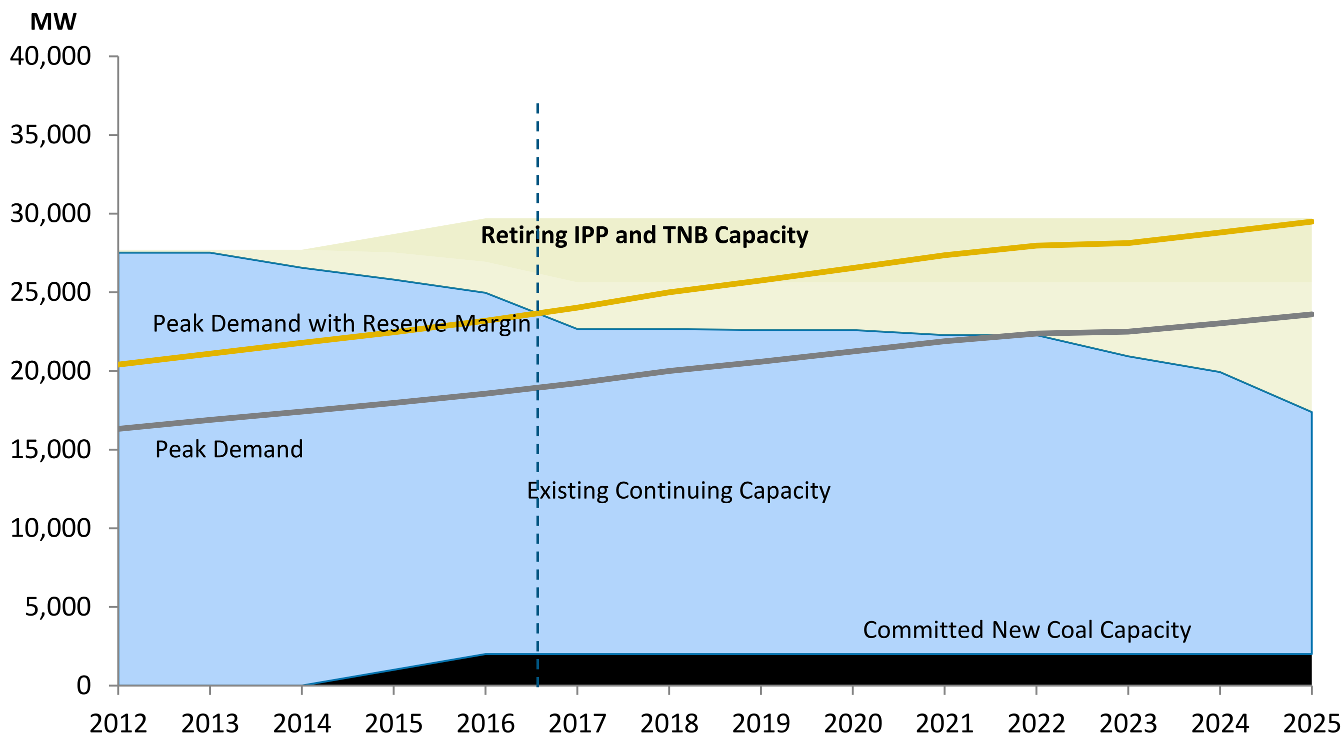
What type of new capacity, and when?

How to manage move to market-pricing of fuel?

A perfect storm of difficult choices with significant consequences

The expiry of 1st Generation IPPs beginning from 2015 and other potential capacity retirements around the same time, create a supply gap in 4 or 5 years

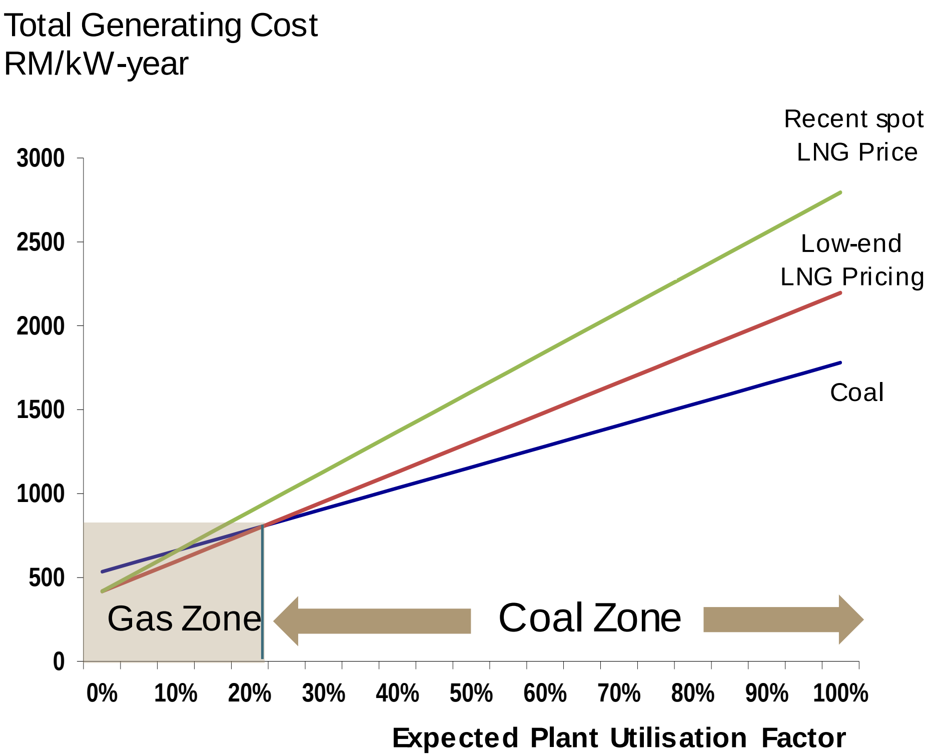
A rapidly approaching supply / demand gap



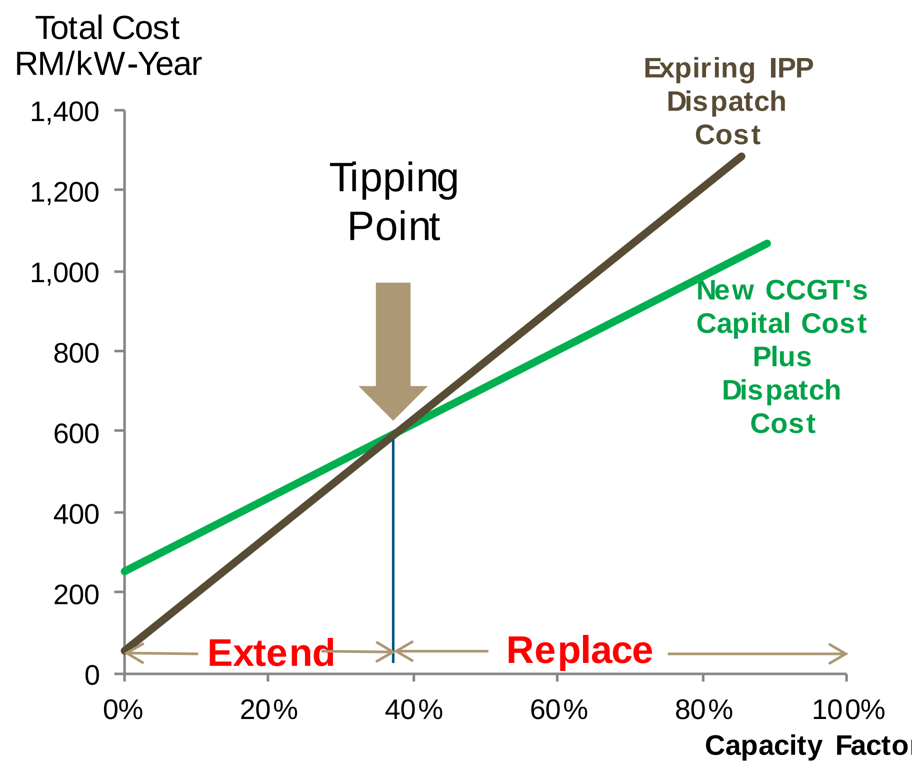
Should retiring capacity be replaced or extended?

The answer to the replace or extend question depends on the price of gas….

Gas is economic for peaking use only (about 25%optimal utilisation rate)



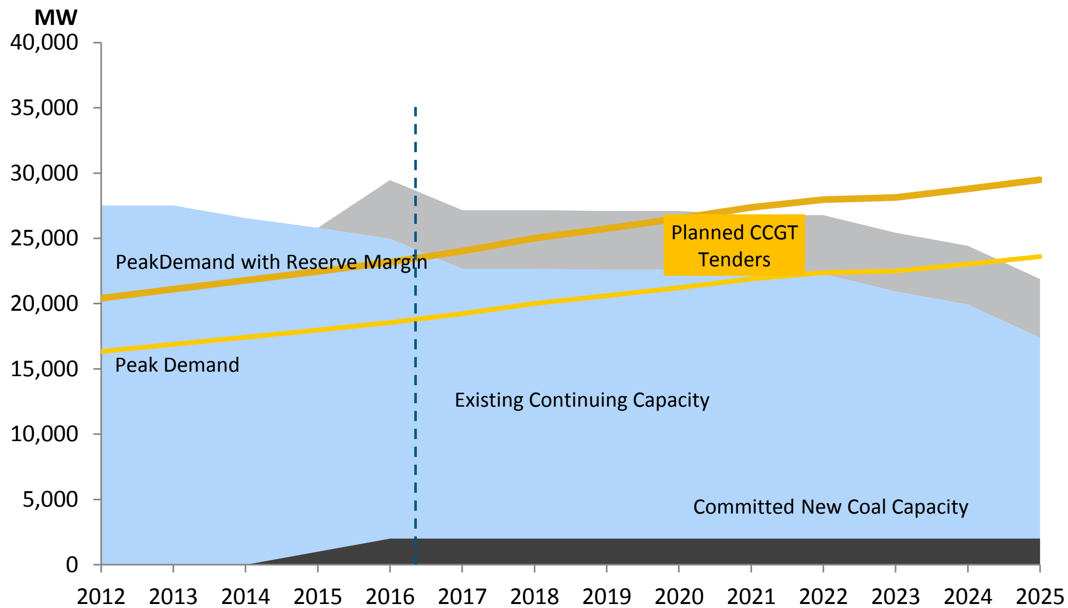
It is probably more economic to extend existing capacity if utilisation rate is below about 40%



Historically, Malaysia has used a non-market gas price in system expansion decisions, resulting in a system skewed heavily towards gas. Market-priced gas changes everything.

