This document represents the response of London Analytics Ltd to the DECC EMR consultation. [redacted]

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

Clearly the existing market has been distorted by insufficient pricing of carbon, effectively acting as a subsidy for coal and gas plant. Furthermore, the ROC regime has produced a great deal of uncertainty for developers, leading to high finance rates. It has been said of ROCs that never, in the field of renewables, has so much been spent by so many to deliver so little. Reform is well overdue. The ROC regime has resulted in high financing rates, with (to illustrate the consequence) UK offshore wind costing far more than Danish offshore wind; this, together with a planning regime hostile to renewable generation, has reduced in Britain with one of the best onshore wind resources in the world falling behind those EU competitors with significantly inferior resources. This failure costs UK plc money. The emphasis must be on removing market barriers where there are economic efficiency gains to be had.

2. Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?

The government has omitted several key threats to the UK's security of supply, though it has modelled one particular type of risk that succumbs to relatively straightforward quantitative analysis. But just because a risk is the easiest to quantify and assess, does not make it the only risk in play. Key risks to security of supply that are in play but have not been properly assessed should be covered by work before significant market reform happens. These could be assessed within a few short months, ensuring that the subsequent market reform is barely delayed but is done on a well-informed basis.

In particular, every generation technology is susceptible to common mode failure, i.e. some problem that would make unavailable many plants of the same type. While government intervention in the market for security of supply is welcome on the grounds that individual operators are not always able to provide the strategic overview of supply security required, it is important that such an intervention does then adequately address issues that the market cannot.

Wind common-mode failures are well understood, predictable, manageable, and are for the time being adequately covered by existing modelling. However, common-mode failure for gas and nuclear are less well understood and go unmanaged.

With much of our energy needs being met by gas for the next 14 years at least, then availability of gas imports, and domestic storage, is a key issue to manage common-mode failure amongst gas plants.

Similarly, for nuclear, there are several common-mode failure risks that must be managed: threat of terrorist attack could result in the need to take all nuclear plants offline at the same time; restrictions on import of fissile material would be a different cause of nuclear common-mode failure; and the known problems with pressuriser cracks (or new system problems that appear across all plants of a single design) in the Pressurised Water Reactor designs proposed for new nuclear build in the UK could result in a situation where a spreading design-specific problem results in a situation where we either take all nuclear plants of that design offline for many months to effect repairs, or we continue to run plants in a state where we know there is a significantly increased risk of catastrophic failure. We recommend that the only way to manage this risk is to ensure that no more than 10% of the country's electricity capacity or mean supply is met by any one single design of nuclear plant.

Getting a correct value for loss of load is crucial for efficiently managing security of supply. The EMR Consultation Document's assumption of a value of lost load [VOLL] of £30,000/MWh (p30) is clearly exaggerated: very many domestic consumers would bite your hand off if you offered £30 to consume 1kWh less of electricity at a given time. Historically high transactional costs prevent a real market for energy security, because most demand-side actors are unable to participate – not through excessively high valuations of security of supply, but through excessively high transactional costs. Not all unserved energy has the same value. Dropping out power at the substation level is very crude – and now we can do much better. The Government can play a key role in bringing this market into being, and ensuring transactional costs are minimal

Risk is best transferred to those best able to manage it.

Leaving a significant element unpriced distorts market. Risks from nuclear and CCS are unpriced elements, and bringing them within the market would remove market distortions. There is only one way to find out if there is a sane market price for these technologies, which is to let them discover the market price of insurance; to protect the public within such a market, national and international regulation must ensure that suitable insurance cover is in place for operators. The current capping of limits on nuclear liability distorts this market, and disincentivises safety within plants. For any profit-led operator, the value of implementing safety measures is equal to the liability resulting from an incident, multiplied by the probability of the incident. If cost of safety improvements are less than this value, then the market will prevent them happening. Through the current capping of liability on nuclear operators, this value of implementing safety measures is artificially reduced to well below its actual levels, resulting in inefficient and inadequate amounts spent on operational safety. To remove this inefficiency, it is necessary to remove the liability cap on nuclear and CCS operators.

There are also risks to security of supply from the oligopoly operated by the Big Six vertically-integrated large energy companies: the power these hold over the market potentially allows them to exert undue pressure on customers, the National Grid and the Government to increase economic rents paid. It is recommended that this is counteracted by regulating to ensure that no company controls more than 20% of the market by derated capacity, or more than 10% of the market by annual energy supplied.

3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

Different generation technologies have different capabilities – a market support mechanism that does not reflect this, will distort the market.

