HINGHAM MUNICIPAL LIGHTING PLANT

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Board Members

Laura Burns, Chair
Michael Reive, Vice-Chair
Tyler Herrald, Secretary

REGULAR MEETING
HINGHAM MUNICIPAL LIGHT BOARD

October 3, 2023
Zoom Meeting
https://us02web.zoom.us/j/81299502421

Meeting Called to Order

A regular meeting of the Board of Commissioners of the Hingham Municipal Light Plant (HMLP) was called to order by the Board's Chair, Laura Burns, at approximately 7:30 am on Tuesday, October 3, 2023, via Zoom.

Present:

Board Members:	Laura Burns, Chair Michael Reive, Vice Chair Tyler Herrald, Secretary
HMLP:	Thomas Morahan, General Manager Mark Fahey, Asst. General Manager Joan Griffin - Business Manager Stephen Girardi, Engineer Ellen McElroy, Customer Service Brianna Bennett, Sustainability Coordinator
Guests:	Mark Beauchamp - Utility Financial Services Mike Johnson - Utility Financial Services

Ms. Burns read the following disclaimer into the record:

This meeting is being held remotely as an alternative means of public access pursuant to Chapter 107 of the Act of 2022 and all other applicable laws temporarily amending certain provisions of the Open Meeting Law. You are hereby advised that this meeting and all communications during this meeting may be recorded by the Hingham Municipal Light Plant in accordance with the Open Meeting Law. If any participant wishes to record this meeting, please notify the chair at the start of the meeting in accordance with M.G.L. c. 30A, § 20(f) so that the chair may inform all other participants of said recording.

Utility Financial Services (UFS) Rate Study
Ms. Burns had sent a list of questions to Utility Financial Services to get a better understanding of several items.

Mr. Beauchamp stated that he did do a quick feasibility on HMLP going to AMI. Mr. Morahan added that this feasibility was requested so that he could get an idea of how much Hingham could save by going with a Time of Use (TOU). Mr. Beauchamp stated that the total community could save over 15 years approximately $7.8 million.
Assumptions made:

- 2 to 1 price differential between "On Peak" and "Off Peak" so assume a 6-12% reduction immediately. Some reduction will shift to "off peak" and some will just go away.
- Fixed charge would have to increase by $3.
- Average Residential Usage of 856.77 kWh
- 8,700 residential meters
- Increasing EVs
- Winter "Off Peak" and "On Peak"
- Summer "Off Peak" and "On Peak"
- $300 installation cost per meter

Total Savings over 15 years	$7,800,000
Assumed Cost of Residential	$2,630,500
Other Cost, Software & Billing System	$ 657,875
Total	$3,289,375
Life of Meter	15 years
Interest Rate	0.05
Annual Payment	$316,906 (over 15 years)

Mr. Morahan stated that HMLP was assuming a cost of $3 million (without labor) to install AMI. Mrs. Burns asked if Mr. Beauchamp could share the spreadsheet being discussed so that the Board could have a closer review.

Terms:
Tier Difference is the difference in price between "On Peak" and "Off Peak."

Response is the estimate of how people will respond to the peak rates by moving their usage. Assumption that winter response is approximately 6.8% and summer response is approximately 11%. Based on that information, three-quarters of peak usage will shift to "off peak" and one-quarter will go away.

Winter Value and ***Summer Value*** these are the savings, measured in cents, on kilowatt hour on any reduction from "On Peak."

Season	Energy	Trans & Capacity	Savings
Summer	0.0358	0.1834	0.22
Winter	0.0054	0.0633	.07

Mr Reive questioned the "Average Residential Usage" of 856.77 kWh as it is higher than what he thought. Mr. Beauchamp explained that the usage was based on test data from 2022.
Mr. Herald expressed his gratitude for this information as it will be very helpful to make an informed decision.

Questions submitted by Mrs. Burns (red=Mr. Beauchamp response, blue = Mrs. Burns understanding)
TOU rates:

1. **Customer Charge: according to the presentation, this is the part of the distribution system that is to be covered by the customer charge.**

   Portion of distribution system
   - **Cost to get a wire from the sub-transmission system to customer.**
   - **Based on minimum sizing (If all customers only use a single kWh)**

   Where does this wire begin? At the transformer? Not clear on what is meant by "sub-transmission system"

This allocation of wire begins at the substation and ends at the distribution transformer. Sub transmission system is the higher voltage distribution that some systems have (69kV). We've updated the slide to reflect that this is just the distribution system.