Malaysia currently plans to meet demand with 4,500 MW of new natural gas-fired capacity

Existing generating capacity falls as plants retire or IPP contracts expire

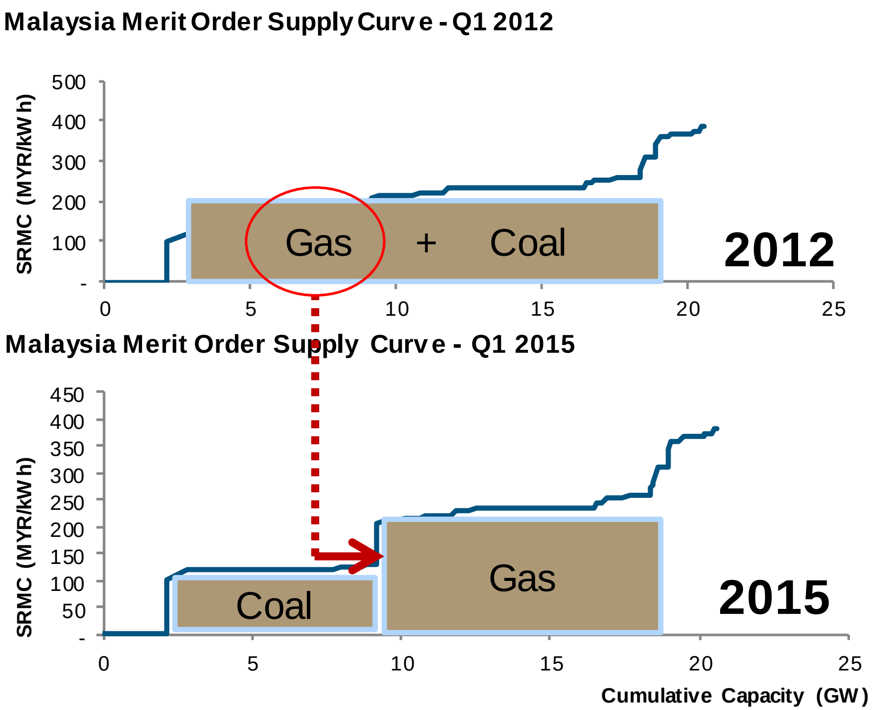


- Shortage against the notional target reserve margin occurs around 2016 / 17
  - Excluding potential international transfers (Singapore / Thailand)
  - Excluding potential DSM
- New coal-fired capacity is planned for 2015-16 at
  - Janamanjung (1,000MW)
  - Tanjung Bin (1,000MW)
- A shortlisting process is underway for a tender for up o 4,500 MW of new CCGT capacity to be available by 2016-17
  - 47 parties have submitted expressions of interest

Why so much **new** gas-fired capacity?

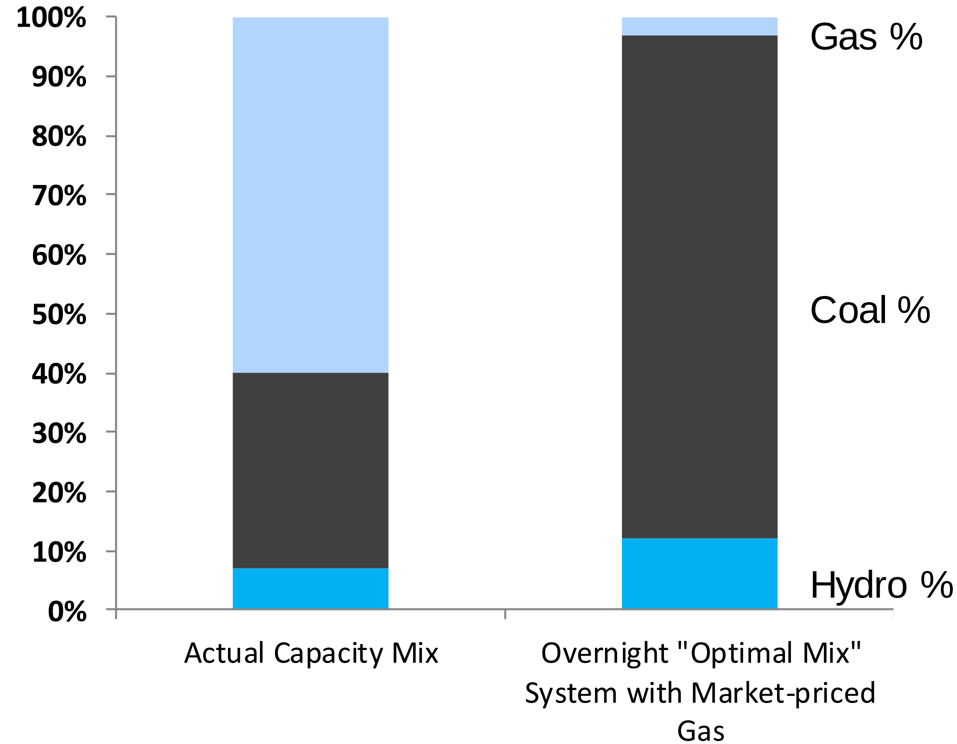
The cost of procuring new gas determines the economics of gas-fired generation and capacity expansion

Market-priced gas will change the shape of the dispatch merit-order



Historically, below-market gas prices supported gas as baseload fuel, but market-priced gas does not

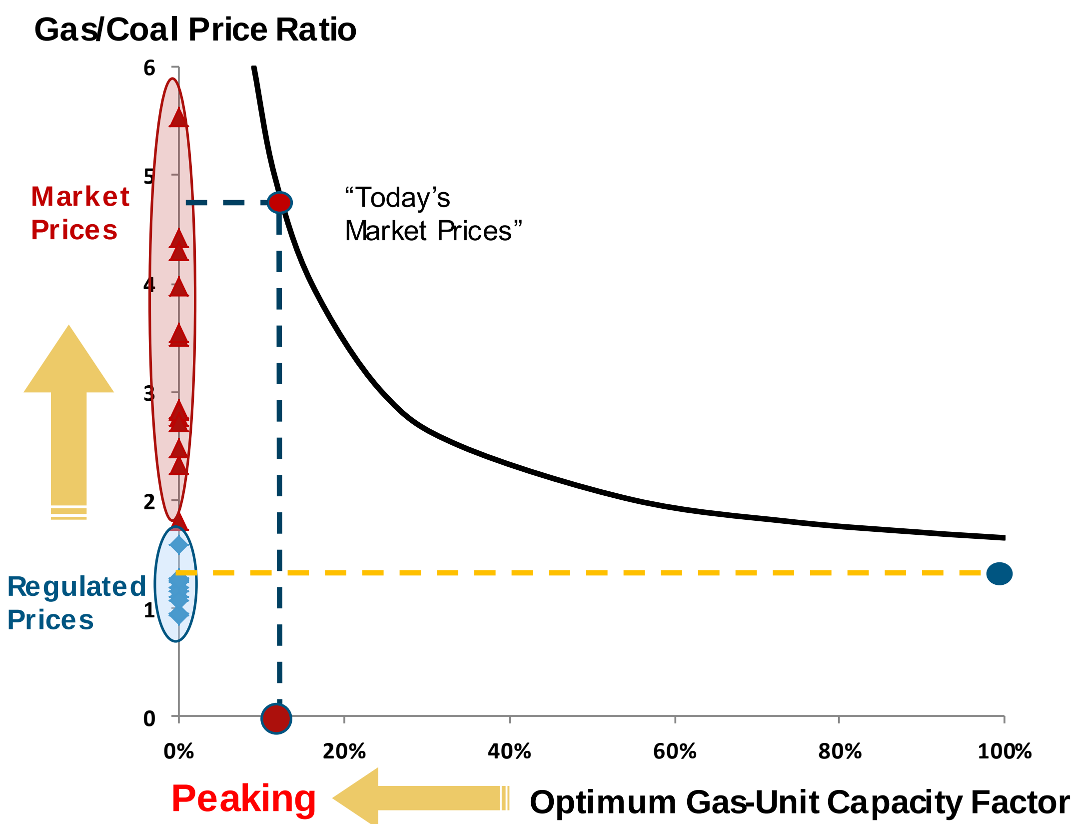
As a result, the optimal fuel mix changes dramatically from gas (historically) to coal



Note: Hydro quantity is fixed. Hydro percent share increases due to reduction in excess capacity in the optimal mix case.

The underlying economics of market-priced gas are very different from managed-priced gas!