Not all generation technologies behave in the same way, and thus the pros and cons of each of the FIT models offered differ by technology. Indeed, given the different behaviours, an economically optimal market will require different FIT models for different technologies.

For those technologies which are non-dispatchable, then there is no economic efficiency to be gained by relating an operator's revenue to the spot price. At the same time, there are **inefficiencies** for doing so: the added uncertainty of revenue must by its nature either increase economic rents for generators, or increase their cost of finance, or both: in any case, the consumer and/or taxpayer loses out. So there are no good economic reasons for choosing premiums or CfDs over fixed FITs for the non-dispatchable clean generators: wind, solar, wave and tidal stream.

However, for those technologies which are capable of some dispatchability: nuclear, CCS and to a degree tidal barrage, there are economic efficiencies to be gained from relating some revenue to spot price. In these cases the fixed FIT is the wrong tool, and a premium or CfD provides a better combination of reducing financing costs and maintaining incentives to actively participate in the spot and near-forward markets through dispatching economically.

Given the levelised costs on p28 of the consultation doc, and taking a point-of-generation carbon emissions of 0.5T CO_2/MWh for gas CCGT, then nuclear should needs no additional subsidy, for any market with a carbon at or above £30/T CO_2. Anything above that is pure rent from the taxpayer, and must be avoided.

FIT with CfD explicitly amounts to support for the mature nuclear industry, and as such represents a direct breaking of a pre-election promise. If a carbon price is insufficient for a technology that reached commercial deployment many decades ago, and if it continues to need underwriting its liability, then the market has declared it a failure. Notably, in Europe, the only country that has deployed lots of nuclear, France, has only done so because it is a largely state-owned enterprise. And this is the only logically consistent route – if the Government is determined to buck the market with mature technology, then the only sensible way to do that is with nuclear as a nationalised industry, ensuring that UK plc can capture as much of the investment as possible. If the tens of billions of subsidy poured into nuclear do not go into a nationalised UK nuclear industry, then they will go into the coffers of a largely-nationalised French nuclear industry, amounting to a direct payment from the British taxpayer and bill-payer to the French public. While such neighbourly generosity and European fraternity may be admirable, it would seem to be a challenging political commitment to make. There is absolutely no good economic reason to allow existing nuclear infrastructure, nor those announced or proposed before these EMR reforms were put forward, to benefit from the new subsidy, as the market had already ensured they would be built without EMR subsidy.

Revising the renewables obligation to become a low carbon obligation is an explicit step in moving it from subsidising infant and adolescent technologies, into also subsidising mature nuclear technology.

On the other cons identified within the EMR consultation document and impact assessment:–

the Impact Assessment report identifies CIRA as a viable mechanism for feeding fixed-FIT renewables back into market, so this a problem with at least one solution already, and is thus no barrier to delivering fixed tariffs for renewables;

negative prices – the upside for the market – incentivising demand-side response to be more supply-following, to compensate for the supply being less load-following. This will take years to evolve, and thus there are good reasons to tolerate 5-10 years of occasional negative wholesale electricity markets, while investing in research and backing infant industries that will devise supply-following technologies. The negative prices are an important market signal that can be harnessed for good.

P19 of the Impact Assessment states that "fixed payments remove exposure to electricity price and offtake risks ... resulting in loss of market efficiency benefits" – but this is not true for non-dispatchable supplies. It is, however true of capacity payments for non-flexible capacity.

The classification of FIT as tax and spend is purely arbitrary – what matters is the impact on public cash flow and national debt. If the money circulates within the wholesale market, there is almost no implication for public cash flow or national debt (except insofar as public-sector utility bills fail to hedge the increases – a small part of public expenditure).

The Impact Assessment (p18) acknowledges that although the Committee on Climate Change [CCC= have established that we need to get down to a grid carbon intensity of 50g CO_2/kWh by 2030, the EMR impact analysis has been done on the basis of reaching 100g CO_2/kWh. Given the importance of hitting 50g, and the expected length of impact of this EMR, it must be worth spending a few months now, getting it right so that we know we will hit that 50g, rather than rushing into something that we find out in 10 years' time cannot deliver less than 100g. And in particular, those methods that risk hiatus carry the highest risk. P19 of the Impact Assessment identifies that a fixed FIT best reduce barriers to entry and "offer the greatest relative potential to attract new investors" – and this is crucial, as decarbonisation requires a lot of new finance.