Distribution is charged in two ways: distribution from the substation to the distribution transformer is reflected in the customer charge. This is calculated based on minimum sizing (If all customers only used a single kWh).
Distribution from the transformer to the meter is reflected in the separate distribution charge. This is based on customer peak demand, whenever it occurs (from solar question 1)

Mr. Beauchamp clarified that distribution from the substation to the home is anything related to the meter and is included in the Customer Charge

- Cost to repair or replace the meter
- Reading of the meter
- Billing the meter
- Cost of the service drop.

These 4 items are all minimum size requirements

Mr. Beauchamp then develops a ratio between what it would cost to replace the system at the minimum sizing requirement and that percentage gets rolled into the Customer Charge. Keep in mind that customers use more than the minimum so that amount will reflect the usage component. He stated that ideally you would oversize from the substation to the home and that cost would be recovered through a demand charge; however, it is mainly captured in the residential kilowatt hour usage charge. He said that the distribution system is designed to handle a customer's peak demand and so that portion from the substation to the facility, that excess charge, should be recovered in demand. Mrs. Burns confirmed that the four fixed items listed above are recovered through the "On Peak" energy charges because they are sized for the system peaks, not the customer peaks.

Mr. Beauchamp explained that most customers understand TOU better than demand but this can be revisited in the future.

2. **Do I have it right that HMLP's labor cost, other than administrative labor, is included in the distribution costs for purposes of cost allocation?** Yes **Also, capital equipment?** Capital equipment is not included in distribution cost. Depreciation of capital equipment and a rate of return to cover inflationary costs to place equipment are included in distribution costs.

   Capital equipment is reflected in the customer charge.

Mr. Beauchamp stated that labor costs and capital equipment are both reflected in the customer charge. He reiterated that minimum sizing requirements go into the customer charge. Mr. Beauchamp said that by using assets it creates stability in the rates over time so that you don't have fluctuations. Mrs. Burns brought up the fact that HMLP has a large transmission project coming up that is causing an increase in the rates for the next 3 years so perhaps TOU would allow us to lower those rates.

3. **Apart from the distribution costs covered in the customer charge, is all the rest of the distribution spread evenly over all the times in the TOU chart?** Yes. **If that's not the case, then exactly how are distribution costs recouped in the TOU scheme?**

Mr. Beauchamp stated that the distribution costs are recovered through "On Peak" energy rates or demand charges.

4. **Suggested time for winter peak rate begins at 6 AM and goes until 8 PM. Is it so long because we actually sometimes hit transmission peaks as early as 6 AM?** I don't know where the 6 AM comes from, winter on-peak is modelled as 8A8P. **What is the actual distribution of our transmission peaks over the last three years, for example?** Peaks for transmission 2021-2022 are provided at the end of this document (see below).

Transmission Peaks

Peak Date	Transmission Peak Hour	HMLP CP	Peak Date	Transmission Peak Hour	HMLP CP
1/29/2021	18	32.32	1/11/2022	18	32.93
2/1/2021	18	31.12	2/14/2022	19	28.83
3/2/2021	19	30.29	3/1/2022	19	25.1
4/16/2021	18	23.92	4/6/2022	12	23.25
5/26/2021	18	38.11	5/22/2022	18	42.13
6/30/2021	18	55.02	6/26/2022	18	38.561
7/16/2021	16	49.63	7/21/2022	16	53.57
8/26/2021	16	52.98	8/8/2022	16	54.57
9/15/2021	17	38.4	9/4/2022	18	34.1
10/14/2021	18	23.11			
11/29/2021	18	26.56			
12/20/2021	18	28.664			

5. **On the weekend rates, why would the winter weekend rate be marginally higher than the summer rate?** The off-peak rate is higher in winter as average market energy prices during the off-peak time period are higher.