At current market gas prices, gas-fired generation in Malaysia would not be economic, except for peaking capacity

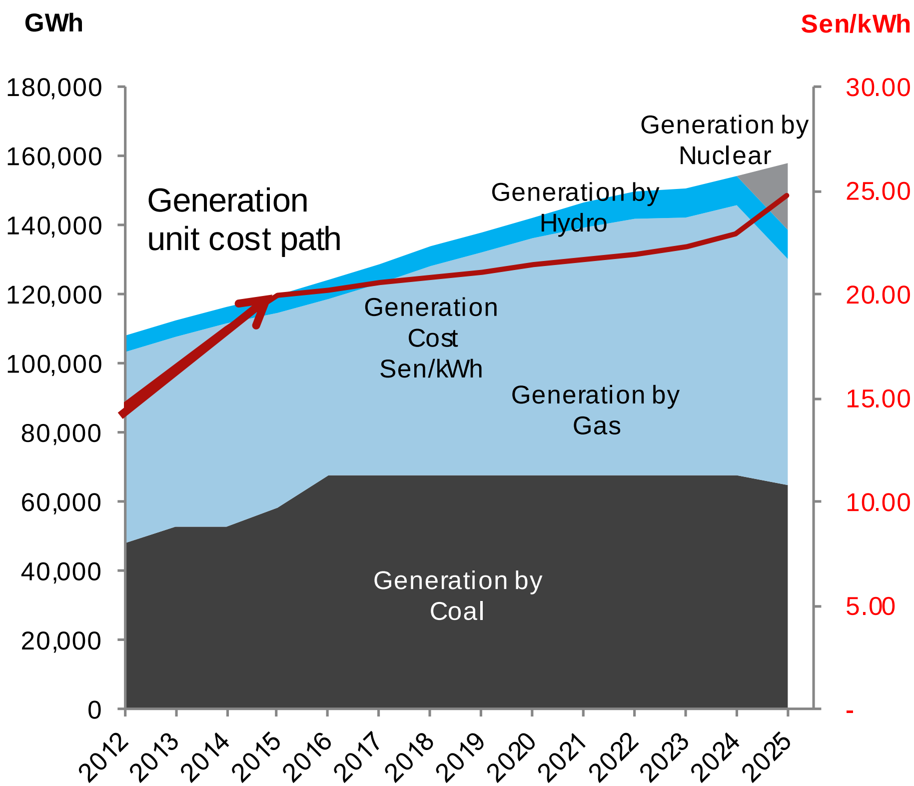


- Peninsular Malaysia sells gas to the power sector at a price that is approximately equal to coal in terms of RM/GJ
- The market-price of gas, (whether measured as the replacement cost, the regional LNG price or the price paid by the non-power sector or Singapore) is much higher
- As Peninsular Malaysia moves to market-priced gas, the ratio of gas price to coal price will increase, changing the economics of gas-fired power generation from baseload to peaking duty
- Coal becomes the least-cost source of baseload power supply

Reliance on gas-fired capacity for **baseload** power is very expensive relative to coal

Baseload generation with gas will increase costs to either power consumers, taxpayers or shareholders

BAU unit system cost and fuel mix 2012-2025



- New gas-fired CCGT capacity would be more efficient than older IPP-owned capacity—and thus may save money relative to continuing to use older, less efficient IPP capacity
- But
  - The efficiency savings will mostly be used up paying for the new capacity, itself
  - Consumers will still see significantly higher costs due to the higher market-price of gas
  - Subsidies will protect electricity consumers, but not taxpayers
- Given the immensely sensitive issue of tariff management and the desired objective of subsidy reduction, why is this happening?

Tariff shock is inevitable without swift action: more coal or increased subsidies

Investors should be wary of a gas-dominated future – even when government appears supportive: example from Hong Kong

Hong Kong Climate Change Agenda

2015 Emission Target emission cut of 64% below 2010 levels

2020 Fuel Mix Target 50% Nuclear, 40% Gas,3-4% Renewable Energy and no more than 10% Coal

CLP Actions

i) HKD 9 billion(~USD 1.15 billion) **Emissions Control Project** at Castle Peak Station

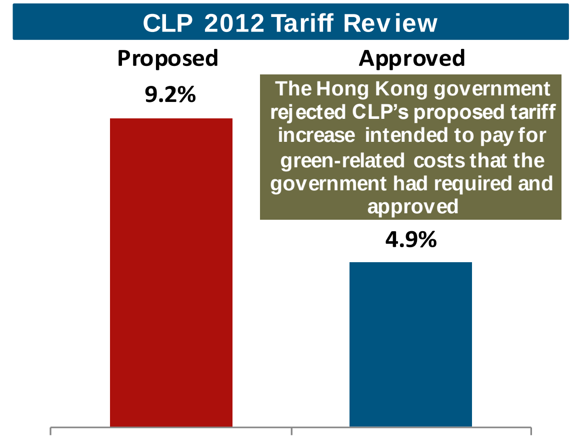
ii) Increased gas import from Mainland China, costing two or three times more than current gas supplies

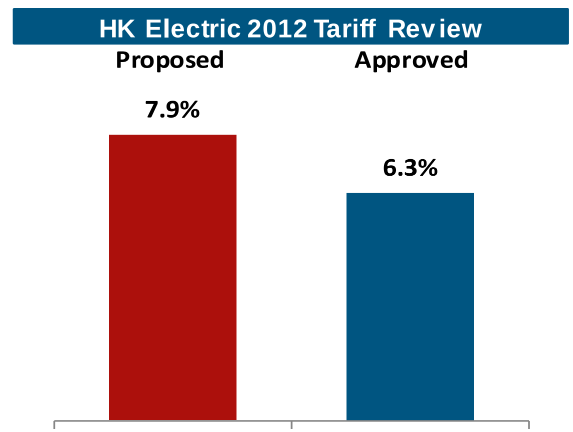
iii) Upgrade infrastructure, new gas receiving station (GRS) and plant modification projects to migrate new with existing gas supplies

HK Electric Actions

i) Emission reduction programme: installation of flue gas desulphurisation units and low nitrogen oxide burners at the Lamma Power Station

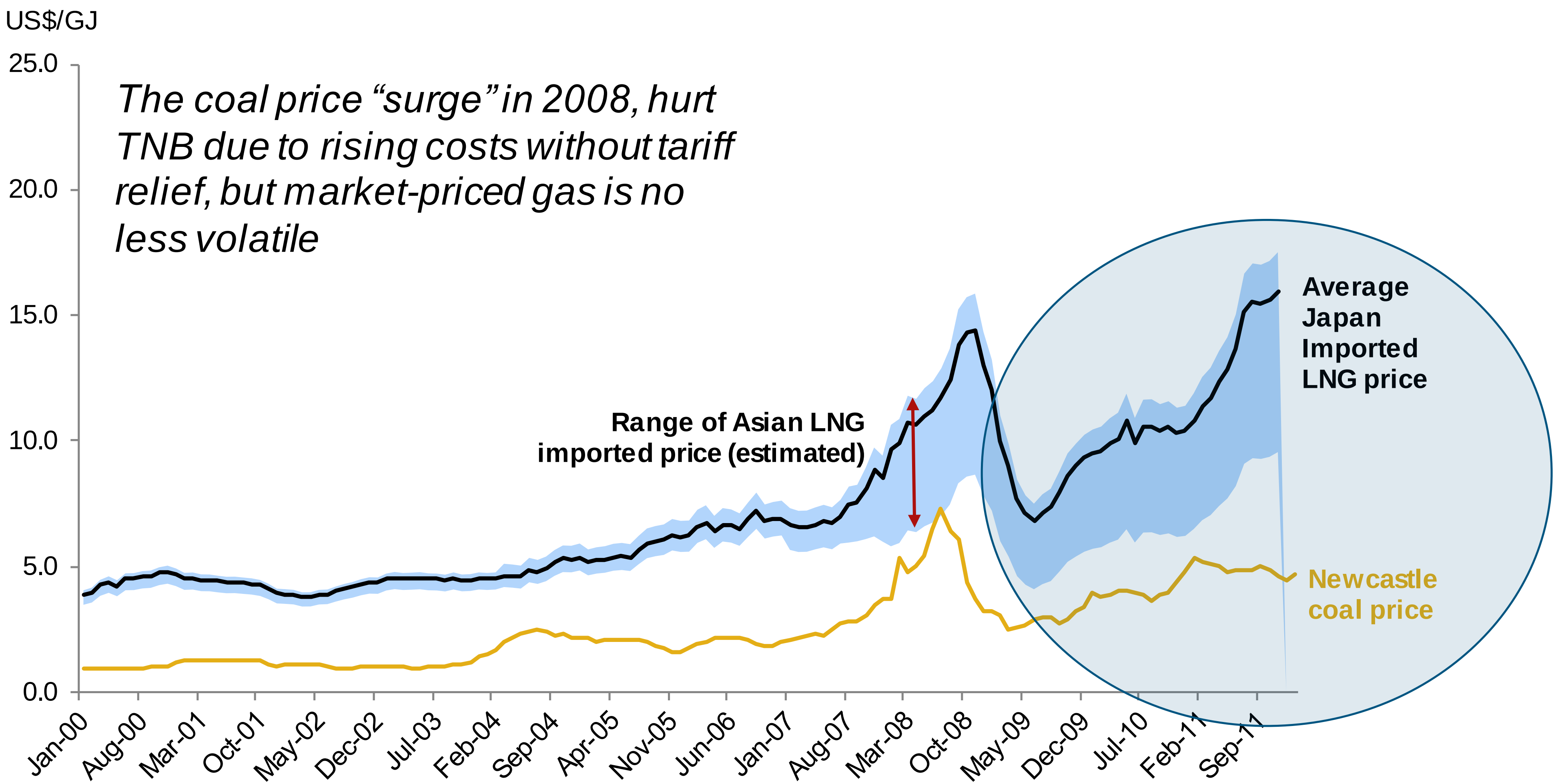
ii) Renewables projects: Proposed 100MW offshore wind farm; and 550 kW thin film photovoltaic system commissioned in 2010