5.29 p108 Consultation Document – Government does not like "the loss of the signals for efficiency which are unavoidable wit the introduction of a foxed FIT scheme" – well that depends on how much of the grid is on fixed FIT. With marginal plant setting the wholesale price, and thus driving consumer price, the trick would be to have fixed FIT plant as marginal plant for at most a few hundred hours a year. High carbon price would ensure early signals for energy efficiency, meaning that these measures would be implemented quickly. For this to happen, more market reform is required, including in electricity retail. Current profit incentives on retailers to sell more electricity will always confound energy efficiency measures: there is a role here for Energy Service Companies to retail in a market where their profits are driven by level of service, but not by level of sales. Additionally, the market must see the real price of energy, including the costs of pollution that are currently externalised, to provide meaningful price signals on value of efficiency versus price of clean generation.

There are advantages to negative spot prices – incentivising demand-side response innovation, which is acknowledged industry-wide to be crucial. So an extra set of benefits at no extra cost – indeed, there are savings because no complexifying mechanism is needed to prevent negative spot prices. If the complexifying mechanisms are put in place, this increases uncertainty for investors, thus delaying investment. Negative spot prices will also speed up the decarbonisation of heat and transport sectors: both the charging of electric vehicles and of thermal stores are not time sensitive at the level of less than 12 hours, giving potentially tens of gigawatts of balancing and tens of gigawatt-hours of effective reserves at the level of seconds to 12 hours.

Fixed payments require low risk/return ratio – i.e. lower financing rates, higher investment. They are simple (unlike CfDs), again resulting in higher investment at lower rates. And fixed payments have resulted in the Danes building offshore wind at less than 10p/kWh, which would make it in Britain far cheaper than nuclear or CCS. In any case, guaranteeing payments for a max 20 years would seem to be prudent, given the potential for disruptive new technologies to come online within that time –for example, the DECC Chief Scientific Adviser's own estimate is that tidal stream may offer the potential for 400GW of mean electricity (i.e. twice the entire GB current energy demand, meeting all our electricity, heat and transport requirements). And this will be a mature tech by 2035. So payments that go beyond 20 years risk serious long-term market distortion.

4. Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

There is no sensible reason why different technologies should not have a different price regime: after all, every option and package proposed in the EMR consultation does this to some degree.

The EMR Impact Assessment identifies that CfDs can be complex and create a hiatus in investment. As Britain has a legal commitment to its renewable targets, risking a hiatus puts Britain at risk of breaking the law. Given that there are no significant advantages in CfDs over fixed FITs for non-dispatchable renewables, but that there is a disadvantage in the risk of hiatus, proceeding with CfDs having been informed by its own impact analysis of the risk of hiatus, risks HMG actively choosing a path that it knows would increase the risk of it breaching its legal commitments.

5. What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?

Risks are best transferred to those best able to manage them: the market cannot operate efficiently any other way. Given that most low-carbon plant is by nature high in capital cost and low in running cost, there is no meaningful way in which the operators of such plant can manage long-term electricity price risk, once a plant has been brought into operation. To that extent, there is little value in putting risk of long-term electricity price risk onto the operator.

However, safety is best managed by the operator. The current and proposed plans to cap the consequential liability of any nuclear operator at levels that are even below the simple rebuilding cost of the plant introduces a major market distortion into the most sensitive possible area - safety: by capping the consequential cost of nuclear (or CCS) catastrophe at a billion pounds or less, this reduces the incentives on the operator to invest in risk reduction. For the correct incentives to be in place for optimal safety, the full risk of consequential loss must therefore be transferred from the public to the nuclear plant operators.

6. What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

For plant that could be designed to have up-regulating flexibility , i.e. nuclear, geothermal, biomass – it makes sense to keep a market mechanism of time of dispatch. For those generators where there is no means of postponing generation, no means of up-regulation beyond doing down-regulation, a time-sensitive tariff makes no sense – it is sending a price signal to which the generator cannot respond. As such, it must be less economically efficient.

For wind, the optimal maintenance cycle takes place in summer anyway, as that is the time of maximum accessibility to the turbine, so a fixed FIT does not change the incentives on a market-optimal maintenance regime. However, for nuclear, operation al requirements say that winter is the best time to do maintenance – however this is the most expensive electricity of the year, and so nuclear payments, even if subsidised, should continue to reflect seasonal changes so that maintenance can be optimally scheduled. Given this, the Fixed FIT is most suitable for tech that cannot up-regulate, such as wind; the premium FIT is more suitable for those that could flex, i.e. nuclear, biomass.

