

Economic Curtailment of Renewable Energy

By Brian Harms; Partner, Troutman Sanders LLP

On May 6th, 2010, the California Public Utilities Commission (CPUC) held a stakeholder meeting to discuss the economic curtailment of renewable energy. The meeting was called to address Southern California Edison's ("Edison") amendment to its 2010 *pro forma* PPA. That amendment expressly allowed Edison to economically dispatch a renewable energy resource, and open the resource to curtailment without payment.

The possibility of such curtailment, however, undermines the certainty the resource will be delivered, as and when available, making the revenue from such resource less certain. Many stakeholders, including the California Wind Energy Association (CalWEA) and the Large-scale Solar Association, argued that such a provision makes a project "un-financeable" and that some sort of mitigation must be included in these renewable energy PPAs. The stakeholder meeting highlighted the tension in independent system operator (ISO) markets between dispatching resources economically, using locational marginal pricing (LMP) or other price signals, and meeting state renewable portfolio standard (RPS) requirements by purchasing higher cost-bundled renewable energy products (i.e. energy plus renewable energy certificates, or RECs).

The best choice for mitigating economic curtailment issues is for counterparties to know the issue and expressly allocate the risk through bilateral negotiation...

Tension: ISO markets vs. RPS requirements

Generally, ISO markets are designed so that LMP price signals will cause the least cost, or most efficient resources to be dispatched where needed on the electric grid. The LMP signal includes an energy price and transmission cost, such as congestion and losses, but does not include a renewable energy premium for the dispatch of renewable energy. If a scheduling entity* bids the bundled price for renewable energy, then this failure to take into account the "environmental attribute" value (not just RECs but, perhaps, greenhouse gas emissions allowances as well) exacerbates the price difference between a gas-fired resource, especially with low natural gas prices and a renewable energy resource.

However, utilities buying renewable energy and wanting to ensure they receive the RECs for RPS compliance can self-schedule or otherwise schedule a renewable resource (and bid at a low price, or even a negative price) to ensure delivery of the energy and RECs. Often, utilities will agree to such scheduling in their renewable PPAs. But if there is no express agreement between the parties, and the utility is the scheduling entity, then there is a risk the scheduling entity's bid price will cause the resource not to be dispatched—even if the renewable resource is capable of being dispatched. That risk may be a greater risk if the utility has already met its RPS obligations for the year.

Setting of terms: Who should control?

The above discussion illustrates a key issue raised at the stakeholder meeting: should economic curtailment be an issue left to bilateral negotiation, or should the state public utilities commission overseeing the RPS program or the ISO play a role?

Most attendees agreed that bilateral negotiation would be best, but CalWEA argued that *pro forma* contracts should not be published with non-financeable terms (i.e. permitting economic curtailment). A different path suggested by attendees was to have the CPUC set a specific term for economic curtailment, such as setting a cap on the number of hours of economic curtailment permitted in any year or providing for no economic curtailment. Of course, differences among the various renewable energy sources means there is no "one size fits

all" solution. For instance, solar resources dispatch when the sun is shining and peak demand is occurring; wind resources dispatch at lower demand times. Taking into account the differing dispatch conditions, wind resources will likely be more prone to economic curtailment than solar resources (i.e. too much generation at a low demand time). Depending on the amount of intermittent renewable resources interconnected to the grid that may not always be the case.

Non-ISO markets: Allocation of risk

In non-ISO markets, counterparties usually agree that a renewable energy PPA is a take or pay contract, so that if a renewable energy resource is capable of producing energy and/or delivers energy, the seller will be paid. The risk allocation results in the buyer accepting the risk because the ability to curtail energy production without damages is not only detrimental to revenues, but could also be detrimental to government incentives based on production of energy (such as production tax credits). Aside from simply requiring take or pay for renewable energy, some PPAs will allow for a limited number of curtailment hours (or MWhs) while others will allow unlimited curtailment, but with payment for the energy curtailed at the PPA price. Either method would provide a negotiated allocation of risk.

Mitigation alternatives

The obvious mitigation for ISO market PPAs is to include provisions in PPAs that limit or eliminate the risk of economic curtailment. During the CPUC stakeholder meeting there was discussion of the fact that Pacific Gas & Electric provides for payment at the PPA price of energy that it economically curtails. This can be achieved through bilateral negotiation, but the question remains: should something more "systemic" be used, such as the public utilities commission in a state (as the RPS overseers) overriding ISO economic principles, when dealing with RPS resources?

A third alternative could be an ISO LMP signal fix that combines the economic dispatch of energy with recognition of the premium placed on renewable energy. Granted, ISOs allow their scheduling entities to bid whatever price is appropriate, and this bidding can be set by bilateral negotiation, which could mean bidding at a price that pulls out the REC premium—and, essentially, is a bid solely of the energy price. Additionally, adding new components to LMP pricing would be complex, potentially difficult to administer, and possibly not cost-effective. For argument's sake, if a day-ahead/real-time REC emission allowance pricing component could be added to LMP pricing, then that could create a better comparison between traditional resources and bundled renewable energy resources being dispatched for RPS purposes and would, potentially, marry the RPS goals of public utility commissions with the economic dispatch goals of ISOs.

Conclusion

The best choice for mitigating economic curtailment issues is for counterparties to know the issue and expressly allocate the risk through bilateral negotiation; with specific scheduling requirements or limitations placed on the scheduling entities. However, as ISO markets and RPS goals evolve and move forward, the tension between economic dispatch and the desire for renewable generation may require a macro-level, systemic solution. If technology and information availability allow a marriage of ISO and RPS goals in pricing signals or other means then, perhaps, that becomes a potential solution.

* Note: a scheduling entity is the entity that interfaces with the ISO to schedule the generation of energy from a resource. Scheduling requirements are different in each ISO.

Troutman Sanders LLP

www.troutmansanders.com | www.renewableinsights.com