

STATE OF VERMONT
PUBLIC UTILITY COMMISSION

CASE NO. 17-5219-INV

IN RE: PUBLIC FORUM ON THE SHEFFIELD-
HIGHGATE EXPORT INTERFACE

January 11, 2018
1:30 p.m.

109 State Street
Montpelier, Vermont

Workshop held before the Vermont Public
Utility Commission, at the Pavilion Building Auditorium,
109 State Street, Montpelier, Vermont, on January 11,
2018, beginning at 1:30 p.m.

P R E S E N T

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Sarah Hofmann
Margaret Cheney

STAFF: John C. Gerhard, Staff Attorney
Andrea McHugh, Utilities Analyst
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3 Chris Root, VELCO
David Blittersdorf, AllEarth and Dairy Aire Wind
4 Jason Pew, VELCO
Hantz Presume, VELCO
5 Doug Smith, GMP
Ed McNamara, DPS
6 Deena Frankel, VELCO
Jeremy Hoff, Stowe Electric
7 Dave Kresock, Stowe Electric
Ellen Burt, Stowe Electric
8 Charlotte Ancel, GMP
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9 Patty Richards, WEC
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10 Tom Flynn, Aegis Renewable Energy
Karin McNeill, ANR
11 Billy Coster, ANR
Mark Sciarrotta, VELCO
12 Molly Connors, ISO New England
Vickie Brown, VEC
13 Peter Rossi, VEC
Amber Widmayer, MMR
14 Shana Louiselle, VELCO
Andrea Cohen, VEC
15 Olivia Campbell-Anderson, REV
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Dan Potter, DPS
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Steve Garwood, Consultant
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Katie Pohl, Agency of Agriculture
19 Anne Margolis, DPS
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21 Ryan Darlow, VERA
Nick Charyk, VERA
22 Kamran Hassan, GMP

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1 PARTICIPANTS CONTINUED:

- 2 Josh Castonguay, GMP
- 3 Geoff Commons, DPS
- 4 Josh Leckey, DRM
- 5 Sash Lewis, Dunkiel Saunders
- 6 David Carpenter, Facey Goss
- 7 Sam Carlson, Green Lantern Group
- 8 Sarah Wolfe, VPIRG
- 9 Gregg Freeman, Aegis Renewable Energy
- 10 Derek Moretz, Encore

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1 CHAIRMAN ROISMAN: Good afternoon.
2 Thank you all for coming out. This is a
3 workshop in Case Number 17-5219-INV, the
4 Public Utility Commission's investigation
5 into transmission system restraints
6 identified in northern Vermont.

7 My name is Tony Roisman, Chair of the
8 Public Utility Commission, and with me today
9 are my fellow commissioners, Margaret Cheney
10 on my right, and Sarah Hofmann on my left,
11 and our staff who is sitting here in the
12 chairs. And I don't know if there is --
13 there may be some out in the audience as
14 well keeping an eye on us.

15 Transmission system constraints
16 identified in northern Vermont demarcating
17 the Sheffield-Highgate Export Interface,
18 we'll call it SHEI today if you like, are
19 increasingly limiting the amount of
20 generation that can operate simultaneously
21 in the area. The commission believes that
22 it would be productive to gather current
23 relevant information on these transmission
24 system limitations, including any possible
25 impact on the state's renewable energy

1 policy requirements and goals.

2 The commission is beginning the process
3 by conducting today's informational
4 workshop. Commission's aware of several
5 pending cases addressing siting new
6 renewable generation cases within the SHEI
7 area. Due to the pending and contested
8 nature of those proceedings, participants
9 who are presenting today should not venture
10 into the specific factual issues that are
11 the subject of ongoing litigation.

12 We expect that this will not be a
13 limitation on presenters' ability to present
14 technical information concerning the nature
15 of the SHEI limitations, how it affects
16 utilities in general and the solutions that
17 are being considered. The commission trusts
18 that presenters and their attorneys will
19 ensure that today's discussion will not
20 venture in the specific factual issues
21 pertaining to current proceedings. However,
22 I have also appointed Tom Knauer as our
23 Sergeant at Arms. And he will raise his
24 hand as an indication to a presenter that
25 they may be addressing inappropriate

1 material, change course back to the purpose
2 of this workshop which is not the subject of
3 pending litigation. There will be no
4 physical impacts on those of you who stray
5 inadvertently.

6 MR. GIBBONS: Thank God.

7 CHAIRMAN ROISMAN: We would like to get
8 notices of appearance, and I know there are
9 a lot of you, and there is a sign-up sheet
10 that's going around. But I think it would
11 still be helpful if we could have everyone
12 of you just identify yourself and your
13 organization. And we will start on the
14 first row of people.

15 MR. GIBBONS: James Gibbons. I'm
16 director of policy and planning representing
17 both Burlington Electric Department and
18 Vermont Public Power Supply Authority.

19 MR. ZIMMERMAN: I'm John Zimmerman. I'm
20 here from Vermont Renewables.

21 MR. ROOT: Chris Root from VELCO.

22 MR. BLITTERSDORF: David Blittersdorf,
23 AllEarth Renewables and Dairy Aire Wind.

24 MR. PEW: Jason Pew, VELCO.

25 MR. PRESUME: Hantz Presume, VELCO.

1 MR. SMITH: Doug Smith, power supply
2 director, GMP.

3 MR. McNAMARA: Ed McNamara, Department
4 of Public Service.

5 MS. FRANKEL: Deena Frankel, VELCO.

6 MR. HOFF: Jeremy Hoff, outside counsel
7 for Stowe Electric.

8 MR. KRESOCK; Dave Kresock, Stowe
9 Electric. K-R-E-S-O-C-K.

10 MS. BURT: Ellen Burt, general manager,
11 Stowe Electric.

12 MS. ANCEL: Charlotte Ancel, Green
13 Mountain Power.

14 MR. GERHARD: John Gerhard, commission
15 staff.

16 MS. McHUGH: Andrea McHugh, commission
17 staff.

18 MARK TREMBLAY: Mark Tremblay, HQUS.

19 MS. RICHARDS: Patty Richards,
20 Washington Electric Co-op.

21 MR. KIENY: Craig Kieny, Vermont
22 Electric Co-op.

23 MR. FLYNN: Tom Flynn, COO, Aegis
24 Renewable Energy.

25 MS. McNEILL: Karin McNeill, Agency of

1 Natural Resources.

2 MR. COSTER: Billy Coster, Agency of
3 Natural Resources.

4 MR. SCIARROTTA: Mark Sciarrotta,
5 VELCO.

6 MS. CONNORS: Molly Connors, ISO New
7 England.

8 MS. BROWN: Vickie Brown, Vermont
9 Electric Co-op.

10 MR. ROSSI: Peter Rossi, COO of Vermont
11 Electric.

12 MS. WIDMAYER: Amber Widmayer, MMR.

13 MS. LOUISELLE: Shana Louiselle,
14 VELCO.

15 MS. COHEN: Andrea Cohen, Vermont
16 Electric Cooperative.

17 MS. CAMPBELL-ANDERSON: Olivia
18 Campbell-Anderson, Renewable Energy Vermont.

19 MS. ZIMET: Timnah Zimet, Renewable
20 Energy Vermont. T-I-M-N-A-H. Z-I-M-E-T.

21 MS. LEVINE: Sandra Levine,
22 Conservation Law Foundation.

23 MR. POTTER: Dan Potter, Public Service
24 Department.

25 MR. WESTMAN: David Westman, Efficiency

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Vermont.

MR. GARWOOD: Steve Garwood, consultant to New Hampshire transmission.

MR. POLHAMUS: Mike Polhamus, Vermont Digger.

MS. POHL: Katie Pohl, Agency of Agriculture.

MS. MARGOLIS: Anne Margolis, Department of Public Service.

MR. LYLE: Tom Lyle, Burlington Electric.

MS. BAILEY: Melissa Bailey, Vermont Public Power Supply Authority.

MS. STASKUS: Martha Staskus, VERA Renewables.

MR. DARLOW: Ryan Darlow, VERA Renewables.

MR. CHARYK: Nick Charyk, VERA Renewables.

MR. HASSAN: Kamran Hassan, Green Mountain Power.

MR. CASTONGUAY: Josh Castonguay, Green Mountain Power.

MR. COMMONS: Geoff Commons, Public Service Department.

1 MR. MARREN: Jake Marren, commission
2 staff.

3 MR. LECKEY: Josh Leckey, Downs Rachlin
4 Martin.

5 MR. LEWIS: Sash Lewis from Dunkiel
6 Saunders.

7 MS. KROLEWSKI: Mary Jo Krolewski,
8 commission staff.

9 MR. YOUNG: George Young with the
10 commission.

11 MR. WATTS: Dave Watts, commission
12 staff.

13 MR. KNAUER: Tom Knauer with the
14 commission.

15 MS. BISHOP: Ann Bishop, commission
16 staff.

17 CHAIRMAN ROISMAN: Well with that much
18 talent, we should be able to solve this
19 problem when this is over. Thank you all
20 very much.

21 The agenda includes and starts with a
22 presentation from VELCO followed by remarks
23 from GMP and BED. And participants are
24 encouraged to ask questions during and
25 following presentations. So whoever is

1 presenting from VELCO would like -- do you
2 want to speak from up there? Okay.
3 Hopefully your mic is more alert than mine.

4 MR. ROOT: Yeah. Seems to be working
5 quite well. I would like to thank the
6 commission for the opportunity to talk a
7 little bit about this issue, and hopefully
8 to educate the people in the room about the
9 situation in northern Vermont.

10 My name is Chris Root. I'm the Chief
11 Operating Officer at VELCO. I'm an
12 engineer. I'll do my best not to do
13 engineer speak, although this is a technical
14 issue, but so if anybody has any questions
15 as I go through that, please don't be afraid
16 to raise your hand, get my attention. I
17 would be more than happy to clarify, ask
18 questions or any of those type things.

19 So, why is this a topic? Why are we
20 here today? Right. So northern Vermont, as
21 many of you know, over the centuries that
22 farming has been a big part of northern
23 Vermont. The electric system there was
24 originally designed to supply a number of
25 dairy farms. It was a relatively modest

1 transmission system. And that was -- and
2 there wasn't a lot of load. There is not a
3 lot of people that live there, it's very
4 sparsely populated. Ideal place to put our
5 generation possibly, and that's what we have
6 seen in the last couple years is that the
7 generation in this northern area has grown
8 quite a bit.

9 Now there have been some transmission
10 upgrades which I'll talk about in a minute,
11 and I'll show a little map of that. That
12 describes some of the improvements that have
13 been made up there. But fundamentally we
14 had a situation that the transmission was
15 all designed to supply a small number of
16 people and farms in this northern area, a
17 few resorts and ski areas.

18 Okay. Now we start putting a lot of
19 renewables in this particular area. Now the
20 renewable generation is greater than what
21 the load is, so now we are exporting it out
22 of that area. So we engineers hate when
23 things get used in a different way than they
24 were designed; they all get nervous. So
25 what happens here is we are using the system

1 that is designed for one purpose for a
2 different purpose.

3 We are supposed to import power into
4 the area. Now we are using it to export
5 power, and that has created some
6 limitations, so as part of the limitations
7 that's what we are going to talk about.
8 Those limitations have consequences that
9 impact people and generation.

10 So this particular export limit came
11 about in 2013. Although it really has
12 become a financial issue in the last year or
13 so. It was put in place to recognize that
14 with certain times of the year when you are
15 exporting out of this area, it could become
16 a reliability problem for northern Vermont.
17 And ISO New England's task is to keep the
18 lights on in northern Vermont, and they are
19 going to make sure the lights stay on in
20 northern Vermont so when situations start
21 occurring that could happen, that the lights
22 go out in northern Vermont, they are going
23 to say, time out. We are not going to let
24 that happen. So now we are going to put a
25 bunch of rules in play that say that when

1 you get to that point, stop. We are going
2 to do something different. When they say
3 stop, do something different, that's now one
4 of the big issues that we are talking about
5 now because there is consequences to that.

6 Now in engineering terms, what they are
7 trying to do in northern Vermont is they are
8 trying to keep the lights on. And there is
9 two types of things that eventually could
10 turn the lights out. One is something
11 called the voltage collapse. And that's
12 what happens when you have a big, widespread
13 outage. The voltage goes down so far it
14 can't recover, and you have big blackout;
15 bad thing. Right. So we do calculations to
16 see if that could occur. On the next chart
17 I'll show you a little bit how that can
18 happen.

19 Then also there is a situation called
20 thermal, which is you have wires of a
21 certain size, and if you put too many amps
22 down them, they get too hot and they burn
23 out. So there's a limit there. You have a
24 voltage collapse limit, which is a
25 calculated limit, and you have a thermal

1 limit. And we have both in this particular
2 geographical area. Doesn't always happen to
3 have both. We have both here. Those are
4 the issues -- two issues that happen there.

5 They do calculations, and ISO is the
6 one who is responsible, and they tell VELCO
7 or directly to generators to change what's
8 going on so we can't get ourselves in
9 trouble. Okay.

10 The other thing is this limit. So
11 isn't one number. It changes every day. So
12 I've got to talk a little bit about that in
13 the next slide.

14 MR. GIBBONS: Is it okay for questions
15 before he advances the slide?

16 CHAIRMAN ROISMAN: Sure.

17 MR. GIBBONS: Just a clarifying
18 question perhaps. You're talking about ISO
19 New England is sending signals to reduce
20 generation to keep the lights on. Isn't it
21 true that in point of fact they are sending
22 signals to reduce the generation so that if
23 something happened to the transmission
24 system, the lights wouldn't go out?

25 MR. ROOT: Correct.

1 MR. GIBBONS: It's not that the
2 generator operating at that level itself
3 would cause the problem. There could be a
4 problem with something else happening.

5 MR. ROOT: James is right. By
6 regulation ISO has to plan for the next
7 contingency. So what they have done is if
8 something happens, if a line trips out, a
9 generator trips out somewhere else, the next
10 contingency would put -- would exceed these
11 limits, so as a result you have to take
12 action before that could happen.

13 MR. GIBBONS: Thank you.

14 MR. ROOT: So it is anticipation of
15 another -- the next thing happening. And by
16 the way, you have to do that by regulation.
17 That's not optional. Yes.

18 MR. GERHARD: John Gerhard from the
19 commission. Is there a size limit on the
20 generator that ISO can control that they can
21 call and say, hey, you have to back off?

