A 21st Century Electricity System

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Introduction

The current regulatory and contractual framework is designed around a 20th century industry (baseload coal and nuclear, dispatchable gas, all other bits are add-ons). The cost of electricity is diverging increasingly from its price: already around half of commercial customers' bills consists of levies and system charges, with only around half (this being a decreasing portion) being for the electricity consumed. In a well designed system, the price of electricity should account for between 75% and 80% of its cost. Thus the headline prices may need to increase, without necessarily affecting the cost of electricity to customers.

A 21st century regulatory and contractual framework must be designed around renewables and storage (with or without nuclear) supported by distributed generation and storage, interconnectors and Demand Side Response. Features of a 21st century system would include the following.

Regulatory Framework

Until RIIO was developed, National Grid was incentivised on cheapest electricity over a 2-year period. That provided cheap headline prices but without any concern for the future of the system. When RIIO was brought in, an 8-year horizon with attendant incentives were brought in, which was a big, but insufficient, improvement.

To ensure system reliability and cost-effectiveness over 15 years requires 15-year timescales. Ditto any other period. This is because the cheapest way to deliver a 2-year contract is to patch up a clapped-out and fully amortised plant. For the next 2-year period the same is done again, and again until the plant dies of old age. But with each repeat, the plant is older, less reliable and more costly to patch up. So over 15 years the total cost of electricity would be higher than under a 15-year contract because the latter would have been delivered by building a new plant. The short term timescales alone therefore ensure that investments with long lives and long term pay-backs are penalised financially, and also are added to the commercial risks that are put against the SO's balance sheet.

Therefore, in addition to the 2- and 8-year regulatory and rewards regimes, there also need to be 15- and 30-year timescales. The shorter timescales would have greater emphasis on consumer prices and lesser emphasis on system integrity, gradually reversing as timescales extend. This will ensure that not only is the grid cost-effective now, but also that it will be both cost-effective and systematically sound in 30 years' time, with all long term investment undertaken as needed.

Another RIIO problem is that every 8 years all "base cases" are re-set. Thus at the beginning of a RIIO period, investments can be made with an 8-year amortisation life; half way through, this drops to 4 years; and towards the end of the period, significant investment is almost impossible. This should be changed to a "regulatory amortisation" of each investment over the viable life of the asset, or over a reasonable lifetime determined by the regulator. Accountants manage such amortisations for large businesses very happily even though every plant is being amortised from a different date for a different period (or one of a set of permitted periods): therefore the regulator should be able to manage "regulatory amortisation" similarly.

Contract Structure
No major investment is possible without long term contracts or other form of revenue assurance. The only capital investments in major infrastructure have come on the back of special arrangements that offer such assurances, e.g. CfDs, ROCs, OFTOs, CATOs.

Without long term contracts, a 2-year contract will appear to be the cheapest way of procuring electricity over a 2-year period. But it will be bid on marginal cost and delivered by patching up a clapped-out and fully amortised plant. On the next 2-year cycle the same will happen again, though the plant will be older, more worn, more expensive to patch up and more prone to break-downs. Over a 20-year period the country will have paid more overall for its electricity than if 20-year contracts had been let, which would have been delivered by new plant – and in the meantime no new plant is built, the old plant dies of old age and the system's capabilities plummet. Meanwhile, in order to incentivise investment there need to be special mechanisms (subsidies by another name) put in place which mean that the total cost of delivering electricity (including subsidies) is greater even in the short term than would be the case under longer term contracts.

A truly sustainable grid will engage most or all services under contracts of lengths that both encourage investment and minimise cost. Such a structure could include:

- 1/3 of energy under 15-20 year contracts, with delivery to start following grid connection, these contracts only being available for new build;
- 1/3 of energy under 5-8 year contracts, with a split between new and existing plant to be decided according to the reviews of the system from time to time;
- 1/3 of energy under contracts of up to two years, for all plant.

There is indeed some measure of uncertainty as to future demand. This can be accommodated by (a) letting such contracts in rolling annual or biennial auctions and (b) flexing the exact amount of mid- and short-duration contracts.

