STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7307

Investigation into Vermont Electric Utilities'	)
Use of Smart Metering and Time-Based Rates	)

Order entered: 8/3/2009

ORDER RE: MEMORANDUM OF UNDERSTANDING

I. INTRODUCTION

In this Proposal for Decision ("PFD"), I recommend that the Public Service Board ("Board") approve a Memorandum of Understanding ("MOU") among many of the parties to this proceeding, subject to certain clarifications and modifications set out herein. The MOU, which was agreed to by all of Vermont's eleven distribution utilities, the Department of Public Service ("Department" or "DPS"), Conservation Law Foundation ("CLF"), and Vermont Electric Power Company, Inc. and Vermont Transco LLC ("VELCO"), sets general guidelines for the implementation of Advanced Metering Infrastructure ("AMI"), also referred to as Smart Metering, as well as policies associated with alternative rate designs.[1] The parties should be commended for the thought and effort they have put into crafting the MOU. These guidelines provide a sound framework for each utility to evaluate the possible deployment of AMI in its service territory.

This PFD recommends several modifications to the MOU. The primary change is that the pre-approval process set out in the MOU should be mandatory. This alteration is necessary and appropriate to be consistent with long-established regulatory standards for providing cost-recovery guarantees. Other changes affect the timing of future actions for each utility to evaluate

1. The concept of a "Smart Grid" encompasses three components: advanced metering; customer site automation; and electrical grid automation. This proceeding has focused on the first component, which may include devices deployed at the customer location to convey price signals, but not necessarily automation on-site.

the cost-effectiveness, and the recommendation that the Hearing Officer convene further workshops to examine certain alternative rate designs that are not related to smart metering.

II. Background and Procedural History

The Board opened this investigation on April 18, 2007. At that time, the Board outlined the purpose of the investigation:

> At a minimum, this investigation will evaluate the current status of Advanced Meter Reading and Advanced Meter Infrastructure technology deployment in Vermont and other jurisdictions, the costs and benefits of increased use of these technologies, analysis of barriers to implementation, the possible necessity of state-wide standards or other requirements, and the value (if any) to be gained by use of a pilot program. Moreover, this investigation will evaluate the use of time-based rates as they relate to smart metering, and may be expanded to include consideration of inclining block rates, should future legislation or a subsequent Board ruling require it.[2]

Subsequent to the Board's Order opening this investigation (as well as the initial stages of the investigation), the Vermont General Assembly enacted Act 92 (2007 Adj. Sess.), which ordered the Board to investigate the implementation of Smart Meters capable of sending two-way signals that would allow for innovative, dynamic rate designs for every rate class and to develop a report and implementation plan by December 31, 2008, for implementation of Advanced Metering Infrastructure and alternative rate designs. This mandate coincided with the scope of the investigation already under way. In 2008, the General Assembly also directed the Board to investigate the benefits and costs of constructing a fiber-optic or other telecommunications facility network linking electric company substations and to submit a report to the Legislature on or before January 15, 2009.[3] The deployment of more robust communications links to substations could produce synergies by using such links both to achieve the state's goal of extending broadband services to all Vermonters and to simultaneously facilitate enhanced

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2. Order of 4/18/07 at 1.

3. The Board did not expand the scope of the docket to include the issue of substation interconnection, but due to the fact that smart metering requires some communications infrastructure, the parties considered it during their collaboration.

substation communications and AMI communications links as part of the pursuit of Smart Grid technologies.

The first phase of this investigation involved a high-level review of the potential benefits of AMI. The Department employed a consultant who analyzed those benefits for each of the Vermont utilities. This analysis showed that, in general, smart-metering technology could lead to net savings for the electric utilities. The most direct effects fall into two categories. Operational benefits reflect the savings that utilities can achieve as a result of replacing existing meters with the advanced metering technology, most significantly in the area of avoided meter-reading costs. Demand-response benefits arise from the savings that can result when consumers receive direct and timely price signals and, as a result, alter their consumption patterns. Achieving demand-response benefits requires the adoption of new rate designs and, generally, some mechanism (such as on-premises equipment) to convey the price signal to the customer. It is also likely that demand response from customers will result in improved reliability and environmental benefits (through the shifting of loads to times when the electric generation fuel mix has fewer emissions).

The analysis of the Department's consultant also suggested that for all but the smaller municipally-owned utilities and Green Mountain Power Corporation ("GMP"), implementation of smart-metering technology may be cost-effective now. If sufficient demand-response savings can be achieved, AMI deployment may produce benefits even for GMP and the smaller municipals.

The Department's analysis was not intended to be comprehensive; rather it was designed as a high-level cost-effectiveness screen to determine whether further examination of the benefits of smart-metering technology was appropriate. The positive results for a large number of Vermont utilities show the need to conduct a more detailed assessment of the cost-effectiveness of deploying some level of AMI infrastructure within those utilities. To examine these (and other) issues relating to AMI infrastructure, the parties engaged in a collaborative process. The collaborative process involved the formation of topic-specific working groups that formulated minimum requirements for AMI in Vermont and recommendations on policy issues that may affect deployment. They also established a process for further evaluation and study of necessary backbone communications facilities. The result of that collaboration was the MOU.

III. FINDINGS

Pursuant to 30 V.S.A. § 8, and based on the record and evidence before me, I present the following findings of fact and conclusions of law to the Board.

1. AMI includes the associated hardware, software, and two-way communications systems that collect time-differentiated energy usage from Smart Meters. AMI technologies collect, process, and record the information, and make the information available to customers and utilities. "Smart Meter" means any meter that functions as part of AMI. MOU at 3.

2. "Smart Grid" refers to a concept that embodies an electricity network that uses advanced sensing, communications, and control technologies to generate and distribute electricity more effectively, economically and securely. MOU at 4.

A. Current Status of AMI implementation

3. Vermont Electric Cooperative, Inc. has commenced a system-wide implementation of AMI and is working to enhance capabilities of its system. MOU at 22.

4. Central Vermont Public Service Corporation ("CVPS") is planning for the system-wide implementation of AMI based on the processes contemplated in the MOU. In accordance with the requirements of the Board's Order of September 30, 2008, in Docket No. 7336, CVPS must file with the Board an AMI Implementation Plan for the introduction of AMI within its service area within 6 months of the date of that Order.[4] In connection with its AMI Implementation Plan activities, CVPS plans to establish forums for briefing Distribution Utilities ("DUs" or "utilities"), the Department, and interested stakeholders on lessons learned concerning AMI implementation issues. MOU at 21–23.

5. The City of Burlington Electric Department ("BED") recently entered a power-supply contract for capacity reduction through a demand-response program operated by a third-party

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4. CVPS has since requested, and received, permission to extend that date.

vendor that leverages AMI capabilities without requiring BED ratepayer investment. MOU at 22.

6. Except for the specific actions described in the preceding findings, there is not presently widespread use of either advanced metering or rate designs that are enabled by AMI by Vermont DUs. MOU at 22.

7. A substantial number of electric utilities around the country are in some stage of planning and/or deploying smart-metering technology. MOU at 23 and Attachment.

8. While there has been much development in AMI technology, much of that technology is new, and is not in universal use at this time. MOU at 23.

9. The collaborative process established in this docket provided a mechanism for utilities to share experiences. Continuation of such coordination will permit the further exchange of information. MOU at 24.

B. AMI Implementation

10. AMI implementation represents a significant expense for the DU, and there exist cost-effectiveness questions regarding AMI implementation. The rural nature of much of Vermont, and the relatively modest use of electricity especially in the residential sector, also influence the timing and cost-effectiveness of AMI investments. MOU at 23.

11. The costs and benefits of AMI implementation also vary by utility. Any implementation of AMI must reflect consideration of utility-specific costs, benefits, and other factors. MOU at 20.