The **idea** of gas in Asia as a baseload power sector fuel is much more attractive than the **cost** of it

The arguments that coal supply is too risky and coal prices are too volatile are not robust arguments in favour of gas



Blending “legacy” (cheap) and “new” (expensive) gas hides the fundamental economic problem – it does not improve the economics of new gas

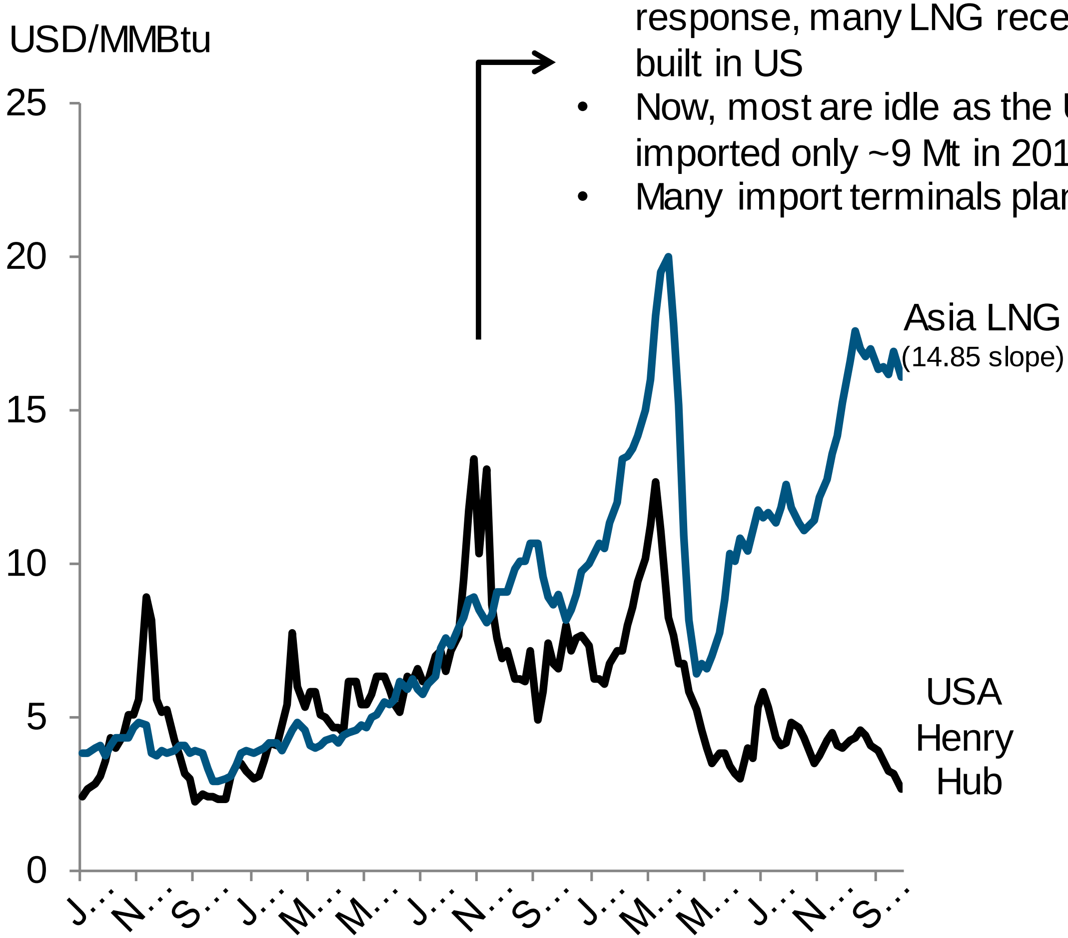
- The economic impact of using gas to generate power is a function of the ***opportunity cost of gas***. Every molecule of gas used that must be replaced has an opportunity cost equal to the cost importing or finding additional gas (or an alternative fuel)

Sell gas to non-power sector	Sell gas to other countries	Use less gas by switching to cheaper fuels	Invest in energy efficiency to reduce reliance on imported gas
Expand non-power sector and use profits to support Malaysian economic growth	Use profits to support Malaysian economic growth	Use savings to support Malaysian economic growth	Energy efficiency investment is more sensible and credible at market-priced electricity

- Blended pricing (legacy gas + new gas) is a blunt mechanism to manage “who bears the cost” – but it cannot decrease (and almost certainly will increase) the overall costs borne by Malaysia if investment and operational (dispatch) decisions are made based on the blended gas price.

Gas is cheaper in some places, but not in Asia

Gas Prices: US vs Asia



- In 2005, US gas prices at Henry Hub increased to ~$15/MMBtu because of strong demand and supply disruption (Hurricanes Katrina). In response, many LNG receiving terminals were planned and some quickly built in US
- Now, most are idle as the US has 134 Mtpa of LNG import capacity but imported only ~9 Mt in 2011
- Many import terminals plan to convert into export terminals

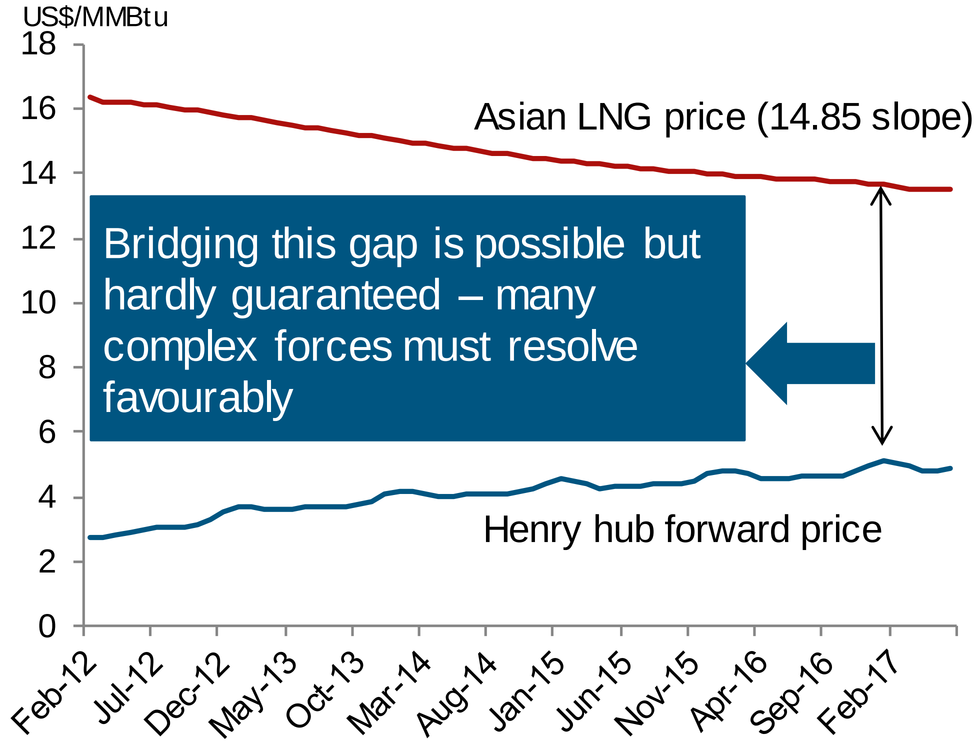
The US / Asia pricing gap has widened to unprecedented levels – more LNG is likely to be diverted to higher pricing regions (i.e. Asia)

- Qatar's original LNG export strategy: 1/3 for US, 1/3 for Europe and 1/3 for Asia; But this strategy is unlikely to be sustainable and Qatar is diverting more LNG cargos to Asia and Europe
- Trinidad & Tobago used to have 86% of its export to US, but it has to seek new customers now, likely in Asia

It is possible, but has not yet happened, that Asian LNG prices will fall. It is also possible that LNG demand in Asia will continue to support higher prices.

Near-term outlook for gas pricing in Asia remains unfavourable

Henry Hub forward price versus Asian LNG Price Implied by forward curve for crude oil

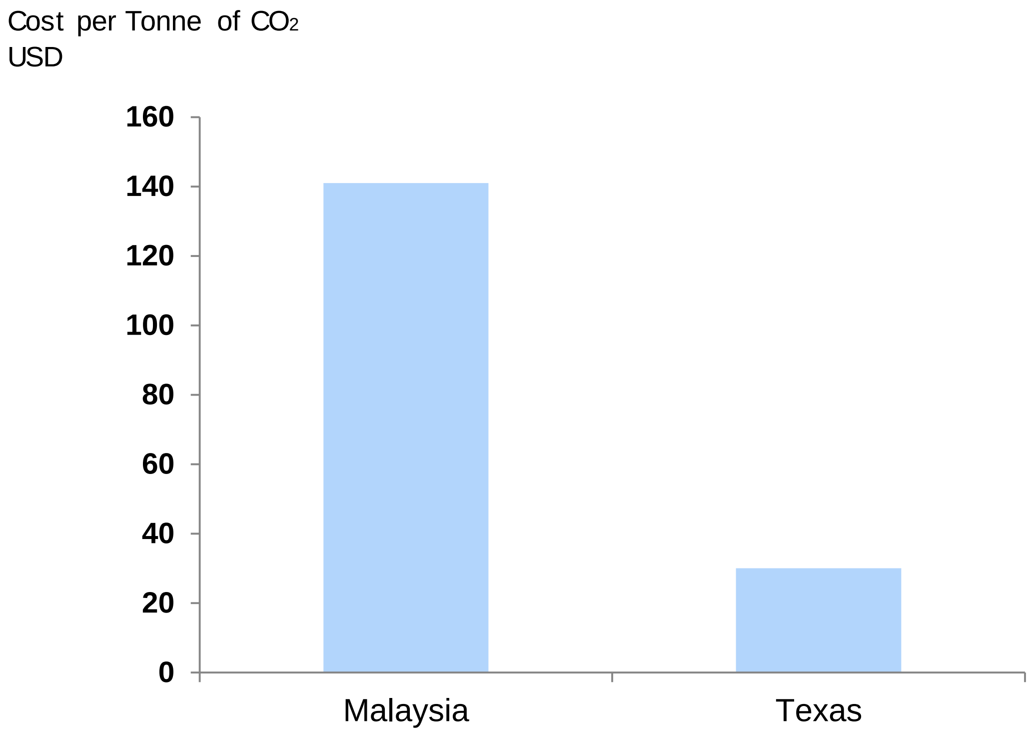


With the large regional price gap, the potential rewards for success (and costs of failure) are enormous

