## Rosier, Michelle (PUC)

**From:** Brian Lydic <brian@irecusa.org>
**Sent:** Tuesday, June 05, 2018 4:37 PM
**To:** Rosier, Michelle (PUC)
**Subject:** RE: Reminder: Prep work and Slides due: 6/8 TSG meetings (16-521)

I'll just paste below:

Brian:

Enphase in Hawaii is the relevant example but is perhaps unique.
Based on HI experience I think most DER vendors do not have this capability today.
Enphase mainly and SolarCity did the heavy lifting in HI last time.

Once the technical requirements were finalized and all the legal issues were ironed out it took us a couple of days to push it out to approximately 800 k units.
We could do it faster but we staged it slowly over a couple of days on a weekend with our folks monitoring the fleet carefully as the updates went out.
We wanted to make sure there were no snafu's with the new settings causing unintended consequences (none found)
In theory we could release an update to all units and they would begin the update the next time they phoned home, i.e. within 15 minutes.
Some companies might have bandwidth limitations as well but this is not an issue at Enphase but then we have spent a lot of money developing scalable communication infrastructure.

BTW there is discussion over a new UL Standard for remote updating of firmware.
IMHO an essential element which is sorely needed.

DER types: Enphase PV inverters and we can do it to our storage products as well but have not needed to yet.

Costs: Yes, there are costs involved which will vary by manufacturer.
We did not have a good estimate then so we did it for free for HEI but could not do so for free again.
Also, recall this was a critically urgent situation required to create acceptable levels of system stability ASAP.
HEI estimated the savings from the remote update were circa $45-50 Million relative to truck rolls to do updates manually.
Our total costs would be a small fraction of this and the majority of the costs are not in the actual update.

Major costs normally come from:

- Development of new functionality / firmware /profile
- Internal validation of new functionality / firmware / profile (required by our ISO processes)
- Recertification of products / functionality / firmware with NRTL
- REPORTING OF COMPLIANCE – all caps because HEI / HPUC added this one after the fact and wanted monthly updates from HEI to comply with HPUC order. We had to run queries for this every month AND we changed the database in the middle of the process so the queries needed to be developed twice.
- Who is responsible for these costs ?
    - Products are sold as compliant at the time of interconnection.
    - Customers and equipment manufacturers are not required to provide forward compatibility for unknown future requirements in perpetuity.
    - HEI interconnection agreements stated customers have to do updates but HEI was responsible for paying for the upgrades

Other and, IMHO, more critical issues to consider in advance / update interconnection agreements to cover:

- Authority: does the AEPS operator have the authority to:
    - Make changes directly to third party owned equipment ?
    - Allow agents acting on behalf of the AEPSO to make changes directly to third party owned equipment ?
        - It is easiest / cheapest to have the third party making the changes (Enphase) to be an agent acting on behalf of the utility. HEI lawyers did not like this but it really is the best way (perhaps only way) to do this. Likely was an issue of urgency of the need rather than a specific legal problem, i.e. no time to develop the agency agreements.
        - If the third party (Enphase) is acting as the agent for the customer then we have to protect their interests over that of the utility and it gets really complicated particularly if the customer says no.
    - Compel third party owners to make changes and if yes, what is enforcement mechanism ?
        - This is what HEI has but politically it is unenforceable
- Ability: Can they make the changes directly even if they have authority to do so ?
    - Likely not.
    - IEEE 1547 requires some capability in this area but any unauthorized changes to our equipment could void the warranty and transfer liability for any damages to the utility. IMHO, a battle which has not yet come up but will in the future.
- Privacy: THIS IS CRITICAL.
    - Can the AEPSO release customer data to a third party ? i.e. how do we know which systems to update unless the AEPSO tells us. It may be a privacy violation to identify customers specifically.
        - Greatly simplified if the third party is an agent acting on behalf of the utility.
    - Can the company doing the update (Enphase) confirm the update has occurred to a specific customers without violating customer privacy ?
        - Answer is no unless they are an agent of the utility or if the customer has provided a limited privacy release
- Opt in versus opt out: (Insert the "I am not a lawyer" disclaimer here).
    - Customers need to be able to make informed decisions and give permission to update their systems.
    - This requires some form of pre-existing permission and if too broad will likely not stand a legal challenge.
    - If the change does not impact system performance OR degrade customer privacy then an Opt out permission might work
    - If the change can reduce system performance in any way (f/W, V/W, FPF, V/VAR or ramp rate limits are examples) then Opt in permission is likely needed.
    - Opt in also needed if the change degrades customer privacy in any way (this is why you have to click the check box on many web sites when you sign up and when they change their privacy policies)

I don't have a PPT on this (was lost on my computer when stolen in Montreal) but the above is a high level summary.