6. **If we are trying to assign costs to those who incur them, why would weekend rates be different from weekday rates?** I think the graphic is causing confusion. On and Off peak are defined by hours. Exceptions to these hours are weekends and identified holiday are off-peak. **Do transmission peaks only happen during the weekdays as a general rule? Do capacity peaks never happen on the weekend? Would it make sense to have no weekend rate so as to simply the rates, or would that result in serious inequities? If we used a peak rate during the weekend, it would allow us to lower the overall peak rate somewhat.** Transmission peaks: in a 120-month period 6 transmission peaks have occurred at the weekend. We can discuss including weekends in on-peak hours.

   If on- and off-peak were the same every day, with no weekend and holiday exceptions, that would have two advantages. It would lower the overall peak hour rate and make it easier for the customer to remember. The disadvantage is that it is a less accurate representation of when costs occur.

Mrs. Griffin reminded Mrs. Burns that currently our systems cannot differentiate between weekends and holidays. Mrs. Griffin cautioned that she does not think we will be able to do this on the data management side. In addition, another system that Mrs. Griffin has recently viewed does not have this ability either. Mr. Beauchamp responded that the meters are just going to provide data into the meter data management system and then the meter data management system will summarize it for the billing system; however, the HMLP meter data management system "will need help" which may be upgrades or changes.
Mr. Herrald stated that he is in support of a weekend structure as it is important for families to have a break at the weekend to catch up on tasks, such as laundry.

7. **The proposed peak rate, which is intended to reimburse for capacity, starts at 1 PM, and runs for at least four hours during the time when capacity peaks do not occur. Is the long period intended to smooth out the large bump in price that would occur is the peak rate was only from 5 to 7 PM, when our capacity peaks actually occur? Or what?** We typically put a 1- or 2-hour buffer on either side to avoid "chasing the peak" which lowers the On-peak rate September 2021 peak was 15:00 (3PM)

   In 2021, solar arrays were likely to be generating well at the 3 PM capacity peak. A peak day is unlikely to be cloudy.

Mr. Girardi stated that the software package that we have can adjust for weekdays, weeknights, weekends, and holidays but we cannot do it with our current meters.

Solar credit:

1. **When I asked why it would not make sense to simply key the solar credit to the TOU rate, the answer was that in general solar arrays are not producing when the capacity peak happens. But to some degree, solar arrays do generate between 5 and 7 pm in the summer. Why would we not reimburse solar generators for the amount that they do cut our capacity charge?** Your statement is correct we would need to back out the distribution costs in the kWh rate, so the distribution rate would be a flat rate (demand) and power supply and transmission energy would be time of use rates listed.

Mr. Beauchamp stated that they looked at 20-30 years of solar data to calculate how much solar produces at different hours of the day and then he coincided it with Hingham's peak hours and energy rate to identify the solar offset. We need to understand that solar capacity is not a one-to-one relationship, it is closer to a one-to-four relationship. We need to think about it from the substation back to the power generators. Your system data has identified the savings, so the issue becomes from the substation to the customer. The size based on the customer's peak and what happens with solar is that it may provide substantial value on the back end and we quantify that but if they peak at 7:00 or 8:00 pm then we need to make sure that when we calculate the credit that we back out the distribution rate from that customer so they do not get credit for when they are not really benefiting us from the substation to the home.

Mrs. Burns would appreciate it if UFS would provide all of the relevant solar spreadsheets to the Board so that they can further their understanding.

Mr. Morahan asked Mr. Beauchamp how HMLP can account for the shift in the peak when we are adding more batteries and more electrification. Mr. Morahan also asked how HMLP goes about adjusting the TOU times to hit that changing peak. Mr. Beauchamp states that in the next few years, as more systems change the peak, then we have to adjust the hours. Mr. Morahan then questioned whether the 15-year analysis of savings with TOU that UFS has provided will still be accurate when the peak has changed, and Mr. Beauchamp stated in the affirmative.