- **Pricing mechanism shifting**: Major LNG buyers, KOGAS and GAIL, have signed HH linked long term contracts with Cheniere. Many new LNG buyers are also interested to get HH linked contracts
- **More trading and arbitrage**: Large surplus in supply is looming after 2015, and it generally leads to more spot trading and arbitrage
  - Trading companies such as BP, Gazprom, Gunvor and Vitol set up their LNG trading teams in Singapore
  - What is driving Malaysia's strategy?

So….what is driving Malaysia's electricity generation planning and investment strategy?

Gas is certainly more environmentally “friendly” than coal, but the use of gas to reduce carbon emissions (relative to coal) is relatively expensive in Asia

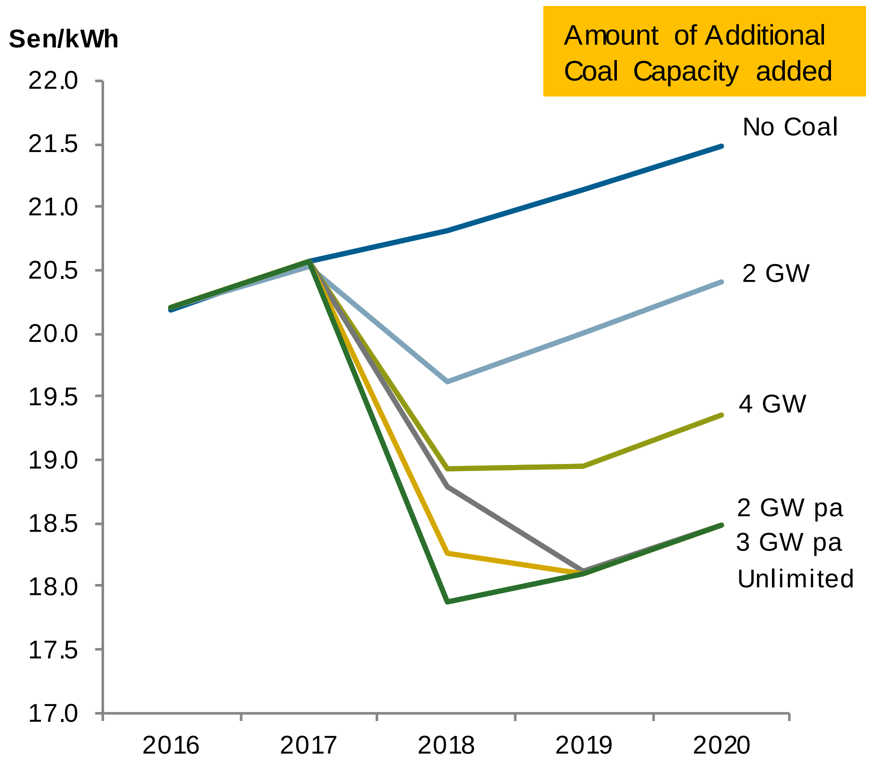


Incremental cost of using more gas rather than coal to reduce carbon emissions in existing power stations in the USA as compared to Malaysia

Does Malaysia want to spend more than US$100/tonne to reduce carbon emissions?
Or is it time to pursue more innovative and effective ways to be green?

Moving away from gas by allowing more coal sooner would reduce total generation cost

Coal Entry Impact on Generation Cost per kWh

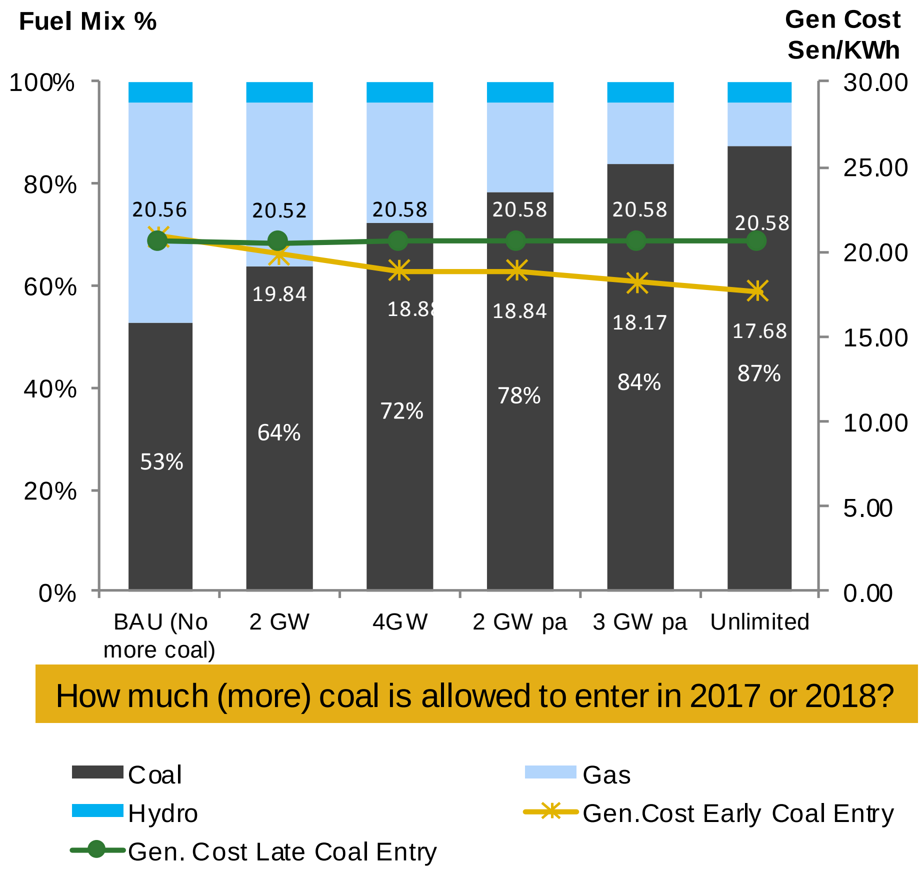


- Scenarios that constrain the entry of new coal-fired capacity have (much) higher costs
  - No additional coal after 2016
  - Additional coal allowed to enter (with or without constraints)
- Generation costs fall about 10% if up to 2 GW of new coal-fired capacity per annum is allowed from 2018, as compared with a base case with no further coal-fired capacity (beyond that already approved)
- If coal-fired capacity could be built on an unconstrained (unlimited) basis, more than 4 GW could economically be commissioned by 2018, and would ease tariff (or subsidy) pressures

Clearly, timing and extent of coal is a policy decision: but the tariff impact is clear

Pushing harder to commission additional coal even sooner would reduce costs even further