12. In general, a determination of whether to deploy AMI systems and what systems and capabilities to implement encompasses consideration of a range of general and utility-specific factors, including:

- the immediate and long-term requirements of the DU and its customers;
- the State of Vermont's energy policy;
- the potential societal and economic benefits of Demand Response ("DR") programs, Time-of-Use and/or Dynamic Pricing, home automation offerings, improved system reliability, increased Smart Grid functionality and other emerging opportunities;

- the costs of deploying a proposed AMI system and/or establishing Dynamic Pricing, new AMl-enabled rate designs and/or a DR program;[5]
- the costs of integrating the AMI system with legacy software systems;
- any operational savings expected to be obtained during the time the AMI system and associated Dynamic Pricing, AMI-enabled rate designs and/or DR programs are in place;
- the estimated costs for any plant retirements resulting from the implementation of an AMI system;
- the estimated severance costs anticipated to be incurred as a result of the implementation of an AMI system; and
- any other estimated costs or benefits attributable to the implementation of the AMI system.

The MOU refers to this rate and cost analysis as the "Business Case" for AMI implementation. MOU at 4–5.

13. The parties agree that each DU should determine whether to include in its AMI Implementation Plan any of the features outlined in Finding 18, below, or new features that may emerge, based on its specific Business Case. The DUs have agreed to consider the costs and benefits of potential additional features on an on-going basis.[6] MOU at 7.

14. Due to the cost and technological fluidity of AMI investments at this time it is difficult to specifically predict the rate effects attributable to AMI investments in the short term. The opportunity to achieve savings in the long term over what otherwise would have occurred depends on such factors as technology selection, the current cost of the metering function, and customer acceptance of the technology and rate designs implemented by the DU. MOU at 24.

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5. For purposes of the MOU, DR programs refer to utility-sponsored programs that use AMI technologies to induce lower electric use at times needed for economic or reliability purposes.

"Dynamic Pricing" means rates that can change based upon short-term market conditions with little advance notice to customers. Some utilities now implement Critical Peak Pricing programs in which customers are charged a higher rate during limited high-load, high-cost periods. These programs are one example of Dynamic Pricing. AMI technologies enable more sophisticated use of such programs, including real-time pricing.

"Time-based pricing," "Time-of-Use Pricing" or "TOU" refers to rates that have different prices depending on the time or type of day. The time periods are pre-defined in the tariff and therefore do not have the variable flexibility present with dynamic rates to react to short-term market conditions.

6. As described in the findings below, under the MOU, a utility that is considering deploying AMI could develop both a Business Case and an AMI Implementation Plan, for which it could request Board approval. The MOU contemplates that the details of the utility's plans would be spelled out in these documents.

15. The parties agree that each DU should periodically review its Business Case and AMI Implementation Plan to confirm or update assumptions and objectives. MOU at 5.

16. The MOU also calls for the following further actions related to evaluation and implementation of AMI:

- On or before February 16, 2009, each DU will present an analysis of the requirements of Act 92 (2007 Adj. Sess.), Section 10, paragraphs (b)(1) through (b)(7) as it relates to that utility;
- Subsequent to the initial utility filings, the Board will hold a workshop to discuss each DU's ongoing analyses and implementation activities relative to AMI issues. The workshop will focus on: (1) the lessons learned by DUs relative to AMI; and (2) the establishment of a procedure for assigning power-cost savings, and revenue streams associated with the DU's AMI-enabled Demand Response, Dynamic Pricing and/or rate designs to the DU, and for assigning efficiency savings and revenue streams attributable to the AMI-related activities of the EEU to the EEU, Efficiency Fund or such other entity or fund.
- Nine months from Board approval of the MOU, each DU will file a report with the Board and the Department discussing its ongoing AMI efforts. The scope of the report will be determined at the workshop and may include requirements for addressing: (1) progress to date in planning for prospective implementation of AMI and advanced rate designs; (2) any capital plans of Vermont utilities implementing AMI; (3) further fact-finding necessary to consider further plans for AMI implementation and advanced rate designs; (4) DU efforts in analyzing or studying the cost effectiveness of such investments; and (5) prospective opportunities for inter-DU cooperation or more formal arrangements regarding meter data management ("MDM") systems, back office or AMI field support, and/or other AMI service options, including MDM services, developed from the vendor community.

MOU at 20–21.

C. Functional Requirements for AMI Systems

17. The parties agree that each DU that implements and deploys an AMI system shall select an AMI solution with basic functionality that includes, at a minimum, the following features:

- Two-way communication whereby the DU has the ability to poll the Smart Meter to gather data from and send data to the Smart Meter.
- Time-based consumption data whereby the DU has the ability to capture from the Smart Meter individual customer energy use recorded in time-stamped intervals at a minimum frequency of once an hour.

- Central collection point and data repository that is sufficient to manage the time-stamped hourly interval data that is retrieved daily, at a minimum, by the DU or more frequently if the DU chooses.
- On-demand readings whereby the DU can poll the Smart Meter at any time.
- Power-outage notification whereby the Smart Meter is capable of capturing power-outage information.
- Tamper-detection alerts whereby the DU is notified of potentially suspicious events that may include meter removal, inversion, or an unexpected programming event.
- Remote firmware and software upgrades whereby end devices can have the latest revisions and enhancements added to them without the DU visiting the premises.

To the extent that open standards are available, they should be considered and given weight in the DU's selection process. MOU at 5–6.

18. The MOU also provides that each DU that deploys an AMI system also take reasonable steps to design a robust system that can deliver, initially or in the future, the following additional features, many of which are currently emerging:

- Direct load control whereby the DU has the ability to remotely turn on or off a predetermined load that has been agreed upon by the DU and its customer.
- Passive load control whereby the DU notifies its customer of real-time pricing, and the customer chooses whether to realize the conservation benefit.
- Whole house service switch whereby the DU has the ability to remotely turn on or off the entire service to its customer.
- Communications to Home Area Networks ("HAN") including in-home displays, programmable thermostats, and smart appliances whereby conservation benefits may be achieved by giving customers and/or their appliances real-time pricing information to assist them in making informed decisions on consumption.
- End-of-line voltage recording whereby the DU can use this information to ensure that voltages are within proper limits, to assist with voltage-reduction opportunities, reduce system losses, and gain Smart Grid functionality.
- Advanced outage management whereby the DU can poll end devices to gather information to assess the scope of an outage and restoration progress with the end result being improved information flow that may result in improvements in the restoration process and a reduction in outage duration and operating expenses.
- Power quality ("PQ") recording whereby the DU has the ability to collect advanced PQ data which may include sags, swells, PQ interval data or harmonic information.

- Communications protocols whereby the DU has the ability to improve control of its distribution system by remotely monitoring and controlling devices such as capacitor banks or voltage regulators to enhance system integrity and gain efficiencies.
- Web presentment whereby customers may take advantage of Internet tools to increase awareness of energy consumption and associated costs by viewing their interval data.
- Additional service offerings such as home-security options whereby the DU may be able to offer or enable services outside of traditional electric utility offerings.
- Water and/or gas meter reading whereby the DU may be able to expand or enable such service offerings.
- Third-party accessibility whereby parties other than the DU and its customer may access meter data with appropriate security measures that insure the integrity of the data is not compromised in place.

The MOU further recognizes that AMI technology is evolving rapidly and new features may emerge or current additional features may become standard offerings. MOU at 6–7.

1. Telecommunications Infrastructure Needs

19. The MOU specifies certain telecommunications infrastructure requirements. These standards are intended to be consistent with North American Electric Reliability Corporation ("NERC") requirements, Energy Independence and Security Act of 2007 requirements, and good utility management practices, while also supplying the functionality necessary for AMI and other utility communications needs. MOU at 7–8.

20. AMI communications needs can complement the utility's needs for communications with its substations for reliability purposes. AMI demands greater bandwidth, while reliability of the communications links is more important for substations. Over time, the parties anticipate that the aggregate communications needed between substation applications and AMI is in the range of 1.5Mbps. MOU at 8.

21. At this time, the AMI communications infrastructure has two components: communications that allow the meter to communicate to a collecting point and communications which allow the collecting points to talk to a head-end system. The MOU specifies that the former will be based upon the specific characteristics of the territory. The latter (also known as

"backhaul") will require the DU to evaluate the potential benefits of combining AMI infrastructure with substation communications needs. MOU at 9.

22. Backhaul communications needs can be met with an array of incremental additions to existing utility infrastructure including the use of microwave, radio, fiber optics, power-line carrier, satellite and leased circuits. MOU at 9–10.

