

Working Group #5—Contracts
Notes from 5/7/2003 meeting

Pat Barry was introduced as the “Staff Advocate” and Janice Nissen as the Facilitator. The objective of the working group will be to explore whether long term contracts might be needed to develop new renewable generation in the state, what the features of these contracts might be, and what the pros and cons of these contracts and features might be.

The group was asked if anyone knew, and could share, what the experience has been in other states that have adopted renewable portfolio standards. Niagara Mohawk/National Grid (NM) offered to make someone available from their affiliate in Massachusetts to discuss their experience if the group would be interested in that. Bill Short from Ridgewood Power Management shared some of his company’s experience. They are the largest renewable developer in Massachusetts and a participant in California. He was asked if it is mandatory for his co. to enter into bilateral contracts. He said no, long term contracts were neither mandatory nor necessary, but that his company had a variety of types of contracts, nonetheless. These included:

- Contracts for certificates only (currently RPS compliance, fuel use, and air emission credits are bundled together)
- Contracts for energy and certificates
- Fixed price for all elements, or a mix of fixed for one element, floating for another
- Some firm (with respect to MWHs), some non-firm
- The term of these contracts vary from 1 month to 1 year

(He offered to send us copies of some of these, with the sensitive details blacked-out.) Typically, his company prefers to subdivide the revenue streams a project receives as follows:

- Energy: Unit contingent bilateral contract with an LSE/ESCO
- ICAP: Bilateral contract with the same or another LSE
- Attributes: Bilateral contract with one of the above, or a third, LSE (firm or non-firm MWHs)
- Ancillary services (generally operating reserves) to the ISO

There followed a general discussion about ISO requirements with respect to renewable, in particular intermittent renewable, generation. Currently, the NYISO does not charge wind generators imbalance penalties. As the aggregate number of MWs of intermittent generation in the state increases, it was argued that the ISO rules might have to change. For example, intermittent generators may be required to bid in the day-ahead market and be subject to the same penalties as other generators. Some felt that it was certain that as the number of intermittent MWs increased, ancillary service costs would also increase.

At this point some asked for a “process check.” What was the objective of this working group? Are we looking to design standard contracts?

Staff responded that Staff was not necessarily looking for standard contracts, but would like, at least, to look at the range of what types of contracts may make sense.

Some wondered if energy contracts were even necessary. We were told that contracts were not mandated in Massachusetts. If we design a model (such as the NYSERDA or ISO Central procurement models) that provide for the payment for attributes (i.e. above-market premiums), would that, in conjunction with the ability to sell the more traditional elements in the market, be sufficient to allow projects to be financed? Some thought that it would be. Others wondered.

Our Facilitator reviewed one objective of the working group: in case it was determined that contracts were needed, what are the options and what issues are raised?

Someone suggested that, if the “central procurement” path were taken, some sort of contract (if only for attributes, and if only via the OATT) would be needed. It was suggested that contracts for just attributes may be sufficient, but they may not be, and flexibility is required to respond to what actual facts and circumstances dictate. The key is to provide what is necessary to get the needed renewable projects financed.

It was stated that, if the market rules and RPS program were designed in a sensible way, projects would be finance-able without long term contracts. Currently, we were told, NYSERDA makes a performance-based incentive payment to accepted projects for 4-5 years, and the plants get financed and built based on “merchant” revenues for the rest.

A developer described the various revenue streams that a developer would project in setting up project financing. He suggested that the premium payments could be reduced if he were allowed to subdivide the attribute element into separate RPS and greenhouse gas attributes. Others suggested that there would be disagreement whether that made sense for separate payment.

At this point, the discussion turned to contract duration. The utilities were asked about their current portfolios. It was suggested that this might help us to get a handle on what “long term” means and what’s required for financing. There was some discussion about NM’s portfolio: 15-20% of the load may be tied up in small, long-term (multi-year) IPP contracts. NM also has larger NYPA and transition contracts. A request was made for the utilities to provide summary information in this regard. NM offered to check with others on its staff during the break. Other utilities suggested confidentiality/trade secret concerns.

The group tried to list the contract features and issues under the Central Procurement approach (see wall notes).

There was a discussion of credit worthiness and the general risk of non-performance. Are utilities concerned with the risk of non-delivery of energy? Or the risk of non-compliance with RPS standards? Answer: both; anything that creates potential financial harm, including the risk of (unfairly) being found imprudent. Don’t some of the models and/or features reduce this risk significantly? For example, the ISO approach under Central Procurement or alternative compliance mechanisms (ACM) (e.g. the \$50/MWH charge in Mass.)? The ACM doesn’t avoid issues of imprudence, at least in some models. If it would be cheaper for a purchaser to sign a long term contract with a

renewable project than simply paying the ACM, wouldn't a utility that just relied on the ACM be at risk of being found imprudent?

There was some discussion of any new market for attributes being similar to the ICAP market. Because the target is administratively set, the market could swing rapidly from situations of shortage (very high price) to glut (close to zero price) depending on how technological/resource capabilities (i.e. supply) compare to targets (i.e. administratively determined "demand"). In such a situation it may be sensible to have mechanisms for price ceilings (e.g. ACMs) and floors (being considered in Mass.). It was noted that this could be influenced by the decisions made on "slippage" and "banking." For example, "slipping" a portion of the target increment from one year to the next could give the supply-side of the market time to "catch up" to the targets without forcing inappropriately high, shortage-based price spikes. Banking may also allow the "smoothing" of some short-term ups and downs.

BREAK

After the break NM reported that 60-70% of its load is tied up in contracts, 30-40% is met through day-ahead and real-time markets.

Return to contract features:

Non-performance risks. One developer's company has had to put up 10% of a project's expected payments in a "bid bond" prior to construction. As milestones are met, portions of the bond would be returned. This addresses construction risk. Operating risk can be handled through escrow accounts to cover times when his supply comes up short. The shorter the term of the contract, the smaller the escrow account can be. (Even under the ISO option, there probably needs to be reconsideration of credit policies.)

Do there need to be restrictions on sending attributes out of state? Worries about the creation of "artificial shortages." Is this a concern in the Central procurement approach? Can NYS control what "deliverability" requirements other states have with respect to NY projects in RPS programs? Does NYS want to limit potentially cost-reducing projects in other states from counting here? Is this consistent with the regional approach or deliberations in the "imports" subgroup? More thought is required

One contract feature: quantity. Would there be limits? What quantities would be purchased, 100%? Something less? Transferability?

ISO Approach

Some have said that the ISO approach provides as much (or more) financial assurance to the developer than a bilateral contract. Why?

With a bilateral contract, if the buyer defaults the developer must take the buyer to court and collect what he can. With the ISO, if one of the LSEs defaults, that's the ISO's problem. The developer still gets paid (the tariff requires it). Essentially, all LSEs pay whatever uplift is necessary, even if that "covers" the default of one of the LSEs. The FERC will not change this tariff lightly.

Individual Compliance

There is a spectrum: at one extreme the PSC could mandate detailed standardized contracts, at the other it could say nothing more than the utilities should act prudently. In between, are various degrees of guidance, for example the PSC could provide broad guidelines on types and features of acceptable contracts.

There were a number of discussions about siting and interconnection concerns with renewables. Also, the group discussed tracking credits and verification of renewable status and emissions. The approaches did not appear to relate to contracts.

Next Steps

Bill Short (Ridgewood Power) will circulate example contracts. It was hoped that this would help us to develop recommendations. The IOUs will consider what they can share about the quantities and durations of existing contracts.