2017 Generation cost and fuel mix comparing early and late coal entry

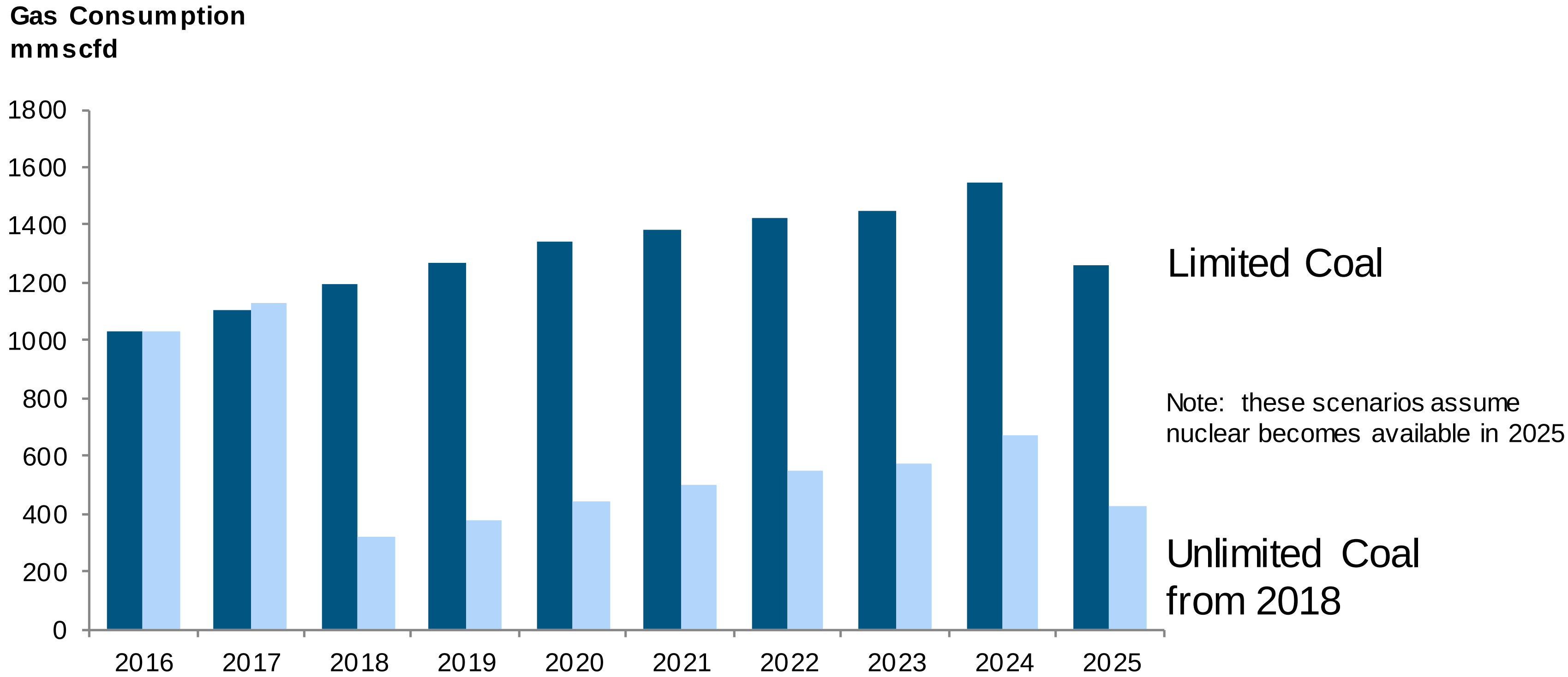


How much (more) coal is allowed to enter in 2017 or 2018?

- Starting from today, additional coal entry by early 2017 may be a challenge, but…
  - A 4- to 5-year timetable is technically achievable
  - The cost savings are potentially great enough to make fast-tracking worthwhile
  - Earlier entry of coal reduces reliance on high cost gas-fired generation and reduces the “capacity gap” caused by PPA expiry
- Optimising coal generation in 2017 could yield additional savings relative to a scenario without more coal and in which gas must be procured at market prices

If Malaysia *does* pursue a gas-based strategy, more flexible gas contracting and trading arrangements will be needed

Least-cost gas volumes swing wildly depending on future technology investments



The optimal gas quantity is too bimodal to lock in with traditional "take or pay" long-term contracts

A gas market would allow flexibility – a source of value given uncertainty

Projects under development

- Melaka LNG Gas Terminal expected in July 2012
- 4,500MW additional CCGT power plants

Contracting Arrangement Options

- Take or Pay Contracts
- Base load

- Flexible
- Trading
- Potential
- Development of Gas Market

A gas market could support a whole new way of thinking – reducing consumer costs while maintaining energy security

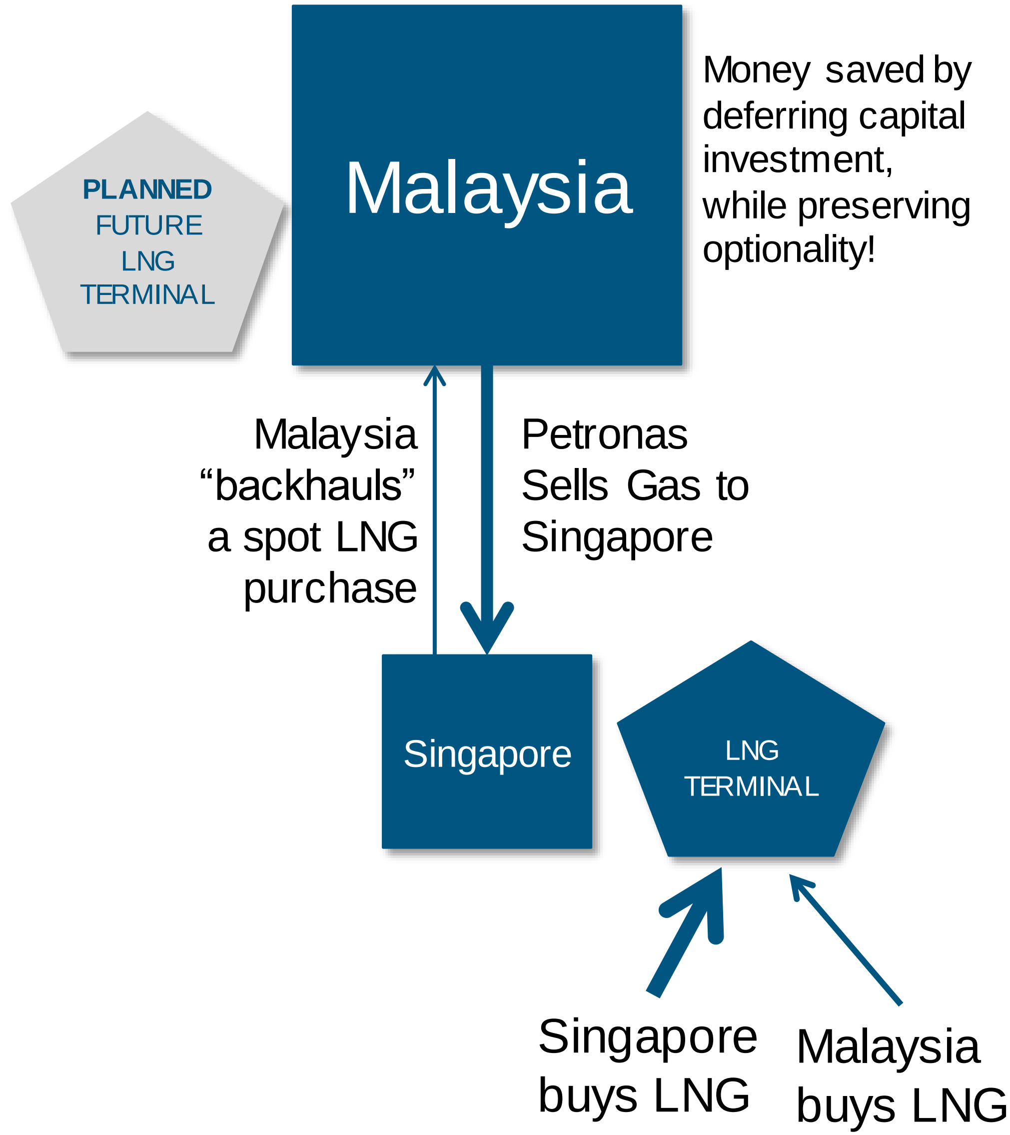
Malaysia could backhaul LNG (or even buy gas opportunistically from Singapore gencos) through the Singapore LNG terminal by netting the quantity from the Petronas export to Singapore

Malaysia could possibly defer some investment in the Melaka LNG terminal, creating value

Malaysia would always retain the option to develop or expand its own LNG terminal as needed, after gaining additional market intelligence and benefitting from further technological developments in LNG regasification technology

At no point would Malaysia be "importing" physical gas from Singapore, but offsetting a portion of gas that otherwise would have been exported by Petronas

Malaysia's energy security would never be at risk.



Summary

- We modelled the Malaysian power system's sensitivity to new entry timing, capacity contract expiry and fuel prices
  - Our assumptions involve "ballpark" estimates
    - Fine tuning is certainly possible
  - But the broad results appear robust
    - Bottom line: coal is cheaper than gas
  - Blended gas price regimes hide the poor economics of gas and lead to potentially inefficient and expensive dispatch decisions and gas volume commitments
    - Who will pay for these outcomes?
- The current plan to pursue 4,500 MW of new gas-fired CCGT capacity
  - Will increase Peninsular Malaysia's power costs,
  - Will make it more difficult to remove subsidies from input fuels in line with 10MP
- A tender process that includes consideration of short-term extension of retiring capacity would be superior to a focus on new capacity development
- Additional coal, as much and as early as possible, would help Malaysia avoid otherwise significant tariff increases (or subsidies)
  - While coal is less environmentally friendly, most emissions can be mitigated except for the additional carbon from coal versus gas
  - How much is Malaysia willing to pay for carbon reduction – *this question needs to be addressed*
- Due to its relatively poor economics for baseload generation compared to coal or nuclear power, the projected volume of natural gas required in Malaysia is fundamentally bimodal (thus very risky)
  - Either gas is *forced* as a baseload technology in which case a lot of gas is needed
  - Or coal-fired capacity is developed, which in turn displaces gas as a baseload fuel, resulting in much, much smaller annual quantities of gas required.
- Flexibility in gas contracting arrangements, and preferably the development of a gas trading market is crucial