The entire subsidy regime and scheme of access charges need to be re-thought:

- Incentivise cleanness of technology, for example with longer contracts going to cleaner technology. An example would be full-length (as above) contracts for zero emissions generation; half-length contracts for CCGTs, with durations on a sliding scale directly proportionate to emissions between the two, that scale continuing to diminish contract length for technologies with worse emissions than CCGTs.

- ◊ Include ancillary emissions in the calculation of the emissions of a given technology: mining, harvesting, refining or otherwise processing, manufacturing, transporting, recycling, disposing of equipment (both main and ancillary, including considerations of operational life), components, materials and fuel.
- ◊ Ensure that imported electricity is deemed to have the emissions performance of the electricity that is delivered to the interconnector. Where that is difficult to determine, default to the average emissions performance of the source country and, if appropriate (e.g. Belgium, Netherlands) considering a proportion of the electricity to come from their neighbouring countries, at their average emissions performance. This would apply to carbon pricing and any other incentivisation scheme including contract duration.

- Incentivise dispatchability with a price premium that reflects the balancing costs avoided (or a large proportion of them, so both sides benefit).

Ensure that all capabilities can be monetised, e.g.

- Permitting real inertia to compete in the EFR market with a premium based on the fact that it is instant and requires no grid intervention, whereas EFR has milliseconds' delay and requires grid intervention. Ditto reactive power.
- There is currently no contract scheme for long term storage. If such a provision were made, then negotiated bilaterally for e.g. the first 1TWh stored (with a minimum installation size of 100GWh) prior to creating an auction for it, then this would enable the scheme to be available when the technology is developed to use it - and would thereby incentivise the development of that technology. It would also enable the contracts to be structured around the actual costs and benefits of the technology, rather than around a theoretical exercise. Similar mechanisms could be used for other services as their need is identified.
- Ensure that the various services are co-ordinated so that any plant that can deliver multiple services is able to contract to do so.

Eliminate the Capacity Market, which is a subsidy for fossil fuelled generation.

Contract Simplicity

There are currently 15 different contracts under which balancing and ancillary services are purchased, and this number is increasing steadily. Germany, for all its faults, has 3. Large scale storage needs a stack of 8-10 contracts in order to earn full returns on investment; small scale storage stacks 6-8, and demand side response almost as many. Even generation, which used to have one contract, now has many. All except one (Capacity Market or EFR, depending on technology) of these has a duration of between 6 months and 2 years. Assuming an average duration of 1.5 years, this means that, at best, large scale storage has to fund an overhead to bid for 8-10 contracts every 1.5 years. And every contract type is different, with different terms, conditions and specifications, all of which have to be understood and juggled not only by the bidding bureaucracy but also by plant operators who have to fulfil all those contracts, and by spot traders who have to know exactly what will be surplus at what time. And it entails similar complexity and overhead in the System Operators Contracts team and control centre.

However each bid carries the risk of losing the bid. This will entail a costly hiatus in contractual cover while another (usually less remunerative) service is bid for. This can double the already huge administrative overhead of bidding. It also means that there is a financial risk, which adds to the risk premium on the investment and therefore to the capital cost of the plant. These risk premia also lead to high levels of profits when things do not go wrong, leading in turn to screaming tabloid headlines and high political risk.

The system needs simplifying. A plant should be able to tender all its services as an individual plant in one tender – or two, if demand side (DSR, demand turn-up) is included. Individual services should only be tendered if there is a specific resultant shortfall in the capabilities that have been engaged – which there shouldn't be, as there is some flexibility in capabilities, such as primary frequency response assets continuing for the duration of secondary response and even fast reserve.

The Most Cost-Effective Contracting Sequence
Letting contracts for such services individually causes major issues and maximises the cost and complexity of letting, administering and delivering the contracts, for both grids and service providers. The biggest problem that it causes is to flexible plants that deliver many services, such as inertial plant which cannot deliver electricity without inertia and other related services.