LMKIYHQ

BR, J

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**From:** Rosier, Michelle (PUC) <michelle.rosier@state.mn.us>
**Sent:** Tuesday, June 5, 2018 5:21 PM
**To:** Brian Lydic <brian@irecusa.org>
**Subject:** RE: Reminder: Prep work and Slides due: 6/8 TSG meetings (16-521)

Hi Brian:

The outlook attachment of the Enphase email is not opening properly. Do you want to try to reattach?

**Michelle Rosier**
Distributed Energy Resources Specialist | Economic Analysis

**Minnesota Public Utilities Commission**
121 7th Place E, Suite 350
Saint Paul, MN 55101-2147
O: 651-201-2212
mn.gov/puc



**From:** Brian Lydic <brian@irecusa.org>
**Sent:** Tuesday, June 05, 2018 4:08 PM
**To:** Rosier, Michelle (PUC) <michelle.rosier@state.mn.us>; Johnson, Pam (PUC) <pam.johnson@state.mn.us>
**Subject:** RE: Reminder: Prep work and Slides due: 6/8 TSG meetings (16-521)

On #3

**Please provide examples of the following if possible.**

a. Controlling voltage by reactive power control using constant power factor mode

*I don't have any specific data, but 0.95 pf was used as the default setting for interconnections compliant with Rule 14 in Hawaiian Electric territory from Jan 2016 - ~March 2018.*

b. Operations leveraging default settings for normal operating performance in Table 8 of IEEE 1547-2018 (page 39)

*I don't have any specific data, but the following volt-var settings, which vary a little from 1547 (in Q/voltage slope, deadband and time response), have been in use for interconnections compliant with Rule 14 in Hawaiian Electric territory from ~March 2018.*

| Volt-var Parameters | Default Value | Minimum Adjustable Range | Maximum Adjustable Range |
|---|---|---|---|
| $V_{Ref}$ | Nominal Voltage ($V_N$) (e.g. 120 volts) | 0.95 of $V_N$ | 1.05 of $V_N$ |
| $V_2$ | $V_{Ref}$ – 0.03 of $V_N$ | $V_{Ref}$ – 0.03 of $V_N$ | $V_{Ref}$ |
| $Q_2$ | 0 | 100% of nameplate reactive power capability, absorption(1) | 100% of nameplate reactive power capability, injection(1) |
| $V_3$ | $V_{Ref}$ + 0.03 of $V_N$ | $V_{Ref}$ | $V_{Ref}$ + 0.03 of $V_N$ |
| $Q_3$ | 0 | 100% of nameplate reactive power capability, absorption(1) | 100% of nameplate reactive power capability, injection(1) |
| $V_1$ | $V_{Ref}$ – 0.06 of $V_N$ | 0.82 of $V_N$ | V2 – 0.02 of $V_N$ |
| $Q_1$ | 44% of nameplate apparent power | 0 | 100% of nameplate reactive capability, injection(1) |
| $V_4$ | $V_{Ref}$ + 0.06 of $V_N$ | $V_3$ + 0.02 of $V_N$ | 1.18 of $V_N$ |
| $Q_4$ | 44% of nameplate apparent power | 100% of nameplate reactive capability, absorption(1) | 0 |
| Response Time | 10 seconds | 1 second | 90 seconds |

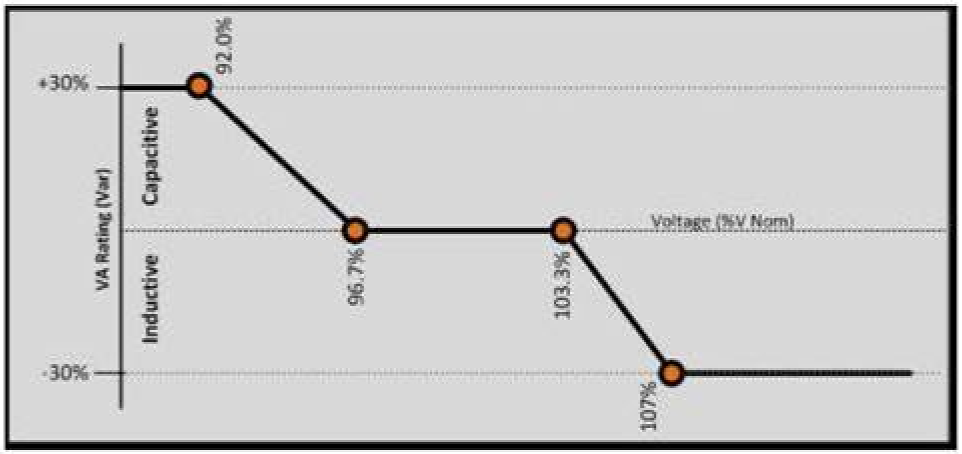
*I don't have any specific data, but the following volt-var settings, which vary from 1547 (voltage and Q setpoints in general), have been in use for interconnections compliant with the CA IOU's Rule 21 since Sept 2017. The default mode was changed from set power factor to volt-var before implementation of the new "Phase 1" smart inverter requirements. Note that this differs from HI and 1547 in that the DER is given "active power priority." The mode will be switched to "reactive power priority" in Feb 2019.*