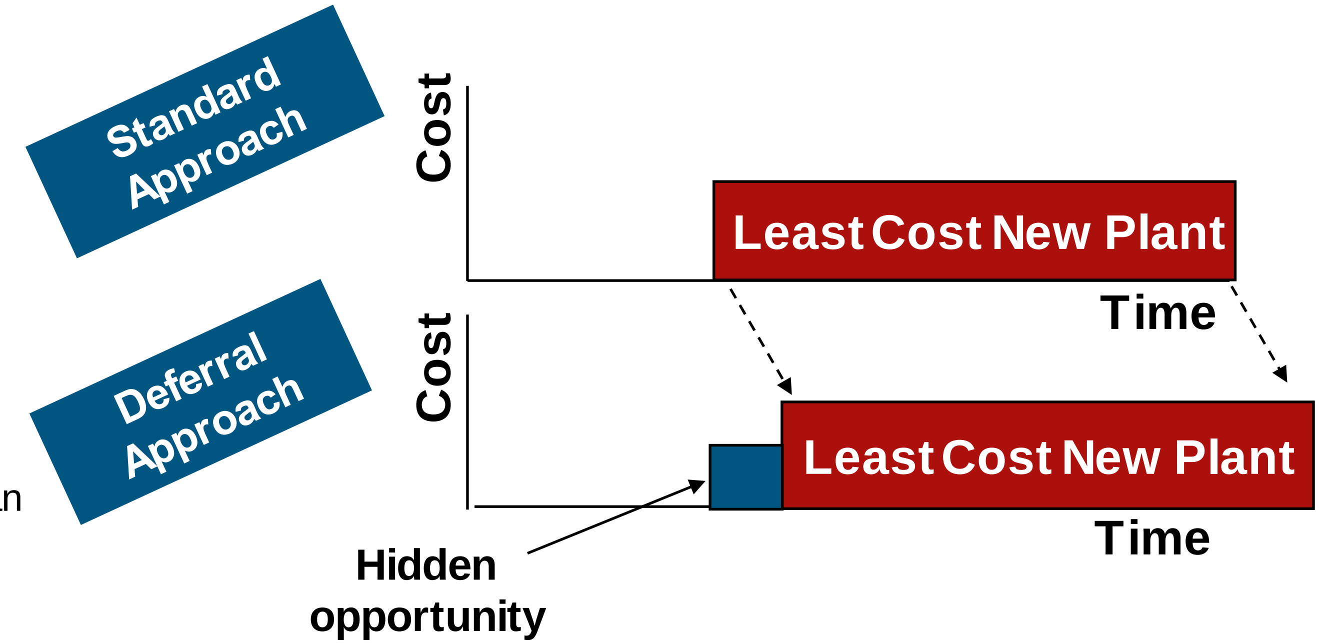
Agenda

1 Is more gas the right choice for Malaysia right now?

2 Isn’t it finally time for a power pool?

The problem

- As PPAs expire…
  - What to do?
  - Who captures the value?
  - Or is the value lost?
- How to integrate extension options within the planning and investment cycle?
  - Extension is less expensive than new build, but can be more complex
  - How to compare short-term extension to long-term procurement?
- Simplified tender processes risk missing hidden opportunities

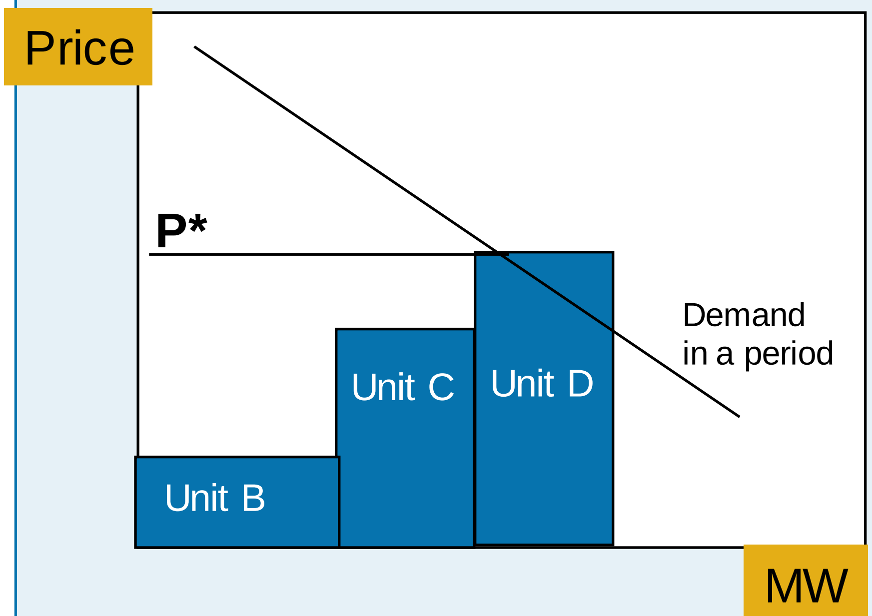


The IPP extension problem is an instance of a broader class of challenges: how to incentivise and promote innovation in the power sector?

Sophisticated integrated resource planning and market-based arrangements regularly address this problem, but simplified "tender-based" models struggle to be as effective.

One way to "extend" IPP operation is to give "expired IPPs" the option to participate in a "cost-based" power pool

- Units are paid the system marginal price



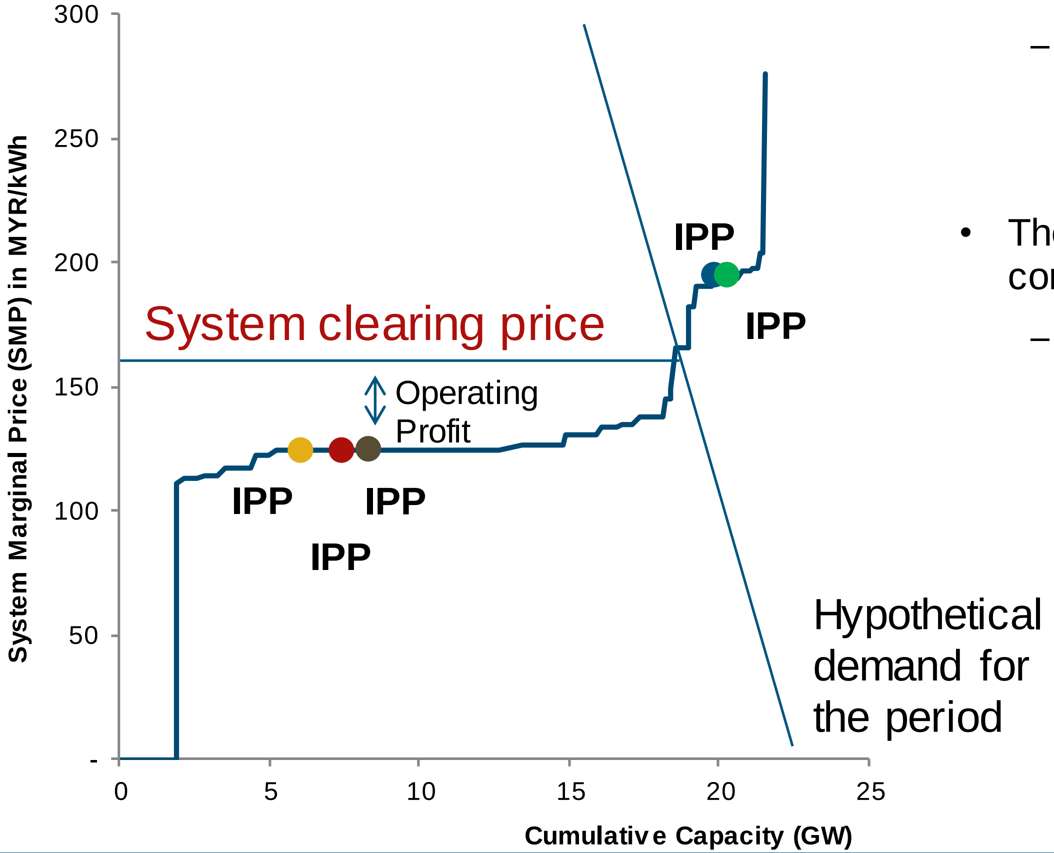
- The system marginal price reflects the clearing price based on the costs associated with dispatching each unit in the system

- Depending on the design and requirements, a separate "capacity payment" may be paid

- Ancillary services may be procured as necessary through contracts

At the end of contract expiry, "expired" capacity could have the option of continuing to be dispatched and receive the "system marginal price" (SMP)

Short-run marginal cost (Merit Order)



- The example to the left uses a cost-based pool concept similar to what is applied in Korea
  - The system clearing price in these examples is the estimated marginal generation cost (or system marginal price) – reflecting the cost incurred to produce an incremental MWh
- The system clearing price is the foundational concept behind power trading and power markets
  - A cost-based system marginal price may not compensate "capacity" (capital investment) adequately, but other mechanisms are available for that, if needed in the short term

System marginal prices can be calculated for any system, regulated or market-based

System marginal prices for Peninsular Malaysia can be used to compensate the continued operation of IPP capacity post contract expiry

Operating profit is the pool clearing price revenues less fuel and variable O&M costs

- Operating profit is calculated assuming no capital investment to extend operating life
- In theory, if an IPP can earn an operating profit greater than its annual fixed O&M and any capital cost required to sustain operations, it should be wiling to remain in operation
- But what process (negotiation, market, declaration) should be use to determine how the available value is shared (or not) between the IPPs and consumers?

