

**North American Association of Issuing Bodies
Behind the Meter Subcommittee
Final Meeting Notes**

March 21, 2006 2:00 - 4:00 pm EDT

Telephone Participants:

- Sakis Asteriadis, APX/GIS
- Robert Burke, ISO NE
- Lynn Fountain (sitting in for Paul Belval) DBH/NEPOOL
- Roger Fujihara, D.C. Public Service Commission
- Jacqueline Geist, PJM EIS
- Paul Helgeson, WI PSC/M-RETS
- Rasa Keanini, CEC/WREGIS
- Joe Kerecman, PJM EIS
- Dan Lieberman, CRS
- Aleka Niedermier, CRS
- Jan Pepper, Clean Power Markets/NJSRECs
- Sam Swanson, Clean Power Markets/NJ SRECs
- Leslie Welsh, Environment Canada
- Meredith Wingate, CRS

Introduction:

Dan Lieberman began by giving a short summary of the last Behind the Meter Subcommittee call. The group continued discussion of the recommended common practices found in the document circulated, "Recommended Common Practices for Treatment of Behind-the-Meter (Customer-Sited Distributed Generation) Certificates," referred hereafter as "the document."

The goals of this call were to:

- Continue our discussion on recommended common practices for treatment of Behind the Meter (BTM) Certificates
- Establish group consensus on the issues and questions outlined in the issue document

For the rest of the meeting, the participants went through the text of the document starting with issue number two.

Recommended Common Practices

Issue 2: Verification of dynamic data; measuring output- meters versus engineering estimates

The conversation started with the general question of whether or not BTM generators needed to meter their output. Consensus emerged that BTM generators should be treated the same as all other generators and in general should be required to meter their output, but there was an acknowledgement among the group that very small generators should be exempted from this requirement at this time. The group agreed to include language indicating that it should be a goal that all BTM generators meter their output, recognizing that some on the call, were not in a position to commit their organization to upholding such a goal. Discussion ensued about whether it should be an open-ended goal, or if there should be some parameters set around when the goal should be realized. For example, it was suggested that maybe at a certain date it should be a requirement for all, or when metering equipment reaches a certain price point. In general, some people were uncomfortable with setting any parameters because of the uncertainty around the technology and pricing, and the goal was left open-ended.

The conversation shifted to the capacity level at which metering should be required. The group adopted the NJ SRECs Program's standard of 10kW and above as a cut off for the metering requirement, recognizing that participants on the call are unable to commit their organizations to making the changes necessary to meet this standard at this time. Under 10kW, generators would be able to estimate their output. There were some who were uncomfortable with estimates without any oversight, and it was felt that certificate buyers should be made aware of when the certificates are based on engineering estimates, and not actual meter readings. The group agreed that in instances when engineering estimates are used, there should be a field added that notifies the buyer of the certificate of the fact that the certificate is based on an engineering estimate and not metered output. Also, it was acknowledged that engineering estimates might be more acceptable if they were audited by a third party. NJ SRECs audits 10-20% of all generators under 10 kW in their system.

The group left as an outstanding issue the question of the quality of the engineering estimate, and to consider if 3rd party verification is needed in all cases when engineering estimates are done.

Issue 3: Reporting BTM output to the tracking system

There are three ways that generation data are reported to tracking system operators. The most common method is generation meter readings are telemetered to the utility or local system operator, settled per the local markets or utility settlement system, and reported to the tracking system operator. Because of the small size of these BTM facilities, most are under the radar of the system operators. In NEPOOL, generators over 5MW must be a part of the market settlement system. Those 5MW and below, can self-report. For CA ISO and PJM the minimum size is 1 MW. WREGIS also requires that any meter-readings that are self-reported must be verified by a qualified third party at least annually.

The group agreed that facilities over 5MW will be treated the same as non-BTM generators and will be required to telemeter their metering data to the control area operator or utility settlement system, or will use an independent third party to report their generation data to the tracking system operator. Sakis raised the issue that some states in New England may have facilities greater than 5MW that are BTM units and that this issue has not yet, been addressed in the GIS Rules so NEPOOL can't commit one way or the other.

The group discussed the use of disclosure, similar to issue #2, to report when a certificate is based on self-reported data. This issue was not resolved.

The group left outstanding the treatment of generators 5 MW or less. 5MW is a significant jump in scale from the other recommendations of 10kW and 1MW, and it was felt that we should try to go lower. It was also left unresolved under what circumstances self-reporting is allowed with no third party oversight, and whether disclosure be used to let buyers know that data was self-reported.

Issue 4: Reporting frequency-

It was decided that there was no need for a common recommended practice for the frequency with which BTM generators are required to report their data to the tracking system operator.

Issue 5: Denomination of Certificates:

There was very little discussion on this issue. All tracking systems issue certificates in 1 MWh denominations. PJM, WREGIS and M-RETS require generators to wait until they accrue a full MWh before issuing a certificate. GIS rounds up or down partial MWhs. It was agreed that BTM generators will be treated the same as all other generators in the tracking system with regards to the denomination of certificates, and accruing generation toward issuing a certificate.

Issue 6: Standards for Metering Equipment

The group discussed standards for metering equipment for BTM generators. We assume that any generator that goes through a utility or control area markets settlement process is using a meter that meets local standards. The group adopted the M-RETS language for BTM generators greater than or equal to 10kW, “that do not go through a control area settlements process, a revenue-quality meter is one that meets the applicable ANSI C-12 standard or applicable state standards.” The group did not address how generators less than 10 kW of nameplate capacity should be treated. Sakis stated that each ISO has its own standards; Joe mentioned that the states have final say regarding RPS standards. M-RETS language will work only to the extent it is consistent with the various states’ regulations and the ISOs’ regulations.

Issue 7: Where is the meter measured and how are losses accounted for?

All tracking systems currently issue certificates for gross generation from BTM generators. By gross generation, we mean generation not netted of load. Also such gross generation assumes there are no line losses since all or most generation is used on-site.

In Canada, certificates from gross generation from a BTM facility are not eligible for some federal programs. The group discussed whether or not it would be possible to remedy this problem through disclosure. First it was suggested that tracking systems to identify which certificates were associated with load consumed on-site or not, but this was found to be unworkable. Instead, it was recommended that there be a mechanism for certificate buyers to be able to identify when a certificate is associated with a BTM generator. It was agreed that this should be part of the static data of the certificate.

There was not time to discuss where should the meter be read or if there is a need for a separate BTM policy on this. It was suggested that we define the location of the meter is to be consistent with IEEE 1547 Series of Interconnection Standards.¹

Issue 8: Data Validity

Some tracking systems (WREGIS and M-RETS) automatically check that generation data fall within certain reasonable bounds for the facility. Others (PJM and NEPOOL) do not. The Subcommittee decided this was not a BTM specific issue.

Announcements About Upcoming Meetings:

The next BTM Subcommittee call was scheduled for Tuesday, April 4th from 12:00-2:00pm EST. It was subsequently changed to the regularly scheduled time, from 2-4 EST on April 4th. Aleka will send out materials for review prior to that call.

¹ Subsequent to the meeting, staff researched this issue and found that the Federal Energy Policy Act of 2005 requires electric utilities to interconnect distributed generation customers upon request. The Act requires that interconnection rules must conform to IEEE Standard 1547. State regulatory authorities must consider these standards by September 2006 and must complete them by September 2007. However, states that have already enacted interconnection standards, have conducted a proceeding to consider the standards, or in which the legislature has voted on the implementation of such standards do not have to meet these timelines.