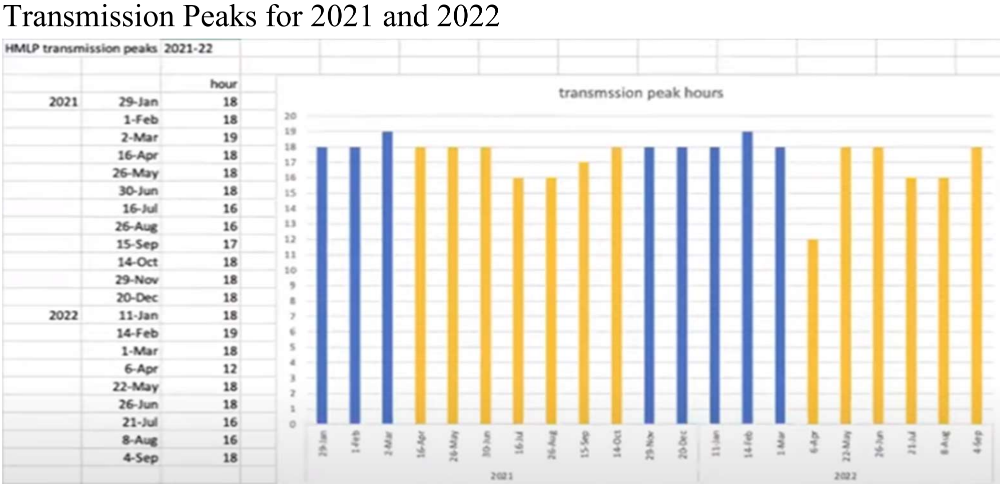
Mrs. Burns wanted to explain her understanding of why the distribution charge should not play into the solar credit.

> She stated that if a solar generator generates 1 kWh and it goes back to the grid and to their neighbor's house, when it reaches the neighbor's house, they pay a distribution charge on that kilowatt hour to HMLP. She stated that then that distribution charge should not positively or negatively affect the solar credit as it is a cost paid by someone else.

Mr. Beauchamp stated this was correct but said that you must be careful with a "buy all sell all" or a value of solar tariff. You must be careful not to overcharge the solar customer, and there is an analysis that we do to ensure this does not happen. Mr. Herrald stated his understanding that the municipal utility owns and maintains all the infrastructure to provide the service to the ratepayers. Each ratepayer, whether buying or selling to the grid, needs to pay for that capability so that it is fair for all. Mr. Beauchamp stated that Mr. Herrald's comment is "exactly right." Mr. Beauchamp stated that what makes it difficult is that residential meters do not capture demand, on a kilowatt hour basis. The cost that we are trying to recover is not reflected in the kilowatt hour rate because it does not reflect demand. Demand is the only thing that reflects the actual cost. Mr. Beauchamp stated that it is very complex because different residential customers create more peak than others and more demand. UFS tries to account for these wide variations so that they recover the appropriate amount from each customer. If you just spread the demand equally across all customers, then you are going to create subsidies for high use customers by low use customers to UFS attempts to get as close to reality as possible. Mr. Herrald how it would be calculated for a customer that has no load, just a solar array. The solar array only sells to the grid. What is the calculation? Is it the absolute value of the peak amount of power that they sell to the grid and then that goes into their demand charge for them to pay for the ability to access and sell

to the grid? Mr. Beauchamp reiterated that this is another level of complexity which would be IPP (independent power producers). IPPs primary goal is to produce energy and sell it into the system. As a utility we cannot count and include solar generation in our capacity requirements, nor can we schedule it. Even if that solar generator hits our peak, we cannot schedule it and we do not know if it is going to be there, so you must pay the transmission cost for it. Mr. Beauchamp stated that is why we only credit larger arrays for energy, but the smaller arrays get both a capacity value and an energy value. Mrs. Burns questioned why the credit is different for rays larger than 20 kWh. Mr. Beauchamp stated that we can make the credits the same; however, you need to be careful. He cautioned that if ISO New England changes things and we need to adjust the credit, which changes the economics for the generator, so as a utility you may have to grandfather customers or create a temporary subsidy. Regarding large commercial companies that could potentially put a solar array on their roof, Mr. Beauchamp is not concerned at all because they would have a demand charge and a TOU rate so it would automatically self-adjust. It comes down to having accurate rate structures which allow you to recover your costs.
Mrs. Burns asked Mr. Girardi how many larger (over 20 kWh) arrays we currently have in Hingham. Mr. Girardi stated that we currently have five (5). Mr. Beauchamp said that those large arrays use "behind the meter" so it is not transported back. If that is the case, then there is very little credit ever given so as long as we have a demand charge set then we will recover our distribution charges. Mrs. Burns questioned if UFS factors in the demand charge for the generation as well as the consumption. Mr. Beauchamp stated that the demand charge is usually off your regular rate tariff and ideally the demand charge would just be distribution so the TOU rate will reflect the recovery capacity for everything else. So the wire from the substation to the facility with the large array is still going to create a peak at some point that is going to recover that cost for that wire. The usage of "on peak" and "off peak" charges will recover any energy that is provided to them when the solar array is not producing enough. Mrs. Burns questioned the accuracy of the demand charge and Mr. Beauchamp responded that distribution demand is accurate, but transmission and power capacity is not necessarily accurate. The transmission and power capacity need to be recovered through the "on peak" energy. As an example, Mr. Beauchamp stated that even if a commercial customer peaks at 2:00 AM, HMLP still must have a properly sized transformer.

