# Heat Pump Discussion – VSPC Forecasting Subcommittee – August 2014

» Itron presented two scenarios for heat pump penetrations. The preliminary forecast is based on EIA's New England heat pump saturation forecast and is significantly lower than the GMP IRP base forecast. The GMP IRP base forecast was based on VEIC's DRP assumptions, and is consistent with their innovation center projection and shows that by 2034 over 25% of customers will have heat pumps. In the last meeting, the Committee expressed skepticism about the GMP ramp rate, and about impacts associated with different saturation levels.

## Questions:

1) **Heat Pump saturation:** Which forecast should be used by ITRON and why?

- EIA New England heat pump saturation forecast

OR

- GMP program-induced saturation forecast

2) **Heat Pump Summer MW forecast:** What growth rate should be forecast for system peak summer demand? From 2014 to 2024, there is barely an increase in summer peak MW under the GMP, EIA and no HP scenarios. Beginning in 2025 and through 2034, there is a noticeable increase in summer peak MW by as much as 75MW under the GMP scenario. Under the EIA forecast, ITRON shows a slight increase in growth rate for both the EIA and no HP scenarios.

**Responses from Shawn Enterline (GMP):**

**1)** GMP advocates for using the DRP heat pump saturation forecast for two reasons. First, heat pumps are the most cost effective HVAC technology on the market. Second, the forecast matches both the DRP and GMP's heat pump lease program expectations. Note that the forecast includes both program-induced and ordinary technology saturation. It is our understanding that the Itron forecast methodology only uses one saturation trend, and does not break out program-induced effects from the overall saturation trend.

**2)** Doesn't the answer to question #1 determine the result in question #2? To our knowledge, there is no other alternative within the Itron forecast methodology unless the VSPC wishes to depart from using the SAE method. Having said that, if there is a more accurate load shape that lowers the summer peak impacts, we would be open to using it.

**Response from Mike Russo (Itron):**

**2)** To clarify we are not departing from the SAE approach when we account for different heat pump saturation assumptions. That it, it is not an exogenous adjustment like the solar adjustment is. The standard SAE approach is still used; we simply adjust the saturation level which flows into the calculation of the heating and cooling intensities.

On the Maine heat pump study; TJ I understand how you arrive at a summer demand impact of around 15 MW given each unit increases demand by around 0.2KW. More formally, in the out years where heat pumps really take off, say 2030:

(342,098 VELCO Res. Custs) × 13.13% HP saturation = 44,917 units × (0.2 KW) = 9.0 MW impact

Using our model we arrive at a 19.2 MW impact in 2030 using the same saturation. The 0.2 KW impact per unit seems low. The study goes on to say that only 35% of the heat pumps were on during summer peak, this also seems very low. Our model assumes that if the technology is in place on the hottest days of the year it is likely being utilized. Given this assumption, the impact would be closer to 0.6 kW per customer (0.2 kW /.35). This would translate into a demand impact of 27 MW. The 19 MW seems about right – that would imply that 70% of the systems are on at peak (19/27).

**Q from TJ to Shawn:** Is there a point in the lease program, or via the IRP, where you determine that the impacts from heat pumps on summer peak are no longer a benefit to the system? That 50-75MW peak, if assumptions hold, would have a significant impact on the T&D system. That $100million project in central VT that was avoided by efficiency and net metering? Is it needed in this forecast? Do they remain cost effective in this instance? Also, the Rutland area subtransmission (?) constraint is only a gap of 3MW +/- . How do heat pumps change the equation? Planning for this scale of adoption, even if the bulk of the impact is in the second 10 years, without considering these impacts seems short-sighted. Do heat pumps remain economic when this investment needs to be made?

**Q from TJ to Hantz:** What is the possibility and cost of using both the EIA and GMP/DRP assumptions, and showing two different paths forward for the last 10 years?

**A from Hantz:** We can test another load scenario as part of the long range plan. There will be additional cost and time, but we will do the analysis.

One thought I would offer is that heat pumps are just one factor that can affect the load in a significant way. Some of us believe electric vehicles will take off during the study horizon. If they are right, EV could contribute to a high load scenario.

**A from Rip:** Both EVs and heat pumps will add to post-sundown loads that are emerging as the definitive peaks.

**Q from TJ to Eric:** Can you clarify is the peak below the 50/50 or 90/10?

**A from Eric:** The preliminary peak forecast is based on expected or 50% probability weather conditions.

**Q from TJ to Shawn:** To question #2 – Aren't we already departing from SAE methodology by treating heat pumps as an exogenous effect? There is no (or very little) load in the forecast associated with heat pumps, so we need to make an adjustment going forward based on penetration and unit intensity.