- What happens if a plant is unable to deliver services A, B and C separately and wins contracts for A and B but not C? Do they have to "give away" C without remuneration, putting them at a commercial and financial disadvantage? Are they penalised for excessive delivery of C?
- What happens if, in delivering A, B and C they are vastly cheaper than the competition in delivering D? The total of A-D is cheaper than any other means of procuring them, but A-C on their own are more expensive. Should the system pay extra to procure them separately or should it aggregate A-D to provide all the services more cost-effectively?

The most cost-effective contracting sequence would be:

1. Let the longest-duration and hardest-to-place contracts first;
2. See what else the winning plants can deliver cost-effectively, and award those contracts to such plants;
3. Only auction off the next-hardest-to-place contracts that remain outstanding after step 2, and repeat.

This will ensure that each plant that wins contracts can amortise its costs over the widest range of contract types for which it is cost-effective. This in turn enables those contract prices to come down due to contractual coverage and revenue security, and also because fewer plants are needed in the system to deliver the requisite energy and services.

For example, of the reverse were to be done, then:

1. Large numbers of peaking plants and batteries would be built to cream of the biggest revenue streams;
2. Harder-to-place contracts would be more expensive as these parts of the revenue streams are no longer available to them;
3. Plants for these harder-to-place (including longer-duration services) contracts will not be built without much higher prices as they cannot be justified on the back of the easier-to-place contracts, and won't already have the other contracts "in the bag" to be able to spread the amortisation of their costs.

Incentivising Clean Energy

All the above is regardless of energy technology. However clean energy can be incentivised, without subsidy or price premium, by superimposing cleanliness-related contract length.

To do so, the base contract lengths would need to be extended so that imperfectly clean technologies can also have sufficient contract duration to enable investment. Thus for a 100% clean / renewable technology, the longer two contract lengths would be 20 years and 10 years. For a diesel or coal (whichever is more polluting for the service being contracted) fired power station, contract lengths would be half of that for the clean technology, i.e. 10 years and 5 years. Maximum contract durations for technologies with intermediate levels of cleanliness between these two end-points would be linearly proportionate between those durations. So a new build with half the emissions of a coal fired power station could have a contract of up to 15 years, and a refurbishment up to 7.5 years. It may be politic to let contracts in steps of whole numbers of years, in which case the refurbishment would have a contract length of either 7 or 8 years depending on whether the decision is to round up, down or to the nearest integer.

The emissions performance should be calculated as a whole-system (or, in the case of storage, round-trip including all energy inputs and useful energy outputs) efficiency *for the particular duty cycle being tendered*, rather than a standard figure being applied for all duty cycles. This is because, for example, a 60% efficient gas-fired power station would be a very high performance for frequency response, but not as good for baseload.

For stand-alone storage, the calculation would take into account two factors: cleanliness and efficiency. In order to be considered on a level playing field with generation, both "inefficiency" and "dirtiness" should be factored down by 50% and then added to obtain the "undesirability factor" which is then subtracted from 100%. Thus a 60% efficient (i.e. 40% inefficient) storage system that creates 20% of the emissions of a coal/diesel fired plant would be factored down by 20% for inefficiency + 10% for dirtiness, total 30% undesirability, for a contract length equivalent to a 70% clean plant, resulting in maximum contract lengths of 17 years for new and 8.5 years for refurbishment. The justification for this factoring down is that storage provides a balancing service that maximises the efficiency of the whole system, and does so

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more effectively as the proportion of renewable energy in the system grows. Thus efficiency is incentivised, as well as cleanliness.

Incentivising Dispatchability

Dispatchability could be incentivised similarly to cleanliness of batteries, in that a non-dispatchability factor could be added to the dirtiness factor. Thus there could be (say) a 10% reduction for long term predictable variability (e.g. tidal lagoons and tidal flow turbines, 4 generation slots per day), 20% for only short term predictable variability (e.g. wind and solar generation). There could be an intermediate step for medium term variability such as wave power at 15% factor, if deemed appropriate.