22 MR. ROOT: Yeah. We will talk about
23 that a little bit further on. But basically
24 it's about -- the visibility is dropped to
25 about five megawatts definitely. And above

1 they actually have control over. It depends
2 whether they are in the market or not. So
3 yes. That plays into this quite a bit.

4 So I will -- we will try to address
5 this. And I know I think, Doug, will you
6 address some of that issue on the market
7 side?

8 MR. SMITH: A little bit, yeah.

9 MR. ROOT: So the GMP people will do
10 that. I'm trying to do it from a
11 transmission grid point of view. But there
12 is a whole market component to that.

13 MR. GIBBONS: I will be as well.

14 MR. ROOT: Several other people will
15 address that point. The last point here,
16 ISO New England is kind of in this position
17 that they say, okay, if something happens,
18 it's going to be a problem. Now we have to
19 figure out how we don't export as much out
20 of this area.

21 So one of the things they implemented
22 last year is this do-not-exceed regulations
23 that basically says, okay, we are going to
24 look at some criteria which I'll go over
25 later on that says, hey, we are getting to

1 that point. We are going to have to stop
2 certain generation from generating from that
3 area. So what they use is generation. They
4 limit how much generation a particular unit
5 can put out. And there is a way -- and I'll
6 talk about what they do. But they directly
7 say to the generator unit, you can't
8 generate more than this amount.

9 Now if it's a wind farm, and they could
10 have more wind to do it, they are not
11 allowed to, to save reliability. That has
12 to do a little bit with the type of
13 interconnection they have. There is
14 different types of interconnections that you
15 can contract for, and the ones typically
16 that are being affected here don't have that
17 full interconnection. Okay.

18 CHAIRMAN ROISMAN: Can you just explain
19 a little bit how the Vermont utilities
20 participate in the decision making by ISO
21 New England? What the set points are, what
22 the priorities are. In other words, how
23 much are you able to influence the decisions
24 that ISO makes on these matters?

25 MR. ROOT: So VELCO and the utilities

1 -- basically the list of rules that came out
2 here, we have to live with what they come
3 out with. It's not a negotiation. We are
4 not allowed to negotiate it. So they set
5 what the numbers are, and we have formulas
6 that we are not allowed to share, but that
7 we are -- that drive this.

8 And Mr. Chairman, if you let me go
9 through a few slides of this thing it may
10 become more apparent, the question that
11 you're raising. I may be just answering it.
12 If not, I'll make sure I answer it if I
13 don't cover it in my slides, okay?

14 Just to let you know this presentation
15 is on the Vermont System Planning
16 Committee's website now. It will be on the
17 ePUC website this afternoon. So this will
18 be something that the public will be able to
19 get ahold of.

20 All right. So this is the northern
21 Vermont. The black lines are the
22 transmission lines in northern Vermont that
23 VELCO controls. The blue lines are
24 subtransmission lines. A small line -- the
25 big one that's B20 is an important line, and

1 that's a GMP line that goes from basically
2 Irasburg, and it heads down towards Johnson,
3 Vermont.

4 One -- a couple points I want to make
5 about this is that northern Vermont is a
6 loop, okay? And it comes over here from
7 Littleton, New Hampshire. Goes up towards
8 Newport. Goes across to Highgate, comes
9 down to Burlington; right? So it's one line
10 really. So what happens if that line is
11 opened up? For example, if there is a
12 problem with the line here, and it opens up,
13 any generation that is in this area is
14 trying to get where? To Burlington.

15 A third of all the energy consumption
16 in Vermont is in the Burlington area which
17 is right over here. You can see there is no
18 good lines that go this way. There is a
19 smaller line here, but it's trying to go a
20 hundred miles to get from where it is to
21 Burlington. And that's -- if this voltage
22 collapses, the generation is too far away
23 from Burlington. There is not enough umph
24 to get there. That's a technical term umph.
25 But what happens -- voltage collapse. And

1 when that scenario happens, you can black
2 out the entire northern part of Vermont. So
3 that is why that limit is set on voltage,
4 because you're trying to get the generation
5 in this northern thing over to Burlington.
6 It doesn't work. And then it goes out. So
7 that's a simplistic thing.

8 And then the other part about it is the
9 thermal limit. The blue numbers here are
10 the lines that VELCO -- our line designation
11 -- the name of the line. So over there K42
12 is a line that goes from Highgate down to
13 St. Albans. That line right there is the
14 thermal limit. A relatively small wire put
15 in many, many years ago, and that is the
16 limit that even if you fix the voltage
17 problem, you're going to run into there is
18 only so many amps you can put down that
19 piece of wire. Which can be -- potentially
20 is the next issue. They are pretty close in
21 those two limits. Yes, James.

22 MR. GIBBONS: Just a point again of
23 clarification.

24 MS. HOFMANN: Can you speak up a little
25 bit?

1 MR. GIBBONS: James Gibbons, Burlington
2 Electric. When you talk about getting the
3 load to Burlington, I would rather he -- I'm
4 concerned about that connotation.

5 Burlington's average load is about 45
6 megawatts. There is hundreds of megawatts
7 of generation in this area. So it's not --

8 MR. ROOT: Okay. Chittenden County.
9 It's really Chittenden County. I'm sorry.
10 Right. Burlington is not Chittenden County.
11 I'm sorry. So you're right. Greater
12 Burlington area, I'll call it that, is where
13 most of the load is in Chittenden County.

14 Okay. So that is the phenomena we are
15 talking about, that circle is the limit. So
16 what they do is they measure how much is
17 coming towards New Hampshire or down to St.
18 Johnsbury. They measure how much is coming
19 from St. Albans down into the Chittenden
20 County area. And there is a connection to
21 Montreal there. I mean to Hydro Quebec. So
22 that's it. They look at that and say how
23 much generation is inside here? And how
24 much is trying to get out.

25 And so when you look at all the

1 additional generation that's in here, you
2 subtract how much is load, how much are the
3 people using there, and that number which is
4 trying to get out has a limit. Once you get
5 to that limit, then something's got to
6 change. And that's the simple explanation
7 of what SHEI limit is.

8 Okay. Yes David.

9 MR. BLITTERSDORF: What about the B20
10 line? Do they measure that?

11 MR. ROOT: B20 line is measured by
12 VELCO. And if the B20 line is in service
13 working the way it's supposed to, that has
14 an impact on the SHEI limit?

15 MR. BLITTERSDORF: Yes, it does have an
16 impact on it.

17 MR. ROOT: All right. So a little bit
18 more of the math of what goes on here. So
19 the total load in northern Vermont is
20 between 20 and 60 megawatts. That's not
21 much. The amount of generation in that
22 area, if it can never do what I'm going to
23 say, the maximum amount -- if every hydro
24 plant was running maximum, the wind was
25 blowing maximum, the sun was shining

1 beautifully, you add them all up, it's over
2 400 megawatts. So if you go back 25 years
3 ago, that may have been a hundred megawatts
4 of generation in 20 and 60 megawatts with
5 the load. The load hasn't changed much in
6 northern Vermont, but the generation
7 certainly has skyrocketed, and that's the
8 crux of our issue. Right? And I just gave
9 you some numbers where they are coming from.

10 Our worst case scenario is typically in
11 the wintertime. So we do have hydro in the
12 springtime. It's really bad because the
13 hydro is all running and you can't store the
14 hydro water. It's going to run-of-river.
15 It's not controllable, so that's very high.
16 That goes up and down every single day
17 depending on rain and snow melt and
18 everything else, so that actually squeezes
19 out some of the generation that's out there.

20 As solar continues to be developed up
21 there, those solar plants are not ones that
22 can be --

23 MR. GIBBONS: Dispatched.

24 MR. ROOT: -- dispatched, are not part
25 of the market necessarily on a day-to-day

1 basis, so as a result this problem keeps
2 getting worse as you keep adding more PV up
3 there.

4 The 430 goes up every single time
5 another PV thing goes up. They are making
6 the problem worse. All right. So what
7 happens? So ISO does its studies on a
8 regular basis, you know, every hour, and
9 they look at it, and go oh oh. The export
10 limit's going to get hit here. We have to
11 do something. So what do they do? So they
12 can't do anything more on transmission
13 lines. So basically what they say is, we
14 are not going to let the system be at risk
15 for reliability. We are going to curtail
16 generation.

17 In this particular case, they make a
18 decision based on a couple of things. So
19 the curtailment priority is based on the
20 price that was offered to the market, so
21 these are market generators which most of
22 that 400 megawatts isn't market -- in the
23 market. Right? So what's behind the
24 meters, the solar's not dispatchable, some
25 of the hydro is behind the meter. So the

1 issue is we have just a few plants that we
2 can actually control. Just a few big
3 plants. And they said -- they look at first
4 what was the price they offered into the
5 market. What was their -- you know, we are
6 going to turn off the most expensive one
7 first. Number one.

8 Number two, distribution factor, which
9 is how effective it's going to be. If it's
10 not in the right place, it's not going to
11 help me as much, so there is a factor they
12 use to say who's the most effective
13 generator for me to control. And then this
14 last one, dispatch range, it just says that
15 certain generation can be run at different
16 levels and some generation has one number.
17 So for example a nuclear plant only has one
18 speed. Full output. You can't reduce it.
19 So certain generators tell ISO we only have
20 one speed. We only have one number, that's
21 it.

22 And other ones have ranges. So they
23 are looking at if there is a range, we could
24 curtail some of the people on the range. So
25 they do this. They do it through their

1 magic on this, and then they decide who is
2 going to get limited. And they send a
3 signal directly to that generating unit and
4 say do not exceed this megawatt number.

5 Now this curtailment priority system
6 came into a place a little over a year ago.
7 I would say maybe almost two years ago. So
8 this may have exasperated some things that
9 were going on before, so in many cases
10 multiple generators were curtailed, and now
11 it typically ends up being just one
12 generator gets curtailed. So I'm setting up
13 Doug to talk and James about some of the
14 impacts there.

15 I think I already talked about most of
16 this stuff. It's a calculation, the
17 computer, the computer sends a signal to the
18 generators directly. So I guess you can't
19 -- none of the behind-the-meter stuff
20 counts. So I think this slide pretty much
21 I've already mentioned. All right.

22 MS. HOFMANN: Chris, if you could go
23 back one though, I did have one question.
24 Which is the third bullet Windham Hydro LNP
25 following institution of a do not exceed.

1 How does that work?

2 MR. ROOT: If you guys want to -- we
3 will get into market stuff. So I know Doug
4 -- will you talk about this in your
5 presentation or do you want to just answer
6 it?

7 MR. SMITH: My sense is it would be
8 best -- I do plan to hit that.

9 MS. HOFMANN: Okay.

10 MR. SMITH: My guess is if I tee it up,
11 you'll either be satisfied or in a good
12 position to follow up. That would be my
13 suggestion.

14 MS. HOFMANN: Okay.

15 MR. SMITH: But I do plan to speak
16 about that change in the market structure.

17 MS. HOFMANN: Thank you.

18 MR. ROOT: I knew that was coming. So
19 --

20 MS. HOFMANN: Okay.

21 MR. ROOT: All right. So ISO New
22 England. And ISO New England has paid for a
23 billion dollars worth of upgrades into
24 Vermont. Okay. We did a lot of
25 transmission upgrades over the last 10, 12

1 years. It's our, you know, it's a regional
2 system and all that. So they are saying --
3 and they will pay for certain things.
4 Certain criteria that they pay for that
5 Vermont ends up paying four percent of the
6 project and we get a return on all that.

7 So but on this case they are saying
8 this limit and the impacts to the Vermont
9 customers does not meet the criteria of an
10 upgrade for reliability purposes. They said
11 it's not reliability. We just turn off the
12 generation. We don't need a big solution.
13 If from their perspective -- in other words,
14 the rest of New England is not going to bail
15 out Vermont for this problem, basically to
16 be blunt about it; right? So we have an
17 issue there. There may be some other ways
18 around the door, the back door to try to
19 figure it out, but it's very -- those are
20 much more complicated and risky.

21 So the problem -- they are saying, hey,
22 we are just going to turn it off. So VELCO
23 with the DU's, and we have started a
24 discussion of saying, hey, how can we fix
25 this? It does affect customers, it affects

1 customers of Vermont. How can we figure a
2 way to fix this problem? So we have done
3 several studies in Vermont looking at how
4 can we solve this problem without spending a
5 hundred million dollars to solve it.

6 So we looked at some modest upgrades to
7 the transmission system and some other
8 things that maybe we could tweak a few
9 things, spend some small amount of money and
10 help us. And that is true. And I'll talk a
11 little bit about where the status of those
12 studies are in a minute, but the problem is
13 that, that's okay. We can get 20 or 30
14 megawatts more on the SHEI limit and up it.
15 And then 120 megawatt PV plant gets built up
16 there and that's the end of that.

17 So we are trying to figure out we can
18 do some short-term stuff, but what's the
19 long-term solution. So we have long-term
20 solution which is probably a bigger
21 solution, some short-term things that we can
22 do in the next year or so that have some
23 benefit, but probably don't allow you to
24 meet the state's long-term goals. I'll say
25 it that way. Okay. And I will talk a

1 little bit more about the upgrades in this
2 study.

3 CHAIRMAN ROISMAN: Let me ask you one
4 question about the solutions question.

5 MR. ROOT: Yeah.

6 CHAIRMAN ROISMAN: We spoke with some
7 legislators yesterday, and they were
8 pressing us on the issue of dealing with
9 this by increasing load in the area. Would
10 that be -- if the load went up by, I mean
11 now, I probably said it's 20 to 60. Let's
12 say it went up to a hundred. Would that be
13 a solution?

14 MR. ROOT: Absolutely. Why don't we
15 put a city right like -- that would be
16 great. You're right. No. Absolutely.
17 More electric load in that area helps this
18 thing. Every megawatt you put in there
19 subtracts from the export.

20 MR. GIBBONS: Point of clarification on
21 that. I would disagree with that statement.
22 Megawatts of load that occur at times where
23 we have curtailment problems help.
24 Megawatthour of load in the middle of July
25 is actually a cost causer for us. It's

1 adding transmission and capacity costs. So
2 to simply say add load, fix, unless you have
3 a load that looks like the curtailments,
4 it's not as simple as that. And I'm going
5 to speak to that too, but I want to be very
6 clear on that point I think.