The suggestion of risk of over-supply in the generation market (paragraph 3.42, p59 Consultation Document) is rather unlikely, given the Herculean task required of decarbonising our grid by 2030. That's at least 40GW mean power of zero-carbon energy. We may also have electrified our car stock by then – another 10GW mean electricity; and should be on our way to electrifying most of our heating too (another 40GW). While it is conceivable that the market will manifest a mean 80GW of low-carbon electricity by 2030, the Government could not fail to notice the massive industrial effort going into this, and curtail subsidies comfortably before excess arises. In short, we are decades away from such a risk, and to look to it as being relevant to policy decision in the next 20 years is utterly preposterous. Indeed, the reverse is the case – any investment that is justified by a carbon price of £70/TCO_2 is better to happen sooner rather than later.

Hence, the Government is wrong about the implications of modelling and impacts (3.43,p 59 Consultation Document)

Questions 7-8 unanswered

10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

Ofgem identifies low liquidity in GB electricity markets relative to other GB commodity markets, and also low relative to electricity markets in a number of other EU countries. Therefore, more higher-capacity interconnectors allow us to plug into that liquidity, as well as bringing us capacity backup – a win-win. Opening up a larger electricity export market will reduce the incidence of negative pricing, to the benefit of GB plc.

Putting in lots of offshore wind in the North Sea gives a timely opportunity within the next decade to make interconnectors to our neighbours happen; also part of creating and participating in a wider market, bringing the economic benefits that we've seen from globalisation to electricity generation. Important to capture that, and Ofgem consultation is only a small part – market mechanisms are crucial, and EMR should capture them.

Forward selling to consumers is also important: a National Grid that is able to obtain reliable information about future wind output, plant maintenance, etc., can provide forward pricing to customers – including residential customers. Usage of certain energy-intensive appliances such as washing machines, dishwashers, storage heaters, immersion heaters, can be automatically scheduled by a smart consumer unit to times of lowest prices, thus removing the risks of any negative pricing. Furthermore, all this control can happen at the consumer end – no question of National Grid controlling consumer appliances – only of these appliances becoming active participants in the market, providing balancing services at the scale of 30 minutes to three hours (wet goods and heating) and 1 second to 20 minutes (refrigeration and cooling). Smart metering small part of this – main part is establishing national communications network and single protocol for dynamic pricing and forward d pricing and bidding.

11. Should the FIT be paid on availability or output?

In order to avoid the expensive and burdensome inspection and enforcement regime that would be required if the FIT were paid on a declared availability basis, the FIT must be paid on output.

Questions 12-17 unanswered

18. Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

Yes, in the short term: in the event of short-term energy shortfalls, the market price would rise high enough until plants that exceeded EPS standards would meet the shortfall while being able to pay a high carbon price: here, the carbon price support would ensure sane behaviour from plants that operated for just a few hundred hours a year to provide security of supply.

Also, there is a role for high-carbon plant that has very low capital cost and only runs for a few hundred hours a year. Best way to deal with this is to not guess the market, but just to have a carbon price that means that it can either be very low carbon, or only run for brief times when wholesale prices spike.

19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

Establishing the market Value Of Lost Load (VOLL) is a crucial element missed from the assessment.

20. Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

To date, the market has provided adequate capacity mechanisms. The government risks introducing a major distortion into the market, in its proposals for a capacity mechanism. Capacity in itself is a poor proxy for security of supply. What matters is flexible supply that can up-regulate, and flexible demand that can down-regulate. If incentives are to be put into the market, they should explicitly target flexible down-regulating demand, and flexible up-regulating supply.

Flexibility works in two directions – up-regulating and down-regulating. Just because most of our plant has been almost-equally flexible in both directions, doesn't mean that this will necessarily be the case in the future. But both are crucial for a stable grid.

Wind, PV, wave, tidal stream and tidal barrage all can offer down-regulation when operating. With most wind turbines generating at least some power around 80% of the time, they offer the potential for a lot of down-regulation. This has a value to the market that should be captured. Nuclear's inflexibility on down-regulation imposes a cost on the rest of the grid, that nuclear operators should bear.

Flexibility will need to be frequently deployed. So although p74 of the Impact Assessment notes that new nuclear can turn down from 100% to 30%, the plant designer EDF has indicated that this could only be done 100 times per year, making it largely inflexible most of the time. However, plant design not finalised, and financial incentives put in place now, must incentivise flexibility.

Security of supply has a price. Diverse market, need to enable minimal transactional costs, and maximum market discrimination, to enable all players with all their diversity of marginal value of security of supply to participate in market. Fixed capacity margins would kill the incentives for this,. Again, its only purpose is to break the pre-election promise of no subsidy for nuclear.

Question 21 unanswered

22. Do you agree with Government's preference for the design of a capacity mechanism:
a central body holding the responsibility;
volume based, not price based; and
a targeted mechanism, rather than market-wide.