# Net Metering Discussion–VSPC Forecasting Subcommittee–August 2014

- » Itron's uses GMP's forecast and expecting to apply to the rest of Vermont.
- » Itron's rooftop solar forecast was based on GMP's solar customer and generation data through April 2014
    - Rooftop units are capped once community/group systems come online in a couple of years.
    - Community solar-based system forecast developed by GMP will close the gap to reach 15% cap by 2022. Additional solar load growth is limited by the rate of system peak demand growth.
- » Costs will continue to decline by 10%/year through 2022 (down to approx. $2/watt).

**Questions:**

1) **Rooftop units:** Should there be a cap to the number of rooftop units as community generation comes on line?

2) **Community system forecast**: Should Itron use GMP's community/group system forecast? If not, what should Itron use?

3) **Capacity Cap:** Should the capacity cap be determined by current solar capacity or by the solar demand impact? That is, solar capacity relative to peak impact.

**Responses from Shawn Enterline (GMP):**

1) GMP believes that rooftop penetration will level off as the economies of scale of group net metering undercuts the cost effectiveness of rooftop net metering. The market for net metering will naturally gravitate to group systems simply because they are so much more cost effective.

2) GMP's group net metering forecast represents about half of the total MW of known development activity (see slide 7 of the attached presentation.). We believe this is a reasonable estimate of the pace of group net metering based on our experience with siting and developing larger scale solar projects. The benefits of using this forecast are two-fold. It will require VELCO to plan for the 15% PV saturation within the 10-year planning horizon, plus the 15% cap is supported (and expected to some extent) by our policymakers in Montpelier.

3) GMP's interpretation of the 15% net metering cap is consistent with the way Itron is modeling. Once the 15% cap is reached, net metering is allowed to grow in tandem with the growth in peak demand such that 15% cap is maintained. This could lead to instances where net metering capacity may exceed the 15% cap based on actual loads vs weather normalized loads.

**Q from Nathaniel to Shawn and to entire group:**

Trying to reconcile the differences between the Itron slides and the GMP forecasts in your presentation; which of the GMP slides matches up with slide 30 in the Itron deck?

1. The polynomial fit based on FY 10 – 14 is impressive. I agree that it underestimates the growth, however a few cautionary points about modifying the forecast by over <u>250%</u>:
   a. There were no major policy changes between FY 10 -14. i.e. the solar adder was available, and there was no cap in GMP territory - the exception to this is that the ITC Cash Grant went away, which arguably slowed down development
   b. The primary changes have been declines system cost and availability of financing, however, isn't some those trends be embedded in the data?
2. I agree that the industry projections are compeling, however, they are "goals" and should be taken in context
   a. For example: SunCommon's FY 15 goal is 10 MW, 20+ projects – In order to meet this goal, they would need to have at least that number of interconnection applications and CPG applications either submitted or about to be submitted. The Interconnection queue on the GMP website is a few months old, but I don't see any 500 kW applications by SunCommon.
   b. GroSolar/GMP – (thought you were different companies?) With three interconnection requests between 13 and 14, it looks like Gro would almost need to double their pace to get to 20 projects by 2017. Again, the queue is old so maybe they are on track.
   c. Do you have a more updated interconnection queue that you could share with the group?
3. There are a few very big factors which will affect growth which I think we need to discuss:
   a. There is a limited supply of highly credit worthy customers for net metering. Most companies are targeting municipalities, schools, etc. for this reason. Once these are gone, there is a very limited supply of credit rated private companies in Vermont. Financing 20 year contracts with smaller companies with no credit rating becomes more and more difficult.
   b. There are a limited number of customers who can utilize all of the power generated from 500kW systems (do you know how many in GMP territory?), developers will have to contract multiple people to form a group. Most developers will tell you that getting people to sign a 20 year PPA is the primary limiting factor. More than one customer per project will certainly slow growth.
   c. For projects installed after 2016, the Investment Tax Credit will decrease from 30% to 10%, unless the law is changed. This will have a significant impact on project economics.
4. Lastly, I am curious what your thoughts are about the physical constraints for that much net metering. You show 362 applications with only 194 substations. Certainly some of those substations/feeders are in areas that are too steep or too shaded for solar development, meaning that we will tend to see projects clustered in more suitable areas. This will undoubtedly have an impact on the availability of interconnections to those clustered feeders.