7 MR. ROOT: Thank you, James. It does
8 help on the curtailment issue during the
9 curtailment time, but there is other costs
10 which it triggers which James is saying the
11 rest of the year Vermont pays into the
12 regional thing based on how much our load is
13 every month. So the rest of the time you
14 may be paying more even though you can solve
15 this problem. So it is a complicated thing.
16 Thank you, James, for that clarification.

17 So we started this discussion this
18 summer about trying to figure out how to do
19 it, and one of the things we wanted to do as
20 a transmission utility, so we walk a fine
21 line between -- since we have all these
22 federal regulations about non-preferential
23 transmissions access, making sure that
24 nobody has insider information who is a
25 market participant, and the fact that the

1 Vermont utilities, in most cases, all own
2 generation that have some market component,
3 we have to be very careful that we don't
4 tell somebody one thing that we haven't told
5 somebody else.

6 And I think we have tried really hard
7 to try to be open about everything that we
8 are doing, and then this is just a list of
9 the studies, and you can get downloads of
10 stuff that we have gone out and shared with
11 everybody what's going on at the same time.
12 The idea is try to make sure everybody knows
13 so, whether you're a developer or a
14 generator owner, that the distribution
15 companies don't have a leg up or insider
16 information. We are trying to tell
17 everybody everything at the same time and
18 trying to do that open.

19 We have used the Vermont System
20 Planning Committee in many ways as our
21 avenue to speak to everybody, all the
22 stakeholders. So we did a study. We hired
23 a company called EIG to do a study that
24 looked at options, what can we do to help
25 fix this problem as terms of the curtailment

1 problem, and they came up with 17 options
2 and 45 combinations of 17 different projects
3 I'll call them; right? Everything from more
4 -- so some battery storage solutions which
5 potentially could help. Although we did a
6 study a year and-a-half ago that we couldn't
7 actually build a battery big enough to store
8 all the curtailed wind, so that was kind of
9 the -- economics didn't work on that.

10 But there were other things that we can
11 do to help out on the storage side. So we
12 looked at storage. We looked at rebuilding
13 that B20 line. We looked at transmission
14 solutions. On the voltage side there is
15 some things we can do with some power
16 electronics as well as some of the -- one of
17 the hydro plants that had an upgrade to its
18 voltage regulator. That could help on the
19 voltage side.

20 So we looked at all -- a long, long
21 list of things, and I won't bore you to show
22 you this chart to all of the solutions out
23 there. But it is on the website. The EIG
24 solution is out there. So if somebody wants
25 to get into the engineering details, it is

1 available as a public document. We made it
2 a public document.

3 So we looked at all these different
4 things. Where we are right now is pricing
5 every one of them out right now. What is
6 the cost of every one of these solutions.
7 Some of them are distribution solutions.
8 Some are storage solutions. Some are
9 transmission solutions. So my sense is in
10 the next probably by March 1 we will have
11 all the numbers, and then what we are not
12 sure about is how do we decide which one to
13 do. I actually don't know the answer to
14 that. Yes.

15 MS. BISHOP: Could part of the solution
16 be working with ISO on whatever formula it
17 uses to calculate the constraint? I mean
18 I'm assuming there is some assumptions that
19 go into that that -- I mean are those
20 assumptions things that reasonable
21 professionals disagree about? Or is this
22 really truly a very engineering-based thing
23 that there is one number that is right and
24 that's it?

25 MR. ROOT: It does change every day.

1 Like if there is a transmission outage line.
2 So they have this calculation they do to
3 determine whether it's an issue. And that's
4 not a public formula, so can't do it. I
5 mean if somebody really wanted to go in and
6 argue with them on it, I don't think it
7 would make that much difference.

8 There are probably a couple things that
9 might be a little controversial. This isn't
10 going to go away. You could do it and do a
11 little bit more, it's not going to go away.

12 MR. ZIMMERMAN: John Zimmerman. You
13 have mentioned though you showed that the
14 imports from Hydro-Quebec are the biggest
15 contributor to the generation problem here.
16 How flexible are we in telling them to
17 throttle that back and solve the problem for
18 us?

19 MR. ROOT: So Hydro-Quebec line is the
20 one that goes into Highgate. That's about
21 200 megawatts. 220 megawatts. That's a big
22 part of the import or the export because it
23 comes in and then goes out. So that is a
24 big part of it; you're right, and a major
25 part of it.

1 The contracts are on that line, and
2 there is market rules about how that gets
3 imported. So it's really a market issue
4 whether Hydro-Quebec -- I don't understand
5 how that actually works as to how that comes
6 in. So and that runs pretty much all the
7 time under contract.

8 MR. ZIMMERMAN: But in theory if you
9 told them to throttle that back, it's
10 probably does not exist.

11 MR. ROOT: You could throttle it back
12 to zero and it would solve all the problems.
13 But somebody has a contract to bring that
14 power down. So James.

15 MR. GIBBONS: We have actually -- to
16 answer your question, we have attempted to
17 start those discussions, but it is a little
18 tricky. That is a -- now you're dealing
19 with another company in another country
20 importing power under ISO market rules. But
21 yes, we are trying to have those discussions
22 as well.

23 MR. ROOT: And we have had those
24 discussions with Hydro-Quebec. Exactly. I
25 went to Montreal and we actually had that

1 discussion with their executives, and they
2 would be more than happy to throttle back.
3 It's just financial. It's complicated. And
4 you know, you're breaking contracts, and who
5 is going to pay for the breaking them, and
6 there is penalties and all that stuff. If
7 somebody is willing to pay them not to
8 generate, they may be willing to do that.
9 It's a money thing in my mind.

10 MR. GIBBONS: If this will give you any
11 tiny comfort, they did ask to increase the
12 import rating for the Highgate converter.
13 We said no, not until we can talk to you
14 about how you're using what you've got now.
15 We are trying to get these discussions
16 going.

17 MS. HOFMANN: Craig?

18 MR. KIENY: Yes, thank you. With
19 respect to the question about working with
20 ISO New England, the utilities, the market,
21 the people at the utilities in the markets
22 have met with ISO New England to try to get
23 more information. It's been very hard to
24 get information. Much of it is
25 confidential. So we have tried. Haven't

1 gotten there yet. Possibly the engineers
2 have in other meetings. But --

3 MR. ROOT: No. The calculation can't
4 go outside of the small group of the
5 operating side by regulation. And ISO
6 information rules do not allow to have that
7 discussion. Sorry.

8 CHAIRMAN ROISMAN: Question back there.

9 MR. GARWOOD: Steve Garwood. Is there
10 a reason why this wouldn't trigger the ISO
11 New England's new tariff revisions for
12 cluster studies if there is more than one
13 generator still in the queue? Being
14 evaluated for interconnection?

15 MR. ROOT: Well they are really
16 connected, so there is not --

17 MR. GARWOOD: Are there any pending in
18 the queue that aren't connected?

19 MR. ROOT: There is two 20 megawatt
20 solar plants in the queue, I believe still
21 in the queue today. I'll let Hantz Presume,
22 the manager of transmission planning, answer
23 that question.

24 MR. PRESUME: You're right, Steve.
25 There is several units, two 20 megawatt

1 solar plants, proposed to connect. And
2 there are wind plants also proposed. Having
3 three units, I think you could say that ISO
4 could study it as a cluster.

5 MR. GARWOOD: Seems like it would be a
6 natural candidate for it. Sounds very
7 similar to the issue they designed that for
8 in Maine.

9 MR. PRESUME: Yeah, in Maine.

10 MR. ROOT: They haven't started those
11 studies yet, I don't believe, on the solar
12 plants yet. And we met with them, and we
13 are pretty negative on the idea of adding
14 solar -- large solar plants into this
15 geographic area because of the potential
16 impact it would have on generation, but I
17 can't stop necessarily that process.

18 But point is well made, Steve. Yes.

19 MR. MORETZ: Derek Moretz with Encore.
20 You mentioned it's a money issue. The
21 constraint is based on the economic and
22 contracted imports. I'm curious where those
23 economic impacts meshes with the system
24 stability criteria that many of us look at
25 when proposing new projects. It may not be

1 a question for you, but others. I'm curious
2 where the economic impacts meet the system
3 stability which many of us think about from
4 a technical perspective.

5 MR. ROOT: So the technical limits get
6 hit or get hit, and then the market rules
7 decide who gets curtailed. So that's the
8 point I'm trying to make. So I'm not sure I
9 understand what you're saying.

10 So every time we add something else, if
11 it does, you know, those rules apply who
12 gets curtailed and gets impacted which has a
13 financial impact on them. So and it depends
14 on those three criteria I said how they
15 decide. If they are in the market and they
16 are dispatchable.

17 So James, is that okay? All right.
18 You can come back to that after, and I'd
19 wait. When a couple other speakers come, I
20 think some of your questions may get
21 answered.

22 CHAIRMAN ROISMAN: You have one more
23 question back on the left. All the way
24 back.

25 MS. POHL: This is just probably going

1 back to basics, but can you briefly describe
2 how surplus generation affects cost to
3 Vermonters? So I'm just confused on the
4 follow through of that most recent point.

5 So my question is just with over
6 surplus generation, how does that affect --

7 MR. ROOT: So Katie, so there is a
8 macro surplus that's required to operate the
9 system. So for example, typically the
10 largest contingencies is the -- it's not the
11 line that goes through Vermont, but it
12 doesn't stay -- it's phase two Hydro-Quebec
13 line which may be 1,500 megawatts carried
14 every single day. If that line were to be
15 lost, it would trip off. You would have to
16 have enough generation within New England to
17 be able to compensate for that so there
18 isn't a blackout.

19 It's a whole list of rules that do
20 that. So that typically I'll just pick a
21 number, maybe about 20 percent roughly, of
22 -- and when I say it's surplus, it's
23 available generation to instantaneously pick
24 up the loss of a generator. If Seabrook
25 were to trip off, that would be 1,100

1 megawatts. Do you have enough available
2 generation from the rest of the generators
3 in New England to pick up that loss in a
4 very fast manner?

5 So that is almost an independent
6 question from what we have here. Because
7 this is one isolated pocket that happens
8 here. But you can't get the power out of
9 it. So that's the issue. So I think they
10 are two different questions. Doug.

11 MR. SMITH: I was just going to
12 volunteer, Doug Smith, GMP, that I'll talk a
13 little bit from a dollar perspective of if
14 there is an interface and it gets
15 constrained, how does that affect Green
16 Mountain Power and our customers in terms of
17 like quantities of energy and dollars. So
18 I'll shed some light, and we can come back
19 to it.

20 MS. POHL: Perfect.

21 CHAIRMAN ROISMAN: James.

22 MR. GIBBONS: I want to make an
23 interesting point here, I think, which is
24 that this is complicated. It crosses
25 transmission, it crosses market boundaries,

1 it crosses tariff boundaries. So you're
2 seeing a transmission person right now
3 talking, he's getting asked market
4 questions. If I'm up there and he asked me
5 what's an AVR, I'm going to gape a little
6 bit and not be able to answer it. He'll be
7 reaching his hand up in the audience helping
8 me out. I think you're seeing here this is
9 a transmission, markets, tariff, you know,
10 everything issue.

11 MR. ROOT: And that's why it's not a
12 simple formula way to solve the problem;
13 right? If it was just pure reliability, we
14 have mechanisms, we can go to ISO and try to
15 figure out, come back to the commission with
16 the proposed project. This one is --
17 doesn't fit the normal process, so we are
18 all struggling with who takes the lead, who
19 pays, and we don't know yet. So we are all
20 trying to figure it all out right now.

21 In our plan hopefully we will come up
22 with some kind of ultimately a solution.
23 And my next slide talks about that, that we
24 can hopefully bring to you eventually some
25 kind of solution to the problem and not just

1 dump a problem on your laps. That isn't the
2 plan right now.

3 CHAIRMAN ROISMAN: Patty, did you have
4 a question?

5 MS. RICHARDS: Yeah. Getting to the
6 question in terms of what is the impact to
7 the Vermonters, at the end of the day Doug
8 is going to present something relative to
9 GMP, but I want to point out every utility
10 is going to have a different impact.

11 MR. ROOT: Good point.

12 MS. RICHARDS: So he'll present the GMP
13 effect. So there is some reduction of cost
14 to load due to suppressed what's called
15 locational marginal prices, but that depends
16 if you have load in that service territory.
17 So Washington Electric Co-op is being
18 impacted. We don't necessarily have direct
19 load in that area, but we have generation.
20 So literally every utility is going to have
21 a different answer to that question.

22 But in short, for WEC we are seeing
23 increased costs as associated with this.

24 MR. ROOT: And if you're a municipal in
25 the southern part of the state, you're

1 saying why do I care about this. Why did my
2 customers care about this problem. It's not
3 my problem. It's tough because there is a
4 geographic component to it.

5 MR. GIBBONS: I've got to disagree with
6 that. If you're Jacksonville, to use an
7 example, but you have Hydro-Quebec power,
8 I'm saying it's not that simple to look and
9 say Bob's not there, so he doesn't care. If
10 he has power being delivered there, even if
11 he's located a long way away, he does care.
12 And you may have utilities that are in that
13 area who don't have ISO market power being
14 delivered in the area that may not care.
15 It's not intuitive.

16 MR. ROOT: Right. Not every single
17 customer in Vermont is affected by this,
18 although a large majority of them are.

19 MR. GIBBONS: Correct.

20 MS. HOFMANN: Chris, one way in the
21 back.

22 MS. STASKUS: Martha Staskus. Can I go
23 back to Steve Garwood's question about the
24 timing, you know, about these two 20
25 megawatt solar projects. They are not --

1 are they in the queue, are they being -- if
2 they are in the queue, aren't they being
3 studied? If they are in the queue and being
4 studied, would they be in the -- eligible
5 for this cluster event -- I'm sorry I didn't
6 understand, but the cluster item. And then
7 taking all of that going back to you have 17
8 options that you've looked at. Is that one
9 of them?

10 And to make my question worse for you,
11 what is the timing of all of this dynamic
12 work that's going on?

13 MR. ROOT: So I will talk about timing
14 on the next slide on the studies. Those two
15 studies are being done by ISO New England as
16 an interconnection study. Those plants were
17 in the queue and then withdrew, and they put
18 it back in, so kind of reset things. As far
19 as I know they haven't actually started the
20 studies for this year. It's going to be
21 soon, but they haven't started it yet. They
22 have not applied, as far as I know, to the
23 Public Utility Commission to site their
24 plans.