23. The MOU specifies that the telecommunications capability and capacity required to meet these needs is 9.6 kbps per substation with 99.99% availability except in a very few cases for current distribution substation communications requirements. Typically AMI needs are 20 kbps per 1000 customers served to support deployment of the functional requirements and features described in Findings 17 and 18, above, (a meter data concentrator generally can support 1000 users) with 99.9% availability at the concentrator. MOU at 8.

24. The parties agree that telecommunications needs at substations or other AMI collecting points should be defined based on what is needed by the utility to support a broad array of communications applications that may be deployed and not limited to the needs of substation and AMI communications. MOU at 9.

25. The communications needs of the AMI systems can be met through a variety of solutions, including utility-developed or co-developed wireless or fiber, as well as carrier-provided services. MOU at 8.

26. Communications serving substation and AMI needs must be secure, consistent with NERC and other regulatory requirements. MOU at 9.

27. It may be possible to coordinate the DU communications needs for AMI with existing state initiatives to deploy broadband ubiquitously, thereby obtaining savings through these synergies. This coordination and cost-sharing (both cash and non-cash costs) may produce some synergies that reduce costs for both ventures. MOU at 10–11.

28. The parties agree that in the case of coordinated deployment, a DU should not be required to incur additional costs or make incremental investments beyond what it requires to meet its own long-term communications needs. MOU at 10.

2. In-home Communications

29. Deployment of consumer in-home displays offers promising benefits to DUs and consumers to enable energy-use awareness, innovative rate offerings, demand-side load reductions and energy efficiency savings. However, these options are just emerging and little industry application, experience and customer-acceptance knowledge currently exists with these offerings. MOU at 11.

30. The parties agree that standard communications protocols for in-home communications are beneficial for the industry and that DUs should monitor and support the continued development of standards. MOU at 11–12.

D. AMI Implementation Process

31. Under the MOU, any DU wishing to deploy AMI and Smart Meters may, in its discretion, make a filing with the Board setting out the DU's Business Case and AMI Implementation Plan for the introduction of AMI, or a phase or portion thereof, within the DU's service area. MOU at 18.

32. The MOU provides that deployment and use of Smart Meters by a DU will be on a voluntary basis, as would development and implementation of any DR program using the smart-metering technology. MOU at 18.

33. An AMI Implementation Plan would be adapted to consider the specific AMI technologies or applications the utility intends to deploy. MOU at 19.

34. The MOU contemplates that a DU, the DPS and stakeholders could enter into a Utility-Specific MOU, which would further define the conditions that apply to the AMI deployment and could describe an ongoing review process by the DPS and stakeholders to allow for verification of results and adjustments. MOU at 19–20.

35. The MOU provides that, as part of a DU's AMI Implementation Plan, a DU may seek approval for the establishment of cost recovery for AMI investments, retirements, costs and expenses. MOU at 18.

36. The MOU provides that any DU's AMI Implementation Plan and Business Case filing should include:

- An analysis that demonstrates to the satisfaction of the Board that the implementation of the proposed AMI and related system investments is in the public interest and has estimated benefits greater than estimated costs;
- Supporting documentation and assumptions to show the reasoning and methodology used in developing the estimates of net benefits for customers described in the Business Case;
- Estimates and supporting documentation for the costs of deploying the AMI and related systems and/or establishing Dynamic Pricing, AMl-enabled rate designs and/or a DR program described in the Business Case;
- Identification of the estimated costs associated with the integration of the AMI and related systems with legacy software systems and any other indirect costs from systems supporting the proposed AMI system described in the Business Case;
- Any operational savings expected to be obtained as a result of the implementation of AMI and a schedule for the timing of such savings;
- Any operational savings expected to be obtained as a result of the implementation of Dynamic Pricing, AMI-enabled rate designs and/or DR programs and a schedule for the timing of such savings;
- A proposed schedule including all major milestones associated with AMI deployment, Dynamic Pricing, AMI-enabled rate designs and/or DR program implementation;
- A proposal for the establishment of cost recovery for the recovery of all investments, retirements, costs and expenses associated with the AMI Implementation Plan;
- Identification of the proposed AMI system's minimum functionality and a listing of any additional service offerings that will be created by the proposed AMI deployment and a schedule of when these services will be available to customers;
- Identification of the technologies to comprise the AMI and related systems and supporting information that these systems are based upon proven technologies.
- A monitoring, reporting and change process for periodically evaluating the actual costs and benefits of implementation and comparing such results with the Utility Specific MOU and Business Case, and where warranted updating the Utility Specific MOU and Business Case for future periods.

MOU at 18–19.

37. The MOU provides that, after notice and an opportunity for hearing, the Board would act upon a DU' s request for approval of an AMI Implementation Plan within a reasonable time. MOU at 20.

E. Cost Recovery for DU AMI Investments, Retirements, Costs and Expenses

38. The National Association of Regulatory Utility Commissions ("NARUC") has adopted a policy recommending that state commissions consider provision for timely cost recovery of prudently incurred AMI expenditures to encourage deployment. MOU at 13, 39–41.

39. To reduce risk for the utilities, the MOU specifies that the Board should adopt a regulatory review process whereby any DU planning to implement AMI may develop, and seek approval of, its AMI Implementation Plan and Business Case. Under this proposal, prior approval would not be mandated, but would be at the option of each utility. MOU at 14.

40. In general, the AMI Implementation Plan and Business Case would identify all aspects of the proposed AMI deployment and ratemaking practices that would apply to the investment. MOU at 14–17.

41. The MOU provides that the AMI Implementation Plan and Business Case would be considered to be in the public interest if all of the following conditions are met:

- The estimated benefits associated with the AMI Implementation Plan and Business Case are shown to be greater than their costs as determined by standard cost-effectiveness tests or other reasonably estimated net benefits analysis reflecting the broader ratepayer/customer interests and societal considerations consistent with Vermont law;
- The proposed AMI Implementation Plan and Business Case have clearly defined goals, implementation schedules and evaluation criteria;
- The proposed AMI Implementation Plan and Business Case include specific functional and operational applications and capabilities;
- The potential rate impact attributable to the AMI Implementation Plan is just and reasonable;
- The AMI Implementation Plan and Business Case include provisions for customer education and outreach, and explain how the DU will coordinate customer outreach related to proposed Dynamic Pricing, AMI-enabled rate designs and/or Demand Response programs; and
- The AMI Implementation Plan and Business Case include full cost recovery provisions consistent with the ratemaking policies set out in the MOU.

MOU at 14–15.

42. The parties agree that Vermont DUs would be granted the full return of and return on prudently incurred capital expenditures, operating expenses, and the net book value (less any

salvage) of the premature retirement of meters and other related assets removed from service that are compliant in all material respects with the provisions of an approved AMI Implementation Plan. MOU at 15–17.

43. The MOU states that the rate of return on AMI capital expenditures would be the same as the authorized weighted average cost of capital granted for the rate base in the DU's most recent general rate proceeding, or an equivalent measure that may apply to a cooperative or municipal DU. MOU at 15–16.

44. The parties agree that the depreciation rate would be stated in the utility's filing. The MOU provides for an initial depreciation rate not less than 10%, although the depreciation rate would actually be determined giving consideration to the assets' expected service life and to technical obsolescence. MOU at 16.

45. For municipal and cooperative DUs, the MOU provides that approval of an AMI Implementation Plan would include appropriate cost-recovery assurances designed to provide a similar level of risk mitigation as are provided for investor-owned utilities. MOU at 16.

46. The MOU specifies that amortization of prematurely retired investments would be accelerated over a reasonably short period of time. In setting the accelerated depreciation period (which the MOU states would normally not exceed five years), the Board would consider the overall rate impact of the proposed AMI Implementation Plan. MOU at 16.

47. The parties agree that each utility would be required to periodically update the Business Case contained within an approved AMI Implementation Plan. MOU at 15–17.

48. The MOU states that once costs incurred under an approved AMI Implementation Plan are included in a DU's cost of service and allowed into rates, the costs could not be subsequently disallowed on any prudence, used and useful or other grounds. MOU at 17.

49. The MOU permits a DU to seek cost-recovery assurances, consistent with normal statutes, rules, policies and practices associated with such exceptions. MOU at 17.