A market-wide mechanism is a recipe for economic rents and taxpayer /consumer rip-off, with no possible economic basis. Indeed, no plant that is currently extant or has been proposed should receive such a mechanism, as these plants have already been built or proposed in the absence of such a mechanism.

23. What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

No, the preferred package will be inadequate. Most market actors have been unable to participate in a market for security of supply – only large industrial customers get offered discounts for supply interruptability, because previously transaction costs have been very high. Technology and communications allows these transaction costs to become insignificantly small – but we do need the infrastructure in place to enable demand-side participation in this market. The market has failed to produce this mechanism, and this is a market failure that the government can and must correct. There is a natural monopoly at work here – that of the communication infrastructure necessary to enable demand-side response. The market is unable to generate a natural monopoly efficiently – to expect it to do so will result in delays, and over-investment into what become stranded assets, taking a couple of decades to settle down into a single united infrastructure. Given the time constraints on decarbonisation, and the large expenses attached to economic rents if only the supply side is able to participate effectively in the capacity mechanism, the demand-side infrastructure should be put in place centrally now.

Question 24 unanswered

25. Do you think there should be a locational element to capacity pricing?

The grid needs some form of locational pricing. Capacity pricing is not the worst way to do this, but is undoubtedly one of the less economically efficient ways. As above, the issue is one of incentivising flexibility equally on the demand and supply side, and these can have locational elements. However, some of the largest market barriers are within the planning system, and addressing these must be a significant part of EMR.

Part of "encouraging the incumbent firms to maximise their pace of investment" (in the words of the consultation document) must include removing planning barriers.

Use planning system to encourage wind location diversity, by providing fast-tracking for onshore and offshore wind in areas where gap between demand and current wind supply is lowest , and where distance is furthers t from other large generators.

Geographic closeness to demand is important for capacity backup plant at times of tightness. Best solution here will be district heating with CHP plant that can switch between thermal-only and CHP running as required by grid needs. Put mechanisms in place to make this happen. District heating works effectively in high-density areas ,which will also be hotspots of electricity demand at times of grid tightness.

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

No. From the Impact Assessment paragraph 6.197 p88, NONE of the packages assessed achieved a carbon intensity of 50g by 2030, which means all are inadequate for the job.

EMR should also look at breaking up vertical integration, as that presents a major barrier to entry and suppresses innovation and liquidity.

Payments for CCS – given CCC target of 50g, then there should be no payments for any plant that comes in at above 50g. Also, look at its whole-life cycle, and cap that at 100g too, to prevent system leakage from operators exporting carbon emissions.

Carbon price support

We acknowledge that the Treasury has just completed a consultation on carbon price support. However, very recently a paper was published that is extremely pertinent to the debate, and there was no opportunity for us to feed our reading of this paper into the Treasury consultation. However, given its significance, it is something that DECC must incorporate into its EMR process. The paper is "When do increasing carbon taxes accelerate global warming? A note on the green paradox" by Ottmar Edenhofer and Matthias Kalkuhl, Energy Policy 2011 (in press) DOI: 10.1016/j.enpol.2011.01.020.

This paper sets out how a slowly rising carbon price can, in the words of its abstract: "accelerate global warming because resource owners increase near-term extraction in fear of higher future taxation". To avoid this, it is clear that rises in carbon taxes must happen sooner rather than later. The EMR Consultation document, on p45 section 45, sets out expectations of a carbon price of £50/TCO_2 by 2020, and £70/TCO_2 by 2030. All trajectories rise to £70/TCO_2 at 2030 – including Treasury (section 15,p 45). There is now every reason to progress to that higher level, £70, as soon as is politically viable; this will give us our best chance of delivering the 2020 renewables targets; the 2030 $50gCO_2$/kWh grid carbon intensity, and our 2050 carbon targets.

Questions 27-32 unanswered

35. Do you agree with the principles underpinning the transition of the Renewables Obligation into the new arrangements? Are there other strategies which you think could be used to avoid delays to planned investments?

As projects are in planning now for delivery by 2020, to minimise risks of delays, putting in place mechanisms in 2012 that can run in parallel with, and can be opted into, between now and 2020, is the path least likely to alienate investors, and most likely to get things delivered.

Questions 36-37 unanswered

38. Which option for calculating the Obligation post 2017 do you favour?

Continue using both target and headroom

Use Calculation B (Headroom) only from 2017

Fix the price of a ROC for existing and new generation

Fixing the price of a ROC for existing and new generation will enable plant owners to refinance at a lower rate, thanks to greater security and certainty of future revenue stream; it is reasonable to expect that much of this will be reinvested in new plant, allowing us to leverage the expertise we have developed, into expanded capacity.