25 So we are trying to discourage them to

1 go down this road because we think it's
2 going to be an issue. So we are trying to
3 convince them that this probably isn't a
4 good location to do it, you're going to get
5 a lot of opposition. We can't say no. We
6 are just saying really in the end it could
7 end up being at the commission level trying
8 to --

9 MS. STASKUS: I guess my question goes
10 to he's offered us another solution.

11 MR. ROOT: There is -- he's not
12 offering the solution. What Steve is saying
13 is that there is a mechanism, they did it in
14 Maine, to look to see that instead of
15 looking at plants individually, do a study
16 for this one, study for this one, study for
17 this one. They did a group study to see
18 does it make sense. Is there a solution for
19 everyone for those plants that are being
20 done. So we definitely will ask the
21 question about that.

22 If those two applications are
23 simultaneous with a third one, which I think
24 there is a third one out there, can they
25 couple those and do the studies

1 simultaneously altogether. Would one
2 solution to that problem solve all of them.

3 It's a process at ISO New England that
4 allows him to do that. They did it in
5 Maine. Unfortunately I don't think it
6 solved --

7 MS. STASKUS: Did they pay for it?

8 MR. ROOT: The study gets paid for by
9 the developer. And then the solution -- who
10 pays for the solution typically would be the
11 people putting the plants in, and that's the
12 issue. So Steve.

13 MR. GARWOOD: I was just going to add
14 the way they have written the tariff it's
15 not discretionary. If the conditions are
16 satisfied, which are in essence if there is
17 two or more generators in the queue in the
18 same vicinity electrically, and the ISO can
19 identify a common large transmission project
20 that would accommodate the interconnection,
21 they have to go through that process to
22 study them that way.

23 MR. ROOT: We will make sure that
24 that's happening.

25 MS. FRANKEL: Just a clarifying

1 question, I'm not sure who to direct it to
2 about that cluster study approach. Would
3 that still be under the minimum
4 interconnection standard? So that the
5 question wouldn't be can all these
6 generators run at once. It would still be
7 can you technically run these generators if
8 you have the ability to shut something else
9 off. Yes?

10 MR. ROOT: So now we are getting into
11 some of the details of interconnection
12 studies. But if you asked ISO to do a
13 minimum interconnection standard, which some
14 of the generators have, and I'm sure these
15 new ones would ask for, that allows you to
16 run for one hour a year.

17 Okay. So they said well, yeah, you can
18 or this is the issues with it. And if you
19 agree to that, hey, don't complain when
20 you're not running. Now the issue here is
21 we have regulated generation that is being
22 impacted by people coming on, and then the
23 market rules have changed since originally a
24 lot of stuff was sited. Some things have
25 changed. It gets very complicated very

1 quickly, and in Vermont it's actually worse
2 because we have regulated generation where
3 in the other states in New England most --
4 it's just a few plants that are still
5 regulated by the distribution companies or
6 owned by them. Yes Ed.

7 MR. McNAMARA: The only other point too
8 is that Chris talked about do-not-exceed
9 dispatch. . That at that moment does not
10 apply to solar facilities.

11 MR. ROOT: Correct.

12 MR. McNAMARA: So you have the
13 additional complication to that.

14 MR. ROOT: Yes. Solar is not
15 dispatchable. It doesn't come towards us.

16 So let me just talk about where we are.
17 We are three quarters of the way through the
18 thing. The engineers have done studies, and
19 they have all these solutions, and which one
20 works? And they go from small priced ones
21 to big ones. But they all have varying
22 degrees of benefits. Now we are pricing
23 them all out. That's going to happen over
24 the next six weeks. So we are getting all
25 the pricing together. We have a meeting

1 coming up in a couple weeks to make sure
2 everybody is estimating it on the same
3 basis.

4 The idea is we are going to put
5 together some type of working group to try
6 to figure out what would be the best
7 long-term and short-term solution. Then
8 after that, the big question is who pays for
9 it because it's not intuitively obvious who
10 is the person who pays for it; right? Does
11 it go to transmission rates? Is it just
12 Vermont? Is it all the utilities in Vermont
13 that pays for it? Is it the generators that
14 pay for it? I don't know the answer to that
15 question.

16 Regulation isn't really super clear on
17 some of this from my perspective. My sense
18 is we will have some more public discussion
19 about this topic in the next couple months
20 when we have all the pricing done and start
21 getting groups of people together to try to
22 figure out what -- which is the best bang
23 for your buck type thing pricing. Then we
24 will have to have those other discussions.

25 Anything else? I hope I didn't take

1 too long. I tried to tee it all up.

2 CHAIRMAN ROISMAN: Thank you very much.
3 Doug? If you have not signed the sign-up
4 sheet, please do. It's one way for the
5 court reporter to identify who it was that
6 spoke and have a correct spelling of your
7 name. I don't know that it's made it back
8 this way. Whoever has it, transmit it.

9 MR. SMITH: Okay. Good afternoon,
10 folks. So I'm Doug -- Doug Smith. Green
11 Mountain Power. Power supply director means
12 that the market implications and the
13 implications of a transmission constraint, a
14 meaningful one anyway on our customers,
15 would be an area that I and my colleagues
16 would watch and try to understand. So I'm
17 here to try to give a little context, and
18 it's sort of -- it's a practitioner's
19 perspective from someone who's been looking
20 at -- for the largest, but certainly not the
21 only utility in the state, how this
22 interface impacts our customers.

23 I have no material differences or
24 concerns with what Chris laid out. That was
25 a really helpful framework. But I'll try to

1 give a few just practical illustrations or
2 magnitudes of numbers to try to help folks
3 from different backgrounds maybe come to a
4 common understanding. And then I'll talk a
5 little bit initial observations about
6 solutions too.

7 We are at a -- well I'll get to that.
8 But we are at the stage where the collective
9 we are learning, and I hope to convey a
10 little bit to the audience and the
11 commission about where we are and what might
12 come next.

13 So the first thing I thought I would
14 hit is just a little bit on the when. Chris
15 gave the main drivers. This is somewhat
16 overlapping. But I just wanted to emphasize
17 that it's a combination oftentimes of big
18 wind output, big hydro, and full deliveries
19 over the Highgate converter. Those are the
20 main types of conditions where in our
21 experience some or all of those together is
22 when we see this constraint occur.

23 As I note down maybe $2/3$, $3/4$ of the
24 way down, I don't have the numbers right
25 with me, but think like 20 percent of the

1 time. It's not like the vast majority of
2 time the interface is congested. But the
3 trick is, that that time is often when sort
4 of by definition there is a lot of power
5 trying to flow up there. And that's power
6 that is -- in general or almost exclusively
7 it's either power that's being purchased by
8 Vermont utilities for the benefit of their
9 customers, or owned by Vermont utilities.
10 As Mr. Root noted, there is -- it's not like
11 other parts of the New England system where
12 there is a lot of merchant generators. A
13 key characteristic of what's up there in
14 northern Vermont is that it operates for the
15 benefit of our Vermont customers. Different
16 utilities, different rate plans, but
17 fundamentally the output they produce and
18 the value they generate in the market they
19 go to help Vermont customers.

20 So the major times of year are there is
21 a pronounced pattern toward winter, as Mr.
22 Root noted, and also spring. So those are
23 the times when you get a combination of big
24 hydro and big wind. In the last couple of
25 years deliveries over the Highgate converter

1 have been strong. I don't have the exact
2 number, but most days it looks to my eyes
3 like flat at the maximum rating or within a
4 couple of megawatts. That's not universal,
5 but it's close to it the last couple of
6 years.

7 The final point I wanted to make is so
8 what does that mean? That means that during
9 some fraction of hours in the year, even if
10 the transmission system up in Vermont is in
11 pretty good shape, there is nothing major
12 out of service. There are times when this
13 interface can be constrained. I'll talk
14 about the dollar impact in a minute. But
15 just that can sometimes happen.

16 The other time it can happen is when a
17 major element on the transmission system is
18 out. There is something that's either out
19 for planned repair, or it could be a
20 transformer or line segment, and when the
21 ISO goes through the process that Mr. Root
22 outlined to make sure there is a reliable
23 and stable grid, they need to pick a lower
24 limit. So those are the two main things
25 that we see, and it varies greatly by hour.

1 I mean within a given day, it could be on
2 many days, there is no constraint. Any
3 generation up there that GMP has just runs
4 fully. We see no constraints on the ISO
5 website and two hours later hits the limit.
6 So it really varies strongly across the year
7 and even within a day, occasionally even
8 within an hour.

9 MR. KIENY: Doug, could I just add to
10 that. When it happens it can happen for a
11 couple hours, it can also happen for several
12 days in a row. It can be an extended period
13 of time.

14 MR. SMITH: Agreed. So I hope that's
15 helpful to just give you a sense of scale.
16 I mentioned day-ahead and real-time markets.
17 This is probably not the best place to go
18 into those details, but for those of you who
19 are familiar with the power market, there
20 are two phases here in New England. A
21 day-ahead energy sale and purchase that's
22 done basically the morning before a calendar
23 day, offers and bids are submitted. And
24 then a real-time market for differences.
25 The dynamic we have been talking about can

1 apply in each one of those; day ahead or
2 real time. And we do see meaningful
3 fractions of time in each of those markets
4 where this SHEI Interface does get
5 constrained.

6 So what's that mean? If the interface
7 gets constrained from this practitioner
8 perspective? Well as Chris went through,
9 that means that there is enough generation
10 lining up to deliver its output within that
11 area of the map. There is more than
12 whatever the limit is established by ISO New
13 England in that period of time. Generally
14 day-ahead market measures this hourly or
15 even in five-minute intervals in real time.
16 But that's what's happening. There is more
17 generation lining up than the limit in a
18 given period of time.

19 And I put my hands pretty close
20 together there. Just -- I'll come back to
21 this later, but to give people a sense that
22 sometimes that gap, when there is big
23 generation, load is light or transmission
24 outage is meaningful by Vermont scale, you
25 know, tens of megawatts, but I want to give

1 you a sense of it's not like hundreds and
2 it's often limited to what we still need to
3 share and take views from other generators.
4 GMP can't see all of the data, but I wanted
5 to just give you a sense that to my eyes so
6 far it looks like a good fraction of the
7 time that depth of this congestion, this
8 amount that can't fit out of the region, it
9 can be as small as 10 megawatts or 20.
10 Other times it can be many tens, but I just
11 want to give you an order of magnitude.
12 It's not like we have a system here which
13 has a maximum of 400 something of
14 generation, and it's a hundred megawatts
15 short to be able to export it typically.
16 That's not the case.

17 The other thing I wanted to mention
18 here is to play off of something that the
19 questioners went over. Transmission
20 congestion today in New England the
21 implications of that are much bigger to
22 market participants like us and the other
23 Vermont utilities than they were a couple of
24 years ago. Chris is right, I think of it as
25 the beginning of June. It was really late

1 May, as he said, that this do-not-exceed
2 dispatch regime came into play. And what
3 that means is a couple of things. One is
4 when there is a transmission constraint, not
5 everything can fit. As Chris went through,
6 the price that's offered to the market by
7 each generator comes into play. And we
8 don't have to make it too complicated. Most
9 of the generation up there has a renewable
10 generally with zero fuel expense. Not all
11 of it, but it's not rocket science to expect
12 that generators like that would offer their
13 output at low prices. But he's right. In
14 the old days, a couple years ago, if there
15 was a constraint, there wasn't a ranking
16 system, at least one that was formal and
17 structured to choose who gets limited. So
18 now price comes more directly into play
19 along with those locational factors that
20 Chris mentioned.

21 And the other implication is the result
22 of that. Think of an example where let's
23 say New England has a prevailing market
24 price or LNP \$20 a megawatthour. Well if
25 the SHEI area has 10 megawatts extra of

1 generation, and the process Chris Root
2 walked us through is conducted, if the
3 locational marginal price ends up at zero
4 because of zero -- a generator offering zero
5 dollars for a megawatthour is the one
6 selected and was the marginal source, what's
7 that mean? We call that congestion. That's
8 what we are referring to. In my example
9 that would be congestion of negative \$20 a
10 megawatthour. What it means is that the
11 market price that gets paid to generation on
12 the surplus side of the interface to be
13 quite different, in my example think \$20 a
14 megawatthour different, from what generators
15 in the rest of the region are getting paid.
16 That was simplified. It ignores the day
17 ahead and the real time. But just to give
18 you a flavor of what we mean when we say
19 negative congestion.

20 Previously that wasn't the case. There
21 was not a huge gap in what power generators
22 were paid or what load paid on different
23 sides of the interface. Now one day a month
24 -- what day was that? A month or two ago --
25 this is snapshot from my mobile phone, the

1 ISO express app. And when I took a look at
2 this, I said I better take a picture,
3 because this might be helpful to tell people
4 what we mean when we say prices are
5 different on different sides of the
6 interface. This is real-time market prices
7 in New England. A five-minute interval.
8 This is a little extreme. But what it shows
9 is there was a great divergence in market
10 price, there was a transmission constraint
11 between southern New England and northern
12 New England, I think it was around the
13 Seabrook plant or just south of that, but
14 look at that.

15 In the Boston area we had the 104.77.
16 That means 104.77 dollars per megawatthour
17 for each incremental megawatthour generated
18 there. But up in Maine the price is
19 actually negative. This doesn't happen all
20 the time. But this is an extreme example of
21 what we mean by congestion, and when we say
22 that market prices diverge. Yes, sir.

23 MR. GIBBONS: I would like to ask if I
24 could use this slide for one second. I
25 don't have a slide. This is really a good

1 example. Vermont utilities pay for the
2 entire load they are serving at what's
3 called the Vermont zone price, so in this
4 case that price was \$57.72 per megawatthour.
5 You can have your resources be located in
6 other places. If you had your resources
7 located in Maine, and you had enough
8 resources to serve your load, you still have
9 a big problem because your resources in this
10 case would be charged \$80 for delivering
11 power to the grid, and you'll still be
12 charged for the load that you think of those
13 resources as serving. A subset of this can
14 occur inside Vermont now. It can look kind
15 of like this, but within the state.

16 MR. SMITH: Thank you. Couldn't have
17 said it better. We may have just assumed
18 it. That's what the negative number means
19 there. It means that a generator putting an
20 unscheduled megawatthour, an extra
21 megawatthour into a location in Maine on
22 average would actually have to pay a
23 significant amount to put that megawatthour
24 in, and a positive number means what you're
25 used to seeing, which is if you consume

1 more, or if you produce more; if you consume
2 more, you pay more. And if you produce as a
3 generator more, you get paid. Negative is
4 backwards. That hardly ever happened until
5 2016.