50. The MOU provides that any Vermont DU operating under an Alternative Regulation Plan ("ARP") that contains non-power and or non-commodity cost caps could request the Board to adjust those caps when costs incurred pursuant to an Approved AMI Implementation Plan have not been adequately considered in initially setting the ARP's caps. MOU at 17.

51. The parties agree that the Board should apply the MOU standards in its review of a DU's AMI Implementation Plan and that any such determination will be final as to the prudence or reasonableness of said DU' s strategy for the introduction of AMI within the DU's service area. MOU at 14–17, 20.

52. The MOU provides that it does not affect existing investments in Smart Grid technologies, such as breaker and switch control systems, that utilities are presently making. MOU at 17.

F. Alternative Rate Designs

53. DUs are charged with the responsibility to maintain appropriate rate designs for the services provided to consumers. These rate designs are embedded in the tariffs filed with and approved by the Board. MOU at 26.

54. The parties to the MOU agree that rate design policies should continue to favor utility-specific strategies for pricing services to customers that are developed as a part of the DU's overall resource strategy and that specific rate designs should not be statutorily mandated. MOU at 26.

55. Historically, the Board has adopted rate design policies that encourage DUs to price electricity as close to marginal cost as reasonably possible. These policies have also generally reflected the daily marginal cost differences in peak and off-peak electricity. As a result of a DU setting its kWh price close to marginal cost, the policies have resulted in the customer charge being set residually. MOU at 26.

56. The parties anticipate that new Dynamic Pricing and rate designs enabled by AMI will provide DUs new opportunities to adjust their rate designs to promote efficiency principles and send better signals to consumers about the costs that their consumption imposes on the electric system. MOU at 26–27.

General Provisions

57. The MOU provides that the Board will have jurisdiction to resolve any disputes arising from it. MOU at 27.

58. The parties agree that the Energy Efficiency Utility ("EEU") will consider, as part of comprehensive treatment of customers, providing support for emerging technology that may facilitate an electricity consumer's participation in EEU-sponsored customer energy savings programs and/or DU-sponsored Demand Response programs, Dynamic Pricing and/or rate designs. The parties also agree that the EEU should participate in the development of each utility's AMI Implementation Plan and any associated Utility-Specific MOU.[7] MOU at 18.

59. Deployment of AMI is not expected to adversely affect net metering. MOU at 7.

60. The Parties agree to engage in formal and informal collaborations among DUs, the Department, and stakeholders regarding the AMI implementation efforts of the parties. MOU at 20.

IV. Discussion

A. Overview

Efficient use of electricity has long been an area of significant focus for the Board. This has been reflected in the push in the late 1980's towards using energy efficiency investments to displace more costly supply-side alternatives and the requirement that utilities engage in least-cost planning that place demand-side investments, transmission and distribution upgrades, and distributed generation on a par with those traditional alternatives. Recently, the dialogue nationally has focused on what is generally referred to as the smart grid. As the Federal Energy Regulatory Commission ("FERC") recently characterized it:

> Smart Grid advancements will apply digital technologies to the grid, and enable real-time coordination of information from generation supply resources, demand resources, and distributed energy resources (DER). This will bring new efficiencies to the electric system through improved communication and

7. The parties to the MOU did not provide any information as to whether the additional work for the EEU contemplated by this provision is within the EEU's budget and capability. In comments upon the PFD, parties, including the EEU, should address this issue.

> coordination between utilities and with the grid, which will translate into savings in the provision of electric service.[8]

The recently passed American Recovery and Reinvestment Act echoes the importance of Smart Grid deployment, including money to support utility deployment of such systems. One component of the smart grid, the deployment of AMI or smart-metering, is the focus of this investigation.

Smart meters provide significant functionality that the meters in place at most customer premises do not have. At the most simple level, smart meters permit two-way communications from the customer's meter to the utility. This can produce operational savings, primarily through the avoidance of meter reading; the two-way communications capability avoids the need for meter readers to physically check each meter. The two-way capability also enables the utility to remotely monitor the network and determine whether power is still reaching a particular meter, thereby improving utility response to outages because the utility no longer needs to rely on the customer to report the outage. The improved communications also allow for remote connection and disconnection, saving costs for the utility through avoiding the need to dispatch personnel.

While operational savings may be significant, much of the greater expectations for smart metering and smart grid applications relates to the use of timely pricing information to influence customer usage patterns. Smart meters, coupled with some form of on-premises devices, allow utilities to more effectively implement demand-response programs and new pricing programs, including real-time pricing or programs under which consumers receive rate discounts in exchange for allowing the utility to exercise some control over certain high-demand appliances.

Nationally, most utilities are evaluating whether to deploy AMI technology and many have begun actual installation of the necessary equipment.[9] In Vermont, VEC has begun deploying smart meters; the majority of VEC's customers already have meters with two-way

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8. *Smart Grid Policy*, Docket No. PL 09-4-000, Proposed Policy Statement and Action Plan (March 19, 2009) at 1(footnote omitted).

9. MOU at 22–23 and attachment.

communications capability in place. CVPS has committed to deploy such a system as well, with an expectation that the first meters would be installed beginning in the fall of 2011.[10]

The preliminary stages of this investigation highlighted the potential that AMI deployment in the state would likely produce savings for many of the utilities solely through operational cost reductions, with further savings possible through demand-response programs.[11] Through the collaborative process, Vermont's electric utilities, CLF, and the Department developed a proposed framework under which future assessment by each utility would further refine the major issues associated with smart-metering deployment, as well as an approach for each utility to move forward and a process for Board review of such decisions. The MOU reflects the parties' agreement on these issues and establishes a framework that addresses the following:

- minimum functionality, including both metering and supporting communications infrastructure, that utilities that move towards AMI deployment should implement;
- a process for on-going assessment of the cost-effectiveness of AMI implementation;
- a process under which a DU may seek prior Board review of its AMI deployment decisions; and
- policies that would govern recovery of costs associated with AMI.

In the following sections, this Proposal for Decision examines each of these issues, as well as the consideration of alternative rate design options that the Board assigned to this docket as a means of implementing 30 V.S.A.. § 218(b).

B. Functionality of AMI Systems

The MOU sets out in some detail the minimum AMI functionality that each utility choosing to deploy an AMI system should attain. The baseline criteria include two-way communications capability, regular usage data (at least hourly), and a centralized system for managing the information being collected. In addition, the parties have identified a range of

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10. Docket 7336, Order of 9/30/08 at 21, 44; MOU at 22.

11. Some caution is appropriate when considering the potential benefits, however, particularly for the residential sector. In-home devices obviously have costs. Experience elsewhere suggests that one of the largest areas of savings that can make these devices cost-effective is central air conditioning, which few Vermont households have.

other features that any utility should consider deploying as part of its AMI plan, such as load-control capability, in-home communications systems, enhanced outage-management assessment and other options that seek to take advantage of the full range of capability that a two-way communications system can provide.

As part of AMI system deployment, a utility will need to establish communications capability between the centralized data management system, the substations, and the customer premises. The MOU addresses these needs, which, while essential, are not large by comparison to the capacity of the fiber-optic or other systems that will carry the signals. The MOU recognizes that the enhanced communications capability is expected to facilitate substation control and reliability. The parties observe that synergies may exist between the greater communications needs associated with smart meter deployment and the state's goals of expanding broadband coverage within the state.[12] However, the MOU provides that the utilities should not be required to incur costs associated with joint utility/broadband deployment that are in excess of those that the utility would incur to meet its own needs.[13]

The agreement on the basic functionality requirements set out in the MOU is reasonable and I recommend that the Board accept it. It provides a framework for any utility that seeks to deploy AMI functionality. Nonetheless, the specific elements that the parties have agreed to for the minimum functionality for all AMI systems and the potential additions that should be considered highlight both the evolving nature of AMI technology and the need to tailor the specific deployment to the costs and benefits expected to be achieved for each utility. The minimum capabilities represent an essential baseline for AMI systems, but they do little to define how extensive the system should be or the full range of capabilities (and thereby savings) that may arise as a result. The list of features ranges from relatively minor enhancements to a more comprehensive system that would enable real-time pricing or utility control of individual appliances.

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12. MOU at 10–11.

13. The utilities expect their needs to be no greater than 1.5 Mbps. This bandwidth may not be adequate for broadband functionality, particularly if it is the limit of the backhaul facilities.