Default Open Loop Response Time for volt/var operation should be five (5) seconds.

Table Hh-4: Voltage and Reactive Default Settings

| Voltage Setpoint | Voltage Value | Reactive Setpoint | Reactive Value | Operation |
|---|---|---|---|---|
| V1 | 92.0% | Q1 | 30% | Reactive Power Injection |
| V2 | 96.7% | Q2 | 0 | Unity Power Factor |
| V3 | 103.3% | Q3 | 0 | Unity Power Factor |
| V4 | 107.0% | Q4 | 30% | Reactive Power Absorption |

Figure Hh-1: Voltage and Reactive Default Settings




Please share any lessons learned.

*I'm unfortunately unaware of any data that's been gathered since implementation.*

c. Making updates to voltage and reactive power control settings
   How long did it take?
   What type of DER was involved?
   Where there any cost implications?
d. Making updates to voltage and active power control setting
   How long did it take?
   What type of DER was involved?
   Where there any cost implications?

*I don't have anything on c) or d) as I don't think it's been done before. The only thing close that comes to mind is Enphase's updating of trip settings in HI. Attached is John Berdner's account of that which can be shared. There certainly are cost implications, even if good comms channels are established. I'd expect those costs to decrease as comms/control becomes more standardized through 1547, but can't be ignored. One big question is what happens with different iterations of equipment. If IEEE 1547-2022 (for example) changes the way volt-var or other functions work, will there be any way to implement similar settings in older equipment. Can a firmware upgrade be done? Will a firmware upgrade be available? Does a manufacturer have a financial incentive to create that firmware? If not, is there a way to get "close" to the new settings? Installers that are asked to visit a site to change settings will want compensation.*

Best regards,
Brian

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**From:** Rosier, Michelle (PUC) <michelle.rosier@state.mn.us>
**Sent:** Monday, June 4, 2018 6:29 PM
**To:** Rosier, Michelle (PUC) <michelle.rosier@state.mn.us>
**Subject:** Reminder: Prep work and Slides due: 6/8 TSG meetings (16-521)

16-521 Phase II Technical Subgroup Members,

Reminder that the prep work (edits on the attached version of the Draft TIIR and slides) are due TODAY for the Friday, June 8th 9:30-12:30 CST: Technical Subgroup Meeting 3. Please copy me and pam.johnson@state.mn.us on prep work.

16-521 Phase II Technical Subgroup Web Meeting
Friday, June 8th
9:30 – 12:30pm CST
https://global.gotomeeting.com/join/432598661

You can also dial in using your phone.
United States: +1 (571) 317-3112

Access Code: 432-598-661

First GoToMeeting? Let's do a quick system check: https://link.gotomeeting.com/system-check

Thanks,

Michelle

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**From:** Rosier, Michelle (PUC)
**Sent:** Tuesday, May 29, 2018 11:56 AM
**To:** Rosier, Michelle (PUC) <michelle.rosier@state.mn.us>
**Subject:** 16-521 DGWG: Updated Agendas for 6/1 DGWG and 6/8 TSG meetings

All:

Congratulations and deep appreciation for all your work in bring Phase II before the Commission for consideration last Thursday! We're still in a bit of a sprint with two more meetings over the next two weeks:

1. Friday, June 1st Full DGWG In Person Meeting 9:30 – 2:30pm CST
    a. Review attached 16-521 Draft DGWG Mtg 6 Agenda 6-1-18 – updated

    b. Utilities – if you have slides for your implementation updates, please send ASAP to be incorporated into a slide deck.
2. Friday, June 8th 9:30-12:30 CST: Technical Subgroup Meeting 3
    a. Review attached 16-521 DGWG TSG Mtg 3 – Draft Agenda
    b. PREP WORK IS DUE: Monday, June 4th
        Including draft slides and edits to the Draft TIIR document (Draft TIIR Edits 4-11-18)

Michelle

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Distributed Energy Resources Specialist | Economic Analysis

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