Where dispatchability is increased by co-location, near-location or contracting with storage, then generation and storage patterns and efficiencies should be modelled to identify the forecast true output and dispatchability figures, and the dispatchability factor scaled accordingly. Where such storage is of limited capacity (e.g. less than the nameplate capacity of the generation) or limited duration (e.g. fewer than 5 hours at nameplate capacity of the storage), then the storage only partially creates dispatchability. In such cases, the storage would not be evaluated separately as stand-alone storage. One could conceive of a storage facility contracting a proportion of its capacity to a dispatchable generator and the remainder as stand-alone, in which case a compound figure could be calculated.

Non-Financially Incentivising Innovation and New Technologies

New technologies from innovative start-ups are actively prevented from developing their plant as contracts are only considered following grant of planning permission, which itself follows the study and reservation of grid connections. Therefore for a large plant, millions of pounds (which an innovative start-up does not have) are needed before the contractual cover is offered which would provide the revenue underpinning required for investors to put in the money needed for the grid connection and planning applications. It's a Catch 22. A second Catch 22 is that many investors won't invest without a reasonable expectation of long term contractual underpinning of revenues, which cannot be granted unless the technology is developed.

A simple way to break through these barriers and to incentivise innovation and new technologies without money (though it would best be done in conjunction with the other incentives, below) would be by early official memoranda of understanding (MOU) and letters of intent, and progress monitored to ensure that the SO understands its impact, likelihood and timing as the project develops. With these, our potential financial backers would almost certainly open their purse strings.

- For a proposal to build a first-of-a-kind plant, a letter of intent from the System Operator to state that provided certain conditions are met (those being specific to the plant being developed, e.g. FEED Study complete and supporting the previously claimed minimum performance, planning permission granted, grid connection application granted), then it is the intention of the SO to grant a 15-year contract at the rates applicable at the time.

- For such a proposal, a memorandum of understanding from the Network Operator to say that prima facie a grid connection (specified) would be available within a specified cost and timescale, unless other applications were received between the date of the MOU and that of the formal grid connection application. This helps to shorten timescales and liberate funds because currently grid connections can only be applied for following grant of planning permission which, for a transmission grid connected scheme, will cost ~£2m and take ~2-3 years. The prospect of an affordable grid connection will help liberate the private funding for the design and planning process.
  - Permitting grid connection applications to be applied for prior to grant of planning would considerably reduce the up-front risks and timescales of any project.
- For an earlier stage innovation, if it would create a technology useful to the SO, then a less binding memorandum of understanding from the SO that if the technology achieves specified milestones (demonstration on paper of technical and commercial viability), then the above letters of intent will be forthcoming. This will provide the support to the project that will show to early stage funders that the technology has a commercial future if it can be developed as claimed.

Additionally, permit system operators to invest in new generation / storage technologies and to own the consequent plant for a limited period, e.g. 5 or 10 years (possibly depending on size of plant / investment) between commissioning and sale. The proportion of the plant they can own could depend on the proportion of innovation in the plant. Any IP should have to be licensed to all who wish, but with royalty revenues accruing to the system operator as per normal commercial R&D investment.

Financially Incentivising Innovation and New Technologies
To encourage new technologies, replace ROCs and CfDs with a price supplement (pence per kW) for early stage installations of new technologies, e.g. add to all revenues 50p/kW for a first-of-a-kind plant (that is, full scale rather than experimental), diminishing linearly to zero for the 6th of a kind. If the differences from other plant types are smaller, then this premium can be reduced accordingly, but should still remain in order to incentivise innovation.

- By incentivising first-of-a-kind plant, it encourages these to be built in Britain. This incentive could be made contingent on (or proportional to) the development, engineering and manufacturing of the technology being located in Britain - which would incentivise innovative foreign companies to move in.

Create a branch of the NIA / NIC investment fund to be administered centrally by Ofgem to incentivise R&D which would benefit the electricity system as a whole but not the grid operators individually due to regulatory or commercial constraints. It should be administered to favour UK-based R&D, manufacturing etc., maybe with the proportion of costs covered being proportionate to the UK-based work (excluding installation - which is a gateway factor) as a percentage of the whole.