These limitations should not be viewed as a problem, however. AMI deployment, as the MOU makes clear, is a potentially complex undertaking with many possible options and capabilities. The parties' agreement will provide a useful framework for utilities in evaluating the value of AMI for their systems and the specific functionality that they will implement. The baseline criteria will also help avoid implementing systems without adequate capabilities (such as meters with one-way communications capability).

C. Evaluation of AMI Deployment by Each Utility

Although the MOU and other information provided to date in this proceeding recognize the potential benefits for Vermont utilities, the cost-effectiveness of AMI for each utility varies. Similarly, the specific components of the AMI system may differ for each utility based upon the nature and extent of operational savings, and the potential for cost-effective demand-response savings. The deployment of AMI also represents a significant undertaking for many utilities. Because of these utility-specific considerations, the MOU provides that the decision to implement AMI would rest with each utility based upon its own Business Case.

The MOU also reflects the parties' views that it may not be appropriate to deploy all of the capabilities, programs and service enhancements that AMI can provide as part of the initial installation of Smart Meters. AMI technology is changing, with enhanced capabilities emerging over time. The MOU recognizes that enhanced AMI-enabled Demand Response programs, rate offerings, outage-detection capabilities, enhanced customer services, and other opportunities enabled by Smart Grid may be more appropriately phased in. The MOU provides that each DU would periodically evaluate its individual circumstances and develop appropriate implementation plans.

The MOU establishes a process for further examination of each utility's AMI deployment plans. Each utility would provide an analysis of how it meets the requirements of Section 10 of Act 92 (2007 Adj. Sess.). Following that submission, the Board would schedule a workshop to consider each utility's filings as well as the methodology for allocating power-cost savings, revenue streams associated with AMI savings, and efficiency savings of the EEU. Utilities would then, within nine months of the order approving this MOU, file more comprehensive statements on AMI implementation efforts as well as specific issues identified during the workshop process.

In general, the parties' agreement represents a reasonable approach to AMI implementation. The report of the Department's consultant highlighted the fact that the costs and benefits of smart metering vary significantly among the utilities. This applies to both operational savings and demand-response savings. In addition, the speed at which it may be appropriate to implement AMI and the specific elements of the system that a utility deploys will be different based not only upon the potential savings, but also upon the availability of capital. Another factor that may influence the deployment is the rapid evolution of AMI capabilities. For all of these reasons, the Board should accept the MOU's allowance for utilities to proceed at separate paces and with different deployment strategies.

I also recommend that the Board accept the MOU's proposed approach for moving forward (described in Finding 16, above), subject to the modification and clarification set out below. The submission of further analysis as contemplated by paragraph 59(A) of the MOU will provide useful baseline information for evaluating the current analyses by the utilities.[14] The subsequent report required by paragraph 59(C) is intended to provide "aggressive consideration of all relevant issues by the utilities, while providing time to evaluate and consider issues that may arise as the CPVS plan moves through regulatory consideration."[15] This report, the parameters of which would be defined in the workshop, would represent a comprehensive analysis of the cost-effectiveness of AMI for each utility. This structure, while delaying the full analysis until nine months from the date of approval of the MOU, would allow the utilities and other parties to further refine the range of issues by using the analysis underlying CVPS's AMI Implementation Plan as well as the regulatory review of that plan to better refine the scope of the analyses. Although it would be preferable to have this analysis completed more quickly, so that individual utilities can begin development of AMI systems if they are found to be cost-effective,

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14. The MOU specifies that this report would be filed by February 16, 2009. Obviously, this date has passed. I recommend that instead, the utilities be required to submit the analysis required by this paragraph no later than July 31, 2009.

15. Letter of February 17, 2009, from Morris Silver.

the approach set out in the MOU (as clarified by CVPS's letter of February 17, 2009) is reasonable and the Board should accept it.

The one modification that I recommend to the process set out in paragraph 59 of the MOU relates to the workshop. The MOU contemplates holding the workshop by May 1, 2009. Obviously, this is not possible. I recommend that the workshop instead occur before the end of September 2009. This would allow enough time for the Board and the parties to incorporate some of the experience arising from CVPS's anticipated AMI filing. At the same time, it would be sufficiently early to allow the utilities to incorporate the scope of issues identified at the workshop into their reports under paragraph 59(C).

My proposed clarification relates to the workshop contemplated by paragraph 59(B). The MOU provides that one of the purposes of the workshop will be to define the scope of the utilities' analyses pursuant to paragraph 59(C). This could allow significant discretion by the utilities. I recommend that the Board make clear that, absent good cause, each paragraph 59(C) report should encompass a utility-specific cost-benefit analysis. This is consistent with the recommendations made by the Department's consultant in its report and will ensure that each utility takes a serious look at the merits of AMI deployment based upon the utility's own characteristics.

D. Process for Approval/Rate Recovery

A major component of the MOU is the parties' agreement on cost-recovery principles that they request the Board to adopt. They assert that, in order to encourage utilities to move forward with AMI investments, "it is appropriate for the DPS and PSB to take steps to mitigate the regulatory risks and barriers associated with those installations and deployments and to clarify how the resulting investments, retirements, costs and expenses will be treated for rate making purposes."[16] To that end, the parties also have identified what they characterize as "important policies and procedures" designed to mitigate DU cost-recovery risks associated with the planning and implementation of other Smart Grid investments. They assert that these policies

16. MOU at 14.

will provide a consistent and uniform approach, thereby facilitating expeditious implementation of AMI by Vermont utilities.

First, the parties ask the Board to adopt a regulatory review process whereby any DU may obtain prior approval of its AMI Implementation Plan. According to the MOU, the purpose of this review would be to ensure that the proposal complies with technical design and functional specifications guidelines set out in the MOU (see Findings 17 and 18), establish and identify costs and benefits associated with the DU's proposed AMI implementation, preclude subsequent cost disallowances in future rate proceedings, and minimize the potential for reconsideration of prior decisions by the Department and Board when the AMI Implementation Plan is executed and carried out by the DU consistent with the scope of approval.[17] Significantly, the review would be optional; a utility would not need to seek prior Board approval.

Second, the parties to the MOU have set out a number of ratemaking policies that the Board would employ in the future. These policies would grant a utility full recovery of operating costs as well as full return of and on capital costs and meters replaced with new systems, provided that the utility's actions are "compliant in all material respects" with its approved AMI Implementation Plan.[18] Once costs were included in rates, they could not be subsequently disallowed. The depreciation period for AMI-related investment would be normally no greater than 10 years, although it could be reassessed as part of a utility's request for approval of its AMI Implementation Plan. These provisions would only apply to utilities that sought and obtained Board approval of an AMI plan.

The MOU raises several questions. Should the Board implement a process whereby a utility may seek pre-approval of its AMI Implementation Plan? Is a guarantee of cost recovery as set out in the MOU consistent with the standards enunciated by the Board for such a guarantee? Should the pre-approval process be mandatory or optional? And what should be the extent of any such rate guarantees?

These questions are interrelated. Turning first to the establishment of a pre-approval process, the Board has in the past adopted requirements for utilities to obtain approval of certain

17. MOU at 14–15.
18. MOU at 15–17.

initiatives even though Vermont statutes did not explicitly require such approval. The most prominent examples are the directives requiring approval of utility demand-side management programs and integrated resource plans (prior to enactment of 30 V.S.A. § 218(c)). In each of these cases, the Board's establishment of an approval requirement was directed towards ensuring that utilities met their statutory obligation to provide services on a least-cost basis. The mandatory pre-approval enabled the Board, the Department, and other stakeholders to evaluate the utilities' plans to ensure that they met the statutory obligation. It also provided the utilities with greater assurances of cost recovery.

Adoption of a pre-approval mechanism here may similarly provide greater certainty for the utilities that seek to use it, depending upon the scope of the review and the extent to which it may include cost-recovery assurances. However, there is one critical distinction — under the MOU the pre-approval mechanism is at the utility's discretion; there is no requirement that a utility seek pre-approval of AMI implementation measures or engage other stakeholders. This means that the primary function the pre-approval process serves is not to ensure review (otherwise it would be mandatory), but rather to provide assurances of cost recovery for those utilities that elect to use it.