6 MR. GIBBONS: In an extreme case if you
7 were a utility who had load in Maine and you
8 were delivering your generation right now in
9 Boston, that's really good. I mean you're
10 literally getting paid to consume energy and
11 paid in Boston to generate energy.

12 MR. ROOT: Can you explain how you can
13 make money with a negative number?

14 MR. SMITH: Thanks a lot. That's
15 always a nice one. So what would be a
16 reason -- a short story. I don't know
17 exactly what happened here. But there are
18 some reasons, why would a generator offer
19 its output negatively? Well one reason is
20 if you're a renewable generator that
21 produces energy, but also useful things like
22 a production tax credit, or a renewable
23 energy certificate, if you're offered the
24 choice, you're a wind plant or one that
25 produces those types of benefits other than

1 just the energy, you might be willing in an
2 hour to accept zero price or negative price
3 for the energy itself because you're
4 generating other valuable things.

5 In my little example you might be
6 willing to accept a price of negative 10,
7 negative 20, even negative 50 dollars a
8 megawatthour if you're a wind generator for
9 energy because you're generating other
10 things. I don't know the details of this
11 case, if there are other dynamics going on
12 that would produce a negative 82. But it's
13 not a crazy thing that a generator would
14 offer that way.

15 And another example would be if the
16 generator had sold a bunch of output in the
17 day-ahead market, and what happens if its
18 output is curtailed for some reason in the
19 real time, they sold 50 day ahead. They
20 have an obligation, and now they are limited
21 to 30. That generator actually would
22 benefit if the market price is negative at
23 its location, because it would get paid for
24 being short of its day- ahead delivery. We
25 call it a real-time deviation. And it could

1 actually make money. Probably more detailed
2 than you wanted, but the main reason, the
3 main observation would be it can be rational
4 for some generators either due to products
5 they produce or operating constraints they
6 have fuel commitments, other things to push
7 their offers negative.

8 MR. GIBBONS: I would just say to give
9 you an example, another one, a nuclear
10 plant. You know if the price signal said
11 shut down for an hour, that's a problem for
12 them, and they would have been negative to
13 avoid that implication. So I'm just saying
14 there are good reasons for it. I think
15 there were things like the nuclears that had
16 sort of the lead in ISO's mind when they
17 were setting negative LNP, but it has some
18 real renewable effects too.

19 MR. KIENY: Doug, before you go on,
20 maybe I'm stating the obvious, but the
21 negative number with respect to the SHEI,
22 that's what's happening in some hours
23 throughout the year inside the SHEI.

24 MR. SMITH: Yes.

25 MR. KIENY: Which is why we are here

1 today.

2 MR. SMITH: Not always. Another
3 example of negative congestion would be
4 imagine the whole region is at \$40 a
5 megawatthour. If SHEI ends up at positive
6 \$20, it's not negative. But it still
7 changes -- reduces significantly the
8 generation revenue to the plants up there.

9 Let me get to the implications of that.
10 So how does this affect our customers. The
11 caveat, I forget who exactly had the
12 exchange, but the caveat about each utility
13 has different balances of supply, location,
14 that's all correct.

15 So I'll start with GMP. First, just
16 the mechanisms. I think we touched on them,
17 but it's important to name them. One
18 mechanism, if there is a limit, is that --
19 and the interface is constrained, someone
20 needs to reduce output. Chris Root went
21 through how that happens. But just someone
22 is reducing 10 megawatthours in my example
23 before, but they don't get to make LNP
24 revenue for energy or any of these other
25 benefits.

1 And the second thing that happens as we
2 went through, we call it negative
3 congestion, but it's a price difference, a
4 lower price for power on the surplus or
5 export side of the interface than outside of
6 it. And that I guess, in my simple words,
7 means lower energy payments. Lower LNP
8 payments to generators in that area than
9 would otherwise have been the case. And
10 under that DNE regime that affects all
11 sources in the area that are selling at that
12 point in the day-ahead or real-time market.
13 What I mean by that is it's not just the
14 single generator that reduces output that
15 gets paid less. In my example if the market
16 price goes from \$40 to 20 or 20 to zero in
17 order to resolve that -- the SHEI Interface,
18 it pushes down the revenues for all the
19 generators in the area. So that's a
20 meaningful difference. And when I've said
21 things are different now than a few years
22 ago, that's a meaningful change.

23 It's been touched on that lower market
24 prices also have the effect of lowering the
25 price for energy that Vermont utilities buy,

1 as James noted, that happens at the Vermont
2 load zone. It's an aggregation of
3 locations, but lower LNP in that SHEI area
4 does bring down the LNP to the rest of
5 Vermont. The key point there though is it's
6 only in proportion to it's weighting in
7 Vermont. And that's a number like five or
8 six or seven percent of Vermont's total
9 load.

10 So if the SHEI area is congested
11 negatively by one dollar per megawatthour,
12 only a few percent typically is what the
13 entire state on average sees as a reduction
14 to the LNP price that is paid to purchase
15 load. So for us, the net of all those, the
16 first two are essentially increased net
17 costs to our customers. The lower cost to
18 purchase load, that's a savings. We are
19 still refining our estimates, but it looks
20 like over the last 18 months the order of
21 magnitude is several million dollars of the
22 net of those is essentially increased net
23 cost to GMP and our customers. And the
24 reason for that is as we were alluding to
25 earlier, GMP along with some of the other

1 utilities, has much more generation in that
2 area than load.

3 In our view, you know, several million
4 dollars is not huge relative to several
5 hundred million of net annual power costs,
6 but it is not nothing, and it's more than
7 enough to justify this effort on finding
8 solutions. And also, bringing visibility to
9 the possible implications of new generation
10 in the area.

11 MR. GERHARD: Do you have a sense --
12 that was a GMP number. Do you have even a
13 rough idea of what it would be statewide for
14 all the utilities?

15 MR. KIENY: I can tell you for VEC the
16 last 12 months ending November it was about
17 six hundred thousand dollars, for 1/8 the
18 size of GMP, so it's in the magnitude of the
19 same impact when you take size into account.

20 MR. GIBBONS: But it is not scalable.
21 I mean it happens that that's the case. You
22 can't assume that.

23 MR. SMITH: Agreed.

24 MR. KIENY: Yes.

25 MR. SMITH: As we went through earlier,

1 it very much depends on how much generation,
2 power purchase agreements or owned plants,
3 each utility has in this area versus the
4 size of their load. As Chris Root's slide
5 showed, for capacity, it's also true for
6 energy in total. The amount of
7 megawatthours produced up in that area, and
8 even exported, is significantly larger in
9 aggregate than the load up there. But you
10 can't say that every utility's affected the
11 same.

12 MR. GERHARD: Can you even give me a
13 rough ball park figure?

14 MR. SMITH: I think at this point I
15 would feel a little uncomfortable going that
16 far. But if Green Mountain Power is several
17 million dollars, I think that we would find
18 that on a statewide basis it's probably, you
19 know, it's less than 10 million dollars.
20 But more than just a few. I don't know
21 whether it's five million dollars or eight
22 or something like that, but more than a few.
23 But not 10.

24 MR. GERHARD: Okay. Thanks.

25 MR. SMITH: By that I'm referring to a

1 period of about 18 months since the
2 beginning of the so-called DNE regime.
3 That's when my estimates went from.

4 MS. BURT: And Doug, to answer your
5 question, for Stowe Electric we are one of
6 the municipals. We are not affected at all
7 because we are not any part of any of the
8 generation projects up there.

9 MS. RICHARDS: Doug, could you
10 translate for GMP your -- maybe one year's
11 cost impact into a rate impact?

12 MR. SMITH: I didn't. But as an order
13 of magnitude, GMP's annual -- the amount of
14 money that our retail rates collect is
15 around 600 million dollars in a year. So
16 that means for us in round numbers if you
17 had a six million dollar impact, that's
18 around a one percent, and if that
19 perpetuated in the future, that would be
20 around as a sense of magnitude a one percent
21 rate impact.

22 Now my period was longer than a year.
23 And so to answer your question, no. I
24 haven't done it. But think tenths of
25 percent for GMP's rates, but probably not

1 one percent.

2 MS. RICHARDS: So for Washington
3 Electric Co-op we have quantified that, and
4 it's over a one percent rate effect. So we
5 have a very large proportion of generation
6 in the SHEI area that we are getting a
7 significant impact. All utilities are
8 different. We have quantified that. To put
9 it in perspective it's about a one percent
10 rate impact.

11 MR. SMITH: Okay. So I think it would
12 be helpful to close by turning towards
13 solutions here. As the other folks have
14 said, it is a complex evaluation. This is
15 one of the more interesting and multifaceted
16 ones in my career. It covers a range of
17 operating conditions. Mr. Root walked
18 through how -- well there can be two types
19 of limits, a voltage one and a thermal. We
20 talked about how they differ greatly by
21 season. So there's a number of moving
22 parts. It's not as simple as stacking up
23 solutions and saying we need 30 megawatts of
24 solutions, let's find one that add up to 30.

25 Big step and a thank you to our VELCO

1 colleagues who conducted the study that
2 Chris described with EIG. That's key.
3 Because without that, it would be very
4 difficult to understand how different
5 solutions affect the interface. And it
6 really matters, as the study work showed,
7 what the system conditions are. Just to
8 give you a flavor, some solutions could have
9 a really nice impact on the interface limit
10 and raise it by let's say 20 megawatts when
11 all lines are in service. There is no real
12 outages. In some outage conditions that
13 same solution might provide that same 20 of
14 benefit, but in other cases, it could be
15 nothing.

16 So it really is important to understand
17 those differences, and I appreciate the way
18 they listened to our peppering sometimes of
19 questions as to which, you know, studies and
20 combinations to screen. That's huge. But
21 there are other -- a couple of other
22 important things that have to happen now.
23 And that's -- I personally will be heavily
24 involved in that along with others.

25 One is comparing those benefits to the

1 depth and breadth of generation that is lost
2 in the area. Do we think that we have a
3 certain number of hours where it's an
4 average of 10 megawatts, or 30, or what?
5 How many hours and how deep? That mapping
6 -- and under what conditions on the
7 transmission system, that's going to be
8 critical to see which solutions are the most
9 cost effective.

10 I mention how representative was the
11 recent history. As you can tell from this,
12 fluctuations in generation and market prices
13 all the time every day and hour have a
14 changing landscape. What I'm particularly
15 interested in or I want to make sure we see
16 what we can characterize is the history with
17 respect to transmission outages. I think
18 today is a little too deep to show you a
19 monthly or more granular breakdown, but a
20 significant chunk of the congestion in this
21 last year and-a-half has been when a
22 transmission element for one year or another
23 is out for maintenance or replacement. And
24 it's hard to tell, I admit, for me right now
25 it's hard to tell what's a representative

1 pattern of that that we need to plan for.

2 You've got to maintain the transmission
3 system. So all lines in is not possible all
4 the time. But what's the right allowance.
5 I think we need to work on that. And Chris
6 Root earlier, as well as some of the
7 questions and answers, alluded to some other
8 potential solutions that aren't exactly
9 addressed in the VELCO EIG study. Rating
10 lines differently. That's a creative
11 solution that might help raise the limit in
12 some months. There is a bit of a discussion
13 with Hydro-Quebec. That is a possibility.
14 The largest source up there in theory, as we
15 discussed, reduced generation or deliveries
16 up there at certain times could make a big
17 difference. Tough yet to see how that
18 happens.

19 My conclusion right now is we should
20 explore that, but don't wait. Don't wait to
21 explore the other possible solutions.

22 MR. CARLSON: Sam Carlson, Green
23 Lantern. Just wanted to pick up on that
24 representative history question. If you --
25 and I take your point the transmission

1 maintenance has to happen all the time. But
2 it would seem to me that VELCO would be able
3 to make some estimate. Were these past 18
4 months unusually busy in terms of
5 transmission outages because of maintenance?
6 And that this congestion problem was not
7 perhaps so much due to generation, but
8 because this maintenance was going on. So
9 that's point one.

10 Going back to your initial point of
11 when this congestion happens, winter and
12 spring mostly, I just make the point that
13 that's an interesting sort of juxtaposition
14 against when solar is most productive which
15 is in the summertime. So in the wintertime
16 the solar really is no threat to the
17 congestion. And in the spring maybe. I'm
18 not sure. I'm trying to interpret when you
19 say there is congestion versus when solar is
20 putting the most generation into the grid,
21 and perhaps it isn't as big a problem.

22 MS. BROWN: I feel like we are getting
23 dangerously close to issues that are being
24 litigated right now.

25 MR. CARLSON: I was just --

1 CHAIRMAN ROISMAN: Okay. We will stay
2 away from that.

3 MS. BROWN: Thank you.

4 MR. SMITH: To your first point, I
5 would just -- I was sort of nodding my head
6 when you asked about the representative
7 outages. Yeah. I'm hoping -- it seems
8 logical that we can -- may be able to get
9 some help from VELCO to shed light on that.
10 I don't know if Mr. Root has any sense. It
11 will still involve an exercise of judgment.

12 MS. BROWN: I think we were going to
13 stay away from this area.

14 CHAIRMAN ROISMAN: I think he was
15 staying away from the discussion of whether
16 solar particularly would be more
17 available --

18 MR. SMITH: That was my discussion.

19 CHAIRMAN ROISMAN: -- in the winter and
20 spring than in the summer and fall, not the
21 more generic question.

22 MS. BROWN: I believe both issues are
23 being litigated right now.

24 CHAIRMAN ROISMAN: All right. Yes.
25 All right. We will stay away from this,

1 Doug.

2 MR. SMITH: Fair enough. Hi.

3 CHAIRMAN ROISMAN: There will be a
4 chance to discuss it. You know, more
5 structured setting.

6 MR. CARLSON: Thanks.

7 MR. BLITTERSDORF: David Blittersdorf.
8 This question of transmission maintenance is
9 really interesting. Because as I understand
10 it, and I don't know what's going on with --
11 going on with this litigation, but my
12 question is, are you guys doing the
13 maintenance at the right time of year?
14 Because I have some information that says
15 you're not. You're maintaining at the
16 constrained times of the year. Why not move
17 the maintenance to late summer, early fall
18 when your wind's not blowing and your hydro
19 is not going?