Other incentives for the development and introduction of new technologies should be considered, not only at the innovation stage but at the pilot and first grid connected plant stages where there is a dismal shortfall in both money and non-financial support to flex the contractual and regulatory regimes (even if only on a one-off basis to test the benefits to the grid) to enable and encourage them.

Conditional contracts would greatly assist fund raising. They could be phrased along the lines of: “if this plant can be built and deliver these services at these prices, then it is the intention of the System Operator to enter into a contract at the higher of these prices and the market prices applying at the time.”

Time to Start of Delivery

Building new plants in new locations requires grid connection. Such grid connection can entail significant grid reinforcement. However the reinforcement can take 5-10 years to plan and implement, which exceeds the longest possible time allowable under the RIIO framework. Contracts for new build need to permit suitable delays to start of delivery of the multi-year contracts, in order to enable new construction.

Some discretion may be given to the System Operator as to whether or not a plant is wanted to be connected to that part of the grid. And the issue is moot for plants that use existing grid connections provided those existing connections retain their access capacity.

Grid Access

Ensure that all generation, whether UK or overseas, pays the same grid access and usage charges.

Treat storage as a grid service, not as generation or consumption – or, at worst, allow storage to pay for charges after netting generation against consumption, which would incentivise efficiency.

Instigate a methodology for ensuring that grid reinforcement costs also capture the benefits of reinforcement deferral arising from some investments (e.g. generation on a particular side of a bottleneck) and sharing those benefits with the investor, e.g. 2/3 to the investor and 1/3 to the grid operator. Some of these benefits may be reflected by one-off payments, others by annual payments: in order to maximise the incentive to build such plant, and to reflect the timing of the benefits to the grid operator, they should be paid in advance; any adjustments can be made the following year to reflect actual usage and/or performance.

Grid Definition of Storage

Create a grid definition of storage modelled on that for interconnectors. This will permit and regulate:

- Contracting for services which are delivered off peak from storage that is replenished when market price differentials are not as high as between delivering at peak and replenishing at trough prices;

- Contracting for storage services per se;
- Ownership and investment into storage systems – maybe for only a fixed period, say 5 or 10 years from start of operation to deadline to sell the plant.

It will also eliminate:

- Over-charging for grid connections and reinforcement, indeed creating a mechanism for payments to developers to reflect a large part (2/3?) of the savings from grid upgrade deferral;
- Double charging for grid access for both charging and discharging;
- Having to pay market premia (profits, mark-ups etc.) for both buying and selling electricity.

Whole-Operation Contracting

Consideration should be given to whether System Operators (SOs) should be permitted to contract with a given storage provider / installation for "all services". This is because the number of services offered by storage far exceeds that offered by generation, and such a contract would maximise the ability of the SO to use each service from storage in the most cost-effective manner. The main issues to be considered are whether and to what extent this would make the SO into a storage system operator, and whether or not such a change would be desirable.

CAES (Compressed Air Energy Storage), for example, can offer:

1. Various embedded benefits;
2. Firm Frequency Response (Secondary, and possibly some primary);
3. Fast Reserve;
4. Short Term Operating Reserve (STOR)
5. Supplementary Balancing Reserve
6. Reactive Power MVAr
7. Demand TurnUp
8. Wholesale Peak
9. Wholesale Off-Peak
10. Balancing Mechanism
11. Capacity Mechanism
12. Black Start

While batteries cannot offer the long generation durations required by STOR and the Balancing Mechanism, they can offer Enhanced Frequency Response and Firm Frequency Response (primary).

There are various models and precedents for such contracts, including CATOs and OFTOs.

Another benefit is that SOs require such services during off-peak times as well as peak times. If required at off-peak times, then the storage would have to re-charge at higher prices while generating its revenues at lower prices, making it unprofitable. Such whole-operation contracts would enable the provision of these services at off-peak times to be profitable for the storage provider.