Transmission Peaks for 2021 and 2022



HMLP transmission peaks 2021-22

		hour
2021	29-Jan	18
	1-Feb	18
	2-Mar	19
	16-Apr	18
	26-May	18
	30-Jun	18
	16-Jul	16
	26-Aug	16
	15-Sep	17
	14-Oct	18
	29-Nov	18
	20-Dec	18
2022	11-Jan	18
	14-Feb	19
	1-Mar	18
	6-Apr	12
	22-May	18
	26-Jun	18
	21-Jul	16
	8-Aug	16
	4-Sep	18

Yellow= daylight savings hours

For example, during Daylight Savings hours in April 2021 and 2022, the peak was 4pm and solar is still generating during those peak hours.

Mrs. Burns asked that UFS send their solar spreadsheets to HMLP and the Board so that the team would be able to understand the peaks and perhaps email UFS back with any questions.

Mr. Johnson and Mr. Beauchamp shared a solar kilowatt production spreadsheet that shows the amount that the solar is producing at different hours when the transmission peaks. The spreadsheet summarizes the dollar value that solar is providing. The three-year average is $0.077 and five-year average is $0.071. Mrs. Burns questioned whether UFS includes energy cost and PCA or just the energy cost? Mr. Beauchamp answered that UFS does not use our rates but rather the market value of the energy. Market rate is the hourly market prices but keep in mind that most of Hingham's energy is on contract. You are either buying from the market or you are avoiding the cost from the market by using contracts. Mr. Herrald questioned whether the market prices are wholesale day ahead prices or real time. Mr. Johnson responded that the figures are day-ahead prices. Mrs. Griffin asked Mr. Beauchamp what figure HMLP should be using for our solar credits; 3-year at $0.077 or 5-year at $0.071? Mr. Beauchamp stated that he does prefer the rolling average for stability purposes. Both the 3 and 5-year rates were part of the rate study provided to HMLP.

Mrs. Griffin asked for clarification on what rate should be charged to people who produce greater than 20 kWh and then less than 20 kWh. Is UFS saying that it does not matter because the people that are greater than 20 kWh are not selling anything back anyway? Mr. Beauchamp stated that HMLP does have some producers and they would still get the $0.077 or $0.073 (should be $0.071) but he is a little concerned that because UFS must identify how much HMLP is using on the day ahead market, we cannot rely on that. He reiterated that using the $0.077 or $0.071 is fine because that is the value of everything being in a perfect world. Mrs. Burns stated that the big power producers (two big arrays in Hingham) are on a PPA. Mr. Beauchamp said that if the PPA is $0.03 or $0.04 per kWh, then HMLP is making money off the array, if it is $0.10 per kWh then it is costing HMLP money. Mrs. Burns questioned whether HMLP could require that large producers do business with us via a PPA so that everyone would understand their investment. Mr. Beauchamp likes Mrs. Burns' suggestion because the purple laws that came out in 2021 were intended for the utilities to provide some stability to the independent power producers and if you do a PPA they have that assured source of revenue which makes it easier for financing. Mr. Morahan clarified that the PPA would be for those arrays that are in front of the meter.