20 MR. SMITH: A couple things. I would
21 like to raise the hand and ask the
22 commission whether this question overlaps
23 too much into the topic that we decided to
24 stay away from, or is it okay to take a
25 swing at that?

1 MR. KNAUER: I would say let's get away
2 from it. This is potentially part of one of
3 the cases that I'm involved in. So --

4 CHAIRMAN ROISMAN: All right. Let me
5 just be clear what we are trying to avoid.
6 We have these pending cases. Some of the
7 most recently asked questions, while they
8 weren't tied to those cases, are tied to
9 issues that can be presented in those cases,
10 and they are not questions that we don't
11 want to have answered. But we want to have
12 them answered in the correct forum,
13 including the opportunity to ask the
14 question Mr. Blittersdorf asked in the
15 context of a litigated case in which someone
16 can then answer that question and address
17 it, rather than try to do it in this
18 workshop setting which we are trying to keep
19 from being a contested proceeding. So we
20 are not trying to say it's not a relevant
21 question. In fact, maybe what we are saying
22 is it's a too relevant question.

23 So let's go on from here and stay away
24 from that. Go ahead, Doug.

25 MR. SMITH: Okay. So a few summary

1 thoughts here. There is a wide range of
2 potential solutions out there that the VELCO
3 study addresses and a few as we have
4 discussed that maybe aren't exactly on that
5 list but are also worthy of consideration.

6 The estimation of capital costs. I
7 think Chris largely covered that. That's
8 one of the key next steps. If you take a
9 look at the VELCO EIG study, it does a
10 really interesting job of painting the
11 picture of effectiveness. How many
12 megawatts of relief could you get under
13 different conditions for a solution? But
14 just it doesn't yet get into the capital
15 costs. It's logical for them to do that
16 first. And now the estimation, trying to
17 match up capital costs with those potential
18 solutions, is a logical next step which will
19 be coming shortly.

20 I've touched a bit on the notion, I
21 called it stacking up solutions against
22 congestion times. But that's really what
23 the next couple of bullets amount to. If we
24 have one solution that is very good, very
25 effective at raising the limit under some

1 conditions but not good at others, how does
2 that match up. How often in a year do those
3 effective conditions occur versus others.
4 That's what I'm getting at, at the
5 effectiveness of solutions bullet.

6 My own hope, which really hasn't been
7 vetted yet with many stakeholders, is just
8 that it probably makes sense to have an
9 initial screening after we get a sense of
10 those capital costs and that stacking, to
11 try to narrow the focus to a manageable
12 subset of options that seems to have a good
13 chance to go all the way in terms of cost
14 effectiveness and feasibility to do it. But
15 that's what we will have to figure out, I
16 think, as a group.

17 Finally, here's a couple of themes that
18 is on our minds at GMP. One is can a mix of
19 moderately-sized options, as Chris said, not
20 hundreds of million dollars, but single
21 millions or 10 million, quicker to build,
22 not as big scale, can they effectively act
23 as a decongestant, if you will, for the SHEI
24 area or not. Do we need a big -- a new
25 line, a major project that is one of the

1 more complex and time consuming ones. Are
2 there any solutions that are worth deploying
3 right away.

4 The only one -- the one that's caught
5 GMP's eyes, and I say initially because we
6 are not done, but one that caught our eye is
7 automatic voltage regulation at the Sheldon
8 Springs hydro plant. That's an existing
9 plant, and it's one of the items in the
10 VELCO EIG study. And I just wanted to note
11 that it has a number of features, relatively
12 low capital cost, not that time consuming to
13 implement, in theory. Fairly effective
14 under some of the conditions studied in the
15 study. It might be an exception to the rule
16 which amounts to we may not need -- it might
17 be a resource that might be worth deploying
18 before the full picture, the full suite of
19 options is fully understood if the economics
20 are good enough.

21 We don't know that for a fact right
22 now, but I just didn't want to surprise
23 people that that's one item that to us looks
24 different from the rest and warrants some
25 accelerated look right now, and we are doing

1 that. The exact process for how to do this,
2 I agree with Chris that it's not fully
3 established. I have been involved in some
4 broad group evaluations in the past in
5 Vermont such as a study group for
6 non-transmission solutions to bulk
7 transmission projects.

8 So from that I just have a couple
9 observations. This involves a good deal of
10 technical and financial analysis, at least
11 some of that is much more suitable to small
12 groups, a few people breaking off at a white
13 board or somehow -- and coming back to a
14 broader group with the questions and
15 findings and vetting that, as opposed to
16 dozens of people in a room trying to do it
17 all in parallel. I feel like some feedback
18 loop like that probably makes sense. And we
19 need -- this is not just a utility-only
20 dialogue. We need to involve -- just look
21 at the attendance list here, we need to
22 involve other parties and stakeholders on a
23 regular basis to do that.

24 So our thinking is that some form of
25 periodic reporting back to the commission

1 between which there are working groups, more
2 technical and economic folks, trying to draw
3 conclusions about the capital costs, cost
4 effectiveness, scope of solutions, that's as
5 far as we have gotten on specifics. But
6 something on those outlines seems to us like
7 it would make sense.

8 CHAIRMAN ROISMAN: Let me ask you one
9 question about your other parties and
10 stakeholders. I assume that part of that
11 group are developers and potential
12 developers who are looking to put projects
13 into the SHEI area but are running up
14 against the constraints that they are part
15 of the group of people --

16 MR. SMITH: Yes.

17 CHAIRMAN ROISMAN: -- that you're
18 consulting with when you're trying to find
19 possible solutions.

20 MR. SMITH: Yes. They might have
21 something to add in terms of the technical
22 how to look at the problem, and even if not,
23 it won't be the most effective solution if
24 one subset of people in the state think they
25 got it, and another set of affected

1 stakeholders are saying I don't follow. You
2 know, how did you get here. We don't see
3 the math working. So that's a way of
4 agreeing with you.

5 CHAIRMAN ROISMAN: Thank you. James,
6 are you ready?

7 MR. GIBBONS: I'm ready.

8 CHAIRMAN ROISMAN: Okay. We have got
9 one more here for Doug.

10 MR. CARPENTER: Sorry. David
11 Carpenter. I'm just, as a sort of
12 regulatory nerd, can you explain the history
13 of the DNE rule? Like where did that --
14 what's the genesis of that? Where did it
15 come from? Is it a NEPOOL thing or
16 something else?

17 MR. SMITH: Yeah. I can take a decent
18 shot at it. DNE means do not exceed. Chris
19 Root went through the foundations, but it
20 was developed through a region wide at ISO
21 New England. The committee process
22 ultimately voted on by the various
23 stakeholder groups that comprise the
24 governance of ISO New England and NEPOOL.

25 The concept, I think a past VELCO

1 presentation might have had a couple good
2 bullets on this. I'm forgetting which one.
3 But the concept was it's better to have when
4 constraints occur, or forget transmission
5 constraints, just in the middle of the night
6 maybe there is a drop in load in the region,
7 or reasons why generation needs to get back
8 down logically some amount. Better to have
9 price, essentially willingness to be
10 reduced, reflected in that decision. That
11 was the concept behind it.

12 And I forget who it was, but a couple
13 of folks in the audience gave a good
14 example. You have nuclear plants, natural
15 gas fired plant, a wind plant. Until 2016
16 there really wasn't a way for one of them to
17 say, no, I really want to be online. And
18 I'll accept no payment in this next interval
19 to stay that way. That was missing.

20 And the other thing that was missing
21 was automation. Without dragging you too
22 deep, if Kingdom Community Wind is a
23 resource that gets one of those limits in an
24 interval, an electronic signal comes
25 through, and it is automated, and you can

1 see it within, you know, a very short time
2 that says 50 megawatts, whatever the number
3 is, that's your limit. It was more a manual
4 -- manual intervention type process.

5 So that's what I know about the theory
6 of it. The practice and the results are
7 some of the charts you've seen and the
8 divergence in market prices. I suspect they
9 are a little more than the theoreticians
10 thought would occur, but that's the genesis.

11 MR. CARPENTER: That was the next
12 question. I don't know if GMP participated
13 in the drafting of the rule or the creation
14 of the rule, but were these kinds of impacts
15 anticipated when this rule was developed?
16 It didn't just drop out of the sky on May
17 25, 2016.

18 MR. SMITH: Directionally, yes. Yes,
19 we did anticipate it. Personally I don't
20 think I anticipated the magnitude being in
21 that several million dollars in a year
22 period that I mentioned. I don't think I
23 was anticipating that, no.

24 So my last point for the group is
25 simply to a reminder what I've talked about

1 here today is overwhelmingly about how to
2 cost effectively reduce congestion and
3 essentially find a cost effective way to
4 address this limit today.

5 Today's mix of loads, power plants, et
6 cetera, my own view is wherever we end up,
7 the number of solutions or the exact type,
8 there will probably need to be an ongoing
9 dialogue, which I'm not trying to attempt
10 today, but about -- what about the policy
11 implications and how to handle new
12 generation stuff that's not online now or
13 maybe even not in the queue. How do we
14 handle that going forward.

15 I think this work here is going to
16 inform that, but I just wanted you to keep
17 in mind, note that we have spent most of our
18 time, or I have today, on the first one.
19 How do we address and cost effectively
20 address today's limit with today's
21 generation. But it will be an ongoing
22 dialogue for us.

23 CHAIRMAN ROISMAN: Ed.

24 MR. McNAMARA: I was just going to ask
25 can you talk a little bit about how durable

1 the solutions that you're talking that are
2 being reviewed? In other words how long
3 lasting?

4 MR. SMITH: Short story. I'm not sure
5 I can today. I have been in the last, you
6 know, couple months working on -- a couple
7 slides back the part about foundational
8 data. I'm actually not sure. I think it
9 would depend to some degree, to some
10 significant degree, on which solutions are
11 chosen. Bigger size more than for just
12 today's congestion or not, and I don't feel
13 confident enough to answer at this point.

14 CHAIRMAN ROISMAN: Probably should go
15 on.

16 MR. GIBBONS: I was just going to say I
17 would agree and that note the bigger the
18 solution, the more it has the potential to
19 address future problems. The smaller
20 solutions and maybe the quicker solutions
21 tend to address the current problems and
22 maybe not even all of those. Is that fair,
23 Doug?

24 MR. SMITH: Well said.

25 CHAIRMAN ROISMAN: Okay. Thank you.

1 We will take five minutes.

2 (Recess was taken.)

3 CHAIRMAN ROISMAN: Okay. Are we ready
4 to get going please? You're on.

5 MR. GIBBONS: Thank you. I just wanted
6 to start with an observation which is a
7 career spectrum observation. I had a
8 younger staff person say, wow, that
9 Sheffield Highgate looks really challenging.
10 I would like to be involved. I looked at
11 him and said that Sheffield-Highgate looks
12 really challenging, it's easy winds.

13 This one is messy. I would have done a
14 Power Point, but I did a search on Google
15 and Far Side and Sheffield-Highgate Export
16 Interface, and I couldn't find a comic. I'm
17 going to do it all by verbal.

18 I'm James Gibbons. Currently I work
19 for BED and VPPSA. I'm here talking on
20 behalf of the municipal utilities with the
21 exception of Stowe who is here on their own
22 behalf. I'm going to touch base at a high
23 level. I'm hoping more to cause questions
24 than to go into granular nuts and bolts
25 about specific things.

1 So I wanted to start by saying who is
2 affected by this Sheffield-Highgate Export
3 Interface that we are talking about? And my
4 answer would be all the Vermont distribution
5 utilities are affected by the
6 Sheffield-Highgate Export Interface as it
7 exists today. The problem has implications
8 for all of them. It doesn't have the same
9 implication for everybody, and that has been
10 said, and I'm going to touch base a little
11 bit on that.

12 There are even potentially utilities
13 that are benefiting from the
14 Sheffield-Highgate Export Interface
15 constraints. If you have absolutely no
16 resources in that constrained area, and all
17 the effect that you were seeing was a minor
18 reduction in the wholesale energy prices for
19 your load, this may not be an issue for you.
20 But equally you can be a utility that's not
21 physically located in that area and be
22 seeing an effect, Burlington Electric being
23 one of those.

24 It isn't so much -- our load, the
25 charges we pay for load, are based on a

1 Vermont statewide average price. They are
2 not based on the prices inside this
3 Sheffield-Highgate Export Interface. It's
4 generation payments that are based on the
5 prices inside that Sheffield-Highgate
6 Interface, and that will have effects.

7 I was going to talk briefly on what
8 kinds of effects there are. We have kind of
9 talked about them. I broke them down into
10 three different categories. I think of
11 curtailment as one effect. Curtailment is
12 not being able to produce in particular
13 renewable energy when you would have liked
14 to. Essentially being asked not to produce
15 energy. And you know that's what's
16 happening, for example, to Kingdom Community
17 Wind. You're being asked not to produce
18 energy when you would have liked to
19 otherwise. So that's primarily though --
20 curtailment is primarily an issue that
21 relates to owned generation. If you own the
22 generation, and you -- especially if it's
23 renewable generation, you've incurred all
24 the fixed cost to build it, you typically
25 would like to produce as much energy as you

1 can. And being told not to produce energy
2 is problematic. There is an effect that I'm
3 calling LNP depression, that is depression
4 on the prices for energy, which sounds good
5 again, until you realize that Vermont
6 utilities are both buyers and recipients.
7 And the relative magnitude of your payment
8 and your receipt and how those prices are
9 changing location, like Doug showed in the
10 screen, the shot of his iPhone, have some
11 very interesting effects.

12 Saying the wholesale energy prices are
13 down is not the same as saying good,
14 especially not for Vermont utilities. That
15 LNP suppression affects both owned and
16 contracted resources. That is not an effect
17 unique to one or the other of those. So for
18 example, Burlington Electric has Sheffield
19 Wind. The primary effect we are seeing
20 there is what I would call LNP suppression
21 effects. Sheffield Wind is producing
22 virtually all the power they wish to
23 produce. And there are sometimes of the
24 year now where Burlington Electric is having
25 to both pay for the power that they have

1 produced and pay the ISO New England to put
2 that same power on the grid. And that
3 causes some very unpleasant effects.