The fact that the MOU's pre-approval process is focused on the provision of cost-recovery assurances requires consideration of the standards the Board has enunciated for guarantees of rate recovery. The Board addressed this issue extensively in Docket 6545, in which it considered a request from GMP and CVPS for guarantee of costs associated with the sale of the Vermont Yankee Nuclear Power Station. The Board concluded that under normal ratemaking principles, the utility would bear the risks associated with its investment and operating decisions (for which it received compensation through the risk premium embedded in the return on equity). This conclusion arose from the traditional balance between the Board's role as overseeing, but not managing, utility action and the utility's ability to exercise discretion in the regular operation of the business. The Board found that, as a result:

> Although the statute would permit the Board to abstain from applying these principles, as long as the resulting rates were just and reasonable, we conclude that we should only do so in rare circumstances and only when the requesting party makes a greater showing than a mere demonstration that the proposed

> transaction promoted the general good. As the Vermont Supreme Court has observed:
>
> > If a utility's income were guaranteed, the company would lose all incentive to operate in an efficient, cost-effective manner, thereby leading to higher operating costs and eventual rate increases.
>
> A party seeking to significantly alter the long-standing balance of responsibilities must make a strong showing of clear and compelling benefits to ratepayers that would not be attainable without such recovery guarantees.[19]

The Board observed that it had found the balance favoring rate guarantees only once, in the context of the Hydro-Quebec contracts.

More recently, the Board affirmed this standard in its review of a request from CVPS for cost-recovery guarantees associated with decommissioning of the Peterson Dam. The Board rejected CVPS's request, finding that CVPS had not demonstrated that the environmental benefits that may arise if the Peterson Dam were removed constituted a clear and compelling benefit that would not otherwise be attainable without such rate guarantees.[20]

Here, the parties have shown that the investment in AMI technology has significant potential benefits to Vermont ratepayers; these benefits are likely to grow over time as AMI technology evolves and enables more programs that take advantage of the ability of the network to provide accurate real-time pricing data. They have not, however, demonstrated that pre-approval of AMI implementation plans provides clear and compelling benefits "that would not be attainable without such rate recovery guarantees." In particular, the fact that the MOU makes the pre-approval process optional demonstrates that the AMI benefits *are* attainable absent rate guarantees. If all utilities are free to deploy AMI systems with no prior review by the Board and Department, then the obvious corollary is that the pre-approval process is not essential to achieving the benefits.

Nonetheless, the MOU and the experience earlier in this docket demonstrate the reasonableness of providing some measure of additional certainty to utilities considering AMI deployment. AMI implementation represents both a complex and potentially costly undertaking for most Vermont utilities. The complexity increases the more a utility attempts to take

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19. Docket 6545, Order of 6/13/02 at 98–104.

20. Docket 6905, Order of 12/22/06 at 29.

advantage of the capabilities that an AMI system may enable. AMI is likely to produce benefits for Vermont ratepayers and lead to the more efficient use of electricity, which is consistent with well-established goals of the state. Thus, I conclude that the Board should take steps to provide additional assurances to utilities that seek to deploy AMI systems through a pre-approval process. The best means to accomplish this would be to modify the optional pre-approval process to make it mandatory. This will have the benefit of allowing for the input of the Department and other stakeholders prior to AMI deployment by any particular utility, enabling the Board and those parties to provide input on changes that may be more beneficial to the utility's ratepayers. It will also provide the utility with assurances from the Board. Although the Board's approval would not constitute a rate-recovery guarantee, the Board has consistently recognized that Board approval, while not a prudence determination, has a similar effect for matters that are reviewed.[21] This procedure reconciles the MOU with long-standing ratemaking principles. Accordingly, I recommend that the Board accept the MOU subject to the condition that any utility be required to seek approval of its AMI implementation plans.

The MOU also contains very broad language concerning the scope of the rate guarantees. The Board should make clear that the rate recovery assurances granted for AMI implementation are not absolute, but instead would be consistent with existing ratemaking practices. The approval should extend only to the matters specifically reviewed and considered during the approval process. For example, if the utility has facts that are not presented to the Board, subsequent reassessment based upon these facts must be allowed.[22] Similarly, a utility bears an affirmative obligation to continue to reevaluate the merits of any action approved by the Board. If subsequent events raise questions about the reasonableness of pursuing a particular course of

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21. Docket 6545, Order of 6/13/02 at 100–101. In that docket, while the Board did not guarantee rate recovery specifically, the analysis of the proposed sale of the Vermont Yankee Nuclear Power Station suggested that the risk of rate disallowances was exceedingly small (based upon the information before the Board). It is expected that the approval process would look to provide a similar level of certainty.

22. *See* Docket 5983, Order of 2/27/98 at 220–221. As the Board observed in considering the degree to which its prior approval of the Hydro-Quebec contract would shield GMP from potential challenge:

> If, for example, prior to the Order approving the Contract with conditions, GMP had available relevant data or knowledge suggesting that the Contract was not favorable and did not make this material information available to the Board, we can and should examine whether, based upon all of the information available to the Company, GMP's entry into the Contract was reasonable.

action that has been approved (in this case, the AMI Implementation Plan), the utility's adherence to the approved plan does not provide full assurance.[23] Consistent with this obligation, the MOU makes clear that the utilities retain the responsibility to monitor their AMI implementation and adjust the Plan as appropriate. Other language in the MOU, however, suggests that a utility would be shielded from subsequent challenge so long as it continued to implement its approved AMI Implementation Plan, notwithstanding subsequent changes in the cost-benefit analysis or technology. Such a broad reading is inconsistent with well-established Board precedent.[24] Finally, since the prior approval will provide utilities with great assurance of cost-recovery, it is essential that any request for approval allow sufficient time for meaningful evaluation by the Board and other interested parties. The reasons put forth for the need for greater cost-recovery assurances are the complexity of the issues and the capital requirements; these same factors also caution against trying to unduly shorten evaluation during the approval process.

The MOU also provides that once costs are allowed into rates, they may not be subsequently disallowed. I interpret this provision to essentially bar retroactive adjustment of rates based upon a subsequent cost disallowance. As such, it is consistent with existing practice.[25]

The final cost recovery issue that merits discussion is the recovery of costs associated with prematurely retired meters and the depreciation of new equipment. The MOU provides for full recovery of the costs of meters that are removed from service. This rate treatment would normally be inconsistent with regulatory principles, as it allows recovery of costs for investment that is not actually used for utility services. In the case of AMI implementation, allowing recovery for the removed meters, where the new systems are shown to be cost-effective, is appropriate, since otherwise the undepreciated plant may create a barrier that would deter the

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23. Docket 5983, Order of 2/27/98 at 221–222; Docket 6545, Order of 6/13/02 at 100–101.

24. This does not mean that a utility must change its implementation strategy whenever technological improvements occur. Considering the evolving nature of smart-metering technology, such a standard would be impossible for a utility to meet. But, if technological or other changes call into question the utility's strategy, the regulatory certainty provided by the pre-approval process does not, and can not, provide assurance against further review of rate recovery issues.

25. It is possible that the parties intended the provision to require that any challenge to AMI implementation costs must be raised at the first time those costs are included in rates or they would be waived. If that is the intent, it is not consistent with long-standing ratemaking principles.

deployment of the AMI systems. I also recommend that the Board allow faster depreciation rates for the new investment associated with AMI. Typically, meters have been depreciated over approximately 25 years (although this varies by company). Smart metering technology is rapidly evolving; it appears likely that the capabilities that will evolve over time will provide greater capabilities that utilities may want to capture. Faster depreciation rates will facilitate such choices in the future. The MOU specifies that the default rate would be not less than 10%. This figure appears reasonable, although it should be reviewed in the context of each company's request for approval of its AMI Implementation Plan.

D. Rate Designs

Section 218(b) of Title 30 (as amended by Act 192 (2007 Adj. Sess.)) requires the Board to investigate alternative rate designs that would encourage more efficient use of electricity. This includes both the possibility of residential inclining block rate designs and expansion of critical-peak-pricing programs or time-of-day rates. In addition, the Board expanded the scope of the examination of rate designs in this proceeding to encompass consideration of the appropriate level of customer charges.