Mrs. Burns said that for potential residential solar generators they have the same problem with the model because if their rate is based on the market, it varies which makes it hard for them to evaluate their investment. She questioned whether a solar credit, for a fixed amount for the first ten years, would be feasible so that the customer could evaluate their investment better and it might encourage renewables. Mr. Beauchamp brought up the risk factor. He said that if you commit to a specific price, you are taking the risk away from the customer and absorbing it. Mr. Beauchamp stated that when solar started ten years ago, he did not have an issue with subsidizing it as we needed to get it started, but he recognized that at some point, this is going to have to change, and that time is now. Mrs. Burns asked whether offering a solar customer the choice to either sign up for the market rate or sign up for a steady rate, where HMLP assumes the risk and receives a risk premium, may be an option. Mr. Beauchamp stated that he does not think it would be complicated for the billing system because the rate would be driven by a code to apply the credit. He cautioned that the complexity is ensuring that the customer understands the risk and the cost associated with the risk. Mr. Reive asked if consideration could be made for taking the dollars out of net metering and just net meter by kilowatt hours. A customer produces each month and on a rolling average over a 12-month period it is just the balance of use versus produced. The kilowatt hours would calibrate out the high production months against the lower production months with the goal of coming out at zero over the year. Mr. Beauchamp reiterated that during several high production months a subsidy would be created and again, when solar first started that was fine, but now we have more of an issue because we do not recover the distribution cost. Mr. Reive proposed that if a customer does not use all of the kilowatt hours over the year, then they lose them. Mr. Beauchamp said that proposal would be good from the standpoint of right-sizing the system. Mr. Reive wants to encourage the average customer with 856 kWh to size a solar system that would allow them, without a huge heating load, to meet their usage with solar panels. Mr. Reive claims that people in the town are discouraged because of the current rate system. He would like to see HMLP fill the capacity and if there is too large an increase, then customers can be placed into a que. Mr. Beauchamp stated that Mr. Reives' idea of net metering, which most utilities have moved away from. Instead, you could consider implementing TOU rates that vary the credit. For instance, if the customer produces in the on-peak window then there are energy and capacity components that can result in a credit based on what they give back to us. Mr. Reive stated that he is not looking to encourage people to develop west-facing roof arrays so they produce in the later parts of the day, instead he would like to adopt as much solar as feasible and economically possible. He explained that the customer gripe is that they may not use what they produce at the exact time but their neighbor does and pays the distribution price, so when they have to buy that kilowatt hour back it is at full retail from HMLP. Mr. Herrald cautioned that energy prices vary drastically with the time value so if you produce an hour ten and you consume an hour fifteen, it is not the same thing. Mr. Reive stated that he understood Mr. Herrald's point. Mrs. Burns asked if under the system that Mr. Reive described, would HMLP "under recover" for distribution? What piece of distribution are we not recovering under net metering? Mr. Beauchamp explained that there are several things but the primary one is the cost of the distribution wires between the substation and the facility itself. In addition, when a residential home tends to peak at 7:00 pm, solar may not be that substantial at that time so it is not a "1 to 1" relationship. As shown in the data earlier in the meeting, it is more like a "0.2 to 1" or a "0.6 to 1" ratio but you are giving them a "1 to 1" when they are only offsetting 0.2 so a subsidy can occur. Mr. Beauchamp gave the example of California where they have moved away from true net metering to better reflect cost recovery. There is so much solar in California being added and produced that now there is a "duck curb" where at 4:30 pm the solar production starts to diminish because people are getting home and using electricity. This results in the afternoon hours not being off-peak but instead are now peak. When the usage ramps up, California was dramatically under recovering from solar customers. That is why California has moved to net billing, "buy all/sell all" methodologies and/or tweaking TOU rates. Mr. Beauchamp asked Mr. Reive if they could take the discussion offline due to time constraints.

Vote on MOU For Transfer of Land for new Sub-Station

This vote has been moved to the next Board Meeting.

Motion to adjourn the meeting.

Mr. Reive: “Aye”
Mr. Herrald: “Aye”
Ms. Burns: “Aye”

Meeting adjourned at 8:56 am