4 And the last thing I would say is we
5 have talked to, I'm going to look towards
6 Tom, there can be a constraint on future
7 options coming from this Sheffield-Highgate
8 Export Interface. So for example, if you
9 were a small municipal utility and you
10 wanted to build a generating plant inside
11 your own service territory, but you are
12 located in that SHEI area, you might find
13 that there are people acting to oppose that
14 desire. That has implications for being
15 able to meet tier two obligations under the
16 Renewable Energy Standard.

17 You might just be affected simply by
18 having constraints on what you would like to
19 do. So the relative magnitudes and types of
20 these impacts that you're exposed to tell
21 you whether you're a utility that's looking
22 at this as a major, you know, problem with
23 serious rate implications, whether it's
24 maybe not that big a deal, or like I say,
25 there may be some utilities where it's a

1 small benefit.

2 I don't think there is any -- by the
3 way, having any distribution utilities
4 seeing a major windfall from this. I just
5 think that that tells you the range of
6 spectrum. It can be big impacts to slight
7 negative impacts perhaps.

8 Talking about, by the way, any time you
9 have a question, what kind of potential
10 solutions am I hearing discussed? I'm
11 hearing load building being discussed. I
12 think that got touched on earlier. I've
13 heard it said in the meeting that, well
14 let's just put a thousand cold climate heat
15 pumps up there and fix this problem. That
16 won't fix this problem. You know, if the
17 problem exists primarily in October,
18 November, April and May, cold-climate heat
19 pumps aren't actually using all that much
20 energy then. And conversely, you know, if
21 we add a whole bunch of load at times to
22 where the curtailments are happening and
23 where the prices are being suppressed, what
24 does that say about what that load will be
25 doing the other times of the year when our

1 system may not have been built to handle
2 that load. It's very hard to predict load.
3 It's very hard to count on that load
4 occurring when there is a constraint and you
5 need it to occur.

6 You're almost thinking of a
7 dispatchable load. That would be really
8 cool, right? Every time there is a
9 constraint we will just add some load and
10 get paid for consuming energy, and we all
11 win. Which tends to lead people I think
12 down the path of talking about batteries.
13 You know, batteries. Batteries can be a
14 dispatchable load. You can ask a battery to
15 start drawing energy from the grid, and you
16 could do with that quick notice, but you've
17 got to remember that batteries have a couple
18 of different dimensions. They have a
19 dimension of their size, their instantaneous
20 ability to export energy to the grid, and
21 how long they can do it for.

22 And another thing you need to keep in
23 mind for batteries is they also have to
24 discharge. Okay? They can't just charge and
25 charge and charge and charge and charge.

1 I'm not an engineer, but I have, by the way,
2 proposed the easy solution to this is a
3 dispatchable fault to ground where everytime
4 there is a SHEI curtailment we dump a bunch
5 of energy into a pond somewhere. I would
6 leave it to the engineers to tell me whether
7 that would work. But it's very much -- for
8 storage it's very much a how long, how much,
9 where is it located, who is going to control
10 it. And will there be times between needs
11 for that to be drawing power for it to
12 discharge and be available to draw power
13 again.

14 Transmission. You're certainly hearing
15 about transmission solutions here. By the
16 way, I include in transmission solutions
17 things like line upgrades and other
18 traditional, you know, AVR equipment.
19 Anything that's a traditional hardware- type
20 solution. They have the merit of being well
21 understood. Okay. They have also got the
22 merit of being generally available all the
23 time for practical purposes. But, you know,
24 there is that issue, and again I'm now
25 looking for Tom, if we build a transmission

1 upgrade that increases the capability in the
2 Sheffield-Highgate Interface area, and the
3 Vermont customers pay for it, for example,
4 what happens if a generator wishes to build
5 there and sell their power to Connecticut?
6 How do we know who is going to benefit from
7 that future investment? It's very difficult
8 with the current rules on open access
9 transmission tariffs and things of that
10 nature to control who gets the use of that
11 transmission.

12 So there was a question about duration.
13 Well if GMP does a relatively quick fix that
14 relieves some of the congestion, that will
15 last, but then does the next person come in
16 and say well now it's available. How does
17 GMP make sure they continue to receive the
18 advantage of that. I suspect that would be
19 a legal proceeding.

20 Contractual. This hasn't, I think,
21 been talked about much. There are some
22 contractual things you can do to alleviate
23 this problem, not remove it; to alleviate
24 it. We have a very interesting disconnect
25 going on in a couple of places. We have

1 situations now where the entity that is
2 bidding the asset in the ISO New England
3 market is not the entity that's paying the
4 price to put the power on the grid. That's
5 a -- those are contracts we signed in 2009,
6 for example, when the words do not exceed
7 and negative bid-in weren't even in
8 discussion.

9 And I use a very specific example. The
10 Sheffield Wind plant. Sheffield, the
11 company that owns that wind plant, is able
12 to bid that asset into the ISO New England
13 energy markets. They are not the ones that
14 pay the locational marginal price for the
15 energy that that unit delivers to the grid.
16 The Vermont utilities are in almost all the
17 cases. There is a small piece that they
18 have, still Sheffield has. But by and large
19 the Vermont utilities see that effect.

20 My analogy was if we get in a fight,
21 and I punch you and you punch somebody else,
22 how long will you fight? I mean the person
23 getting punched isn't feeling the pain. The
24 person punching isn't feeling the pain in
25 this case. Sheffield is acting perfectly

1 reasonably. They would bid minus \$150 to
2 put as much generation on the grid as they
3 can because they have a contractual right to
4 be paid a known price for every megawatthour
5 that they deliver to that interconnection
6 point.

7 Now when they do that, the Vermont
8 utilities who own the entitlement to that
9 energy will pay the \$150 to allow that power
10 to be put on the grid. You have a
11 disconnect between the person who is making
12 the energy bidding and the people who feel
13 the price signal under market pricing. And
14 I think that that's something you could
15 address with contracting.

16 BED has taken some different stances in
17 contracting over the years. So Sheffield is
18 an example from 2009. Subsequent to that
19 there was Georgia Mountain Community Wind
20 which was your plant until fairly recently.
21 In that contract Burlington Electric is the
22 lead market participant, and Burlington
23 Electric could make the bidding decisions,
24 and we are the ones subject to the market
25 price when it delivers power.

1 More recently we have a Hancock Wind
2 contract which is up in Maine. We are not
3 the lead participant of that. We are not
4 the majority off taker or anything like
5 that, but we have required that entity who
6 is bidding it to deliver price wise to the
7 Vermont load zone where we pay for our load.
8 So they could bid minus 150 if they really
9 wanted to deliver energy to the grid. But
10 they would have to eat the difference
11 between that minus \$150 price at the
12 delivery point, and the price that we are
13 paying to serve our load. They would
14 therefore no longer be motivated to bid
15 minus 150. They would probably be looking
16 back to a more question like what are my
17 RECs worth, and do I have any, and what are
18 my production tax credits worth.

19 Anytime -- somebody from GMP has said
20 this, but I'll quote them. Anytime you see
21 minus \$150 wholesale energy prices the
22 market isn't working very well. That is not
23 a price that most rational people with a
24 possible exception of a nuclear plant would
25 pay to generate, and when you see renewable

1 plants bidding minus 150, you know it's
2 broken. Because there is no reason not to
3 curtail your renewable plant at an energy
4 price of minus 150 unless you're the one who
5 is not paying it. So I think that that in
6 my mind is very informative.

7 There could be some operational things.
8 We certainly have -- I'm on the VELCO
9 Operating Committee. And I would again -- I
10 interrupted Chris lots of times, so Chris
11 can interrupt me anytime he wants. I think
12 some of the early outages did occur during
13 constrained times. But they may have been
14 outages that were scheduled before any of us
15 became aware of what this really meant. And
16 I certainly did not foresee the magnitude of
17 this I will say that clearly. We are now
18 certainly talking at VELCO when we schedule
19 outages about looking for times where they
20 won't be as problematic. You get a very odd
21 backward land sort of feeling going up
22 there. You'll charge for generating, pay to
23 serve load, and when do we want to take our
24 transmission outages? Middle of the summer.
25 You know, it's a very strange place. And we

1 are reacting to it, and VELCO is reacting to
2 it.

3 I would offer that this is I think the
4 most complicated thing I've seen in 27 years
5 in the Vermont utility industry, and I don't
6 think that -- I would -- I can't think of
7 anything else. And I would say that anybody
8 who says to anybody in this room that, oh,
9 we can just fix this by fill in the blank is
10 dangerously over simplifying a very
11 complicated problem. This is not going to
12 be simple to solve. And I think it will
13 inevitably come up who pays for it and who
14 gets the benefit of it.

15 Burlington Electric -- somebody asked
16 what's the order of magnitude. For
17 Burlington Electric probably just shy of
18 half a million dollars a year is coming out
19 of our impact from the Sheffield Wind plant
20 and from the Highgate converter where we
21 take deliveries of some Hydro-Quebec. But
22 we have less Hydro-Quebec prorata than GMP
23 does or than VEC does, so we don't see as
24 much of that. We don't have any Kingdom
25 Wind, so these things do move. But we only

1 have a Sheffield Wind contract for the next
2 four years. I'm certainly not going to
3 re-sign that contract as it sits right now.
4 I mean I would not accept those terms today.
5 So you know, but you will get to at some
6 point who pays for the solution. You know,
7 if we are going to do this AVR and it lasts
8 this long, and it relieves some of the
9 current constraints, who benefits? BED
10 would benefit from that for four years. You
11 know, there are utilities that might not
12 benefit at all from that. Small utilities
13 might not benefit at all from that. It does
14 matter a lot again how you're positioned for
15 this.

16 And I think I do have some grounds for
17 optimism. I'm not by nature an optimist.
18 But Vermont -- those are the people that
19 know me laughing by the way. Vermont didn't
20 deregulate its utilities. Okay. We are not
21 in a cutthroat competition mode. We never
22 have been in a cutthroat competition mode.
23 I was at a meeting at GMP where I was
24 representing BED and VPPSA. Vermont
25 Electric Co-op was there. We were sharing

1 numbers. My staff is fully authorized to
2 share any information, any insights they
3 have on this problem with any other Vermont
4 distribution utility. We will end up
5 working towards a solution. I think we have
6 a history of working together more than we
7 have had the history of working at opposite
8 ends. When it comes to who pays, that's
9 where we sort of melt down a little bit. I
10 think we will figure it out this time. But
11 we have a lot of really sharp people at the
12 utilities right now. We have a lot of sharp
13 people at VELCO.

14 This goes back to the complexity of the
15 issue. If it were simple, we would have
16 fixed it. It's not simple. I think we will
17 get done. Again it gives me some comfort to
18 know that I have a lot of respect for the
19 people that I'm dealing with in both VELCO
20 and all of the other distribution utilities
21 and at the state. So that's really all I
22 wanted to say.

23 Like I said, I didn't know my audience.
24 I tried to make it very high level. I would
25 happily answer any questions either from a

1 specific -- I would offer one last thing. I
2 mentioned earlier there is no one expert
3 that's going to be able to answer all of
4 your questions on this. I'm going to be
5 able to have a strong opinion on markets, I
6 deal a lot with transmission rates,
7 transmission tariffs, things like that.
8 Physical transmission I know next to nothing
9 about, although I can identify a Hendrix
10 line at a distance.

11 I think you have questions that are
12 being directed to Chris where I might be
13 raising my hand or Doug might be raising his
14 hand. If a question gets asked to me what
15 about this transmission solution on the B20
16 line, I'm going to desperately look to the
17 audience. With that, I would happily take
18 any questions you guys have.

19 CHAIRMAN ROISMAN: Mr. Blittersdorf.

20 MR. BLITTERSDORF: James, I have to
21 disagree. You made fun of the 1,000 heat
22 pumps as a solution. It's actually as we
23 electrify heat and electrify everything as
24 we go into this future of all renewables for
25 our energy supply, we are going to have

1 probably a hundred thousand heat pumps. We
2 are going to need to do demand control and
3 control load. And that's hot water heaters,
4 so that you can now store. It's not going
5 to be batteries. I agree with you there.

6 But we have to really look at this in a
7 whole different way. And I don't see that
8 in this workshop. And just for the PUC
9 commission, where is the speaker besides two
10 utilities and the transmission entity that's
11 owned by the utilities in this room
12 speaking?

13 MR. GIBBONS: Apparently he's sitting
14 about three rows back. Right there. No,
15 you sir. But so we have had this
16 disagreement before, and I will tell you I
17 still think you're wrong. I'm sure you're
18 shocked; right? It's not that you're wrong.
19 It's that there are nuances.

20 I mean I would ask you is April and May
21 and October, November the highest
22 consumption months for heat pumps? For
23 energy?

24 MR. BLITTERSDORF: No.

25 MR. GIBBONS: They are not. Where are

1 the constraints worst in those months? You
2 know, how many heat pumps would you have to
3 add to solve a constraint in April and May
4 or October and November? Well now how much
5 do you have to control? I'm just saying
6 it's a simplification to say that putting a
7 thousand heat pumps out there or 10,000 or
8 50,000 will solve this problem. It will
9 not. It will create a different problem.

10 MR. BLITTERSDORF: My point is -- your
11 point is there is no one solution. I agree
12 with that. But when you look at heating hot
13 water with electricity again, which we have
14 gone off of because of Efficiency Vermont,
15 we moved to fossil fuels, propane,
16 everything else, we have to get back to
17 that. We have to do demand control with the
18 experiment that GMP is doing with a virtual
19 peaker in controlling demand.

20 MR. GIBBONS: Actually we were doing
21 that first by the way.

22 MR. BLITTERSDORF: You were first?

23 MR. GIBBONS: Packetized energy we
24 worked with originally.

25 MR. BLITTERSDORF: We will see who wins

1 that battle, who does it best. But the
2 point is there is a lot of things that we
3 are going to electrify, and we don't totally
4 know how much, but it's going to be massive,
5 and we are going to need to grow demand by
6 two to three times what we have today.

7 MR. GIBBONS: We have a tier three
8 program that's required to do some of that.
9 My comment is adding load to the extent it
10 occurs at the times of the curtailments will
11 help. But it will have load that occurs at
12 times other than curtailments, and we have
13 to understand that implication. I don't see
14 how that can be debated.

15 And again, like I say, tier three was
16 very specific. Tier three said you must use
17 demand, we understand, you need to do it.
18 But I'm saying this is all happening, and
19 while it's happening millions of dollars are
20 getting expended by Vermont ratepayers. So
21 I just think again I'm trying not to let
22 this get over simplified because I think
23 oversimplification is not going to help us
24 here.