The MOU addresses the requirements of Section 218(b) in two ways. The MOU and the parties' analysis through the collaborative process were aimed largely towards evaluating the scope of issues that required consideration as part of prospective deployment of AMI technology, thereby facilitating such deployment. As a utility actual deploys advanced-metering capabilities, it will then be able to implement rate designs that take advantage of the new technology. The specific rate design options that may be both available and appropriate for implementation will depend on the capabilities of the system that the utility deploys and the utility's own characteristics. These issues will be explored as part of each utility's implementation process. Thus, the parties have reached agreement that the appropriate time for evaluation of the rate designs that should accompany smart-metering implementation is during the planning, pre-approval, and deployment of those systems.[26]

26. MOU at 23, 28–30.

As for examination of alternative rate designs that could (a) be implemented separate and apart from AMI technology and (b) could produce energy savings, the MOU does not demonstrate that the parties conducted the full analysis contemplated by the legislature. In general, the parties consider the implementation of rate designs to be a choice that each DU will undertake on its own.[27] In addition, the parties note that the Board has traditionally adopted rate design policies that encourage DUs to price electricity as close to marginal cost as reasonably possible and they recommend continuation of this practice.[28] The parties also conclude that mandatory inclining-block rate designs limit the options for DUs and have the potential to distort the pricing signals sent to consumers, thereby reducing societal efficiency.

The MOU does not, however, reflect a full consideration of whether alternative rate design options could encourage the efficient use of electricity as contemplated by Section 218(b). For example, would an inclining-block rate structure achieve this result, even if it may deviate from the rate design pricing methodology and signals the Board has traditionally used? Would more extensive use of critical-peak-pricing programs produce sufficient benefits that the Board should require other utilities to adopt them? Conversely, would any efficiency gains from such rate designs be outweighed by losing the connection between energy rates and the marginal energy costs?

To fully meet the legislature's intent, I recommend that an additional workshop be held in this proceeding on rate design issues to examine these questions.[29] The workshop should also be used to consider the question referred to this docket by the Board: how should the customer charge be set? The Department, in consultation with the parties, should be requested to develop a proposed agenda for the workshop (which would be held in September) by August 7, 2009.[30]

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27. MOU at 23.

28. MOU at 23.

29. This additional review is consistent with the parties' agreement in the MOU. Letter of 2/17/09 from Morris Silver, Counsel for CVPS.

30. Consistent with earlier rulings in this proceeding, the evaluation of rate design options will continue to be treated as a non-contested case.

V. Conclusion

For the reasons set out above, I recommend that the Board approve the MOU, subject to the conditions and modifications set out herein.

This Proposal for Decision has been served on all parties to this proceeding in accordance with 3 V.S.A. § 811.

Dated at Montpelier, Vermont, this 31st day of July, 2009.

s/George E. Young
George E. Young
Hearing Officer

VI. BOARD DISCUSSION

The Group of Municipal Electric Utilities, GMP, CVPS, BED, VEC, WEC, and Vermont Marble (collectively, the "Utilities") and the Department filed comments asking that we modify certain aspects of the Hearing Officer's Proposal for Decision ("PFD"). For the most part, the parties support the PFD, which accepts the majority of the MOU prepared by the parties. The parties' disagreement with the PFD focuses on the areas of pre-approval and cost recovery. We address each of the issues raised by the parties below.

A. Pre-Approval of AMI Implementation Plans

The PFD recommends modifying the MOU to require that a utility seeking to implement AMI be required to obtain pre-approval of its AMI implementation plan from the Board. The MOU had provided a pre-approval process, but use of this mechanism was at the discretion of each utility. The Utilities object to the Hearing Officer's recommended change, which they argue is based upon a misconception of the settling parties' intent and may not be consistent with aggressive AMI implementation. The Utilities assert that the Hearing Officer mistakenly links the pre-approval and cost-recovery provisions of the MOU. They argue that for large scale projects, both pre-approval and cost-recovery guarantees may be appropriate, but maintain that some utilities may implement AMI in a more incremental manner, which decreases the need for either pre-approval or rate guarantees.

The Department also argues that pre-approval should be an option and not mandatory. According to the Department, utilities are in the best position to determine whether pre-approval should be required.

We do not agree with the Utilities that the PFD misconceives the connection between pre-approval and cost recovery. The MOU makes clear the inherent link between the two: under the MOU, a utility that obtains pre-approval receives the benefit of cost recovery, whereas one that elects not to seek pre-approval obtains no assurances that it will recover its costs. The MOU also sets out no further benefits of pre-approval. It is hard to imagine a more direct connection. The Utilities' comments on the PFD, while objecting to the relationship, in fact, underscore it by pointing out that regulatory assurances coupled with pre-approval are likely needed where a utility seeks to make a significant investment.

The parties' objection to the mandatory pre-approval process also fails to address the underlying rationale that led the Hearing Officer to recommend it. The MOU makes clear the parties' desire for a mechanism by which some utilities could obtain guarantees of cost recovery. As the PFD explains, under existing Board precedent, the Board does not provide such guarantees absent a clear public benefit that could not be obtained other than by providing the guarantee. The Hearing Officer found, and the parties do not contest, that that test had not been met. The mandatory pre-approval process was intended as a constructive mechanism by which the distribution utilities could still obtain some measure of rate-recovery assurance.

Nonetheless, we have concluded that we should modify the PFD to remove the mandatory pre-approval requirement. Instead, we will accept the parties' recommendation and retain the pre-approval as an option.

We reach this conclusion largely because of our desire to provide incentives for utilities to aggressively pursue AMI implementation where their analysis shows that it is expected to be cost-effective. The Hearing Officer's analysis focused on our established test for cost-recovery guarantees. That standard does not, however, take into account situations such as smart-metering where it may be appropriate to provide special incentives to utilities to encourage investments that are likely to provide least-cost electricity services to customers over a sustained period of time. We recognized such values years ago in the context of demand-side management ("DSM") programs. It is appropriate to adopt special consideration for AMI to provide similar incentives. In particular, at the present time, utilities have the potential to obtain substantial funding under the American Recovery and Reinvestment Act of 2009 ("ARRA"). The incentives we create by establishing the pre-approval mechanism should encourage utilities to move quickly in deploying AMI by taking advantage of this funding.

We are also persuaded that the mandatory pre-approval process may encompass some small-scale investments that should not require review and approval. While we have decided to make the pre-approval discretionary so as to exclude such projects, we want to make clear that we expect that any utility AMI implementation plan that is significant in scope will be submitted to the Board for review and approval. The determination of significance should be based upon each utility's specific circumstances and the scope and cost of the AMI project relative to the utility's overall costs. We also expect to continue to monitor utility progress towards AMI deployment and may require pre-approval in particular circumstances. We expect this judgment to be informed by the analysis of the cost-effectiveness of AMI deployment that each utility is required to develop by paragraph 59(C) of the MOU. Where that analysis shows that a large-scale implementation of AMI would be cost-effective for a particular utility, we may direct the utility to seek pre-approval. At this time, however, we have insufficient information on the costs and benefits for each utility, so will simply adopt the MOU provision allowing the utility discretion to seek pre-approval.

The special rate treatment and the process for pre-approval that we accept today are not permanent adjustments. Instead, we adopt them to encourage utilities to move to take advantage of the opportunities provided to reduce costs for themselves and their customers that smart metering offers. The ARRA funding that will assist in this effort, and that we seek to help utilities to obtain, is for a limited duration. The technology that companies are likely to implement is also changing, so that it is difficult to assess whether these ratemaking principles will remain appropriate in the future. Thus, we limit the availability of the optional process for utilities to obtain pre-approval and rate guarantees to AMI implementation plans submitted between now and four years from the date of this Order. We will then reevaluate whether any special accommodations are appropriate.

B. Cost-Recovery Guarantees

The PFD contains a number of clarifications and interpretations of the MOU provisions related to cost-recovery. In large part, the Utilities agree with these recommendations. As a result, any utility that receives pre-approval of its AMI Implementation Plan has some assurances of cost-recovery for the investments made under that Plan. As the PFD explains, the Board has consistently recognized that Board approval, while not a prudence determination, has a similar effect for matters that are reviewed. This assurance is not absolute, as the Utilities recognize. Each utility retains the responsibility to implement approved measures in a reasonable manner and continually reevaluate the merits of its Plan and particular investments. The Board's approval of the Plan does not extend to matters not reviewed or disclosed or to the manner in which utilities adapt their implementation plans (or decline to adapt them) in response to subsequent events that may change the cost-effectiveness and thus the reasonableness of a deployment strategy.