Note: peaking units (OCGT) earn very little, as the system marginal price just covers their operating costs if they run

- If additional pure peaking capacity is needed, a separate capacity payment is necessary

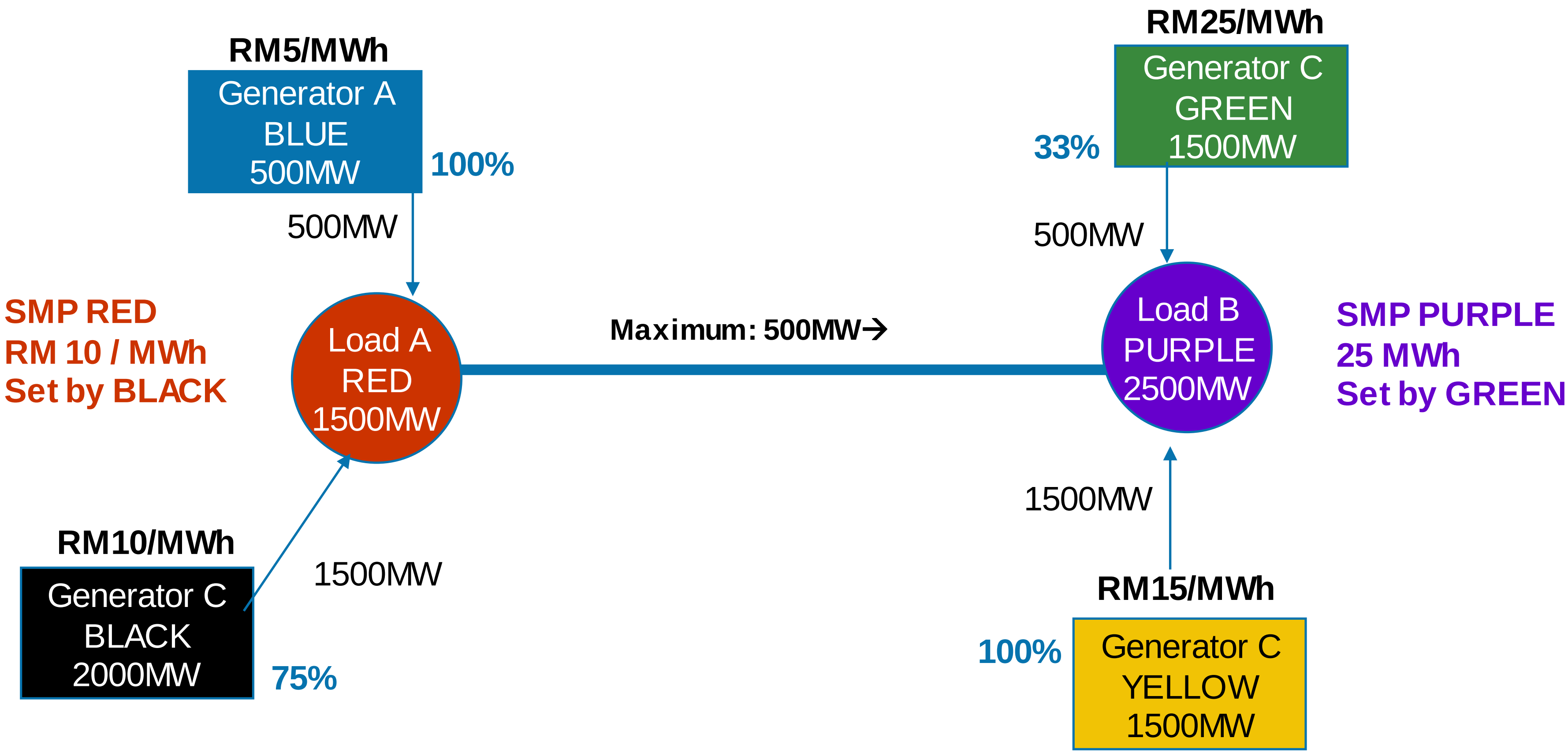
Cost-Based Pool Operating Profit to Continuing IPPs

Year	IPP OCGT	IPP OCGT	IPP CCGT	IPP CCGT	IPP CCGT
2015	19	-	-	-	-
2016	0	0	105	171	-
2017	1	1	188	306	170
2018	0	0	70	114	127
2019	0	0	104	169	188
2020	0	0	122	198	220
2021	-	-	134	217	242
2022	-	-	123	200	223
2023	-	-	115	187	208
2024	-	-	175	284	317
2025	-	-	107	98	194
2026	-	-	7	-	93
2027	-	-	-	-	19
2028	-	-	-	-	-
2029	-	-	-	-	-
2030	-	-	-	-	-
2031	-	-	-	-	-
2012 NPV (2015-2031)	**16**	**1**	**737**	**1,159**	**1,111**

Assumptions:

- Limited to 2000MW of additional coal entry beyond the 2000MW currently planned/underway
- Gas price transitions to "market" (assumed: RM 30.12/mmbtu in 2015 – note this is below current market prices). Clearly, extended units may not be able to operate until 2031, but the concepts and implications are the same. A capacity payment, if adopted, would supplement these revenues.

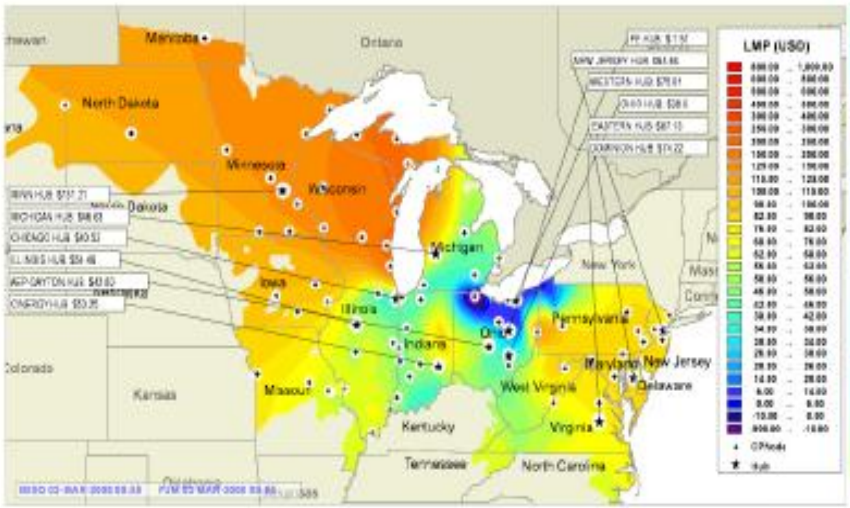
System marginal prices by location can be calculated for any system, market or non-market



System marginal prices can be as complex as needed to convey appropriate signals for dispatch and operational efficiency

Markets (like PJM, which began as a cost-based pool) expanded on this basic logic, producing thousands of prices across time and location based on “bids”

The MISO and PJM markets set thousands of location-based market prices each hour



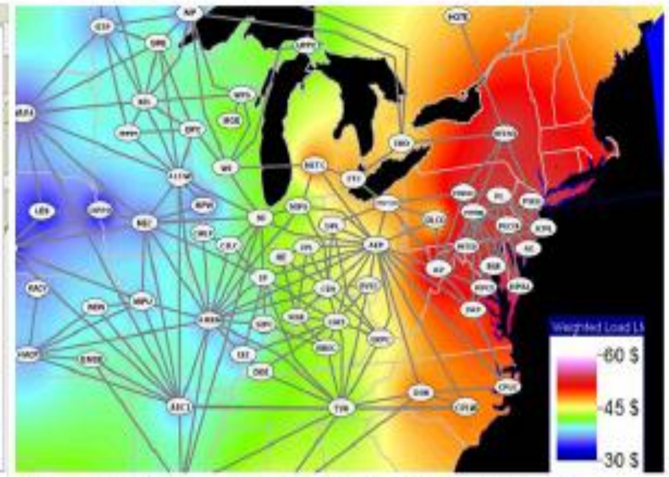


Figure 2.2-3 Contour Map of Annual Load Weighted LMP

Minnesota Hub: $131.21/MWh. First Energy Hub: $-1.57/MWh.

From MISO-PJM Joint and Common Market, http://www.jointandcommon.com/ for March 3, 2008, 9:55am. Projected 2011 annual average from 2006 Midwest ISO-PJM Coordinated System Plan.

System marginal prices are a fine foundation for a longer-term market-evolution programme

Summary

- Market-priced gas changes everything
  - It affects planning, dispatch and optimal system expansion
  - New gas-fired capacity is more efficient than existing, older, gas-fired capacity, but both new and old gas-fired capacity is more expensive than coal-fired capacity

- A least-cost scenario would require some form of short-term extension to the IPPs, but negotiating these is difficult
  - Not the same technologies or time frames
  - Not all the capacity may be required
  - Extension may only be required (or possible) for a few years
  - But ignoring the retiring capacity is likely to increase costs to Malaysian power consumers, or will require longer-term subsidies

- A cost-based pool with compensation to expired IPP capacity based on system marginal prices offers a way forward

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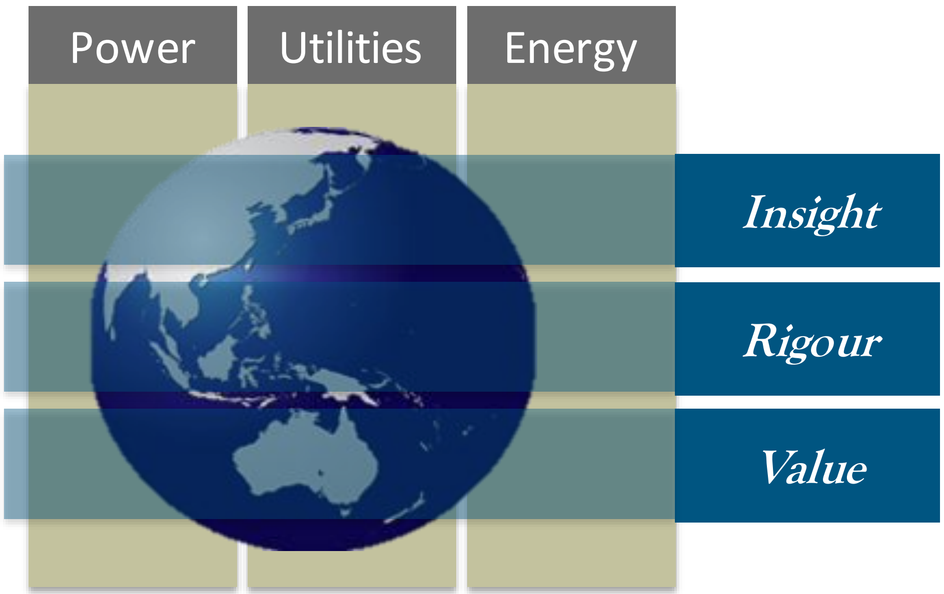

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