25 CHAIRMAN ROISMAN: I just want to be

1 clear so there is no confusion. When we
2 announced the workshop we invited anybody
3 who wanted to speak to speak. The only
4 people who spoke up and asked to make
5 presentations are the ones you heard. But
6 if you're here, you shouldn't feel
7 constrained to use a word --

8 MR. GIBBONS: In fact, if you're here
9 in the audience still wanting to speak,
10 maybe you should be thinking --

11 CHAIRMAN ROISMAN: Right. I want to
12 encourage anybody at this point either
13 questions for James or comments to make
14 about what we are talking about. I don't
15 think there is anybody in this room, unless
16 I'm misreading the audience, that doesn't
17 want to see a solution to this. And as I
18 said at the beginning, given all this
19 talent, we ought to be able to figure that
20 out. No one suggests it would be easy, but
21 where there is a will there is a way.

22 So speak up. If you've got something
23 to say, to add, to raise a question about,
24 that's what we are here for.

25 MR. GIBBONS: And -- sorry. And so far

1 to the extent we talked about cost
2 allocation, VELCO is incurring some costs to
3 look at options for this, and all the
4 Vermont utilities have said we understand
5 that. We will pay our share. It has not
6 been a barrier to having VELCO doing the
7 work to set us up for this. But there is a
8 limit to the list of things that you've seen
9 there. And I agree with you on that.

10 CHAIRMAN ROISMAN: Question.

11 MR. CARPENTER: Yeah. Dave Carpenter
12 again. You said something that in all the
13 hours and hours of VSPC meetings and stuff I
14 had not heard until it just came out of your
15 mouth is that there are some folks who are
16 benefiting from the constraints.

17 Can you drill down on that a little bit
18 and explain that in more detail?

19 MR. GIBBONS: I will try. So again,
20 I'm speaking on behalf of -- I lose track --
21 is it 12 or 13 utilities? Does anybody
22 remember how many utilities are in VPPSA
23 right now? I'm a little schizophrenic. I'm
24 also a bit sleep deprived right now so I'm
25 trying not to do an alternate reality view

1 of SHEI.

2 MR. CARPENTER: Adequately caveated.

3 MR. GIBBONS: Thank you. Let's take a
4 utility, and I'm going to -- I think Barton,
5 for example, does not have any Hydro-Quebec
6 power. Okay. They also, to the extent they
7 have generation inside that SHEI area, those
8 generators are not settled through the
9 market system. So they are not exposed to
10 nodal pricing at those depressed prices.

11 The only thing that I can think of
12 Barton -- I'm using it as an example --
13 there are others in a similar position, but
14 I'm using Barton because I checked this one.
15 Barton would be exposed to LNP suppression
16 for the Sheldon-Highgate facility. That is
17 a PURPA unit. That is a PURPA unit under a
18 20-year rule 4.100 contract. That is at
19 known prices. Again you've got a situation
20 where the utility is paying for its share of
21 generation, the known fixed price, and the
22 value of that generation has been depressed
23 relative to what that utility is paying for
24 its load. That contract expires March 31,
25 2018.

1 At that point in time you'll have
2 Barton looking at -- they have nothing
3 settled in the SHEI Interface at depressed
4 prices. To the extent there's a small
5 effect on Vermont, overall zonal average
6 LNP, that's what Barton pays for its load.
7 If all other resources are settled outside
8 that area, it's very possible this would be
9 a small benefit for Barton. Does that
10 answer your question?

11 MR. CARPENTER: Starts to.

12 MR. GIBBONS: I'm trying to explain
13 some of these things to people in the
14 audience who are industry experts and some
15 of it is pretty nuanced.

16 CHAIRMAN ROISMAN: Chris?

17 MR. ROOT: So coming off transmission
18 outages we have to do maintenance
19 periodically. We do 300 structures in 2018.
20 We have to take out --certain lines we have
21 to take out.

22 We are very sensitive to issues about
23 generation, impact on generation. we are
24 sensitive to that. Certain of our capital
25 projects have impacted over the last 18

1 months. We did a big job in Essex. We had
2 to replace a big piece of equipment, had a
3 big outage with it.

4 We just put the cables underneath Lake
5 Champlain two weeks ago and upgraded that.
6 But there was environmental constraints that
7 only certain times of the year you could do
8 it. Some of our outages are constrained by
9 you have to do it when the wetlands are
10 frozen. So we do work in frozen times. So
11 there is certain environmental impacts that
12 we have to do on certain capital work that
13 constrains us to doing in the wintertime.
14 Other times we like to do other times. You
15 can't do all your maintenance in a
16 three-month period of time in the summertime
17 where the loads in southern New England is
18 very high. VELCO applies to ISO New England
19 and say we would like to do this
20 maintenance, this is when we would like to.
21 We have to -- usually three months in
22 advance we actually set that time what we
23 need. We can go down to as short 30 days.
24 We are asking for permission, and then we
25 get permission from them to allow us to do

1 that maintenance. So it isn't totally a
2 hundred percent up to VELCO to decide when
3 we do maintenance. We have to plan it with
4 other things.

5 For example, when we were doing the
6 cable underneath Lake Champlain and we had a
7 two-week outage at the end of it to connect
8 it into the Vermont system. If we were late
9 on that job, we would be told that we could
10 not finish the job until May. And the
11 reason for that is there was other work
12 going on in between New York and Connecticut
13 that was scheduled behind us which was going
14 to take place after we were done. So it
15 gets very complicated on that.

16 But we are sensitive to this issue.
17 Even though we have certain constraints
18 legally,

19 we can't favor one generator over another generator;
20 not allowed to do that. We are sensitive to
21 the issue of SHEI. Now we look at -- every
22 time we are going to take an outage, we ask
23 the question, can we move it? Is there
24 another time to do it? Is there another way
25 to do?

1 MR. GIBBONS: Is there a time when it
2 would not adversely affect the SHEI
3 Interface as much as it would when we do it
4 here.

5 MR. ROOT: The outage we have moved it
6 out of these areas. There is some things
7 that we have actually already done
8 proactively to try to do it. We are
9 considering all the impacts of this thing as
10 we plan our maintenance. So it's not like
11 we are not concerned about this. We are.

12 MR. GIBBONS: And the general forum I
13 think in that case is the VELCO Operating
14 Committee where all of the distribution
15 utilities have representation on the VELCO
16 Operating Committee. And outages are
17 discussed. And the first question these
18 days is have you looked at the SHEI
19 Interface implications of this outage. So
20 we are learning.

21 CHAIRMAN ROISMAN: Other questions,
22 comments? Mike?

23 MR. POLHAMUS: Mike Polhamus. I'm
24 sorry if I'm proceeding under some wrong
25 assumptions here. I probably am. I seem to

1 recall that there is a cable that might go
2 in under the lake we have dibs on 200
3 megawatts from, and that's coming from
4 Hydro-Quebec, I believe.

5 If that project went in, would that
6 potentially allow some of these contract
7 holders to --

8 MR. GIBBONS: Could I take a first
9 pass, Chris? So there were two projects;
10 the TDI line which is a thousand megawatt
11 line that would come down the lake, connect
12 eventually to the VELCO system at the
13 Coolidge substation in Ludlow, Vermont,
14 which is on the south -- well south of the
15 SHEI Interface. The other one was the
16 Vermont Green Line which was, I think,
17 withdrawn. Okay. Which was a 600 megawatt
18 project that was proposed to come ashore in
19 New Haven and tie into the 115 kilovolt
20 system in or around New Haven. 345 system.

21 But that was a lot further north, and
22 these questions were certainly raised in the
23 context of those, generally speaking, and
24 there is a Vermont -- okay, not say that
25 one. But yes. These questions are looked

1 at as to where they are going to tie into
2 the system, how robust the system is at the
3 point they are going to tie into it. Do
4 they therefore tend to -- we are talking
5 about the SHEI like it's a fixed area. If
6 you change the generation injections and
7 things like that, it can move. You can have
8 the constraint move further south.

9 It was possible that adding the Vermont
10 Green Line would have moved this constraint
11 south of Burlington, and suddenly you would
12 have McNeil in the constrained area. You
13 would have Winooski One in the constrained
14 area. You would have Georgia Mountain
15 Community Wind in the constrained area. I
16 think at a qualitative level I would say it
17 is going to be important to understand when
18 we talk about putting a generator anywhere
19 what it will do to other generation. So if
20 we are looking at a statewide economic
21 benefit test and we are saying I'm going to
22 put this generator here, and I'm going to
23 produce a thousand megawatthours, what if
24 you're causing another renewable generator
25 that's already been built to back off 300

1 megawatthours?

2 James, stop talking now. He was
3 looking in the right direction at the moment
4 though. So I have no further comments on
5 this point.

6 CHAIRMAN ROISMAN: Anybody else?
7 Staff? Tom? Mary Jo? All right. Thank
8 you.

9 MR. GIBBONS: Thank you.

10 CHAIRMAN ROISMAN: Okay. So the next
11 steps we are not sure where you think we
12 ought to go from here. You've done a good
13 job of helping us understand that this is
14 not an understandable problem. So and it
15 sounds like there is going to be some
16 possible solutions coming in the foreseeable
17 future, next couple of months.

18 Does it make sense for us to get
19 together again after that's done and see
20 what those look like? Chris.

21 MR. ROOT: I think it makes sense,
22 because it's a public forum, to be able to
23 share ideas with a large constituency.
24 That's what we tried to do with the Vermont
25 System Planning Committee. We tried to

1 present some of this stuff.

2 My anticipation is that later on, late
3 winter, we will have a lot more facts, and I
4 think the more discussion we have about it
5 the better. I mean that's VELCO's position.
6 We want to be the facilitator, but in the
7 end we are probably not the decision maker.
8 It's going to be -- going to have to
9 deciding who is paying, and that's kind of
10 beyond what VELCO is doing. But we
11 certainly would like to come to an answer
12 that hopefully there is a solution set here
13 that people will be comfortable with and
14 then that they can bring to people.

15 But having discussion on a broader open
16 forum, we think that's a good idea.

17 CHAIRMAN ROISMAN: And that does seem
18 to make sense to us also. I think if we are
19 going to proceed that way, I would urge you
20 to use this docket and ePUC and put into our
21 docket everything that you're ready to make
22 public so that everybody -- everyone here
23 and any people who aren't here can look at
24 it before we try to have another
25 conversation. So people aren't seeing it

1 for the first time when they are here, they
2 have a chance to look at it and raise
3 questions about it.

4 And then maybe suggest parameters for
5 what a workshop second phase ought to look
6 like. Does that make sense?

7 MS. HOFMANN: It does make sense. The
8 only thing I would add is that in submitting
9 things to ePUC please keep in mind the
10 caveat that we had at the beginning that --
11 stay away from case-specific things that are
12 in an open docket.

13 CHAIRMAN ROISMAN: Right. Yes. Okay.

14 MR. SMITH: Could I ask a question on
15 that? Do you have any advice for us if we
16 are not sure if a piece of information
17 crosses that line? Just today we had our
18 colleague, Tom, to raise a hand or flag, but
19 seriously can we ask for procedurally any
20 way to screen to make sure we are not
21 getting in a problematic area with
22 information that's case sensitive like you
23 said?

24 CHAIRMAN ROISMAN: Well let me suggest
25 that you start with your lawyers. Ask them

1 what their advice is. I know it's hard to
2 find lawyers at GMP but -- should you find
3 one. (Laughter) I'm not -- seriously. It's
4 hard. We are not comfortable sort of giving
5 out legal advice. We are all right with
6 giving orders. (Laughter)

7 So seriously, I think that if you talk
8 to your lawyers and there is a question
9 there, because this is an ex-parte process,
10 contact Tom or one of -- Mary Jo, one of the
11 other lead staff people, and just ask them.
12 Say, hey, I wanted to talk about this. Do
13 you see any problem with that.

14 MR. SMITH: Very good.

15 CHAIRMAN ROISMAN: I don't see a
16 problem with that. My guess is seriously
17 that the lawyers for all of you parties and
18 those of you who are lawyers here have a
19 pretty good idea of where the boundary is
20 between what's a generic matter that doesn't
21 cross the line and where, you know, where
22 there is a problem.

23 MR. GERHARD: I'm sorry, Mr. Chairman,
24 for unrepresented folks in the audience or
25 people who want to comment, then their first

1 line of defense would be Tom or Mary Jo?

2 CHAIRMAN ROISMAN: Yes. Sure.

3 MR. GERHARD: Okay. Thank you.

4 CHAIRMAN ROISMAN: Tom and Mary Jo look
5 really happy about that.

6 MS. KROLEWSKI: Non lawyers.

7 CHAIRMAN ROISMAN: You should add that
8 caveat. It happens that the two most
9 knowledgeable people on staff neither one of
10 them are lawyers. But --

11 MS. CHENEY: That's true at large.

12 CHAIRMAN ROISMAN: I will tell you my
13 own personal experience is that the best
14 lawyers I ever met never went to law school
15 and don't have law degrees, but they think
16 analytically, so I think you'll get good
17 advice.

18 All right. So as we pointed out, this
19 is not contested, so don't be reluctant to
20 give other thoughts. Share them with us,
21 file them in the ePUC, let us see what your
22 comments are. We are trying to be
23 knowledgeable enough so we can evaluate
24 solutions when and if they are submitted to
25 us.

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And ePUC is by far the best way if you can possibly use it or have any trouble with it at all, we are blessed with a brilliant deputy clerk, Holly Anderson. Just contact her. And she will help you navigate any problems that you might have with it.

And thank you again everyone. It's been very, very helpful.

(Whereupon, the proceeding was adjourned at 3:50 p.m.)

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I, Kim U. Sears, do hereby certify that I recorded by stenographic means the Workshop re: CASE NO. 17-5219-INV, at the Pavilion Auditorium, 109 State Street, Montpelier, Vermont, on January 11, 2018, beginning at 1:30 p.m.

I further certify that the foregoing testimony was taken by me stenographically and thereafter reduced to typewriting and the foregoing 108 pages are a transcript of the stenograph notes taken by me of the evidence and the proceedings to the best of my ability.

I further certify that I am not related to any of the parties thereto or their counsel, and I am in no way interested in the outcome of said cause.

Dated at Williston, Vermont, this 16th day of January, 2018.

A rectangular box containing a handwritten signature in cursive script that reads "Kim U. Sears". The signature is written in dark ink on a light-colored background.

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