Although they accept these conditions, the Utilities object to the Hearing Officer's statement that, if Paragraph 47 of the MOU were interpreted to require a challenge to any AMI implementation costs the first time those costs are included in rates, it would be inconsistent with long-standing ratemaking principles. The Utilities assert that they did intend the MOU to alter those traditional principles by limiting the opportunity for "look back reviews" of investments that have already occurred and "that were reviewed, approved, and implemented under an approved AMI Plan."[31] In particular, the Utilities are concerned about the prospect of later application of the economic "used and useful" test that could result in disallowance of costs associated with AMI even though the initial deployment decision was rational and cost-effective. The Utilities thus seek assurance that the economic used-and-useful test will not be applied to disallow costs due to technological changes or a drop in the price of meters. In support of this argument, the Utilities point to the fact that the Board has granted such certainty of cost recovery in the context of DSM programs, so as to remove a disincentive to such investments.

The Department agrees with the Hearing Officer's analysis of the principles the Board has applied to guarantees of cost recovery. Nonetheless, the Department observes that the utilities are concerned about the potential application of the used-and-useful test. Recognizing that government policy-makers have been encouraging rapid deployment of smart-metering systems, the Department recommends that the Board go beyond traditional practices and provide some measure of protection to utilities against such disallowances.

We are not persuaded that we should modify existing ratemaking practices to require any challenge to costs to be made the first time such costs are included in rates. Such an approach would require a party, such as the Department, or the Board to investigate each investment immediately or face the prospect of not being able to review that investment later. As a result, it

31. Utilities' Comments at 8.

is likely to force evaluation of cost additions that would likely never be contested, simply as a precaution, and could thereby raise the regulatory costs for utilities. In addition, with Vermont's two largest electric utilities under alternative regulation plans that include annual rate adjustments, it would complicate and perhaps lengthen the annual review process.

It also is not clear that the utilities would derive significant benefits from the limit on challenging investments. Although the Utilities suggest that their proposed standard would avoid what they call "look back reviews" into investments that had already been made, this will be true even if the evaluation and challenge must be made immediately. Any review by the Board or parties will, of necessity, be based upon investments that have already been made and which represent sunk costs. We recognize that the Utilities' proposal could limit the exposure to disallowances by having the overall investment scheme be reviewed more regularly, however, we do not find that this provides sufficient benefits when considered against the costs and difficulties.[32]

Finally, the Utilities already have an ability to protect themselves if they are concerned about disallowances reaching back a substantial amount of time. The limitation proposed by the Utilities would only apply if an individual utility had sought and received pre-approval of its AMI Implementation Plan. The utility would thereby have already obtained substantial certainty of cost-recovery as explained in the PFD and above. If significant changes had occurred that may call into question the reasonableness of continuing deployment or of changing implementation plans, the utility would be able to protect itself by seeking approval of a modified Plan.

The Utilities' concern about the application of the economic used-and-useful test to the AMI investments has more merit. AMI and smart-metering is an evolving field. A national effort is now underway to set standards for various aspects of the smart grid, including the devices in the customer's premises that will help optimize the use of energy. Since changes are likely to occur over time, with more enhanced meters and more sophisticated devices for communicating with customers, any early adoption has some risk that in five or ten years new

32. We also find it curious that the utilities are seeking to limit pre-approval requirements to allow more flexibility and limit costs for utilities while at the same time requiring immediate assessment of AMI investments that would have the effect of increasing regulatory costs, perhaps significantly.

technology will exist with greater benefits. The MOU, which the Hearing Officer accepts, partially addresses this concern through accelerated depreciation rates. But we agree with the Utilities that it is reasonable to provide a greater level of assurance. We have previously concluded that, where it would not be unfair to ratepayers, "the traditional used-and-useful test need not be stringently applied if a greater recovery is 'necessary to ensure efficiency and progress in the art and continued attraction of capital to the enterprise.'"[33] Applying this test, we have treated certain costs as if they were used-and-useful, even if they might otherwise be subject to exclusion from rates based upon that principle as traditionally implied.[34] Based upon the considerations set out in the PFD, including the risks associated with technological changes, we conclude that utility investments as part of an approved AMI Implementation Plan should be treated *as if* they are economically used-and-useful.

Our determination on the treatment of these investments under the economic used-and-useful test is subject to the same limitations that apply to assurances of rate-recovery under the prudence standard. It only applies to investments and expenses reviewed during the pre-approval process. Moreover, the utility bears a continuing obligation to monitor and adapt its Plan in light of changing circumstances. Our determination that a Plan is acceptable will not shield a utility from a subsequent investigation and potential disallowance based upon the economic used-and-useful principle if events following approval should have led to an alteration of the AMI deployment.

C. Future Filings

The MOU specified that the electric utilities would file certain baseline information on February 16, 2009.[35] Due to the passage of time, the Hearing Officer recommends a new date of July 31, 2009. The Utilities request that we modify the PFD to defer the filing until October 31, 2009. According to the utilities, this later filing is needed because the time for filing is short, the utilities are focused on implementation plans and the immediate need to file applications for

33. Docket 5132, Order of 5/15/87 at 132–133, n. 43 (citations omitted).
34. *See* Docket 6107, Order of 1/23/01 at 80–81.
35. MOU at ¶ 59(A).

federal funding of AMI programs under the ARRA, and a delay will allow parties to benefit from a workshop in September (as recommended by the PFD). The Department supports the Utilities' request.

We agree with the parties' recommended change to the filing date. The filing contemplated by paragraph 59(A) of the MOU will be due on October 31, 2009.

D. Submission of Aggregate Analysis by GMEU members

The PFD recommends that the reports due under paragraph 59(C) of the MOU should encompass a utility-specific cost-benefit analysis. The Utilities contend that "[a]ggregation of efforts by some or all of the GMEU members may well enhance both the quality of those efforts and an ultimate cost effective implementation of AMI measures." Accordingly, the Utilities seek clarification that GMEU members may submit aggregate filings.

We accept the Utilities' proposed clarification and will permit some or all of the GMEU members to submit the paragraph 59(C) filing jointly. It is possible, if not likely, that a collaborative effort of some or all of these utilities may be more cost-effective than separate implementation. For example, many of the potential benefits of smart-metering require a data management system. The smaller utilities may find it more cost-effective to invest jointly in such a system. An aggregated filing could reflect the benefits of joint implementation efforts and thus is permissible.

E. EEU

The PFD requested parties to provide comments as to whether the additional work for the EEU contemplated by Paragraph 58 of the MOU was within the EEU's budget and capability. No party commented. The Board will pursue this matter directly with the EEU to ensure that it can meet these duties along with its other obligations.

VII. ORDER

IT IS HEREBY ORDERED, ADJUDGED, AND DECREED by the Public Service Board of the State of Vermont that:

1. The findings and recommendations of the Hearing Officer are adopted, except as modified herein.

2. The Memorandum of Understanding ("MOU") among the participants to the Collaborative Process is approved, subject to the modifications set out in this Order.

3. By August 28, 2009, the Vermont Department of Public Service, in consultation with other parties, shall propose an agenda for a workshop to examine alternative rate designs.

4. This proceeding is remanded to the Hearing Officer for further proceedings consistent with this Order, including the compliance filings contemplated by Paragraph 59 of the MOU.

Dated at Montpelier, Vermont, this 3rd day of August, 2009.

s/James Volz)	PUBLIC SERVICE
s/David C. Coen)	BOARD
s/John D. Burke)	OF VERMONT

OFFICE OF THE CLERK

FILED: August 3, 2009

ATTEST: s/Susan M. Hudson
Clerk of the Board

NOTICE TO READERS: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Board (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: psb.clerk@state.vt.us)

Appeal of this decision to the Supreme Court of Vermont must be filed with the Clerk of the Board within thirty days. Appeal will not stay the effect of this Order, absent further Order by this Board or appropriate action by the Supreme Court of Vermont. Motions for reconsideration or stay, if any, must be filed with the Clerk of the Board within ten days of the date of this decision and order.